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Thermodynamic and operating-cost assessment of boiler and CHP pathways for coal-based district heating modernization

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ABSTRACT

Coal-based district heating systems in Central and Eastern Europe face increasing pressure from carbon pricing, aging infrastructure, and decarbonization requirements. This study presents a screening-level thermodynamic and operating-cost assessment of modernization pathways for a municipal coal-fired district heating plant. The analyzed options include replacement of the existing pulverized-coal boiler with a biomass-fired unit and conversion to three gas-turbine-based combined heat and power configurations: a simple cycle, a regenerative cycle, and an externally fired air-turbine system. Hydrogen was considered at mass shares of 0, 50, and 100 wt.%, and annual performance was evaluated for an equivalent operating time of 8.500 h and a common useful heat production of 315,360 GJ/year. The economic assessment included fuel expenditure, direct CO_2 allowance costs, and revenues from heat and electricity sales, while capital and infrastructure costs were excluded. For the heat-only cases, biomass reduced the selected operating cost from 4.41 million USD/year for coal to 2.64 million USD/year, mainly because no direct CO_2 allowance cost was assigned within the adopted EU ETS boundary. Among the natural-gas CHP cases, the simple gas turbine achieved the highest annual operating balance despite having the lowest electrical efficiency. At a hydrogen price of 1 USD/kg, increasing the hydrogen mass share improved the operating balance of all CHP configurations, with the 100 wt.% H_2 cases reaching 8.99–15.41 million USD/year. At 3 USD/kg, only the simple gas turbine with 50 wt.% H_2 retained a positive annual operating balance, whereas at 5 and 8 USD/kg all hydrogen-containing cases generated operating losses. The calculated break-even hydrogen prices ranged from approximately 2.25 to 3.32 USD/kg. The results indicate that thermodynamic efficiency alone does not determine operating competitiveness under the adopted assumptions; fuel demand, fuel price, electricity output, and direct carbon-cost exposure jointly shape the economic boundary conditions of district heating modernization.

Keywords: district heating, combined heat and power, hydrogen co-firing, biomass, gas turbine, carbon pricing, operating-cost analysis.

INTRODUCTION

The continued growth of energy demand associated with economic development, urbanization, and population growth has increased pressure on existing energy infrastructure and contributed to greenhouse-gas emissions and environmental degradation [1–4]. Although renewable energy deployment is expanding, fossil fuels continue to play a major role in heat and power generation, particularly in sectors characterized by long-lived assets and limited operational flexibility [5–7]. Decarbonizing such systems requires balancing emission reduction, energy affordability, reliability, and the practical constraints of infrastructure modernization.

District heating systems constitute an important component of urban energy infrastructure, especially in Central and Eastern Europe. Heat and power generation account for a substantial share of global greenhouse-gas emissions [8]. In many district heating networks, coal-fired heat-only boilers remain in operation, resulting in high direct carbon emissions and increasing exposure to carbon-pricing mechanisms. Under the European Union Emissions Trading System, the cost of CO_2 allowances can substantially increase the operating expenditure of fossil-fuel-based heat production [9,10]. District heating modernization is therefore both an environmental and an operating-economic challenge, particularly in regions with aging infrastructure and limited investment capacity.

Possible modernization pathways include replacing coal-fired boilers with biomass-fired units, converting heat-only plants into combined heat and power systems, and partially or fully substituting fossil fuels with lower-carbon energy carriers [11–13]. Recent thermodynamic studies of industrial energy-conversion systems have demonstrated that cycle configuration and heat-source conditions strongly affect net power output and conversion efficiency [14]. Biomass combustion is based on established boiler technologies and may reduce exposure to direct CO_2 allowance costs within the accounting boundary applied under the EU ETS [12,15]. However, its broader environmental performance depends on fuel origin, transport, processing, and supply-chain conditions. Conversion to CHP can improve fuel utilization by producing useful heat and electricity simultaneously, but its operating performance depends strongly on cycle configuration, fuel demand, electricity output, and market prices.

Hydrogen has received increasing attention as a potential energy carrier for power generation, industrial heat, energy storage, and sector coupling [16–19]. It can be blended with natural gas and used in combustion-based CHP systems, although the extent of required burner, control-system, material, and turbine modifications depends on the hydrogen fraction and equipment design [20]. Hydrogen co-firing may reduce direct combustion-related CO_2 emissions while maintaining dispatchable heat and electricity production. At high hydrogen shares, however, technical challenges become increasingly important. The high reactivity and flame propagation speed of hydrogen increase susceptibility to flashback and combustion instabilities, while high local flame temperatures can promote thermal NO_x formation. Hydrogen-rich operation may therefore require modifications to burner design and combustion-control strategies. In addition, hydrogen exposure can affect the mechanical integrity and durability of metallic components through hydrogen-assisted degradation mechanisms, including hydrogen embrittlement, making material compatibility an additional consideration for high-hydrogen gas-turbine operation [21–23].

Hydrogen also plays a prominent role in European decarbonization strategies and related standardization activities [9,10,24,25]. Nevertheless, the near- and medium-term operating-economic feasibility of hydrogen use in district heating CHP remains uncertain. A major source of uncertainty is the delivered hydrogen price. Clean hydrogen production currently remains more expensive than conventional fossil-fuel supply in many applications [26–28], while values close to 1 USD/kg are generally discussed as ambitious long-term targets rather than typical current procurement conditions [29]. The economic performance of hydrogen-fired CHP is therefore expected to be highly sensitive to the assumed hydrogen price, natural gas price, carbon allowance cost, and electricity revenue.

Although numerous studies address hydrogen production technologies and system-level energy-transition scenarios, fewer provide transparent, plant-level comparisons of alternative CHP configurations for district heating under a common heat-demand and operating-cost boundary. Direct comparisons that combine gas-turbine performance, hydrogen mass share, fuel expenditure, electricity revenue, and direct CO_2 allowance costs are particularly limited. Comparisons with biomass-based modernization options are also often complicated by differences in system boundaries and technology-specific assumptions.

Poland provides a relevant case for such an assessment. Its district heating sector is one of the largest in the European Union and remains strongly dependent on coal [30]. Many systems therefore face simultaneous pressure to reduce direct emissions, control heat-production costs, and modernize aging generation assets. Similar conditions occur in other coal-dependent and transition economies, meaning that the operating-economic relationships identified for a Polish municipal plant may also be informative for systems facing comparable infrastructure and carbon-cost constraints.

The objective of this study is to compare selected modernization pathways for a municipal coal-based district heating plant using a common annual useful heat demand and a consistent market-price framework. The analyzed options include replacement of the existing coal-fired boiler with a biomass-fired boiler and conversion to three gas-turbine-based CHP configurations: a simple cycle, a regenerative cycle, and an externally fired air-turbine system. Hydrogen is analyzed at mass shares of 0, 50, and 100 wt.% in the supplied gas–hydrogen fuel. Unless otherwise stated, hydrogen content is expressed on a mass basis throughout the manuscript.

The assessment combines steady-state thermodynamic results with an annual operating-cost model that includes fuel expenditure, direct CO_2 allowance costs, and revenues from heat and electricity sales. Capital expenditure, financing, and discounted investment indicators are outside the adopted system boundary. The main contribution of the study is a consistent plant-level comparison of heat-only and CHP modernization pathways and an evaluation of how fuel price, hydrogen mass share, direct carbon cost, and electricity output affect their annual operating balance.

SCOPE AND LIMITATIONS

This study applies a screening-level thermodynamic and operating cost framework to compare selected modernization options for a municipal district heating plant. The analysis is based on steady-state cycle modelling and representative annual operation. The primary objective is to identify relative performance trends and the corresponding economic boundary conditions rather than to provide a fully optimized plant design or a complete investment appraisal.

The economic assessment includes fuel expenditure, direct CO_2 allowance costs under the European Union Emissions Trading System, and revenues from heat and electricity sales. Auxiliary electricity consumption is included for the heat-only boiler cases, whereas separate auxiliary-energy and maintenance costs are not included in the CHP operating balances. Capital expenditure, financing structure, depreciation, and discounted cash-flow indicators are outside the scope of the analysis. Dynamic operation, detailed part-load performance, electricity-market volatility, grid constraints, and ancillary-service participation are also excluded.

Environmental performance is represented by direct combustion-related CO_2 emissions within the adopted ETS accounting boundary [31]. Upstream emissions, fuel production and transport, life-cycle greenhouse-gas impacts, hydrogen production pathways, biomass supply-chain effects, and infrastructure requirements for fuel storage and distribution are not included. The assumption of zero direct CO_2 cost for hydrogen and biomass should therefore not be interpreted as zero life-cycle emissions.

The analysis also does not account for fuel-specific technical constraints associated with high hydrogen shares, including burner modification, combustion stability, flashback risk, NO_x formation, material compatibility, and long-term component degradation. The 50 and 100 wt.% H_2 cases should therefore be interpreted as thermodynamic and operating-cost boundary scenarios rather than immediately deployable retrofit configurations.

Given these limitations, the results should be interpreted as scenario-based indicators of relative operating-cost performance under the adopted technical and market assumptions. The framework is intended for preliminary screening of modernization pathways before detailed engineering, investment, and life-cycle assessments are undertaken.

MATERIALS AND METHODS

The study considers a representative municipal district heating plant in Poland equipped with a pulverized coal-fired heat-only boiler, shown schematically in Figure 1a. The analyzed modernization pathways include replacement of the existing coal-fired boiler with a biomass-fired boiler of similar thermal duty and conversion of the heat-only plant into a combined heat and power system.

Three CHP configurations were considered. The first was a simple open-cycle gas turbine system (Figure 1b). The second was a regenerative gas turbine cycle in which the turbine exhaust was used to preheat the compressed air before combustion, thereby reducing the required fuel input and improving electrical efficiency (Figure 1c). In both configurations, natural gas–hydrogen operation was analyzed at hydrogen mass shares of 0, 50, and 100 wt.%.

The third configuration was an externally fired air-turbine cycle with a bypass system (Figure 1d) [32]. In this arrangement, clean air flows

through the compressor and turbine, while fuel combustion takes place in an external combustion chamber outside the main turbomachinery flow path. This limits direct contact between the turbine components and the combustion products and may reduce fouling when non-conventional fuels are used. The configuration also provides greater fuel flexibility and was therefore analyzed for natural gas–hydrogen mixtures and, in a separate fuel-specific case, for biomass.

All configurations were evaluated for the same annual useful heat production of 315,360 GJ. The CHP systems were analyzed under a heat-led operating assumption, with electricity treated as a co-product. Common annual operating and market-price assumptions were applied in the economic comparison. Fuel-specific thermodynamic outputs, including net electrical power, were retained from the corresponding steady-state simulation cases.

The thermodynamic performance of the heat-only and CHP configurations was evaluated using steady-state mass and energy balances. The CHP cycle calculations were based on standard gas-turbine relations reported in the literature [32,33] and implemented in Ebsilon Professional. The model provided compressor work, turbine work, net electrical output, exhaust-gas conditions, fuel demand, and recoverable heat supplied to the district heating network.

For the heat-only boiler configurations, annual useful heat production, fuel demand, direct CO_2 emissions, and operating costs were calculated using fuel-specific energy balances and emission factors. For the CHP configurations, steady-state thermodynamic outputs were converted into annual electricity and heat quantities using an equivalent annual operating time.

The annual economic assessment included fuel expenditure, direct CO_2 allowance costs, and revenues from heat and electricity sales. Auxiliary-electricity costs were included separately for the heat-only boiler configurations. Separate auxiliary-electricity and maintenance costs were not included in the CHP operating balance.

Heat-only boiler calculations

For the heat-only boiler configurations (Fig. 1a), annual energy and economic quantities were calculated sequentially from the useful heat demand, boiler efficiency, fuel properties, and market-price assumptions.

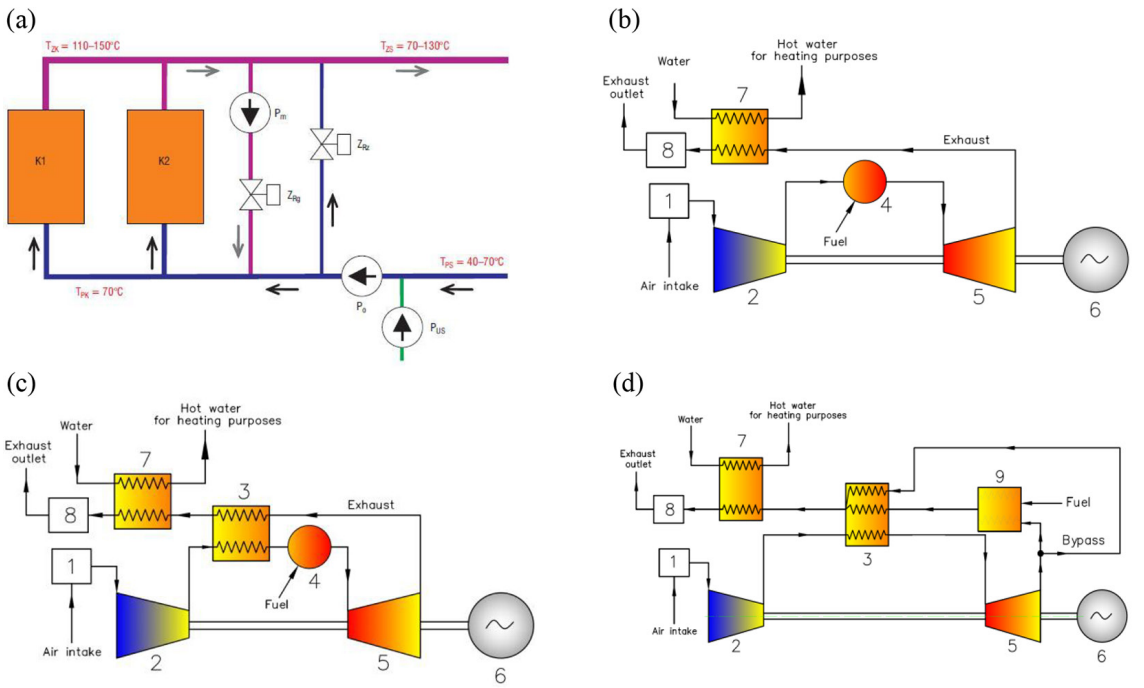


Figure 1. Simplified system layouts of the analyzed district heating and CHP configurations: (a) district heating plant with a pulverized coal or biomass-fired boiler; (b) gas-turbine-based CHP plant operating in a simple open cycle; (c) gas-turbine-based CHP plant with a regenerator; (d) air-turbine-based CHP plant with an external combustion chamber and bypass. Components: 1 – air filter, 2 – compressor, 3 – regenerator, 4 – combustion chamber, 5 – turbine, 6 – generator, 7 – heat exchanger, 8 – silencer, 9 – external combustion chamber

Annual useful heat production is defined as:

$$P_a = N \cdot t_a \cdot 3.6 \quad (1)$$

where: Pa – annual heat production [GJ/year], N– thermal output power [MW], ta – annual operating time [h].

The corresponding annual fuel energy input is obtained from:

$$F_{ac} = \frac{E_{fa}}{w_d \cdot 1000} \quad (2)$$

where: η – boiler efficiency [-], E_{fa} – annual fuel energy input [GJ/year].

Annual fuel mass consumption is calculated as:

$$F_{pa} = F_{ac} \cdot F_p \quad (3)$$

where: w_d – lower heating value (LHV) of the fuel [MJ/kg], F_{ac} – annual fuel consumption [kg].

The annual fuel cost is then:

$$AE_{CO2} = F_{fa} \cdot W_{CO2} \quad (4)$$

where: F_p – price of fuel [USD/1000 kg] (unit conversions between USD/MWh, USD/GJ and USD/kg are applied consistently across fuels), F_{pa} – annual cost of fuel [USD/year].

Annual CO_2 emissions for fossil fuels are determined as:

$$AP_{CO2} = AE_{CO2} \cdot P_{CO2} \quad (5)$$

where: W_{CO2} – emission factor [kgCO_2/GJ], AE_{CO2} – annual CO_2 emission [kg].

The corresponding annual emission cost is:

$$AP_{CO2} = AE_{CO2} \cdot P_{CO2} \quad (6)$$

where: P_{CO2} – price of CO_2 emission [USD/1000kg], AP_{CO2} – annual cost of CO_2 emission [USD/year].

The annual auxiliary electricity cost required for plant operation is calculated as:

$$C_e = N_{aux} \cdot t_a \quad (7)$$

where: C_e – electricity price [USD/MWh], N_{aux} – the power of auxiliary systems needed to operate a district heating plant [MW], t_a – annual operating time [h].

Annual income from heat sales is given by:

$$I_{ha} = P_a \cdot H_p \quad (8)$$

where: I_{ha} – annual income from the heat sales [USD/year], H_p – heat selling price [USD/GJ].

CHP cycle calculations

For CHP configurations (Figure 1b–d), the net electric power of the turbine-generator set is defined as:

$$N_{GT} = \eta_m \cdot \dot{m}_T \cdot l_T - \dot{m}_C \cdot l_C \quad (9)$$

and the corresponding unit work

$$l_{GT} = \eta_m \cdot \left(\frac{\dot{m}_T}{\dot{m}_C}\right) \cdot l_T - \left(\frac{\dot{m}_C}{\dot{m}_C}\right) \cdot l_C = \eta_m \cdot \left(\frac{\dot{m}_T}{\dot{m}_C}\right) \cdot l_T - l_C \quad (10)$$

where: η_m – mechanical efficiency, [-], $\dot{m}_c$, $\dot{m}_T$ – mass flow of air, flue gases, [kg/s], l_{GT}, l_C, l_T – unit work, work needed to drive the compressor, turbine work, [kJ/kg].

The compressor work is:

$$l_C = \frac{1}{\eta_C} \cdot c_{pC} \cdot T_1 \cdot \left(\left(\frac{p_2}{p_1}\right)^{\frac{\kappa_C - 1}{\kappa_C}} - 1 \right) \quad (11)$$

and turbine work:

$$l_T = \eta_T \cdot c_{pT} \cdot T_3 \left(1 - \left(\frac{p_4}{p_3}\right)^{\frac{\kappa_T - 1}{\kappa_T}} \right) \quad (12)$$

where: η_T , η_C – internal efficiency of the turbine, compressor, [-], c_{pT}, c_{pC} – specific heat at constant pressure for exhaust gas, air, [kJ/(kg·K)], η_T, η_C – adiabatic exponent for flue gas, air, [-], T_1, T_3 – temperature of air at inlet to compressor, turbine, [K], p_1, p_2, p_3, p_4 – pressure before and after the compressor, before and after the turbine, [Pa].

Gas turbine thermal efficiency

The thermal efficiency of the gas turbine cycle is defined as:

$$\eta_{GT} = \frac{N_{GT}}{\dot{Q}_1} \quad (13)$$

where the heat input in the combustion chamber is:

$$\dot{Q}_1 = \left(\dot{m}_T \cdot i_3 - \dot{m}_C \cdot i_{2'}\right)\frac{1}{\eta_{CC}} = \dot{m}_f \cdot W_d \quad (14)$$

where: $\dot{m}_f$ – fuel mass flux, [kg/s], η_{CC} – combustion chamber efficiency [-], $i_{2'}$, i_3 – specific enthalpy at inlet and outlet of combustion chamber [kJ/kg], Q_1 – heat flux delivered in fuel, [kW], W_d – lower heating values of the fuel, [kJ/kg].

The general expression for the gas turbine cycle efficiency can be written as:

$$\eta_{GT} = \frac{\eta_m \cdot \dot{m}_T \cdot l_T - \dot{m}_C \cdot l_C}{\left(\dot{m}_T \cdot i_3 - \dot{m}_C \cdot i_{2'}\right) \cdot \dfrac{1}{\eta_{CC}}} \quad (15)$$

After algebraic transformations and substitution of temperature and pressure relations for the compressor and turbine, the efficiency of a simple gas turbine cycle can be expressed in analytical form as:

$$\eta_{TG} = \eta_{KS} \cdot \frac{\eta_m \cdot \eta_T \cdot c_{pT} \cdot \dfrac{T_3}{T_1}\left[1 - \left(\dfrac{1}{\Pi_T}\right)^{\frac{\kappa_T - 1}{\kappa_T}}\right] \cdot \dfrac{\dot{m}_T}{\dot{m}_C} - \dfrac{1}{\eta_C} \cdot c_{pC} \cdot \left[(\Pi_C)^{\frac{\kappa_C - 1}{\kappa_C}} - 1\right]}{\dfrac{\dot{m}_T}{\dot{m}_C} \cdot c_{pCC} \cdot \dfrac{T_3}{T_1} - \dfrac{1}{\eta_C} \cdot c_{pC} \cdot \left[(\Pi_C)^{\frac{\kappa_C - 1}{\kappa_C}} - 1\right]} \quad (16)$$

where c_{pCC} – specific heat at constant pressure for the combustion chamber, [kJ/(kg·K)], $\Pi_C = p_2/p_1$ – compressor pressure ratio, [-], $\Pi_T = p_3/p_4$ – turbine expansion ratio, [-].

Regenerative cycle

For the regenerative cycle, the heat flux transferred from the exhaust gas in the regenerator is calculated as:

$$\dot{Q}_{VIIT} = \dot{m}_T \cdot \left(i_4 - i_5\right) \quad (17)$$

The corresponding heat flux received by the compressed air is calculated as:

$$\dot{Q}_{VIIC} = \dot{m}_C \cdot \left(i_{2'} - i_2\right) \quad (18)$$

Annual electricity production and sales

Annual net electricity production was calculated using the net electrical output obtained from the steady-state cycle model and the equivalent annual operating time:

$$E_{el,a} = P_{el,net} t_a \quad (19)$$

where: $E_{el,a}$ – annual net electricity production, MWh/year; $P_{el,net}$ – net electrical output, MW; t_a – equivalent annual operating time, h/year.

The amount of electricity sold to the grid was determined as:

$$E_{el,s} = f_{sale} E_{el,a} \quad (20)$$

where: $E_{el,s}$ is the annual electricity sold [MWh/year] and f_{sale} is the fraction of net electricity generation available for sale. A value of 0.95 was adopted for all base case calculations.

Annual income from electricity sales was calculated as:

$$I_{el,a} = E_{el,s} P_{el} \quad (21)$$

where: $I_{el,a}$ is the annual income from electricity sales [USD/year] and P_{el} is the electricity selling price [USD/MWh].

The selected annual operating cost of the CHP configurations was defined as the sum of fuel expenditure and direct CO_2 allowance cost:

$$C_{op,a}^{sel} = C_{fuel,a} + C_{CO_2,a} \quad (22)$$

Total annual revenue from heat and electricity sales was calculated as:

$$I_{tot,a} = I_{h,a} + I_{el,a} \quad (23)$$

The annual operating balance was then determined as:

$$B_a = I_{tot,a} - C_{fuel,a} - C_{CO_2,a} \quad (24)$$

Separate auxiliary-electricity, maintenance, and capital costs were not included in the CHP operating balance. For the heat-only boiler configurations, electricity-sales revenue was equal to zero.

OPERATING CONDITIONS AND KEY ASSUMPTIONS

Annual energy quantities were calculated using an equivalent full-load operating time of 8.500 h/year. All CHP configurations were analyzed under a heat-led operating strategy and were required to provide the same annual useful heat output of 315,360 GJ/year. Electricity generation was treated as a co-product of useful heat production. For all configurations, the flue-gas temperature downstream of the heat-recovery exchanger was fixed at 100 °C to maintain a consistent heat-recovery boundary.

The reference natural gas price was set at 46.83 USD/MWh. Hydrogen was analyzed at mass shares of 0, 50, and 100 wt. % in the supplied fuel. Accordingly, the 50 wt.% H_2 case contained equal annual masses of hydrogen and natural gas. The lower heating value of the mixture was calculated as the mass-weighted average of the component lower heating values:

$$LHV_{mix} = x_{H_2,m} LHV_{H_2} + (1 - x_{H_2,m}) LHV_{NG} \quad (25)$$

where: $x_{H_2,m}$ is the mass fraction of hydrogen in the supplied fuel.

Hydrogen prices of 1, 3, 5, and 8 USD/kg were considered to evaluate the sensitivity of the annual operating balance to fuel procurement cost. These prices were treated as scenario assumptions rather than observed Polish market prices. Hydrogen was considered an externally supplied fuel, and costs associated with its production, storage, transport, compression, and distribution infrastructure were outside the adopted system boundary.

Fuel-specific lower heating values and direct CO_2 emission factors were adopted from the national guidelines used for monitoring emissions under the EU ETS [31]. Direct CO_2 allowance costs were applied only to the fossil fraction of the fuel input. For mixed natural gas–hydrogen operation, emissions were calculated from the energy input associated with the natural-gas fraction, whereas hydrogen was assigned a direct combustion emission factor of zero. Biomass was assigned no direct CO_2 allowance cost within the ETS accounting boundary adopted in this study.

A constant electricity selling price of 114.56 USD/MWh and a heat selling price of 26.44 USD/GJ were adopted for all configurations [34,35]. In the base case, 95% of annual net electricity production was assumed to be available for sale:

$$f_{sale} = 0.95 \quad (26)$$

For the heat-only boiler cases, the selected annual operating cost included fuel expenditure, direct CO_2 allowance cost, and auxiliary-electricity cost. For the CHP cases, the operating balance included fuel expenditure and direct CO_2 allowance cost; separate auxiliary-electricity and maintenance costs were not included.

The thermodynamic performance of the CHP configurations was evaluated using Ebsilon Professional [36–38]. The thermodynamic efficiencies presented in Table 1 correspond to representative design-point values adopted for steady-state simulations performed using Ebsilon Professional. These values were selected based on technical data reported for industrial CHP systems of comparable size and operating characteristics, as well as on published literature. The efficiencies were intentionally kept constant throughout the comparative analysis to ensure consistent thermodynamic boundary conditions for all modernization pathways and to isolate the effects of fuel type, fuel cost and CO_2 emission costs on system performance. Consequently, the adopted efficiencies should be interpreted as comparative modelling assumptions rather than performance predictions for specific commercial installations [15, 33].

In the present study, the efficiencies of the principal system components were assumed to remain unchanged for all analyzed fuel compositions. This assumption was adopted intentionally to establish a common thermodynamic framework for comparing alternative modernization pathways and to isolate the effects of fuel type, fuel price and CO_2 emission costs on the operating performance. Although changes in fuel composition—particularly increasing hydrogen content—may influence combustion characteristics, burner operation and achievable component efficiencies, accurate representation of these effects requires detailed combustion modelling and manufacturer-specific performance data, which are beyond the scope of the present comparative assessment.

To assess the thermodynamic plausibility of the developed Ebsilon models, selected model outputs were benchmarked against representative published performance data. For the simple gas-turbine configuration, the comparison was made

with the Siemens Energy SGT-400 industrial gas turbine [39]. The purpose of this comparison was not to reproduce a specific commercial unit, since the present model represents a generic retrofit configuration of a different capacity, but to assess whether the calculated electrical efficiency and exhaust-gas parameters are of a technically plausible magnitude. The externally fired configuration was additionally compared with published results for gas-turbine cycles employing an external combustion chamber. The benchmarking results are summarized in Table 2. This comparison should be interpreted as a model plausibility assessment rather than as experimental validation against measurements from an operating plant.

The steady-state models provided net electrical output, fuel demand, exhaust-gas conditions, and recoverable heat. These outputs were subsequently used in the annual energy and operating-cost calculations. All financial results were reported in USD. PLN-denominated prices were converted using the fixed model exchange rate of 4.00 PLN/USD.

Fuel and energy prices were derived from publicly available Polish market data and, where indicated, from explicit scenario assumptions. The coal price was based on the annual PSCMI2 index for 2025 published by the Industrial Development Agency and amounted to 455.66 PLN/t, corresponding to 113.92 USD/t at the fixed model exchange rate of 4.00 PLN/USD [40]. The reference natural gas price was calculated by the authors as the unweighted arithmetic mean of the quarterly average prices of contracts concluded on the Polish Power Exchange in 2025, as reported by the Energy Regulatory Office [41–44]. The quarterly values of 207.19, 187.49, 177.27, and 177.32 PLN/MWh gave a reference price of 187.32 PLN/MWh, equivalent to 46.83 USD/MWh. The electricity selling price was based on the annual average electricity sales price in the competitive market in 2025 and amounted to 458.24 PLN/MWh, corresponding to 114.56 USD/MWh [34]. The heat selling price was based on the average price of heat sold from all licensed heat-generation sources in Poland in 2024 and amounted to 105.74 PLN/GJ, corresponding to 26.44 USD/GJ [35]. A delivered wood-chip price of 25.00 USD/MWh was adopted as an explicit scenario assumption on an LHV basis. The CO_2 allowance price was based on the volume-weighted average EUA price for 2025, equal to 73.64

Table 1. Assumed technical and economic input data used in the calculations

Parameter	Symbol	Value	Unit
Annual heat production	P_a	315,360	GJ/year
Lower heating value – coal	W_{dc}	23	MJ/kg
Lower heating value – biomass	W_{db}	7	MJ/kg
Lower heating value – natural gas	W_{dg}	50	MJ/kg
Lower heating value – hydrogen	W_{dh}	120	MJ/kg
Boiler efficiency – coal	η_{bc}	0.90	-
Boiler efficiency – biomass	η_{bb}	0.85	-
Turbine isentropic efficiency	η_T	0.88	-
Compressor isentropic efficiency	η_C	0.85	-
Mechanical efficiency	η_m	0.98	-
Generator efficiency	η_G	0.90	-
Combustion chamber efficiency	η_{CC}	0.95	-
Coal price	F_{pc}	113.92	USD/t
Biomass price (wood-chip)	F_{pb}	25.00	USD/MWh
Natural gas price (reference)	F_{pg}	46.83	USD/MWh
Hydrogen price (scenario range)	F_{ph}	1-8	USD/kg
Electricity selling price	P_{el}	114.56	USD/MWh
Heat selling price	P_h	26.44	USD/GJ
CO_2 emission factor (coal)	$W_{CO2,c}$	95.05	$kgCO_2/GJ$
CO_2 emission factor – natural gas	$W_{CO2,g}$	55.35	$kgCO_2/GJ$
CO_2 price	P_{CO2}	78.50	USD/tCO_2

Table 2. Benchmarking of selected Ebsilon model outputs against representative published gas-turbine performance data

Parameter	Present Ebsilon model	Published benchmark	Assessment
Simple GT electrical efficiency	31.50%	34.8–35.6% (SGT-400)	Lower, but of a comparable thermodynamic magnitude
Simple GT exhaust-gas temperature	510 °C	510–555°C (SGT-400)	Within the published range
Simple GT electrical output	5.67 MWe	10.5–14.3 MWe (SGT-400 reference variants)	Lower-capacity model; comparison used primarily as a thermodynamic plausibility check
External firing electrical efficiency	42.67%	Up to approximately 47% for advanced external-combustion GT configurations [29]	Consistent with the performance level reported for advanced EFGT configurations
Heat-recovery exchanger efficiency	95%	Model assumption	Assumed parameter; not independently benchmarked

EUR/tCO₂ according to KOBiZE [45]. It was converted using the adopted model exchange rate of 1.066 USD/EUR, giving 78.50 USD/tCO₂.

Figure 2 illustrates the steady-state Ebsilon model of the simple-cycle CHP configuration. Corresponding models were developed for the regenerative and externally fired cases.

For each configuration, the steady-state thermodynamic results obtained from Ebsilon were used to calculate annual heat and electricity production, fuel consumption, and emission levels.

One limitation of the present analysis is the assumption of constant component efficiencies for different fuel compositions. In practice, hydrogen-rich fuels may affect combustion behavior, emissions, material durability and achievable turbine efficiency. These aspects were intentionally excluded in order to maintain consistent comparison conditions and should be addressed in future studies using detailed combustion and equipment-performance models.

The economic assessment included fuel costs, direct CO₂ emission costs and revenues from heat and electricity production. Auxiliary electricity consumption was considered only for the reference heat-only boiler systems because these values are well established and constitute a direct operating cost. For the analyzed CHP configurations, auxiliary electricity demand strongly depends on plant-specific design features, including compressor systems, cooling systems, lubrication systems and control equipment. Since comparable auxiliary-power data were unavailable for all investigated CHP concepts, auxiliary electricity consumption was intentionally excluded from the comparative assessment. Consequently, all CHP configurations were evaluated using identical

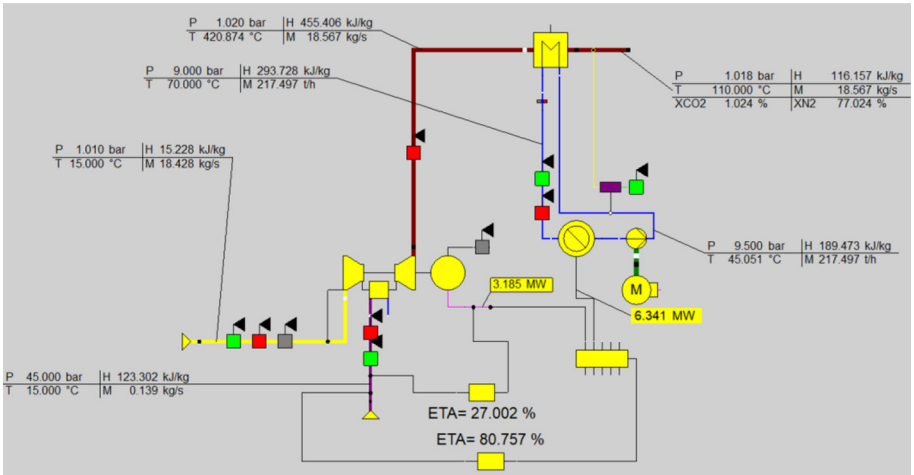


Figure 2. Steady-state thermodynamic model of a simple-cycle gas turbine CHP configuration implemented in Ebsilon Professional software

economic assumptions to ensure methodological consistency.

These values served as inputs to the operating cost model described in the previous subsection. The calculated thermodynamic outputs were used as inputs to the annual operating-cost analysis.

RESULTS AND DISCUSSION

Reference heat-only boiler performance

We begin the analysis with the evaluation of the reference heat-only configurations, representing the existing coal-fired district heating plant and the biomass-based alternative. These systems provide the reference heat-only cases against which CHP modernization options are assessed. Table 3 summarizes the key operating and economic indicators for both configurations under the adopted assumptions.

Both heat-only configurations achieve a positive annual operating balance, but their cost structures differ substantially. The biomass-fired boiler requires a higher annual fuel input because of its lower assumed efficiency, 0.85 compared with 0.90 for coal. Combined with the adopted fuel prices, this results in annual fuel expenditure of approximately 2.58 million USD for biomass and 1.74 million USD for coal.

In the coal-fired case, however, the direct CO_2 allowance cost reaches approximately 2.61 million USD/year and exceeds the annual fuel expenditure. Consequently, the total selected operating cost increases to approximately 4.41 million USD/year. The corresponding cost for the biomass-fired boiler is approximately 2.64 million USD/year because no direct CO_2 allowance cost is assigned within the adopted ETS boundary.

The resulting operating heat production cost is 13.98 USD/GJ for coal and 8.36 USD/GJ for biomass. Under the adopted fuel-price and carbon-price assumptions, the biomass-fired option therefore achieves a lower operating cost and a higher annual operating balance. The result indicates that direct carbon-cost exposure is a major determinant of the operating competitiveness of coal-based district heating under the adopted assumptions.

Thermodynamic performance of CHP configurations

Following the reference heat-only assessment, three CHP modernization configurations were analyzed: (i) a simple gas turbine cycle, (ii) a regenerative gas turbine cycle, and (iii) an externally fired air-turbine configuration with a bypass.

Each CHP configuration was evaluated at the same annual useful heat production of 315,360 GJ/year. Electricity generation was treated as a co-product of heat-led operation. Table 4 presents the thermodynamic performance of the CHP configurations under the reference natural-gas case corresponding to 0 wt.% H_2. Fuel-specific changes in net electrical output for the hydrogen-containing cases were included separately in the annual operating-cost calculations.

The regenerative cycle achieves a higher electrical efficiency than the simple cycle

Table 3. Operating performance of reference heat-only boiler configurations (coal vs biomass)

Parameter	Unit	Coal boiler	Biomass boiler
Annual heat production	GJ/year	315,360	315,360
Fuel input	GJ/year	350,400	371,012
Annual fuel cost	USD/year	1,735,546	2,576,472
Direct CO_2 emissions	kt/year	33.31	0*
CO_2 emission allowance cost	USD/year	2,614,483	0*
Auxiliary electricity cost	USD/year	59,404	60,563
Total operating cost	USD/year	4,409,434	2,637,035
Heat sales revenue	USD/year	8,338,118	8,338,118
Annual operating balance	USD/year	3,928,685	5,701,083
Operating heat production cost **	USD/GJ	13.98	8.36

Note: * No direct CO_2 allowance cost was assigned to biomass within the ETS accounting boundary adopted in this study. Upstream and life-cycle emissions were outside the system boundary. ** Operating heat production cost was calculated as the ratio of total annual operating cost to annual useful heat production.

because the turbine exhaust is used to preheat the compressed air before combustion. The externally fired configuration achieves the highest electrical efficiency and net electrical output among the analyzed natural-gas cases. It is also characterized by the highest exhaust-gas mass flow rate. Although Ebsilon Professional also allows the overall CHP efficiency to be determined, electrical efficiency was retained as the principal thermodynamic indicator because all analyzed CHP configurations were constrained to deliver the same annual useful heat output. Under this common heat-output boundary, differences in electrical efficiency directly reflect differences in electricity generation and therefore in electricity-sales revenue.

The larger electrical output of the externally fired configuration results in greater potential electricity revenue. However, because capital expenditure was not included, the analysis does not account for the potentially higher investment cost and technical complexity of this configuration. The following sections therefore compare the annual operating results under different fuel compositions and hydrogen prices.

Economic performance at a hydrogen price of 1 USD/kg

The CHP configurations were first evaluated at a hydrogen price of 1 USD/kg. This value represents a highly optimistic long-term boundary scenario rather than a typical current delivered-fuel price. The calculations used a natural gas price of 46.83 USD/MWh, an electricity selling price of 114.56 USD/MWh, a heat selling price of 26.44 USD/GJ, and a CO_2 allowance price of 78.50 USD/tCO_2. A constant fraction of 0.95 of annual net electricity production was assumed to be sold. Table 5 presents the resulting annual operating balances for hydrogen mass shares of 0, 50, and 100%.

At a hydrogen price of 1 USD/kg, all analyzed CHP cases achieve a positive annual operating balance within the adopted selected-cost boundary. For natural-gas operation, corresponding to 0 wt.% H_2, the annual balance ranges from approximately 1.97 million USD/year for the externally fired configuration to 4.03 million USD/year for the simple gas turbine.

Increasing the hydrogen mass share improves the operating balance of all three configurations in the 1 USD/kg scenario. At this price, the energy-equivalent cost of hydrogen is lower than the adopted natural gas price, while replacing the fossil fuel fraction also reduces direct CO_2 allowance costs. Consequently, the 100 wt.% H_2 case achieves the highest operating balance within each CHP configuration.

The externally fired configuration reaches the highest absolute balance, approximately 15.41 million USD/year, mainly because of its larger net electrical output and corresponding electricity-sales revenue. This result should be interpreted cautiously because the comparison excludes capital expenditure, fixed and variable maintenance costs, separate auxiliary-electricity costs, hydrogen infrastructure, and possible grid-connection constraints. The results therefore represent operating-cost competitiveness within the adopted boundary rather than total investment profitability.

Sensitivity to hydrogen price

To evaluate the sensitivity of the results to hydrogen procurement cost, the analysis was extended to hydrogen prices of 3, 5, and 8 USD/kg, in addition to the optimistic 1 USD/kg long-term boundary scenario. The 5 and 8 USD/kg cases were included to represent more conservative

Table 4. Thermodynamic performance of analyzed CHP configurations

Parameter	Unit	Simple GT	GT + Regenerator	External firing
Net electrical output	MWe	5.67	13.31	19.95
Electrical efficiency	%	31.50	40.71	42.67
Annual net electricity production	MWh/year	48,195	113,135	169,575
Annual heat production	GJ/year	315,360	315,360	315,360
Exhaust gas temperature (before heat exchanger)	°C	510.0	510.0	175.4
Exhaust gas mass flow	kg/s	21.6	41.1	139.5
Heat exchanger efficiency	%	95	95	95

Table 5. Annual operating results of the CHP configurations at a hydrogen price of 1 USD/kg for different hydrogen mass shares

Configuration	Hydrogen mass share	Annual fuel cost (USD/year)	CO_2 cost (USD/year)	Fuel and CO_2 operating cost (USD/year)	Total revenue (USD/year)	Annual operating balance (USD/year)
Simple GT	0 wt.%	7,164,990	2,393,212	9,558,202	13,583,277	4,025,074
	50 wt.%	5,347,350	703,886	6,051,236	13,583,277	7,532,041
	100 wt.%	4,590,000	0	4,590,000	13,583,277	8,993,277
GT + Regenerator	0 wt.%	13,014,277	4,346,961	17,361,237	20,650,827	3,289,590
	50 wt.%	9,795,839	1,289,452	11,085,291	20,798,838	9,713,547
	100 wt.%	8,408,446	0	8,408,446	20,798,838	12,390,392
External firing	0 wt.%	18,610,678	6,216,241	24,826,919	26,793,305	1,966,385
	50 wt.%	14,208,893	1,870,355	16,079,248	27,459,357	11,380,109
	100 wt.%	12,302,826	0	12,302,826	27,709,126	15,406,300

near-term hydrogen procurement conditions. All other technical and economic assumptions were kept unchanged. Table 6 summarizes the resulting annual operating balances.

The sensitivity analysis reveals a differentiated economic response across the analyzed CHP configurations. The natural-gas cases remain profitable in all hydrogen-price scenarios because their operating balances are independent of the assumed hydrogen price. Under the adopted natural gas, electricity, heat, and CO_2 price assumptions, their annual operating balances range from approximately 1.97 million USD/year for the externally fired configuration to 4.03 million USD/year for the simple gas turbine.

At a hydrogen price of 3 USD/kg, the simple gas turbine with a 50 wt.% hydrogen share retains a positive annual operating balance of approximately 1.05 million USD/year. The corresponding 100 wt.% hydrogen case is close to the operating break-even point, with an annual loss of approximately 0.19 million USD/year. In contrast, the regenerative and externally fired configurations are unprofitable at both 50 and 100 wt.% H_2 because their greater annual hydrogen consumption makes them more sensitive to fuel procurement cost.

At 5 USD/kg, all hydrogen-containing cases generate operating losses, and these losses deepen substantially at 8 USD/kg. At the latter price, annual operating losses range from approximately 15.15 million USD/year for the simple gas turbine with 50 wt.% H_2 to 70.71 million USD/year for the externally fired configuration with 100 wt.% H_2. This illustrates the strong sensitivity of hydrogen-rich CHP configurations to hydrogen procurement cost (Figure 3).

A break-even analysis was additionally performed to identify the maximum hydrogen price at which each hydrogen-containing configuration maintains a non-negative annual operating balance. The resulting threshold prices range from approximately 2.25 USD/kg for the externally fired configuration with 100 wt.% H_2 to 3.32 USD/kg for the simple gas turbine with 50 wt.%

Table 6. Annual operating balance as a function of hydrogen price and hydrogen mass share

Configuration	Hydrogen mass share	1 USD/kg	3 USD/kg	5 USD/kg	8 USD/kg
Simple GT	0 wt.%	4,025,074	4,025,074	4,025,074	4,025,074
	50 wt.%	7,532,041	1,052,041	−5,427,959	−15,147,959
	100 wt.%	8,993,277	−186,723	−9,366,723	−23,136,723
GT + Regenerator	0 wt.%	3,289,590	3,289,590	3,289,590	3,289,590
	50 wt.%	9,713,547	−2,157,200	−14,027,947	−31,834,068
	100 wt.%	12,390,392	−4,426,500	−21,243,392	−46,468,730
External firing	0 wt.%	1,966,385	1,966,385	1,966,385	1,966,385
	50 wt.%	11,380,109	−5,838,443	−23,056,995	−48,884,823
	100 wt.%	15,406,300	−9,199,352	−33,805,004	−70,713,482

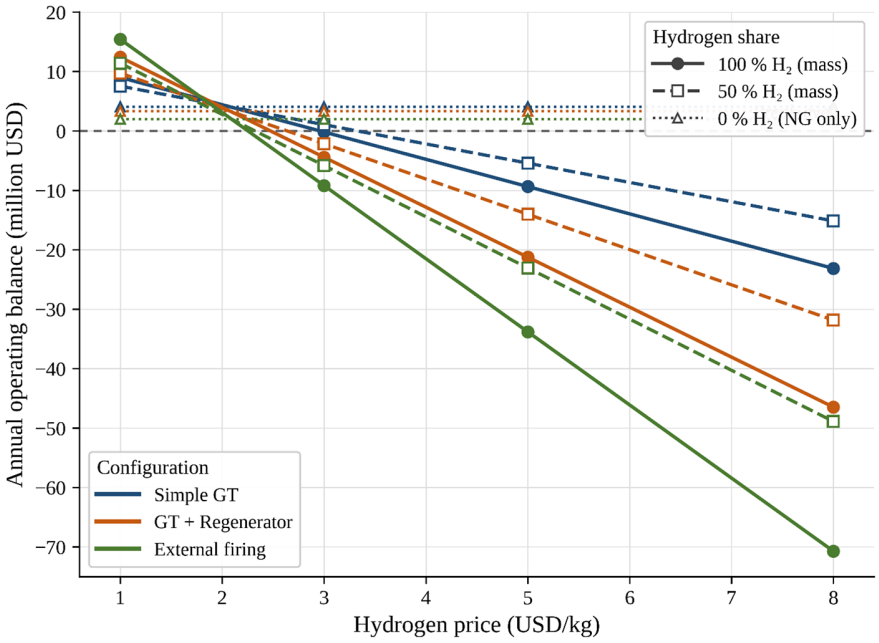


Figure 3. Sensitivity of the annual operating balance of the analyzed CHP configurations to hydrogen price and hydrogen mass share. The 0 wt.% H_2 cases represent the natural-gas reference configurations and remain independent of hydrogen price. The horizontal dashed line indicates the zero annual operating balance

H_2. The simple gas turbine therefore exhibits the highest tolerance to increasing hydrogen procurement cost, whereas the externally fired configuration reaches the operating break-even boundary at the lowest hydrogen price. The results are presented in Table 7.

The break-even hydrogen price was determined by linear interpolation of the annual operating balance as a function of hydrogen price. This approach is appropriate because, with fuel consumption and all other technical and economic assumptions held constant, hydrogen expenditure varies linearly with the assumed hydrogen unit price.

Higher electrical efficiency alone does not determine the economic ranking. Although the regenerative and externally fired configurations generate more electricity than the simple gas turbine, they also have greater annual fuel requirements. At elevated hydrogen prices, the additional electricity revenue is insufficient to offset the higher hydrogen expenditure. Under the adopted assumptions, natural-gas operation and the 50 wt.% hydrogen case in the simple gas turbine show greater operating-cost robustness than hydrogen-rich operation in the larger configurations.

The lower operating costs obtained for the biomass-fired boiler should be interpreted within the adopted economic system boundary. Under the current EU ETS framework, sustainably sourced biomass is not subject to direct CO_2 emission allowance costs. Consequently, the observed economic advantage results primarily from the adopted regulatory and accounting framework rather than from an assessment of the complete environmental performance of biomass. Since the present study focuses exclusively on operating costs, life-cycle greenhouse-gas emissions associated with biomass production, processing and transportation were not considered.

The present analysis assumed steady-state operation at nominal load, represented by an equivalent annual operating time of 8,500 full-load hours. This assumption was adopted to provide a common basis for comparing alternative modernization scenarios. Consequently, seasonal variations in district-heating demand, part-load operation and transient operating conditions were not considered. In practical CHP systems, fluctuations in heat demand influence both electricity generation and overall plant efficiency. However, incorporating these effects would require dynamic simulations of the CHP plant integrated with the district-heating network, which were beyond the scope of the present comparative assessment. Future work will therefore focus on extending the developed models to include seasonal demand

Table 7. Approximate break-even hydrogen prices for the analyzed CHP configurations

Configuration	Hydrogen mass share	Break-even hydrogen price (USD/kg)
Simple GT	50 wt.%	3.32
	100 wt.%	2.96
GT + Regenerator	50 wt.%	2.64
	100 wt.%	2.47
External firing	50 wt.%	2.32
	100 wt.%	2.25

profiles, part-load characteristics and dynamic operating conditions.

Comparison with biomass-based CHP

To compare hydrogen and biomass within the same general cycle architecture, the externally fired CHP configuration was also evaluated using biomass as the primary fuel. The biomass case was compared with the 100 wt.% hydrogen case at a hydrogen price of 1 USD/kg. Fuel-specific steady-state simulations resulted in different net electrical outputs while maintaining the same annual useful heat production of 315,360 GJ. Table 8 summarizes the resulting annual operating performance.

The hydrogen-fired configuration achieves a higher net electrical output and consequently generates greater electricity-sales revenue. At a hydrogen price of 1 USD/kg, its annual operating balance reaches approximately 15.41 million USD/year, compared with 12.62 million USD/year for the biomass-fired configuration. The higher balance of the hydrogen case results primarily from its larger electricity output rather than from lower fuel expenditure.

The biomass-fired configuration has a substantially lower annual fuel cost, approximately 7.62 million USD/year compared with 12.30 million USD/year for hydrogen. Its lower electrical output, however, limits the corresponding electricity-sales revenue. Neither case is assigned a direct CO_2 allowance cost within the ETS accounting boundary adopted in this study.

The comparison demonstrates that operating performance depends on the interaction between fuel expenditure and electricity output. Under the highly optimistic hydrogen price of 1 USD/kg, the additional electricity production of the hydrogen-fired configuration compensates for its higher fuel cost. At 3 USD/kg, however, the externally fired 100 wt.% hydrogen case records an annual operating loss of approximately 9.20 million USD/year. The biomass case remains profitable at the single biomass price adopted in the analysis.

Hydrogen may therefore provide a higher annual operating balance under exceptionally favorable procurement conditions, whereas the biomass case remains profitable at the adopted fuel price and is not exposed to hydrogen-price uncertainty. This conclusion applies only to the adopted operating-cost boundary and does not

Table 8. Economic comparison of externally fired CHP configurations (hydrogen vs biomass)

Parameter	Unit	H_2 (100 wt.%, 1 USD/kg)	Biomass
Net electrical output	MWe	20.94	12.87
Annual electricity production	MWh/year	177,990	109,395
Annual electricity sold	MWh/year	169,091	103,925
Annual heat production	GJ/year	315,360	315,360
Annual fuel cost	USD/year	12,302,826	7,624,341
CO_2 allowance cost	USD/year	0	0
Fuel and CO_2 allowance cost	USD/year	12,302,826	7,624,341
Heat sales revenue	USD/year	8,338,118	8,338,118
Electricity sales revenue	USD/year	19,371,008	11,905,677
Total annual revenue	USD/year	27,709,126	20,243,795
Annual operating balance	USD/year	15,406,300	12,619,454

account for capital investment, maintenance, fuel-storage infrastructure, supply-chain constraints, or life-cycle greenhouse-gas emissions.

DISCUSSION OF ECONOMIC BOUNDARY CONDITIONS

The results show that higher electrical efficiency does not necessarily lead to greater operating-cost robustness. This finding is consistent with the broader thermoeconomic principle that cycle efficiency and economic performance are governed by different variables. Regeneration and external firing improve electricity production, but they also increase total fuel demand and plant scale. Consequently, their economic advantage depends not only on thermodynamic performance but also on the relative prices of fuel, electricity, heat, and CO_2 allowances.

The electrical efficiencies obtained for the regenerative and externally fired configurations are consistent with the expected effect of heat recovery and external combustion reported in earlier gas-turbine studies [15,32,33]. In the regenerative cycle, part of the exhaust-gas energy is returned to the compressed air, reducing the heat required in the combustion chamber. The externally fired configuration achieves an even higher electrical output, but this benefit is accompanied by a substantially greater fuel requirement. The present results therefore support the observation that high-efficiency configurations may not be economically preferable when fuel prices are high or when the additional electricity revenue is limited.

Under the adopted 2025 market assumptions, all natural-gas CHP configurations achieve positive annual operating balances. The simple gas turbine provides the highest balance among the gas-only cases, despite having the lowest electrical efficiency. This result differs from a purely thermodynamic ranking and demonstrates the importance of system scale. The additional electricity generated by the regenerative and externally fired configurations does not fully compensate for their higher annual fuel expenditure. In practical terms, the smaller simple-cycle configuration is more robust under the adopted gas and electricity prices, while the larger systems become more dependent on favorable electricity-market conditions.

The effect of hydrogen is strongly price dependent. At 1 USD/kg, hydrogen has an energy-equivalent price of approximately 30 USD/MWh, which is lower than the assumed natural gas price of 46.83 USD/MWh. In addition, replacing natural gas with hydrogen reduces direct CO_2 allowance costs. These two effects explain why increasing the hydrogen mass share improves the annual operating balance in all three configurations at 1 USD/kg. The economic advantage observed in this scenario should not, however, be interpreted as evidence of current market competitiveness. Earlier studies and industry outlooks generally describe values close to 1 USD/kg as ambitious long-term targets rather than typical delivered prices [26–28].

The sensitivity results confirm that the hydrogen price is the dominant economic variable for hydrogen-rich operation. At 3 USD/kg, only the simple gas turbine with 50 wt.% H_2 retains a positive annual operating balance, whereas the 100 wt.% case is close to break-even. The regenerative and externally fired configurations become unprofitable because their larger hydrogen consumption amplifies the effect of the higher procurement price. At 5 USD/kg, the additional electricity revenue is insufficient to offset hydrogen expenditure in all hydrogen-containing cases. At 8 USD/kg, the operating losses deepen substantially across all hydrogen-containing configurations, further illustrating their sensitivity to hydrogen procurement cost. This result is consistent with the broader hydrogen literature, which identifies fuel cost as a major barrier to deployment in heat and power applications [24,26,27].

The use of mass-based fuel shares is important for interpreting these findings. A mixture containing 50 wt.% H_2 contains approximately 70.6% hydrogen on an energy basis because the lower heating value of hydrogen is substantially higher than that of natural gas. The 50 wt.% scenario therefore represents a hydrogen-rich fuel rather than a moderate blending level. Its economic and technical implications should not be compared directly with studies that define hydrogen share on a volumetric or energy basis. Because hydrogen has a much lower density and a considerably higher lower heating value than natural gas, mass-based hydrogen fractions cannot be directly compared with volumetric fractions commonly reported in combustion studies. The adopted mass-based approach was selected to maintain consistency with the economic calculations rather than to describe combustion behavior.

The comparison with biomass reveals a different trade-off. The biomass-fired externally fired CHP case produces less electricity than the corresponding hydrogen case, but its annual fuel expenditure is substantially lower at the adopted biomass price. Consequently, the hydrogen configuration achieves the higher annual operating balance only in the highly favorable 1 USD/kg scenario. At higher hydrogen prices, this advantage disappears. The result supports the view that mature biomass pathways may offer lower near-term fuel-cost exposure than hydrogen-based alternatives, although their broader sustainability depends on feedstock origin, transport distance, moisture content, land-use effects, and supply-chain availability [12,15].

The biomass result should nevertheless not be interpreted as proof of universally superior environmental performance. Biomass was assigned no direct CO_2 allowance cost within the adopted ETS accounting boundary, whereas upstream and life-cycle emissions were not included. Similarly, hydrogen was assigned zero direct combustion emissions, but the analysis did not distinguish between renewable, low-carbon, and fossil-based hydrogen production. The study therefore compares direct operating-cost exposure rather than complete life-cycle decarbonization performance.

The comparison also illustrates the importance of electricity-sales assumptions. Configurations with a high electricity-to-heat ratio benefit substantially from the assumed electricity selling price and from the assumption that 95% of annual net generation can be sold. In real district heating systems, grid constraints, electricity-price variability, self-consumption, balancing-market participation, and heat-led operating limitations may reduce this revenue. The economic advantage of the externally fired configuration is therefore more sensitive to electricity-market conditions than that of the simple gas turbine or the heat-only boiler cases.

The results must also be interpreted in light of the excluded technical constraints. High hydrogen mass fractions may require burner redesign, modified control systems, measures to limit flashback and NO_x formation, and verification of material and turbine compatibility. These issues are widely recognized in hydrogen-combustion applications but were not represented in the present steady-state model. The 50 and 100 wt.% H_2 cases should therefore be treated as thermodynamic and operating-cost boundary scenarios rather than immediately deployable retrofit options.

The economic results presented in this study are strongly influenced by the assumed hydrogen procurement price. Therefore, in addition to the optimistic long-term boundary scenario of 1 USD/kg, sensitivity calculations were performed for hydrogen prices of 3, 5, and 8 USD/kg. The results show a progressive deterioration in the annual operating balance as hydrogen procurement cost increases, with all hydrogen-containing configurations generating operating losses at 5 and 8 USD/kg. The break-even analysis further indicates threshold hydrogen prices of approximately 2.25–3.32 USD/kg, depending on the configuration and hydrogen mass share. The 1 USD/kg scenario should therefore be interpreted as a highly optimistic long-term boundary scenario.

Finally, the assessment does not include capital expenditure, maintenance costs, financing, fuel-storage systems, or infrastructure for hydrogen delivery and biomass handling. This limitation is particularly important for the externally fired configuration, whose high electricity output may be accompanied by greater technical complexity and investment cost. The results therefore identify operating-cost boundary conditions, but they do not establish an investment ranking. A configuration with a high annual operating balance may still be unattractive once capital and infrastructure requirements are included.

CONCLUSIONS

The operating-cost comparison of the heat-only configurations indicates that direct carbon-cost exposure can substantially reduce the operating competitiveness of coal-based district heating under the adopted market and regulatory assumptions. Although the coal-fired boiler has a lower annual fuel cost than the biomass-fired boiler, its CO_2 allowance cost increases the selected annual operating cost to approximately 4.41 million USD/year. The corresponding cost for biomass is approximately 2.64 million USD/year, resulting in operating heat-production costs of 13.98 and 8.36 USD/GJ, respectively.

The thermodynamic ranking of the CHP configurations differs from their operating-economic ranking. The regenerative and externally fired configurations achieve higher electrical efficiencies and electricity outputs than the simple gas

turbine, but their larger annual fuel requirements make their operating balances more sensitive to fuel-price changes. Under the adopted natural gas, heat, electricity, and CO_2 price assumptions, the simple gas turbine achieves the highest annual operating balance among the natural-gas cases despite having the lowest electrical efficiency. This indicates that electrical efficiency alone is insufficient to determine the operating-economic attractiveness of alternative CHP configurations.

Hydrogen-containing configurations become economically attractive only under sufficiently favorable procurement conditions. At the optimistic boundary price of 1 USD/kg, increasing the hydrogen mass share improves the annual operating balance in all CHP configurations because, under the adopted assumptions, hydrogen has a favorable energy-equivalent procurement cost and eliminates direct CO_2 allowance costs associated with the displaced natural gas fraction. The 100 wt.% H_2 cases achieve annual operating balances ranging from approximately 8.99 to 15.41 million USD/year.

This advantage deteriorates rapidly as the assumed hydrogen procurement price increases. At 3 USD/kg, only the simple gas turbine with 50 wt.% H_2 retains a positive annual operating balance, while the corresponding 100 wt.% case is close to the operating break-even point. At 5 USD/kg, all hydrogen-containing configurations generate operating losses. At 8 USD/kg, these losses increase substantially, ranging from approximately 15.15 million USD/year for the simple gas turbine with 50 wt.% H_2 to approximately 70.71 million USD/year for the externally fired configuration with 100 wt.% H_2. The calculated break-even hydrogen prices range from approximately 2.25 to 3.32 USD/kg, depending on the configuration and hydrogen mass share. These results indicate that hydrogen procurement cost and annual hydrogen consumption are more influential for operating-economic performance than electrical efficiency alone.

In the externally fired CHP comparison, the 100 wt.% hydrogen case at 1 USD/kg achieves a higher annual operating balance than the biomass case because of its greater electricity output. The biomass configuration, however, has a substantially lower annual fuel cost and remains profitable under the adopted biomass-price and EU ETS accounting assumptions. Hydrogen may therefore outperform biomass in operating-economic terms under exceptionally favorable hydrogen procurement conditions, but this advantage is not maintained as hydrogen prices increase.

The results suggest that the operating-economic feasibility of hydrogen-fired CHP systems is highly sensitive to future hydrogen procurement conditions. Although favorable operating balances are obtained under the optimistic 1 USD/kg boundary scenario, the extended sensitivity and break-even analyses show that increasing hydrogen prices rapidly reduce economic competitiveness. The practical attractiveness of hydrogen-based CHP will therefore depend on future developments in hydrogen production, transport and supply costs, as well as on electricity prices, carbon costs and the operating characteristics of individual CHP systems.

Overall, the study indicates that the modernization ranking of coal-based district-heating systems cannot be inferred from thermodynamic efficiency alone. Fuel price, total fuel demand, direct carbon-cost exposure, electricity generation and sales, and fuel composition jointly shape the annual operating balance. The findings should be interpreted as screening-level, scenario-based operating-cost results rather than as a complete investment appraisal or life-cycle environmental assessment. CAPEX, financing, dynamic and part-load operation, upstream fuel-chain impacts, and technology-specific implementation costs remain outside the adopted system boundary and should be considered in future assessments of investment feasibility.

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