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Economic Analysis of Renewable Power-to-Gas in Norway

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Abstract: The steep reduction in costs of electrolysis and methanation has made renewable power-to-gas much more affordable. Reeling from an energy crisis, Europe could use this technology for near-shoring production of clean and reliable synthetic natural gas (SNG) and end dependence on Russian gas. This article investigates the economic feasibility of producing SNG in Norway, which has amongst the cleanest and cheapest electricity production in Europe. It is found that SNG can be produced for 141 €/MWh at a 10 MW electrolyzer facility in 2023; and for 108 €/MWh at a larger 100 MW electrolyzer facility in 2030. The relevance of these prices is discussed in the context of the current and future European gas markets, and recommendations are made to reduce the production costs even further.

Keywords: synthetic natural gas; economic analysis; power-to-gas; Norway; Europe energy crisis; electrolysis

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1. Introduction

The Russian invasion of Ukraine in 2022 and the ensuing disruption of natural gas supplies to Europe has led to an energy crisis [1]. The European Union (EU) depends on natural gas for nearly a quarter of its energy needs [2], and more than 40% of this gas is supplied by Russia [3]. The supply disruption caused European gas prices (Dutch TTF) to soar nearly ten times in a year, as shown in Figure 1, and touch all-time highs of 339 €/MWh [4]. The energy crisis led to the RePowerEU Plan, which aims to make Europe independent of Russian fossil fuels before 2030 and proposes increasing the renewables target to 45% of electricity generation within the same time frame [5]. The policy builds upon the 2019 European Green Deal [6], which requires EU member states to reduce emissions by at least 55% by 2030, compared to 1990 levels.

Renewable Power-to-Gas (PtG) technologies could help address the trilemma of secure, affordable, and sustainable natural gas supply in Europe. This article focuses on PtG applications which convert electricity to methane in a two-step process. In the first step called electrolysis, electrical energy is passed through water to decompose it into its constituents, i.e., hydrogen and oxygen. In the second step, also called methanation or the Sabatier reaction, hydrogen reacts with carbon dioxide to produce water and synthetic natural gas (SNG) The so-formed methane is referred to as synthetic natural gas (SNG), and the reaction is highly exothermic, releasing 165 kJ/mol of heat as shown in Equation (1) [7,8].

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \; \Delta H_R = -165 \text{ kJ/mol} \quad (1)$$

PtG applications can help achieve significant reductions in carbon emissions, especially in geographies with limited availability of CO_2 underground storage. Furthermore, SNG can be used for manifold applications such as long-term storage of renewable energy (RE) and load balancing of electricity grids [9], helping reduce capital costs in upgrading the grid to accommodate more RE. Additionally, converting power to SNG instead of H_2 could help reduce upgrade costs of existing pipeline and gas transportation infrastructure. The European Hydrogen backbone study estimated that repurposing existing natural gas

pipelines to transport hydrogen within 21 European countries would need between €43 and €81 billion by 2040, mainly driven by compression costs [10,11]. Another European study suggests that only four "no-regret" pure hydrogen corridors are sufficient for early investment in hydrogen pipelines, and emphasizes that there is no justification for creating a larger, pan-European hydrogen backbone [12].

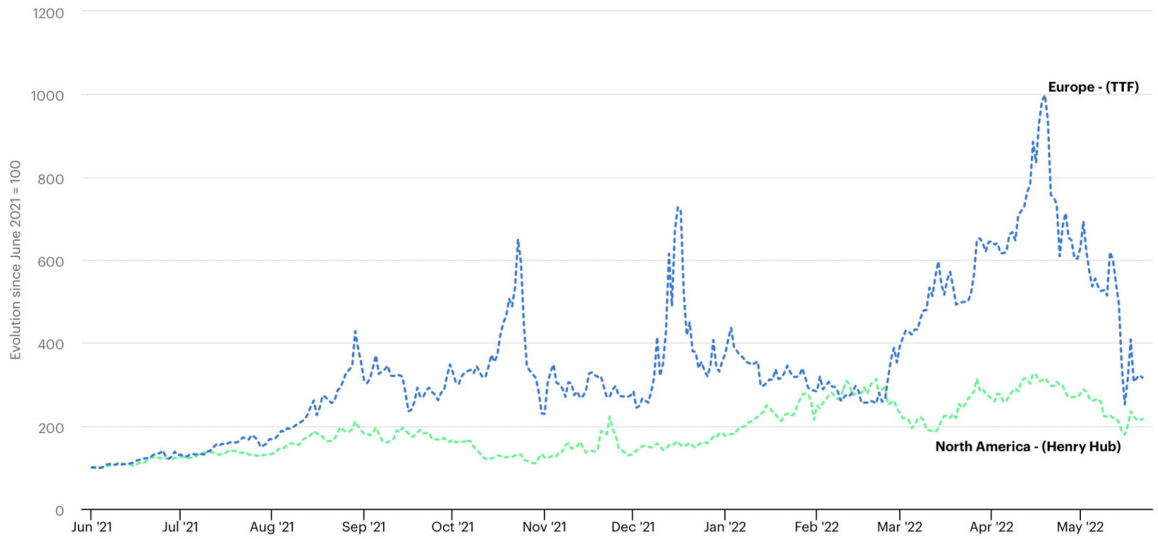


Figure 1. The European (TTF) gas price (blue dashed curve) has increased significantly from June 2021 to October 2022 as compared to the US (Henry Hub) price (green dashed curve) [13]. Gas prices are indexed to a starting index value of 100 in June 2021 to enable comparison between different price markers. The European TTF prices increased by ~10× from June 2021 to August 2022, while North American prices increased by ~3× over the same period. The peak European TTF price in August 2022, corresponding to index value of 1000, was 339 €/MWh [4].

While PtG production has been explored in many geographies around the world, the potential of Norway as a PtG producer has not been studied adequately. Norway generates cheap and abundant clean electricity, which can be used to produce renewable SNG. This article aims to investigate the economic feasibility of SNG production in Norway, while factoring in long-term cost trends for electricity, electrolyzers, methanation units and other key components. A sensitivity analysis has been performed as well to estimate the impact of key parameters on SNG production costs.

The article consists of six sections. After the Introduction, Section 2 examines existing literature on the economic analysis of PtG applications and discusses the missing gap. Section 3 dives into the methods and key cost assumptions used for performing the economic analysis. Section 4 presents the main results of the analysis including cost breakdown and sensitivity tornado charts. Section 5 discusses key results with regards to natural gas price trends and compares them with results obtained in previously performed studies. The last section concludes the article and points towards additional strategies and future research areas to further improve the economic feasibility of SNG.

2. Literature Review

2.1. Existing PtG Projects and Associated Studies

The idea of large-scale PtG to enable the transition of energy systems was first published by Sterner in Germany [14], where CO_2 methanation was discussed in the context of fuel cells in the early 2000s [15]. The European Union has funded various research and pilot scale PtG facilities to improve process efficiency and develop a roadmap for large-scale PtG conversion in Europe. One of these initiatives, HELMETH, focused on the development of a proof of concept of a highly efficient PtG system by thermally integrating methanation with

high-temperature electrolysis using a solid oxide electrolyzer cell (SOEC) [16]. Another European initiative, STORE&GO, operated three pilot plants located in Italy, Switzerland and Germany with a mix of electrolysis and methanation technologies [17].

A review of operational PtG projects by Thema et al. suggests that 38 methanation projects were active worldwide in 2019. Of these, the bulk of projects were located in Germany, Denmark and Netherlands [18], and only represent an installed production capacity of 6 $MW_{LHV\text{-}SNG}$ [18]. STORE& GO estimated that the European power-to-methane capacity would be in the range of 40 to 200 GW_{SNG} in nearly half of the analyzed low-carbon scenarios [19]. Böhm et al. estimated that European demand for large-scale PtG could go up to an even higher 600 GW_{SNG} by 2050 as supply of renewable power and the demand for decarbonized fuel increases [20].

Given the importance of PtG towards achieving energy transition, many studies have been performed on the technical and economic feasibility of producing SNG from electricity [20–29]. Böhm et al. developed a calculation model for learning curves of main components of a PtG system [22], and used it to estimate the future costs of SNG production [20]. Gorre et al. [23] evaluated the production costs of SNG for an optimized PtG system, while considering variations in full load hours of plant operations. Hoffman et al. [21] determined additional system costs to inject produced SNG into the pipeline network.

Additional studies have focused on the economic feasibility of SNG production in a more localized context. A study executed by Agora Energiewende investigates the economic feasibility of producing SNG in Germany versus importing it from Iceland, North Africa and the Middle East [24]. Ipsakis et al. [26] estimates the production cost of SNG for a typical cement industrial facility in Europe. Leeuwen et al. [27] examine the PtG operator's willingness to pay for electricity prices in Germany, France, Netherlands and Denmark. Jiang et al. [28] determine the production cost of SNG for a factory located in Northwest China, while Dominguez-Gonzalez et al. [29] evaluate the business case for integrating a PtG system with power production in the UK.

While these studies reveal the general methodology, system configurations and cost assumptions for estimation of SNG production costs, they fail to contextualize these costs with respect to market trends for natural gas prices. Furthermore, these studies refrain from addressing the potential of Norway in producing and supplying Europe with SNG. prices. This study aims to fill the missing gaps and appraise SNG production costs for Norway.

2.2. Norway as a Potential SNG Supplier for Europe

Norway is the second largest supplier of natural gas to the EU after Russia [3]. Given the geopolitical situation, the EU is seeking to increase pipeline and liquified natural gas (LNG) imports from Norway even further [5]. Additionally, Norway's electricity production is not only amongst the cheapest in Europe [30–32], but also amongst the cleanest, nearly ten times lower than Germany [33] (Figure 2). Thus, Norway could use its abundant clean electricity to generate "clean" natural gas and send it to European countries through the existing pipeline network.

Norway's clean and cheap electricity supply could be attributed to hydropower. In 2021, Norway produced 157 TWh, of which 91% was from hydropower, 8% from onshore wind and <1% from thermal sources [32]. Norway typically generates surplus electricity and exports 19 TWh to neighboring countries in normal weather years [34]. Norway's power grid is divided into five different pricing zones, with the consumption concentrated in the three southern regions of Oslo, Stavanger and Bergen [31]. However, surplus production in the northern regions, and limited transmission capacity to southern demand centers result in significantly cheaper prices in north Norway, which could be used to produce SNG.

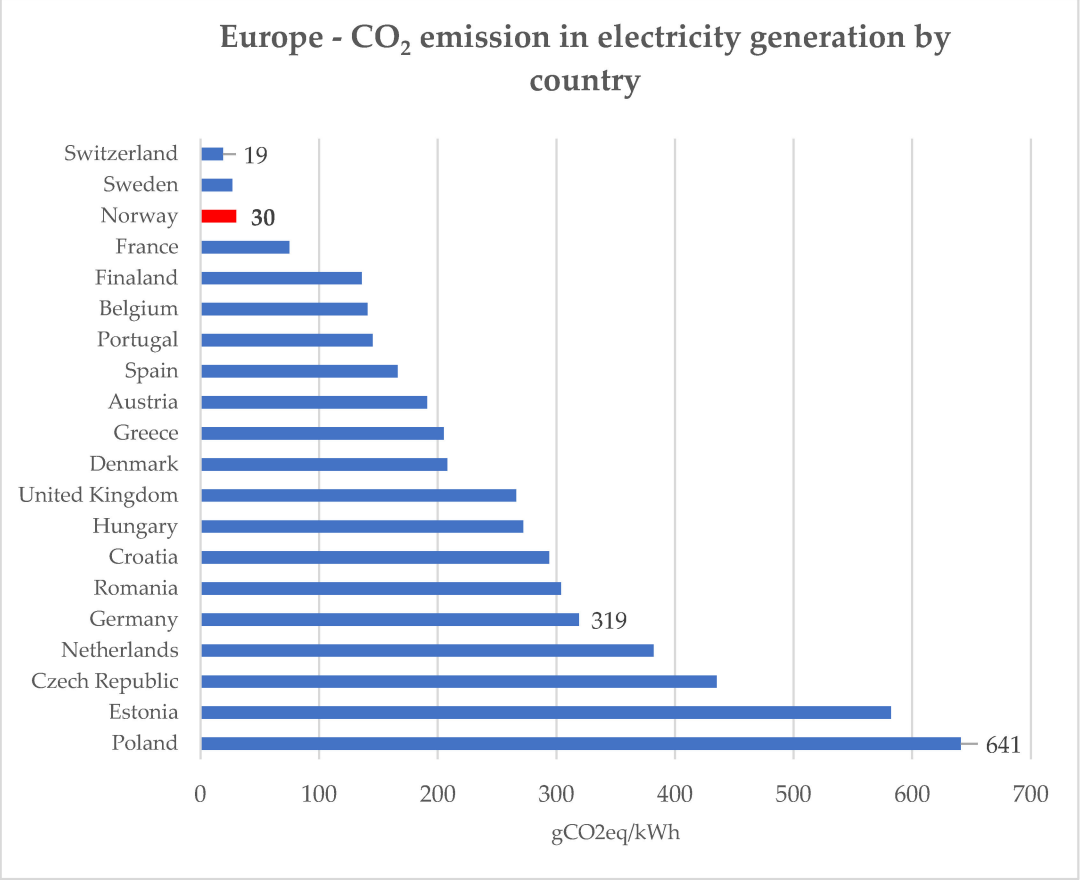


Figure 2. CO_2 emissions from electricity production by country on 28 October 2022 [33].

3. Materials and Methods

3.1. Methodology

The economic feasibility of SNG is estimated using a levelized cost of energy (LCOE) approach, which calculates the lifetime costs for the facility per unit energy produced. This methodology enables cost comparison between different technologies and configurations of PtG systems while factoring in the time-value of money [23]. The levelized cost approach has been adapted to estimate the gas production costs (GPC) for SNG as below Equation (2) [35]:

$$\text{GPC} = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t + Energy_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{SNG_t}{(1+r)^t}} \quad (2)$$

where GPC = Gas Production Cost, or Levelized cost of SNG production;
$CAPEX_t$ = Capital expenditure, calculated using depreciation expenses in year t (€);
$OPEX_t$ = Operation and maintenance expenditure in year t (€);
$Energy_t$ = Electricity costs in year t (€);
SNG_t = Synthetic methane gas produced in year t (MWh);
r = Discount rate (%);
n = Operations lifetime of facility (years), assumed to be 20 years.
Decommissioning costs have not been considered for the purpose of this analysis.

3.2. PtG System Configuration

Leeuwen et al. [36] proposed a PtG system configuration (Figure 3) for the STORE&GO project. This study considers a similar setup composed of two principal systems, electrolyzer and methanation, further discussed in Section 3.3.

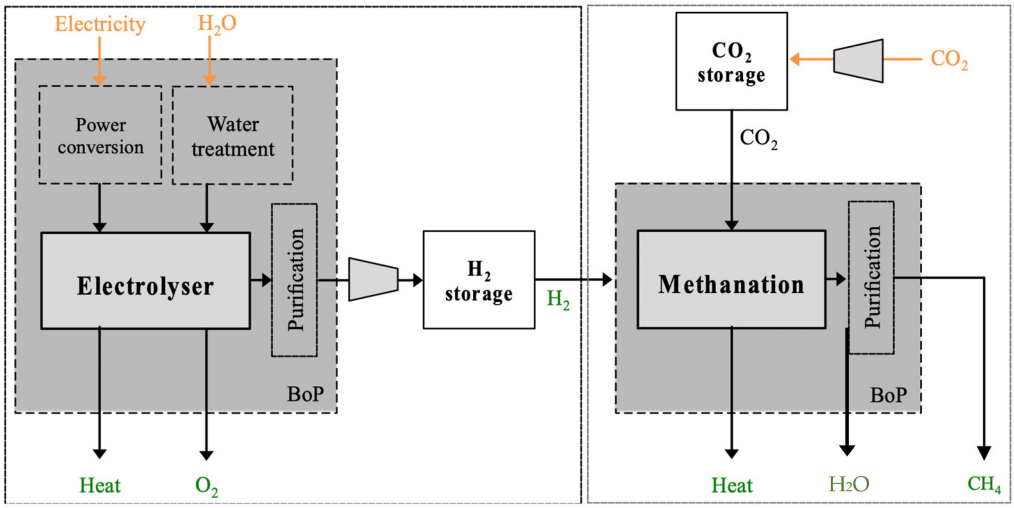


Figure 3. Overview of a methane producing PtG facility. The feedstocks are marked in orange, while outputs are marked in green [36].

Electrolysis is at the core of producing natural gas from power. Currently, two main electrolysis technologies are commercially available—alkaline electrolysis (AE), which uses a strong base such as potassium hydroxide as the electrolyte, and proton exchange membrane (PEM), which uses an ionically conductive solid polymer [37]. While AE is more matured and cheaper, PEM is more efficient, easier to handle, has a relatively lower footprint and produces pressurized hydrogen. PEM is more expensive than AE currently, but is expected to become more cost-efficient than AE as the technology matures [38–40].

A third electrolysis technology, solid oxide electrolysis cell (SOEC), also holds significant potential for improving overall process efficiency, as the heat generated by methanation could be used to drive efficient electrolysis at high temperatures. This concept was being researched by the HELMETH consortium in Europe [16], but it is not as mature as AE or PEM. Consequently, PEM electrolysis has been considered for this analysis. A more detailed comparison between the various electrolyzer technologies is presented in Table 1.

Table 1. Electrolysis production technologies [41].

	Alkaline Electrolysis	**Proton-Exchange Membrane (PEM)**	**Solid Oxide Electrolysis Cell (SOEC)**
Description	Alkaline technology is used extensively in the chlorine industry; a strong base such as potassium hydroxide is generally used as the electrolyte due to its high conductivity.	PEM uses a ionically conductive solid polymer; hydrogen ions travel through the polymer membrane toward the cathode. PEM has a very short reponse time of less than 2 s.	SOEC is based on steam water electrolysis at high temperatures, thereby reducing need for electrical power. Heat is only needed to vaporize water and can be obtained from waste industrial heat.
Capital Costs (stack-only, >1 MW, USD/kWe)	270; <100 expected	400; <100 expected	>2000; <200 expected
Efficiency (%, LHV)	52–69%	60–77%	74–81% excluding heat to vaporize water)
Typical Plant Size (tpd H_2)	60; 100 expected	50–80; 100–120 expected	<20; 80 expected

Table 1. *Cont.*

	Alkaline Electrolysis	Proton-Exchange Membrane (PEM)	Solid Oxide Electrolysis Cell (SOEC)
Stack Lifetime (in thousands of hours)	60; 100 expected	50–80; 100–120 expected	<20; 80 expected
Operating Temperature (°C)	60–80	50–80	650–1000
Operating Pressure (bar)	1–30	20–50	1
Expected R&D Improvements	Scaling benefits to reduce costs; improvement in lifetime; improved heat exchangers.	Scaling benefits to reduce costs; improvement in material and component lifetimes.	Improvement in component lifetime by improving the resistance to high temperatures and improving the response to fluctuating energy inputs.
Pros and Cons	Most mature technology; has the lowest capital cost but also the lowest efficiency.	Highly efficient but more expensive than alakaline electrolysis.	High future potential but still in the developmental stage.

The second part of the PtG process, methanation, can be performed using both biological and chemical approaches. Biological methanation uses methanogenic microorganisms as biocatalysts under anaerobic conditions [42]. Chemical methanation typically uses nickel (Ni) as catalyst in an adiabatic fixed-bed reactor at relatively higher temperatures of 200–550 °C [43,44]. A review by Götz et al. [43] of different methanation techniques suggests that while biological methanation is relatively simpler, it is still at lab scale compared to chemical methanation, which is commercially developed and cheaper. Furthermore, the high temperature level of thermochemical methanation helps improves process efficiency. Thus, chemical methanation has been considered for this study.

3.3. Principal Scenarios

The study evaluates two main scenarios, those of a mid-scale 10 MW electrolyzer in 2023, and that of a large-scale 100 MW electrolyzer in 2030. Given the recent natural gas price shock in Europe, there is an imperative need to secure gas production. Thus, the first scenario considers the immediate startup of a mid-size (10 MW electrolyzer) PtG facility in Norway, which can export 33.2 GWh_{SNG}/year of gas to European consumers. The second 2030 scenario estimates the future GPC for a large-scale PtG facility and determines long-term economic feasibility of this process. The main scenarios are listed in Table 2, and the key inputs and assumptions used for GPC calculation are listed in Table 3 below.

Table 2. Principal scenarios considered in the analysis.

Item	2023 Scenario	2030 Scenario
Electrolyzer Capacity	10 MW_{el}	100 MW_{el}
SNG Production	33.2 GWh_{SNG}/year	344.4 GWh_{SNG}/year
Electricity Consumption	79.2 GWh/year	788.7 GWh/year
Operations Lifetime	20 years	20 years

Table 3. Key inputs used in estimation of GPC for PtG process.

Item	2023 Scenario	2030 Scenario	Remarks	Reference(s)
CAPEX [1]				
PEM Electrolyzer Stack	450 €/kW_{el}	245 €/kW_{el}	See discussion below	[15,23,27,36,45,46], Assumption
Balance of System	660 €/kW_{el}	535 €/kW_{el}		
Stack Replacement Cost	225 €/kW_{el}	123 €/kW_{el}		
Stack Lifetime	60,000 h	70,000 h		
Methanation Unit	600 €/kW_{SNG}	275 €/kW_{SNG}		[45]
Contingency	10%	10%	% of Total Installed Cost	Assumption
OPEX				
Electrolyzer	3%	1.5%	% of Electrolyzer CAPEX	[23,46], Assumption
Methanation	3%	3%	% of Methanation CAPEX	[25]
Insurance	0.5%	0.5%	% of Total Installed Cost	Assumption
CO_2	50 €/ton	50 €/ton	Includes cost to capture and transport CO_2.	[23,36]
Transportation	2.3 €/MWh	2.3 €/MWh	Assuming pipeline distance of 1000 km between Norway and Germany.	[47]
Energy Costs				
Electricity	2022: 44 €/MWh 2030: 40 €/MWh 2035: 32 €/MWh 2040: 23 €/MWh		See discussion below	[34,48–50], Assumption
Utilization and Efficiency				
Utilization Rate	90%	90%	High utilization is assumed due to continuous operation mode (See discussion below).	Assumption
Electrolyzer Efficiency (% HHV)	75%	78%	Electrolyzer efficiency is assumed to increase by 2030.	[25,51]
Methanation Efficiency	85%	85%	Assuming that surplus heat generated in methanation is used.	[52]
Financing				
Depreciation	Straight line depreciation over useful life		Assumed total plant life of 20 years, policy support through accelerated depreciation could improve returns.	Assumption
Discount Rate	9%	9%	Based on the weighted average cost of capital for a large energy company in Norway.	[53]
Funding source	Equity	Equity	100% equity is considered to simplify model.	Assumption

[1] Input assumptions are segregrated by categories with category headings in bold.

Several studies have discussed historic as well as future cost trends in electrolysis technologies [38,39,54–58]. All of these establish that electrolysis, and in particular PEM, has a very high learning rate with costs dropping rapidly. Given the rapidly declining costs, CAPEX assumptions are based on the most recent LCOH analysis by the investment bank, Lazard, in order to be as close to market as possible [46]. The 2023 scenario considers the average price case for a mid-size (20 MW) PEM electrolyzer, with stack replacement costing 50% of the original stack price. The 2030 scenario for a large-scale (100 MW) PEM electrolyzer is based on estimates by Sterner et al. [15], with stack replacement costing 50% of original stack price. It is assumed that the costs of electrolyzer technologies will keep

decreasing till they stabilize at <100 €/kW_{el} as mentioned in Table 1. Lastly, it is assumed that research in PEM technologies will lead to a substantial increase in the total operating hours over the next decade.

The cost estimates for chemical me"hana'Ion units are based on an analysis by STORE&GO [45]. It suggests that small-scale catalytic reactors cost around 600 €/$kW_{SNG,}$ but can go down to 275 €/kW_{SNG} in 2030 for a 25 MW_{SNG} facility [45], which would correspond to a 100 MW electrolyzer plant.

Electricity is one of the major inputs in the PtG process, and SNG's economic viability depends to a large part on the cost of electricity in Norway. In the short to mid-term, Norway's electricity system operator, Statnett, predicts that average electricity prices in Norway are expected to increase due to increasing export capacity to Europe, where electricity prices would be impacted by the increased fuel and carbon prices. This is also expected to exacerbate the differences between pricing in the southern and northern regions of Norway in the mid-term, which could even out by 2040 as investments are made to improve grid capacity [50]. In the long-term, i.e., 2040+, increasing penetration of cheaper wind and solar would help lower the electricity pricing, though carbon and fuel prices will still continue to be key drivers [34].

The near-term pricing for electricity is based on latest available data (from July 2022) on electricity prices for energy-intensive manufacturing sectors on Norway's official statistics website [48]. The mid-term 2030 price is based on estimates by Norway's system operator, Statnett [50]. 2040+ prices are based on the low case estimated in an analysis on Norwegian long-term power prices by Jåstad et al. [34]. The price in 2035 is extrapolated, assuming a linear cost decline between 2030 and 2040.

Lastly, the significantly large portion of hydroelectricity in Norway's energy mix ensures a continuous supply of low-carbon electricity. This is expected to result in continuous operation of the PtG system, where both electricity and natural gas is covered under long-term contracts [23]. The continuous operation mode would help lead to a significantly large utilization rate, assumed to be 90%, while also diminishing the need for gas storage facilities. Consequently, no CAPEX or OPEX has been assumed towards storage.

3.4. Sensitivity Analysis

A sensitivity analysis has been performed around key parameters to evaluate the impact of a step change of 10% in parameter value on GPC. Unless specified, a range of −20% to +20% variation in values of below parameters is analyzed:

- CAPEX: Both electrolyzers and methanation processes have high learning rates, due to which there is significant uncertainty in estimates of future equipment and construction pricing. Furthermore, it has a significant impact on GPC. CAPEX includes both the initial setup costs, as well as costs towards electrolyzer stack replacement.
- OPEX: The overall operating expenses are expected to decrease due to improving technology, but can also increase, depending on site-specific conditions, the labor market, land lease and other macroeconomic variables.
- Electricity Price: Electricity is the main energy input in the PtG process, and hence a key variable for the sensitivity analysis. Statnett's long-term market analysis also states that Norway's electricity pricing is expected to become more volatile over the coming years [50], which further highlights the necessity for a sensitivity analysis.
- Utilization Rate: The realized production of SNG is based on the overall utilization rate of the PtG facility, which can go up or down based on availability of electricity and system maintenance requirements. Since the base utilization rate is significantly high at 90%, a sensitivity range of only +10% to −20% is considered. The corresponding range of utilization rate is 72% to 99%.
- Discount Rate: The discount rate will be dependent on both market conditions and the individual investor. It is expected to be lower for state-owned utilities, and higher for private small companies. Additionally, a low interest rate regime is expected to

decrease the discount rate. A sensitivity analysis has been carried out to isolate these impacts on GPC.

The price of CO_2 is not considered in the sensitivity analysis since it is not the principal focus of this study. The STORE&GO study has estimated the cost to capture CO_2 from various industrial and biogenic sources [36]. However, the actual cost incurred will depend on a mix of capture cost, transportation cost and regulatory policies. In Norway, industrial CO_2 emitters need to pay the Norway carbon tax and EU ETS, resulting in ~110 €/ton of CO_2 emitted [59]. Since emission tax price is higher than the cost to capture CO_2, emitters in Norway might be willing to pay for capture and transportation. However, this needs to be analyzed on a case-by-case basis.

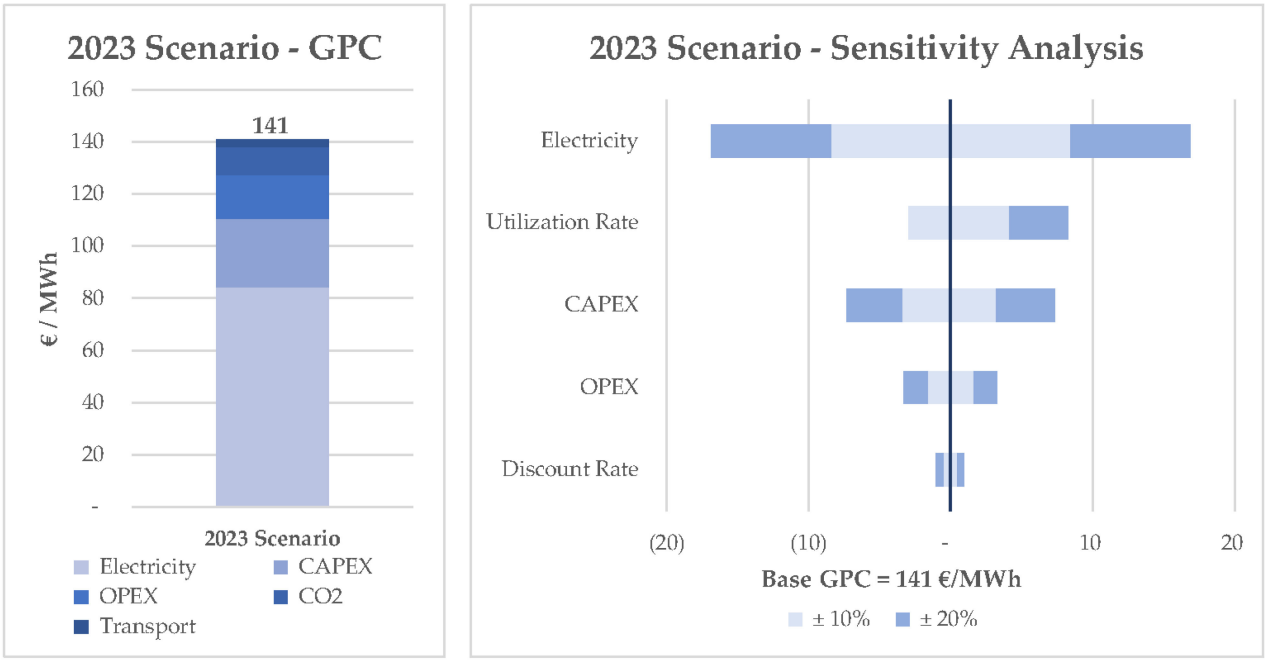
4. Results

4.1. 2023 Scenario

The GPC for SNG is estimated to be 141 €/MWh_{SNG} for the 2023 scenario (Table 4, Figure 4a). Energy is the key cost contributor, making up around 60% of the total cost. CAPEX and OPEX are responsible for nearly 30% of the cost, and CO_2 and transportation make up the last 10%.

Table 4. Gas Production Cost for 2023 Scenario.

2023 Scenario	Levelized Cost (€/MWh_{SNG})	% of Total Costs
Electricity	84	60%
CAPEX	26	19%
OPEX	17	12%
CO_2	11	8%
Transport	3	2%
Total	**141**	**100%**



(a) (b)

Figure 4. Results for 2023 Scenario: (**a**) GPC buildup; (**b**) sensitivity analysis for various parameters, the values on *y*-axis represent change in GPC in €/MWh_{SNG} for a 10–20% change in parameter values.

The sensitivity analysis (Figure 4b) finds that electricity price has the highest impact on GPC, which is expected given its substantial share in overall costs. A 10% change in electricity price impacts the GPC by 8 €/MWh_{SNG}. Utilization Rate and CAPEX are the next most impactful parameters, where a 10% variation leads to a ~4 €/MWh_{SNG} change in GPC. However, there is limited scope for increase in utilization rate since it is already at 90%. OPEX and the discount rate are the least important amongst all the studied variables, affecting the GPC by less than 2 €/MWh_{SNG} for a 10% change.

4.2. 2030 Scenario

The GPC for the large-scale 2030 scenario is estimated to be 108 €/MWh_{SNG}. The nearly 25% reduction from 2023 GPC is attributable to decline in costs for electricity (Figure 5), CAPEX and OPEX. Even though electricity costs decline on an absolute basis, its overall share in the total costs is predicted to increase to 63%. This is likely due to the relatively higher learning rates of electrolysis and methanation, which reduces CAPEX and OPEX more significantly as compared to the drop in electricity prices. Subsequently, the contribution of CAPEX and OPEX reduces to only 25%, while the share of CO_2 and pipeline transportation costs increases to 12%. (Table 5 and Figure 6a)

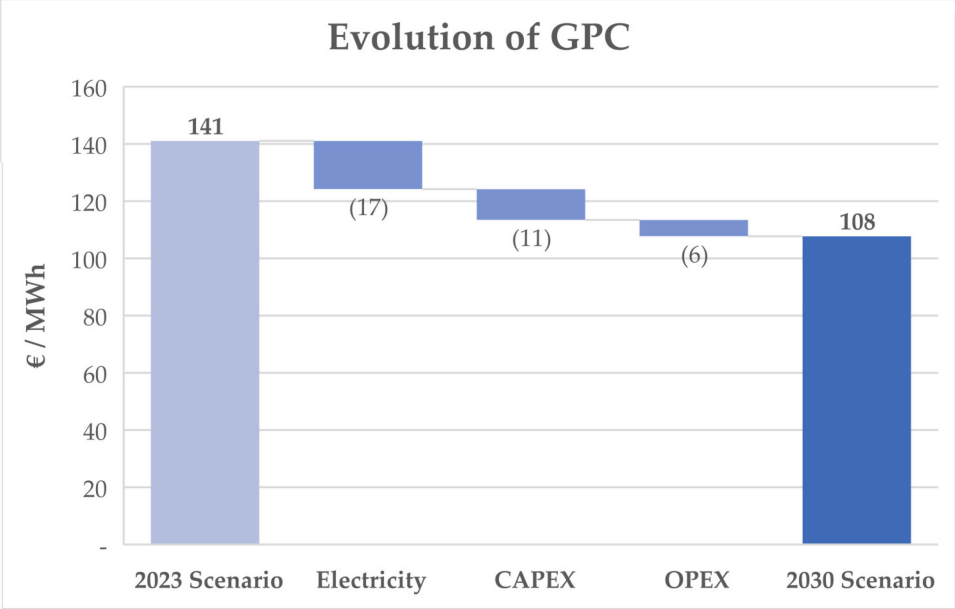


Figure 5. Waterfall diagram highlighting main cost updates between 2023 and 2030 scenarios. On a levelized basis, decline in electricity costs lead to the largest decline of 17 €/MWh, followed by CAPEX reductions of 11 €/MWh and OPEX reductions of 6 €/MWh.

Table 5. Gas Production Cost for 2030 Scenario.

2030 Scenario	Levelized Cost (€/MWh)	% of Total Costs
Electricity	67	63%
CAPEX	16	15%
OPEX	11	10%
CO_2	11	10%
Transport	3	2%
Total	**108**	**100%**

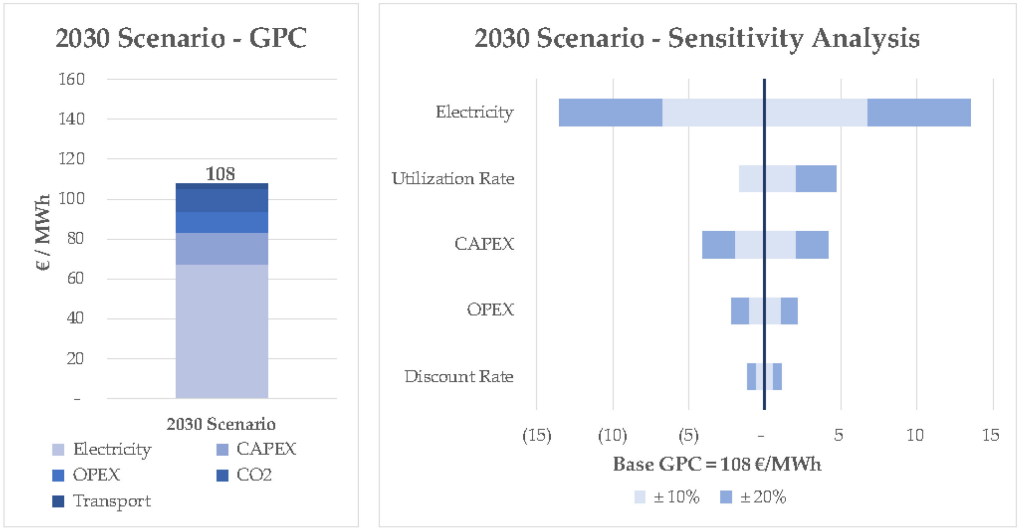


Figure 6. Results for 2030 Scenario: (**a**) GPC buildup; (**b**) sensitivity analysis for various parameters, the values on y-axis represent change in GPC in €/MWh_{SNG} for a 10–20% change in parameter values.

The parameter sensitivity (Figure 6b) follows a similar pattern as the 2023 scenario, though the volatility in GPC is lower due to a decline in the total cost. A 10% change in electricity price impacts the GPC by 7 €/MWh_{SNG}. Additionally, a 10% variation in utilization rate and CAPEX changes GPC by 2 €/MWh_{SNG}, while the same change in OPEX and discount factor only impacts the GPC by 1 €/MWh_{SNG}. It is interesting to note that the impact of CAPEX and OPEX is halved compared to the 2023 scenario due to high technology learning rates. Furthermore, a 12% reduction in electricity costs is required to achieve a GPC of less than 100 €/MWh_{SNG}.

5. Discussion

The disruption in Russian natural gas supplies led to unprecedented gas prices in Europe (TTF prices), averaging above 100 €/MWh in Q1 and Q2 of 2022 [60,61]. The average TTF price further increased to 185 €/MWh in Q3-2022, touching an all-time high of 340 €/MWh on 26 August 2022 following Gazprom's announcement of unplanned maintenance on the Nord Stream pipeline system [62]. The soaring gas prices have also led to a steep decline in fertilizer production, which is expected to accelerate food inflation [63]. While the TTF price is unlikely to stay at such high levels in the coming months as LNG imports replace Russian gas [64], geopolitical and meteorological uncertainty could still drive high price volatility. Furthermore, countries in central and eastern Europe lacking regasification facilities, which are necessary to import LNG, will still need to pay an additional premium over TTF prices [62].

Amidst this backdrop, the proposed PtG system could be a reliable source of "clean" natural gas. The estimated GPC for the 2023 scenario, 141 €/MWh, is well below the Q3-2022 average price and could make economic sense for industries in central Europe seeking a reliable and carbon-neutral source of fuel. The decline in electricity and equipment costs is expected to further lower the GPC to 108 €/MWh for a large scale PtG facility in Norway by 2030.

The result is aligned with previously conducted studies. Data from the pilot plants under STORE&GO project suggest that cost to produce SNG from the grid in 2030 will vary between 90–125 €/MWh depending on taxes, charges and network tariffs [65]. Bohm et al. [20] determined that large scale PtG plants will be able to reach production costs of 100 €/MWh by 2030 over a broad range of operating hours based on an optimized electricity purchasing strategy. Gorre et al. [23] estimate a GPC of 119 €/MWh for an

average electricity price of 50 €/MWh_{el}. Jiang et al. [28] estimate a GPC of 118 €/MWh for operations in Northwestern China.

However, this steep reduction in SNG prices might still not be sufficient. In the long term, European gas prices are likely to trend towards prices of imported US LNG, which have varied between 15–30 €/MWh prior to COVID [66]. Assuming that the nominal US LNG prices reach 20–40 €/MWh based on an average inflation of 2.5%, SNG at 103 €/MWh will be much more expensive and economically unfeasible. A study by Guilera et al. suggests that in a feasible future scenario, SNG can be produced for just 40 €/MWh in countries such as Germany and Spain [67]. Section 5 lists potential areas of future research which could help reduce SNG prices even further. A similar or even lower cost might be feasible for SNG production in Norway, making it competitive with US LNG and paving the path for large-scale deployment of PtG facilities.

6. Conclusions

The study concludes that high natural gas prices in Europe due to recent geopolitical issues make it economically attractive to produce SNG using PEM electrolysis and chemical methanation in Norway. This could help attract investment from industry to further develop PtG technology and reduce associated costs.

In the mid- to long term, lower SNG production costs will be needed to compete with natural gas prices. Future studies could explore dedicated wind/solar energy facilities in Norway to feed the PtG system. Given the steep decline anticipated in renewable costs [68], a dedicated plant could reduce electricity price significantly. However, the intermittency of renewable generation will reduce utilization rate and could necessitate additional investment to store hydrogen and natural gas. The design and location of PtG systems will have to be optimized to achieve lowest GPC.

Additionally, PtG systems present additional monetization opportunities through oxygen generated during electrolysis and the high temperature heat generated during catalytic methanation. These could effectively lower the GPC.

Lastly, regulatory support could be a significant driver of reduction in GPC. There is a significant global impetus on transitioning to a hydrogen-based economy and more than 30 major countries, including Norway, have announced commitments to developing their local hydrogen production [41]. Additional support for generating hydrogen through investment grants and production credits could help scale SNG production in Norway. Furthermore, credits for using low-carbon fuel could make SNG competitive. SNG production in Norway is expected to generate carbon-neutral methane, avoiding release of ~189 kg of CO_2 per MWh of natural gas. Thus, a credit of 100 €/ton of CO_2 avoided could lower GPC by 19 €/MWh.

Given the EU's strong focus on securing clean and affordable energy, enabling policies such as the ones discussed above could make SNG more competitive as compared to imported LNG.

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