Renewable Power-to-Gas: A Technical and Economic Evaluation of Three Demo Sites Within the STORE&GO Project

Ruth Schlautmann[1,*], Hans Böhm[2], Andreas Zauner[2], Friedemann Mörs[1,3], Robert Tichler[2], Frank Graf[1,3], and Thomas Kolb[1,3]

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For a successful energy transition, Power-to-Gas (PtG) offers the opportunity to convert renewable electricity to substitute natural gas. This renewable synthetic natural gas (SNG) can be used for long-term storage, transport, or can be integrated into other energy sectors. Main challenges for the commercial application of PtG are to achieve a high PtG process efficiency, dynamic operation capability, and low investment and production costs. Within the STORE&GO project, three demo sites were developed, operated, and evaluated. An overall efficiency of > 75 % is possible, the SNG production costs are expected to drop to less than 10 €-Cent kWh^{-1} in 2050.

Keywords: Demo sites, Dynamic operation, Efficiency, Future cost development, Investment costs, Power-to-Gas, Production costs

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1 Introduction

Within the energy transition, an increase in the share of renewable energies (RE) to 32 % of the total electricity consumption (3000 TWh in 2018) is being targeted by the EU until 2030 [1–4]. In addition, the decarbonization of the energy system and the industrial sector is being driven forward. To ensure efficient usage of RE, various energy sectors, i.e., electricity, gas, heat, and fuels must be integrated, and sector coupling technologies must be enhanced [5, 6]. By means of Power-to-Gas (PtG) applications, electricity from RE can be converted into gaseous energy carriers and, hence, used for manifold applications like long-term storage of RE, load balancing of electricity grids, as feedstock or fuel to the industrial sector, and as fuel in the mobility sector [7–9]. This article focuses on the evaluation of PtG processes with respect to different methanation technologies. In the first step of the PtG process, electrical energy is converted to hydrogen (H_2) via electrolysis. Subsequently, H_2 reacts with carbon dioxide (CO_2) to form methane (CH_4), i.e., synthetic natural gas (SNG) and water (H_2O) (Eq. (1)). The stoichiometric CO_2 methanation is highly exothermic and releases 165 kJ mol^{-1} heat, which has to be removed from the reactor to ensure stable operation. The methanation technologies in general can be broadly divided into two categories: catalytic (metallic catalyst) and biological (biocatalyst) methanation [7, 10]. For the catalytic methanation (CM), a nickel-based catalyst is used, whereas Archaea are used as biocatalyst for biological methanation (BM). Archaea are unicellular microorganisms that work under anaerobic conditions at moderate temperatures ($T < 100\,°C$).

$$\begin{aligned} &CO_2(g) + 4H_2(g) \rightleftharpoons CH_4(g) + 2H_2O(g) \\ &\Delta H_r^0 = -165.1\ \text{kJ mol}^{-1} \end{aligned} \tag{1}$$

The integration of PtG-plants into the European energy system and, more importantly, its market launch must take into account certain technical, economical, and legal

[1]Ruth Schlautmann, Friedemann Mörs, Dr. Frank Graf, Prof. Dr.-Ing. Thomas Kolb
schlautmann@dvgw-ebi.de
DVGW-Forschungsstelle am Engler-Bunte-Institut des Karlsruher Institut für Technologie, Engler-Bunte-Ring 1, 76131 Karlsruhe, Germany.

[2]Hans Böhm, Andreas Zauner, Dr. Robert Tichler
Energieinstitut an der Johannes Kepler Universität Linz, Altenberger Straße 69, 4040 Linz, Austria.

[3]Friedemann Mörs, Dr. Frank Graf, Prof. Dr.-Ing. Thomas Kolb
Karlsruher Institut für Technologie, Engler-Bunte-Institut, Chemische Energieträger – Brennstofftechnologie, Engler-Bunte-Ring 1, 76131 Karlsruhe, Germany.

considerations. To operate PtG plants commercially, the following aspects need to be ascertained [7]: high efficiencies of the overall PtG process, dynamic operation capability, and low investment and production costs.

To increase the efficiency as well as to reduce the costs of PtG plants, many research activities are ongoing. Wulf et al. [11] estimate that about 120 PtG pilot and demonstration projects were launched in Europe by 2017. Worldwide, 153 completed, recently started, or planned PtG projects are estimated [12]. In 2019, 95 plants were operated globally. The share of methanation plants on the PtG plants was about 40 % (38 projects) divided equally between biological and catalytic methanation [12]. Current methanation projects reach an average efficiency of 41 % (refer to LHV; electricity to methane) [12]. Additionally, there is a lack of investigation regarding dynamic operation of the PtG or methanation plants. It would be an advantage if the mode of operation of the PtG plant is adapted to synchronize with power peaks and load changes in the electricity grid. Such a strategy, e.g., minimizes the need of H_2 storage leading to lower capital expenditure (CAPEX) [9]. Furthermore, the data evaluating the CAPEX of PtG plants are still uncertain and often extrapolated from laboratory results. The CAPEX figures can broadly vary between 190 € kW^{-1} and 1500 € kW^{-1} based on SNG output [13–17]. Also, future cost reduction due to process improvements, economies of scale, and economies of scope must be considered [12, 18].

In the European project STORE&GO (www.storeandgo.info), these challenges have been addressed. In this project, 27 partners from six European countries successfully investigated different technical, economic, ecological, and legal aspects of implementation of PtG [19]. Here, the integration of decarbonized gas into the current energy infrastructure of the EU was assessed and approaches for future energy supply were formulated. In addition, a key focus area of the project was the development and evaluation of three innovative PtG demonstration sites for the production of SNG or liquefied (synthetic) natural gas (LNG). Therefore, three different methanation concepts were implemented. Further, measurements were carried out on these plants for evaluating various aspects. The demo sites were located in Falkenhagen (Germany), Solothurn (Switzerland), and Troia (Italy) [19]. Based on the results, recommendations for the integration of PtG plants into future energy systems were determined.

This article gives an overview of the results of the process evaluation and cost calculations for the demo sites. Fig. 1 outlines the evaluation approach within the STORE&GO project. The focus of the technical evaluation is the reactor performance with respect to dynamic operation and overall PtG process efficiency. Furthermore, an estimation of investment costs was performed. These cost calculations are based on operated demo sites and, therefore, provide a more reliable estimation of the CAPEX. Due to operation experience, technical and economical optimization potentials for the three PtG concepts are pointed out. Furthermore, the estimation of SNG production costs is performed and the future cost development is analyzed.

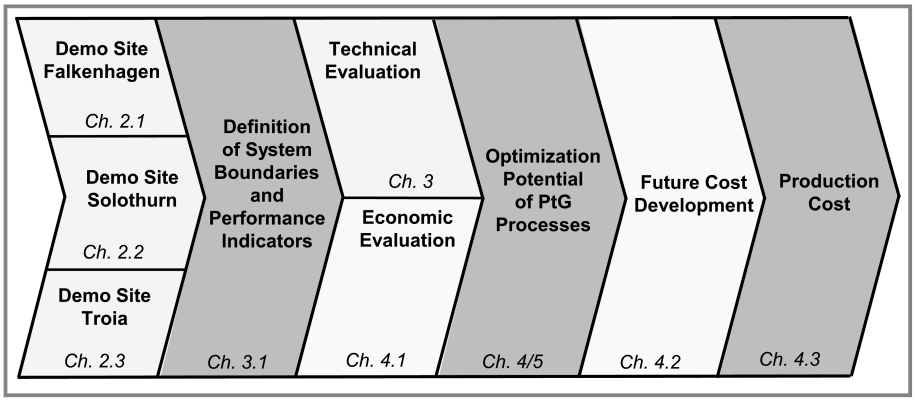

Figure 1. Approach of the PtG process evaluation within the STORE&GO project.

2 Overview on STORE&GO Demo Sites

The construction and operation of three different PtG demo sites was one core objective of the STORE&GO project. In general, each demo site consists of the core technologies: CO_2 conditioning, electrolysis, methanation, and injection/liquefaction. The focus of the project was designing and testing of three different methanation technologies and the overall evaluation of the PtG process at each demo site. CM was performed in a honeycomb and a milli-structured reactor and BM in a stirred bubble column. An overview of the technical data of the demo sites is given in Tab. 1.

2.1 Catalytic Honeycomb Reactor in Falkenhagen PtG Plant

At the Falkenhagen PtG plant (see block flow diagram in Fig. 2), an innovative catalytic honeycomb methanation reactor was tested with a maximum synthetic natural gas (SNG) output of 576 kW. The required hydrogen was delivered by an on-site alkali electrolysis (AEL). At full load, the AEL fed a volumetric hydrogen flow $\dot{V}_{H_2,STP}$ = 210 m^3h^{-1} into the methanation reactor (STP, T_{STP} = 0 °C, p_{STP} = 1.01325 bar). CO_2 for the methanation was supplied in liquid form from a bioethanol plant. Originally, it was planned to use a biogas plant nearby as CO_2 source. Therefore, in the following calculations of the performance indicators (PIs), an absorption process of biogas is assumed

Table 1. Technical data of the demo sites within the STORE&GO project.

Methanation reactor	Falkenhagen	Solothurn	Troia
	Catalytic honeycomb reactor [20]	Biological stirred bubble column [21, 22]	Catalytic milli-structured reactor
Nominal volumetric input flow of H_2 $\dot{V}_{H_2,STP}$ [m^3h^{-1}]	210	120	40
CO_2 source	bioethanol plant	wastewater treatment plant	direct air capture (DAC)
Nominal volumetric input flow of CO_2 $\dot{V}_{CO_2,STP}$ [m^3h^{-1}]	52.5	30	10
Operation pressure reactor [bar]	14	11	4
Operation temperature reactor [°C]	220 (oil cooling), approx. 350 (catalyst)	62	290–310
Further process units	polishing reactor, drying	membrane unit (optional), drying	membrane separation, drying
Heat usage	Veneer mill	district heating	heat integration with DAC
Injection/liquefaction	injection into a transportation grid ($p > 45$ bar)	injection into a distribution grid ($p = 4$ bar)	liquefaction
Operating hours [h]	1186	1299	824
Produced SNG/LNG [kg]	11 367	11 165	441

for CO_2 conditioning. The methanation unit was designed as two-stage catalytic methanation with a stoichiometric input of $y_{H_2}/y_{CO_2} = 4$. The first reactor stage consisted of a metallic honeycomb reactor (multi-tube structured reactor) coated with a commercially available Ni-based catalyst. The second reactor stage was a fixed bed polishing reactor and served to reach the required product gas quality for injection into a high-pressure transportation pipeline ($p > 45$ bar). The reaction heat was used in a nearby veneer mill. Within the STORE&GO project, the Falkenhagen PtG plant was operated for 1186 h (CO_2 supply) and the injection time was 668 h.

2.2 Biological Stirred Bubble Column in Solothurn PtG Plant

At the PtG plant Solothurn (see block flow diagram in Fig. 3), the SNG was produced by a biological stirred bubble column. Here, CO_2 and H_2 were metabolized by a biocatalyst (Archaea) to CH_4 and H_2O at a temperature of 62 °C and 11 bar [23]. Subsequent to the BM, a H_2S removal and a drying column were installed. To operate the plant at full load, the microorganisms need time to grow. Hence, during commissioning, the volumetric input flow (load) was gradually increased, so that the Archaea had time to be cultivated. After almost 1000 h of operation, the PtG plant could be operated at full load. The maximum SNG output of the plant in Solothurn was 326 kW. The PtG plant was embedded into an existing energy plant (hybrid plant). H_2 was provided by proton exchange membrane (PEM) electrolysis, which was already available at the location. The volumetric input flow of H_2 into the biological methanation reactor was $\dot{V}_{H_2,STP} = 120\ m^3h^{-1}$ at full load. A nearby wastewater treatment plant served as CO_2 source. CO_2 was transported via pipeline to the PtG plant and compressed to the methanation pressure. The SNG was injected into a distribution grid at 4 bar. The low temperature waste heat (T_{use} = 48 °C) from the PEM was dissipated via a heat pump at a district heating grid. The methanation unit was also designed to use the reaction heat from the BM reactor (T_{use} = 50 °C) in the same way. The PtG plant Solothurn operated 1299 h in total, with 1057 h of injection into the grid.

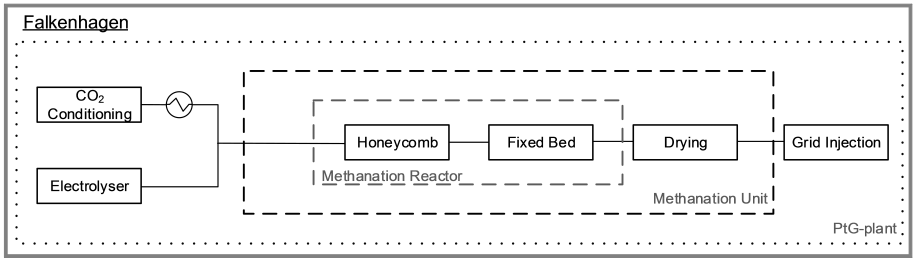

Figure 2. Block flow diagrams of the demo site Falkenhagen including the chosen system boundaries (dashed lines) for the technical and economic evaluation.

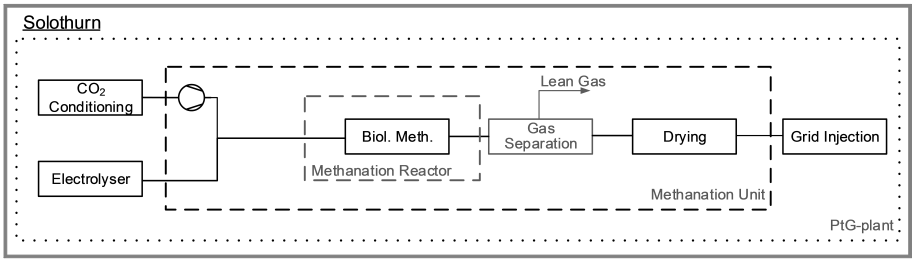

Figure 3. Block flow diagrams of the demo site Solothurn including the chosen system boundaries (dashed lines) for the technical and economic evaluation.

2.3 Catalytic Milli-Structured Reactor in Troia PtG Plant

The plant in Troia is an innovative PtG concept consisting of a catalytic milli-structure methanation reactor, a direct air capture (DAC) unit, and a liquefaction unit (Fig. 4). This design ensures a flexible operation independent of local gas infrastructure and CO_2 point sources. The maximum SNG/LNG output of the PtG plant was 112 kW. H_2 was delivered by an AEL electrolysis already implemented at the site. The volumetric input flow of H_2 into the reactor was 40 m^3h^{-1} at full load. The volumetric input flow of CO_2 was delivered by the on-site DAC plant. The reactor concept in Troia included only one methanation stage. Due to the structured packing of 56 small channels filled with catalyst in the reactor, the heat transfer was efficient and high rates of conversion were possible. After the methanation unit, the product gas was cooled down to condense the produced water. Thereafter, the remaining H_2 and CO_2 in the product gas were separated by a subsequent membrane unit and recycled into the reactor. In contrast to the Falkenhagen and Solothurn plant, the produced SNG was liquefied via a reversed Stirling cycle. To reach the specification for the liquefaction process, the SNG was treated by temperature swing adsorption for separation of the remaining CO_2 and H_2 after the membrane separation. Within the STORE&GO project, the methanation unit in Troia was operated for 824 h.

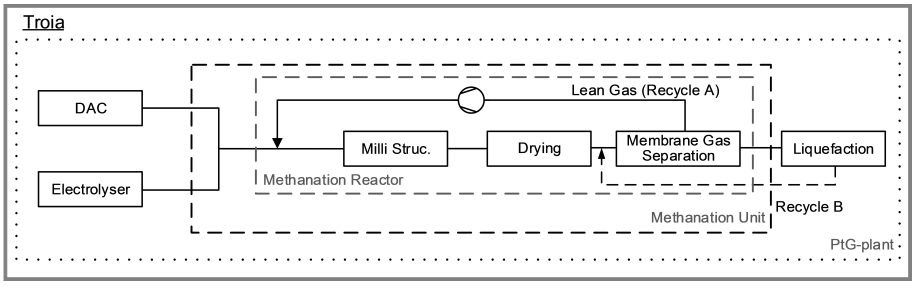

Figure 4. Block flow diagrams of the demo site Troia including the chosen system boundaries (dashed lines) for the technical and economic evaluation.

3 Technical Evaluation of the Demo Sites

For the technical evaluation of the three PtG plants, performance indicators (PI) were calculated based on measurement data. Therefore, measurements were taken at highest possible load during constant operation. To ensure constant operation, the standard deviation of the data was checked. In Falkenhagen, the evaluation was based on measurement data at 95 % load ($\dot{V}_{H_2,STP}$ = 200 m^3h^{-1}). In Solothurn, constant operation could only be achieved at about 75 % load ($\dot{V}_{H_2,STP}$ = 90 m^3h^{-1}). In Troia, the calculation of the PIs was based on measurement data, which were taken at constant operation (20 h) at 80 % load ($\dot{V}_{H_2,STP}$ = 32 m^3h^{-1}). Based on constant operations, the following PIs were chosen for technical evaluation: conversion X_i, gas hourly space velocity (*GHSV*), and overall process efficiency of the PtG demo site.

Additionally, the dynamic operation capability based on load changes of the demo sites was tested. Here, dynamic test profiles were used based on volumetric H_2 input flow ($y_{H_2,in}/y_{CO_2,in}$ = 4) and a load change rate (*LCR*) was defined.

3.1 Definition of Performance Indicators

To calculate the PIs, the general energy streams of a PtG plant and the system boundaries for the different demo sites must be defined. As described above, each demo site consists of four core process units (CO_2 conditioning, electrolysis, methanation unit, and injection/liquefaction unit). Depending on the PIs, different system boundaries were chosen for the evaluation (see Figs. 2–4).

To evaluate the performance of the methanation reactors, the conversion X_i with regard to CO_2 or H_2 (Eq. (2)) and the *GHSV* (Eq. (3)) are calculated. Therefore, the gray dashed system boundaries (methanation reactor) shown in the block flow diagrams (Figs. 2–4) are chosen. In Troia, the evaluation of the reactor performance also includes the gas recycle besides the methanation reactor.

$$X_i = \frac{\dot{N}_{i,in} - \dot{N}_{i,out}}{\dot{N}_{i,in}} \quad (2)$$

For the calculation of the *GHSV* (Eq. (3)), the volumetric input flow $\dot{V}_{in,STP}$ into the reactor is related to the catalyst volume V_{cat}. The catalyst volume depends on the reactor design. In

Falkenhagen and Troia, the tubes coated/filled with catalyst are defined as catalyst volume. Whereas in Solothurn, the volume of the bubbly flow (liquid and gas) is defined as catalyst volume. A more detailed description of the catalyst volume in the different methanation reactors can be found in [24].

$$GHSV = \frac{\dot{V}_{\mathrm{in,STP}}}{V_{\mathrm{cat}}} \tag{3}$$

For the dynamic operation, load changes were performed for each PtG plant according to a defined load profile. The *LCR* is referred to the transient volumetric input flow of H_2 $\dot{V}_{H_2,STP}$. To examine the influence of load changes on SNG composition, specified *LCR* values were applied to the reactor. Subsequently, a possible effect of load changes on the quality of the product gas, e.g., y_{CH_4}, was carefully monitored to ensure high quality of the product gas.

$$LCR = \frac{\frac{\partial \dot{V}_{H_2}}{\partial t}}{\dot{V}_{H_2,\mathrm{full\ load}}} \tag{4}$$

One of the major aspects in technical evaluation of the PtG plant is the calculation of its overall process efficiency (Eq. (5)). A general approach for the evaluation of the efficiency of PtG plants is given in [25, 26]. For the evaluation of the demo sites, the input and output energy flows (for chemical ($\dot{E}_{i,ch}$), electrical (P_{el}), and thermal ($\dot{E}_{th}$) energy) of the core technologies must be considered. Fig. 5 shows a general overview of the energy streams of a PtG plant. The chemical energy flows ($\dot{E}_{i,ch,in}$, $\dot{E}_{i,ch,out}$) are based on the higher heating value (HHV_i).

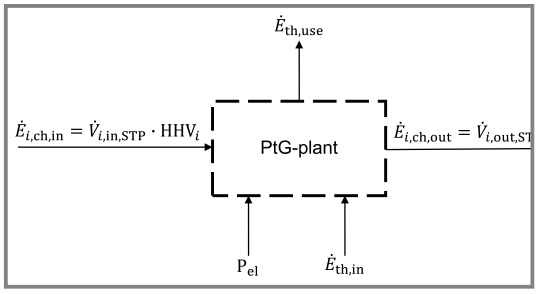

Figure 5. Overview of the general energy flows of a PtG plant.

For the calculation of energy output flow of the SNG $\dot{E}_{SNG,ch,out}$, only the produced methane is considered. A remaining H_2 fraction in the product gas is neglected. The energy input flow of H_2 ($\dot{E}_{H_2,ch,in}$) includes the efficiency of the electrolysis. The thermal energy flows $\dot{E}_{th,use,Meth}$ and $\dot{E}_{th,use,Ely}$ indicate the usage of the methanation heat and the waste heat of the electrolysis, respectively [24].

$$\eta_{PtG,HHV,ov} = \frac{\dot{E}_{SNG,ch,out} + \dot{E}_{th,use,Meth} + \dot{E}_{th,use,Ely}}{\frac{\dot{E}_{H_2,ch,in}}{\eta_{Ely}} + P_{el,Meth} + \dot{E}_{th,CO_2-Con} + P_{el,CO_2-Con} + P_{el,Inj/Liq}} \tag{5}$$

3.2 Conversion and *GHSV*

In general, each methanation technology (gray dashed system boundaries) provided high overall CO_2 conversion rates X_{CO_2} of more than 99 %, which led to high methane fractions in SNG ($y_{CH_4} \geq 96$ vol %). In Falkenhagen and Solothurn, an even higher methane fraction of $y_{CH_4} > 99$ vol % could be achieved. The demo site-specific requirements on the product gas, e.g., injection, could be fulfilled at all demo sites. Also, LNG production of produced SNG via methanation could be shown. However, if higher H_2 volume fractions in the grid would be permitted, the reactor size could be reduced or even a single stage process would be possible.

In Falkenhagen, the total $GHSV_{Falkenhagen}$ (both reactors) was calculated to be 500 h^{-1} for the chosen measurement (97 % load) point. Thereby, the $GHSV_{honeycomb}$ of the first stage (honeycomb reactor) was determined to be 732 h^{-1}. Furthermore, lab tests had shown that by adjusting the design of the honeycombs, the radial heat transfer could be improved. Additionally, the length of the catalyst-coated channel could also be reduced. Both optimization measures would lead to a significant higher $GHSV_{honeycomb}$ of 7000 h^{-1}, which is significantly higher in comparison with literature data [24]. Depending on the reactor concept, *GHSV* values between 500 and 5000 h^{-1} are indicated in literature for the catalytic methanation [10, 22].

In Solothurn, $GHSV_{Solothurn}$ was determined to be 31 h^{-1} for the chosen measurement point at xxx % load. At maximum load, $GHSV_{Solothurn}$ was increased to nearly 40 h^{-1}. Compared to the demo plant of ©Viessmann Werke GmbH & Co. KG (BioPower2Gas), the *GHSV* is almost 3 times higher ($GHSV_{BioPower2Gas}$ = 15 h^{-1}) [27]. Additionally, according to Electrochaea GmbH, the reactor was oversized in Solothurn and $GHSV_{Solothurn}$ could be further increased to 80 h^{-1} [28].

For the chosen measurement point, $GHSV_{Troia}$ was calculated to be 9100 h^{-1} for the PtG plant in Troia. Increasing the load to 100 %, $GHSV_{Troia}$ would increase to 11 400 h^{-1}. For the determination of $GHSV_{Troia}$, only the feed (y_{H_2}/y_{CO_2} = 4) without recycle was considered. Due to the definition of the catalyst volume (only milli-structured tubes), $GHSV_{Troia}$ was quite high. The housing of the reactor was neglected. However, it must be considered that the manufacturing of the reactor and the replacement of the catalyst are elaborate. In addition, there is no scale-up procedure pointed out for the reactor. For higher SNG production capacities, the reactor has to be numbered-up.

3.3 Dynamic Operation

For the Falkenhagen plant, load changes between 40 and 100 % were realized. Fig. 6 shows measurement data for a load change from 71 to 81 % load. The average *LCR* according to the volumetric input flow of H_2 was taken as

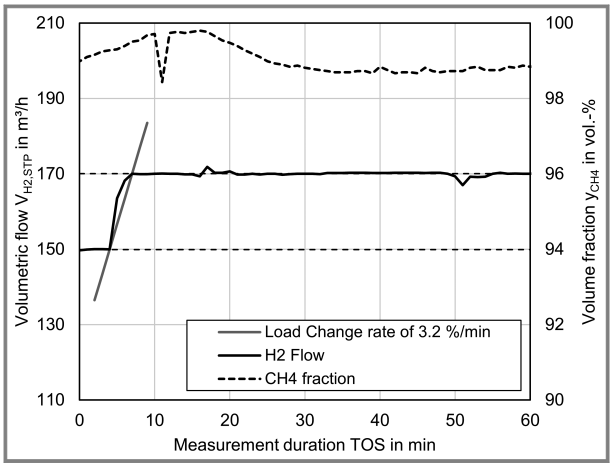

Figure 6. Analysis of the load change rate of the Falkenhagen demo site based on measurement on January 28, 2020. Load change from 71 to 81 %.

3.2 % min^{-1}. The methane fraction was not affected significantly during the load change and remained at a high level above 98 vol %. Based on the results, it can be assumed, that higher *LCR* values could be applied to the reactor without losses in the product gas quality. This corresponds with results from the Zentrum für Sonnenenergie- und Wasserstoff (ZSW) for a tube bundle methanation reactor [9, 29].

For the demo site in Solothurn and in Troia, load changes between 20 and 100 % could be achieved with a constant product gas quality. Even load changes at lower loads were feasible. For example, a load change rate of 5.5 % min^{-1} was applied from hot standby to 60 % load without losses of the product gas quality in Solothurn. Also, in Troia, an *LCR* of about 5 % min^{-1} could be reached without losses on gas quality.

In conclusion, a dynamic operation could be demonstrated for the three demo sites with *LCR* values up to 5 % min^{-1}, which is in the order of the *LCR* of conventional gas-steam power plants [30]. The results show the feasibility of a dynamic operation for the methanation. Thus, the costs could be optimized by avoiding high H_2 storage capacities [9]. However, the start-up procedure of the methanation units must be improved to increase the availability.

3.4 Process Efficiency

In Solothurn, the overall process efficiency of the realized PtG plant $\eta_{PtG,HHV,ov}$ was determined to be 76 %. Due to the local conditions, the energy demand for CO_2 separation and injection could be neglected as CO_2 was a waste product of a nearby wastewater treatment plant. Due to the injection into a distribution grid ($p_{grid} < p_{reactor}$), no additional compression was needed. In addition, the low-temperature waste heat from the electrolysis could be used for district heating by a heat pump system. The example of the Solothurn plant shows that the approach of considering an entire energy system is advisable. By integrating the PtG plant into a local energy system (here hybrid plant) and usage of synergy effects, high energetic efficiencies could be achieved.

In a second step, by optimization of the process in Solothurn, an overall efficiency of 89 % could be reached. The main reason for this increase was the additional usage of the waste heat of the methanation for district heating (T_{use} = 48 °C, about 3.0 kWh m^{-3} based on SNG). The electricity demand of the methanation unit in Solothurn was also reduced to 0.5 kWh m^{-3} (initial energy demand of 1.0 kWh m^{-3}). Gorre et al. indicate the future electrical demand of methanation systems to be 0.28 kWh m^{-3} in 2030 [31]. The results of the STORE&GO project show that such low power consumption can be almost achieved for current small-scale methanation units as well. Considering a PtG plant optimized by scale-up, the estimated electrical demand seems to be accessible. Additionally, the efficiency of the electrolysis regarding H_2 utilization could be improved to 76 % by using a state-of-the-art (StA) electrolysis (current electrolysis η_{Ely,H_2} = 62 %) [32]. However, the potential of heat usage thereby decreased. The optimized overall PtG plant efficiency $\eta_{PtG,HHV,ov,opt}$ remained almost constant since the overall electrolysis efficiency stayed constant ($\eta_{Ely,H_2+therm}$ = 92 %). However, the utilization of electrical energy regarding SNG was improved by using an StA electrolysis unit.

The example of Solothurn shows that in addition to optimizing the efficiency of a PtG plant, an evaluation of the energy use should also be performed. An optimized utilization of electrical energy in form of SNG is worthwhile for a PtG plant since SNG has a higher exergy and can be used more widely, whereas a site-specific evaluation according to heat sinks must be carried out to use waste heat especially at low temperatures.

Furthermore, the optimized overall PtG plant efficiency $\eta_{PtG,HHV,ov,opt}$ was determined to be 69 % for the demo site Falkenhagen and 46 % for the demo site Troia [24]. In Falkenhagen, the following optimization potentials were included into the calculations: StA electrolysis, optimized heat usage of the methanation unit, and usage of low-temperature heat. Due to the small scale of the Troia PtG plant, there was high energetic optimization potential. Hence, the electricity demand of the methanation unit and the liquefaction unit could be reduced by scaling the plant. Furthermore, the chosen plant design offered high potential for heat integration of the methanation and the DAC plant. Thus, the electricity demand of DAC could be reduced from 7.2 kWh m^{-3} to 1.9 kWh m^{-3} [24].

In addition, for CM, the high-temperature steam electrolysis (SOEC) offers the possibility for internal heat integration. This enables to use the reaction heat of methanation for the production of high-pressure steam required in SOEC. By this, the overall efficiency can be optimized with regard to the conversion of electrical energy into SNG. [33]

4 Economic Evaluation of the Demo Sites and Future Costs

This section gives an overview of the economic evaluation of the demo sites. First, the investment costs of the scaled-up PtG plants are determined. Based on the cost estimations, a future cost development is performed. Afterwards, an estimation of the overall production costs is given on the basis of the calculated investment costs.

4.1 Investment Costs of the Methanation Plants

The calculations of the $CAPEX_{Meth}$ (black dashed system boundaries) are based on the add-on factor method. Therefore, the main equipment costs of the methanation unit were calculated based on cost correlation functions [24, 34]. The error applicable in this method, is about 20–30 %. The $CAPEX_{Meth}$ determined in US $ was transferred to € using the average exchange rate of 2017. Furthermore, the costs were adjusted for inflation.

The $CAPEX_{Meth}$ for different configurations of the Falkenhagen plant is shown in Fig. 7. The levelized $CAPEX_{Meth}$ of the realized demo site Falkenhagen is estimated to 3740 € kW^{-1} based on the SNG output. If the plant size based on SNG output is scaled to 5 MW, the $CAPEX_{Meth}$ is reduced to 1430 € kW^{-1}.

The technical evaluation reveals that optimization potential in the reactor and process design has a positive impact on the $CAPEX_{Meth}$. The methanation unit of the Falkenhagen plant could be optimized with respect to the compression of the gas input flow (optimization step 1). By increasing the *GHSV*, the required catalyst amount (optimization step 2) and the reactor size (optimization step 3) can be reduced. In the current plant design, H_2 and CO_2 are mixed and then compressed. By adapting the pressure of the volumetric outlet flow of H_2 from the electrolysis to the methanation reactor pressure, the volumetric input flow into the reactor, which needs to be compressed, could be reduced. Including all optimizations in the $CAPEX_{Meth}$ calculations, the specific $CAPEX_{Meth}$ of a 5-MW plant can be nearly halved to 720 € kW^{-1}. Compared to the averaged $CAPEX_{Meth}$ for a CM of 5 MW SNG output by Zauner et al. [18] (580 € kW^{-1}), the costs are slightly higher for the Falkenhagen plant. However, the given costs are based on the plant's data and give an estimation of the current investment costs. By upscaling to plant sizes up to 50 MW another $CAPEX_{Meth}$ reduction of 50 % (360 € kW^{-1}) is realistic.

The optimized $CAPEX_{Meth}$ for a 5-MW (SNG output) plant based on the Solothurn configuration is 870 € kW^{-1}. Based on the Troia plant, the optimized $CAPEX_{Meth}$ was calculated to 1090 € kW^{-1}. More detailed information about the optimization steps applied on the different demo sites are found in [24].

The $CAPEX_{Meth}$ estimations of the demo sites show that high optimization potential is available. Technical optimizations as well as scale-up of the plant size lead to significant cost reductions for PtG plants. To estimate future cost reduction potential, market potentials and learning curves must be applied to the cost estimations (see Sects. 4.2 and 4.3).

4.2 Future Development of Investment Costs

To assess the future economic performance of PtG, appropriate cost reduction effects have to be assessed for the underlying technologies. On the one hand, this includes technological learning effects induced by increasing production volumes due to growing markets (Eq. (6)). On the other hand, there will be scaling effects with increasing unit capacities of individual PtG plants (Eq. (7)).

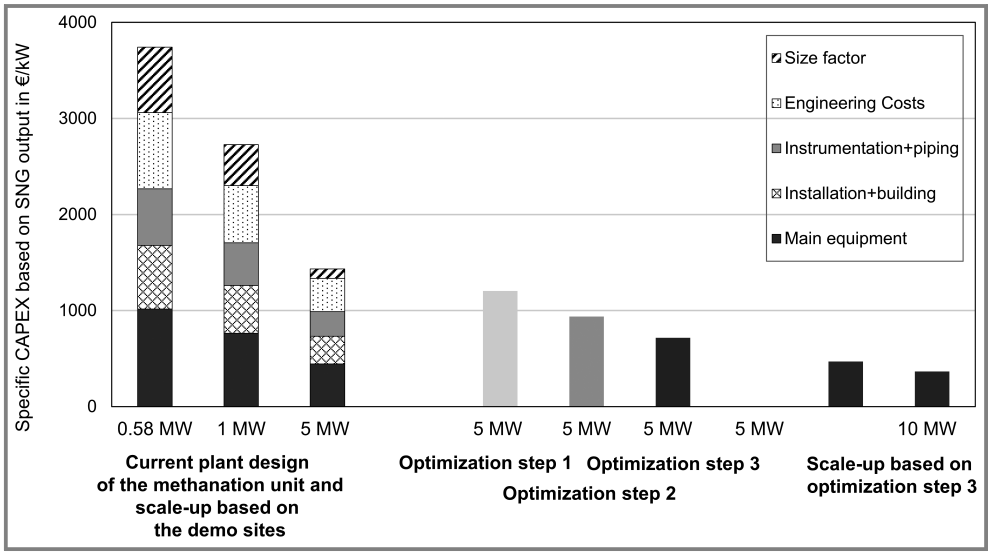

Figure 7. $CAPEX_{Meth}$ calculations for different configurations of the Falkenhagen plant. In a first step, $CAPEX_{Meth}$ was calculated for the demo site. Based on plant design of the demo site, a scale-up to an SNG output of 5 MW was performed. Subsequently, the impact of different optimization potentials on $CAPEX_{Meth}$ was determined. Optimization step 1, reduction of compressor size; optimization step 2, catalyst reduction; optimization step 3, reactor size. Based on the optimized plant design, scale-up was performed.

$$C(X_t) = \sum_{i=1}^{n} C_{0i}\left(\frac{X_t}{X_0}\right)^{-r_i} = C_{01}\left(\frac{X_t}{X_0}\right)^{-r_1} + C_{02}\left(\frac{X_t}{X_0}\right)^{-r_2} + \ldots + C_{0n}\left(\frac{X_t}{X_0}\right)^{-r_n} \quad (6)$$

where X_0 is the cumulative production at time $t = 0$, X_t is the cumulative production at time t, C_{0i} are the costs of component i at time $t = 0$, $C(X_t)$ are the total costs at time t, and r_i is the learning parameter for component i (where $lr = 1 - 2^{-r}$).

$$C_b(S_b) = \sum_{i=1}^{n} C_{ai}\left(\frac{S_b}{S_a}\right)^{f_i} \quad (7)$$

where S_a is the reference scale, S_b is the target scale, C_{ai} are the absolute costs of component i at reference scale, C_b are the absolute total costs at target scale, and f_i is the scaling factor for component i.

Except for individual systems, e.g., AEC, and single commercial installations, PtG as an integrated technology still represents a relatively novel concept, at a technology readiness level of about 5–7 [11]. Thus, an estimation of these cost reduction effects based on past observations and literature data is significantly limited. Consequently, a disaggregated approach, as described by [35], is used to evaluate learning rates on a per component basis for better comparability to well-observed technologies and processes and associated savings. While the calculation models for the electrolysis are directly taken over from [35], the availability of cost data from the STORE&GO demo sites allows for a more detailed analysis of the component and cost structure of the different methanation plants. Based on the investment cost analysis of the plants Falkenhagen (CM) and Solothurn (BM) (see Sect. 4.1), individual scaling factors per component are determined by referring to literature on technical and chemical plant engineering. While scaling effects are mathematically limited in the model for electrolysis stacks, to accommodate technical boundaries of upscaling, limitations were neglected for methanation in accordance with the findings from the demo plants [36].

To evaluate cost reductions through technological learning in an annual context, corresponding market potentials have to be presumed. For these, the theoretical global demand potentials for hydrogen and renewable SNG assessed in the STORE&GO project have been quantified describing a logistic curve (S-shaped curve) and reaching those cumulative target capacities (11.5 TW H_2 and 5.8 TW SNG for the moderate case) in 2050 [37]. Fig. 8 shows the resulting cost ranges for plant capacities of 5–100 MW in the moderate market potential scenarios, revealing significant reduction potentials for CAPEX of individual PtG core technologies. However, it has to be considered that these are highly dependent on the presumed market potentials, especially concerning the course of the development curve. Even though the underlying STORE&GO scenarios are aiming on a more PtG-dependent future energy system compared to previous studies, similar cost levels are reached in the long-term at least for electrolysis systems [36]. Beyond that, considering the recently published EU hydrogen strategy [2], a similarly rapid increase in electrolyzer production will be necessary to follow their ambitious mid-term targets of 6 GW until 2024 and up to 80 GW until 2030, respectively, to serve the EU only. For methanation technologies, learning effects for biological systems are projected to reach 120–310 € kW^{-1} in 2050 – depending on the capacity – and, therefore, be higher than for catalytic systems with 130–290 € kW^{-1}, presuming the given production amounts. Thus, despite costs for the former are found to be higher today, based on the detailed cost structures of the STORE&GO demo plants, both technologies are about to be economically competitive in the long term. Altogether, this would represent cost reduction potentials of about 60–90 % based on the given reference values.

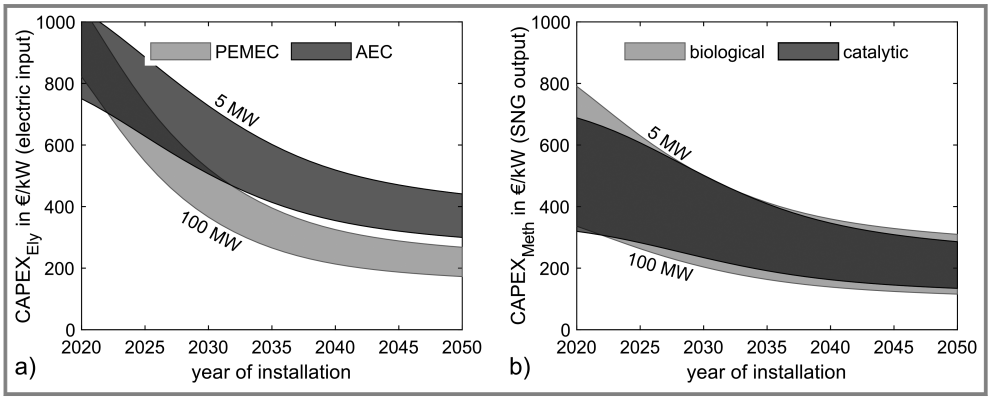

Figure 8. Learning curve and scaling effects for common PtG technologies. a) Electrolysis, b) methanation.

4.3 Future Development of Production Costs for Renewable SNG

The development of future renewable SNG production costs is analyzed on the basis of a PtG plant with a nominal electrical input power of 100 MW, which is powered either by a photovoltaic power plant (PV), a wind power plant (Wind), or by the public power grid (Grid). In addition, different production technologies and combinations, in terms of electrolysis and methanation technologies, for the production of SNG are available.

The specific production costs of renewable SNG are calculated from the total annual costs (using the annuity method following VDI 2067 [38]) in relation to the amount of annually produced energy. The total annual costs include capital-, demand-, operating-related, and other costs. The capital-related costs refer to investment and replacement costs. Annual demand-related costs include energy costs and costs for auxiliary energy. Operating-related costs include annual costs for the maintenance, operation, and cleaning of the plant. Other cost items include insurance, levies, and administration costs.

In Fig. 9, the specific SNG production costs of a PtG plant (reference plant: PEM with a nominal electric input power of 100 MW with subsequent catalytic methanation) powered by different electricity sources in 2020, 2030, and 2050 are shown. In addition, the cost ranges, which result on the one hand from varying technologies and their combination or, on the other hand from the sensitivity of selected parameters (e.g., investment costs, electricity costs, and efficiency) by variation of ±25 %, are indicated. Further, in case the PtG plant is powered from the public power grid, taxes, charges, and network tariffs for PtG plants must be taken into account (summarized as "Grid tariffs"). However, this is only a rough estimation, since there are open questions regarding the current situation (which and in what amount) and, even more so, for the future. Furthermore, CAPEX of the whole PtG plant, electricity energy price (there are no tariffs and taxes included), and full-load hours (*FLH*) of the PtG plant are listed in Tab. 2. In case of PV and Wind, an average location in Austria is considered. For the PV and Wind case, it is assumed that the nominal electric input power of the PtG plant is lower (about 15 %) than the nominal output power of the renewable energy plant and, therefore, comparatively higher *FLH* for the PtG plant are possible. For the Grid case, *FLH* result from an optimized operation in which case the PtG plant is operated at times with the cheapest electricity prices.

The SNG production costs from a PtG plant, which is directly coupled with a photovoltaic power plant, are about 40 €-Cent kWh^{-1} in 2020 (the comparatively high costs are due to low *FLH* and relatively high CAPEX) and will drop significantly in future to about 9 €-Cent kWh^{-1} in 2050. If electricity is obtained from a wind power plant, SNG could already be produced in 2020 at a lower price of about 26 €-Cent kWh^{-1}, whereby the costs do not decrease as much in future, which means that similar costs of about 9 €-Cent kWh^{-1} will be reached in 2050.

As the current legal situation is not yet clearly clarified and the future development of taxes, charges, and network tariffs is difficult to predict, the SNG production costs are divided into two parts (with and without taxes, charges, and network tariffs). Without taxes, charges, and network tariffs (optimal case), the resulting costs are around 12 €-Cent kWh^{-1} for the reference year 2020 and will be more than halved to about 5 €-Cent kWh^{-1} in 2050, which would be significantly lower than for PtG plants directly coupled with PV or Wind. If the development of taxes, charges, and network tariffs is rather unfavorable for PtG plants (conservative case), this will result in higher SNG production costs. However, compared to the case of direct coupling to PV or Wind, the SNG production costs are still significantly lower for the reference year 2020, similar in 2030, and can be significantly higher in 2050.

In principle, it can be stated that the production costs for SNG from PtG plants will fall significantly in future, which is mainly due to falling investment costs and, in the case of PV and Wind, falling electricity costs.

Especially in early applications, the share of investment costs is dominating, and the source of electricity supply has a significant impact on the specific production costs of SNG. In case of Wind and PV, the still high investment costs of the PtG plant in combination with the relatively low reachable *FLH* leads to higher SNG costs. In the future, electricity costs will tend to determine the level of SNG production costs. Therefore, in early applications, PtG plants operated with electricity from the grid will need to run at *FLH* > 5000 h a^{-1} to achieve low SNG production costs. Thereby, the plant is operated only at the lowest electricity prices. In future applications, the lowest costs will be achieved at fewer *FLH* (2000–4000 h a^{-1}). However, several factors, such as the requirement for green gas production,

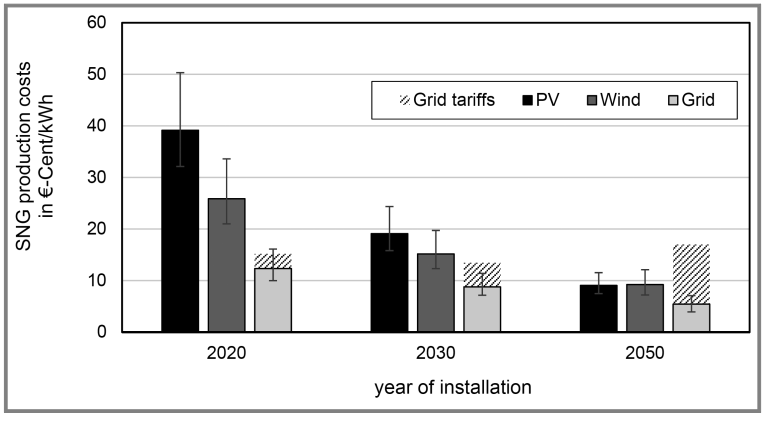

Figure 9. Range of SNG production costs of a 100-MW (nominal electric input) PtG plant in 2020, 2030, and 2050 for different electricity sources.

Table 2. Selected input parameters for the calculation in Fig. 9.

	2020			2030			2050		
	PV	Wind	Grid	PV	Wind	Grid	PV	Wind	Grid
$CAPEX_{PtG}$ [million €]	237	237	237	116	116	116	57	57	57
Electricity energy price (without tariffs and taxes) [€ MWh^{-1}]	40	60	18	30	50	21	20	40	16
Full-load hours PtG plant [h a^{-1}]	1400	3100	6000	1400	3100	4000	1400	3100	3000

may argue for higher full-load hours, albeit with somewhat higher SNG costs.

Sensitivity analyses indicate that reducing SNG costs requires purchasing low-cost electricity, maximizing plant efficiency, reducing investment costs, and in cases where the plant is connected to a PV or wind park, building them in locations where high full-load hours can be reached.

Regarding the influence of the different technologies on the SNG production costs, it can be stated that the technology used for methanation (catalytic or biological) has little influence. However, as stated before, a PtG plant consisting of SOEC and catalytic methanation could tend to have lower SNG production costs in the future due to the high potential for heat integration within the process and, therefore, a higher overall efficiency of the system.

Nonetheless, the development of PtG technology is still fundamentally dependent on energy and climate policy decisions, which has a major influence on the assumed parameters, e.g., development curve of installations, and further on the future SNG production costs calculated from them.

5 Summary and Outlook

This article focuses on the evaluation of the three PtG demo sites built within the STORE&GO project. The main technical aspects, which are described in detail, are reactor performance (conversion and *GHSV*), capability of dynamic operation, and efficiency. A high methane content of the product gas ($y_{CH_4} > 95$ vol %) could be achieved for all three demo sites. *GHSV* depends on the methanation concept. For an optimized reactor concept, a *GHSV* of 80 h^{-1} for a BM and of 7000 h^{-1} for a catalytic honeycomb reactor could be achieved at 100 % load. For testing the dynamic operation of the demo sites, load changes with regard to H_2 input ($y_{H_2,in}/y_{CO_2,in} = 4$) flow were applied. Load changes between 40 and 100 % load were realized for the plant in Falkenhagen. In Solothurn and Troia, even load changes between 20 and 100 % load could be reached. Based on test profiles, *LCR* values of 3–5.5 % min^{-1} were achieved. However, to investigate the impact of load change on the long-term catalyst behavior and the long-term methane concentration, further tests must be performed. Nevertheless, the possibility of dynamic operation for methanation plants generates new opportunities for cost reduction and support load balancing of electricity grids. The calculation of the demo sites' efficiencies shows that it is crucial to implement heat usage. Therefore, PtG plants should be embedded into existing energy systems to use synergy effects. Additionally, high efficiency with regard to the produced SNG and high utilization of electrical energy towards SNG should be targeted. Based on the optimized demo sites' configurations, CAPEX values of the methanation plants were calculated for scaled plants (5-MW SNG output: 720–1090 € kW^{-1}). Based on these results, cost developments were estimated. It was shown that scaling effects and economy of scope have a high influence on the cost development. For example, it is expected that the levelized $CAPEX_{Meth}$ for a CM will be reduced to 290 € kW^{-1} in 2050. The calculation of the production costs (between 12 € kWh^{-1} and 40 € kWh^{-1} for the reference year 2020) shows a strong dependency on electricity price and *FLH*.

Supporting Information

Supporting Information for this article can be found under DOI: 10.1002/cite.202000187. This section includes additional references to cost structures and scaling factors for the investigated methanation plants (see Sect. 4.2).

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Symbols used

C_{0i}	[€]	costs of component *i* at time $t = 0$
C_{ai}	[€]	absolute costs of component *i* at reference scale
C_b	[€]	absolute total costs at target scale
$C(X_t)$	[€]	total costs at time *t*
$\dot{E}$	[kW]	chemical energy flow
f_i	[–]	scaling factor for component *i*

FLH	[h a^{-1}]	full-load hours
$GHSV$	[h^{-1}]	gas hourly space velocity
ΔH_r^0	[J mol^{-1}]	reaction enthalpy at standard temperature and pressure
LCR	[% min^{-1}]	load change rate
$\dot{N}_i$	[mol s^{-1}]	molar flow
p	[bar]	pressure
r_i	[–]	learning parameter for component i (where $lr = 1 - 2^{-r}$)
S_a	[kW]	reference scale
S_b	[kW]	target scale
T	[°C]	temperature
V_{cat}	[m^3]	catalyst volume
$\dot{V}_i$	[$m^3 h^{-1}$]	volumetric flow
X_0	[–]	cumulative production at time $t = 0$
X_i	[%]	conversion
X_t	[–]	cumulative production at time t
y_i	[vol %]	volumetric fraction
η	[%]	efficiency

Sub- and superscripts

ch	chemical
CO_2-con	CO_2 conditioning
el	electrical
Ely	electrolysis
g	gaseous
i	H_2, CO_2, CH_4
in	input
Inj	injection
Liq	liquefaction
meth	methanation
opt	optimized
out	output
ov	overall
STP	standard temperature and pressure
th	thermal

Abbreviations

AEL	alkali electrolysis
BM	biological methanation
CAPEX	capital expenditure
CM	catalytic methanation
DAC	direct air capture
ELY	electrolysis
HHV	high heating value
LNG	liquid natural gas
PEM	proton-exchange-membrane electrolysis
PI	performance indicators
PtG	Power-to-Gas
PtH_2	Power-to-Hydrogen
PtM	Power-to-Methane
PV	photovoltaic power plant
RE	renewable energy
SNG	synthetic natural gas
SOEC	high-temperature steam electrolysis
StA	state-of-the-art
STP	standard temperature pressure

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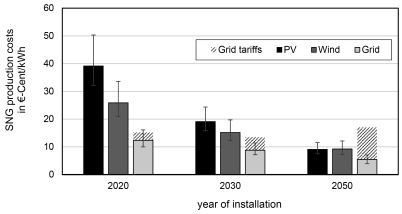
Renewable Power-to-Gas: A Technical and Economic Evaluation of Three Demo Sites within the STORE&GO Project

R. Schlautmann, H. Böhm, A. Zauner, F. Mörs, R. Tichler, F. Graf, T. Kolb*



Research Article: All three PtG demo plants comprise electrolysis, CO_2 conditioning, biological or catalytic methanation, and liquefaction or injection. Thereby, an overall efficiency of more than 75 % could be achieved for the entire process chain. Depending on the full load hours, the SNG production costs vary between 12 and 40 €-Cent kWh^{-1} in 2020.

Supporting Information available online

