Techno-Economic Analysis of Green Hydrogen Production from Solar Energy in MENA and Transport to Central Europe

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Abstract

This techno-economic study investigates a Power-to-Hydrogen (PtH_2) and Power-to-Methane ($PtCH_4$) process chain producing 120 TWh (higher heating value, HHV) hydrogen or methane per year. The aim is to estimate the efficiency as well as the production cost of green hydrogen and methane from solar energy in the MENA (Middle East and North Africa) region followed by transport to central Europe. The examined PtH_2 process chain includes a photovoltaic (PV) system, desalination system, Polymer Electrolyte Membrane Electrolysis (PEM), H_2-storage, and pipeline transport. The $PtCH_4$–process chain contains an additional unit to capture CO_2 from air (direct air capture, DAC) and a methanation unit. Two key aspects are evaluated in this study. The first is the evaluation of optimal capacities of the electrolysis plant with respect to PV capacities and second, the challenge of storing large amounts of hydrogen due to volatile hydrogen production. Results suggest that the cost of hydrogen production in the MENA region and its transport to Central Europe are 12 €-cent/kWh in 2021 and 6 €-cent/kWh in 2050, whereas the purchase costs of methane are 19 €-cent/kWh and 9 €-cent/kWh respectively.

Keywords: Electrolysis, Green hydrogen, MENA, Photovoltaics, Power-to-gas, Process chain, Techno-economic analysis

1. Introduction

The current worldwide consumption of H_2 is 120 Mt or 4,700 TWh (HHV) (2018) (Gielen et al., 2019). According to political initiatives such as the European Green Deal, the hydrogen demand will continue to increase (Europäische Kommission, 2019). 95 % of the hydrogen is currently produced from fossil sources (Gielen et al., 2019), which causes high CO_2-emissions. As anthropogenic greenhouse gases have significantly affected the world's climate, the reduction of CO_2 emissions during the H_2 production process is crucial for H_2 to become a renewable and sustainable energy carrier. Electrolysis using renewable energy and water seems to be a promising technology for the production of carbon neutral green hydrogen. However, large-scale green hydrogen production requires large amount of renewable electricity. Geologically, due to the availability of intense solar radiation, the MENA region holds a high potential to supply energy using photovoltaics (PV) for the production of green hydrogen (Jensterle et al., 2019; van Wijk et al., 2019). In this work, a Power to Hydrogen (PtH_2) process chain in Morocco is assessed that covers the expected German H_2-consumption of 120 TWh (HHV) in 2030 (BMWi, 2020). Additionally, the integration of a CO_2-methanation in the PtH_2 process chain for the production of renewable methane (CH_4) is evaluated. The examined process chain (see Fig. 1) includes solar power generation, water conditioning, electrolysis, and transport to Central Europe. For the alternative Power-to-Methane process chain, this study further investigates a CO_2-capture and a methanation unit.

2. Process chain

To calculate the purchase costs of H_2 in Central Europe, for each part of the process chain (see Fig. 1) the costs are calculated separately using the annuity method (Verein Deutscher Ingenieure, 2012). The sum of levelized costs of hydrogen (LCOH) and transport costs constitute the purchase costs. For the exact location of H_2-production, many regions in MENA are possible. According to different studies, due to its political stability, specialist workers and infrastructure, Morocco is deemed to be a suitable location (Jensterle et al., 2019; van Wijk and Wouters).

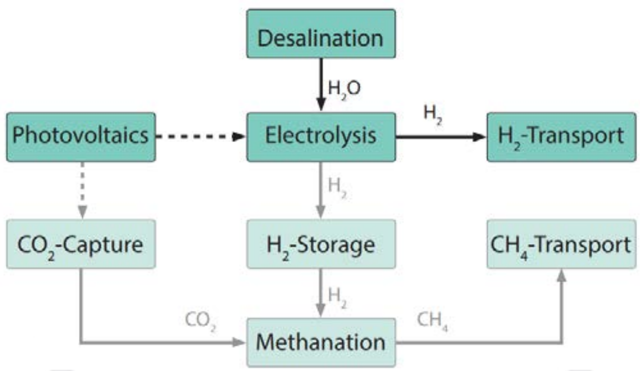

Fig. 1: Process chain of hydrogen production in MENA and pipeline transport to Central Europe. Additional possibility of methanation after H_2-production.

The electrolysis modules make up the main part of the whole process, producing 120 TWh (HHV) H_2 in the desert of Morocco. In contrast to the other systems, PEM electrolysis has many advantages. PEM electrolysis has a flexible response to load changes and hydrogen is produced at increased pressure (see Tab. 2) (Smolinka et al., 2018). These advantages are particularly important with regard to fluctuating electricity generation and the subsequent hydrogen transport using pipelines. Hence, this study considers a PEM electrolysis system for the following calculations. PV cells convert solar radiation into electricity and supply the renewable electricity for electrolysis. Apart from renewable electricity, hydrogen production requires large quantities of freshwater. Freshwater scarcity is a problem especially in MENA. This study considers the desalination of seawater via reverse osmosis as freshwater source. The last part of the process chain forms the hydrogen storage and transport via pipelines (3,000 km). This also includes the compression of hydrogen before its injection into the gas transportation network.

The integration of H_2 in sectors like industry, energy transport, heat and mobility requires changes in existing infrastructure, which is not expected in the short term. Further, H_2 cannot be used in certain sectors at all. To mitigate this, this study investigates a further conversion of hydrogen with carbon dioxide (CO_2) into methane. The conditioning of CO_2 can be performed by capturing it from flue gas of industrial processes like cement production or from ambient air (direct air capture, DAC) (Schäffer et al., 2019). This study primarily investigates capturing CO_2 via DAC. In the DAC process, large quantities of air pass through an adsorbent. The CO_2 adsorbs on the absorbent until it is saturated. The pure CO_2 is then released by heating and applying a vacuum. During the methanation process, carbon dioxide reacts with hydrogen in the presence of a catalyst to produce methane (eq. 1). Suitable rector concepts are fixed bed reactors, bubble columns or honeycomb reactors (Götz et al., 2016).

$$CO_2 + 4\,H_2 \rightleftharpoons CH_4 + 2\,H_2O \quad \Delta_R H = -165\;kJ/mol \qquad \text{(eq. 1)}$$

As a last step, the CH_4 is transported via the existing European natural gas pipeline system to Central Europe.

3. Techno-Economic Analysis

3.1 Simulation of PV power generation

This chapter describes the simulation model applied to evaluate the PV and electrolysis capacities ($P_{PV,max}$, $P_{ELY,max}$) with the goal of minimizing H_2 production costs corresponding to a given solar irradiation profile. The power generated in the PV module fluctuates depending on the weather data. To evaluate $P_{PV,max}$ and $P_{ELY,max}$, the fluctuating PV power P_{PV} (t) is simulated from real weather data at a reference location with the same solar radiation as in MENA (e. g. Morocco) for one year (Wetter et al., 2014). The weather data consists of horizontal diffusive and global solar radiation with a temporal resolution of 15 minutes. The simulation model calculates solar irradiation H_S (t) from weather data on tilted module according to the PV performance indicators orientation, inclination of modules and latitude (see Tab. 1).

Tab. 1: PV performance indicators

Orientation	South
Inclination of modules	25 °
Latitude	34 °
Efficiency	η_{PV} = 17 %
Active area	$\eta_{active\ area}$ = 89 %
$H_{S,max}$	858 W/m²

With solar irradiation H_S (t), efficiencies of PV (see Tab. 1) and PV area A_{PV}, the simulation model calculates the time-resolved PV power P_{PV} (t) for one year (eq. 2).

$$P_{PV}(t) = H_S(t)\, A_{PV}\, \eta_{PV}\, \eta_{active\ area} \qquad \text{(eq. 2)}$$

P_{PV} (t) is restricted by the nominal capacity $P_{PV,max}$, which depends according to (eq. *2*) on the maximum solar irradiation $H_{S,max}$, PV efficiencies and the PV area. Maximum solar irradiation and PV efficiencies are given parameters, whereas the PV area is variable and has to be adjusted to obtain the required $P_{PV,max}$.

Fig. 2 shows P_{PV} (t) (black line) for a PV area of 852 km² with the corresponding nominal capacity $P_{PV,max}$ = 110,7 GW. These two values result from the economic optimization described in the following chapter.

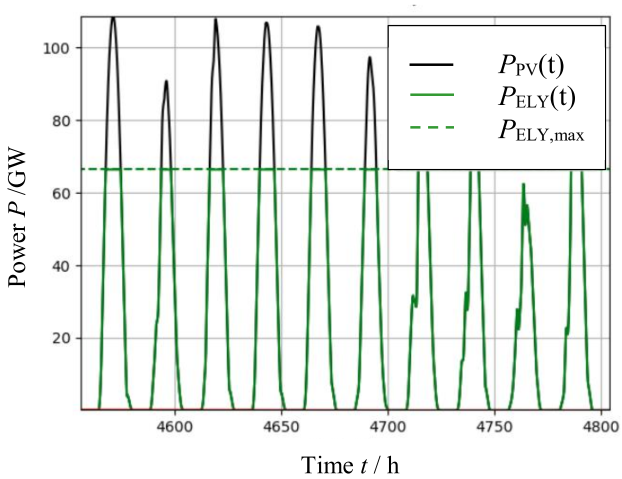

Fig. 2: Fluctuating PV power from weather data (Wetter et al., 2014). Total area A_{PV} = 852 km², $P_{PV,max}$ = 110.7 GW, $P_{ELY,max}$ = 66.4 GW

The electrolysis unit undergoes transient operation to be synchronized with fluctuating renewable energy production. The solid green line in Fig. 2 shows the time dependent power input required by the electrolysis P_{ELY}(t), which equals the generated power of PV. The time during the day in which solar radiation is at maximum and the PV plant output is highest does not last long. To still achieve high full load hours of electrolysis, it is essential to optimize $P_{ELY,max}$ with respect to $P_{PV,max}$. The optimal ratio of these two parameters is evaluated by a parameter sweep described in the following chapter. The parameter optimization results in a value for the nominal capacity of $P_{PV,max}$ = 66.4 GW (see dashed green line in Fig. 2).

3.2 Parameter sweep

This study investigates a techno-economic analysis of a PtH_2-chain producing an annual amount of $E_{H2,ELY}$ = 120 TWh H_2 (HHV). According to (eq. 3), assuming an efficiency (η_{ELY}) of 73 % for the electrolysis plant (Tab. 2), the annual production of 120 TWh requires $E_{el,ELY}$ = 164.4 TWh of electrical energy per year.

$$E_{el,ELY} = \frac{E_{H2,ELY}}{\eta_{ELY}} \qquad \text{(eq. 3)}$$

Tab. 2: Technical parameters of PEM electrolysis (Smolinka et al., 2018)

Efficiency	η_{ELY} = 73 %
Spec. energy demand	4.875 kWh (el.)/m³ (H_2)
Temperature	< 100 °C
Pressure	30 bar
Size of module	100 MW
Stack lifetime	44,500 h

The nominal capacity of electrolysis $P_{ELY,max}$ is calculated from the annual electrical energy demand $E_{el,ELY}$ and the full load hours of the electrolysis plant FLH_{ELY} (eq. 4).

$$P_{ELY,max} = \frac{E_{el,ELY}}{FLH_{ELY}} \qquad \text{(eq. 4)}$$

The FLH_{ELY} is variable and depends on the nominal capacities of the PV and electrolysis plants. Higher FLH_{ELY} can be used to lower $P_{ELY,max}$. And this results in lower investment costs for electrolysis. However, high FLH_{ELY} also requires a higher availability of electricity from the PV plant. This implies higher nominal capacities of PV units, which in turn increases PV investment costs.

The focus of this study is to minimize the levelized cost of Hydrogen (LCOH). For this, a parameter sweep is performed with the aim of finding the optimal ratio of nominal capacities for electrolysis and PV ($P_{ELY,max}/P_{PV,max}$) that would minimize the LCOH (see Fig. 3). The parameter sweep is performed by variation of $P_{ELY,max}$ for a constant $P_{PV,max}$ = 110.7 GW. Finding the value of constant $P_{PV,max}$ is an iterative process. The iteration is finished when at the ratio with lowest LCOH the electrolysis plant delivers the required amount of hydrogen ($E_{H2,ELY}$ = 120 TWh (HHV)). One iterative step includes the following calculations for each ratio between $P_{ELY,max}/P_{PV,max}$ = 0.1 - 1 in steps of 0.1:

- The FLH_{ELY} are calculated by integrating the dynamic electrolysis power input P_{ELY} (t) (see Fig. 2) over one year, divided by $P_{ELY,max}$ (eq. 5 or (eq. *4* transposed).

$$FLH_{ELY} = \frac{\int_0^t P_{ELY}(t)\ dt}{P_{ELY,max}} \qquad \text{(eq. 5)}$$

- The utilization is defined by the ratio of annual electricity demand of the electrolysis $E_{el,ELY}$ unit to the maximum possible electricity generation $E_{el,PV}$ (eq. 6).

$$Utilization = \frac{E_{el,ELY}}{E_{el,PV}} = \frac{\int_0^t P_{ELY}(t)dt}{\int_0^t P_{PV}(t)dt} \qquad \text{(eq. 6)}$$

- Specific investment of electrolysis $CAPEX_{spec,ELY}$ is defined by the annual investment of electrolysis $CAPEX_{a,ELY}$ divided by the energy amount of annual produced hydrogen (eq. 7). $CAPEX_{a,ELY}$ is calculated by annuity method, where $CAPEX_{i,ELY}$ is the initial investment at given nominal capacity, i = 0.691 is interest rate and n = 20 a is depreciation time of electrolysis plant.

$$CAPEX_{spec,ELY} = \frac{CAPEX_{a,ELY}}{E_{\mathrm{H2,ELY}}} = \frac{\frac{CAPEX_{i,ELY}}{\sum_{\mathrm{t=0}}^{\mathrm{n}} \frac{1}{(1+\mathrm{i})^{\mathrm{t}}}}}{E_{\mathrm{H2,ELY}}} \qquad \text{(eq. 7)}$$

- Levelized cost of electricity (LCOE) results from the sum of annual investment and operational costs divided by the energy amount of electricity used (not produced) for hydrogen production (eq. 8). $\mathrm{CAPEX_{a,PV}}$ is, calculated by annuity method (eq. 7) from the initial investment costs for at given nominal capacity with an is interest rate of *i* = 0.691 and depreciation time *n* = 25 a is for electrolysis plant.

$$LCOE = \frac{CAPEX_{a,PV} + \mathrm{OPEX_{a,PV}}}{E_{\mathrm{el,ELY}}} \qquad \text{(eq. 8)}$$

- LCOH is defined as the sum of annual investment and operational costs of electrolysis, divided by the energy amount of annual produced hydrogen (eq. 9). The LCOE are included in the OPEX of electrolysis.

$$LCOH = \frac{CAPEX_{a,ELY} + \mathrm{OPEX_{a,ELY}}}{E_{\mathrm{H2,ELY}}} \qquad \text{(eq. 9)}$$

The calculation of the parameters described above is based on specific cost data from literature (see Tab. 3).

Tab. 3: Economic parameters for PV and PEM electrolysis plant

	Unit	**Today**	**2030**	**2050**
Interest rate (Bundesnetzagentur, 2017)	%		6.91	
PV				
$\mathrm{CAPEX_{PV}}$(Kreidelmeyer et al , 2020)	€/kW (peak)	550		
$\mathrm{OPEX_{PV}}$ (Kreidelmeyer et al , 2020)	€/kW (peak)	12		
LCOE 2030, 2050 (Brändle et al., 2020; Kost et al., 2018)	€-cent/kWh		2.4	1.4
Depreciation time	a		25	
PEM electrolysis				
$\mathrm{CAPEX_{PV}}$ (Smolinka et al., 2018)	€/kW (el.	619	417	413
$\mathrm{OPEX_{PV}}$ (Smolinka et al., 2018)	€/kW (el.	13	8	7
Depreciation time	a		20	

At a low ratio of nominal capacities, high full load hours is possible for the electrolysis unit (Fig. 3, grey bars). At the same time, LCOE is high because of the high amount of unused electricity (green triangles). At $P_{\mathrm{ELY,max}}/P_{\mathrm{PV,max}} = 1$, the full load hours of electrolysis (FLH_{ELY}) is equal to the FLH of PV (1,700 h/a). In this case the LCOE is low but due to higher electrolysis investment costs, the specific $\mathrm{CAPEX_{spec,ELY}}$ rise (black crosses). The utilization of the solar energy rises with the ratio of nominal capacities and at $P_{\mathrm{ELY,max}}/P_{\mathrm{PV,max}} = 1$ the utilization is 100 %.

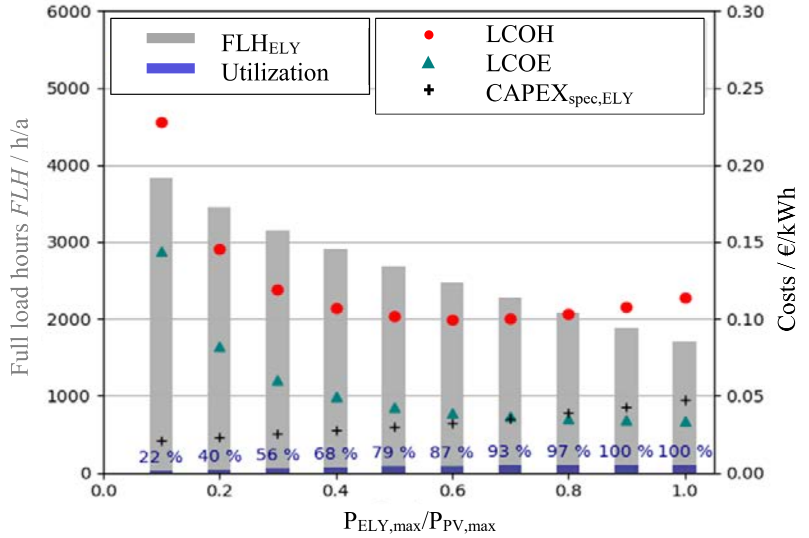

Fig. 3: Parameter sweep to find the minimum levelized costs of hydrogen. Depreciation time PV or ELY: 25 a or 20 a, interest rate (both): 6,91 %, $CAPEX_{PV}$ = 550 €/kW (peak), $OPEX_{PV}$ = 12 €/kW (peak)/a, $CAPEX_{ELY}$ = 619 €/kW (el), $OPEX_{ELY,fix}$ = 13 €/kW (el)/a

The parameters described above, influence the LCOH (red dots) and cause a minimum at a ratio of $P_{ELY,max}/P_{PV,max}$ = 0.6. Tab. 4 shows the set of parameters that results from the minimum ratio.

Tab. 4: Results from parameter sweep

LCOH	10 €-cent/kWh
LCOE	3.9 €-cent/kWh
FLH	2,450 h/a
Utilization	87 %
Ratio P_{ELY}/P_{PV}	0.6
$P_{ELY,max}$	66.4 GW
$P_{PV,max}$	110.7 GW

3.3 Transport and storage

Various options are possible for transporting hydrogen from Morocco to Germany. It is possible to transport hydrogen via a newly built hydrogen pipeline or via a repurposed natural gas pipeline. Another possibility is to liquefy the hydrogen and transport it by ship. Furthermore, the hydrogen can be transported chemically bound in form of liquid organic hydrogen carrier (LOHC) or ammonia. As suggested in several studies, this study examines the construction of a new H_2 transport pipeline from Morocco via Spain and France to Germany (see Fig. 1) (Gielen et al., 2019; Michalski et al., 2019; van Wijk et al., 2019; van Wijk and Chatzimarkakis, 2020).

Fig. 4: Pipeline transport route from Morocco via Spain and France to Germany (3000 km)

Hydrogen injection into the gas pipeline is not continuous due to volatile production. Huge hydrogen buffer tanks or underground storages are therefore needed to homogenize the gas flow into the pipeline. As buffer tanks need lot of space and underground storage in Morocco is not sufficiently studied yet, this work suggests a conceptual design in which the first part (400 km) of the gas pipeline is used as the storage unit. The first part has the required capacity to store 52 Mio. m³ (NTP) and balances the fluctuating H_2 production, while the second part (2,600 km) transports the hydrogen to Europe. The first part of the transport pipeline risks large pressure fluctuations and hydrogen embrittlement. This means that the pipeline material and design may be subject to high safety requirements which may lead to higher costs.

The maximum pressure in the H_2 pipeline is 100 bar with a pressure loss of Δp = 0.175 bar/km at maximum gas velocity of v_{gas} = 20 m/s. The distance of compressor stations is restricted by the maximum pressure loss of Δp = 50 bar, which leads to a compressor distance of 250 km in the second part of the pipeline. The compressors are driven by renewable electrical energy, as using valuable hydrogen for the turbine would increase the OPEX. The CAPEX of H_2 transport consists of investment costs for the pipelines (material, labor, right of way) and compressors. OPEX include costs for electricity and maintenance. All technical and economic parameters for the H_2 transport are shown in Tab. 5 and Tab. 6.

Tab. 5: Technical parameters of pipeline transport

		Unit	**Part 1**	**Part 2**
Head compressor	Compressor capacity P_{Comp}	MW	673	-
	Pressure in p_{in}	bar	30	-
	Pressure out p_{max}	bar	100	-
Pipeline and compressor stations	Transport capacity	GW (CH_4 HHV)	48	26
	Utilization	h/a	2,475	4,500
	Max.pressure p_{ein}	bar	100	100
	Min. pressure p_{min}	bar	20	56
	Length L	km	400	2,600
	Diameter d	inch	56	48
	Velocity v_{gas}	m/s	28	20
	Compressor power P_{Comp}	MW	246	164
	Polytropic efficiency η_{poly}	%	90	90
	Electric efficiency η_{el}	%	90	90
	Effficiency, shaft η_{Welle}	%	98	98
	Compressor distance	km	133	250
	Number of compressors	-	2	11

Tab. 6: Economic parameters of pipeline transport

		Unit	Part 1			Part 2
	LCOE Morocco (Brändle et al., 2020; Kost et al., 2018)	€-cent/kWh	**2020** 3.9	**2030** 2.4	**2050** 1.4	-
	LCOE Spain and France today, 2030 and 2050	€-cent/kWh		-		8
	Interest rate (Bundesnetzagentur, 2017)	%		6.91		6.91
Head compressor	Spec. CAPEX (Posch, 2019)	Mio. €/MW		3.57		-
	OPEX (fix)	% of investment		1		-
	OPEX (variable, electricity)	Mio. €/a	**2020** 74	**2030** 45	**2050** 26	-
	Depreciation time	a		25		-
Pipeline	Spec. CAPEX pipeline (Posch, 2019)	€/m		4,345		3,410
	Spec. CAPEX compr. (Posch, 2019)	Mio. €/MW		3.57		3.57
	OPEX (fix)	% of investment		1		1
	OPEX (variable, electricity)	Mio. €/a	**2020** 54	**2030** 33	**2050** 19	725
	Depreciation time compressor	a		25		25
	Depreciation time pipeline	a		50		50

4. Results

Fig. 5 shows the purchase costs of hydrogen produced in Morocco and transported to Central Europe. Purchase costs consist of LCOH and transport costs. Additionally purchase costs of a forecast for the years 2030 and 2050 are presented. Results suggest that purchase costs of H_2 are 12.3, 8.2 or 6.3 €-cent/kWh H_2 (HHV) for today, 2030 and 2050 respectively. Electricity costs (PV) account with 27 % - 43 % which is the largest or second largest share of costs.

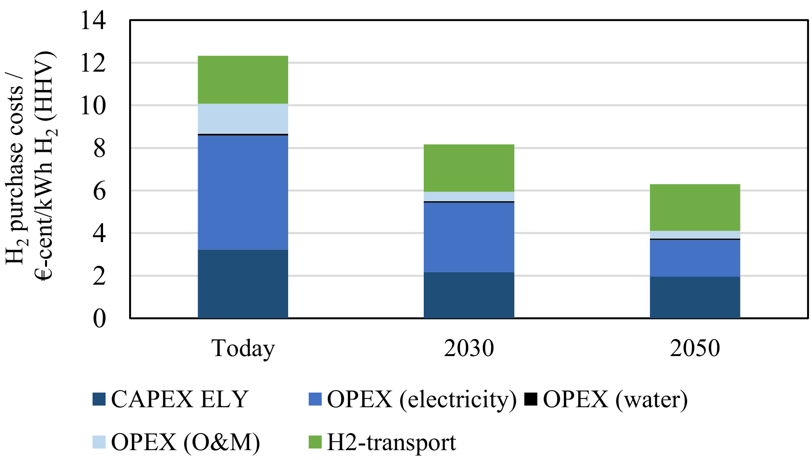

Fig. 5: Hydrogen purchase costs today and a forecast for 2030 and 2050

A forecast for 2050 reveals that the costs decrease by nearly 50 % to 6.3 €-cent/kWh H_2 due to savings in investment costs of electrolysis and PV modules (see Tab. 3). Conventional grey hydrogen via steam reforming costs around 3 €-cent/kWh (Bär et al., 2021). Compared to conventional H_2 production via steam reforming, H_2 from water electrolysis provides a technology with low CO_2-emissions. CO_2-emissions of steam reforming process are between 0.25 kg CO_2/kWh H_2 and 0.34 kg CO_2/kg H_2 and emissions from the PtH_2 process are around 0.09 kg CO_2-eq/kg H_2 (Bär et al., 2021).Another possibility to import renewable gas includes the methanation of H_2 with CO_2. Results of the techno-economic analysis of a $PtCH_4$ process chain (see) investigated other studies is depicted in Fig. 1 (Lehnert et al., 2021). The main aspect here is the economic optimization between H_2-storage volume and methanation capacity to identify minimum CH_4 purchase costs. Results show, that methane purchase costs are higher than hydrogen import costs due to the additional process steps (see Fig. 6). Especially direct air capture accounts for a large part of the costs (19 %) of which 61 % accounts for electricity and heat costs. Lux et al. calculated a similar process chain and has confirmed the results of this study. (Lux et al., 2021)

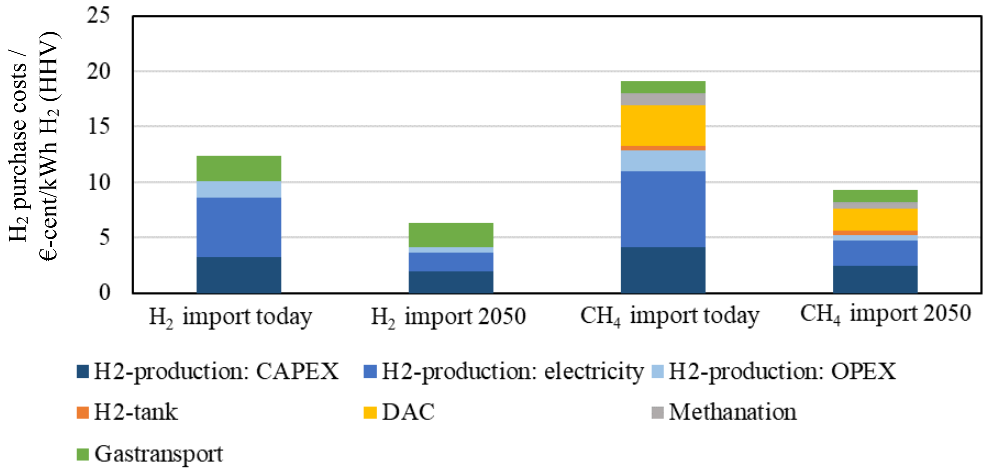

Fig. 6: Comparison of green H_2 and green CH_4 purchase costs

5. Summary and Outlook

This study suggests a technical design and economic evaluation of a PtH_2-chain delivering 120 TWh H_2 (HHV) per year to Central Europe. A simulation of time-resolved PV and electrolysis power was performed based on weather data to evaluate nominal capacities. The economic optimization between PV and electrolysis nominal capacity reveals, that LCOH is lowest at a ratio of $P_{ELY,max}/P_{PV,max} = 0.6$. At this ratio, full load hours of electrolysis is 2,475 h/a, the electricity price amounts to 3.9 €-cent/kWh and the LCOH is estimated to be 10 €-cent/kWh. Additionally, a technical design of a pipeline system was performed to store large amounts of H_2-and transport the H_2 to Central Europe. The first part (400 km) of this pipeline system has the capacity to store 52 Mio. m³ (NTP) to balance the fluctuating H_2 production and the second part (2,600 km) transports the hydrogen to Europe. Due to high pressure fluctuations in the storage unit, the risk of hydrogen embrittlement and material failure increases. Further investigation is necessary to ensure a reliable operation of hydrogen storage units.

The sum of LCOH and transport costs are the purchase costs. Results suggest that the purchase costs of hydrogen for today, 2030 and 2050 are 12.3, 8.2 or 6.3 €-cent/kWh H_2 (HHV) respectively.

Methane is still used in various sectors like industry, heat, and mobility. In contrast to H_2, the use of methane requires no transformation of the respective sectors. In addition, the existing natural gas network is capable to transport large amounts of renewable methane without changes in the system. Therefore, no approval processes are necessary and a quick integration of renewable energy in various sectors in form of gas is possible. Still, CH_4 purchase costs (today: 19 €-cent/kWh CH_4 (HHV)) are higher than H_2 purchase costs due to additional process steps. To improve the efficiency of the $PtCH_4$ process, an integration of a high temperature electrolysis or the electricity generation by a combination of solar and wind power should be investigated.

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