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SCUOLA DI INGEGNERIA INDUSTRIALE E DELL'INFORMAZIONE

Executive Summary of the Thesis

Strategies for Decarbonization and Economic Optimization of a Cogeneration Power Plant with Integration of Pumped Thermal Energy Storage

Laurea Magistrale in Energy Engineering - Ingegneria Energetica

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Abstract

Recovering and utilizing waste heat effectively is essential for improving energy efficiency and reducing reliance on fossil fuels. In this context, Pumped Thermal Energy Storage (PTES) has emerged as a promising solution, enabling thermal energy storage and reuse to enhance system flexibility and sustainability.

This study explores strategies for the decarbonization and economic optimization of a cogeneration plant for self-consumption, focusing on PTES integration. First, a reference model of the plant is developed using real operational data to evaluate energy efficiency, costs, and emissions. Then, various control strategies are analyzed to minimize operating costs while maintaining high efficiency, alongside assessing the impact of photovoltaic (PV) integration. Thermal energy storage is finally introduced to enhance system flexibility, reducing gas consumption and emissions by recovering waste heat. A Mixed-Integer Linear Programming (MILP) model is implemented to optimize energy flows, considering economic and environmental aspects.

Results demonstrate that optimized control strategies significantly reduce operating costs, while PTES further improves performance by maximizing thermal energy utilization and lowering emissions. This study underscores the benefits of integrating cogeneration, renewable energy, and thermal storage to create a more sustainable and cost-effective energy system.

1. *PoliGrid* power plant

This study analyzes the *PoliGrid* cogeneration plant, which supplies electrical and thermal energy to the *Leonardo-Bassini-Bonardi-Golgi* campus at Politecnico di Milano. Energy consumption varies throughout the year due to seasonal fluctuations and the academic calendar, totaling approximately 14 GWh and 11 GWh of electricity and heat, respectively.

At the core of the plant is a 2,000 kW_{el} CHP unit, which meets both electrical and thermal demand by recovering heat from engine oil, cooling water, and exhaust gases. A diverter modulates heat recovery, while a 12,000 kW_{th} boiler system is activated when thermal demand exceeds CHP capacity. The CHP unit, constrained by a 50% minimum load, operates continuously, whereas the boilers can handle short peak demands. Additionally, the CHP is integrated with an absorption chiller, forming a trigeneration system that converts excess heat into chilled water for cooling needs.

1.1. Benchmark Model

To optimize CHP control, a *Benchmark Model* replicating the plant's real behavior is required. Using hourly measurements from the 2023 reference year and technical datasheet specifications, operational curves for each component are developed, correlating input and output energy.

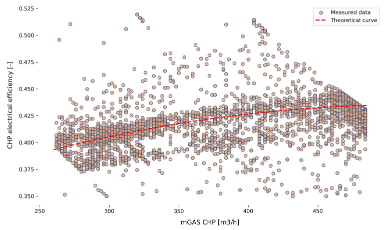

Figure 1: CHP electrical efficiency curve

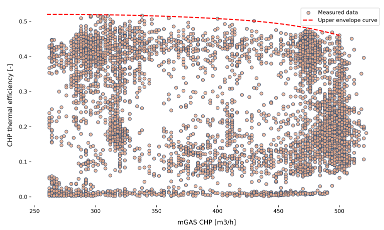

Figure 2: CHP thermal efficiency curve

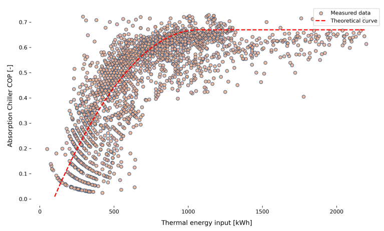

Figure 3: Absroption chiller COP

Figure 1 shows the CHP electrical efficiency curve as a function of gas consumption, ranging from 0.39 to 0.43, based on datasheet values. Figure 2 presents the CHP thermal efficiency curve, varying between 0.52 and 0.47. Due to the presence of the diverter, the upper envelope is used. The measured efficiencies exceed those in the datasheet, as campus operating temperatures are lower than in performance tests. Figure 3 illustrates the chiller COP curve against input thermal energy, varying between 0.2 and 0.7, derived directly from measurements due to the absence of a datasheet. The boiler efficiency remains constant at 0.98, regardless of gas consumption.

Two periods are defined: *cold period* (1st January to 16th May and 1st November to 31st December) and the *hot period* (17th May to 30th September). The absorption chiller operates during the *hot period*.

Using these operational curves, the *Benchmark Model* is constructed as follows: 1. The hourly gas consumption is derived from the electrical efficiency curve based on the measured electrical energy. 2. The maximum recoverable thermal energy is then calculated using the thermal efficiency curve. 3. The useful heat is determined as the minimum between the maximum thermal energy and the hourly measurement, simulating the diverter's operation; during the *hot period*, the CHP thermal energy is not taken from measurements but computed from the cooling demand using the COP curve. 4. The boiler thermal energy is obtained as the difference between the hourly thermal demand and the useful heat from the CHP. 5. Finally, the boiler gas consumption is calculated based on its efficiency.

The global results of the *Benchmark Model* closely match the measured data, indicating that the performance curves accurately represent the plant behavior. The percentage variation between the model and the measurements is presented in Table 1.

Parameter	**var%**
$m_{\text{GAS,CHP}}$	-1.8%
D_{thermal}	0%
$E_{\text{th,CHP}}$	-1%
$E_{\text{th,boiler}}$	1%
$m_{\text{GAS,boiler}}$	3%

Table 1: *Benchmark Model* vs measurements

The model is then validated using the 2024 measurements. The percentage difference between the global results and 2024 measurements remains within the same range as in 2023.

1.2. Emissions and costs

To evaluate strategies for optimizing the CHP unit's control in terms of cost reduction while monitoring emission variations, it is essential to define the cost components and emission types considered in this study.

1.2.1 Costs

Two primary costs influence plant operation: the cost of electricity purchased from the grid and the cost of natural gas consumption. Their annual values are determined as the integral over the year of the hourly product between purchased electricity and consumed gas with their respective prices—*Prezzo Unico Nazionale (PUN)* for electricity and *Punto di Scambio Virtuale (PSV)* for natural gas—both obtained from the GME database.
The plant also benefits from two revenue streams: electricity sales to the grid and incentives for high-efficiency energy systems, known as *Titoli di Efficienza Energetica (TEE)*, or *Certificati Bianchi*. Electricity is assumed to be sold at the northern *Prezzo Zonale (PZ)*, also sourced from the GME database. The number of TEEs is calculated based on the primary energy savings (*RISP*) achieved annually, compared to reference values set by the Italian government, following GSE guidelines [1]. To obtain the incentives, the relative *Primary Energy Savings (PES)* must be above 10%. The price per TEE is assumed to remain constant at its upper limit of 250 €/TEE. Thus, the total operating cost is computed as:

$$C_{\text{tot}} = \sum_t \Big[\text{PSV} \cdot (m_{\text{GAS,cd}} + m_{\text{GAS,CHP}}) \cdot LHV + \text{PUN} \cdot E_{\text{in,grid}} - \text{PZ} \cdot E_{\text{out,grid}} - 250 \cdot CB \Big]$$

1.2.2 Emissions

Regarding emissions, not only the direct emissions (*Scope 1*) generated by fuel combustion should be considered, but the entire emission cycle must be accounted for. Therefore, indirect emissions associated with electricity purchased from the grid (*Scope 2*) and the avoided emissions due to the sale of electricity produced more efficiently than the national average (*Scope 3*) should also be included.
The emission coefficients for natural gas and electricity are sourced from the *Istituto Superiore per la Protezione e la Ricerca Ambientale (ISPRA)* database. Other indirect emissions, such as those related to natural gas extraction and transportation, are not considered. A complete *Life Cycle Assessment (LCA)* would be required to account for all emissions associated with the plant, but this falls outside the scope of this study.
The total emissions are then computed as:

$$CO_{2,\text{tot}} = \sum_t \Big[1.956 \cdot (m_{\text{GAS,cd}} + m_{\text{GAS,CHP}}) + 0.251 \cdot E_{\text{in,grid}} - 0.251 \cdot E_{\text{out,grid}} \Big]$$

The results are represented in Table 2.

BENCHMARK		
Cost of Natural Gas	1,457,037	€
Cost of Electricity	349,368	€
TEE revenues	218,657	€
Total Operating Cost	**1,587,747**	**€**
Scope 1 emissions	6,450	tons
Scope 2 emissions	855	tons
Scope 3 emissions	-207	tons
Total Emissions	**7,099**	**tons**

Table 2: **Benchmark Model** - Costs and Emissions

2. CHP control optimization

2.1. Model implementation

The optimal control of the CHP unit for minimizing total operating costs is determined using a heuristic approach. The most common CHP control strategies are considered: *thermal-load-following (TLF)* and *electrical-load-following (ELF)* [3]. In the first case, the CHP unit adjusts its operation to match thermal demand, with any surplus or deficit in electricity being sold to or purchased from the grid, respectively. In the second case, the unit follows electrical demand, with excess heat being wasted and deficits

covered by the boiler system. Since the CHP cannot operate below its minimum load, subscenarios are considered in which the unit either shuts down or remains on when demand falls below this threshold. Additionally, two other scenarios are analyzed: one where the CHP operates continuously at maximum load and another where it is disconnected from the district heating network.
To determine the optimal control strategy, all feasible scenarios with an efficiency above an arbitrary threshold ($PES_{\text{threshold}}$) are evaluated for each hour, and the one with the lowest cost is selected. The threshold ensures that the global *Primary Energy Saving (PES)* remains above the minimum required for obtaining TEE incentives. Notably, even without enforcing $PES_{\text{threshold}}$, the optimized control strategy naturally exceeds this limit.

2.2. Results

Two optimization cases are examined: the first prioritizes *self-consumption*, aligning with the current operational strategy of the plant, and thus excludes the *maximum-load* scenario. The second prioritizes *electricity sales*, incorporating this scenario. The optimal distribution of CHP control modes for both cases along the year is illustrated in Figure 4 and Figure 5.

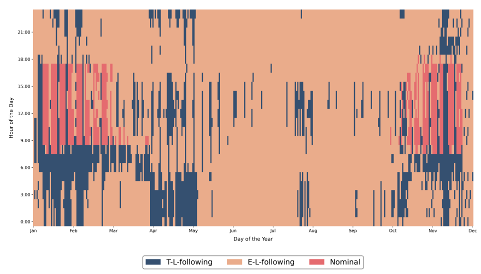

Figure 4: Optimal CHP control mode distribution (*self-consumption*)

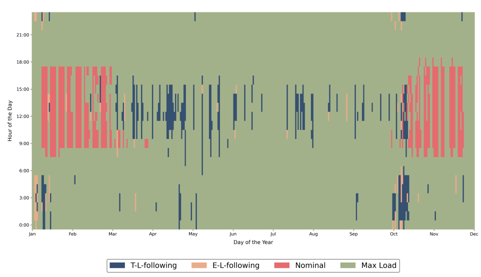

Figure 5: Optimal CHP control mode distribution (*electricity sales*)

Electricity costs outweigh natural gas costs, driving an optimization of grid exchanges by minimizing purchases (*self-consumption case*) or maximizing sales (*electricity-sales case*). In the latter, *electrical-load-following* mode (orange) is largely replaced by *maximum-load* mode (green), as surplus electricity generation becomes economically advantageous. This shift occurs when the Zonal Price sufficiently compensates for the additional gas consumption.
In the *self-consumption case*, *thermal-load-following* mode (blue) is more frequent at night during the *cold period*, when electricity demand and prices are low. Conversely, in the *electricity-sales case*, it appears primarily during daylight hours in mid-seasons, when purchasing electricity is more cost-effective than burning fuel, often leading to CHP shutdown.
CHP operation at nominal load to meet electrical and thermal demands exceeding its capacity is categorized separately (red), as all control modes exhibit the same behavior in these conditions. This occurs most frequently in the *cold period*, particularly during daylight hours, when both demands exceed the CHP capacity.
The global results variation with respect to the *Benchmark Model* are shown in Table 3.

	C1	**C2**
Cost of Natural Gas	6%	30%
Cost of Electricity	-69%	-209%
TEE revenues	20%	28%
Total Operating Cost	**-13%**	**-22%**
Scope 1 emissions	7%	33%
Scope 2 emissions	-57%	-62%
Scope 3 emissions	53%	373%
Total Emissions	**1%**	**11%**

Table 3: **Self-Consumption (C1) vs Electricity-Sales (C2)** - Costs and Emissions

A significant reduction in total operating costs is observed; however, this comes at the expense of an increase in total emissions, primarily due to the extended operating hours of the CHP unit (+7% and +33%). Although *Scope 2* emissions and, in the second case, *Scope 3* emissions are notably reduced, the increase in natural gas con-

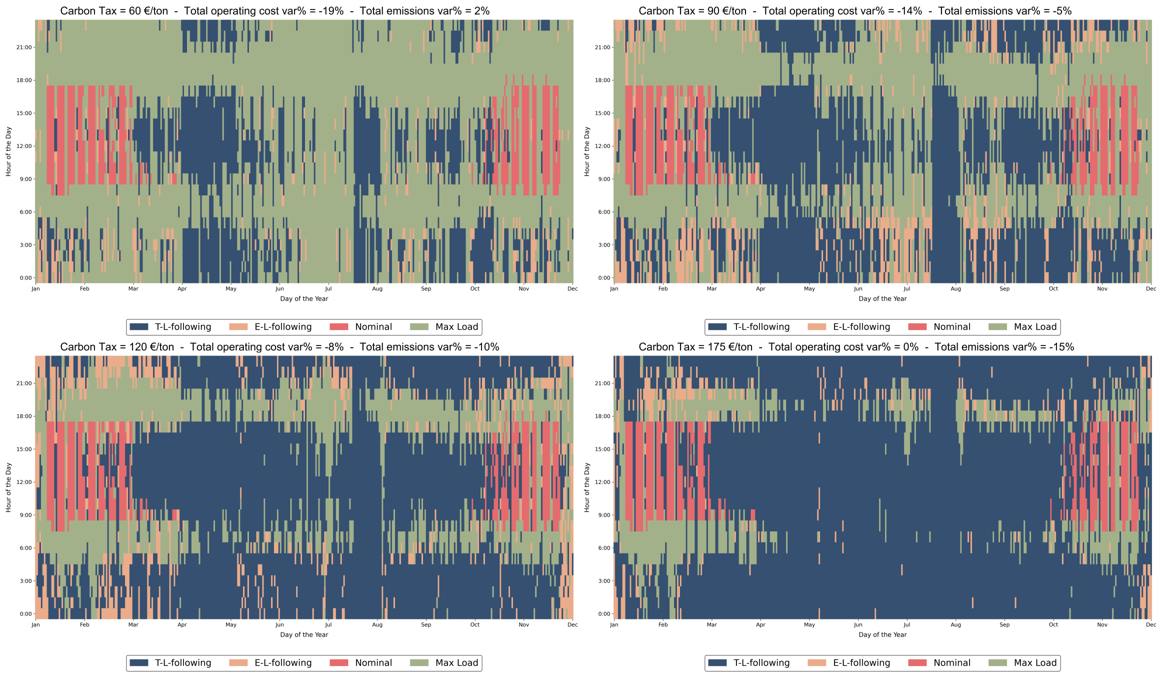

Figure 6: CHP optimal control mode distribution for different carbon taxes

sumption leads to a rise in total emissions, highlighting its dominant impact among the different emission categories.

Additionally, revenues from TEE incentives increase in both cases, as the CHP produces a higher amount of useful electricity and heat, resulting in an increased RISP. The total electricity cost also decreases due to the minimization of purchased electricity in the first case and the maximization of electricity sales in the second case.

2.3. Carbon tax

Since emissions and costs follow opposite trends, incorporating a fictitious cost for direct emissions in the CHP optimization discourages *maximum-load* operation. Instead, it promotes *thermal-load-following* and *electrical-load-following* modes. A fictitious carbon tax is introduced, starting from the *Optimized Scenario - electricity sales*, to balance economic and environmental objectives. Figure 6 illustrates the adaptation of CHP control to increasing carbon taxes, prioritizing *Scope 1* emissions reduction. As the tax rises, *maximum-load* operation decreases, while *thermal-load-following* and *electrical-load-following* modes increase. Mid-season hours are the first to shift, except for peak demand periods (6-9 a.m. and 6-9 p.m.), which remain at *maximum-load* even under high taxes. Initially, night hours transition to *electrical-load-following*, avoiding surplus electricity generation. With stricter emissions constraints, they further shift to *thermal-load-following*, reducing gas consumption and increasing electricity purchases from the grid.

3. RES integration

In 2023, a 1 MWp PV plant was installed, expanding to 1.5 MWp in 2024. The integration of photovoltaic energy affects CHP control optimization, as PV generation is weather-dependent and must take priority, requiring the CHP to operate accordingly. The *RES Integrated Model* incorporates the 1.5 MWp PV plant into the heuristic scenarios. Hourly PV yield is estimated using *Renewables.ninja*, acknowledging its approximations, as precise simulations require specialized tools like *PVSyst*. However, this approach is sufficient since PV production is not the primary focus.

As shown in Table 4, the main effect is a decrease in purchased electricity and an increase in grid exports, reducing total operating costs. In the *self-consumption case*, lower electrical demand leads to occasional CHP shutdowns when operating below the minimum load, slightly decreasing gas consumption. Maximizing cost reduction also results in lower emissions compared to the

Optimized Model: in the *self-consumption case*, emissions fall below the reference case due to reduced gas consumption and lower grid electricity purchases; in the *electricity-sales case*, emissions decline from 11% to 3%, as the reduction in purchased electricity and increased grid feed-in offset direct emissions, bringing total emissions close to the reference level.

	C1	**C2**
Cost of Natural Gas	1%	29%
Cost of Electricity	-109%	-273%
TEE revenues	18%	28%
Total Operating Cost	**-26%**	**-37%**
Scope 1 emissions	1%	32%
Scope 2 emissions	-79%	-86%
Scope 3 emissions	7%	-494%
Total Emissions	**-9%**	**3%**

Table 4: **Self-Consumption (C1) vs Electricity-Sales (C2)** - Costs and Emissions

In the first case, the PV integration causes the CHP to shift from *electrical-load-following* to *thermal-load-following* during periods of lower electrical demand, operating at minimum load to meet thermal needs while selling excess electricity. This behavior reduces annual gas consumption and decreases the hours when the CHP operates at maximum load to satisfy demands exceeding its capacity. In the *electricity-sales case*, only the grid exchange quantities change, and the overall yearly control distribution remains essentially the same as in the model without PV integration.

4. PTES integration

Despite cost optimization, a significant portion of recoverable thermal energy remains unused due to low demand. In the *RES Integrated Model* with *electricity-sales*, only 8 GWh of the 18.36 GWh available is utilized, resulting in 56% waste. Implementing thermal energy storage (TES) is a viable solution to recover and utilize part of this wasted heat during critical hours. The objective is to reduce gas consumption while maintaining cost savings. Since TES is charged using waste heat from the CHP, decreasing CHP operating hours limits the available heat for storage. However, as boiler gas consumption accounts for only 8% of total gas use, the strategy must prioritize eliminating boiler demand while also reducing CHP operating hours to achieve significant emissions reductions. Thus, CHP operation must be optimized to balance emissions mitigation and cost efficiency.

4.1. Assumptions and TES control strategy

A Reversible Heat Pump-Organic Rankine Cycle system is considered. In charge mode, the heat pump consumes electricity, depending on its COP_{HP}, to recover waste heat from the ambient at *low temperature* and raise it to the storage temperature at *high temperature*. In discharge mode, heat at *high temperature* is used in the heat engine to generate electricity, based on its η_{HE}, while supplying thermal demand with *low temperature* heat. The following assumptions are made:

- Given that most studies in the literature focus on storage temperatures between 90°C and 200°C, a storage temperature of 150°C is assumed [4]. Consequently, the key performance parameters are:
  - $COP_{\text{HP}} = 4$
  - $\eta_{\text{HE}} = 0.1$
- These performance parameters are assumed to remain constant under off-design conditions and across different storage capacities.
- No thermal or mixing losses are considered, assuming an ideal storage system.
- No constraints on the nominal power for the heat pump and heat engine.
- The initial *State of Charge (SoC)* is always set equal to the final one, in order to avoid discontinuities at the extremes of the year.

The heuristic model is based on the hourly optimization found in the *RES Integrated Model* in the *electricity-sales case*, since it presents the highest cost reduction and the highest wasted heat. Hence, TES control strategy prioritizes discharging heat during the *cold period* to reduce boiler thermal demand, provided that stored energy is sufficient to fully cover it and simultaneously produce electricity.

$$Q_{\text{th,OUT}} = Q_{\text{th,boiler}} + W_{\text{el,OUT}} = Q_{\text{th,boiler}} \cdot \left(1 + \frac{\eta_{\text{HE}}}{1 - \eta_{\text{HE}}}\right)$$

During the *hot period*, when thermal demand is low, TES discharges heat to fully meet demand, allowing the CHP to be turned off. This occurs only during low-efficiency hours, defined by an hourly PES lower than an arbitrary $PES_{\text{threshold}}$. Since shutting down the CHP increases costs, $PES_{\text{threshold}}$ is set to maintain the same cost savings as the *RES Integrated Model*.

$$Q_{\text{th,OUT}} = D_{\text{th}} + W_{\text{el,OUT}} = D_{\text{th}} \cdot \left(1 + \frac{\eta_{\text{HE}}}{1 - \eta_{\text{HE}}}\right)$$

Conversely, when excess heat is available from the CHP, TES charges until reaching its maximum capacity.

$$Q_{\text{th,IN}} = Q_{\text{th,LT}} + W_{\text{el,IN}} = Q_{\text{th,LT}} \cdot \left(1 + \frac{1}{COP_{\text{HP}} - 1}\right)$$

Wasted heat is highest during the *hot period* due to low demand, while in the *cold period*, thermal demand peaks, requiring boiler support for the CHP. Thus, seasonal TES (250 MWh to 2000 MWh) is considered a viable solution. However, due to the large storage volumes required, diurnal TES (10 MWh, 25 MWh, 50 MWh) is also analyzed. With seasonal TES, heat is stored in the *hot period* and utilized in the *cold period* to eliminate boiler demand. In contrast, diurnal TES supplies boilers with stored heat from low-demand hours, primarily at night. Although the control logic remains the same, the cycling behavior differs significantly between the two storage types.

4.2. Seasonal storage

Figure 7 shows the SoC trend along the year for different seasonal storage capacities. Each of these curves represents the SoC trend in the case of maximum emissions reduction without defecting the cost savings obtained in the *RES Integrated Model*.

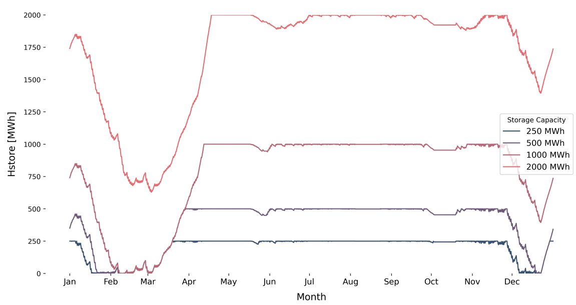

Figure 7: Seasonal storage trend along the year

Therefore, $PES_{\text{threshold}}$ is adjusted to reduce the CHP operating hours in the *hot period* enough to obtain 0% cost variation with respect to the previous model.

Storage capacities of 250 MWh, 500 MWh, and 1000 MWh are fully discharged in the early months, before energy storage levels rise again due to the high excess heat produced from March onward. Hence, they temporarily function as diurnal storage until March. To prevent this, larger storage capacity is needed. The 2000 MWh storage avoids full depletion of SoC, but 750 MWh of stored heat are never discharged, making a portion of the capacity unused. An optimal storage capacity is identified between 1000 MWh and 2000 MWh, with 1400 MWh proving sufficient to fully discharge once in March, eliminating unnecessary energy while maintaining performance equivalent to the 2000 MWh case. Hence, increasing the capacity to values larger than 1400 MWh will not improve the emissions reduction but it will only store useless energy.

As shown in Figure 8, for every storage capacity considered, it is possible to achieve a significant reduction in emissions while maintaining the total cost savings obtained in the previous model without storage. As storage capacity increases, more CHP operating hours can be eliminated, as a greater amount of thermal energy can be stored and subsequently utilized to meet demand without compromising the reduction in boiler gas consumption. The increase in electricity costs is offset by the reduction in natural gas costs through the decreased consumption of both the CHP and boiler systems. With a capacity of 1400 MWh, it is possible to reduce the emissions by 20% with respect to the *Benchmark Model*, while keeping the costs savings (-37% with respect to *Benchmark Model*). The boiler system is completely detached from the plant (-100%) since its demand is fully met by the TES. However, it is important again to remark the fact that the emissions reduction is mainly due to the CHP operating hours reduction (-33%).

4.3. Dirunal storage

Diurnal storage can be relatively easily implemented, particularly in the *PoliMi Campus*, which has spatial constraints due to surrounding buildings. However, achieving significant emissions reductions is challenging, as the heat stored overnight can only cover a limited num-

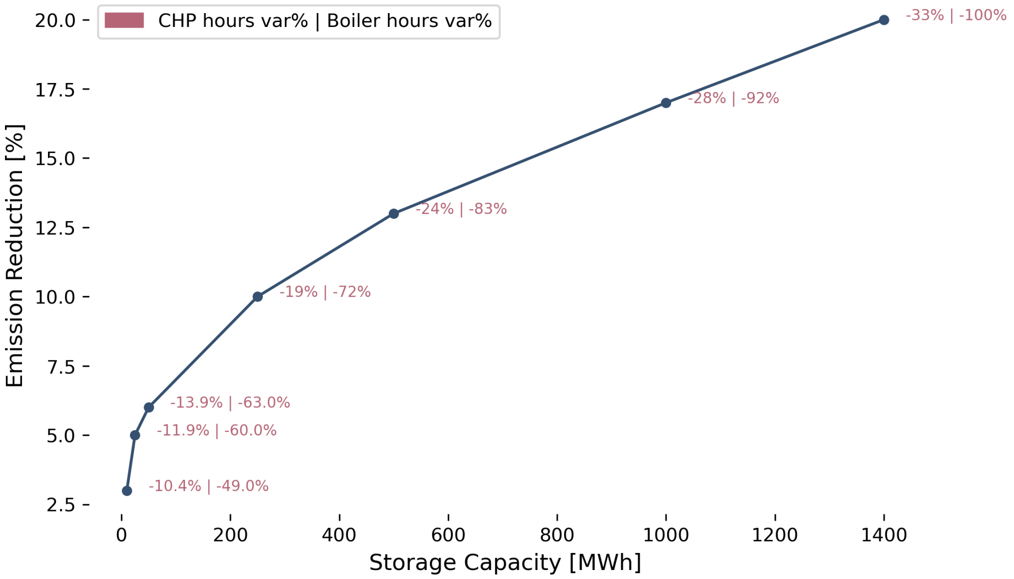

Figure 8: Emissions & CHP and Boiler operating hours reduction for different capacities

ber of peak hours, resulting in only a slight reduction in CHP operating hours without compromising cost savings. As shown in Figure 8, the emissions reduction attainable without affecting cost savings remains minimal. Notably, for small capacities, a slight decrease in CHP operating hours—corresponding to a small increase in $PES_{\text{threshold}}$—can nearly triple the emissions reduction. This suggests that the least efficient hours correspond to those with lower gas consumption, highlighting the importance of optimizing CHP operation to balance cost savings and emissions reduction.

4.4. MILP approach

The heuristic approach for TES integration offers a simpler and more practical power management logic but may yield suboptimal solutions. A key limitation is its inability to anticipate future conditions, unlike mathematical models that optimize over a broader time horizon. Additionally, the *TES integrated Model* in the heuristic approach relies on the hourly results of the *RES integrated Model*, keeping CHP behavior unchanged except when turned off. However, storage integration likely alters the optimal CHP control, necessitating an optimization model to identify the best strategy. Hence, a *MILP (Mixed-Integer Linear Programming)* model is introduced to overcome these limitations. It determines the optimal solution within a feasible region defined by linear constraints, maximizing or minimizing an objective function while ensuring operational feasibility.
The MILP approach is employed in this study to compare the heuristic solution developed in the *TES Integrated Model* with the optimal one. Due to computational constraints, a *Rolling Horizon approach* is adopted [2]. However, since the optimization time window is limited, the model cannot anticipate long-term trends, making seasonal storage implementation unfeasible within this framework. As a result, the MILP model is used to validate the diurnal storage configuration, considering a 25 MWh storage capacity, which corresponds to the average daily thermal energy produced by the boilers during the *cold period*.

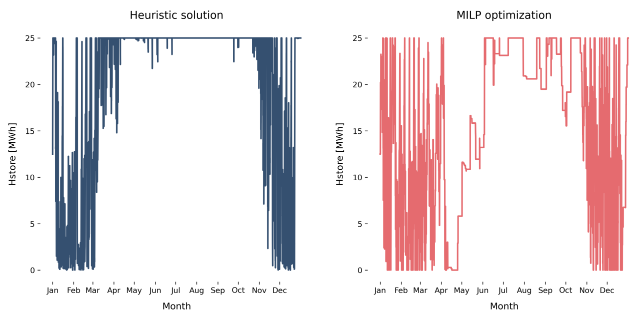

Figure 9: Heuristic vs MILP (diurnal storage)

Figure 9 illustrates the SoC trends throughout the year for the two models. During the *cold* *period*, both models exhibit a consistent daily cycling pattern. However, in the *hot period*, the MILP model optimizes CHP operation by forecasting demand and electricity prices, unlike the heuristic approach. As a result, storage is charged during low PUN hours and high PV production periods, minimizing electricity costs for the PTES heat pump activation. Additionally, the MILP model selectively shuts down the CHP and discharges stored heat when cost-effective, whereas the heuristic model bases shutdowns on efficiency (PES). This leads to different operational patterns, yet despite these differences, the overall reduction in CHP operating hours remains minimal. On a global scale, no significant discrepancies are observed between the results of the heuristic and mathematical models. Further analysis on larger storage capacities is recommended to evaluate whether this difference could have a more substantial impact on global performance.

5. Conclusions

Before concluding, it is essential to emphasize the fundamental trade-off between cost minimization and emissions reduction. While emissions are primarily influenced by direct gas consumption (*Scope 1*), cost optimization is driven by electricity exchanges with the grid, where fluctuating electricity prices encourage increased gas use to reduce electricity purchases and maximize sales. As a result, the minimization of costs is inherently opposed to the minimization of emissions.

Adding TES in the *TES Integrated Model* enables the recovery of up to 2.5 GWh of thermal energy, maintaining cost reductions of *-37%* while cutting emissions by up to *-20%* with respect to the *Benchmark Model*. For large TES capacities, boilers can be eliminated, covering demand peaks with stored energy. However, substantial emissions reductions require not only reducing boiler use but also limiting CHP operating hours. For meaningful emissions reductions, TES capacity must be sufficiently large to partially satisfy winter thermal demand using heat recovered during summer. However, it must not be excessively large to remain feasible in terms of economic and spatial constraints. Thus, the optimal solution is in the middle between large capacities, that present high emissions reductions but large volumes, and small capacities, which are the most practical solution but the emissions reduction is small.

Looking ahead, several key improvements and research directions can be considered. Integrating predictive models for energy prices and demand would enhance optimization by introducing uncertainty and enabling more robust decision-making based on historical trends. Future studies should account for CHP maintenance costs. Also, real TES systems experience thermal and mixing losses, which should be evaluated in relation to storage size. Higher storage temperatures could be explored given the system's exhaust temperatures, but also alternative storage designs without temperature elevation. Finally, assessing TES investment costs (CAPEX and OPEX) over its lifetime, along with comparing different storage fluids, is essential for determining the most cost-effective solution.

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