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Potential of Power-to-Methane in the EU energy transition to a low carbon system using cost optimization

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HIGHLIGHTS

- Scenarios show up to 546 GW PtM capacity with 27 of 55 of them above 40 GW.
- Large PtM capacity (~550 GW) can be deployed with limited impact on system cost.
- System drivers favoring PtM are low CO_2 storage potential and > 60% VRE penetration.
- System drivers exert more influence over PtM potential than technology drivers.

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ABSTRACT

Power-to-Methane (PtM) can provide flexibility to the electricity grid while aiding decarbonization of other sectors. This study focuses specifically on the methanation component of PtM in 2050. Scenarios with 80–95% CO_2 reduction by 2050 (vs. 1990) are analyzed and barriers and drivers for methanation are identified. PtM arises for scenarios with 95% CO_2 reduction, no CO_2 underground storage and low CAPEX (75 €/kW only for methanation). Capacity deployed across EU is 40 GW (8% of gas demand) for these conditions, which increases to 122 GW when liquefied methane gas (LMG) is used for marine transport. The simultaneous occurrence of all positive drivers for PtM, which include limited biomass potential, low Power-to-Liquid performance, use of PtM waste heat, among others, can increase this capacity to 546 GW (75% of gas demand). Gas demand is reduced to between 3.8 and 14 EJ (compared to ~20 EJ for 2015) with lower values corresponding to scenarios that are more restricted. Annual costs for PtM are between 2.5 and 10 bln€/year with EU28's GDP being 15.3 trillion €/year (2017). Results indicate that direct subsidy of the technology is more effective and specific than taxing the fossil alternative (natural gas) if the objective is to promote the technology. Studies with higher spatial resolution should be done to identify specific local conditions that could make PtM more attractive compared to an EU scale.

1. Introduction

Anthropogenic emissions need to be drastically reduced if the increase in global temperature is to be maintained within 1.5 °C compared to pre-industrial times. Global emissions need to be cut by more than 50% by 2050 (vs. 2010) with developed countries carrying out a larger change [1]. Key components to achieve this target are energy efficiency, renewable energy sources (RES) including biomass and carbon capture and storage (CCS). Wind and solar[2] are identified as crucial technologies for the early stages of the transformation. A disadvantage they have is their great variability in time and space. Therefore, there is a need for complementary alternatives to provide flexibility to the system and compensate their fluctuations. Power-to-Gas (PtG) arises as option to satisfy this need. PtG implies the conversion of Power-to-Hydrogen, which can be subsequently used as energy carrier (i.e. hydrogen economy [2–4]) or as reactant for further compounds (e.g. methane, methanol, long chain hydrocarbons). Typical efficiencies (energy output vs. energy input) are 65–75% for Power-to-

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[1] The views expressed are purely those of the authors and may not in any circumstances be regarded as stating an official position of the European Commission.
[2] Referred in the rest of the document as VRE = Variable Renewable Energy.

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Hydrogen (electrolysis), 75% for hydrogen to methane [5,6] (HHV). The term PtG refers to the conversion of Power-to-Hydrogen and methane (both gases) and for that reason PtM will be used henceforth to refer to methane. Key advantages of PtM are: (1) It allows converting power into a commodity that can be used to reduce CO_2 emissions in other sectors; (2) It uses existing infrastructure; (3) When considered as storage option, it has a high energy density (CH_4 has > 1000 kWh/m^3 while hydrogen has 270 kWh/m^3 and pumped hydro storage has 0.7 kWh/m^3 and [7]) and over 1000 TWh of storage capacity already deployed and operating; (4) It is suitable for long term and large scale storage.

Nevertheless, the technology does not come without challenges. Currently, it is in the early stages of development (Technology Readiness Level – TRL [8–10] 5–7 [11,12]) and more research is needed to de-risk it and promote its large scale deployment. Economically, it needs a low electricity price (< 10 €/MWh [13,14]), low specific CAPEX (currently up to 1500 € per installed kW of synthetic gas [13,15]) and high number of operational hours (> 3000 h to reduce the CAPEX contribution to the cost) to reach a similar price as fossil-derived natural gas including additional costs (e.g. CO_2 certificates). Environmentally, it needs a low electricity CO_2 footprint [16–19] (< 50 gCO_2e/kWh) to represent a better alternative than fossil gas and lead to net CO_2 reduction. These conditions make the use of biogenic CO_2 and power from renewable sources the best sources for its process inputs.

This study aims to explore alternative low CO_2 emission scenarios (reduction targets of > 80%), where it is envisioned that PtM will play a key role and understand better the drivers that promote its use in the energy system. The approach chosen is cost optimization of the entire energy system looking at the longer term (2050) and at a large scale (European level). The reasons for this selection are: (1) PtM is a technology connecting various sectors and there lies the importance of looking beyond power; (2) Only in the long term low carbon scenarios will be achieved; (3) Most previous studies focus on a local or national scale with few considering the dynamics of the entire EU region and (4) Cost optimization is the first step to identify the most economically sustainable routes to meet energy demand. Some of the key insights that can be gained with this approach are: (1) RES fraction (or CO_2 reduction target) that makes PtM necessary (or result in a lower cost system); (2) Amount of PtM used in different scenarios (capacity and energy); (3) Difference in deployment due to different technology parameters (cost and efficiency); (4) Comparison with competing flexibility options (e.g. pumped hydro storage, batteries, demand side management (DSM), grid expansion, excess of installed capacity); (5) Additional system cost for presence/absence of the technology. To explore these issues, an energy system model is used, which allows analyzing the evolution of the capacity mix considering investment and operational components.

The energy model used is JRC-EU-TIMES [20], which covers the EU28 plus Switzerland, Norway and Iceland,[3] where each member state (MS) is one region. Its temporal horizon is from 2010 to 2050 (although it can be used beyond this timeframe). To reduce calculation time, it uses hierarchical clustering into representative hours of a year (24 time slices for the power sector and 12 for others), when there are different levels and compositions of supply and demand. Prices for all commodities are endogenous considering the supply and demand options, demand elasticity and consumer and producer surplus. It covers 5 sectors (residential, commercial, industry, transport and agriculture). The approach followed is parametric analysis, where individual parameters are changed and their effect is evaluated on both the entire system and the specific technology.

Key questions that are answered in this study are: (1) What is the PtM capacity deployed in potential future low carbon scenarios for EU; (2) What are the conditions that promote PtM deployment; (3) How does PtM compare with other flexibility options; (4) What is the effect PtM has on system cost and (5) What are the CO_2 sources that PtM uses when it is deployed in the energy system.

This study is structured in the following manner. Section 2 makes the comparison between the model used in this study and literature. Section 3 explains model topology and structure with focus on PtM. Section 4 is dedicated to the scenario definition. Section 5 discusses the results for the different scenarios and summarizes key outcomes. Finally, Section 6 highlights key conclusions, input for further studies and subsequent work.

2. Literature review and gaps

CO_2 methanation is currently not widely employed, with only a handful of pilot projects, most of them located in Germany (10 projects) and where the largest scale is 6 MW [21,22]. This technological approach has drawn interest in the last couple of years and power conversion to hydrogen only has been more thoroughly discussed [23–27]. Before a major technology rollout, further research, pilot and demonstration plants are required. CO methanation, on the other hand, is deployed in larger scale, however, often with fossil feedstock [21]. A review on PtM was recently done by the authors [28] including 66 studies on PtM and discussing 13 with a special emphasis on energy system models, which is the scope of the current study. Insights from these studies are included in Section 5 to put in perspective results from the current study. It has been identified that there are a set of features each model can cover, but there are trade-offs to be made to limit model complexity and calculation time, where no model includes all features. These are used to compare this study with previous ones and understand the remaining gaps. The different features are:

- *Hourly time step*. This allows better estimating the electricity surplus and hourly choices on options to manage it. It better captures generation flexibility (ramping of power plants) and storage role.
- *Capacity expansion*. Some models [14,29,30] focus on the operational component or use a simulation approach [31] without finding an optimal PtM capacity for a given scenario. Capacity constitutes an exogenous input rather than an output. This could lead to overestimating the role of PtM since the capacity used might not be needed.
- *Energy system coverage*. Some models [30,32–34] focus on the power sector and dealing with power surplus rather than using the surplus for other sectors (e.g. PtX[4]) or finding alternatives routes to deal with the gas demand. Therefore, the coverage should be the entire energy system instead of power only.
- *Grid expansion*. The model should be able to make the trade-off between using (or curtailing) power surplus and investing in the grid to find a sink far enough from the source. For this, the model should have both the investment component and at least a simplified grid representation.
- *Other flexibility options*. With more alternatives to accommodate fluctuations, there is a lower chance of overestimating PtM role. The model should cover as many as possible from: optimal wind/PV ratio (due to its complementary patterns [35–37], DSM, short and long term storage, grid expansion, flexible generation, PtX, to make sure the model has enough outlets for any possible electricity surplus.
- *Endogenous commodity prices*. PtM economic case is directly dependent on the prices for electricity/hydrogen and methane. These are determined by supply/demand dynamics. Models should capture dynamics that determine these prices rather than take them as exogenous assumptions.

[3] Referred from this point onwards as "EU28+".

[4] PtX = Power-to-X = Power-to-Heat, Hydrogen, Methane, Methanol and other liquids.

- *Geographical scope*. PtM has been analyzed on a local [32,38,39], national [40–42], regional [43–45] and global [33,46] scale. Resolution, data requirements and conclusions will be different depending on the scale of the model. A higher spatial resolution will require either small geographical scope or fewer model features from this list.
- *Technology performance*. The study should assess the difference of deployment due to different cost or efficiency since this remains a large uncertainty for the technology due to its needs for development and limited deployment.
- *Variable RES/CO_2 targets*. Need for PtM is greater for low carbon systems [47,48] and it is important to understand how its role can change for a variable target of the system.

Not all of these have been covered by a single study and the challenge lies in trying to cover as many as possible while still using the right tool for the right purpose and still keeping model complexity at a manageable level (both for use and understanding of results). For a list of the studies and features included in each one, refer to [28]. The current study counts with all the features above, except for an hourly time step. An area where a trade-off has been made and where further work will be needed is the temporal and spatial scales. The model represents the year in 12 time slices (24 TS for power sector) and additional constraints are introduced to improve the representation of possible excess of variable RES, but its output will differ from an hourly model. Each country is a single node, there is no spatial allocation within the node for generation and consumption and there is a simplified consideration of the transmission and distribution grid.

This study works towards closing the gap of determining PtM capacity on a European scale with an energy wide model that counts with enough flexibility options to deal with power surplus (storage, hydrogen, Power-to-Liquid (PtL), Power-to-Heat and DSM). This is relevant since some studies [32,39,49–51] only look at the possible use of power surplus for PtM without considering if there are better options or even if the alternative will have a positive economic return, while others [52–54] look at the potential and possible outlook for the technology based on cost, performance and foreseen electricity growth without establishing the trade-off with other options for either electricity surplus, CO_2 use or meeting final energy demand. Another gap covered is the exhaustive uncertainty analysis done on the influence of various parameters and assumptions and these affect future system evolution and methanation.

3. Model topology and representation

TIMES model is a partial equilibrium, linear optimization, bottom-up technology model created with the generator from Energy Technology System Analysis Program (ETSAP) of the International Energy Agency [55–57]. Its objective is the satisfaction of energy services demand while minimizing (via linear programming) the discounted net present value (NPV) of energy system costs, subject to several constraints. Energy system optimization is different from doing NPV calculations for analyzing the business case of a certain technology. The most important difference is that in an energy system model, prices (e.g. for electricity) are not predefined, but endogenous.

As a partial equilibrium model, JRC-EU-TIMES does not model the economic interactions outside of the energy sector. However, it does capture the most important feedback through the use of price elasticities that change the final energy demand of services. This is a proxy for converting the cost minimization to economic surplus maximization. Moreover, it does not consider in detail demand curves and non-rational aspects that condition investment in new and more efficient technologies.

A key feature of the model is that the end use demand is not defined as power, gas, oil demand, but instead the services that are satisfied with those commodities (e.g. number of houses, space to be heated, materials, traveling distance) and the energy carrier used to satisfy those needs is an endogenous option.

There are common characteristics and limitations of energy system models, specifically with cost optimization. These include in terms of approach: perfect foresight (knowledge in the base year of all the future demand and global prices), central optimization (best decision across sectors, which in reality include many stakeholders), rational behavior (choice for cost optimal alternative without consideration of politics, social acceptance, personal interests) and perfect competition (no market distortions).

The structure and considerations of this specific model have been covered in the past [20,58–61]. This section builds upon that effort and explains the scope of the model in more detail. The criteria to reflect information in this section is either (1) Sections that have been improved with respect to those previous publications or (2) Due to its relevance for PtM to make sure it is clear what is included (and how it is represented) in the model. Some parts of the model (e.g. hydrogen or biomass) are explained in more detail in a parallel publication [62] (in preparation).

3.1. Overview of major inputs

The key parameters used as input to the model are:

- *Macroeconomic data*. This includes energy services and material demand projections, differentiated by economic sector and final use service. These are taken from [63], which uses the GEM-E3 model. The other macroeconomic variables are the fuel import prices for oil, gas and coal, which are in line with [63] and taken from POLES. Global fuel prices reach almost 100 $/bbl for oil, 10 $/MMBtu (7.9 €/GJ) for gas and 100 $/ton for coal. See Appendix A for more details on price evolution in time for individual commodities.
- *Base year calibration*. Mainly done with Eurostat and an internal JRC database.[5] For more detail on the categories used for each sector, refer to [20].
- *Technology parameters*. This covers cost, efficiency and lifetime for the various technologies beyond the base year (i.e. learning curves). For electricity, these are mostly taken from an internal database at JRC and for the other sectors mostly from [64]. Technology specific discount rates are from [63]. These parameters have been published before as part of the full model documentation [20] and data for technologies that have been added or modified as part of this study can be found in Appendix A.
- *Resource potentials*. The present and future sources (potentials and costs) of primary energy and their constraints for each country are from the GREEN-X model and the POLES model, as well as from the RES2020 EU funded project, as updated in the REALISEGRID project.
- *Interconnection between countries*. This is relevant for electricity (ENTSO-E and Annex 16.9 of [20] for specific values), CO2 transport costs (taken from [65]) and gas. The net transfer capacities are used. There is a 15% interconnection between EU countries to be achieved by 2030 [66].

PV and wind potentials are important given that they will affect the electricity price and will determine the variability to be compensated. For PV, an initial assumption of 10 m^2 per capita is made, which already includes suitable roof area, green and brownfields, combined with an average irradiation of 850 W/m^2. This could lead to up to 1600 GW of PV capacity for the region, compared to ~100 GW deployed by 2016.[6]. This is still a conservative value, where using data from [67], an

[5] JRC Integrated Database on the European Energy Sector (IDEES).

[6] https://www.eea.europa.eu/publications/renewable-energy-in-europe-2017/download.

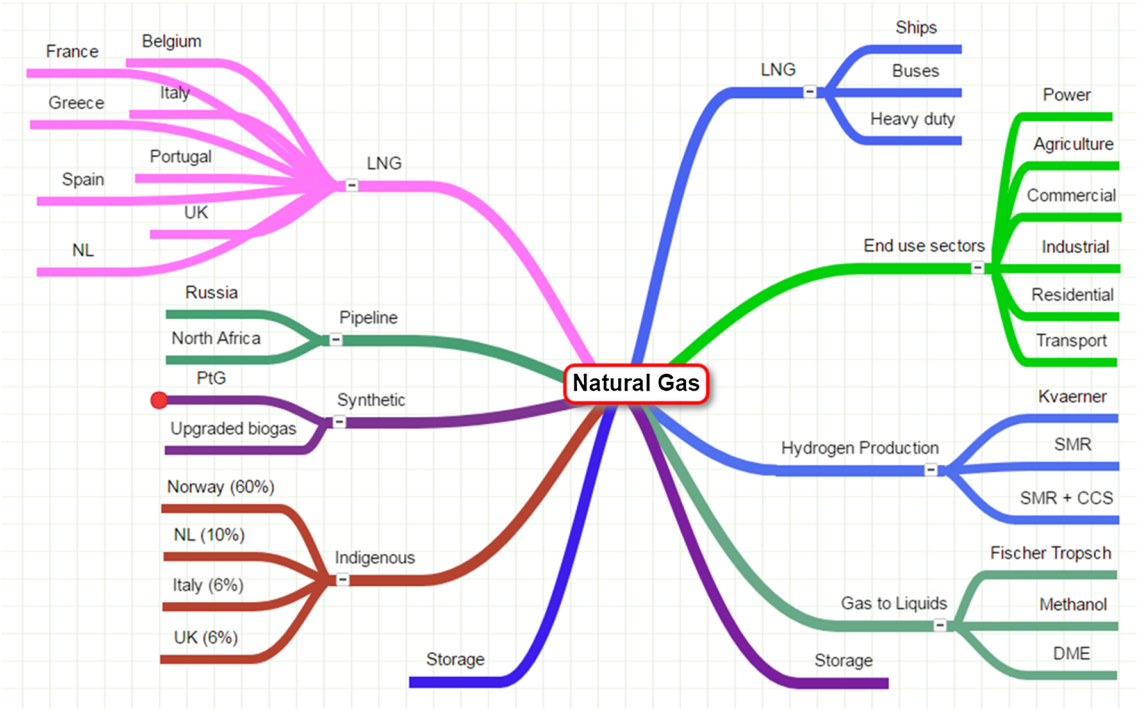

Fig. 1. Methane sources and uses considered in JRC-EU-TIMES.

average of 33 m^2 per capita for EU28+ (see Appendix B) was obtained. Because of this, scenarios with a higher potential equivalent to 25 m^2 per capita are evaluated as part of the sensitivities. Similarly, for wind, JRC-EU-TIMES uses a conservative estimate of 320 GW of onshore capacity (to put it in perspective, installed capacity in 2015 was 140 GW [68]) and 730 GW for offshore (only 11.1 GW in 2015 [68]). Other estimates are actually between 1020 and 1460 GW [69] respectively and even 1740 GW only for onshore [67]. Therefore, the approach has been to use the conservative estimate as reference point to avoid an overreliance on this technology and use higher estimates as sensitivities to quantify the impact. See Appendix B for more information on VRE potentials. Biomass potential is relevant since it can satisfy end services where PtM could play a role and because it can act as CO_2 source for PtM. This potential ranges widely in literature [70] and this study considers between 10 and 25.5 EJ/year (Appendix A for categories and breakdown). This parameter is more relevant when considering the competition with transport and Power-to-Liquid, which is part of an upcoming publication [62] (in preparation). A limitation on CO_2 underground storage is not considered, since it has been shown [71] that potential is orders of magnitude higher than needed. Global potential is almost 11,000 $GtCO_2$ when considering saline aquifers, whereas IEA estimates foresee 120–160 $GtCO_2$ of storage will be needed by 2050. The limitation assessed is the social acceptance aspect (rather than potential), where the extreme case is used (no CO_2 storage allowed).

For geothermal potential, there are two contrasting sources. One is the GEOELEC project, which ran from 2011 to 2013. It assessed geothermal electricity potential across EU28 plus Switzerland and Iceland at 3000 TWh for 2050 using 100 €/MWh as hurdle for the economic potential. This translates to almost 380 GW of potential installed capacity [72]. Among studies performed by international organizations, the highest geothermal capacities are from GreenPeace Energy Revolution, which have 50 and 40 GW for EU by 2050 in their "Advanced ER" and "ER" scenarios which achieve 100 and 92% CO_2 reduction vs. 1990 [73]. Energy Technology Perspectives by IEA (International Energy Agency) has more modest capacities of 9 GW by 2050 for EU, even in their beyond 2 °C scenario. The technology roadmap by IEA estimates a global deployment of 1400 TWh (or 3.5% of the global electricity production), equivalent to 200 GW of installed capacity by 2050. For this study, a relatively high CAPEX of 8200 €/kW is considered for EGS (Enhanced Geothermal System) [74] to ensure there is a high cost penalty in case the potential is used. To account for these extremes and assess any potential impact on PtM, this parameter is varied between the potential assessed by GEOELEC and one set of scenarios using 10% of such potential (~3000 and 300 TWh respectively).

A potential business case for PtM is to store power surplus over summer as methane and to be able to use this energy in winter to satisfy space heating demand or even contribute to closing the gap between electricity supply and demand. The model has three features that make it suitable to evaluate this application for heating. It has the actual building space that needs to be heated based on houses stock. Differentiation is made among 3 dwelling types with 6 different vintages by country (almost 560 classes). Various ceiling, walls, windows and floor alternatives for insulation are provided, each one with their own cost and thermal constant [75]. Therefore, it can make the trade-off between lower space heating demand through energy efficiency and more efficient heating technologies (e.g. heat pumps) to satisfy such need. For more details on this residential sector, refer to Appendix A and [20]. The other two features are the possibility to change energy carrier to satisfy heat demand and that it captures the seasonal component.

3.2. Gas system

The model has the option of producing indigenous gas, importing from outside EU+ or synthetize gas (through PtM) to satisfy demand. In turn, gas can be used directly at each of the five considered sectors or alternatively for hydrogen production or gas to liquids technology. The overview for the gas system is presented in Fig. 1.

Gas from PtM can be either injected in the natural gas grid or used directly in any of the sectors. Biogas can be upgraded either with carbon capture and injected in the natural gas grid or coupled with PtM to increase methane yield at the expense of hydrogen consumption, which is a common business case for PtM [29,49–51,76,77]. For specific CAPEX and efficiencies refer to Appendix A. Biogas can also be directly used for heat and power generation (not shown in Fig. 1), which requires the end users to be adapted for a lower calorific value.

This is the largest (90%) use (2015) for biogas [78]. PtM needs to compete with indigenous reserves, most of which (60%) are held by Norway. Total gas reserves for EU28+ are 610 EJ at an average production cost of 1.2 €/GJ. gas is also available and could add 545 EJ of reserves, although at a higher production cost of 15.4 €/GJ. As reference values, current gas demand is around 20 EJ/year and a price for the imported gas of 5.2 €/GJ.

Natural gas is connected to the LMG (Liquefied Methane Gas) network. The term LMG is used since it can either be imported, liquefied from natural gas or liquefied from PtM gas. Therefore, there is the possibility the gas is not fossil and the term "natural" is not applicable. At the same time, once biogas or PtM product is in the grid, it cannot be differentiated from fossil LNG. It can be used for heavy duty trucks, buses and marine transport. However, LNG competes with hydrogen and electricity in the former two and with synthetic liquid fuels in the latter. Liquefaction can be on-site (small scale for PtM) or centralized (large scale for NG). Once PtM gas is injected in the grid, it could also take advantage of the centralized liquefaction since it mixes with NG. For LMG use in ships, the reference fuel consumption from LMG carriers is taken. These can use a steam turbine that uses boil-off gas (BOG) with an efficiency of 26% from BOG to power, dual fuel diesel engines that complement BOG with diesel with an efficiency of 47% and slow speed diesel where the BOG is passed through a re-liquefaction unit leading to an efficiency of 43% [79]. This leads to operational efficiencies between 12 and 27 $gCO_2/(ton*nautical\ mile)$ (0.26–0.12 MJ/km) [80,81] where the upper range corresponds to old carriers with steam engines. In a scenario where shipping follows an emission 2 °C path, annual emissions need to be reduced by 80% by 2050. This would require design efficiencies of less than 2 $gCO_2/(ton*nm)$ and would favor shifting away to hydrogen [82]. The more emissions from other sectors are reduced, the less strict this target efficiency will be for marine transport. Operations and ship design (related to efficiencies) are estimated to be around half of the potential of the mitigation potential in the sector (the other half being fuel switch) [83]. At the same time, the more efficient dual fuel engines can have methane slip of 4.6% (in 4-stroke engines, but not in direct gas injection) that can increase emissions by 115% when considering the higher global warming potential of methane leading to operational emissions that are higher than steam turbines [79]. There are already oxidative catalysts being developed to reduce this slip, so in the future it is expected these emissions will be drastically reduced. Considering these effects, future operational efficiencies of 12 $gCO_2/(ton*nm)$ are used. Nevertheless, more important than the absolute number is the difference with respect to diesel engines. Therefore, 12 $gCO_2/(ton*nm)$ covers a scenario where it is more efficient than diesel/HFO engines, whereas the base scenario is one with higher emissions.

Once PtM product is injected in the grid, it can end up in any of the gas uses. This includes hydrogen production with steam reforming, which would lead to inefficiency. In reality, a system with guarantee of origin could be set in place to avoid this situation. However, this does not prevent the physical methane molecules from PtM ending back as hydrogen if it is part of the same network. In the model, this route would lead to higher costs and does not arise for any of the scenarios. Reforming is only present in scenarios with CO_2 storage and when there is CO_2 storage, there is no CO_2 use (i.e. PtM). Re-conversion to power in spite of being inefficient is one of the options left to satisfy the winter peak, which has zero contribution from wind, solar and wave and does occur to some extent.

The gas network has 3 main components: trading between countries, transmission and distribution. For the trading between countries, the base year capacities (reflected in Table 107 of [20] and repeated in Appendix C for convenience) are kept until 2020, year after which, the model can invest in new pipeline capacities. Typical costs for gas pipelines are around 715 k€/km for 12″ pipelines [84], assuming 500 km of length and 75 bara of transport pressure, this translates to ~5 €/(GJ/y).

For the transmission and distribution network, it has to be ensured that in spite of a future gas flow reduction, the cost for the network does not decrease as well in time (since the pipelines cost represent an invariable cost and with lower demand the cost per unit of gas delivered will actually be higher). Hence, the costs for the assets cannot be expressed per unit of energy (e.g. €ct/kWh), but need to be translated to capacity (e.g. €/kW). This ensures that if additional capacity is installed or the utilization is lower, the annuity is paid regardless of the energy flow. The procedure followed, sources and resulting infrastructure cost are reflected in Appendix D.

3.3. CO_2 network

PtM uses CO_2 as feedstock. Its compatibility with fossil technologies is low since the CO_2 used will ultimately be released to the atmosphere (upon combustion). Therefore, biogenic CO_2 sources have to be used. The model has the flexibility to obtain CO_2 from carbon capture in industry, electricity, biogas, hydrogen or the atmosphere directly (data in Appendix A). Once captured, it can be used either for underground storage (with an additional cost of 5–12 €/ton [85]) or for fuel synthesis (methanol, diesel, kerosene and methane). The different sources and sinks for CO_2 are shown in Fig. 2.

Possible CO_2 uses included in the model are methane, Fischer Tropsch, co-electrolysis to produce diesel and jet fuel and methanol production. Therefore, the model is focused on CO_2 use for fuels and does not include chemicals and other applications [86–88]. This is due to the scope on energy system, where sectors such as chemicals or polymer production are not explicitly represented and only the largest commodities (ammonia, chlorine) are disaggregated. However, this analysis is done from the perspective of changes needed to achieve lower CO_2 emissions, while CO_2 use can only contribute marginally to this challenge [71]. Currently, global CO_2 use is 0.2 $GtCO_2$/year and only 25% of the CO_2 is permanently sequestered. Even assuming an ambitious growth of 3%/year, the total amount sequestered would be 3.9 $GtCO_2$ by 2050 [71].

From the CO_2 use perspective, there are various aspects that favor applications other than methanation. Energy-wise, conversion to carboxylates, carbonates, urea and polymeric materials are less energy intensive than Syngas-derived products [89] and even formic acid and methanol are more attractive (lower energy requirement).[7] In economics, other products have a higher price per ton of product (e.g. formic acid) and have a lower CAPEX to synthetize[8] [90] being more attractive than methane which is a relatively simple molecule (compared to carboxylic acids). A differentiator in favor of methane is the market size. Methanol is the chemical with the largest market (around 70 mtpa on a global scale equivalent to ~1500 PJ), while current gas consumption only in EU is almost 20,000 PJ. These chemical routes have not been included in this study.

Direct air capture (DAC) can play a key role when it has lower cost than mitigating the last CO_2 molecules to reach the target. This is defined mainly by the learning curve assumed for cost and efficiency. Performance assumed by 2050 is close to 300 €/ton and 7 GJ of energy consumption per ton of CO_2 (see Appendix A). The technology is currently not deployed at large scale and to avoid overreliance on it, this performance is done as sensitivity to identify its potential, but not as reference (that assumes limited learning).

[7] Methane has a Gibbs of formation of -51 kJ/mol, while methanol has -166 and formic acid has -361 compared to CO_2 with -394 kJ/mol [91].

[8] Formic acid has a market price of around 1100 €/ton with a production cost of 200 €/ton, with carbon monoxide having 900 and 300 €/ton respectively, while methane has 200 and 4200 €/ton (see [91]).

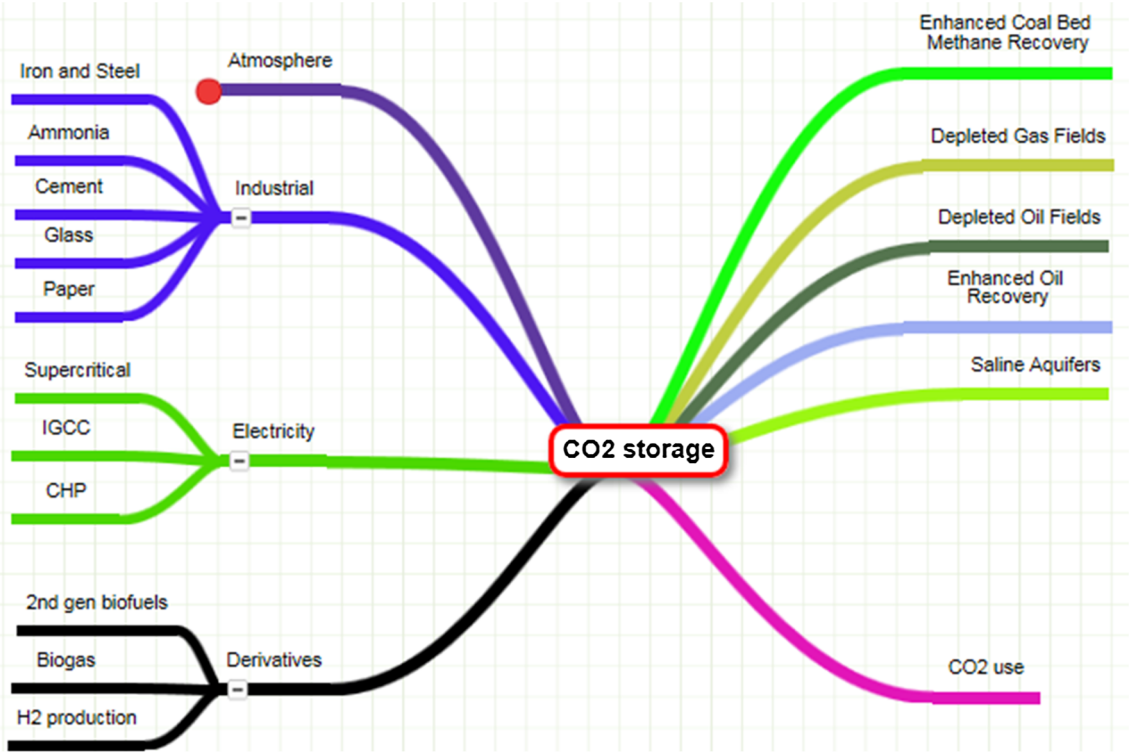

Fig. 2. CO_2 sources and uses considered in JRC-EU-TIMES.

3.4. Electricity network

The relevance of this component for PtM is that electricity storage competes in some cases with network expansion. In places with line congestion and high VRE, an alternative to curtailment or grid expansion is to transform the power surplus to gas and use the capacity available in existing gas infrastructure. Even though the model does not include the spatial network within a country, it does consider its corresponding cost needed in case of a larger power demand. This introduces an additional cost penalty in case the electricity demand increases, but it does not account for line congestion. For this, a similar approach as for the gas network was followed. Electricity prices were taken from Eurostat (extracting only the network costs which are the transmission tariffs) for industrial (IE Band: 20–70 GWh) [91] and domestic (DC Band: 2.5–5 MWh) [92] consumers discounting the taxes and levies. This specific cost (€/kWh) accounts for the sum of (1) capital cost caused by past investment e.g. for replacement of equipment or grid expansion, (2) OPEX for the observation time range, and (3) the allowed/regulated margin for the system operator. Multiplication with the electricity demand yields the total annuity for infrastructure operation. This cost is divided by the installed network capacity of the base year to calculate the specific investment cost (€/kW). The network is divided in voltage levels, each sector (users) is assigned to a voltage level and the network cost (resulting from a demand increase in a specific sector) is assigned to the capacity needed (GW) to satisfy such demand. With this methodology, a country like Germany would incur in a total network cost of 1500 €/kW of installed capacity for transmission, while requiring almost 2800 €/kW for distribution. These costs are then annualized. An advantage of this method is that it is based on actual costs paid by consumers for the network and it does not require explicit distances and locations. This allows considering the network cost as electricity demand increases or as expansion is needed in case of high distributed generation (e.g. PV). During the summer peak time slice, the capacity factor for PV is 0.8, which corresponds to the maximum PV output and ensures that the grid can handle this peak or instead that the energy curtailment increases in case the investment in the grid results in a higher cost. Nevertheless, the expansion of electricity infrastructure faces not only financial and technical hurdles but also headwind from municipalities and population, solutions are expected to follow other criteria than cost only. For more details on the approach and values used refer to Appendix E.

3.5. Power surplus estimation

In the present and coming years, PtM is meant to use only power surplus as input due to (1) PtM only has lower CO_2 emissions than natural gas in cases with low carbon footprint of the electricity (< 50 gCO_2e/kWh) [16–19]; (2) PtM provides flexibility to compensate for VRE variability (through the upstream hydrogen production). In the future, this situation can change since PtM demand can become so large that it cannot operate anymore only with surplus. At the same time, the electricity CO_2 footprint is expected to decrease, resulting in a larger number of hours where it is attractive for PtM. In such scenario, PtM could operate instead as part of the demand. It will be one of the last users to satisfy since it has the possibility of large scale storage and possibility to adjust and follow electricity production.

To ensure computational tractability, not all the 8760 h in a year are used. To simplify the problem, hierarchical clustering is used taking advantage of recurrent hourly, daily and seasonal patterns [93]. Even though this method does not perform as well as other clustering algorithms [94], it allows maintaining the chronological sequence of importance for storage calculations. A day (11 h), night (12 h) and peak (1 h) time slices are used for each season, leading to 12 time slices. The range of hours that they cover is from 77 to 1428 h. VRE penetration and system costs can be estimated with 12 time slices [95], while still avoiding a large increase in calculation time. This approach can lead to deviations due to the smoothening of the shape of the profile [93].

Additional equations are introduced to improve the accuracy of the amount of power surplus and utilization of the dispatchable power plants. From a certain threshold of VRE, part of the power production will become a power surplus. To account for the variability within a time slice, an additional equation is introduced based on VRE and

demand (both in energy terms) to estimate this surplus. This equation was validated with a more detailed analysis with an hourly model outside JRC-EU-TIMES in which different wind and solar combinations have been made for all Member States, using 30 years of meteorological data as explained in Appendix F. The result of the statistical analysis is that the parametrization of the surplus power becomes a simple function of VRE. Moreover, we found that the inaccuracies of the surplus estimates are smaller than the annual variations. The result of this equation is that each time slice is divided into two sub-periods: one with and one without surplus. As shown in the results section, the surplus becomes as important as the power that is directly providing the final electricity needs.

In addition, summer peak uses the maximum PV output (80%), while winter peak considers zero contribution from VRE combined with 10% higher demand, ensuring is enough capacity adequacy for sustained periods of no wind and solar. Energy balances are satisfied within a time slice and can be transferred across time slices with storage (daily and seasonal). Within a time slice there will be a variable capacity factor because variations in VRE are faster than the length of the time slice. To account for this, an additional equation is introduced based on VRE and demand (both in energy terms) to estimate the surplus. An additional consideration is that other technologies cannot ramp up as fast to compensate for low VRE contribution. Therefore, for estimating the surplus, a minimum generation of 20% should be available for dispatch (from nuclear, geothermal, concentrated solar with storage and fossil power plants) to ensure system stability. Surplus can be used for DSM, storage, PtX or curtailed. For more details on this, refer to Appendix F.

Capacity factors for wind and solar are calculated considering the time slice definition provided before (4 seasons, day of 11 h, night of 12 h and 1-h peak) using data for 2010. To reduce dependence of the results on this reference year, summer and winter peaks ensure there is enough capacity to deal with both a surplus (high capacity factor for PV) and a shortage (no VRE contribution) combined with a (10%) higher demand. Therefore, a different reference year will only have an impact over the operational costs, but not on the capacity installed. This covers the two periods (low and high VRE contribution leading to back-up capacity and potential curtailment) that have been identified as the most important in clustering algorithms [94]. Electricity demand is an endogenous variable resulting from its use among the end services.

3.6. Other flexibility options (storage and DSM)

The JRC-EU-TIMES model considers storage solutions that can store energy produced in one time slice and make it available in another time slice in form of either electricity or heat. Therefore, storage is the link between day and night time slices, but also seasonal (only batteries cannot cover seasonal). The technologies covered are: compressed air energy storage (CAES), pumped hydro, hydrogen conversion and batteries (lead acid, Li-ion, NaS, NaNiCl) and thermal (low temperature and underground). Batteries of electric cars are also included with different charging modes. PtM has the advantage over the above technologies that it can serve as a vector between sectors and that it can provide a different commodity other than power back to the system. Since PtM can provide storage capacity for months, it would fall in the area where the marginal value of every additional hour of storage is negligible. Even though once the gas is produced, it could end up in any of the gas uses (including power if it is a lower cost option).

Each storage technology is represented with two different processes, one for the energy component and one dummy component for the power capacity (same process for charging and discharging, but where the amounts of each operation can be segregated). For thermal storage, the commodity stored is directly heat leading to interaction with the electricity system through allowing a more flexible operation of CHP and gas turbines (when gas is used for heating). For the representation and storage technologies covered in the model, refer to Appendix G.

Surplus has so far (Section 3.5) been introduced for an entire time slice and in energy terms. This would imply that the storage has to be large enough to manage the entire surplus over the time slice. Nevertheless, the storage might operate in an hourly/daily mode, which would mean a much smaller energy capacity for the storage. Based on this, additional equations are introduced. One to convert the time slice surplus to daily surplus (using the shortest duration of a season, which would result in the maximum daily amount) and one for obtaining the power capacity (based on energy/power ratio which is different for each technology and covered in Appendix A).

For DSM, it is assumed that a fraction of the demand can be satisfied within the same time slice at no cost (assuming the cost corresponds to the IT infrastructure and associated software development, which is considered negligible compared to the costs in other parts of the system). DSM constitutes one of the options to manage the available electricity surplus (see Fig. 11 in Appendix F). The fraction that can be shifted depends on the sector (25% for water heating, 15% for space heating and 10% for space cooling, these categories are for electricity consumption in residential and commercial sectors) [96]. DSM in industry is only taken in scenarios with high DSM potential to avoid overreliance in the flexibility option. The fraction that can be shifted is 10% for aluminum and chlorine, 15% for paper and 25% for cement and steel.

3.7. PtM performance

For the methanation step, there was a wide range of values found in literature (especially for cost), where in some cases it is difficult to identify the specific elements that are included in the cost estimate (e.g. engineering, installation, construction) and even in some cases the reference for the cost (e.g. kW of H_2 input vs. kW of methane output). To tackle this uncertainty a set of values is defined to be used in the base scenario and also an optimistic performance is identified to establish the upper bound for the role of the technology. Techno-economic parameters for methanation are presented in Table 1. The use of the low CAPEX only made a difference in scenarios where the system drivers were favorable for PtM. Two out of the eight main scenarios (see next section) have a low CAPEX, where the low CAPEX was evaluated for the other six scenarios as sensitivity (see Appendix H). Range of parameters for electrolysis can be found in Appendix A.

4. Scenario definition

The scenarios used for this study are intended to be a combination of normative and exploratory. They are normative given that the system will reach the defined CO_2 reduction target (mandatory as constraint for the model), while they are exploratory for the range of technologies and routes the model has to meet such constraint and where the choices in either techno-economic parameters or possible routes available will lead to different possible future systems. The scenarios are not meant to be forecasts on how the energy system will evolve, but instead to shed some light on the effect of the uncertainties and inform decision makers on the robustness of the technology and its potential outlook under different unfolding sets of events.

The scenarios are created based on parametric analysis. This translates to first selecting parameters that will change the entire energy system (e.g. CO_2 target) or specific for the technology (e.g. PtM CAPEX). Combinations of these parameters were made to understand their effect on the system and outlook for the technology. The ones with the largest influence are presented in Table 2, while the rest are listed in Appendix H. These parameters were combined leading to over 120 scenarios, out of which 55 were selected (Appendix H) and their insights are included in Section 5. These scenarios were selected based on previous studies and results during preliminary runs. However, to facilitate understanding of the results, 8 main scenarios are selected for emphasis in the analysis (see Table 2 for more on the assumptions for

Table 1
Base and extreme techno-economic parameters for methanation.

	Year	CAPEX [26,97,98] €/kW	Fixed OPEX[a] €/kW	Variable OPEX[b] €/kWh	Efficiency[c]	Availability Factor[d]	Lifetime Years
Base	2015	750 [14]	37.5	–	0.75 [34]	0.95	25
	2020	600	30		0.78	0.95	25
	2030	450	22.5		0.81	0.95	25
	2050	250 [99]	12.5		0.85 [98]	0.95	25
Min	2020	150 [100]	4.5		0.85 [101]	0.95	30 [47]
	2030	125	3.75		0.87	0.95	30
	2050	75[e] [98]	2.25		0.90[f]	0.95	30
Max	2020	1350 [102]	101.3		0.65 [103]	0.85 [98]	20 [13]
	2030	1000	75		0.70	0.85	20
	2050	700 [13]	52.5		0.75	0.85	20

[a] Range is from 3 to 7.5%, as a fraction of the CAPEX from [17,18] (excluding CO_2 cost).
[b] Most of the variable cost is the CO_2 source.
[c] Efficiency is expressed as energy output (methane plus heat recovered, if any) divided by the energy input (contained in the hydrogen)
[d] The reactor itself usually has limited trip initiators (related to temperature control). Most of the trip in the system impacting the availability will occur elsewhere in the system (e.g. compressors)
[e] Biological methanation is cheaper and assuming a capacity of > 3 MW per unit
[f] Assuming part of the heat released is recovered as steam

each parameter):

- Low carbon (2 scenarios). Only CO_2 target as constraint and full flexibility for the rest of technologies. The two scenarios are 80 (reference) and 95% CO_2 reduction.
- No CCS (2 scenarios). Same as above two scenarios, but without CO_2 underground storage possible. This can be the result of limited social acceptance, a general ban of fossil fuels or limited research on the technology.
- *Realistic* (1 scenario). Scenario with what is perceived (by the authors) as highly possible constraints that favor PtM. This includes 95% CO_2 reduction, no CO_2 underground storage, low CAPEX (75 €/kW) for methanation step, high wind and solar potential (see Appendix B) and low efficiency for LMG use in ships.
- Alternative without PtM (1 scenario). Scenario with a different set of constraints that are also likely, but that do not favor PtM. This aims to show that it is also possible that the system evolves in a direction where PtM plays a limited role. This includes 95% CO_2 reduction, CCS possible, high biomass potential, high VRE potential, high electrolyzer performance, electric heavy-duty transport possible and low LMG efficiency in ships (25 gCO_2/ton∗nm).
- Optimistic (1 scenario). This covers the most favorable set of conditions for PtM and establishes an upper bound for the technology activity. This includes the set of conditions in the "*Realistic*" scenario plus low biomass potential, high gas price, high cost for the electricity network, high PtM efficiency, high electrolyzer performance,

Table 2
Key parameters[a] varied across scenarios to identify trends and shifts in the system.

Parameter	Explanation	Rationale	Scenarios
CO_2 reduction target[b]	Emissions target for 2050 expressed as a percentage of 1990 emissions	It is expected that PtM will play a larger role as target becomes stricter since there is limited budget for emissions from gas	• 80% CO_2 reduction* • 95% CO_2 reduction
CCS	Absence of CO_2 underground storage (e.g. due to lack of social acceptance)	This has been identified as key option to decarbonize the energy system, specially sectors other than power. Not having CCS will make the need for other technologies larger	• CO_2 storage available* • No CO_2 storage
VRE potential	Higher PV and wind potential (see Appendix B)	Initial estimates are conservative. If higher potential is assumed, more VRE deployment will lead to more electricity surplus to deal with and a larger need for flexibility where PtM can play a role	• Reference* • Higher potential for solar and wind from [67,69]
Biomass potential	Refers to the potential available for each category	Biomass can be used in all sectors (where it can compete with gas). Limited potential requires the development of other technologies.	• Reference* (10 EJ/y) • Low potential (7 EJ/y) • High potential[c] (25.5)
PtM Cost	Lower CAPEX for the technology	Tackle uncertainty in cost learning curve and assess how a lower cost can affect its future deployment	• Base performance* • Optimistic (Min values from Table 1)
PtM efficiency	Maximum theoretical efficiency of 100% (including heat recovery)	Upper bound for technology outlook with best possible performance and production of additional revenue stream	• Reference efficiency (refer to Table 1)* • 100% efficiency
PtM subsidy	Subsidy to promote the technology with 1 €/GJ in 2025, 2 €/GJ in 2040 and 3 €/GJ in 2050	PtM is currently not commercially deployed. Technology might require subsidy to start deployment. Subsidy is chosen to be equivalent to 20–30% of the gas prices for 2050	• No subsidy* • Increasing subsidy from 1, 2, 3 €/GJ in 2020, 2040 and 2050 respectively)
LMG efficiency in marine transport	There is a factor 2 between the best and worst performers based on current data (12–25 gCO_2/ton*nm)	Future performance can further improve and become more efficient (MJ/km) than fossil options. LMG role in transport is evaluated for this scenario	• High (12 gCO_2/ton*nm) efficiency* • Low (25 gCO_2/ton*nm) efficiency

* Assumption for the base case.
[a] There are parameters directly associated to hydrogen and PtL, which are discussed (including more detailed data) as part of a separate article [62] (in preparation).
[b] There are 3 interlinked variables: RES fraction, CO_2 price and CO_2 reduction target. This was selected given that the main target is to achieve a low carbon system and the response of the other two variables will depend on the set of technologies and constraints (indirect effect).
[c] See Appendix A for reference, low and high values including breakdown by category.

low PtL performance, SOEC possible and high LMG efficiency in ships (12 gCO_2/ton∗nm).

- Business as Usual (1 scenario). This is only included to establish a reference for cost (CO_2 price) and energy consumption. However, this only achieves a CO_2 reduction of 48% by 2050 and therefore would make more challenging achieving the 2 °C scenario.

5. Results and discussion

First, scenarios are introduced by looking at general indicators such as final energy demand, annual system cost (and corresponding CO_2 price) and composition of the electricity mix (focus on electricity given it is the largest supply sector). Then, specific parameters for PtM are analyzed, specifically (1) the price of its output (which is an indication of how competitive it is compared to natural gas); (2) gas balance (including sources and sinks); (3) the seasonal use of PtM and (4) the CO_2 balance (since PtM should use biogenic sources and to understand how it compares with the other possible CO_2 sinks).

Previous studies [14,47,104–107] have estimated that PtM will only play a role in the system for high CO_2 reduction targets, since only then there are adequate hours with low cost and low CO_2 footprint electricity, to justify the investment from an economic perspective. This is not expected to occur in the short term. Because of these two reasons, only numbers for 2050 are shown across scenarios. In case PtM is not used in 2050, it is considered highly likely that it will not be part of the system for previous years. Variables like system inertia, market dynamics and politics, among others are not captured as part of the model. Because of these, achieving high decarbonization targets (such as the ones explored in this study) could take longer than foreseen. Therefore, results presented hereinafter are to be understood as bounded to a system with such CO_2 reduction rather than linked to the specific 2050 time horizon. The difference between the annual system cost of a specific scenario and the *BAU* scenario is an indicator for the additional cost of the requirements to the point of an energy system with 80% or 95% CO_2 reduction.

5.1. Energy, electricity and cost overview for scenarios

This section aims to understand how the low carbon system differs from one with higher emissions and how the different constraints influence the design of this system. Fig. 3 illustrates the changes in energy balance with the final energy demand split by energy carrier, while Fig. 4 provides insight into the total system cost, sectorial contribution and associated CO_2 price. Complementary results are included in Appendix I.

The largest changes across scenarios are in liquid, gas and hydrogen flows. Liquid includes fossil oil-derived products, Fischer-Tropsch, biomass conversion to liquid (BtL) and PtL, this forms a large part of the *BAU* scenario, with mostly fossil oil. Transport is one of the more difficult sectors to decarbonize, which leads to still using fossils in this sector for the *BAU* scenario (overall 48% CO_2 reduction). The three largest drops in liquid demand are (1) the shift away from diesel in private transport (where diesel is more than 8500 PJ in the *BAU* scenario), (2) the shift in heavy-duty trucks (to LMG/hydrogen depending on the scenario), which is a sector that has a demand of 5000 PJ and (3) the shift from fuel oil to LMG in marine transport (demand of 2000 PJ). Gas contribution can be high either when CO_2 storage is possible, lower CO_2 target is set or for a high biomass potential, when the biomass is used for negative emissions in power and hydrogen and positive emissions can be incurred in the commercial sector with gas. Biomass contribution is small since it is converted to another energy carrier (e.g. electricity or liquid) and the final use of direct biomass without previous conversion is limited (in industrial or commercial sector). Coal is negligible across all scenarios including *BAU* scenario.

There is a progressive electrification as the scenario becomes more restrictive, with up to 50% of the final demand. There is a large difference between the generated electricity and final demand since electricity consumption for electrolysis can be up to 40% of generation (reflected as either hydrogen or liquid in the final energy demand, see Appendix I). Electricity production in *BAU* is similar to today (3600 vs. 3200 TWh), but it almost doubles with 95% as CO_2 target and up to 11,000 TWh with higher VRE potential (see Appendix I) and when additional constraints are added. VRE (wind and solar) can be up to 70% of the mix when their potential is the highest. BECCS (gasification) plays a limited role in terms of electricity share for scenarios with CO_2 storage, given that scarce biomass (10 EJ/year for EU28+) is better used in other sectors and only plays an important role with higher biomass potential (25.5 EJ/year). However, it makes a large difference in terms of CO_2 emissions and total electricity CO_2 footprint since it can provide up to 180 $MtonCO_2$/year. Electricity generation with fossil

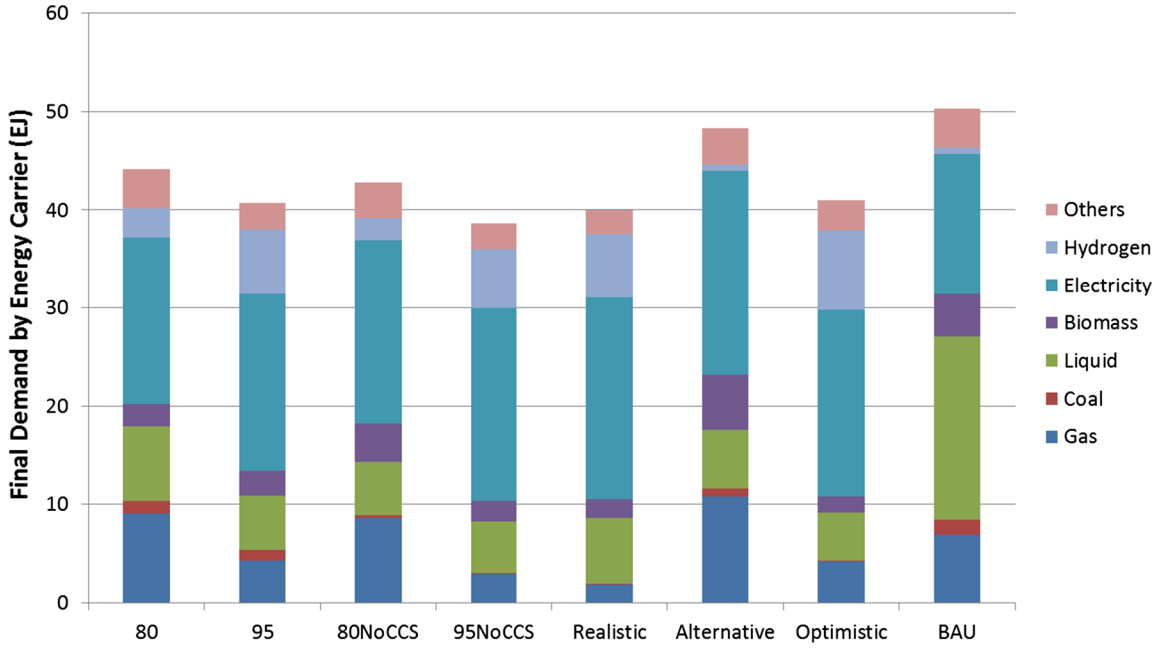

Fig. 3. Final energy demand by energy carrier across main scenarios.

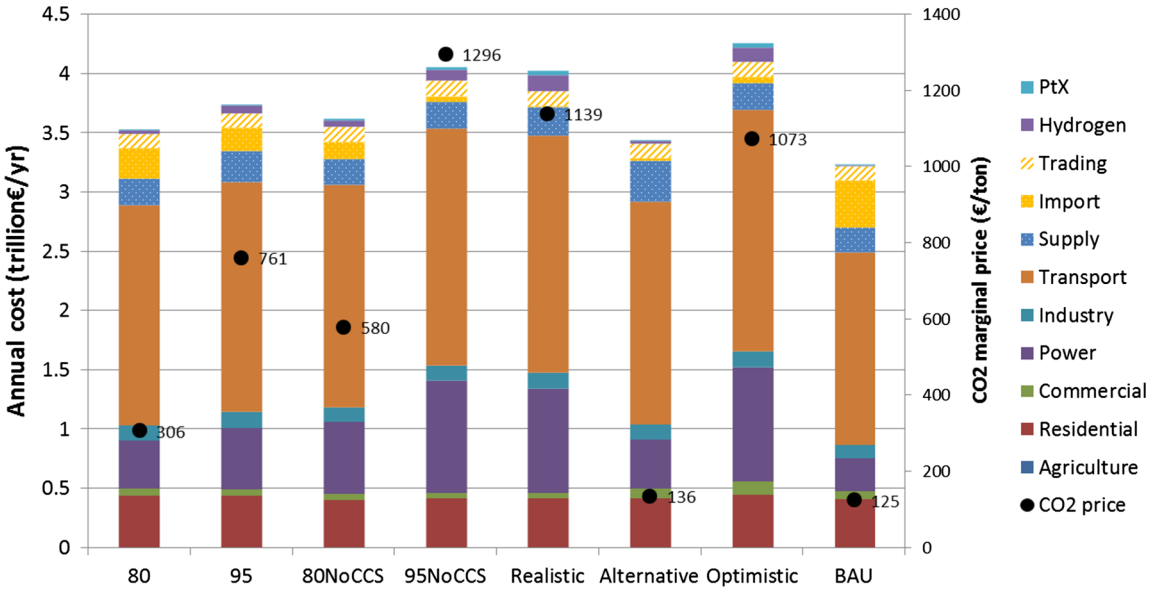

Fig. 4. Total annual system cost split by sector and marginal CO_2 price.

fuels using CO_2 capture plays a larger role in scenarios with CO_2 storage, with its largest contribution at almost 900 TWh. Nuclear and hydro are relatively constant across scenarios regardless of parameters given that they have low CO_2 footprint without the variability of wind and solar and therefore tend to be exploited to the maximum. The electricity sector is the most cost-effective to decarbonize. Because of this, even in *BAU* scenario (48% CO_2 reduction), the total emissions for power production correspond to around 20 gCO_2/kWh, while for most of the scenarios they are -15 to 0 gCO_2/kWh. This is drastically lower than current values, which are close to 350 gCO_2/kWh for EU28+ (see Appendix J).

Values represented in Fig. 4 are the total annual costs for the energy system in 2050. This includes also energy efficiency measures and actual devices (heat pumps, lighting, stoves, heaters) for the residential sector and the vehicles (cars, buses, trucks) for the transport sector. These can represent around 0.12, 0.3 and 1.8 trillion€/yr respectively from values in Fig. 4. Such cost covers 97–98% of the transport costs in Fig. 4 with the remainder represented by BtL and the charging stations for battery electric vehicles (BEV). Scenarios with lower targets use less efficient (cheaper) cars and this results in 15% lower cost for *BAU* (compared to 80% CO_2 reduction). Cost in the power sector increase with more restricted scenarios[9] (higher electricity generation) and the fraction (in cost) for the network varies between 15 and 32% of the total sector cost, with the high value actually corresponding to *BAU* scenario and decreasing progressively with more restrictions. This corresponds to 105–140 bln€/yr for most of the scenarios (including replacement) compared to around 90 bln€/yr for *BAU*. A large advantage of low carbon scenarios is the reduction of the import bill. Imports represent around 400 bln€/yr for *BAU*, which is reduced to around 250 bln€/yr for 80% CO_2 reduction and further to 190 bln€/yr with 95% CO_2 reduction. As the scenario becomes more restrictive, imports are reduced even further reaching levels below 50 bln€/yr. To put these numbers is perspective, the GDP for EU28 was 15.3 trillion€ for 2017[10] and expected to be 22.5 trillion€ by 2050 [63].

A low carbon scenario does not necessarily translate into a high CO_2 price. For the "*Alternative*" scenario that combines a high biomass, wind and solar potential, the marginal CO_2 price can be only 10% higher than the *BAU* scenario (136 vs. 125 €/ton). The largest changes in CO_2 prices are the CO_2 target, CO_2 storage absence and biomass potential. The CO_2 target can more than double the price by the individual changes from *BAU* to 80% and further to 95% CO_2 reduction. CO_2 storage potential has a similar effect of doubling the CO_2 price when CCS is not possible. A high biomass potential can actually compensate for the cost increase caused by the lower CO_2 target. The rest of the lower CO_2 price in the "*Alternative*" scenario comes from the rest of the changes (higher VRE potential, electric trucks, better electrolyzer performance).

The use or not of LMG in the marine transport has a negligible effect on the CO_2 price (< 1% change) and can actually lead to an increase in marginal CO_2 price for more restricted scenarios[11] The impact is through reallocation of the biomass since marine transport is mainly satisfied with diesel when LMG is not an option. When biodiesel is used, it causes a larger BtL activity and biomass for power and H_2 production decreases. The reduction in total costs can be between 0.5 and 1% for scenarios with LMG in transport. However, this is mostly associated with the higher efficiency used (0.12 MJ/(ton∗km)) compared to diesel engines rather than the specific fuel (LMG).

A sensitivity with an additional 200% for the grid cost decreases total centralized generation by 8% (from 11,100 to 10,200 TWh) with limited impact in the electrolysis and industrial capacity (which do not require distribution grid expansion and are less impacted by the assumption), while sectors at the distribution level experienced a 15% decrease in demand. Nevertheless, part of this is replaced by more decentralized generation with PV that increases by almost 450 TWh. A higher grid cost makes the power system more expensive (+9%) and also the commercial sector (> +100%) since the heating needs to be satisfied with μ-CHP and gas, which represent a more expensive option than heat pumps, with a similar effect occurring in the residential sector as potentially positive effects of aggregation of μ-CHP were not considered in this work. Overall, the change results in a system 5% more expensive (annual costs).

The effect PtM has on marginal CO_2 price is 0.5% when the technology is initially deployed (only lower CAPEX), 2% with its higher deployment associated to the higher efficiency and up to 10% when it is subsidized. Costs for PtM are negligible for the entire system and

[9] "Restricted" means that there are fewer options to achieve the CO_2 target (e.g. no CCS) or that the target becomes more ambitious demanding larger changes in the system.

[10] Code tec00001 from Eurostat.

[11] Scenario with 95% CO_2 reduction, no CO_2 storage, high wind and solar potential and low PtM CAPEX ("95CCSVRECost").

represent only a fraction up to 0.0005 of the total system cost. This fraction increases to 0.0013 for a high efficiency (combined with 95% CO_2 reduction, no CO_2 storage, low CAPEX and high VRE potential), 0.0014 with cheaper hydrogen (better electrolyzer performance) and 0.0024–0.0025 when either no PtL is used (no other sink for CO_2) or "*Optimistic*" scenario. When compared to the gas supply system[12] (import, LMG, storage, without including costs for downstream conversion), the fraction increases to 0.45% for the "*Realistic*" scenario and up to 5.7% for the "*Optimistic*" scenario. This translates into annual costs of 2.5 bln€ for the "*Realistic*" scenario and up to 10 bln€ for the "*Optimistic*" scenario, with a split close to 70/30 in CAPEX/OPEX.

5.2. Natural gas and PtM gas price comparison

Even in scenarios where PtM is not used, the model is able to calculate the cost of producing the first unit of gas (marginal production) based on: PtM CAPEX, hydrogen and CO_2 prices. As the technology becomes more attractive, its calculated price will be closer to the NG price and when it reaches price parity, it will start contributing to gas supply. Consequently, from an economic perspective, the price gap between NG and PtM is an indicator of how close the technology is to being deployed and what the drivers are that cause the largest change in this differential. Fig. 5 shows this difference comparison across the main scenarios. This leaves out local circumstances like social acceptance or incentives for early business cases that also play a role in investment decisions.

Fig. 5 shows the average prices for all the countries and for all time slices for visualization, while the specific values by country and time slice were used for analysis and discussion. As an example, the *Realistic* scenario has 29 out of 112 time slices when synthetic natural gas (SNG) from PtM is produced in spite of the average values being above the gas price (see Appendix K for all the time slices). Nevertheless, PtM deployment goes in agreement with the differential on the average prices. As the system becomes more restricted, hydrogen demand in other applications increases its price and makes it less attractive for PtM. With no CO_2 storage, hydrogen prices can be 3.8–5.7 €/kgH_2, which is too high for PtM to be attractive since methane becomes cheaper given that its demand is lower (see Section 5.3)[13] Therefore, with more restrictions the gap between H_2 and CH_4 becomes wider and can only be closed if the PtM performance outweighs the decrease in NG price. This occurs in the "*Optimistic*" scenario where better electrolyzer and PtM performance (including higher efficiency and cost) make PtM synthetic product cheaper leading to the highest deployment. This scenario considers a high gas price for imported gas, but since favorable conditions make PtM cheaper, this (combined with Norway) is defining the gas price.

Contrary to expectations, technology CAPEX has a limited impact on price differential since this ratio is highly determined by hydrogen price and variables affecting the entire system. Similarly, higher biomass potential does not affect the appearance of PtM as it is used in sectors where there is limited competition with gas (i.e. transport). A higher wind potential has a positive effect on PtM, but the one with the largest influence is PV potential.

Gas has to be expensive enough to make PtM attractive, which means it has to have a significant demand. In some cases, gas demand in Germany decreased sharply making gas too cheap and unattractive for investing in PtM. In other cases (e.g. Greece), gas was mostly (70%) used to satisfy marine transport (LMG), which unlocks a market with a higher commodity price attenuating the large depreciation in price (but still declining to around 35% of *BAU* levels) and increasing the attractiveness of PtM.

The presence of high VRE capacity is not a sufficient condition for PtM use. An example is Cyprus. In the *Realistic* scenario, Cyprus obtains over 95% of its electricity from solar (PV and CSP). During the day, around 60% of the demand is from electrolysis. From the hydrogen produced, almost 40% is stored. During the night, electrolysis production is zero. Electricity demand itself is also lower by less than half and the rest of the demand is met with gas, wind, biogas and storage (see Appendix L). During a night in winter, when the load is higher due to electrification of heating, almost 70% of the electricity is produced with gas. However, this gas is not produced by PtM, but instead it results more advantageous to import LNG (through Greece) and use it to generate the electricity needed. This is around half of the demand, where the other 50% is transport. There is actually some (around 5% of the gas demand) PtM, but this is not significant enough to satisfy demand in winter. Hydrogen and CO_2 are instead used for PtL, which is used downstream to satisfy aviation and heavy-duty trucks (90/10 split) demand. This will change depending on the imported LNG price (exogenous assumption). For the scenario of high (200%) gas price, LNG import is too expensive and the use of PtM is more attractive[14] However, this results in doubling the marginal gas price (20 €/GJ vs. 11 €/GJ) due to the use of PtM. A similar situation in a larger country is Spain. It has almost 90% of the electricity demand covered by wind and solar (annual average) with a 1:2 ratio. During the day, electrolyzers are up to 75% of the demand and the hydrogen produced is used in a 1:4:4:4 ratio for industry (steel), storage, PtL and transport (buses). During the night, electrolyzers load is reduced to around 25% relying mostly on wind. PtL activity does not markedly decrease its capacity and uses the stored hydrogen. During winter peak (no wind or solar), demand is satisfied by halting hydrogen production, relying on nuclear, hydro and imports from France and Portugal. Methane is used in a 3:1:1 ratio for industry, residential and other heat generation and it has a relatively low price (8 €/GJ) that makes the use of expensive (~40 €/GJ) hydrogen not suitable for this application. The liquids produced are used downstream for cars, ships and aviation in 1:5:7 ratio.

5.3. Gas supply and demand

Gas prices are undoubtedly linked to gas demand and supply. Fig. 6 shows the sources and sinks for gas across scenarios. This serves several purposes: understanding in which sectors the gas is used, storage contribution, PtM production in comparison to gas supply total (role in energy security), drivers for fluctuations in demand and interaction between supply and demand that determine the prices shown before.

The range of flows varies between 3800 and 14,000 PJ. To put these in perspective, gas demand for 2016 in EU28 was close to 18 EJ (~5000 TWh). Even in a *BAU* scenario, gas demand is not much different than a flexible 80% CO_2 reduction scenario. It only has a different distribution among sectors with the largest difference of LMG use for transport. As the system becomes more restricted, gas demand is progressively reduced. A commonality among scenarios is the low contribution from the residential sector, which shifts away from gas even for low CO_2 target (see Appendix M), giving its way to electricity as energy carrier and energy efficiency measures to reduce the final demand (which can reduce energy demand by 30–40%). Only Spain and Italy retain 30–40% of its current demand, where gas is used for cooking, while countries with a high fraction of gas for heating like Germany and the Netherlands make a drastic change away from gas. Similarly, the industry sector is a relative constant across scenarios. Its use for heat and steam production varies between 1800 and 3600 PJ depending on the scenario. The largest variants are the electricity and the commercial sector. Gas for electricity plays a larger role in the scenarios that have CO_2 storage as possibility. However, it is also

[12] These costs range between 200 and 300 bln€/yr.

[13] More on the dynamics (production, consumption, prices, drivers) for hydrogen and Power-to-Liquid are part of a different study [63] (in preparation).

[14] Not even for this scenario is the demand 100% satisfied with PtM, but instead around 80%.

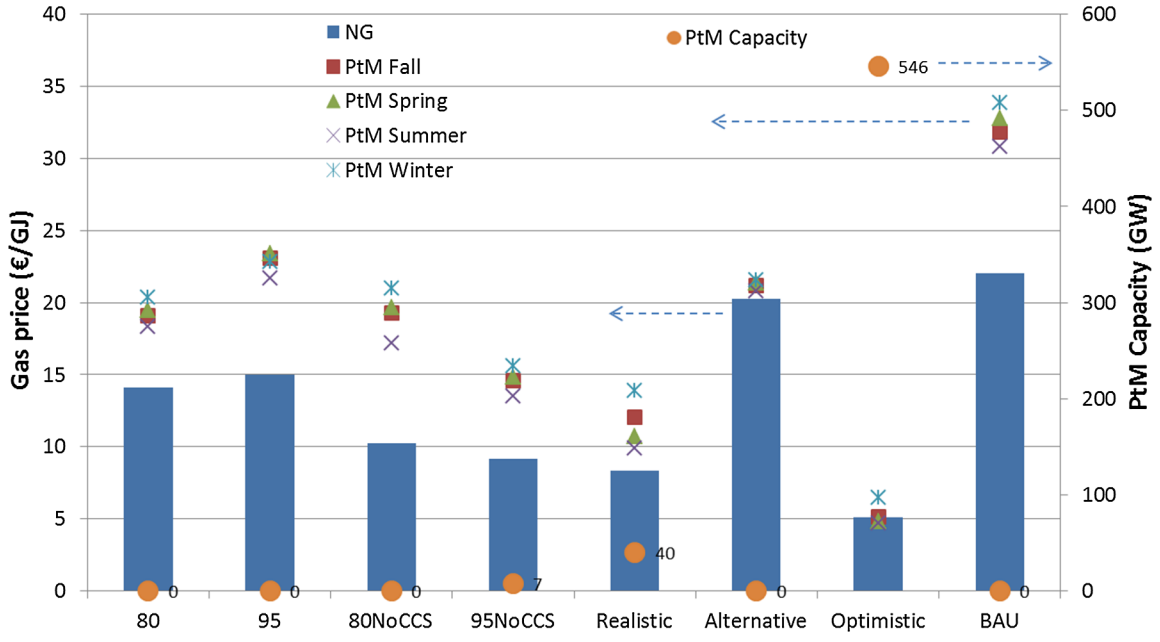

Fig. 5. Price comparison between NG and PtM across main scenarios.

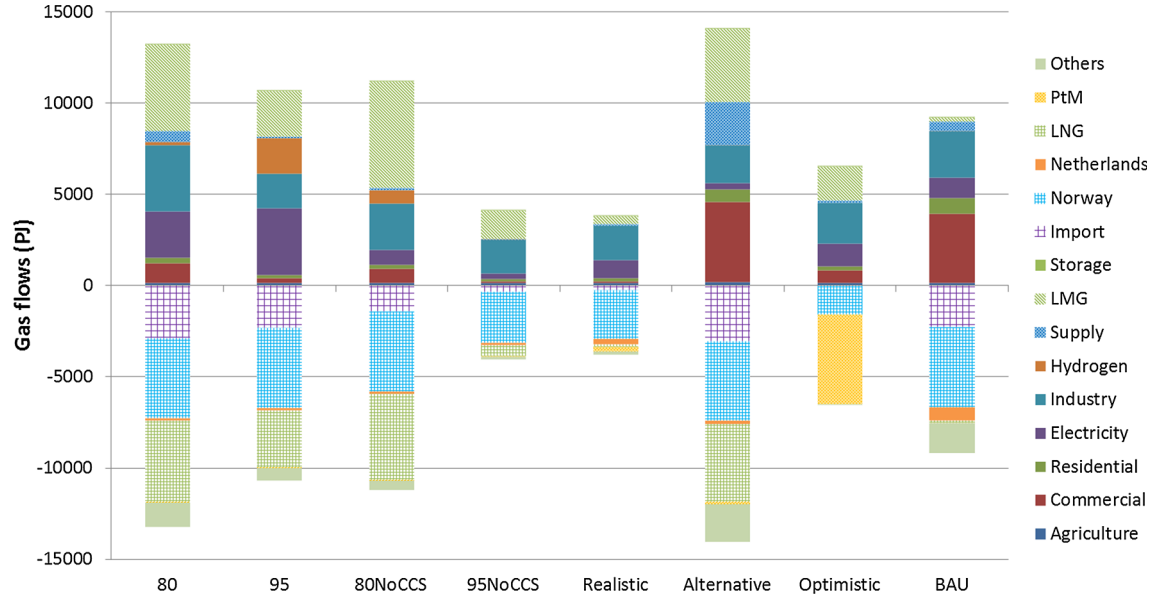

Fig. 6. Gas supply (lower) and demand (upper) breakdown across main scenarios.

required that the biomass potential is at most at its reference value (~10 EJ/yr) and not higher. In such case ("*Alternative*" scenario), biomass displaces gas in electricity taking advantage of the negative emissions of biomass plus CCS and using this benefit in other sectors. This last effect is what in turn causes the fluctuations in the commercial sector. When biomass is used for electricity (and hydrogen) production, the negative emissions can balance the positive emissions in the commercial sector, which are more costly to reduce. Only when the scenario is more restrictive (either target or alternatives), the more expensive emissions from the commercial sector are reduced resulting in a lower gas demand. If CO_2 storage is available, methane is used for hydrogen production (instead of the opposite).

In terms of supply, the largest contribution is from Norway. It has the advantage of large reserves (350 EJ) and low production cost (1.2 €/GJ). In spite of having an upper annual production bound (of around 4400 PJ), it satisfies up to 80% of the demand. This level of production is feasible considering its current production is around 4000 PJ. The largest fraction is attributed to the lower total gas demand. This is complemented by import by pipeline from outside the EU and LNG import. Gas from the Netherlands has decreased by at least 70% compared to current values to 100–700 PJ/year. Other sources include gas from UK, Germany, Romania and the upgrading of biogas with carbon capture.

The role of PtM is limited in most of the scenarios and it only contributes significantly to energy independence in the "*Optimistic*" scenario. It provides up to 1.5% of the gas demand in the "*Alternative*" scenario or even with 95% CO_2 reduction and no CO_2 storage. In the "*Realistic*" scenario, it has 40 GW (280 PJ) of installed capacity (see Appendix I) and satisfies close to 8% of the gas demand. If the efficiency in marine transport is attractive enough to cause a shift in energy carrier to LMG, then PtM capacity increases to 122 GW (840 PJ) and 19% of total demand. The largest PtM contribution is when all the

conditions that favor PtM are present. This implies the co-occurrence of 11 conditions away from the reference scenario (see Table 17 in Appendix H). For this scenario, PtM capacity reaches 546 GW (4900 PJ) across EU28+ and providing 75% of the gas demand. This "*Optimistic*" scenario has almost 6% higher annual costs compared to the "*Realistic*" scenario (see Fig. 4), mainly because drivers that favor PtM (such as high gas price for import, higher cost for electricity grid expansion and low PtL performance) actually result in a higher cost to achieve the same CO_2 target. The gas allocation among sectors is similar to the scenario with 80% CO_2 reduction and no CCS. Some changes are that there is no H_2 production from methane when PtM is the source and that LMG completely covers the marine transport and heavy-duty sectors.

The single change that causes the largest positive change in PtM deployment is when the other options for CO_2 sink are not available. In the scenario when there is no PtL (in addition to no CO_2 storage), PtM total capacity is 482 GW (4400 PJ). A better electrolyzer performance enabling cheaper hydrogen can lead to 263 GW of PtM capacity (vs. 122 GW). A high CO_2 reduction target and absence of CO_2 storage, even together, prove to be necessary, but not sufficient to make PtM attractive, with only 7 GW of PtM deployed in this scenario. The system drivers have a larger influence than the technology drivers. This means that even with low PtM CAPEX (< 100 €/kW) and highest efficiency for the technology, the deployment is zero if CO_2 storage is still an alternative.[15]

Three regulatory measures to promote PtM technology have been assessed within this study: (1) direct PtM CAPEX subsidy, (2) indirect fossil gas tax, and (3) minimum target share of methane from PtM. With gas tax and minimum target share increasing the commodity price, they cause unwanted side effects such as a reduction of gas demand potentially motivating a fuel shift. The more effective instrument between tax on gas and PtM subsidy in terms of capacity installed is direct subsidy of the technology which leads to almost 6 times the deployment of a higher tax. A reason for this is that tax will increase gas price and will decrease the demand (through elasticity), while subsidy only has influence over the technology making it directly more attractive. This is in agreement with previous studies that identify that "SNG from PtM processes is not competitive with natural gas or even biomethane [from fermentation processes]" and different simultaneous drivers are needed [6]. However, both instruments do not guarantee a certain minimum target share of methane from PtM as instrument (3) does. Setting a minimum target share that is the same for all European countries seems not advisable as it does not consider nationally differing hydrogen demand and supply structures that make PtM unequally attractive across European countries.

To put these figures in perspective, PtM estimates for Germany are 7.5 GW [97], 6–12 GW [106], 28 GW [108], 1–59 GW [109], 48–87 GW [104] and even 89–134 GW [40]. For Ireland, 0.5 GW has been explored [29], 5 GW in UK [110], 7–13 GW in Spain with 27% VRE [111], Finland had 25 GW for a 100% RES system [41]. On the global scale, PtM had over 2300 GW [112], which even considering a small fraction of this being deployed in EU28 + is still far above the results for most unrestricted scenarios in this study. Some differences of the present study with respect to the previous references are: system boundaries, most of these studies [29,40,97,106,110,112] focus only on the power system. This leaves options like Power-to-Liquid and hydrogen for transport (the two dominant flexibility options for this study) out of scope, which might overestimate both electricity storage and PtM role. Other approaches (e.g. [111]) only estimate the power surplus and its potential use for PtM. Some of the studies focus on the operational aspect (e.g. hourly electricity price and operating hours) rather than the investment component and only do PtM capacity as sensitivity, which might lead to sub-optimal combinations, whereas in the current study the capacity is an output of the calculation. Finally, some studies (e.g. [29,113]) have gas demand as an exogenous variable, whereas in this study it is the result of the competition among technologies (endogenous).

Today, almost 20% of the gas is used in the residential sector for heating and gas constitutes 40% of the fuel mix to satisfy the heating and cooling services across EU [114]. This represents one of the main reasons to support PtM, where it is foreseen that to continue satisfying the heat demand, a lower carbon route has to be found for the gas. Nevertheless, across the range of scenarios evaluated, remaining heating demand after considering energy efficiency, is mainly satisfied with electricity (a range between 70 and 85%), complemented (5%) by biomass, solar (0–15%) and district heat (10%). Gas role in residential heating is limited to central CHP with carbon capture (see Appendix M) distributed using the district heating network.

Since LMG constitutes a large part of gas demand, drivers that promote LMG have a positive impact on gas demand. The order of magnitude for the energy consumed in heavy-duty, marine transport and buses (sectors where LMG can be used) is 5000, 2000 and 500 PJ respectively. The fuel choice for marine transport is directly dependent on commodity price and efficiency (leading to €/km). Consequently, when the efficiency is high enough, this sector is satisfied with LMG rather than diesel/HFO.[16] Buses are fueled with hydrogen in most scenarios, except if the electric option is possible or by diesel in *BAU*. Heavy duty is both the largest demand and the one with the largest changes across scenarios (see Appendix N for the fuel mix for the different transport modes across the main scenarios). LMG is used either if the CO_2 target is low (80%) or if CCS is available (which leads to negative emissions when combined with biomass and positive emissions can be afforded in transport). In scenarios with a high biomass potential, where CO_2 could be used for PtM, CO_2 is used instead for PtL to produce diesel.

The lower efficiency of the PtL process (78% for Fischer Tropsch [115], while it is 85% for PtM, see Table 1) is compensated by the higher efficiency and lower cost of diesel trucks downstream (7.5 vs. 8.9 MJ/km and almost 20 k€ cheaper by 2050 [115]). However, recent studies [116,117] also show this gap might already be closing with the total cost of ownership of LNG trucks falling below diesel trucks in less than five years, while subsidies of up to 12 k€/truck in Germany decrease the difference in CAPEX compared to diesel trucks. Even in the scenarios where LMG is used across these sectors, the LMG is sourced in imports for the scenarios where LMG is used in heavy-duty trucks complemented by large scale liquefaction of imported gas. The value chain of liquefaction of PtM product is not selected. Therefore, the same conditions that favor the use of LMG for heavy-duty trucks are the ones that do not favor PtM (low CO_2 target and use of CCS). This proves that the additional cost for hydrogen distribution and refueling (4.6–6 €/kgH_2) plus the higher (+35%) cost of the end vehicle itself is still smaller than the extra cost caused by efficiency losses in PtM (10–15%), liquefaction (6–8%), end use (energy consumption in an LMG truck is 45% higher than one with fuel cell [115]). However, this represents the outlook for 2050, while LMG could be attractive in the transition period. Considering as well that the PtM route involves extra CAPEX for both steps (PtM and liquefaction), while the saving is the distribution infrastructure. This does not even consider the extra costs for refueling stations that would be needed for LMG. Gas application in the transport sector requires another system to be in place to track the source of the CO_2 emitted and legal frameworks to ensure compliance. In contrast, hydrogen has zero tailpipe emissions and CO_2 emissions (if any) are centralized. In the long term, these two reasons make hydrogen more

[15] Scenario"80CostEff", which means 80% CO_2 reduction, low PtM CAPEX and high efficiency testing if the positive technology drivers outweigh the negative system drivers.

[16] Diesel from Power-to-Liquid/Biomass-to-Liquid when LMG efficiency is low and HFO only for *BAU* scenario.

attractive for these two sectors (heavy-duty and buses) as the scenario becomes more restricted.

From the above, a key parameter is the efficiency considered for LMG in ships. However, diesel engines are also expected to improve their performance and this could actually represent up to a third of the CO_2 mitigation in this sector [118]. If this is considered, efficiency for both fuels would be comparable and fuel choice is left to other factors. LMG would have the disadvantage of the need to develop new bunkering infrastructure. Doing this in the major 160 ports around the world, would cost around 11 bln$ [118], excluding all the upstream costs. LNG can have up to 200% of the life cycle emissions compared to conventional NG [119], which would make it more challenging until PtM is large enough to satisfy all demand. The methane losses in the parts of the system that would remain with PtM (e.g. storage, long distance transport by pipelines, distribution to costumers) can be 1.4–3.6% of the gas produced [120]. This can increase the GHG life cycle emissions by 25–50%. LMG also implies a more complex on-board storage system for the vessels, additional training, less space for loads (since the storage is larger), additional investment for ship adaptation and new safety regulations [118]. For these reasons, the "*Realistic*" scenario in this study does not consider LMG as dominant fuel for navigation.

5.4. Seasonal component of PtM

VRE represents up to 70% of the electricity mix. This introduces a strong seasonal and daily component in production. Electrolyzers (mostly for the scenarios without CO_2 storage) represent up to 40% of the electricity demand and even larger fractions for specific countries or time slices. Their share is large enough to influence electricity prices by manipulating demand. There is almost (< 1%) no hydrogen production during the winter peak (when there is no wind and solar contribution) and for countries dominated by solar, a similar behavior is observed during night. Production during summer peak can be up to 3–4 times higher than peak for the other two seasons. This produces a flattening effect of the electricity prices. Prices in summer can be 25% lower than in spring or fall, while prices in winter can be up to 80% higher (this also includes a capacity adequacy component to ensure there is enough capacity to satisfy the winter peak). Hydrogen prices in turn are attenuated by both the use of hydrogen storage (in tanks for daily fluctuations) and relatively flexible demand (when it is used for PtX). Consequently, hydrogen prices only fluctuate up to ± 10% across time slices. This flexible operation causes the electrolyzers to be operating only close to 50% of the time. In spite of the higher CAPEX contribution caused for this, it still represents an attractive option. This lower difference in daily prices reduces the incentive for price arbitrage through storage, which will only become smaller as the storage capacity increases [121].

PtM makes use of these small price differences across seasons and there is a seasonal pattern observed for PtM activity (see Fig. 7 and Appendix I). The seasonal storage fraction (primary Y-axis in Fig. 7) indicates the fraction of PtM gas that is stored each season compared to the total amount of PtM product routed to storage. The secondary Y-axis on Fig. 7 indicates the fraction of PtM routed to storage for every scenario compared to the total PtM energy produced. Stored fraction during summer can be up to double the fraction stored in spring or fall, while the fraction stored in winter can be around half of these, only sustained by countries with a significant wind contribution. This effect is more pronounced (see Appendix I) as the scenario becomes more restricted. Similarly, around 70–90% of the PtM product is routed through storage and then mixed with the rest of the gas, although it can be used in some cases within the same season.

The main driver for seasonal storage is satisfying demand when there is a low contribution from VRE in a system where other dispatchable RES technologies capacity is low. This application is investigated using the winter peak time slice. The intermediate case (only wind) presents itself over every night time slice. The technologies that provide flexibility when there is no VRE are nuclear, geothermal, biomass (biogas and CHP), hydro and to a less extent fossil with CCS. This is in agreement with previous studies with hourly resolution that show low VRE periods of up to one week can be bridged with limited contribution from PtM and with relatively small additions of gas capacity or biomass for the case of 100% RES [109]. When there is no solar, the combined effect of a larger wind output with a lower demand (on average half of the diurnal demand) aids covering the gap left. PtM will be favored as any of these technologies satisfying the winter peak demand is constrained. For example, if geothermal potential is constrained to 10% of the reference scenario value (to ~300 TWh), then gas demand for electricity almost doubles,[17] while also increasing the share of biomass. Use of gas with CCS also doubles for winter peak. Similarly, the case for PtM becomes more attractive and its capacity increases by 20% (263–313 GW). This increases the PtM contribution to gas demand from 25 to 33%. A similar effect can be expected when restricting any of the other dispatchable RES and nuclear technologies, even though this was not tested. For a more detailed breakdown of the technology contribution by time slice and by country, refer to Appendix O.

5.5. CO_2 sources and sinks

PtM should use CO_2 from biogenic sources for the following reasons: (1) The CO_2 will ultimately be emitted and if the CO_2 is sourced from fossil it will cause a net positive increase of CO_2 in the atmosphere; (2) if CO_2 comes from an ETS (Emissions Trading Scheme) sector (e.g. power) and ultimately ends up in a sector not covered by ETS (e.g. transport), it could lead to an emissions reduction for ETS, while in reality not leading to a reduction of CO_2 emissions for the entire system; (3) it could prolong the use of fossil fuels in the energy system. The sources and final sinks of CO_2 across the main scenarios are shown in Fig. 8. Note that for the second reason, the model does contain the ETS and ESR (Effort Sharing Regulation covering non-ETS sectors) policies until 2030 (43 and 30% reduction respectively compared to 2005 levels). For 2050, the CO_2 target is for the entire system regardless of sectors.

For the scenarios where CO_2 underground storage is possible, it is the preferred sink for CO_2. Sources are varied across power (BECCS, fossil CHP and gas), H_2 production (with biomass gasification and most of "Others" category) and industry (two largest contributors are cement and steel). With the reference biomass potential, biomass provides around 25% of the CO_2 that ultimately ends up underground (three main routes: combined cycle for power, H_2 production through gasification and BtL). With the highest biomass potential (e.g. "*Alternative*" scenario) biomass supplies close to 80% of the CO_2 stored. These emissions allow for (the most expensive) positive emissions elsewhere in the system. Only when CO_2 storage is not possible, CO_2 use arises. This techno-economic approach supports the environmental conclusion that when CO_2 storage is an alternative, that is the best sink for the CO_2 when compared to methane [16,17,122]. Furthermore, when there is CO_2 use, the preferential sink is Power-to-Liquid. In the "*Realistic*" scenario PtL is almost 25 times larger (in terms of CO_2 consumption) than PtM. A key sector that promotes this trend is aviation. The total demand for EU28+ is close to 4000 PJ, which translates to almost 0.3 Gton of CO_2 if all that demand were to be satisfied by PtL. Not all of it is satisfied with PtL and the ratio is about 4:1 PtL/BtL. It even has fossil-derived fuels for 80 and 95% CO_2 reduction scenarios. Another driver is the use in heavy-duty trucks with diesel, where the lower conversion

[17] Scenario used was 95CCSVRECostPEM which has conditions that favor PtM including cheaper hydrogen not to make the case optimistic, but instead to establish an upper bound for the benefit. A similar effect was observed in other scenarios with limited geothermal potential.

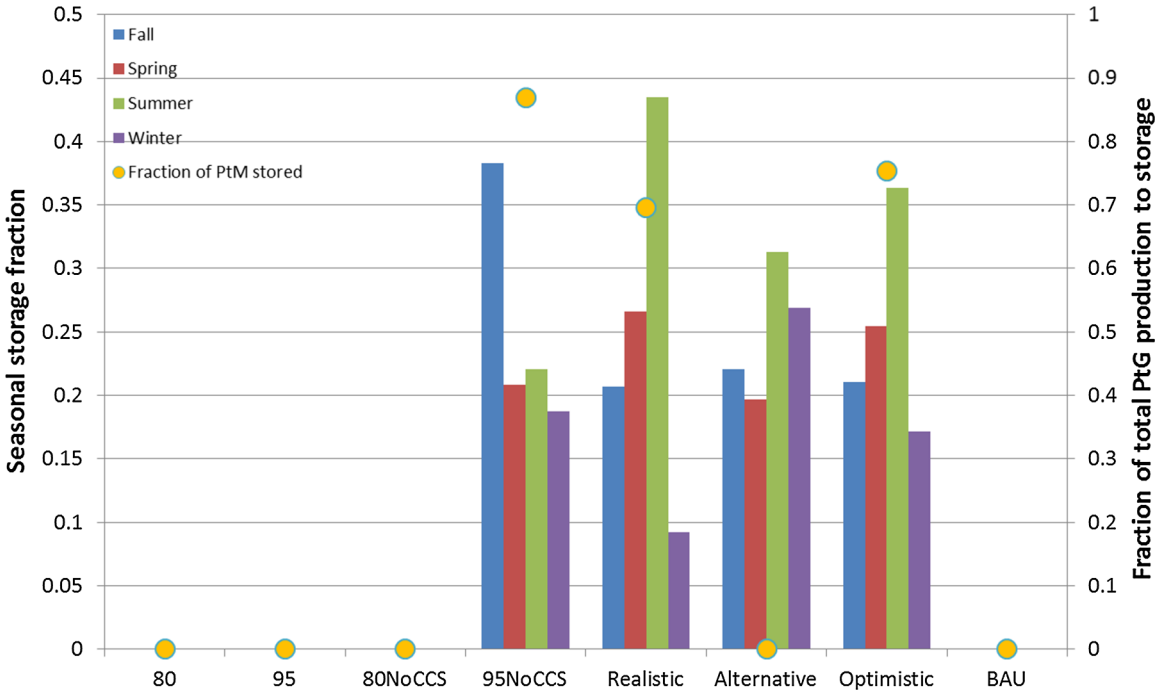

Fig. 7. Fraction of PtM production stored in each season across all scenarios.

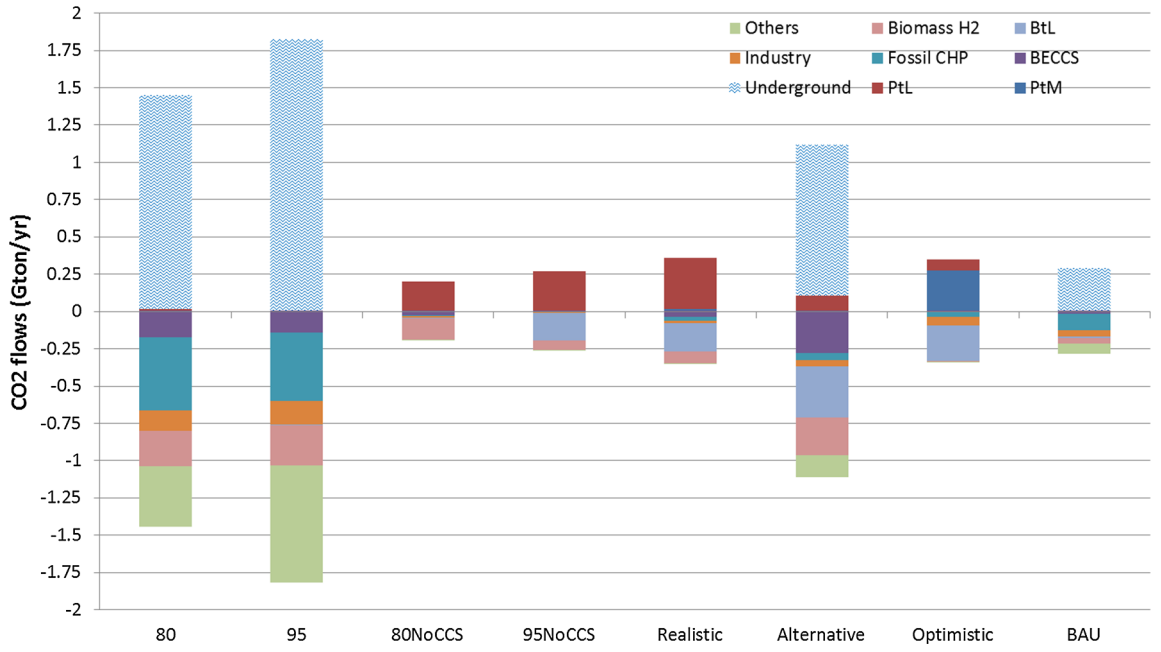

Fig. 8. CO_2 sources and sinks across main scenarios.

efficiency of the Fischer Tropsch route (fuel production) is compensated by a higher efficiency of the engine and lower cost in the fuel use (compared to methane). More detail on the dynamics of PtL is part of a separate study focused on H_2 and PtL [62] (in preparation). Electricity dominates private transport and the extra cost of the electricity network is outweighed by the higher pathway efficiency. To avoid an overly optimistic reliance on electric vehicles, their share is limited to 80% (assumption by authors). Part of the 20% remaining is covered by diesel vehicles (most efficient ones [123]), biofuels and hydrogen. When there is neither PtL nor CO_2 storage, PtM is used, but CO_2 flow is reduced by 30%. CO_2 use for PtM can be up to one third of the total CO_2 captured when PtM has a higher efficiency and almost 75% for the "*Optimistic*" scenario. A tax on gas has limited effect on CO_2 use, as its main effect is to reduce natural gas consumption rather than significantly increase PtM.

The largest CO_2 consumption is for the "*Optimistic*" scenario. Close to 270 Mton/yr are used for PtM, representing close to 5000 PJ of methane, which translates to 6000 PJ of H_2 input and almost 2000 TWh of electricity input required to satisfy such demand. This is more than half the current annual generation for EU (at 3200 TWh) only because of the additional constraints introduced (see Appendix H for constraints of "*Optimistic*" scenario). A key biogenic CO_2 source is BtL. Biomass has a low (~0.5) hydrogen to carbon ratio and it needs to be adjusted (i.e. Syngas shift) to be suitable for Fischer Tropsch (H_2/CO of 2). This gas shift produces CO_2 that can be captured downstream. For this scenario, 70% of the CO_2 used for PtM comes from biomass (BtL), 18% comes

from industry (cement and ammonia) and even a 10% from combined heat and power with fossil (see Appendix I for a better visualization). Two alternatives are identified. In one case, specific BtL plants could be co-located with wind farm/commercial solar plants and there would be a one-to-one match of CO_2 sources or sinks. In another one, there is a CO_2 network and all the producers and consumers are connected to the network without the possibility of allocating a consumer to a specific producer since they are all interacting through the grid. The model uses the second approach, coupled with the representation of one country per node, it is not possible to allocate specific BtL sources for PtM. However, it is optimistic to assume that all the CO_2 produced by BtL can be used by PtM, because it would imply that all the sites would have either wind or solar surplus, a nearby (suitable) biomass source, limited electricity grid capacity and enough gas grid capacity (otherwise PtM loses its claimed advantage of using existing facilities). This representation does not necessarily imply that full nationwide CO_2 networks need to be developed. Instead, main sources and sinks could be connected through critical pipeline corridors, perhaps even partly using former natural gas infrastructure.

DAC capacity is a function of the CO_2 target, underground storage and biomass potential. Capacities of over 400 Mton/yr of CO_2 were observed for the "95" scenario (with CO_2 storage and a biomass potential of 10 EJ/yr), while there was limited deployment for 80% CO_2 reduction scenarios. Capacity was larger when underground storage was possible. For these scenarios, the cost of reducing emissions is the CAPEX for the unit (~300 €/ton), the energy consumption (depending on the source, but it can be as high as the CAPEX component) and the cost for transport and storage (usually less than 15 €/ton for each step). DAC arises since the sum of these costs is still lower than the reduction of the marginal CO_2 unit. The heat used for DAC is mainly provided by CHP with gas and CCS. In the opposite case (of limited CO_2 storage), additional costs to displace the marginal unit of fuel are the CAPEX for electrolysis and fuel synthesis, plus their energy consumption (main cost component in the case of electrolysis). This increases the pathway cost leading to actually a decrease in amount of CO_2 directly captured when no CO_2 storage is possible to around 150 Mton/yr (still with the reference biomass potential). With the high biomass potential (25.5 EJ/yr), the need for DAC decreases since biomass provides enough carbon neutral feedstock for downstream processes and DAC is not necessary anymore regardless of the CO_2 storage assumption.

A CO_2 source that has a limited contribution across scenarios and that has been identified as preferential for PtM is biogas production. CO_2 capture on biogas occurred only when CO_2 storage was possible. Raw biogas is directly used for electricity, heat and steam generation through CHP for industrial use. This even assumes a cost penalty in CAPEX due to adaptation of equipment to use the lower heating value gas. Throughout the scenarios studied, biogas was used around 75–90% for steam and heat generation in industrial processes in scenarios with CO_2 storage and mainly (65%) for electricity generation when CO_2 storage was absent. Additionally, studies [77] suggest that upgrading with amines (standard process) has lower GHG emissions and other LCA indicators (human health, ecosystem and resources) than upgrading with PtM. Only for scenarios with a high biomass potential, PtM for biogas upgrading appeared as potential option. A high biomass potential, promotes the less efficient gas use in residential and commercial sector (due to the negative CO_2 emissions), which increases gas prices (in some countries even doubles), while at the same time causing a saturation effect in the biogas (industrial) users that produces a decrease (20–70%) of the biogas price. A cheaper feed and more expensive methane increase PtM attractiveness, but even then it only supplies up to 0.3% of the gas demand.

6. Conclusions

Scenarios explored in this study range from 80 to 95% CO_2 reduction by 2050 (vs. 1990). Uncertainty in possible evolution of parameters has been tackled by doing an extensive sensitivity analysis resulting in 55 scenarios. Trends observed include the importance of carbon capture and storage and high biomass potential to achieve a low system cost. Total electricity production reaches at least 5200 TWh (over 11,000 TWh for scenarios with more limited choices) with carbon footprints near zero and a reduction of the import bill for fossil fuels to at least 190 bln €/y (vs. a current bill of 400 bln €/y with 100 $/bbl oil). Specifically, for Power-to-Methane (PtM), it was present in 21 of the 55 scenarios with a capacity ranging from 40 to 200 GW and it represented between 0.45 and 5.7% of the gas supply cost. System drivers such as limited CO_2 storage, high (95%), CO_2 reduction targets and high (> 60%) VRE penetration had a larger impact over methanation deployment than technology drivers like investment for the technology. High VRE penetration is a necessary, but not sufficient condition for PtM. Countries with up to 95% electricity from VRE did not have PtM. Flexibility for these countries was mostly provided by electrolysis, but it did not extend to methane.

Periods of low VRE generation are bridged by a combination of hydro, nuclear, biomass (biogas and CHP) and geothermal. If any of these options is constrained further, the outlook for PtM improves. The system could evolve in a direction where PtM plays a crucial role and that is why it is important to continue R&D to have the technology available in case future conditions make it necessary. In an optimistic scenario where all the drivers are favorable, almost 75% of the gas is supplied by PtM with a simultaneous reduction of 70% of the total gas demand. To promote technology deployment, direct subsidy (up to 3 €/GJ) is more effective than taxing the fossil alternative (i.e. natural gas) and this is a measure that can be used in early stages of development to improve the economic case for private investors. A high efficiency of PtM had a large positive impact in deployment. Projects that include heat recovery and where there are local users for the heat should be the target for deployment.

Use of liquefied methane for navigation and heavy-duty transport can make a large difference in PtM capacity deployed. For both sectors, LMG is promoted when the end use fuel efficiency for methane is higher than liquid fuels. Gas trucks reaching parity in total cost of ownership in the near future might shift the heavy-duty transport supply structure from diesel to LMG and then eventually to hydrogen for the more restricted scenarios. Therefore, research on gas engine, combustion process and focus on reducing the methane slip could improve the outlook for PtM. Follow up work includes improving the temporal (hourly) and spatial resolution, where local conditions such as electricity grid congestion might make the technology more attractive using gas technology for integration of local gas infrastructure. Potential complement between production of synthetic fuels inside EU as well as imported should be studied.

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Appendices. Supplementary material

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