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The Role of Thermal Storage in Nuclear Hybrid Energy Systems

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Abstract

Electricity systems with increasing shares of variable renewable energy sources are characterized by stronger price volatility, more frequent periods of very low or negative prices, and a growing need for operational flexibility. In this context, large light-water nuclear plants, traditionally operated as steady baseload units, may face reduced market value if they cannot adapt output to price signals without incurring efficiency penalties, additional wear, or constraints on safe operation.

Thermal Energy Storage offers a pathway to decouple reactor heat production from electricity generation, allowing the nuclear island to remain at high thermal utilization while shifting electrical output in time. This thesis explores Thermal Energy Storage as a flexibility option for nuclear systems and frames its potential both as a market-value enhancer and as a tool to reduce the occurrence of uneconomic operation during oversupply periods.

The work first reviews integration concepts and key design choices for coupling Thermal Energy Storage with nuclear plants. It then develops and evaluates a specific hybrid configuration in which a $1GW_e$ nuclear unit charges a two-tank molten-salt Thermal Energy Storage via a steam Compressor Heat Pump, optionally supported by an Electrical Heater, and discharges through a dedicated peaker steam Rankine cycle. The techno-economic performance is quantified with an optimization model that determines the optimal dispatch and sizing of components under representative electricity market conditions, reporting operational indicators (Round Trip Efficiency, Capture prices, Capture rates and Capacity Factors) and economic metrics (Levelized Cost Of Energy). Four scenarios (no storage, integration with Electrical Heater, integration with Heat Pump, integration with both Electrical Heater and Heat Pump) are assessed for three European spot markets (Poland, Germany, France).

Results indicate that Thermal Energy Storage systematically reduces exposure to negative-price periods by diverting part of the reactor output to heat storage and helps generating electricity during higher-price hours. Heat-pump charging delivers high electric round-trip efficiencies, whereas heater-only charging remains lower. Optimal operation requires

extracting a limited share of boiler steam for the Compressor Heat Pump and baseload turbine electricity for both the Heat Pump and the Electrical Heater, when deployed. Economically, Heat Pump-based configurations can increase the Total Capture Price of the integrated system but also introduce significant additional costs, making profitability sensitive to assumed inputs. Under an energy-only arbitrage framework, the investment case is strongest in markets with higher price volatility and may require complementary revenues as prices spreads narrow.

Riassunto

I sistemi elettrici caratterizzati da quote crescenti di fonti rinnovabili variabili presentano una maggiore volatilità dei prezzi, una frequenza più elevata di periodi con prezzi molto bassi o negativi e un fabbisogno crescente di flessibilità operativa. In questo contesto, i grandi impianti nucleari ad acqua leggera, tradizionalmente gestite come unità di baseload costante, possono subire una riduzione del proprio valore di mercato qualora non siano in grado di adattare la produzione ai segnali di prezzo senza incorrere in riduzioni di efficienza, maggiore usura o vincoli legati alla sicurezza operativa.

Lo stoccaggio di energia termica (Thermal Energy Storage) offre una possibile soluzione per disaccoppiare la produzione di calore del reattore dalla generazione di elettricità, consentendo all'impianto nucleare di essere utilizzato più frequentemente mentre la produzione elettrica viene spostata nel tempo. Questa tesi analizza il Thermal Energy Storage come opzione di flessibilità per i sistemi nucleari, inquadrandone il potenziale sia come strumento di incremento del valore di mercato sia come mezzo per ridurre il ricorso a operazioni economicamente svantaggiose durante periodi di eccesso di offerta.

Il lavoro presenta innanzitutto una rassegna dei concetti di integrazione e delle principali scelte progettuali per l'accoppiamento del Thermal Energy Storage con le centrali nucleari. Successivamente, sviluppa e valuta una configurazione ibrida specifica in cui un'unità nucleare da 1 GWe carica un sistema di stoccaggio termico a sali fusi a due serbatoi mediante una pompa di calore a compressione di vapore (Compressor Heat Pump), eventualmente supportata da un riscaldatore elettrico, e scarica l'energia accumulata attraverso un ciclo Rankine a vapore dedicato di tipo peaker. Le prestazioni economiche sono quantificate tramite un modello di ottimizzazione che determina il dispacciamento ottimale e il dimensionamento dei componenti sotto condizioni rappresentative dei mercati elettrici, restituendo indicatori operativi (rendimento di andata e ritorno, prezzi di cattura, tassi di cattura e fattori di capacità) e metriche economiche (costo livellato dell'energia, LCOE). Vengono analizzati quattro scenari (assenza di stoccaggio, integrazione dello stoccaggio con riscaldatore elettrico, integrazione con pompa di calore, integrazione sia con riscaldatore elettrico che con pompa di calore) per tre mercati elettrici europei (Polonia, Germania, Francia).

I risultati indicano che il Thermal Energy Storage riduce sistematicamente l'esposizione ai periodi di prezzo negativo, deviando parte della produzione del reattore verso lo stoccaggio termico, e consente di generare elettricità nelle ore caratterizzate da prezzi più elevati. La carica tramite pompa di calore consente di ottenere elevati rendimenti elettrici di andata e ritorno, mentre la carica basata esclusivamente su riscaldatore elettrico presenta rendimenti inferiori. Un funzionamento ottimale richiede l'estrazione di una quota limitata di vapore dalla ciclo Rankine baseload per alimentare la pompa di calore a compressione e l'utilizzo dell'elettricità della turbina baseload per alimentare sia la pompa di calore che il riscaldatore elettrico, quando presente. Dal punto di vista economico, le configurazioni basate su pompe di calore possono aumentare il prezzo di cattura totale del sistema integrato, ma introducono anche costi aggiuntivi significativi, rendendo la redditività fortemente sensibile alle ipotesi di input adottate. In un contesto limitato al solo arbitraggio energetico, il caso di investimento risulta più solido nei mercati caratterizzati da maggiore volatilità dei prezzi e può richiedere entrate complementari man mano che gli spread di prezzo si riducono.

Preface

This Master's Thesis was written at the Department of Electric Energy (IEL) at the Norwegian University of Science and Technology (NTNU). The Master's Thesis was carried out during the autumn semester of 2025, as part of the Erasmus project from the University of Padua (UNIPD). The work was carried out in cooperation with Quantified Carbon.

I would like to thank my supervisor at UNIPD, Anna Stoppato, for allowing me to have this unique experience abroad and for helping and coordinating my work.

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Nomenclature

BWR Boiling Water Reactor

CF Capacity Factor

CHP Combined Heat and Power

CoHP Compressor Heat Pump

COP Coefficient Of Performance

C Capacity

DE Germany

EH Electrical Heater

FR France

FSD Flash Steam Drum

HP-TES Heat Pumped-Thermal Energy Storage

HPT High Pressure Turbine

HP Heat Pump

HTF Heat-Transfer Fluid

HX Heat Exchanger

IPT Intermediate Pressure Turbine

LCOE Levelized Cost Of Energy

LPT Low Pressure Turbine

LWR Light Water Reactor

NPP Nuclear Power Plant

PCM Phase-Change Material

PL	Poland
PP	Power Plant
PSRC	Primary Steam Rankine Cycle
PT	Peaker Turbine
PWR	Pressurized Water Reactor
RH	Resistive Heater
RTE	Round Trip Efficiency
S./S. HX	Steam/Salts Heat Exchanger
SG	Steam Generator
SSRC	Secondary Steam Rankine Cycle
TES	Thermal Energy Storage

1 Introduction

1.1 Background and Motivation

The rapid expansion of wind and solar power is changing how electric power systems operate. In modern power systems with high shares of wind and solar, variable renewable generation is effectively dispatched first because it has very low marginal operating costs and, in many cases, priority access to the grid. Conventional baseload, mid-merit, and peaking plants increasingly operate on the residual load that remains after renewable generation. When wind and solar output is high, electricity prices often become very low or even negative, whereas when their output is low, prices can increase sharply. This greater variability creates operational and economic challenges for technologies designed to run at steady baseload, such as large light-water nuclear reactors.

Nuclear Power Plants (NPPs) can operate in load-following mode, but this approach has several drawbacks. Reducing electrical output lowers total energy sales and often decreases average thermodynamic efficiency, while frequent power changes increase thermal and mechanical cycling of components and make reactivity control and fuel management more complex [1, 2, 3, 4].

These limitations become more relevant in power systems with growing shares of wind and solar. Since both nuclear and variable renewables are capital-intensive technologies with low marginal operating costs, they increasingly compete for the same low-price hours. This can either force nuclear units to reduce output or lead to curtailment of renewable generation. In both cases, low-carbon assets are used less effectively and overall profitability declines, which is why nuclear and rapidly expanding renewables are often seen as a poor match when they are simply added to the existing system and operated conventionally.

An alternative is to integrate nuclear, renewables, and flexibility options, such as energy storage, into coordinated hybrid energy systems. However, these hybrids also introduce challenges. They require more advanced control strategies, because electricity production, heat delivery, storage charging/discharging, and industrial demand must be coordinated in real time. In addition, they depend on business models and market arrangements that can properly value multiple outputs from a single facility, as well as regulatory frameworks able to address the tighter coupling between nuclear units, storage technologies, renewables, and industrial loads. High upfront capital costs, long construction times, and persistent issues of public acceptance for nuclear projects remain important constraints [5, 6, 7].

On the other hand, designing them as complementary parts of integrated hybrid energy systems has some advantages [8, 9]. In these systems, nuclear reactors, renewable generators, energy storage and industrial processes are planned and controlled together as one coordinated facility. Operating these low-carbon technologies in an integrated way can increase the effective utilisation of nuclear and renewable generation, reduce CO_2 emissions in both the power system and in industrial heat supply, and improve the use of shared infrastructure such as grid connections, steam pipelines and cooling systems. Therefore, these hybrids are not a universal solution, but an option that may be attractive under specific local conditions, such as high renewable penetration, strong policy support for decarbonizing industry and suitable electricity-market designs.

Coupling nuclear power plants with Thermal Energy Storage (TES) is a promising way to provide the flexibility that modern power systems require [10, 3, 11, 12, 13].

TES decouples the production of heat in the reactor from the conversion of that heat into electricity. The reactor can operate at nearly constant thermal output, close to its optimal operating point, while surplus heat is stored when electricity prices are low or renewable output is high. The stored energy can then be discharged later, either to generate electricity during peak-price periods or to provide heat to industrial processes, district heating networks, hydrogen production or desalination processes. In this way, TES reduces the need to ramp the reactor itself and allows the plant to respond to market signals without deep cycling of the core.

A nuclear–TES hybrid offers several system-level advantages.

It provides reliable, dispatchable capacity that can follow rapid changes in net load by charging or discharging the storage, instead of changing reactor power. Many TES technologies are suitable for large-scale and long-duration energy storage and can be more cost-effective than electrochemical batteries [11, 14]. By operating the reactor at a more nearly constant power level, instead of frequently ramping up and down, TES supports high capacity factors, improves fuel utilization and reduces wear on components, with potential benefits for both economics and safety margins. In systems with high shares of wind and solar, nuclear–TES units can also help to absorb excess renewable generation and reduce curtailment, while still guaranteeing firm low-carbon capacity when renewable output is low. However, even in these kind of grids, nuclear–TES is not yet widely deployed because integrating TES with nuclear power plants introduces design and safety questions, adds regulatory uncertainty, and still lacks enough validated compatibility/performance evidence to mitigate risk investment and commercialization [10, 15].

Within this context, the present work investigates TES as a key enabling technology for flexible nuclear operation in power systems with high renewables penetration and increasing demand for low-carbon industrial heat.
Although several nuclear–TES concepts have been proposed, the field is still relatively new and is largely based on modelling studies, with limited experimental validation. Moreover, many coupling layouts have been suggested but a systematic selection methods and further demonstration are still needed [10, 16].
The thesis reviews promising nuclear–TES integration layouts and assesses their technical performance and economic implications when embedded in broader nuclear–renewable hybrids. The objective is to identify the conditions under which these systems can effectively reduce renewable curtailment, maintain high reactor capacity factors, deliver competitive low-carbon energy services and to clarify the main technical and economic trade-offs associated with their deployment.

1.2 Project Description

Coupling nuclear power plants with TES keeps the reactor at steady thermal output while the power block follows demand.
During periods of high renewable generation and low prices, steam from the main cycle is routed to a high-temperature Compressor Heat Pump (CoHP) to heat the storage medium. In a Heat Pumped-Thermal Energy Storage (HP-TES) setup, a fraction of the main-cycle electricity drives the heat pump to charge the TES; an auxiliary Electrical/Resistive Heater (EH/RH) can be added to increase the charging rate and further

widen the temperature gap when needed. Because the HP-TES load is controllable on short timescales, it provides an additional lever for fast, flexible operation.
When the system becomes capacity-constrained or prices rise, the store discharges by supplying heat to a Secondary Steam Rankine Cycle (SSRC) Peaker Turbine, boosting electrical output without cycling the core.

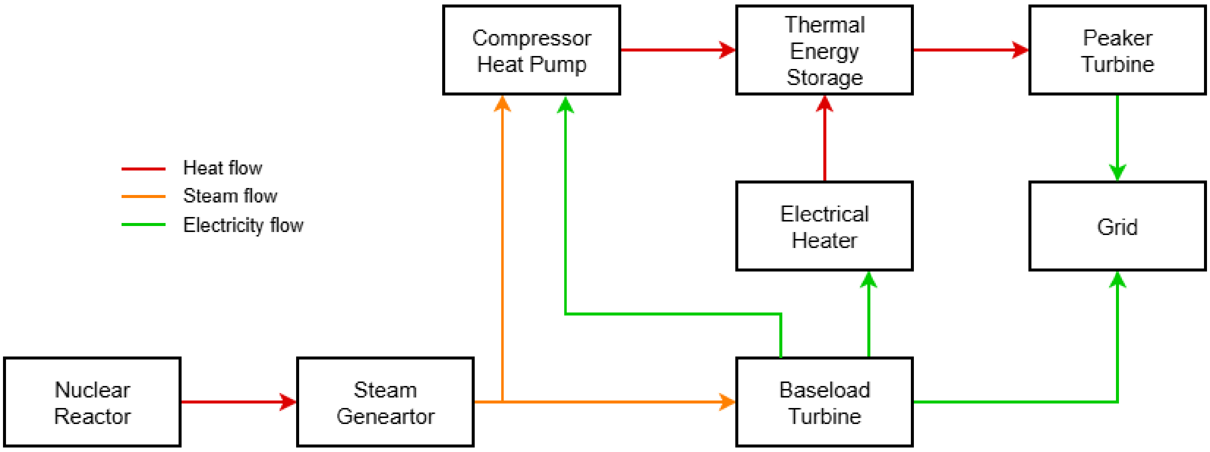

Figure 1.1: *Simplified graphical representation of the studied system.*

The storage option considered is molten salts sensible-heat system, because it is one of the most mature at large scale.
On the market side, flexibility is linked to different metrics:

- Perturbation magnitude of spot market hour prices lower than 0 EUR/MWh and higher than 200 EUR/MWh that represents how the market volatility changes.
- Capture prices and Capture rates (value factor).
- Utilization/Capacity Factor (CF).
- Levelized Cost Of Energy (LCOE).

All these parameters are calculated once the Coefficient Of Performance (COP) of the CoHP and the efficiency of the Peaker Turbine (PT) are known, which derive from an assumed system layout design.
The calculations are finally performed through an optimization model provided by Quantified Carbon (QC), an international energy consultancy firm.
In particular, four different scenarios are simulated and compared in three different electricity markets (Poland, France and Germany):

- Baseload power plant without the TES.
- Implementation of a SSRC working with a TES heated by a EH.
- Implementation of a SSRC working with a TES heated by a CoHP.
- Implementation of a SSRC working with a TES heated by a EH and a CoHP.

The overall aim is to identify which NPP–TES configuration provides the best balance between operational flexibility and economic performance across the three different electricity markets while reducing market volatility, by decreasing the frequency of very low or negative price hours and by limiting exposure to scarcity-driven price peaks.

Here, operational flexibility refers to the ability of the integrated plant to shift electricity production in time, storing reactor heat when prices are low and releasing it when prices are high, so that the reactor can run more steadily while the electrical output remains dispatchable. Economic performance refers to whether this added flexibility increases revenues enough to justify the additional investment.

To do this, the four scenarios and the three markets are compared after having exploited and collected the results from the optimization-based dispatch model by QC. The assessment considers not only efficiency and cost metrics, but also how the integrated system affects the market itself and the reactor capacity factor, since a key goal is to preserve a high annual utilization of the nuclear unit while still enabling flexible delivery through the TES.

2 Theory

2.1 Light Water Reactors

Light Water Reactors (LWRs) are thermal nuclear reactors that use ordinary water both as coolant and as neutron moderator. The two main commercial types are Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs). In a PWR, water in the primary circuit is kept at high pressure to avoid boiling, and heat is transferred to a secondary circuit through steam generators. Steam produced in the secondary circuit then drives the turbine. In a BWR, water boils directly in the reactor vessel and the generated steam is sent to the turbine.

LWR technology is mature and widely deployed. Several decades of operating experience have led to standardized designs, established operating procedures and high reliability. Modern LWRs incorporate several layers of safety measures, including multiple barriers between the fuel and the environment, large volumes of water for cooling, and engineered safety systems. Many recent designs also include passive safety functions that can remove decay heat for a certain time using natural circulation and gravity, without relying on powered equipment. In normal operation, LWRs can achieve high availability and high capacity factors, making them important sources of low-carbon, dispatchable electricity [10].

Typical LWR unit sizes range from a few hundred megawatts to more than $1\mathrm{GW_e}$ of electrical power. This large unit size contributes to economies of scale, but it also implies high upfront capital expenditure and long construction times [17].
The use of light water as coolant limits the maximum coolant and steam temperatures, due to saturation and material constraints. As a consequence, the directly usable temperature range on the secondary side is mainly suitable for low- and medium-temperature heat applications.
Large LWRs have also been traditionally designed and licensed for steady baseload operation, which influences their design choices in terms of core layout, control systems and balance-of-plant. This baseload design focus is largely economic and operational: LWRs are most cost-effective when operated at steady power, because load-following reduces an-

nual energy output and capacity factor, making capital recovery harder. In addition, the existing fleet was optimized for constant operation and has practical limits on rapid power modulation, mainly due to the risk of thermal stresses in the fuel and plant components [3, 18].

In many decarbonization strategies, LWRs remain a central technology because they provide reliable, high-capacity, low-carbon power that can displace fossil-based generation. In addition to electricity production, their thermal output can be used for applications such as district heating, desalination and industrial steam, especially when combined with appropriate heat-extraction and distribution systems.

2.2 Nuclear Thermal Energy Storage

2.2.1 Operating principles

- NPPs can charge a thermal battery when electricity is inexpensive or the grid has surplus power.
- Charging adds heat to the storage; during discharge the process is reversed and heat is returned, or given, to the power block.
- TES options can hold energy from hours to weeks [10].

2.2.2 Advantages and Disadvantages

General advantages of TES coupled with a NPP

- Faster load-following with lower stress on the reactor: net electrical output can change quickly because the TES provide most of the flexibility [19]. This limits thermal stress on the fuel and primary components and reduces the need for frequent core ramping. Frequent cycling typically increases maintenance needs, reduces efficiency, and can shorten component lifetime. TES mitigates these effects by letting the reactor operate more steadily while the plant still follows net load [2, 18].
- Because nuclear energy is produced as heat, storing it thermally, so in the original

form, avoids extra conversions. In contrast, the pathways from electricity to heat and then back to electricity are constrained by heat-to-power efficiency. TES on the thermal side preserves optionality for either power generation or industrial needs and district heating supply.

- Better compatibility with variable renewables: TES enables temporal shifting of generation toward high-value periods or times of low renewable output, improving system adequacy without forcing rapid changes in reactor power. TES coupled with NPP is mainly used to increase operational flexibility in power systems with high renewable penetration, while keeping the reactor close to steady operation [3].
- Grid support and resilience contributions: TES can act as an additional heat sink and can support ride-through during disturbances. If charged, it can provide extra power during short peaks, helping with balancing and ramping needs [10, 11, 16].
- Reduced need for fossil backup heat: integrating TES can reduce the need for auxiliary fossil-fired heating systems that may otherwise be used for flexibility [13].

Specific advantages of a two-tank molten-salt TES with a Peaking Turbine
Since this is the technology that is exploited in our system, some specific advantages are presented [11, 13, 2, 18]:

- High-power, dispatchable peaking capability: a dedicated peaker turbine can convert stored heat into electricity during high-demand hours, increasing peak output without requiring changes to the main turbine operation.
- Separation of baseload and peaking functions: the main unit can remain focused on steady operation, while the peaker unit provides fast response. This reduces off-design operation of the baseload turbine and simplifies operational control.
- Stronger value capture in volatile markets: the peaker configuration supports off-peak/peak arbitrage and can provide ancillary services (e.g., reserves and ramping support), because stored heat can be dispatched when prices or system needs are highest.
- Stable heat output: with separate hot and cold tanks, the discharge temperature

is more constant. This helps keep steam conditions stable and supports steady power-cycle operation.

- High maturity and lower technology risk: two-tank molten-salt storage has extensive industrial experience, which reduces development and deployment risk compared with less proven TES concepts.
- Good scalability and storage capacity: storage capacity can be increased by enlarging tank volume, enabling multi-hour storage. This makes the concept applicable to both smaller units and large NPPs.

Disadvantages of TES coupled with a NPP

On the other hand, we can also find some limitations of TES [19, 10]:

- Full Round Trip Efficiency is governed by the power cycle. Electric resistive heating of molten salts can be nearly lossless at the point of use, but the discharge back to electricity sets the overall limit.
- Heat extraction and re-injection must meet strict temperature and pressure conditions to protect turbine performance; insufficient/excessive or mistimed heat transfer reduces cycle output or stresses equipment.
- The either potential over-sizing of the turbine generator or the addition of a peaker turbine and the addition of TES increases the upfront cost and site complexity; economic success depends on adequate price spreads, storage duration, and charge/discharge power.
- Ramp rate limits: even if energy is stored, the plant can only change power as fast as the turbines and their control system can safely change steam flow and as fast as the TES heat exchangers can transfer heat. A dedicated peaker turbine is typically designed for more frequent cycling and faster load changes, so it can tolerate higher ramp rates than the baseload unit; however, it is still constrained by thermal-stress limits and control-system protections.
- With regard to technology and licensing challenges, high temperature reactors promise better thermodynamics but raise materials, safety, and licensing challenges; LWRs face a lower integration risk but a lower peak conversion efficiency.

2.2.3 Technologies

A nuclear plant can be paired with several energy-storage types (as shown in Figure 2.1): mechanical, chemical, electrical and thermal, each with distinct benefits and drawbacks.

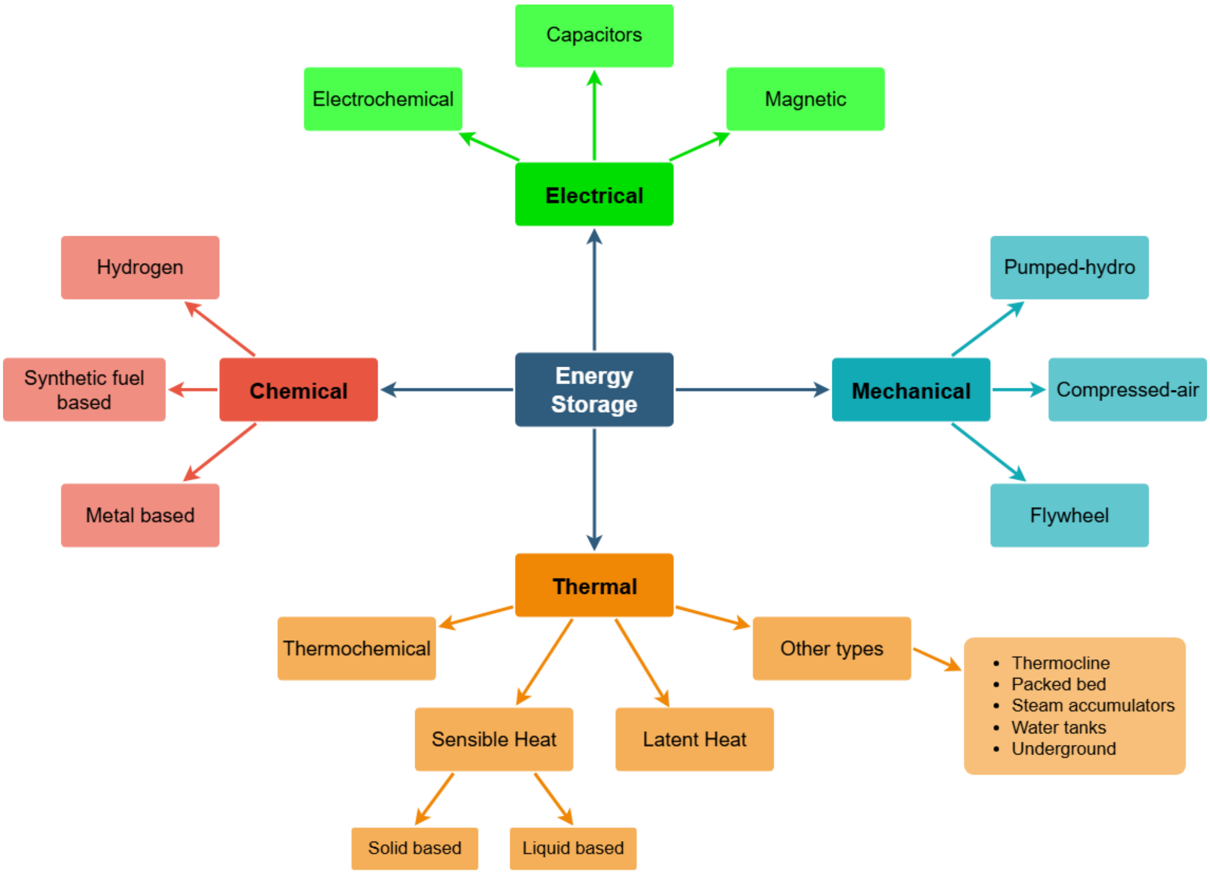

Figure 2.1: *Energy storage technologies.*

Mechanical energy storage systems

Energy can be stored mechanically by exploiting kinetic energy, gravitational potential, or pressure energy in compressed gases. While the basic ideas, spinning a flywheel, elevating a mass, or compressing air, seem simple and are highly reversible, implementing reliable mechanical energy storage requires sophisticated engineering and control systems, they still incur notable losses and typically require large, site-dependent infrastructure and significant space at grid scale.

Chemical storage systems

Nuclear plants can be coupled with chemical energy storage systems that convert reactor heat and/or electricity into storable chemical energy. Options include the production of energy carriers such as hydrogen, synthetic fuel-based storage, and metal-based storage using reversible metal or metal-oxide cycles [10].

Electrical storage systems

Electrical storage retains energy in an immediately usable form and is therefore well suited for fast response and grid support, although costs can be high and round-trip efficiency depends on the specific technology. In power systems with variable generation, electrical storage helps shift output toward peak periods and provides stability services such as frequency and voltage support. At grid scale, batteries are widely used for multi-hour balancing, while capacitors (including supercapacitors) and magnetic energy storage are typically associated with very rapid, short-duration power smoothing [17].

Thermal Energy Storage systems

Thermal Energy Storage (TES) systems charge and discharge by heating, cooling, melting, or solidifying a storage medium; the stored energy is recovered later by reversing the process, commonly via a heat exchanger. Thermal storage is constrained by the relatively low efficiency of converting heat into electricity; however, because nuclear generation is inherently thermal, it aligns with the plant's primary energy form. The suitability of a thermal approach depends on reactor operating conditions and coolant. Light-water reactors run at lower temperatures with pressurized water, whereas advanced designs operate at higher temperatures using molten salts or high-temperature gases, opening different options for storage media and heat-transfer fluids. Selecting those media and fluids is therefore a key design decision. Unlike other storage types, thermal storage can couple directly into the steam power cycle.

TES can be classified along two main axes.

- By operating principle: systems are labeled active or passive, depending on whether heat is stored indirectly, via a circulating Heat-Transfer Fluid (HTF) that exchanges heat with a separate medium, or directly in the HTF itself held in dedicated tanks.
- By storage mechanism: systems are grouped as sensible heat (temperature change without phase change), latent heat (phase change), and thermochemical (reversible

chemical reactions).

In practice, TES options are further organized by the heat-storage technology, the chosen medium and installation form or geometry, which together determine suitability for specific nuclear operating conditions and integration pathways [10, 15]:

- **Sensible Heat Storage**

  In sensible heat storage, a solid or liquid medium stores energy by raising its temperature without changing phase. Typical media include high heat capacity materials such as water, rock/ceramic beds, and molten salts. Because many candidate materials are available, sensible systems can operate across a broad temperature range. Storage density is governed by the mass of the medium, its specific heat capacity, and the temperature swing achieved during operation.

  TES designs may use one or more HTFs, depending on the characteristics of both the heat source and the power block consuming the heat; in some configurations, the transport fluid also serves as the storage medium.

  The most common sensible options use either solids or liquids, each with trade-offs.

  - **Solid based sensible heat storage**.

    Solid media energy storage is a form of sensible heat storage in which thermal energy is stored by raising the temperature of a stationary solid medium such as concrete or firebrick. Compared to liquid-based sensible heat storage technologies, solid-state storage materials offer reduced capital costs while also limiting the environmental impact. Solid media can offer higher volumetric energy density but often require a tertiary HTF loop, complicating design and integration.

  - **Two-tank system (liquid based)**.

    The two-tank configuration is exploited in the further project work and is the predominant sensible-heat storage approach for high-temperature applications requiring multi-hour capacity. It has been widely deployed in concentrated solar power plants where, depending on operating temperature, the heat-transfer fluid and the storage medium are thermal oils or molten salts. In some schemes that use both, thermal oil serves as the HTF moving heat from the generator

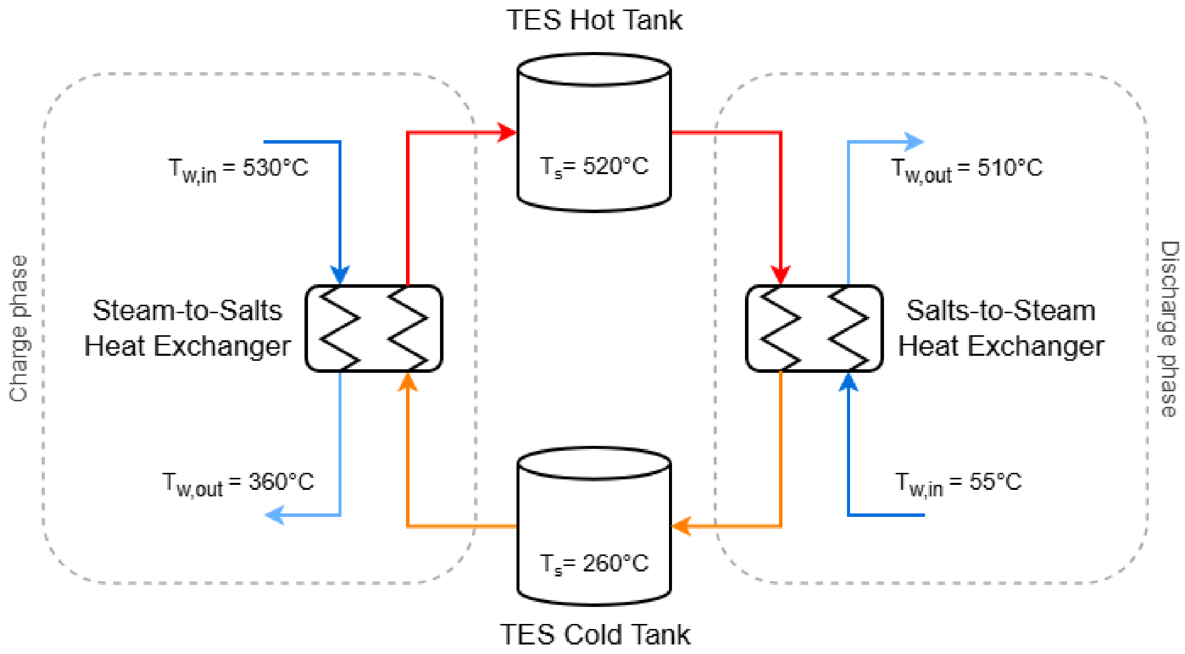

Figure 2.2: *Two tanks - Thermal Energy Storage.*

to the store, while molten salt provides the storage medium. For temperatures >400°C, two tank-molten salts setup is the only viable option for sensible heat storage.

As shown in Figure 2.2, the system employs two tanks at different temperatures: a hot tank and a cold tank. During charging, the cold fluid is heated by the chosen source (e.g., solar or nuclear) and sent to the hot tank. During discharge, heat is extracted from the hot fluid via a heat exchanger for use in the power block or process, and the cooled fluid is returned to the cold tank. The design aim is to preserve the stored heat with minimal temperature drop, since lower temperature directly reduces the efficiency of converting thermal energy to mechanical or electrical output.

Liquid media, especially molten salts, can often act as both the HTF and the storage medium, eliminating the need for an additional intermediate loop. Because their vapor pressure remains low at typical operating temperatures, they can be stored hot in near-atmospheric tanks rather than pressurized vessels, while their relatively high volumetric heat capacity enables compact storage.

- **Latent Heat Storage**

  Latent heat storage systems store energy by exploiting a material's phase change rather than a temperature rise. Special Phase-Change Materials (PCMs) absorb heat during charging and transition, typically from solid to liquid (or, in some cases, liquid to gas), capturing energy as latent heat. When discharged, the material reverses the phase change and releases the stored heat.

  Because the transition occurs at an approximately constant temperature, latent systems can deliver (or accept) heat with a stable thermal profile. Using molten salts as PCMs can provide high energy storage densities, allowing smaller storage volumes than comparable sensible-heat systems. However, the phase transitions introduce added design and operational complexity.

  Despite these challenges, the performance advantages of latent TES have strengthened its prospects for accelerated development and deployment in recent years.

- **Thermochemical Heat Storage**

  Thermochemical Heat Storage relies on reversible chemical reactions. Thermochemical systems store energy as chemical potential. During charging, an endothermic reaction splits reactants, which are then kept in separate vessels. During discharge, the separated reactants recombine in an exothermic reaction, releasing heat for use. This pathway is therefore attractive for extended-term storage.

- **Other types**

  In addition to the broad categories mentioned earlier, there are specific thermal energy storage systems according to their configurations.

  Here are some examples.

  - Thermocline.

    Although two-tank TES is often the most thermally efficient, it is also costly because one tank is largely empty at any given time. A thermocline configuration mitigates this by reducing the amount of storage medium, and therefore tank size and cost. In a thermocline tank, hot fluid is injected and withdrawn near the top while cold fluid is introduced and removed near the bottom. Temperature gradients and buoyancy create stratified hot and cold regions separated by a thermocline layer. However, fluid motion can disturb this stratification, degrading thermal efficiency.

- Packed bed.

  If the HTF is expensive or has low volumetric heat capacity, using it as the storage medium is not advisable. Moreover, if the HTF must be kept at high pressure to remain liquid, a large storage vessel will experience significant mechanical loads, increasing the TES system's cost. Packed-bed TES offers a clear advantage by storing substantial thermal energy in a compact volume. However, because heat must transfer between the HTF and the packed bed, the storage efficiency is inherently low, and the outlet HTF temperature declines over the discharge period.

- Steam accumulators.

  This technology is widely deployed because it offers high energy-storage capacity and very fast response. Steam accumulators store a water-steam mixture during the charging cycle, pressurizing the steam at the top of a vessel. The mixture stays at saturation conditions throughout charging. When discharging begins, a release valve opens and steam exits the vessel, and as it continues, the vessel pressure and corresponding saturation temperature fall, causing part of the remaining liquid to flash into steam, which is then also released.

- Hot and cold water thermal storage tanks are commonly used to shift cooling or heating in locations with peak demands.

- Underground energy storage systems store heat by pumping it into underground locations in depth such as boreholes (30–100 m), aquifers (20–200 m) and caverns (30–60 m).

2.2.4 Materials

TES technologies employ many different types of material as energy storage media, as extensively described in Tables 2 and 3 of [15]. Their total energy density depends on the physical density of the material, the specific heat capacity and the nominal temperature change that the storage material would experience during the charging or discharging cycle. The maximum or "critical" temperature limit for each material is considered to evaluate the material's applicability within a particular advanced NPP category.

2.2.5 Layouts

Extraction point

Efficient integration of TES with the steam cycle depends on where steam is extracted (as shown in Figure 2.3) and re-injected.

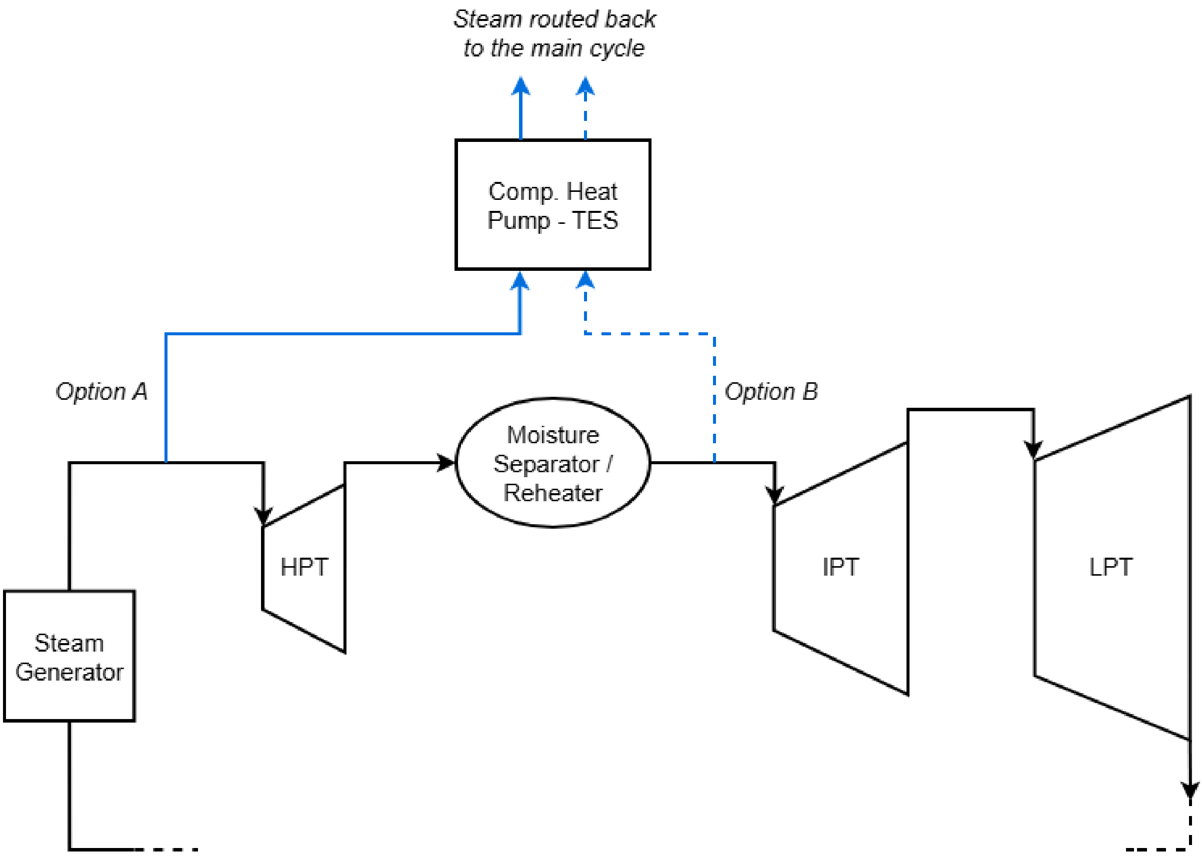

Figure 2.3: *Options for the steam extraction point from the baseload steam cycle. Solid blue line represents the choice for the thesis project.*

- Option A: when the TES requires high-temperature steam, extraction will generally occur upstream of the High Pressure Turbine (HPT). This increases the penalty on electrical output but supplies higher-grade heat to the storage system. Directly supplying steam upstream of a turbine to a TES unavoidably reduces turbine performance during charging. The steam flow through the HPT, Intermediate Pressure Turbine (IPT) and Low Pressure Turbines (LPT) is lowered and the machine is forced into off-design operation; the associated efficiency loss increases with the charging rate. However, this loss can be acceptable if charging is scheduled during off-peak periods, when electricity prices are low, thereby maximizing the overall value of the TES and the coupled plant.

- Option B: if the required TES temperatures are relatively low, branching downstream of the HPT helps to minimize the impact on the reference power block performance.

In all cases, the optimal extraction and re-injection locations depend on the specific storage technology and its operating window. Effective integration therefore requires careful matching of steam temperatures, flow rates, and re-injection conditions so that both the TES and the turbine–generator remain within their allowable operating ranges.

Primary and Secondary Rankine Cycles

Integration options of TES with nuclear power fall into two categories, discharge to the existing Primary Steam Rankine Cycle (PSRC) or discharge to a Secondary Steam Rankine Cycle (SSRC), as shown and described in [14, 4, 18].

- In the PSRC-TES arrangement the storage unit is embedded within the existing Rankine loop. During discharge, the previously stored condensate is pumped to pressure and heated inside the TES to produce superheated steam, which is mixed with the flow of the PSRC and then expanded in the turbines to supply peak power. Because turbines must be engineered to accommodate the larger mass flows that occur in discharge, one large over-dimensioned turbine-generator is exploited and it operates off-design under baseload and charging conditions, incurring an additional efficiency penalty whose magnitude depends on the target peak output.

- In the SSRC-TES arrangement, the storage system is embedded in a Peaker SSRC separate from the primary one. When discharged, the steam produced in the TES drives a dedicated secondary Rankine cycle to generate electricity. Because no alterations to the baseload turbine-generator are required, the performance of the main unit remains identical to conventional operation (it does not operate off-design), a principal advantage of SSRC-TES. The efficiency is only reduced during charging.

Overall, the SSRC-TES configuration is generally preferred because it preserves the primary turbine's baseload operation and avoids persistent off-design conditions during charging and baseload operation. By decoupling peaking generation from the primary cycle, the reactor and main power block can operate more steadily and reliably.

2.2.6 Technologies classification and NPP-TES evaluation

A central aim is to identify which TES technologies best match each class of nuclear reactor. As presented and described in [15], to choose storage approaches compatible with NPPs, the key engineering, phenomena, and system decision points for integration are defined, which leads to a Figure-Of-Merit (FOM) framework presented in Table 2.1. Additionally, a ranking framework from [16] could be exploited to determine the optimum way to couple a TES system to an existing PWR. The ranking applies the seven criteria presented in Table 2.2.

It must be pointed out that these frameworks are not used for the study of the system layout but are presented for additional information.

Table 2.1: *Figure-Of-Merit framework.*

FOM	Description
Technology readiness level.	It evaluates whether the technology will be deployable in an appropriate timeframe for the advanced nuclear system of interest.
Capability to discharge high-quality heat.	The TES system must be capable of charging/discharging its energy capacity at a high relative temperature.
Energy storage density.	It measures the ability of a technology to provide a high amount of stored energy while minimizing the physical footprint of the storage system.
Total energy storage capacity.	It reflects the ability of a technology to provide a large overall amount of stored energy, allowing relatively small generating units to deliver energy over extended periods or at higher effective output.
Ramp/Response Time.	Unlike electrochemical batteries, which can switch instantaneously from one operational mode to another, TES technologies have relatively lower ramp times when switching between modes (i.e., from charge to discharge).
Cycle frequency.	It differs from ramp time in regard to the potential need and the time it takes for the technology to fully complete its charging or discharging cycle before regaining usefulness.
Realignment frequency.	It considers the system's need to either wait on some phenomenon or correct a non-ideal process, thus resulting in reduced system availability.
Geographical insensitivity.	Geographical needs are considered because it is desired that advanced reactors with TES be deployed globally with as little redesigning as possible.
Environmental concerns.	Concerns under this category include those that arise during construction, direct use, and deconstruction.
Minimum turndown/Thermal support requirements.	It reflects whether the storage technology can be fully turned down or placed in standby without additional heating, or whether it requires continuous heat tracing or a minimum thermal input to remain within its allowable temperature range.

Table 2.2: *TES coupled with a NPP ranking framework.*

Criterion	Description
Safety level.	A primary concern should always be the integrity of the reactor vessel and public safety from radiation dosage. Placing a TES unit inside the containment dome may negatively impact the nuclear power plant safety systems, as the TES could potentially add direct heat to the containment system, which could raise pressure inside the dome to the point of failure for the containment vessel.
System stability (accident control).	It is defined by the system returning to normal operating conditions after experiencing a disturbance. A nuclear power plant's stability is vital during both steady-state operation and transient conditions. The system stability criterion considers if an accident scenario was underway and how the TES system would impact the reactor's stability during the accident.
Regulatory uncertainty.	It is associated with modifications to coolant systems or plant layout, necessitating intensive licensing review.
Mechanical integrity.	Elements of mechanical integrity that were utilized in this ranking process are corrosion, mechanical wear, and thermal striping/stratification.
Economic increase.	It is based on major equipment needs and capital cost.
Exergy efficiency.	Exergy is defined as the maximum amount of work produced while the system is brought into equilibrium with its surroundings.
Kinetic capability.	It focuses on determining which TES system design will have the fastest charging and discharging rate, which will mostly be affected by the design of the TES unit itself including mechanical design, materials of construction and storage media.

2.3 Cogenerative Nuclear Energy Systems

2.3.1 Operating principles

Conventional nuclear power plants convert only about 30–35% of reactor heat to electricity, largely because the steam cycle operates at comparatively modest maximum temperatures: in today's light-water reactors, coolant and materials/safety constraints limit the achievable steam conditions, which bounds the Rankine cycle efficiency and leaves a large fraction of heat to be rejected in the condenser. In wet-cooled stations, this discharge, typically 5–7 °C above ambient river or seawater, can reduce dissolved oxygen, alter organism metabolism, and degrade aquatic ecosystems.

By contrast, nuclear cogeneration (Combined Heat and Power, CHP) treats this thermal by-product as a resource: instead of sending all remaining steam heat to the condenser, part of the steam is extracted after the HPT and used for heat purposes. This comes at the cost of a limited reduction in electricity output, since only a relatively small additional amount of power would be produced from that steam in the downstream turbine stages, while a large amount of usable heat can be recovered. Overall, CHP reduces waste-heat rejection, increases energy utilization, and supports decarbonization in urban heat networks and low- to medium-temperature industrial heat demand [20].

A flexible cogeneration architecture can route reactor heat along three pathways: to the turbine-generator for dispatchable electricity, to thermal storage, or to heat uses (e.g., district heating, process steam, hydrogen production). When power prices are low, a minimal steam flow keeps the turbine online for rapid return to full output, and surplus heat is diverted to storage and possibly heat customers. When prices rise, reactor heat is supplemented with stored heat to deliver peak electrical output above the reactor's baseload capability. Off-peak electricity can also be purchased and converted to stored heat via resistive heaters, enabling temporal arbitrage and additional operational flexibility. In practice, CHP plants must coordinate thermal and electrical demands while interfacing with external grids, a challenge that nuclear-based CHP addresses by actively allocating heat and power. Because many end-use heating systems rely on modular, standardized components, retrofitting fossil-fired CHP to nuclear heat could be implemented in a relatively "plug-in" manner with modest engineering effort, provided that a district heating network or equivalent heat distribution infrastructure already exists; if not, constructing such a network from scratch is typically very costly [11, 21].

Taken together, these features position nuclear cogeneration to improve thermodynamic efficiency, mitigate thermal pollution, enhance grid services, and materially reduce carbon emissions across hard-to-abate sectors.

2.3.2 Advantages and Challenges

Pairing NPPs with cogeneration systems offers a strong pathway to improve project economics and system value. Conventional load-following plants can achieve more robust financial performance when heat supply is integrated. Selling heat to high-temperature industries can outperform electricity-only operation, with carbon pricing further enhancing the value of low-carbon heat.

The key advantages of nuclear cogeneration in this setting include [20, 22]:

- Higher overall efficiency by utilizing reactor heat, lowering primary energy waste, operating costs, and carbon intensity.
- Improved project economics through combined heat-and-power synergies, with cogenerated heat often significantly cheaper than fossil-based alternatives.
- Large CO_2 abatement by displacing fossil fuel heat.
- Nuclear CHP can improve grid flexibility and security by shifting heat production to off-peak hours (often using thermal storage) and reducing heat output during peak periods so more capacity is available for electricity generation, which helps balance the grid.
- Revenues from heat sales and advantages under carbon pricing schemes improve overall profitability and investment performance.

However, several integration challenges must be addressed [13]:

- Process heat integration is most straightforward below ∼300°C; while high-temperature reactors can provide much higher outlet temperatures, many industrial systems are optimized around direct fossil combustion, making high-temperature coupling difficult.
- High-temperature service is dominated by radiative transfer and requires careful return-temperature control to keep HTF within reactor inlet limits.
- Process-specific barriers (e.g., direct fuel conversion in iron and steel) and the internal use of by-products as fuels can compete with nuclear heat substitution.
- For applications above ∼500°C, supplying heat via high-temperature steam extraction imposes a large electricity opportunity cost because the extracted steam has

high useful energy and would otherwise produce substantial turbine work. As a result, deep decarbonization at these temperatures often favors electrified heating or synthetic fuels, unless the industrial process is redesigned to accept indirect heat.

2.3.3 Reactor Technologies

Nuclear CHP encompasses a broad space of end uses and reactor options. For CHP, reactor options can be grouped mainly into Light-Water Reactors (LWRs) and advanced High-Temperature Reactors (HTRs) [20].

- LWRs are a mature and widely deployed technology and are typically best suited to low-temperature services (<250°C) such as district heating and desalination, often leveraging steam bypass to hot-water networks. They can also support the lower end of medium-temperature services (∼250–330°C) by providing low-carbon steam for steam-intensive industries, replacing fossil-fired steam generation while improving the reliability of steam delivery; however, the upper medium-temperature range (∼330–550°C) is generally beyond practical LWR cogeneration conditions.
  Within LWRs, a key CHP-relevant distinction is whether the steam is produced in a primary or secondary circuit:
  - PWR: heat is transferred to a separate secondary steam loop, which is non-radioactive under normal operation, facilitating interfaces for heat delivery.
  - BWR: water boils in the core and steam goes directly to the turbine; steam is therefore associated with the radioactive primary circuit, which can impose tighter constraints on extraction and heat delivery for cogeneration.
- Advanced HTRs (HTGRs/VHTRs, MSRs, Lead Fast Reactors) are characterized by higher outlet temperatures (∼750–950°C), enabling CHP beyond LWR capability: they can cover the upper medium-temperature range (∼330–550°C) and extend to high-temperature services (>550°C), including cost-competitive low-carbon hydrogen production and high-grade industrial process heat.
  Cogeneration integration in Advanced High-Temperature Reactors takes advantage of secondary-loop configurations that employ intermediate heat exchangers to isolate nuclear and industrial circuits.

2.3.4 Economic Evaluation Models

The economic assessment of nuclear cogeneration compares the total capital investment, operating costs, and revenues from multiple products with those of a conventional, electricity-only plant [20].

A key challenge is how to allocate costs between heat and power, since they are produced jointly. Two main methods are commonly used.

- Energy-equivalent approaches assign part of the thermal cost based on the amount of electricity that is "sacrificed" to produce heat.
- Exergy-based approaches, instead, allocate costs according to the quality of the energy, using second-law (exergy) analysis to reflect the different thermodynamic value of heat and electricity.

Technical and economic performances also depend on how variable thermal demand is managed. This can involve adjusting primary-side flow conditions, increasing thermal capacity on the secondary side, integrating thermal energy storage and dynamically shifting the split between heat and power production.

2.3.5 TES for Nuclear Cogeneration

TES improves NPP flexibility by separating steady reactor heat production from variable demand, then using charge/discharge control and switching between heat and power conversion paths to manage dispatch. In nuclear CHP, this buffering also stabilizes heat supply for industrial users with fluctuating thermal loads, reducing reliance on non-nuclear backup systems [13].
CHP integration is typically implemented either in parallel (diverting steam before the turbine) or in series (extracting/bleeding steam during turbine expansion at suitable pressure/temperature points) [21].

2.4 Nuclear Heat Pumped-Thermal Energy Storage

Nuclear Heat Pumped–Thermal Energy Storage (HP-TES) integrates a mostly steady-output nuclear reactor with a heat pumped thermal energy storage system so that load following and renewable balancing are handled by the storage plant rather than by frequent reactor ramping. A typical layout relies on hot and cold thermal storages and operates in two main directions: during charging, part of the reactor's electricity is sent to the grid while the remaining powers a heat pump (optionally supported by an electric heater) to increase the temperature difference between storages, effectively converting electrical energy into stored thermal energy; during discharging, the cycle is reversed and the stored heat is routed to a power block (peaker turbine) to deliver dispatchable electricity quickly. For graphical representation please refer to Figure 1.1. Increasing the hot–cold temperature lift reduces the required storage mass and, in general, higher storage temperature improves the conversion efficiency back to electricity.
Overall, Nuclear HP-TES can reduce reliance on peaking plants, improve reliability in high-renewables grids, and create additional revenue opportunities, while keeping the reactor near steady operating conditions. Successful deployment depends on matching the storage concept and control strategy to each reactor's temperature window, coolant and materials limits, and site constraints; further validation on component compatibility, control performance, and lifetime behavior would help reduce risk and guide technology selection [12].

In cogeneration configurations, HP-TES can act not only as an electricity buffer but also as a thermal integration point that supplies both dispatchable power and useful heat. In this heat pumped CHP arrangement, heat can be extracted from the hot storage (or from the steam cycle) to serve district heating or industrial process heat while the remaining thermal stream continues to the power cycle, allowing operators to flexibly allocate stored energy between electricity and heat products without sacrificing steady reactor operation [22].

3 System Layout

3.1 Scope and Overview

The goal of the project is to study and evaluate the system shown in Figure 3.1, composed of:

- Extraction of steam by the primary steam cycle that goes through a Compressor Heat Pump in order to increase its temperature when the electricity prices are low.
- This upgraded steam charges molten salts of a Thermal Energy Storage.
- The condensed steam then is returned to the primary steam cycle at specific points depending on the pressure and temperature levels.
- When the electricity prices are high and peak power is needed the two-tank TES discharges heat to a Secondary Steam Rankine Cycle whose steam is preheated, evaporated, superheated before the HPT and reheated between the High Pressure Turbine and Intermediate Pressure Turbine of the Peaker Block.

This chapter defines the steam Compressor Heat Pump-Thermal Energy Storage layout adopted for the thesis case study and reports the design set-points, component interfaces, and the enthalpy-based performance metrics used later for techno-economic evaluation. The final design of the system added to the baseload NPP is shown here below, whose parts are described in the following paragraphs.

For information only: apart from Figure 3.1, ”steam” is represented by lines and tables boxes in light blue, ”water” is represented by lines and tables boxes in aqua green, ”salts” are represented by orange lines and green tables boxes.
All the enthalpies and temperature values which are not directly calculated or chosen are taken from an online steam/water table calculator (https://www.spiraxsarco.com/resources-and-design-tools).

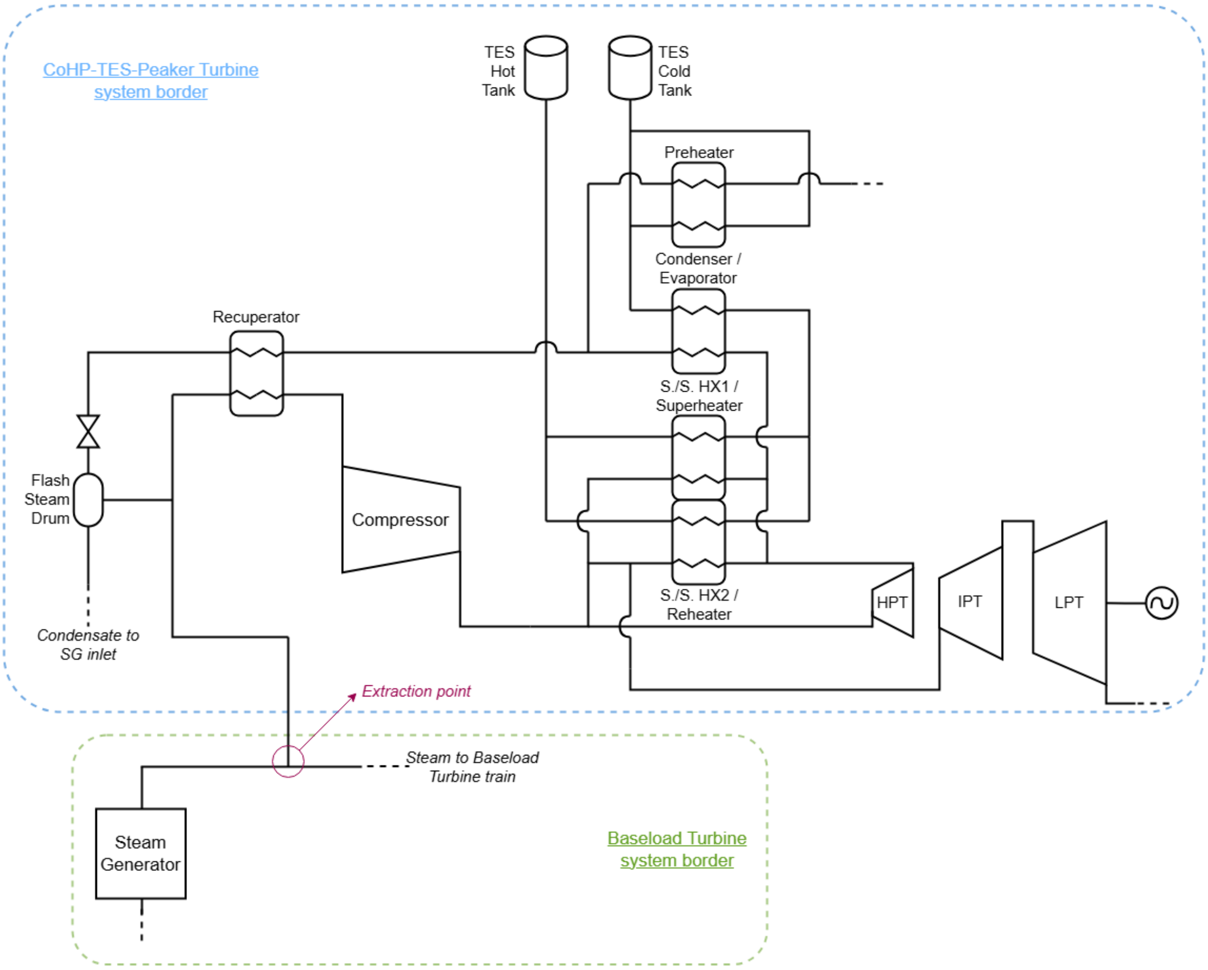

Figure 3.1: *General Compressor Heat Pump - Thermal Energy Storage Layout.*

3.2 Primary Steam Rankine Cycle (extraction and return)

Extraction point To reach the assumed condensing pressure value without exploiting too much electrical work at the CoHP, it has been evaluated, even if not shown in this work, that steam extraction just after the Steam Generator of the PSRC is an appropriate choice (higher pressure compared to extraction after the Reheater and before the IPT), as shown in Figures 2.3 and 3.1. As reference for the PSRC, the baseload cycle data of a European Pressurized Reactor have been exploited, as provided by QC. So, dry steam is extracted downstream of the SG at 75 bar, 290°C and routed to the CoHP train and all three turbine stages of the baseload turbine will work with a reduced amount of steam.

Return point Saturated liquid at 75 bar, 290°C from the Flash Steam Drum (FSD) is re-admitted to the high-pressure feedwater line, just before the steam generator.

3.3 Compressor Heat Pump

The appropriate number of compressor stages must be evaluated, also considering if we have intercooling between them, so how many Heat Exchangers between Steam and Salts (S./S. HX) are present for the charge phase (one HX after each compressor stage plus one Condenser at the end of the charge path). The steam coming back into the compressor from the FSD, which is used to separate saturated steam and water at the outlet pressure of the HP cycle, must be taken into account.

It has been calculated, even if not shown in this work, that one compressor stage is sufficient to reach the desired steam temperature and pressure values and this leads to relatively lower system complexity and therefore cost. So, as a consequence, a single Heat Exchanger and one Condenser are exploited during the charge phase, since additional HX would be needed between the compressor stages only if we had more than one of them.

3.3.1 Charge phase

The amount of steam extracted from the primary steam cycle is evaluated considering the flow rate needed to deliver the desired amount of heat to the salts (whose mass, specific heat and charge/discharge time are chosen as a reasonable random values, since they will not affect the Heat Pump performance), so having as inputs the molten salts temperatures and the Condenser pressure/temperature.

The steam mass flow rate through the Compressor is higher than the extraction flow, since a percentage (16%, as described in Table 3.5) of the water closing the HP cycle flashes to steam in the FSD and is returned at the beginning of the cycle.

Table 3.1: *CoHP and TES inputs.*

CoHP			TES					
T_{cond}	360	°C	T_{in}	260	°C	$T_{ch,di}$	2	h
p_h	187	bar		533	K	$E_{th,in}$	650.00	MWh_{th}
p_l	75	bar	T_{out}	520	°C	$Q_{act,in}$	325.00	MW_{th}
Π	2.486			793	K	S	833.33	kg/s
η_{is}	0.7		m_s	6.00E+06	kg			
γ	1.3		c_p	1.5	kJ/kgK			

Figure 3.2 highlights steam/water and salts paths during charge phase, whose water/steam cycle is plotted in Figure 3.3 and points are summarized in Table 3.2.

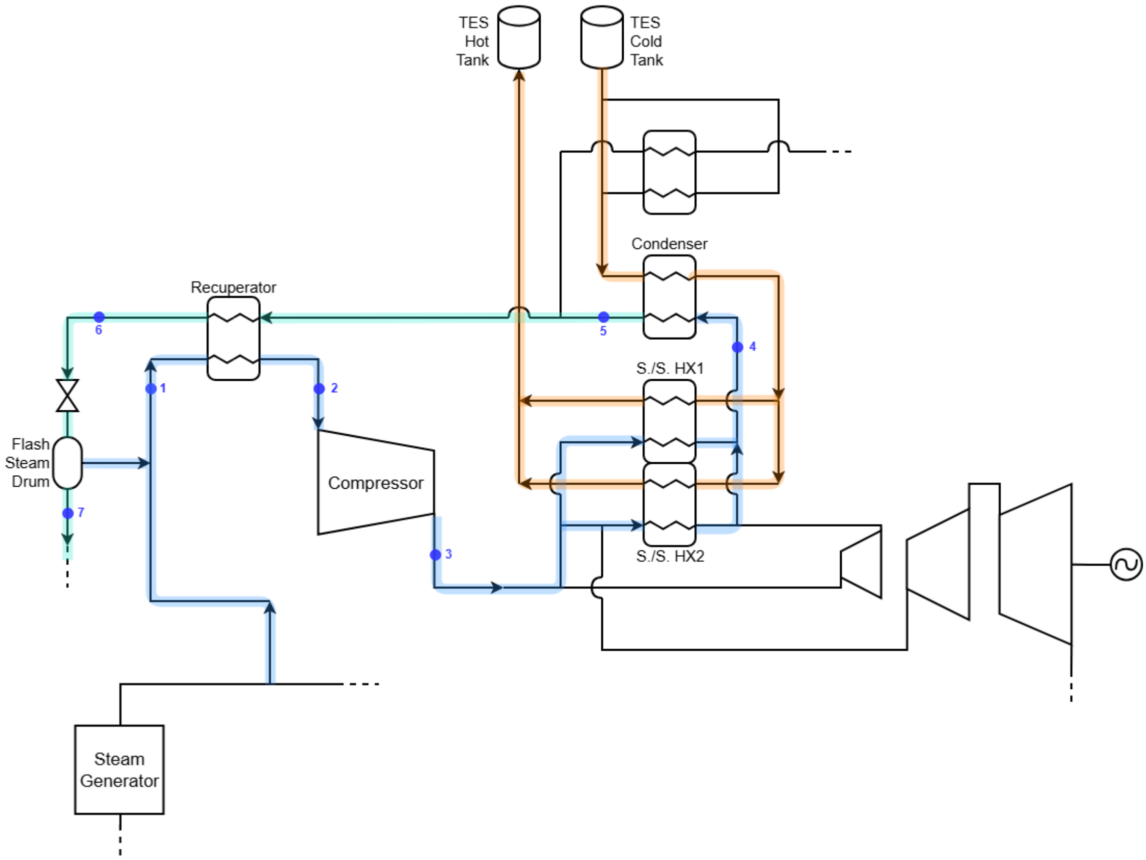

Figure 3.2: *Steam (light blue)/water (aqua green) and salts (orange) paths during charge phase.*

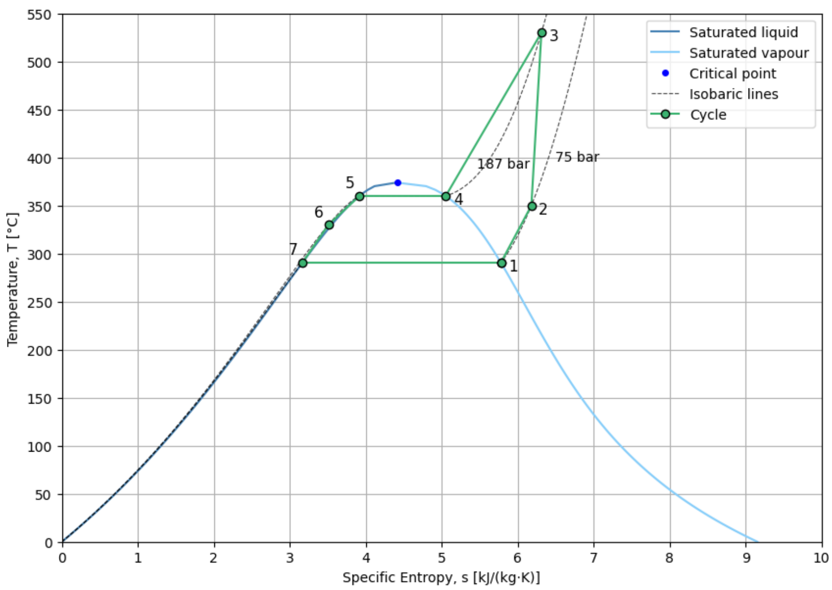

Figure 3.3: *T-s diagram for water/steam cycle during charge phase.*

Table 3.2: *Steam/water cycle points during charge phase.*

Point	Pressure [bar]	Temperature [°C]
1	75	290
2	75	350
3	187	530
4	187	360
5	187	360
6	187	330
7	75	290

Table 3.1 shows different fixed values for the CoHP: the condensing temperature of steam at the end of the CoHP cycle (T_{cond}), that gives us the High Pressure value for the compressor (p_h); the Low Pressure value relative to the steam extraction (p_l), the pressure ratio (Π), the isentropic efficiency of the CoHP (η_{is}) and the specific heats ratio of steam (γ).
While for the TES the assumed values are: cold (T_{in}) and hot (T_{out}) tanks temperatures, mass of the molten salts (m_s), specific heat of the molten salts (c_p), charge and discharge time ($T_{ch,di}$).
The total Energy that the salts must receive to achieve that temperature increase comes from:

$$E_{th,in} = m_s \cdot c_p \cdot (T_{out} - T_{in}) \tag{3.1}$$

From this it is possible to find the actual thermal Power in the salts:

$$Q_{act,in} = \frac{E_{th,in}}{T_{ch,di}} \tag{3.2}$$

The salts flow rate is calculated as:

$$S = \frac{m_s}{T_{ch,di} \cdot 3600} \tag{3.3}$$

Mixing and Preheating The extracted steam at 75bar, 290°C (point 1) mixes isobarically with saturated steam at 75bar, 290°C produced in the FSD. The mixed steam is pre-heated to 350°C (point 2) in the Recuperator using the returning condensate at 360°C, 187bar from the HP Condenser with an hot-end approach $T_{hot,in}$-$T_{cold,out}$ = 10K, as can be seen in Table 3.4.

Compression A single compressor (assumed isentropic efficiency $\eta_{is} = 0.70$) raises the pre-heated steam to the Condenser pressure level (fixed at 187 bar) with a design outlet temperature of 530°C (point 3).
Knowing how much steam must be upgraded from 350°C to 530°C, the Compressor work can be calculated by exploiting the enthalpies at inlet and outlet, as can be seen in Table 3.3.

Heat delivery and Condensation The superheated steam delivers heat (point 4) and fully condenses (point 5) isothermally at 360°C against the molten-salts loop (hot-end pinch=10K) in a S./S. HX and a Condenser; from this enthalpy drop and the total heat that must be given to the salts, the steam flow rate is calculated, as can be seen in Table 3.3.
Regarding the steam in the CoHP, from the enthalpy at the inlet (h_{in}), the isentropic enthalpy at the outlet ($h_{out,is}$) and the isentropic efficiency of the Heat Pump from Table 3.1 (η_{is}) the enthalpy at the outlet is calculated in order to find the related outlet temperature (T_{out}):

$$h_{out} = h_{in} + \frac{h_{out,is} - h_{in}}{\eta_{is}} \tag{3.4}$$

Now that we know the steam enthalpy increase in the Compressor (Δh_{HP}), in order to calculate the Compressor work we need the steam flow rate.
Assuming a global heat exchanger efficiency between Steam and Salts ($\eta_{hx,ch}$) we calculate the total heat that the Steam must give to the Salts:

$$Q = \frac{Q_{act}}{\eta_{hx,ch}} \tag{3.5}$$

From the fixed enthalpy drop of Steam in the HX + Condenser block (Δh_{HXC}) we evaluate the needed steam flow rate:

$$V = \frac{Q \cdot 1000}{\Delta h_{HXC}} \tag{3.6}$$

Finally, the Compressor power is evaluated:

$$W_e = \frac{V \cdot \Delta h_{HP}}{1000} \tag{3.7}$$

Table 3.3: *Steam properties in the CoHP, the Heat Exchanger and in the Condenser, with the goal to evaluate the Compressor power.*

CoHP			Heat Exchanger + Condenser					
T_{in}	350	°C	T_{in}	530	°C	Δh_{HXC}	1591.10	kJ/kg
h_{in}	3001.96	kJ/kg	T_{out}	360	°C	V	208.43	kg/s
$h_{out,is}$	3247.18	kJ/kg		633	K	Q	331.63	$\mathrm{MW_{th}}$
h_{out}	3352.27	kJ/kg	ΔT	170		Q_{act}	325.00	$\mathrm{MW_{th}}$
T_{out}	530	°C	h_{in}	3352.27	kJ/kg	$\eta_{hx,ch}$	0.98	
Δh_{HP}	350.31	kJ/kg	h_{out}	1761.17	kJ/kg			
V	208.43	kg/s						
W_e	73.02	$\mathrm{MW_e}$						

3.3.2 Recuperator and Flash-Steam Drum loop

Recuperator outlet (water) Saturated water from the HP Condenser (360 °C, 187 bar) is cooled in the Recuperator to 330 °C (remains compressed liquid at 187 bar, point 6).

To calculate the exiting water temperature from the Recuperator ($T_{w,out}$), the recuperated heat and the outlet water enthalpy must be known.

For the former, the steam flow rate V from Table 3.3 and the steam enthalpy increase in the Recuperator are exploited:

$$Q_{rec} = \frac{V \cdot \Delta h_s}{1000} \tag{3.8}$$

The latter is calculated in the following way and the outlet water temperature is found:

$$h_{w,out} = h_{w,in} - \frac{Q_{rec} \cdot 1000}{V} \tag{3.9}$$

Table 3.4: *Water and Steam properties in the Recuperator.*

Recuperator					
Water			Steam		
$h_{w,in}$	1761.17	kJ/kg	$T_{s,in}$	290	°C
$h_{w,out}$	1524.45	kJ/kg	$h_{s,in}$	2765.24	kJ/kg
$T_{w,out}$	330	°C	$T_{s,out}$	350	°C
			$h_{s,out}$	3001.96	kJ/kg
			Δh_s	236.72	kJ/kg
			Q_{rec}	49.34	MW_{th}

Throttling and separation The 330°C water is expanded isoenthalpically to 75bar and enters the FSD as a mixture at saturation temperature (290 °C). The steam leg (75 bar, sat.) is recycled to the HP inlet mixer; the liquid leg (75 bar, sat., point 7) is returned to the plant feedwater path.

The flash steam fraction is dictated by the enthalpies of water at inlet ($h_{w,in}$) and outlet ($h_{w,out}$, corresponding to 75 bar) of the FSD and the latent heat of saturated steam at outlet ($h_{ws,out}$):

$$r = \frac{h_{w,in} - h_{w,out}}{h_{ws,out}} \tag{3.10}$$

Then we firstly find the ratio between the steam flow rate in the CoHP cycle (from Table 3.3) and the extracted steam flow rate, which must be > 1, as said previously.

$$\frac{V}{V_{extr}} = \frac{1}{1-r} \tag{3.11}$$

And finally the extracted steam flow rate:

$$V_{extr} = V \cdot (1-r) \tag{3.12}$$

Table 3.5: *Water and Steam properties in the Flash Steam Drum.*

Flash Steam Drum					
Water			Steam		
$h_{w,in}$	1524.45	kJ/kg	r	0.16	
$h_{w,out}$	1292.91	kJ/kg	V/V_{extr}	1.187	
$h_{ws,out}$	1472.33	kJ/kg	V_{extr}	175.65	kg/s

3.4 Two-Tank Molten-Salts TES

Charge phase The steam-side duty is set so that, with a heat-exchanger effectiveness of 0.98, the fixed amount of molten salts are heated from 260°C to 520°C, with a 10 degrees hot-end approach with the steam, as seen previously in Table 3.1.

Discharge phase The fixed mass of molten salts goes from 520 to 260 °C; again a hot-end pinch $\Delta T_{ss} = 10$ is chosen, which means that steam of the secondary steam Rankine cycle reaches a maximum temperature $T_H = 510$°C, as further illustrated in Table 3.6.

3.5 Secondary Steam Rankine Cycle (Peaker Turbine)

During discharge phase, salts deliver heat first in the same HX as the charge phase, which is split into two parts, one to superheat the steam before the HPT (Superheater) and the other one to reheat the steam before the IPT (Reheater), then in the Evaporator, and finally in the Preheater.

Table 3.6: *TES and Peaker Turbine inputs data.*

TES						Peaker Turbine		
T_{in}	520	°C	$T_{ch,di}$	2	h	ΔT_{ss}	10	
T_{out}	260	°C	$E_{th,out}$	650.00	MWh_{th}	T_H	510	°C
ΔT	260		Q_{out}	325.00	MW_{th}		783	K
m_s	6.00E+06	kg	S	833.33	kg/s	T_C	55	°C
c_p	1.5	kJ/kgK					328	K
						η_{is}	0.85	
						η_{gen}	0.97	

Again, steam/water and salts paths during discharge phase are highlighted in Figure 3.4, whose steam/water cycle is plotted in Figure 3.5 and points are summarized in Table 3.7.

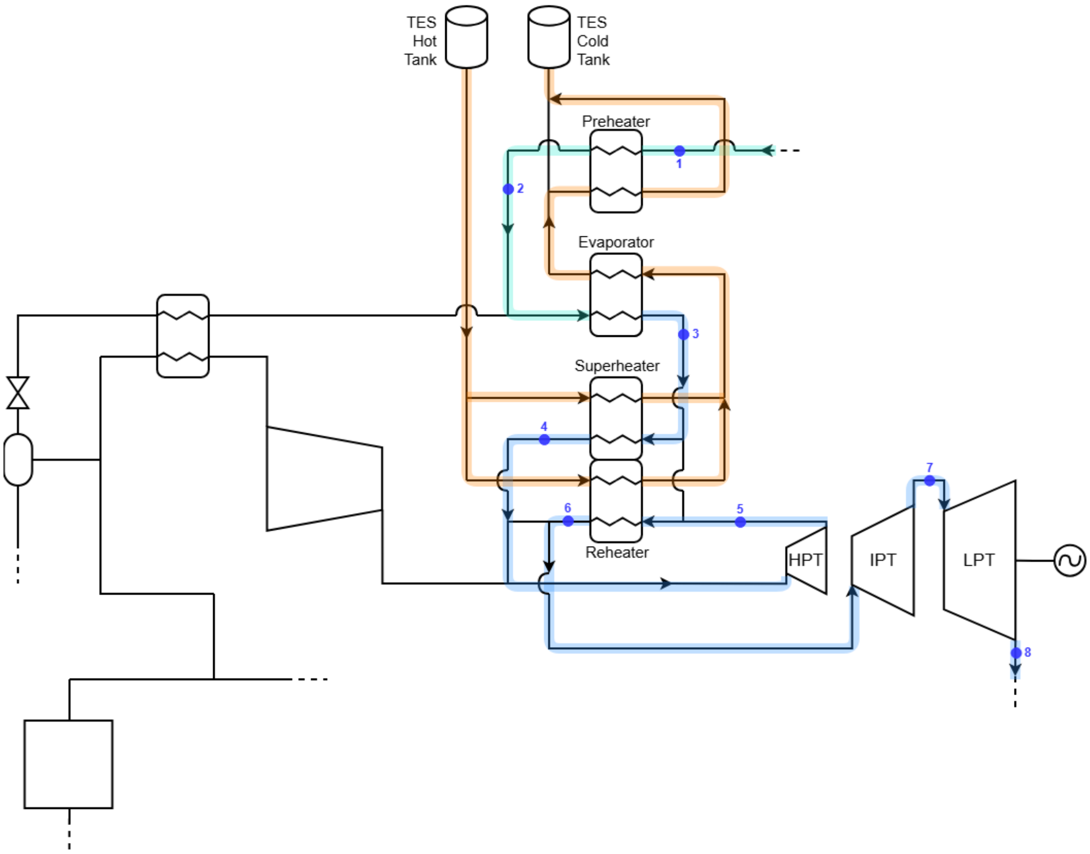

Figure 3.4: *Steam (light blue)/water (aqua green) and salts (orange) paths during discharge phase.*

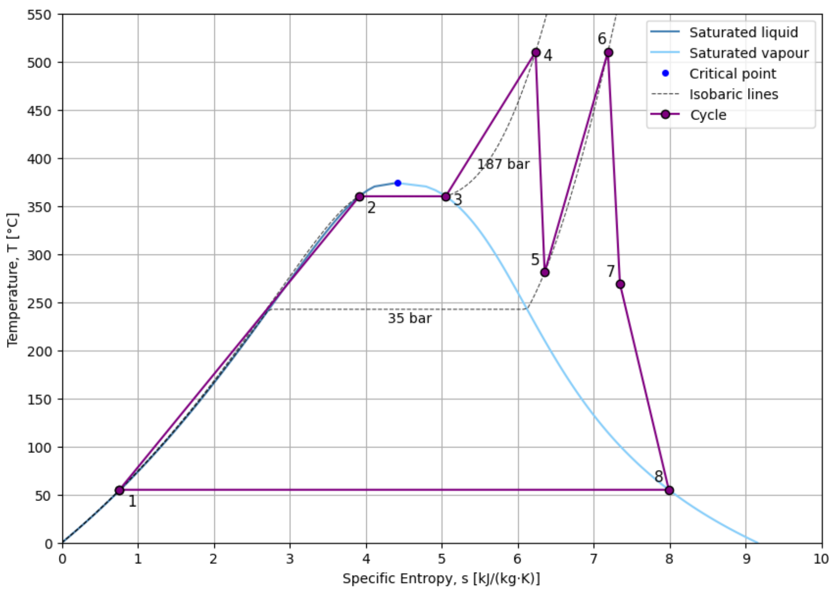

Figure 3.5: *T-s diagram for water/steam cycle during discharge phase.*

Table 3.7: *Steam/water cycle points during discharge phase.*

Point	Pressure [bar]	Temperature [°C]
1	187	55
2	187	360
3	187	360
4	187	510
5	35	281
6	35	510
7	5	269
8	0.16	55

Goal of this analysis is to find out the electrical work produced by the peaker turbine.
To do so we must evaluate the steam mass flow rate needed to receive all the heat accumulated in the salts.
This is done by exploiting the enthalpies changes in all four heat-exchangers presented above, taking into account appropriate temperature pinch points.

As can be seen in Table 3.6, several TES data were already described before, in particular: the discharge time ($T_{ch,di}$) is assumed equal to the charge time, since we are exploiting the same Heat Exchanger block as the charge phase, while in this case a global heat exchanger efficiency between Steam and Salts is not taken into consideration since losses are already accounted in the charge phase, during the dwell time (in the next project step) and again we have a hot-end pinch of 10 degrees between salts and steam.
The condensing temperature of the Secondary Steam Rankine Cycle is set to be 55°C, the isentropic efficiencies of the Peaker Turbine stages are set to be 0.85, while the generator efficiency is assumed to be 0.97.

3.5.1 Heat Exchangers block

In order to find the steam mass flow rate of the PT all the enthalpy increases in the four Heat Exchangers (Δh_{pr}, Δh_{ev}, Δh_{hx1}, Δh_{hx2}) must be evaluated since:

$$V_{PT} = \frac{E_{th,act,out}}{\Delta h_{pr} + \Delta h_{ev} + \Delta h_{hx1} + \Delta h_{hx2}} \cdot \frac{1}{T_{ch,di} \cdot 3600} \tag{3.13}$$

This value results in $V_{PT} = 90.03$ kg/s and it can be exploited to evaluate the amount of heat released by the salts in all four HX (Q_{pr}, Q_{ev}, Q_{hx1}, Q_{hx2}), with the following rule of thumb:

$$Q_* = \frac{\Delta h_* \cdot V_{PT}}{1000} \tag{3.14}$$

Preheater As shown in Table 3.8, water of the Secondary Steam Rankine Cycle is brought from 55°C (condensing temperature of the SSRC, point 1) to 360°C with the full molten salts mass flow rate (from Table 3.6) entering at 370°C and exiting at 260°C (as already fixed and stated in Table 3.1).

The inlet temperature of the salts comes from:

$$T_{in} = \frac{Q_{pr} \cdot 1000}{S \cdot c_p} + T_{out} \tag{3.15}$$

where S and c_p are taken from Table 3.6.

Table 3.8: *Preheater Steam and Salts parameters.*

Preheater					
Water			Salts		
T_{in}	55	°C	S	833.33	kg/s
T_{out}	360	°C	T_{in}	370	°C
$p_{in,out}$	187	bar		643	K
h_{in}	229.75	kJ/kg	T_{out}	260	°C
h_{out}	1761.17	kJ/kg		533	K
Δh_{pr}	1531.42	kJ/kg			
Q_{pr}	137.88	MW_{th}			

Evaporator As shown in Table 3.9, water of the SSRC evaporates at constant temperature of 360°C (equal to the outlet water temperature from the Preheater, point 2) and pressure of 187 bar with all the salts entering at 422°C and exiting at 370°C, which is equal to the inlet salts temperature in the Preheater, as can be checked in Table 3.8, and it is calculated with the same approach of Equation 3.15.

Table 3.9: *Evaporator Water, Steam and Salts parameters.*

Evaporator								
Water			Steam			Salts		
T_{in}	360	°C	T_{out}	360	°C	S	833.33	kg/s
h_{in}	1761.17	kJ/kg	h_{out}	2480.98	kJ/kg	T_{in}	422	°C
p_{evap}	187	bar	Δh_{ev}	719.81	kJ/kg		695	K
			Q_{ev}	64.81	$\mathrm{MW_{th}}$	T_{out}	370	°C
							643	K

Superheater As shown in Table 3.10, steam is superheated at constant pressure of 187 bar from 360°C (equal to the outlet water temperature from the Evaporator, point 3) to 510°C (point 4), considering the temperature pinch previously indicated in Table 3.6. In this case the flow rate of the molten salts is split into two parts, working in parallel with the Reheater; they enter at 520°C (hot tank temperature) and exits at 422°C, which is equal to the inlet salts temperature in the Evaporator, as can be checked in Table 3.9. Anyway, it can be demonstrated with the following equation:

$$T_{out} = T_{in} - \frac{Q_{hx1} \cdot 1000}{S_1 \cdot c_p} \tag{3.16}$$

Salts flow rate (S_1) is scaled according to how much heat is needed by the steam before entering the HPT, with the following equation:

$$S_1 = \frac{S \cdot Q_{hx1}}{Q_{hx1} + Q_{hx2}} \tag{3.17}$$

Table 3.10: *Superheater Steam and Salts parameters.*

Superheater (HX_1)					
Steam			Salts		
T_{in}	360	°C	S_1	496.90	kg/s
T_{out}	510	°C	T_{in}	520	°C
$p_{in,out}$	187	bar		793	K
h_{in}	2480.98	kJ/kg	T_{out}	422	°C
h_{out}	3291.10	kJ/kg		695	K
Δh_{hx1}	810.12	kJ/kg			
Q_{hx1}	72.94	MW_{th}			

Reheater As shown in Table 3.11, after the HPT steam is reheated from 281°C (point 5, HPT output, as can be further seen in Table 3.12) to again 510°C (point 6) with the other part of the molten salts (S_2), which go from 520°C to 422°C as well.
Outlet salts temperature and salts flow rate are calculated respectively with Equation 3.16 and Equation 3.17. It can be checked that:

$$S = S_1 + S_2 \tag{3.18}$$

The pressure between HPT and IPT ($p_{in,out}$) is assumed to be 35 bar.

Table 3.11: *Reheater Steam and Salts parameters.*

Reheater (HX_2)					
Steam			**Salts**		
T_{in}	281	°C	S_2	336.44	kg/s
T_{out}	510	°C	T_{in}	520	°C
$p_{in,out}$	35	bar		793	K
h_{in}	2925.29	kJ/kg	T_{out}	422	°C
h_{out}	3473.80	kJ/kg		695	K
Δh_{hx2}	548.51	kJ/kg			
Q_{hx2}	49.38	MW_{th}			

3.5.2 Peaker Turbine stages

The total power produced by the peaker turbine will be the sum of the individual powers coming from the three turbine stages, where the turbine isentropic efficiency and the generator efficiency from Table 3.6 are taken into account.
To evaluate the individual powers, the enthalpy drop of the steam must be calculated, which comes from the calculation of the steam outlet enthalpy in all stages.

$$h_{out} = h_{in} - (\eta_{is} \cdot (h_{in} - h_{out,is})) \tag{3.19}$$

$$\Delta h_* = h_{in} - h_{out} \tag{3.20}$$

$$W_{pr,*} = \frac{V_{PT} \cdot \Delta h_*}{1000} \cdot \eta_{gen} \tag{3.21}$$

High Pressure Turbine As shown in Table 3.12, assuming a steam pressure of 35 bar between the HPT and IPT, steam in this point of the cycle reaches 281°C.

Table 3.12: *High Pressure Turbine parameters.*

HPT		
T_{in}	510	°C
h_{in}	3291.10	kJ/kg
$h_{out,is}$	2860.73	kJ/kg
h_{out}	2925.29	kJ/kg
T_{out}	281	°C
Δh_{HP}	365.81	kJ/kg
$W_{pr,HP}$	31.95	MW$_e$

Intermediate Pressure Turbine A shown in Table 3.13, assuming a steam pressure of 5 bar between the IPT and LPT, steam in this point (point 7) of the cycle reaches 269°C.

Table 3.13: *Intermediate Pressure Turbine parameters.*

IPT		
T_{in}	510	°C
h_{in}	3473.80	kJ/kg
$h_{out,is}$	2917.46	kJ/kg
h_{out}	3000.91	kJ/kg
T_{out}	269	°C
Δh_{IP}	472.89	kJ/kg
$W_{pr,IP}$	41.30	MW_e

Low Pressure Turbine As shown in Table 3.14, the outputs from the IPT are the inputs of the LPT.

Since it is unknown if the steam at the LPT outlet will have a quality < 1, it is not possible to find the isentropic outlet enthalpy on the online steam tables as before.

In fact, it can be demonstrated that since $s_w < s_{in} < s_s$, we will have $0 < x < 1$.

As a consequence, the following procedure to calculate the outlet (point 8, at the condensing pressure = 0.158 bar relative to $T_C = 55$°C) enthalpy and quality is used.

First the isentropic quality is calculated with the steam entropy at inlet (s_{in}), steam entropy at outlet (s_s) and water entropy at outlet (s_w):

$$x_{is} = \frac{s_{in} - s_w}{s_s - s_w} \tag{3.22}$$

Then, considering also the water outlet enthalpy (h_w) and the outlet latent heat of saturated steam (h_{ws}), the outlet isentropic enthalpy is evaluated:

$$h_{out,is} = h_w + (h_{ws} \cdot x_{is}) \tag{3.23}$$

Then finally the outlet steam enthalpy (h_{out}) is determined.

Secondly, the steam quality can be found:

$$x = \frac{h_{out} - h_w}{h_{ws}} \tag{3.24}$$

Table 3.14: *Low Pressure Turbine parameters.*

LPT					
T_{in}	269	°C	s_{in}	7.347	kJ/kgK
h_{in}	3000.91	kJ/kg	s_w	0.769	kJ/kgK
$h_{out,is}$	2388.78	kJ/kg	s_s	7.989	kJ/kgK
h_{out}	2480.60	kJ/kg	x_{is}	0.91	
T_{out}	55	°C	h_w	229.95	kJ/kg
Δh_{LP}	520.31	kJ/kg	h_{ws}	2369.72	kJ/kg
$W_{pr,LP}$	45.44	MW$_e$	x	0.95	

Turbine Train Ultimately, the total power (W_{pr}) produced by the Peaker Turbine is calculated and considering the total power coming from the TES this gives a PT efficiency (η_{PT}) of 0.37, needed for the next project step.

$$W_{pr} = W_{pr,HP} + W_{pr,IP} + W_{pr,LP} \tag{3.25}$$

$$\eta_{PT} = \frac{W_{pr}}{Q_{out}} \tag{3.26}$$

Table 3.15: *Peaker Turbine results.*

Peaker Turbine		
W_{pr}	118.68	MW$_e$
Q_{out}	325.00	MW$_{th}$
η_{PT}	0.37	

3.6 Performance Indicators

To evaluate and compare the system in different electricity markets we use the Peaker Turbine efficiency just calculated as well as the CoHP's Coefficient Of Performance (COP) which comes from the Compressor work and the Heat given to the salts.
It's also necessary to compare the calculated COP with the *Lorenz* COP (which is a better indicator compared to *Carnot* COP since we are dealing with temperature glides) to understand how far this machine is from the ideal one.
Firstly, the COP of the CoHP is calculated:

$$COP = \frac{Q}{W_e} \tag{3.27}$$

To evaluate the ideal *Lorenz* COP, the source and sink temperatures are needed, as stated in [23].

- For the source temperature the isothermal steam entering the Heat Pump is considered (T_{source}).
- For the sink an overall entropic mean temperature is used:

$$T_{sink} = \frac{Q_{se} + Q_{la}}{S_{se} + S_{la}} = \frac{Q_{se} + Q_{la}}{\frac{Q_{se}}{LMT_{se}} + \frac{Q_{la}}{T_{la}}} \tag{3.28}$$

  where S stands for entropy and the total heat received Q by the sink is split into its sensible (Q_{se}, related to the S./S. HX) and latent parts (Q_{la}, related to the Condenser).
  From the saturated steam enthalpy before entering the condenser (h_{mid}), the steam enthalpy drops in the HX (Δh_{se}) and in the Condenser (Δh_{la}) are evaluated; exploiting the steam flow rate V from Table 3.3 this leads to:

$$Q_{se} = \frac{V \cdot \Delta h_{se}}{1000} \qquad Q_{la} = \frac{V \cdot \Delta h_{la}}{1000} \tag{3.29}$$

  The S./S. HX works with steam decreasing its temperature, so a logarithmic mean temperature from the salts-side is exploited, as indicated in [23]:

$$LMT_{se} = \frac{T_{out} - T_{mid}}{\ln \frac{T_{out}}{T_{mid}}} \tag{3.30}$$

  where the salts outlet temperature (T_{out}) comes from Table 3.1 and T_{mid} represents the salts temperature between the Condenser and the HX.
  The Condenser is characterized by a constant temperature T_{la} of water/steam.

With these values, the ideal maximum *Lorenz COP* of the machine can be calculated:

$$COP_{id} = \frac{T_{sink}}{T_{sink} - T_{source}} \tag{3.31}$$

Finally, the percentage of the COP relative to the COP_{id} is found.

Table 3.16: *Comparison between COP and ideal COP.*

CoHP			HX + Condenser			TES		
T_{source}	290	°C	T_{la}	360	°C	T_{mid}	378	°C
	564	K		633	K		651	K
COP_{id}	5.946		h_{in}	3352.27	kJ/kg	T_{out}	520	°C
Q	331.63	MW_{th}	h_{mid}	2480.96	kJ/kg		793	K
W_e	73.02	MW_e	h_{out}	1761.17	kJ/kg	LMT_{se}	719	K
COP	4.542		Δh_{se}	871.31	kJ/kg	T_{sink}	678	K
	76.39%		Δh_{la}	719.79	kJ/kg			
			Q_{se}	181.61	MW_{th}			
			Q_{la}	150.03	MW_{th}			

4 Methods

4.1 Goal of the analysis

Once the CoHP Coefficient Of Performance and the Peaker Turbine efficiency are known, it is possible to proceed with the methodical simulations part of the Thesis work.
An economical analysis of a $1GW_e$ Nuclear Power Plant coupled with a Thermal Energy Storage and a Peaker Turbine is carried out.
Four different scenarios are considered for the system layout:

1. NPP without TES (traditional operation).
2. NPP with TES integrated with Electrical Heater.
3. NPP with TES integrated with Compressor Heat Pump.
4. NPP with TES integrated with both Electrical Heater and Compressor Heat Pump.

These four scenarios are simulated in three different electricity markets:

- Poland.
- Germany.
- France.

The previous Thesis step was focused only on the design of the CoHP since the Electrical Heater technology is already diffused and implemented in TES systems.
It's important to remember that the TES dicharges its energy only to the steam cycle of a Peaker Turbine. Moreover, thanks to the high temperature reached by the salts in the TES, the steam in the SSRC is characterized by higher temperatures compared to the PSRC, this is the reason why the Peaker Turbine efficiency has been previously evaluated.
The different systems are analyzed and compared, in order to:

- Find the highest **Round Trip Efficiency**.
- Understand how they influence the **volatility of the market**: a market with high shares of negative price hours and high price hours can be considered highly

volatile, because it frequently experiences both surplus conditions (very low prices) and scarcity conditions (very high prices).
Charging tends to increase prices in very low/negative-price hours (valley filling) because it absorbs surplus electricity (either by increasing demand or by reducing net injections). Discharging tends to reduce prices in very high-price hours (peaks shaving) because it adds electricity supply when the system is under scarcity conditions (either by increasing injections into the grid or by reducing the need for other expensive marginal units). So, in the system-integrated cases the system affects the market outcome because it actively changes its net interaction with the grid.

- Display how the **Capacity Factors** of all the elements of the system change.
- Visualize how the added systems change the **Market price**.
- Find out the highest and lowest **Capture prices** and **Capture rates** during discharge and charge phases. The capture price of an asset is the average electricity market price that the asset actually experiences, weighted by when it produces (or consumes) electricity. It differs from the simple average market price because it accounts for the fact that the unit is not active uniformly over time: it “captures” higher prices if it operates mostly during high-price hours, and lower prices if it operates mostly during low-price hours. The capture rate is the ratio between the asset capture price and the market price.
- Measure the impact of the Compressor Heat Pump on the baseload plant in terms of **heat flows** and **electricity production**.
- Evaluate the best one in terms of **Levelized Cost Of Energy** and assess whether the additional flexibility plant investment is economically reasonable.

4.2 Quantified Carbon model

At the base of this thesis there is a collaboration with the international consultancy firm Quantified Carbon, and it is through a shared Pyomo-based optimization model, called “optiTES”, that the simulation of implementation of the Thermal Energy Storage with the Peaker Turbine is carried out. This work relies on Quantified Carbon’s cGrid framework (documented in [24]), a non-linear power market simulation tool that models price formation and market equilibrium through an iterative price-setting procedure based on supply-demand balance and short-term price forecasts.
This model most importantly generates all the detailed technical and economical outputs needed for the analyses, as well as plots in a two-week period:

- Market price curve.
- How the electrical power flows in the Baseload and Peaker turbines, in the Electrical Heater (EH) and in the Heat Pump (HP).
- How the thermal power flows inside and outside of the TES.
- The TES storage level.

Additionally, to better visualize the heat flows in all the system elements, some Python-written modules were implemented in the already existing modeling code to carry out an heat/electricity balance of the system that is displayed through Sankey-style diagrams.

After choosing the desired inputs, the model finds the optimal configuration of the system for the electricity market considered, which is implemented through a “Price Ladder” of the market, that in this case represents the electricity prices as different balances between supply and demand. Moreover, as can be seen in the plotted market price curve, negative prices are cut off at 0 EUR/MWh.

4.3 Simulations Reports

The chosen inputs and the figures of interests considered in the simulations outputs are split in several sections (General Summary, Spot market volatility (price), Boiler, Power Plant, Heat Pump, Electrical Heater, TES, Peaker Turbine, Grid, Cost Breakdown) and

explained one by one in Appendix A.
All together they form a reports table for each Electricity market: Table 4.1 for Poland, Table 6.1 for Germany and Table 6.2 for France.
In particular, reports tables for Germany and France Electricity Markets can be found in Appendix B.
For the different scenarios descriptions please refer to Paragraph 4.1.
Considering the most relevant scenario the one characterized by the utilization of the CoHP and the EH, the optiTES results plots as well as the Sankey heat flow/electricity diagram are presented for this case. In the same way as before, the optiTES results plots as well as the Sankey heat flow/electricity diagrams for Germany and France for this scenario are presented in Appendix B.

Poland Electricity Market

Table 4.1: *Simulations results of the four scenarios in the Polish Electricity Market.*

		Poland Electricity Market				UoM
		Scenario 1: noTES	Scenario 2: EH	Scenario 3: HP	Scenario 4: HP+EH	
General Summary	RTE		34.74%	164.11%	143.50%	
	RTE_{pen}			73.76%	69.54%	
	Market price	53.63	53.46	53.15	53.19	EUR/MWh
	Cap. price total	76.50	77.64	87.35	87.12	EUR/MWh
	Cap. price charg.		0	12.05	9.82	EUR/MWh
Spot market volatility (price)	<0 perturbed	9.66%	8.70%	8.98%	8.94%	
	>200 perturbed	1.61%	1.63%	1.91%	1.89%	
Boiler	Utilization	0.68	0.70	0.69	0.69	
Power Plant	W_{th}	3000				MW_{th}
	η_{PP}	0.35				
	W_e	1050				MW_e
	Utilization	0.68	0.70	0.59	0.59	
	Capture price	76.50	74.23	84.88	84.47	EUR/MWh
	Capture rate	1.43	1.39	1.60	1.59	
Heat Pump	COP	/	/	4.5		
	C			300.0		MW_e
				1350.0		MW_{th}
	Utilization			0.27	0.26	
	Capture price			12.05	11.71	EUR/MWh
	Capture rate			0.23	0.22	
	Heat extraction			13.60%	13.19%	
	COP_{pen}			2.0	2.0	
Electrical Heater	η	/	0.95	/	0.95	
	C		873.5		139.1	MW_e
			829.8		132.2	MW_{th}
	Utilization		0.25		0.11	
	Capture price		0		0	EUR/MWh
TES	C	/	5761.2	9031.4	9340.6	MWh
	Efficiency		97.03%	97.25%	97.18%	
Peaker Turbine	η_{PT}	/	0.37			
	C		1305	1351.4		MW_{th}
			482.8	500.0		MW_e
	Utilization		0.16	0.26	0.27	
	Capture price		110.63	99.05	99.59	EUR/MWh
	Capture rate		2.07	1.86	1.87	
Grid	C	1050.0	1532.8	1550.0	1550.0	MW_e
	Utilization	68%	44%	45%	44%	
Cost Breakdown (LCOE)	**Fuel**	15.9	18.5	16.8	17.0	EUR/MWh
	Flexible plant	/	6.9	12.9	13.4	EUR/MWh
	Heater (HP + EH)		1.2	3.9	4.1	EUR/MWh
	TES		4.4	6.3	6.6	EUR/MWh
	Peaker turbine		1.3	1.3	1.3	EUR/MWh
	Charging cost		0.0	1.4	1.4	EUR/MWh
	Grid	5.8	6.7	6.4	6.4	EUR/MWh
	TOTAL COST	21.7	32.1	36.1	36.8	EUR/MWh

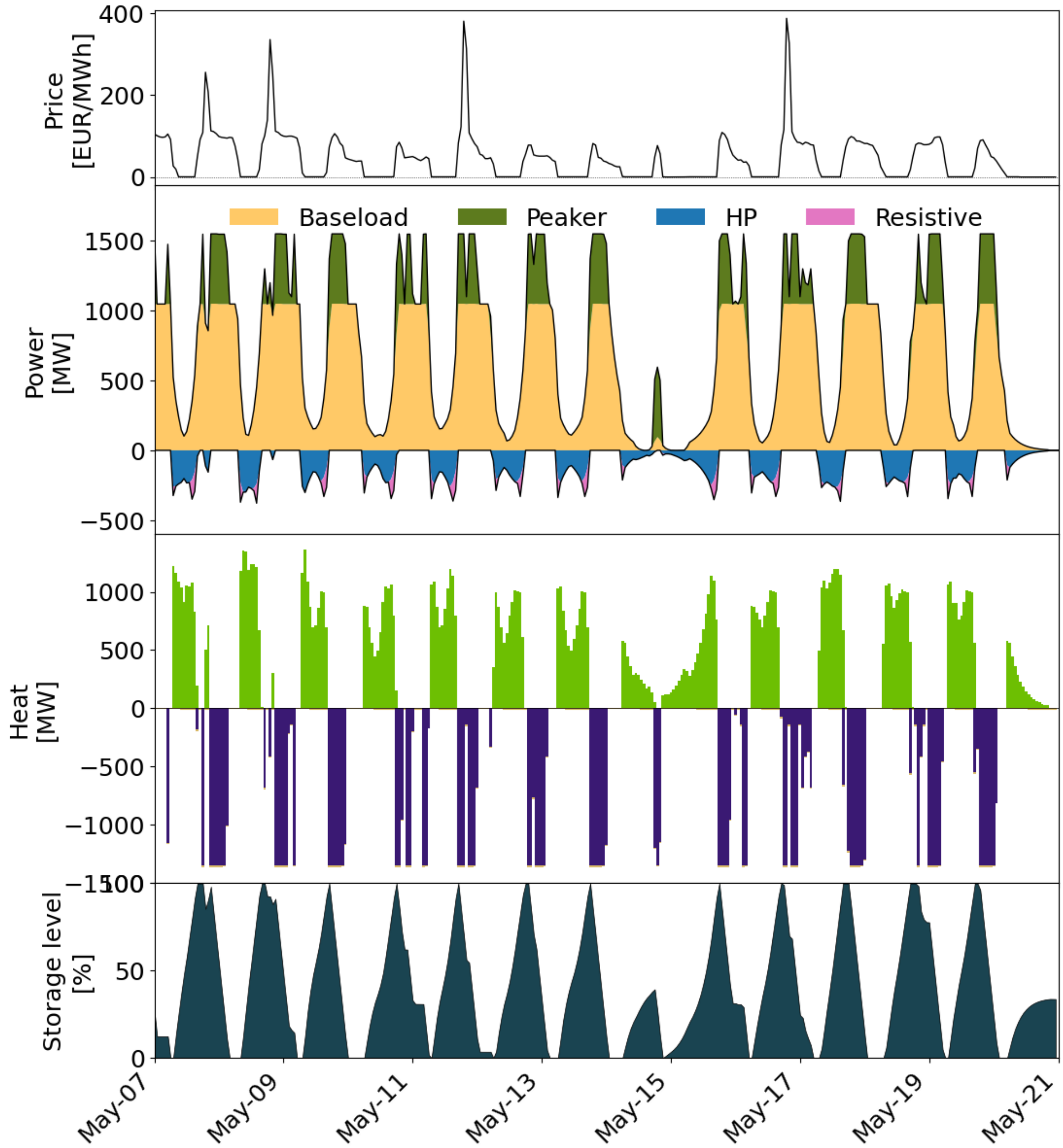

Figure 4.1: *Simulation of the HP + EH scenario in the Polish Electricity Market.*

Analyzing this Figure we can see how the Baseload Power Plant reduces its output power in periods characterized by low prices, and it is in this time window that the reactor power is channeled to the Compressor Heat Pump and, if necessary, also to the Resistive Heater.

Additionally, it can be understood how the Peaker Turbine enters in operation when there is a sharp and fast increase in the market prices, covering the demand power peaks that the Power Plant (PP) couldn't have produced, since it has a maximum electrical capacity

and a lower ramp-up time.
A positive Heat Flow means heat entering the Thermal Energy Storage, while a negative one means heat exiting the Thermal Energy Storage.

Here below the Heat/Electricity Balance is presented through a Sankey diagram, in order to better understand the magnitude of the heat flows and the powers in every element of the system.

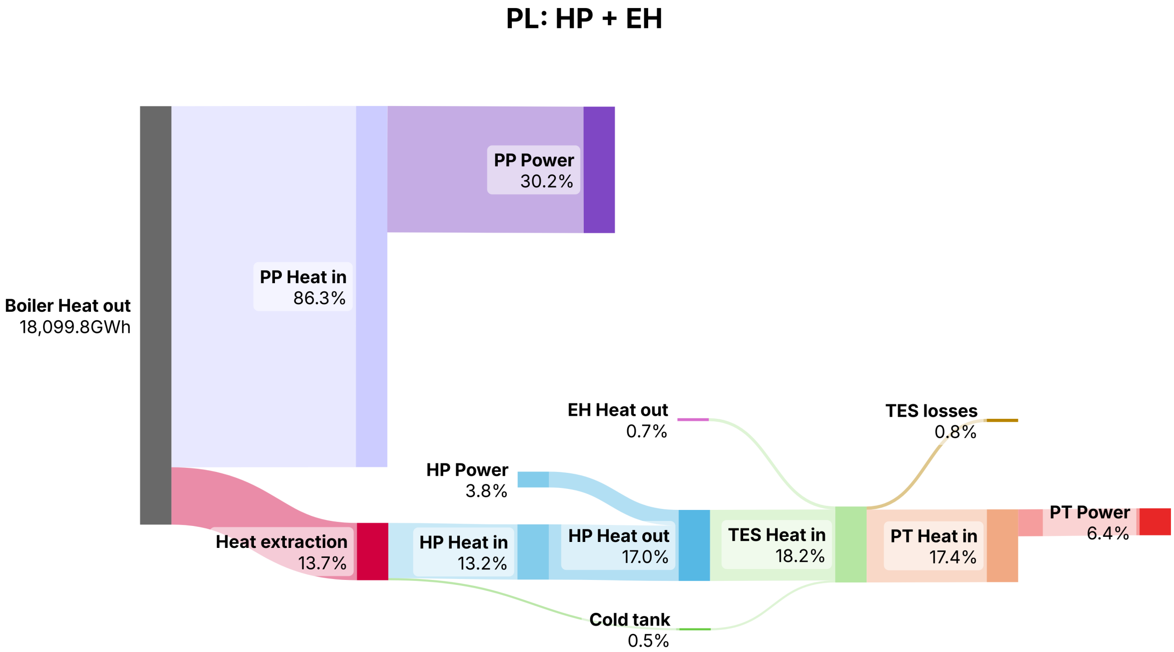

Figure 4.2: *Heat/Electricity Balance of the HP + EH scenario in the Polish Electricity Market.*

It has been found that 13.7% of the heat generated in the Boiler is the optimal amount that must be extracted.

5 Results and Discussion

5.1 Scenarios comparison

In this paragraph the results comparisons are made, dividing them in the three markets considered. In particular, results for Germany and France Electricity Markets can be found in Appendix C.

For the different scenarios descriptions please refer to Paragraph 4.1.

Poland Electricity Market

Round Trip Efficiency

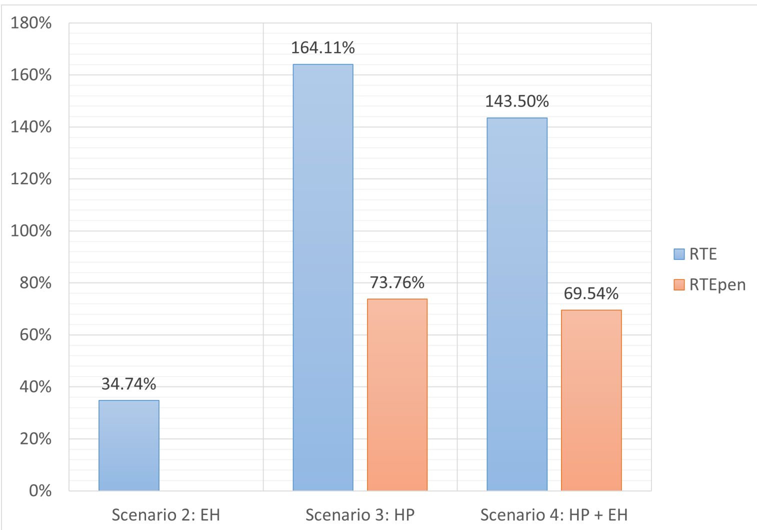

Figure 5.1: *Comparison of the RTE and RTE_{pen} in the Polish market for the different scenarios.*

Figure 5.1 compares the electric Round Trip Efficiency (RTE) of the flexibility block, defined as the ratio between the electricity generated by the peaker turbine during discharge and the electricity consumed by the charging element. For the EH-only case, charging is a direct electricity-to-heat conversion, followed by heat-to-electricity conversion in the peaker turbine and TES losses; therefore, the electric RTE remains below 100%. When the heat pump is used, the electric RTE can exceed 100% because the compressor electricity does not provide all the heat stored in the TES. Instead, the heat pump upgrades thermal energy extracted from the NPP steam cycle: the TES receives a heat input larger than the compressor work by a factor $COP > 1$. As a result, the peaker can generate more electricity during discharge than the electricity absorbed by the compressor during charge. If we consider the steam extraction as electricity not produced/consumed, so at the denominator of the calculation, the RTE goes below 100% (RTE_{pen}).

Spot market hours (price)

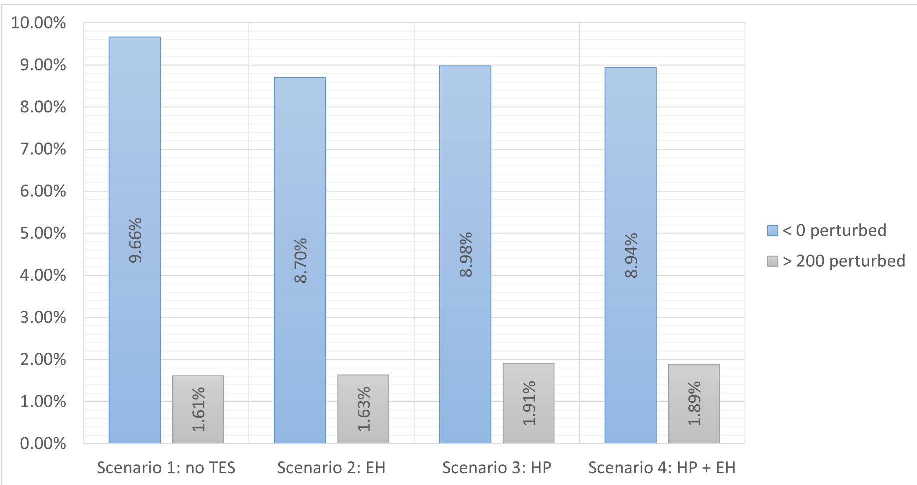

Figure 5.2: *Comparison of the Spot market hours below 0* $\frac{EUR}{MWh}$ *and above 200* $\frac{EUR}{MWh}$ *in the Polish market for the different scenarios.*

The figure compares four market-perturbation scenarios for the electricity spot price after installing the NPP-based system with different options for charging the TES.
When it is introduced, the most consistent effect across all TES options is a reduction in negative-price hours. This indicates that storage provides flexibility by diverting part of the energy that would otherwise be exported as electricity into stored heat, thereby reducing the tendency of the NPP to worsen oversupply conditions.
The response of the high-price tail depends on the TES charging technology. With electrical-heater charging, the frequency of very high-price hours remains broadly similar to the reference, suggesting that the main benefit is the mitigation of low-price extremes rather than a strong impact on scarcity events. With HP charging (and HP+EH),

negative-price hours still decline, but very high-price hours can be slightly more frequent. Because the TES cold tank needs to be kept above a temperature threshold with steam coming directly from the Baseload Power Plant, this represents a reduction in net baseload export. During strained system conditions, the lower net supply can reinforce scarcity pricing. Overall, TES reduces volatility linked to oversupply, but its characteristics may lead to more frequent undersupply conditions.

Utilization (CF)

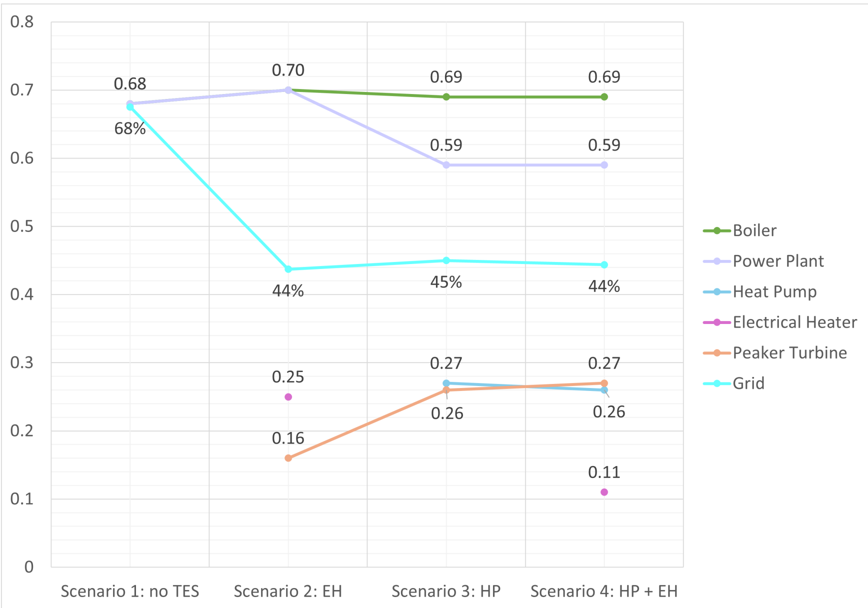

Figure 5.3: *Comparison of the Capacity Factors of the different elements composing the system in the Polish market for the different scenarios.*

As we can see in Figure 5.3, when steam is extracted from the boiler and sent to the CoHP, less steam remains available for expansion in the main turbine. This reduces the net electrical output and therefore lowers the Capacity Factor of the baseload Power Plant in the HP-based configurations.

Conversely the PT capacity factor increases in the HP scenarios mainly because the optimization selects a much larger TES energy capacity, which allows more frequent and/or longer discharge periods during favorable price hours. In the HP cases, discharge is also less concentrated only on extreme price spikes: this is reflected by a lower peaker capture price and capture rate, meaning the peaker operates over a broader set of profitable hours (as shown in Figure 5.4).

A useful comparison is between the Boiler CF and the Power Plant CF. In the HP-based cases, the boiler remains highly utilized, while the PP CF drops significantly. This happens because the reactor/boiler can still operate for many hours, but a relevant share of its thermal output is diverted as extracted steam to charge the TES through the heat pump and to maintain the storage salt inventory above the cold-tank temperature level. By contrast, in the EH-only case the Boiler CF and PP CF are almost identical, because most of the heat used for charging is provided electrically by the heater and only a small thermal contribution is needed to maintain the cold tank near its minimum operating temperature.

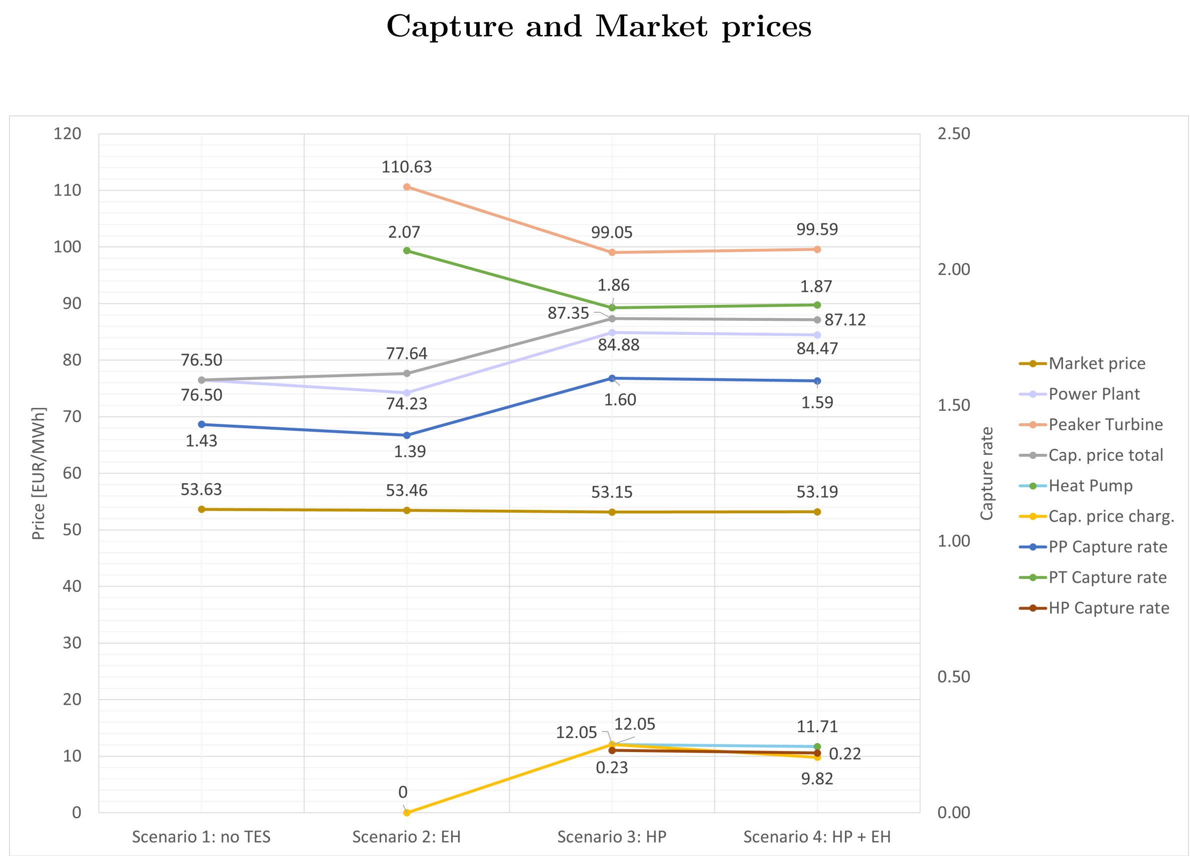

Figure 5.4: *Comparison of the Capture prices of the different elements composing the system and the Market price in the Polish market for the different scenarios.*

Overall, the average market price remains broadly stable, with a small reduction in the CoHP-based configurations. This is consistent with the arbitrage behavior introduced by TES: the system tends to charge in low-price hours and discharge during high-price periods, thereby mitigating price extremes at the system level.

In parallel, the total capture price increases when moving from the reference case to TES-enabled configurations and rises further in the CoHP cases.

This reflects the fact that the PP capture price (and therefore the PP capture rate) increases when TES is introduced because storage provides flexibility to avoid selling baseload electricity during low-price hours. Part of the PP output is diverted to charging, so fewer MWh are sold in cheap hours and a larger share of the remaining PP sales occurs in higher-price periods, increasing the output-weighted average price captured by the PP. This effect is stronger in the CoHP cases because charging requires PP electricity for the compressor and steam extraction reduces the net PP electric output during charging hours, further limiting PP sales when prices are low and rising the average captured price of the electricity that is sold.

Regarding the PT capture price (and also capture rate), a decrease can occur even if the peaker is used more (as shown in Figure 5.3), because it is just the output-weighted average market price during the hours when the peaker runs. With a larger TES and more effective charging, the peaker may discharge not only during the highest price spikes but also during other high-price hours, which lowers this average. In addition, peaker discharge tends to reduce price peaks, which can further decrease the capture price.

A key difference emerges on the charging side. In the EH-only scenario, the EH capture price is equal to 0 EUR/MWh, indicating that charging is attractive only when electricity is available at (approximately) zero or negative prices. By contrast, in the CoHP cases the charging capture price becomes clearly positive (and the HP capture rate is <1), meaning that charging can remain economically viable even when prices are low but not necessarily negative, due to the higher effective conversion performance of the HP-based option.

The close similarity between HP and HP+EH outcomes indicates that the EH plays a marginal role (it is used primarily in the cheapest hours), rather than substantially reshaping the overall value captured by the system.

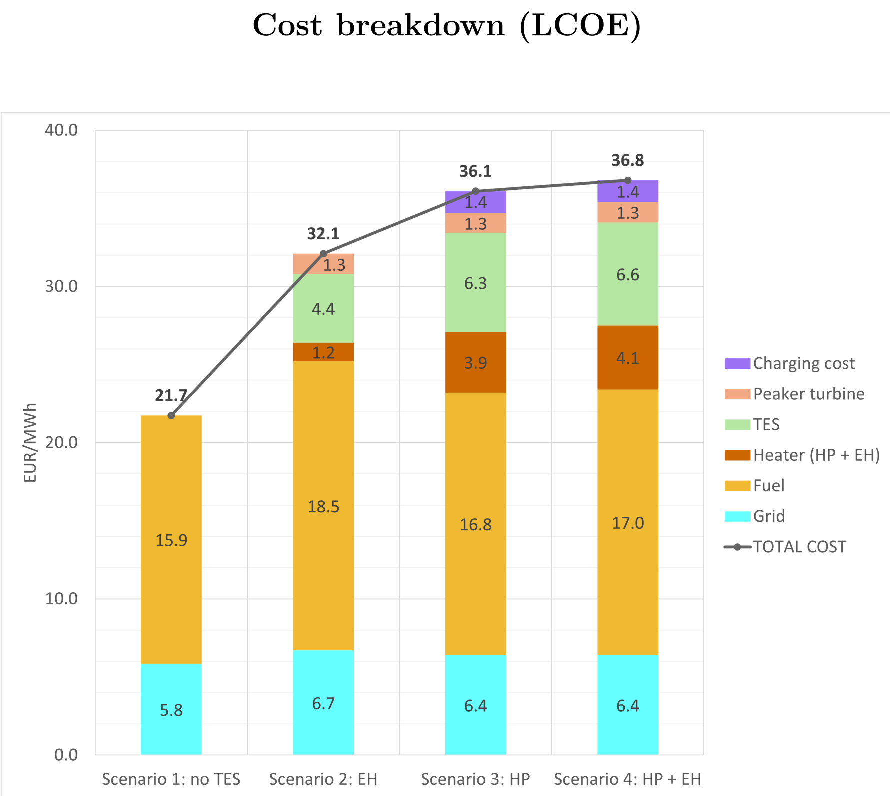

Figure 5.5: *Comparison of the different elements costs composing the system in the Polish market for the different scenarios.*

In the Polish market, introducing TES-enabled flexibility changes the LCOE structure by adding non-negligible contributions from the flexibility block (EH/HP, TES, Peaker Turbine, and charging-related terms) on top of the baseline cost drivers.

In particular, the scenarios with the CoHP show a higher TES cost contribution, because the optimization selects a larger thermal storage capacity, which increases the fixed-cost term attributed to the TES.

At the same time, the EH-only case exhibits the highest fuel cost per net MWh sold, which is consistent with the definition of the fuel-cost term: when charging relies on resistive heating, the electricity consumed for charging reduces the net electricity sold, thereby increasing cost components expressed per net MWh.

From an economic perspective, Figure 5.5 should be read together with Figure 5.4, which lead to Figure 5.6. The additional flexibility investment is justified only if the extra cost terms introduced by the flexibility block (heater fixed cost, TES fixed cost, peaker-turbine fixed cost, and charging variable cost) are compensated by a higher value of electricity sales, here reflected by the increase in the Total Capture Price. Their difference is represented by the parameter "delta" in Figure 5.6.

In Poland, the EH case increases the Total Capture Price only slightly (+1.14 EUR/MWh), while it introduces an additional flexibility cost (6.9 EUR/MWh) and increases the effective costs per net MWh sold due to charging; therefore, the uplift in Capture price is relatively small compared to the added cost items. By contrast, the HP-based cases show a much larger increase in Total Capture Price (HP: +10.85 EUR/MWh; HP+EH: +10.62 EUR/MWh), but they also require a larger and more expensive flexibility block (HP: 12.9 EUR/MWh; HP+EH: 13.4 EUR/MWh), dominated by TES and other fixed-cost components, which raises the total cost. In these scenarios the Capture price increase is of the same order of magnitude as the cost increase, so the investment case appears borderline and sensitive to the assumed inputs. The investment becomes more attractive if the plant can earn additional revenues from flexibility services (e.g., capacity or ancillary services), beyond energy arbitrage.

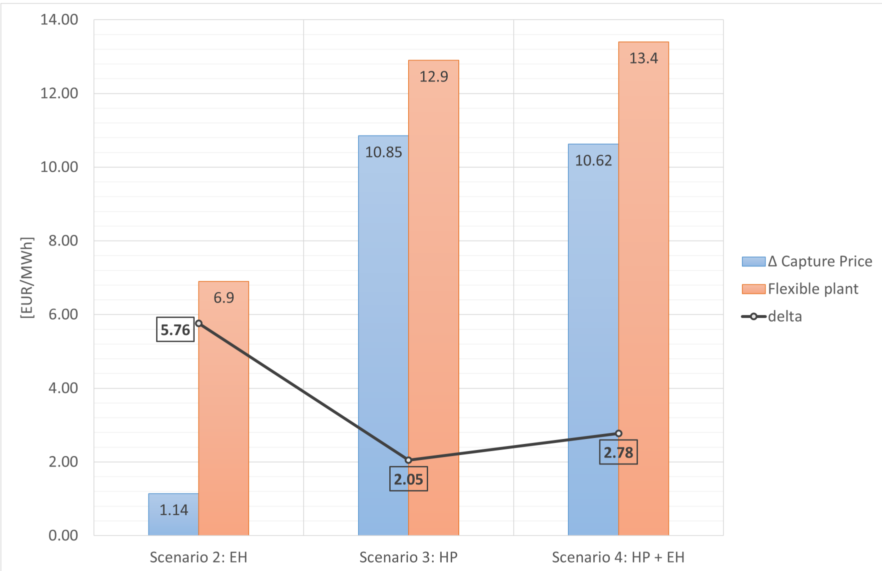

Figure 5.6: *Economic evaluation of the three integrated scenarios in the Polish Electricity Market.*

5.2 Markets comparison

In this paragraph the results comparisons of the different electricity markets are divided into the four scenarios considered.

In particular, since the most relevant scenario is considered the one characterized by CoHP and EH, results for the no TES, EH and HP scenarios can be found in Appendix D.

For the different scenarios descriptions please refer to Paragraph 4.1.

5.2.1 HP + EH scenario

Round Trip Efficiency

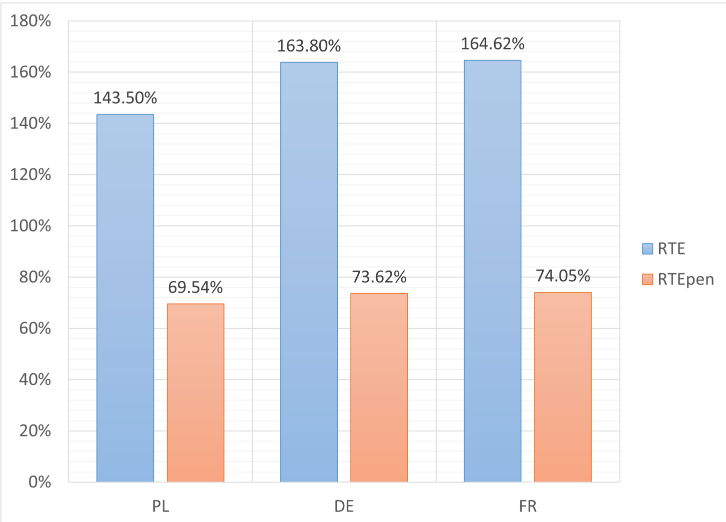

Figure 5.7: *Comparison of the RTE and RTE_{pen} in the HP+EH scenario for the different electricity markets.*

Germany and France show similarly high RTE values, while Poland has a lower RTE. In the HP+EH layout, a lower RTE indicates a higher share of charging performed by the EH, because resistive heating requires more electricity per unit of useful stored heat than heat-pump charging ($COP > 1$). Therefore, the lower RTE in Poland suggests that the EH is used more there, whereas in Germany and France the model selects no meaningful installation of the EH, as shown in Tables 6.1 and 6.2. If we consider the steam extraction as electricity not produced/consumed the RTE goes below 100% (RTE_{pen}).

Spot market hours (price)

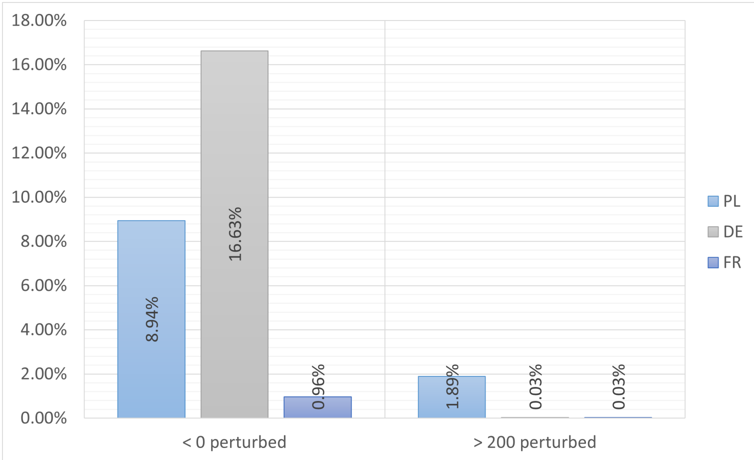

Figure 5.8: *Comparison of the Spot market hours below 0* $\frac{EUR}{MWh}$ *and above 200* $\frac{EUR}{MWh}$ *in the HP+EH scenario for the different electricity markets.*

The figure compares the same configuration, TES charged with the HP and EH, across the three spot markets. For negative prices, the result is strongly market-dependent: Germany shows the largest share of negative-price hours, Poland is clearly lower, and France is much lower. This indicates that oversupply-driven extremes remain a structural feature in Germany even with the HP+EH option, while they are far less common in France. For very high prices, Poland shows a noticeable share of hours above the high-price threshold, whereas Germany and France remain close to zero. This suggests that scarcity-driven price spikes are mainly relevant in Poland under this configuration.

Utilization (CF)

A clear pattern is that HP utilization and PT utilization are closely aligned within each market, indicating a consistent annual balance between charging and discharging. The overall use of the flexible plant is highest in Poland, intermediate in Germany, and lowest in France, reflecting that the TES–peaker system is used more often in markets where price spreads are larger.

The electrical heater plays a secondary and market-specific role: in Germany and France the optimal heater capacity is zero, meaning the model does not rely on resistive charging in those markets; in Poland, instead, the optimizer installs a non-zero EH capacity with

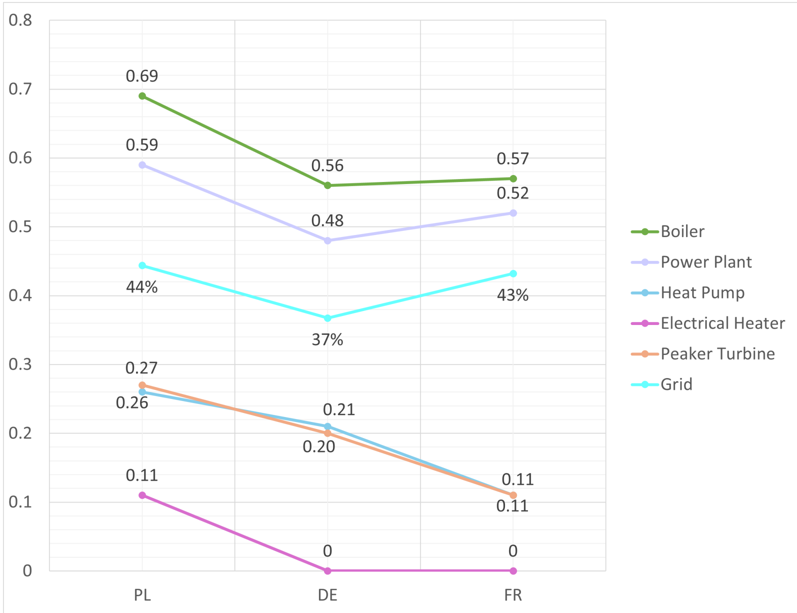

Figure 5.9: *Comparison of the Capacity Factors of the several elements composing the system in the HP+EH scenario for the different electricity markets.*

a low CF, suggesting it is used only in a limited set of very cheap hours to complement HP charging.

Finally, in all three markets the Boiler CF remains higher than the PP CF. This is consistent with the need to extract steam for the CoHP and to provide heat for TES temperature maintenance, which sustains boiler operation even when the net electric output of the main turbine is reduced.

Capture and Market prices

The generation-side capture rates show a clear difference between the main PP turbine and the PT. The latter captures the highest prices in Poland and progressively lower prices in Germany and France because very high-price hours are still relevant in Poland, while they are almost absent in the other markets, as already seen in Figure 5.8. In Poland and Germany, the PT capture rate is higher than the PP capture rate, meaning the peaker operates more selectively in the highest-price hours than the main turbine; in France, instead, the PP capture rate exceeds the PT capture rate, indicating that PP generation is better aligned with expensive hours than peaking operation.

On the charging side, only Poland has a non-zero electrical-heater capacity, and the EH capture price is always zero; therefore, the overall charging capture price (HP+EH) in

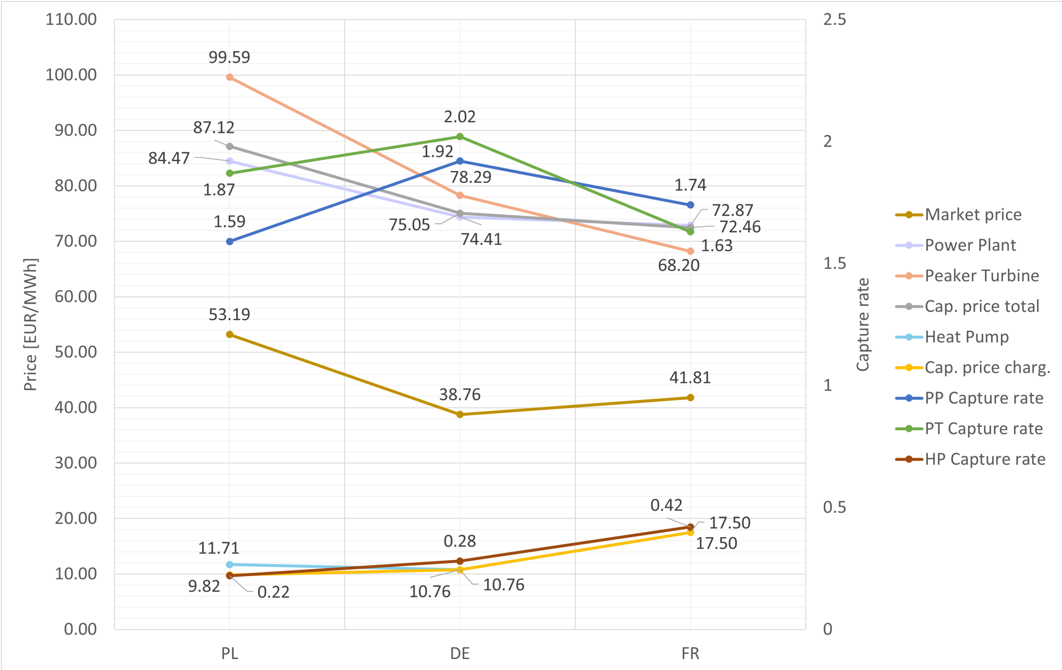

Figure 5.10: *Comparison of the Capture price of the several elements composing the system and the Market price in the HP+EH scenario for the different electricity markets.*

Poland becomes lower than the HP charging capture price, because the zero-price heater pulls the average charging cost down. In Germany and France, where the EH is not used, the overall charging capture price coincides with the HP charging capture price. This is also reflected in the HP capture rates across markets: they are lowest in Poland, higher in Germany, and highest in France, implying that charging the TES via the heat pump tends to occur in relatively cheaper hours in Poland, while in Germany and France it happens in comparatively more expensive hours, reducing the economic advantage of storing heat for later dispatch to the peaker.

Cost breakdown (LCOE)

The cost structure in the HP+EH configuration is market-dependent because the optimizer activates the electrical heater only where it is economically useful.

From an economic perspective the HP+EH option is economically meaningful only if the increase in Total Capture Price is large enough to compensate the additional cost of the flexible plant. A shown in Figure 5.12, in Poland, HP+EH yields a large revenue increase but also a large flexibility cost (as described in 5.1), so the value gain and cost increase are of similar magnitude and the investment case appears borderline under the assumed

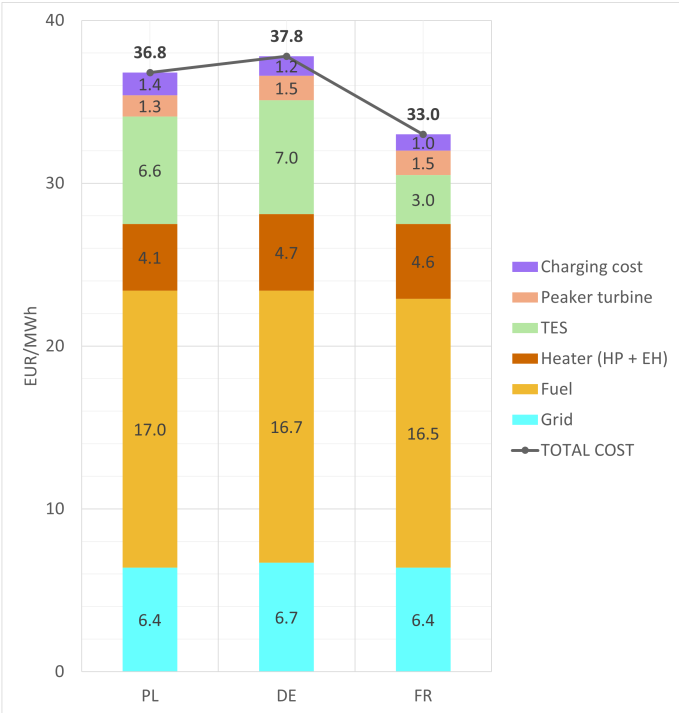

Figure 5.11: *Comparison of the several elements costs composing the system in the HP+EH scenario for the different electricity markets.*

inputs. In Germany, HP+EH increases Total Capture Price while the flexible-plant cost is much higher (as described in C.1), so the added cost outweighs the increase in revenue and the investment looks weak under the assumed inputs. In France, HP+EH provides only a modest revenue increase while adding a substantial flexible-plant cost (as described in C.2), so the HP+EH option is also weak in this market under the assumed inputs.

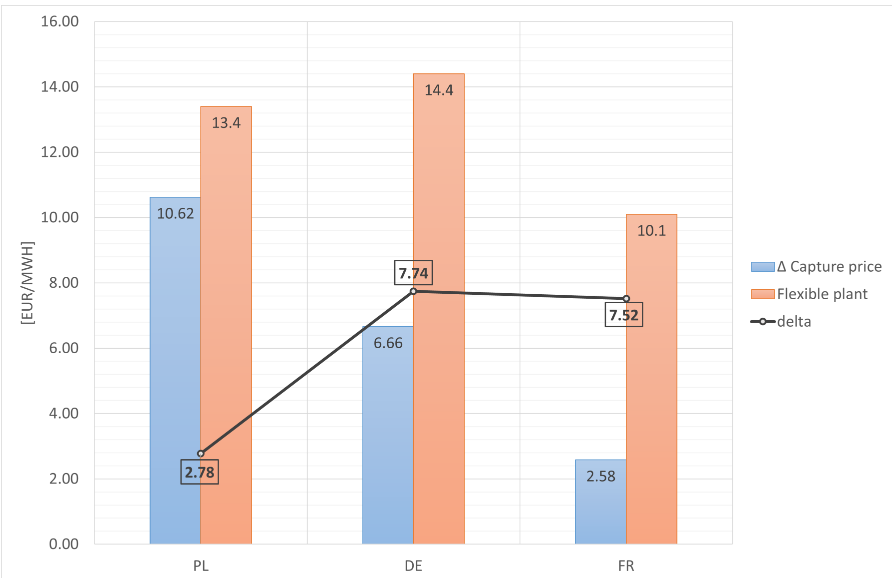

Figure 5.12: *Economic evaluation of the electricity markets in the HP+EH scenario.*

6 Conclusions

This thesis evaluates a hybrid concept in which a large nuclear unit provides flexibility through molten-salt thermal energy storage and a peaker steam cycle, rather than relying only on deep electrical ramping. The simulations indicate that the concept can follow market signals through systematic charging during low-price periods and discharging during price peaks, but the overall benefit depends strongly on the charging technology and on the price patterns of the market considered.

A consistent operational behavior emerges from the optimized dispatch. When market prices are low, the baseload unit reduces direct electricity production and diverts part of the available output to the charging devices. When prices increase sharply, the peaker turbine is dispatched to cover peaks that the baseload turbine cannot supply economically or within its operating limits. This confirms that the TES-based architecture can provide short-term flexibility while keeping the nuclear heat source closer to steady operation.
In particular, it has been evaluated whether the proposed integrated system allows a higher utilization (Capacity Factor) of the nuclear heat source. The results show that adding TES mainly decouples the boiler operation from the net baseload electricity output: the Boiler CF stays similar or increases slightly, while the Power Plant CF can decrease because part of the steam and electricity is diverted to charging and because a continuous heat input is needed to keep the TES cold tank within its operating temperature range.

- In Poland, Boiler utilization remains around 0.68–0.70 across scenarios, but in the HP-based cases the PP CF drops to 0.59, showing a clear decoupling between reactor heat production and baseload electricity export.
- In Germany, Boiler CF increases from 0.53 (no TES) to 0.56 (HP/HP+EH), while PP CF decreases from 0.53 to 0.48, again indicating that the reactor can operate more steadily while flexibility is delivered through the TES–peaker path.
- In France, the EH-only case leads to no investment (and therefore no change), while the HP cases slightly increase Boiler CF (0.55 to 0.57) and reduce PP CF (0.55 to 0.52).

Overall, this shift is generally positive from an operational perspective because it reduces the need for deep electrical turndown of the nuclear unit and shifts flexibility to the storage–peaker block instead of the reactor-baseload turbine.

The most important technical result is the clear performance advantage of heat-pump-based charging over pure resistive charging. With the Round Trip Efficiency definition adopted in this work (electricity produced by the peaker turbine divided by electricity consumed by the charging devices), the HP scenarios reach RTE values above 100%, while EH-only scenarios remain close to one 35%.

- In Poland the EH scenario has $RTE = 34.74\%$, whereas the HP scenario reaches $RTE = 164.11\%$ and the combined scenario has $RTE = 143.50\%$.
- In Germany the EH scenario has $RTE = 34.54\%$, while the HP scenarios reaches $RTE = 163.80\%$.
- In France, the HP scenarios reaches $RTE = 164.62\%$.

From a thermodynamic standpoint, this is consistent with the role of the CoHP: its COP enables a higher thermal input to the molten salts per unit of electricity used for charging, which increases the discharge potential of the peaker cycle.

Market volatility in this work is described using two indicators that are directly relevant for storage-based value shifting: the share of hours with negative prices and the share of hours with very high prices. These two regions reflect different system conditions: negative prices typically occur during oversupply and limited downward flexibility, whereas very high prices indicate scarcity and a high value of fast, dispatchable generation.
Within the modeling approach adopted here, the hybrid plant can influence market outcomes through its operating strategy. Charging the TES changes the plant's interaction with the grid, while discharging through the dedicated peaker turbine increases net supply during high-value periods. The resulting frequency of extreme-price hours should therefore be interpreted as a modeled system response and as an indicator of how effectively TES reallocates energy from low-value to high-value hours.
In practical terms, TES provides value by reducing exposure to oversupply conditions that drive negative prices and by enabling targeted discharge during scarcity events. This improves the timing of electricity sales and increases the ability of the plant to capture value

when market prices are highest.

A complementary way to interpret the results is through the market price level and the technology-specific capture metrics (prices and rates). These indicators vary across markets and scenarios because they are driven by the time correlation between generation/consumption profiles and hourly prices. In general, the Peaker Turbine shows the highest capture rates because discharge is scheduled mainly in above-average price hours; however, its capture price can decrease when utilization increases, if discharge becomes less concentrated on peak hours and is spread over a broader set of moderately priced hours. Conversely, the baseload plant capture price often increases when TES is introduced, because storage allows the system to avoid selling electricity during low or negative price hours (by charging or by reducing net exports), leaving a larger share of PP sales in higher-price periods. The effect is typically stronger when the CoHP is available, because charging requires steam extraction and compressor power, which further limits PP net sales during low-price charging windows and increases the average price of the electricity that is actually sold.
On the charging side, the HP capture rate is far below unity, confirming that charging is preferentially shifted to the cheapest hours; this is a positive outcome for value capture, but it does not by itself guarantee profitability because the HP capture price must be balanced against the fixed costs of the flexibility block.
Overall, market price, capture prices and capture rates clearly show when the system charges and discharges, and they indicate that the concept creates value mainly by charging when prices are low and discharging (selling) when prices are high. They also clarify why economic performance depends not only on average prices, but also on price distributions, low-price charging availability, and the degree of selectivity in peaker dispatch.

From an economic standpoint, the results show a clear cost premium associated with flexibility in the analyzed cases. The no-storage baseline has the lowest total cost, while TES-based configurations increase total cost due to additional equipment and capital-related contributions.

- In Poland, total cost is 21.7 EUR/MWh in the no TES case, 32.1 EUR/MWh with EH, 36.1 EUR/MWh with HP and 36.8 EUR/MWh with HP+EH.
- In Germany, total cost is 22.0 EUR/MWh in the no TES case, 26.4 EUR/MWh

with EH, and 37.8 EUR/MWh with HP (and HP+EH).

- In France, total cost is 21.9 EUR/MWh in the no TES case, 21.9 EUR/MWh with EH, and 33.0 EUR/MWh with HP (and HP+EH).

A particularly informative outcome is observed in Germany for the combined scenario and in France for both the EH-related configurations: the optimization selects zero EH capacity (C = 0 MW_e), meaning that resistive charging does not create sufficient value to justify investment in that asset under the assumed parameters, so in the HP+EH configuration the molten salts are fully heated by the CoHP. This suggests that, for similar cost and performance assumptions, adding an EH on top of a CoHP may increase complexity without guaranteeing meaningful utilization. EH may still be useful as a backup or under constraints not represented in the simplified model, but it should not be assumed to contribute significantly to annual energy shifting unless its use is clearly supported.

To judge whether the additional flexibility investment is economically sensible in this study, the key comparison is between the increase in Total Capture Price (higher average revenue from electricity sales) and the increase in total cost per net MWh sold (LCOE impact driven by the flexible plant and charging-related terms).

- In Poland the EH increases Total Capture Price only slightly (+1.14 EUR/MWh) while total cost increases much more (+10.4 EUR/MWh), so the investment is not justified in this configuration. HP and HP+EH raise Total Capture Price strongly (+10.85 and +10.62 EUR/MWh), but total cost also rises substantially (+14.4 and +15.1 EUR/MWh). Under the assumed inputs, these cases remain borderline: the revenue gain is of the same order as, but still smaller than, the cost increase.
- In Germany the EH provides the best balance in the tested cases: Total Capture Price increases by +5.69 EUR/MWh while total cost increases by +4.4 EUR/MWh, giving a small positive net effect. By contrast, HP/HP+EH increase Total Capture Price only slightly more (+6.67 EUR/MWh) but require a much larger cost increase (+15.8 EUR/MWh), so they are not economically attractive under the inputs assumed and market conditions. So, in this market the EH case provides the most reasonable balance and this result is achieved with only a small flexibility investment (small optimal sizes of heater, TES and Peaker Turbine), meaning that

limited, targeted flexibility is sufficient to improve value capture, whereas larger HP-based configurations are penalized by high fixed costs that are not matched by additional capture-price gains.

- In France the HP/HP+EH case increase Total Capture Price by +2.58 EUR/MWh but increase total cost by +11.1 EUR/MWh, so the investment is not justified in an energy-only arbitrage setting for this dataset.

In summary, the integrated concept is technically effective at shifting electricity sales toward higher-price hours, but its economic viability is highly market- and assumption-dependent. In this context, the proposed architecture can be interpreted as a flexibility-oriented asset and, with the current inputs, its value increases only when markets exhibits frequent and sharp scarcity events while also providing sufficiently low-price charging windows, so when they offer sufficiently large and frequent price spreads between charging and discharging periods.
Accordingly, the viability of NPP–TES–Peaker Turbine solutions should not be evaluated only through average price levels, but also through additional indicators that describe peak frequency, peak duration, peak steepness, and the availability of low-price hours for charging, which may lead to revenues for flexibility beyond spot energy arbitrage. This also implies that the conclusions may change under future market evolution even if average annual prices remain similar, because the concept is driven more by spreads and extreme events than by averages.

Overall, the thesis supports the following conclusion: the NPP–TES–Peaker Turbine concept provides flexibility and shifts production toward higher-value hours, and the CoHP is the main enabler of high energetic performance and, when available, it tends to dominate the charging operation; however, under an energy-only arbitrage framework and with the assumed cost and performance inputs, the additional equipment increases total system cost, so economic attractiveness ultimately relies on strong and frequent price spreads and, potentially, on complementary revenue streams that reward flexibility beyond the spot market.

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Appendices

A Simulations Parameters

A.1 General Summary

Round Trip Efficiency

The Round Trip Efficiency (RTE, expressed in percentage) represents the total power produced by the Peaker Turbine divided by the total power used by the HP and the EH.

$$RTE = \frac{W_{PT}}{W_{HP} + W_{EH}} \tag{6.1}$$

In addition, the RTE_{pen} represents the "penalized" RTE: it accounts for the electricity not produced because of the steam extraction from the Baseload PP.

$$RTE_{pen} = \frac{W_{PT}}{W_{HP} + W_{EH} + (Q_{HP,in} \cdot \eta_{pp})} \tag{6.2}$$

Market Price

Expressed in $\frac{EUR}{MWh}$, it represents the average of the spot market prices, which depends on the operation of the system.

Capture Price Total

Expressed in $\frac{EUR}{MWh}$, it represents a weighted average of the capture prices of the Power Plant Turbine (PP) and the Peaker Turbine (PT).

It is weighted on the total power produced by the turbines.

$$Capture\ Price\ Total = \frac{(W_{PT} \cdot Capture\ Price_{PT}) + (W_{PP} \cdot Capture\ Price_{PP})}{W_{PT} + W_{PP}} \tag{6.3}$$

Capture Price Charging

Expressed in $\frac{EUR}{MWh}$, it represents a weighted average of the charging capture prices of the HP and the EH.

It is weighted on the total power used by the heating element.

$$Capture\ Price\ Charging = \frac{(W_{HP} \cdot Capture\ Price_{HP}) + (W_{EH} \cdot Capture\ Price_{EH})}{W_{HP} + W_{EH}} \tag{6.4}$$

A.2 Spot Market Volatility

Spot price volatility is assessed by comparing a set of market simulations that differ only in the presence and configuration of the proposed NPP–TES integration. The reference case represents the power system with a conventional NPP and no TES, which means without the additional flexibility introduced by the hybrid concept. The system-integrated cases represent the same market setting with the integrated system in operation and with alternative charging options (EH, CoHP or combined operation). In these cases, the system affects the market outcome because it actively changes its net interaction with the grid: it can introduce a controllable electricity demand when charging the TES, enable temporal shifting of energy through TES charging/discharging, and provide additional generation during high-price periods via the separate Peaker Turbine.
Volatility is evaluated using two indicators that capture the tails of the price distribution: the annual share of very high-price hours (>200 $\frac{EUR}{MWh}$) and the annual share of very low-price hours (<0 $\frac{EUR}{MWh}$). By tracking how these shares vary across the reference case and the different TES configurations, it is possible to quantify how the integrated system changes spot market volatility depending on both the market setting and the chosen system design.

A.3 Boiler

Fixed inputs

The Boiler Utilization is the only value taken in consideration for this element of the system and it is used for a comparison with the Utilization of the baseload turbine of the Power Plant.

A.4 Power Plant

Fixed inputs

For all the simulations carried out the assumed input data for the Power Plant turbine are: its Thermal power ($W_{th} = 3000\ \mathrm{MW_{th}}$), its Efficiency ($\eta_{PP} = 0.35$) and so its Electrical power ($W_e = W_{th} \cdot \eta_{PP} = 1050\ \mathrm{MW_e}$).

Figures of interest

The outputs considered are:

- Utilization: it represents the Capacity Factor.
- Capture price of the PP turbine.
- Capture rate: it represents the ratio between the Capture price and the Market price.

$$Capture\ Rate = \frac{Capture\, Price}{Market\, price} \tag{6.5}$$

A.5 Heat Pump

Fixed inputs

For all the simulations that deal with the CoHP the assumed input data are: its Coefficient Of Performance ($COP = 4.5$, as calculated in the previous thesis chapter), its Electrical Capacity ($C_e = 300\ \mathrm{MW_e}$) and so its Thermal Capacity ($C_{th} = C_e \cdot COP = 1350\ \mathrm{MW_{th}}$).
As seen in the System Layout chapter, during charge (from the CoHP to the TES) and discharge (from the TES to the SSRC) phases the same Heat Exchangers are used; for this reason the Thermal Capacity of the CoHP is fixed and it must be equal to the Thermal Capacity of the Peaker Turbine.

Figures of interest

The outputs considered are:

- Utilization: it represents the Capacity Factor.

- Capture price of the CoHP.
- Capture rate: it represents the ratio between the Capture price and the Market price.
- Heat extraction: it's the ratio between the heat going in the HP and the total heat generated by the Steam Generator of the PP.

$$Heat\ Extraction = \frac{Q_{HP,in}}{Q_{boiler,out}} \tag{6.6}$$

- Compared to the previously described COP, COP_{pen} represents the "penalized" COP: it accounts for the electricity not produced because of the steam extraction from the Baseload PP.

$$COP_{pen} = \frac{Q_{HP,out}}{W_{HP} + (Q_{HP,in} \cdot \eta_{pp})} \tag{6.7}$$

A.6 Electrical Heater

Fixed inputs

For all the simulations that deal with the EH, its efficiency ($\eta = 0.95$) is the only assumed input data.
Differently from the CoHP, the EH capacity is not constrained, so the model is left free to find the optimal capacity for the system and market considered.

Figures of interest

The outputs considered are:

- Electrical Capacity: C_e [$\mathrm{MW_e}$]
  Thermal Capacity: C_{th} [$\mathrm{MW_{th}}$] $= C_e \cdot \eta$
- Utilization: it represents the Capacity Factor.
- Capture price of the EH.

A.7 Thermal Energy Storage

For all the simulations that deal with the TES the model is left free to find its optimal capacity.

Figures of interest

The outputs considered are:

- Capacity: C [MWh]
- Efficiency: expressed in percentage, it represents the ratio between the energy discharged and the energy charged, so, in other terms, the TES losses.

$$Efficiency = \frac{Q_{TES,out}}{Q_{TES,in}} \tag{6.8}$$

A.8 Peaker Turbine

Fixed inputs

For the simulations that deal with the PT and the CoHP the assumed input data are: the efficiency of the PT (η_{PT} = 0.37, as calculated in the previous thesis chapter), the PT Electrical Capacity (C_e = 500 MW_e) and so the PT Thermal Capacity ($C_{th} = \frac{C_e}{\eta_{PT}}$ = 1351 MW_{th}); the Electrical Capacity represents the output power and it is a fixed chosen value since the PT Thermal Capacity, in these cases, must be equal to the CoHP Thermal Capacity, as already stated in Section A.5.

For the simulations that deal with the PT and the EH, the PT efficiency is the only assumed input data and the model is left free to find the optimal PT capacity.

Figures of interest

For the simulations that deal with the PT and the CoHP the outputs considered are:

- Utilization: it represents the Capacity Factor.
- Capture price of the PT.
- Capture rate: as shown in Equation 6.5.

For the simulations that deal with the PT and the EH the outputs considered are:

- Electrical Capacity: C_e [$\mathrm{MW_e}$]
  Thermal Capacity: C_{th} [$\mathrm{MW_{th}}$] $=\frac{C_e}{\eta_{PT}}$
- Utilization: it represents the Capacity Factor.
- Capture price of the PT.
- Capture rate: as shown in Equation 6.5.

A.9 Grid

Fixed inputs

For all the simulations carried out the model is left free to find the optimal Grid capacity.

Figures of interest

The outputs considered are:

- Electrical Capacity: C_e [$\mathrm{MW_e}$]
- Utilization: expressed in percentage, it represents the Capacity Factor.

A.10 Cost breakdown (LCOE)

Assuming to have the same Baseload Power Plant for all the simulated scenarios, the Cost breakdown compares how the different cost changes for all the remaining variables, which are mainly divided into two categories: individual Fuel cost and Flexible plant individual costs.
All individual costs are measured in $\frac{EUR}{MWh}$.
All "Total Fixed" costs are the sum of the CAPEX and OPEX of the element and are measured in $[EUR]$.

Fuel cost

It represents the fuel cost per net MWh of Electricity sold.

$$Fuel\ cost\ = \frac{Total\ Fuel\ cost}{Electricity\ sold} \tag{6.9}$$

where the net Electricity sold [MWh] comes from (plus sign for the Electricity sold, minus sign for the Electricity consumed):

$$Electricity\ Sold\ =\ E_{PP}\ +\ E_{PT}\ +\ E_{bought}\ -\ E_{HP}\ -\ E_{EH} \tag{6.10}$$

Flexible plant

It is made up of:

- Heater cost: it is the sum of the Electrical Heater and the Heat Pump fixed costs per net MWh of Electricity sold.

$$Heater\ cost\ = \frac{Total\ HP\ Fixed\ cost\ +\ Total\ EH\ Fixed\ cost}{Electricity\ sold} \tag{6.11}$$

- TES cost: it represents the TES cost per net MWh of Electricity sold.

$$TES\ cost\ = \frac{Total\ TES\ Fixed\ cost}{Electricity\ sold} \tag{6.12}$$

- Peaker turbine cost: it represents the PT cost per net MWh of Electricity sold.

$$Peaker\ Turbine\ cost\ = \frac{Total\ Peaker\ Turbine\ Fixed\ cost}{Electricity\ sold} \tag{6.13}$$

- Charging cost: it is the sum of the Electrical Heater and the Heat Pump variable costs per net MWh of Electricity sold.

$$Charging\ cost\ = \frac{Total\ HP\ Variable\ cost\ +\ Total\ EH\ Variable\ cost}{Electricity\ sold} \tag{6.14}$$

Total cost

To finally get the Total system cost, all these individual cost must be summed with the Grid cost, which is represented by the sum of the fixed and variable grid costs per net MWh of Electricity sold.

$$Grid\ cost\ = \frac{Total\ Grid\ Fixed\ cost\ +\ Total\ Grid\ Variable\ cost}{Electricity\ sold} \tag{6.15}$$

Now it's possible to find out the Total cost.

$$\begin{aligned} Total\ cost = Fuel\ +\ Flexible\ plant\ +\ Grid\ = \\ Fuel\ +\ Heater\ +\ TES\ +\ Peaker\ turbine\ +\ Charging\ cost\ +\ Grid \end{aligned} \tag{6.16}$$

B Simulation Reports

B.1 Germany Electricity Market

Table 6.1: *Simulations results of the four scenarios in the German Electricity Market.*

		Germany Electricity Market				UoM
		Scenario 1: noTES	Scenario 2: EH	Scenario 3: HP	Scenario 4: HP+EH	
General Summary	RTE		34.54%	163.80%	163.80%	
	RTE_{pen}			73.62%	73.62%	
	Market price	38.73	38.90	38.76	38.76	EUR/MWh
	Cap. price total	68.39	74.08	75.06	75.05	EUR/MWh
	Cap. price charg.		0	10.76	10.76	EUR/MWh
Spot market volatility (price)	<0 perturbed	17.11%	16.93%	16.63%	16.63%	
	>200 perturbed	0.03%	0.03%	0.03%	0.03%	
Boiler	Utilization	0.53	0.54	0.56	0.56	
Power Plant	W_{th}	3000				MW_{th}
	η_{PP}	0.35				
	W_e	1050				MW_e
	Utilization	0.53	0.49	0.48	0.48	
	Capture price	68.39	74.22	74.40	74.41	EUR/MWh
	Capture rate	1.77	1.91	1.92	1.92	
Heat Pump	COP	/	/	4.5		
	C			300.0		MW_e
				1350.0		MW_{th}
	Utilization			0.21	0.21	
	Capture price			10.76	10.76	EUR/MWh
	Capture rate			0.28	0.28	
	Heat extraction			12.99%	12.99%	
	COP_{pen}			2.0	2.0	
Electrical Heater	η	/	0.95	/	0.95	
	C		204.0		0	MW_e
			193.8		0	MW_{th}
	Utilization		0.20		0	
	Capture price		0		0	EUR/MWh
TES	C	/	1160.6	8146.9	8146.9	MWh
	Efficiency		96.76%	96.86%	96.86%	
Peaker Turbine	η_{PT}	/	0.37			
	C		144.9	1351.4		MW_{th}
			53.6	500.0		MW_e
	Utilization		0.27	0.20	0.20	
	Capture price		69.14	78.30	78.29	EUR/MWh
	Capture rate		1.78	2.02	2.02	
Grid	C	1050.0	1103.6	1550.0	1550.0	MW_e
	Utilization	53%	43%	37%	37%	
Cost breakdown (LCOE)	**Fuel**	15.9	18.5	16.7	16.7	EUR/MWh
	Flexible plant	/	1.7	14.4	14.4	EUR/MWh
	Heater (HP + EH)		0.4	4.7	4.7	EUR/MWh
	TES		1.1	7.0	7.0	EUR/MWh
	Peaker turbine		0.2	1.5	1.5	EUR/MWh
	Charging cost		0.0	1.2	1.2	EUR/MWh
	Grid	6.1	6.3	6.7	6.7	EUR/MWh
	TOTAL COST	22.0	26.4	37.8	37.8	EUR/MWh

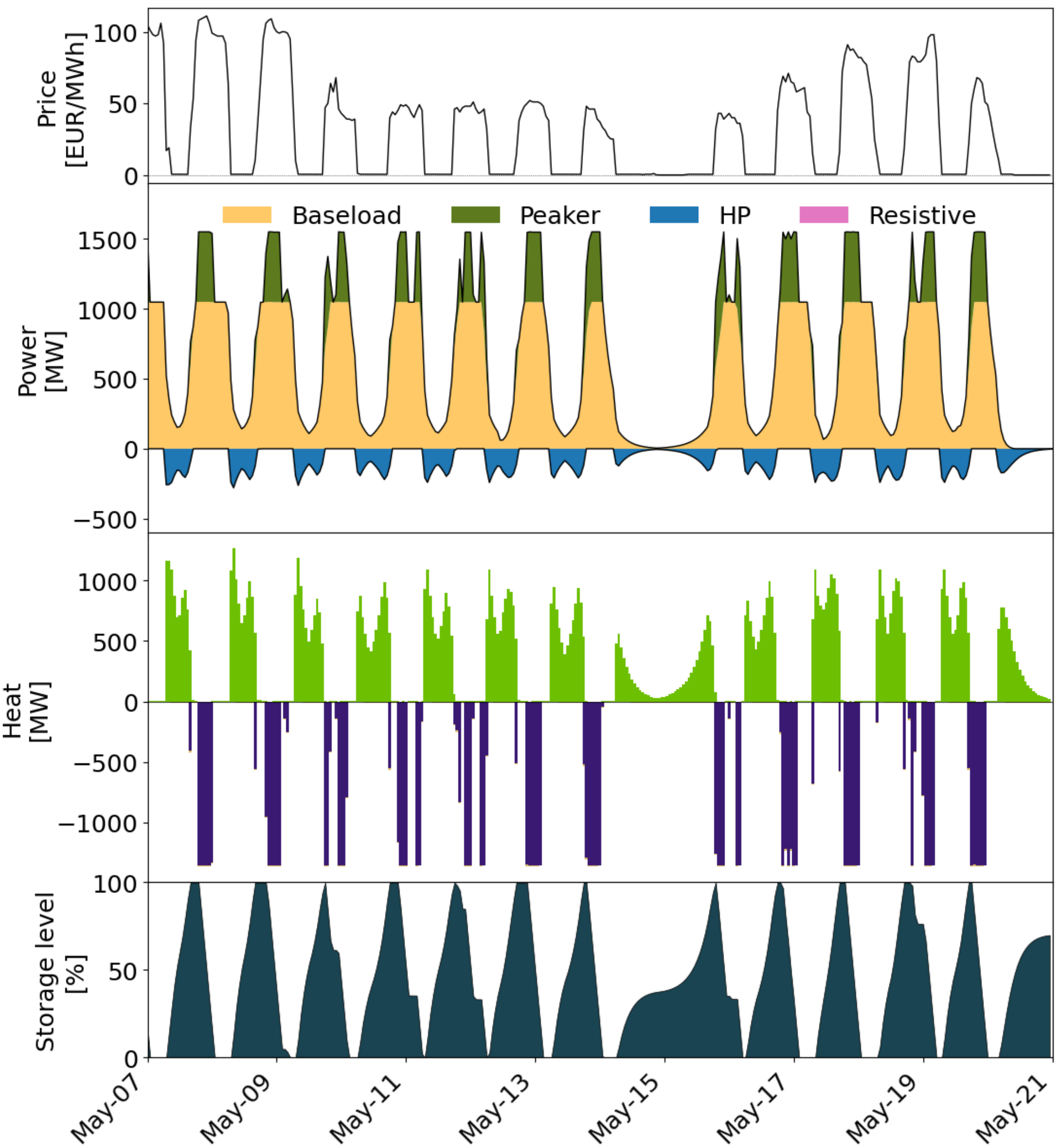

Figure 6.1: *Simulation of the HP + EH scenario in the German Electricity Market.*

As we can see from Figure 6.1 and from Table 6.1, it is not profitable to use the Resistive Heater in this configuration, so the molten salts in the TES are fully heated by the CoHP.

Here below the Heat/Electricity Balance is presented through a Sankey diagram, in order to better understand the magnitude of the heat flows and the powers in every element of the system.

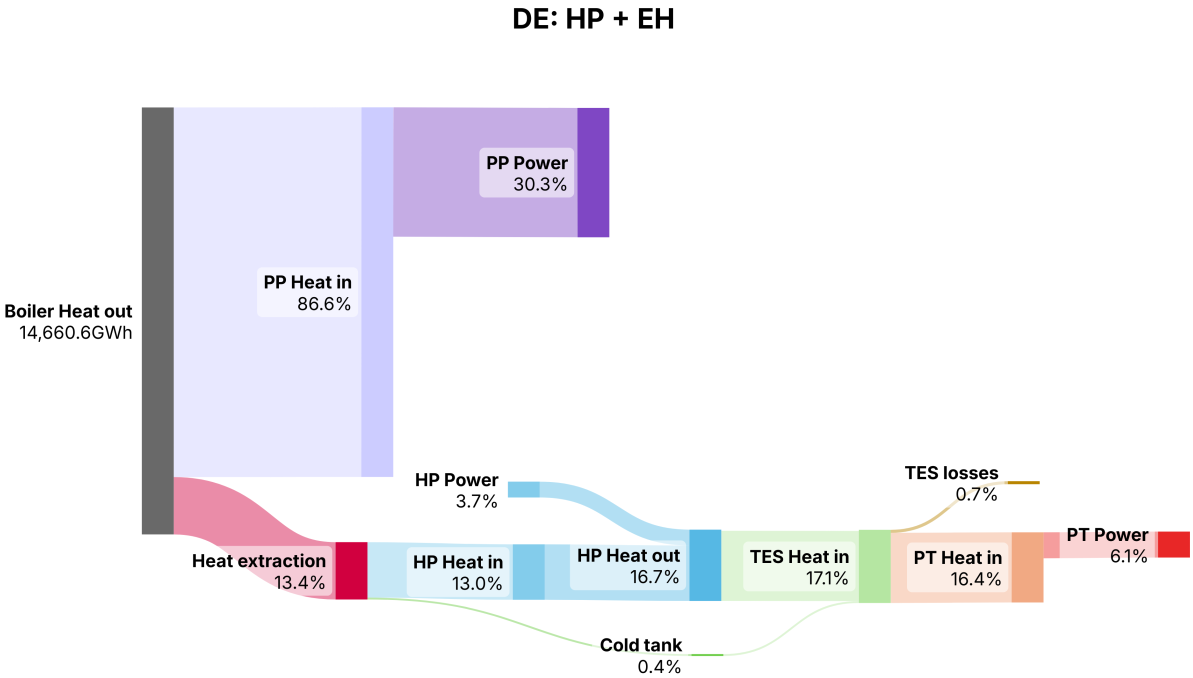

Figure 6.2: *Heat/Electricity Balance of the HP + EH scenario in the German Electricity Market.*

It has been found that 13.4% of the heat generated in the Boiler is the optimal amount that must be extracted.

B.2 France Electricity Market

Table 6.2: *Simulations results of the four scenarios in the French Electricity Market.*

		France Electricity Market				UoM
		Scenario 1: noTES	Scenario 2: EH	Scenario 3: HP	Scenario 4: HP+EH	
General Summary	RTE		/	164.62%	164.62%	
	RTE_{pen}			73.99%	74.05%	
	Market price	41.82	41.82	41.81	41.81	EUR/MWh
	Cap. price total	69.88	69.88	72.46	72.46	EUR/MWh
	Cap. price charg.		0	17.51	17.50	EUR/MWh
Spot market volatility (price)	<0 perturbed	1.44%	1.44%	0.96%	0.96%	
	>200 perturbed	0.03%	0.03%	0.03%	0.03%	
Boiler	Utilization	0.55	0.55	0.57	0.57	
Power Plant	W_{th}	3000				MW_{th}
	η_{PP}	0.35				
	W_e	1050				MW_e
	Utilization	0.55	0.55	0.52	0.52	
	Capture price	69.88	69.88	72.87	72.87	EUR/MWh
	Capture rate	1.67	1.67	1.74	1.74	
Heat Pump	COP	/	/	4.5		
	C			300.0		MW_e
				1350.0		MW_{th}
	Utilization			0.11	0.11	
	Capture price			17.51	17.50	EUR/MWh
	Capture rate			0.42	0.42	
	Heat extraction			6.62%	6.61%	
	COP_{pen}			2.0	2.0	
Electrical Heater	η	/	0.95	/	0.95	
	C		0		0	MW_e
			0		0	MW_{th}
	Utilization		0		0	
	Capture price		0		0	EUR/MWh
TES	C	/	0	3627.6	3627.6	MWh
	Efficiency		/	97.38%	97.38%	
Peaker Turbine	η_{PT}	/	0.37			
	C		0	1351.4		MW_{th}
			0	500.0		MW_e
	Utilization		0	0.11	0.11	
	Capture price		/	68.22	68.20	EUR/MWh
	Capture rate		/	1.63	1.63	
Grid	C	1050.0	1050.0	1333.2	1333.2	MW_e
	Utilization	55%	55%	43%	43%	
Cost breakdown (LCOE)	**Fuel**	15.9	15.9	16.5	16.5	EUR/MWh
	Flexible plant	/	0.0	10.1	10.1	EUR/MWh
	Heater (HP + EH)		0.0	4.6	4.6	EUR/MWh
	TES		0.0	3.0	3.0	EUR/MWh
	Peaker turbine		0.0	1.5	1.5	EUR/MWh
	Charging cost		0.0	1.0	1.0	EUR/MWh
	Grid	6.0	6.0	6.4	6.4	EUR/MWh
	TOTAL COST	21.9	21.9	33.0	33.0	EUR/MWh

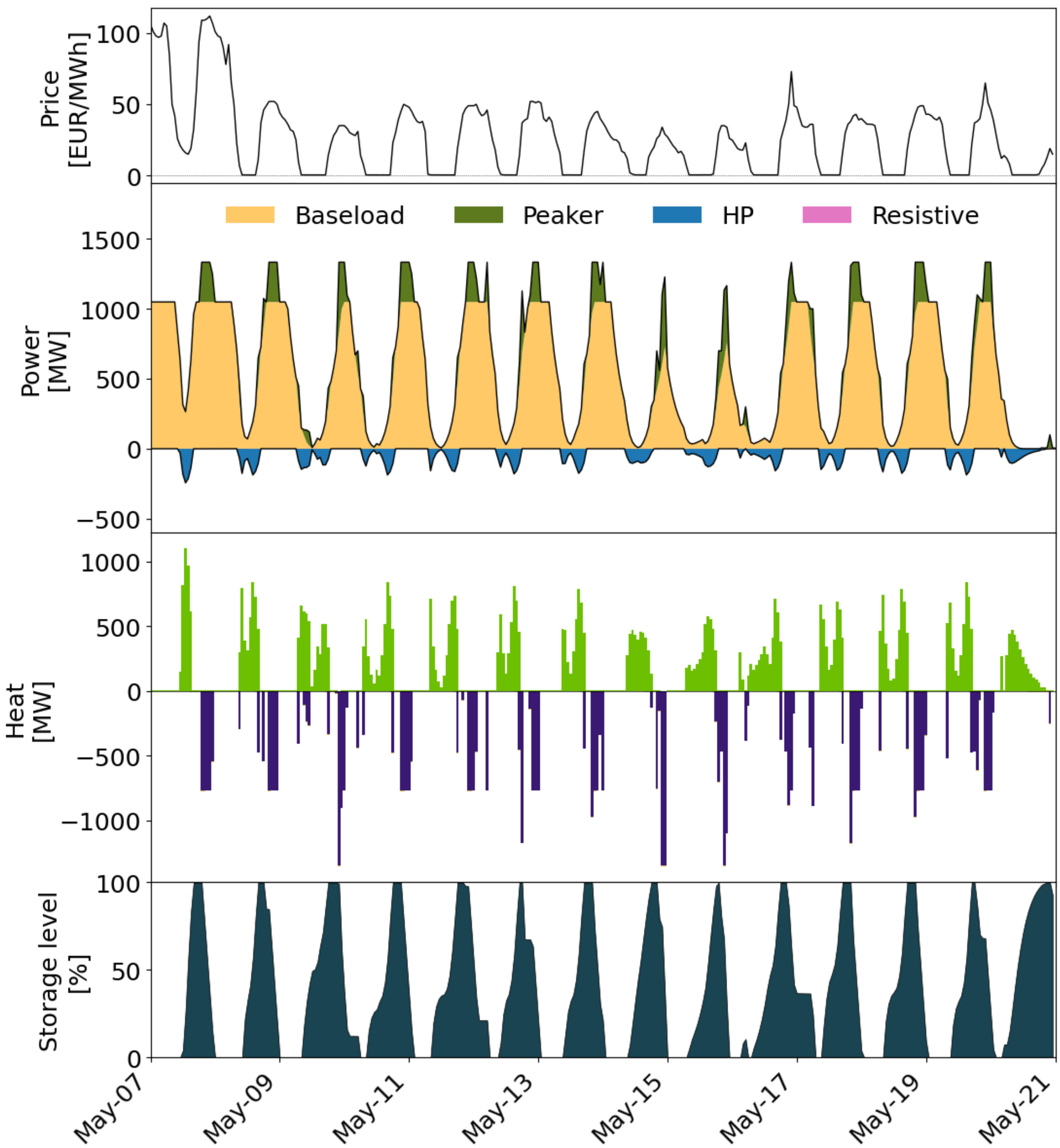

Figure 6.3: *Simulation of the HP + EH scenario in the French Electricity Market.*

As we can see from Figure 6.3 and from Table 6.2, also in this case it is not profitable to use the Resistive Heater in this configuration, so the molten salts in the TES are fully heated by the CoHP.

Here below the Heat/Electricity Balance is presented through a Sankey diagram, in order to better understand the magnitude of the heat flows and the powers in every element of the system.

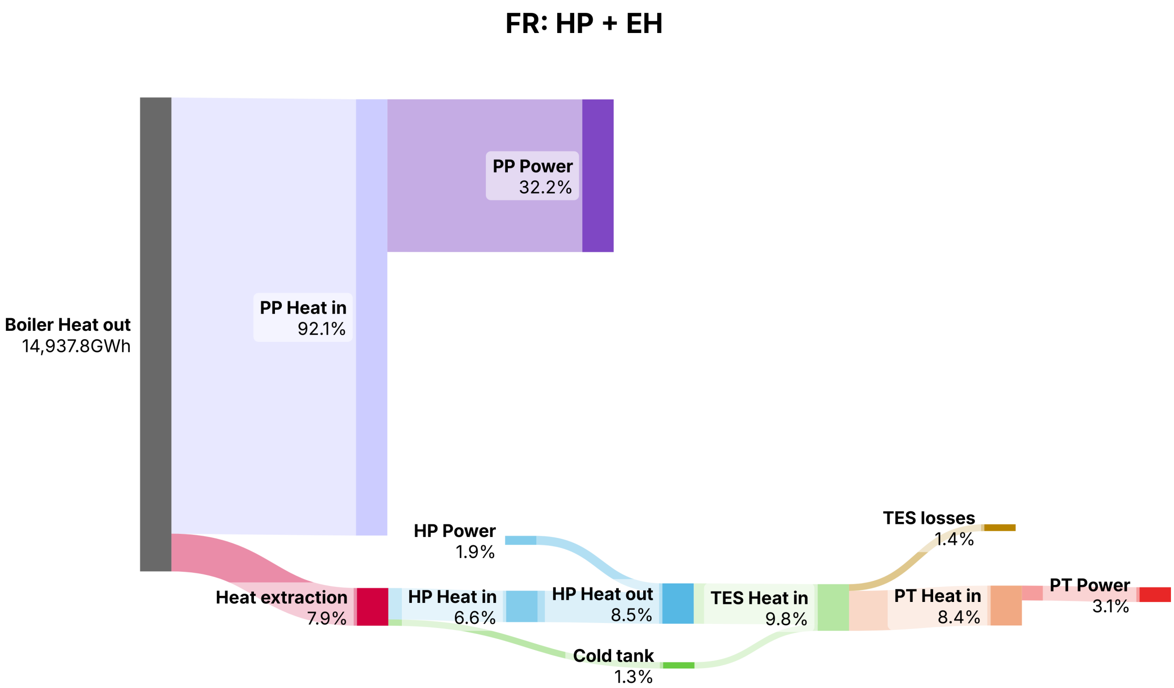

Figure 6.4: *Heat/Electricity Balance of the HP + EH scenario in the French Electricity Market.*

It has been found that 7.9% of the heat generated in the Boiler is the optimal amount that must be extracted.

C Scenarios comparison

C.1 Germany Electricity Market

Round Trip Efficiency

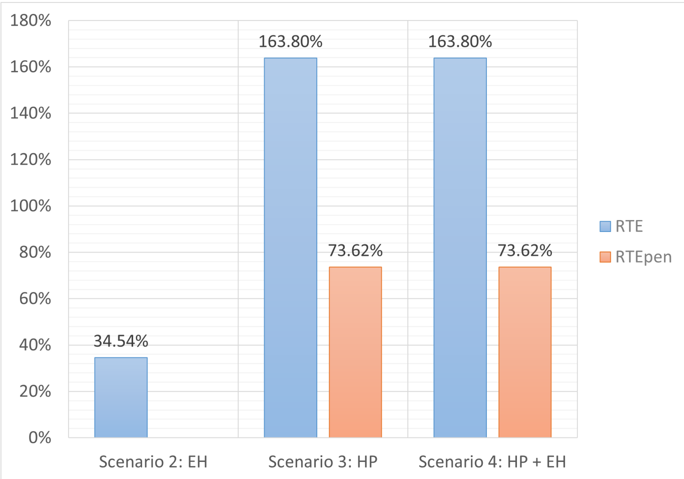

Figure 6.5: *Comparison of the RTE and RTE_{pen} in the German market for the different scenarios.*

The HP+EH configuration yields essentially the same RTE as the HP-only case, suggesting that the Electrical Heater is not dispatched in an economically optimal way under the analyzed German market conditions.
If we consider the steam extraction as electricity not produced/consumed the RTE goes below 100% (RTE_{pen}).

Spot market hours (price)

The figure compares four market-perturbation scenarios for the electricity spot price after installing the NPP-based system with different options for charging the TES. In the reference case (no TES), the market is mainly characterized by negative-price hours, while very high-price hours are almost absent. This means that price extremes are driven mostly by oversupply, not by scarcity.
After adding TES, all charging options lead to a slight reduction in negative-price hours.

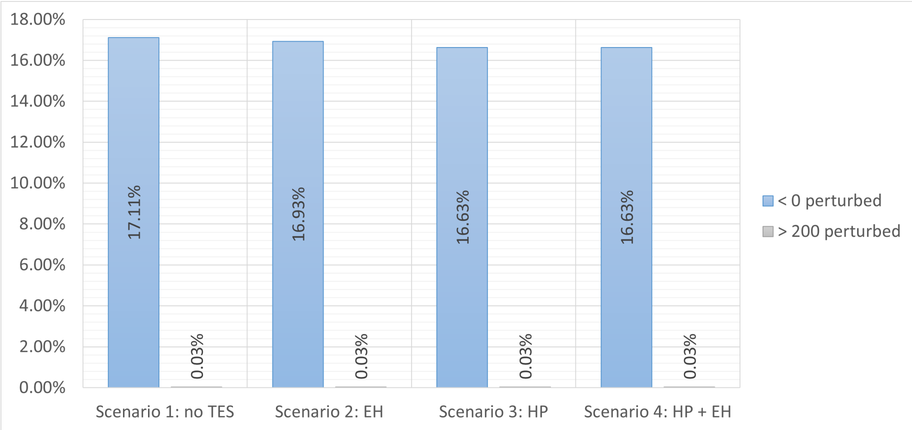

Figure 6.6: *Comparison of the Spot market hours below 0* $\frac{EUR}{MWh}$ *and above 200* $\frac{EUR}{MWh}$ *in the German market for the different scenarios.*

This suggests that TES provides flexibility by storing part of the energy as heat instead of exporting it as electricity, which helps limit oversupply situations and reduces the frequency of negative prices. The differences between EH, HP, and HP+EH are small, indicating that the main effect is simply the presence of TES.

The share of very high-price hours remains almost unchanged in all scenarios. This implies that events above the chosen high-price threshold are very rare in this case, so the system has little opportunity to change the annual share of such hours, even if the peaker turbine may still reduce prices during some high-price periods.

Overall, the figure shows that volatility is mainly linked to oversupply, and TES mainly reduces volatility by lowering the occurrence of negative prices, while the high-price extreme is largely unaffected.

Utilization (CF)

As shown in the Figure 6.7, the PP capacity factor decreases when TES is introduced, because the simulation is economically optimal: it prefers to reduce baseload generation during low or negative price hours rather than exporting electricity at poor prices, and it shifts part of the operation to higher-value hours. This is consistent with the fact that PP utilization decreases while the PP capture price increases (check Figure 6.8), meaning fewer MWh are produced but they are sold in more valuable hours.

A useful comparison is between Boiler CF and PP CF. In the TES cases, the boiler utilization remains higher than the PP utilization. This indicates that in the EH case a

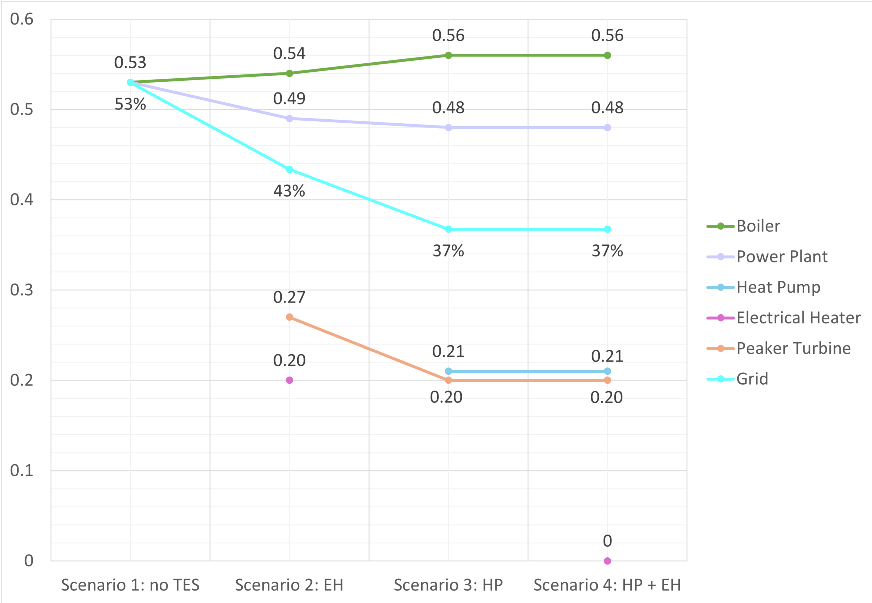

Figure 6.7: *Comparison of the Capacity Factors of the different elements composing the system in the German market for the different scenarios.*

significant part of energy is exploited to keep the cold tank near the minimum working temperature (since the EH has a very small capacity) while in the CoHP scenarios, the difference in the CF increases further because charging requires steam extraction from the boiler to supply the CoHP and electricity from the PP to drive the compressor. Steam extraction reduces the steam flow available for expansion in the main turbine, lowering the PP net electric output and therefore its utilization.

Finally, the PT capacity factor is lower in the CoHP cases than in the EH case because the PT capacity is fixed to a large value in the CoHP configurations, while in the EH case the model can choose a smaller peaker size that is easier to utilize. With limited profitable discharge opportunities, the larger fixed PT runs fewer equivalent full-load hours, so its CF decreases.

Capture and Market prices

The market price is almost unchanged across all cases, indicating that the introduction of TES and the different charging options leads only to marginal changes in the yearly average price level.

At the same time, the total capture price increases when moving from the no TES case to TES-enabled configurations. This reflects an output-weighted effect: the flexible op-

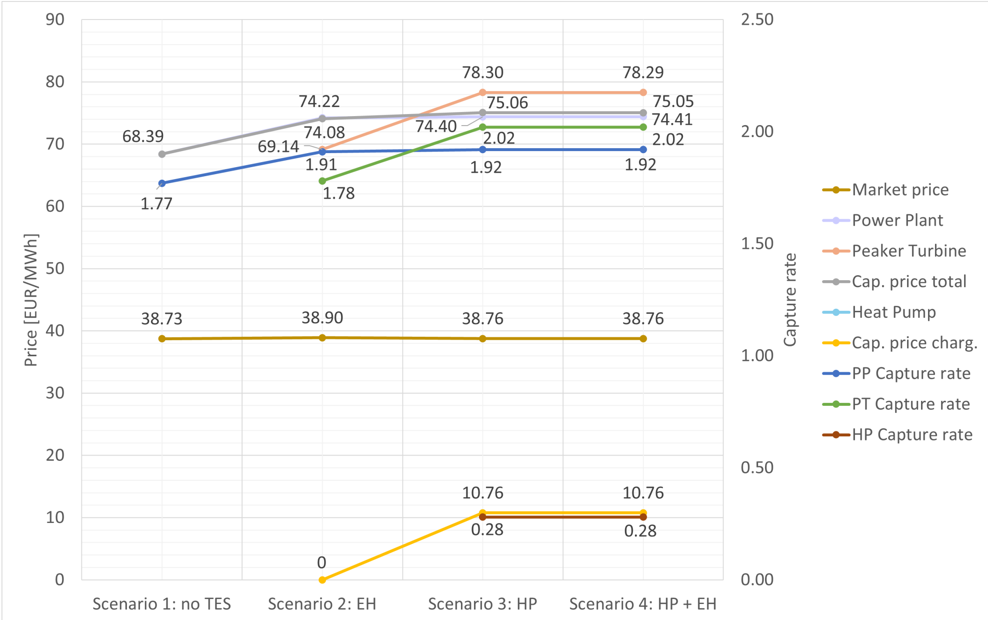

Figure 6.8: *Comparison of the Capture prices of the different elements composing the system and the Market price in the German market for the different scenarios.*

eration enabled by TES shifts a larger share of net electricity sales towards hours with higher prices, raising the average price effectively captured by the system even though the market average remains almost constant. In the EH scenario the peaker is relatively small, so discharge tends to be spread over more hours rather than concentrated only in the very best ones, which can lower the PT output-weighted capture price (and capture rate) even below the PP. In the HP cases, charging is more selective and the larger peaker can concentrate discharge in higher-price hours, increasing the PT capture price and capture rate.

A clear distinction is visible on the charging side. In the EH scenario, the charging capture price is 0 EUR/MWh, meaning that charging is selected only when prices are around zero (or negative). In the HP and HP+EH scenarios, the charging capture price becomes positive (and the HP capture rate is <1), showing that charging can occur profitably also in low-price hours that are not necessarily zero/negative, thanks to the heat-pump-based charging pathway.

Finally, HP and HP+EH outcomes are essentially identical in Germany because the electrical heater is not dispatched.

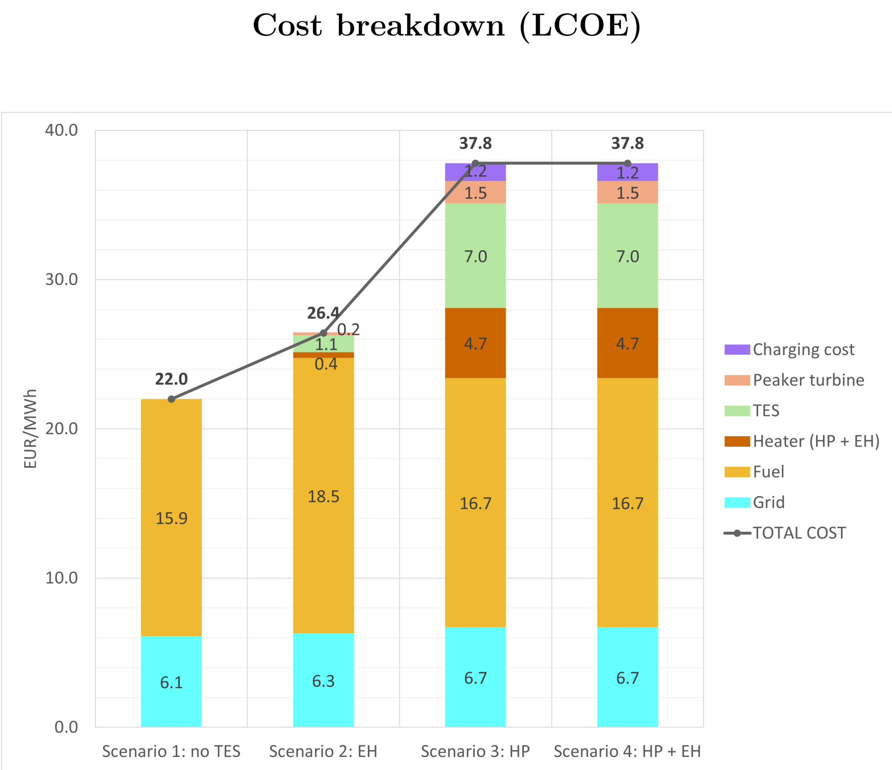

Figure 6.9: *Comparison of the different elements costs composing the system in the German market for the different scenarios.*

In the German market, the LCOE breakdown highlights a clear separation between the EH configuration, where the additional cost contributions from the flexibility block remain contained, and the HP-based configurations, where the result is dominated by the sizing and fixed costs of the flexible plant.

The EH case only moderately changes the overall cost composition, indicating that the optimization adopts a relatively small flexibility setup in terms od capacity.

By contrast, in the HP and HP+EH cases the model selects a much larger flexibility configuration, and the fixed-cost terms become the main contributors to the LCOE. Finally, HP and HP+EH are identical, showing that adding the Resistive Heater does not materially change the optimal result when the Heat Pump option is available.

To assess whether the additional flexibility investment is economically reasonable, Figure 6.9 should be read together with Figure 6.8. The basic check is whether the increase in Total Capture Price is large enough to compensate the extra cost components introduced by the flexibility block (heater, TES, Peaker Turbine, and charging cost). In Germany, moving from no TES to the EH case increases the Total Capture Price(+5.69 EUR/MWh), while the total cost of the flexibility block remains relatively limited (1.7

EUR/MWh). By contrast, switching to the HP-based configurations raises the Total Capture Price to (+6.67 EUR/MWh), but it requires a much larger and more expensive flexibility block (14.4 EUR/MWh). The HP configurations require a much larger flexibility block because the CoHP option fixes the peaker size to match the CoHP thermal capacity, and the optimizer therefore selects a much larger TES energy capacity; as a result, the large fixed PT is under-utilized (low CF, as shown in Figure 6.7). Under the assumed inputs, the EH option appears closer to a reasonable cost–benefit balance, while the HP options look less attractive, because they add substantial flexibility costs for only a limited additional increase in Total Capture Price.

C.2 France Electricity Market

Round Trip Efficiency

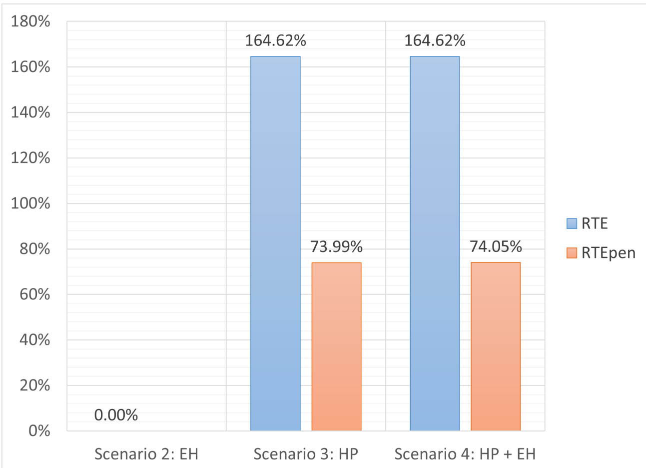

Figure 6.10: *Comparison of the RTE and RTE_{pen} in the French market for the different scenarios.*

The RTE in the EH scenario goes to zero since the optimal Electrical Capacity in this market is 0 MW_e. As a consequence, the HP+EH configuration yields the same RTE as the HP-only case. If we consider the steam extraction as electricity not produced/consumed the RTE goes below 100% (RTE_{pen}).

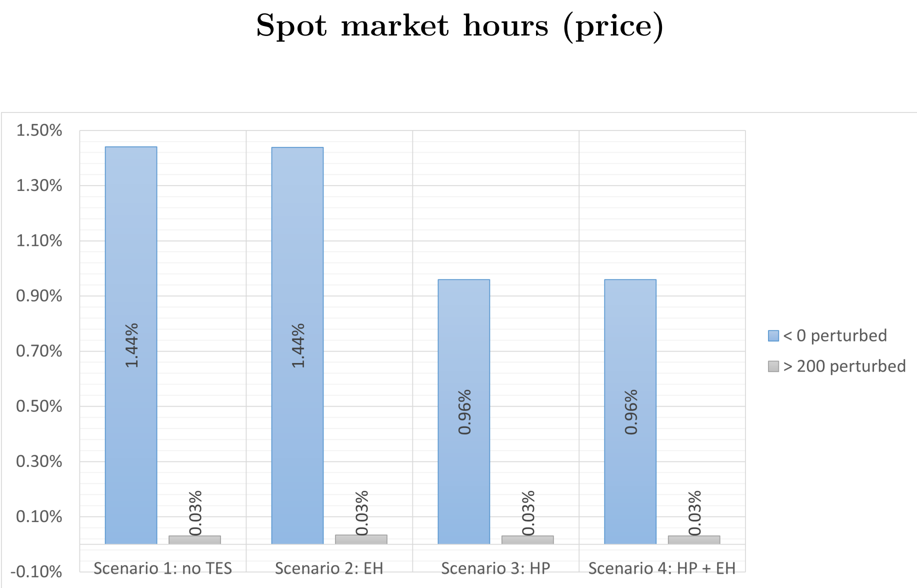

Figure 6.11: *Comparison of the Spot market hours below 0 $\frac{EUR}{MWh}$ and above 200 $\frac{EUR}{MWh}$ in the French market for the different scenarios.*

The figure compares four market-perturbation scenarios for the electricity spot price after installing the NPP-based system with different options for charging the TES. In the reference case (no TES), negative-price hours are relatively limited, and very high-price hours are extremely rare. This suggests that, in this dataset, strong scarcity events are uncommon, and price extremes are mostly linked to occasional oversupply. When TES is added, negative-price hours decrease further in all configurations, with the largest reduction observed in the HP-based cases. This indicates that TES mainly acts as a flexibility option that reduces exposure to oversupply conditions: part of the energy that would otherwise be exported as electricity is shifted into stored heat, which lowers the likelihood of prices dropping below zero. The stronger effect with HP is consistent with the larger storage capability in those scenarios, which increases the system's ability to absorb and shift energy through hours.

Across all scenarios, the frequency of very high-price hours remains almost unchanged and stays close to zero. This implies that price spikes above the chosen threshold are too rare for the TES–Peaker system to noticeably change their frequency, even though the Peaker Turbine may still reduce prices within some high-price periods.

Overall, the figure shows a clear reduction in oversupply-driven volatility (fewer negative-price hours), while the high-price extreme is essentially unaffected because it occurs only rarely in this case.

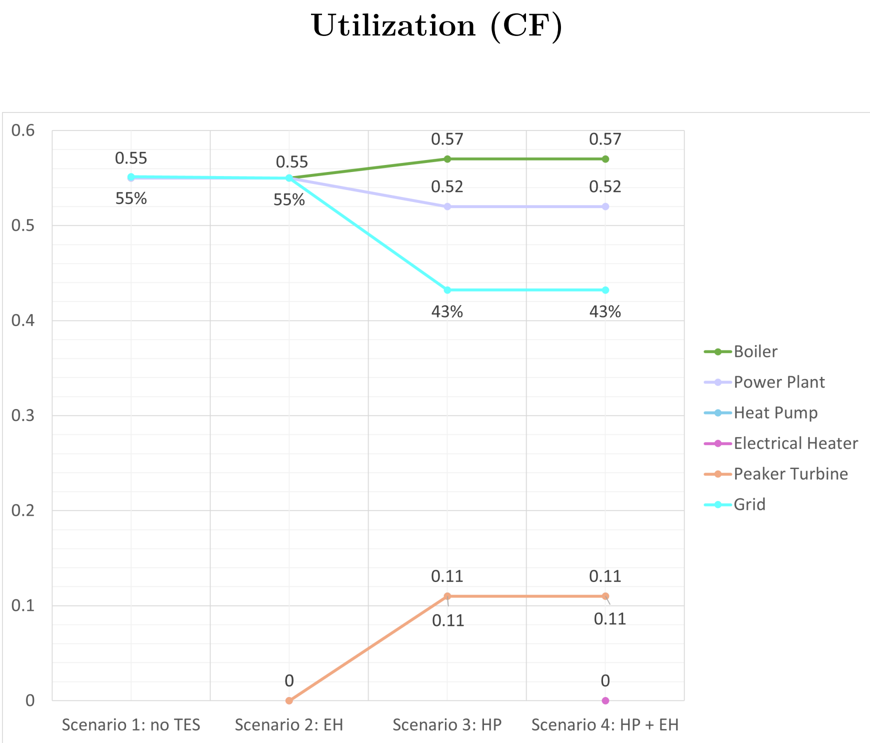

Figure 6.12: *Comparison of the Capacity Factors of the different elements composing the system in the French market for the different scenarios.*

When moving to HP-based configurations, the PP Capacity Factor decreases slightly and the Boiler CF increases because a fraction of the steam flow is diverted from expansion in the main turbine to keep the cold salt tank within its operating temperature and, during charging, to supply the CoHP.

At the same time, the Peaker Turbine becomes active in the HP cases, but with a relatively low utilization, which is consistent with the limited price volatility of the French market. The Electrical Heater remains unused, indicating that, under the analyzed assumptions, adding the EH does not provide additional economic value beyond the CoHP-driven charging strategy.

Capture and Market prices

The market price is essentially unchanged across all cases, suggesting that the introduction of TES and alternative charging options does not materially affect the annual average price level in this market.

Moving from the no TES case to TES-enabled configurations, the total capture price

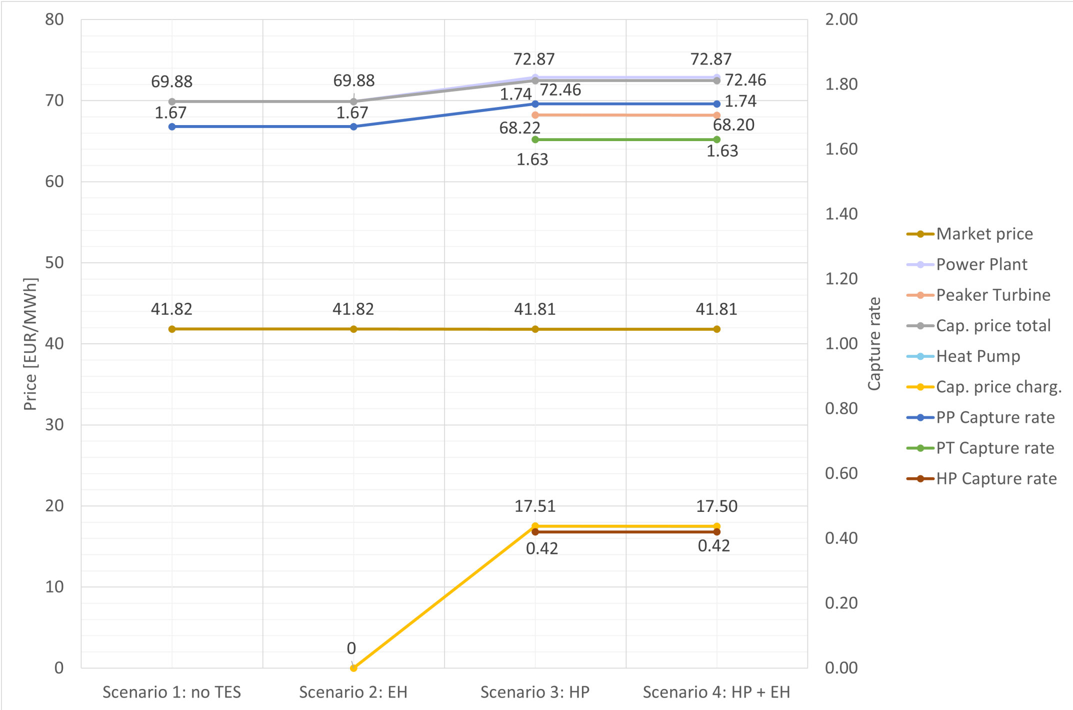

Figure 6.13: *Comparison of the Capture prices of the different elements composing the system and the Market price in the French market for the different scenarios.*

increases, indicating that operational flexibility allows the system to shift part of its effective revenues towards higher-price hours (even if the yearly market average remains stable).

In the HP-based configurations, the PP capture price/rate remains higher than the PT capture price/rate. This is consistent with the limited number of extreme-price hours in the French market, which reduces the opportunity for the peaker to operate exclusively during very high-price spikes and leads to dispatch also in moderately priced hours.

When the HP is available, the charging capture price rises (and the HP capture rate is <1) showing that charging can still be convenient also in low, but positive, price hours thanks to the more efficient HP-based charging pathway.

Finally, HP and HP+EH results are almost identical, confirming that the Resistive Heater does not provide an additional economic advantage when the HP option is available.

Cost breakdown (LCOE)

In the French market, the LCOE breakdown shows that in the EH scenario the optimizer chooses zero capacity for the flexibility assets and therefore the related cost components

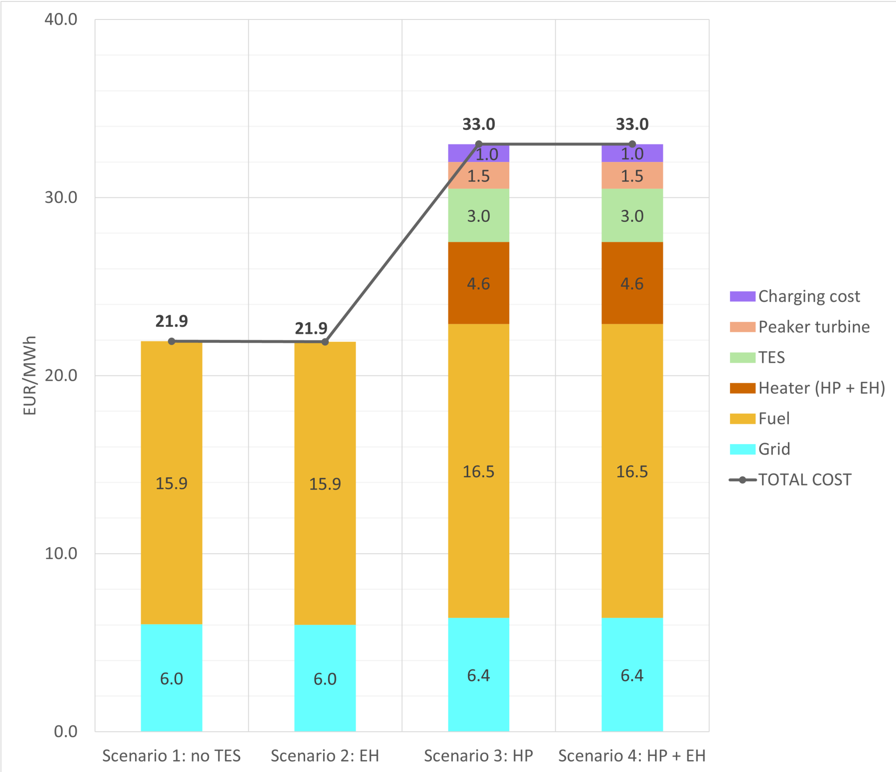

Figure 6.14: *Comparison of the different elements costs composing the system in the French market for the different scenarios.*

are zero; the total cost is made only of the baseline terms.

When the Heat Pump is available, the model installs a non-zero flexibility configuration and the LCOE increases mainly because of fixed costs (TES, charging equipment, and peaker capacity).

From an economic perspective, Figure 6.14 should be interpreted together with Figure 6.13: the flexibility block is economically justified only if the increase in Total Capture Price compensates the additional cost items introduced by the flexible plant. In the French market, the EH case results in no additional flexibility capacity being installed; therefore, the cost of the flexible plant is null. When the CoHP is available (HP and HP+EH, which result equal, as the EH does not change the optimal solution when the Heat Pump option is present), the system installs a non-zero flexibility configuration and Total Capture Price increases, but only modestly (+2.58 EUR/MWh). At the same time, the cost increases much more because the flexible block adds significant fixed-cost contributions (10.1 EUR/MWh) and because costs are spread over a lower net electricity sold. Therefore the HP-based investment looks weak in France, because the Capture Price uplift is clearly smaller than the cost increase.

D Markets comparison

D.1 No TES scenario

Spot market hours (price)

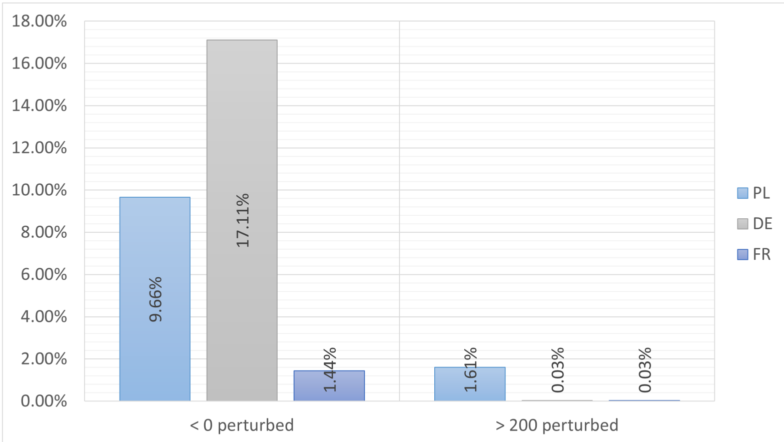

Figure 6.15: *Comparison of the Spot market hours below 0* $\frac{EUR}{MWh}$ *and above 200* $\frac{EUR}{MWh}$ *in the no TES scenario for the different electricity markets.*

It can be seen how Germany has by far the largest fraction of negative-price hours, while France has the lowest. For very high-price hours (>200 EUR/MWh), Poland shows the highest share of these hours, while Germany and France show only a small fraction.
These results in the reference case already show how often each market experiences very low/negative (oversupply) prices and very high (scarcity) prices. Germany offers many opportunities for charging in very cheap hours, while Poland offers more opportunities for discharging during scarcity hours, which can help reduce price spikes (peak shaving).

Utilization (CF)

Even in the absence of flexibility, market conditions alone lead to different annual utilization of the same baseload plant, with Poland dispatching it for a larger share of the year.

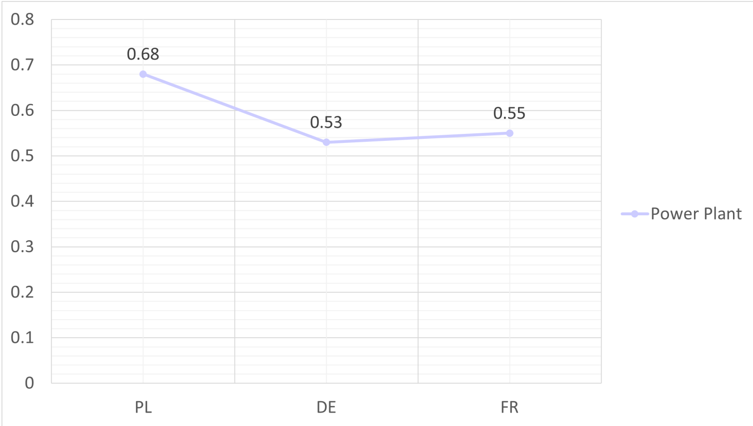

Figure 6.16: *Comparison of the Capacity Factors of the single element composing the system in the no TES scenario for the different electricity markets.*

Capture and Market prices

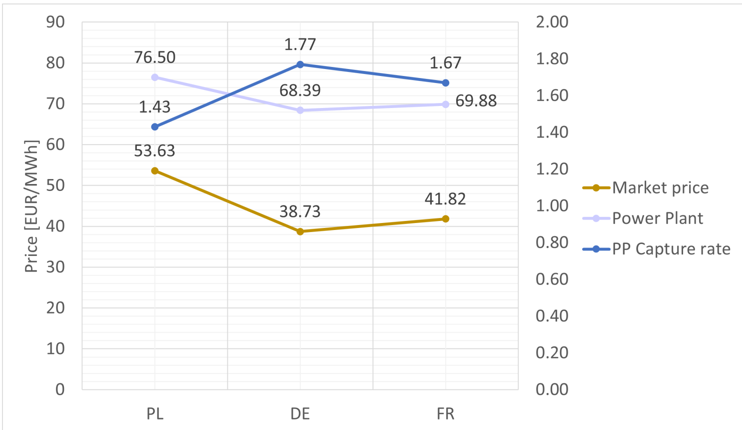

Figure 6.17: *Comparison of the Capture price of the single element composing the system and the Market price in the no TES scenario for the different electricity markets.*

In all cases, the Power Plant capture price is substantially higher than the market average, meaning that the plant's production is concentrated in hours with above-average prices. This is also shown by the capture rate: it is above 1 in all countries, so the plant earns higher-than-average prices. The capture rate is highest in Germany and France, meaning the plant is more strongly concentrated in high-price hours there than in Poland.

Cost breakdown (LCOE)

Fuel costs are identical because the same baseload power plant is used, and the net

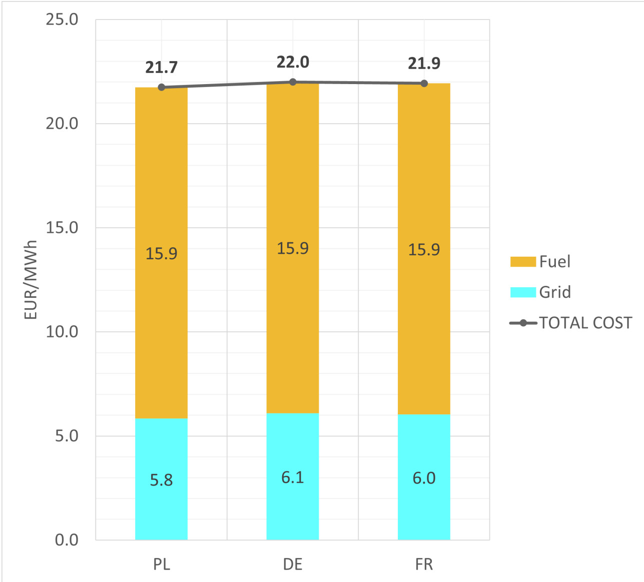

Figure 6.18: *Comparison of the different elements costs composing the system in the no TES scenario for the different electricity markets.*

electricity sold is essentially the baseload electricity output in this configuration.
Since the annual electricity sold differs slightly across markets (due to different plant utilization in each market), the same grid-related costs are spread over a different number of sold MWh, producing small differences in EUR/MWh.

D.2 EH scenario

Round Trip Efficiency

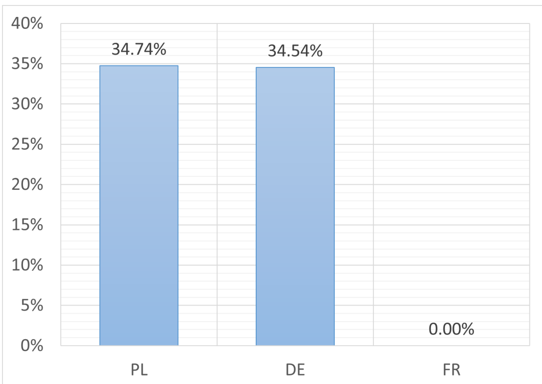

Figure 6.19: *Comparison of the RTE in the EH scenario for the different electricity markets.*

In Poland and Germany the RTE is almost identical. This is expected because the dominant losses occur during discharge: the conversion of stored heat back into electricity is constrained by the power-block efficiency, which largely determines the overall RTE.
In France, the RTE is not reported because the optimizer installs zero flexibility capacity in the EH case (TES and charging assets are not deployed), so there is no meaningful charge–discharge cycle to evaluate.

Spot market hours (price)

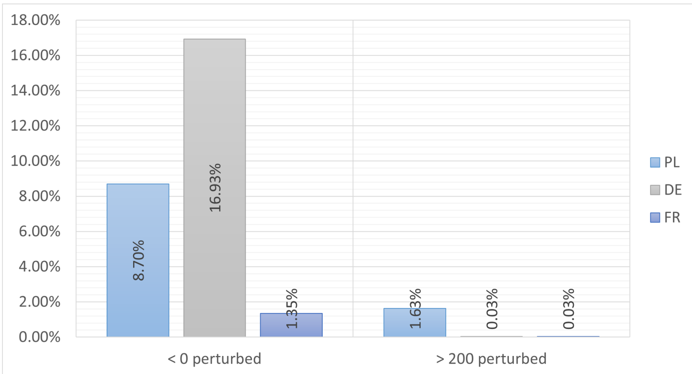

Figure 6.20: *Comparison of the Spot market hours below 0* $\frac{EUR}{MWh}$ *and above 200* $\frac{EUR}{MWh}$ *in the EH scenario for the different electricity markets.*

The figure compares the same configuration (EH) across the three spot markets. The main difference across markets is clear. Germany has the highest share of negative-price hours, meaning that oversupply events remain frequent even with the EH-based system. Poland also shows negative prices, but less than Germany. France has only a small share of negative-price hours, indicating fewer oversupply extremes.
For very high prices, the pattern changes: Poland shows the largest share of hours above the high-price threshold, while Germany and France show almost none. This suggests that, under this scenario, Poland is more affected by scarcity-driven price spikes.

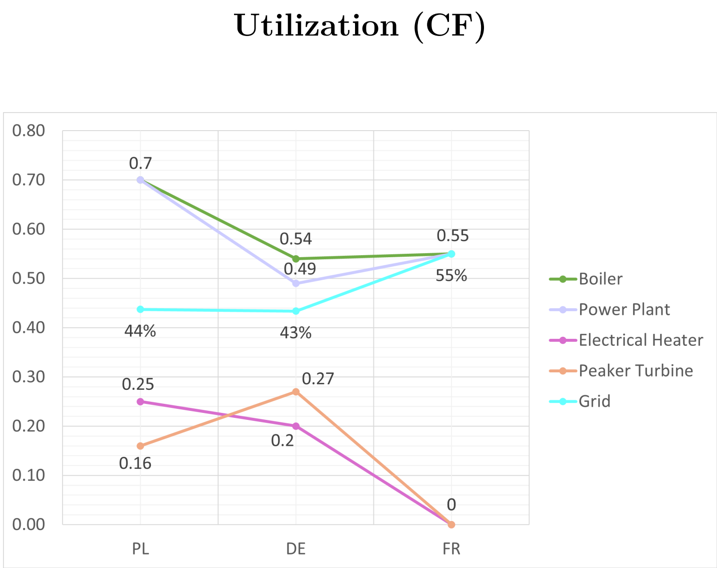

Figure 6.21: *Comparison of the Capacity Factors of the several elements composing the system in the EH scenario for the different electricity markets.*

In the EH scenario, the comparison between Boiler CF and PP CF helps to understand how much of the thermal output is converted into baseload electricity. Even without the HP, the TES requires a small heat input to keep the molten-salt cold tank within its operating range. This maintenance duty can keep the boiler relatively utilized even when the PP electrical output is reduced. In Poland, Boiler and PP utilization are almost the same. The reason is that the EH is relatively large, so it can absorb a significant share of the PP output during low-price hours, reducing the need to lower the PP generation. In Germany, Boiler CF is higher than PP CF. Here the EH is much smaller, so charging cannot absorb much electricity during the many negative-price hours. At the same time, some heat is still required to maintain the cold-tank temperature. As a result, the model more often reduces PP generation.

Although very high-price hours are more frequent in Poland than in Germany (refer to Figure 6.20), this does not lead to a higher PT utilization. The CF also depends on the installed PT size. In the EH scenario, the optimizer selects a much larger PT in Poland than in Germany. As a result, even if the peaker produces significant energy in Poland, it is concentrated into fewer equivalent full-load hours, which yields a lower CF but a higher capture price. In Germany, the PT is much smaller, so it can operate more often across moderate price spreads, which increases the equivalent full-load hours and therefore the CF, even though the captured price is lower. Please refer to Figure 6.22.

Capture and Market prices

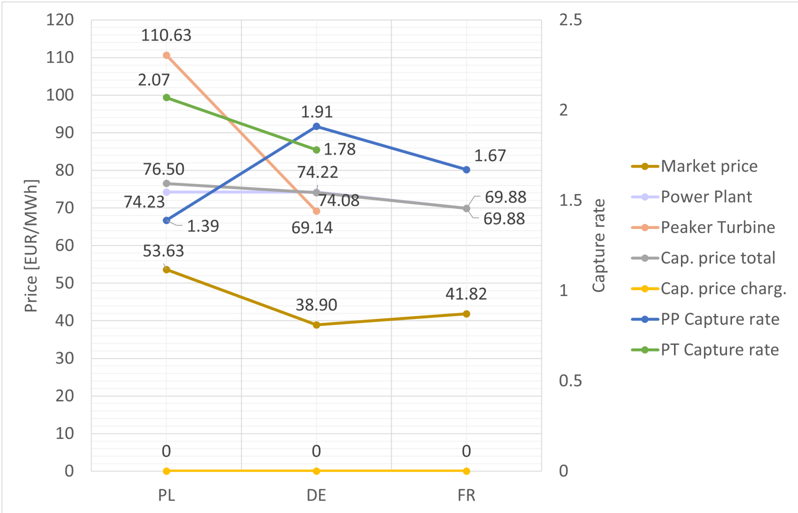

Figure 6.22: *Comparison of the Capture price of the several elements composing the system and the Market price in the EH scenario for the different electricity markets.*

The Peaker Turbine capture price is particularly high in Poland, while it is much lower in Germany, suggesting that peaking operation in Poland is more strongly associated with high-price hours. This is also reflected in the capture rates: in Poland the peaker turbine has a higher capture rate than the main Power Plant turbine, meaning it is more strongly concentrated in the most expensive hours, whereas in Germany the opposite holds (the Power Plant capture rate is higher than the peaker's), indicating that the PP output is more consistently aligned with high-price periods than the peaker. In France, the peaker and the heater have zero utilization (no installed capacity), so the only relevant capture price is the Power Plant one.

Cost breakdown (LCOE)

When the EH is used, part of the electricity is diverted to charging, which reduces net electricity sold and tends to increase fuel cost in EUR/MWh even if the baseload plant itself is unchanged.
This market effect is combined with the fact that the model installs different amounts of flexibility. Poland shows the highest total cost because the optimizer builds a larger

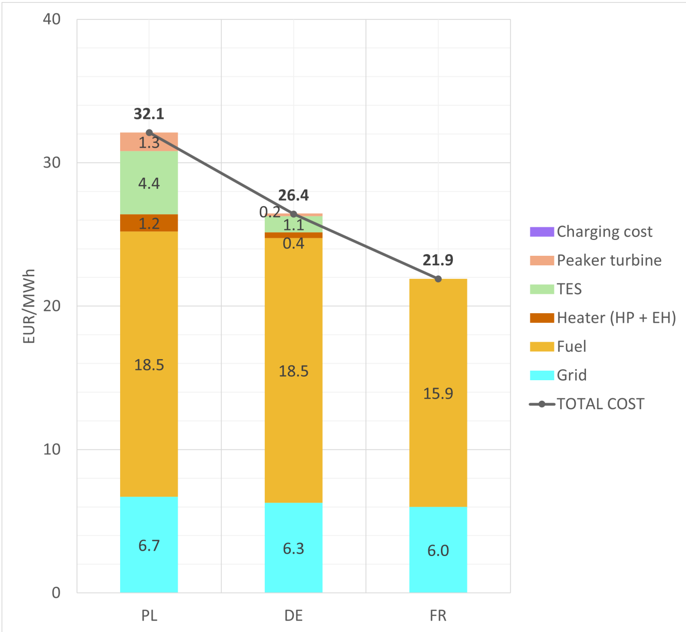

Figure 6.23: *Comparison of the several elements costs composing the system in the EH scenario for the different electricity markets.*

flexible plant. Germany reaches a lower total cost because the installed flexible plant is smaller, so the flexible-plant cost is limited. In France, flexibility capacity is zero, so flexible-plant cost components are null. To evaluate whether the EH flexibility option is economically meaningful, the key metric is the increase in Total Capture Price compared with the additional cost introduced by the flexible plant. In Poland, the EH case provides only a small value uplift while the flexibility block still has a non-negligible cost (as described in 5.1), so the EH economic case is borderline under the assumed inputs. In Germany, the EH case delivers a larger uplift of the Total Capture Price with a relatively small flexibility cost (as described in C.1), so EH appears closer to a reasonable cost–benefit balance and is the most attractive among the EH outcomes. In France, the EH option is simply not selected as an economically beneficial option.

D.3 HP scenario

Round Trip Efficiency

With the heat pump the RTE becomes very high and is almost the same in all markets. This happens because it allows the system to store more thermal energy than the electric-

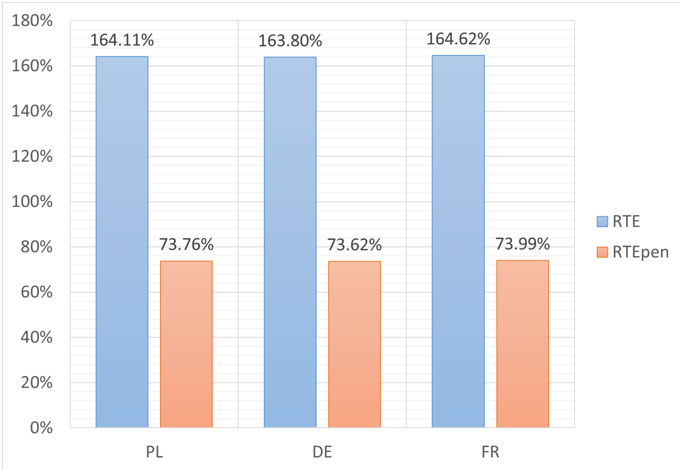

Figure 6.24: *Comparison of the RTE and RTE_{pen} in the HP scenario for the different electricity markets.*

ity used for charging ($COP > 1$). As a result, the system can generate more electricity during discharge than the electricity consumed during charge.

Therefore, in the HP case the RTE is mainly set by the technology assumptions (COP and discharge efficiency) and only weakly depends on the specific market.

If we consider the steam extraction as electricity not produced/consumed the RTE goes below 100% (RTE_{pen}).

Spot market hours (price)

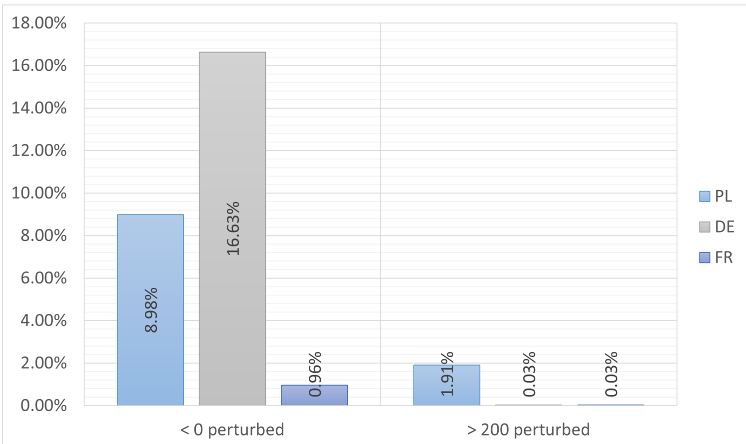

Figure 6.25: *Comparison of the Spot market hours below 0 $\frac{EUR}{MWh}$ and above 200 $\frac{EUR}{MWh}$ in the HP scenario for the different electricity markets.*

For negative prices, the cross-market difference is strong: Germany has by far the largest share of negative-price hours, Poland is clearly lower, and France is much lower. This means that, even with HP-based TES, oversupply conditions remain a key feature in Germany, while they are much less common in France. For very high prices, the pattern is different: Poland shows a noticeable share of hours above the high-price threshold, while Germany and France remain almost at zero. This suggests that, under the HP scenario, scarcity-driven price spikes are mainly relevant in Poland.

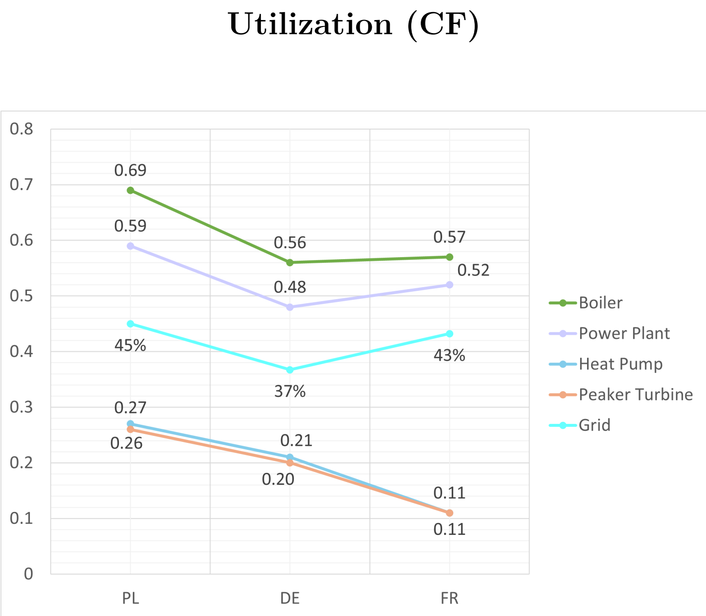

Figure 6.26: *Comparison of the Capacity Factors of the several elements composing the system in the HP scenario for the different electricity markets.*

A useful comparison is between the Boiler CF and the PP CF. The former is higher than the latter in all three markets and this gap is explained by the steam diversion required by the CoHP and by the cold-tank of the TES: extracting steam from the Boiler reduces the steam available for expansion in the main turbine, lowering the PP net electric output and therefore its utilization.

The Peaker Turbine CF decreases across markets because the overall use of the CoHP–TES-PT flexibility loop becomes less intensive when profitable discharge opportunities are fewer and/or the optimal TES energy capacity is smaller. HP CF and PT CF remain closely paired within each market, so a lower annual charging intensity with the HP directly translates into fewer equivalent full-load hours for the peaker turbine.

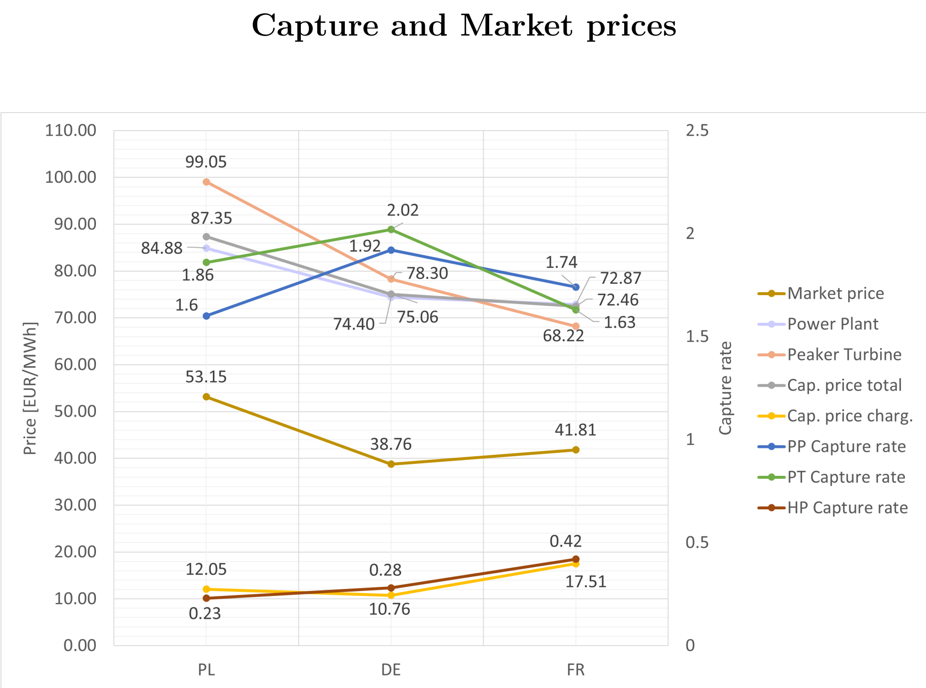

Figure 6.27: *Comparison of the Capture price of the several elements composing the system and the Market price in the HP scenario for the different electricity markets.*

The PT capture price is highest in Poland because the peaker mainly discharges during the highest-price hours, which are more common in the Polish market (as shown in Figure 6.25). However, the PT capture rate is lower in Poland compared to Germany because the average market price is also higher there.

When comparing technologies, the PT capture rate is higher than the main PP capture rate in Poland and Germany, so the peaker operates more strongly in the most expensive hours than the PP, while in France the PP capture rate is higher than the peaker's, indicating a stronger alignment of PP generation with high-price periods.

On the charging side, HP capture rate/price is a key indicator of how "cheap" the thermal input for peaking operation is: a higher HP capture rate (as in France) means the TES is charged in relatively expensive hours, which reduces the economic advantage of storing heat for the peaker, whereas lower HP capture rates (as in Poland and Germany) indicate charging is concentrated in cheaper hours, improving the overall charge–discharge arbitrage.

Consequently, the difference between the charging capture price and the discharge capture price is more pronounced and favorable in Poland and Germany than in France.

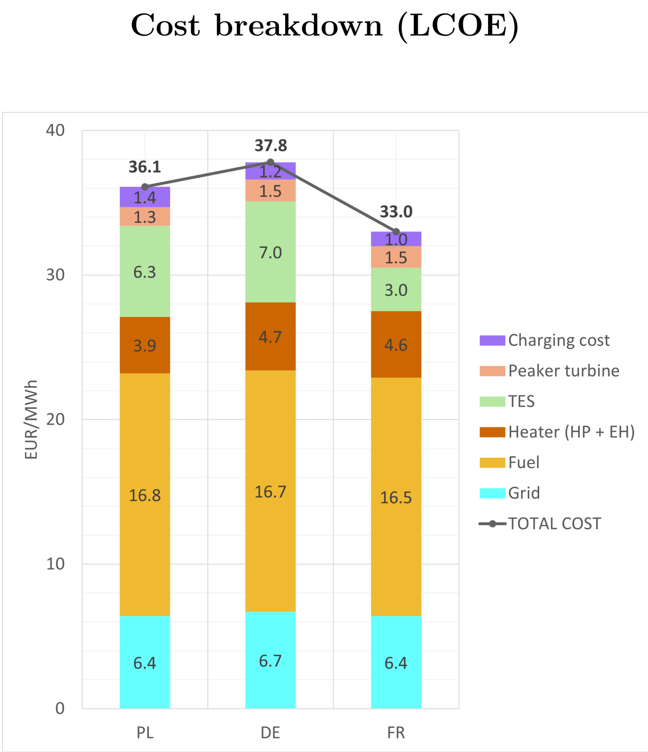

Figure 6.28: *Comparison of the several elements costs composing the system in the HP scenario for the different electricity markets.*

In the HP scenario the flexible plant becomes a major cost component in all markets.
The main driver for the TES cost component is the different optimal TES sizing: France installs a much smaller TES than Poland and Germany, which directly reduces the total fixed cost attributed to storage. A second driver is the normalization effect: since the TES fixed cost is divided by net electricity sold, markets with lower annual utilization dilute fixed costs less effectively (refer to Figure 6.26). This helps explain why Germany shows a higher TES cost per MWh than Poland despite comparable TES sizing.
The HP option is economically meaningful only if the increase in Total Capture Price is large enough to compensate the cost of the flexible plant. In Poland, HP delivers a large price uplift while the flexible-plant cost is also significant (as described in 5.1); therefore, the benefit and the added cost are of similar magnitude and the investment case appears borderline under the assumed inputs. In Germany, HP increases the Total Capture Price but the flexible-plant cost is much higher (as described in C.1), so the added cost clearly outweighs the price uplift, making the HP option weak. In France, HP provides only a modest price uplift while adding a substantial flexible-plant cost (as described in C.2), so the HP option also appears weak in this market under the assumed inputs.

E NDA

The following Appendix presents the Non-Disclosure Confidentiality Agreement with Quantified Carbon, stating that confidential information and software models are not to be shared in this Master's Thesis.

NON-DISCLOSURE AGREEMENT

This non-disclosure agreement (”**Agreement**”) is entered into by and between:

1) **QuantifiedCarbon Limited**, company registration number 10916120, with its registered office at 37 Summerleaze Road, Maidenhead, United Kingdom (**“QC**”),

   And

2) Christian Cozzarizza
   Whose registered office is at Herman Krags veg 16, 7050, Trondheim, Norway
   (“**Consultant**”)

QC and the Consultant may be referred to in this Agreement as ”**Party**” and collectively as the ”**Parties**”.

BACKGROUND

A. The Consultant has been engaged by QC to assist in methods development and organization (the “**Assignment**”). As a part of the Assignment, information of a sensitive nature will be generated and QC will disclose certain confidential information to the Consultant.

B. Prior to making any such disclosure to the Consultant, QC requires the Consultant to enter into this Agreement to ensure that the Consultant will keep such disclosures confidential and make use of them solely as specified below. The Parties have therefore agreed as follows.

1. CONFIDENTIAL INFORMATION

1.1. The “**Confidential Information**” includes information which QC or its Affiliates disclose to the Consultant during the Assignment including, without limitation, the following: Invention description(s), technical and business information, ideas, patentable ideas, trade secrets, drawings and/or illustrations, patents searches, existing and/or contemplated products and services, research and development, production, costs, profit and margin information, finances, customers, clients, marketing, and current or future business plans and models, data provided from QC and results from the assignment regardless of whether such information is designated as “Confidential Information” at the time of its disclosure. The information is to be considered confidential regardless of the form in which it is provided.

1.2. For the avoidance of doubt, all information disclosed by QC or its Affiliates to the Consultant within the Assignment shall be considered to be confidential, unless otherwise clearly stated in writing by QC.

1.3. In this Agreement "**Affiliate**" shall mean any entity that forms part of the same group as QC or that is controlled by, or under direct or indirect common control of QC. For the purposes of this Agreement, "control" means the direct or indirect, legal or economic ownership of more than 50% of the voting rights in the entity concerned, the ability to elect or otherwise designate and dismiss a majority of the board of directors or other governing body of the entity concerned, or such other relation with the entity concerned that it in fact constitutes control.

2. OBLIGATIONS

2.1. The Consultant undertakes

a) to treat the Confidential Information strictly confidential and not to disclose or make it, or any part of it, otherwise available to any third party;

b) to protect the disclosed Confidential Information by using the same degree of care, but no less than an adequate degree of care, to prevent unauthorized use, dissemination or publication of the information as the Consultant uses to protect its own confidential information of a like nature;

c) to only use the Confidential Information for the purposes and within the scope of the Assignment according to the terms of this Agreement and, in particular, not to exploit it commercially;

d) to take all necessary measures to prevent the Confidential Information from unauthorized use or reproduction and promptly notify QC of any suspicion of such use or reproduction; and

e) to make it available only to those of its directors, officers or employees who need to have access to such information for the purposes of the Assignment and who are contractually or otherwise obligated to keep it confidential.

2.2. The Consultant represents that each person to whom disclosure of Confidential Information is made as permitted hereunder is made aware, in advance of disclosure, of the terms of this Agreement and that each such person adheres to those terms as if they were a party to this Agreement.

2.3. Confidential Information disclosed to the Consultant shall not be reproduced by the Consultant in any form, except as required for the purpose of fulfilling its obligations relating to the Assignment.

2.4. The Consultant shall, without delay, return any Confidential Information and copies thereof (whether in possession of the Consultant or any other party) to QC or destroy it upon QC's request and confirm that such destruction has been completed, it being understood that no disclosed information, including but not limited to any copies or reproductions, shall be retained by the Consultant unless otherwise required by applicable law.

3. EXCEPTIONS

3.1. This Agreement imposes no obligation upon the Consultant with respect to information which the Consultant can prove

a) was or becomes generally available to the public through no fault of the Consultant;

b) was in the Consultant's rightful possession before receipt from QC and this is shown by the Consultant´s prior written record;

c) the information is received by the Consultant in good faith from a third party without a duty of confidentiality;

d) can be disclosed by the Consultant with QC's prior written consent; or

e) was independently developed by the Consultant without the use of any of the Confidential Information.

3.2. The removal of restriction regarding Confidential Information above shall be effective only from and after the date of occurrence of the applicable event.

3.3. Specific information shall not become exempt from the obligations under Article 2 merely because it is embraced by general information within any of the exceptions under Article 3.1. Combinations of parts of information are not exempt from the obligations if any of the exceptions of Article 3.1 applies only to such parts but not to their combination.

3.4. If the Consultant is required to disclose any Confidential Information under applicable laws and regulations or a valid and binding order from any court or administrative agency, the Consultant shall give QC as much notice thereof as possible to enable QC to protect its Confidential Information to the extent possible under applicable laws and regulations and/or the said order.

4. TITLE

4.1. This Agreement shall not be construed as creating, conveying, transferring, granting or conferring upon the Consultant any rights, license or authority in or to the information received, except the limited right to use Confidential Information for the Assignment.

4.2. The Consultant does not acquire any intellectual property rights under this Agreement.

4.3. Neither Party has an obligation under this Agreement to purchase, sell or license any service or item from the other Party. Furthermore, both Parties acknowledge and agree that the disclosing of information under this Agreement shall not commit or bind either

Party to any present or future enter into any business relationship or transaction, or to enter into any discussion or negotiations with respect thereto, with the other Party.

4.4. If discussions or negotiations concerning the Assignment or any subsequent negotiations terminate, for whatever reason, any right which the Consultant has to use, copy or disclose Confidential Information shall terminate. The obligations of Parties under this Agreement shall, however, continue in effect.

5. NO WARRANTY

QC does not make any representation or warranty about the accuracy or completeness of the Confidential Information and QC will not have any liability to the Consultant or any other party or entity resulting from the Confidential Information or any use thereof.

6. DURATION

6.1. Obligations in accordance with this Agreement shall remain in force during ten (10) years from the day the Agreement was signed by both Parties.

6.2. This Agreement also applies to such Confidential Information that has been disclosed by QC prior to the signing of this Agreement, if the information has been disclosed within the framework of the Assignment.

7. REMEDIES

7.1. The Consultant shall be fully responsible for the compliance of their directors, officers or employees with the terms of this Agreement.

7.2. The Consultant shall indemnify QC in respect of any claim, action, damage, loss, liability, expense or payment that QC pays, suffers, incurs or is liable for as a result of any breach of this Agreement by the Consultant. The Consultant recognizes that the disclosure or unauthorized use of Confidential Information may cause QC irreparable harm, which could not adequately be compensated by monetary damages. Accordingly the Parties agree that QC, in addition to any other remedies available to it, shall have the right to seek injunctive relief to enforce the terms of this Agreement.

8. WAIVER

No failure or delay in exercising any right, power, or privilege under this Agreement shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or further exercise thereof or the exercise of any right, power or privilege under this Agreement.

9. SEVERABILITY

If any of the provisions of this Agreement are found to be unenforceable the remainder shall be enforced as fully as possible and the unenforceable provision(s) shall be deemed modified to the limited extent required to permit enforcement of the agreement as a whole.

10. AMENDMENTS

All amendments or modifications to this Agreement must be in writing and signed by both Parties.

11. ASSIGNMENT

Neither Party may assign this Agreement, or any rights or obligations under it, without prior written consent by the other Party.

12. GOVERNING LAW AND DISPUTE RESOLUTION

12.1. This Agreement shall be governed by United Kingdom law.

12.2. The arbitration seat shall be London, United Kingdom. The language to be used in the arbitral proceedings shall be English.

12.3. The Parties undertake and agree that all arbitral proceedings conducted hereunder shall be kept strictly confidential, and all information, documentation, materials in whatever form disclosed in the course of the proceedings shall be used solely for the purpose of those proceedings.

This Agreement has been signed by the Parties in two (2) identical copies of which each Party has taken one.

QuantifiedCarbon Limited

Place: Stockholm

Date: 2025-09-02

Anton Såmark-Roth

Signature

Anton Såmark-Roth, Head of Projects

Name, Job Title

Consultant

Place: Trondheim

Date: 2025-09-02

Signature

Christian Cozzarizza, student

Name, Job Title