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Economic Analysis of the Power to Methane Process Using a High Temperature Molten Carbonates Electrolyzer

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Power to Gas is a promising technology capable of resolving two main issues. This approach addresses the need for energy storage associated with renewable energy integration in the power grid. Besides, it can potentially be a viable technique for sequestration and re-using the captured CO_2 as synthetic fuels. The overall process is currently being studied using different types of electrolyzers. This work focuses on the Power to Methane technology, which employs a high-temperature Molten Carbonates Electrolyzer (MCEC). Its purpose is to investigate the economic feasibility of the overall methane production process. A rigorous parametric analysis is performed for this objective by developing a VBA Excel code to have a better understanding of the cost drivers of methane production cost. This study revealed that this process might be economically competitive with other technologies if the operating costs are low (20-40 €/t CO_2 and 20-80 €/MWh electricity cost), the cell cost is below 3,000 €/kW, and the operating hours are higher than 5,000 h/y. The vision for the future on these targets appears optimistic in terms of operating cost; nevertheless, there are still some challenges due to a lack of the cell cost forecast in the upcoming years.

1. Introduction

The call for mitigating climate change has boosted renewable energy installations globally. However, the massive integration of these sources for electricity generation poses some problems related to the difficulty in balancing electricity production with the demand due to its intermittence and fluctuation affected by the meteorological conditions. Energy storage systems are relevantly needed to store the surplus of renewable energy. Different energy storage technologies offer varying efficiency, capacity, and duration, and the choice of technology depends on the required storage period and capacity. For example, Superconducting Magnetic Energy Storage (SMES), supercapacitors, and flywheels are short-term storage options, while batteries, pumped hydro storage, and compressed air are mid-term storage options. Long-term storage options include power-to-gas systems and chemical storage techniques such as synthetic methane. For effective integration of VRES, high-capacity, long-term storage technologies such as synthetic methane, hydrogen, compressed air, and pumped hydro storage are essential (Brandeis et al., 2016).

The power-to-gas process involves one or two conversion steps, depending on whether the final storage vector is hydrogen (power-to-hydrogen) or methane (power-to-methane). Hydrogen is produced by the electrolysis of water, while methane production requires a second step called methanation, which converts hydrogen and carbon dioxide (Kezibri and Bouallou, 2020). While power-to-hydrogen presents technical, economic, and system-level challenges associated with hydrogen storage and transport (Hashimoto et al., 1999), power-to-methane is preferable because of the existing infrastructure for methane storage, compression, and injection into the natural gas grid. Methane synthesis allows for the utilization of CO_2 captured from industrial or power-plant flue gas instead of being used in enhanced oil recovery techniques for fossil fuel production. Converting excess electricity to methane could have negative environmental consequences due to the risk of gas leakage, and its efficiency may be lower than that of the power-to-hydrogen pathway.

This technology is now encountering some economic implementation challenges that necessitate in-depth research. A series of studies were performed to investigate the economic aspect of the Power-to-Gas. They are mainly based on alkaline (AEL), proton membrane (PEM), and Solid Oxide electrolyzers (SOEC). For instance,

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Götz et al. (2015) examined the existing electrolysis and methanation technologies in terms of the technical and economic requirements of the power-to-gas chain. Peters et al. (2019) analyzed the techno-economic features of the power-to-gas system using the three existing technologies and evaluated the ecological aspects of using methane as a transport fuel. Lately, Szima and Cormos (2021) assessed the techno-economic aspects of synthetic methane production from renewable hydrogen obtained from different renewable resources and captured CO_2. All studies revealed that synthetic natural gas produced from renewables is still non-competitive with conventional natural gas at the current stage.

On the other hand, Power-to-gas systems that use Molten Carbonate electrolyzers are not currently in the field of economic research. This technology is in the research and development stage, so all research focuses on the technical rather than the economic aspects. An economic study of the power-to-gas system using Molten carbonate Electrolyzer was first addressed in our earlier research (Monzer et al., 2021). In this analysis, the economic assessment was limited to three values of each variable parameter, and only their impact on CAPEX and OPEX was studied. However, in this work, a wider range of variables, including plant operating hours per year, was examined to determine their impact on the final synthetic methane price. The goal was to identify values that would result in a price that is nearly competitive with natural gas while also offering insights into how to achieve a competitive synthetic methane price in the future.

2. Methodology

2.1 Cost calculations and assumptions

The economic assessment was performed based on a developed process simulation consisting of the electrolyzer and all the balance of plant equipment, presented in a previous paper (Monzer et al., 2021). This assessment evaluated the capital and operating expenses of the process at the current conditions. The actualized cost per the amount of methane produced was calculated using Eq. 1.

$$\mathrm{CTA}_i = \frac{\sum_{t=0}^{T}\left(C_{invest_t} + C_{electrolzer_t} + C_{energy_t} + C_{feedstock_t} + C_{replacement_t} + C_{maintenance_t}\right)\times(1+\tau)^{-t}}{\sum\left[P_{i_t}\times(1+\tau)^{-t}\right]} \tag{1}$$

This equation includes several parameters that represent both the capital investment and the operating expenses of the process. CTA_i stands for the actualized total cost €/kg of methane produced. The capital investment parameters consist of C_{invest}, which is the investment cost without the electrolyzer in €, and $C_{electrolyzer}$, which is the electrolyzer's investment cost in €. On the other hand, the operating expenses involve the cost of energy consumption (C_{energy}) in €, the annual cost of feedstock ($C_{feedstock}$) in €, the replacement cost of equipment and electrolyzer ($C_{replacement}$) over the plant's lifetime (T) in y, and the maintenance expenses ($C_{maintenance}$) as a percentage of the energy cost, excluding replacement expenses. All of these costs are divided by the product of the annual production (P_i) of methane in kg and an actualization term, which is a function of the actualization rate (τ) and the year in which the expenses are executed (t).

2.2 Sensitivity analysis parameters

The target of the sensitivity analysis is to gain a better understanding of the cost drivers and find out the limits of the cost reductions. In previous work (Monzer et al., 2021), an investigation study was carried out on the impact of both CAPEX and OPEX on the final methane production cost by a limited sensitivity analysis. The sensitivity analysis involved the variation of different parameters, such as cell cost, lifetime, CO_2 and electricity cost within a finite margin. In this work, a profound parametric study is performed by developing a VBA excel code. It includes all the previously stated parameters in addition to the operating hours of the plant. The summary of all studied parameters with their margins are represented in Figure 1.

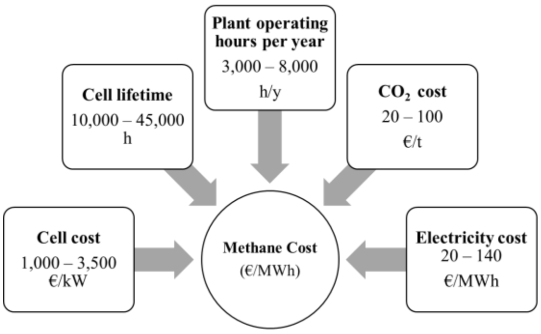

Figure 1: Schematic representation of the study's margin of the different sensitivity analysis parameters

Knowing that the MCEC requires a CO_2 feed with low sulfur content, an economic study was conducted on the carbon capture and purification processes in previous work (Monzer and Bouallou, 2022). Nevertheless, these processes' capital and operating expenses are not included in this economic analysis; on the contrary, a CO_2 cost is selected as a variable parameter in this analysis.

3. Results and discussion

3.1 Impact of sensitivity parameters on the production cost of synthetic methane

The sensitivity analysis was conducted to examine the impact of CAPEX (cell cost and lifetime) and OPEX (CO_2 and electricity cost) on the methane selling price, assuming that the plant operates for 8,000 h/y. After that, the influence of the operating h/y was studied while maintaining all other parameters fixed.
The first part of the analysis is divided into three categories. The CAPEX parameters (cell cost and lifetime) are variable in the three sections. However, for the cell lifetime, two values were selected to be presented: the low value at 10,000 h and the high at 40,000 h. The high lifetime of 40,000 h was selected for study since the Molten Carbonate Fuel Cell (MCFC) has proven to have a 40,000 h lifetime (Cassir et al., 2012). It was interesting to evaluate the economic aspect of this lifetime. In the first category, the CO_2 cost (€/t) was varied, keeping the electricity cost fixed at 140 €/MWh. Figure 2 depicts the effect of the CO_2 feed cost and the cell capital cost on the methane cost at two cell lifetimes. In this figure, the x-axis displays the variation in CO_2 cost, and the colored curves represent the cell cost. At a cell lifetime of 10 000 h (Figure 2a), the methane cost increases with the increase in the CO_2 cost, whatever the cell cost is. Besides, it increases at a rate of around 100 €/MWh when increasing the cell cost by a step of 500 €/kW. In this case, the lower methane cost reached is 450 €/MWh at a CO_2 cost of 20 €/t and a cell cost of 1,000 €/kW. Nevertheless, under these conditions, the methane cost at a cell lifetime of 40 000 h is 350 €/MWh. When the cell lifetime is 40,000 h, the cost of 450 €/MWh can be attained at 20 €/t CO_2 and 4,000 €/kW cell cost, 30 €/t and 3,000 €/kW, 40 €/t and 2,500 €/kW, or 50 €/t and 1,000 €/kW. It can be deduced that if a cell lifetime of 40,000 h is reached, it is sufficient to have a cell cost below 3,000 €/kW and a CO_2 cost between 20 and 50 €/t.

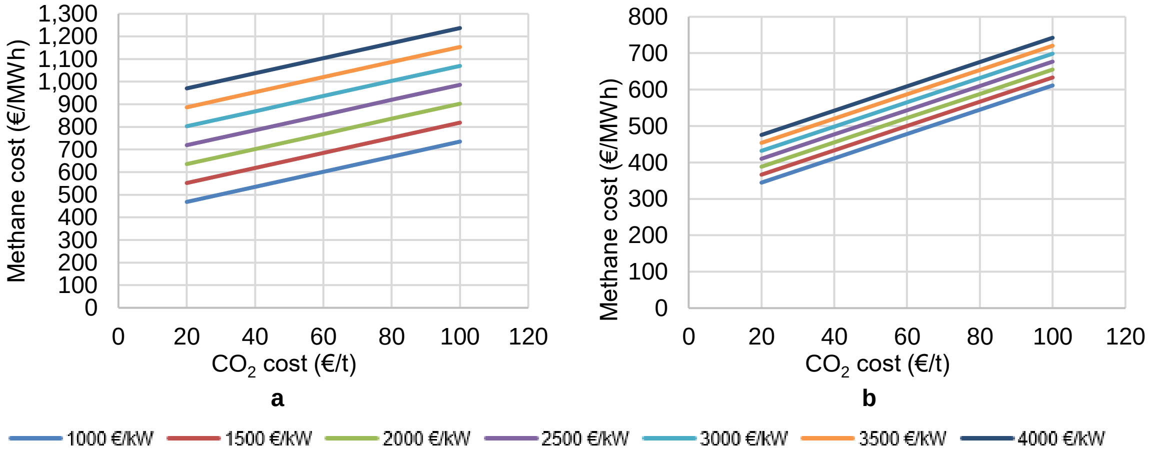

Figure 2: Impact of CO_2 feed cost (€/t) and the cell capital cost (€/kW) on the final methane cost (€/MWh) at a fixed electricity cost of 140 €/MWh, and two different cell lifetimes: 10,000 h (a), and 40,000 h (b)

By comparing the two figures of different lifetimes, it can be noticed that the curves at a high cell lifetime of 40,000 h are incredibly close to each other, which implies that the cell cost has a negligible impact on the methane cost when the cell lifetime is high. This finding coincides with the fact that a high lifetime indicates less replacement cost is needed, and no significant effect of the cell cost is observed. For example, the plant lifetime is assumed to be 15 y in this study. A cell lifetime of 40,000 h while operating 8,000 h/y means the cell must be replaced twice (every 5 y) within 15 y. In contrast, a cell lifetime of 10,000 h requires a cell replacement approximately every year, meaning 14 times throughout the plant's lifetime. Besides, the additional improvement in the cell's lifetime after reaching 40,000 h has no significant impact on the methane selling price when the plant lifetime is 15 y. However, it could slightly impact the methane cost when the plant's lifetime is more than 15 y. From this study's approach, it can be deduced that a cell lifetime of 40,000 h is essential to have an acceptable synthetic natural gas cost.

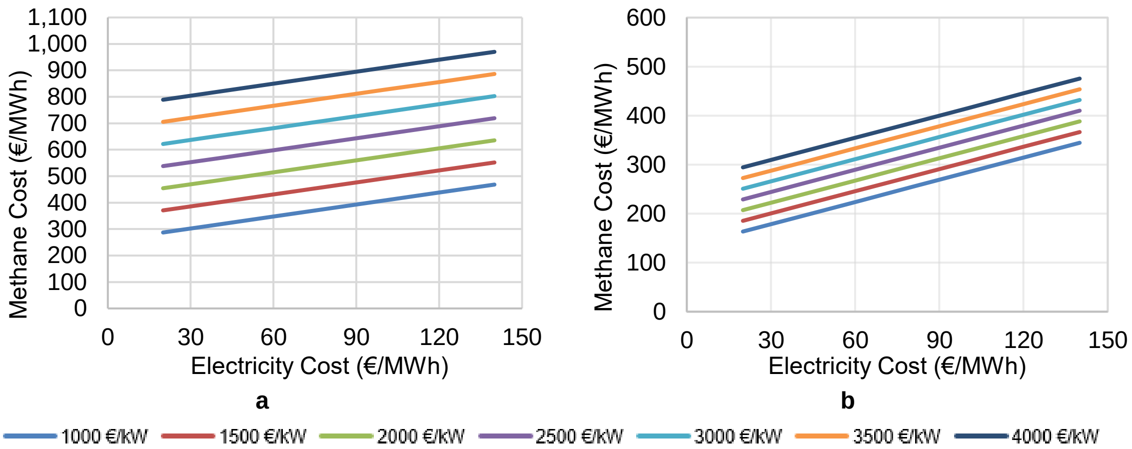

Figure 3: Impact of Electricity cost (€/MWh) and the cell capital cost (€/kW) on the final methane cost (€/MWh) at a fixed minimum CO_2 cost of 20 €/t, and two different cell lifetimes: 10,000 h (a), and 40,000 h (b)

The second category corresponds to the electricity cost variation at a fixed minimum CO_2 cost of 20 €/t. The effect of the electricity cost and the cell cost at two different lifetimes on the methane production cost is illustrated in Figure 3. As expected, the higher the electricity cost, the higher the methane cost. Similar to the first section, at a lifetime of 10,000 h, the cell cost increase has the same impact on methane cost with the same growth rate of 100 €/MWh per 500 €/kW increase in cell cost. The minimum methane cost that could be reached with a minimum CO_2 price of 20 €/t is 300 €/MWh at a lifetime of 10,000 h and 150 €/MWh at a lifetime of 40,000 h when the electricity cost is low at 20 €/MWh and a cell cost of 1,000 €/kW.

Nevertheless, at a 40,000 h lifetime, the methane cost is almost optimistic as it varies between 150 to around 500 €/MWh with the electricity and cell cost change. The minimum methane cost of 150 €/MWh could be said that it is competitive with the actual natural gas price after the crisis, which is 126 €/MWh in France and 340 €/MWh in the Netherlands in 2022 for household applications (GlobalPetrolPrices.com, 2022). Indeed, these results confirm the importance of having a cell lifetime of 40,000 h and demonstrate that a cell cost below 3,000 €/kW with an electricity cost range of 30 to 90 €/MWh when the CO_2 feed cost is low at 20 €/MWh is a tempting target to have a competitive synthetic natural gas price.

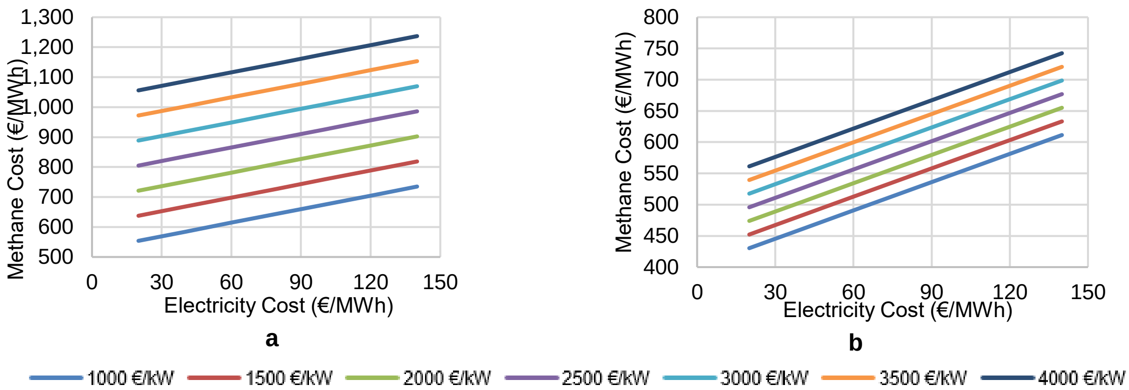

Figure 4: Impact of Electricity cost (€/MWh) and the cell capital cost (€/kW) on the final methane cost (€/MWh) at a fixed maximum CO_2 cost of 100 €/t, and two different cell lifetimes: 10,000 h (a), and 40,000 h (b)

On the other hand, in the third category, the study of the second one is repeated at a maximum CO_2 cost of 100 €/t. The results of this study are depicted in Figure 4. The main difference between the two categories can be observed in the range of methane cost at both lifetimes. At a lifetime of 10,000 h, the lowest methane cost reached is 550 €/MWh compared to 300 €/MWh at minimum CO_2 cost. On the other hand, at a 40,000 h lifetime, the methane cost between 150 €/MWh and 300 €/MWh at minimum CO_2 cost is shifted to a range of 420 to 580 €/MWh at maximum CO_2 cost.

This category was essential for selecting the best operating cost to compete with other technologies. Based on the last two categories, it can be revealed that a low CO_2 cost with an electricity price range of 20-80 €/MWh at a low capital cost is sufficient to reach a competitive methane price. Otherwise, if the CO_2 cost is high, the lower methane price that might be attained is 420 €/MWh when having an electricity cost of 20 €/MWh, a cell cost of 1,000 €/kW, and a cell lifetime of 40,000 h.

In reality, the power-to-gas system is being studied to overcome the challenge of renewable energy storage. However, this intermittent energy does not allow the plant to operate for 8,000 h annually. As a result, the plant's operating hours per year were also studied to determine the plant's optimal operating hours per year. For this study, the cost of the cell, electricity, and CO_2 were fixed at 3500 €/kW, 100 €/MWh, and 60 €/t. The resulting methane costs in €/MWh are presented in Table 1, as a function of the plant's operating hours per year ranging from 3,000 h/y to 8,000 h/y, and the cell's lifetime. The analysis revealed that the methane cost decreases with an increase in the plant's operating hours. However, there are some turning points where the methane cost starts to increase. This situation is due to the cell's lifetime, which directly affects the replacement cost. To determine the optimal values of the cost drivers, a comparative study involving the three categories mentioned above was conducted at plant operating hours of 5,000 h/y and 3,000 h/y. The study showed a similar trend with an average increase of 6 % in the methane cost at 5,000 h compared to 8,000 h, whereas, at a plant operating time of 3000 h, the methane price seems unlikely to reach below 300 €/MWh based on the studied range of variables. This outcome is also observed in Table 1, where at a cell lifetime of 35,000 h and 40,000 h, the methane cost can approach 300 €/MWh if the cell cost and the electricity and CO_2 costs are lowered, and the plant operates for more than 5,000 h/y. Therefore, operating the plant for more than 5,000 h/y is favorable.

Table 1: Methane cost in €/MWh with different plant operating hours and cell lifetime.

		Cell lifetime (h)						
		10,000	15,000	20,000	25,000	30,000	35,000	40,000
Plant's operating time (h/y)	3,000	993.54	802.67	717.51	661.27	646.58	634.44	629.19
	4,000	834.54	721.64	691.39	642.03	585.34	579.57	574.32
	5,000	870.30	738.58	648.25	624.06	584.57	572.96	539.22
	6,000	784.37	674.60	674.60	599.33	579.17	546.26	536.59
	7,000	1045.52	726.87	632.78	568.26	568.26	550.98	522.77
	8,000	959.48	680.66	598.34	598.34	541.88	541.88	526.76

Finally, although the cell capital cost and its lifetime highly affect the methane cost, it can only reach a competitive price with the conventional ones by reducing the operating cost. The methane production cost must drop below 300 €/MWh to obtain a competitive synthetic methane selling price. According to the results analyzed, the methane price is below 300 €/MWh when the CO_2 cost is low (20-40 €/t CO_2), and the electricity cost is between 20-80 €/MWh at a cell cost below 2,000 €/kW. It can be deduced that the operating and capital costs considerably influence the final synthetic methane selling price. In conclusion, the target of methane price below 300 €/MWh can be attained if the operating costs are low, the cell cost is below 3,000 €/kW, and the plant's operating duration is longer than 5000 h/y.

3.2 Future perspectives

The future perspectives for having these conditions depend on several criteria. The future perspectives for having a 40,000 h cell lifespan, 40 €/MWh electricity cost, 20 €/t CO_2 cost, and 1,000 €/kW cell cost depend on several criteria. The cell lifetime of MCFC has reached over 40,000 h lifespan in fuel cell mode (Cassir et al., 2012). Besides, Hu et al. (2014), in his study on a 3 cm^2 cell, proved that the cell exhibited better electrochemical performance in MCEC mode than in MCFC mode, which leads to a higher lifetime of the MCEC. However, a study carried out by Frangini et al. (2021) on an 81 cm^2 cell revealed that there is a degradation of the cell during electrolysis mode due to: electrolyte loss, increase in the chemical instability of the oxygen electrode NiO, reduction of the porosity of both electrodes and corrosion of the oxygen-current collector. According to this information, it can be deduced that there is no current certitude about the lifetime of MCEC. Based on the literature, some research strategies have been proposed to increase the stability of conventional electrodes and current collectors in the reverse mode of MCFC using advanced surface modification and coating technologies (Frangini et al., 2021).

The parametric study outcomes encourage profound research on the operating and capital costs situation. First of all, the electricity is driven by the cost of the renewable energy source since MCEC is the most electric energy consumer. The International Renewable Energy Agency (IRENA) (IRENA, 2021) has reported the decreasing trend of the Levelized Cost of the different renewable energy sources from 2010 to 2020. According to their outcomes, the cost of onshore wind turbine electricity was 39 $/MWh (~36 €/MWh) and that of PV electricity was 57 $/MWh (~54 €/MWh) in 2020. These costs are expected to be very low in the coming years. On the other hand, the CO_2 cost depends on the carbon capture technology used. Each technology has a different investment and operating cost. The selling price of the produced CO_2 will change. The MCEC cost is determined by the technology improvements and the manufacturing capacity, which will be reflected in an increase in the cell market causing a reduction in the cell cost per installed capacity. In 2003, MTU (a former fuel cell manufacturing company in Germany, that transferred its assets to Fuel Cell Solution GmbH in 2012, a subsidiary of the FuelCell energy USA) expected that the commercial MCFC cost will attain a value <1,250 €/kW once the production volume reaches 160 to 200 systems annually (Krewitt and Schmid, 2005). However, there is still no public available information on the current status of the MCEC cost and its roadmap.

4. Conclusion

The power-to-gas system, which is based on a Molten carbonate electrolyzer, is an appealing concept for storing energy and recycling CO_2. Major cost feasibility breakthroughs are necessary. As a result, the economic analysis performed in this paper allows us to make a preliminary assumption about the cost drivers for competitive synthetic methane pricing. According to this study, this approach may be economically feasible when the operational expenses, including CO_2 and electricity costs, are low, the cell cost is below 3000 €/kW with a lifetime of 40,000 h, and the operating duration of the plant is longer than 5,000 h/y. This target allows for attaining a synthetic methane price below 300 €/MWh. Looking at the future projection concerning these goals, they seem encouraging regarding operating costs; nevertheless, there are still limits at the cell cost level due to the lack of its cost forecast over the coming years.

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