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# Technoeconomic analysis of High Temperature Reactors for industrial applications in Poland

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**Abstract.** The paper analyses Polish industrial energy market requirements and the economic boundary conditions of for High Temperature Reactor (HTR)-based hybrid energy systems for electricity, heat, and hydrogen production. The Polish industry suffers from high imported gas prices and high dependence on domestic coal sector. Most industrial coal boilers are ageing and will need replacement within two decades. Increasing emission prices will soon cripple the profitability of coal in favour of natural gas and leave an opening for HTRs. HTRs can be competitive for both heat and electricity generation if used at load factors above 90% and constructed within budget and on time. The competitiveness of HTRs grows further with rising fossil fuels and CO<sub>2</sub> emission prices. For industrial hydrogen, steam methane reforming (SMR) is competitive against any other alternative. Large-scale hydrogen production with HTR-based Sulphur Iodine cycle may compete with SMR if capital and operational costs can be decreased. High temperature steam electrolysis requires more durable materials and lower capital cost. Electrolysis, given its relatively low CAPEX and scalability, can be competitive when electricity is cheap as a result of over-production from intermittent power capacities. Other fossil-based hydrogen production methods appear more costly and CO<sub>2</sub>-intensive than SMR. The study was done as a part of the GEMINI+ project.

## 1. Introduction

One of long-envisioned prospects of the nuclear community included in the technology roadmap of the Generation IV International Forum is expansion of the use nuclear energy beyond electricity production. GEMINI+ and Next Generation Nuclear Plant (NGNP) Alliance are initiatives to accelerate introduction of nuclear energy into industrial cogeneration [1].

HTRs have the advantage over other nuclear technologies of addressing a much wider array of technological processes which comprise the industrial heat generation market. It is one of the few technologically and economically feasible sustainable ways of generating high-quality heat. This quality, combined with the fact that non-electric energy requirements are larger than the entire electricity market [2] and the emission prices are expected to increase in the future [3], creates a major opportunity in regions with carbon taxes and/or with emission allowance trading schemes, like the European Union Emissions Trading System (EU ETS).

Poland is an example of a country subject to EU ETS which has a sizeable chemical industry with large demand for high quality heat, which is currently dependent on fossil fuels, and a vested interest in HTR technology [4]. Its case study is the focus of this technoeconomic analysis.



## 2. Polish Market Requirements

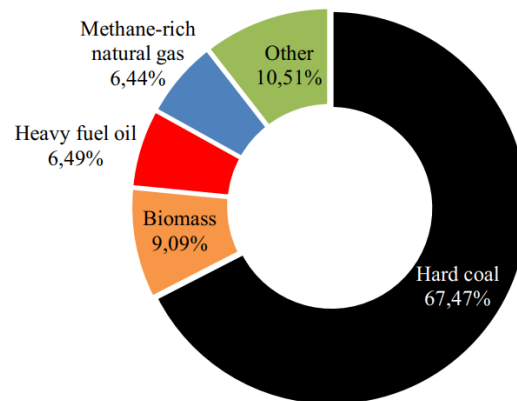
Poland is a major player in the European mineral fertilizer market with 19,6% of phosphate and 18,2% of nitrogen fertilizer production shares in the EU [5]. In addition, it houses several refineries, one of which, PKN Orlen, is among the largest in Europe, with over 2,1 GWt of installed generating capacity [6] and 18,7 megatons of crude oil processing capacity per year [7]. Another sector with demand for sub-550°C heat is the pulp and paper industry, with large coal consumption and a major facility with 692 MWt of installed capacity near Kwidzyń. The combined installed heat generating capacity of large facilities with demand for heat in the range between 250-550°C is over 7 GWt (Table 1).

**Table 1.** List of Polish facilities with the largest heat consumption in the range of 250-550°C [4]

Facility	Installed capacity [MWt]
PKN Orlen	2153
Anwil S.A. – Grupa Orlen	997
Grupa Azoty Puławy	755
Grupa Azoty Police	481
Grupa LOTOS	465
Grupa Azoty Tarnów	558
Grupa Azoty Kędzierzyn	557
International Paper Kwidzyń	692
PCC Rokita	160
Orlen Południe Zakład Trzebinia	93
LOTOS Jasło	74
Orlen Południe Zakład Jedlicze	62
<b>Total</b>	<b>7047</b>

Most primary energy in cogeneration systems in Poland comes from hard coal (see Figure 1). The importance of coal in the industry is further underlined by the fact that Poland has the largest fleet of industrial coal boilers in the EU, though the installations are old with less than 10% being under 30 years old, and relatively small, averaging about 100 MW each [8]. It creates a major problem for the country as there is an upcoming demand for new installations which, depending on regulations, may need to be not coal-fired. The most readily available alternatives are natural gas installations but both fuel prices and the security of supply are not favourable for Poland in that case as the country is currently still largely dependent on Russia for its supply.

Many efforts are made to bolster the stability of pricing and security of natural gas supply through construction of *Baltic Pipe* gas transmission pipeline and further expansion of a Liquefied Natural Gas Terminal in Świnoujście [9][10][11].



**Figure 1.** Heat in cogeneration systems by fuel in Poland in 2017 [12]

### 3. Methodology

The paper analyses several heat generating technologies for both CHP and hydrogen production applications. Economic assessment is based around comparison of levelized costs of heat, electricity, and hydrogen and the sensitivity of the costs to changes in selected variables.

#### 3.1. Technologies selected for the analysis

The assessment focused on comparing ready-to-market solutions with those close to deployment, both for heat and hydrogen generation. It includes pulverized coal boilers, gas boilers, Combined Cycle Gas Turbines and High Temperature Gas-cooled Reactors for heat generation. Hydrogen production technologies include electrolysis, High Temperature Steam Electrolysis (HTSE), Sulphur-Iodine Cycle (SI) and Steam Methane Reforming (SMR). With exceptions for CCGT and natural gas boilers, which will be explained later, all the heat-generating technologies were matched with each hydrogen generating technology for cost analysis. Gas boilers and CCGT contain exceptions – gas-fired SMR is a standalone solution not utilizing either heat source, SI cycle was done with NG boiler only and electrolysis together with HTSE were not considered with gas boilers.

Each technology considered in the analysis has some advantages and drawbacks.

- Pulverized coal boiler.  
Most used technology in Poland for industrial heat generation. Relatively high flexibility, moderate capital cost and very high emissions
- Gas-fired boiler.  
Mature technology with very high flexibility and quick deployment with low capital cost
- Combined Cycle Gas Turbine.  
Very high efficiency for electricity production with relatively low emissions and average flexibility – high share of primary energy must always be converted to electricity
- High Temperature Gas-cooled Reactor.  
Not yet commercially utilized but with many reactor- years of experience and potentially short market deployment, the least flexible heat generation technology with the highest capital cost and the lowest fuel cost and potentially highest availability factor.  
Given that the paper is an outlook for hybrid energy systems within the next few decades, for the purpose of this analysis it is assumed that HTGR can deliver temperatures sufficiently high for hydrogen production methods which follow:
  - Steam Methane Reforming.  
Mature technology, the most employed dedicated hydrogen production method, with very high thermodynamic efficiency, low capital cost and innate CO<sub>2</sub> production when

processing its feedstock – methane [13][14]. Hydrogen requires purification for fuel cell applications

- Electrolysis.

Mature and flexible technology with somewhat higher capital cost than SMR at large scale and very high electric energy demand despite being near its theoretical efficiency limit [15][16]. Its specific capital cost is not significantly affected by scale of deployment. It can deliver pure hydrogen

- High Temperature Steam Electrolysis.

Technology recently added to market with considerably higher efficiency than conventional electricity [17] but with lower flexibility, high capital, and operational expenses [15], [18], [19] as well as requirement of very high temperature source for efficient operation [20]. Can deliver pure hydrogen at high pressure for fuel cells

- Sulphur-Iodine Cycle.

Thermochemical method of hydrogen generation pursued by several countries, can offers high thermodynamic efficiency over 50%. Efficiency drops rapidly with temperatures lower than 850°C and the process stops completely below 700°C [21][22]. High capital and operational cost. Can deliver pure hydrogen at high pressure for fuel cell applications [20]

### 3.2. Hybrid Energy Systems

The definition of Hybrid Energy Systems is broad it is an energy system utilizing more than one energy generation technology and/or outputting more than one product [23]. The simplest system which can be called *hybrid* is Combined Heat and Power, commonly found in chemical plants or for district heating. The paper limits investigation to simple CHP and cogeneration with hydrogen production without regard for stochastic of demand variations. A deeper investigation into more complex hybrid energy systems (HES), including analyses of impact of varying loads, energy storage, virtual plants comprised of energy generation technologies, such as nuclear with coal or gas boilers and CCGT and/or renewables, as well as other cogeneration use cases, such as district heating or desalination, should follow this study to help determine economically and ecologically optimal solutions.

### 3.3. Model equations

The analysis is based around comparison of levelized costs of electricity, heat, and hydrogen. The investigated hybrid systems have different cost structures and energy requirements for hydrogen production - calculation of levelized costs permits more straightforward comparison of financial feasibility of each technology despite the differences.

The first element of the calculation is calculation of the Capital Recovery Factor (CRF) (Equation 1) [24].

$$CRF = \frac{r(1+r)^T}{(1+r)^T - 1} \quad (1)$$

Where  $r$  is discount rate expressed as a fraction and  $T$  is operational lifetime.

Once obtained, the levelized cost (LC) can be calculated (Equation 2) [24]:

$$LC = \frac{\sum_{i=1}^{CT} f_i x (1+r)^{CT-(i-1)}}{8760 x LF x (SOCC x CRF)^{-1}} + O\&M + FC \quad (2)$$

Where  $CT$  is construction time (in years),  $f_i$  is fraction of capital investment in year  $i$ ,  $LF$  is load factor, expressed as a fraction of effective full power hours in a year,  $SOCC$  is Specific Overnight Capital Cost, expressed in EUR/MW for energy installations and EUR/(t/h) for hydrogen facilities, O&M is Operations and Maintenance cost, expressed as EUR/MWh for energy installations and EUR/t for

hydrogen facilities, and FC is fuel cost per obtained MWh for energy installations and per ton of hydrogen in case of hydrogen facilities.

The analysis linearizes the sensitivity of levelized cost to changes of cost components around standard model assumptions (see Table 2), as shown in Equation 3.

$$\text{Nominal sensitivity} = \frac{|LC(v_f) - LC(v_0)|}{\left(\frac{|v_f - v_0|}{v_{ref}}\right) \times 100\%} \quad (3)$$

Where  $LC(v)$  is levelized cost under standard assumptions except for the variable  $v$ ,  $v_0$  is the lowest value of respective variable,  $v_f$  is the highest value of the respective variable and  $v_{ref}$  is the reference value under standard assumptions.

#### 4. Standard model assumptions

The model assumes current pricing of rules and state-of-the-art efficiencies and load factors for each technology. The chosen discount rate is relatively low but not unprecedented in energy cost analyses, thus creating favourable conditions for HTRs. Given the long-term nature of environmental policies and predictable baseload operation envisioned in these scenarios, however, the value is justifiable. The price of emission is ~5 EUR/tCO<sub>2</sub>eq higher than around the time of writing but is likely to increase past the chosen value within the decade.

The analysis assumes following price margins for fuels: 6,0-11,5 EUR/GJ for natural gas, 2,75-4,00 EUR/GJ for coal [25] and 0,94-2,81 EUR/GJ for HTGR fuel [20][26]. Load factors are between 60 and 99% for the purpose of sensitivity analysis. Sensitivity of construction time is subject to  $\pm 2$  years uncertainty.

**Table 2.** Standard assumptions for external factors and operational parameters [3], [8], [26]–[30]

Variable	Value
Discount rate	5%
Load factor	90%
Operational lifetime	60 years - HTRs 40 years - coal and hydrogen units 30 years - gas units
Construction time	5 years - HTRs 3 years - other technologies
Fuel prices (without taxes or transport fees)	1,87 EUR/GJ - HTGR fuel 2,79 EUR/GJ - hard coal 8,67 EUR/GJ - natural gas
Emission prices	30 EUR/tCO <sub>2</sub> eq
Electric efficiency	61,0% - CCGT 43,3% - other technologies

Capital cost and operational lifetime sensitivity ranges are between 50 and 150% of standard assumptions (see Table 3).

**Table 3.** Specific Overnight Capital Cost of technologies selected in the analysis [4], [20], [31]–[33]

Specific Overnight Capital Cost of	Value
Pulverized coal boiler	390,0 EUR/kWt
Gas boiler	235,4 EUR/kWt
Combined Cycle Gas Turbine facility	947,3 EUR/kWe
High Temperature Reactor	2636,4 EUR/kWt
Steam turbine	140,0 EUR/kWe
Sulphur-Iodine cycle hydrogen facility	71,1 MEUR/(t <sub>H2</sub> /h)
Electrolysis facility	26,5 MEUR/(t <sub>H2</sub> /h)
High Temperature Steam Electrolysis facility	49,0 MEUR/(t <sub>H2</sub> /h)
Gas-fired Steam Methane Reforming facility	13,7 MEUR/(t <sub>H2</sub> /h)
Unconventional Steam Methane Reforming facility	26,5 MEUR/(t <sub>H2</sub> /h)

Operational costs and process energy requirements are summarized in Table 4. The values were constant throughout the analysis.

**Table 4.** Operational costs and process energy requirements of investigated technologies [14], [20], [34]–[36]

Variable	Value	
O&M as a share of standard CAPEX	33 % for coal and gas 5,8% for HTGR	
O&M cost per ton of H <sub>2</sub>		
Electrolysis facility	134,3 EUR/tK <sub>2</sub>	
High Temperature Steam Electrolysis facility	1071,7 EUR/tK <sub>2</sub>	
Sulphur-iodine Iodine hydrogen facility	602,4 EUR/tK <sub>2</sub>	
Unconventional Steam Methane Reforming facility	100,8 EUR/tK <sub>2</sub>	
Steam Methane Reforming facility	67,2 EUR/tK <sub>2</sub>	
Technology	Energy requirement [GJ/tH <sub>2</sub> ]	
Sulphur-Iodine hydrogen facility	Thermal	Electric
High Temperature Steam Electrolysis facility	254,2	0,0
Electrolysis facility	24,0	124,7
Steam Methane Reforming facility	0,0	180,0
Unconventional Steam Methane Reforming facility	63,7	2,0
Sulphur-Iodine hydrogen facility	70,7	2,3



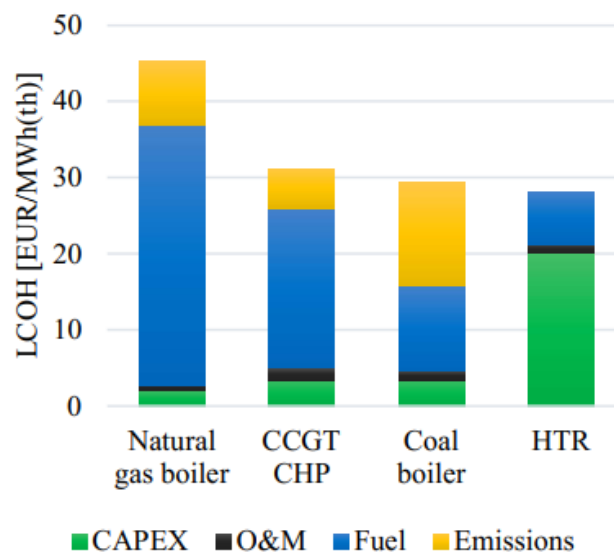
Some cost components were treated as variables, others were kept constant throughout the analysis. Overnight cost, fuel price, carbon emission price, load factor, discount rate, construction time and operational lifetime were treated as variables whereas efficiencies, O&M costs, output power, cost of desalinated water and grid electricity cost were kept constant. The output power was set to 165 MWt, which in the case of CCGT meant a gas turbine connected to a 165 MWt heat recovery steam generator (HRSG) and in case of hydrogen installations, input of 165 MWt of process heat combined with its equivalent in electricity for the respective electricity generation method. Cost of distilled water was fixed at 1,84 EUR/t. Levelized price of electricity from the grid was kept at 70 EUR/MWh [37]. The specific capital cost of a large steam turbine added to CHP installations was 140 EUR/KWe [31].

## 5. Results

The section of results is divided into three sections: discussion on levelized costs of CHP under standard assumptions, analysis of impacts of cost components on the levelized costs of CHP and comparison of different systems for hydrogen production.

### 5.1. Levelized costs of Combined Heat and Power

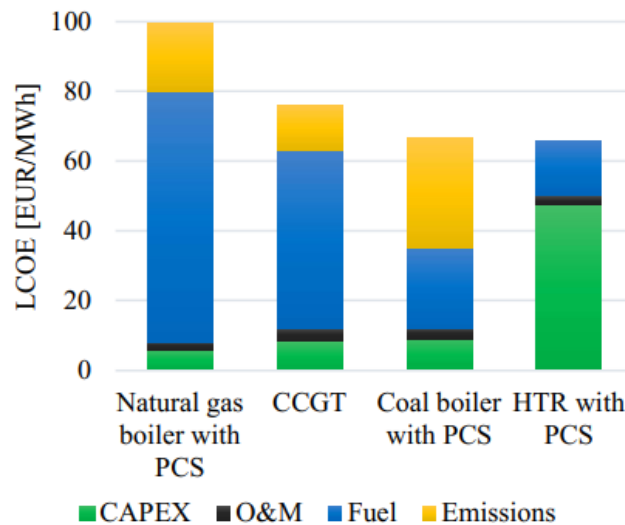
Given that the most relevant competitive advantage of HTRs over other nuclear technologies in the context of this technoeconomic analysis is the ability to supply industrial heat at high temperatures, most of the presented results refer to the levelized costs of heat. The analysis is based on Deliverable 3.12 of GEMINI+ [38].



**Figure 2.** Levelized cost of process heat under standard assumptions

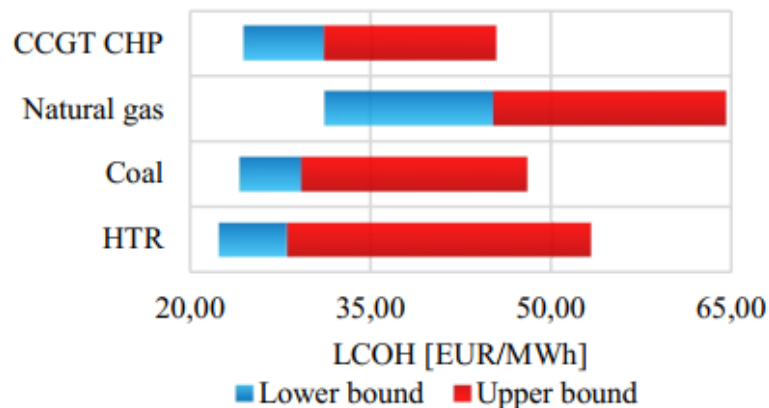
Figure 2 provides a breakdown of most relevant cost components for considered heat generating technologies. Under the standard scenario assumptions, the HTR can provide the most affordable industrial heat, followed by coal and CCGT.

For gas boilers, the price of fuel determines 80% of the price. The remaining costs are relatively low, despite the presumed high price of emissions of 30 EUR per ton. In case of CCGT, there is a notably higher capital and operational cost, but the vast majority of the price is related to fuel cost, followed by emissions cost. Coal boilers comprise evenly of fuel and emissions cost, making them highly susceptible to two external variables. 74% of the cost of heat from the HTR is related to its CAPEX, with the rest being related almost solely on fuel. The fuel cost is much lower than in case of competing technologies. The very high share of CAPEX in the levelized cost places most of the investment risk in internal factors related to construction costs and planning as well as financing scheme.



**Figure 3.** Levelized cost of electricity under standard assumptions

Much like in the previous plot, Figure 3 places HTRs on a very similar level as coal boilers for electricity production. CCGT is more costly than coal or HTRs under standard assumptions despite the highest electric efficiency due to very high cost of natural gas. CCGT is best utilized as a cogeneration technology, taking advantage of an efficient gas turbine for electricity production and high fuel utilization factor when delivering industrial heat, leading to lower primary consumption. Gas boilers are significantly more costly for baseload power generation than the rest.

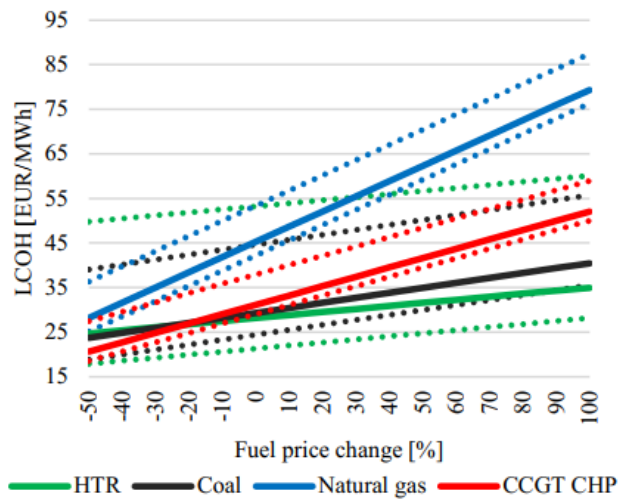


**Figure 4.** Range of LCOH with two most sensitive cost parameters offset by the highest plausible amounts

Taking into consideration the probable ranges of cost components place the technologies on a similar playing field (Figure 4). Natural gas boilers, whose LCOH for baseload energy production is ~ 15 EUR/MWh(th) higher than competition, are an exception. Factors impacting fossil-fired technologies are predominantly external - fuel and emission price, whereas HTRs are impacted by internal factors - construction time, overnight cost, load factor, discount rate.

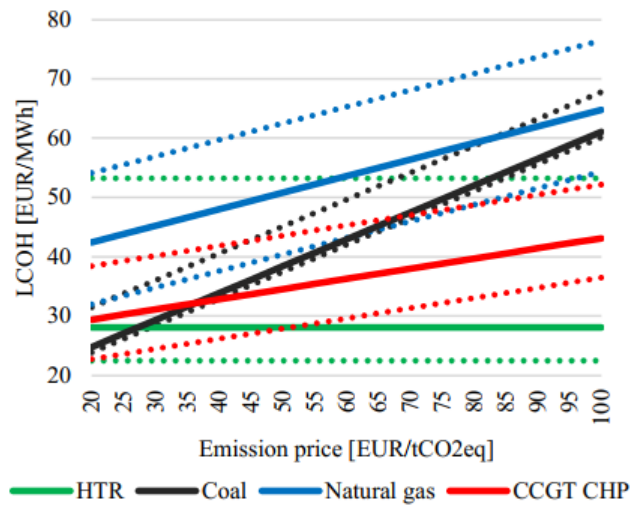
### 5.2. Impact of selected cost components on levelized costs

The following graphs (Figure 5 to Figure 10) show levelized costs of heat from different technologies under standard assumptions, represented with solid lines, as well as under their respective best- and worst- case scenarios, shown with dotted lines.



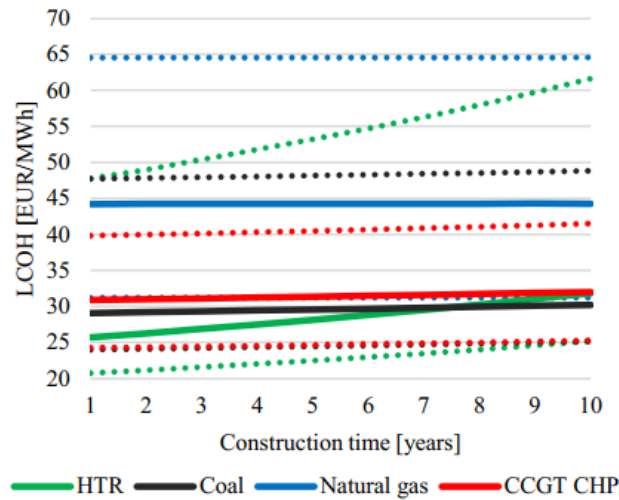
**Figure 5.** Cost of process heat as a function of fuel price

Fuel price has a moderate impact on costs of energy from coal boilers and HTRs. It is by far the most important cost component for gas boilers and CCGT stability of gas prices should have the highest priority to investors when considering the two technologies. It is worth noting that real-world scenarios need to add the fixed costs of transport of fuel, which would impact profitability of coal most notably.



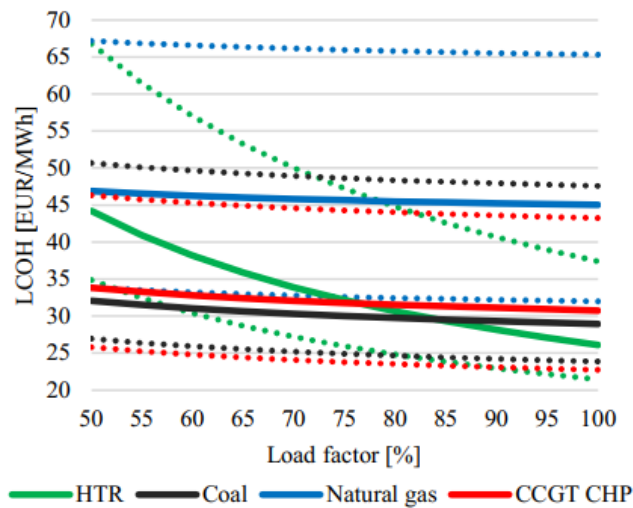
**Figure 6.** Cost of process heat as a function of emission price

Among the greatest advantages of nuclear energy is its independence from emission prices. Rising emission prices can rapidly make coal uncompetitive –the model price of 30 EUR/tCO<sub>2</sub> is about the border of profitability for coal. At 35 EUR/tCO<sub>2</sub>, it stops being cheaper than heat from CCGT.



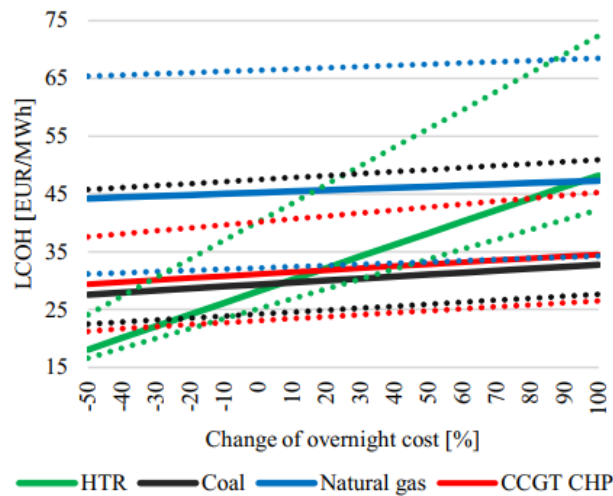
**Figure 7.** Cost of process heat as a function of construction time

Many nuclear projects are famously delayed by several years, leading to increased CAPEX. An effect of such delays on the levelized cost is illustrated in Figure 7. An added consideration is the delayed return on investment in such situations. The graph underlines an importance of good management of a nuclear plant construction as it is the only technology impacted this severely by it. On the other hand, bringing the construction time in line with other technologies at three years is highly favourable for an HTR, showing the potential of modular reactor construction which could lead to faster deployments.



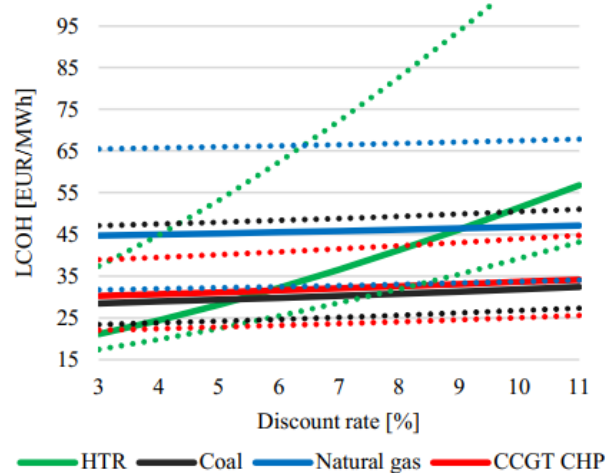
**Figure 8.** Cost of process heat as a function of load factor

The high CAPEX of HTRs can be amortized with high load factors. Very high effective utilization factors exceeding 90% render HTRs the most affordable energy source. On the other hand, load factors below 50% make them uncompetitive even with gas boilers. In cases of very low utilization, the cost of energy increases dramatically, amplified in case of HTRs by their high CAPEX. At very low load factors, below 10%, gas boilers start making economic sense, positioning them as the most suitable backup generators, particularly considering their flexibility with regards of fuels accepted and short start-up times.



**Figure 9.** Cost of process heat as a function of overnight cost

Much like in the case of load factor, Figure 9 shows the severe impact of changes in overnight cost on the economic feasibility boundaries of HTRs. Even in our scenario which favours HTRs, an overnight cost increase of 20% could render an HTR uncompetitive with established technologies under otherwise standard assumptions.



**Figure 10.** Cost of process heat as a function of discount rate

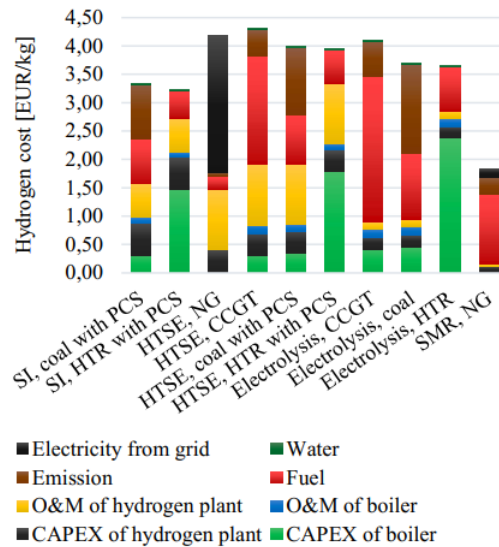
While being a secondary consideration for fossil-fired technologies, the discount rate is among the deciding factors for the levelized costs of energy from HTRs at 3% discount rate, which would imply increase value of long-term investment and low risk, it is by far the most affordable heat and electricity source.

At 7% discount rate, an HTR becomes 30% more costly than heat from coal or CCGTs. Figure 10 shows that discount rate determines the economic feasibility of HTRs. Unlike most variables, discount rate is both known and fixed once project financing is established therefore it was not considered in best- and worst- case scenario calculations.

5.3. Costs of hydrogen

SMR remains the most affordable method of hydrogen production, regardless of implementation method. Its advantage exceeds 1 EUR/kgH<sub>2</sub> (Figure 11). SI with HTR is the most affordable emission-free source of hydrogen. In addition, it is the second most affordable source of hydrogen after SMR.

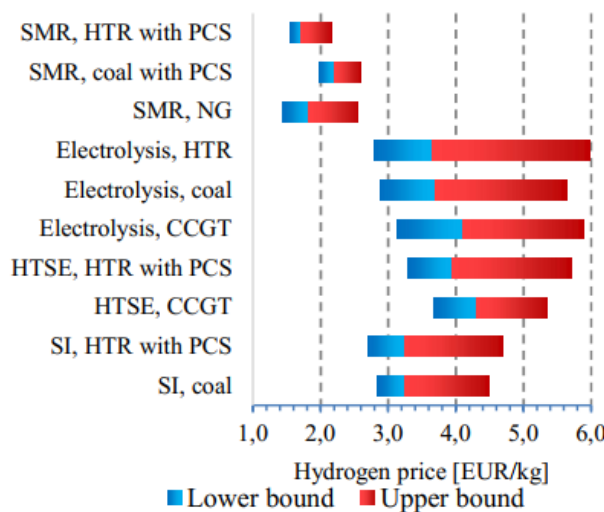
Any non-SMR hydrogen generation method without an HTR generates more emission than SMR, furthering the established position of the technology.



**Figure 11.** Levelized cost of hydrogen for selected technologies under standard assumptions

It is difficult to compete with SMR due to its very high thermodynamic efficiency, even in worst-case scenarios (Figure 12). Improvements to efficiency of SI or lowering its CAPEX and O&M could make it competitive with SMR.

The O&M combined with CAPEX of HTSE make it currently prohibitively expensive



**Figure 12.** Range of hydrogen prices with plausible offsets of two most sensitive parameters

Electrolysis is not an effective baseload method of hydrogen production but its relatively low CAPEX enables opportunistic hydrogen production during periods of cheap electricity

## 6. Summary

HTRs can be competitive with coal or gas technologies, particularly in scenarios with higher fuel or emission prices than our standard assumptions. The greatest disadvantage of HTRs is linked to its high CAPEX, which is very sensitive to underutilization or mismanagement during construction and planning which would result in prolonged construction or higher overnight cost. The assumed discount rate is the determining factor which can make or break a nuclear project, though, necessitating an advantageous financing scheme.

Both fuel and emission prices in the upcoming decades remain highly uncertain, particularly for Poland which makes considerable efforts towards higher energy security, partially ensured by domestic coal and gas reserves, leading to an argument for an HTR. In addition, Poland needs new generating capacities, given its large share of aged, coal-fired boilers - the facilities highlighted in Table 1 alone could host 42 units of 165 MWt reactors. If sustainable and captive generating technologies were to be excluded (such as burning sulphur, biomass or oil processing by products) the number of potential units would be between 25 and 35.

Hydrogen from SMR is notably cheaper than from other production methods, even with fuel and emission prices being unfavourable, meaning it will be difficult to replace without innovation in hydrogen generation technologies, fuel or emission prices outside of scope of our analysis or environmental policies limiting use of the technology.

SI and HTSE need development to lower their CAPEX and O&M costs to become competitive with SMR. SI could also compete if it were upscaled over 10 times to lower the specific capital cost.

Electrolysis can take advantage of periods of cheap electricity due to its scalability, flexibility, and low CAPEX, though it is not economically viable as a large-scale baseload hydrogen generation method in the scope of our scenarios.

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