The Green Gas Opportunity: Exploring Novel and Emerging Sources of Green Gas

FINAL REPORT

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Table of Contents

Introduction

Context

The UK is committed to reaching Net Zero by 2050. To do so will require the mobilisation of all available resources and technologies.

Progress is being made across decarbonisation technologies. However, many sectors and end-uses remain a challenge to decarbonise. Green gases, including novel green gases, offer a solution to addressing this demand.

The momentum for green gases overall is growing: The latest work undertaken by the Green Gas Taskforce (GGT) estimated a potential of up to 120 TWh in 2050 from anaerobic digestion. Novel green gases could further add to this potential and play a key role in the future energy mix.

There is great value to a decarbonised energy system of a dispatchable and storable low carbon energy source. As it stands, biomethane is the one of best ways of realising this benefit, however additional low carbon gas beyond the 120 TWh biomethane potential is still economically sensible to the energy system, even if it's significantly more expensive than biomethane.

This report provides an initial view to the production potential and costs of producing novel green gases in GB. Further analysis is required in order to quantify the macro economic benefits of greater levels of green novel gas supply.

Study objective

On behalf of the GGT and National Gas Transmission, Guidehouse has assessed the production potential[1] and costs of the following novel green gases:

1. Biological e-methane
2. Chemical e-methane
3. Synthetic methane

The study further covers the deployment of these green gases in leading international markets and offers actionable policy recommendations to promote their production in the UK.

Note: Given the novel nature of these pathways, significant uncertainties remain regarding their deployment at scale and the impact on costs. All outputs from this report should therefore be taken as theoretical and indicative.

[1] In Great Britain

Executive Summary

This report highlights the following key findings:

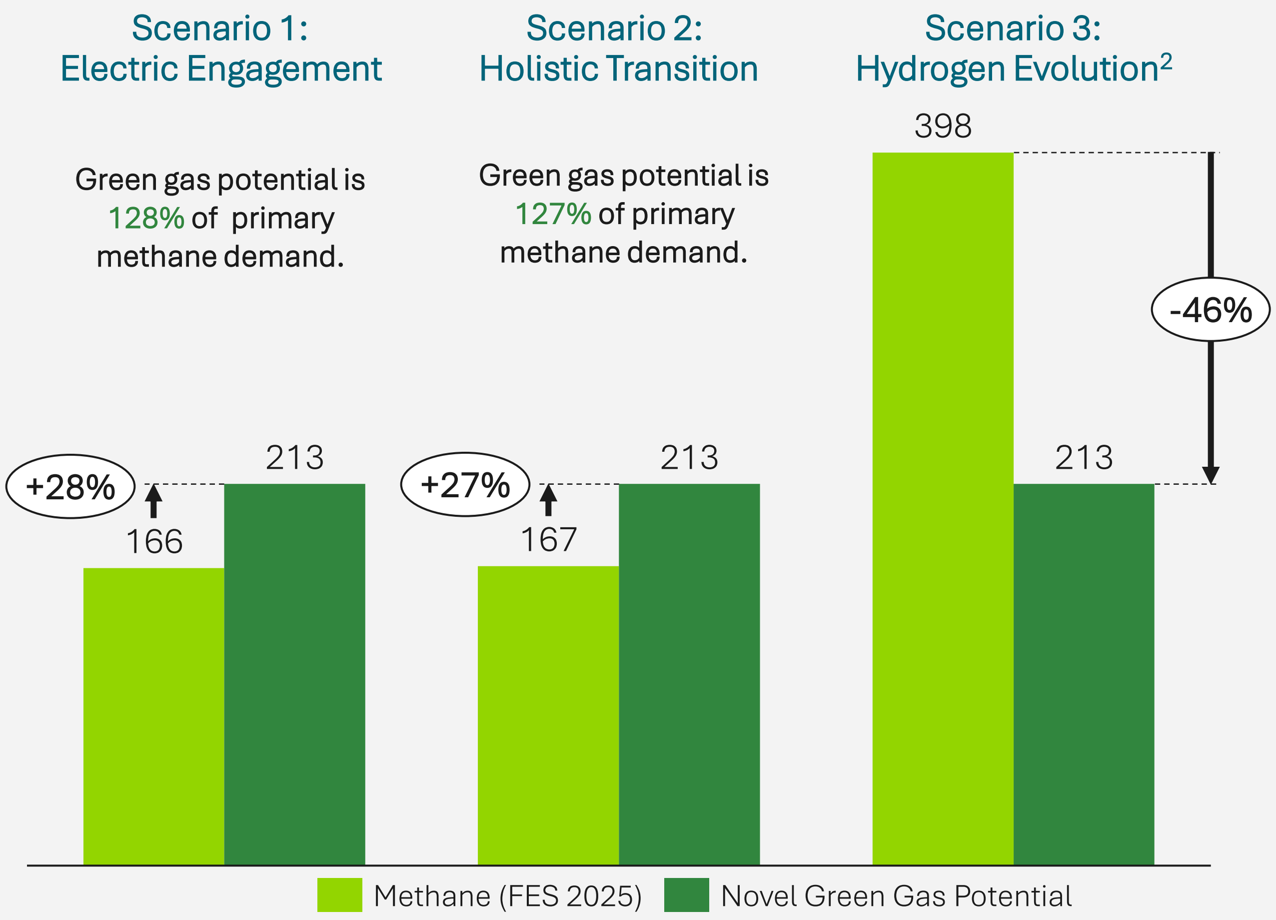
Cost-effectiveness of biomethane	Biomethane is the most cost-effective low carbon methane source and will likely remain that way to 2050. Biomethane development should be prioritised accordingly.
CO_2 offtake market	Increased biomethane production unlocks the use of biogenic CO_2 as a feedstock for further novel green gas generation. This provides an alternative market for the use of biogenic CO_2 alongside existing uses and other potential uses such as CCS.
H_2 scale-up opportunity	The scaling up of domestic hydrogen production is necessary to support the production of e-methane, with e-methane enabling the conversion of hydrogen into a more easily transportable and storable molecule.
Water scarcity solution	Producing green hydrogen and converting it to e-methane can operate with a net zero water balance, mitigating water consumption impacts and addressing water scarcity concerns associated with hydrogen production.
Value of gas grid	The expansive GB gas grid is critical to ensure that novel gases can be transported from production sites to end users at least cost.

Maximum theoretical production potential of novel green gases (213 TWh) is equivalent to 127% of primary methane demand in GB by 2050

Key Takeaways

- **Novel green gas production potential in GB across the three pathways could reach 213 TWh by 2050, equivalent to ~127% of primary methane demand.[1]**
- Novel green gases have the potential to meet the entire primary methane demand of 166–167 TWh in 2050 (FES 2025).[1]
- If scaled up, novel green gases can therefore offer an opportunity of supporting the UK's Net Zero decarbonisation goals and promoting energy security.

Production potential of novel green gases, 2050



[1] Under NESO 'Electric Engagement' and 'Holistic Transition' scenarios. [2] The NESO 'Hydrogen Evolution' scenario assumes a higher level of fossil methane to produce blue hydrogen. As e-methane is already low carbon it would not be applicable to meeting this share of demand.

Novel green gas production costs range from £156 to £285 per MWh depending on the production pathway, with potential for cost reductions as scale increases

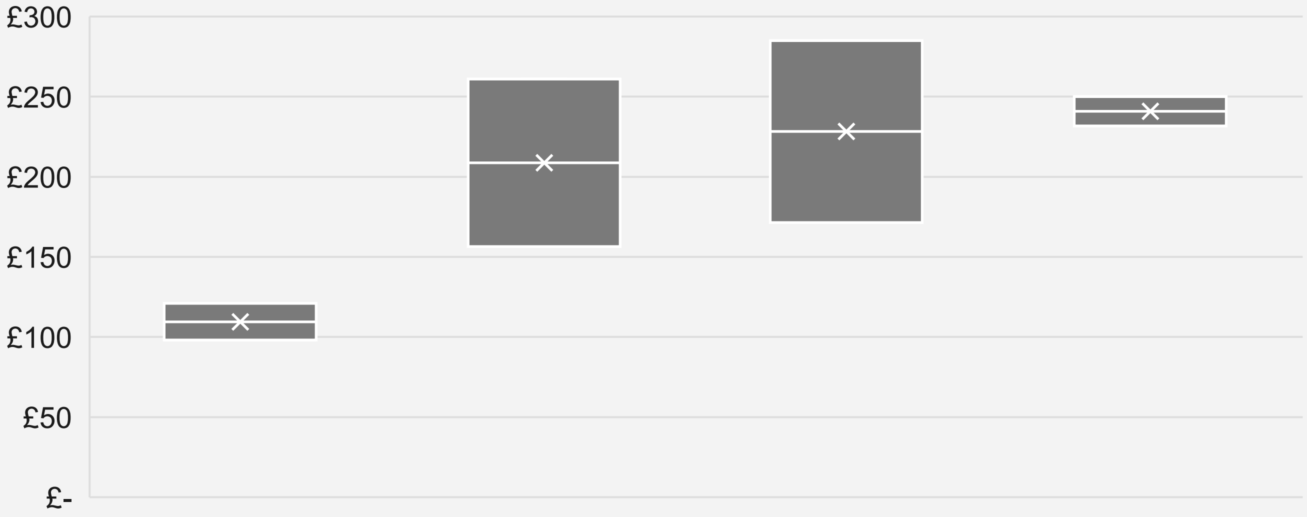
Key Takeaways

- **Novel green gas cost of production in GB across the three pathways ranges between £156 and 285 per MWh.**
- Due to the nascent status of novel green gas production today, scaling up and providing additional support could significantly lower future production costs.
- Supporting GB's biomethane and green hydrogen sectors is critical for enabling the most cost competitive production pathways for e-methane production.

Note: The production costs for novel green gases are derived from literature and industry estimates, which vary across technologies. Since these technologies are still immature, the cost estimates remain uncertain.

Production costs of novel green gases, 2025

Biomethane[1]		Biological E-methane		Chemical E-methane		Synthetic Methane	
Low Scenario (£/MWh)	High Scenario (£/MWh)	Low Scenario (£/MWh)	High Scenario (£/MWh)	Low Scenario (£/MWh)	High Scenario (£/MWh)	Low Scenario (£/MWh)	High Scenario (£/MWh)
98	121	156	261	171	285	232	250



[1] GGT-Cadent, Reducing the cost of Net Zero with biomethane (2025)

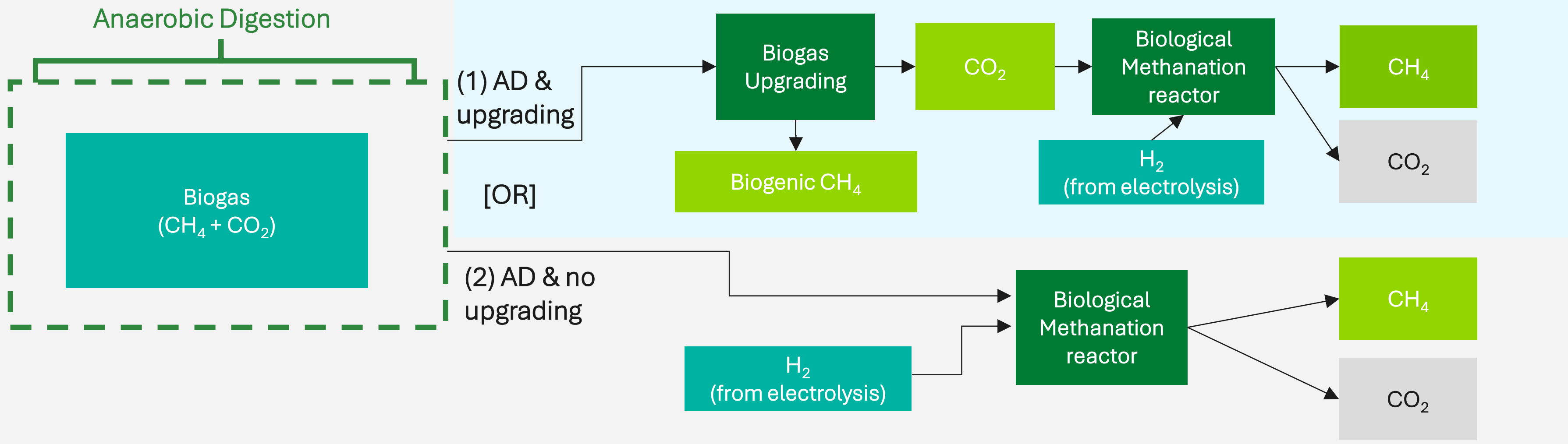
Policy intervention is essential to ensure that the production potential of novel green gases can be fully realised

Policy Principle	Policy recommendation	Rationale
Encourage Research and Innovation	• Given the immaturity of novel gases, it is premature to recommend a specific support mechanism. Nevertheless, Government should monitor sector progress and encourage research and development in novel gases to unlock cost reduction opportunities.	• Biomethane as a proven technology should be the priority of government policy via strong economic incentives for suppliers as a means of prioritizing cost-effective GHG savings from now.
Remove barriers to market	• As biomethane generation scales up and a new future framework is provided, Government should be flexible to apply future learnings and frameworks to all green gases. Removing barriers to market early could allow more rapid deployment of novel gases in the future should cost reductions be realised or if deployment of other decarbonisation vectors prove more challenging.	• The scaling up of biomethane unlocks co-location benefits of novel gases. Given novel gases are interchangeable with the natural gas used today, creating the conditions for cost reduction of lower carbon gases is a logical first step.
Integrate E-Methane into Gas Quality Standards and Infrastructure	• Revise gas grid specifications to permit injection of e-methane with biomethane and natural gas without imposing unnecessary enrichment requirements, while ensuring compatibility with hydrogen blending strategies.	• Removing unnecessary enrichment requirements reduces costs and accelerates deployment, making the transition more economically viable.
Incentivise Carbon Recycling and CO_2 Utilisation	• Classify e-methane as a low-carbon fuel under the UK Emissions Trading Scheme (ETS) and other compliance markets and recognise biomethane as zero-carbon within the UK ETS to enhance its competitiveness.	• By recognising e-methane as a low-carbon fuel, the UK ETS can stimulate investment in innovative solutions that reduce fossil carbon extraction and support decarbonization goals.

Production Pathways

1a. Biological e-methane: ‘ex-situ’ methanation

Ex-situ biological methanation combines H_2 with CO_2 in a separate tank where methanogenic archaea microorganisms react with the molecules to produce CH_4



Temperature	30-60°C
Methanation pressure	~1 bar
Methanation Efficiency	79%
TRL	7-9

Input	Byproduct	Study scope
Process	Output	

Technology Overview

- In biological methanation, methanogenic archaea convert H_2 and CO_2 to CH_4 in an anaerobic environment. With ‘ex-situ’ biological methanation, the methanation reaction takes place in a separate tank, either fed by biogas or a CO_2 source (e.g. from the biogas upgrading process).
- Ex-situ biological methanation is well-suited to co-location with existing biogas plants as a way to increase the overall CH_4 yield of the system but can otherwise take place at an external site (e.g. in a chemical cluster).
- Green H_2 is typically produced via an on-site electrolyser. H_2 is supplied in the correct stoichiometric ratio per the CO_2 source.

Opportunities and barriers

Opportunities

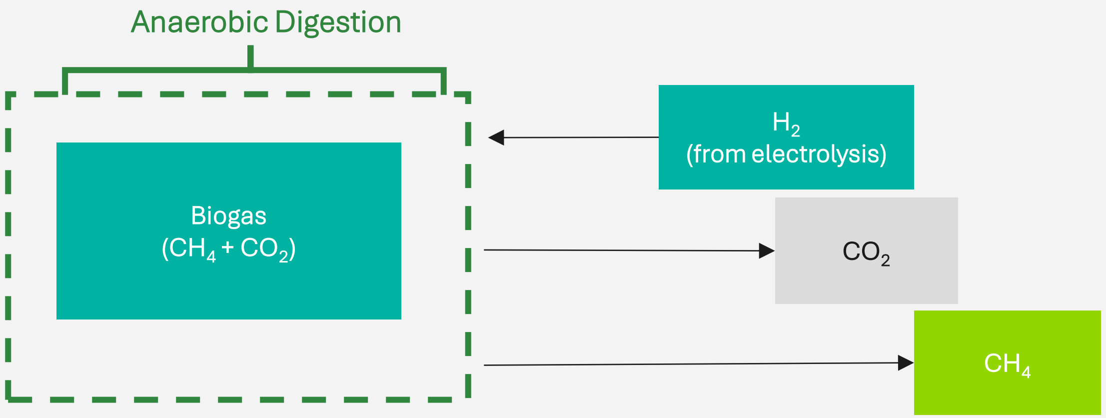
- Option 1) Enables greatest flexibility in terms of either producing e-methane or otherwise selling biogenic CO_2. Greater control of methanation tank. Enables use of external CO_2 supply if needed.
- Option 2) Does not require biogas upgrading technology, therefore reduction in CAPEX relative to Option 1.

Barriers

- Economies of scale may limit application to larger AD plants (e.g. >60 GWh/yr).
- Option 1) Requires both upgrading and methanation infrastructure. Higher CAPEX relative to ‘in-situ’ biomethanation.
- Option 2) Biomethane production pathway no longer possible, only e-methane production is.

1b. Biological e-methane: 'in-situ' methanation

In-situ biological methanation occurs when H_2 is added directly to a digester, where methanogenic archaea microorganisms react to produce additional CH_4 compared to conventional AD



Note: The scope of this report's modelling and further analysis focuses on 'ex-situ', rather than 'in-situ' biological e-methanation.

Temperature	30-60°C
Methanation pressure	~1 bar
Methanation Efficiency	79%
TRL[1]	6-8

Input	Byproduct
Process	Output

Technology Overview

- With 'in-situ' biological methanation, the methanation reaction takes place in the digester itself prior to upgrading the biogas.
- Green H_2 is added directly into the digester increasing the overall CH_4 yield per amount of feedstock and CH_4 concentration in the biogas.
- Green H_2 is typically produced via an on-site electrolyser – either supplied with on-site renewable electricity or through a grid connection and PPAs.

Opportunities and barriers

Opportunities

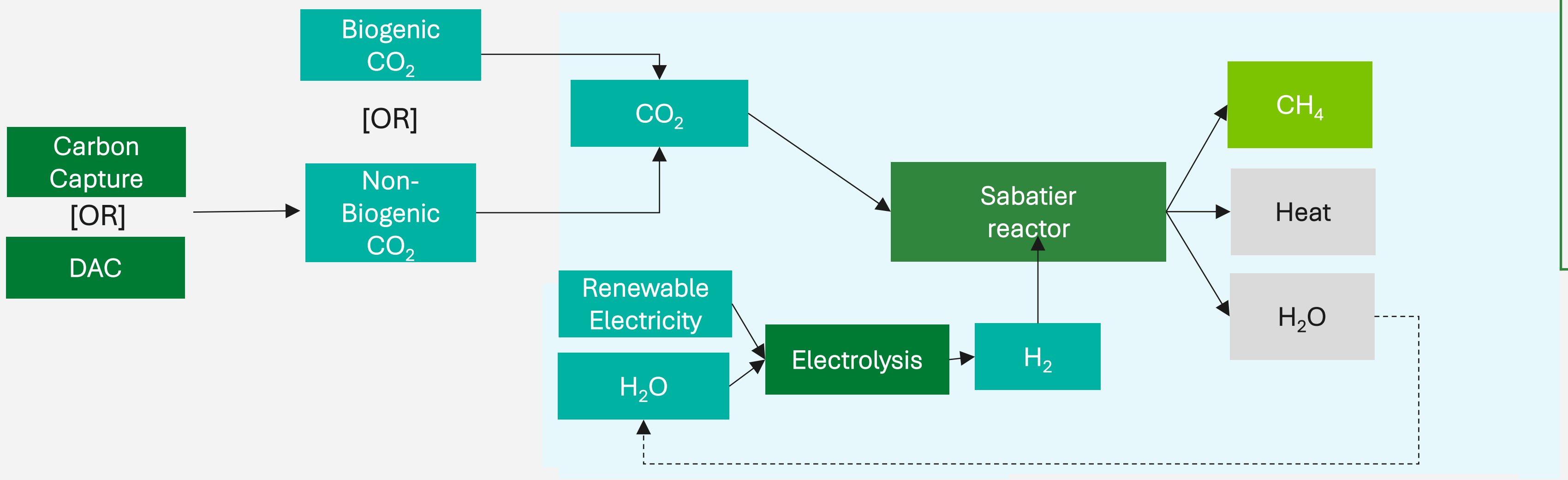
- Increases overall yield of methane relative to biomethane from AD (BAU).
- Does not require installation of additional reactor, therefore significantly lower CAPEX relative to 'ex-situ' biomethanation.

Barriers

- Injection of H_2 into AD tank alters reactions and must be carefully maintained or gradually adjusted. Less flexible compared to 'ex-situ'.
- Limited production relative to 'ex-situ' as can only rely on AD activity as basis for CH_4.

2. Chemical e-methane

Chemical methanation is a process that produces CH_4 by reacting H_2 with CO_2 over a catalyst



Temperature	~200-600°C
Pressure	~10 bar
Energy conversion efficiency	83%
TRL	7-9

Input	Byproduct	Study scope
Process	Output	

Technology Overview

- Methanation is the process of converting carbon dioxide or carbon monoxide with hydrogen into methane, using a metal catalyst, typically Nickel or Ruthenium-based. A specific methanation reaction is the Sabatier process.
  $CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O$ (ΔH = -165 kJ/mol[2])
- This reaction is highly exothermic, releasing heat along with producing water.
- These outputs - heat and water - create a synergy with electrolysis, which requires water and benefits from heat to improve efficiency. One potential integration route is using the heat generated by the Sabatier process to preheat water for electrolysis.
- Currently, the Sabatier reaction is the only commercially viable method of producing e-methane.

Opportunities and barriers

Opportunities

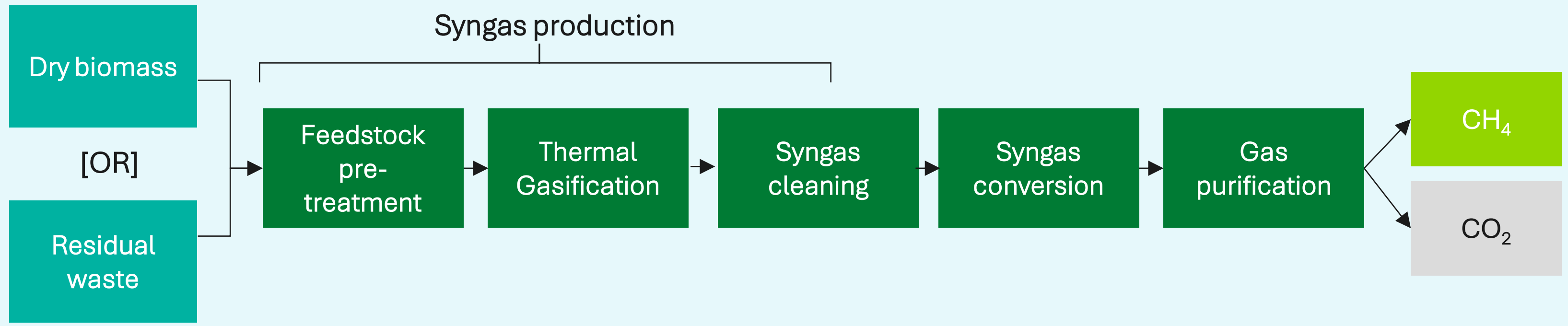
- Opportunity to utilise water by-product from methanation to supply electrolysers via closed-water cycle.
- Exothermic reaction heat could be utilised for district heating or industrial processes.
- E-methane can be injected into existing gas grid without major modifications.

Barriers

- Higher CAPEX costs per unit production relative to biological e-methane.
- Sabatier reaction and electrolysis requires significant renewable electricity input.
- Catalysts can be sensitive to impurities, so requires precise temperature control.

3. Synthetic Methane (via Thermal Gasification)

Process involves multiple steps including thermal gasification of feedstocks to syngas and subsequent conversion to CH_4



Gasifier temperature	~800°C
Methanation temperature	~500°C
Methanation pressure	~14 bar
Energy conversion efficiency	61%
TRL	6

Input | Byproduct | Process | Output | Study scope

Technology Overview

Synthetic methane production is a multi-step process:

- **Feedstock pre-treatment:** Feedstock drying and pre-treatment (e.g. shredding) required to ensure optimal gasification conditions (greater pre-treatment required for residual waste and waste wood vs clean biomass feedstocks).
- **Thermal Gasification:** Feedstocks are partially combusted in the presence of steam to produce syngas (H_2, CO and CH_4).
- **Syngas cleaning:** Tars and sulphur and chlorine compounds are removed.
- **Syngas conversion:** A combination of reactions convert the syngas to methane using a nickel-based catalyst. This reaction is highly exothermic.

$$CO + 3H_2 \rightarrow CH_4 + H_2O \ (\Delta H = -206 \text{ kJ/mol})$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \ (\Delta H = -165 \text{ kJ/mol})$$

- **Gas purification:** Residual CO_2, H_2 and other unwanted trace gases are removed to produce grid, or transport quality, specification gas.

Opportunities and barriers

Opportunities

- Leverages feedstocks otherwise not suitable in AD plants (e.g. woody biomass, residual waste).
- Opportunity to produce pure stream of pre-combustion biogenic CO_2.
- Synthetic methane can be injected into existing gas grid without major modifications.

Barriers

- Synthetic methane production pathway is technically complex due to the multiple process steps involved; recent demonstration projects have not performed well.
- Projects to date have faced very high CAPEX costs and OPEX costs (due to high electricity demand).
- Feedstock pre-treatment can be intensive.

Production Potentials

We have assessed and modelled the theoretical production potential for each pathway using scenarios developed through industry engagement

Production pathway assumptions

	Biological E-methane	Chemical E-methane	Synthetic Methane
Setting	‘Ex-situ’ biological methanation plant, co-located with AD plant.	Standalone chemical methanation plant located in, or near to, an industrial cluster.	Standalone plants located with access to GB feedstock supply.
Inputs	**CO_2** Sourced directly from on-site biomethane production via biogas upgrading. **Green H_2** On-site PEM electrolyser. **Electricity** Grid connected electricity with a PPA.	**CO_2** Sourced and transported from nearby industrial cluster. **Green H_2** On-site PEM electrolyser. **Electricity** Grid connected electricity with a PPA.	**Biogenic feedstocks include:** • Arboricultural arisings • Forestry harvesting residues • Sawmill residues • Short rotation forestry • Small roundwood • Waste wood • Residual waste (biogenic share) **Non-biogenic feedstocks included:** • Residual waste (fossil share) [These feedstocks do not compete with biomethane production from AD]. **Electricity** Grid connected electricity.

Biological e-methane theoretical production potential

When co-located with AD plants, there is a maximum biological e-methane theoretical production potential of 35 TWh per annum in 2030 and 85 TWh in 2050, representing a ~70% increase to business-as-usual biomethane production[1].

Theoretical production potential

35 TWh/y
Production potential in 2030

85 TWh/y
Production potential in 2050

Feedstocks ('high' scenario)

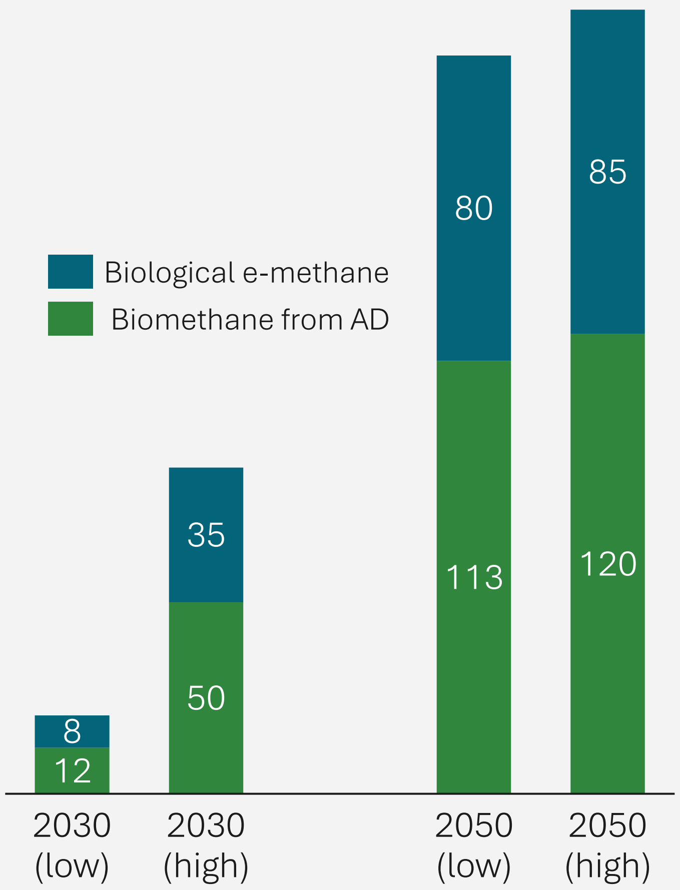
17.1 Mt
Of biogenic CO_2 from biogas upgrading potential in GB in 2050

112 TWh
Of green H_2 offtake demand generated in GB in 2050

Yield increase ('high' scenario)

~70%
Increase in CH_4 yield on AD plants relative to BAU biomethane production

Production potential relative to BAU



Key assumptions

- Biological methanation occurs 'ex-situ', using captured CO_2 stream from biogas upgrading, to produce e-methane in a co-located methanation reactor.
- High scenario: Production potential 50 TWh / 120 TWh of biomethane production in 2030 / 2050, respectively, and full utilisation of resulting CO_2 from biogas upgrading.
- Low scenario: Production potential assuming 12 TWh / 113 TWh of biomethane production in 2030 / 2050, respectively, and full utilisation of resulting CO_2 from biogas upgrading.
- H_2 supply availability assumed to fully meet demand.
- 98% mass conversion efficiency (residual 2% CO_2 assumed to be vented due to relatively high cost of separation).

Share of primary methane demand

Biological e-methane could make up 55% of primary methane demand based on FES(2025) forecast for 2050.[2]

[1] Production potentials in this study are based on Lower Heating Values (LHV) | [2] Based on the FES (2050) 'Holistic Transition' Scenario.

Chemical e-methane theoretical production potential

Assuming a supply of biogenic CO_2 from biomethane-to-power with CCS, there is a maximum chemical e-methane theoretical production potential of 43 TWh per annum in 2030 and 102 TWh in 2050.

Theoretical production potential

43 TWh/y
Production potential in 2030

102 TWh/y
Production potential in 2050

Feedstocks ('high' scenario)

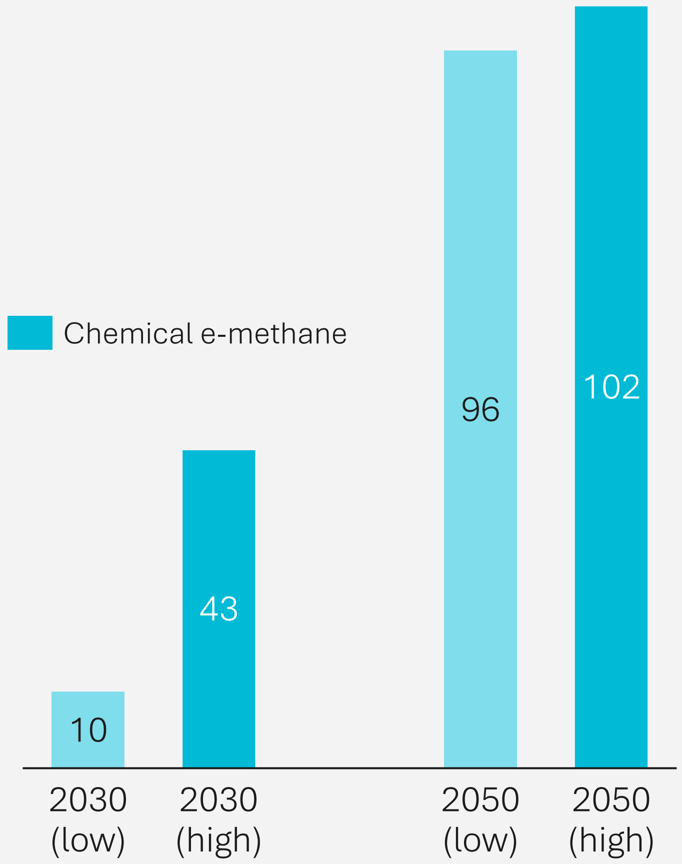
20.6 Mt
Of biogenic CO_2 from biomethane to power CCUS potential in GB in 2050

124 TWh
Of green H_2 offtake demand generated in GB in 2050

Additional CO_2 sources[1]

Could be leveraged from power plants or captured industrial sources, geological sources or from direct air capture (DAC)

Production potential

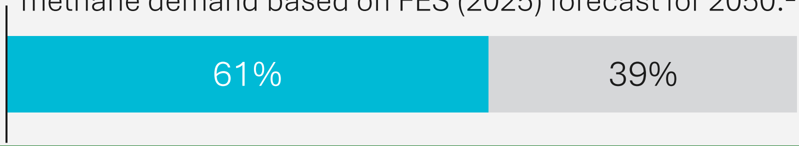


Key Assumptions

- High scenario: Production potential 50 TWh / 120 TWh of biomethane production in 2030 / 2050, respectively, and full utilisation of resulting biomethane in biomethane-to-power with CCS.
- Low scenario: Production potential assuming 12 TWh / 113 TWh of biomethane production in 2030 / 2050, respectively, and full utilisation of resulting biomethane in biomethane-to-power with CCUS.
- Captured fossil CO_2 is not counted due to low supply in 2030 and expected ineligibility[1] as a CO_2 source in 2050.
- DAC CO_2 is not considered due to limited availability in 2030 and uncertainty of availability (and cost) in 2050.
- H_2 supply availability assumed to fully meet demand.
- 98% mass conversion efficiency (residual 2% CO_2 assumed to be vented as with biological e-methane).

Share of primary methane demand

Chemical e-methane could make up 67% of primary methane demand based on FES (2025) forecast for 2050.[2]



[1] UK regulations currently allow the use of fossil CO_2 without restriction. However, should these regulations align with the European Union's regulations, then fossil CO_2 is only permitted to be used until 2040, and if covered by an effective carbon pricing scheme. | [2] Based on the FES (2050) 'Holistic Transition' Scenario.

Synthetic methane theoretical production potential

Based on available GB feedstocks, there is a maximum synthetic methane theoretical production potential of 35 TWh in 2050, of which 69%/75% is from biogenic feedstocks, respectively.

Theoretical production potential

35 TWh/y

Production potential in 2050

Feedstocks

11.7 Mt

Of feedstock available in GB in 2050

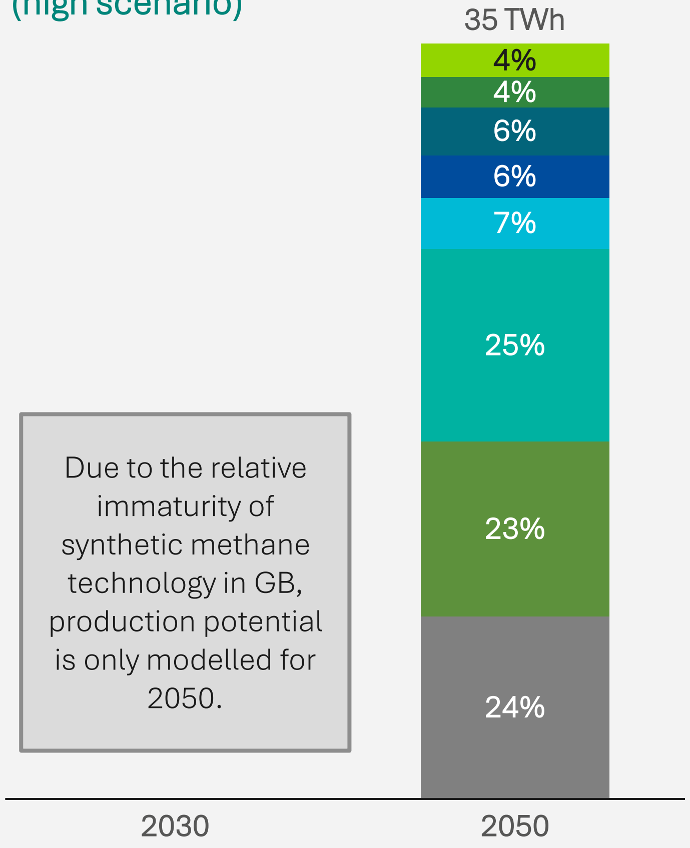
75%

Of the feedstocks are from biogenic sources

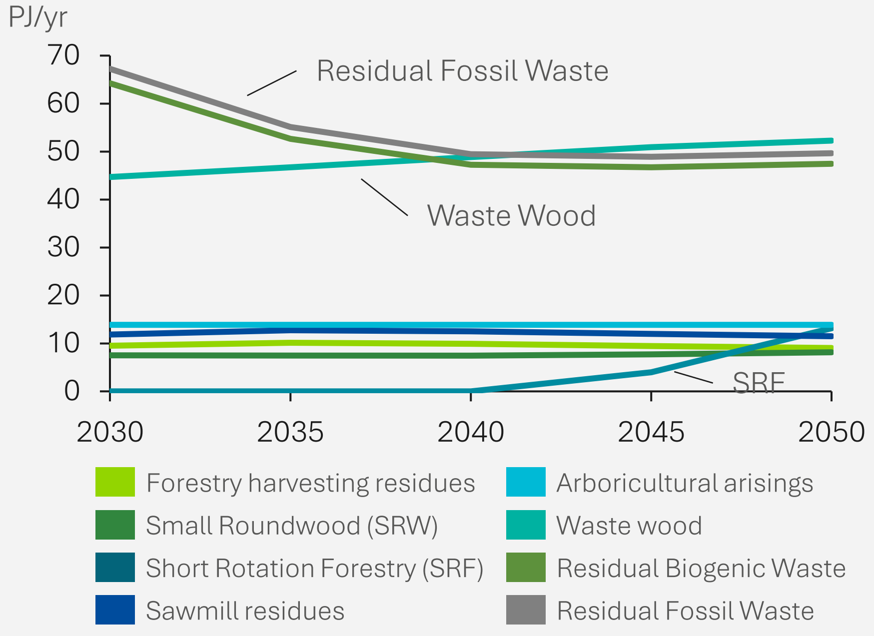
Key assumptions

- Feedstock supply considers technical and environmental constraints, and existing non-energy uses.
- Competition with other energy uses (e.g. BECCS, SAF) not considered.
- Assumes full feedstock utilization; applies 61% conversion efficiency.

Proportion of potential from each feedstock (high scenario)



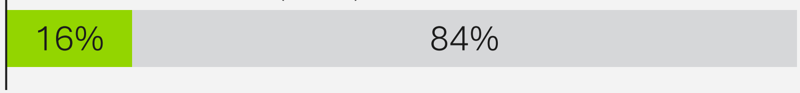
GB feedstock availability (high scenario)



Source: DESNZ, UK & Global Bioenergy Resource Model (2024)

Share of primary methane demand

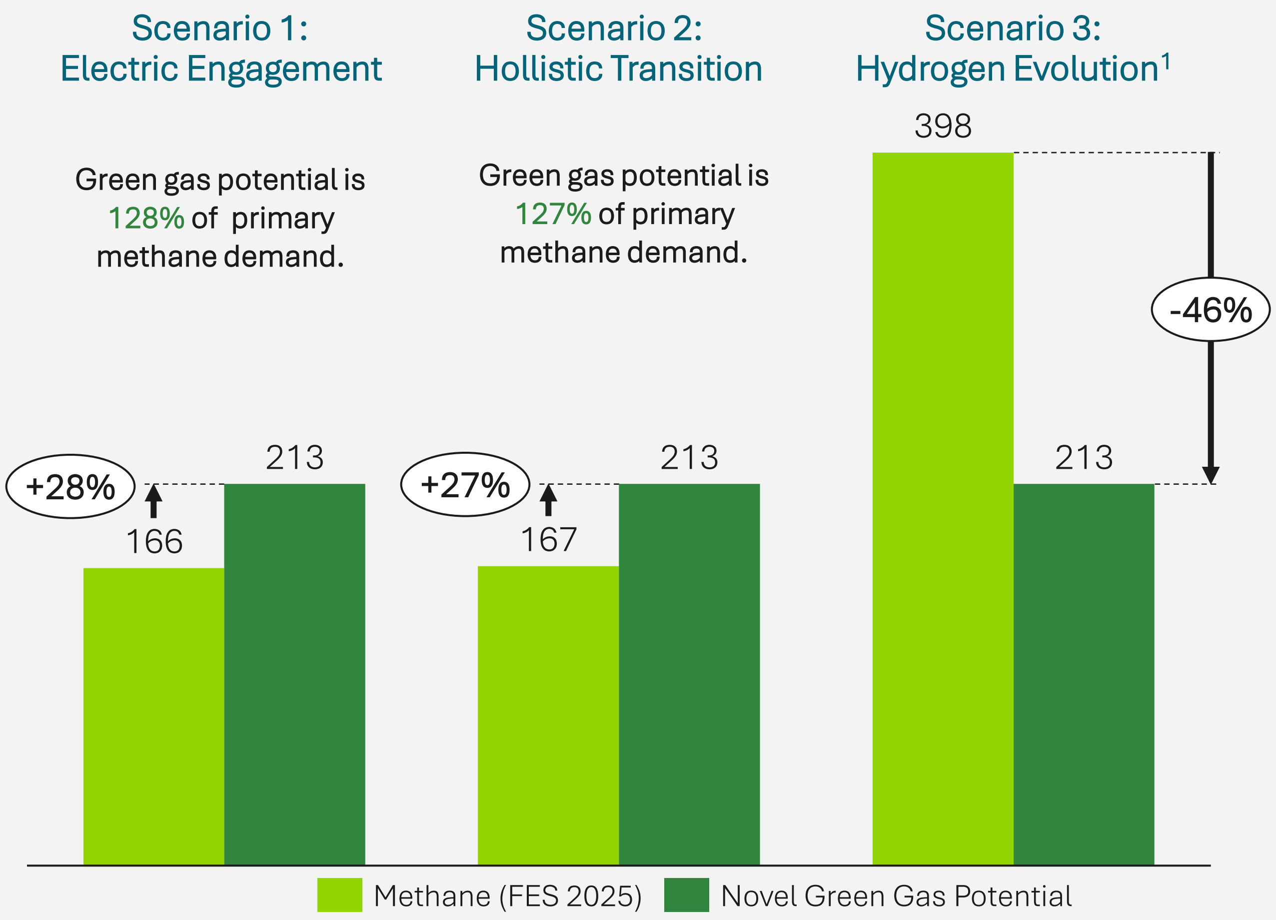
Synthetic Methane could make up 16% of primary methane demand based on FES (2025) forecast for 2050.[1]



[1] Based on the FES (2025) 'Holistic Transition' Scenario.

Maximum theoretical production potential of novel green gases (213 TWh) is equivalent to 127% of primary methane demand in GB by 2050

- **Novel green gas production potential in GB across the three pathways could reach 213 TWh by 2050, equivalent to ~127% of primary methane demand.**
- Novel green gases have the potential to compensate the entirety of primary methane demand of 166–167 TWh in 2050 (FES 2025).
- If scaled up, novel green gases can therefore offer an opportunity of supporting the UK's Net Zero decarbonisation goals and promoting energy security.



[1] The NESO 'Hydrogen Evolution' scenario assumes a higher level of fossil methane to produce blue hydrogen. As e-methane is already low carbon it would not be applicable to meeting this share of demand. This scenario has been included here for completeness.

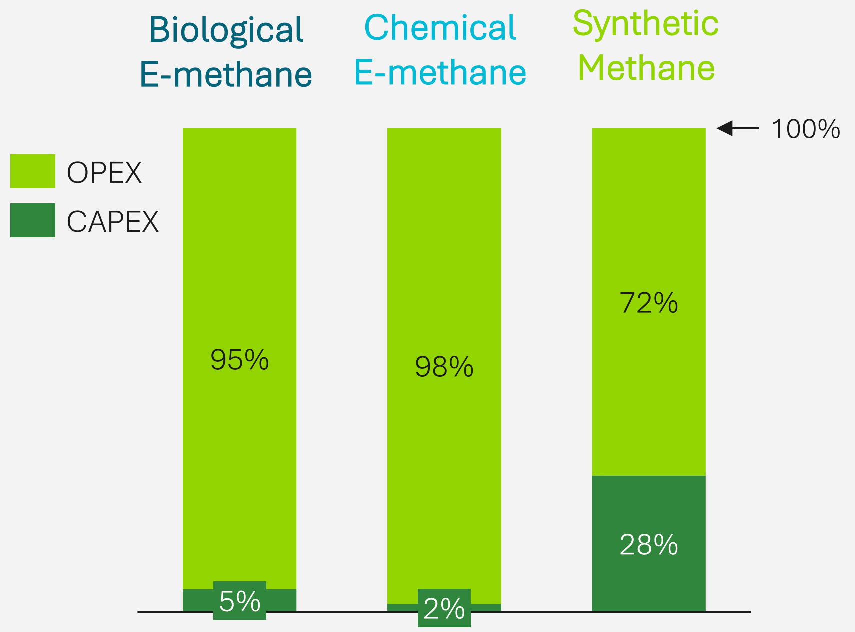
Cost of Production

Novel green gas production cost ranges from £156 to £285 per MWh depending on the production pathway, with OPEX driving cost outcomes

Cost of production, 2025 (LCOE)

Biomethane[1]		Biological E-methane		Chemical E-methane		Synthetic Methane	
Low Scenario (£/MWh)	High Scenario (£/MWh)	Low Scenario (£/MWh)	High Scenario (£/MWh)	Low Scenario (£/MWh)	High Scenario (£/MWh)	Low Scenario (£/MWh)	High Scenario (£/MWh)
98	121	156	261	171	285	232	250

LCOE cost breakdown



OPEX is the largest component of total cost of production for all three technologies.

- The production costs for novel green gases were derived from literature and industry estimates, the level of detail of which varies across technologies. Since these technologies are still immature, the cost estimates remain uncertain.
- As is the case with anaerobic digestion, larger e-methane plants will likely have economies of scale benefits in generation costs. As the e-methane sector grows nationally and internationally, the ability to quantify these costs benefits will improve and our models can be refined accordingly.

[1] GGT-Cadent, Reducing the cost of Net Zero with biomethane (2025)

Biological methanation is the most cost competitive production pathway as it benefits from a co-located biomethane production plant

Levelised Cost (LCOE) of biological e-methane ranges from £156/MWh to £261/MWh in 2025.

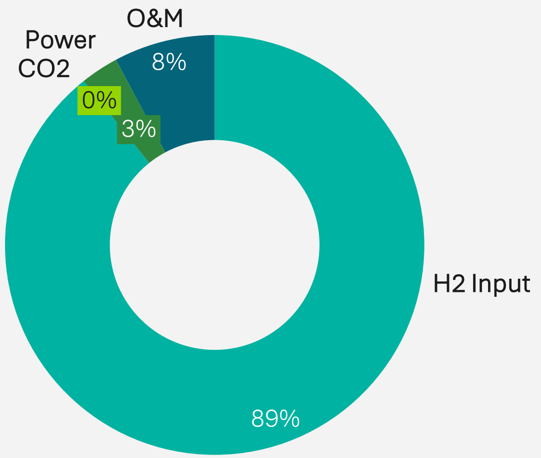
LCOE model assumptions

		Description	Model Components
Fixed parameters	Plant characteristics	• Based on co-location with notional biomethane plant of 60 GWh/yr capacity, and corresponding CO_2 output from biogas upgrading feeding a 44 GWh/yr biological e-methane plant. • Biological e-methane plant estimated to be 90% available.	• Conversion efficiency • Operational lifetime
	Capital expenditure (CAPEX)	• CAPEX consists of the biological methanation reactor and gas conditioning. • CAPEX for the biomethane plant facility is not included.	• Methanation system • Gas conditioning • Contingency
Variable parameters	Hydrogen	• Assumes on-site electrolyser. • Levelised Cost of Hydrogen (LCOH) is inclusive of electrolyser capex and fixed/variable OPEX (primarily renewable electricity consumption).	• LCOH
	Carbon dioxide	• Includes revenue opportunity cost of not receiving Greenhouse Gas Removal (GGR) credits.	• CO_2 value • GGR credit value
	Electricity	• Assumes grid connection. • Electricity power consumption for the facility and process.	• Electricity price

Cost outcomes for **biological e-methane** would reduce as hydrogen costs decrease over time

Hydrogen contributes 89% of OPEX

OPEX – Low Scenario



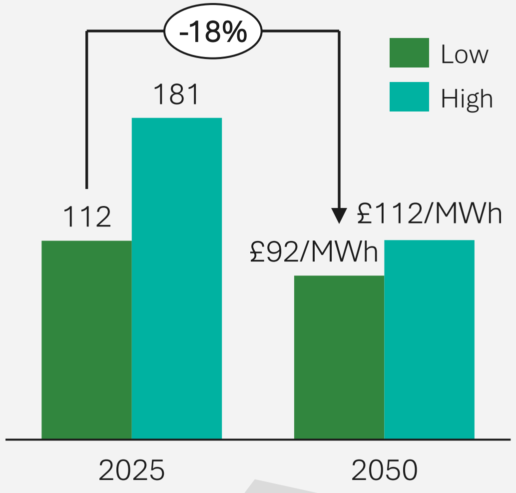
- For both low and high scenarios, the largest operating expenditure is H_2 input cost.
- Approximately 1.19 MWh of H_2 input is required to produce 1 MWh of biological e-methane.

Hydrogen prices are forecasted to reduce to 2050

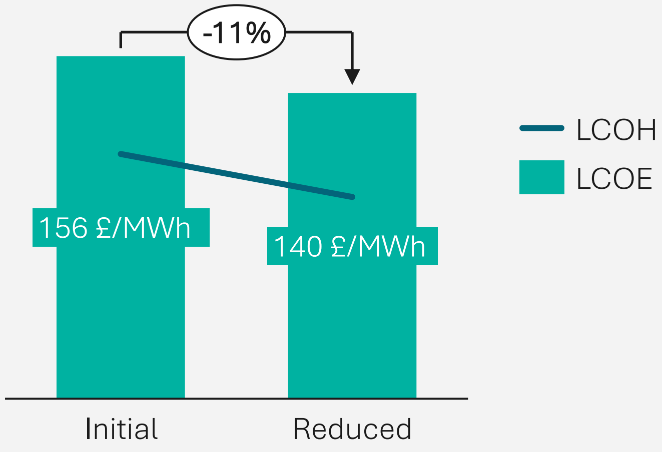
LCOH is forecast to reduce by nearly 20% to 2050.

When isolated, reducing H_2 prices by 20% reduces the low range of LCOE **by 11% to 140 £/MWh.**

LCOH[1] – 2025 - 2050



LCOE – Low Scenario H_2 adjusted



A high and low range of costs for electricity and H_2 are modelled to account for uncertainty. In 2025, the **variance between the high and low LCOH is over 60%**, resulting in a 58% difference between the high and low LCOE outcomes.

[1] NESO Green H2 LCOH.

Biological methanation offers biomethane producers with an alternative revenue stream for CO_2

Biomethane production in 2030 is estimated to produce 7.1 Mt CO_2 increasing to 17.1 Mt CO_2 by 2050. This can be utilised for e-methane production

E-methane production provides an alternate use-case for CO_2 from biogas upgrading

Use case	Description	Advantages (+) and Challenges (-)
Venting	Intentional release of excess CO_2 into the atmosphere.	+ No additional financial cost. - Foregone revenue from not selling CO_2.
Sale for usage	Off-takers such as the food and beverage industry purchase CO_2 for utilisation.	+ Existing and developed market (~0.6 Mt/yr demand). - No current market premium for biogenic CO_2.
GGR credits	GGR credits for CO_2 are tradable certificates that represent the verified removal of CO_2 from the atmosphere through technologies or natural processes.	+ Potential revenue stream to biomethane producer, depending on evolution of market value for GGRs. - Network availability and government support currently unclear, may be costly to participate in market.
E-methane production	Use CO_2 supply as input to on-site biological e-methane production.	+ Increases overall methane yield, generating additional revenue stream from e-methane production. - Initial capital investment for methanation system.

Given that our scenario assumes on-site supply of CO_2 from co-located biomethane production, an additional CO_2 purchase or liquefaction is not included in our costs.

We have included a "buy-out" cost to account for the potential forgone revenue of participating in the GGR market.

See next page for buy-out cost breakdown

GGRs offer potential future revenue for biomethane producers that should be accounted for in the cost to produce e-methane

We modelled the potential profit of selling biogenic CO_2 for GGR credits

Biomethane operators could theoretically sell their CO_2 on the GGR market, although this would incur additional costs. The "buy-out" cost of forgoing the opportunity to use CO_2 for e-methane production has been accounted for in the production cost.

	Low Scenario (£/tCO_2)	High Scenario (£/tCO_2)
2030	-	44
2050	-	95

Low scenario: Assumes greater trucking distance required to reach T&S network, and higher range of costs to use T&S network. *In this scenario, the cost to participate outweighs the potential market value of the CO_2.*

High scenario: Assumes lesser distance to T&S network and lower range of costs to access network. *In this scenario, this generates some profit from GGR sales.*

Note: The market value of CO_2 for each year is kept uniform across the low and high scenarios to demonstrate the impact of access to the T&S network.

Modelling assumptions and limitations

Input	Description	Value	Source
Market entry costs	Includes CO_2 processing costs and cost to transport CO_2 to the T&S network. Varies depending on distance and size of plant.	73 – 123 £/tCO_2	Informed by previous modelling conducted by GHD for the GGT[1]
T&S network costs	The costs to use broader T&S network and store CO_2. These costs are currently highly uncertain as the T&S network is still under development. Government support may alleviate these costs, but the extent of support is uncertain.	30 – 90 £/tCO_2	
Distance to T&S network	Varies depending on location of biomethane plant and may significantly impact cost and feasibility of GGR market participation.	20 – 350 km	
Value of GGR credits	The evolution of the willingness-to-pay for GGR credits is highly uncertain.	2030: 147 2050: 199 £/tCO_2	UK Treasury Green Book

[1] Net Zero Ambition to Action: The Role of Green Gas in Permanent Carbon Removals

Chemical e-methane cost of production is dependent on a reliable biogenic CO_2 source from industry

Levelised Cost (LCOE) of chemical e-methane ranges from £171/MWh to £285/MWh in 2025.

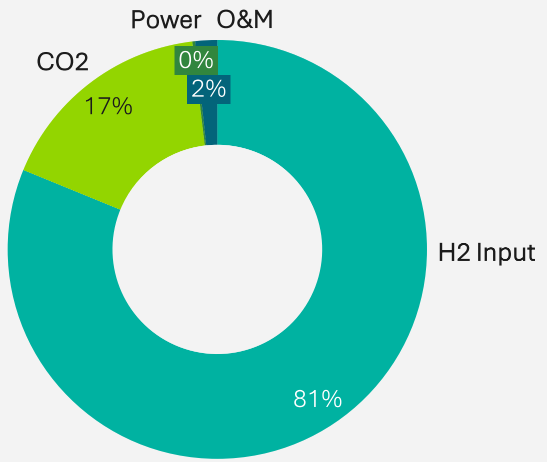
LCOE model key assumptions

		Description	Model Components
Fixed parameters	Plant characteristics	• Based on a 125 GWh/yr capacity stand alone plant, located in or near to an industrial cluster. • Chemical e-methane plant estimated to be 90% available.	• Conversion efficiency • Operational lifetime
	Capital expenditure	• CAPEX consists of the chemical methanation reactor and gas conditioning.	• Methanation system • Gas conditioning • Contingency
Variable parameters	Hydrogen	• Assumes on-site electrolyser. • LCOH is inclusive of electrolyser capex and fixed/variable opex (primarily renewable electricity consumption).	• LCOH
	Carbon dioxide	• CO_2 purchased and transported from nearby industrial cluster.	• Purchased CO_2 price
	Electricity	• Assumes grid connection. • Electricity power consumption for the facility and process.	• Electricity price

Cost outcomes for **chemical e-methane** would reduce as hydrogen costs decrease over time

Hydrogen contributes 81% of OPEX

OPEX – Low Scenario



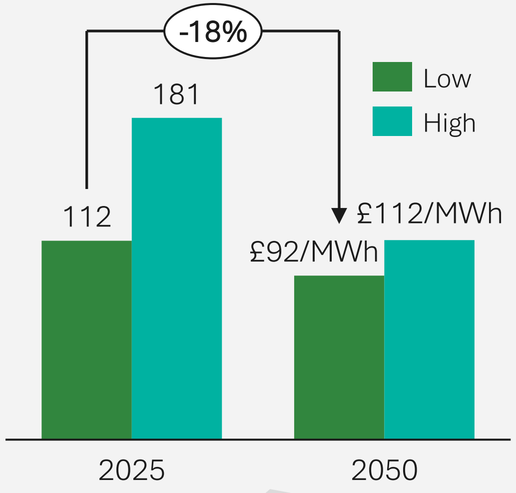
- For both low and high scenarios, the largest operating expenditure is H_2 input cost.
- Approximately 1.19 MWh of H_2 input is required to produce 1 MWh of biological e-methane.

Hydrogen costs are forecasted to reduce to 2050

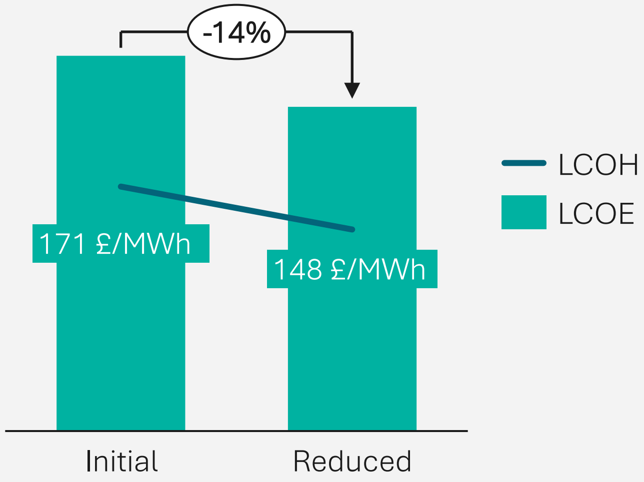
LCOH is forecast to reduce by nearly 20% to 2050.

When isolated, reducing H_2 prices by 20% reduces the low range of LCOE **by 14% to 148 £/MWh.**

LCOH[1], 2025 - 2050



LCOE, Low Scenario H_2 adjusted



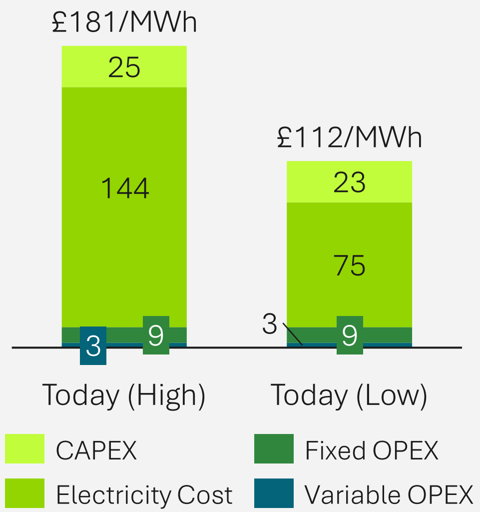
A high and low range of costs for electricity and H_2 are modelled to account for uncertainty. In 2025, the **variance between the high and low LCOH is over 60%**, resulting in a 48% difference between the high and low LCOE outcomes.

[1] NESO Green H2 LCOH.

Supporting the GB green hydrogen economy is critical to reduce costs of production for both biological and chemical e-methane production

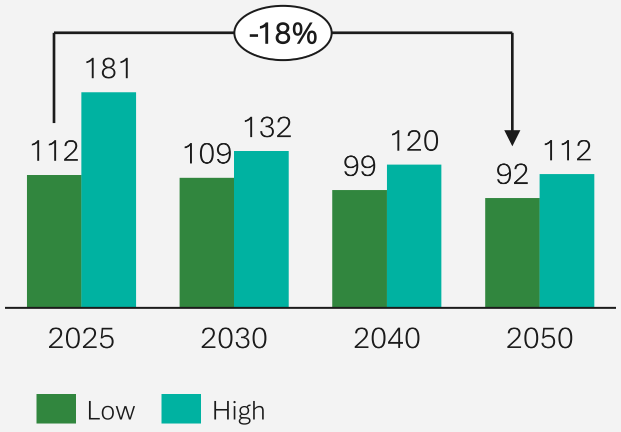
Over time the LCOH is expected to decrease...

LCOH[1] 2025



- The **largest determinant of LCOH today is the electricity** cost due to the high cost of grid electricity.

LCOH (£/MWh) 2030, 2040, 2050



- By 2050, **LCOH could decrease around 20%** compared to today.

Further support is required to reduce costs

1. **Lower energy costs**
   - Lower electricity costs through co-location and flexible operation.

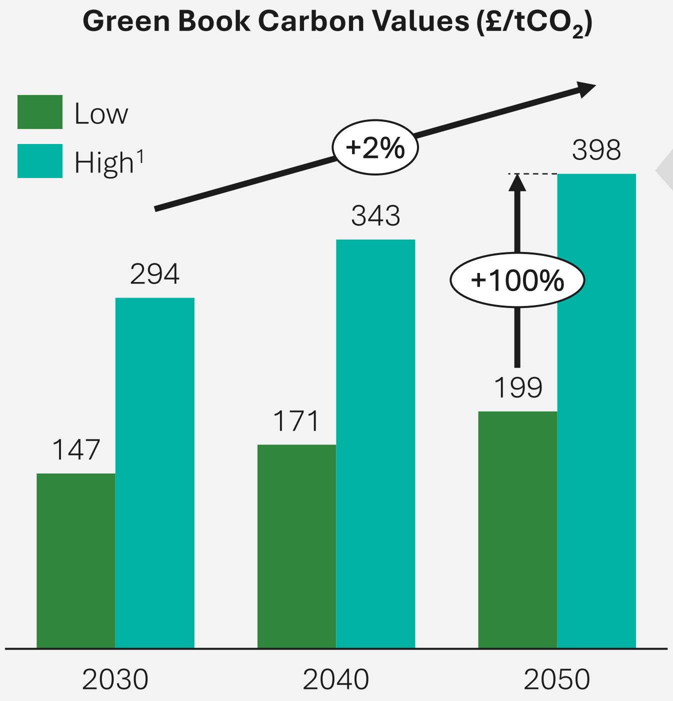
2. **Support Mechanisms**
   - Introduce realistic strike prices under Contracts for Difference (CfD) to attract investment and provide revenue certainty for developers.

3. **Improve efficiency**
   - Utilise batteries or other storage to maintain operation and improve the capacity factor during renewable dips.
   - Utilise long-term PPAs to lock in renewable energy at stable prices.

[1] Based on PEM electrolyser technology; NESO Green LCOH.

Chemical e-methane cost of production would increase by nearly 20% if higher range of projected CO_2 value is realised

As no co-located source of CO_2 is available in modelled chemical methanation scenario, CO_2 input must be purchased at market value



Projected growth in CO_2 value within scenarios is relatively slow, with **2% growth** between 2030 to 2050.

However, projected costs for carbon values vary between scenarios by a factor of more than **100%**.

A 100% increase in CO_2 costs would increase the cost of chemical e-methane LCOE by 18%.[2]

CO_2 values are driven by national and global market influences

Green Book modelled carbon values are recommended by UK Government for use in policy appraisals and other analysis. These values are modelled based on "target-consistent" valuation approach, which aligns carbon values with the abatement costs needed to meet net zero targets. The real-world evolution of willingness to pay is difficult to predict and may differ from these assumptions. Factors impacting carbon values could include:

Driver	Description
UK ETS evolution	The development of the UK Emissions Trading Scheme (ETS), including number of allowances available, sectors requiring allowances, etc. could drive up demand and prices for GGRs.
Fossil fuel prices	If fossil fuel prices are relatively low and therefore more cost-competitive with renewables, a larger number of allowances will be demanded, driving up costs.
GDP growth	Higher economic activity may lead to more emissions, generating more demand for GGRs.

[1] High scenario utilizes central cost estimates from Green Book. | [2] Assuming low cost-range scenario for other variable inputs.

Synthetic methane is currently the least cost competitive production pathway, primarily due to its low technological maturity

The Levelised Cost (LCOE) of synthetic methane ranges from £232/MWh to £250/MWh in 2025

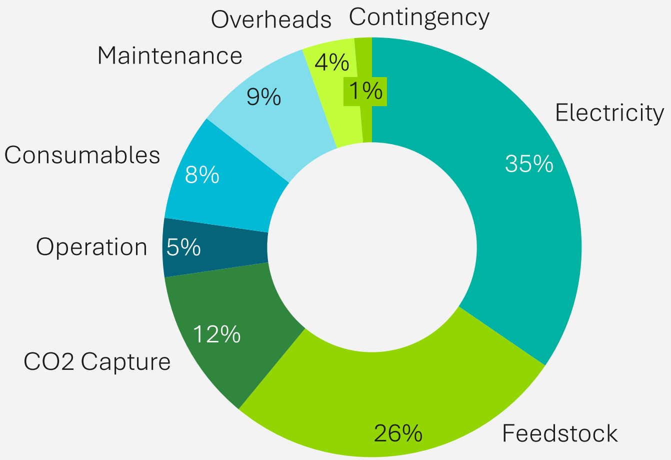
LCOE model key assumptions

		Description	Model Components
Fixed parameters	Plant characteristics	• Based on 322 GWh/yr plant capacity with 90% availability.	• Plant efficiency • Operational Life
	Capital expenditure	• CAPEX based on GB commercial plant based on detailed FEED including the facility thermal gasification and syngas conversion systems.	• Gasification system capex • Contingency
	Feedstocks	• Average feedstock cost based on the respective feedstock shares of the modelled feedstocks. • Feedstock costs include the cost of transportation and preparation.	• Feedstock price
Variable parameters	Electricity	• Assumes grid connection. • Electricity power consumption for the facility and process.	• Electricity price

Synthetic methane has a high portion of its operational cost due to feedstock and electricity costs

Electricity contributes 35% of OPEX

OPEX – Low Scenario



- For both low and high scenarios, the largest operating expenditure is electricity cost due a significant amount of power required for the process.
- Achieving cost competitiveness largely hinges on securing affordable electricity and effectively controlling feedstock expenses, as these two elements are critical in determining production economics.

The type and overall share of feedstocks used impacts the estimated LCOE

- Woody feedstocks such as short rotation forestry, sawmill residues and small roundwood typically command the highest market per tonne due to their higher (and more consistent) quality and higher market demand. Waste wood is cheaper in comparison as it can be of variable quality and may include some contaminants.
- In contrast, residual waste represents a feedstock with a negative cost per tonne (or "gate fee"), meaning that suppliers will pay you to remove it because it reduces their landfill tax disposal burden.

[1] The average feedstock cost is weighted according its overall share in GB. It does not reflect what an individual plant may source.

International case studies

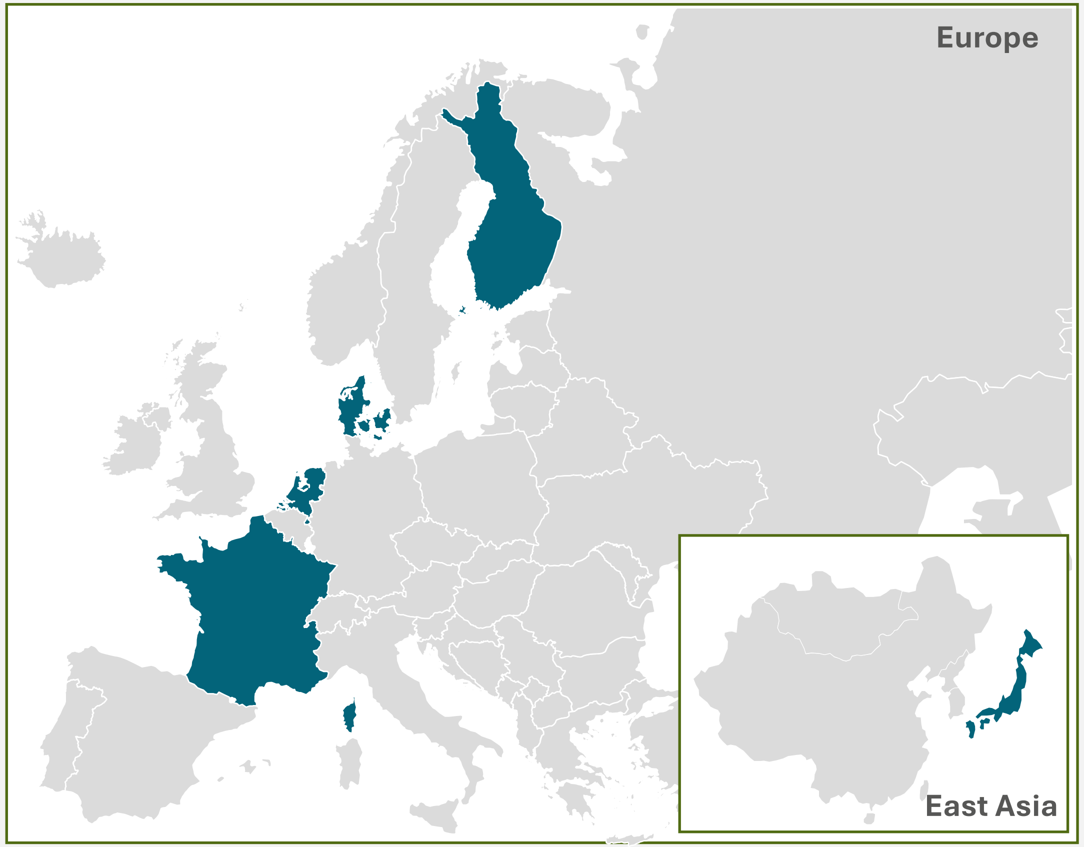
Energy landscape in selected European countries and Japan

Denmark

- Renewables account for ~74% of the electricity mix, dominated by wind power. Targeting 100% biomethane in gas grid by 2030. Well developed gas infrastructure.
- Significant investment in hydrogen export market and involvement in green hydrogen pipeline to Germany planned by 2030.

France

- Renewables account for ~96% of electricity mix, dominated by nuclear.
- 4th in Europe for fossil fuel imports, despite strong domestic nuclear base. Extensive gas grid.



Finland

- Heavy dependence on Russian gas imports and a strong transmission network highlight the need for domestically produced green gas.
- Renewables account for around 90% of electricity mix, dominated by nuclear, wind and hydro.

Netherlands

- Significant import dependency for oil and gas, though domestic natural gas still plays a role. Major existing gas transmission network.
- Aggressive targets for offshore wind (21 GW by 2032) and hydrogen (3–4 GW electrolyser capacity by 2030).

Japan

- Japan remains heavily reliant on gas imports.
- Renewables account for ~25% of electricity mix, dominated by solar.
- Energy plan includes ambitious goals for hydrogen and synthetic fuels.

Japan

Japan is actively developing the green gas industry through several biomethane and novel green gas projects, supported by coherent targets and policy incentives

	Green Gases	Electricity	H_2	CO_2
Status	• Japan's Clean Gas Certificate Program (2024) certifies synthetic methane and biomethane confirming CO_2 emissions from burning these gases support carbon neutrality goals.	• Japan's Renewable Energy Act and liberalized electricity market supporting decarbonization goals.	• Japan's Basic Hydrogen Strategy (2017) and Green Growth Strategy promoting hydrogen adoption.	• Japan's has invested $5.2million in public funds on domestic and overseas CCUS projects since 2024.
Targets	• Osaka Gas: Inject 1% e-methane into the national gas grid by 2030 (~60 million m^3/year), with a long-term goal of carbon neutrality by 2050.	• Increase renewable share to 36-38% by 2030 including 19-21% from solar and wind.	• Cost reduction to $1.50/kg target by 2050. • Hydrogen supply target for 3 million tonnes per year by 2030 and 20 million tonnes by 2050.	• Reduce carbon capture price to below carbon price by 2040.
Incentives and enablers	• Eligible projects can finance R&D and demonstration projects in priority fields via Green Innovation Fund.	• Feed-In-Tariff (FIT) scheme redesigned in 2022 into Feed-In-Premium (FIP). • FIP pays generators a subsidy based on market price and marginal rate to incentivise supply during peak hours.	• Promoting public-private partnerships (e.g. German Siemens & Japan NEDO). • Contract for Difference (CfD) offer delivery-based subsidies to incentive production.	• Carbon levy on fossil fuel importers and domestic fossil fuel extractors will be introduced from 2028.

Project showcases

OSAKA GAS

Osaka Gas aims to inject **1% e-methane into Japan's urban gas grids by 2030** (~60 million m^3/yr) and replace 90% of urban gas with e-methane by 2050.[1]
Domestic and overseas initiatives include:

- **Osaka Bay Large-Scale Facility:** Joint study with ENEOS to build Japan's first large-scale e-methane plant (capacity: 60 million m^3/year). Target start: 2030.
- **US (Nebraska) e-methane:** Total Energies, TES, Osaka Gas JDA to produce 75,000 tonnes e-methane for export to Japan. Target operation: 2030.

TOKYO GAS

Tokyo Gas methanation facility[2]
In Yokohama producing e-methane equivalent to daily city gas use for 260 households since 2022.

経済産業省 Ministry of Economy, Trade and Industry

ReaCH$_4$ Project:
Joint venture with US firms to produce e-methane in Louisiana using renewable energy. Target: 130,000 t/yr e-methane methane exported to Japan by 2030.

[1] Osaka Gas: Initiatives for carbon neutrality | [2] Tokyo Gas methanation facility | [3] Wood Mackenzie: E-methane

Denmark

Denmark has ambitions to leverage its strong supply of biogenic CO_2 and renewable electricity to become a significant producer and exporter of e-fuels

	Green Gases	Electricity	H_2	CO_2
Status	• Denmark currently has a strong foundation of biomethane supply, at around 8 TWh as of 2025, with plans to increase by 25% in the next two years.[1]	• Approximately 50% of current electricity supply is derived from wind and solar, with an additional large share of biomass-generated electricity.[4]	• Denmark recently announced plans for a hydrogen pipeline connecting to Germany, in an effort to unlock additional hydrogen off-takers through exports.[6]	• Approx 6.5 mtCO_2 of biogenic CO_2 from incineration and CHP plants and 800,000 mtCO_2 from current biogas plants.[8]
Targets	• Targeting 100% green gas consumption by 2030, the majority of which will be biomethane.[2] • Active in Global Methane Pledge.	• Aiming to achieve 100% renewable electricity production by 2030.[4]	• Aiming to develop 4-6 GW of electrolyser capacity by 2030.[7]	• 70% CO_2 reduction by 2030 target, 110% reduction by 2050, relative to 1990.[9]
Incentives and enablers	• EU Commission approved €1.7 billion scheme to support new and extended biogas and e-methane plants. Aid will be via competitive tenders and 20-year price premiums.[3]	• Upcoming tenders to offer up to €7.4 billion • €400 million Danish aid scheme to support electricity production from renewable sources, offering 20-year contracts for difference.[5]	• PtX tender under Danish Energy Agency offers ~€167 million in support for green H_2 production, subsidy paid to lowest bidders over a 10-year period.[7]	• Carbon tax is applied to agricultural emissions, rising to €100/tCO_2 by 2035.[9]

Project showcase

EUROPEAN ENERGY MITSUI&CO.

Kassø e-methanol facility

- First large-scale e-methanol facility globally, with the capacity to produce 42 kt/year of e-methanol.
- Leverages CO_2 from biogas plants and 52 MW electrolyser units. 50% of electricity is from neighbouring solar park, with remainder from grid.

nature energy

Glansager biological e-methane facility

- Demonstration-scale project with partnering with Andel.
- Utilises biogenic CO_2 from adjacent AD to produce biomethane and a 6 MW capacity electrolyser.
- Estimated to produce 12,000 m^3 of e-methane daily.

[1] Denmark biomethane expansion | [2] Biogas in Denmark | [3] Danish State aid scheme | [4] Green energy | [5] State aid: €400 million Danish aid scheme renewable energy | [6] Denmark Hydrogen Pipeline | [7] Denmark | European Hydrogen Observatory | [8] Carbon Removers | [9] Carbon Removal in Denmark: Policy, Targets & Funding

Finland

Finland is targeting an ambitious carbon neutrality date of 2035, underpinned by policies and incentives which could be leveraged for green gas production

	Green Gases	Electricity	H_2	CO_2
Status	• ~32% of total energy supply is derived from biofuels and waste.[2]	• Renewable sources account for ~52% of power generation.[2]	• First industrial-scale green hydrogen plant opened in early 2025.	• ~28 Mt biogenic CO_2/y from large point sources. 16+ projects currently capture 1-1.5 $MtCO_2$ for use in e-fuel production.[1]
Targets	• Finland has adopted REDIII into national law, creating favorable conditions for RFNBOs.[3]	• Committed EU renewable energy target of 50% of gross final energy consumption deriving from renewable sources.	• Aim to supply 10% of EU clean hydrogen by 2030, one million tonnes H_2.	• Aims to contribute to EU target of 50 $MtCO_2$ stored annually by 2030.
Incentives and enablers	• CAPEX funding available for e-methane plants (from EU's Recovery and Resilience Facility (RRF)).	• €2.3 billion state aid scheme supporting investments in solar panels, wind turbines, electrolysers. Also supports green hydrogen and biomethane production.	• €50 million support from Business Finland for hydrogen R&D and commercialization projects. • Additional funding from Interreg Aurora and other EU programs.	• Finland's geography is unsuitable for geological CO2 storage solutions – memorandums of understanding signed with Denmark and Norway to promote cross-border transport and storage of CO_2.[4]

Project showcases

HY2GEN

Vihreäsaari e-methane project

- German company Hy2gen announced in November 2025 plans to develop a green hydrogen and e-fuels plant in the Port of Oulu in northern Finland.
- At 200 MW, the planned project would be largest hub of synthetic fuel production in the Baltic Sea Region.[5]

FREIJA

Nokia chemical e-methane project:

- Norwegian company Freija is developing one of the largest e-fuel facilities in Europe in Nokia, Finland.
- The plant will be developed in three phases, each with a capacity of 58,000 t/yr of e-methane.

TES

Luoto Energia chemical e-methane project:

- Joint project between Tree Energy Solutions and CPC Finland.
- Will produce 125,000 t/yr e-methane via the Sabatier process.

[1] European Bioenergy Days | [2] Finland - Countries & Regions – IEA | [3] Renewable Fuels of Non-Biological Origin | [4] Finland and Denmark agree on framework | [5] Hy2gen plans e-fuel plant in Finland | [6] Freija Plans Largest Green Hydrogen-Based E-Methane Facility | [7] TES, CPC launch major e-NG project in Finland port

France

France has allocated several billion euros to date in support of the production of biofuels and other green gases

	Green Gases	Electricity	H_2	CO_2
Status	• About a dozen power-to-methane projects under development, aiming for 8 TWh by 2035.	• Although 94% of France's electricity is supplied by low carbon sources, the majority of this is powered by nuclear, with 12% of electricity generated by solar and wind.[3]	• The French National Hydrogen Strategy includes the development of a synthetic fuel industry as among its key pillars.[5]	• France's first bioenergy with carbon capture and storage (BECCS) project was launched in early 2025.[7]
Targets	• Long Term Energy Schedule (PPE) sets injection target of 7-10% biomethane in 2030, interim target of 14-22 TWh by 2028.[1]	• Aim to increase installed renewable capacity to 100 GW by 2050.[4] • Target 41% share of renewables in gross final consumption by 2030.	• Hydrogen strategy targets 4.5 GW in electrolyser capacity by 2030, rising to 8 GW by 2035.[6]	• Targets a 50% cut in GHG emissions by 2030 relative to 1990 levels. • CDR target of 65 to 80 Mt CO_2 in 2050.[8]
Incentives and enablers	• €1.5 billion French State aid scheme to support biomethane through contracts for difference approved in 2024.[2]	• France 2030 plan includes €1 billion in renewable energy innovation projects	• France 2030 includes €34 billion investment, including €1.9 billion for green hydrogen and synthetic fuels.	• France 2030 plan includes €3 billion to decarbonise industry with carbon capture and storage.[8]

Project showcases

enosis

DENOBIO biological e-methane project

- Industrial demonstrator inaugurated in 2025 in Hauts-de France, led by Enosis.
- The project will increase methane yield from an existing agricultural methanization unit Energia Thiérache, using the CO_2 byproduct with biomethanation technology.

ENERGO

ENERGO demonstrator:

- Demonstration project involving ENGIE and GRDF conducted first test of injection of synthetic methane into the gas distribution system.
- Synthetic methane was produced via CO_2 from a co-located biomethane plant.

[1] Biomethane in France in 2023 | [2] IP_24_3986_EN.pdf | [3] France | Ember | [4] France 2030 investment Plan | [5] National Hydrogen Strategy | [6] European Hydrogen Observatory | [7] BECCS developer signs France's first biogenic CO2 storage deal | [8] Carbon Removal in France – National Policy Overview |

Netherlands

Driven by biomethane blending obligations and supporting subsidies, Netherlands' gas network is shifting to renewable gases

	Green Gases	Electricity	H_2	CO_2
Status	• Produced ~0.27 bcm biomethane in 2023.[1]	• Renewable sources accounted for ~48% of power generation in 2023.[2]	• Target of 500 MW hydrogen production by 2025.	• The Dutch Carbon Removal Roadmap includes the use of biogenic CO_2 for production of fuels as a form of temporary removal.[4]
Targets	• Government aims to produce 2 bcm of green gas annually by 2030. • A blending obligation will require gas suppliers to include up to 20% biomethane to increase the production of green gas in the built environment by 2030, boosting demand for green gas.	• Increase renewable share to 70% by 2030 (mainly wind and solar). • By 2040, 120 GW renewable electricity production capacity with 70 GW from solar.[3]	• Achieve €1.50–€2/kg cost target by 2030, scale infrastructure for industry and mobility. • National Hydrogen Programme aims for 4 GW electrolysis capacity by 2030. • National hydrogen network rollout planned by 2032.	• Committed to significant GHG emissions reduction target of 55% by 2030 compared to 1990. • Deploy CCS to cut 14% of industrial emissions by 2030.
Incentives and enablers	• Subsidies under the SDE++ scheme and other programs support green gas projects.	• Strong growth in offshore wind and solar PV, backed by grid expansion plans and SDE++ auctions (€8B budget in 2026).	• Subsidies under the SDE++ scheme and other programs support hydrogen projects.	• CCS projects eligible for SDE++ support.

Project showcases

Hynetherlands project[5]

- Collaboration between Engie, OCI, and EEW to produce e-methanol.
- To be anchored around a 100 MW electrolyzer installation in 2028, scaling to 1.85 GW after 2035.
- Biogenic CO_2 is sourced from non-recyclable waste and circularity of oxygen.
- Intended to contribute to decarbonisation of local chemical industry.

EemsGas Project[6]

- A commercial gasification plant converting woody biomass into synthetic methane.
- Expected output: 12 million m^3/yr of synthetic methane by 2030.

SCW Project[7]

- Hydrothermal gasification plant has a total processing capacity of 10-16 t/hr, equivalent to 20 MWth gas output depending on the energy content and type of feedstock.

[1] EBA Statistics | [2] NL Times | [2] Roland Berger | [3] Stercore | [4] Netherlands Carbon Dioxide Removal Roadmap | [5] Hynetherlands | [6] EemsGas | [7] SCW Project

Policy Recommendations

Policy intervention is essential to ensure that the production potential of novel green gases can be fully realised

Policy Principle	Policy recommendation	Rationale
Encourage Research and Innovation	• Given the immaturity of novel gases, it is premature to recommend a specific support mechanism. Nevertheless, Government should monitor sector progress and encourage research and development in novel gases to unlock cost reduction opportunities.	• Biomethane as a proven technology should be the priority of government policy via strong economic incentives for suppliers as a means of prioritizing cost-effective GHG savings from now.
Remove barriers to market	• As biomethane generation scales up and a new future framework is provided, Government should be flexible to apply future learnings and frameworks to all green gases. Removing barriers to market early could allow more rapid deployment of novel gases in the future should cost reductions be realised or if deployment of other decarbonisation vectors prove more challenging.	• The scaling up of biomethane unlocks co-location benefits of novel gases. Given novel gases are interchangeable with the natural gas used today, creating the conditions for cost reduction of lower carbon gases is a logical first step.
Integrate E-Methane into Gas Quality Standards and Infrastructure	• Revise gas grid specifications to permit injection of e-methane with biomethane and natural gas without imposing unnecessary enrichment requirements, while ensuring compatibility with hydrogen blending strategies.	• Removing unnecessary enrichment requirements reduces costs and accelerates deployment, making the transition more economically viable.
Incentivise Carbon Recycling and CO_2 Utilisation	• Classify e-methane as a low-carbon fuel under the UK Emissions Trading Scheme (ETS) and other compliance markets and recognise biomethane as zero-carbon within the UK ETS to enhance its competitiveness.	• By recognising e-methane as a low-carbon fuel, the UK ETS can stimulate investment in innovative solutions that reduce fossil carbon extraction and support decarbonization goals.

Appendix

Abbreviations

Abbreviation	Full Term	Meaning / Context
AD	Anaerobic Digestion	Biological process for producing biogas
BEIS	Department for Business, Energy & Industrial Strategy	UK government department referenced
Bio-SNG	Biological Synthetic Natural Gas	Green gas produced from biomass via gasification
CAPEX	Capital Expenditure	Cost of building infrastructure for green gas
CCS	Carbon Capture and Storage	Technology for capturing and storing CO_2
CCU	Carbon Capture and Utilisation	Technology for capturing and reusing CO_2
CH_4	Methane	Primary component of natural and synthetic gas
CO_2	Carbon Dioxide	Key input for methanation processes
E-methane	Electro-methane	Methane synthesised using renewable electricity and CO_2
FES	Future Energy Scenarios	UK energy system projections referenced in analysis
GB	Great Britain	Geographic scope of production potential
GHG	Greenhouse Gas	Emissions contributing to climate change
GHG Protocol	Greenhouse Gas Protocol	Standard for emissions accounting
GGT	Green Gas Taskforce	Stakeholder group commissioning the study
H_2	Hydrogen	Used in chemical and biological methanation
HHV / LHV	Higher Heating Value / Lower Heating Value	Energy content metrics for gas
LCOE	Levelized Cost of Energy	Metric for comparing energy costs
LCOH	Levelized Cost of Hydrogen	Metric for comparing hydrogen costs
Net Zero	Net Zero 2050	UK's climate commitment to zero emissions by 2050
NG	Natural Gas	Conventional fossil-based gas
NGG	Novel Green Gases	Emerging gas technologies beyond biomethane
OPEX	Operational Expenditure	Ongoing costs for operating facilities
PEM Electrolyser	Proton Exchange Membrane electrolyser	Electrolysis with the use of a proton exchange membrane (PEM) made from a special polymer
PPA	Power Purchase Agreement	A contract that allows businesses to either purchase or sell electricity generated from renewable sources
RES	Renewable Energy Sources	Wind, solar, etc., used for e-methane
TRL	Technology Readiness Level	Scale for assessing maturity of technologies based on EU Horizon (2022)

Units

Unit	Full Term	Meaning/Context
°C	Degrees Celsius	Temperature for process conditions
%	Percent	Efficiency, share of energy mix
€/kg H_2	Euro per kilogram of Hydrogen	Hydrogen production cost
€/MWh	Euro per Megawatt hour	Cost metric for energy
£/MWh	Pound per Megawatt hour	UK-specific cost metric
bar	Bar	Pressure for gas storage and methanation
gCO_2/kWh	Grams of CO_2 per kilowatt hour	Emission intensity metric
GW	Gigawatt	National-scale renewable capacity
GWh	Gigawatt hour	Annual production potential
kt	Kiloton	Large-scale CO_2 or gas quantities
kWh	Kilowatt hour	Energy content for gas and electricity
MW	Megawatt	Capacity of electrolysis and plants
MWh	Megawatt hour	Larger-scale energy calculations
Mt	Megaton	National-scale CO_2 or gas quantities
Nm^3	Normal cubic meter	Volume of gas at standard conditions
tCO_2	Metric ton of Carbon Dioxide	Emissions or capture quantities