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LIFE-CYCLE GREENHOUSE GAS EMISSIONS OF BIOMETHANE AND HYDROGEN PATHWAYS IN THE EUROPEAN UNION

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EXECUTIVE SUMMARY

Gaseous fuels with low life-cycle emissions of greenhouse gases (GHG) play a prominent role in the European Union's (EU) decarbonization plans. Renewable and low-GHG hydrogen are highlighted in the ambitious goals for a cross-sector hydrogen economy laid out in the European Commission's Hydrogen Strategy. Renewable hydrogen and biomethane are given strong production incentives in the Commission's proposed revision to the Renewable Energy Directive (REDII). The EU uses life-cycle analysis (LCA) to determine whether renewable gas pathways meet the GHG reduction thresholds for eligibility in the REDII.

This study aims to support European policymakers with a better understanding of the uncertainties regarding gaseous fuels' roles in meeting climate goals. Life-cycle GHG analysis is complex, and differences in methodology as well as data inputs and assumptions can spell the difference between a renewable gas pathway qualifying or not for REDII eligibility at the 50% to 80% GHG reduction level. It is thus important for European policymakers to use robust LCA to ensure that policy only supports gas pathways consistent with a vision of deep decarbonization. For this purpose, we conduct sensitivity analysis of the life-cycle GHG emissions of a number of low-GHG gas pathways, including biomethane produced from four feedstocks: wastewater sludge, manure, landfill gas (LFG), and silage maize; and hydrogen produced from eight sources: natural gas combined with carbon capture and storage (CCS), coal with CCS, biomass gasification, renewable electricity, 2030 EU grid electricity, wastewater sludge biomethane, manure biomethane, and LFG biomethane. For each pathway, we estimate the life-cycle GHG intensity using a default central case, identify key parameters that strongly affect the fuel's GHG intensity, and conduct a sensitivity analysis by changing these key parameters according to the range of possible values collected from the literature.

Figure ES1 summarizes the full range of possible GHG intensities for each gaseous pathway we analyzed in this study—biomethane is depicted in the top figure and hydrogen is shown in the bottom. The bars represent the GHG intensity of the central case and vertical error bars indicate the maximum and minimum GHG intensity of each pathway, according to our sensitivity analysis. The dotted orange horizontal line illustrates the fossil comparator, which is 94 grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ) for transport fuels in the REDII. The dotted yellow line represents the GHG intensity of a 65% GHG reduction goal for biomethane used in the transportation sector, or 70% GHG reduction for hydrogen. Pathways are situated from left to right in increasing order of GHG intensity of the central case.

Comparing the central cases of the four biomethane pathways, the waste-based biomethane pathways generally have negative GHG intensity. However, considering the uncertainty in these GHG intensities, manure biomethane might have more limited carbon reduction potential in the 100-year timeframe if methane leakage from its production process is high. In contrast, wastewater sludge biomethane and LFG biomethane, even after accounting for uncertainties, retain relatively low GHG emissions. On the other hand, biomethane produced from silage maize can have much higher emissions; in the central case, we find that silage maize biogas only reduces GHG emissions by 30% relative to the fossil comparator—the low carbon reduction potential is due to the significant emissions emerging from direct and indirect land use change involved in growing maize. Taking into account the variation in assumptions, silage maize biomethane can be worse for the climate than fossil fuels.

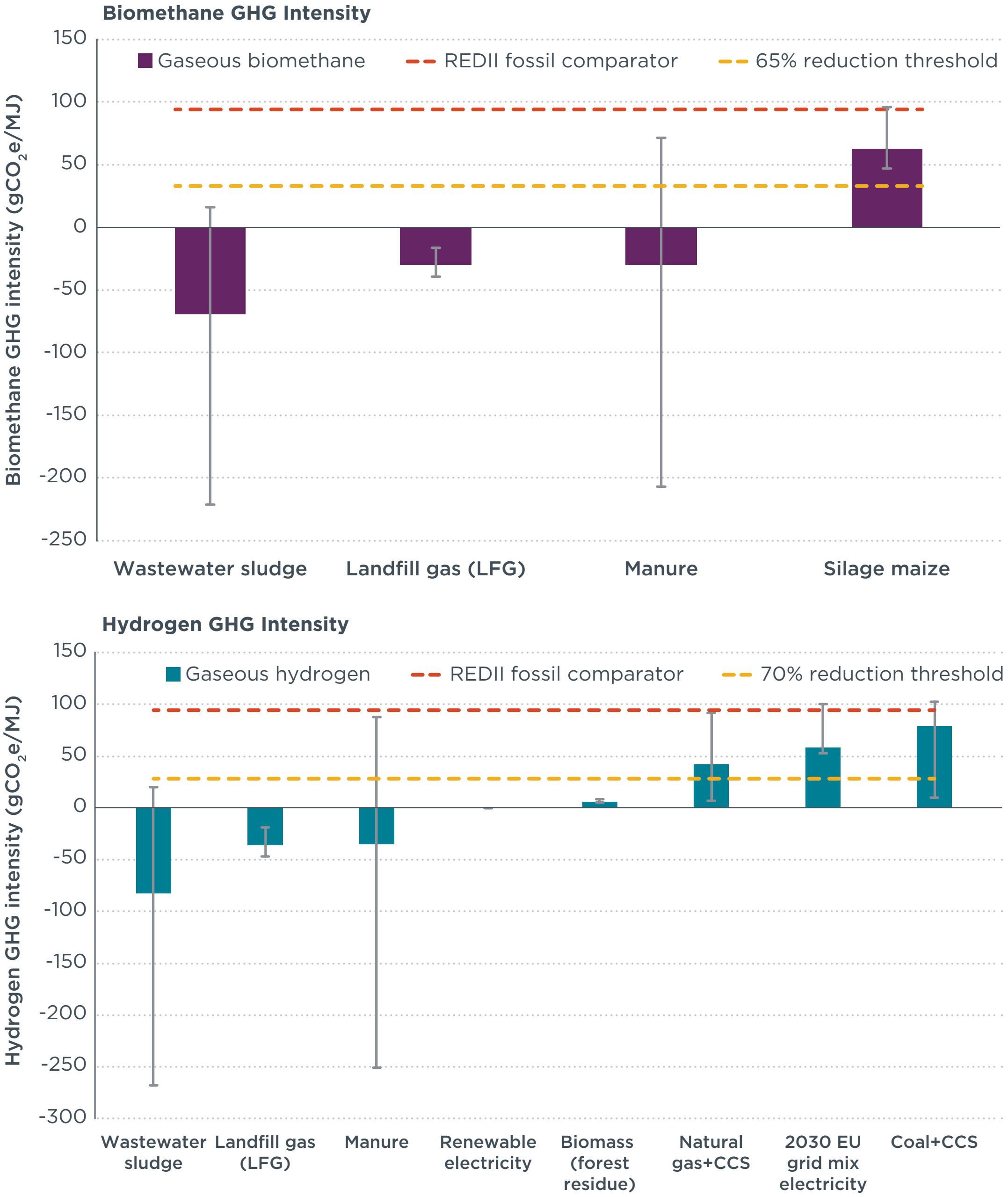

Figure ES1. GHG intensity sensitivity analysis of four biomethane pathways and eight hydrogen pathways using 100-year global warming potential from the Fourth Assessment Report (AR4) of the Intergovernmental Panel on Climate Change.[1]

Among the eight hydrogen pathways, hydrogen produced from renewable electricity and forest residue biomass can have low GHG emissions even after accounting for uncertainties in parameters. Hydrogen produced from biomethane (made from wastewater sludge, LFG, or manure) and natural gas plus CCS can deliver significant GHG reductions, but it is also possible that some of them could have similar or even higher GHG intensity than the fossil comparator. This is due to the potentially high methane leakage rate during biomethane production or from upstream natural gas extraction and transporting. Hydrogen produced from coal plus CCS and from 2030 EU grid electricity have the highest GHG intensities among the eight hydrogen pathways assessed here and are therefore unlikely to contribute to meeting the climate targets in the EU. The GHG intensity of fossil-based hydrogen with carbon capture can be as low

1 As originally published, the figure showed higher GHG emissions for hydrogen made from wastewater sludge, landfill gas, and manure, thereby underestimating their potential contributions to decarbonization.

as 10 gCO_2e/MJ with a 99.9% carbon dioxide (CO_2) capture rate. However, it is unlikely to achieve that capture rate for economic reasons; current industrial practices can only capture approximately 55% of the total CO_2 generated during hydrogen production.

Based on the results of this study, we provide several recommendations in two domains: (1) exclusion of certain pathways from use in meeting climate targets and (2) life-cycle methodology for calculating GHG intensity values to determine compliance with legislative mandates. First, we encourage policymakers not to add fossil-based hydrogen as an eligible pathway in the REDII and not to incentivize this pathway in any other relevant climate and gas policies, such as the upcoming Hydrogen and Decarbonised Gas Market Package. In addition, we recommend that policymakers exclude crop-based biomethane from the REDII and from any other climate policies. This is because of the significant GHG emissions emerging from direct and indirect land-use change associated with crop growing, which fails to meet decarbonization goals.

For any gaseous pathways to be considered for REDII compliance, we recommend facility-level measurements of life-cycle GHG intensity. In particular, this facility-level measurement should also include the measurement on methane leakage. To facilitate this process, we recommend that policymakers provide detailed and consistent guidelines on the methodology for measuring methane leakage and provide related guidance to verification schemes regarding how to verify these measurements. For waste-based biomethane in particular, we recommend that policymakers develop a consistent and comprehensive LCA methodology to account for changes in GHG emissions that result from switching from current waste management practices (i.e., the reference case) to biomethane production (i.e., the alternative case).

Finally, we recommend that the European Commission adopt robust rules for the REDII requiring that electrolysis hydrogen be produced from additional renewable electricity that would not be generated without hydrogen production. This can be demonstrated with Power Purchase Agreements (PPAs) or Guarantees of Origin (GOs) showing that the renewable electricity used has received no other policy support.

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INTRODUCTION

Gaseous fuels that emit low levels of greenhouse gases (GHG) are a key element of the EU's decarbonization strategy. The European Commission's Hydrogen Strategy communication lays out a vision for an ambitious expansion of low-GHG hydrogen used across the European economy (European Commission, 2020a). This communication sets goals of 1 million tonnes of renewable hydrogen produced in the EU by 2024, 10 million tonnes by 2030, and a fully mature renewable hydrogen industry between 2030 and 2050. Renewable hydrogen and biomethane have been incentivized in the Renewable Energy Directive (REDII), and the European Commission's proposed revision of that directive increases the ambition for these pathways (European Parliament & Council of the European Union, 2018; European Commission, 2021a). The Commission has proposed that 2.6% of the energy used in the transport sector be from renewable fuels of non-biological origin (RFNBOs), which includes renewable hydrogen and renewable electrofuels. The proposal also includes a target that 50% of hydrogen used in industry be renewable. The proposal includes stronger support for biomethane than in the previous version of the directive, with an ambitious 2.2% energy target for advanced biofuels. Several waste biomethane pathways are eligible for this target.

The GHG accounting of renewable gas pathways is important because only fuels that meet a certain threshold of life-cycle GHG reductions can qualify for support under the REDII. These life-cycle GHG emissions include the GHG emissions generated from all stages of the production and consumption of fuels—from production of the original energy source to use of the fuel in combustion or in other ways. Renewable hydrogen and e-gas used in transport must achieve a 70% life-cycle GHG reduction compared to fossil fuels. Biomethane must achieve a 50-65% life-cycle GHG reduction when used in transport and a 70-80% life-cycle GHG reduction when used for electricity, heating and cooling, depending on when the facility began production. Moreover, a fuel pathway's GHG intensity score determines its value toward the 13% GHG reduction target for the transportation sector in the Commission's proposed revision to the REDII; fuels with lower GHG intensity scores count more toward the target and are thus incentivized more than fuels with higher scores. It is therefore important that the EU use a robust life-cycle GHG accounting methodology to ensure that the best performing pathways are properly incentivized.

Only renewable hydrogen, produced from renewable electricity or biomass, is eligible in the REDII, but which electricity counts as "renewable" is a complex question. The REDII allows three options for demonstrating that electricity-derived hydrogen is renewable: 1) by using grid electricity and counting the renewable fraction according to the share of renewable electricity in the grid in that country, 2) by using electricity through direct connection to a renewable installation without importing electricity from the grid, and 3) by using grid electricity and demonstrating that it is exclusively from renewable sources. The European Commission is tasked with adopting a delegated act (an act that amends or supplements legislation) by December 31, 2021 to set out a methodology for demonstrating the second and third options. Without a robust methodology to ensure that renewable electricity used for hydrogen production is additional, it is possible that grid electricity could be counted as renewable in the REDII. It is thus important to understand the full life-cycle GHG emissions from producing hydrogen using both renewable and grid electricity.

Hydrogen produced from fossil fuels, including pathways that use carbon capture and storage (CCS) to reduce GHG emissions, are not eligible for support in the Renewable Energy Directive. However, the Hydrogen Strategy names this as one type of "low-carbon hydrogen" and states that such pathways are needed in "the short to medium term." It is thus possible that other incentives for fossil-based hydrogen combined with

CCS could be introduced in Europe. Understanding the life-cycle GHG emissions from these hydrogen pathways is thus also important for European policymaking.

Life-cycle GHG accounting is complex. GHG intensity estimates depend on a large number of data inputs and assumptions, and also on methodological choices used in the life-cycle calculation. Indirect land-use change (ILUC) emissions, which are extremely complicated to estimate and highly uncertain (Valin et al., 2015), are an important example of the difficulty faced in performing life-cycle analysis of alternative fuels. The methodological choices and assumptions used in life-cycle analysis can ultimately decide the eligibility of a given renewable gas pathway under the Renewable Energy Directive. It is thus very important for the EU to utilize the most robust life-cycle methodology possible in making pathway GHG determinations in order to ensure that European policy only incentivizes gas pathways consistent with a vision of deep decarbonization.

In this study, we perform sensitivity analysis to estimate the life-cycle GHG intensity of each of the four biomethane and eight hydrogen pathways. More importantly, we estimate GHG intensity of each pathway using a central case developed by an existing LCA model, identify key parameters and assumptions that may contribute to uncertainty in estimating each fuel's GHG intensity, and collect a possible range for each parameter and assess their impact on the range of possible emissions outcomes from those pathways.

METHODOLOGY

GASEOUS PATHWAYS IN THIS STUDY

We cover four biomethane pathways and eight hydrogen pathways in this study, as presented in Figure 1 below: biomethane produced from wastewater sludge, manure, landfill gas (LFG), and silage maize; and hydrogen produced from natural gas combined with carbon capture and storage (CCS), coal with CCS, biomass gasification, renewable electricity, grid electricity, wastewater sludge biomethane, manure biomethane, and LFG biomethane. These are representative gaseous fuel feedstocks and technologies that are most likely to be adopted today and in the near future.

Biogas, a mixture of gases, can be produced from anaerobic digestion of organic matter, such as manure, sewage wastewater sludge, maize, and wastes at landfill, known as landfill gas (LFG). Biogas can then be upgraded by separating methane from other component gases, mainly carbon dioxide (CO_2), and the separated methane is so-called biomethane or renewable natural gas. The produced biomethane can be used just like fossil natural gas in heat and power or as a transportation fuel, provided it is upgraded to the purity and heating characteristics of natural gas used in the grid.

In addition to the uses just mentioned, biomethane as well as natural gas can also be used as a feedstock to produce hydrogen, as shown in Figure 1. Currently, the most mature technology for such a conversion is steam methane reforming (SMR) where natural gas or biomethane reacts with high-temperature steam to form a syngas that contains hydrogen and carbon dioxide (CO_2). Besides SMR, autothermal reforming (ATR) is another technology that converts methane into hydrogen. However, since there is limited information available for life-cycle analysis, we do not include this conversion pathway in this study. We discuss the potential implications of using ATR in the Hydrogen section under Results and Discussion.

Gasification can convert carbonaceous feedstocks, such as coal and biomass, into a syngas that includes hydrogen, carbon dioxide, and other products. While industries can burn syngas directly or convert it into synthetic fuel such as drop-in biomass-to-liquids or biomethane, it is also possible to extract hydrogen from it.

Another way to produce hydrogen is through electrolysis, a process in which electricity is used to split water into hydrogen and oxygen. The source of electricity plays a big role in determining the GHG intensity of this pathway. Therefore, we consider both grid electricity and renewable electricity as the feedstock for electrolysis hydrogen.

Because natural gas and coal are both fossil fuels and are known to have high upstream GHG emissions, capturing and storing carbon dioxide from the produced syngas is necessary in order to produce low-carbon hydrogen. Therefore, in this study, we include carbon capture and storage (CCS) for these two fossil-based pathways. We provide more detailed descriptions and flow charts on each gas pathway in the Biomethane and Hydrogen sections.

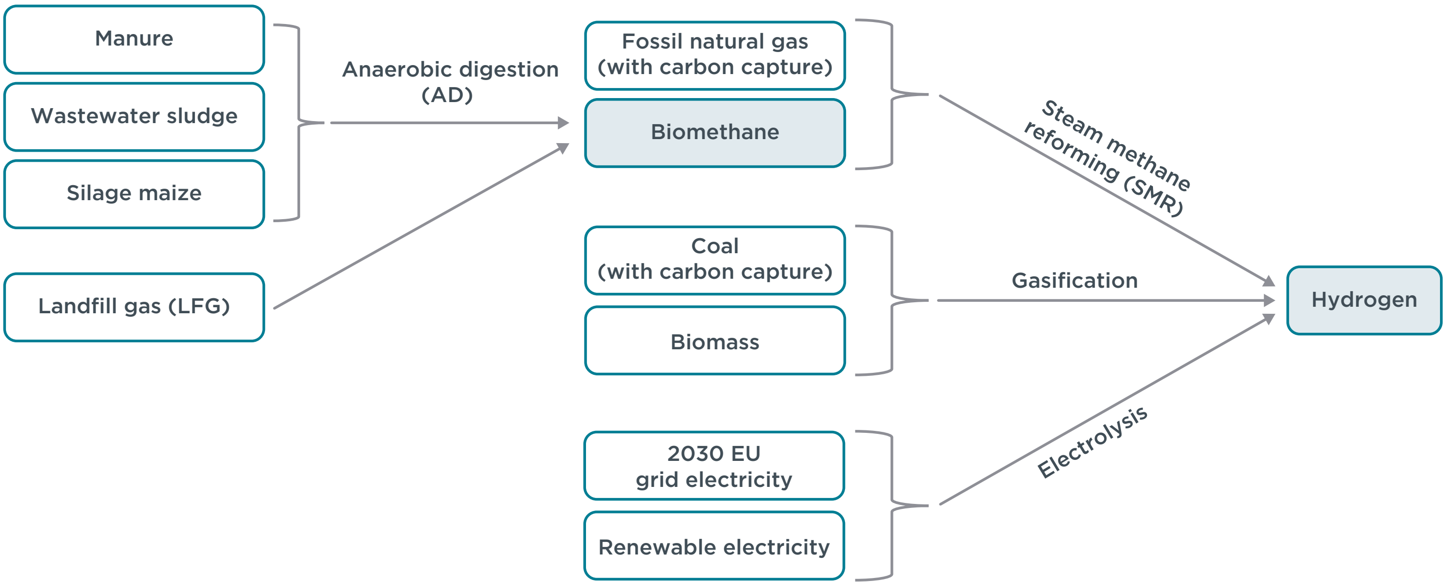

Figure 1. Biomethane and hydrogen pathways included in this study

LIFE-CYCLE GHG ASSESSMENT

We use the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model to estimate GHG intensity of various biomethane and hydrogen pathways in this study (Argonne National Laboratory, 2020). GREET not only provides a comprehensive framework for the full life-cycle (well-to-wheel) modeling of different types of transportation fuels, but also provides the flexibility of changing underlying assumptions, which facilitates further sensitivity analysis. As a US-based model, GREET is widely used for providing science-based insights for fuels policies in the United States, such as California's Low-carbon Fuel Standard (LCFS).

We evaluate well-to-wheel GHG emissions for both biomethane and hydrogen in this study, which include emissions from feedstock extraction, fuel production, and fuel combustion. We consider zero GHG emission during fuel combustion for both fuels because for biomethane, combustion emissions are generally assumed to be fully offset by carbon sequestration in growing the bio-feedstock; and for hydrogen combusted in a fuel cell, water vapor is the only product. We note that methane slip, i.e., leakage, from engines can happen when combusting biomethane, which is beyond the scope of this study. For pathways combined with CCS, we include energy use and associated emissions for the process of carbon capture.

For the purpose of this study, we have customized some of the underlying data in GREET to better reflect GHG intensity of biomethane and hydrogen produced in the EU. In particular, we updated the upstream emissions of natural gas using the EU average mix retrieved from the JRC-Eucar-Concawe (JEC) (Prussi et al., 2020). For electricity, we used the 2030 EU average grid electricity GHG intensity from EEA (2020) that is needed to meet the current policy target of a net 55% reduction in EU's GHG emissions by 2030. Since the value from EEA (2020) represents the emissions only during power generation, but does not include upstream emissions from feedstocks, we added the estimated upstream emissions based on the possible 2030 EU grid mix from the European Commission (2020b).

To understand the possible range of GHG intensities of each gas pathway, we conduct sensitivity analyses. Specifically, we undertake the following steps: create a central case with default assumptions for all parameters that feed into the LCA model; identify key parameters; define a range of values for each parameter based on a literature review; apply the maximum or minimum value of each parameter, one at a time, without changing other defaults in the central case; and summarize the range of GHG intensity results. For all cases, we use the 100-year global warming potential (GWP) values that convert climate impacts of methane and nitrous oxide into CO_2 equivalents (CO_2e). To better understand near-term impacts, we also apply a 20-year GWP, but only to the central case of each pathway. We use the GWP of both time frames from the Intergovernmental Panel on Climate Change (IPCC) Assessment Report 4 (AR4), in order to be consistent with the REDII. We did not conduct our own analysis on biomethane produced from silage maize because this pathway is not included in GREET; rather, we depended on the REDII and previous studies for the GHG intensity of silage maize biomethane.

PARAMETER SELECTION

To assess the uncertainty and full potential range of GHG intensities of biomethane and hydrogen, we need to answer two questions: (1) what are the parameters that have significant impacts on final GHG intensity, and (2) what is the range of possible values for each. To answer the first question and to reduce the list of parameters, we used natural gas SMR+CCS as a representative of all hydrogen pathways and did a sensitivity analysis to understand how sensitive the model is to each parameter that we are able to change in GREET. In particular, we adjusted GREET's default value of each parameter, one by one, by ±10% and compared the percentage changes in GHG intensity. We show the results from this first screening in Table 1. From this practice, we identified two key parameters for hydrogen produced from natural gas+CCS: production efficiency and carbon capture rate, as shown in Table 1. In addition to these two parameters, we also include in our analysis the methane leakage rate. Although the model is not very sensitive to methane leakage—adjusting leakage rate by ±10% only leads to ±2.5% in GHG intensity—there is huge uncertainty in the parameter itself, meaning that the leakage rate probably varies by more than 10% of the default value in GREET. In other words, high uncertainty in the leakage rate of methane will result in a greater percentage change in hydrogen's GHG intensity. Thus, we believe this is a crucial parameter to include in our analysis.

Table 1. First screening of parameters for hydrogen produced from natural gas+CCS

Parameter (adjusted by ±10%)	% change in hydrogen GHG intensity
Hydrogen production efficiency	(-7.9%, 9.7%)
Carbon capture rate	± 24.9%
Compression efficiency	± 1.2%
Methane leakage rate	± 2.5%
Pipeline distance	± 1.5%
Steam export credit	± 4.4%
Hydrogen loss rate during production	± 0.1%
Boil-off recovery rate during production	± 0.03%
Share of natural gas used as feedstock	± 0.02%

For biomethane pathways, previous studies have gone through similar sensitivity analyses and included key impacting parameters. Han et al. (2011) evaluated manure biomethane and Lee et al. (2016) evaluated wastewater sludge biomethane. We include the key parameters identified in those two studies for our own analysis. We show the list of all key parameters for each of the gas pathways in Table 2.

To evaluate the possible range of values for the key LCA parameters identified, we next conducted a comprehensive literature review to collect the possible range of values for each parameter. We show the central value used to develop the central case, as well as the range for sensitivity analysis in Table 2. We take GREET's defaults for the central values unless otherwise described. We discuss more about the values in the following sections on each pathway. We follow the terminology used in GREET for parameters of each pathway, which might differ in other applications.

Table 2. Key parameters analyzed in this study, their central values, and a possible range, collected from the literature

Gas pathway	Key parameters	Central value	Range	Literature
Manure biomethane	Percentage of generated methane that is flared at manure management facility	60%	0% – 70%	(Wright et al., 2017)
	Temperature (this informs the methane conversion factor)	15°C	10°C – 28°C	(Argonne National Laboratory, 2020)
	Methane leakage rate during anaerobic digestion and biogas upgrading	From digester: 1% of biogas produced	0.65% – 10% of biogas produced	(Hjort-Gregersen, 2013; Holmgren, 2015; Delre et al., 2017; Reinelt et al., 2017; Samuelsson et al., 2018; Scheutz & Fredenslund, 2019; Fredenslund et al., 2018; UNFCC, 2005; UNFCCC, 2012)
		From biogas upgrading: 2% of biogas produced	0.04%–5% of biogas produced	(Liebetrau et al., 2013; Holmgren, 2015; Kvist & Aryal, 2019)
Wastewater sludge biomethane	Percentage of volatile solid reduction (this informs methane yield)	Reference case: 45.3%	Reference case: 45.3%	(Argonne National Laboratory, 2020)
		Alternative case: 63.7%	Alternative case: 50%–65.4%	
	Fertilizer replacement credit	100%	0%–100%	(Möller & Müller, 2012; Suschka & Grübel, 2014; Lee et al., 2016; Plana & Noche, 2016; Barzee et al., 2019; Barłóg et al., 2020; Jamison et al., 2021)
	Methane leakage rate during anaerobic digestion and biogas upgrading	From digester: 1% of biogas produced	0.65%–10% of biogas produced	(Hjort-Gregersen, 2013; Holmgren, 2015; Delre et al., 2017; Reinelt et al., 2017; Samuelsson et al., 2018; Scheutz & Fredenslund, 2019; Fredenslund et al., 2018; UNFCC, 2005; UNFCCC, 2012)
		From biogas upgrading: 2% of biogas produced	0.04%–5% of biogas produced	(Liebetrau et al., 2013; Holmgren, 2015; Kvist & Aryal, 2019)
Landfill gas	Methane leakage rate during anaerobic digestion and biogas upgrading	From digester: 1% of biogas produced	0.65%–10% of biogas produced	(Hjort-Gregersen, 2013; Holmgren, 2015; Delre et al., 2017; Reinelt et al., 2017; Samuelsson et al., 2018; Scheutz & Fredenslund, 2019; Fredenslund et al., 2018; UNFCC, 2005; UNFCCC, 2012)
		From biogas upgrading: 2% of biogas produced	0.04%–5% of biogas produced	(Liebetrau et al., 2013; Holmgren, 2015; Kvist & Aryal, 2019)
Natural gas SMR+CCS	Hydrogen production efficiency	71.9%	56.6%–75%	(Spath & Mann, 2000; Mueller-Langer et al., 2007; Ramsden et al., 2009; Kurokawa et al., 2010; Martínez et al., 2013; Mosca et al., 2013; Spallina et al., 2016; IEA, 2017b; Y. Salkuyeh et al., 2017; Keipi et al., 2018)
	Carbon capture rate at hydrogen production plant	54.6% of CO_2 generated during hydrogen production	39.2%[2]–99.9%	(Kelly et al., 2005; Mueller-Langer et al., 2007; Ramsden et al., 2009; Kurokawa et al., 2010; Kandziora et al., 2014; Shahani & Kandziora, 2014; IEA, 2017b; Power et al., 2018; Pellegrini et al., 2020; Nazir et al., 2021; Regufe et al., 2021)
	Upstream methane leakage rate	From natural gas extraction and recovery: 0.41%	0.1%–9%	(Dedikov et al., 1999; IEA, 2006; Howarth et al., 2011; Wigley, 2011; Brandt et al., 2014; Balcombe, 2015; Howarth, 2015; Alvarez et al., 2018; Howarth & Jacobson, 2021)
		From natural gas transmission and storage: 0.11%	0.1%–10%	
Coal gasification+CCS	Hydrogen production efficiency	55.1%	50%–80%	(Mueller-Langer et al., 2007; Lv et al., 2008; Ramsden et al., 2009; Y. K. Salkuyeh et al., 2018; Ishaq & Dincer, 2022)
	Carbon capture rate at hydrogen production plant	54.6% of CO_2 generated during hydrogen production	39.2%–99.9%	(Kelly et al., 2005; Mueller-Langer et al., 2007; Ramsden et al., 2009; Kurokawa et al., 2010; Kandziora et al., 2014; Shahani & Kandziora, 2014; IEA, 2017b; Power et al., 2018; Pellegrini et al., 2020; Nazir et al., 2021; Regufe et al., 2021)
Biomass gasification	Hydrogen production efficiency	50.5%	40%–60%	(Mueller-Langer et al., 2007; Lv et al., 2008; Ramsden et al., 2009; Y. K. Salkuyeh et al., 2018; Ishaq & Dincer, 2022)
Electrolysis	Hydrogen production efficiency	72%	40%–80%	(Spath & Mann, 2004; Ferreira-Aparicio et al., 2005; Mueller-Langer et al., 2007; Holladay et al., 2009; Ramsden et al., 2009; Ursua et al., 2012; Bhandari et al., 2014; Keipi et al., 2018; IRENA, 2018; IEA, 2019)

2 The lower end of the carbon capture rate accounts for a potential 10% CO_2 loss when exiting the hydrogen plant, during CO_2 transportation, and during injection for storage. The same is assumed for coal gasification+CCS pathway.

BIOMETHANE

We first provide an overview of biomethane pathways and then provide more details on the key parameters. In some cases, diverting wastes such as animal manure, wastewater sludge, and landfill gas (LFG) into biomethane diverts them from their pre-existing waste management methods. In these cases, the LCA of biomethane from waste feedstocks differs from other fuel pathways in that it needs to consider energy use and emissions from both the reference case (the so-called counterfactual, or current waste management practice) and the alternative case (i.e., biomethane production). The GHG emissions from these waste-based biomethane pathways would therefore include the difference in GHG emissions between the alternative and reference cases. In this way, the emissions for these pathways would include avoided GHG emissions as a credit (i.e., negative emissions). Therefore, the final GHG intensity of waste-based biomethane pathways depends on assumptions of their pre-existing, reference waste management practices as well as the production of the fuel itself (Han et al., 2011).

Figure 2 provides a high-level illustration of the process of manure and wastewater sludge in both reference and alternative cases based on the scenario design in GREET. We indicate at which stage this study's key parameters factor in for each pathway in orange text. We provide more explanations on each parameter in the following sections.

For the manure-based pathway shown in first graph of Figure 2, the reference manure management system, such as liquid or slurry storage, generates both gaseous and solid outputs. The rate of methane generation depends on ambient temperatures and the type of manure management system in place, which together inform the methane conversion factor (MCF)—one of the parameters we assess in this study. Since methane is a potent GHG, manure handlers can combust the gas (i.e., flare it) to convert methane into carbon dioxide to reduce its climate impact. We also evaluate flaring rates on the overall GHG impact of manure biomethane pathways. The solid residue from manure management can be used as fertilizer for soil application for its nutrients and during this process, some of the carbon contained in the solid would be sequestered by soil and some would inevitably be emitted inevitably. If manure were diverted from waste management to biomethane production, it would go through anaerobic digestion (AD) instead. AD generates biogas, along with a residue known as digestate, which can also be used for soil application. The biogas goes through two stages of upgrading (i.e., gas cleaning). After the first upgrade, a portion of cleaned biogas is combusted in combined heat and power (CHP) system for onsite energy usage; the rest goes through a second upgrade to remove impurities and produce biomethane suitable for injection into natural gas pipelines. In this alternative case, methane leakage can occur during AD and both stages of gas upgrading, and the leakage rate determines the amount of methane that is emitted into the atmosphere.

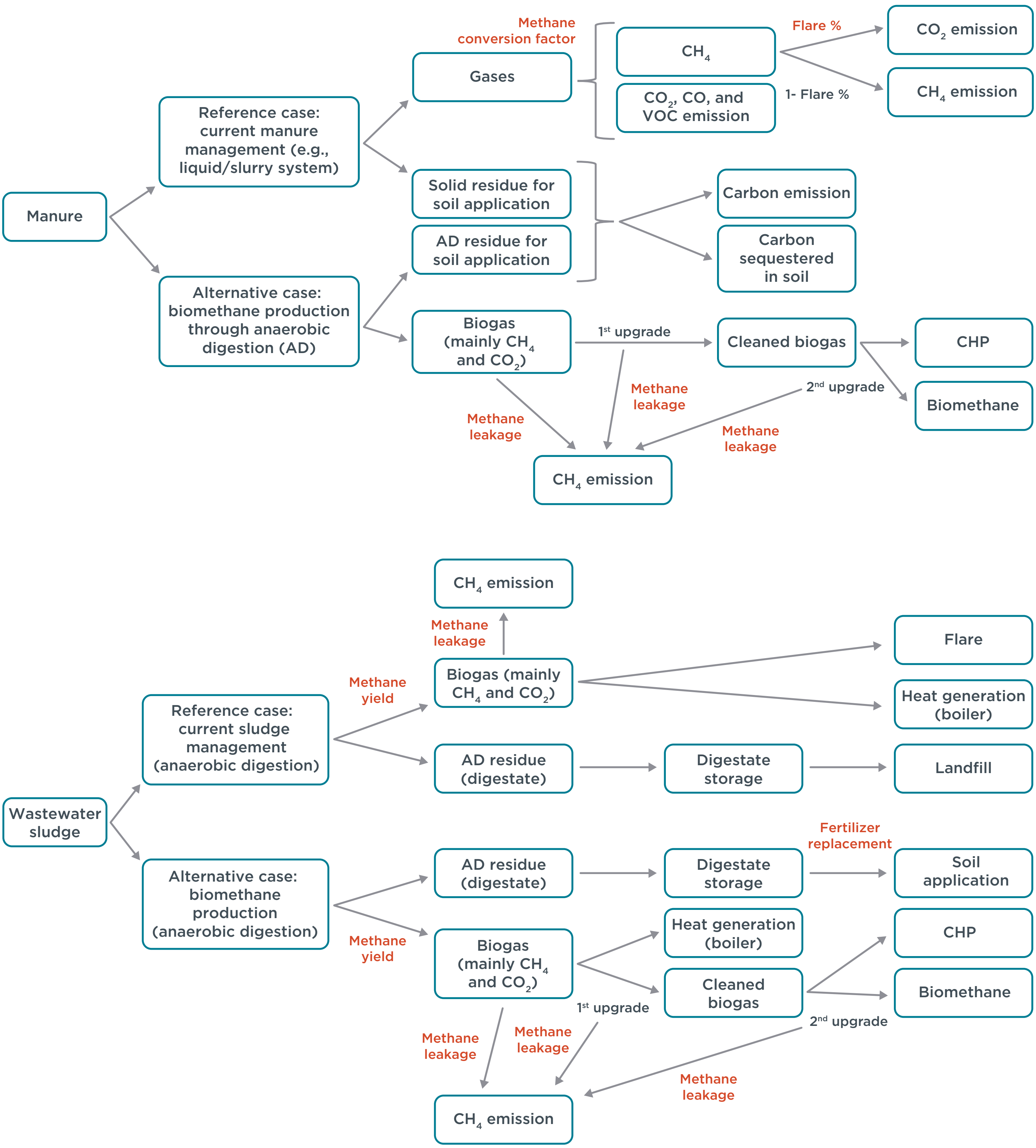

Figure 2. Simplified scheme of the reference case (i.e., current waste management) and alternative case (i.e., biomethane production) for manure and wastewater sludge. Text in orange highlights the key parameters analyzed in this study. CHP = combined heat and power, CO_2 = carbon dioxide, CH_4 = methane, CO = carbon monoxide, VOC = volatile organic carbon

The wastewater sludge pathway, shown in the second graphic in Figure 2, differs from the manure pathway in that GREET assumes that current sludge management already applies AD as a way to reduce the volume of sludge for disposal (Lee et al., 2016). While both pathways utilize AD, the main difference is that in the reference case, the generated biogas is not upgraded; instead, a portion of it is combusted in a boiler to meet onsite heat demand, and the rest is flared. Depending on the type of AD technology, the AD residue generated may or may not meet the quality standards for fertilizer based on US regulations. The most widely-used AD technology in sludge management in the U.S., Meso-1 AD, does not generate high-quality residue and is landfilled rather than used as a soil amendment.

In the alternative case, except for heat generation in a boiler, some of the biogas is cleaned for CHP applications that not only supply additional heat but also provide electricity to be used onsite or exported if excess. The remaining biogas is next upgraded into biomethane. For the solid residue, we assume that more advanced AD technology is adopted in the alternative case, resulting in fertilizer-grade digestate that could replace conventional fertilizer. The fertilizer replacement ratio thus determines the avoided emissions from digestate soil application. In both reference and alternative cases treating wastewater sludge, the methane yield determines the amount of methane generated from the sludge and the methane leakage rate indicates the amount of methane that escapes during AD and gas upgrading. While MCF and methane yield have similar meaning and could be used interchangeably, in this study, we differentiate them by using the term MCF to represent current manure management while methane yield refers to the AD process specifically.

GREET provides multiple scenarios to account for regional differences in key assumptions; we used the IPCC Western Europe scenario for this study. For LFG, while GREET assumes all LFG is flared for the reference case, this may not be common practice in the EU; we therefore change GREET's default and instead assume 80% LFG used for electricity generation and 20% flared (EurObserv'ER, 2019; Eurostat, 2021). While silage maize is a common feedstock for biomethane generation in the EU, this pathway is not included in GREET. Therefore, we collected the GHG intensity from the REDII and literature rather than estimating its emissions using GREET.

Animal manure biomethane parameters

We first changed the default share of livestock in GREET to better represent the share for biomethane generation in the EU based upon Kampman et al. (2016). We show the share of livestock used in this study in Table 3.

Table 3. Share of livestock for manure biomethane generation in the EU

	Dairy cow	Other cattle	Market swine	Breeding swine	Poultry
Share of livestock	18.9%	18.9%	31.1%	31.1%	0.0%

Han et al. (2011) conducted a sensitivity analysis of the life-cycle GHG emissions of manure biomethane. Based on their findings, two parameters in the reference case of current manure management system have a significant impact on GHG intensity: the percentage of generated methane that is flared at the manure management site and the methane conversion factor (MCF), as indicated in Figure 2.

Flaring, or gas combustion, is one way to reduce methane emissions as methane is converted into carbon dioxide through flaring. However, there is very limited information on the share of methane that is typically flared at manure management sites. While the default value in GREET is 60%, one US study utilizes a 50% flare rate (Wright et al., 2017). However, it is likely that many small facilities do not flare nor are required to in the EU. Therefore, we use 0% as the lower boundary to represent the extreme case and assume 70% as the upper boundary in our sensitivity analysis.

The methane conversion factor (MCF), which in this study describes the reference manure management system, is the ratio of the actual amount of methane generated to the theoretical maximum methane generation for a specific type of manure. MCF, in the range of 1% to 80% in GREET, differs for each manure management system and is dependent on temperature. For example, when holding the temperature at 10°C, manure treated in a liquid/slurry system has a MCF of 17%, while manure treated in solid storage has a MCF of 2%. Within liquid/slurry treatment, if the temperature increases from 10°C to 28°C, MCF increases from 17% to 80%. GREET retrieves the default values of MCF from the IPCC, which are the most accepted values. Therefore, we did not change the default MCFs in GREET. In the real world, different regions and countries are likely to adopt different manure management methods. In Table 4, we show the shares held by various manure management systems for the four types of livestock used for biomethane production in the EU, using IPCC's western Europe scenario in GREET. We also show the US average share in parentheses as a comparison. The US scenario has a higher share of lagoon systems, which generates relatively high methane emissions. In contrast, because Europe has smaller and less-dense farms, it has a higher share in solid storage and pasture/range/paddock, which has lower methane emissions. This means that the reference case of manure management in Europe would have lower GHG emissions than that in the US, leading to less credit for avoided emissions and higher GHG intensity of manure biomethane, assuming all other parameters in the reference and alternative cases are the same between the EU and US. This indicates the importance of the values chosen for shares of various manure management systems to be used as the reference case. Due to the fact that we already selected the western Europe scenario in GREET, we did not change the default share of manure management in Table 4. Rather, we used the upper and lower temperature boundary (10°C to 28°C) in GREET to generate a range of values for MCF.

Table 4. Share of manure management systems for different types of livestock using IPCC's western Europe scenario. For comparison, average scenario shares for the US are shown in parentheses.

	Lagoon	Liquid/ slurry	Solid storage	Dry lot	Pit<1mn	Pit>1mn	Pasture/ Range/ Paddock	Daily spread	Digester	Other
Dairy cow	0% (31.8% US)	35.7% (21.2% US)	36.8% (22.7% US)	0%	0%	0% (2.1% US)	20% (7.1% US)	7.0% (15.2% US)	0%	0.5%
Other cattle	0%	25.2% (0.7% US)	39.0%	0% (100% US)	0%	0%	32%	1.8%	0%	2%
Market swine	8.7% (34.6% US)	0.0% (17.8% US)	13.7% (4.4% US)	0%	2.8%	69.8% (40.9% US)	0% (2.2% US)	0%	2%	3%
Breeding cattle	8.7%	0.0% (0.2% US)	13.7%	0% (77.5% US)	2.8%	69.8%	0% (7.3% US)	0% (15.3% US)	2%	3%

Wastewater sludge biomethane parameters

As described above and illustrated in Figure 2, AD is used in both reference and alternative cases for the sludge pathway. According to Lee et al. (2016), methane yield and assumptions about using the digestate as fertilizer both impact the GHG intensity of wastewater sludge biomethane.

Methane yield, which in this study refers to methane generated from the AD process specifically, describes the biogas, and subsequently the quantity of methane, produced from AD. While this parameter is relevant to both reference and alternative cases because both utilize AD, we only consider a range of methane yields for the alternative case. Methane yield is estimated through the percentage of volatile solids reduction (VSR), which estimates the amount of biogas generated when the volatile solids present in the sludge are destructed. For biogas, GREET assumes 65% of it is methane and we do not change this value. VSR and consequently methane yield is affected by the type of AD technology used. In our central case, we use GREET's default AD technology, which is the Meso-1 baseline for the reference case (VSR percentage of 45.3%) and the Thermohydrolysis baseline for the alternative case (VSR percentage of 63.7%). To evaluate the impact of methane yield on emissions in the alternative case, we input a range of VSR values (50–65.4%) from the nine AD technologies provided in GREET, while holding the methane yield for the reference case constant at 45.3%.

Digestate, the residue by-product of the AD process, can be used to displace fertilizer depending on its quality and nutrient content. GREET assumes a one-to-one displacement of digestate to conventional fertilizer. However, there are uncertainties and debates not only regarding the nutrient levels of digestate, but also about the performance of digestate as fertilizer (Möller & Müller, 2012; Suschka & Grübel, 2014; Lee et al., 2016; Barzee et al., 2019; Barłóg et al., 2020; Jamison et al., 2021). In addition, there may be mass loss during storage and transport of digestate to the application field (Plana & Noche, 2016). More importantly, there could be uncertainties in farmers' behavior. For instance, farmers might apply the same amount of conventional fertilizer with or without digestate application, simply because it is their custom or because they do not want to risk lower yields. In short, the one-to-one displacement is likely optimistic and given all the uncertainties, we assume a lower boundary of 0% replacement. In other words, the sensitivity is 100% versus 0% fertilizer replacement rate.

Upstream methane leakage from biomethane

In this study, we consider the impacts of structural and accidental methane leakage from two stages along biomethane's life-cycle: AD and biogas upgrading. Leakage from anaerobic digesters is relevant to manure biomethane (alternative case) and wastewater sludge biomethane (both reference and alternative case), and biogas upgrading is relevant to landfill gas as well as the alternative case of manure and wastewater sludge biomethane pathways. While numerous studies have mentioned methane emission from digestate storage (Liebetrau, Clemens, Cuhls, Hafermman, et al., 2010; Boulamanti et al., 2013; Liebetrau et al., 2013; Battini et al., 2014; Holmgren, 2015; Hrad et al., 2015; Baldé et al., 2016), we did not analyze its uncertainty impact in this study but kept default values in GREET since it is not clear whether the GREET model refers to open storage or closed storage of digestate, which by contrast is specified in the REDII.

The default leakage rate from anaerobic digester in GREET is 1% of methane leakage of biogas produced by volume. From a literature review, we collected a possible range of 0.65% to 10% leakage rates (Hjort-Gregersen, 2013; Holmgren, 2015; Delre et al., 2017; Reinelt et al., 2017; Samuelsson et al., 2018; Scheutz & Fredenslund, 2019; Fredenslund et al., 2018; UNFCC, 2005; UNFCCC, 2012). For leakage during upgrading biogas, we collected a range of 0.04% to 5% leakage from the literature (Liebetrau et al., 2013; Holmgren, 2015; Kvist & Aryal, 2019). We note that in addition to the two stages included in this study and methane emission from digestate storage, leakage could also occur during storage and transportation of waste feedstock, from digestate, and from biomethane itself, which we do not analyze in this study.

Maize biomethane

The LCA of maize biomethane differs from that of other waste-based pathways in that no reference case is needed; rather, it needs to account for emissions from maize cultivation and consequently direct and indirect land-use change (LUC). Since this pathway is not included in GREET, we rely on the values in the REDII and previous studies to get a range of GHG intensity estimates for this pathway (Ploechl et al., 2009; Agostini et al., 2015; European Commission, Joint Research Centre, 2017). Some of the studies did not consider LUC impacts and for these we added the LUC value from European Commission (2015), which is 21 gCO_2e/MJ for maize biomethane. For our central case, we calculated the average of the four typical values provided in REDII, which is 42 gCO_2e/MJ, and added 21 gCO_2e/MJ to account for LUC emissions.

HYDROGEN

We consider eight hydrogen production pathways in this study. We provide a high-level illustration of the production process in Figure 3 and indicate the key parameters in orange text. We present a detailed explanation of each parameter in the following sections. In this study, we consider three hydrogen production technologies: steam methane reforming (SMR), gasification, and electrolysis.

For SMR, the feedstock can be natural gas or biomethane, as indicated in the first graph of Figure 3. In the reformer, methane reacts with steam to form hydrogen and carbon monoxide, which then goes through a water-gas shift that generates more hydrogen and carbon dioxide, so-called syngas. This syngas output contains 60% of the total carbon dioxide generated at the SMR plant. Hydrogen in the syngas is then separated from other gas impurities, usually by using pressure-swing adsorption (PSA). Because the difference between syngas and tail gas is simply the removal of hydrogen, tail gas still contains 60% of the total carbon dioxide generated in the process. The impurities in the tail gas are then fed back into the reformer to go through the process again. Ultimately, all carbon ends up in the flue gas from the reformer. We consider use of CCS for natural gas SMR; because carbon dioxide is present in three streams, there are three options for placement of the carbon capture unit. We address this more fully in the carbon capture rate section.

Coal or biomass can be fed into a gasifier, which, with the presence of oxygen, converts carbonaceous materials into a mixture of gas including carbon monoxide and hydrogen, without combustion. Similar to SMR, the generated carbon monoxide also goes through a water-gas shift for more hydrogen production. Unlike SMR, the gasification pathway requires an additional step, acid gas removal, which extracts the hydrogen sulfide that is generated. Carbon capture units can be installed at this stage to separate carbon dioxide for storage. After that, PSA is used to separate hydrogen; its tail gas can be used for power or heat generation to meet onsite energy demand and the carbon dioxide present in the tail gas can also be captured. As mentioned, we only consider CCS for fossil-based hydrogen pathways, i.e., coal in this case.

In the case of electrolysis, electricity is used to split water into hydrogen and oxygen, which takes place in an electrolyzer. This process results in a stream of high-purity hydrogen. In this study, we consider two electricity sources for electrolysis: EU grid electricity in 2030 and 100% renewable electricity.

Among the three hydrogen production technologies, SMR is the most mature and the cheapest. Almost half of hydrogen produced globally is from natural gas SMR (IRENA, 2020). Of course, the technology distribution would differ by region. For instance, while coal gasification might not gain much interest in the EU because of its adverse environment impacts, this pathway is nonetheless the most popular in China where about 40% of hydrogen is produced from coal (EV100, 2020, p. 100). Various biomass feedstocks, including forest residues, agricultural residues, and energy crops can be used in gasification, as provided in GREET. Through our preliminary analysis, the GHG intensities using different feedstocks in GREET are similar to one another. In this study, we use forest residues as the feedstock. We assume that forest residues are not used in other ways, given the large supply available in the EU (Searle & Malins, 2016). We also assume there is no added or avoided emissions from using forest residues for hydrogen production because residue decays quickly; however, this is a simplification since forest residues can continue to store carbon for several years in colder climates (Alessandro et al., 2014).

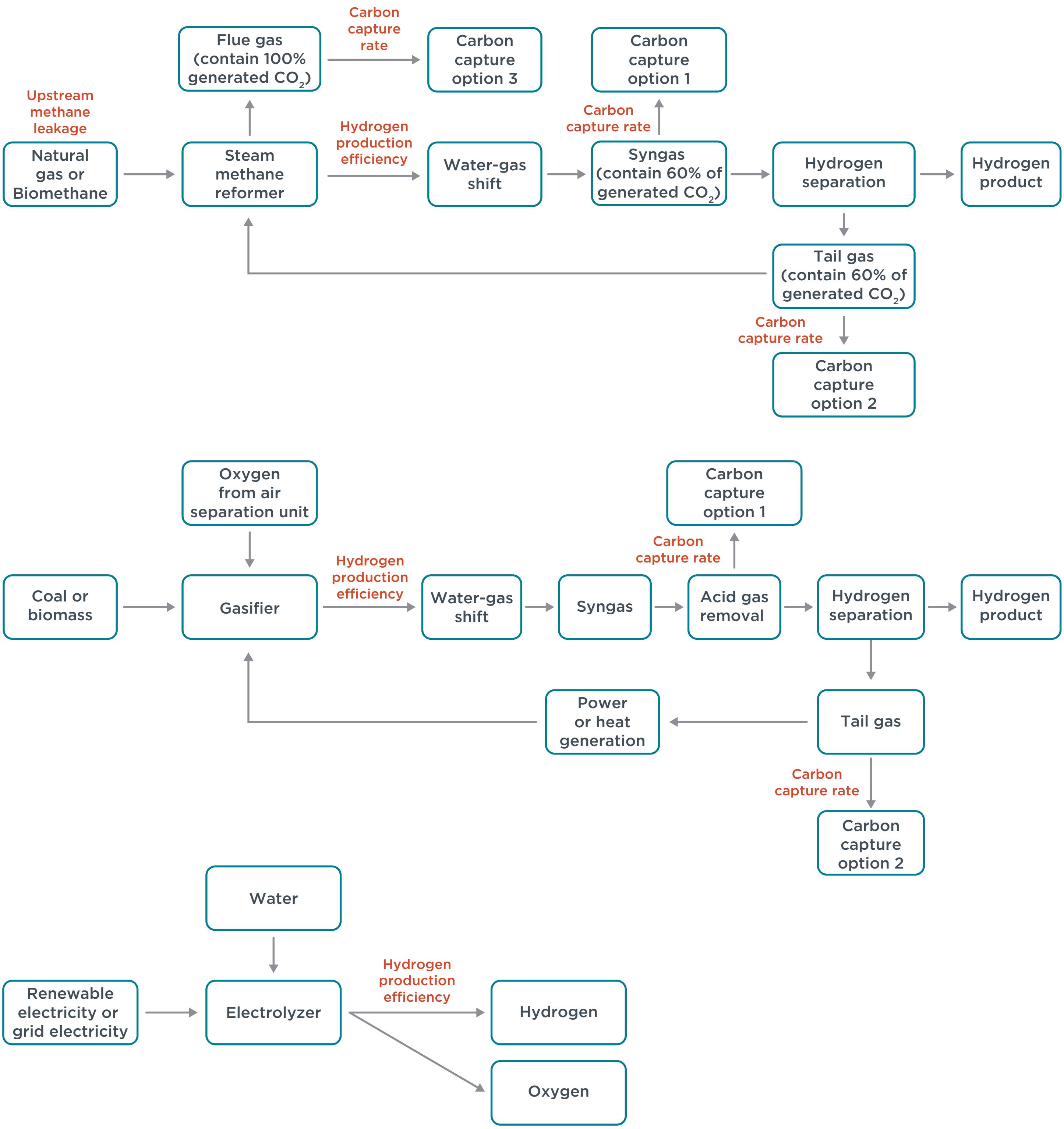

Figure 3. Simplified scheme of hydrogen production. Text in orange identifies the key parameters analyzed in this study. CO_2 = carbon dioxide

The uncertainties of the three biomethane pathways described above—manure biomethane, wastewater sludge biomethane, and LFG—are also fed into the hydrogen model for the pathways that involve biomethane. Therefore, in the section below, we introduce the key parameters in the remaining four hydrogen pathways: natural gas SMR+CCS, coal gasification+CCS, biomass gasification, and electrolysis using grid or renewable electricity. As shown in Table 2 and Figure 3, the key parameters for natural gas SMR+CCS are hydrogen production efficiency, carbon capture rate, and upstream methane leakage rate; for coal gasification+CCS they are hydrogen production efficiency and carbon capture rate; and for biomass gasification and electrolysis it is hydrogen production efficiency.

Hydrogen production efficiency

In this study, we define hydrogen production efficiency, also called the net energy ratio, as the total energy output divided by the total energy input. We focus on input for hydrogen production only. In particular, we do not consider energy input for carbon capture as part of hydrogen production efficiency. We also do not include co-products, such as extra steam or electricity, as energy output. Energy efficiency based on lower heating value (LHV) and higher heating value (HHV) differs; therefore, special attention is needed when collecting this information. Particularly for the electrolysis pathway, many of the studies report energy efficiency on a HHV basis, which is typically 15% higher than LHV-based efficiency. In this study, for consistency, we show only LHV-based efficiency.

Natural gas SMR

For SMR, energy input is typically in the form of natural gas, which is used as both a feedstock and a process fuel. In addition to natural gas, electricity is sometimes also used as a process fuel, but at a very small portion compared to natural gas (Ramsden et al., 2009). GREET assumes the share of total natural gas consumed as a feedstock to be 59.4% (the remainder is used as process fuel). Through our first screening, we found GHG intensity is not sensitive to this parameter and thus used GREET's default in our model.

As a general practice, SMR plants tend to produce steam in excess of the requirement of the steam reforming reactions and the excess steam can be exported and sold to other facilities for extra revenue (Spath & Mann, 2000; Mosca et al., 2013). In some studies, researchers count exported steam as an energy output when calculating efficiency and therefore present higher efficiency values. In this study, we are only focusing on the energy needed to produce hydrogen, i.e., hydrogen as the only energy output, and do not consider credit from steam export for efficiency. Exported or not, it does not change the amount of hydrogen produced (Spath & Mann, 2000). GREET includes steam export separately in the LCA model.

Multiple factors can affect hydrogen production efficiency, such as plant size and configuration, SMR operation including temperature and pressure, and energy content in natural gas feedstock (Contadini et al., 2002; Mueller-Langer et al., 2007; Liu et al., 2010; Mosca et al., 2013; IEA, 2017a; PATWARDHAN et al., 2013). Previous studies reported a range of 56.6% to 75% as hydrogen production efficiency from natural gas SMR (Spath & Mann, 2000; Mueller-Langer et al., 2007; Ramsden et al., 2009; Kurokawa et al., 2010; Martínez et al., 2013; Mosca et al., 2013; Spallina et al., 2016; IEA, 2017b; Y. Salkuyeh et al., 2017; Keipi et al., 2018).

Coal gasification and biomass gasification

The energy input for coal gasification is mostly coal with about 1% electricity, and for biomass gasification is about 95% biomass with the remaining energy input coming from natural gas and electricity (Argonne National Laboratory, 2020). Different types of gasifier and gas separation systems can have different energy efficiencies (Mueller-Langer et al., 2007; Ramsden et al., 2009; Y. K. Salkuyeh et al., 2018). While most studies report efficiency of around 55%–60%, the latest technology aims to improve coal gasification efficiency to 64–68% (Mueller-Langer et al., 2007). Even further, by optimizing the flow rate of reactants, hydrogen production efficiency of coal gasification can theoretically reach 80% (Chen et al., 2021). With all the information collected, we use a range of 50% to 80% as the hydrogen production efficiency for coal gasification (National Academy of Sciences, 2004; Mueller-Langer et al., 2007; Ramsden et al., 2009; Cetinkaya et al., 2012; Mehmeti et al., 2018; Systems, n.d.; Chen et al., 2021).

Unlike coal gasification, biomass gasification is not commercialized yet as the gasification system has to be adapted to biomass feedstocks (Mueller-Langer et al., 2007). Therefore, most of the efficiency data we collected are based on small-scale projects or plant design modeling, which may not reflect actual commercial uses. Nonetheless, our research found efficiency levels in the range of 40% to 60% (Mueller-Langer et al., 2007; Lv et al., 2008; Ramsden et al., 2009; Y. K. Salkuyeh et al., 2018; Ishaq & Dincer, 2022).

Electrolysis

For the electrolysis efficiency, while some studies trace the source of electricity back to solar or wind power, in this study we define hydrogen production efficiency only at the stage where electricity is turned into hydrogen rather than accounting for energy loss from turning solar into electricity, then into hydrogen. There are three types of electrolyzers, each with different efficiencies. In general, solid oxide electrolysis cells (SOEC) electrolyzers are highly efficient, but are the least developed (Holladay et al., 2009; IRENA, 2018). Alkaline, which is the most developed and most economical, has relatively low efficiency, while polymer electrolyte membrane (PEM) tends to have efficiency levels that fall between the other two types (Holladay et al., 2009). In this study, we do not specify the type of electrolyzer but instead use the full range of electrolysis efficiency values, 40% to 80%, found in previous studies of any of the three electrolyzer types (Spath & Mann, 2004; Ferreira-Aparicio et al., 2005; Mueller-Langer et al., 2007; Holladay et al., 2009; Ramsden et al., 2009; Ursua et al., 2012; Bhandari et al., 2014; Keipi et al., 2018; IRENA, 2018).

Carbon capture rate

We define the carbon capture rate as the percentage of carbon dioxide (CO_2) generated during hydrogen production that is captured onsite. We only consider carbon capture for fossil-origin pathways in this study, which are natural gas SMR and coal gasification. As illustrated in Figure 3, during SMR, the generated CO_2 is present in three streams: the syngas, the tail gas, and the flue gas outlets, suggesting three places where a SMR plant might install a carbon capture unit: (1) at the syngas outlet; (2) at the tail gas outlet; and (3) at the flue gas outlet. For option 1 and 2, either stream holds approximately 60% of total generated CO_2, while flue gas in option 3 holds 100% of CO_2 (Ramsden et al., 2009; Kurokawa et al., 2010; Kandziora et al., 2014; Spallina et al., 2016; IEA, 2017a; Pellegrini et al., 2020; Gorski et al., 2021; Nazir et al., 2021). Considering the stream pressure, carbon dioxide concentration, and cost of required energy input, the current industry is generally adopting option 1 or 2 (Kandziora et al., 2014; Shahani & Kandziora, 2014; IEA, 2017a; Gorski et al., 2021). Although option 3 presents the greatest potential for CO_2 capture, it is nonetheless very expensive, potentially doubling the cost of the other two options (Kandziora et al., 2014), which is significant because CCS already represents a significant portion of the cost of hydrogen production combined with CCS.

The CO_2 present in the stream cannot be entirely captured, even at the flue gas outlet. Previous studies showed a range of 82% to 99.9% for carbon capture efficiency, which depends on the type of technology applied (Kelly et al., 2005; Mueller-Langer et al., 2007; Ramsden et al., 2009; Kurokawa et al., 2010; IEA, 2017b; Power et al., 2018; Pellegrini et al., 2020; Regufe et al., 2021). Considering the share of total CO_2 emissions on which carbon capture is practiced, in addition to the carbon capture efficiency, we assume an overall carbon capture range of 49.2% to 99.9% at a hydrogen production plant. For our central case, we changed the default of 90% carbon capture rate in GREET to 54.6% to better reflect current industrial practices of adopting option 1 or 2. However, it is unlikely that all of the captured CO_2 will remain stored underground; instead, there could be leakage potential after CO_2 exits the hydrogen plant, during CO_2 transportation and injection. Therefore, we set a 10% CO_2 loss as our lower range. This 10% is informed by previous studies of CO_2 injection for enhanced oil recovery

(JRC, 2005). Accounting for potential CO_2 loss leads to a final range of 39.2% to 99.9% of carbon capture and storage. For simplicity and consistency, we assume the same central and range values of carbon capture rate for coal gasification.

Upstream methane leakage rate from natural gas

We consider methane leakage from upstream natural gas only with reference to the natural gas SMR+CCS pathway since this is the only hydrogen pathway that uses natural gas for a majority of energy input, as detailed in the Hydrogen production efficiency section. We consider upstream methane leakage during natural gas extraction and recovery as well as during transportation and storage. Previous studies using different methods of estimating methane leakage have shown huge uncertainties in this parameter. Specifically, inventories that rely on assumptions tend to underestimate leakage emissions, particularly because inventories typically do not capture high emissions during malfunctions, which could be as high as 7 times normal rates (Brandt et al., 2014; Alvarez et al., 2018). Therefore, we drew upon studies with onsite measurements and settled on a range of 0.1% to 9% as the rate of methane leakage from natural gas extraction and recovery and 0.1% to 10% as the rate from transportation and storage (Dedikov et al., 1999; IEA, 2006; Howarth et al., 2011; Wigley, 2011; Brandt et al., 2014; Balcombe, 2015; Howarth, 2015; Alvarez et al., 2018).

RESULTS AND DISCUSSION

In this section, we present the results from all sensitivity analyses and discuss the implications from these results. We first show our central case GHG intensity of all hydrogen and biomethane pathways in Figure 4. This figure presents a full picture of climate implications using both 100-year and 20-year GWP. GWP, or global warming potential, converts the climate warming impact of different GHGs into carbon dioxide equivalent. The typical timeframe of GWP used is 100 years. However, certain types of GHG, such as methane, have a much shorter lifetime than 100 years and in order to better reflect the near-term climate impacts from these short-life GHGs, a 20-year GWP value can be used. For each pathway in Figure 4, the blue bar is the GHG intensity using 100-year GWP and the orange bar is based on a 20-year GWP. The dotted grey line is the fossil comparator, which is 94 gCO_2e/MJ for transport fuels in the REDII, and the dotted yellow line represents the GHG intensity of EU natural gas, which is 67 gCO_2e/MJ (Agostini et al., 2017; Prussi et al., 2020). Different pathways have different trends in near- or long-term climate performance. In particular, biomass gasification as well as electrolysis from either renewable electricity or grid electricity show no difference between near-term and long-term outcomes; wastewater sludge and manure show better near-term performance; while landfill gas, natural gas, and coal probably cannot provide much carbon reduction potential in the near term. Of particular note, the GHG intensity of fossil-based hydrogen would be 15% higher in the near term.

Among all the pathways, manure-based pathways show the greatest difference between near-term and long-term climate impacts. This is because of the higher amount of avoided methane emissions that results from turning animal manure into hydrogen.

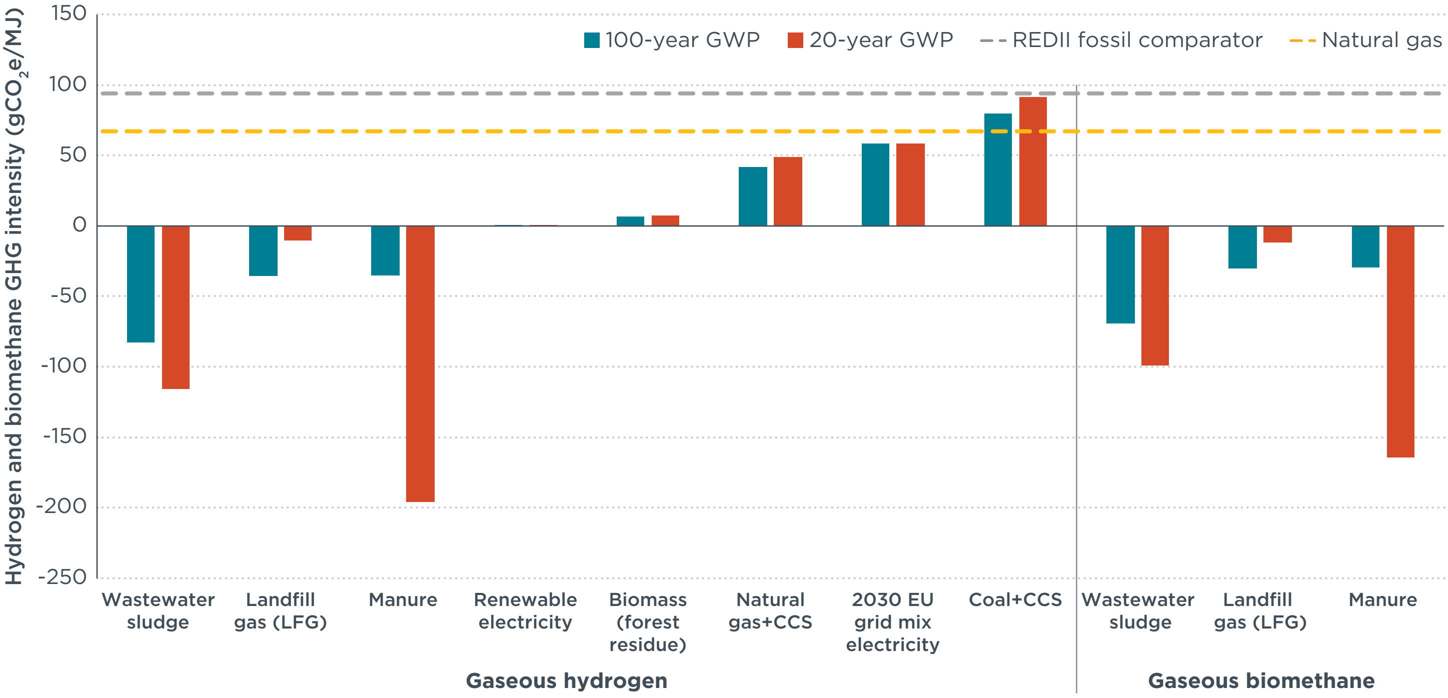

Figure 4. GHG intensity of gaseous hydrogen and biomethane pathways of the central case using both AR4 100-year GWP and 20-year GWP.[3]

In the next sections, we explore details regarding the impact of each key parameter analyzed in this study. We show the sensitivity results for biomethane pathways first and then hydrogen pathways. Results in the following sections use 100-year GWP only.

3 As originally published, the figure showed higher GHG emissions for hydrogen made from wastewater sludge, landfill gas, and manure, thereby underestimating their potential contributions to decarbonization.

BIOMETHANE

Figure 5 shows how uncertainty in each key parameter affects the GHG intensity of waste-based biomethane production. Values in Figure 5 are GHG intensities in units of gCO_2e/MJ using 100-year GWP. For each pathway, the vertical grey line represents the central case, and its GHG intensity is shown as the value at the bottom of each graph. Under the central case value, we show the GHG intensity of each pathway presented either in the REDII or in the LCA study by JEC as a comparison (Prussi et al., 2020). Each bar indicates the range of GHG intensity that is driven by the uncertainty of each parameter and the degree of deviation from the central case—the larger the bar area, the greater the deviation. The value to the left of a blue bar is the minimum GHG intensity and the value to the right of an orange bar is the maximum GHG intensity in our sensitivity analysis. Negative GHG intensity indicates avoided emissions from the alternative case compared to the reference case, i.e., lower GHG emissions from producing biomethane from waste compared to emissions from typical waste treatment, even before considering the GHG benefits of avoided fossil fuel use when consuming biomethane. Using manure biomethane as an example, the GHG intensity of its central case is -30 gCO_2e/MJ. Uncertainty in upstream methane leakage can lead to a range of manure biomethane GHG intensities of -44 gCO_2e/MJ to 72 gCO_2e/MJ.

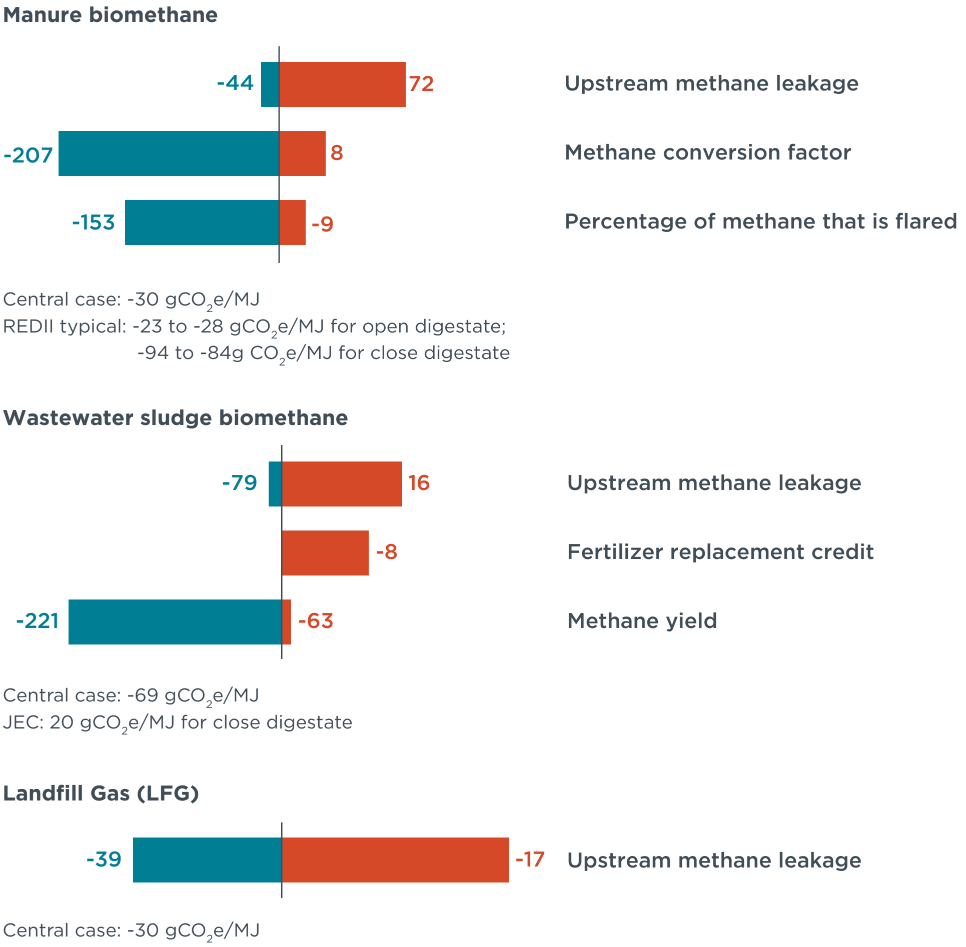

Figure 5. Range of GHG intensities caused by uncertainty in each key parameter for three waste-based biomethane pathways. Values are in units of gCO_2e/MJ using AR4 100-year GWP.

Upstream methane leakage has a significant impact on the climate benefit of all three biomethane pathways. For the manure and wastewater sludge-based pathways, uncertainty in upstream methane leakage can lead to higher GHG intensity than uncertainty in any other parameters. Between the two pathways, upstream methane leakage has a relatively smaller impact (i.e., smaller degree of change) on the wastewater sludge pathway because leakage from digesters is counted under both the reference and alternative scenarios, meaning the impact is somewhat negated. In contrast, AD and thus leakage from digesters is only involved in the alternative case for manure biomethane and the impact from it is amplified.

Different measurement approaches can also lead to variations in leakage estimates due to measurement uncertainty and to varying capacities to detect leakage (Fredenslund et al., 2018; Holmgren, 2015; Samuelsson et al., 2018). In particular, the same biogas plant that adopts different measurements (remote sensing or onsite measurement) shows that leakage rates vary by a factor of more than 2 (Fredenslund et al., 2018). As described in the Methodology section, results in Figure 5 only consider methane leakage from digester and biogas upgrading, not accounting for additional digestate emissions or leakage during feedstock or biomethane storage and transport. For example, methane emission from digestate storage tanks can vary from less than 1% to 12% (Liebetrau, Clemens, Cuhls, & Hafermann, 2010; Liebetrau et al., 2013; Baldé et al., 2016). In an extreme case, one measurement during operational difficulties at the anaerobic digester at a wastewater treatment plant showed that methane leakage could be as high as 32.7% (Yoshida et al., 2014), compared to the maximum digester leakage rate of about 10% in our sensitivity analysis. If considering additional leakage from other stages as well as higher leakage rate for a worst-case scenario, it is likely that biomethane, especially manure biomethane, would provide minimal to zero climate benefits on a 100-year timescale.

While studies may focus more on emissions from the process of biomethane production, i.e., the alternative case, we find that assumptions for the reference case are just as crucial. Taking manure biomethane as an example, using different methane conversion factors can deviate GHG intensity from the central case by as much as five times (Figure 5).

As for wastewater sludge biomethane, there is no blue bar for fertilizer replacement credit; this is because we use GREET's default value of 100% replacement for the central case and the lower replacement rate, 0%, used for the sensitivity analysis would simply result in higher GHG intensity of wastewater sludge biomethane. Methane yield is a parameter that might be counterintuitive. While greater yield of the end product might seem to lead to lower emissions, the opposite is true. This is because of displacement effects: when biogas yield is lower, the amount of wastewater sludge needed to produce the same amount of biogas is higher. Consequently, the greater quantity of wastewater sludge results in more power and heat being generated, leading to more avoided emissions. This finding was also discussed in Lee et al. (2016).

Comparing our central value to the typical value in the REDII or estimates by the JEC (if not included in the REDII), we find that our estimate for manure biomethane pathways using GREET is similar to the open digestate scenario in the REDII. The closed digestate storage scenario in the REDII would have a much smaller GHG intensity. This indicates that methane emissions from digestate has a significant impact on biomethane pathways. However, as mentioned, because it is unclear which digestate storage option GREET considers, we do not evaluate this parameter in our study. While the REDII does not have GHG intensity values for wastewater sludge biomethane, the JEC has done LCA on this pathway; it is significantly higher than our central case using GREET. This is because for this pathway, unlike GREET, the JEC does not consider avoided emissions comparing the alternative case to the reference case. On the other hand, manure biomethane in the REDII, which is informed by JEC's calculation, includes avoided emissions. This again emphasizes the importance of reference case assumptions and the necessity of using consistent methodologies.

In Figure 6, we summarize the full range of final GHG intensities resulting from our sensitivity analysis for wastewater sludge, landfill gas, and manure biomethane, as well as the range we collected from previous studies for maize biomethane. The bars represent the GHG intensity of the central case and vertical error bars indicate the maximum and minimum GHG intensity of each biomethane pathway. The dotted orange line is the fossil comparator as 94 gCO_2e/MJ for transport fuels in REDII, and the dotted yellow line represents REDII's 65% GHG reduction target for biomethane used in the transporation sector. We order the pathways by GHG intensity of the central case, from left to right. The central case of maize biomethane is taken as the average of the typical values in REDII plus the 21 gCO_2e/MJ LUC emissions.

In general, wastewater sludge biomethane and landfill gas can provide significant carbon reduction compared to fossil fuels, even after taking the uncertainty into account. As mentioned, the majority of landfill gas is already deployed for power generation in the EU, leaving little available for injection into the gas grid as biomethane. Although the central case of manure biomethane also shows good climate performance, the risk of upstream methane leakage is huge. Specifically, a high leakage rate would change the impact of manure biomethane significantly; it would deliver only a 20% carbon reduction from the fossil comparator on a 100-year timescale, which is inconsistent with climate targets in the EU. However, as discussed above, manure biomethane shows great GHG reduction potential in the near term. Maize biomethane also has limited climate benefits. Its central value is close to the GHG intensity of EU natural gas and the higher end of the uncertainty range makes this pathway even worse than the fossil comparator from a climate perspective. This is because of the significant emissions from maize cultivation and land-use change. While waste-based biomethane generally has low GHG intensity, feedstock availability appears to be a big barrier to its deployment and its role in decarbonizing Europe's economy (Baldino et al., 2018). In addition, because we do not include potential methane slip from engines when combusting biomethane in this study, the real GHG intensity values for all biomethane pathways may be greater than this study suggests.

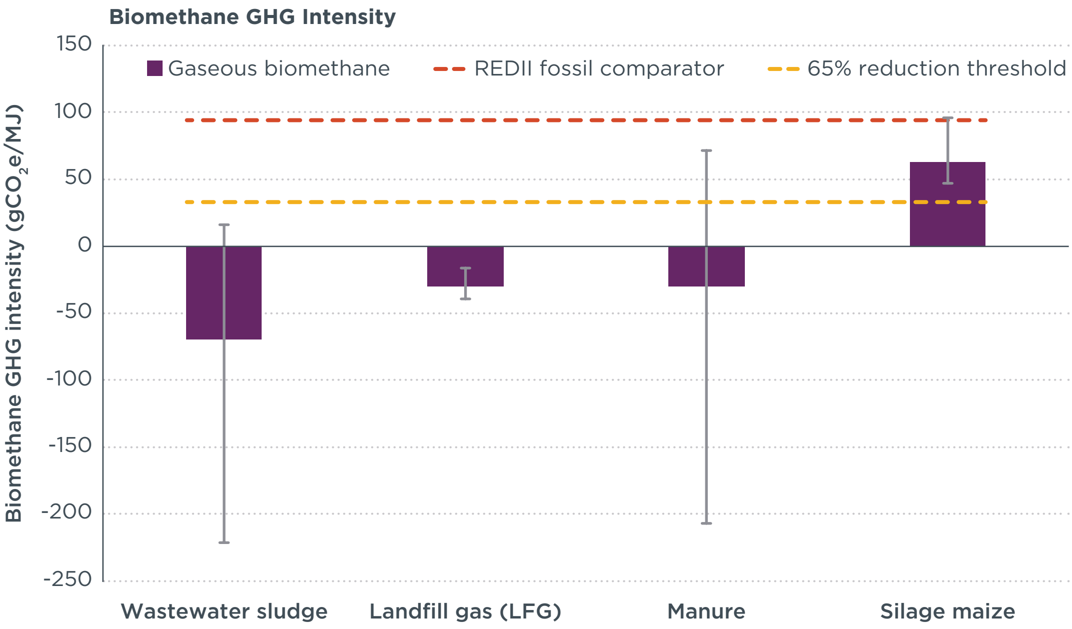

Figure 6. GHG intensity range of four biomethane pathways using AR4 100-year GWP

While this study analyzes the biomethane GHG intensity of each feedstock separately, in reality co-digestion using multiple feedstocks is more common. For this reason, the REDII also provides typical values of mixing manure and maize as the input feedstocks for biomethane production. While using maize as the single feedstock does not provide much climate benefit, mixing it with other waste feedstocks in co-digestion might allow the mixture to meet the 65% GHG reduction threshold requirement as shown by the typical values currently in the REDII. However, it is necessary to incorporate

GHG emissions from LUC for silage maize and such inclusion will lead to lower GHG reduction potential from using the mixture of manure and maize.

HYDROGEN

Results regarding hydrogen pathways are for compressed gaseous hydrogen only, not liquid hydrogen. For context, in the same hydrogen production pathway, liquid hydrogen tends to have higher GHG intensity than gaseous hydrogen because of the greater amount of electricity used in liquefaction than in compression. Figure 7 shows the uncertainty range of GHG intensity affected by each key parameter for seven hydrogen pathways. For each pathway, the vertical grey line represents the central case, and its GHG intensity is shown as the value at the bottom of each graph, along with estimates from the JEC if they exist (Prussi et al., 2020). Each bar indicates the range of GHG intensity that is driven by the uncertainty of each parameter and the degree of deviation from the central case. We discuss the uncertainties in hydrogen produced from the three biomethane pathways in the Biomethane section above and do not repeat that discussion here.

Figure 7. Range of gaseous hydrogen GHG intensity caused by uncertainty in each key parameter. Values are in units of gCO_2e/MJ using AR4 100-year GWP.[4]

4 As originally published, the figure showed higher GHG emissions for hydrogen made from manure, wastewater sludge, and landfill gas, thereby underestimating their potential contributions to decarbonization.

Upstream methane leakage poses a significant risk to climate performance of hydrogen produced from natural gas. Total methane leakage rates from natural gas extraction and distribution can be as high as 20% in some cases, based on measures of real leakage (IEA, 2006; Howarth et al., 2011; Balcombe, 2015). In addition, leakage is also possible at SMR plants, which we did not include in this study and which would result in higher GHG intensity of natural gas SMR+CCS than is shown in Figure 7.

Combining CCS with fossil-based hydrogen pathways is not likely to be beneficial to the climate in the near future. First, carbon capture does not trap all of the CO_2 emissions at a hydrogen production site; SMR plants capture only about half of the total CO_2 generated. The maximum carbon capture rate of 99.9% can lead to low GHG emissions of around 10 gCO_2e/MJ for both natural gas and coal-based hydrogen. However, this capture rate may not be easy to reach for economic reasons. Even if this maximum rate is reached, a risk still exists that carbon will leak after exiting the hydrogen plant during CO_2 transportation, CO_2 injection, as well as from the CO_2 storage site. In particular, the risk of long-term CO_2 leakage from storage sites is unknown, but could potentially be significant (Zhou, 2020). In addition, carbon capture is an energy-intensive process that requires additional energy to increase heat in the reformer, drive the carbon capture unit, and compress the captured CO_2. From a whole-plant perspective, the energy efficiency of a SMR plant with CO_2 capture drops by 14% compared with a reference SMR plant without CO_2 capture (Spallina et al., 2016). On the other hand, several studies mentioned that hydrogen produced from natural gas using ATR might achieve a higher carbon capture rate than SMR. This is because unlike SMR, where carbon dioxide presents in three different streams, ATR results in highly concentrated carbon dioxide in a single stream, making it easier to capture carbon at a higher rate. For example, two ATR projects in planning have a carbon capture target of 95% (Gorski et al., 2021). However, electricity demand for carbon capture appears to be higher at an ATR plant than an SMR plant and achieving the high carbon capture rate requires even more electricity (Gorski et al., 2021; Hydrogen Council, 2021), which could offset the climate benefits from high carbon capture through ATR depending on how clean the electricity is. Nonetheless, ATR has not been deployed extensively for hydrogen production, nor is it likely to be in the near future, leading to minimal impact on the role of natural gas-based hydrogen in meeting climate goals.

The indirect effects from CCS carry other poorly understood risks. The most common and economical form of CCS today is in enhanced oil recovery (EOR), which involves pumping CO_2 into oil deposits to push the oil out, thereby increasing oil production. The CO_2 should in theory remain sequestered underground. There are two potential adverse indirect effects of policies that support CCS through EOR. The first is that creating a new, inexpensive supply of CO_2 could encourage greater EOR production, increasing global oil supply and consumption and generating higher GHG emissions. For example, EOR production in the North Sea could likely be increased with a boost in inexpensive CO_2 supply (JRC, 2005). The magnitude of this response—the increase in GHG emissions from increased oil consumption compared to the GHG savings from storing the CO_2—is unknown. The second indirect effect is displacing CO_2 that would have been supplied and stored from another source. For example, an existing EOR project in Croatia is using CO_2 from a gas processing plant (Mol Group, 2016). If a SMR+CCS hydrogen project were built near this EOR site and supplied CO_2 at a cheaper price than the gas processing plant, the EOR project would switch to using the CO_2 from the hydrogen plant. The gas processing facility might then emit its CO_2 to the atmosphere. In this theoretical example, the increased CO_2 emissions from the gas processing plant would entirely offset the CO_2 savings from performing CCS with the hydrogen plant. The SMR hydrogen would thus be no cleaner overall than SMR hydrogen produced without CCS. One scenario in which hydrogen production with CCS would not have any negative indirect effects would be if CO_2 from the hydrogen project replaced CO_2 sourced from an underground CO_2 deposit in an EOR project that is already in operation. In this case, the CO_2 in the underground deposit would stay underground and all the CO_2 from the hydrogen project used in EOR would be additional CO_2 sequestered in the ground as well. It is not clear which of these three scenarios—two with adverse significant indirect effects and one without—would be most common if SMR+CCS hydrogen production were to increase significantly in the EU. We do not attempt to take these indirect effects into account in the LCA analysis presented here but note that these possibilities add considerable uncertainty to the overall climate impact of SMR+CCS hydrogen.

Hydrogen production efficiency in all pathways shows great uncertainties. While the default efficiency in central cases is relatively optimistic for hydrogen produced from natural gas, biomass, and electricity, it is likely that efficiency can be much lower due to uncertainties in plant operation, leading to higher GHG intensity. For coal gasification, more advanced technology is aiming to increase efficiency significantly; however, those studies are laboratory tests and whether industrial practice can actually reach the 80% efficiency level is a question. Electrolysis efficiency is only relevant to hydrogen produced from grid mix electricity, because turning renewable electricity into hydrogen has no upstream emissions and therefore is not shown in Figure 7.

With the uncertainty range from each parameter shown in Figure 7, Figure 8 summarizes the full range of GHG intensity from all key parameters for each of the eight gaseous hydrogen pathways. The bars represent the GHG intensity of the central case and vertical error bars indicate the potential maximum and minimum GHG intensity. Dotted horizontal lines are the 94 gCO_2e/MJ fossil comparator in REDII and the 70% GHG reduction target for gaseous hydrogen. We show the pathways in the order of increasing GHG intensity of the central case.

In general, hydrogen produced from renewable electricity as well as waste feedstocks, such as wastewater sludge and forest residues, provides significant carbon reduction potentials. Hydrogen produced from manure, although being under the waste feedstock category, has a huge range in GHG intensities and the high end, resulting from high methane leakage, makes this pathway no better than fossil fuel on a 100-year timescale. The range of GHG intensities for manure hydrogen is higher than for manure biomethane due to the conversion losses in SMR when producing hydrogen from biomethane.

For hydrogen produced from natural gas+CCS, the central case, which is most representative of current industrial practice, only reduces GHG emissions by half compared to the fossil comparator, which is not consistent with Europe's ambitions for a net-zero economy nor with the established and proposed GHG reduction threshold of 70% for hydrogen fuel in the REDII. Even more, high methane leakage rates from upstream natural gas lead to GHG intensity as high as the fossil comparator.

Coal gasification combined with CCS has the highest life-cycle GHG emissions among the eight hydrogen pathways. Even with carbon capture, hydrogen produced from coal provides very limited carbon reduction potential. The minimum GHG intensity achievable with fossil-based hydrogen, 10 gCO_2e/MJ, is only possible by achieving the maximum 99.9% carbon capture rate. While high carbon capture enables both pathways to meet the 70% GHG reduction threshold, it does not reflect industry practice for economic reasons.

Electrolysis hydrogen, if produced using 2030 EU grid mix electricity, has significantly higher GHG emissions than if produced from renewable electricity. This is true even though we expect renewables penetration in EU's grid to continue to increase through 2030. The GHG emissions from producing electricity from fossil fuels such as coal and natural gas are effectively amplified by the energy losses in hydrogen production. This is why grid electricity-derived hydrogen may deliver limited climate benefits compared to directly using fossil fuels in transport and other gaseous uses, even though some of the energy is from renewables. If the EU electricity grid managed to become cleaner faster, grid electrolysis hydrogen could potentially become a low-GHG fuel. Nonetheless, the best scenario of electrolysis hydrogen is produced from 100% renewable electricity, which has close to zero GHG emissions, indicated in the second pathway in Figure 8. The poor climate performance of grid electricity-derived hydrogen in 2030 underscores the importance of establishing a robust methodology in the forthcoming delegated act to ensure that only additional renewable electricity is used to produce REDII-eligible hydrogen. Even if the methodology is somewhat effective, any significant level of leakage, and thus increase in the use of fossil-derived electricity, will be associated with significant GHG emissions, especially because of the conversion loss in hydrogen production. Good options for ensuring the additionality of renewable electricity used in hydrogen production include both Guarantees of Origin (GOs) and Power Purchase Agreements (PPAs) coupled with certification showing that the renewable electricity used was not supported by any other policy incentive (Timpe et al., 2017; Malins, 2019). This should greatly reduce the chance that the renewable electricity claimed by the GOs and PPAs would have been used otherwise, and thus are being diverted from other uses and potentially replaced by fossil-derived electricity.

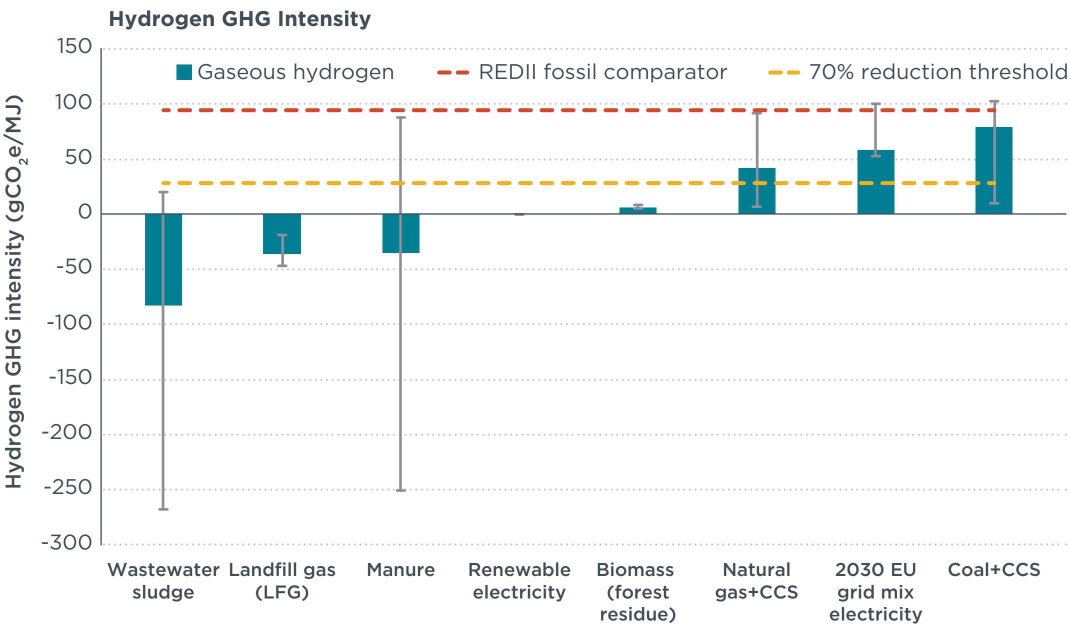

Figure 8. GHG intensity range of eight hydrogen pathways using AR4 100-year GWP[5]

5 As originally published, the figure showed higher GHG emissions for hydrogen made from wastewater sludge, landfill gas, and manure, thereby underestimating their potential contributions to decarbonization.

POLICY RECOMMENDATIONS

Results from this study suggest several policy recommendations regarding hydrogen and biomethane pathways in the REDII and other relevant climate or gas policies in the EU. To be eligible to be counted towards REDII targets, renewable hydrogen and electrofuels used as transport fuel must achieve a 70% life-cycle GHG reduction compared to fossil fuels. The target for biomethane is 50-65% reduction when used in transport or 70-80% reduction when used for electricity, heating and cooling. Fuels with lower life-cycle GHG intensity make a greater contribution toward the proposed 13% GHG target for the transportation sector and should thus be incentivized more than fuels with higher GHG intensity. Biomethane producers can choose to use the default GHG intensity value provided in the REDII or to calculate a facility-specific GHG intensity using data that reflects their real-world operations. Our recommendations pertain both to excluding certain pathways from eligibility toward meeting climate targets as well as to a life-cycle methodology for calculating GHG intensity values to determine compliance.

RECOMMENDATIONS FOR HYDROGEN PATHWAYS

1. Do not allow eligibility for fossil-based hydrogen in the REDII and avoid providing incentives in any other climate- or gas-related policies such as the forthcoming Hydrogen and Decarbonised Gas Market Package

Results from our analysis show that with the current industrial practice of carbon capture, the life-cycle GHG reduction compared to the REDII fossil comparator is only 15% for hydrogen produced from coal and 55% for hydrogen made from natural gas, if assuming a low (0.5%) rate of upstream methane leakage. In reality, the upstream methane leakage rate could be as high as 20%, making hydrogen from natural gas+CCS no better than fossil fuel from a climate perspective. The near-term climate impact of natural gas+CCS hydrogen is even worse due to the high climate-forcing impact of methane. The use of fossil-based hydrogen is not consistent with the EU's goal of a zero-carbon economy by 2050. Therefore, we encourage European policymakers to continue to exclude fossil-based hydrogen from the REDII and to avoid providing any form of incentive for it in the REDII or in any other climate- or gas-related policies, such as the forthcoming Hydrogen and Decarbonised Gas Market Package. Rather, we encourage policymakers to promote only hydrogen pathways that have deep decarbonization potential, such as hydrogen produced from 100% renewable electricity.

2. Adopt safeguards to limit the climate risk of this pathway (if, despite our recommendation, fossil-based hydrogen is included in the REDII)

Such safeguards include the following:

- Set a 70% GHG reduction requirement for fossil-based hydrogen, consistent with that for renewable hydrogen;
- Mitigate the risk of methane leakage by:
  - Requiring facility-level measurements of GHG intensity, including emissions from methane leakage, with no option for using a default value;
  - Providing detailed and consistent guidelines on methane leakage measuring methodology and providing related guidance to verification schemes on how to verify leakage measurements;
  - Using 20-year GWP for GHG intensity calculation to account for near-term impacts from methane;
- Set detailed requirements for the verification of CCS projects;

» Do not allow coal as a feedstock;

» Signal no continued policy support for fossil-based hydrogen beyond 2030.

If fossil-based hydrogen is given production incentives through EU policies, policymakers should set a 70% GHG reduction threshold for fossil-based hydrogen. This threshold would be the same as some other fuels in a similar category, such as renewable hydrogen and power-to-liquids in the REDII. While the current practice of fossil-based hydrogen can only achieve as high as 55% carbon reduction, setting a more stringent threshold means that the industry would need to invest more in improving carbon capture rates in order to be eligible.

Second, we recommend three measures to mitigate the risk of methane leakage from natural gas-based hydrogen. To understand the actual GHG emissions throughout the life-cycle of natural gas-based hydrogen, it is important to measure methane leakage and losses at each step, which can be addressed by the initiative of reducing methane leakage in the oil, gas, and coal sectors that is currently under formulation by the European Commission (European Comission, 2020). In addition, we recommend that policymakers require facility-level calculation of GHG emissions rather than allowing producers to opt for use of a default GHG intensity value in the REDII. Currently in the REDII, the default values are set slightly higher than a calculation of typical GHG emissions to account for potential accidental emissions, including methane leakage. However, methane leakage rates could be even higher at poor-performing facilities, especially during malfunctions (IEA, 2006; Howarth et al., 2011; Balcombe, 2015). A facility-level measurement on the other hand helps to capture that risk. We encourage the European Commission to develop detailed and robust guidelines on methane leakage measuring methodology that different facilities and verification schemes can all follow. Previous studies warned that different measuring methodologies can lead to great variation in leakage estimates (Brandt et al., 2014; Alvarez et al., 2018; Rutherford et al., 2021) and the lack of comprehensive and credible methane leakage regulation is the major barrier to developing serious methane reduction strategies (Larsen et al., 2015). Such measuring guidelines could go in line with the initiative of reducing methane leakage in the oil, gas, and coal sectors (European Comission, 2020). We also recommend that policymakers provide related guidance to verification schemes on how to verify these measurements. Given the fact that methane is a potent greenhouse gas with a short lifetime, we recommend considering 20-year GWP when estimating GHG intensity and when counting fossil-based hydrogen toward the EU's carbon reduction target. Looking at the central case in our analysis, GHG intensity of fossil-based hydrogen is 15% higher in the 20-year timeframe compared to the 100-year timeframe and the difference would be still greater with higher methane leakage. Therefore, using 20-year GWP helps to ensure the real climate benefit in the near term.

We also recommend that the European Commission strengthen its requirements for CCS projects. The Commission has proposed rules for voluntary schemes to verify CCS projects for the purpose of GHG calculations in the REDII (European Commission, 2021b). At present, these rules would only apply to pathways currently eligible in the REDII, such as CCS from ethanol facilities. This proposal includes a requirement that CO_2 be "effectively captured and safely stored" and that "in case of leakages, the storage facility shall ensure that any leakage does not exceed the current state of technology." This requirement is not specific and could still allow substantial long-term CO_2 leakage from CCS sites. If fossil hydrogen is added to the REDII, we recommend that the European Commission apply these rules for voluntary schemes to fossil hydrogen pathways as well, and greatly strengthen these rules by including more specific requirements to minimize leakage, such as specifying a maximum allowed CO_2 leakage rate and accounting for the leaked CO_2 in the GHG calculation of the fuel pathway. A good example is California's extensive CCS protocol (California Air Resources Board, 2018).

Since hydrogen produced from natural gas and coal both fall under the category of fossil-based hydrogen, policymakers would need to insert clear language in the REDII that coal is not allowed as a feedstock. Although adopting the most stringent carbon capture rate would enable coal-based hydrogen to meet the GHG reduction threshold, this level is unlikely to be achieved any time soon. On the other hand, our results indicate that hydrogen produced from coal, even with carbon capture, poses too great a climate risk and might be unmanageable.

Last, while the target timeframe in the REDII is until 2030, if despite our recommendation fossil-based hydrogen is indeed added to the REDII, we would then recommend including a recital in the REDII clearly stating that this pathway will not be supported in any further revision of REDII targets beyond 2030. This would be consistent with the EU Hydrogen Strategy released by the European Commission in 2020, which describes a potential role for fossil-based hydrogen in the 2020-2030 timeframe but not thereafter (European Commission, 2020a).

3. Introduce robust criteria for ensuring the additionality of renewable electricity used in electrolysis hydrogen in the REDII

Our analysis shows that hydrogen produced from grid electricity may offer limited climate benefits compared to using fossil fuels directly. If robust requirements are not put in place ensuring that only additional renewable electricity is used for hydrogen in the REDII, there is a strong risk that European policy could inadvertently support the use of grid electricity in hydrogen production and its high associated GHG emissions. Additionality of renewable electricity can be ensured by requiring the use of PPAs or GOs where the certified renewable electricity is shown not to have received any other policy incentives.

RECOMMENDATIONS FOR BIOMETHANE PATHWAYS

1. Exclude crop-based biomethane pathways due to high land-use change emissions.

We recommend that policymakers exclude crop-based biomethane as an eligible pathway in the REDII due to its significant GHG emissions emerging from land-use change, even if it is used as one of the feedstocks for co-digestion. For biomethane produced from crops, such as silage maize, the current GHG intensity values of this pathway in the REDII does not consider emissions from land-use change. The inclusion of LUC emissions would lower the GHG reduction value to 30% from the fossil comparator. Moreover, the highest GHG intensity of maize biomethane, including LUC emissions, reported from previous studies can get even higher than the 94 gCO_2e/MJ fossil comparator, indicating great risk in including crop-based biomethane as an eligible pathway in the REDII.

2. Provide consistent and comprehensive LCA methodology for waste-based biomethane.

Such a methodology should include the following elements:

» Require facility-level measurements of GHG intensity, including the measurement of methane leakage, and develop clear rules and consistent guidelines on LCA methodology as well as data assumptions;

» Create a reference case that is specific to each waste feedstock using comprehensive modeling to reflect real-world waste management practices, and do not allow facilities to change the reference case value;

» Provide related guidance to verification schemes on how to verify these measurements.

The REDII currently only provides default GHG intensity of two waste feedstocks for biomethane—manure and biowaste, both of which do not fully reflect all of the important emission terms in LCA. Therefore, we recommend that the European Commission develop consistent and comprehensive LCA methodology for waste-based biomethane pathways, not only for the two feedstocks currently given default values in the REDII, but also for additional feedstocks that might also have deep decarbonization potential.

Similar to hydrogen produced from natural gas, we recommend requiring facility-level measurement of biomethane production, including measurement of methane leakage. Even further, the policymakers could develop detailed rules on certain data assumptions, such as fertilizer replacement credits. This would enable the capture of any potential uncertainties among the facilities but avoid unreasonable assumptions while enabling better monitoring of actual methane leakage.

From our analysis, we find that assumptions in the reference case (i.e., current waste management) and alternative case (i.e., biomethane production) can both impact the final GHG intensity of waste-based biomethane pathways. Comparing REDII's LCA methodology for the two feedstocks, the manure biomethane pathway considers the credits resulting from avoided emissions from diverting the feedstock from current waste management to biomethane production; however, such avoided emissions are not considered for the biowaste pathway. Therefore, it is crucial for policymakers to develop LCA methodology that is consistent among the waste-based biomethane pathways.

We recommend that policymakers model a reference case specific to each waste feedstock. It is necessary to have a thorough understanding of present-day waste management practices for each biomethane feedstock and how they differ by member state. With that knowledge, policymakers could come up with assumptions that best reflect real-world management practices for different waste feedstocks. In the end, each waste feedstock should have its own emission value for the reference case based on real-world practices. In the absence of that baseline-setting, there could be an incentive for facilities to, perhaps incorrectly, assume a worst-case reference scenario for their own feedstock supply chains to maximize avoided emissions in their facility-level GHG intensity calculations. Therefore, we recommend that the European Commission set a fixed value for each reference case and not allow biomethane producers to change that value.

In addition, as explained in the Recommendations for hydrogen pathways section, it is also necessary to provide detailed and robust measurement guidelines on methane leakage for biomethane producers to avoid discrepancies caused by different measuring methodologies. All these measures could be integrated with the Initiative of reducing methane leakage in the oil, gas, and coal sectors (European Comission, 2020).

The REDII considers two different uses of biogas, for electricity or for biomethane, and provides different calculations and carbon values for each. We recommend that policymakers apply all of the above-mentioned recommendations to both uses or any additional uses to be included in the REDII.

CONCLUSIONS

This study aims to help European policymakers understand the uncertainties in carbon reduction potentials from gaseous fuel pathways. Specifically, this study conducts a thorough sensitivity analysis of the GHG intensity of four biomethane pathways and eight hydrogen pathways. For each pathway, we identify key impacting parameters; collect a range of values for each parameter from the literature; and model the uncertainty range in the pathway's final GHG intensity.

We find that methane leakage is a crucial parameter and poses significant climate risks on biomethane as well as hydrogen produced from natural gas or biomethane. Previous studies have shown huge uncertainties in methane leakage rates; high leakage rates would make certain pathways, such as hydrogen produced from natural gas or from manure biomethane, even worse than fossil fuels in terms of climate impact.

Fossil-based hydrogen, even with carbon capture, has a very limited role in GHG reduction because current industrial practices do not achieve a high carbon capture rate. While hydrogen produced from electrolysis using renewable electricity can reach a close-to-zero GHG intensity, using EU grid electricity results in the high-GHG fuel that may not deliver GHG reductions compared to direct use of fossil fuels. This is a risk if the European Commission does not introduce robust requirements to ensure the use of only additional renewable electricity for hydrogen producers claiming 100% renewable sources in the REDII.

Biomethane produced from waste feedstocks generally perform well from a climate perspective. However, there are uncertainties in assumptions in both the reference case (i.e., current waste management) and the alternative case (i.e., biomethane production), all of which affects final GHG intensity. Crop-based biomethane, such as silage maize, on the other hand, is unlikely to help the EU meet its GHG reduction goal and this is because of the high emissions from direct and indirect land-use change emissions from crop growing.

Based on these findings, we provide several policy recommendations to the EU policymakers on both hydrogen and biomethane pathways. First, we encourage the policymakers not to include fossil-based hydrogen as eligible pathways under the REDII and not to provide any form of incentives for fossil-based hydrogen in any other climate or gas policies, including the forthcoming Hydrogen and Decarbonised Gas Market Package. We also recommend that policymakers exclude crop-based biomethane due to high land-use change emissions.

Additionally, we provide policy recommendations on LCA strategy. We recommend facility-level measurements on life-cycle GHG, including measurement on methane leakage. We recommend that policymakers provide consistent and detailed guidelines on LCA methodology and data assumptions. Such guidelines are also necessary for the measurement of methane leakage. We also recommend that policymakers provide related guidance to verification schemes on how to verify these measurements. For waste-based biomethane pathways specifically, it is necessary to adopt consistent and comprehensive methodologies addressing both the reference case (i.e., current waste management) and the alternative case (i.e., biomethane production).

While the European policymakers have made great efforts to develop strong climate policies, these recommendations aim to help mitigate potential climate risks from gaseous fuels and to ensure the effectiveness of the REDII in achieving its climate goals.

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