International Journal of Hydrogen Energy 78 (2024) 52–67

Contents lists available at ScienceDirect

International Journal of Hydrogen Energy

journal homepage: www.elsevier.com/locate/he

Grid-neutral hydrogen mobility: Dynamic modelling and techno-economic assessment of a renewable-powered hydrogen plant

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ARTICLE INFO

Keywords:
Power-to-Gas
Hydrogen
Fuel cell vehicles
Techno-economic assessment
Methanation
Seasonal storage

ABSTRACT

The seasonally varying potential to produce electricity from renewable sources such as wind, PV and hydropower is a challenge for the continuous supply of hydrogen for transport and mobility. Seasonal storage of energy allows to avoid the use of grid electricity when it is scarce; storage systems can thus increase the resilience of the energy system. For grid-neutral and renewable hydrogen production, an electrolyser is considered together with a Power-to-Gas seasonal storage system, which consists of a methanation, the gas grid as intermediate storage and a steam reformer. As feed stream, electricity from an own photovoltaic (PV) system is considered, and for some cases additional electricity from the grid or from a wind turbine. The dynamic operation of the plant during a year is simulated. It is possible to safely supply fuel cell vehicles with hydrogen from the grid-neutral plant without using electricity when it is scarce and expensive. To supply 135 kg_{H2}/day, unit sizes of 1 MW–2.9 MW for the PV system and 0.9 MW–2.6 MW for the electrolysis are required depending on the amount of available grid-electricity. The usage of grid-electricity increases the capacity factor of the electrolysis, which results in decreased unit sizes and in a better economic performance. Seasonal storage of energy is required, which results in an increased hydrogen production in summer of approximately 50% more than directly needed by the fuel cell vehicles. The overall efficiency from electricity to hydrogen is decreased due to the storage path by 10%-points to 56% based on the higher heating value. Assuming a cost-equivalent hydrogen price per driven kilometre in comparison to the actual diesel price and electricity costs of 10 Ct/kWh_{el} from the grid, the revenues of the system are higher than the operating costs.

1. Introduction

The greenhouse gases are targeted to be reduced drastically over the next decades in the European Union in order to reach net-zero emissions of greenhouse gases by 2050 [1]. From 1990 onwards, while emissions have dropped by 32% in various sectors across the EU, transport-related emissions have increased by 33% [2]. In 2018, both domestic and international transport activities together accounted for 29% of the total greenhouse gas emissions in the EU, the largest contributors being light-duty vehicles, including passenger cars and vans, followed by heavy-duty vehicles like trucks and buses, maritime transportation, and aviation [2] with an annual growth rate of emissions of 1.7 [4].

Therefore, for decarbonisation of the mobility sector, renewable-based technologies must be implemented such as battery electric cars or fuel cell vehicles. The volatility of the renewables sources wind and solar radiation can cause the necessity to include a storage application for safe supply, particularly during winter and especially if photovoltaic electricity has a large contribution as is planned for Switzerland. Increased purchase of electricity from the grid should be minimised in times of shortage due to insufficient electricity production. An internal seasonal storage concept could be a solution which allows a grid-neutral energy supply [3] in the sense that no electricity is to be used for the electrolysis in times of net electricity import, such that the electrolyser operation does not create an additional burden to the system. Here, hydrogen can play an important role, as the storage of molecules is easier than electricity storage.

The recent review article [4] discusses advancements in green hydrogen (GH) production techniques via water electrolyzers fuelled by renewable energy. It covers various electrolyzer types, examines H_2 production methods using solar, wind, and hybrid systems, and evaluates the economic aspects by comparing costs across renewable sources. Additionally, it delves into challenges, advantages, and considerations for large-scale commercial GH implementation. In a case study conducted in Spain, J. Brey et al. [3] assessed the utilization of a hydrogen

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https://doi.org/10.1016/j.ijhydene.2024.05.331
Received 27 January 2024; Received in revised form 19 May 2024; Accepted 21 May 2024
Available online 24 June 2024

storage system for storing surplus energy on a seasonal basis. The approach involved employing electrolysis to convert excess electrical power into hydrogen, with the existing natural gas network utilized for seasonal storage. Torreglosa et al. [5] introduced a strategy to reduce the operational expenses of a hydrogen and battery hybrid system. This involved developing an intelligent Energy Management System (EMS) that incorporates the net present cost as an economic parameter, along with considering the technological limitations of its components. Recently,

Martinez de Leon et al. [6] reported various aspects and limitations of green hydrogen production from a stand-alone PV system. Producing hydrogen through solar energy is both technically and economically viable. However, the intermittent nature of solar power can affect hydrogen production, influencing its price, which is closely tied to the electricity source and the utilization factor of the electrolyser. A techno-economic evaluation was conducted by Barhoumi et al. [7] on a stand-alone PV-battery system for green hydrogen production for a refuelling station in Oman. The results showed that a 3 MW PV system integrated with a 1 MW electrolysis unit is required to produce c.a. 59 tons of hydrogen per year at a cost of 5.74 €/kg.

Wind energy has been utilized in several research activities to fuel hydrogen refuelling stations. For instance, Ayodele et al. [8] delved into optimizing the design of a hydrogen refuelling station driven by wind turbines. Hydrogen was generated on-site through water electrolysis, with the minimum hydrogen cost amounting to 6.34 $/kg. Similarly, Wang et al. [9]examined the ideal scale of a hydrogen refuelling station, where the production of green hydrogen was powered by offshore wind turbines. Their findings indicated that the hydrogen cost ranged from 11.8 to 15 $/kg. Hybrid solar and wind systems have been also researched for powering hydrogen production in refuelling stations. Murat and Kale [10] assessed the economic feasibility of such a setup, where an off-grid hybrid solar/wind system fuelled a hydrogen refuelling station. Designed to cater to 25 vehicles daily, the station yielded hydrogen at a cost of 8.92 $/kg. In another study [11], the technical potential of on-site wind-powered hydrogen-producing refuelling stations in the Netherlands was evaluated. The study took into account various risks, such as installing wind turbines near built-up areas, critical infrastructure, and ecological networks. They found that 4.6% of existing fuelling stations are suitable.

Brynolf et al. [12] conducted a thorough analysis of fuels production costs, including a literature review that emphasized impactful and uncertain steps, a comprehensive examination that encompassed costs and efficiencies for individual production stages, and calculations for a harmonized comparison of fuel options. The assessment covered methane, methanol, dimethyl ether, diesel, and gasoline, with a sensitivity analysis on parameters that significantly influenced total fuel production costs.

Walker et al. [13] employed an Analytical Hierarchy Process to assess Power-to-Gas against other energy storage technologies, examining applications ranging from residential load shifting to bulk energy storage and utility-scale frequency support. The study concluded that Power-to-Gas proves advantageous in utility-scale energy storage scenarios, particularly when considering criteria such as energy portability, energy density, and the capability for seasonal storage. Ravi et al. [14] reviewed various approaches to the utilization of hydrogen and e-fuels for mobility applications, discussing their respective advantages and limitations. The article highlighted that e-fuels, despite initial concerns about efficiency and cost, could be seen as an opportunity due to their compatibility with existing fossil-fuel vehicles and potential for carbon neutrality. The realization of a promising hydrogen economy was emphasized, underscoring the importance of infrastructure development to meet emission goals set in the Paris Climate Accord.

In summary, publications about Power-to-Gas (PtG) concepts discuss three main aspects:

i. How to operate a (stand-alone) renewable electricity production plant with hydrogen as intermediate energy storage to balance the electricity supply on an hourly, daily and seasonal time scale.
ii. Renewable hydrogen and methane production for use as fuel.
iii. Hydrogen and methane as storage medium and the potential usage of the gases in the mobility or heating sector at system level for the whole year, however without considering the dynamic operation modes for single plants.

The scope of this work includes a renewable hydrogen production plant for the un-interrupted supply of fuel cell vehicles (small scale) and hydrogen trains (large scale). That can be a stand-alone unit, only powered by electricity from the own PV system (and wind turbine for the larger scale), or a grid-connected plant. The seasonal storage is implemented via a Power-to-Gas (PtG) approach, which includes a methanation, the gas grid as intermediate storage and a steam reformer.

This study comprehensively addresses all three aspects by delving into various operational modes of the hydrogen plant, scrutinizing them on an hourly, daily, and seasonal basis. Furthermore, it investigates the use of methane as a seasonal storage medium, considering the national-scale seasonal electricity shortage in the grid. This way seasonal storage is combined with sector coupling which avoids the issue of using electricity in times of shortage but may yield higher efficiencies than systems that aim to store electricity in molecules and the reconvert them back to electricity. The key questions tackled in this investigation include: (1) Can we achieve grid-neutral hydrogen production when dealing with input energy sources characterized by high volatility? (2) If feasible, what level of technological complexity is required? (3) What are the associated costs, and is it a financially viable endeavor?

2. Methods

2.1. Concept for a grid neutral hydrogen production

In this case study, the production of hydrogen is investigated for the operation of a small fleet of fuel cell vehicles with a total consumption of 135 kg H_2/d. This amount allows around 15 000 km driving of passenger cars or 6500 km of delivery vans or 1700–1900 km of trucks. Further, a larger scale with 600 kg H_2/d production is investigated. This amount of H_2 can be used to run 2000 km of hydrogen trains [15]. The following boundary conditions have to be considered:

1) The resources for the hydrogen production are mainly renewable or contribute to a direct reduction of CO_2 emissions.
2) Grid-Neutrality with respect to electricity and gas; i.e. no electricity from the grid can be purchased if there is a shortage of electricity, and the amount of methane taken from the gas grid must match the amount of methane injected into the grid over a year.

For an increased share of photovoltaic systems in the electricity production mix, a shortage of electricity production in the winter has to be expected. Therefore, it is considered to store part of the energy from summer to winter. This can be realised with a PtG concept, where surplus electricity in summer is converted to gas, which can be stored in large amounts in the existing gas grid. In Fig. 1, a corresponding concept for the hydrogen production is illustrated. For the large scale H_2 production, a wind turbine of 2.2 MW size is coupled with the PV system, which is not shown in this figure.

A photovoltaic system produces the required electricity for the hydrogen production via electrolysis. Additionally, also electricity from the grid can be used if there is no electricity-shortage on a national level. The produced hydrogen first passes an intermediate tank and is then directed to the filling station fuel cell vehicles. The seasonal storage concept is illustrated on the left side of the figure and contains the methanation, the gas grid and the reformer. If there is not enough electricity available for the hydrogen production via electrolysis (typi-

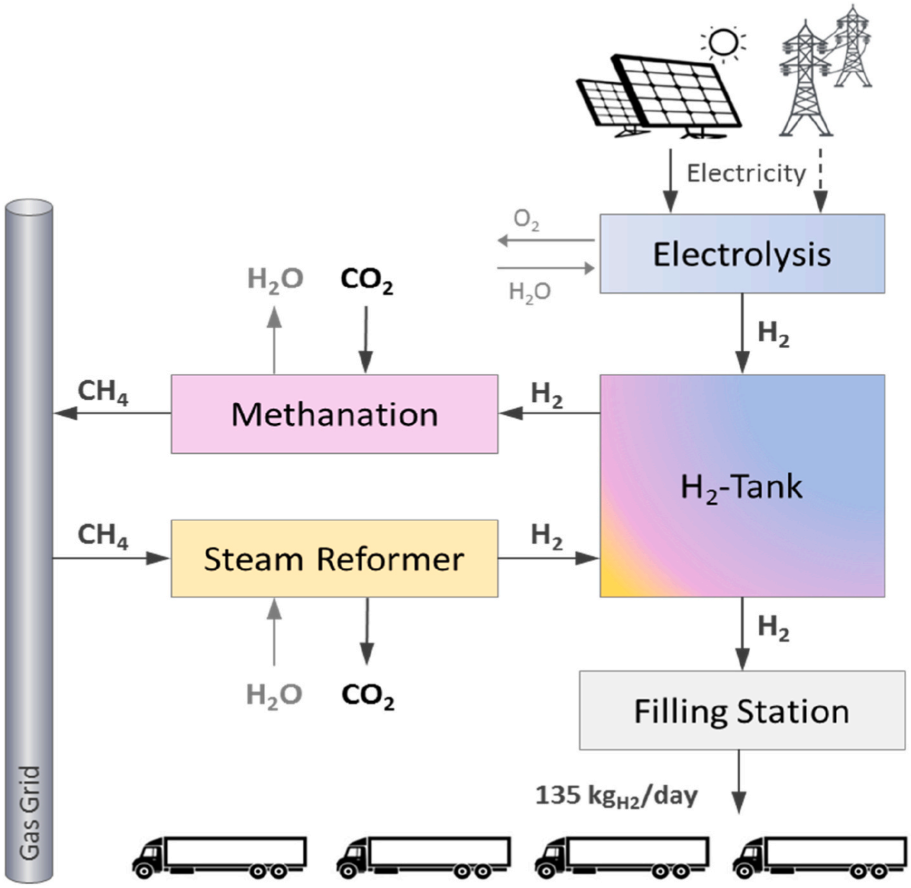

Fig. 1. Concept of a Power-to-Gas plant for the hydrogen production for the supply of a small fuel cell vehicle fleets; (blue: hydrogen from the electrolysis directly for the fuel cell vehicles filling station, pink: hydrogen for methane production, yellow: hydrogen from the reformer). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

cally during winter), the reformer takes over the hydrogen supply. Here, methane from the gas grid is converted to hydrogen via steam reforming. The amount of consumed methane in winter is produced during summer with the methanation unit. Hence, the gas grid serves as an intermediate storage from summer to winter. While this is no problem for smaller plants (< few MW) today, for larger plants and in a future with generally less gas consumption, injection into the then bidirectional transport grid (20 bar) might be necessary to enable methane storage in a cavern. The methane is produced from surplus hydrogen in summer and from a carbon dioxide source in a process optimised for flexible operation, i.e. equipped with a hydrogen tank and the option for deep part load operation:

$$CO_2 + 4\,H_2 \leftrightharpoons CH_4 + 2H_2O \quad \Delta H^0_{reac} = -165.12\ kJ/mol$$

The methanation reaction is in total exothermic while in the reformer, the reversed chemical reaction takes place, which requires therefore an additional heat source. The methane production in summer must match the methane consumption in winter for grid neutrality. As mentioned, the methanation reaction requires carbon dioxide, and the reforming reaction releases this gas. It is interesting to evaluate the carbon dioxide capture from the reformer in winter and re-use it for the methanation in the summertime. Storage of carbon dioxide can be done in stationary tanks in liquid phase at low temperatures under pressure. Commercial suppliers provide cryogenic CO_2 tanks at 22 bars and up to 60 m^3 size [16]. To describe the operation of the combined system, a model is built that considers the different units of the PtG-system and their efficiencies (all based on higher heating value). The efficiency values contain the main reactions as well as further upgrading steps for a sufficient gas quality. For the electrolysis, an efficiency of 71% is assumed [17] from electricity to purified hydrogen. It has to be considered that the maximum efficiency occurs at partial load of the electrolyser. The efficiency at peak power can be 20% lower [18]. Therefore, a combined efficiency is used in this work and not the maximum efficiency. For the methanation and the reformer, efficiencies of 78% [19] and 65% [20] are considered respectively, which also include purification efforts, heat demand and compression.

The small case study considers a site in the densely populated region of Switzerland where an industrial area is present with i) transportation companies that can operate the hydrogen cars; ii) sufficiently large industrial roofs for the required solar panels; iii) connections to the gas and electricity grid. Captured carbon dioxide from industrial sources (anaerobic digestion, fermentations, waste incineration, and cement plants) can be stored in pressurised gas tanks and transported to the site. For the seasonal storage of methane in the gas grid, an annual fixed fee is considered [18]. For the larger case study, a windy and sunny region of Switzerland is considered, where a wind turbine of 2.2 MW is available.

2.2. General description of electrolysis, methanation and reformer

For the grid-neutral hydrogen production from PV-electricity (and wind if available), besides the solar panels and the wind turbines, three key units are required: electrolysis, methanation and reformer. Eventually, a battery can be included. In general, these technologies must fulfil two requirements for the presented concept: (1) The units must operate dynamically, especially the electrolysis since its electricity consumption must follow directly the electricity production of the photovoltaic system (required response time: seconds). The methanation must be able to operate also in partial load, but due to the hydrogen tank, the requirement to the response time is not as high as for the electrolysis and is in the range of hours. The reformer is fed by methane from the gas grid. Hence, it is possible to operate this unit continuously in full load. However, it is required to switch off and on the reformer during days. (2) The units need to be available in small scale. The main technical input data are shown in Table 1.

There are two types of electrolyser systems commercially available, the alkaline system (AEL) and the proton exchange membrane (PEM) system. Both technologies currently reach the same efficiencies and have sufficiently fast response time in the range of seconds [21]. The cold-start time for the PEM and alkaline system is less than 20 min and less than 60 min respectively [22]. Both systems are available in small-scale in the range of a few megawatts as required for the concept [23,24].

For the methanation, catalytic fixed bed, catalytic fluidised bed and biological methanation are commercially available. In the biological methanation, typical restrictions are caused by the mass transport limitations from the gas into the liquid phase which require large reaction volumes an order of magnitude higher than for the catalytic technologies [25,26]. All technologies are also available in small-scale in the range of 200–300 kW as required and are able to operate at partial load.

Conventional steam reforming of natural gas in large scale (100–400 MW [27,28]) operate at conditions of 850 °C and between 15 and 25 bar [29]. The whole reformer plant consists of a desulphurisation unit, the reformer, a CO shift reactor and a pressure swing adsorption for the purification of the hydrogen. However, the required scale for the reformer in this concept is significantly smaller with about 200 kW, which results in much higher specific cost due to the economy of scale. For this size, lower pressures at about 3 bar are applied to save material costs [28]. Currently, there are a few companies which offer compact steam reformers [30–32]. Some reformers can work at partial load until 40%–10% of the peak load.

2.3. Technical model of a dynamic hydrogen production plant within a power-to-gas system

The aim of the simulation is the demonstration of a grid-neutral continuous supply of hydrogen for the fuel cell vehicles (small scale) and hydrogen trains (large scale) during the whole year despite the volatile energy flows varying in the range of days, weeks and seasons. For the simulation of small scale, the capacity factors for the site Rothrist, Switzerland, are considered on an hourly basis, Fig. 2. For the large scale, wind and PV capacity factor for the city of Martigny in the alpine region are taken into account. The calculation of the capacity factors is based on [33] and is provided by the internet site *www.renewables.ninja*. The evaluation of the years from 2010 to 2015 showed that the year 2012 was an average year regarding the yearly PV capacity factor (13.8%). Additionally, that year comprised a severe shortage of electricity production with the PV system for more than a week, which a PtG system must be able to compensate. Due to these reasons, all simulations refer to the hourly capacity factors of the year 2012. The wind profile is only available for the year 2019. For this reason, for the larger scale case study, the PV and wind profiles of the year 2019 are considered (profiles are shown in the supplementary material).

Table 1
Technical parameters for the energy system.

Parameter	Value	Unit	Ref.
General assumptions			
Small scale H2 production rate	135	kg/day	Assumption
Interest rate	600	kg/day	Assumption
Units			
Methanation eff., $\eta_{Meth,\ HHV}$	78	%	[19]
Methanation load	20–100	%	Assumption
Reformer eff., $\eta_{Refo,\ HHV}$	65	%	[20]
electrolysis eff., $\eta_{Meth,\ HHV}$	71	%	[17]
Electrolysis load	0–100	%	Assumption

For some scenarios (which will be explained in the next section), the purchase of electricity from the grid is allowed if at that specific time, no electricity is imported from other countries to the Swiss electricity grid. The balance of the Swiss electricity grid for the year 2012 is illustrated in Fig. 2 [34]. Here, the national electricity consumption is subtracted from the national electricity production so that negative values indicate a lack of electricity and vice versa, positive values indicate excess of electricity which requires import and export of electricity, respectively, for balancing the grid. Two cases are calculated which refer to the current electricity mix in Switzerland (60% hydroelectric power, 32% nuclear power, 4% thermal power plants, 4% renewable energies [35]) and to a possible future electricity mix where the nuclear power is replaced by renewable sources. For this, the photovoltaic electricity production increases significantly with the assumption that on 50% of all appropriate roof areas, PV-systems are installed [34]. In the case of the current electricity mix, in summer a continuous excess of electricity is produced whereas in winter, electricity must be imported frequently. In the case of the future electricity mix, in summer also excess electricity is evident. However, the balance of import and export is clearly more volatile due to the increased PV-electricity. As a result, excess electricity is available also in winter for some hours per day, which can be used for the hydrogen production if the own PV electricity production is not sufficient at the corresponding winter-day.

2.3.1. Calculation algorithm

Fig. 3 illustrates the algorithm of the dynamic model for grid-neutral hydrogen production over the year, which was implemented in MATLAB. First, an initial value for the total power of the PV system is set. Together with the hourly capacity factors F_{CAP} for the location Rothrist, the hourly electricity profile is determined and with that the dynamic hydrogen production via electrolysis. Since a hydrogen tank is installed after the electrolyser, and additionally the fuel cell vehicles are considered to be refuelled once per day, the hydrogen production rate can be expressed now on a daily basis. For every day of the year, the corresponding electricity E_{El}^{PV} production is calculated. Afterwards, the model decides if the amount of electricity at a day suffices for the minimum required hydrogen production E_{H2}^{must} (5319 kWh_{HHV}/d for the small scale). If that is the case, the electrolyser is operated only by PV-electricity E_{El}^{PV}. Furthermore, the model checks if excess hydrogen (E_{H2}-E_{H2}^{must}) is produced with which the methanation can be operated. This path is typically chosen in the summer. In the case of large scale hydrogen production for the train, a wind turbine of 2.2 MW is also considered as electricity production according to the wind profile. So, the electricity need of the electrolyser is provided by both PV and wind turbine, and no electricity from the grid has to be purchased for this case.

For the small scale, in case the electricity production from the PV system is not sufficient, first the model checks if electricity from the grid is available, i.e. whether Switzerland is not importing electricity on that day. If so, the amount of the required electricity to reach the minimum of hydrogen is taken from the grid. In this case, no excess hydrogen and thus no methane is produced. If no electricity from the grid can be purchased due to a general lack of electricity in the grid (import-criterion), the low hydrogen production rate of the electrolyser is supported by the reformer, which converts methane from the gas grid to hydrogen and carbon dioxide ($\eta_{Reformer}$ * $E_{CH4}^{consumed}$). The reformer and electrolysis produce together the minimum required hydrogen amount. This path typically occurs in winter times.

When the calculation for every day of the model year is completed, the accumulated total amount of methane produced is compared to the total amount of methane consumed. Due to the desired grid-neutrality, the two values must be equal ($E_{CH4,tot}^{consumed} = E_{CH4,tot}^{produced}$). If the deviation is too high, the power of the PV-system is adapted. The whole calculation is repeated until the deviation is sufficiently low. Hence, the size of the

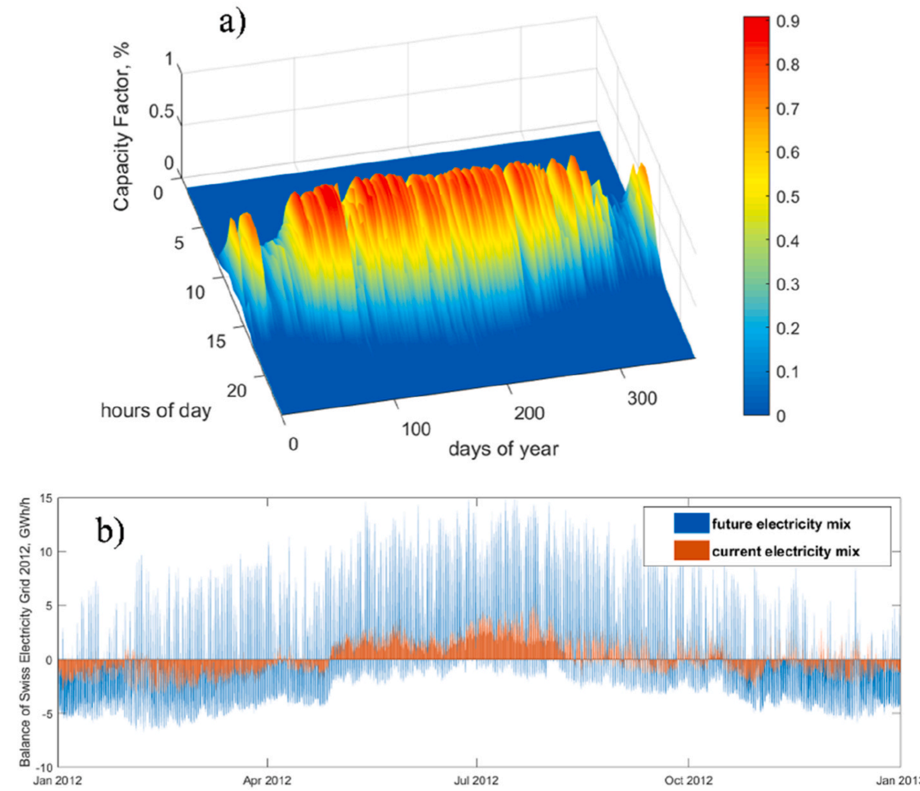

Fig. 2. a) Capacity-factor profile of the PV system in 2012 for the site in Rothrist, Switzerland; data from Ref. [33]. b) Hourly balance of Swiss electricity grid 2012 for the current Swiss electricity mix (blue) and the future electricity mix (scenario assuming no nuclear power, but using 50% of PV-potential), data from [34]. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

PV system is determined so that in summer of the model year, sufficient electricity is produced and in consequence, additionally produced hydrogen and methane can close the energy-gap in winter. Due to the losses in the methanation unit ($\eta_{Meth,\ HHV} = 78\%$) and the reformer ($\eta_{Refo,\ HHV} = 65\%$), the excess hydrogen production by the electrolyser must be around two times the required amount of hydrogen produced by the reformer in winter.

In a next step, the maximum size of the units: electrolyser, methanation and reformer is determined with the maximum required energy flows obtained in the previous step. The actual size of the methanation and the reformer can be decreased with the usage of a hydrogen tank. In the simulation, a balance for the hydrogen tank is applied. The inlet and outlet flows of the tank depend on the electricity production, the size of the units and the operation mode. For instance, if the hydrogen production on a winter day is not sufficient for the fuel cell vehicles while the hydrogen tank is filled, it is considered that first the hydrogen tank is emptied before the reformer produces the rest of the required hydrogen. This operation mode reduces the amount of hydrogen produced via the methanation-reformer path, which has a lower efficiency than the direct path. The methanation can be operated until a partial load of 20% when the level of the hydrogen tank is low, while the reformer is performing at nominal capacity. The electrolysis is designed to peak load corresponding to the electricity profile of the PV system, but can be operated from 0 to 100% load.

2.4. Scenarios

Eight scenarios are considered for the evaluation of the dynamic operation of the PtG-hydrogen production. An overview of the scenarios is listed in Table 2. In all scenarios, electricity from the PV-system is used for the hydrogen production (PV). Additionally, in some scenarios electricity from the grid can be purchased if at that time no electricity is imported from other countries into Switzerland.

For the identification of times where electricity is imported or exported, two cases are considered: *current* and *future*, which are related to the current electricity production in Switzerland (GC – grid current) and to the future electricity production with no nuclear power but with an increased share of renewable energy, mostly realised with photovoltaic systems (GF – grid future). In the scenario PV-Max, the hydrogen production is provided with electricity only from the PV-system (no electricity from the grid). Additionally, the scenarios differentiate between the maximum size of methanation and reformer with peak load (Max) that is necessary when a small hydrogen tank is desired, on the one hand, and a decreased size together with a larger hydrogen tank, respectively (Min), on the other hand. In the scenario PV-GF-Max-Bio, more methane is produced in summer than is consumed in winter. The surplus methane is sold to the gas grid as biomethane. The scenario PV-GC-Max-Bat considers the usage of a battery upstream of the electrolyser, which allows a smaller size of the electrolyser.

The last case, PV-Max-Wind-Bat is related to the larger scale scenario. As the production scale is different compared to the previous scenarios, it is not compared with the others. In this scenario, the hydrogen production is provided with electricity from PV and a wind turbine system, and no electricity from the grid is available. There are large fluctuations in the wind profile, due to which a battery upstream of the electrolyser is considered.

For the different scenarios, the capacity factor profile of the PV system from 2012 is applied (except for the last scenario, PV-Max-Wind-Bat) for the site in Rothrist, Switzerland. This profile is illustrated in Fig. 2. The capacity factor is defined as:

$$F_{cap} = \frac{P}{P_{peak}}$$

The capacity factor puts the actual power of the PV system P into

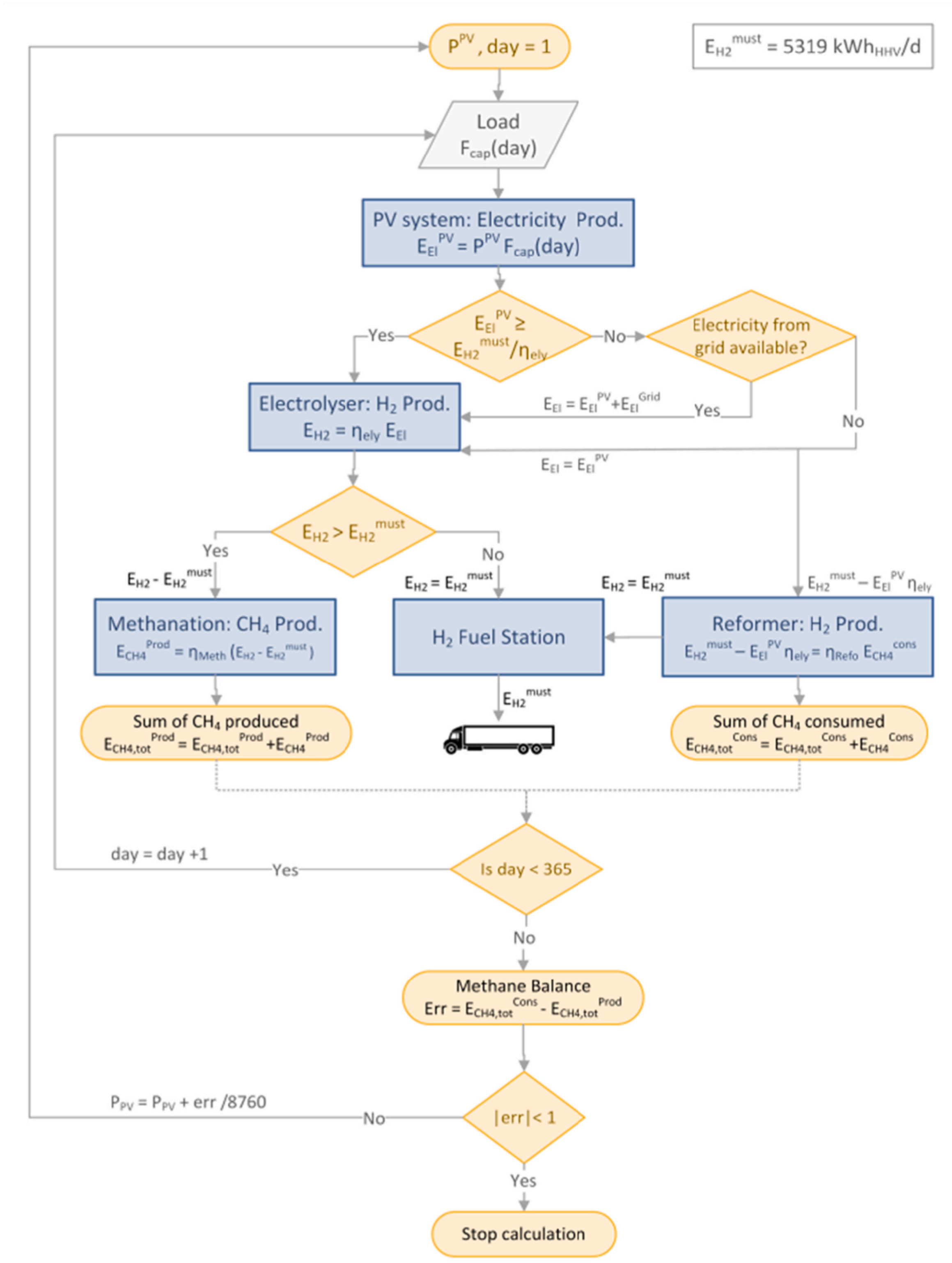

Fig. 3. Algorithm of the model for a dynamic grid-neutral hydrogen production.

relation to the peak power P_{peak} which a PV cell can achieve at standard test conditions (light intensity: 1000 W/m^2, incident angle: 90°, at 25 °C). The highest capacity factors are reached in May with about 90% at noon due to clear weather. The maximum power P_{peak} is never reached since the standard test conditions are not met.

During summer in Switzerland, it is possible to have a sunlight intensity of up to 1000 W/m^2. However, due to the geographical position, an incident angle of 90° is not possible with a standard tilt of the panel of 35°. The lowest capacity factors occur in December where for two weeks the maximum capacity factor of a day is between 5% and 20%. Another period of low factors occurs typically in February. Longer periods of time with low capacity factors are especially demanding for the PtG system, since the steam reforming must produce the required hydrogen almost completely on its own which results in a larger size of the plant than

Table 2
Name and description of the corresponding scenarios.

Abbreviation	Ren. Energy source	Grid	Methanation size	Biomethane	Battery
PV-GF-Min	PV	Future	Minimum	–	–
PV-GF-Max	PV	Future	Maximum	–	–
PV-GF-Max-Bio	PV	Future	Maximum	+	–
PV-Max	PV	–	Maximum	–	–
PV-GC-Max-Bat	PV	Current	Maximum	–	+
PV-GC-Min	PV	Current	Minimum	–	–
PV-GC-Max	PV	Current	Maximum	–	–
PV-Max-Wind-Bat	PV + Wind	–	Maximum	–	+

without those PV-gaps.

2.5. Economic model and key factors

For the economic assessment, investment costs, operation costs and revenues are considered. The specific investment costs of the units are listed in Table 3. For the operating costs, electricity costs from the grid are assumed with 10 Ct/kWh (expected market price of electricity in times with high production plus grid-use fees). Additionally, grid-use fees have to be paid for the PV-electricity due to the infrastructure of the industrial area in Rothrist, which are accounted with 5.3 Ct/kWh. An offer from an industrial company was given to deliver carbon dioxide in pressurised bottles captured from industrial exhaust gases with the costs of 235 $/ton_{CO2}$ (including delivery and storage tank). For the intermediate storage of methane in the gas grid, a fixed rate of 4000 $/a was suggested by the local gas grid operator. The revenues consist of the sale of hydrogen and of high-temperature process heat. In the scenario with additional methane production, the revenues of biomethane are considered as well.

Table 3
Economic parameters for the energy system.

Parameter	Value	Unit	Comments & Ref.
General assumptions			
Lifetime of the plant	15	years	[38]
Interest rate	5	%	[38]
Units specific costs			
PV system	1100 (opt. assumption) 1400 (base case)	$/kW$_{el}$	Local business provider
Electrolysis unit	1000 1500 (conservative)	$/kW$_{el}$	[39]
Methanation unit	2000	kW$_{CH4}$	down-scaled from Ref. [40] with a scaling factor of 0.62
Reformer unit	3000	$/kW$_{H2}$	small scale: 50 Nm$^3_{H2}$/h [41]
Battery unit	250–1100	$/kWh	[39,42,43]
hydrogen tank, 40 bar	35	$/Nm^3	[44]
fuelling station incl. tank 400 bar	1.2	M$	small scale: 135 kg/d [45],
Operation costs			
Methanation unit	5	% CAPEX	
Reformer unit	5	% CAPEX	
Electrolysis unit	1.5	% CAPEX	
PV system O&M	22	$/a. kW$_{el}$	
CO2	235	$/ton$_{CO2}$	Local provider
Ni catalyst for methanation	100	$/kg	
storage of methane in the gas grid	4000	$/a	Local provider
Energy prices			
Grid electricity	10	Ct/kWh	Assumption
PV Grid-use fee	5.3	Ct/kWh	Local provider
High temperature heat	4	Ct/kWh	Local provider
Biomethane	12	Ct/kWh$_{CH4}$	[40]

In order to assess the economic feasibility of the different scenarios, the share of covered investment costs S_{cov} is investigated regarding the EBITDA (earnings before interest, tax, depreciation and amortization). For the share of covered investment costs, the EBITDA for the whole lifetime of the plant a is put into relation to the total investment costs $C_{inv,tot}$.

$$S_{cov} = \frac{a\ (Revenues - OPEX)}{C_{inv,tot}}$$

The selling price of hydrogen shall be equal to the selling price of Diesel (before the Ukraine war) per driven kilometre. The average Diesel-price in Switzerland 2018 was 1.75 $/l [36]. From an average consumption of 6 l_{Diesel}/100 km results a distance-specific price of 10.50 $/100 km. The average consumption of a hydrogen vehicle is 0.88 kg_{H2}/100 km [37]. The combination of the distance-specific price and the higher heating value of hydrogen, results in an equivalent hydrogen price of 30.2 Ct/kWh$^{HHV}_{H2}$. Due to the higher efficiency of a hydrogen-fuelled vehicle, the price per kWh can be higher than for a conventional diesel vehicle. The assumed Diesel-price includes taxes. The calculated equivalent hydrogen price is only valid if no taxes have to be paid. Additionally, the Diesel consumption is a value based on experience, whereas the hydrogen consumption is a specification from the producer. It is possible that the hydrogen consumption on the road is higher. On the other hand, in some countries like Switzerland, trucks for heavy-duty transport have to pay special fees (LSVA), from which hydrogen fuels are exempted, as their burden for environment is low. This advantage is not considered in the presented economic calculation, but can be an important factor in these specific markets as the heavy-duty transport fees are higher than the fuel costs.

3. Results and discussion

3.1. Technical feasibility

3.1.1. Small scale H_2 production

In the dynamic simulations, a continuous supply of hydrogen for the fuel cell vehicles can be achieved despite highly volatile energy sources. The combination of a direct hydrogen production (electrolysis) together with a storage system (methanation, gas grid, reformer) allows a sufficient supply of the fuel cell vehicles with hydrogen over the year. The boundary conditions stated in section 2 for a grid neutral (electricity and gas grid) renewable hydrogen production can be fulfilled.

The dynamic operation of the hydrogen production over the year for the scenario PV-GC-Min is illustrated in Fig. 4. Here, the electricity profile of the PV system is shown (full grey line) based on the capacity factors from 2012 (Fig. 4). The hydrogen production via electrolyser in diagram a) is represented by the blue points which correlate with the electricity production. The pink points represent the hydrogen feed to the methanation. The yellow points show the hydrogen production by the steam reformer. The dotted line represents the required hydrogen production per day for the fuel cell vehicles. The blue line in diagram b) shows the level of the hydrogen tank. In Fig. 4, the scenario PV-GC-Min is illustrated, in which the current grid conditions in Switzerland are considered and the methanation unit is minimised (see Table 2). Here, only 5% of the total electricity consumption is taken from the grid. In most cases, when the own PV electricity production is not sufficient, also the electricity grid is not in export-mode. On 50 days in the year 2012, it was possible to use grid-electricity, mainly in September and October. However, from mid of December until March, when the lack of the own PV-electricity is most dominant, no grid-electricity is available. The PV-

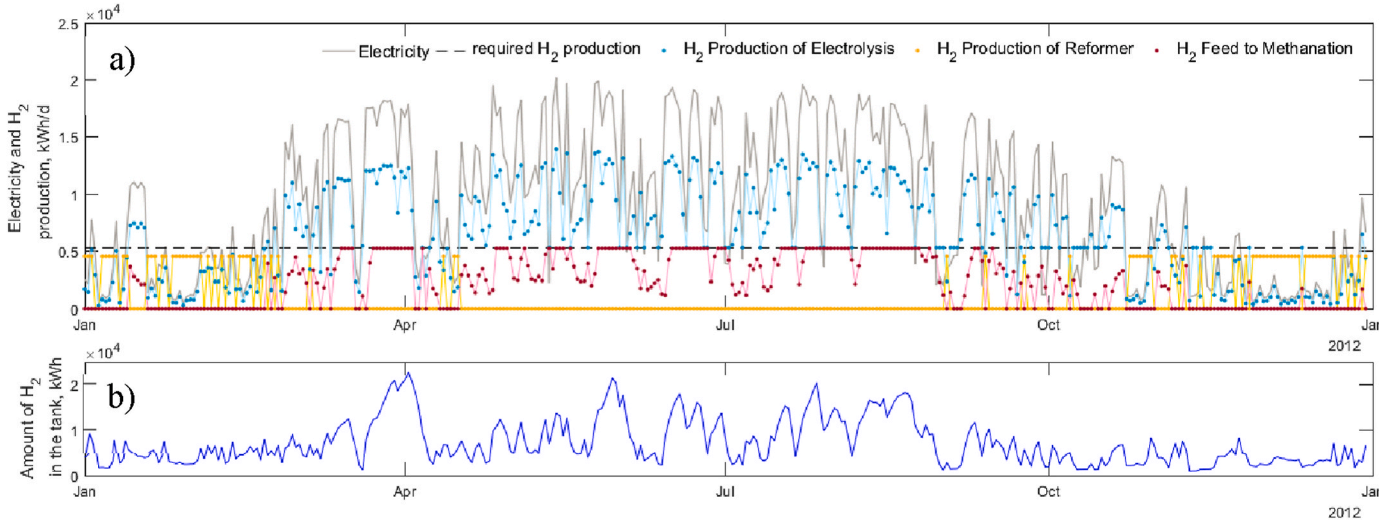

Fig. 4. a) Dynamic electricity and hydrogen production and b) level of hydrogen in the intermediate tank over the year 2012 within the Power-to-Gas system for the site in Rothrist, Switzerland; Scenario: PV-GC-Min.

electricity profile is highly volatile and with that the hydrogen production profile of the electrolyser. From March until August (summer period), in most cases the hydrogen production from PV-electricity for the fuel cell vehicles is sufficient. From end of October until February (winter period), the hydrogen production must be supported by the reformer since neither enough PV-electricity nor electricity from the grid is available (boundary condition (2) in section 2).

During the summer period, in most cases the hydrogen production via electrolysis is larger than needed for the cars so that methane is produced via methanation mainly in full load. The amount of methane consumed in winter is equal to the amount of methane produced in summer. During the transition periods between summer and winter, the methanation operates dynamically in partial load. The reformer operates by definition in full load. In diagram b) the corresponding hydrogen tank level is displayed. The corresponding required size of the H_2-tank for this scenario is 6414 Nm^3 which is equal to three forty-feet long shipping containers (for 30 bar pressure difference in the tank). High filling levels are reached for longer periods with high PV-electricity production like at the end of March or frequently over the summer. Low filling levels typically occur during the winter.

In PV-GF-Max scenario (future grid situation), the PV electricity production profile is lower since more electricity from the 'future'-grid can be purchased at times in need. In the future scenarios, for several hours per day grid-electricity is available for the majority of days over the year, even in winter. In the scenario PV-GF-Max, 3505 h of grid electricity in one year can be used to run the electrolyser. For these hours, the electrolyser operates at full load with electricity partially from the PV system and partially from the grid, which is valid for this case since the future Swiss electricity mix consists almost completely of energy from renewable sources. As a result, the PV system and the electrolyser can be decreased in size and have higher capacity factors than for the scenarios with current grid conditions. Due to the larger size of the methanation unit, the tank size can be decreased to 3910 Nm^3, which corresponds to two forty-feet shipping containers. At times of intensive hydrogen production, a larger size of the methanation can process the hydrogen faster. On the other hand, the methanation is operated less often at full load which translates into a lower capacity factor.

The scenario without using grid electricity, PV-Max, is similar to the scenario PV-GC-Max since the amount of consumed grid-electricity in the PV-GC-Max scenario is very low. For the present time, it is beneficial to design the hydrogen production plant with PtG-system as independent from the electricity grid. For the scenarios regarding the future, it makes sense to have a connection between the own PV system and the electricity grid for balancing different weather conditions which affects the PV electricity production nationally.

The obtained capacity factor (% full load operation) of the reformer is about 25% for all scenarios. Regarding the methanation, the scenarios with a minimal size of the methanation unit (Min) show a capacity factor of 32% and for a maximised methanation unit (Max) a capacity factor of 25%. The capacity factors of the storage system (methanation and reformer) are decoupled from the capacity factor of the electrolysis due to the intermediate hydrogen tank. The capacity factor of the electrolyser depends on the PV-system, the electricity supply from the grid and the battery size. The higher the electricity supply from the grid, the higher is the capacity factor of the electrolyser which results in these capacity factors: for no grid-electricity 15% (PV-Max), for highly restricted grid-electricity 16% (PV-GC-Min/Max) and for moderately available grid-electricity of 42% (PV-GF-Min/Max). With the usage of an economically optimised battery, the capacity factor of the electrolyser can be increased only by 1 %-point.

In Fig. 5, the size of the units PV-system, electrolysis, methanation and reformer is illustrated for the different scenarios. Two levels of sizes are evident, which can be assigned to the scenarios, which consider either current electricity grid conditions (GC) or future grid conditions (GF). For the current situation (case GC), the size of the units is about twice the size in a future situation (case GF). For the current grid conditions, only a small amount of grid-electricity is available at times of low PV electricity production of the own unit. The biggest part of the hydrogen production must be supported by the own PV-system which has a direct influence on the size of the PV system and the electrolyser. The electrolyser must be correspondingly large to be able to process the high peak electricity flows during noon. Therefore, the size of the electrolyser and the PV system are between 2500 kW and 2900 kW for the case *grid-current* (GC) and between 900 kW and 1500 kW for the case *grid-future* (GF). For the scenarios with the case *grid-future* (GF), a larger amount of grid-electricity can be purchased due to more export hours during winter times. As a result, the PV system and the electrolysis can be decreased in size. In the scenario PV-GC-MaxBat, the integration of the battery results in a lower required electrolyser power due to the more continuous operation mode. However, the optimum size of the electrolyser in combination with a battery is only 4% smaller than without a battery due to the high costs of the battery system which is explained more into detail in the next section. The difference of units sizes between the scenarios including the case *grid-current* and the scenario PV-Max with no usage of grid-electricity at all is only marginal due

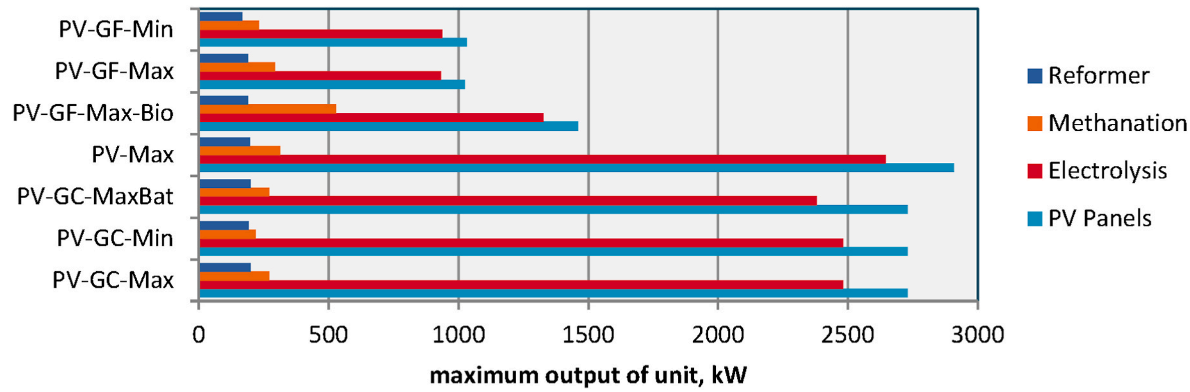

Fig. 5. Maximum output of the units PV-System, Electrolysis, Methanation and Reformer for the corresponding scenarios.

to the low potential of using grid electricity at current conditions.

The variation of the size of the hydrogen tank (scenarios Min/Max) results in medium changes for the methanation unit of about 55 kW difference. The size of the reformer is similar for all scenarios due to the need to cover an electricity shortage for more than two weeks in December. For smaller sizes, the reformer could not provide the fuel cell vehicles sufficiently with hydrogen over the mentioned two weeks. The maximum output of the methanation is between 200 kW and 300 kW according to the size of the hydrogen tank and the grid conditions. In the scenario PV-GF-Max-Bio, more methane is produced as it is consumed in winter, so that it can be sold to the gas grid provider as biomethane. Here, the maximum output of the methanation unit is 528 kW. Correspondingly, the sizes of PV system and electrolyser are larger than for the other scenarios for the case *grid-future* (GF).

An overview of the energy and mass flows per year is illustrated in Fig. 6 for the scenario PV-GC-Max. The other scenarios at current grid conditions show similar results. 3.5 GWh of electricity from the PV system and the grid is consumed by the electrolyser to produce 2.4 GWh of hydrogen. The resulting HHV based efficiency for the direct hydrogen production is $\eta_{H2,direct} = 66\%$ which includes also the compression of hydrogen to 400 bar for the fuelling station. The indirect path for the hydrogen production includes the electrolyser, the methanation, the reformer and the compression. The product of the efficiencies of these single units represents the efficiency of the indirect hydrogen production which is $\eta_{H2,indirect} = 36\%$. For the safe supply of the fuel cell vehicles with a continuous stream of hydrogen, about one third of the produced H_2 by the electrolyser must be stored via methanation and subsequent grid injection. Considering both paths with its corresponding shares, a total efficiency of $\eta_{H2,total} = 56\%$ is obtained for the current grid case. For the future grid case, the share of the direct path of hydrogen production is slightly increased due to the larger availability of electricity during shortage times. Less hydrogen is used as a storage medium. Hence, the overall efficiency is increased to $\eta_{H2,total} = 58\%$ for the future grid case.

3.1.1.1. CO_2 supply. An annual CO_2 feed of 59 000 Nm^3 is required for the methanation. This carbon dioxide can be obtained from biogas, which would require a biogas production rate of about 30 Nm^3/h and a CO_2 fraction of 40%. This production rate is typical for small biogas plants in Switzerland. Another possibility would be to recycle the CO_2 produced by the reformer and use it as feed for the methanation. A respective calculation is conducted for the scenario of PV-MAX, and the results are shown in Fig. 7. In winter time, when the reformer is operated, CO_2 is produced during reforming and accumulated in a tank. Consumption of the CO_2 starts when the methanation is active around the day 50 of this figure. In the summer time, the CO_2 tank is empty and it has to be purchased. From the October time, the CO_2 tank refilling starts with a peak by end of the year. The middle graph in Fig. 7 shows

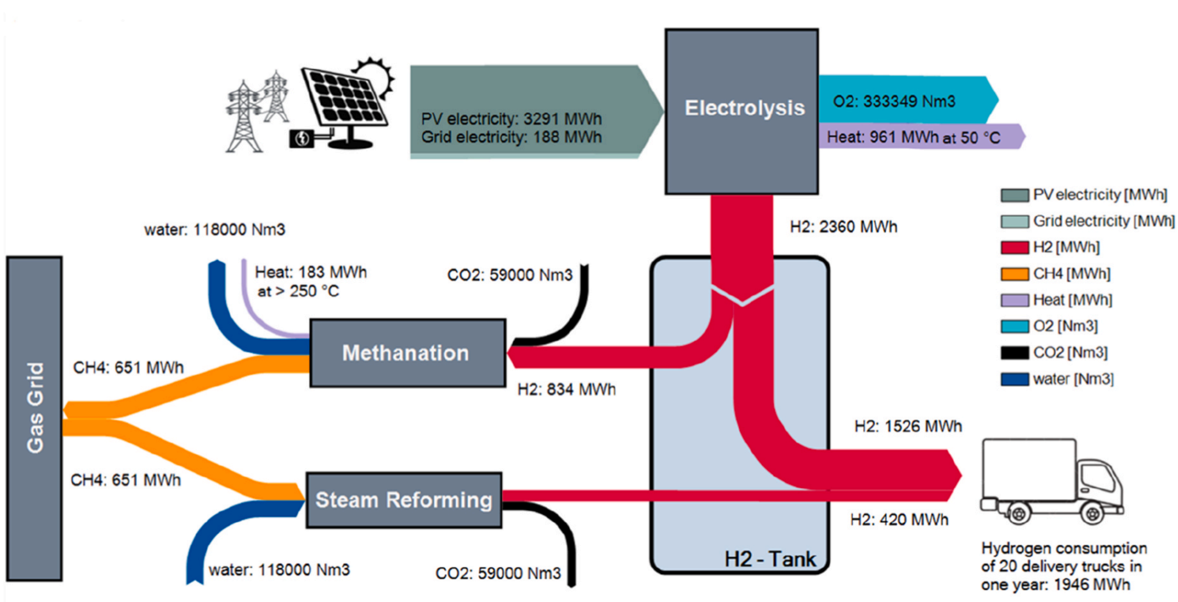

Fig. 6. Annual energy (HHV based) and mass flows of the grid-neutral hydrogen production within a power-to-gas system for the scenario PV-GC-Max.

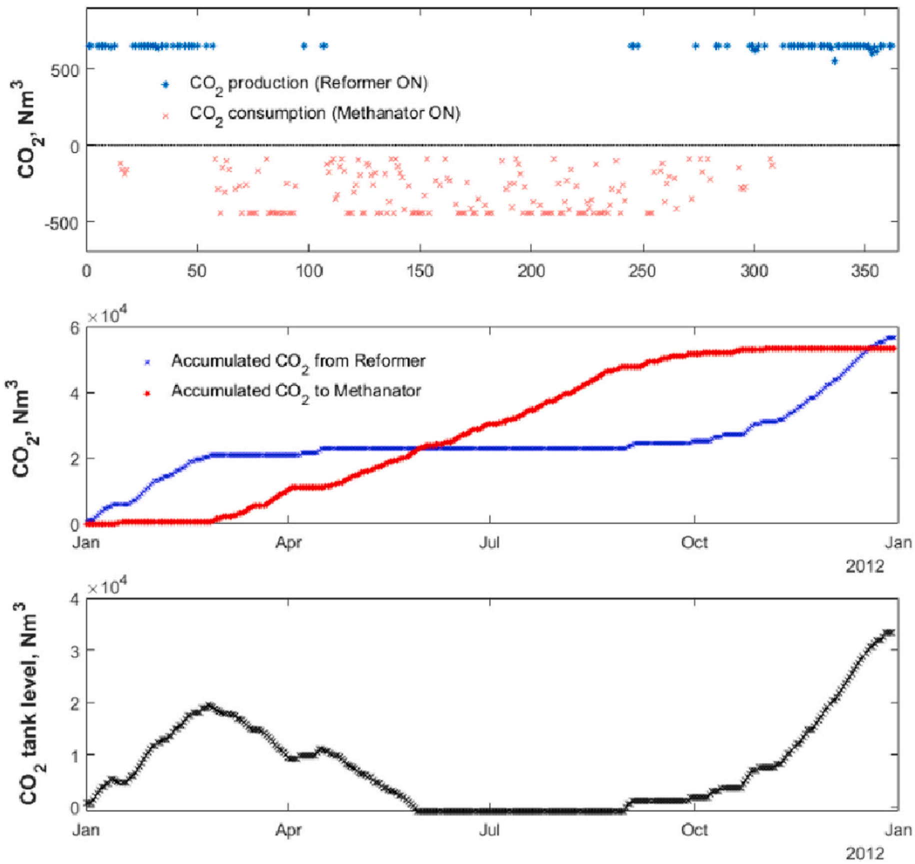

Fig. 7. a) CO_2 profile over the year. During reforming, CO_2 is produced and during the methanation, CO_2 is consumed. b) accumulated CO_2 during methanation and reforming, c) CO_2 accumulation in tank during one year cycle.

that if the full amount of CO_2 was captured and stored from the reformer, there is no need to purchase any new CO_2. However, technically this is not possible as part of the CO_2 is lost with the flue gas from the combustion part unless an external heat source for the endothermic steam reforming was found. To calculate the size of CO_2 tank for full accumulation of CO_2, one can sum up the two peaks in the lower graph

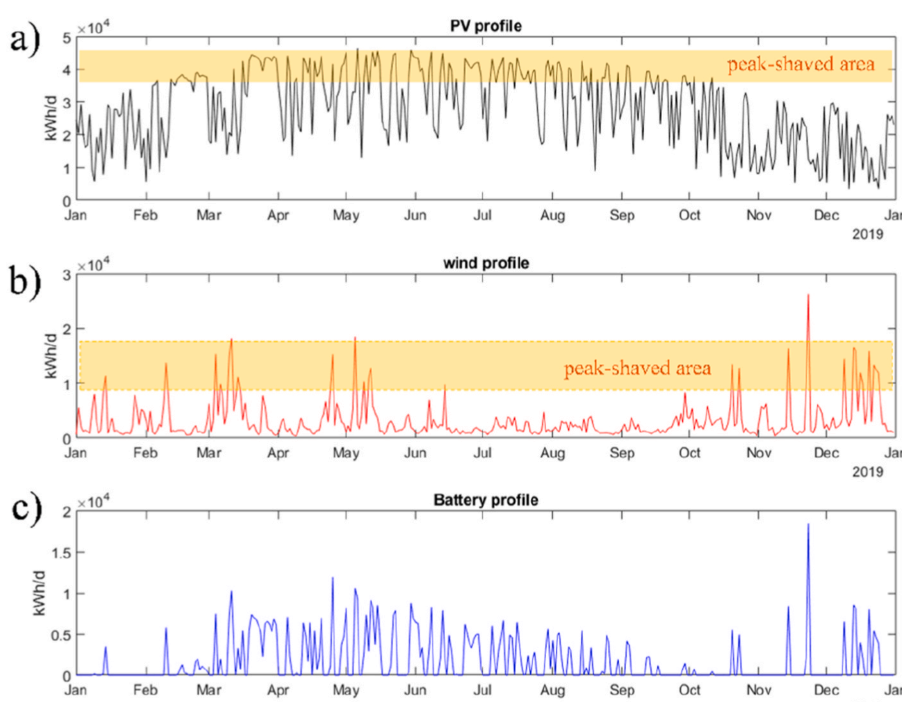

Fig. 8. a) PV electricity generation profile, b) wind electricity generation profile and c) battery load profile for the year 2019, Martigny- Switzerland.

of Fig. 7. This however leads to a tank storing nearly 100 t liquid CO_2 which is not attractive as long a continuous CO_2 supply is available.

3.1.2. Large scale H_2 production

To investigate the interaction of such a seasonally balanced hydrogen supply system with two different volatile renewable sources, i.e. photovoltaic systems and wind turbines, a further scenario PV-Max-Wind-Bat considers hydrogen production by electricity from the PV and wind turbine system, while no electricity from the grid is available. Due to the size of wind turbines, a significantly larger hydrogen demand of 600 kg/day is considered. Such an amount corresponds to two fuel cell driven trains, which can run 1000 km on a single tank of 300 kg H_2. This would allow for example a half-hour rhythm for a local train connection between two towns 30 km apart from each other.

There are large fluctuations in the wind profile as shown in Fig. 8; due to this, a battery upstream of the electrolyser is considered. It was decided to perform peak shaving for both PV and wind profiles, as indicated by the yellow shaded areas in Fig. 8. The corresponding battery profile is also shown in the bottom of this figure. The dynamic electricity generation, hydrogen production and the level of hydrogen in the intermediate tank over the year are shown in Fig. 9.

Knowing the nominal power of wind turbine 2.2 MW, the size of PV-system was calculated to be 6675 kW. If we use PV system with the capacity factor of 18%, the surface required to produce this amount of electricity is estimated 37′000 m^2. The required electrolyser size in this scenario is 6.4 MW with a battery size of 18.4 MWh. Considering a battery with the C-rate of C/3 (i.e. the rate which the battery is discharged relative to its maximum capacity), the electrolyser can be run for ~3 h during night. The sizes of methanation and reformer are 197 kW and 584 kW, respectively.

3.2. The impact of PV profile

As mentioned in section 3.2, all simulations are performed based on the hourly capacity factors of the year 2012. To understand the impact of the variability of the weather situation on the considered energy storage system, the results for the year 2012 are compared to the simulations of a year, in which the number of sunny days is higher. For this reason, the capacity-factor profiles of the PV system in 2012 and 2019 for the site in Rothrist are shown in Fig. 10. According to this figure, the number of sunny days in 2019 is higher than in 2012, especially on the winter days. The scenario PV-MAX was chosen as the base scenario, and the size of electrolysis, methanation and reformer are calculated. The results are shown in Table 4. Due to lower number of sunny days in 2012, the amount of hydrogen directly produced by electrolysis running on PV electricity is lower than in 2019; in consequence, the demand for steam reforming of methane to produce hydrogen is higher. This in turn means that more renewable methane has to be produced during a fewer number of sunny days. As a result, the necessary PV, electrolysis and methanation capacity to cover the balance the seasonal imbalance increases to higher extent (+28%) than the number of sunny hours is decreased compared to 2019 (-6.2%)

The design of such seasonal storage systems should be based on average years, this makes it possible to create in years better than average an excess of renewable methane in the grid, which could be consumed in years which are worse than the average year used for the design of the plant.

3.3. Economic evaluation

The average investment costs for a grid-neutral hydrogen production plant with a capacity of 135 kg_{H2}/day are around 10 Mio $ for the current grid conditions and around 5 Mio $ for future grid conditions. The technical and economic data for the scenarios are listed in Table 5.

The different shares of investment and operation costs for the scenarios are illustrated in Fig. 11. The highest investment costs are obtained for the scenario without the usage of any grid electricity (PV-Max). However, the investment costs for the current grid conditions are only slightly decreased due to the low availability of grid-electricity. The investment costs for the future grid scenarios are approximately half of the ones in the current grid scenarios due to the strongly decreased unit sizes. The higher availability of grid electricity results in higher capacity factors of the units so that they can be decreased in size for the same amount of hydrogen produced.

As will be presented in the next section, the implementation of a battery upstream the electrolyser shows no beneficial costs with the assumed battery costs of 800 $/kWh. Here, an optimisation between costs and battery/electrolyser size was conducted. For the mentioned battery costs, the minimum of the combined costs of battery and electrolyser is found for a decreased size of the electrolyser to 96% with a corresponding required battery capacity of 182 kWh. The largest parts of the investment costs for the large scale scenario, PV-Max-Wind-Bat, belongs to the battery as shown in Fig. 11b.

In most scenarios, the largest parts of the investment costs belong to the PV system and the electrolyser. Together, they represent two thirds of the total investment costs for the current grid scenarios and about half

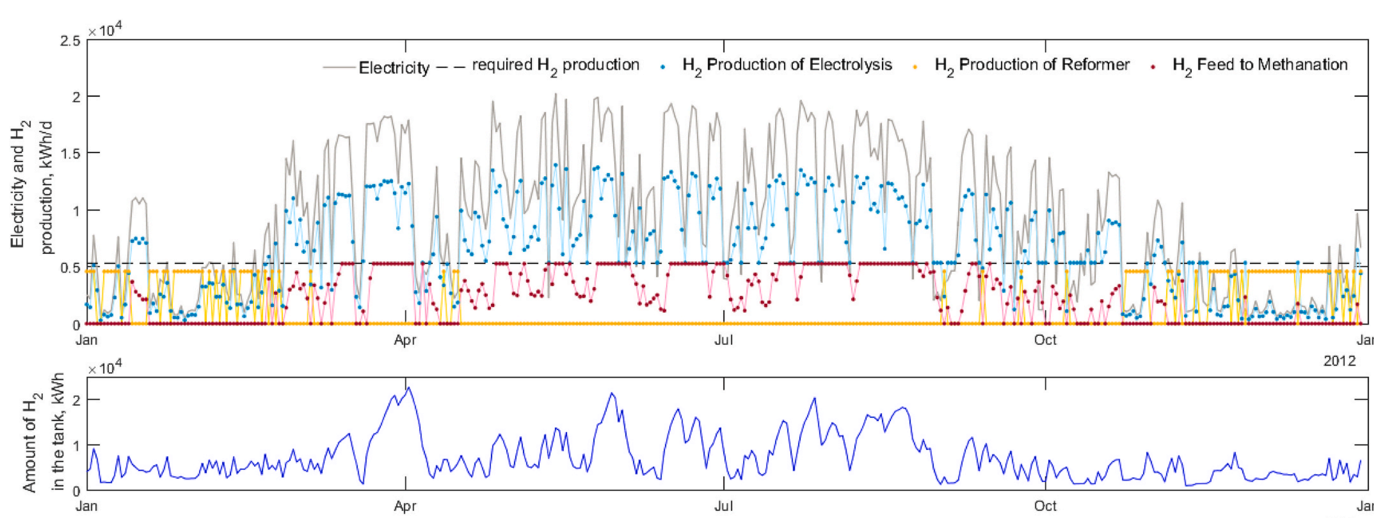

Fig. 9. a) Dynamic electricity and hydrogen production and b) level of hydrogen in the intermediate tank over the year 2019 within the Power-to-Gas system for the site in Martigny, Switzerland. Scenario PV-Max-Wind-Bat.

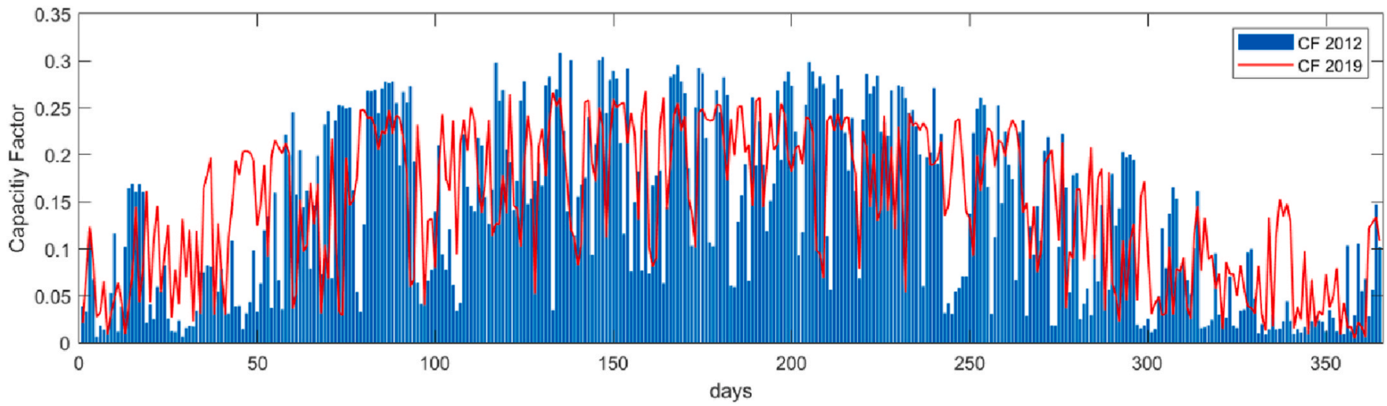

Fig. 10. Capacity-factor profile of the PV system in 2012 and 2019 for the site in Rothrist, Switzerland; data from Ref. [33].

Table 4
Unit sizes for two different years, 2012 and 2019, the scenario PV-MAX.

Unit	2012	2019
Methanation (kW)	314	249
Reformer (kW)	198	194
Electrolysis (kW)	2644	2040
N° days Methanation ON	168	175
N° days Reformer ON	84	60

Table 5
Technical and economic data of the scenarios using the more conservative cost assumptions for electrolysis, PV and the battery.

	PV-GC-Max	PV-GC-Min	PV-GC-Max-Bat	PV-Max	PV-GF-Max-Bio	PV-GF-Max	PV-GF-Min
Size PV system, kW	2819	2819	2819	2908	1436	1028	1031
PV electricity, MWh/a	3399	3399	3399	3507	1735	1242	1246
Grid electricity, MWh/a	121	121	121	0	2840	2033	2039
Size Electrolyser, kW_{el}	2562	2562	1794	2644	1305	935	937
H_2 prod. from Electrolyser, MWh/a	2391	2391	2391	2388	3235	2316	2322
Size H_2 tank, Nm^3	4813	6638	4813	4922	5087	4516	7194
Size Methanation, kW	287	231	287	314	548	304	234
CH_4 prod., MWh/a	704	704	704	696	1196	581	592
CO_2 feed, Nm^3/a	63 858	63 889	63 858	63 143	108 449	52 717	53 704
Size Reformer, kW	199	191	199	198	189	189	165
H_2 prod. from Reformer, MWh/a	457	457	457	451	244	371	381
Total investment costs, k$	10 328	10 257	11 808	10 631	7006	5372	5265
Operating costs, k$/a	369	367	391	367	524	365	364
Production Costs, $/$MWh_{H2}$	545	543	542	568	564	404	404
Revenues, k$/a	493	493	493	493	597	493	492

of the costs for the future grid scenarios. The variation of changed methanation size and corresponding tank size show no effect on the costs. The cost benefits of a smaller methanation unit are compensated by the increased costs for the larger hydrogen tank.

The operating costs for the scenarios are presented in Fig. 11c. The total operating costs are slightly lower for the *current-grid* scenarios due to the smaller amount of purchased grid-electricity. However, due to the higher Operation & Maintenance (O&M) costs, the cost difference between current and future grid conditions is not that pronounced. The scenario with additional biomethane production (PV-GF-Max-Bio) has significantly higher operating costs since more electricity is needed to produce additional hydrogen and in a next step additional methane. The O&M costs are dominant at current-grid conditions with a share of 45%. For the future grid conditions, another big part of the costs is represented by the electricity costs from the grid. However, also the grid-use fees for the PV system have its significance, which are mandatory if the power supply line between PV system and electrolyser is crossing public land.

The production costs of hydrogen including the seasonal storage system of methanation and reformer are between 400 and 570 $/MWh$_{H2}^{HHV}$ for the future and the current case respectively (see Table 5). For these costs, about two thirds refer to the direct production costs of hydrogen with PV-system, electrolyser and fuel station. The other third refers to the storage costs via methanation, gas grid and reformer. In literature, production costs between 180 and 600 $/MWh$_{H2}^{HHV}$ are stated [12,46–48]. The differences in costs depend on the amount of consumed grid-electricity and with that on the capacity factor of the electrolyser. Low hydrogen production cost refers to high capacity factors of about 80% in literature, whereas high production costs are obtained for stand-alone units with capacity factors below 20% and seasonal storage systems. With the obtained capacity factors (i.e. H_2 production from electrolysis*eff./(electrolysis size*8760 h) in this work of 16%–42% for the electrolyser, the obtained production costs fit to the cost interval given by literature for a renewable hydrogen production. The conventional fossil based hydrogen production route is realised via methane steam reforming with production costs between 20 and 40 $/MWh$_{H2}^{HHV}$ depending on the natural gas price [49]. Scenarios regarding the current grid conditions show higher investment costs but slightly lower operating costs in comparison to the scenarios with future grid conditions.

The relation between operating costs, revenues and covered investment costs is illustrated in Fig. 12 for all small scale scenarios. The revenues for all scenarios are by far dominated by the selling of hydrogen to a price of 30.2 Ct/kWh$_{H2}^{HHV}$. Heat revenues are also considered but they contribute to the total revenues only to 1%. For all scenarios without additional biomethane production, the revenues are approximately 500 000 $/a. The revenues for the scenario with additional biomethane production (PV-GF-Max-Bio) increase to approximately 600 000 $/a, but also the operating costs are higher for this

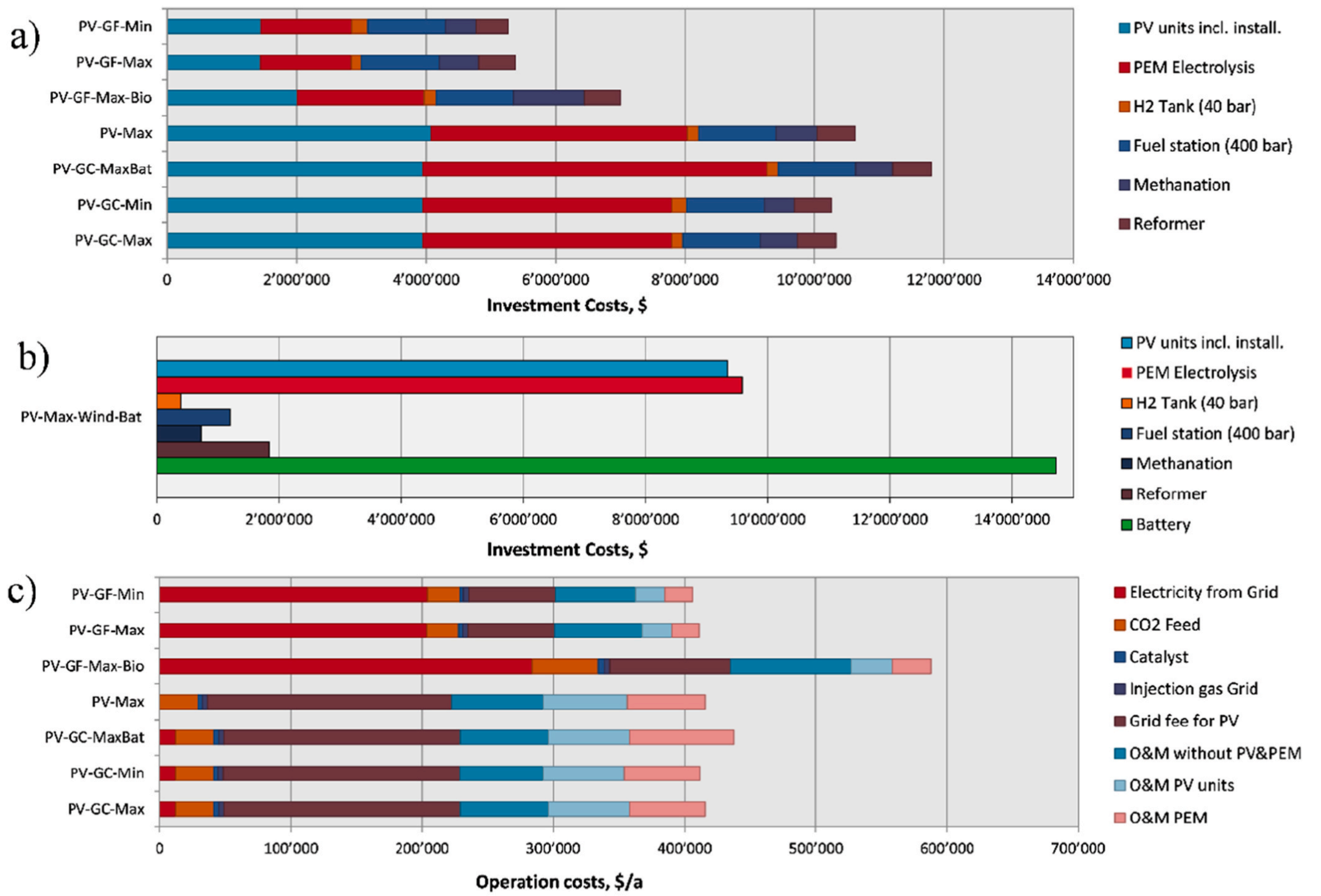

Fig. 11. Shares of a) investment costs, b) share of investment for the large scale scenario PV-Max-Wind-Bat and c) share operation costs of the units for the hydrogen production plant via PtG for the different scenarios.

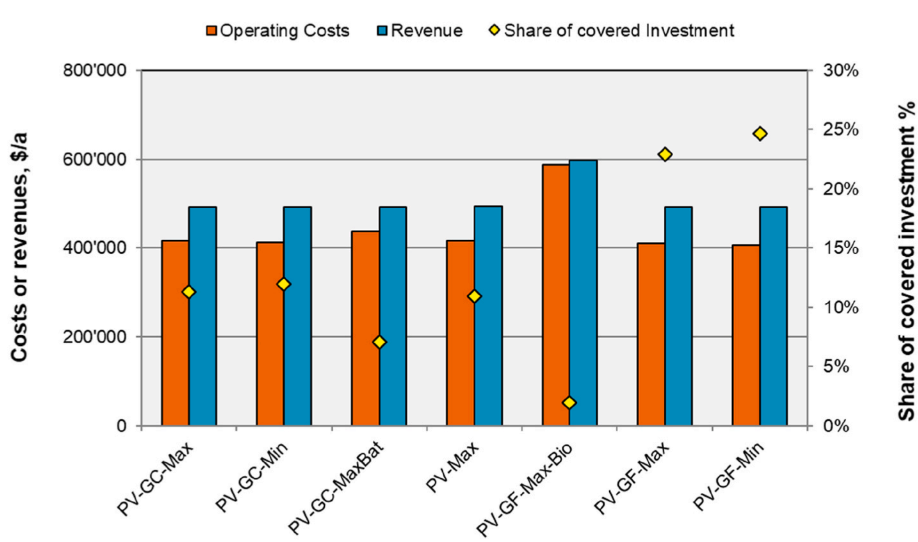

Fig. 12. Operating costs, revenues and share of covered investment costs (regarding EBITDA) for the different scenarios for a hydrogen selling price of 30.2 Ct/ kWh_{H2}^{HHV} with conservative assumptions for CaPEX of PV and electrolyser systems.

scenario. For all scenarios the revenues are higher than the operating costs. Two levels of the share of covered investment costs are evident in Fig. 12. For the scenarios at current grid conditions (GC), about 12% of the investment costs are covered without interest. The scenarios at future grid conditions (GF) show significantly higher shares of covered investments of about 25%. Here, the total investment costs are lower so that despite higher operating costs, the economic situation is more feasible. The situation for the scenario with additional biomethane production (PV-GF-Max-Bio) is worse with a share of only 2%.

For the larger scale plant, the investment costs are including the large battery around 38 million $; the revenues of 2 M$/y exceed the OPEX of 1.1 $/y. This results in a coverage of the CAPEX of the large scale system of 34%.

With the assumed hydrogen price, which is cost-equivalent to the current diesel price per driven kilometre, the hydrogen production plant is not fully profitable since not the whole investment costs can be earned over the lifetime. Additionally, the current diesel price includes a margin for the fuel sellers and taxes, which are not considered for the hydrogen selling price under the used assumptions. On the other hand, possible exemption from heavy duty fees and lower capital costs of electrolysers and PV systems in future are not considered. When using the two more optimistic assumptions for the price of electrolysis (1000 $/kW instead of 1500 $/kW) and for PV systems (1100 $/kW instead of 1400 $/kW), the share of covered investment reaches up to 30% for the future grid scenarios. The difference between revenues by hydrogen selling (500′000 $/a) and operating costs (400′000 $/a) for the two future grid scenarios PV-GF-Min and PV-GF-Max is around 100′000 $/a that covers about a quarter of the annuity (or 30% for the more optimistic assumptions). When comparing to the cost structure of the operating costs in Fig. 11, it is obvious that the grid electricity price needs to go down by a factor two to double the coverage of the annuity. To reach full coverage of the annuity, the hydrogen price has to go up by around 40% (or 1/3 for the optimistic assumptions) and around 60% in case of constant electricity prices (or around 45% for the optimistic assumptions). As the accepted hydrogen price is connected to the Diesel price in 2018, the recent developments show that in future, full coverage of the capital costs might be reached.

3.3.1. *Effect of battery costs*

The battery costs decide whether the usage of a battery upstream the electrolyser is economically beneficial or not. Part of the PV-electricity peak at noon is stored in the battery so that the electrolyser can consume the electricity in the evening hours. This procedure results in a decreased size and a higher capacity factor of the electrolyser. For different sizes of the electrolyser, different storage capacities of the battery are required, which is explained in the right diagram of Fig. 13. The cost savings from the electrolyser must be larger than the costs of the battery itself for improved economics. Depending on the price of the battery, different optimal configurations of battery size and electrolyser size are obtained as it is illustrated in Fig. 13. For a linearly decreased size of the electrolyser, the battery size and therefore the costs are increasing exponentially due to the peak form of the consumption profile of the electrolyser. For a high battery price of 1100 $/kWh, the minimum of investment costs for battery and electrolysis (B + E) together are obtained when no battery at all is implemented. However, with decreasing specific costs of the battery, the combined investment costs B + E form a minimum at a specific electrolyser size and corresponding battery capacity.

The lower the specific costs of the battery are, the more beneficial becomes a bigger capacity of the battery and respectively a smaller size of the electrolysis. As a result, the point of minimum costs shifts towards smaller electrolyser sizes and larger battery capacities. For the actual price of a battery of 450 $/kWh, the minimum of investment costs B + E is obtained for an electrolyser which is 4% smaller than the peak power together with a battery capacity of 182 kWh. Data from literature indicate a decreasing battery price to 250 $/kWh until 2030 [39]. For this price, the minimum investment costs B + E are obtained for a decreased size of electrolysis by 12% and a corresponding battery capacity of 624 kWh. For the actual battery price, the costs benefits are low for the usage of a battery. However, in future with a decreased battery price, 5% of the investment costs of B + E can be saved with the combination of electrolysis and battery. One further advantage of a battery investment is the option to conduct peak-shaving in winter for neighboured consumers, which however is not considered in the cost calculation.

Comparing a power-to-gas system for energy storage with a PV-only system to increase the electricity production in winter for a sufficient hydrogen production, the Power-to-Gas system is economically more feasible. For the option of a larger PV system, the size of the PV unit would need to be ten times larger than for the presented scenarios such that in winter enough electricity was produced for the hydrogen production via electrolysis. As a result, massive excess electricity would be produced in summer and the investment costs only of the PV system would be approximately 30 Mio $ which was about four times more expensive than the whole investment costs of the hydrogen production plant with methanation-reformer storage path of the stand-alone scenario (PV-Max). Additionally, if this concept without storage was applied on national scale, the excess electricity in summer could not be consumed. Hence, the existence and use of a storage infrastructure based on molecules (methane grid, maybe H_2 grid in future) allows avoiding curtailment of PV energy. This value creation from summer PV electricity can be an important pillar for the economic feasibility of large PV

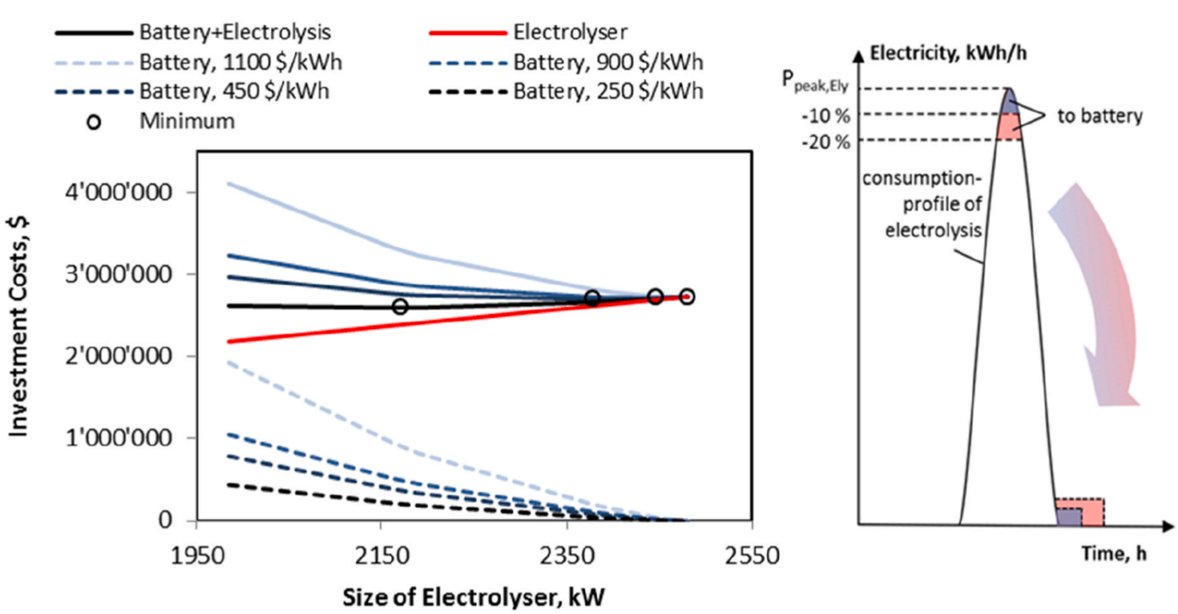

Fig. 13. Sensitivity of battery costs to the combined costs of battery and electrolysis and optimum battery size.

fractions in the energy supply.

4. Conclusions

The grid-neutral and renewable hydrogen production for a fleet of fuel cell vehicles is technically feasible. It is possible to supply the fuel cell vehicles continuously despite high volatilities of the resource streams. The shortage of electricity in winter caused by renewable electricity production can be compensated by steam reforming of methane to hydrogen. The required methane can be produced in summer by excess electricity from the own PV system. The operation of the hydrogen plant is highly dynamic and dependent on weather conditions, which requires advanced controlling of the plant. Stand-alone plants with no electricity grid connection show the highest efforts technically and economically due to low capacity factors and therefore larger sizes of the single units. The more grid-electricity can be used, the better the economic performance within the given limitation (no electricity use when Switzerland has to import it). However, the current electricity production in Switzerland causes already a shortage of electricity in winter so that the usage of grid-electricity in winter is strongly restricted and cannot contribute to considerably higher capacity factors. For future conditions of the electricity production with an increased share of PV electricity in Switzerland, also in winter sufficient electricity is present for some hours per day, which increases the availability of grid electricity in times of need. As a result, the capacity factor of the electrolysis increases and with that also the economic performance. For a sufficient seasonal storage of energy, approximately 50% more hydrogen needs to be produced than the fuel cell vehicles directly consume which passes the storage path of methanation, gas grid and reformer. The overall efficiency from electricity to hydrogen including the storage path is 56% for the current conditions of electricity production and 58% for the future conditions. The production costs strongly depend on the capacity factors of the units, so that for future conditions, economic feasibility is almost reached for a cost-equivalent hydrogen price per driven kilometre in comparison to the actual diesel price. However, for the current conditions only half of the investment costs can be earned after paying the operating costs. Nevertheless, the application of the seasonal energy storage path is clearly less expensive than increasing the size of the PV-system so that in winter enough electricity is produced for the hydrogen production.

Especially with a heat integration between the storage system and neighbouring industrial plants or district heating grids, such local storage system as presented here can increase the resilience of the energy system.

CRediT authorship contribution statement

Julia Witte: Writing – original draft, Visualization, Software, Investigation, Data curation. **Hossein Madi:** Writing – review & editing, Software, Methodology, Investigation, Formal analysis, Data curation. **Urs Elber:** Validation, Supervision, Methodology, Conceptualization. **Peter Jansohn:** Validation, Supervision, Resources, Project administration, Funding acquisition, Formal analysis. **Tilman J. Schildhauer:** Writing – review & editing, Validation, Supervision, Methodology, Investigation, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

This research project, especially the work of J.W., was financially supported by the Kanton Argovia, and the work of H.M. was supported by Professor Alexander Wokaun and the ETH Zurich Foundation within the ReMaP project. All authors would like to acknowledge financial and other support from the ESI Platform at PSI. The authors would like to thank Philipp Dietrich, CTO H_2 energy Switzerland, for valuable discussions.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2024.05.331.

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