Outlook for Biogas and Biomethane

A global geospatial assessment

International Energy Agency

World Energy Outlook Special Report

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 31 member countries, 13 association countries and beyond.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Lithuania
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Republic of Türkiye
United Kingdom
United States

The European Commission also participates in the work of the IEA

IEA association countries:

Argentina
Brazil
China
Egypt
India
Indonesia
Kenya
Morocco
Senegal
Singapore
South Africa
Thailand
Ukraine

Revised version, May 2025
Information notice found at: www.iea.org/corrections

Source: IEA.
International Energy Agency
Website: www.iea.org

This study was prepared by the Office of the Chief Energy Economist in the Directorate of Sustainability, Technology and Outlooks, in co-operation with other directorates and offices of the International Energy Agency (IEA).

Peter Zeniewski, Senior Energy Analyst, co-ordinated the work and was the lead author; he designed and directed the report together with **Tim Gould**, Chief Energy Economist, and **Christophe McGlade**, Head of the Energy Supply Unit.

Jeanne-Marie Hays and **Gyubin Hwang** led the biogas and biomethane supply modelling. The other main authors were **Ana Alcalde Báscones**, **Quentin Minier**, **Natalie StClair** and **Jun Takashiro**.

Other valuable contributions from the IEA came from **Ethan Burkley, Darlain Edeme, Chiara Hampton, Luke Hatton** and **Ryszard Pospiech**.

The report benefited from the advice and guidance of visiting professor **Jerry Murphy**, Director of the SFI MaREI Centre for Energy, Climate and Marine, and Chair of Civil Engineering at University College Cork.

Eleni Tsoukala and **Davina Till** provided essential support.

Caren Brown carried editorial responsibility.

Several colleagues within the IEA provided valuable comments, data and feedback, in particular Yasmine Arsalane, Tomás De Oliveira Bredariol, Carole Etienne, Ilkka Hannula, Dennis Hesseling, Akos Losz, Jeremy Moorhouse, Arthur Roge, Courtney Turich, Ivo Walinga, Qi Wang and Daniel Wetzel.

Thanks go to the IEA Communications and Digital Office for help in producing the report and website materials, particularly Jethro Mullen, Poeli Bojorquez, Curtis Brainard, Astrid Dumond, Liv Gaunt, Grace Gordon, Julia Horowitz and Wonjik Yang. The IEA Office of the Legal Counsel, Office of Management and Administration and Energy Data Centre provided assistance throughout the preparation of the report.

This analysis has been supported by the Clean Energy Transitions Programme, the IEA's flagship initiative to transform the world's energy system to achieve a secure and sustainable future for all.

Peer reviewers

The comments and suggestions of the following experts who provided input and reviewed preliminary drafts of the report were of great value:

Anastasiya Agapova	European Biogas Association
Sacha Alberici	Guidehouse
Marco Buffi	European Commission Joint Research Centre
Sophie Casenave	STX Group

Giulia Ceccarelli	World Biogas Association
Suani Coelho	University of São Paulo, Brazil
Christian Cuenot	Independent consultant
Harmen Dekker	European Biogas Association
Bernhard Drosg	IEA Bioenergy Task 37
Matthias Edel	Erneuergas
Delphine Eyraud	Ministry for Europe and Foreign Affairs, France
Nina Fahy	Rabobank
David Gallardo	Naturgy
Julio Gutiérrez	Sedigas
Tim Hamers	The European Renewable Gas Registry
Mette Smedegaard Hansen	Nature Energy
Beau Hoffman	United States Department of Energy
Natalie Lefton	United States Department of Energy
Sam Lehr	Molecule Group
Pradeep Monga	World Biogas Association
Charlotte Morton	World Biogas Association
Callipe Panoutsou	BP
Daan Peters	Common Futures
Maria Sicilia	Enagas
Anna Venturini	European Biogas Association
Phil Vos	Coalition For Renewable Natural Gas
Maria Wellisch	MWA Consultants

Comments and questions are welcome and should be addressed to:

Tim Gould

Chief Energy Economist
International Energy Agency
9, rue de la Fédération
75739 Paris Cedex 15
France

E-mail: WEO@iea.org

Biogas and biomethane are seeing new momentum

For many energy policymakers today, there is a premium attached to projects that deliver on energy security objectives while reducing emissions and creating local value; this is a world of opportunity for biogases. Producers of biogases turn organic waste into sustainable, locally produced, low-emissions fuels. Biogas can be used directly in the form of heat by households and industry, and to produce electricity. Biomethane, which is an upgraded form of biogas, is a locally sourced, drop-in substitute for natural gas.

Over 50 new policies have been introduced to support biogases since the IEA's first special report on biogases, released in 2020. Strong biomethane targets form a core part of the European Union's efforts to eliminate dependence on Russian energy and develop energy sources that can be produced domestically. Some countries in the bloc are making significant strides. In Denmark, for example, biogases already represent 40% of overall gas demand, and production in France is growing rapidly. Meanwhile, India has introduced a 5% biomethane blending target for compressed natural gas to reduce dependence on imported fuels and improve air quality and waste management. Biomethane features prominently in Brazil's new Fuels of the Future law. Oil and gas companies have also made large bets on biomethane in recent years, injecting capital and technical expertise into the sector.

The potential benefits of biogases are broad – but still under-utilised

The technologies and supply chains required to produce biogases are mature and well known, and they score highly on energy security metrics. Biogas and biomethane are homegrown resources, produced close to where they are consumed. An anaerobic digester, which produces biogas by breaking down organic matter in an oxygen-free environment, requires no inputs of critical minerals and most of the materials needed are sourced domestically. Biomethane, as an upgraded form, requires no substantial modifications to existing gas infrastructure such as pipelines, turbines or boilers. Both biogas and biomethane are dispatchable sources of clean power: biomethane can be stored and used to generate power when it is needed, bridging gaps in generation from variable renewables across days, months and seasons. Biogases can also be part of a broader energy value chain: potential linkages with hydrogen opens up new avenues for producing a range of synthetic fuels.

The co-products that come with biogases production can also be valuable. The production of biogases yields a nutrient-rich by-product known as digestate. In certain circumstances this can be used as a biofertiliser and applied back to the land where crops were grown, thereby lowering the need for chemical fertilisers. Upgrading biogas to biomethane produces a pure stream of biogenic carbon dioxide (CO_2) which can be captured and stored, or utilised in industries such as food and beverage production.

Currently, biogas and biomethane play a relatively small role in the global energy system. Around 40 billion cubic metres of natural gas equivalent (bcme) of biogas is produced each year, mostly in Europe, the United States and China. Most of this is utilised to generate local heat and electricity, and in some cases for clean cooking. Biomethane is growing rapidly, at around 20% per year, but only around 10 bcme is produced globally, equivalent to just 0.2% of natural gas demand.

Our new, detailed geospatial assessment brings new insights on the potential for biogases

This report presents a first-of-a-kind global spatial analysis of the potential for biogases. We assess the potential and costs of developing biogas or biomethane in over 5 million locations worldwide, using data sets covering agricultural output, biowaste generation and forestry residues. We have produced detailed country- and location-specific supply cost curves for over 30 types of feedstocks, considering proximity to infrastructure such as roads, electricity grids and gas pipelines. We include only feedstocks that can be considered sustainable, i.e., wastes and residues that can be processed with existing technologies, which do not compete with food for agricultural land and that do not have other adverse sustainability impacts, such as reducing biodiversity.

Globally, we estimate that nearly 1 trillion cubic metres of natural gas equivalent of biogases could be produced sustainably each year, using today's organic waste streams. This is equivalent to one-quarter of global natural gas demand today. Almost 80% of the sustainable potential for producing biogases is in emerging and developing economies, led by Brazil, China and India. The potential in India is almost twice as large as its current natural gas consumption. Most of the biogases potential remains untapped today: around 5% of the total potential for sustainable production of biogas and biomethane is currently being used. The European Union uses the largest share of its potential at around 40%.

A relatively small share of the untapped potential for biogases is cost-competitive, but more can be unlocked if co-benefits are valued

The total costs of producing biogas and upgrading it to biomethane exhibit a wide range. On average, biomethane can be produced for USD 18 per gigajoule (GJ). This is lower than end-user gas prices in many markets, but is around five times higher than the average cost of producing natural gas, and equivalent to around USD 100 per barrel of oil. The majority of our assessed potential is, therefore, not currently cost-competitive under existing policy conditions. There are, however, some untapped resources that are commercially attractive today, in areas with dense, high-yielding feedstocks. For example, we find that nearly 40 bcme of biomethane potential could be exploited in emerging and developing economies in Asia at a cost equal to or lower than prevailing wholesale natural gas prices. This is already four times the current biomethane production globally. There is also some scope for cost reductions; for example, the cost of building large-scale biodigesters can be up to 40% cheaper than small-scale plants, and developing clusters with shared infrastructure can reduce operating expenses.

The competitiveness of biogases can be improved if a value is attached to the positive externalities arising from their use. This applies to emissions reductions as well as the potential value of co-products such as biogenic CO_2 or nutrient-rich digestate. For example, with a CO_2 price of USD 70 per tonne, up to 400 bcme of biomethane can be a competitive alternative to natural gas, globally. Under the right conditions, selling processed digestate can yield additional revenue for biomethane producers.

The investment case for biogases is strongest when local economic development is a priority. Like other sources of bioenergy, biogas and biomethane have relatively high operating and feedstock costs, representing around two-thirds of the total levelised cost of production. In other words, a large share of the money spent to produce a unit of biogas is spent on labour, services and feedstock supply chains, meaning more of the commodity's value is generated locally, over a long period of time.

The barriers facing biogases are significant, but not insurmountable

Logistical hurdles and complex permitting procedures have held back increases in biogases production in many countries. Biogases are decentralised resources: transporting bulky and low-energy density feedstock is costly over long distances, meaning a large number of individual plants are required to reach meaningful production levels at a national scale. Securing a permit to produce biogases can in some cases take up to 7 years, requiring compliance with a range of local and national regulations, including environmental review processes that vary by location. The factors that make biogases attractive – integration of energy, agricultural and waste management goals – also create significant co-ordination challenges across a fragmented value chain and policy landscape. There is no one-size-fits-all approach to biogases, as each project faces different local circumstances.

Several countries are developing a more supportive policy architecture for low-emissions fuels such as biomethane, but hurdles remain. In Europe, efforts are underway to streamline permitting processes, clarify incentives and rules governing organic waste, and widen the market for biogases through certification and cross-border traceability. In some emerging and developing economies, however, initial ambitions to scale up biogases production have fallen short. Producers have encountered several challenges that have prevented the envisioned scale-up, including difficulties accessing finance, negotiating offtake agreements, accessing or building infrastructure, or securing a reliable stream of feedstock supplies.

The environmental upside for biogases depends on how they are produced

Biogas and biomethane production from some feedstocks can avoid methane emissions that would have otherwise occurred and they can therefore provide negative lifecycle GHG emissions. Manure from livestock, biowaste sent to landfills and wastewater sludge are responsible for close to half of total anthropogenic methane emissions each year. Capturing some of this methane and using it as a biogas would avoid methane emissions from agriculture and waste management and emissions from fossil fuel use. For example, if the global potential of manure were utilised, amounting to some 280 bcme, this would avoid 1 000 Mt CO_2-eq in GHG emissions in the agricultural sector, and a further 400 Mt CO_2-eq from displacing fossil fuel use in the energy sector.

Nonetheless, the full emissions reduction potential of biogases depends crucially on how the biogas and biomethane is produced. Methane leaks along the value chain can undercut or eliminate entirely the GHG emissions benefits of biogases. In many cases there is insufficient measurement and reporting on emissions from existing plants to fully confirm their environmental benefits. The evidence that exists suggests that, on average, biogas plants emit methane emissions equivalent to 6% of their output. There are many ways to reduce these methane leaks, and the concerted application of best practices – notably through closed digestate storage and the combustion of off-gases during upgrading processes – is essential to make the environmental case for biogases.

Emerging market and developing economies lead growth in WEO scenarios

Biomethane is set to be the fastest growing form of bioenergy to 2035. In the Stated Policies Scenario (STEPS), which is based on today's policy settings, biomethane grows by 15% per year over the next decade. Europe and North America together make up just above 60% of today's global demand for biogases, and Europe in particular is projected to see strong growth. But most of the growth happens in emerging and developing economies: China sees the largest increase in absolute terms, reaching 15 bcme by 2035 up from 1 bcme today. India and Brazil also see rapid growth, with demand increasing sevenfold by 2035. Globally, the share of biogases potential that is exploited reaches 18% by 2050 in the STEPS. In some regions, such as China and Europe, some individual feedstocks are fully exploited.

The energy security benefits of developing biogases are particularly visible in a scenario in which energy transitions advance rapidly. In the European Union, for example, biomethane development avoids around USD 30 billion in imported natural gas costs between 2024 and 2035, in a scenario where its climate targets are fully met. The majority of the USD 100 billion capital investment and operating expenditure required over this period is spent domestically, creating around 200 000 jobs, many in rural areas. Globally, the full utilisation of today's biogases potential could support up to 10 million jobs by 2035, giving rural communities a strong stake in energy transitions.

Consistent and robust policy support is essential

Currently, the vast majority of production of biogases is supported through policies and incentives, and this is likely to continue. Complex feedstock supply chains and the need for bespoke projects make it difficult to standardise or modularise the biogases value chain. This limits the scope for large cost decreases. Moreover, the finite amount of organic waste generated each year puts a natural limit on the quantities of biogases that can be produced sustainably. Policies should therefore be targeted at the most promising feedstocks and use cases. This invariably requires coordination amongst different competent authorities, alongside a thorough assessment of local conditions and the role biogases can play in meeting national energy policy goals.

It is important for policy-makers to carefully monitor the impacts of scaling up biogas and biomethane production, including on food systems, biodiversity, and farming practices. Biogas connects a complex eco-system of agricultural land and waste management facilities, energy production and transport infrastructure. Avoiding perverse incentives is essential – waste is best minimised in the first place, and there are several other possible uses for crop residues and municipal waste streams. The promise of biogases is substantial, but realising it at scale will require careful policy design, investment in best practices, and a clear-eyed understanding of trade-offs. With consistent, well-targeted support, biogases can become a valuable part of a secure and sustainable energy system.

Biogases today

Surveying the field

SUMMARY

- Biogases are an underutilised resource. They can bring multiple benefits if managed responsibly, including gains for energy security, energy access, rural and agricultural development, waste management and emissions reductions. As an upgraded form of biogas, biomethane is a direct substitute for natural gas.
- Policy momentum has grown since the first landmark International Energy Agency (IEA) report on the outlook for biogases in 2020. Since then, more than 50 new policies have been introduced around the world. High natural gas prices during the height of the global energy crisis in 2022 reinforced or strengthened interest in the potential for biogases. However, high costs relative to incumbent fuels and complex permitting procedures remain significant barriers.
- Combined global biogas and biomethane production in 2023 was nearly 50 billion cubic metres of natural gas equivalent (bcme). Europe, led by Germany, is the largest producer of biogases, followed by the People's Republic of China (hereafter, "China"), the United States and India. Denmark has the highest share of biogases in overall gas demand, with a 40% share in 2024.
- Consumption of biogases is increasing. However, biogases are still a relatively small part of the global energy mix – representing around 3% of total modern bioenergy production. Biomethane use has increased at a rate of 20% annually over the past 5 years, although from a low base (it is currently around 0.2% of natural gas demand).
- Most markets rely on a combination of pricing externalities from the use of fossil fuels and providing different incentives to biogas and biomethane producers to close the cost gap that typically exists between biogases and fuels such as oil and natural gas. Mandates that oblige market actors to achieve certain consumption or blending targets for supply of biogases, alongside robust emissions accounting frameworks and growing markets for certificates, have provided demand certainty to investors.
- Biodigesters provide a viable option to increase access to clean cooking fuels in emerging market and developing economies, especially for rural households. However, maintaining their use has proved challenging in many countries, as they are supplanted or abandoned because of technical issues or due to expansion of the natural gas or liquefied petroleum gas supply chains.
- As a homegrown resource, biogases can enhance energy security and contribute to power system flexibility. The benefits also go well beyond energy, contributing to improved waste management, reduced synthetic fertiliser use, rural job creation and agricultural development. Realising and remunerating the co-benefits associated with producing biogases improves the underlying economics.

1.1 Introduction

Biogases hold great promise. They can help provide solutions to a wide range of challenges if managed responsibly. These include improving energy security, energy access, rural and agricultural development, waste management and emissions reductions. Biogas can be used directly as heat by households and industry, and to produce electricity. Biomethane, which is an upgraded form of biogas, is capturing attention for its multiple advantages as a locally sourced, drop-in substitute for natural gas.

The IEA's landmark 2020 report provided a global perspective on the prospects for biogases, highlighting the huge untapped potential and scope for growth across advanced and emerging market and developing economies (IEA, 2020). At least 50 new policies have been introduced since then, making now an opportune moment to take stock of the sector's progress. There is a growing recognition that biogases can provide broad, system-wide benefits when effectively integrated into the energy system. These include helping to sustain a circular economy while supporting energy security, economic and environmental goals.

However, high costs relative to natural gas, and complex permitting procedures remain significant barriers. The factors that make biogases attractive – integration of energy, environmental, agricultural and waste management goals – also create co-ordination challenges among multiple stakeholders across a fragmented policy landscape. There is no one-size-fits-all approach to biogases, as each project faces different local circumstances. Moreover, the environmental benefits of biogases can vary widely, depending on how projects are executed; they can be undercut entirely if methane leakages are not properly minimised across the supply chain.

This report provides an in-depth analysis of how much biogas and biomethane can be produced sustainably using existing wastes and residues. It presents a novel global spatial analysis of the potential for biogases. This builds on the 2020 assessment, adding new depth by mapping feedstock density and proximity to infrastructure such as roads, electricity grids and gas pipelines. It also provides an updated estimate of costs and production technologies, considering the potential to unlock lower costs, higher yields or economies of scale.

This first chapter defines biogas and biomethane, their main production pathways and use cases, and key feedstock considerations. It then discusses the policy and regulatory frameworks that have supported the sector in different countries and regions. It also considers how biogases projects have responded to incentives and how business models have been developed, particularly in emerging market and developing economies. Chapter 2 maps the sustainable potential and cost of feedstocks for biogases in selected regions, and assesses the cost-competitiveness of biogases relative to other fuels. Chapter 3 considers the key issues affecting projects on biogases such as feedstock policies, infrastructure access, permitting challenges and environmental considerations. Chapter 4 provides a perspective on future growth to 2050 through the lens of the IEA World Energy Outlook scenarios.

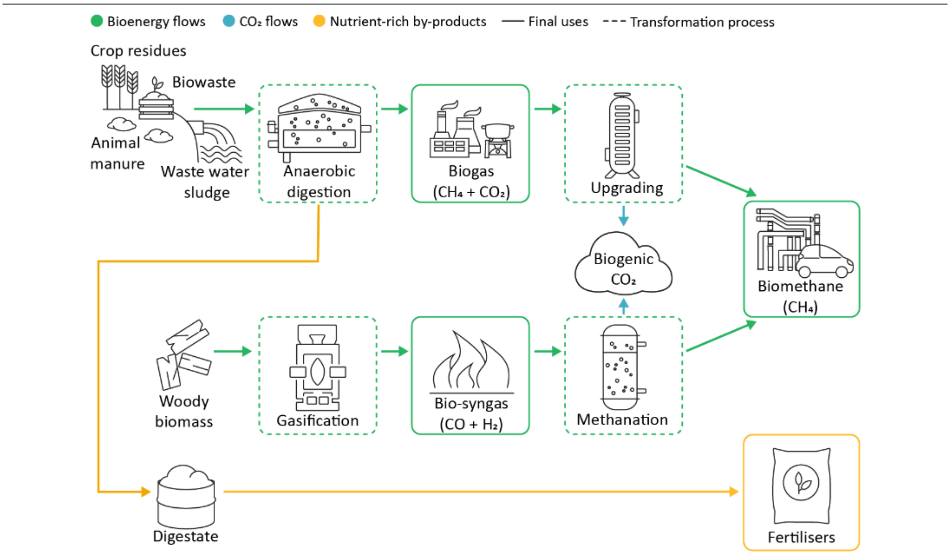
1.2 Biogas and biomethane

This report uses "biogases" as an umbrella term that refers to biogas and biomethane. These are two closely related but distinct sources of energy (Figure 1.1).

Biogas is a mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment. Its precise composition depends on the type of feedstock and the production pathway. The methane content of biogas typically ranges from 45% to 75% by volume. Biogas is usually produced using the following technologies:

- Biodigesters: These are airtight systems (e.g. containers or tanks) in which organic material is broken down by naturally occurring micro-organisms. Contaminants and moisture are usually removed before use of the biogas.
- Landfill gas recovery systems: The decomposition of municipal solid waste (MSW) under anaerobic conditions at landfill sites produces biogas (also known as "landfill gas"). This can be captured using pipes and extraction wells along with compressors to induce flow to a central collection point.
- Wastewater treatment plants: These can be equipped with anaerobic digesters to stabilise and reduce the volume of sewage sludge. Wastewater facilities can also treat wastes from bio-based industries such as pulp and paper.

Figure 1.1 ▷ Production pathways for biogases



Most biogases are now produced through anaerobic digestion. About 20% of biogas is upgraded to biomethane – a share that is growing each year.

Note: CH_4 = methane; CO = carbon monoxide; H_2 = hydrogen.

Biomethane (sometimes also referred to as a "renewable natural gas") is a near-pure source of methane, and so is extremely similar to natural gas. It is produced mainly through biogas upgrading by removing CO_2, water and other contaminants, using methods such as water scrubbing, membrane separation or pressure swing adsorption. Biomethane can also be produced through gasification of solid biomass followed by methanation, although this is far less common. This process involves breaking down woody biomass at high temperature (700-800 °C) and high pressure in a low-oxygen environment. Under these conditions, the biomass is converted into a mixture of gases, mainly carbon monoxide and hydrogen (syngas), which is commonly used for producing chemicals such as methanol or ammonia. To produce a pure stream of biomethane, the syngas is cleaned to remove any acidic and corrosive components, and then undergoes a methanation process to produce pure methane.

Feedstocks

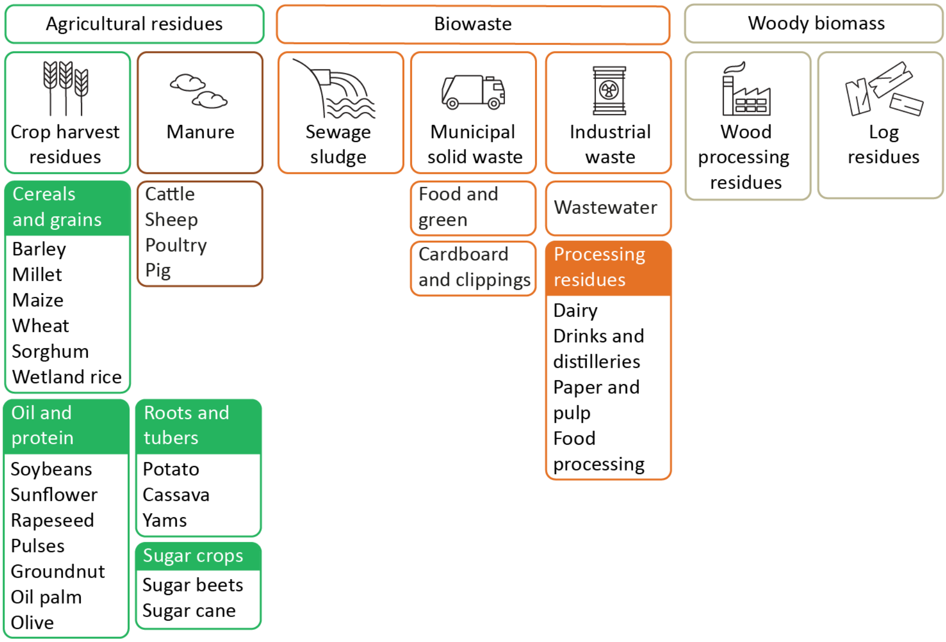
A wide variety of feedstocks can be used to produce biogases, with varying levels of suitability for collection and processing. For this report, we considered three broad categories (Figure 1.2):

- **Agricultural residues and wastes** are grouped into crop residues (e.g., straw, husks or other organic material left over from harvesting) and animal manure (from cattle, pigs, poultry and sheep). Residues are categorised by type of crops harvested, namely, cereals and grain, oil and protein, sugar-based crops, and roots and tubers.
- **Biowaste** includes the organic fraction of MSW (e.g., food and green waste or cardboard and paper waste). For this study, we also included in this category industrial wastes (e.g., organic by-products from food and drink processing) and wastewater sludge (semi-solid organic matter recovered from municipal wastewater treatment plants).
- **Woody biomass** sources such as log residues or wood processing waste are generally suitable for biomethane through the thermal gasification production route.

Other feedstock sources can be used to produce biogases, such as sequential crops – which are grown between two harvested crops – or marginal lands. Sequential cropping can be done to preserve the fertility of soil, retain soil carbon and avoid erosion, to maximise agricultural output or to produce biogases. Italy is noteworthy for employing sequential cropping as part of its Biogas Done Right concept developed by the Italian Biogas Association, which involves producing biogases in a way that complements, rather than competes with, food production, while improving sustainability and soil fertility. Sequential cropping may enlarge considerably the estimated potential for production of biogases in other countries or regions where it is practised, such as France, Germany, India and the United States. However, it is difficult to quantify on a global scale.

Therefore, along with marginal lands, sequential crops are excluded from our estimates, as they require detailed local viability assessments to accurately estimate their potential. Dedicated energy crops (low-cost and low-maintenance crops grown solely for energy production) and aquatic biomass sources such as algae are also excluded.

Figure 1.2 ▹ Feedstocks assessed in this report



This report assesses over 30 feedstock types

Note: Analysis excludes potential from sequential cropping, marginal lands and aquatic biomass sources.

Producing biogas or biomethane through anaerobic digestion can be viewed as a waste management solution for a range of feedstocks that need to undergo treatment. Methane yield is an important characteristic, which is usually expressed either as a share of fresh or dry matter weight, or as a share of volatile solids. There are also other important considerations for the choice of feedstock. These include the nutrient balance (e.g., the ratio of carbon to nitrogen), moisture content, temperature, and presence of inhibitory substances (e.g., heavy metals or toxic chemicals) and the overall ease with which feedstocks can be collected, processed and stored.

Some feedstocks lend themselves to co-digestion to achieve an optimal methane yield (e.g., pairing nitrogen-rich manure with carbon-rich crop residues). Biogases producers target different combinations of feedstock that yield the highest possible outputs. Using animal manure can reduce GHG emissions to a greater extent than other feedstocks, but manure produces lower yields of biogases. It therefore lends itself to co-processing with other richer substrates such as food waste. Crop residues such as straw waste from grain crops have untapped potential, but are more difficult to digest. Producers are developing pre-treatment strategies to make them more digestible for micro-organisms used in digesters.

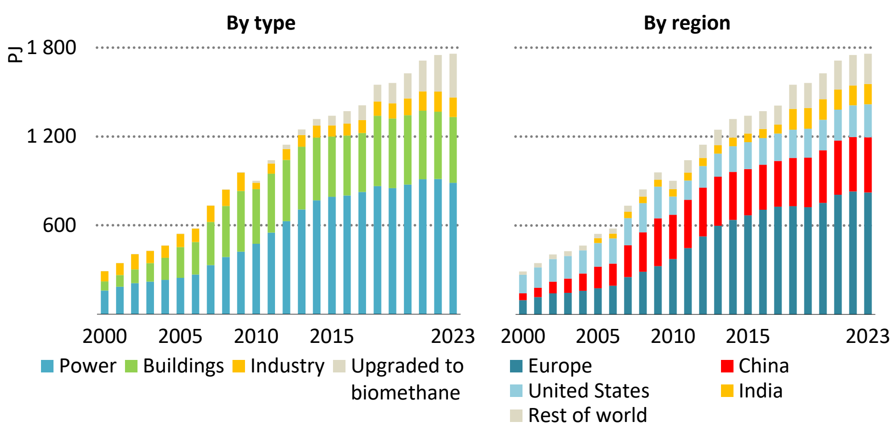
The anaerobic digestion of organic matter generates a residue of liquid and solid materials known as digestate. As biogas primarily consists of methane and CO_2, the nutrient content – nitrogen, phosphorus, potassium and trace elements – present in the original substrate is retained along with the undigested, stable carbon in the digestate. Therefore, digestate can be a substitute for synthetic fertilisers, helping to improve soil structure and water retention.

The use of digestate can contribute to a circular economy, allowing for the reuse of waste. However, the volumes of digestate associated with biogas and biomethane output are significant. Digestate can also contain chemical contaminants, particularly in wastewater streams. Whether it is a valuable co-product of biogas and biomethane production or a costly waste product to be disposed of depends on local conditions.

1.3 Production and consumption trends

Biogases are a relatively small part of the global energy mix – making up around 3% of total modern bioenergy production and equivalent to 1% of natural gas demand. Nevertheless, prospects have improved with the growing interest in the potential for biogases to generate negative emissions (for example, when carbon capture, utilisation and storage technologies are applied to their use), and the attraction of biomethane as a drop-in substitute for natural gas. In 2023, combined biogas and biomethane production globally was just under 50 bcme (1 800 petajoules (PJ)) (Figure 1.3).[1]

Figure 1.3 ▷ Production of biogases by use type and by region, 2000-2023



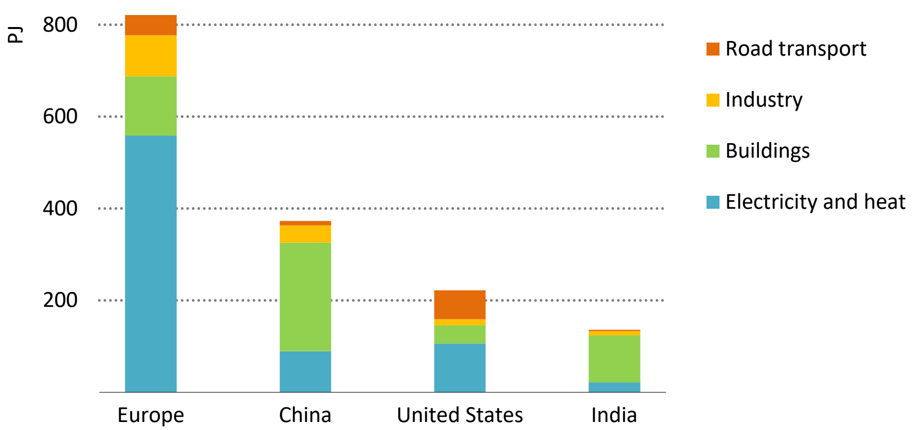
Europe produces nearly 50% of the global total biogases. While historically used for electricity generation, a rising share of biogas is upgraded to biomethane.

[1] One bcme is a measure of energy (rather than volume) and equals 36 PJ based on the lower heating value. Raw biogas has a lower heating value of around 21 megajoules per cubic metre (MJ/m^3) and biomethane has a lower heating value of 36 MJ/m^3. 1 bcme of biogas occupies a larger volume than 1 bcme of biomethane.

Around 80% of the production of biogases is used directly as biogas, primarily to generate electricity and heat (with an about equal split between electricity-only facilities and co-generation facilities). Biogas is also used in buildings, mainly for cooking. There are more than 40 million household-scale biodigesters in the world, primarily in China, but also in Brazil, India, Southeast Asia and parts of Africa. The remaining 20% of biogas produced is upgraded to biomethane.

Biomethane production in 2023 was around 8 bcme, with the majority injected into natural gas grids for use in industry, transport and buildings and the remainder bottled as compressed natural gas (CNG) for use as a transport fuel. While biogas demand for direct use has remained flat in recent years, biomethane demand has grown at an average rate of around 15% annually since 2020.

Figure 1.4 ▷ Main uses of biogases in selected regions, 2023



Europe accounts for nearly half of the global demand for biogases, most of which is for co-generation. China, the United States and India make up 80% of the remaining demand.

Europe is the largest producer of biogases, accounting for nearly 50% of global production in 2023 (Figure 1.4). The primary use case for early adoption in Europe was biogas as a low-emissions source of local electricity and heat supply, thanks to generous feed-in tariffs (FiTs). Germany is Europe's largest producer, contributing close to 40% of the region's biogases production in 2023. In recent years, the focus has turned to biomethane as a target for policy support and investment. Denmark leads in the integration of biomethane into its gas supply, with 0.7 bcme accounting for more than 35% of total gas demand in 2023 (Energinet, 2025). Biomethane production has grown rapidly in France, from 0.05 bcme in 2017 to 0.8 bcme in 2023. Most other European countries are also actively promoting biomethane production. These developments brought annual biomethane production in Europe to over 4.5 bcme in 2023. However, this represents less than 2% of total natural gas demand in the region.

China produces around 10 bcme of biogases. Biogas was promoted at the household level in the 2000s and early 2010s, with widespread adoption of small-scale biogas digesters in rural areas to provide cooking fuel and improve waste management practices. However, since the mid-2010s, public funding strategies have shifted to mid- and large-scale industrial projects.

The **United States** produced around 6 bcme of biogases in 2023, including 3 bcme of biomethane, a tripling from 2017 levels. The primary pathway for biogas and biomethane production has been through landfill gas collection, which accounts for nearly 50% of the total. However, most new projects are targeting agricultural waste, as the sector is responsible for more than one-quarter of methane emissions in the country. Incentives in the Inflation Reduction Act, the federal-level Renewable Fuel Standard and state-level initiatives such as California's Low Carbon Fuel Standard have boosted the prospects of biomethane use in transport, with the number of plants growing fourfold between 2018 and 2023 (Argonne, 2024).

Around 13% of the global production of biogases in 2023 was in **emerging market and developing economies in Asia (outside China)**, notably India and Thailand. These markets have embraced biogases primarily as a waste management solution. Thailand produces biogas from the waste streams of its cassava starch sector, biofuel industry and pig farms. India is targeting biogas as a way to manage waste whilst increasing energy security, and is looking to expand into the transport sector through bio-compressed natural gas (bio-CNG).

Brazil is a major bioenergy producer, although its annual biogas production – around 0.7 bcme – remains relatively small. Most of its production of biogases comes from landfill sites, but there is also potential from vinasse, which is a by-product from the ethanol industry. Growth is anticipated from the quota obligations within the country's new Fuel of the Future law.

Several countries in **Africa** use biogas as a renewable energy source to address energy shortages, reduce deforestation and improve waste management. In some cases, development finance has supported its use, and it is primarily produced from agricultural waste and animal manure. Countries like Ethiopia, Kenya, Rwanda and South Africa have promoted biogas adoption, particularly in rural areas, for cooking and local electricity generation. However, challenges such as high initial costs, limited technical expertise and inadequate infrastructure hinder large-scale implementation.

1.4 Policies and regulatory frameworks

Most markets rely on public incentives to provide support and certainty to biogas and biomethane producers. Several different routes are available as follows:

- **Targets,** although not always mandatory, help bring visibility to a country's ambitions in scaling up biogases (Figure 1.5). They can underpin national roadmaps or strategies, alongside justifying the need for reform or new regulations to meet the targets, such as organic waste collection regulations, and infrastructure planning. For example, the European Union set a non-binding target of 35 bcme of biomethane by 2030 in its REPowerEU plan in 2022, as a route to reducing reliance on gas from the Russian Federation (hereafter "Russia") after Russia's full-scale invasion of Ukraine.

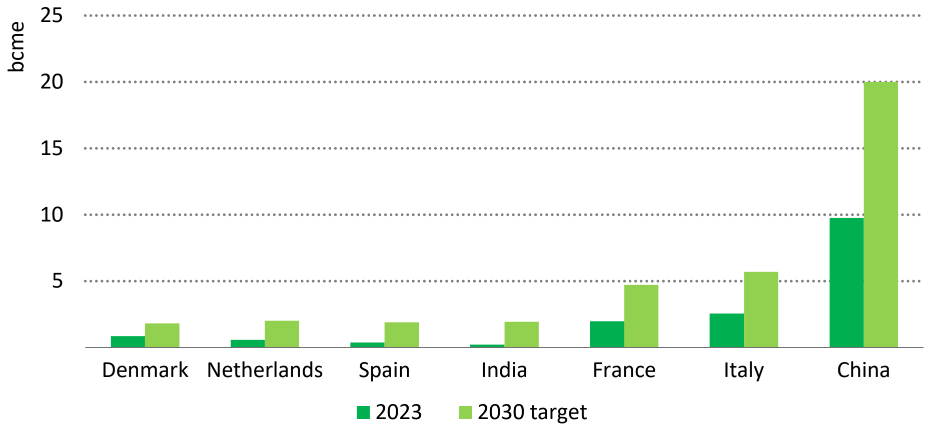
- **Supply-side incentives.** FiTs were the main policy support tool that drove the early phase of development of biogas plants in some European countries. These are a form of subsidy providing a government-guaranteed fixed price for a long-term period, usually 15-20 years. As markets have grown, some governments have recently sought to provide tools that are more market-oriented such as auctions or tenders. In general, price-based subsidies that support continuous production have been more successful in growing markets than investment support alone. This is because the production of biogases has relatively high operating costs.

- **Demand-side incentives** include tax incentives (e.g., reducing taxes for using sustainable fuels) or mandates that oblige actors in a certain sector (usually transport, but also buildings or heating) or more generally gas suppliers to comply with certain quotas or shares of biogases in the natural gas grid. Mandates provide demand certainty to investors to help deploy production. Such incentives exist in several countries in Europe (e.g., France is setting obligations for 4% blending by 2028), some states in the United States (e.g., 12% in California gas grids by 2030), India (up to 5% compressed or injected in city grids by 2028) and Brazil (10% in gas grids by 2034). In the European Union, biomethane in transport contributes to the 29% renewable energy binding target by 2030. In the United States, the Renewable Fuel Standard sets annual energy-based obligations for specific types of renewable fuels, including biomethane.

- **Indirect support** includes measures to enable easier connection to gas grids through planning or subsidising part of the cost, the development of national certificate registries to promote tracking and trading, or support to specific feedstocks that provide environmental benefits (e.g. animal manure) or that favour waste valorisation.

Countries have developed different tools to fulfil the mandates. These include fixed remuneration rates to producers (as in India) or the creation of markets where producers and obligated parties can exchange credits, normally based on energy content or emissions intensity (Table 1.1). Penalties can also be applied in the case of non-compliance. California's Low Carbon Fuel Standard and Germany's GHG quotas in transport are examples of these markets. They have been successful in driving growth and are based on emissions intensity.

Figure 1.5 ▷ Production of biogases in 2023 and targets for 2030 in selected countries



Achieving 2030 targets could more than double biomethane production. This could bring the share of biomethane in gas grids to around 15% in France or 100% in Denmark.

Notes: India's target is calculated assuming a 5% share of biomethane in total demand for compressed and pipeline natural gas in 2030. The target in Spain is non-binding.

If projects are managed well, biomethane can offer low life-cycle GHG emissions in sectors where emissions are hard to abate. The European Union and the United Kingdom have developed emissions trading systems for some industrial sectors. These are based on the cap-and-trade principle, in which total GHG emissions are limited, and allowances to emit are traded in a carbon market. This can encourage industry offtakers to support projects for biogases as a route to managing emission allowances.

Subsidies play a crucial role in supporting the development of biogas and biomethane markets. Investment subsidies lower market entry barriers, while FiTs or feed-in premiums in countries like France, Germany, India, Italy and the United Kingdom guarantee stable revenues for producers. In Europe, the market is fragmented among the European Union and national regulations. In some countries, subsidies apply specifically for grid injection (France), power generation (Germany) or transport (Italy). These may vary depending on the plant size and type of feedstock, as well as being restricted to domestic production.

In countries with mature markets, as the biogases sector grows, subsidies are often adjusted or set by competitive tenders, and governments seek to enable remuneration from green certificate markets that reduce reliance on public funding.

Table 1.1 ▹ Support for biogases in selected regions

Category	Measure	European Union	Denmark	France	Germany	Italy	California, USA	United Kingdom	Brazil	China	India
Targets	**Renewable energy share**	🟢	🟢	🟢	🟢	🟢					
	Biomethane targets										
	Production	🟠	🟠	🟠		🟠				🟠	
	Transport										🟢
	For natural gas suppliers			🟢					🟢		
	Share in gas grids		🟢	🟠				🟠			🟢
Supply-side incentives	**Investment subsidies**			🟢			🟢			🟢	🟢
	Production support										
	FiTs and FiPs										
	Power generation			🟠*	🟠**						🟢
	Grid injections							🟢			🟢
	Auctions										
	Power generation				🟢						
	Grid injections		🟢	🟢		🟢					
	Transport		🟢								
	Revenues from GOs/credits	🟢	🟢	🟢	🟢	🟢	🟢	🟢	⚪		
Integration and planning	**Right to connect**		🟢	🟢	🟢						
	Registry and trade	⚪	🟢	🟢	🟢						
	Feedstock limitations/incentives		🟢	🟢	🟢						
	National strategy for biogases		🟢	🟢		🟢			⚪		
Demand-side incentives	**Tax incentives**		🟢						🟢	🟢	
	Mandates/quotas										
	Transport	🟢	🟢	🟢	🟢	🟢	🟢	🟢			🟢
	Buildings and heating				🟠		🟢				🟢
	Industry (ETS)	🟢	🟢	🟢	🟢	🟢		🟢			

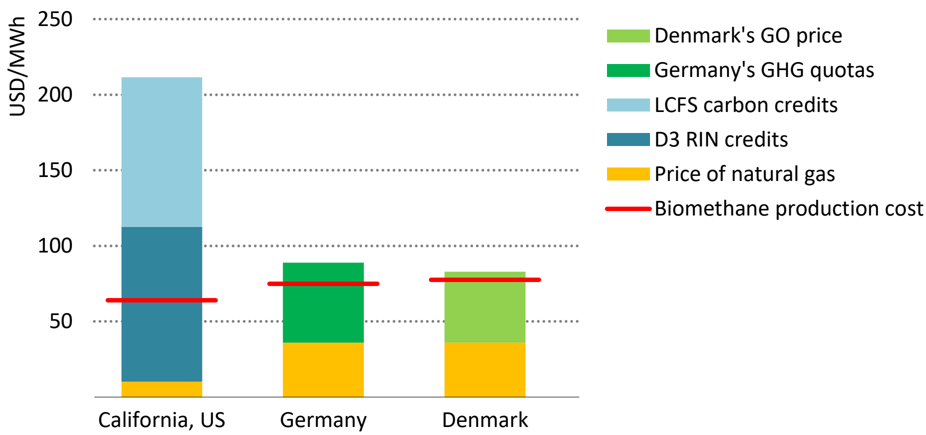
🟢 Obligations and mandates; 🟠 non-binding targets; ⚪ non-binding targets under development.

* Available only for plants under 25 gigawatt hours (GWh) per year; ** available only for plants under 150 kilowatts (kW).

Note: ETS= emissions trading system; FiP = feed-in premium; FiT = feed-in tariff; GO = guarantee of origin.

The sale of green certificates provides an additional source of revenue for subsidised biomethane in some jurisdictions. The United States has a generous revenues scheme. Federal subsidies in the form of investment tax credits under the Inflation Reduction Act and production renewable identification numbers under the Renewable Fuel Standard are stackable with state revenues, such as the carbon credits in California's Low Carbon Fuel Standard market or similar programmes in Oregon and Washington. Estimated total revenues in some countries range from USD 80 per megawatt hour (MWh) to USD 210/MWh (Figure 1.6).

Figure 1.6 ▹ Illustrative sources of revenues from biomethane certificates in selected markets compared with production costs, 2024



Emission credits can create significant value for biomethane producers in California, while they bridge the cost gap between biomethane and natural gas in Denmark and Germany

Notes: D3 RIN = renewable identification number; GO = guarantee of origin; LCFS = Low Carbon Fuel Standard; MWh = megawatt hour; US = United States. LCFS and D3 RIN credit values are the average of 2015-23 values. LCFS credits are for dairy manure. Germany's GHG quotas value is based on 2023 prices for biomethane from manure. Denmark's GO price is based on 2023 values.

Voluntary markets are gaining interest. Corporations, municipalities and other entities are looking for tools to help them comply with their voluntary emissions reduction targets. Robust methodologies and certification tools that allow transparent tracking and avoid double counting are needed. Compliance markets have developed their own frameworks, which also include GHG accounting methodologies.

Different types of certificates are used in national/regional compliance and voluntary markets (e.g., guarantees of origin (GOs), proofs of sustainability and certificates of origin). Efforts are underway to ensure compatibility between the different schemes and promote international trading. For example, in the European Union, the Union Database for Biofuels – a general registry that will include biomethane transactions with a proof of sustainability green certificate in the European Union – is expected to be fully operational in 2025. There is also work in progress to adapt the Greenhouse Gas Protocol used in voluntary corporate reporting to provide evidence for the use of biomethane blended in natural gas pipelines.

1.5 Biogases in emerging and developing economies

Business models for biogases vary according to the underlying drivers for development, the type of public support available, the profile of the project sponsors, the feedstock supply strategy and the targeted end-use (Table 1.2). Different types of business models are illustrated below through examples on how biogas and biomethane projects have been implemented, focusing on emerging market and developing economies. Some of the challenges and opportunities faced by developers are highlighted.

Table 1.2 ▹ Selected biogas and biomethane business models in emerging market and developing economies

Case study	Key actors	Key policy incentives	Co-benefits	Example
As a clean cooking fuel	Households, development agencies and NGOs	Grants and subsidies	Reduced fuel expenses Increased amount of free time	Africa Biogas Partnership Programme
Valorising digestate as a biofertiliser	Farmers and cooperatives	Certifications for biofertiliser	Increased soil fertility and plant resistance	Indonesia Domestic Biogas Program
Improving urban waste management	Municipalities	Carbon credits and ETS	Reduced air pollution Cheap and sustainable source of energy	City of Indore (India)
Boosting electricity system flexibility	Utilities	Net metering FiTs	Increased stability in electricity prices	Minigrid in the municipality of São Miguel do Iguaçu (Brazil)
As a transport fuel	Governments	Blending mandates	Reduced air pollution Increased stability in fuel prices	Indian bio-CNG market
Use in industry	SMEs, distilleries and food manufacturers	GOs	Lower energy costs Self-generation	Sugar cane industry (Brazil)

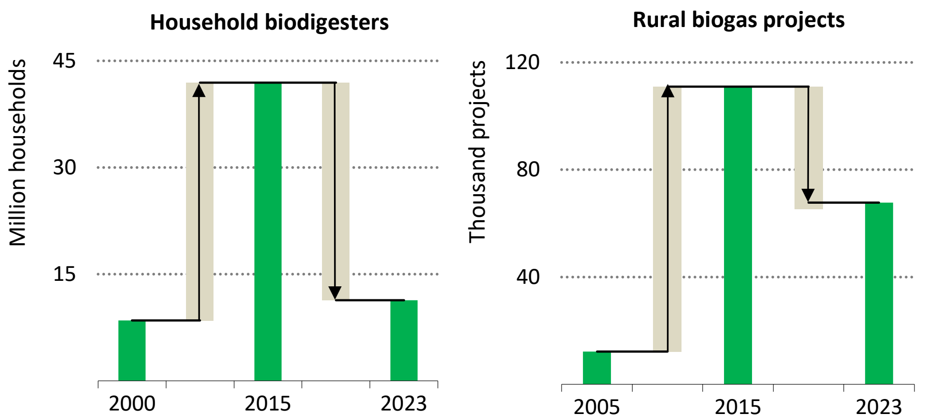
Note: CNG = compressed natural gas; ETS = emissions trading system; FiT = feed-in tariff; GO = guarantee of origin; NGO = non-governmental organisation; SME = small and medium-sized enterprise.

1.5.1 Biogas as a clean cooking fuel

Around 2 billion people lack access to clean cooking facilities, relying on the traditional use of solid biomass, kerosene or coal as their primary cooking fuel. Household air pollution, mostly from smoke due to cooking, is linked to around 2.7 million premature deaths a year. About 75% of people without access to clean cooking are located in rural areas, where it is more challenging to guarantee reliable access to more modern cooking fuels. Turning organic waste such as animal manure or crop residues into biogas via a simple household biodigester offers a way to support rural development and to alleviate these health impacts.

Some programmes have looked to increase clean cooking access by adopting the use of biodigesters. For example, in China, small-scale biogas systems have been promoted widely for over 20 years, with 42 million units installed by 2015 (Figure 1.7). India's National Biogas and Manure Management Programme supported the installation of over 4 million household-scale biodigesters in the country (Government of India, 2025). The Africa Biogas Partnership Programme (ABPP) promoted small-scale biogas units in Burkina Faso, Ethiopia, Kenya, Tanzania and Uganda, where over 65 000 units were constructed between 2009 and 2019 (Ton et al., 2019). In Indonesia, nearly 30 000 units were installed under the Indonesia Domestic Biogas Program between 2009 and 2023 (Rumah Energi, 2023).

Figure 1.7 ▹ Number of households using biodigesters and number of rural biogas projects in China, 2000-2023



IEA. CC BY 4.0.

After a huge surge between 2000 and 2015, the Chinese biogas market collapsed, with the number of household biodigesters almost back to the 2000 level by 2023

Source: IEA analysis based on Ministry of Agriculture (2001, 2006, 2016) and National Bureau of Statistics (2024).

Recently, many countries have seen a reversal in trends for household-scale biodigesters. For example, in China, the number of digesters began to fall from 2016; around 30 million units are no longer operational, and the number installed in 2023 was almost back to the 2000 level. Several factors caused this decline, including abandonment linked to urbanisation, household connection to gas grids, and technical failures caused by insufficient follow-up services and management from the government.

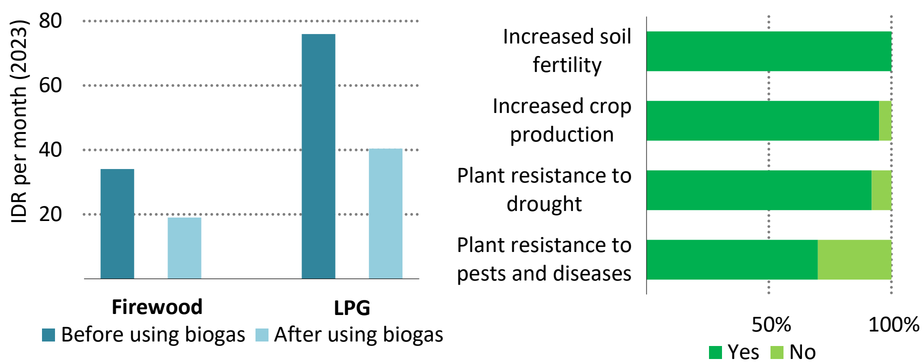
A similar abandonment rate of 27% was reported in 2016 in Kenya, Tanzania and Uganda for household biodigesters built under the ABPP. Household surveys and programme evaluations revealed that a significant portion of this abandonment rate was due to technical problems (Clemens et al., 2018). In response, the ABPP created quality assurance systems and put programmes in place. As key potential beneficiaries, the ABPP has also sought to train women in the construction, operation and maintenance of biogas plants.

The Indonesia Domestic Biogas Program also identified abandonment as a key issue in a 2022 user survey, where 256 of 554 respondents reported discontinuing use or facing issues with their biodigesters. In response, 225 units were repaired in 2023, and monitoring systems were strengthened with economic incentives. Construction companies in Indonesia now receive a subsidy of approximately USD 20 per monitored unit (Rumah Energi, 2023).

1.5.2 Valorising digestate as a biofertiliser

Digestate is typically applied as a soil conditioner or biofertiliser to agricultural land. Many countries have quality standards and systems in place to ensure digestate is appropriately applied to agricultural soils. Digestate can be supplied whole to nearby farms, be separated into solid and liquid fractions, or be further processed (e.g., co-composted with other crop residues). The value of digestate depends on its composition, such as the amount of stabilised carbon, nitrogen and phosphorus concentrations. In the right contexts, valorising digestate can enhance the economic viability and sustainability of rural biogas production, making the business model more robust.

Figure 1.8 ⊳ Impact of biogas adoption on average monthly household fuel cost and perceived benefits of digestate use, Indonesia, 2023



IEA. CC BY 4.0.

In addition to halving monthly fuel expenses, using biogas and subsequently using digestate as a fertiliser have generated valuable co-benefits to farmers in Indonesia

Notes: IDR = Indonesian rupiahs; LPG = liquefied petroleum gas. Monthly fuel cost includes paid firewood.

Source: IEA analysis based on data from Rumah Energi (2023).

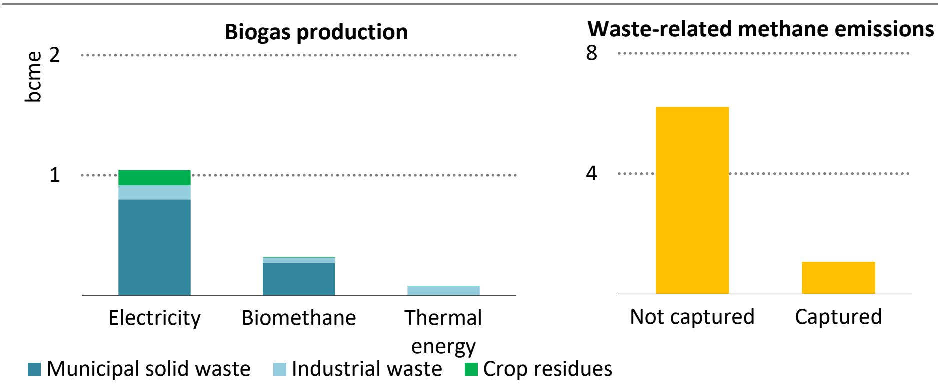
In 2023, the Indonesia Domestic Biogas Program conducted a user survey to assess the use of digestate and found nearly half of respondents were using it regularly (Rumah Energi, 2023). By replacing synthetic fertilisers purchased from foreign agrochemical companies with digestate, farmers in the country have reduced their synthetic fertiliser consumption by more than 30% the year following the installation of the biodigesters. In addition, respondents reported enhanced plant resistance to drought or disease (Figure 1.8).

In India, the National Dairy Development Board has spearheaded an initiative to promote the development of farm-scale biodigesters, offering co-funding to assist farmers in setting up plants. The resulting digestate is either used as organic fertiliser by the farmers or collected, processed and sold by the cooperative. This aggregated digestate can be processed into solid and liquid biofertilisers, which are then sold to farmers as a substitute for chemical fertilisers. The Indian government is supporting development of biofertiliser production through subsidies for biogas plants equipped with digestate filter units. The market for the biofertiliser phosphate-rich organic manure (PROM) was valued at USD 200 million in 2020, and total production capacity of digestate was 13 million tonnes per year in 2024 (Deutsche Gesellschaft für Internationale Zusammenarbeit, 2024).

1.5.3 Improving urban waste management

Biogas plants can be part of solid waste management solutions, including biogas capture at landfill sites and converting separated organic waste to biogas in standalone facilities. In Brazil, MSW is the largest feedstock used for production of biogases (Figure 1.9). The government aims to replace all dumps with landfill sites equipped with production units for biogases. The Fuel of the Future law passed in late 2024 has improved the commercial prospects for producers by mandating the blending of biomethane in grids and establishing national programmes to encourage the adoption of low-emissions fuels.

Figure 1.9 ▷ Biogas production by feedstock and waste-related methane emissions, Brazil, 2022



One-fifth of methane emissions from waste in Brazil is used as biogas, representing three-quarters of the country's total biogas production

Sources: IEA analysis based on data from CIBiogás (2023) and Global Methane Tracker (IEA, 2025a).

1.5.4 Boosting electricity system flexibility

Brazil already uses biogas plants as a small-scale source of flexibility. In the municipality of São Miguel do Iguaçu, a biogas-powered plant is connected to a microgrid (Itaipu Binacional, 2019). If sudden reductions in generation from solar and wind occur, the plant is used to generate electricity for nearby consumers. A larger unit of around 500 kilowatts (kW) of capacity is planned.

Biogas-generated electricity can also provide flexibility for larger electricity grids. Electricity in Brazil is already mostly carbon neutral, although plants fired by natural gas continue to play a crucial role in balancing the grid during droughts. In 2024, a severe drought led to a 55% year-on-year increase in backup gas-fired generation and a rise in liquefied natural gas imports (IEA, 2025b). For biogas to provide the same flexibility as natural gas, increasing on-site storage may not be a practical solution due to the volumes required and the costs incurred. However, upgrading to biomethane enables storage in the main gas grid for later use. A diverse feedstock mix is essential to limit the seasonal variability of biogas production and enable greater flexibility.

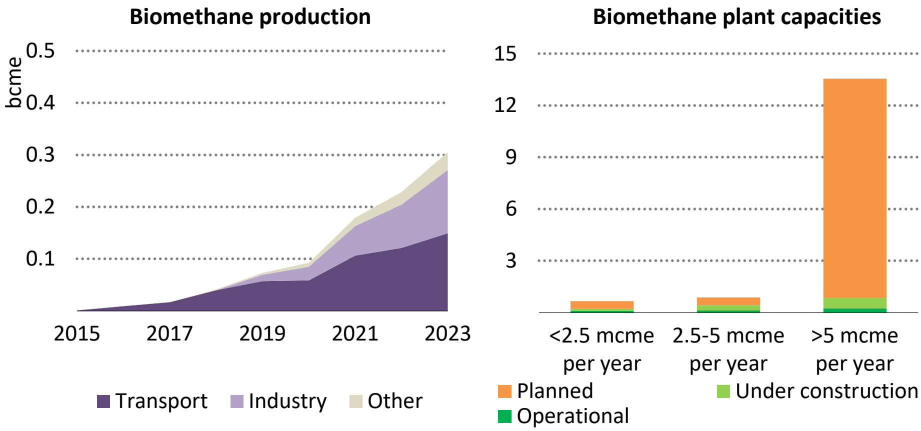
1.5.5 As a transport fuel

In India, the government has encouraged adoption of CNG as a transport fuel in the country, to improve air quality. India has one of the world's largest markets for CNG in transport, with around 7.7 million CNG-fuelled vehicles on the road. In 2023, 7.6 bcme of CNG was consumed in road transport, a near-40% increase from 2021 (IEA, 2025c).

Historically, retail prices for CNG have been around 30-60% lower than gasoline prices, partly due to the preferential allocation of inexpensive government-subsidised gas to the CNG sector (IEA, 2025c). From 2024, these subsidies are being phased out, narrowing the price advance of CNG. Displacing CNG with compressed biomethane offers the potential to stabilise prices. Multiple scheme have supported the development of biogases, including the Galvanizing Organic Bio-Agro Resources Dhan scheme, encompassing a range of measures, such as enabling the trading of emission credits, providing financial support and promoting digestate valorisation. A mandatory blending obligation for biomethane has also been approved, and is set to gradually increase from 1% in 2025 to 5% of total CNG and piped natural gas consumption by 2028 (Ministry of Petroleum and Natural Gas, 2023). If met, this would imply around 1 bcme of biomethane production in 2028, a near threefold increase compared to 2023.

The new project pipeline seems able to meet this level of growth: around 0.5 bcme per year of capacity exists, and there is around 1 bcme per year of new capacity under construction, with a further 14 bcme of capacity planned (Figure 1.10). Nonetheless, planned projects still need to overcome hurdles related to securing land and feedstock availability, alongside financing and offtake contracts, as well as scaling up the logistics and supply chains.

Figure 1.10 ▷ Biomethane production by use, 2015-2023, and status of plant capacities in 2025, in India



Biomethane production has grown strongly in India; meeting blend share targets implies a threefold increase in demand, for which there is a healthy pipeline of planned projects

Note: mcme = million cubic metres of natural gas equivalent.
Source: IEA analysis based on data from the Galvanizing Organic Bio-Agro Resources Dhan Unified Registration Portal (Ministry of Jal Shakti, 2025).

1.5.6 Use in industry

Different routes are available to industry to support the development of biogases. One pathway is to develop onsite biodigesters. This is attractive for industries producing significant agricultural by-products and waste streams such as food processing, paper manufacturing and distilleries. Another possible pathway is to partner with a nearby external biogas producer, securing offtake agreements. A third possibility is to buy biomethane from the gas grid using GOs (IEA Bioenergy, 2025).

Co-locating bioenergy plants with energy-intensive facilities can reduce waste treatment costs while providing a cost-competitive energy source. Further valorisation of biomass inputs can be achieved through biorefinery models, where residues are used to produce biofuels and also other high-value products such as hydrogen and biochar.

By leveraging abundant by-products and residues, several major sugar producers in Brazil are producing, consuming and even selling a range of low-emissions fuels such as ethanol, biogas, biomethane and hydrogen. Other Brazilian industrial players – including steel manufacturers, cosmetic companies, construction material producers and automakers – are purchasing biomethane from external producers (mainly landfill operators). The biomethane is distributed by truck, but agreements between producers and pipeline operators have been signed to permit grid injection.

Supply potential and costs of biogases

Waste to money?

SUMMARY

- This chapter provides a first-of-a-kind picture of the spatial distribution of the availability and costs of sustainable feedstock for biogases. It considers aspects such as feedstock density and diversity, and proximity to gas infrastructure. It provides detailed country- and region-specific supply curves for over 30 types of feedstocks.
- We estimate that nearly 1 000 billion cubic metres of natural gas equivalent (bcme) of biogases could be produced sustainably each year, using readily available feedstocks. This amounts to around one-quarter of global natural gas demand. This is nearly 30% higher than the assessed potential in our 2020 report, mainly because of higher agricultural output and waste generation.
- Almost 80% of the sustainable potential for producing biogases is in emerging market and developing economies, led by Brazil, China and India. The potential in India is larger than its natural gas consumption. The United States has the largest potential among advanced economies. The European Union uses the largest share – around 40% – of its sustainable potential, compared with less than 5% in India.
- The production costs of biomethane lie in a wide range, with 90% of the potential being between USD 10 per gigajoule (GJ) and USD 30/GJ. Emerging market and developing economies in Asia typically have the lowest costs, with 40 bcme available at less than USD 10/GJ.
- Around 45 bcme of biomethane potential could be exploited in different parts of the world at a cost equal to or lower than prevailing wholesale natural gas prices. This is already more than 5 times the current biomethane production globally.
- Biomethane may be more competitive than natural gas if value is attached to the positive externalities arising from its use (e.g. emissions reductions) or its co-products (e.g., biogenic CO_2 and nutrient-rich digestate). If best practices for emissions management are implemented, a CO_2 price of USD 50 per tonne (t) can make 280 bcme of biomethane a competitive alternative to natural gas.
- Biomethane is competitive with other low-emissions fuels in sectors such as maritime transport (where electrification options are limited), in industries that use high-temperature processes or where gaseous fuels are required as a feedstock. Such sectors can use biomethane without major modifications to existing equipment.
- Proximity to existing infrastructure helps to incentivise larger-scale developments and brings down cost. Production from large-scale biodigesters can be up to 40% cheaper than from small-scale digesters. However, this may also mean that feedstocks need collecting and transporting across longer distances.

2.1 Introduction

This chapter provides a first-of-a-kind estimate of the sustainable technical potential and costs of biogas and biomethane supply globally. The assessment of feedstock potential utilises detailed spatial datasets covering agricultural output (FAO, 2024), population density (WorldPop, 2024), managed forests (World Resources Institute, 2024) and wastewater treatment plants (HydroWaste, 2022). It provides a granular picture of the geographic distribution of feedstocks that incorporates feedstock density, diversity and proximity to infrastructure like gas pipelines and electricity grids. Costs are estimated based on these variables and process-specific technology data. This detailed assessment results in more than 5 million data points and allows us to construct country-specific supply cost curves for biogas production.

2.2 Sustainable feedstock potential

Feedstocks considered

This assessment considers over 30 types of feedstocks for biogases. They can be broadly grouped together as crop residues, animal manure, biowaste and woody biomass. We assess feedstocks that can be processed without direct competition with food for agricultural land or animal feed, and that do not have any other adverse sustainability impacts.

Crop residues include straw, husks and stover left over from cereal and grain crop (e.g. maize, wheat and barley) stalks, leaves and residues left from oil and protein crops (e.g. soybean, rapeseed and sunflower), and bagasse, molasses and cake from sugar-based crops (e.g. sugar beet and sugar cane). Our assessment includes only the volumes that remain after harvesting for food and animal feed, and use for soil organic matter and nutrient replenishment and animal bedding. The dry weight of the feedstock available for collection and processing as a biogas feedstock is 30-50% of the total residue remaining after harvest.

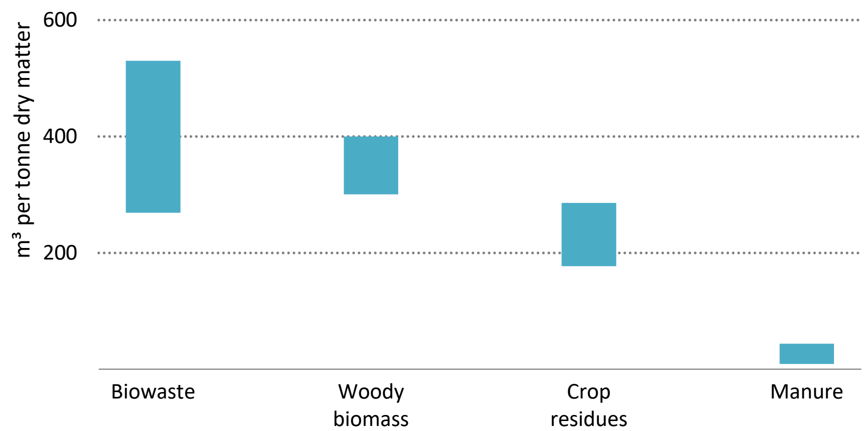
Animal manure includes manure from housed dairy and beef cattle, pigs, and, to a lesser extent, poultry and sheep. Due to higher moisture content, biogas yields tend to be lower per tonne of animal manure than for feedstocks based on crop residues. Feedstock potential is based mainly on volumes of manure that can be collected from animal housing rather than volumes spread across wider grazing areas (which are generally not suitable for collection).

Biowaste comes mainly from the organic fraction of municipal solid waste (MSW), in particular food waste. Industrial wastewater and sewage sludge are also categorised as biowaste. There is considerable variation in waste management practices around the world, which influences the collection and availability of this feedstock. Effectively separating biowaste from other waste streams is crucial for maximising its use as a biogas feedstock. Contamination with plastics, metals or non-organic materials can reduce efficiency and require additional processing. Global data on the location of landfills and waste treatment plants are not available. Therefore, we use population density as a proxy indicator for determining areas where MSW could be directed towards anaerobic digestion or, if necessary, to landfill gas capture units. We reduce the amount of biowaste available for use as a biogas feedstock by subtracting the share that is more likely to be composted, incinerated or diverted to other uses such as animal feed or waste-to-energy plants. This varies considerably by region, but the global average available for digestion is around 50%.

Woody biomass includes residues from managed forests ("log residues") and wood processing waste that can be converted into syngas through gasification. For log residues, we base our estimate on country-level fellings to annual forest increment ratios (a measure of sustainable forestry management comparing the volume of trees felled in a given year to the annual growth of the forest). We discount this potential by taking into consideration other competing uses, such as heat and power generation. The log residue potential has been assessed spatially using data on managed forests, but without spatial data, we have left our 2020 estimates of wood processing waste potential unchanged for this report (IEA, 2020).

Biogas and methane yields are key indicators of how suitable a feedstock is for energy production. Biogas yield refers to the total volume of gas produced from a feedstock through anaerobic digestion, primarily methane (CH_4) and CO_2. Methane yield, by contrast, accounts only for the methane portion, which is the component usable as fuel. The biogas and methane yields can be expressed in different ways: *per tonne of fresh matter*, the total weight of the feedstocks including any water content; *per tonne of dry matter* (also known as "total solids"), defined as the total moisture-free organic material as well as any inorganic solids; or *per tonne of volatile solids*, referring to the digestible organic material only.

Figure 2.1 ▻ Ranges of methane yields for selected biogas feedstocks



Feedstocks carry different methane production potential; there is a high level of variation in how they are collected, processed and valued

Notes: m^3 = cubic metres. Wastewater sludge is not shown due to the high variability of yields, depending on wastewater and treatment technologies in different regions.

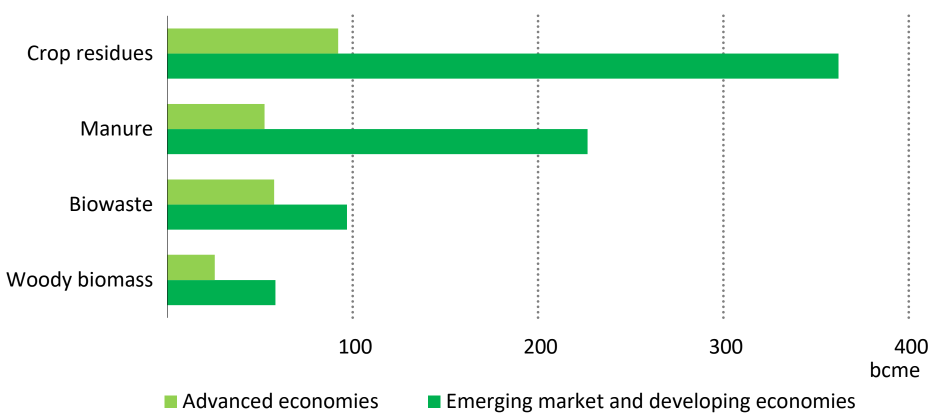
For this report, we assigned methane yield per tonne of dry matter for a range of different feedstocks (Figure 2.1). For crop residues, methane yields can vary according to moisture content as well as local conditions such as climate, soil type, geography, method and time of harvest, and storage method. Cereal and grain residues tend to have the highest biogas yields due to their high starch content. Pre-treatment (e.g. grinding, hydrolysis or fermentation) can improve methane yields, especially for residues such as rice husk, cotton stalks and sugar cane bagasse. Biowaste can have higher yields than crop residues if the organic portions of the waste are well sorted and undergo pre-treatment. In contrast, manure typically has lower methane yields, though it remains an attractive feedstock due to its widespread availability.

Feedstock potential

At a global level, we estimate that nearly 890 bcme of biogas and 990 bcme of biomethane (with woody biomass sources included in biomethane) could be produced sustainably each year. The overall potential for biogases is equivalent to around a quarter of global natural gas demand.

Nearly half of the total potential is from crop residues – most of which arise from cereals and grain crops – and about 30% is from animal manure (Figure 2.2). Biowaste makes up 15%, most of which comes from the organic fraction of MSW, with the rest stemming from industrial waste and wastewater. Log residues and other woody biomass sources are a significant additional source of biomethane potential, and these are relatively evenly dispersed around the world.

Figure 2.2 ▷ Potential for biogases by feedstock



Some 75% of the total potential for biogases comes from agricultural residues, with emerging market and developing economies accounting for nearly 80% of total potential

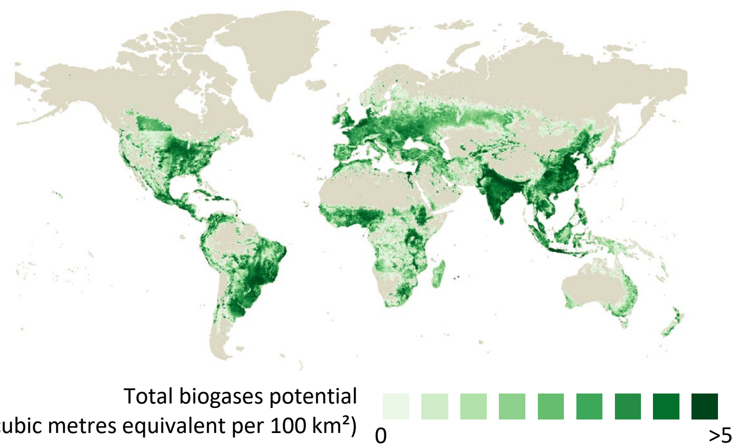
IEA. CC BY 4.0.

The global sustainable potential is around 15% higher for biogases than the assessed potential in the 2020 report (IEA, 2020). The main reason is the higher level of agricultural output and waste generation in 2024 (the base year of our feedstock potential assessment) compared with in 2018 (the base year of the 2020 report).

Assessed potential by geography

Emerging market and developing economies account for 80% of the global potential for biogases, which is concentrated in countries where the agricultural sector plays a prominent role in the economy (Figure 2.3). This is the case for example, in India, where agriculture accounts for around 15% of GDP and half of overall employment, and there is a large potential from rice and wheat crop residues (Government of India, 2023). In Brazil, large volumes of maize and sugar cane residues come from the sugar and ethanol industries. The scale of the meat industry in China, meanwhile, means it has the highest quantity of animal manure available for production of biogases.

Figure 2.3 ▻ Geographic distribution of potential for biogases



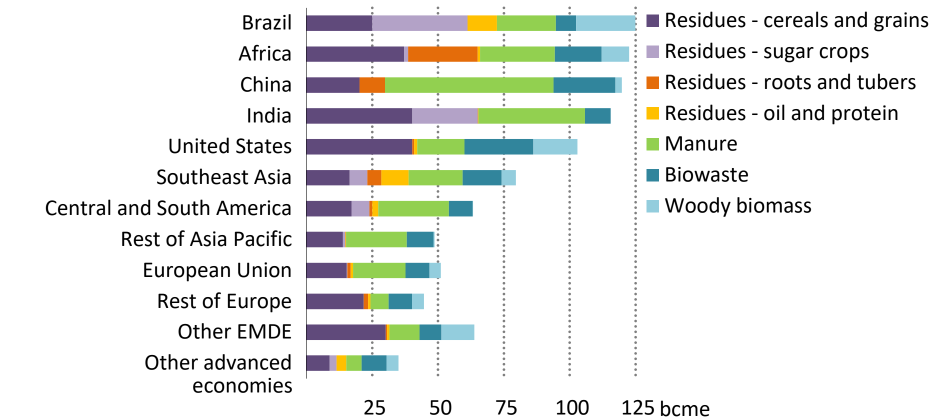
Potential for biogases exists in many parts of the world, but it is concentrated primarily in emerging market and developing economies

Notes: Analysis excludes protected areas and primal forests. Beige coloured areas were not assessed. All maps shown are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA analysis based on data from WorldPop (2020), HydroWASTE (2022), FAO (2024) and World Resources Institute (2024).

The European Union is the region that utilises the largest share of its overall sustainable potential. It produced over 20 bcme of biogases in 2023, compared to an annual sustainable potential of around 50 bcme. Elsewhere, the feedstock potential being exploited is much lower. China is the world's largest biogas-producing country (at around 11 bcme), but it is tapping into less than 10% of its sustainable feedstock potential. India is producing less than 5% of its sustainable feedstock potential (Figure 2.4).

Figure 2.4 ▹ Potential for biogases by region and by feedstock type, 2024



Brazil, China, India and the United States together account for nearly half of the world's potential for biogases while representing only 23% of the global land surface.

Note: EMDE = emerging market and developing economies.

2.3 Production costs

There are many different pathways for production of biogases, involving a range of feedstocks and biogas technologies. In addition to yields, the costs and efforts required for collecting different volumes of feedstock vary. The key considerations affecting overall project economics are plant size, feedstock composition and quality, and locational factors such as collection radius, access to grids, roads and other supporting infrastructure.

This report uses the latest available cost estimates, including survey-based studies of biogas project developers in Europe and recent cost estimates carried out for projects in India and the United States.

2.3.1 Capital costs

Biogas

The main cost component of a biogas project is the anaerobic digester. Capital expenditure for biogas plants demonstrates significant economies of scale, with larger facilities offering lower costs per unit of production capacity. Our analysis uses seven different plant size categories for anaerobic digesters, ranging from a rated output capacity of 25 cubic metres (m^3) of biogas per hour (or 0.1 megawatt (MW)) to 3 000 m^3/hour (or 18 MW).

The smallest systems carry an average levelised capital cost of about USD 8/GJ, assuming a lifetime of 20 years, and the largest around USD 5/GJ. These costs encompass the complete anaerobic digestion system, including feedstock pre-treatment equipment, digester tanks, gas handling systems, covered digestate storage and basic control systems. They exclude the investments required to transform biogas into electricity or heat. Such investments can be considerable; for example, adding a co-generation unit and including grid connection and heat recovery distribution can add an additional 40-70% to the costs of an integrated project.

Landfill gas recovery systems, which capture methane from existing MSW decomposition, also have a distinct cost profile. Although they require lower upfront investment in the digestion process, additional capital and operational expenditures are required for the associated gas collection infrastructure.

Biomethane

Multiple technologies are available to upgrade biogas to biomethane, with membrane separation being the most common in Europe (EBA, 2024a). The costs of upgrading biogas to biomethane at a medium-to-large facility using a membrane separation system are around USD 3/GJ. The thermal gasification route to producing biomethane involves investment in a gasifier, methanation reactor and purification system. Capital costs depend highly on scale, but range from as low as USD 6/GJ to USD 20/GJ (Chanthakett et al., 2021; EBA, 2024b).

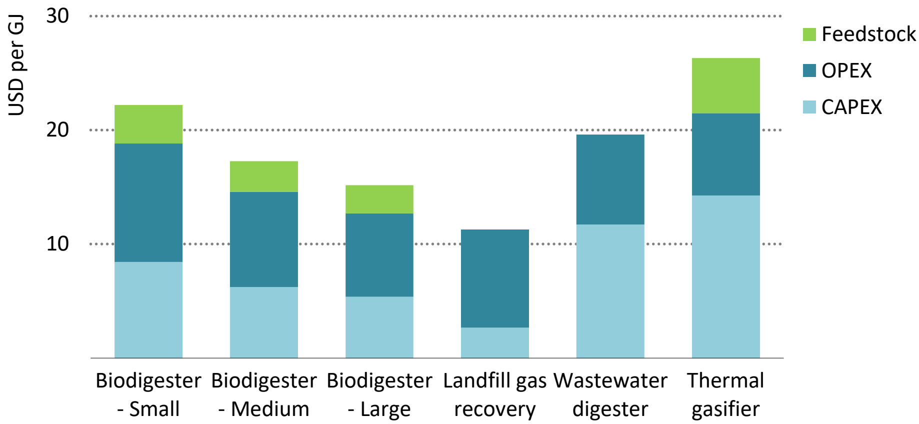
Depending on their size, location and output, as well as any regulatory incentives, many biomethane plants look to secure a connection to the gas grid, adding additional capital expense. We estimate that, on average, it costs around USD 3/GJ for a large-scale biomethane plant to secure a grid connection at a distance of under 10 km. However, this masks a wide range of costs that are affected by topography and regulatory environments.

2.3.2 Operating costs

Biogas and biomethane projects tend to have relatively high ongoing operating expenses, compared with other energy sources such as solar, wind or oil and gas projects. Variable operating expenditures include the cost of feedstock, which may be significant if the feedstock is scarce and needs to be transported across long distances. There are also expenses associated with pre-treatment and processing, and the energy required for onsite equipment such as digesters, combined heat and power (CHP) engines and upgrading facilities.

Parasitic energy demand – the amount of electricity and thermal energy consumed internally by the plant for its own operation – is around 15% for biogas, and up to 20% for biomethane plants given the additional energy required for upgrading and compression (IEA Bioenergy, 2011). This adds to cost, especially where the required energy comes from external sources. Larger plants can achieve lower parasitic demand per unit of output due to economies of scale, as well as through enhanced heat recovery, optimised membranes or better insulation.

Figure 2.5 ▻ Total average estimated costs of producing biomethane by technology



Large biodigesters can reduce levelised unit capital costs by about a third on average. However, differences in the feedstock mix can lead to higher operating costs.

Notes: CAPEX = capital expenditure; OPEX = operating expenditure; small = <250 m^3/hour; medium = 250-1 000 m^3/hour; large = >1 000 m^3/hour. Capital costs are levelised over lifetime production.

Biomethane can be bottled for use as a transport fuel or injected into gas grids, depending on the plant type and use case. The associated compression costs vary, but generally fall in a range between USD 0.5/GJ and USD 2/GJ. Grid injection costs are typically charged at less than USD 0.5/GJ, depending on the location and the tariff structure of the grid operator (see Chapter 3). However, in some cases, upgraded biogas may need to be admixed with propane by network operators to conform to gas quality criteria; this can significantly increase the operating expenditure for plant operators.

Feedstock costs

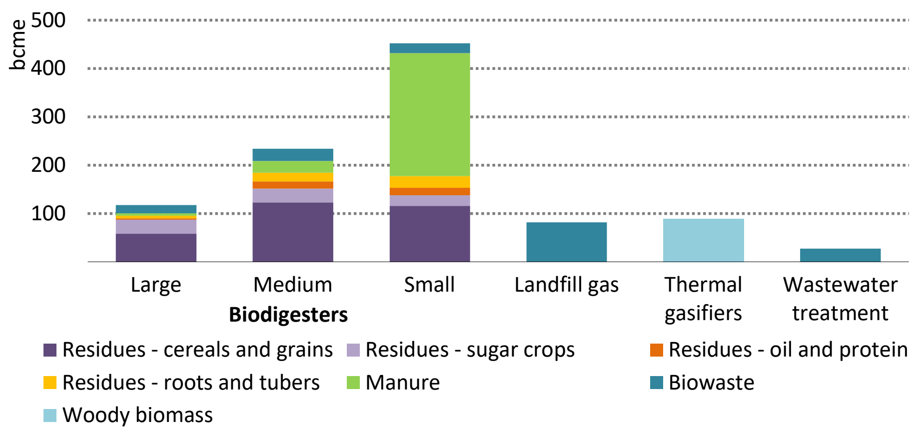
The economics of feedstock procurement vary considerably, depending on the source material and local market conditions. Agricultural residues typically incur collection, transport and storage costs of approximately USD 15/t to USD 30/t of feedstock. For food waste and other biogenic materials from municipal or commercial sources, operators can often receive fees ranging from USD 10/t to USD 150/t, creating a revenue stream rather than a cost. However, these materials frequently require more intensive pre-treatment, adding around USD 30/t to USD 80/t to processing costs to remove contaminants and homogenise the feedstock. These costs largely net out the revenue potential of biogenic waste, and there is also a risk that competition for feedstock enhances the cost of waste.

Regardless of the variability of feedstock procurement, a survey-based study of European producers showed that feedstock costs are similar per unit of biogas produced. Biowaste, manure and crop residues all fall within a range of around USD 10/GJ to USD 12/GJ (Common Futures, 2023). In other jurisdictions, feedstock costs may be considerably cheaper; for example, rice paddy residues in India cost as little as USD 3/GJ.

Global supply

Transportation costs and general feedstock availability represent significant factors in the economics of biogas projects, and often dictate the optimal plant scale. Our spatially resolved dataset allows us to refine our cost estimates based on "clustering" the amount and type of sustainable feedstock available for collection within a given geographic area. For example, animal manure has a high moisture content and is thus costly to transport, meaning the economical collection radius is typically 10 km from a centralised biodigester. For crop residues, areas with dense and high-yielding crop residues can support large-scale plants – thereby enlarging the radius for collection (up to 50 km) and potentially also lowering the cost through economies of scale. The potential for MSW was defined in 100 km² areas, cognisant that waste transportation pathways invariably differ depending on whether the waste is incinerated, composted or sent to landfill sites.

Figure 2.6 ▷ Spatial allocation of global potential for biogases to plant types



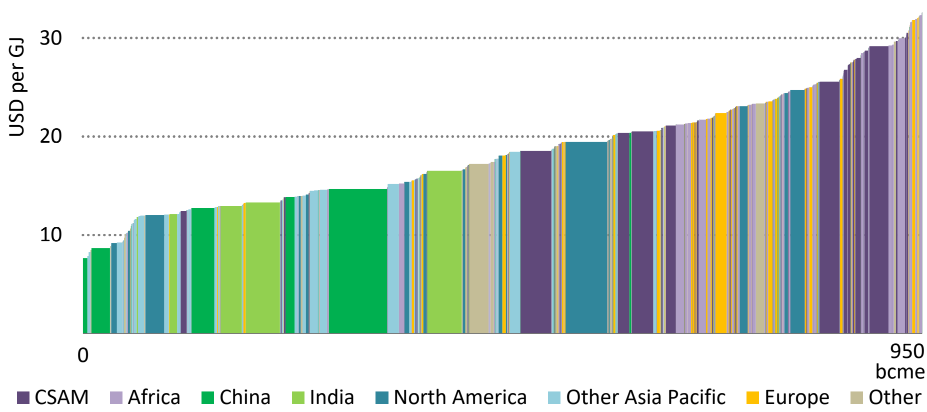
IEA. CC BY 4.0.

Fully developing the assessed potential for biogases requires a mix of different biodigesters, depending on the scale, diversity and collection radius of available feedstocks

After defining these clusters, we then accounted for infrastructure proximity, discounting costs for locations nearer to a denser network of roads or gas pipelines. This clustering assessment resulted in an allocation of feedstock to different types of biogas production facilities (Figure 2.6). In addition to this spatial assessment, costs were varied depending on labour and material cost indices in different regions.

The resulting allocation model yielded supply curves estimating the costs of developing over 30 types of feedstocks across almost 5 million points worldwide. We present the results by focusing on biomethane, aggregating to the country and feedstock level (Figure 2.7).

Figure 2.7 ▷ Supply cost curve of global biomethane potential by region, 2024



Around 300 bcme of biomethane, or 7% of global natural gas demand, can be developed for less than USD 15/GJ. Most of the cheapest potential lies in developing Asia.

Notes: CSAM: Central and South America Costs include production only and do not include grid connection costs.

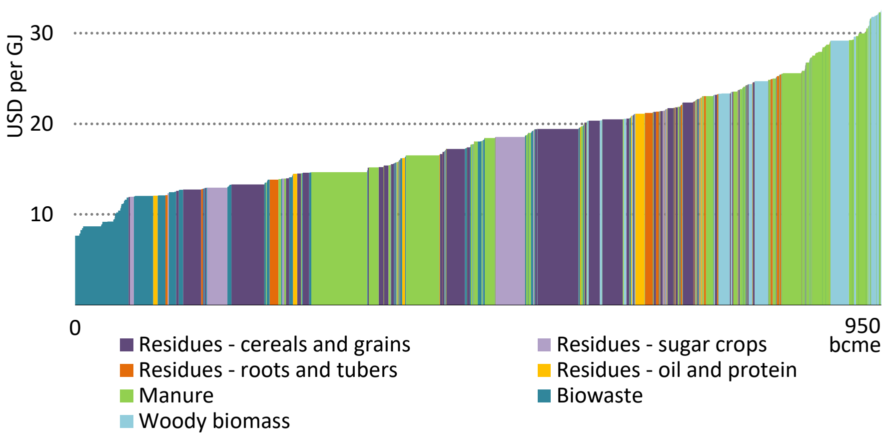
Globally, the costs of producing biomethane cover a wide range, with 90% of potential lying between USD 10/GJ and USD 30/GJ. There are significant variations among regions. In Europe, the average cost is around USD 22/GJ (or EUR 74 per megawatt hour (MWh) in 2024 exchange rates), while in Southeast Asia, it is USD 13/GJ. Around 20-40% of the total biomethane production costs are for installing biodigesters, with the rest covering feedstock procurement and processing and plant operating and maintenance expenses.

Around 12% of the total sustainable potential for biogases (about 120 bcme) is located in areas of dense, high-yielding feedstock with good infrastructure links that can accommodate large-scale operations, thereby benefiting from economies of scale. Biomethane can be produced in these areas at a cost of around USD 15/GJ, which is about 15% lower than the global average. Small-scale plants have higher unit capital and operational costs, but can be located nearer to a source of cheaper feedstocks. On average, small-scale plants in our model produce biomethane at a cost of around USD 21/GJ.

Equipping landfill sites with gas recovery systems and upgrading systems or valorising biowaste streams are some of the cheapest ways of producing biomethane, averaging around USD 11/GJ (Figure 2.8). However, landfill gas typically yields less methane than anaerobic digesters, has higher impurities and is more difficult to optimise. Thermal gasification is at the top end of the supply curve, but this technology has potential for cost reductions from learning and scale effects, in particular to improve process efficiencies from the current level of around 65% (Guidehouse, 2023).

This report estimates that nearly 50 bcme of the biomethane potential could be exploited in different parts of the world at a cost equal to or lower than prevailing natural gas prices. This is already around five times the current level of biomethane production globally.

Figure 2.8 ▻ Supply cost curve of global biomethane potential by dominant feedstock, 2024



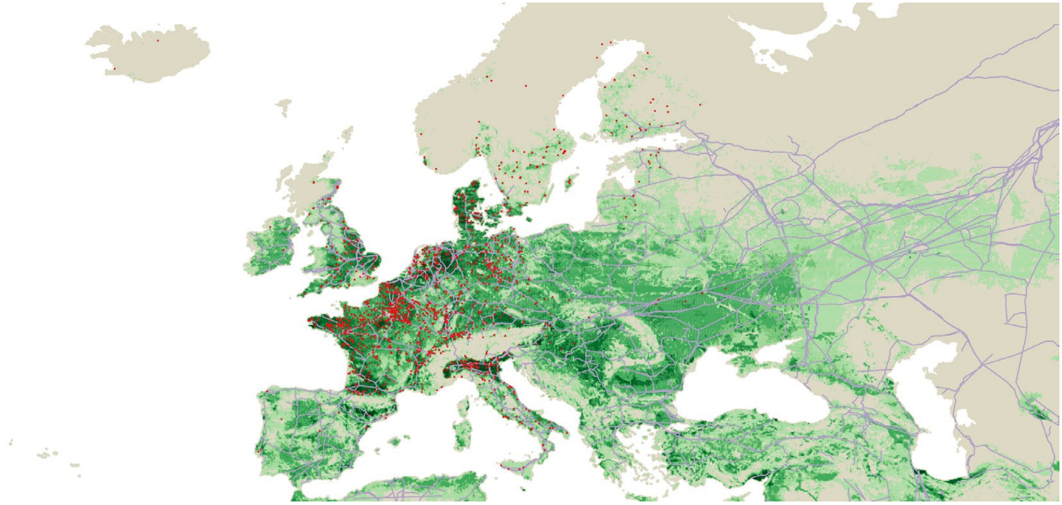
Biomethane production costs average around USD 18/GJ. The most cost-competitive supply comes from biowaste and agricultural areas with dense, methane-rich residues.

Note: Costs include production only and do not include grid connection costs.

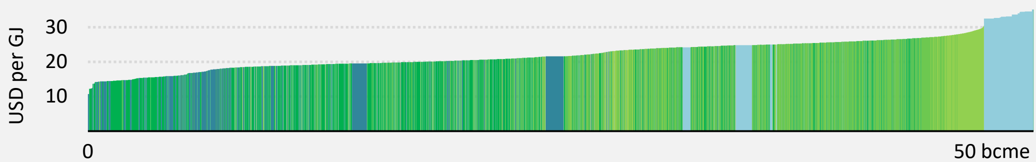
2.4 Selected region and country summaries

The following infographics summarise our spatial analysis of feedstock for biogases. The lowest-cost areas on the map are those where high potential exists (dark green) near to infrastructure such as gas transmission pipelines (shown) or electricity grids and roads (not shown). Where data are available, red dots show the approximate location of existing biogas and biomethane plants. All maps shown are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

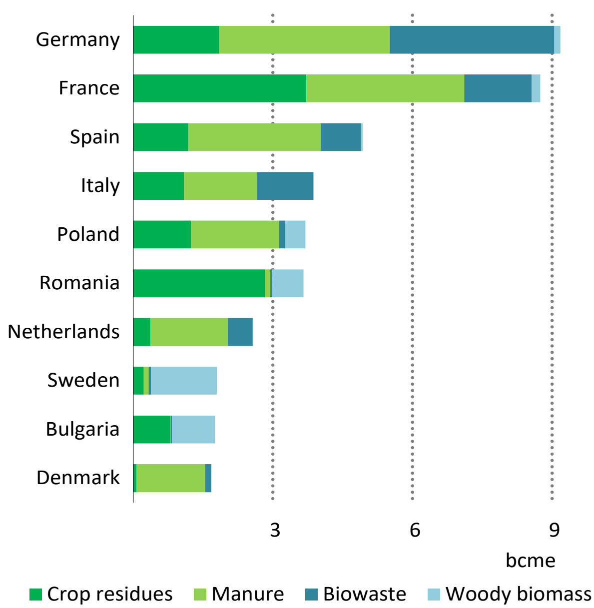
Biogases – feedstock density in the European Union and surrounding areas



Biomethane – supply cost curve



Biogases – potential by country



15 bcme

biogas demand in 2023

4 bcme

biomethane demand in 2023

51 bcme

potential for biogases today

15%

as a share of natural gas demand

USD **22**/GJ

average cost of biomethane

USD **15**/GJ

average cost of producing the cheapest 10% of potential

60%

potential <20 km from gas transmission pipelines

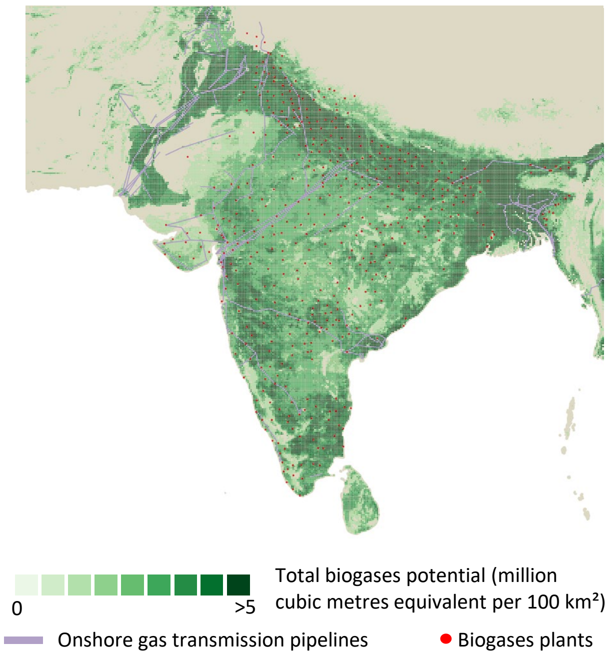
Note and sources: Beige areas have not been assessed. The locations of plants are based on data from EBA (2024c). The locations of gas transmission pipelines are based on data from the Global Energy Monitor (2024).

Table 2.1 ▹ Selected policies related to biogases in the European Union

Policy	Year	Key information
EU: REPowerEU Plan (COM/2022/230)	2022	Sets a non-binding target of 35 bcme/year of biomethane production by 2030.
EU: Renewable Energy Directive 2018/2001 (RED II) and 2023/2413 (RED III)	2018, 2023	Obligates fuel suppliers to include a minimum share of renewable energy in transport. Advanced fuels count double. Imposes thresholds for minimum GHG reductions.
EU: Waste Framework (2008/98), Wastewater Treatment (2024/3019) and Nitrates (91/676) Directives	1991, 2008, 2024	Sets obligation to collect biowaste separately from 2024, encouraging use for digestion. Wastewater treatment plants must be energy neutral (e.g. by producing biogas from sludge) on a country level by 2045. The Nitrates Directive regulates use of fertilisers to avoid nitrogen discharge into water supplies, limiting the application of digestate.
DE: Renewable Energy Sources Act	2000, 2017, 2021, 2025	FiTs for renewable electricity. The 2017 amendment shifted to tenders, with flexible operations. The 2021 amendment designated specific tenders for biomethane.
DE: Building Energy Act	Updated 2024	Biomethane eligible for meeting renewable heating targets in buildings (65% clean in 2024, 100% in 2045).
DE: Federal Emission Control Act	Updated 2024	Supports biomethane use in transport, setting GHG reduction quotas.
FR: Climate and Resilience Law	2021	Reinforced the right to inject biomethane into the natural gas grid. Created biogas production certificates. Decree released in 2024 to implement this scheme, requiring suppliers to provide biogas certificates from 2026.
FR : Decrees of 2016, 2020 and 2023	2016, 2020, 2023	Established conditions for purchase tariffs for biomethane grid injection. Maintained FiTs for small projects.
FR: National Energy Climate Plan 2021-2030	Updated 2024	Increased the non-binding target to 50 TWh of biogases, of which 44 TWh would be injected by 2030.
IT: Biomethane Decree 2022	2022	Provides biomethane incentives in the form of capital contributions and FiTs over a 15-year period.
ES: National Energy and Climate Plan 2021-2030	Updated 2024	Sets non-binding target of 20 TWh of annual biogas production by 2030.
ES: Resolution Approving the Procedure for Managing Connection of Renewable Gas Generation Plants	2024	Streamlines a procedure for managing transmission and distribution grid connection requests for biomethane, including deadlines for operators to respond to requests.
NL: National Climate Agreement	2019	Targets 70 PJ of green gas production by 2030. Proposed introduction of a Green Gas Blending Obligation in 2026 would support this goal.

Note: DE = Germany; FR = France; IT = Italy; ES = Spain; NL = Netherlands. FiT = feed-in tariff

Biogases – feedstock density in India and surrounding areas



4 bcme biogas demand in 2023

0.3 bcme biomethane demand in 2023

115 bcme potential for biogases today

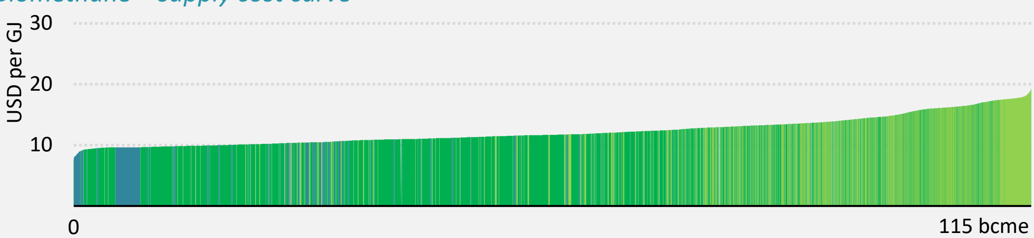
160% as a share of natural gas demand

USD 14/GJ average cost of biomethane

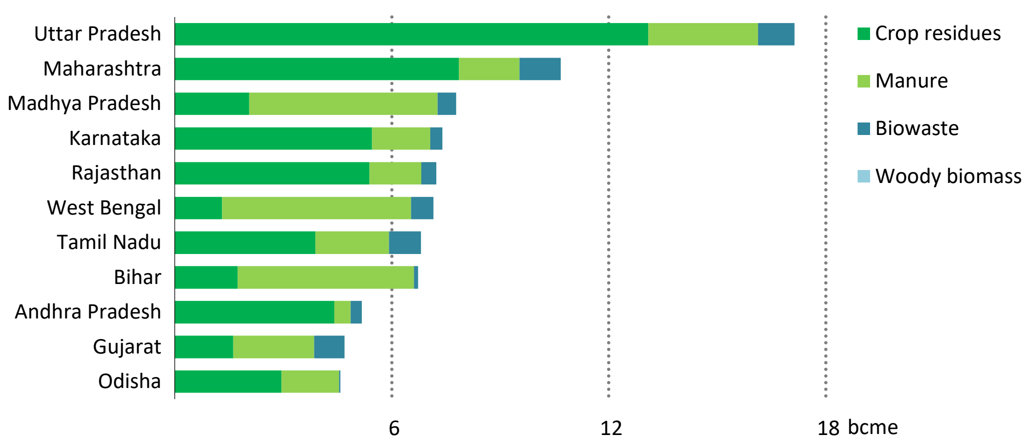
USD 11/GJ average cost of producing the cheapest 10% of potential

25% potential <20 km from gas transmission pipelines

Biomethane – supply cost curve



Biogases – potential by state



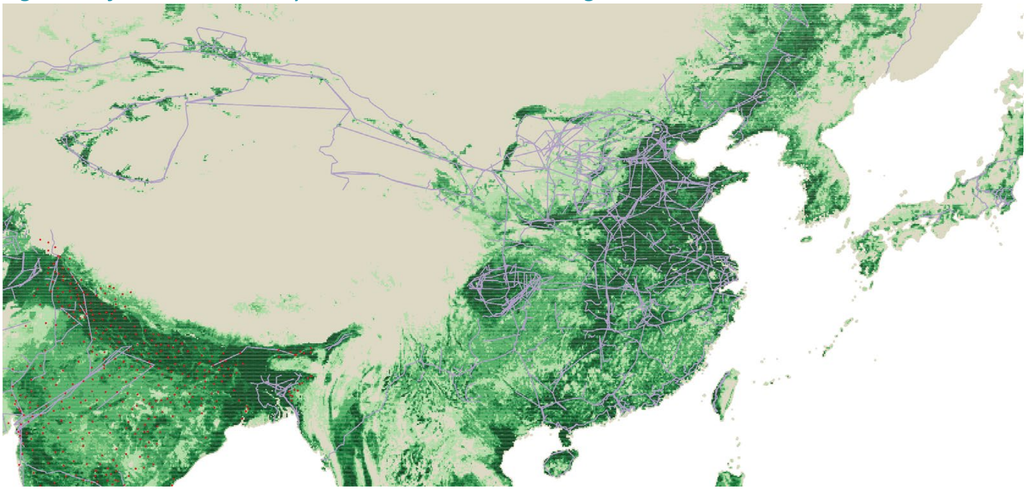
Note and Sources: Beige areas have not been assessed. The locations of plants are based on data from the Ministry of Jal Shakti (2025). The locations of gas transmission pipelines are based on data from the Global Energy Monitor (2024).

Table 2.2 ▷ Selected policies related to biogases in India

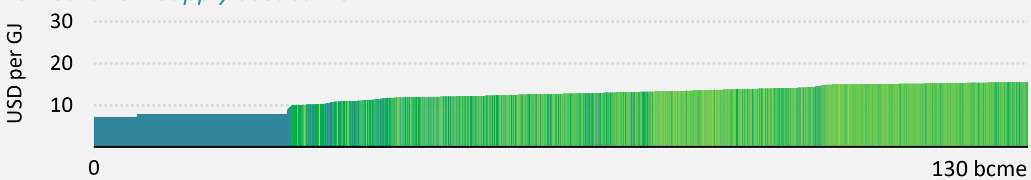
Policy	Year	Key information
Sustainable Alternative Towards Affordable Transportation Programme	2018	Enables purchase offtake agreements with oil and gas companies, with a minimum purchase price guaranteed until 2029; provides some tax exemptions. First target of 5 000 CBG plants and 15 million tonnes per year of production by the 2023/24 fiscal year; this target remains unmet, with around 100 plants commissioned as of April 2025.
Waste to Energy Programme	2022	Targets an increase in energy production from urban, industrial and agricultural wastes by providing financial assistance to developers. Phase I carries a budget of 600 crore (USD 70 million) for the 2025/26 fiscal year.
Biogas Programme	2022	Offers financial assistance for setting up small- and medium-size biogas plants (up to 2 500 m^3/day).
Galvanizing Organic Bio-Agro Resources Initiative	2018	Comprises several initiatives encouraging valorising organic waste through transformation into CBG or organic manure. Offers financial assistance for organic fertiliser sales, CBG injection in city gas networks and purchasing of machinery. Launched the Unified Registration Portal for biogases in 2023.
CBG Blending Obligation	2023	Mandates blending of compressed biomethane in transport fuel and domestic piped gas, starting at 1% in the 2025/26 fiscal year and rising to 5% in 2028/29. Initially voluntary, this will become mandatory by 2025/26.

Note: CBG = compressed biogas.

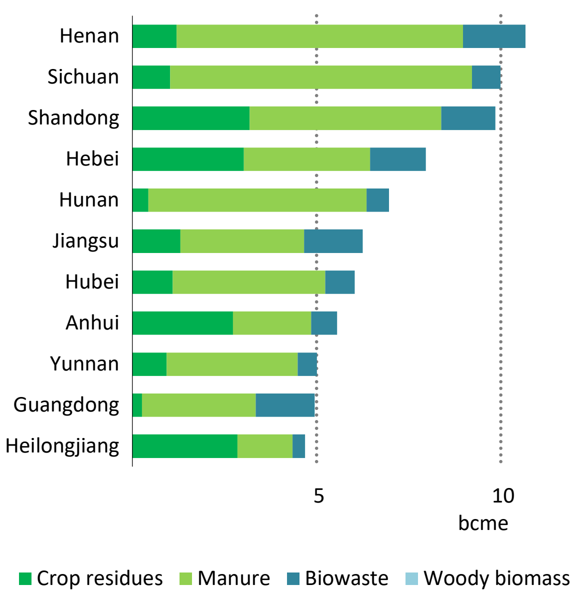
Biogases – feedstock density in China and surrounding areas



Biomethane – supply cost curve



Biogases – potential by province



10 bcme
biogas demand in 2023

1 bcme
biomethane demand in 2023

135 bcme
potential for biogases today

30%
as a share of natural gas demand

USD 13/GJ
average cost of biomethane

USD 8/GJ
average cost of producing the cheapest 10% of potential

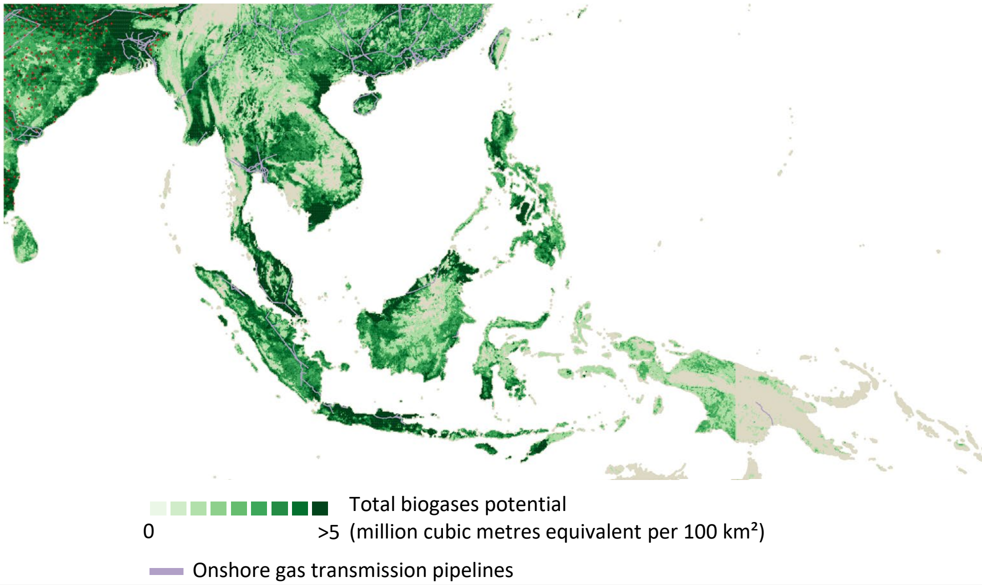
50%
potential <20 km from gas transmission pipelines

Note and source: Beige areas have not been assessed. The locations of gas transmission pipelines are based on data from the Global Energy Monitor (2024).

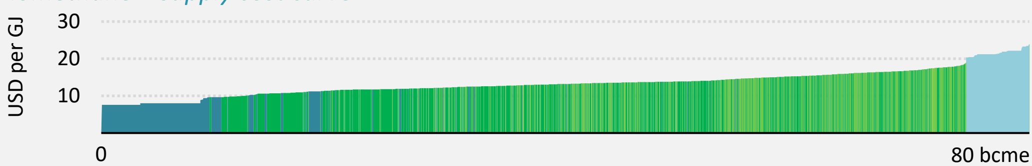
Table 2.3 ▷ Selected policies related to biogases in China

Policy	Year	Key information
Guiding Opinions on Promoting the Industrialisation of Bio-natural Gas	2019	Discusses implementation strategies and sets biogas targets of 10 bcme by 2025 and 20 bcme by 2030.
14th Five-Year Plan for the Development of Renewable Energy	2021-25	Specifies provinces for biogas demonstration plants to show use cases for fertiliser production, power generation and heating.
Action Plan for Methane Emissions Control	2023	Promotes waste reduction through use in biogas/biomethane plants. Sets target of 85% use of animal and poultry waste by 2030.
Notice on the Rural Energy Revolution Pilot County Construction Plan	2023	Requires pilot provinces to implement plans for increasing solar, wind and bioenergy generation in rural areas.

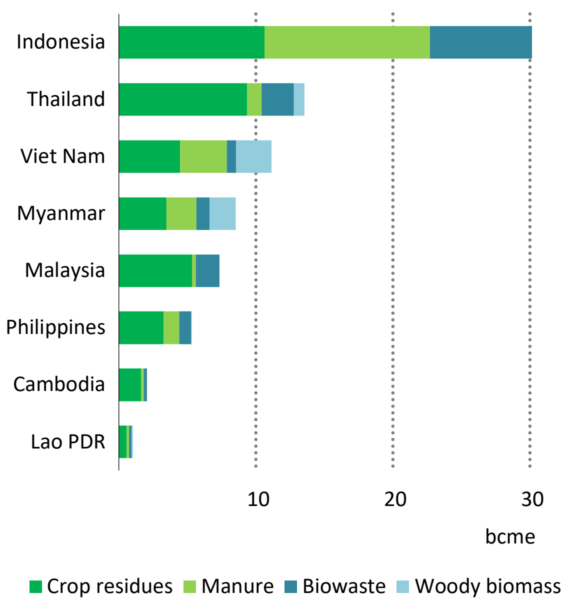
Biogases – feedstock density in Southeast Asia and surrounding areas



Biomethane – supply cost curve



Biogases – potential by country



2 **bcme**

biogas demand in 2023

0.2 **bcme**

biomethane demand in 2023

80 **bcme**

potential for biogases today

45%

as a share of natural gas demand

USD 13/GJ

average cost of biomethane

USD 8/GJ

average cost of producing the cheapest 10% of potential

20%

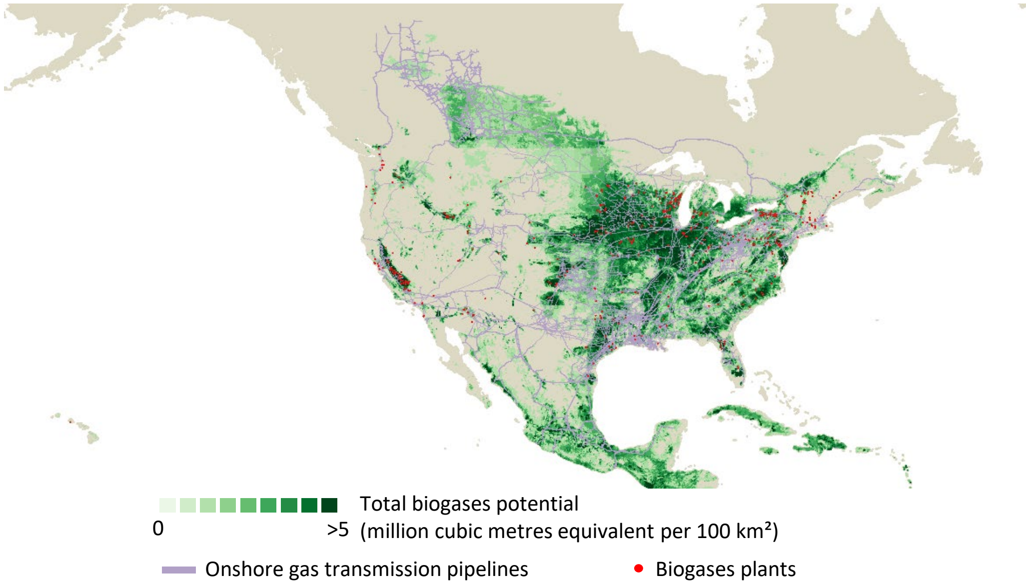
potential <20 km from gas transmission pipelines

Notes and source: Lao PDR = Lao People's Democratic Republic. Beige areas have not been assessed. The locations of gas transmission pipelines are based on data from the Global Energy Monitor (2024).

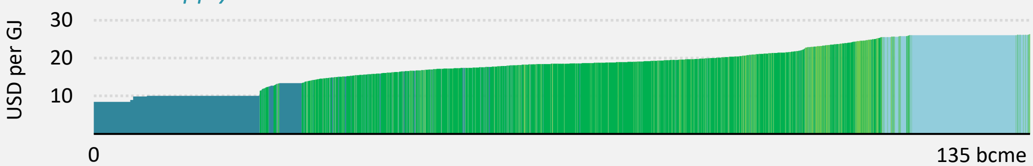
Table 2.4 ▹ Selected policies related to biogases in Southeast Asia

Country	Policy	Year	Key information
Indonesia	Presidential Decree No. 35 on Acceleration of Waste-to-Energy Plant Construction	2018	Mandates creating waste-to-energy facilities in 12 major cities.
Thailand	Feed-in Tariff Scheme	2022	Implements feed-in tariffs to 2030 for biogas, wind and solar projects.
	Alternative Energy Development Plan	Proposal only: 2024-37	Would target 756 MW of biogas from energy crops and 925 MW from wastewater by 2037.

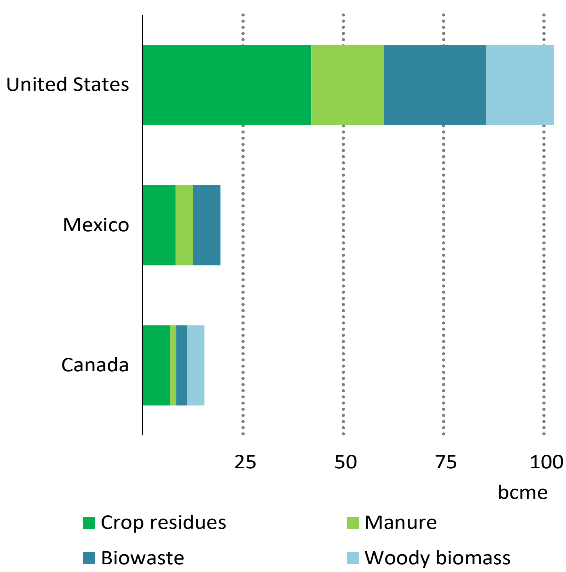
Biogases – feedstock density in North America and surrounding areas



Biomethane – supply cost curve



Biogases – potential by country



4 **bcme**

biogas demand in 2023

3 **bcme**

biomethane demand in 2023

140 **bcme**

potential for biogases today

10%

as a share of natural gas demand

USD 18/GJ

average cost of biomethane

USD 9/GJ

average cost of producing the cheapest 10% of potential

60%

potential <20 km from gas transmission pipelines

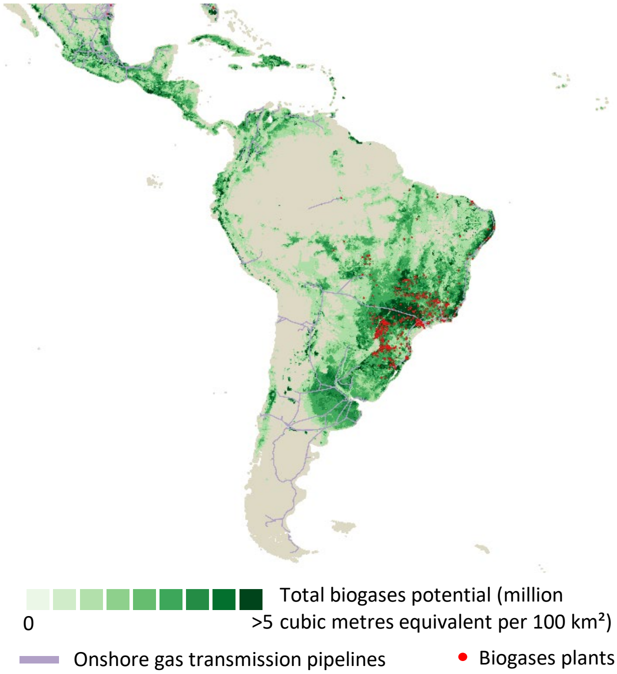
Note and sources: Beige areas have not been assessed. The locations of plants are based on data from US Environmental Protection Agency (2024) and Argonne National Laboratory (2024). The locations of gas transmission pipelines are based on data from the Global Energy Monitor (2024).

Table 2.5 ▹ Selected policies related to biogases in North America

Country	Policy	Year	Key information
Canada *Federal level*	**Clean Fuel Regulations**	2022	Sets requirements for gasoline and diesel suppliers to decrease CI, targeting 15% decrease from 2016 levels by 2030.
British Columbia	**Low Carbon Fuel Standard**	2024, updated 2025	Sets annual CI reduction targets for diesel, gasoline and jet fuels.
Quebec	**Renewable Natural Gas Blending Mandate**	2019, updated 2025	Regulation requires natural gas distributors to reach 10% biomethane in their networks by 2030.
United States *Federal level*	**Renewable Fuel Standards**	2023	Sets volume requirements for biofuels. Non-renewable fuel producers or importers must buy credits from biofuel producers. Statutory targets ran through 2022, with the Environmental Protection Agency setting new annual requirements thereafter.
	Inflation Reduction Act	2022	Established investment tax credits and production tax credits for renewable energy and alternative fuel projects. Incentives under Internal Revenue Service 48E switched in 2025 from technology specific to technology neutral.
California	**Low Carbon Fuel Standard**	2009, updated 2020	Sets annual CI standards for fuel; uses a trading system for credits generated via low-carbon fuel production, emissions avoidance within in the fuel supply chain or development of electric vehicle charging infrastructure.
	Biomethane Procurement Program	2022	Mandates procurement targets for gas utilities, with priority given to organic waste diverted from landfills (0.5 bcme/year by 2025) and expanding to all feedstocks (2.06 bcme/year by 2030).
Oregon	**Clean Fuels Program**	2016	Sets annual average CIs for transportation fuels produced in-state or imported; uses credit trading system. Targets CI reduction of 20% from 2015 levels by 2030 and 37% by 2035.
Washington	**Clean Fuels Program**	2023	Similar set-up to Oregon's programme, with a CI reduction target for transportation fuels of 20% below 2017 levels by 2034.

Note: CI = carbon intensity.

Biogases – feedstock density in Central and South America and surrounding areas



1 bcme
biogas demand in 2023

0.7 bcme
biomethane demand in 2023

190 bcme
potential for biogases today

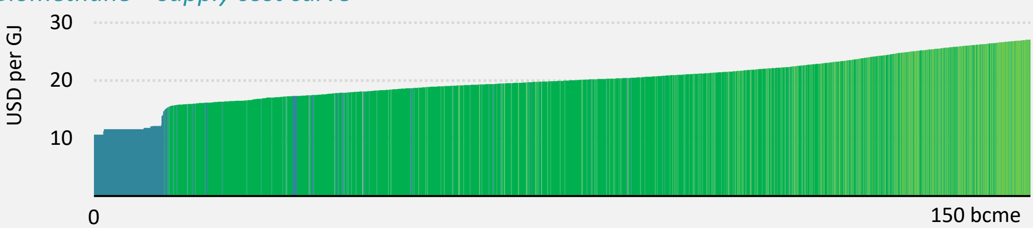
120%
as a share of natural gas demand

USD **23**/GJ
average cost of biomethane

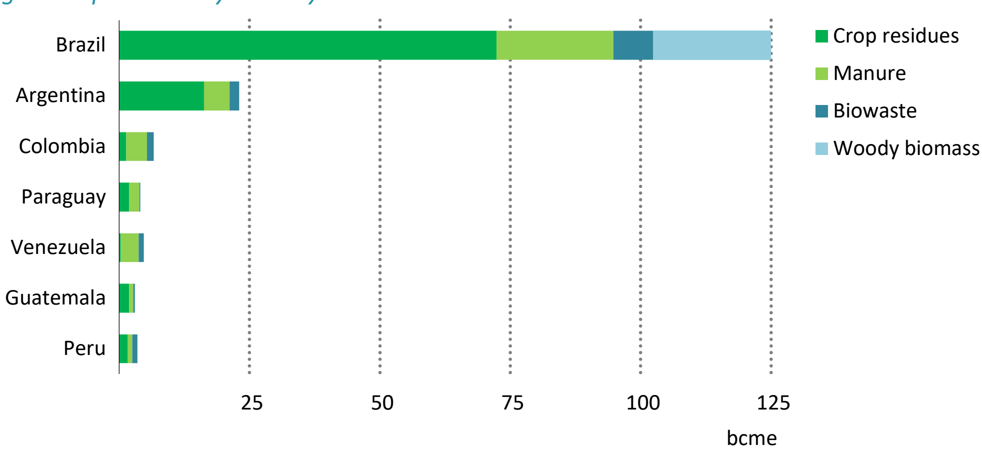
USD **14**/GJ
average cost of producing the cheapest 10% of potential

10%
potential <20 km from gas transmission pipelines

Biomethane – supply cost curve



Biogases – potential by country



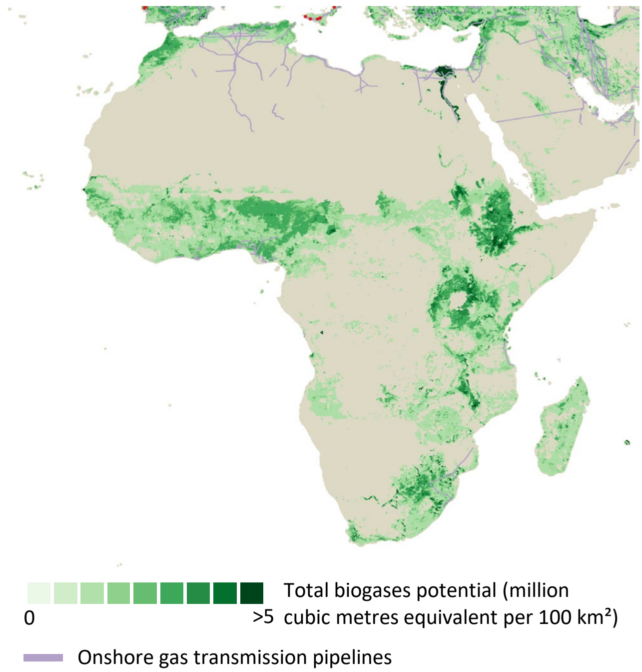
Note and sources: Beige areas have not been assessed. The locations of plants are based on data from CIBiogás (2023). The locations of gas transmissions pipelines are based on data from the Global Energy Monitor (2024).

Table 2.6 ▹ Selected policies related to biogases in Central and South America

Country	Policy	Year	Key information
Brazil	Future Fuels Law	2024	Natural gas producers must reduce their GHG emissions by transitioning to biomethane (self-production or purchase of certificates). GHG emissions reduction target to be set annually, starting at 1% in 2026 compared to the past 10-year average. The target may not exceed 10% for a single year.
	National Methane Emission Reduction Programme	2022	Ordinance promoting the growth of biogas and biomethane; encourages methane credits in the carbon market.
	Special Incentive Regime for Infrastructure Development	2022	Normative Ordinance 37 includes biomethane within the project types eligible for tax exemptions for materials and equipment under the REDI scheme.

Note: GHG = Greenhouse gas.

Biogases – feedstock density in Africa and surrounding areas



0.1 bcme

biogas demand in 2023

0.02 bcme

biomethane demand in 2023

120 bcme

potential for biogases today

65%

as a share of natural gas demand

USD **24**/GJ

average cost of biomethane

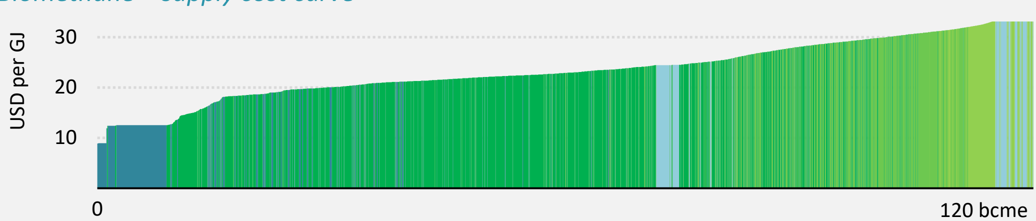
USD **13**/GJ

average cost of producing the cheapest 10% of potential

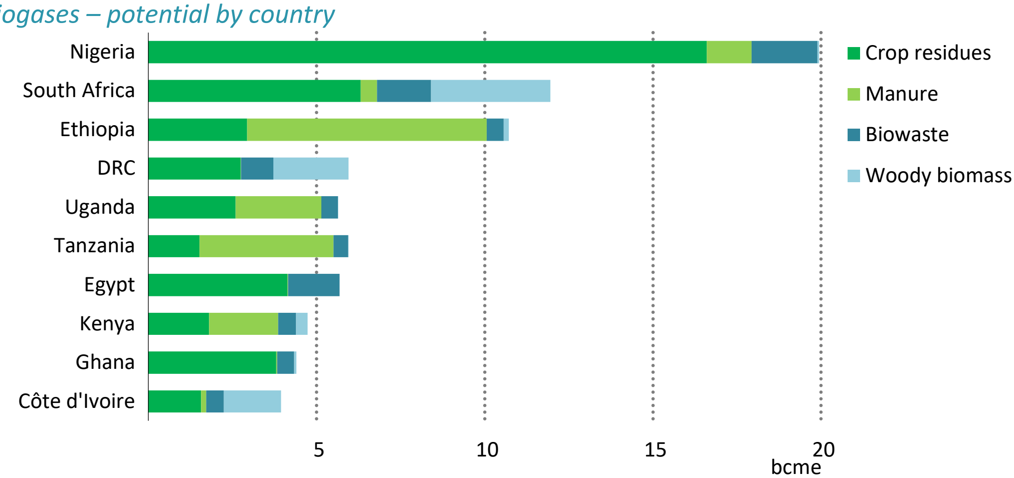
10%

potential <20 km from gas transmission pipelines

Biomethane – supply cost curve



Biogases – potential by country



Notes and source: DRC = Democratic Republic of the Congo. Beige areas have not been assessed. The locations of gas transmissions pipelines are based on data from the Global Energy Monitor (2024).

Table 2.7 ▹ Selected policies related to biogases in Africa

Country	Policy	Year	Key information
Egypt	Waste-to-Energy Decree #41-2019	2019	Sets FiT of EGP 1.4 (USD 0.028)/kWh for landfill biogas and EGP 1.03 (USD 0.02)/kWh for wastewater biogas.
Ghana	Renewable Feed-in Tariff, National Energy Policy	2016, 2021	Sets FiT for landfill and sewage gas at 0.69 GHC (USD 0.045/kWh). National plan establishes biogas promotion as a policy objective.
Kenya	Bioenergy Strategic Action Plan	2023	Targets 3% biogas usage in clean cooking by 2028; goal of building 400 domestic and 10 institutional demonstration digesters each year until 2028.
Nigeria	National Energy Policy	2022	Sets general objective of promoting waste to energy and substituting fuelwood with biogas.
Rwanda	Ministry of Infrastructure Energy Policy	2025	Goal of transitioning from wood and charcoal in cooking to clean fuels by 2035. Sets intention for new subsidies for clean cooking technologies and new standards for biogas digesters.
Senegal	National Bioenergy Action Plan	2020	Targets 58% clean fuels in cooking (liquefied petroleum gas, biogas) by 2030; biogas to satisfy 3% of domestic fuel demand. Sixty thousand home biodigesters to be installed by 2030 under extension of the National Biodigester Programme.
South Africa	National Waste Management Strategy	2020	Targets 70% waste diversion from landfills by 2035. Supports upscaling biogas as part of the circular economy.

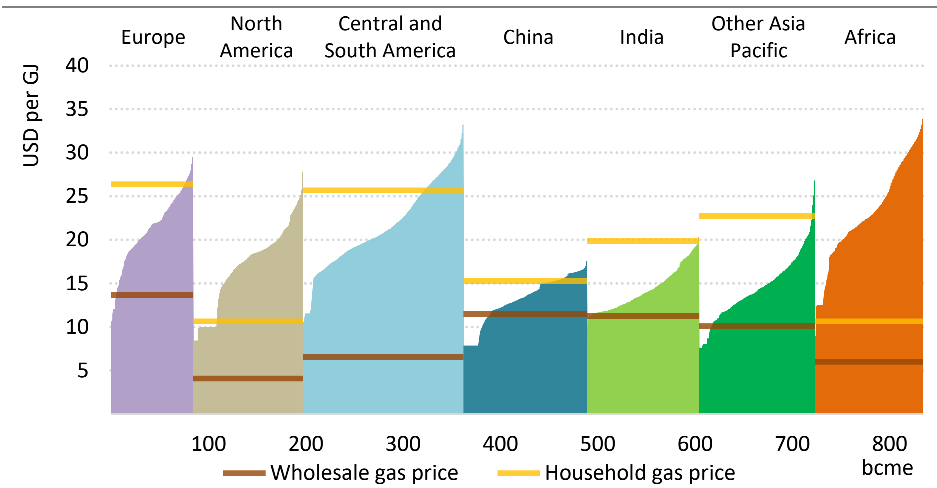
Note: EGP = Egyptian pound; FiT = feed-in tariff; GHC = Ghanaian cedi.

2.5 Competitiveness of biogases

Making the case for biogases on costs alone is challenging. The levelised cost of biogas as a source of electricity generation stands at around USD 100/MWh, far above the levels for most solar or wind projects (USD 30/MWh to USD 50/MWh) (Trinomics, 2020). The economic case for biogas improves when biodigesters are favourably located (e.g. close to feedstock sources, electricity networks and local heat offtake) or where co-benefits (e.g. the ability of biogas plants to treat wastewater with high levels of organic pollutants) are recognised and remunerated.

For biomethane, the results of our feedstock potential and cost analysis show that in most regions, average production costs are generally much higher than the wholesale natural gas price (Figure 2.9). However this is not always the case, including in China, India and other emerging market and developing economies in Asia that rely on imported natural gas. Moreover, in most regions, biomethane can be produced at a lower cost than that of household gas (the price of which includes taxes, network costs and other surcharges). This suggests that policy support – in the form of quotas, credits, fuel standards or other support schemes, or exemptions on taxes or network costs – could bring more biomethane into gas networks without significant increases in retail prices. Biogases could also have an advantage over incumbent fuels through taxes on GHG emissions or through valuing the co-benefits of biogases.

Figure 2.9 ▷ Biomethane supply cost curves in selected regions compared with average natural gas wholesale and retail prices, 2019-2024



Biomethane is costlier to produce than natural gas, although the gap between wholesale and retail natural gas prices gives policy makers bandwidth to design incentives

Note: The African household gas price is an index linked to liquefied petroleum gas (LPG).

Natural gas may not always be the main competing fuel for biogas or biomethane. For example, in Africa, liquefied petroleum gas (LPG) prices may be more relevant, or in India, the petroleum price is also a relevant comparator for biocompressed natural gas (bio-CNG). Moreover, biogases in general also compete with other sources of bioenergy, which have their own set of incentives, as well as other low-emissions sources such as hydrogen. Below we consider the prospects for biogases in different sectors when competing with other low-emissions fuels and technologies. We then consider whether some of the benefits of the production of biogases that extend beyond energy provision, such as emissions reductions and rural development, if valued appropriately, can add to the business case for development.

2.5.1 Transport

In long-distance shipping, biomethane can reduce GHG emissions when used in ships powered by liquefied natural gas (LNG). Biomethane is a drop-in substitute for natural gas, meaning it would not require any major modifications to ship engines. LNG-powered ships make up only 7% of the global fleet in gross tonnage, but comprise more than one-third of the order book for new vessels and almost three-quarters of new alternative fuel vessels (DNV, 2024). Several other possible low-emissions shipping fuels (including methanol, ammonia and low-emissions hydrogen) require modifications to ship engines, tanks, layout and additional safety measures, as well as special facilities to supply the fuel to the port, store it and fuel the ships.

A key challenge is that biomethane propulsion is not always the most cost-competitive option. While biomethane tends to be much cheaper than other low-emissions fuels, the ships require higher upfront investments due to the much larger storage tanks and the need for cryogenic refrigeration. Additionally, LNG ships contend with methane slips, where about 6% of the fuel could escape unburnt into the atmosphere (a particular risk in low-pressure, dual-fuel, four-stroke engines), posing further environmental challenges (Comer et al., 2024).

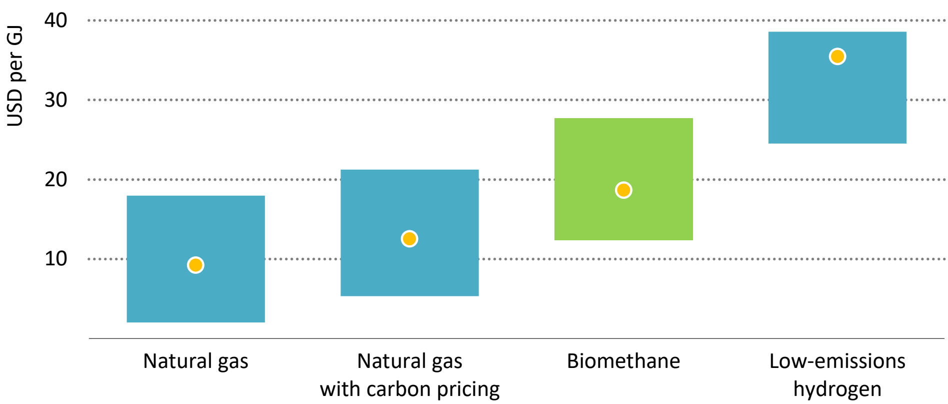
In the road sector, biomethane can be used as a drop-in fuel for the 30 million vehicles powered by natural gas – whether they run on compressed natural gas (CNG) or LNG. Road transport thus already accounts for around 15% of global biomethane demand. Some markets, such as Sweden, have a relatively larger share. However, natural gas vehicles represent less than 2% of the global vehicle fleet, and the rapid pace of electrifying cars and vans looms large over the sector's prospects. The main growth markets for CNG in recent years have been for captive fleets such as buses and long-distance heavy-duty transport. For example, China has recently experienced rapid growth in its LNG trucking fleet due to favourable economics against diesel trucks. However, the higher cost of biomethane means it is unlikely to penetrate this market without further public support. Apart from electrification, the use of biomethane in road transport also competes with other low-emissions fuels (e.g. conventional vehicles powered by synthetic fuels or liquid biofuels, hydrogen fuel cells or hydrogen internal combustion engines).

2.5.2 Industry

Several different routes are available to industry to support the development of biogases. One is to develop an onsite biodigester, which is attractive for industries producing significant agricultural by-products and waste streams such as food processing, paper manufacturing and distilleries. A second possible route is to partner with a nearby external biogas producer, securing offtake agreements. And a third is to buy biomethane from the gas grid by using guarantees of origin (Wall and O'Shea, 2025).

End-user prices of biomethane for industrial consumers range between USD 12/GJ and USD 28/GJ, positioning it between conventional natural gas (USD 2/GJ to USD 18/GJ) and low-emissions hydrogen (USD 25/GJ to USD 39/GJ). With carbon pricing at USD 50 per tonne of carbon dioxide (t CO_2), natural gas costs would increase to USD 5/GJ to USD 21/GJ, thus narrowing the cost gap with biomethane (Figure 2.10).

Figure 2.10 ▷ Global average ranges of end-user prices of gaseous fuels for industry, 2024



IEA. CC BY 4.0.

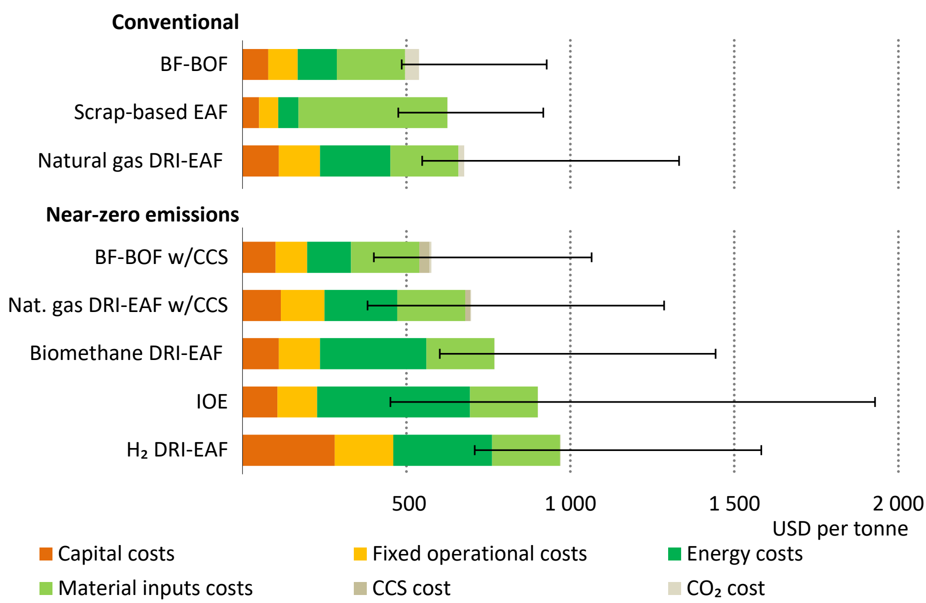
The cost of producing biomethane for industry lies between natural gas and low-emissions hydrogen, but carbon pricing could significantly improve its competitiveness

Note: CO_2 price is USD 50 per tonne of CO_2 in the carbon pricing case. Dots represent median prices.

Given the limited availability of sustainable biomass resources, there is a case for developing biomethane for applications where few other decarbonisation alternatives exist, such as in sectors requiring high-temperature heat (i.e. above 400 °C), where electrification can face technical and economic barriers. Examples include glass and ceramics manufacturing, and some food production.

Biomethane could also replace natural gas as a feedstock, such as in the steel sector, in the production of direct reduced iron (DRI) paired with producing steel in electric arc furnaces (EAFs). A pure stream or a blend of biomethane could offer a lower-emissions alternative to coal-based blast furnaces and provide feedstock flexibility to DRI processes. Although costs for these fuels vary widely by region and site-specific context, using biomethane in DRI-EAF processes is likely to be about 15% more expensive than using natural gas, but approximately 20% less expensive than using low-emissions hydrogen. With carbon pricing at USD 50/t CO_2, the cost differential with natural gas falls to around 15% (Figure 2.11). This assessment is broadly in line with other estimates in the literature (Common Futures, 2024).

Figure 2.11 ▷ Levelised cost of production for steel by technology



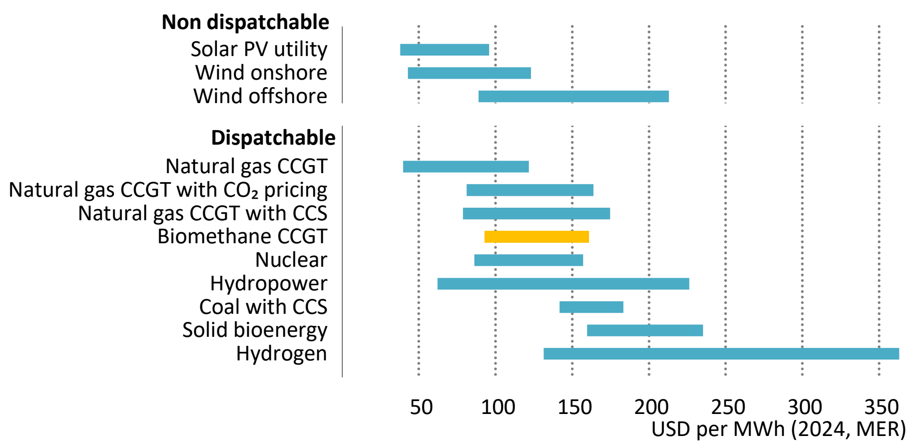
Biomethane can be blended with other fuels in DRI processes, potentially offering a cost-competitive route to bring down overall emissions from steel-making

Notes: BF = blast furnace; BOF = basic oxygen furnace; w/ CCS = with carbon capture and storage; H_2 = hydrogen; IOE = iron ore electrolysis. Bars show the levelised cost using typical regional costs for best available technology energy performance. CO_2 pricing is assumed at USD 50 per tonne of CO_2. Costs are exclusive of explicit financial support, but may include financial support embedded in individual cost components (e.g. fossil fuel subsidies).

2.5.3 Power generation

During high-demand periods or when other renewable energy sources such as wind or solar are not available, increased biogas production or stored biogases can be leveraged to provide power system flexibility. The ability to provide flexibility depends on the business model and the operational characteristics of biogas plants. For example, whether they are biogas-based or biomethane-based units, whether standalone or grid connected, and whether they have the capacity to store sufficient quantities of either feedstock or biogases onsite. CHP-based biogas plants can optimise thermal and electrical output depending on short-term and seasonal variations in local heat and power demand. CHP units connected to the electricity grid can provide firm, renewable baseload power, or additional dispatchable capacity if storage is available. Units connected to the gas grid (e.g. open-cycle gas turbines) are flexible and could run on a blend of natural gas and biomethane. This also depends on the incentive scheme; plants benefiting from feed-in tariffs typically seek to maximise continuous operation, whereas capacity contracts or other forms of remuneration for providing ancillary services for the power grid could encourage units to run more flexibly.

Figure 2.12 ▹ Levelised cost of electricity produced from biomethane and other dispatchable and non-dispatchable technologies, 2024



IEA. CC BY 4.0.

Despite higher levelised cost of electricity than solar photovoltaics and onshore wind, biomethane power plants offer competitive dispatchable electricity generation

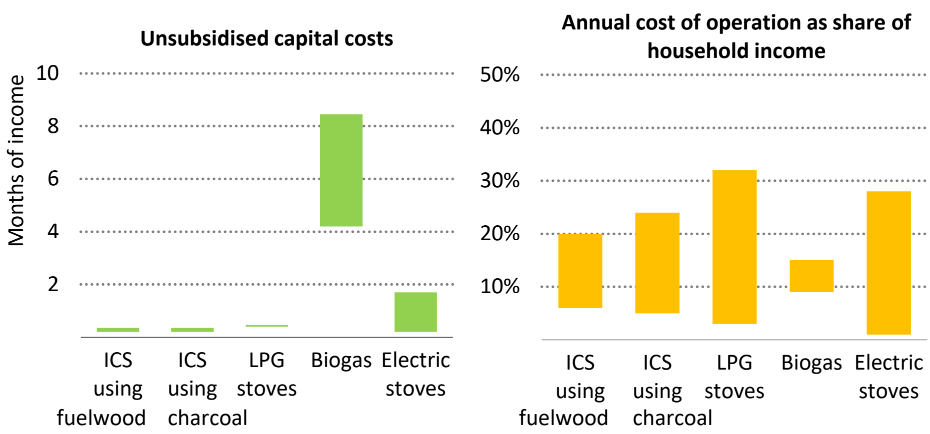
Note: CCGT = combined-cycle gas turbine; MER = market exchange rate; "Natural gas CCGT with CO_2 pricing" = natural gas with a CO_2 price of USD 50 per tonne; PV = photovoltaics.

The levelised cost of generating electricity from biomethane ranges from USD 95/MWh to USD 160/MWh. These costs are around 50% higher than for onshore wind and solar photovoltaic generation. However, biomethane plants can operate in a flexible manner and so provide balancing and other ancillary services to the electricity network. For seasonal flexibility, gas-fired power plants are still one of the few readily available options. The use of biomethane would enable this role to be performed with lower emissions than using natural gas. The levelised cost of electricity of power plants fired by natural gas is around 15-70% lower than that of biomethane, but a CO_2 price of USD 50/t CO_2 would reduce this gap to 0-50% (Figure 2.12).

2.5.4 Clean cooking

Biogas is one of several modern fuels and technologies that can provide clean cooking. The increased use of these fuels and technologies would mean lower rates of premature deaths related to indoor and outdoor air pollution, as well as positive socio-economic benefits such as less time spent collecting fuelwood. Small biodigesters, which are suitable for households with a few cows, are a clean cooking solution primarily for rural areas.

Figure 2.13 ▻ Annualised total cost of cooking and upfront cost as a share of income for low-income households in sub-Saharan Africa, 2022



Household biodigesters have higher upfront costs but lower fuel and operating costs than other clean cooking options

Notes: ICS = improved cook stoves. Electric cooking includes traditional hot plates and induction. Annual cost of operation shown for collected biomass users includes the opportunity cost of the time used for biomass gathering/harvesting (collection) and the stove cost for ICS. The analysis assumes two cooked meals a day.

Source: IEA (2023).

The main economic challenge for biogas as a clean cooking solution is the relatively high upfront cost of the biodigester. In sub-Saharan Africa, upfront costs for an average-size biodigester can reach up to 8 months of income for a low-income household, compared with less than 2 months for improved solid fuel burning stoves or LPG and electric stoves (Figure 2.13). However, on a total cost-of-ownership basis, biodigesters have a corresponding advantage since they have low or zero fuel costs. Nevertheless, producing and gathering sufficient feedstock cannot be taken for granted. Generating enough biogas to prepare one family meal requires 20-30 kilogrammes (kg) of fresh manure daily, along with an equivalent quantity of water.

2.5.5 Closing the competitiveness gap

Producing biogas results in positive externalities that go beyond its role as a renewable energy source. For example, biogas helps to prevent the environmental damage that can be caused by the dispersal of waste (e.g. contaminating aquifers by manure), as well as avoiding methane emissions that would otherwise have occurred. It also contributes to energy security and creates jobs, particularly in rural areas. Previous studies have analysed some of these co-benefits (EBA, 2023). In the following, we consider how valuing avoided GHG emissions, using the CO_2 produced during biogas upgrading and valorising digestate can improve the value proposition for biogas projects.

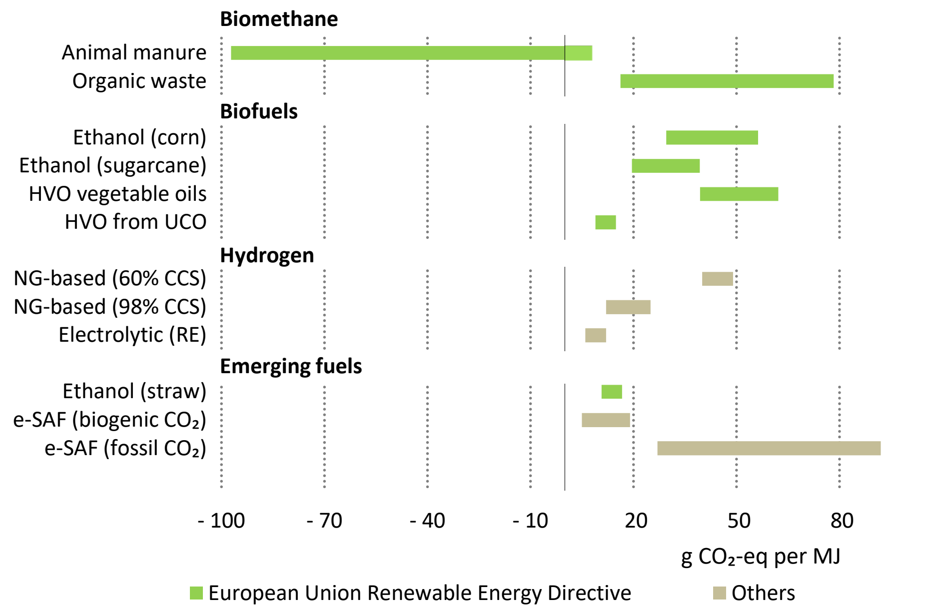
Valuing greenhouse gas emissions reductions

If GHG emissions prices are applied to the combustion of natural gas, then biomethane would be a more attractive proposition. When policy recognises the value of avoided methane emissions that would otherwise take place from the decomposition of feedstocks, an even larger quantity would be commercially attractive. However, methane leaks that occur in the biogas production process can risk undercutting the environmental benefits of production of biogases (see Chapter 3). For example, biogas production from manure in the European Union with best operational practices and methane leak detection programmes has a life-cycle emissions intensity of around -80 grammes of carbon dioxide (g CO_2) per megajoule (MJ), while production without best practices would be closer to 10 g CO_2/MJ.

When compared to other current and emerging sustainable fuels, biomethane can have a competitive advantage in markets that take GHG reduction performance into account (Figure 2.14). Biomethane produced from manure reports the lowest carbon intensity scores when compared to other liquid biofuels, low-emissions hydrogen and hydrogen-based fuels. This is due to the accounting of avoided methane emissions from untreated manure. Biomethane production from other types of waste, such as food waste, can report low scores when best practices are put in place, with further potential reduction if it is combined with CO_2 capture and sequestration. Conversely, liquid biofuels can report low carbon intensity scores for certain types of feedstocks, such as used cooking oil. In the case of hydrogen, carbon intensity will rely mostly on the source of electricity used in electrolysers or the degree of carbon sequestration in hydrogen produced from natural gas with carbon capture and storage. In the case of synthetic fuels, the main driver will be the source of CO_2 (fossil fuels versus biogenic fuels).

The difference between applying best practices for development of biogases (explored further in Chapter 3) against not doing so has a major impact on the cost-competitiveness of biogases. For example, without using best practices, a GHG emissions price of around USD 200 per tonne of carbon dioxide equivalent (t CO_2-eq) would be required to make one-third of the biomethane potential cost-competitive with natural gas. With best practices, this increases to half of the potential, with a price closer to USD 100/t CO_2-eq (Figure 2.15). As the cost of avoiding methane leaks is usually low, this would improve significantly the bankability of biomethane projects.

Figure 2.14 ▷ Typical GHG emissions ranges for biomethane and other low-emissions fuels



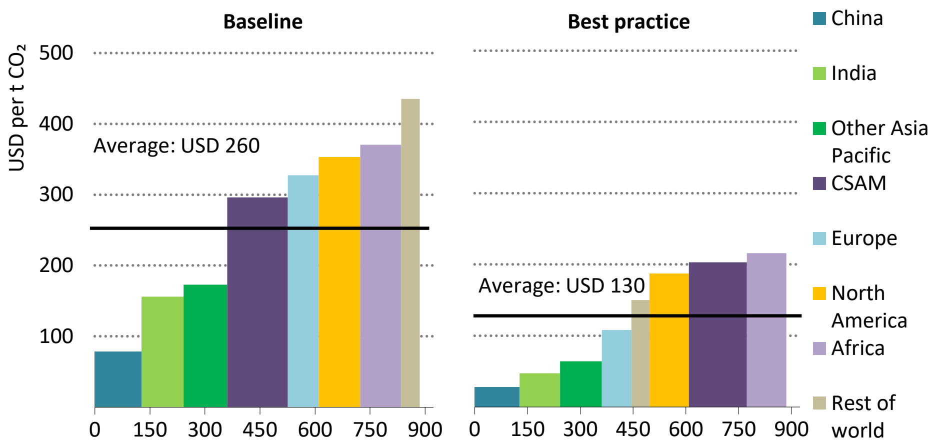
Biomethane can achieve exceptionally low GHG emissions, especially when using animal manure and applying best practices for managing methane emissions

Notes: e-SAF = synthetic sustainable aviation fuel; g CO_2-eq = grammes of carbon dioxide equivalent; HVO = hydrotreated vegetable oil; NG = natural gas; RE = renewable energy; UCO = used cooking oil. Others are calculated ranges based on IEA analysis.

Source: RED II, Annex VI, updated with the last estimation of methane leakage from biogas plants from the Joint Research Centre (Directive (EU) 2018/2001) (JRC, 2024).

For example, emission allowances on the EU emissions trading system have averaged around USD 85/t CO_2-eq over the past 3 years, and so most biomethane production using best practices in Europe would have been cost-competitive with natural gas, even without considering additional subsidies or value added from digestate or biogenic CO_2 sales.

Figure 2.15 ▷ Marginal abatement cost of biomethane following standard and best practices, 2024



Applying best practices in minimising methane emissions can significantly reduce the GHG emissions prices needed to make biomethane competitive

Note: CSAM = Central and South America

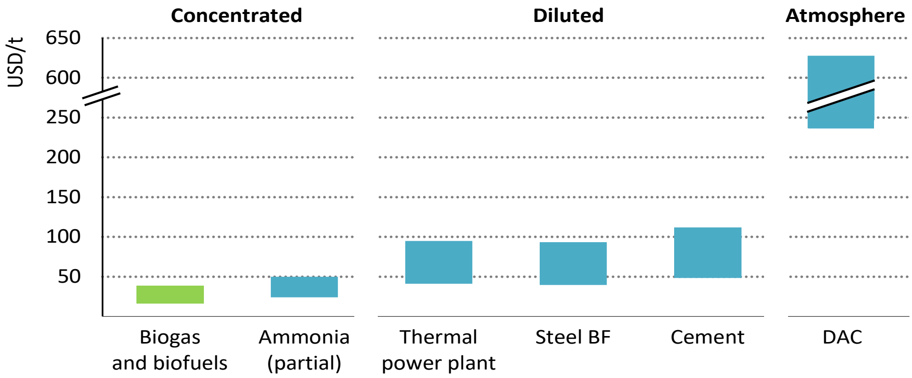
Using carbon dioxide by-products

Biogas upgrading results in a highly concentrated stream of biogenic CO_2. This can be used as an input into low-emissions fuels production (when combined with renewable or low-emissions hydrogen) or captured and stored.

The opportunity to recover CO_2 from biogas upgrading depends heavily on the characteristics of the plant. If the plant is too small or too remote, it may not be able to justify the additional costs involved in conditioning or transporting the CO_2. Transporting the CO_2 by truck is likely to be the most viable option for most plants, with costs estimated at around USD 0.10/t CO_2-km (Stolaroff et al., 2021). Plants with access to local offtakers or the ability to valorise CO_2 onsite such as through methanation may be better positioned to reduce logistics costs.

In large biogas upgrading plants, which benefit from economies of scale, the concentrated stream of CO_2 can often be captured for around USD 15/t CO_2 to USD 40/t CO_2. This is much lower than the more dilute streams produced by the steel and cement industries and thermal power plants (which often cost USD 40/t CO_2 to USD 110/t CO_2), and by direct air capture (Figure 2.16). If the CO_2 is captured, it can be used in the food or beverage industry or mineralised in building materials. Several projects already do this. For example, OCO Technology in the United Kingdom injects CO_2 from biogas upgraders and distilleries in three concrete curing facilities, providing around 20 000 t CO_2 removal per year. And Neustark in Switzerland provides around 2 000 t CO_2 removal per year (IEA, 2025). The use of CO_2 in this way allows for a CO_2 removal credit on voluntary carbon markets worth around USD 500/t CO_2 to USD 600/t CO_2 (CDR.fyi, 2025).

Figure 2.16 ▹ Levelised cost of capture from biogas upgrading and other sources of CO_2, 2024



CO_2 capture from biogas upgrading is significantly cheaper than less concentrated CO_2 streams from industry or direct air capture

Note: DAC = direct air capture.

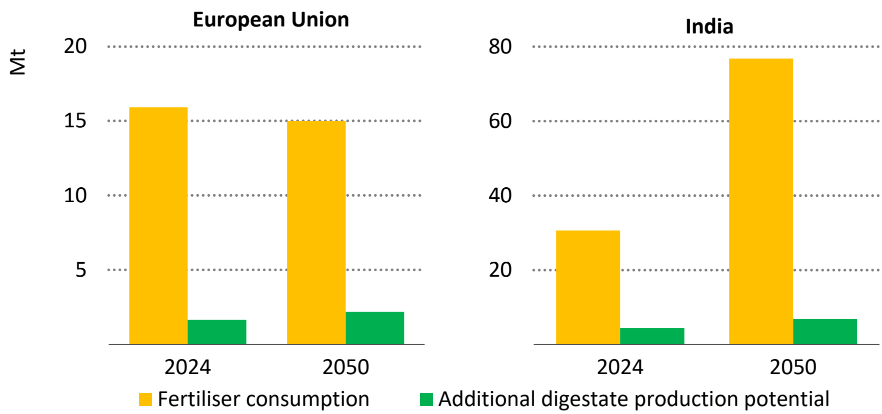
Valorising digestate

Many regions rely heavily on imports of conventional fertilisers to meet their domestic needs. In 2022, the European Union imported about half of its total fertiliser consumption, while India imported around a third (Fertilizers Europe, 2023; FAI, 2024).

The use of digestate from anaerobic digestion can meet a small fraction of total fertiliser consumption demand. Depending on the type of feedstock and local regulations, specific steps are required to convert digestate into a crop-available biofertiliser, enabling closed-loop nutrient recycling and reducing reliance on synthetic fertilisers.

Considering the nutrient content of digestated-based agricultural residues and biowaste, as well as the current use of undigested manure and digestate as biofertilisers, we estimate that fully harnessing the potential of biogas and using the resulting additional digestate could replace around 15% of the European Union's and 10% of India's projected fertiliser demands by 2050 (Figure 2.17). This would reduce fertiliser imports, which are valued at nearly USD 9 billion in the European Union and avoid the CO_2 emissions associated with fertiliser production (European Commission, 2024). If fertiliser companies were to source a proportion of what they sell from low-emissions sources such as digestate, this would significantly improve the economics of biogas projects.

Figure 2.17 ⊳ Volume of fertiliser consumption and potential digestate production in the European Union and India, 2024 and 2050



Digestate production potential could cover 10-15% of fertiliser demand in the European Union and India by 2050

Notes: Mt = million tonnes. Fertiliser refers to nitrogen-, phosphorus- and potassium-based fertilisers.

Sources: IEA analysis based on data from EBA (2023), Fertilizers Europe (2023) and FAI (2024).

Depending on local conditions, digestate can be applied directly to land or undergo various post-treatments. Some of them aim at facilitating transport, when the distance from the biogas plant exceeds 10 km, such as separation of solids (using a screw press or centrifuge), thermal drying or membrane processes. Others (e.g. nitrogen stripping) aim to avoid soil pollution, especially when there is excess digestate or in nitrate-vulnerable zones. Ensuring quality standards can be a significant challenge towards wider digestate uptake. One option is to co-compost digestate solids with other agricultural residues to produce a high-quality organic fertiliser.

Digestate can also be transformed into biochar through direct pyrolysis. Biochar is a solid, charcoal-like substance that has received interest for the role it can play as a carbon store and to improve soil productivity (see Section 3.5).

According to the EU Renewable Energy Directive Implementing Regulation (EU) 2022/996, digestate and biochar, when added into soils where crops for biofuels are cultivated and produced within the same biomass cycle, can generate a bonus up to 25 grammes of carbon dioxide equivalent (g CO_2-eq)/MJ for digestate and up to 45 g CO_2-eq/MJ for biochar. This credit reduces the carbon intensity of the biofuels produced from such areas, including biogas or biomethane (Regulation (EU) 2022/996).

Key issues affecting biogases

What keeps cropping up?

SUMMARY

- This chapter considers issues and barriers that affect the development of biogases, grouped into four areas: feedstock trends and availability; sustainability and life-cycle emissions; permitting and infrastructure; and potential for cost reductions through innovation.
- Country policies governing feedstock use for production of biogases vary widely. Regulatory frameworks for waste management in municipalities and agriculture can facilitate or hinder the availability of certain feedstocks. For example, in Europe, several governments have taken steps to curb or ban the use of energy crops, shifting feedstock towards a mix including crop residues, animal manure, organic municipal solid waste (MSW) and industrial waste. In the United States, landfill gas is the main source of biogas, but policies targeting the treatment of manure have shifted the focus to large-scale dairy operations.
- Methane leaks can undercut the GHG emissions benefits if biogas and biomethane projects are poorly operated. Evidence suggests that today's biogas and biomethane plants emit methane emissions in a range between 2% and 5% of their output. In some cases, projects also avoid methane emissions that would otherwise occur, but operational leakage rates are nonetheless far above average levels seen in the oil and gas industry. The concerted application of best practices – notably through closed digestate storage, combustion of off-gases during biogas upgrading processes, and leak detection and repair programmes – is essential to underpin the environmental case for biogases.
- Some biogas plants have encountered difficulties and delays with permitting. However, they are not at a noticeable disadvantage compared with other onshore clean energy projects. Timelines vary by jurisdiction and type of plant, but it typically takes 2-5 years to develop a biogas project. Projects may come to market sooner if they can avoid the need to secure an electricity grid connection, which is one of the main bottlenecks to clean energy deployment worldwide.
- The main technologies used for biogas and biomethane production are already mature, although there is still scope for improvement. The use of innovative technologies or approaches could increase methane yields, improve energy efficiency and recovery at biogas plants, and integrate biogas production processes and waste streams with the production of other low-emissions fuels. For example, combining CO_2 streams from biomethane production with hydrogen can generate synthetic fuels, and digestate can be converted to higher-value fertiliser products and biochar (a concentrated carbon-rich material).

3.1 Introduction

If designed well, policies promoting biogases can have positive impacts on energy security, environmental sustainability, waste management and agricultural development. However, the potential for biogases is not recognised or exploited in most of the world. Chapter 2 considered techno-economic conditions affecting the global prospects for biogases. This chapter considers other non-economic barriers facing biogases projects, and also explores the potential to increase methane yields via innovation, and the role of the circular economy.

Biogases projects compete with cheaper incumbent fuels for market share; therefore, they can struggle to secure funding. Policies are key to lowering barriers to enter the market and ensure profitability for producers. Public awareness and political will also play an essential role in driving supportive policy frameworks. Without strong stakeholder engagement, implementation gaps can limit the effectiveness of even the most well-crafted policies.

Policies governing feedstocks for biogases vary widely among jurisdictions, reflecting local environmental priorities, energy policy goals and waste management strategies. Some countries incentivise the use of food waste and manure to reduce life-cycle methane emissions, while others focus on diverting MSW from landfill sites to biogases production, or capturing landfill gas.

Permitting is another area where biogases plants have encountered difficulties. On average, it takes about 3 years to develop a biogases project; however, in some cases, it can take up to 7 years just to secure the necessary permits. However, biogas projects are not unique compared with other clean energy projects. By targeting injection into gas grids or using biomethane as a transport fuel, several projects could sidestep the issue of having to secure an electricity grid connection (which is one of the largest technical bottlenecks to clean energy deployment worldwide).

The sustainability credentials of biogases have been increasingly scrutinised in recent years. The move away from energy crops in Europe is laudable, but recent published data show a wide range of uncertainty around methane emissions. On average, biogas plants emit methane emissions equivalent to between 2% and 5% of their output, which is a value above the average level seen in the oil and gas industry (IEA, 2025). However, the overall impact on life-cycle emissions depends on the feedstock mix, especially if methane emissions would otherwise occur if they were not captured for production of biogases. The overall impact also depends on the application of best practices along the supply chain.

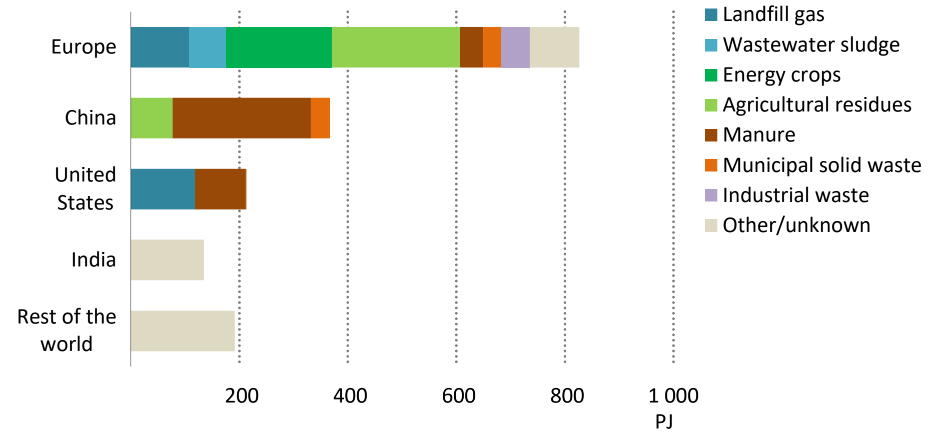
3.2 Feedstock trends and availability

Production of biogases depends heavily on the type and volume of available local feedstocks (Figure 3.1). Awareness of the trends and drivers of feedstock use can help policy makers design successful frameworks for deployment of biogases.

Biogas was first observed in the 17th century, with practical use beginning in the late 1800s when sewage gas was used to power street lamps in the United Kingdom. From the 1950s, large rural biogas programmes expanded in China and India as a way to treat animal manure in rural areas, and in industry to treat sewage sludge from wastewater. At first, the use of crops for biogas production was not economically feasible, and vegetation was added only occasionally to biodigesters.

In the 1990s, in the context of high oil prices, some countries in Europe developed favourable frameworks with feed-in tariffs (FiTs) rewarding renewable power production, including power from biogas. This supportive environment fostered rapid growth in the sector. The use of energy crops with higher yields played an important role in countries such as Germany and the United Kingdom. However, starting around 2010, the use of energy crops raised concerns regarding potential adverse impacts. These included competition for land use with food and feed crops, and negative environmental impacts like soil degradation and biodiversity losses.

Figure 3.1 ▷ Feedstock use for production of biogases by selected country and region, 2023



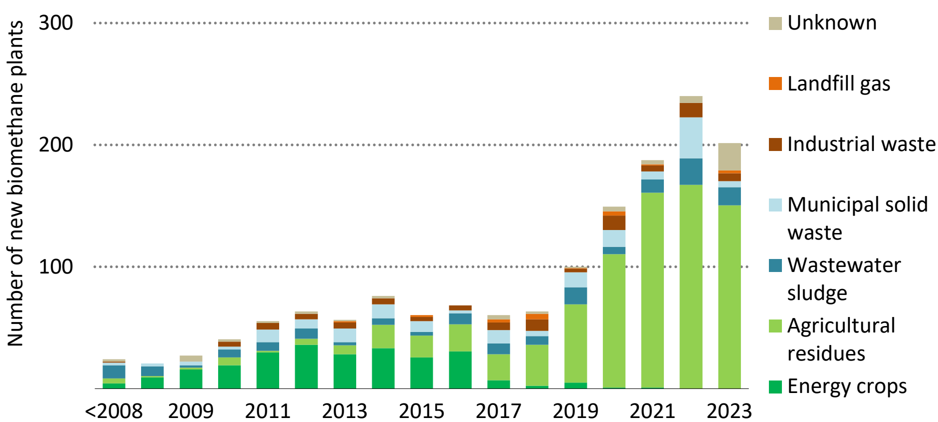
Feedstock mix differs starkly by region and country. While Europe has a varied feedstock mix, China's is 70% manure based and the United States' feedstock is 60% landfill gas.

Note: PJ = petajoules.
Source: IEA analysis based on data from Wang et al. (2023), EBA (2024a) and CI Consulting (2024).

In light of the potential adverse impacts of energy crops, some governments have since taken steps to curb or ban their use altogether. The European Union supports the preferred uptake of waste and residues, double counting their share towards renewable energy quotas in the Renewable Energy Directive (RED). In Germany, operators are required to disclose the sources and volumes of feedstocks annually, and are subjected to caps on the proportion of whole maize and cereal crops used for energy production. Under the German Renewable Energy Sources Act, maize is capped at 35% for the years 2024-25 and 25% in 2026-28. In France, food and energy crops may not exceed a maximum proportion of 15% of the total gross weight of inputs into biogas plants per year. In Denmark, the maximum input share of energy crops from 2025 is set at 4%, and the use of maize is prohibited (Energistyrelsen, 2024).

With these restrictions in place, the overall feedstock mix for biogases in Europe is evolving towards a mix of agricultural residues, MSW and industrial waste. Although still used in existing plants in some countries, energy crops have largely been phased out of use in European biomethane plants constructed since 2020 (Figure 3.2).

Figure 3.2 ▹ Feedstock use in new biomethane plants in Europe, 2010-2023



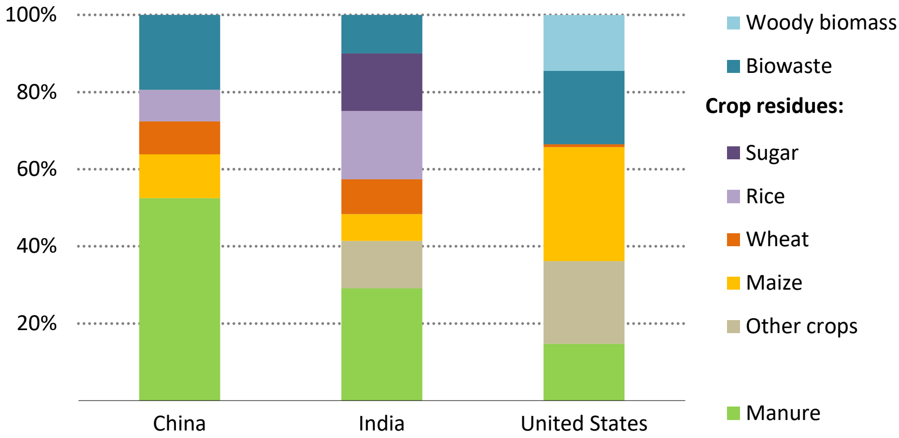
Energy crops historically accounted for up to half of the feedstock mix, but new regulations have supported the shift to use of residues, manure and waste

Source: EBA (2024a).

In other jurisdictions, waste management and rural development agendas have driven feedstocks for biogases. In China, production of biogases was integrated into the 11th Five-Year Plan for the Development of Renewable Energy (2006-2010). This set targets of 40 million household biodigesters and 4 700 industrialised biogas projects at livestock or poultry farms by 2010. The One Digester Plus Three Renovations approach promoted household installations, where kitchens, toilets and animal barns were renovated to channel waste to the newly constructed digesters (UNDP, 2011). In later Five-Year Plans, the policy priorities shifted to promote mid- and large-scale biogas plants that use rural and urban waste feedstocks in an integrated manner with animal manure and agricultural residues.

India's National Biogas and Manure Management Programme in rural and semi-rural areas aims to treat livestock waste to provide biogas for clean cooking and biofertiliser for agricultural purposes. Other national programmes such as the Galvanizing Organic Bio-Agro Resources Dhan programme include organic waste collection from municipalities to produce biogas.

Figure 3.3 ▷ Feedstock potentials in China, India and the United States



China, India and the United States illustrate the different potential feedstock mixes available for production of biogases

In the United States, landfill gas is the main source of biogas. With lower natural gas prices than in other countries, landfill gas was traditionally the only source of biogas competitive with natural gas. However, in recent years, the sector has expanded into the use of agricultural residues. In particular, dairy farms have received intensive support for biomethane production for transport use, rewarded by federal subsidies and markets based on carbon intensity such as the one under California's Low Carbon Fuel Standard (LCFS). California also has a mandate for gas utilities to supply a certain share of biomethane from organic waste diverted from landfills. The United States has potential to diversify its feedstock mix into crop residues, biowaste and wood residues (Figure 3.3).

Options for the sector to continue growing the use of sustainable feedstocks include alternative agricultural practices that do not require additional land use, such as the use of cover or sequential crops or cultivation in marginal and contaminated lands (Edrisi and Abhilash, 2015). For example, the Biogas Done Right concept developed by the Italian Biogas Association uses cover crops that are co-digested with manure, with the digestate returned to fields to recover nutrients and carbon. However, further evaluation of such lands is required to establish their suitability for bioenergy production.

Waste management frameworks and agriculture regulations may also indirectly affect biogas development by facilitating or hindering the availability of certain feedstocks. EU legislation is a good example. The 2024 EU Urban Wastewater Directive includes targets for climate neutrality and energy efficiency of wastewater treatment plants, which bolsters the case for equipping them with anaerobic digesters. The EU Waste Framework Directive set an obligation to collect organic waste in municipalities separately from 2024, which provides an additional possible feedstock stream for anaerobic digestion (Directive 2008/98). The European Commission's Clean Industry Deal highlights the importance of sustainable biofertiliser production as meeting circularity and security goals, providing a spur to valorising digestate (COM/2025/85) (Box 3.1).

Box 3.1 ▻ Digestate as a biofertiliser: policy considerations

As the nutrient-rich co-product of anaerobic digestion, digestate has significant potential as a biofertiliser. It could reduce reliance on synthetic fertilisers and close nutrient loops in agriculture. However, several policy considerations shape its widespread adoption.

Some jurisdictions provide incentives for digestate use to improve soil health and reduce emissions from conventional fertilisers. Under the EU Fertilising Products Regulation, digestate can be classified as an organic fertiliser if it adheres to strict standards regarding contaminants like heavy metals and pathogens. This regulatory framework is part of the broader EU circular economy strategy, aiming to promote the safe and effective recycling of nutrients from organic waste. Moreover, EU guidance on nutrient management and environmental protection – such as through the Nitrates Directive – ensures digestate is applied in a way that minimises risks like nitrate leaching, thereby protecting water quality and soil health (Directive 91/676). In India, the use of organic manures and fertilisers are promoted under the Paramparagat Krishi Vikas Yojana programme.

Regulatory frameworks for waste and agricultural management may also create unintended challenges for digestate. The designation of digestate as a waste in national law (Ireland and Portugal) or the lack of its legal recognition as a biofertiliser tend to hinder utilisation, as producers must apply for specific authorisation for application. Even where digestate is given "end-of-waste" status (France and Spain) or directly categorised as a fertiliser (Austria and Germany), administrative burdens may persist. For example, France limits the use of digestate due to concerns about nutrient infiltration into groundwater, soil acidification and eutrophication of surface waters. The variance of regulatory requirements by feedstock and the lack of harmonisation among national standards complicate the widespread use of digestate.

Industry quality standards can help overcome consumer wariness and promote confidence and uptake of digestate as a biofertiliser. In Sweden, the Certified Recycling quality assurance scheme has contributed to the extensive use of organic fertiliser from digestate on agricultural land (EBA, n.d.).

In Europe, each gigawatt hour of biogas produced from agricultural residues results in around 200 tonnes of digestate. This can vary considerably depending on the type and composition of the feedstock used (EBA, 2023). The European Biogas Association estimates that close to 90% of digestate produced in Europe is ultimately used as biofertiliser, either directly as produced or after an upgrading process (EBA, 2024b). The remaining portion, once dried or treated, is exported or applied to other uses (e.g. soil production, animal bedding, landfill coverage and nutrient recovery).

However, as the sector scales up, it is less certain that digestate can be valorised locally. For large digester systems with large quantities of digestate, application of digestate to existing farmland may result in considerable expense and logistical complexity, and the transport of liquid digestate is impractical over large distances. For areas suffering from eutrophication (as evidenced by algal blooms in receiving waters), there may be low capacity for the land to accept digestate.

Challenges in mobilising feedstock

There are logistic, economic and organisational challenges in collecting feedstock for biogas. Developing reliable supply chains involves building a new market for feedstock and developing trust between farmers and biogas plant operators, both of which take time and careful co-ordination.

A key challenge is ensuring a reliable supply of feedstock for the lifetime of a biogas plant. The size of a plant is closely tied to feedstock availability. For example, larger plants need a steady, high-volume feedstock supply, while smaller plants may be more flexible but face higher per-unit costs. Biogas and biomethane offtakers also often require long-term contracts (15-20 years), but it can be difficult securing a reliable supply of waste feedstock for this duration. Another challenge relates to the changes in the availability and quality of biogas feedstock over seasons. Producers therefore often rely on a mixture of different types of waste that allows them to take into account the seasonal variability of residues, and storage needs.

To address these challenges, countries are developing cooperative models, centralised collection hubs and digital platforms to co-ordinate logistics and improve transparency. Policy incentives, technical assistance and pilot projects are also helping to show viable business models and encourage broader participation and investment.

Feedstock competition

The wet organic feedstocks identified in this report are most suitable for biogases production in terms of the ease with which they can be broken down in anaerobic digesters. These include manure, sludges, low-lignin grasses and residues, and legumes. Together, these feedstocks amount to around 300 billion cubic metres of natural gas equivalent (bcme), or around 30% of the total potential of biogases.

The remaining feedstocks for biogas, such as biowaste, high-lignin crop residues and woody biomass, may also be suitable for other bioenergy pathways, such as ethanol, biodiesel or biojet fuel. For example, wood processing or log residues (15% of the potential for biogases), or high-lignin crop residues such as stover (another 17% of the potential), could be used to produce sustainable aviation fuels via gasification. In the case of straw, despite the potential for competition with second-generation ethanol plants, biogas seems to be the prevailing use for straw residues in places like Brazil and India, due to lower capital costs and technology risks.

Other feedstocks are less suitable for biogases. Fats, oils and greases are valuable for biodiesel and biojet production, which are a preferred use of these feedstocks. Therefore, competition between biogases and biofuels for these specific feedstocks is unlikely.

There are also complementary pathways for biogases and other forms of bioenergy. Production of biogases can be integrated into existing food industry or biofuel production pathways. For example, residues from ethanol production, such as grain husks, or rice cakes, or by-products from the sugar cane industry such as vinasse, filter cake and tips, are all suitable feedstocks for production of biogases. Section 3.5 explores the potential for synergies in different bioenergy and low-emissions fuel value chains.

3.3 Sustainability, life-cycle emissions and methane

The potential to realise emissions reductions from using biogas or biomethane depends on how these gases are produced and where they are used in the value chain. While the end-use consumption of biogas and biomethane is considered CO_2 neutral[1], emissions can occur during feedstock collection, transport and processing. Such emissions can come from, for example, the energy needed to drive tractors and trucks, to dry, grind and mix feedstocks, to operate anaerobic digesters, and to store and apply digestate. The upgrading of biogas to biomethane can also produce emissions.

In addition, biogas is predominantly methane, which is a potent GHG (30 times greater than CO_2 on a 100-year scale). Methane leaks to the atmosphere can occur during feedstock storage and open storage of the digestate, as leaks from tanks, valves and pipes, and from off-gases that escape during biomethane upgrading. A high methane leakage rate could undermine some of the environmental benefits of biogases over fossil fuels (Figure 3.4).

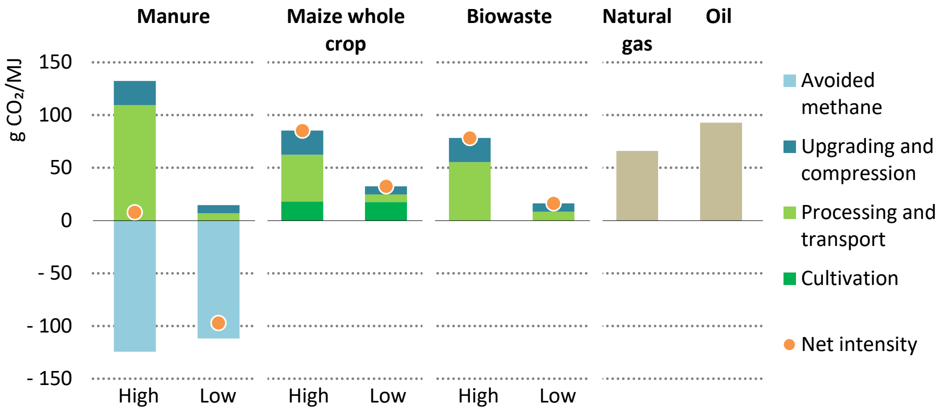
Some of the feedstocks that can be used to produce biomethane would have otherwise decomposed in the absence of oxygen and resulted in methane emissions to the atmosphere. This applies particularly to animal manure and food waste when landfilled. Biomethane production can avoid these emissions by capturing and processing them instead. Most other feedstocks would otherwise degrade in the presence of oxygen and so do not commonly result in methane emissions to the atmosphere.

Evidence suggests that methane emissions to the atmosphere from biogas and biomethane plants in Europe are relatively high. There is a wide range of estimates depending on the type of technology used, the size of plants and how they are operated (JRC, 2024). About 0.1-2.4%

[1] CO_2 emissions arise when biogas and biomethane are combusted. But the organic material used to produce the biogases captures a similar quantity of CO_2 from the air, and net CO_2 emissions to the atmosphere from their use are assumed to be zero.

of the methane produced from a biogas plant is estimated to leak during feedstock reception (Wechselberger et al., 2023). The biogas production process can see leakage rates ranging from 0% to 12% (with the higher end resulting primarily from more frequent use of pressure release valves attached to the biodigesters (Reinelt et al., 2016)), and a further 0.2-10% is estimated to leak during biomethane upgrading, depending on the technology used (with water scrubbers exhibiting higher leakage rates than membrane separation) (IEA Bioenergy, 2009; Sun et al., 2015; Ardolino et al., 2021; JRC, 2024). Leakage from digestate storage can range from 0.8% to as high as 15%, depending on whether digestate is stored in open conditions, such as lagoons, or in gas-tight tanks. Site-specific measurements for whole plants have suggested average leakage rates of around 2.4% for agricultural biogas plants and 7.5% for wastewater treatment plants (Scheutz and Fredenslund, 2019), and around 2% for large-scale plants compared with 5.5% for small- and medium-scale plants. For comparison, the global average methane emissions leakage rate for oil and gas production was around 1.2% in 2024 (IEA, 2025).

Figure 3.4 ⊳ Reference life-cycle greenhouse gas emissions intensities of European Union biomethane compared with natural gas and oil



Life-cycle emissions vary by operational practices and feedstock – methane leaks are a key factor. In some cases, biomethane could result in higher emissions than fossil fuels.

Notes: g CO_2/MJ = grammes of carbon dioxide per megajoule. Intensities show the lowest- and highest-emitting production routes. GHG life-cycle emissions for natural gas and oil are global averages and include emissions from production, processing, transport and combustion. Combustion emissions are not included for biomethane since they are biogenic CO_2. Avoided manure credits are lower in the low-emissions case because best practice operations capture greater quantities of the methane.

Source: IEA analysis based on data from the EU RED, Annex VI, updated with methane values from JRC (2024).

Technology and policy options to minimise emissions from biogases

There are several technology and process options available to reduce emissions from biogases (Figure 3.5). In some cases, the cost of deploying these is less than the value of the additional methane that is produced and can be sold. Examples of the options available include:

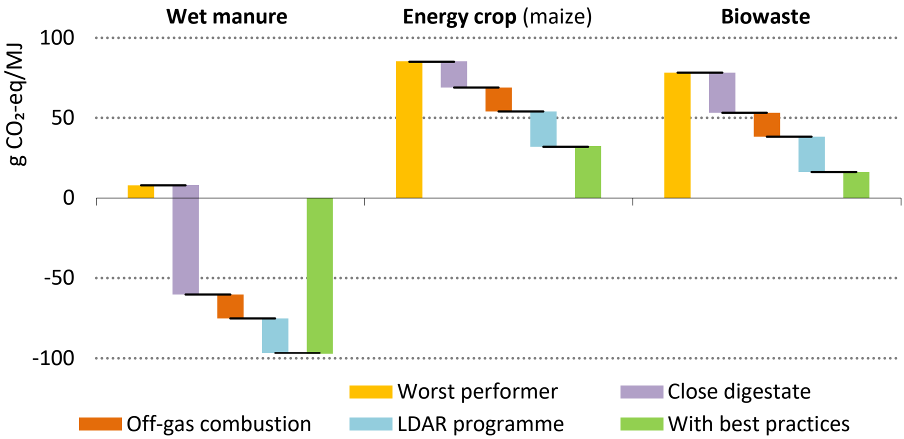
- Using gas-tight tanks to prevent leaks during feedstock intake and digestion.
- Ensuring a low feedstock filling level in digesters, which avoids the need to release methane via pressure release valves as a safety mechanism.
- Storing digestate in gas-tight tanks. This is now a best practice, with some countries implementing requirements for minimum closed digestate storage times (e.g. 30 days in Italy) (JRC, 2024).
- Increasing digestate hydraulic retention time (number of days in the digester) to ensure full anaerobic breakdown.
- Churning digestate to provide oxygen and inhibit methanation.
- Combusting off-gases produced during upgrading. The most common approach is regenerative thermal oxidation.
- Deploying leak detection and repair programmes across the supply chain to avoid and quickly remedy accidental leaks.

Some countries are introducing regulations to reduce methane emissions from biogas plants. For example, in 2023, Denmark implemented a national rule aimed at limiting leakage rates to 1%. There are also opportunities to reduce GHG emissions through the use of carbon capture, utilisation and storage. The CO_2 streams produced during biomethane upgrading are relatively pure compared to other production pathways. Therefore, costs are relatively low to capture them for use in the food or beverage sectors, or for storage underground to provide negative CO_2 emissions. Another option is to make biochar from digestate via pyrolysis and store the carbon in solid form (see Section 3.5).

From a policy perspective, it is important to ensure the consumption of biogases delivers net life-cycle GHG emissions reductions. The development of frameworks to report on the emissions intensity of different production routes is an important first stage. There are already examples such as the EU RED and California LCFS (Figure 3.6).

The EU RED establishes binding 2030 renewable energy targets for EU member states. RED II defines sustainability requirements and maximum GHG emissions intensities that biofuels and biomethane must comply with to be counted towards the target and to be eligible to receive funding and subsidies. For biofuels in transport, the limit is 33 grammes of carbon dioxide equivalent (g CO_2-eq) per megajoule (MJ), and for electricity and heat, the limit is 37 g CO_2-eq/MJ electricity and 16 g CO_2-eq/MJ heat.

Figure 3.5 ▷ Emissions reductions possible in biomethane production by measure and feedstock type



A range of technologies and practices exist that can significantly reduce the emissions intensity of biomethane production

Note: LDAR = leak detection and repair. The value for worst performer using wet manure includes a methane avoidance credit.

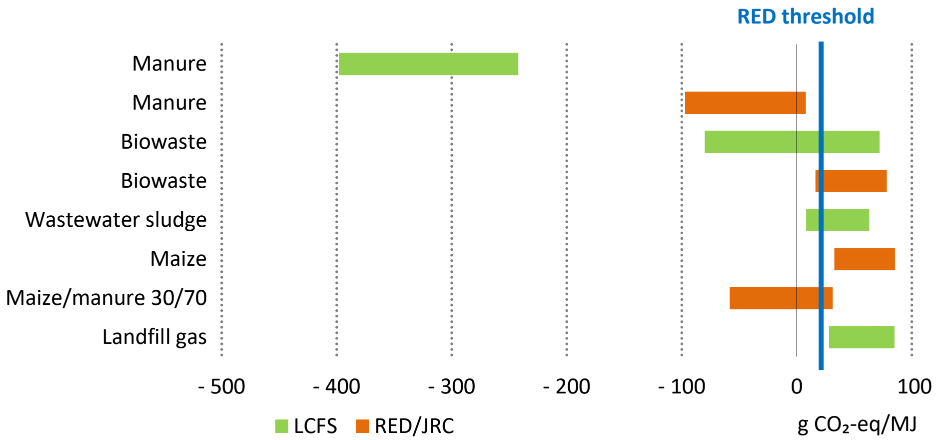
Sources: IEA analysis based on data from the EU RED, Annex VI, updated with methane values from JRC (2024).

The California LCFS aims to reduce the carbon intensity of its transport sector by establishing a decreasing annual goal for the sector (the "carbon intensity benchmark"). Each provider is required to calculate the GHG emissions intensity of their fuels. Fuels performing above and below the carbon intensity benchmark generate emission deficits or credits. Producers with deficits are obliged to buy credits from other producers to ensure targets are achieved.

The RED and LCFS use life-cycle assessments and include GHG emissions from production, distribution, use and land-use change. They also consider "counterfactual cases" for any avoided emissions (the emissions that would have occurred if the feedstocks had not been converted into biomethane). The level of avoided emissions varies significantly between the two schemes. For example, in the European Union, organic municipal solid waste is restricted from going to landfill sites, and no methane avoidance credit is allocated in the EU RED. In California, similar restrictions are being put in place, but the LCFS still includes a methane avoidance credit. Animal manure methane avoidance credits are also larger in the United States than in Europe given different agricultural practices.

Policies can promote the use of sustainable feedstocks and drive down GHG emissions from production and use of biogases (Table 3.1). Several existing policies rely on minimum GHG emissions reduction thresholds that producers must achieve. Meeting thresholds depends on the mix of feedstocks used and the emissions that occur along the biogas production supply chain, especially methane.

Figure 3.6 ⊳ **Typical greenhouse gas emissions ranges in legislation in the European Union and California, United States**



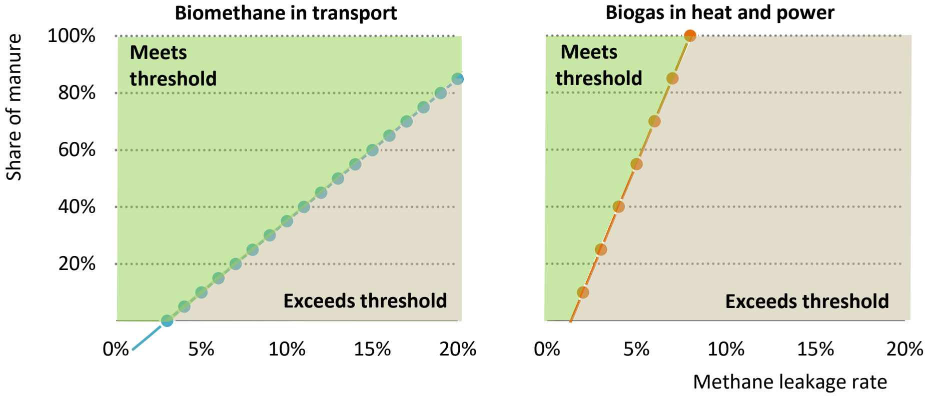
Avoiding emissions from animal manure can give producers of biogases a significant emission credit, which varies depending on waste management policies

Notes: LCFS ranges for manure represent the 25-75% pathways carbon intensity range. Biowaste under the LCFS includes food scraps, urban landscaping waste and other organic waste. Maize represents silage of the whole plant. The RED threshold represents the minimum required GHG emissions reduction for transport.

Source: IEA analysis based on data from the EU RED, Annex VI, updated with methane values from JRC (2024) and from LCFS' Certified Fuel Pathway carbon intensities (California Air Resources Board, 2025).

For example, in the European Union, a credit of 45 g CO_2 eq/MJ manure is given for manure-based projects, because they avoid the methane emissions that would have occurred otherwise. Producers of biomethane therefore often mix different feedstock types to comply with regulatory thresholds. For example, a project targeting biomethane use as a transport fuel could have a methane leakage rate of 15% and still meet the EU sustainability criteria if the share of manure in the feedstock mix is at least 65% (Figure 3.7). On the other hand, the same share of manure in the feedstock mix would need a methane leakage below 6% to meet the threshold if biogas is used in a combined heat and power plant (CHP). In a case where no manure is used, a methane leakage rate higher than 3% in the case of biomethane for transport and higher than 1.3% when using biogas for CHP would exceed the sustainability threshold.

Figure 3.7 ▷ Indicative sustainability thresholds for biogases in the European Union based on use case, share of manure and methane leakage rate



Producers of biomethane often mix different feedstock types to comply with regulatory thresholds; if not carefully managed, methane leaks can undermine sustainability benefits

Notes: Thresholds are based on the EU RED (power production 37 g CO_2-eq /MJ electricity, heat production 16 g CO_2-eq/MJ heat, fuel for transport 33 g CO_2/MJ fuel and a 45 g CO_2/MJ manure bonus for manure). For power, assume a biogas-based CHP plant with a net electrical efficiency of 35% producing 70% power and 30% heat. The remaining feedstock mix is assumed to be a split between biowaste and maize. CO_2 emissions (excluding methane) are typical EU RED values.

Table 3.1 ▷ GHG performance requirements in selected jurisdictions

Region/state/country	Regulation	Minimum GHG emissions reduction	Rewards improve GHG emissions performance
European Union	Renewable Energy Directive (RED II/III)	65% transport; 80% electricity, heating and cooling	Open to member states to include
United States	Renewable Fuel Standard	60% (cellulosic biofuel); 50% (advanced biofuel)	No
California	Low Carbon Fuel Standard	No	Yes, carbon credits
Germany	GHG Quota	65% (compliance with RED)	Yes, carbon credits
Brazil	RenovaBio	No	Yes, carbon credits

3.4 Permitting and infrastructure

3.4.1 Permitting for biogas and biomethane plants

Permitting for biogas and biomethane can be lengthy due to a mix of local and national regulations, including environmental review processes that vary by location.

Within the European Union, it takes on average 18 months to build a biomethane plant. Securing the necessary permits can take 2-7 years, including procedures related to grid connection (BIP, 2023). The European Commission introduced a regulation in 2022 to accelerate permitting for renewable energy projects, but many member states have not yet transposed it into national law (DSO Entity, 2025). However, some countries have specific provisions that support rapid development timetables. For example, in Denmark, permits may be granted in the concept phase, shortening the permitting process to as little as 3 months (BIP, 2023).

Biogas installations in North America face similar multilevel permitting challenges. In Canada, each province requires a unique combination of permits from local, provincial and national authorities, as well as different agreements with local gas utilities. Surveys report permitting timelines of up to 5 years for agricultural biodigesters (CBA, 2022). A lack of biogas-specific regulatory pathways in some provinces stymies the process. For example, the non-classification of biogas plants as an agricultural activity in British Columbia added an additional zoning step to the permitting process.

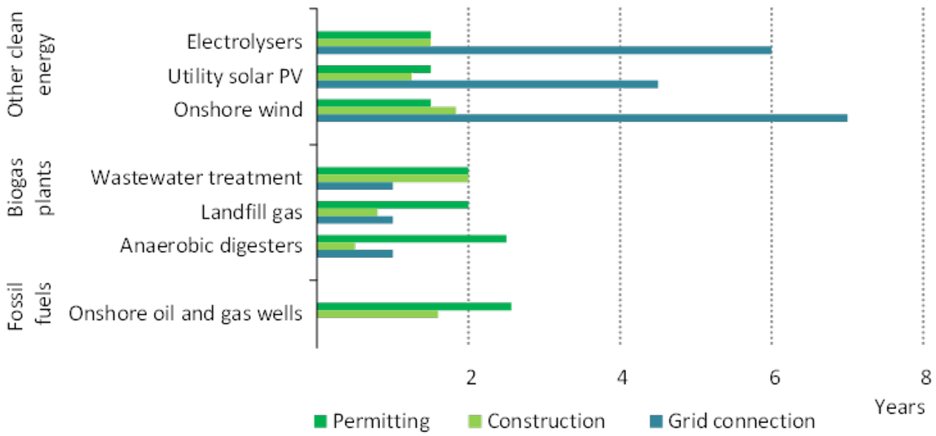
Permitting procedures in the United States are similarly multilevel. Provisions under federal statutes such as the Clean Air Act, Clean Water Act, Resource Conservation and Recovery Act and other environmental legislation are applied based on the size and location of the installation. Although these factors make a precise understanding of permitting timelines difficult, the US Environmental Protection Agency estimates 6-18 months for biogas and biomethane projects (EPA, 2024).

Several Indian biomethane plants have reported permitting delays due to the lack of awareness of local authorities about biogas regulations (EPA, 2025). One producer, Anaerobic Energy Private Limited, created its own set of permitting standards based on experience, to raise awareness of the process among agencies. By contrast, a plant developed by IndianOil, which is government owned, experienced a much smoother process.

A lack of standardisation of biogas plants has implications for permitting timelines. Each biogas plant is unique in context and design, requiring time for evaluation and approval. There have been some efforts to address these issues. For example, the World Biogas Association's Making Biogas Happen programme has a Global Biogas Regulatory Framework providing standardised policies and criteria to streamline approvals and reduce permitting lead times.

Although timelines for permitting vary by jurisdiction and type of plant, biogas plants have shorter lead times on average than other renewable energy sources (Figure 3.8). This gap becomes wider when accounting for the time it takes to connect utility-scale solar and wind capacity to the electricity grid compared with upgraded biomethane plants to the natural gas grid. Large-scale transmission projects for remote solar and wind systems can take a decade or more to complete, often much longer than the new assets that connect to them. By contrast, a gas connection takes around 1 year on average. In most cases, the application runs in parallel to other permitting procedures, meaning it is not typically a bottleneck.

Figure 3.8 ⊳ Average observed lead times for selected energy projects



Biogas and biomethane plants tend to have shorter lead times than other clean energy projects

Note: PV = photovoltaics.

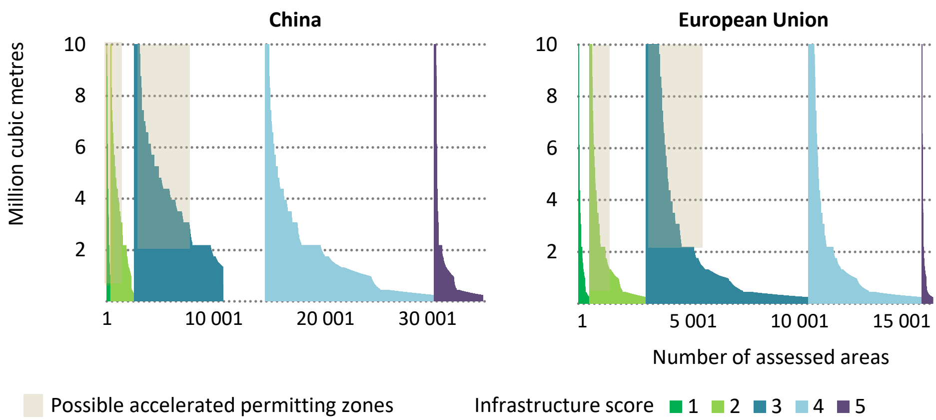
Sources: IEA (2024) and IEA analysis based on CBA (2021), BIP (2023) and EPA (2024).

One option to avoid lengthy development lead times is to designate areas where biogas and biomethane projects can benefit from simple or streamlined permitting procedures. We used our spatial analysis to identify areas with high biogas potential that are also close to roads, natural gas pipelines or electricity grids. Infrastructure density scores were developed, with those nearest to infrastructure scoring 1 and the most remote areas scoring 5. We defined the minimum potential for biogases in a given area of 2 million cubic metres of natural gas equivalent (mcme) for each 10 square kilometre (km^2) area, and selected sites within the top three scores for infrastructure density.

The results show that in the European Union, there is around 6 bcme of potential over an area of around 300 000 km^2 that could be a candidate for accelerated permitting zones. This is equivalent to 7% of the EU landmass, and around 20% of its agricultural area. In China, the same set of conditions yields around 8 bcme over an area of around 270,000 km^2, or 3% of its landmass (Figure 3.9).

Designating go-to areas creates risks of unintended consequences when development is compressed in a small area over a short time. A balance therefore needs to be struck between avoiding unnecessary delays or uncertainties in the permitting process and ensuring development is responsibly managed and takes into account local stakeholder interests.

Figure 3.9 ▹ Areas identified for accelerated biogas project permitting in China and the European Union, by feedstock potential and infrastructure score



IEA. CC BY 4.0.

Faster development of biogases can be unlocked by targeting areas with high potential and close proximity to existing infrastructure

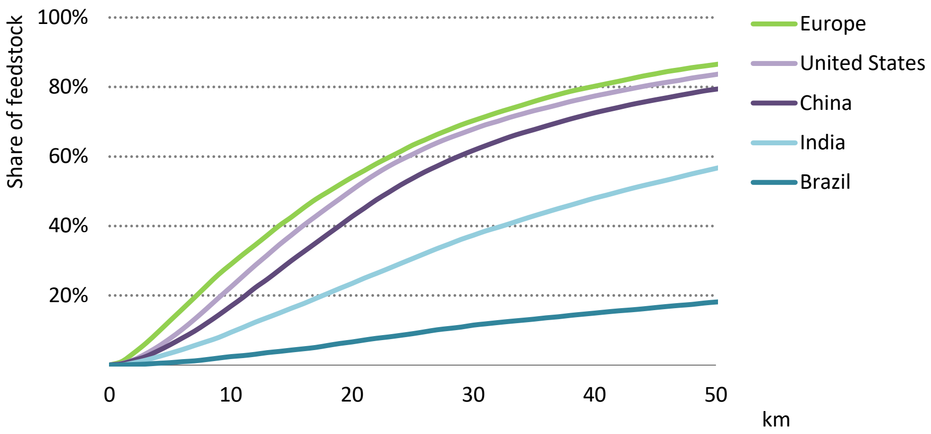
Notes: Infrastructure scores are calculated using proximity to gas pipelines and roads (a lower score means closer proximity). The horizontal axis shows the number of clusters in our spatial assessment for each region; these vary by size but typically average around 100 km^2.

3.4.2 Integrating biomethane into natural gas grids

The feasibility and cost of connecting a biomethane project to the natural gas grid vary by country. Successfully integrating biomethane may often require upgraded grid infrastructure, regulatory frameworks and market incentives to ensure seamless injection, distribution and use of biomethane across residential, industry and transport sectors.

In India, for example, a less-dense gas grid has turned the focus to compressing biomethane onsite and transporting it via trucks. By contrast, around 30% of our assessed feedstock potential in Europe – around 15 bcme – is less than 10 kilometres (km) from a gas transmission pipeline (Figure 3.10), suggesting close proximity to gas distribution networks. Globally, about 300 bcme of biomethane potential lies within 20km of an existing natural gas pipeline. In Brazil, biomethane projects are co-located with other bioenergy production facilities such as sugar cane mills that generate a by-product called vinasse. The sugar-to-ethanol industry's demand for a diesel equivalent then incentivises upgrading these plants to produce biomethane. The focus on large-scale plants means biomethane plants account for only around 1% of the total number of operational plants, but almost a quarter of total biogas volume produced (CIBiogás, 2021).

Figure 3.10 ▷ Distance of sustainable feedstocks for biomethane production from natural gas transmission pipelines in selected regions



IEA. CC BY 4.0.

Around 30% of Europe's biomethane potential (around 15 bcme) is less than 10 km away from a transmission pipeline, compared with 10% in India and less than 5% in Brazil

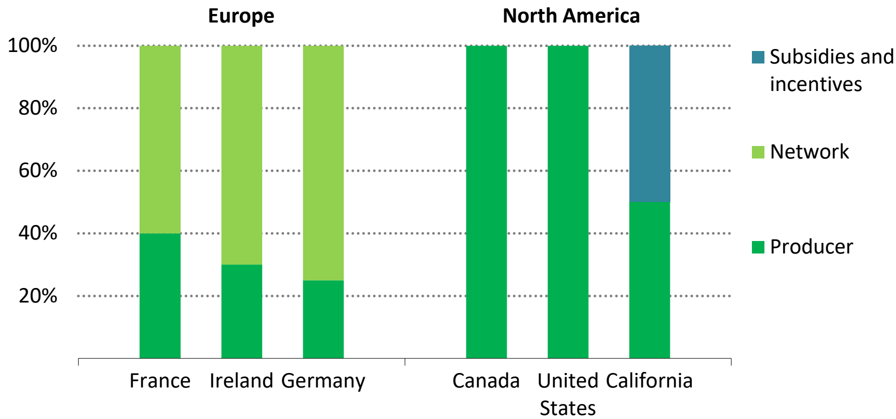
3

Technical and regulatory considerations

The average biomethane plant produces around 3.5 mcme per year. These plants are generally more dispersed than gas wells and therefore require multiple small injection points into gas distribution networks. Each of these injection points must be properly equipped for metering and measurement of gas volumes and fall within defined quality limits. The defined limits is a key issue, as there is a risk that biomethane fails to meet grid quality specifications given the potential for impurities arising from a heterogenous mix of feedstock.

Grid connection costs – the upfront capital required to build a pipeline connection and the ongoing costs of grid injection – are an important part of the project economics of a biomethane plant. Cost-sharing models between producers and grid operators vary widely (Figure 3.11). Different agreements specify the responsibility of each party for costs such as pipeline construction, injection stations, pressure regulation, odorisation, quality control and metering. Biomethane injection fees may or may not be distinguished from general gas grid charges and may be levied based on the capacity of the injection point or the total volume of gas injected (EBA, 2025).

Figure 3.11 ▷ Cost-sharing models of capital expenditure for biomethane grid connection in different regions



European biomethane producers tend to assume less of the overall costs of grid connection than producers in North America

Notes: In France, the contribution of the network operator (distribution system operator or transmission system operator) for capital expenditure of a pipeline is capped at EUR 600 000 (Acceleration of Renewable Energies Production Law). In Ireland, producers may pay more than the minimum 30% of connection costs subject to an economic test based on the projected volume of production over a 10-year period (Gas Networks Ireland Connections Policy Document).

Source: IEA analysis based on data from BIP (2023) and EBA (2024c).

In Europe, several countries have taken steps to promote the injection of biogas into the grid by requiring grid operators to cover part of the expenses of grid connection, particularly for distribution system operator connections. Under Germany's FiT scheme for biogas and biomethane, grid operators cover the bulk of the costs of grid connection, and fees for project developers are limited to EUR 250 000 when plants are less than 1 km from the grid. Certain costs, such as those related to grid reinforcement, reverse compression and network meshing, are most often borne by grid operators.

In North America, the cost burden of grid connection typically falls on the producer by default, but federal- and state-level incentive programmes may be available. For instance, in 2016, California adopted a biomethane interconnector monetary incentive programme, which reimburses up to 50% of the interconnection costs of eligible biomethane projects (SoCalGas, 2025). Half of the USD 80 million funding for the programme comes from gas utility cap-and-trade auction proceeds. Elsewhere in North America, municipalities may enter into purchase agreements with biomethane producers to recover capital expenditure, including interconnection costs (British Columbia Utilities Commission, 2016).

In 2024, India established standard financial assistance for the development of pipeline infrastructure for injection of compressed biogas from eligible plants (Government of India, 2024). Under the scheme, the government assumes up to 50% of the cost of laying pipelines up to a length of 75 km. Brazil has not yet mandated any cost-sharing provisions, although it has stated aims to foster infrastructure projects to connect economically viable biomethane production plants to natural gas networks under the National Programme for Decarbonisation of Natural Gas Producers and Importers and Incentives for Biomethane.

The diversity of observed approaches to regulating permitting and grid connection demonstrates the range of options available to policy makers who wish to facilitate biomethane development in their jurisdiction (Table 3.2).

3

Table 3.22 ▻ Examples of regulatory interventions to facilitate permitting and grid connection

Policy	Examples
Legal obligation for grid operators to assess requests for gas grid connection	Czech Republic: Energy Act 458/2000 France: Law 2018-938 – Article 94 Sweden: Natural Gas Act
Grid capacity allocation and mapping	France: Gaz Réseau Distribution France indicative zoning map
Cost-sharing mechanisms for grid injection	Italy: Resolution 64/2020 France: Energy Code L452 India: Scheme Guideline for Development of Pipeline Infrastructure for injection of Compressed Bio Gas in City Gas Distribution network
Standards for injection stations	European Union: Standard 1623-1 Biomethane Injection into the Natural Gas Grid and Measuring Instruments Directive 2014/32/UE

Regulators may also facilitate various several technical solutions that improve integration of biomethane into natural gas networks, such as:

- Grid meshing, which connects neighbouring distribution networks of the same pressure tier, to increase consumption capacity over a wider area.
- Reverse flow facilities, which push gas flow from low- to high-pressure lines while ensuring the gas meets the qualifications of the destination (Jansons et al., 2024).
- Virtual pipelines, by which compressed or liquified biomethane is transported by truck to an injection site. Such systems require additional equipment for compression and liquefaction but can serve multiple producers.
- Aggregating biogas from multiple plants through dedicated pipelines that feed into a biomethane upgrading plant for grid injection.

Regulators have an important role in defining clear frameworks for procedures, requirements, roles and responsibilities of various stakeholders. Mapping of network capacity, in dialogue with grid operators, is a crucial step in providing the perspectives of producers, operators and regulators, from which to make well-informed decisions. This can also help regulators establish criteria for project feasibility and prioritisation.

3.5 Pathways for innovation

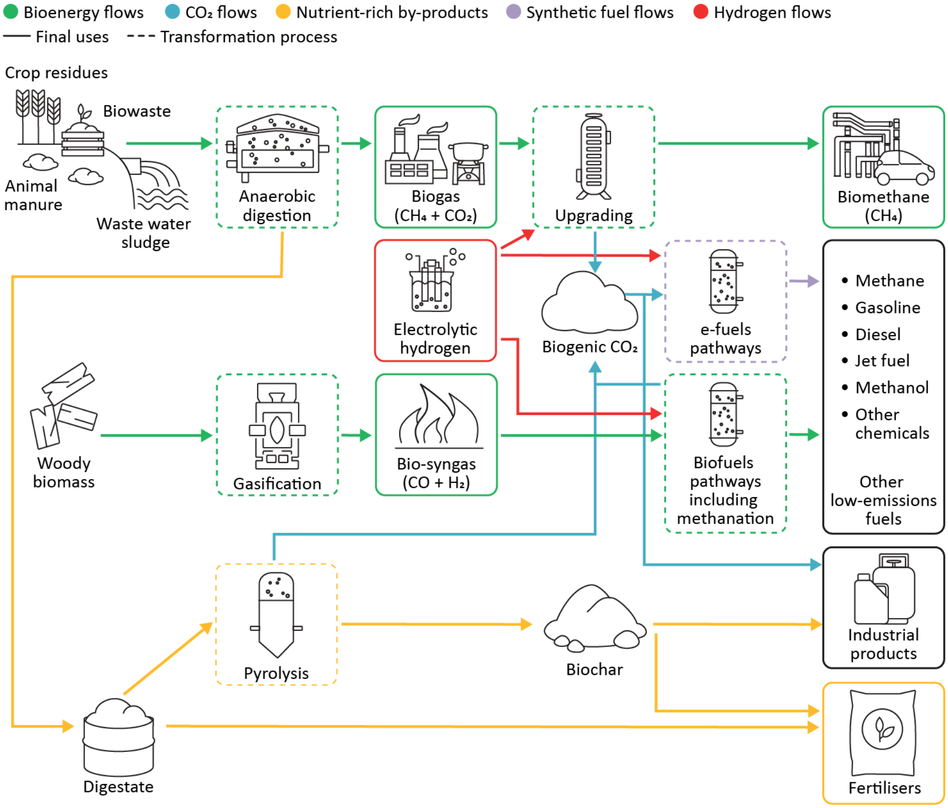
The main technologies used for biogas and biomethane production (and any associated upgrading and purification steps) are largely mature, efficient and commercially proven at scale. For example, humans have used anaerobic digestion processes in differing forms for thousands of years, to generate fuel for heating, with modern forms of the technology not differing substantially from approaches used in the early 20th century (Klinkner, 2014). While the technology may be mature, the integration of biogas and biomethane production into existing energy systems and emerging value chains is a promising area for innovation. This could aid the realisation of a circular economy through reductions in waste and emissions.

There are several emerging technology pathways through which production of biogases could be integrated into other low-emissions value chains (Figure 3.12). For example, the process of upgrading biogas to biomethane yields a relatively low-cost, concentrated source of biogenic CO_2 that could be reacted with the hydrogen produced from electrolysis to generate a range of synthetic fuels (e.g. e-methane or e-methanol). Thermal gasification of biomass can also yield bio-syngas that can be upgraded to biomethane through a methanation process. Such synthetic fuel pathways are costly and involve significant efficiency losses over multiple transformation steps. Nevertheless, they can play an essential role in decarbonising hard to abate sectors, such as long-distance shipping, aviation, chemical production and fertilisers.

Combining production of biogases with other biofuel production processes could give rise to integrated "biorefineries" that produce fuels and chemicals with renewable biological feedstocks (instead of relying only on the use of crude oil). There are more than 400 biorefineries in operation in Europe alone, although only some use production of biogases within their processes. Petrochemical companies are increasingly exploring the viability of converting existing refineries into biorefineries. For example, in 2025, Petrobras announced a USD 960 million investment to transform its Riograndense Refinery into Brazil's "first biorefinery". And WasteFuel and ITC announced plans for a green methanol biorefinery in Türkiye based on biogas from anaerobic digestion.

Co-locating biogas facilities alongside other existing and emerging processes (e.g. alcohol production, wastewater treatment and dedicated renewable-electrolyser systems) could lead to a more circular economy that delivers cost and energy efficiencies together with reductions in emissions and waste. Producing biogas from energy crops in degraded areas and lands under erosion (often called "marginal lands") can also improve soil quality and support biodiversity in short time frames.

Figure 3.12 ▷ Innovative pathways to integrate biogases into other low-emissions fuel and technology pathways



IEA. CC BY 4.0.

There are several emerging technology pathways through which production of biogases could be integrated into other low-emissions value chains.

Note: CH_4 = methane; CO = carbon monoxide; H_2 = hydrogen.

Converting digestate to biochar

When biogas is produced at scale, the large quantities of digestate produced can be difficult to integrate into agricultural management processes. One option is to process it into biochar by drying it and then heating it in an oxygen-free environment to high temperatures in a pyrolyser. The resulting biochar is a solid, charcoal-like substance that can be used to improve soil productivity and agricultural crop yields, in water purification, as an additive to construction materials, or to capture and store atmospheric CO_2 in solid form. Biochar production through pyrolysis also generates by-products (including oil products and combustible gases) that can be used to produce renewable energy or that can be used as an industrial feedstock.

Harvesting and converting aquatic feedstocks

Aquatic feedstocks (including microalgae, macroalgae and aquatic waste) are potential feedstocks for biogases that may convey some advantages over land-based materials. Research has been ongoing for decades, although there have been limited commercial breakthroughs to date (Anacleto et al., 2024). Projects seeking to optimise biogas production from microalgae have high upfront and operating costs for cultivation system construction, nutrient addition and efficient harvesting. Researchers are still studying the ideal species and processes (Oliviera et al., 2025). Macroalgae (e.g. kelp) can be stimulated in natural coastal settings and produce large volumes of feedstock, but projects have faced challenges maintaining stocks given frequent storms and in the efficient conversion to biogas. The use of aquatic waste (e.g. invasive species such as water hyacinth) as a biogas feedstock is at an early stage of research and development, as is the use of organic-rich aquatic sediments.

Box 3.2 ▹ Increasing biomethane yields through innovation

Most of the supply chains for biogases are mature, thus limiting the scope for future cost reductions. Nevertheless, some areas of research and development hold promise for driving efficiency gains and enabling biogas projects to significantly increase yield and output. Areas of particular interest include are listed below. These technologies are at an early stage of development, with uncertainties over their cost and effectiveness at scale.

Biochar can boost the performance of anaerobic digestors, through enhanced methane production, improved system stability and reduction in retention time.

Biomethanation involves the use of biological organisms and hydrogen produced by an onsite electrolyser to increase methane yields from biogas by more than 50% compared with existing separation technologies. Pilot and demonstration-scale projects are in operation, with research and development needed to determine commerciality.

Two-phase anaerobic digestion can perform better than single-phase anaerobic digestion (where all digestion takes place within a single reactor). Two-phase digestion allows for higher levels of biomethane production from smaller overall digester sizes, with more stable operation of biological processes. It also offers increased control over biogas production rates, enhancing the potential for biogases as a localised energy source that can respond to changing demand. Such systems are not yet widely used on a large scale due to the increased complexity, additional costs, and the need for more precise process control and constant, homogenous feedstocks.

The use of **microbial electrolysis cells** involves using microbes to convert wet organic material into hydrogen and methane. Integrating microbial electrolysis cell technologies with anaerobic digestion can increase feedstock degradation and convert more CO_2 into methane. Using microbial electrolysis cells at laboratory scale has doubled biomethane yield from feedstocks. However, scale-up will need to overcome several barriers including challenges associated with scaling up electrode materials beyond laboratory conditions.

Outlook for biogas and biomethane

Ploughing ahead

SUMMARY

- Starting conditions for the scenario projections in this chapter have changed considerably since our last major outlook for biogases published in 2020. High natural gas prices during the global energy crisis have driven renewed policy momentum towards biomethane. In addition, electricity now accounts for a higher share of future energy demand in our scenarios, because the world is electrifying at an increasing pace. Overall, future demand for biogases is higher than in our previous assessment.
- Biogas and biomethane start from a low base. Nevertheless, they are the fastest growing forms of bioenergy in the Stated Policies Scenario (STEPS), which is based on today's policy settings, and in the Announced Pledges Scenario (APS), which assumes all national energy and climate pledges, including long-term net zero emissions goals, are met on time and in full. The share of biogases in total gaseous fuel demand grows from 1% in 2023 to around 5% by 2050 in the STEPS and 10% in the APS.
- Europe and North America together make up 60% of today's global demand for biogases. However, emerging market and developing economies dominate future growth in both scenarios. China sees the largest increase in absolute terms, but India grows more rapidly, with demand tripling by 2035.
- Biogas produced for direct consumption grows by around 3% per year in the STEPS between 2023 and 2035, reaching around 60 billion cubic metres of natural gas equivalent (bcme). There is modest additional growth in the APS, mainly to meet energy access goals in emerging market and developing economies. Biomethane grows much more quickly than biogas in both scenarios, registering a fourfold increase in the STEPS by 2035 and a tenfold increase in the APS.
- The power sector is a key driver in the growth of biogases. Consumption also grows strongly in industry, especially in subsectors such as food and beverage or pulp and paper production. Biomethane is also increasingly blended into natural gas grids, and used in compressed form as a low-carbon alternative to diesel for transport.
- Less than 5% of the total sustainable potential for production of biogases is used currently. This reaches 17% globally by 2050 in the STEPS and 25% in the APS; in key regions such as China and Europe, some feedstock potentials are fully exploited.
- The rise of biogases brings benefits for energy security, especially in fuel-importing regions. Biomethane production in the European Union already avoids the need to import around 15 thousand barrels per day (kb/d) of oil and 2 bcme of natural gas each year. By 2050, in the STEPS, biogases avoid 75 kb/d and 7 bcme, respectively. It also reduces emissions, where producing and transporting biogases are done responsibly.

4.1 Introduction

At least 50 new policies related to biogases have been introduced in the 5 years since our previous outlook was published. This chapter explores how this momentum changes the outlook for biogases across all regions and end-use sectors. We use two scenarios from the World Energy Outlook 2024 (IEA, 2024):

Stated Policies Scenario (STEPS): This provides a sense of the prevailing direction of travel for the energy system, based on a detailed assessment of today's policy settings.

Announced Pledges Scenario (APS): This outlines a trajectory for the energy sector if all national energy and climate pledges, including long-term net zero emissions goals, are met on time and in full.

Our 2020 Outlook for Biogas and Biomethane assessed the prospects for biogases under different conditions to the ones today (IEA, 2020). Natural gas prices at the time were hitting record lows as new liquefied natural gas (LNG) supplies came to market, just as demand was falling after the onset of the Covid-19 pandemic.

Today's backdrop is one of heightened geopolitical tensions, high gas prices and supply volatility, still reverberating from Russia's full-scale invasion of Ukraine. In 2022, gas prices in Europe regularly exceeded the production cost of biomethane. This sparked renewed momentum, especially in Europe, for developing biomethane as a substitute to costly imported natural gas. Gas market balances, which are currently tight in 2025, are expected to ease as new LNG supplies come online from 2026. Nevertheless, the security of supply benefits of developing a sustainable, homegrown resource remain compelling.

Another change is that the world is electrifying at an increasing pace. It is doing so with more renewables than projected at the time of our 2020 outlook. In that year's New Policies Scenario, the share of electricity in total final consumption reached 24% by 2040. In the Stated Policies Scenario of the World Energy Outlook 2024, the level reaches 28% by 2040. The share of wind and solar in the electricity generation mix was projected to reach 25% by 2040 in the 2020 outlook; it now reaches 50% by 2040.

The importance of "clean molecules" for a low-emissions future remains high, even in this "age of electricity". Biogases have multiple advantages in this regard. These include the ability to provide power system flexibility, seasonal storage, and a route to emissions reductions in energy-intensive industries or in heavy-duty transport modes that are not easily electrified. Their potential contribution to a circular economy belies a simple comparison of the cost of providing clean electricity. We therefore consider the extent to which biogases can not only decrease emissions, but also increase energy security by reducing dependence on imported fossil fuels and by providing flexibility to energy systems increasingly influenced by weather-dependent supply and demand.

4.2 Scenario results

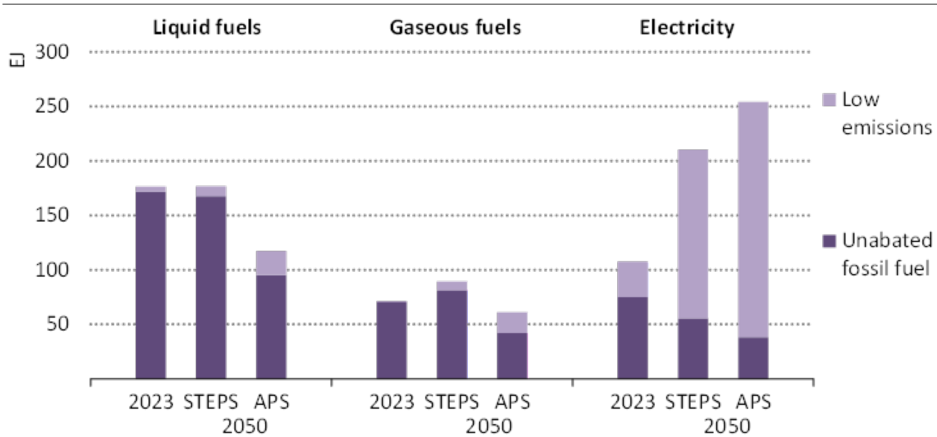
4.2.1 Overview

Liquid and gaseous bioenergy plays a small but important role in the energy system. Transport biofuels displace around 2 million barrels per day (mb/d) of oil demand each year. Biogases deliver around 50 terawatt hours (TWh) of electricity and heat, and provide clean cooking access for around 120 million people. In addition, biogas upgraded to biomethane provides around 10 bcme for light, heat, mobility and other energy services that would otherwise require coal, natural gas or oil.

The use of transport biofuels and biogases is growing in an increasingly electrifying world. In the STEPS, electricity's share in total final energy consumption rises from 20% in 2023 to over 30% by 2050. In the APS, electrification accelerates even faster, reaching around 40% by 2050. An even faster growth in renewables complements this rapid pace: renewables in the APS meet over 80% of the world's electricity demand by 2050 – three times today's share.

Nonetheless, liquid and gaseous fuels still meet 50% of the total final energy consumption in 2050 in the STEPS, and around 40% in the APS (Figure 4.1). This underscores the important contribution that low-emissions fuels – including modern bioenergy, as well as hydrogen and hydrogen-based fuels – can make in sectors where electrification options are limited.

Figure 4.1 ▷ Final energy consumption of liquid and gaseous fuels and electricity in 2023, and in 2050 by scenario



IEA. CC BY 4.0.

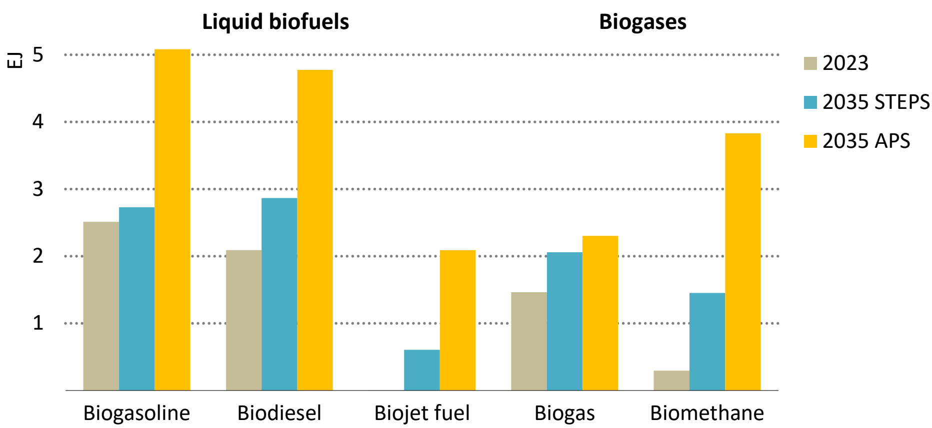
Electricity's share rises strongly in the STEPS and the APS, but liquids and gases still account for at least 40% of total final consumption in 2050

Note: EJ = exajoules.

In the STEPS, blending mandates, quotas, feed-in tariffs and other forms of policy support drive a 50% increase in overall liquid and gaseous bioenergy production between 2023 and 2035 (Figure 4.2). They grow twice as fast in the APS, reaching around 18 000 petajoules (PJ) by 2035.

Biogases start from a low base, but they are the fastest growing forms of bioenergy in both scenarios. Overall, the share of biogases in total gaseous fuel demand grows from 1% in 2023 to around 5% by 2050 in the STEPS and 10% in the APS.

Figure 4.2 ▹ Total liquid and gaseous bioenergy in 2023, and in 2035 by scenario



In the STEPS, total liquid and gaseous bioenergy increases by half by 2035, with biogases accounting for half of the growth

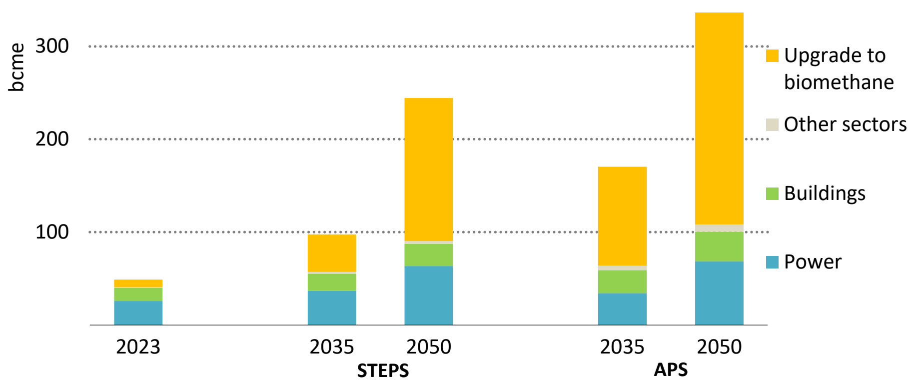
4.2.2 Demand for biogases

Overall demand for biogases doubles between 2023 and 2035 in the STEPS and nearly quadruples in the APS. By 2050, annual demand for biogases exceeds 200 bcme in the STEPS and 300 bcme in the APS.

Biogas produced for direct consumption grows by around 4% per year in the STEPS between 2023 and 2035, reaching around 60 bcme (Figure 4.3). There is modest additional growth in the APS, mainly in buildings, as a way to meet energy access goals for rural populations in emerging market and developing economies.

Biomethane grows much more quickly than biogas in both scenarios, registering a fivefold increase in the STEPS by 2035 and a more than tenfold increase in the APS. Biomethane makes up about 40% of overall demand for biogases in 2035 in the STEPS and 60% in the APS, from a level of around 20% in 2023. This share increases further to 2050.

Figure 4.3 ▷ Global demand for biogases by use in 2023, and in 2035 and 2050 by scenario



IEA. CC BY 4.0.

By 2050, more than 60% of biogas is set to be upgraded to biomethane; in the APS, this reaches over 200 bcme, equivalent to 40% of LNG trade in 2023.

Sectors

The **power sector** is a key driver of growth in overall demand for biogases (Figure 4.4). Total installed capacity of biogas plants reaches 20 gigawatts (GW) by 2035, up from a level of around 11 GW in 2023. These plants are typically situated close to feedstock sources like agricultural farms, landfill sites and wastewater treatment facilities. This allows for decentralised power generation with minimal transmission losses. Additionally, in remote regions, biogas provides off-grid electricity for local communities, decreasing their dependence on diesel generators and enhancing access to electricity.

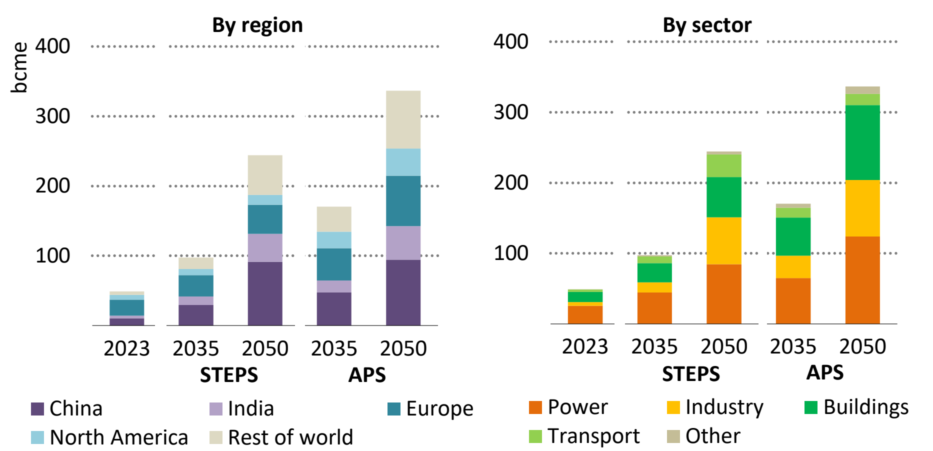
In both scenarios, using biomethane in power plants fired by natural gas, such as in combined- or open-cycle gas turbines, becomes more attractive than local biogas-based combined heat and power units. This is due to the added value they bring to power system flexibility despite the higher fuel costs. In the STEPS, there is a threefold rise in the use of biomethane in the power sector by 2035, and more than a tenfold increase in the APS.

Biogases also grow strongly in the **industry** sector, especially biomethane in subsectors such as food and beverage, and pulp and paper production, which are well placed to develop projects on-site using their own waste products. This is especially pronounced in the APS, delivering reductions in operational emissions (e.g., substituting natural gas for industrial heating) and waste management requirements. Where available at scale, biogases are also targeted by industries requiring a constant, predictable source of low-emissions heat and power or as a feedstock in energy-intensive subsectors such as cement, steel, glass and ceramics. In the STEPS, the use of biomethane in industry as a drop-in replacement for natural gas reaches over 65 bcme by 2050. In the APS, growth is stronger: while natural gas use declines by 25% between 2035 and 2050, biomethane use grows nearly threefold over the same period, reaching 80 bcme globally.

In the **buildings** sector, emerging market and developing economies use biogases as a route to increase energy access. By 2030, around 40 million people gain access to clean cooking via household-scale anaerobic digesters in the STEPS, doubling the amount of biogas used for this purpose compared with in 2023. In the APS, more access goals are met, and the number of people connected to a biodigester reaches 140 million by 2030. Biomethane is also increasingly blended into natural gas grids, providing a lower-emissions source of heating and cooking for grid-connected buildings in all economies. By 2050, overall use of biogases in buildings reaches nearly 60 bcme in the STEPS and over 100 bcme in the APS.

In the **transport** sector, biomethane is used in compressed form, as bio-compressed natural gas (bio-CNG), and small quantities are also liquefied as bio-LNG. The primary use case is for trucks, buses and ships, offering a low-carbon alternative to diesel. The transport sector remains a niche in the overall demand for biomethane, but it is central to fuel switching.

Figure 4.4 ⊳ Total demand for biogases by region and by sector in 2023, and in 2035 and 2050 by scenario



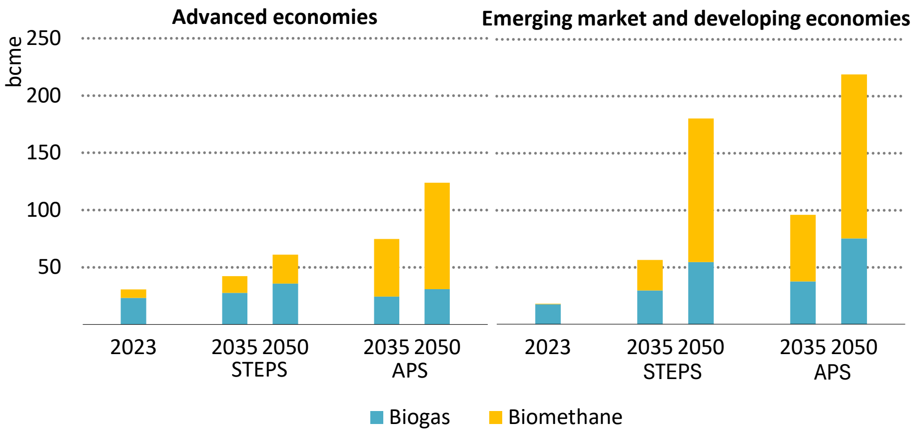
Demand for biogases sees strong growth in all parts of the world, driven by increases in all major sectors, including power, industry, buildings and transport

Regions

Europe and North America together make up around 60% of the demand for biogases in 2023. However, in our projections, emerging market and developing economies dominate global growth (Figure 4.5).

Already the world's largest producer of biogases, China accounts for about 40% of the global increase in demand between 2023 and 2035 in the STEPS, maintaining its overall market share of around 30% of global demand. India's demand for biogases rises from 4 bcme in 2023 to 12 bcme by 2035. It is backed by a renewed policy push in India to develop more of the country's biogas and biomethane resources as a waste management strategy and a way to reduce air pollution in the transport sector. Brazil is also poised for significant growth, with production set to increase threefold by 2035. Robust government support for renewable fuels drives this growth, particularly through the recently introduced Fuel of the Future law.

Figure 4.5 ▷ Global demand for biogases by economic group in 2023, and in 2035 and 2050 by scenario



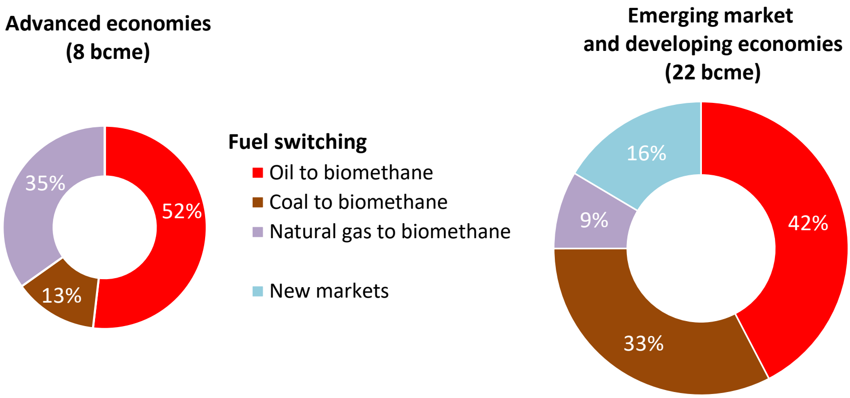
IEA. CC BY 4.0.

Biomethane grows over five times faster than biogas in the STEPS and APS. Emerging market and developing economies account for most of the growth of biogases in both scenarios.

In the STEPS, around half of the growth in biomethane demand to 2035 is attributable directly to fuel switching away from oil products, notably in the transport sector, but also in buildings and industry (Figure 4.6). A further 15% of the growth is due to switching away from natural gas, primarily in the power and buildings sectors. This is especially the case in advanced economies, which have greater scope to blend biomethane into established natural gas networks. Around 30% of demand growth is linked to coal displacement, primarily in the power sector. The remaining growth is to meet new demand due to rising energy service demand (rather than fuel substitution).

Overall, demand for biogases has been revised upwards since the 2020 Outlook for Biogas and Biomethane, driven by stronger public support with over 50 policies introduced over the last 5 years (Box 4.1)

Figure 4.6 ▷ Drivers of growth in biomethane demand in the STEPS, 2023-2035



IEA. CC BY 4.0.

Half of the biomethane produced to 2035 displaces oil. In emerging markets, biomethane substitutes more coal than gas; the reverse is true in advanced economies.

Box 4.1 ▷ Comparing biomethane in the World Energy Outlook 2024 with the 2020 Outlook for Biogas and Biomethane

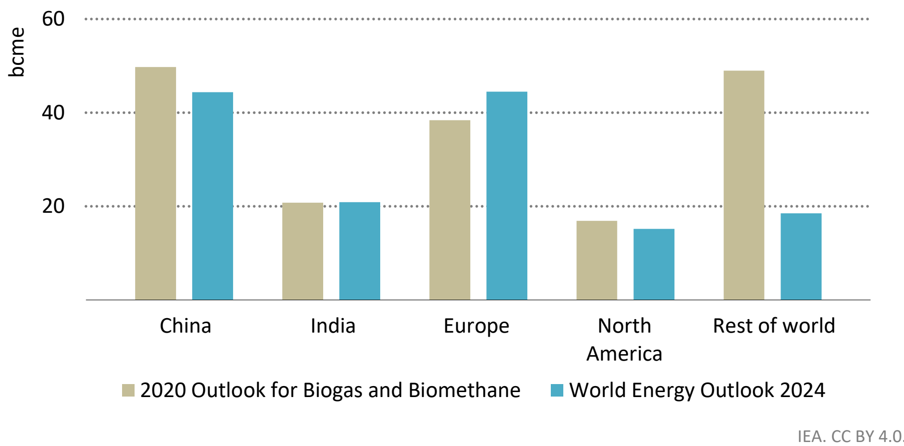
Total demand for biogases in 2040 in the STEPS of the World Energy Outlook 2024 is 15% lower than in the New Policies Scenario, which underpinned the 2020 Outlook for Biogas and Biomethane. By 2040, around 150 bcme of biogases are produced in the STEPS, compared to around 175 bcme in the 2020 Outlook. A more supportive policy environment has led to upward revisions in Europe, but slower-than-projected growth in emerging market and developing economies has led to downward revisions (Figure 4.7).

In North America, overall production of biogases in 2040 is largely unchanged. The Inflation Reduction Act and new incentives based on Low Carbon Fuel Standard in California provide a spur for development. However, these are offset by the lower starting point for growth compared with that anticipated in our 2020 outlook.

In China, some new policy initiatives have supported biogases, such as China's 14th Five-Year Plan on Renewable Energy and Rural Energy Revolution pilot programme. However, falling biogas use in rural areas and slow penetration of biomethane – along with lower overall gaseous fuel demand projected for China compared to the 2020 Outlook – mean projected deployment in 2040 is lower by around 10% compared to the previous outlook.

In India, ambitious bio-CNG production targets set by the government in 2018 were missed. Producers have encountered several challenges that have prevented the envisioned scale-up, including difficulties accessing finance for capital-intensive projects, securing permits and a reliable stream of feedstock supplies and negotiating offtake agreements. However, our outlook remains broadly unchanged to 2040, as new policies such as the Galvanizing Organic Bio-Agro Resources Dhan scheme and a compressed biogas blending mandate have injected new momentum into the sector.

Figure 4.7 ▷ Comparison of production of biogases in selected regions in 2040, in the 2020 Outlook for Biogas and Biomethane and the World Energy Outlook 2024



Strong policy momentum in Europe has raised the projections for 2040 by 15%, although slower growth in other parts of the world has led to an overall downward revision.

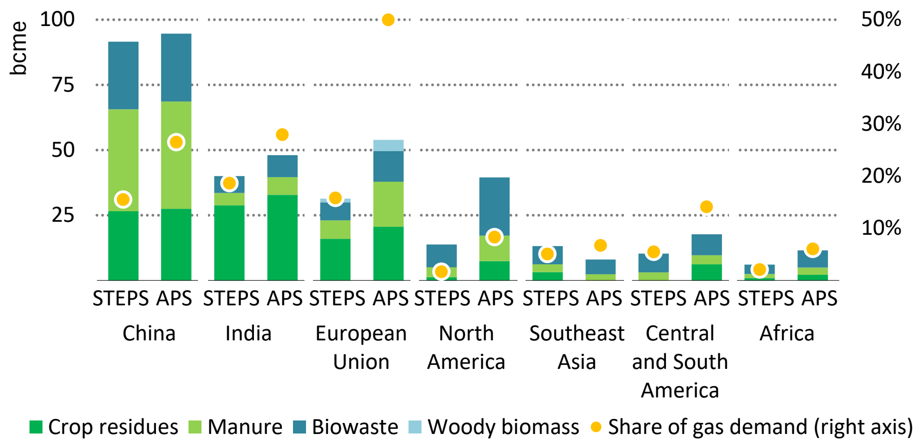
Note: Scenarios shown are the New Policies Scenario in the 2020 Outlook for Biogas and Biomethane and the STEPS in the World Energy Outlook 2024.

Projections for Europe have been revised upward by 15% for 2040 compared with the 2020 outlook. This adjustment reflects a number of national policy targets introduced in European countries since 2020, particularly after Russia's full-scale invasion of Ukraine. Although the REPowerEU goal of reaching 35 bcme of biomethane is not included in the STEPS, it has sent strong signals for project developers, contributing to the near 20% annual growth of biomethane seen in 2023.

4.2.3 Supply of biogases

The total potential for biogases is 990 bcme in 2023, increasing by 40% by 2050 in both scenarios (Figure 4.8). Most of the global biomethane potential is linked to the upgrading of biogas. Less than 5% of the total potential for biogases is currently exploited, and only 18% is exploited by 2050 in the STEPS. A significant amount of feedstock potential is used to produce other biofuels such as ethanol and biodiesel, as well as sustainable aviation fuels. In Brazil, ethanol production increases by 500 PJ between 2023 and 2050 in the STEPS compared with 400 PJ for biogases, with both building on abundant corn and sugar cane residues.

Figure 4.8 ▷ **Total production of biogases by feedstock and as a share of gas demand in selected regions, in 2050 by scenario**

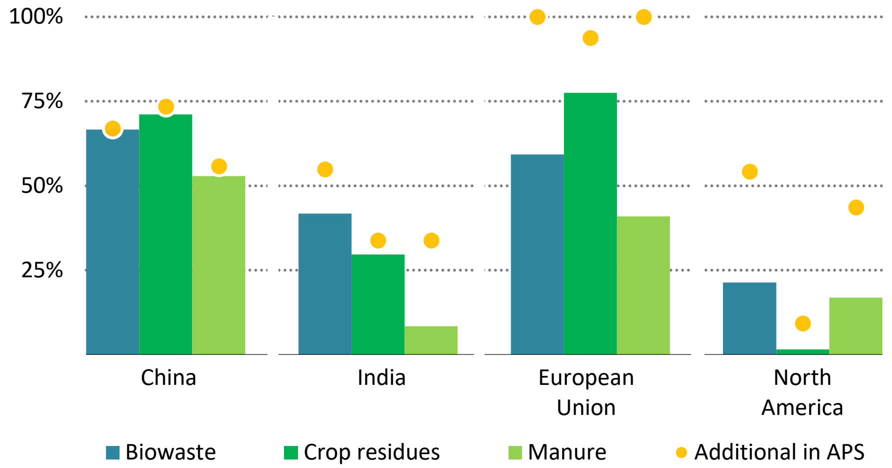


By 2050, China and India emerge as the largest producers of biogases in both scenarios. In the European Union, biogases cover nearly half of total gas demand in 2050 in the APS.

Municipal waste is generally the cheapest feedstock used to produce biogases. By 2050, 30% of biowaste potential is developed in the STEPS, with this value rising above 65% for China. (Figure 4.9). Under China's Rural Revitalization Strategy, agricultural feedstocks are targeted, and so crop residue and manure potentials are used to produce 75% of the biogases in the country. Europe also uses 75% and India 35% of their crop residue potentials in the STEPS by 2050. In the APS, this rises to 100% for Europe and 55% for India. Although manure-based biogases are more expensive to produce, they hold potential for greater emissions reductions and so are more aggressively developed in the APS compared with in the STEPS, especially in the European Union.

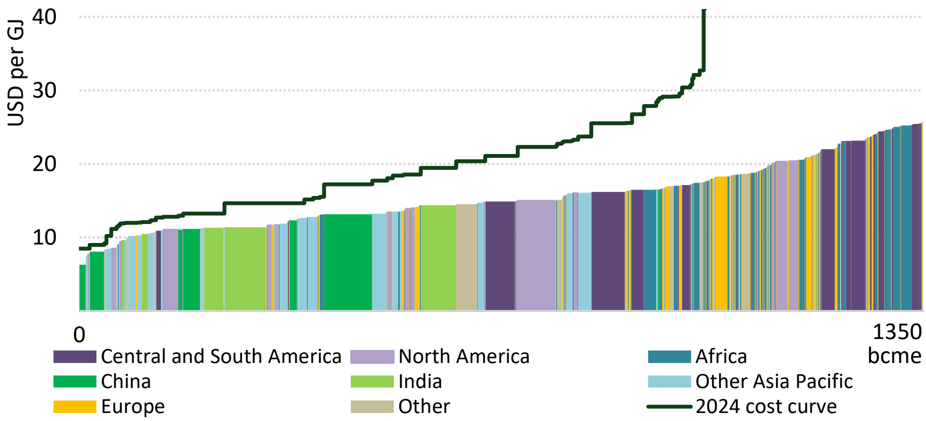
Our estimate for the average cost for biomethane that can be produced sustainably today is around USD 18 per gigajoule. By 2050, over 1 350 bcme of biomethane could be produced globally, with the average cost falling by 13% (Figure 4.10). Increased crop yields, technological learning effects and economies of scale primarily drive this reduction.

Figure 4.9 ▷ Share of feedstock potential developed to produce biogases by selected region in 2050 in the STEPS, and additional in the APS



By 2050, China and the European Union exploit more than half of their biowaste feedstock to produce biogases. In the APS, the European Union maximises its potential.

Figure 4.10 ▷ Cost curve of potential global biomethane supply by region in 2024 and STEPS 2050



By 2050, global biomethane potential increases by 40% while average costs decrease by around 13%

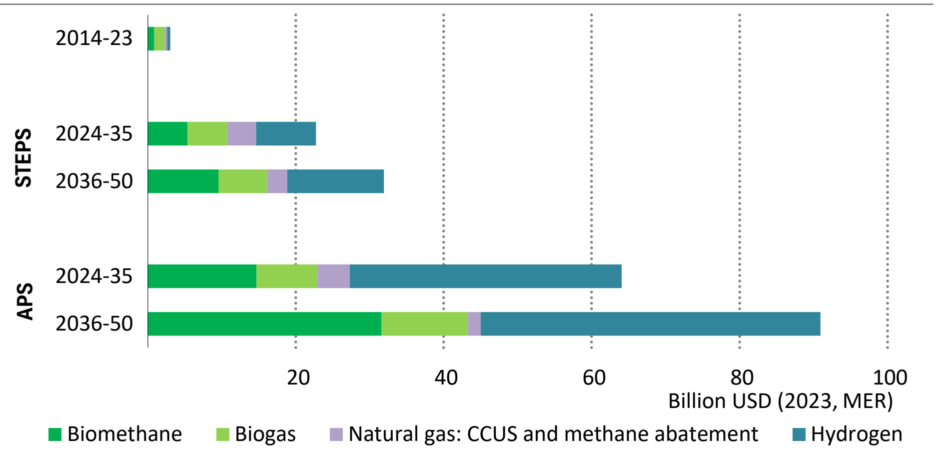
4.3 Implications

Investment

Between 2014 and 2023, an average of USD 3 billion was invested annually to increase production of low-emissions gases (hydrogen, biogas, biomethane and natural gas used with carbon capture, utilisation and storage). This was less than 2% of what was spent annually on unabated natural gas. In the STEPS, average annual investment in biogas and biomethane production rises to more than USD 15 billion by 2050 (Figure 4.11). This trend accelerates in the APS, with annual investment reaching nearly USD 45 billion by 2050. By 2040, total investment in low-emissions gases exceeds annual investment in unabated natural gas.

Emerging market and developing economies in Asia comprise 30% of the increase in investment in biogases globally by 2035 in STEPS, rising to 45% in APS. China dominates growth, investing USD 20 billion annually in biogases in the APS through to 2050 (40% of the total).

Figure 4.11 ▷ Average annual investment in low-emissions gases by scenario, 2014-2050



Investments in biogases average around USD 10 billion in the STEPS over the next decade; this is on par with spending on hydrogen, CCUS and methane abatement

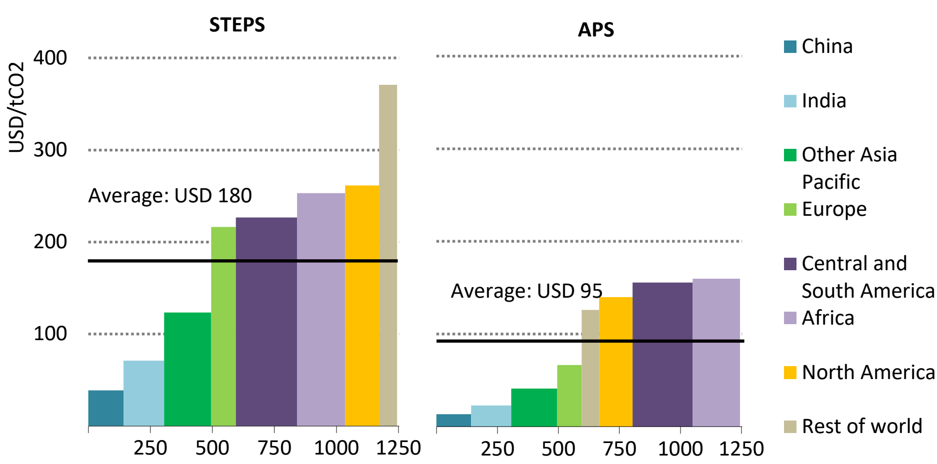
Investment projections in the APS assume several financing barriers are overcome. Biogas and biomethane projects require significant upfront investment and have longer payback periods than other renewables like solar photovoltaics. From a finance perspective, some risks can be difficult to assess, such as the ability to secure reliable feedstock of consistent quality or, for biomethane, the ability to meet the rigorous gas quality specifications for injection into grids. These issues can increase risk perceptions and raise the cost of debt or reduce the loan tenure available to potential investors.

Emissions

GHG emissions reductions from the use of biogas or biomethane depend on how these gases are produced and where they are used in the value chain. From a policy perspective, the production of biogases must deliver net life-cycle GHG emissions reductions. For instance, using gas-tight components for storage covers, valves, tanks, and other components can cut a plant's emissions by more than 40%.

In the STEPS, best practices for GHG emissions reductions are applied to production of biogases wherever policies are in place (e.g. in the European Union and parts of the United States). For the rest of the world, reference values from Section 3.3 are taken. Differences in the feedstock mix, along with fuel substitution of biogases with either coal, oil or natural gas, also determine the overall emissions savings.

Figure 4.12 ▹ Marginal abatement cost of biomethane in the Stated Policies and Announced Pledges Scenarios, 2050



IEA. CC BY 4.0.

If best practices are adopted globally, half of the biomethane potential could be cost competitive with natural gas by 2050, under a CO_2 price below USD 100/t CO_2

Note: t CO_2 = tonne of carbon dioxide.

In the STEPS, emissions avoided from production of biogases in advanced economies by 2050 are around 40 grammes of carbon dioxide (g CO_2) per megajoule (MJ) compared with natural gas. In emerging market and developing economies, the value is just under half of this amount. In contrast, in the APS, it is assumed that best practices are applied across the board. The global average emissions avoided in the APS by 2050 are 41 g CO_2/MJ, compared with

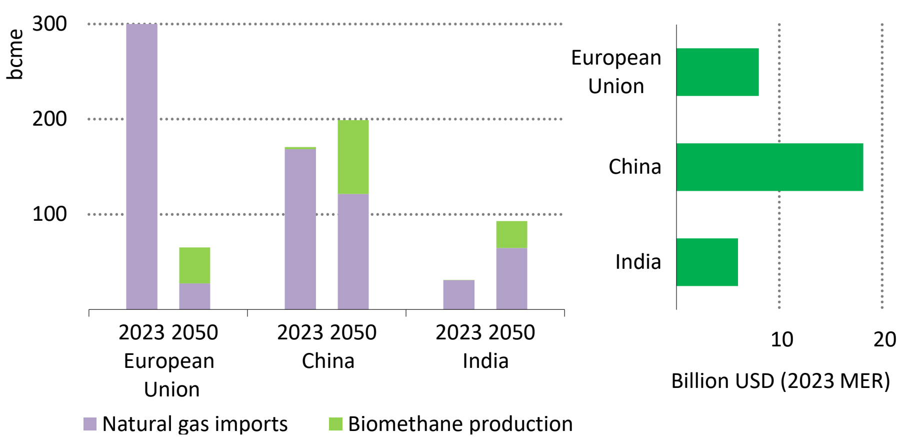
28 g CO_2/MJ in the STEPS. Along with the higher production in the APS, biogases avoid 540 million tonnes of carbon dioxide equivalent (Mt CO_2-eq) in 2050 in the APS, compared with 200 Mt CO_2-eq in 2050 in the STEPS.

These differences also mean that emissions reductions in the APS are more cost-competitive than in the STEPS (Figure 4.12). In the APS by 2050, almost 700 bcme of potential is cost-competitive at a carbon cost of under USD 100 per tonne of carbon dioxide (t CO_2). Furthermore, biogas upgrading generates a highly concentrated by-product stream of CO_2 that could be captured for as little as USD 15/t CO_2 to USD 40/t CO_2, making it one of the cheapest sources of biogenic CO_2 in the APS.

Avoiding natural gas imports

Biogases are homegrown resources, and are consumed within the country in which they are produced. In countries that rely heavily on imported fossil fuels, this confers an energy security benefit by reducing dependence. For example, biomethane production in the European Union avoids the need to import around 15 kb/d of oil and 2 bcme of natural gas each year. In the APS, the savings in natural gas import costs from biomethane consumption in the European Union reach over USD 8 billion by 2050. China and India also save large sums by 2050 (Figure 4.13).

Figure 4.13 ▷ Natural gas imports and biomethane production in the APS in 2050 (left) and resulting natural gas import cost savings due to biomethane (right), by selected region



IEA. CC BY 4.0.

As a local gas source, biomethane reduces imports of natural gas and can mitigate the exposure of energy systems to volatile international markets

Gas infrastructure

In the APS, natural gas demand in advanced economies falls from 1 850 bcme in 2023 to 490 bcme by 2050. Biomethane injected into the gas grid grows from 6 bcme to nearly 100 bcme over the same period. This raises questions about which parts of the gas infrastructure are necessary and which may be decommissioned. It also engenders questions about which actors bear the costs of adapting and maintaining gas grids.

In the European Union, network charges accounted for, on average, nearly 20% of household gas tariffs in 2023 (Trinomics, 2024). European gas transmission network operators are already directing a higher proportion of their investments towards asset replacement (DNV, 2022). This trend is expected to increase as more assets reach their end of life. In addition, in scenarios like the APS, a shrinking customer base will increasingly bear the network costs. Decommissioning, combined with a decreasing pool of grid users, could cause network charges to increase significantly.

Another consideration is whether to maintain or extend infrastructure with the view of increasing biomethane injection or repurposing for hydrogen. As discussed in Chapter 3, a sufficiently dense gas grid enables better development of biomethane in areas with feedstock potential. The energy security value of overlapping infrastructure is also an important consideration for policy makers in this context. Maintaining a gas infrastructure system adds a layer of resilience compared with an approach that relies exclusively on electricity. It also provides a useful hedge against the possibility that electrification and the development of new electricity networks do not increase at the pace needed to displace existing fuels while meeting energy service demands.

Increasing depreciation rates for gas network assets, which mean investment costs in the network must be paid back sooner, would help distribute the cost more broadly among current customers rather than deferring it to a future group of vulnerable customers. Other policy options include using public funds or requiring network investors to pay for decommissioning. In some cases where biomethane use would require additional grid investments, it could lock in legacy infrastructure that is less efficient than alternative options, particularly with lower predicted levels of biomethane in the network compared with current natural gas use. A combined approach to electrification and gas grid planning can yield cost savings. This could be done through a phased approach, electrifying specific sections of the gas grid, which avoids a low-density network remaining for a few holdout users. Planning is important to unlock this potential, as is careful consideration of the contribution of biogas and biomethane production to security of supply (Box 4.2).

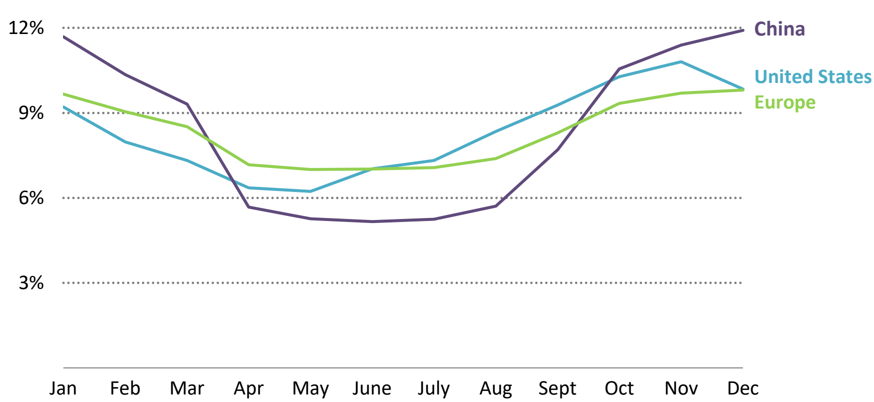
Box 4.2 ▷ Security of supply considerations for production of biogases

It is becoming increasingly important to evaluate the reliability and flexibility of production of biogases, as countries seek to increase the share of biogases in overall gas demand. Whether supply of biogases can contribute to gas system flexibility depends largely on the mix of feedstocks used.

Municipal waste and wastewater treatment plants have a relatively constant availability throughout the year. But agricultural residues depend on farming practices and operational considerations. Crops are harvested at different times of the year, and the time between harvest and first production of biogases depends on the biodegradability of feedstocks and their need for pre-treatment. Feedstocks also have different retention times (the period over which liquid remains in a biodigester), affecting methane yields.

The ability to store silage – without risking spoilage or nutrient loss – is also crucial to ensure a constant output throughout the year. Co-digestion of different feedstocks is an important part of optimising plant use. Specific farming practices, such as putting cows to pasture in spring and summer months, also affect the production profile. For example, in China, a large share of manure in the overall feedstock potential for biogases means pasture grazing compared with barn housing is an important determinant of the seasonal production profile. Higher yields over winter months can match the seasonality of gas usage for heating. In the United States, availabilities are determined to a large extent by harvest cycles and on-farm storage capacity (Figure 4.14).

Figure 4.14 ▷ Seasonal profile of potential production of biogases in selected regions based on assessed feedstock availability

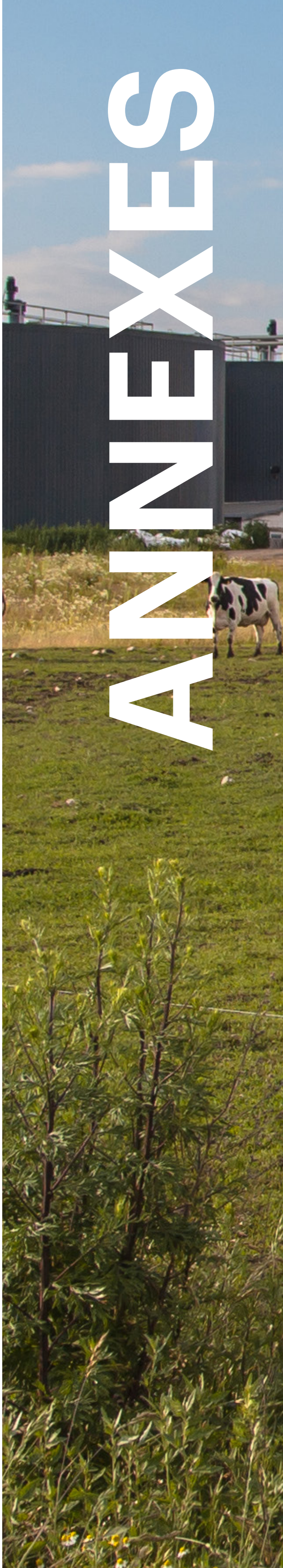


Potential biomethane production in China in the summer can be as low as 50% that in winter months due to a stronger reliance on manure, limiting availability in the summer

Note: Graph shows monthly shares of annual production of biogases.

Generally, like other sources of gas supply, biogas and biomethane plants seek to ensure continuous output throughout the year. This limits the prospects for flexible spare capacity that can ramp up and down in response to changes in demand. Gas networks and storage infrastructure are therefore likely to continue to act as the main source of flexibility in the gas system. Where such infrastructure is limited, the ability of biogases to provide seasonal flexibility may also be limited. The ability of network operators to manage supply sources at the distribution level is an important consideration in this context.

ANNEXES



Definitions

This annex provides general information on terminology used throughout this report including: units and general conversion factors; definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Units

Area	km^2	square kilometre
Distance	km	kilometre
Emissions	g CO_2	gramme of carbon dioxide
	g CO_2-eq	gramme of carbon dioxide equivalent
	g CO_2/MJ	gramme of carbon dioxide per megajoule
	g CO_2-eq/MJ	gramme of carbon dioxide equivalent per megajoule
	Mt CO_2-eq	million tonnes of carbon dioxide equivalent
	t CO_2	tonne of carbon dioxide
	t CO_2-eq	tonne of carbon dioxide equivalent
Energy	EJ	exajoule (1 joule x 10^{18})
	GJ	gigajoule (1 joule x 10^9)
	MJ	megajoule (1 joule x 10^6)
	MBtu	million British thermal units
	kWh	kilowatt hour
	GWh	gigawatt hour
	MWh	megawatt hour
	TWh	terawatt hour
Gas	m^3	cubic metre
	bcme	billion cubic metres of natural gas equivalent
	mcme	million cubic metres of natural gas equivalent
Mass	kg	kilogramme
	t	tonne (1 tonne = 1 000 kg)
	Mt	million tonnes (1 tonne x 10^6)
Monetary	USD	US dollar
	USD/GJ	US dollar per gigajoule
	USD/t	US dollar per tonne
	USD/t CO_2	US dollar per tonne of carbon dioxide
Oil	barrel	one barrel of crude oil
	kb/d	thousand barrels per day
	mb/d	million barrels per day
Power	GW	gigawatt (1 watt x 10^9)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)

Definitions

Agriculture: The practice of cultivating the soil, growing crops and raising animals for food, fibre, fuel and other products used to sustain and enhance human life. It involves a variety of activities such as planting, harvesting, breeding and managing natural resources like soil and water.

Agricultural residues and wastes: In the context of biogas production, organic material grouped into crop residues (e.g. straw, husks or other organic material left over from harvesting) and animal manure (from cattle, pigs, poultry and sheep). Residues are categorised by type of crops harvested, namely, cereals and grain, oil and protein, sugar-based crops, and roots and tubers.

Ammonia (NH_3)**:** A compound of nitrogen and hydrogen that is an industrially produced input to fertiliser manufacturing, typically produced by using fossil fuel inputs to generate the input hydrogen. With properties similar to liquefied petroleum gas, ammonia can also be used directly as a fuel in direct combustion processes, as well as in fuel cells, and can be cracked to release its hydrogen content. As it can be made from low-emissions hydrogen, ammonia has the potential to be a low-emissions fuel if the production process, including nitrogen separation, is powered by low-emissions energy. Produced in such a way, ammonia is considered a low-emissions hydrogen-based liquid fuel.

Anaerobic digestion: A biological process in which micro-organisms break down organic material (such as food waste, agricultural residues or sewage sludge) in the absence of oxygen. This process produces biogas and a solid residue called digestate.

Biochar: A charcoal-like substance produced when digestate is heated to high temperatures in an oxygen-free environment (a process called "pyrolysis").

Biocompressed natural gas (bio-CNG)**:** A compressed form of biomethane.

Biodiesel: A diesel-equivalent fuel made from the transesterification of vegetable oils and animal fats, hydrogenated vegetable oil, thermal processes such as gasification and fermentation.

Biodigester: An airtight system, such as a container or tank, in which organic material is broken down by naturally occurring micro-organisms.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid bioenergy, liquid biofuels and biogases. It excludes hydrogen produced from bioenergy, including via electricity from a biomass-fired plant, as well as synthetic fuels made with CO_2 feedstock from a biomass source.

Biofertiliser: A natural fertiliser that contains living micro-organisms that, when applied to soil or plants, enhance nutrient availability and promote plant growth by improving soil fertility. This can also include fertiliser produced via bioconversion techniques such as anaerobic digestion rather than synthetic (chemical) methods.

Biogas: A mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment. It includes "landfill gas", which is biogas captured from landfills where municipal solid waste decomposes under anaerobic conditions, and gas from wastewater sludge.

Biogases: An umbrella term referring to biogas and biomethane.

Bagasse: The residue remaining after the sugar-containing juice used in bioethanol production has been extracted from plants like sugar cane. Bagasse can be burned to provide a renewable source of heat, for example at biorefineries. See biorefining.

Biogas yield: The amount of biogas produced per unit of feedstock, usually measured in cubic metres per kilogramme of volatile solids.

Biogenic CO_2: The CO_2 produced from living organisms within the naturally occurring carbon cycle. The CO_2 produced during biomethane upgrading falls under this category, meaning its capture is considered a negative emission.

Biomethanation: A technique, currently at demonstration phase, for increasing methane yields from biogas upgrading by adding hydrogen to the digester. Micro-organisms called hydrogenotrophic methanogens then convert the hydrogen and CO_2 from the digestion process into methane.

Biomethane: A near-pure source of methane produced either by "upgrading" biogas (a process that removes any CO_2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. It is also known as renewable natural gas and bionatural gas.

Biorefinery: A facility producing chemicals or other products using biomass as a feedstock.

Biowaste: Waste derived from food, agriculture or other organic matter. It includes food waste and paper or cardboard from municipal solid waste, wastewater sludge and organic by-products from industrial processing.

Carbon capture, utilisation and storage (CCUS): The process of capturing CO_2 emissions from fuel combustion, industrial processes or directly from the atmosphere. Captured CO_2 emissions can be stored in underground geological formations, onshore or offshore, or used as an input or feedstock in manufacturing.

Carbon dioxide (CO_2): A gas consisting of one part carbon and two parts oxygen. It is an important greenhouse (heat-trapping) gas.

Carbon monoxide (CO): A gas consisting of one part carbon and one part oxygen. It is a main component of synthesis gas (syngas) along with hydrogen. It is a product of the incomplete combustion of carbon-containing fuels. It is a colourless, odourless, tasteless and poisonous gas that can cause severe health problems if inhaled.

Chemical absorption scrubbing: A method for upgrading biogas to biomethane using amine solvents to bind CO_2 molecules.

Clean cooking: Cooking solutions that release less harmful pollutants and which are more efficient and environmentally sustainable than traditional cooking options that make use of solid biomass (such as a three-stone fire), coal or kerosene. This refers to the use of improved cook stoves, biogas/biodigester systems, electric stoves, liquefied petroleum gas, natural gas or ethanol stoves.

Clean energy: An umbrella term that groups energy sources, infrastructure, applications and related assets that are compatible with a net zero emissions energy system. In power, clean energy includes: renewable energy sources, nuclear power, fossil fuels fitted with carbon capture, utilisation and storage, hydrogen and ammonia; battery storage; and electricity grids. In efficiency, clean energy includes energy efficiency in buildings, industry and transport, excluding domestic navigation. In end-use applications, clean energy includes: direct use of renewables; electric vehicles; electrification in buildings, industry and international marine transport; and carbon capture, utilisation and storage in industry and direct air capture. In fuel supply, clean energy includes low-emissions fuels, direct air capture and measures to reduce the emissions intensity of fossil fuel production.

Coal: Consists of primary coal (lignite, coking and steam coal) and derived fuels (e.g. patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas works gas, coke-oven gas, blast furnace gas and oxygen steel furnace gas). Peat is also included.

Combined heat and power (CHP): The simultaneous generation of electricity and heat from the same fuel, enabling a higher efficiency of fuel use.

Compressed natural gas (CNG): A means of storing and transporting natural gas in situations where high volumetric energy density is valuable. Used as a fuel in CNG vehicles, where it is stored in high-pressure fuel cylinders. Produces fewer exhaust and greenhouse gas emissions than motor gasoline or diesel oil, but more direct emissions than electric vehicles. Used most frequently in light-duty passenger vehicles and pickup trucks, medium-duty delivery trucks, and in transit and school buses. CNG vehicles can also run on compressed biomethane (See biocompressed natural gas).

Conventional natural gas (CNG): Natural gas extracted using traditional drilling techniques. It includes onshore and offshore natural gas (including from the Arctic).

Digestate: A liquid or solid residue from anaerobic digestion of organic matter. Nutrients from the original substrate, such as nitrogen, phosphorus, potassium and trace elements, are retained in the digestate, meaning it can be used as a substitute for synthetic fertiliser.

Dispatchable generation: Electricity from technologies whose power output can be readily controlled up to the nameplate capacity (i.e. increased to maximum rated capacity or decreased to zero), to help match supply with demand.

Dry matter: Moisture-free content of a mixture of substances.

Electric vehicles: Electric vehicles comprise battery electric vehicles and plug-in hybrid electric vehicles.

Electricity generation: The total amount of electricity generated by power only or combined heat and power plants including generation required for own use. It is also referred to as gross generation.

End-use sectors: Sectors including industry, transport, buildings, agriculture and other non-energy use.

Energy-intensive industries: Industries including production and manufacturing in the branches of iron and steel, chemicals, non-metallic minerals (including cement), non-ferrous metals (including aluminium), and paper, pulp and printing.

Ethanol: An alcohol with broad application in the chemical sector and as a fuel additive. When produced from bioresources it is known as bioethanol, which has applications as biogasoline (a liquid fuel) and as a biochemical.

Feed-in premium (FiP): A support mechanism in which producers of renewable energy receive a "premium" or additional payment on top of the electricity spot price for each unit sold. Premiums may be fixed or variable depending on the arrangement.

Feed-in tariff (FiT): A support mechanism in which producers of renewable energy are paid a fixed price for each unit of output.

Feedstock: A raw material for digestion, including crop residues like straw or husks, animal manure, biowaste and woody biomass (log residues and wood processing waste).

Fossil fuels: Fuels such as coal, oil, natural gas or peat. Total fossil fuel use is equal to unabated fossil fuels plus fossil fuels with CCUS plus non-energy use of fossil fuels.

Fresh matter: Total mass of a biological material, including water and dry content.

Gaseous fuels: Fuels in gaseous form including natural gas, biogas, biomethane, hydrogen and synthetic methane.

Greenhouse gas (GHG): A gas that exacerbates the greenhouse effect. Includes carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulphur hexafluoride (SF_6).

Guarantee of origin (GO): A certificate proving that a unit of electricity or gas was generated from renewable sources. It enables consumers to choose the source of energy they buy from the grid.

Heat (end-use): Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). It refers to a wide range of end-uses, including space and water heating, and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

A

Heat (supply): Obtained from the combustion of fuels, nuclear reactors, large-scale heat pumps, and geothermal or solar resources. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation.

Heavy-duty transportation: Includes buses and medium and heavy freight trucks.

Hydraulic retention time: The number of days material stays in an anaerobic digester. This duration affects the microbial profile of the digestate; a longer time can help reduce methane emissions from digestate.

Hydrogen: Hydrogen is used in the energy system as an energy carrier, as an industrial raw material or is combined with other inputs to produce hydrogen-based fuels.

Hydrogen-based fuels: Fuels including ammonia and synthetic hydrocarbons (gases and liquids) that derive their energy content from a pure (or nearly pure) hydrogen feedstock. If produced from low-emissions hydrogen, these fuels are low-emissions hydrogen-based fuels.

Improved cook stove (ICS): Intermediate and advanced improved biomass cook stoves (ISO tier ≥ 3). It excludes basic improved stoves (ISO tiers 0-2).

Industry: The sector includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemicals and petrochemicals, cement, aluminium, and paper, pulp and printing. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. There is an exception for fuel transformation in blast furnaces and coke ovens, which are reported within iron and steel. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption of fuels by off-road vehicles is reported under the specific sector. For instance, fuels consumed by bulldozers as a part of industrial operations is reported in industry.

Industrial waste: Organic by-products or residues generated by industrial processes that can be used as feedstock for biogas production through anaerobic digestion.

Landfill gas recovery system: Systems capturing the biogas produced from the decomposition of municipal solid waste under anaerobic conditions at landfill sites (known as "landfill gas''). Landfill gas recovery systems use pipes, extraction wells and compressors to induce biogas flow to a central collection point.

Levelised cost of electricity: An indicator of the expected average production cost for each unit of electricity generated by a technology over its economic lifetime. It combines into a single metric of all the cost elements directly associated with a given power technology, including construction, financing, fuel, maintenance and costs associated with a carbon price. It does not include network integration or other indirect costs.

Life-cycle greenhouse gas emissions: A metric considering all greenhouse gas emissions generated across the production, use and disposal of a product.

Liquefied natural gas (LNG): Natural gas that is liquefied by reducing its temperature to -162 °C at atmospheric pressure, reducing its space requirements for storage and transport by a factor of over 600.

Liquefied petroleum gas (LPG): Liquefied propane (C_3H_8) and butane (C_4H_{10}) or mixtures of both. Commercial grades are usually mixtures of the gases with small amounts of propylene, butylene, isobutene and isobutylene stored under pressure in containers.

Liquid biofuels: Liquid fuels derived from biomass or waste feedstock, including ethanol, biodiesel and biojet fuels. They can be classified as conventional and advanced biofuels according to the combination of feedstock and technologies used to produce them and their respective market maturity. Unless otherwise stated, biofuels are expressed in energy-equivalent volumes of gasoline, diesel and kerosene.

Liquid fuels: Include oil, liquid biofuels, synthetic oil products and hydrogen-based fuels (ammonia and methanol).

Low-emissions fuels: Include modern bioenergy, low-emissions hydrogen and low-emissions hydrogen-based fuels.

Low-emissions gases: Include biogas, biomethane, low-emissions hydrogen and low-emissions synthetic methane.

Marginal land: Land that is degraded and has lower quality soil, making it suboptimal for agricultural use

Membrane separation: A method for upgrading biogas to biomethane involving a polymeric membrane that is permeable to CO_2, water and ammonia molecules but retains methane.

Methanation: a chemical process in which carbon oxides (mainly carbon monoxide and carbon dioxide) react with hydrogen to produce methane and water.

Methane (CH_4): A hydrocarbon gas that is the major constituent of natural gas and biogases. Methane is a potent greenhouse gas with a GWP100 (global warming potential over 100 years) of 27-30 (depending on the measurement system and origin) and a GWP20 (global warming potential over 20 years) of 81-83.

Methane yield: The amount of methane produced per unit of feedstock, usually measured in cubic metres per kilogramme of volatile solids.

Methanol: A chemical compound comprising carbon, hydrogen and oxygen. One of the world's most widely used industrial chemicals, it can be used as a fuel, including in fuel cells.

Microbial electrolysis cell: A biochemical reactor. While in an early stage of development, this technology may be viable for increasing biomethane yields in the anaerobic digestion process.

Minigrids: Small electric grid systems, not connected to main electricity networks, linking a number of households and/or other consumers.

Modern bioenergy: Bioenergy excluding the traditional use of biomass and other low-efficiency or unsustainable practices. Includes modern solid bioenergy, liquid biofuels and biogases.

Municipal solid waste (MSW): Waste collected from households or waste in a similar form from other sources, such as businesses and institutions.

Natural gas: A gaseous fossil fuel, consisting mostly of methane. Occurs in deposits, whether liquefied or gaseous. In IEA analysis and statistics, it includes non-associated gas originating from fields producing hydrocarbons only in gaseous form, and associated gas produced in association with crude oil production, as well as methane recovered from coal mines (colliery gas).

Off-gas: A CO_2-rich gas stream produced during biogas upgrading. It may also contain air, oxygen, hydrogen sulphide or water vapour, as well as small quantities of methane. The methane content varies depending on the upgrading method.

Off-grid systems: Minigrids and standalone systems for individual households or groups of consumers not connected to a main grid.

Oil: A liquid fuel. Usually refers to fossil fuel mineral oil. Includes oil from conventional and unconventional oil production.

Power generation: Electricity generation and heat production from all sources of electricity, including electricity-only power plants, heat plants and co-generation (combined heat and power) plants.

Pressure swing adsorption: a technology that uses pressure to selectively adsorb and separate different types of gases from a mixture of gases.

Renewables: Include modern bioenergy, geothermal, hydropower, solar photovoltaics, concentrating solar power, wind, marine (tide and wave) energy and renewable waste.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking.

Road transport: Includes all road vehicle types (passenger cars, two/three-wheelers, light commercial vehicles, buses, and medium and heavy freight trucks).

Shipping: This transport mode includes domestic and international navigation and their use of marine fuels.

Solar energy: Includes solar photovoltaics, concentrated solar power, and solar heating and cooling.

Solar photovoltaics (PVs): Solar photovoltaic cells including utility-scale and small-scale installations.

Syngas: A gas mixture of primarily hydrogen and carbon monoxide. It can be produced via the gasification of biomass and used for various applications including creating synthetic fuels. To be upgraded into biomethane, syngas must be cleaned and methanated.

Synthetic fertiliser: A chemically manufactured fertiliser containing nutrients such as phosphorus, nitrogen or potassium.

Synthetic fuel: A fuel, either synthetic liquid fuel or synthetic gaseous fuel, obtained via a process other than the refining of crude oil or bituminous oils. Also known as synfuel.

Synthetic methane (also called e methane or renewable methane): Methane produced through chemical processes, such as methanation, rather than being extracted from fossil fuel sources like natural gas.

Traditional use of biomass: The use of solid biomass with basic technologies, such as a three-stone fire or basic improved cook stoves (ISO tier < 3), often with no or poorly operating chimneys. Forms of biomass used include wood, wood waste, charcoal, agricultural residues and other bio-sourced fuels such as animal manure.

Transport: Includes fuels and electricity used in the transport of goods or people within the national territory irrespective of the economic sector within which the activity occurs. This includes: fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Energy consumption from marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at a domestic level.

Two-phase anaerobic digestion: An advanced process for anaerobic digestion in which the digestion of organic materials is split into two distinct stages, each carried out under different environmental conditions. It is designed to optimise biogas production by improving the efficiency of the breakdown of organic material, particularly for high-solid feedstocks.

Vinasse: As a by-product of the sugar and ethanol industry, it is the waste liquid that remains after the sugar-containing juice is distilled into ethanol. It can then be used as a biogas feedstock.

Volatile organic solid: The biodegradable portion of dry matter that can be decomposed by micro-organisms, especially during anaerobic digestion.

Wastewater sludge: A semi-solid by-product generated during the treatment of wastewater. It contains organic and inorganic matter, micro-organisms, water and sometimes toxins or heavy metals, depending on the source of the wastewater.

Wastewater treatment plant: A facility that treats wastewater (municipal, industrial and agricultural) for reuse or safe disposal. Sludge collected during the cleaning process can be subjected to anaerobic digestion to produce biogas.

Water scrubbing: A method for upgrading biogas to biomethane in which pressurised biogas is injected into water columns. The higher solubility of CO_2 compared to methane enables them to then be separated.

Woody biomass: Biomass from trees or woody plants, such as log residues or wood processing waste

Regional and country groupings

Advanced economies: OECD regional grouping and Bulgaria, Croatia, Cyprus,[1,2] Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, People's Republic of China (China), Democratic People's Republic of Korea, India, Japan, Korea, Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka, Chinese Taipei, and other Asia Pacific countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Central and South America: Argentina, Plurinational State of Bolivia (Bolivia), Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Guyana, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Bolivarian Republic of Venezuela (Venezuela), and other Central and South American countries and territories.[4]

China: Includes People's Republic of China and Hong Kong, China.

Developing Asia: Asia Pacific regional grouping excluding Australia, Japan, Korea and New Zealand.

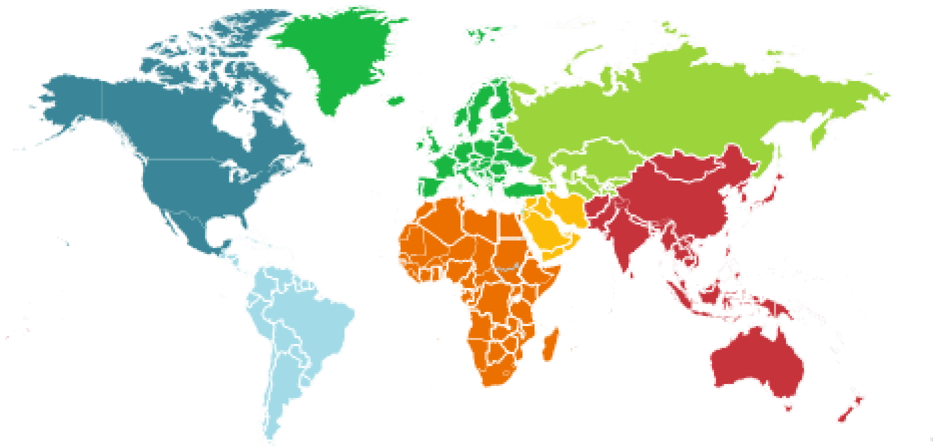
Emerging market and developing economies: All other countries not included in the advanced economies regional grouping.

Eurasia: Caspian regional grouping and the Russian Federation (Russia).

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, Gibraltar, Iceland, Israel,[5] Kosovo, Montenegro, Republic of Moldova (Moldova), Republic of North Macedonia (North Macedonia), Norway, Serbia, Switzerland, Türkiye, Ukraine and United Kingdom.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus,[1,2] Czech Republic (Czechia), Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

Figure A.1 ▷ Main country groupings



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

IEA (International Energy Agency): OECD regional grouping excluding Chile, Colombia, Costa Rica, Iceland, Israel,[5] Latvia and Slovenia.

Latin America and the Caribbean: Central and South America regional grouping and Mexico.

Middle East: Bahrain, Islamic Republic of Iran (Iran), Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic (Syria), United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

Non-OPEC: All other countries not included in the OPEC regional grouping.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development): Australia, Austria, Belgium, Canada, Chile, Colombia, Costa Rica, Czech Republic (Czechia), Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel,[5] Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Türkiye, United Kingdom and United States.

OPEC (Organization of the Petroleum Exporting Countries): Algeria, Republic of the Congo (Congo), Equatorial Guinea, Gabon, Islamic Republic of Iran (Iran), Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, Bolivarian Republic of Venezuela (Venezuela) and United Arab Emirates.

OPEC+: OPEC grouping plus Azerbaijan, Bahrain, Brunei Darussalam, Kazakhstan, Malaysia, Mexico, Oman, Russian Federation (Russia), South Sudan and Sudan.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations.

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo (Congo), Côte d'Ivoire, Democratic Republic of the Congo, Equatorial Guinea, Eritrea, Kingdom of Eswatini (Eswatini), Ethiopia, Gabon, Ghana, Kenya, Madagascar, Mauritius, Mozambique, Namibia, Niger, Nigeria, Rwanda, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Uganda, Zambia, Zimbabwe, and other African countries and territories.[6]

Country notes

[1] Note by Republic of Türkiye: The information in this document with reference to "Cyprus" relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".

[2] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, Sint Eustatius and Saba, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Montserrat, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and the Grenadines, Sint Maarten (Dutch part), and Turks and Caicos Islands.

[5] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

[6] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Malawi, Mali, Mauritania, Sao Tome and Principe, Seychelles, Sierra Leone and Somalia.

Abbreviations and acronyms

ABPP	African Biogas Partnership Programme
APS	Announced Pledges Scenario
BF	blast furnace
bio-CNG	biocompressed natural gas
BIP	Biomethane Industrial Partnership
BOF	basic oxygen furnace
CAPEX	capital expenditure
CBA	Canadian Biogas Association

CBG	compressed biogas
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CH_4	methane
CHP	combined heat and power; the term co-generation is sometimes used
CI	carbon intensity
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon dioxide equivalent
DAC	direct air capture
DRI	direct reduced iron
EAF	electric arc furnace
EBA	European Biogas Association
EMDE	emerging market and developing economies
EPA	Environmental Protection Agency (United States)
e-SAF	synthetic sustainable aviation fuel
ETS	emissions trading system
EU	European Union
FAI	The Fertiliser Association of India
FAO	Food and Agriculture Organization of the United Nations
FiP	feed-in premium
FiT	feed-in tariff
GDP	gross domestic product
GHG	greenhouse gas
GO	guarantee of origin
H_2	hydrogen
HVO	hydrogenated vegetable oil
ICS	improved cook stove
IEA	International Energy Agency
IOE	iron ore electrolysis
JRC	Joint Research Centre
LCFS	Low Carbon Fuel Standard
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MER	market exchange rate
MSW	municipal solid waste
NG	natural gas
NGO	non-governmental organisation
OECD	Organisation for Economic Co-operation and Development

OPEC	Organization of the Petroleum Exporting Countries
OPEX	operating expenditure
PROM	phosphate-rich organic manure
PV	photovoltaics
RE	renewable energy
RED	Renewable Energy Directive
RIN	renewable identification number
SME	small and medium-sized enterprises
STEPS	Stated Policies Scenario
UCO	used cooking oil
US	United States

References

Chapter 1: Surveying the field

Argonne National Laboratory, (2024), Renewable Natural Gas Database (accessed March 2025), https://www.anl.gov/esia/reference/renewable-natural-gas-database

CIBiogás (2023), BiogásMap, https://cibiogas.org/tags/biogasmap/

Clemens, H. et al. (2018), Africa Biogas Partnership Program: A review of clean cooking implementation through market development in East Africa, Energy for Sustainable Development, Vol. 46, pp. 23-31, https://doi.org/10.1016/j.esd.2018.05.012

Department of Economic Affairs (2025), Gobardhan Bio CNG Plant, http://www.pppinindia.gov.in/bestpractices/best-practice-detail/gobardhan-bio-cng-plant

Energinet (2025), Biomethane, https://en.energinet.dk/gas/biomethane

Deutsche Gesellschaft für Internationale Zusammenarbeit (2024), Business Model for Bio PROM, https://snrd-asia.org/2023_08_31_business-model-for-bio-prom_en_in

Government of India (2025), Frequently Asked Questions, https://mnre.gov.in/en/faq

IEA (International Energy Agency) (2025a), Global Methane Tracker 2025, https://www.iea.org/reports/global-methane-tracker-2025

IEA (2025b), Gas Market Report Q1-2025, https://www.iea.org/reports/gas-market-report-q1-2025

IEA (2025c), India Gas Market Report, https://www.iea.org/reports/india-gas-market-report

IEA (2020), Outlook for Biogas and Biomethane: Prospects for Organic Growth, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth

Itaipu Binacional (2019), Itaipu e Copel desenvolvem projeto inédito de microgrid no Oeste Paranaense, https://www.itaipu.gov.br/sala-de-imprensa/noticia/itaipu-e-copel-desenvolvem-projeto-inedito-de-microgrid-no-oeste-paranaense

Ministry of Agriculture (2016), China Agriculture Statistical Yearbook 2016.

Ministry of Agriculture (2006), China Agriculture Statistical Yearbook 2006.

Ministry of Agriculture (2001), China Agriculture Statistical Yearbook 2001.

Ministry of Jal Shakti (2025), Unified Registration Portal for GOBARdhan Plants (accessed March 2025), https://gobardhan.sbm.gov.in

Ministry of Petroleum and Natural Gas (2023), Government Announces Mandatory Blending of Compressed Bio-Gas in CNG (Transport) & PNG (Domestic) Segments of CGD Sector, https://pib.gov.in/PressReleseDetailm.aspx?PRID=1979705&reg=3&lang=1

National Bureau of Statistics (2024), China Rural Statistical Yearbook 2024.

Rumah Energi (2023), Indonesia Domestic Biogas Program Annual Report 2023, https://www.rumahenergi.org/wp-content/uploads/2024/11/IDBP-Report-2023-Final.pdf

Ton, P. et al. (2019), Africa Biogas Partnership Programme (ABPP) Phase 2 - Effect Evaluation: Final Report, https://www.government.nl/documents/reports/2019/05/13/africa-biogas-partnership-programme-abpp-phase-2---effect-evaluation

Wall, D. and R. O'Shea (2025), Biogas Systems in Industry: An Analysis of Sectoral Usage, Sustainability, Logistics and Technology Development, IEA Bioenergy, https://task37.ieabioenergy.com/technical-reports/biogas-systems-in-industry/

Chapter 2: Waste to money?

Argonne National Laboratory (2024), Renewable Natural Gas Database (accessed March 2025), https://www.anl.gov/esia/reference/renewable-natural-gas-database

California Air Resources Board (2025), Current Fuel Pathways spreadsheet (accessed January 2025), https://ww2.arb.ca.gov/es/resources/documents/lcfs-pathway-certified-carbon-intensities

CDR.fyi (2025), We Bring Transparency and Accountability to the Carbon Removal Market (accessed April 2025), https://www.cdr.fyi

Chanthakett, A. et al. (2021), Performance assessment of gasification reactors for sustainable management of municipal solid waste, Journal of Environmental Management, Vol. 291, 112661, https://doi.org/10.1016/j.jenvman.2021.112661

Comer, B. et al. (2024), Fugitive and Unburned Methane Emissions from Ships (FUMES). International Council on Clean Transportation, https://theicct.org/publication/fumes-characterizing-methane-emissions-from-lng-fueled-ships-using-drones-helicopters-and-on-board-measurements-jan24

Common Futures (2024), Biomethane for Emission Abatement by 2040, https://www.europeanbiogas.eu/wp-content/uploads/2024/04/Common-Futures_Biomethane-for-emission-abatement-by-2040.pdf

DNV (2024), Maritime Forecast to 2050, https://www.dnv.com/maritime/publications/maritime-forecast

EBA (European Biogas Association) (2024a), EBA Statistical Report 2024, https://www.europeanbiogas.eu/eba-statistical-report-2024

EBA (2024b), Gasification: Diversification of Biomass Processing and Waste Utilisation, https://www.europeanbiogas.eu/wp-content/uploads/2024/12/EBA-Gasification_December-2024.pdf

EBA (2024c), European Biomethane Map 2024, https://www.europeanbiogas.eu/european-biomethane-map-2024/

EBA (2023), Beyond Energy – Monetising Biomethane's Whole-System Benefits, http://www.europeanbiogas.eu/wp-content/uploads/2023/02/20230213_Guidehouse_EBA_Report.pdf

European Commission (2024), AgriData, Fertiliser Trade, https://agridata.ec.europa.eu/extensions/DashboardFertiliser/FertiliserTrade.html#

FAO (Food and Agriculture Organization of the United Nations) (2024), Crop Production, Yield, Harvested Area and Processed (Global – National -Annual) – FAOSTAT (database), https://data.apps.fao.org/catalog/dataset/crop-production-yield-harvested-area-and-processed-global-national-annual-faostat

FAI (The Fertiliser Association of India) (2024), Summary Tables, https://www.faidelhi.org/general/con-npk.pdf

Fertilizers Europe (2023), Fertilizer Industry Facts & Figures 2023, https://www.fertilizerseurope.com/wp-content/uploads/2023/07/Industry-Facts-and-figures-2023.pdf

Global Energy Monitor (2024), Global Gas Infrastructure Tracker, https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker

Government of India (2023), Starred Question No.228: Workforce Engaged in Agriculture, https://sansad.in/getFile/loksabhaquestions/annex/1714/AS228.pdf?source=pqals

Guidehouse (2023), Thermal Gasification: A Key Technology to Decarbonize Europe and Improve Energy Security, https://guidehouse.com/insights/communities-energy-infrastructure/2023/thermal-gasification

HydroSHEDS (2022), HydroWASTE Database, https://www.hydrosheds.org/products/hydrowaste

IEA (International Energy Agency) (2025), The State of Energy Innovation, https://www.iea.org/reports/the-state-of-energy-innovation

IEA (2023), A Vision for Clean Cooking Access for All, https://www.iea.org/reports/a-vision-for-clean-cooking-access-for-all

IEA (2020), Outlook for Biogas and Biomethane: Prospects for Organic Growth, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth

JRC (Joint Research Centre) (2024), Methane Emissions in the Biogas and Biomethane Supply Chains in the EU, https://publications.jrc.ec.europa.eu/repository/bitstream/JRC139485/JRC139485_01.pdf

Ministry of Jal Shakti (2024), Advancing Sustainability, C.R. Patil Reviews Progress of GOBARdhan Initiative, https://pib.gov.in/PressReleaseIframePage.aspx?PRID=2080546

Murphy, J. et al. (2011), Biogas from Crop Digestion, IEA Bioenergy, https://task37.ieabioenergy.com/wp-content/uploads/sites/32/2022/02/Update_Energy_crop_2011.pdf

Stolaroff, J. et al. (2021), Transport Cost for Carbon Removal Projects With Biomass and CO2 Storage, Frontiers in Energy Research, Vol. 9, https://doi.org/10.3389/fenrg.2021.639943

Trinomics (2020), Cost of Energy (LCOE): Energy Costs, Taxes and the Impact of Government Interventions on Investments, https://trinomics.eu/wp-content/uploads/2020/11/Final-Report-Cost-of-Energy-LCOE.pdf

United States Environmental Protection Agency (2024). Livestock Anaerobic Digester Database, https://www.epa.gov/agstar/livestock-anaerobic-digester-database

Wall, D. and R. O'Shea (2025), Biogas Systems in Industry: An Analysis of Sectoral Usage, Sustainability, Logistics and Technology Development, IEA Bioenergy, https://task37.ieabioenergy.com/technical-reports/biogas-systems-in-industry/

World Resources Institute (2024), Spatial Database of Planted Trees (SDPT Version 2.0), https://www.wri.org/research/spatial-database-planted-trees-sdpt-version-2

WorldPop (2020), Population Counts / Unconstrained Individual Countries 2000-2020 (1km resolution), https://hub.worldpop.org/geodata/listing?id=74

Chapter 3: What keeps cropping up?

Anacleto, T. M. et al. (2024), Opportunities for biogas production from algal biomass. Biofuels, Bioproducts, and Biorefining, Vol. 19, No. 1, pp. 163-173, https://doi.org/10.1002/bbb.2702

Ardolino, F. et al. (2021), Biogas-to-biomethane upgrading: A comparative review and assessment in a life cycle perspective, Renewable and Sustainable Energy Reviews, Vol. 19, No. 1, pp. 1-14, https://scijournals.onlinelibrary.wiley.com/doi/10.1002/bbb.2702

British Columbia Utilities Commission (2016), Order Number E-3-16, https://www.ordersdecisions.bcuc.com/bcuc/orders/en/142661/1/document.do

BIP (Biomethane Industrial Partnership) (2023), Accelerating Biomethane Permitting, https://bip-europe.eu/wp-content/uploads/2023/10/BIP_Task-Force-2_Accelerating-biomethane-permitting_Oct2023.pdf

CBA (Canadian Biogas Association) (2022), Analysis of Regulatory Barriers Impacting Agricultural Biogas Development in Canada, https://biogasassociation.ca/images/uploads/documents/2022/resources/Agricultural_Biogas_Regulatory_Analysis_April_2022.pdf

CBA (2021), CBA Factsheet: Key Questions about Biogas, https://farmingbiogas.ca/wp-content/uploads/2021/01/CBA_Farming-biogas_Factsheet_QA-v11.pdf

CI Consulting, S&P Global (2024), Renewable Gas Tracking Systems – Value of Biomethane/RNG Certificates, https://www.europeanbiogas.eu/wp-content/uploads/2024/10/Value-of-Biomethane-Certficates-Study-Complete-White-Paper-FINAL-for-Publishing-20241021.pdf

CIBiogás (2021), Brazilian Biogas Overview 2021, https://cibiogas.org/wp-content/uploads/2022/06/BRAZILIAN-BIOGAS-OVERVIEW-2021.pdf

DSO Entity (2025), Guidance on EU Permitting-related Provisions on Grid and Renewable Energy Projects, https://eudsoentity.eu/wp-content/uploads/2025/01/2025-Permitting-Paper-DSOEntity-1.pdf

EBA (European Biogas Association) (2025), How Costs to Connect Biomethane to Gas Grids are Paid For, https://www.europeanbiogas.eu/wp-content/uploads/2025/04/How-costs-to-connect-biomethane-to-gas-grids-are-paid-for_Common-Futures-study-for-EBA.pdf

EBA (2024a), EBA Statistical Report 2024, https://www.europeanbiogas.eu/eba-statistical-report-2024

EBA (2024b), Exploring Digestate's Contribution to Healthy Soils, https://www.europeanbiogas.eu/exploring-digestates-contribution-to-healthy-soils-2

EBA (2024c), Variations in National Regulation with Respect to Biomethane Grid Connection, https://www.europeanbiogas.eu/wp-content/uploads/2024/02/GreenMeUp-Variations-in-Natl.-Grid-Connection.pdf

EBA (2023), EBA Statistical Report 2023, https://www.europeanbiogas.eu/eba-statistical-report-2023

EBA (n.d.), Open Market for Digestate from Anaerobic Digestion: Uppsala Sweden, https://www.europeanbiogas.eu/wp-content/uploads/2016/03/Uppsala.pdf

Edrisi, S.A. and P.C. Abhilash (2015), Exploring marginal and degraded lands for biomass and bioenergy, Renewable and Sustainable Energy Reviews, Vol. 54, pp. 1537-1551, https://www.sciencedirect.com/science/article/pii/S1364032115011296

Energistyrelsen (2024), Biogas in Denmark, https://ens.dk/en/energy-sources/biogas-denmark#:~:text=The%20production%20of%20biogas%20in,also%20used%20for%20producing%20biogas

EPA (United States Environmental Protection Agency) (2025), Methane Mitigation: Lessons Learned from India's Compressed Biogas (Renewable Natural Gas) Projects, https://www.globalmethane.org/documents/CBG_Report_%20January%202025.pdf

EPA (2024), AgSTAR Data and Trends, https://www.epa.gov/agstar/agstar-data-and-trends#adfacts

Government of India (2024), Scheme Guideline for Development of Pipeline Infrastructure (DPI) for Injection of Compressed Bio Gas (CBG) in City Gas Distribution (CGD) Network, https://gobardhan.sbm.gov.in/whats-new/Scheme%20guidelines%20for%20development%20of%20pipeline%20infrastructure%20for%20injection%20of%20CBG%20in%20CGD.pdf

IEA (International Energy Agency) (2025), Global Methane Tracker 2025, https://www.iea.org/events/global-methane-tracker-2025

IEA (2024), Energy Technology Perspectives 2024, https://www.iea.org/reports/energy-technology-perspectives-2024

IEA Bioenergy (2009), Biogas Upgrading Technologies – Developments and Innovations, https://www.ieabioenergy.com/wp-content/uploads/2009/10/upgrading_rz_low_final.pdf

Jansons, L. et al. (2024), Injection of renewables gases into the existing gas distribution grids and employment of reverse gas flow technique, Latvian Journal of Physics and Technical Sciences, Vol. 61, No. 2, pp. 66-79, https://sciendo.com/article/10.2478/lpts-2024-0013

JRC (Joint Research Centre) (2024), Methane Emissions in the Biogas and Biomethane Supply Chains in the EU, https://publications.jrc.ec.europa.eu/repository/bitstream/JRC139485/JRC139485_01.pdf

Klinkner, B.A. (2014), Anaerobic digestion as a renewable energy, University of Massachusetts Law Review, Vol. 9, pp. 68-96, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2420832

Oliveira, J. et al. (2025), Exploring microalgae species for integrated bioenergy Production: A multi-fuel cascade valorisation approach, Energy Conversion and Management, Vol. 332, https://doi.org/10.1016/j.enconman.2025.119736

Reinelt, T., J. Liebetrau and M. Nelles (2016), Analysis of operational methane emissions from pressure relief valves from biogas storages of biogas plants, Bioresource Technology, Vol. 217, pp. 257-264, https://doi.org/10.1016/j.biortech.2016.02.073

Scheutz, C. and A. Fredenslund (2019), Total methane emission rates and losses from 23 biogas plants, Waste Management, Vol. 97, pp. 38-46, https://doi.org/10.1016/j.wasman.2019.07.029

SoCalGas (2025), Biomethane Monetary Incentive Program, http://www.socalgas.com/sustainability/renewable-gas/biomethane-monetary-incentive-program

Sun, Q. et al. (2015), Selection of appropriate biogas upgrading technology-a review of biogas cleaning, upgrading and utilisation, Renewable and Sustainable Energy Reviews, Vol. 51, pp. 521-532, https://doi.org/10.1016/j.rser.2015.06.029

United Nations Development Programme (2011), One Digester Plus Three Renovations: Biogas Plants for Rural China, https://www.undp.org/asia-pacific/publications/energy-access-case-study-05-one-digester-plus-three-renovations-biogas-plants-rural-china

Wang, Y. et al. (2023), China's Biogas Industry's Sustainable Transition to a Low-Carbon Plan - A Socio-Technical Perspective, Sustainability, https://www.mdpi.com/2071-1050/15/6/5299

Wechselberger, V. et al. (2023), Methane losses from different biogas plant technologies, Waste Management, Vol. 157, pp. 110-120, https://doi.org/10.1016/j.wasman.2022.12.012

Chapter 4: Ploughing ahead

DNV (2022), Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments, https://www.acer.europa.eu/sites/default/files/documents/Media/News/Documents/Future%20Regulation%20of%20Natural%20Gas%20Networks%20-%20Final%20Report%20DNV.pdf

IEA (International Energy Agency) (2024), World Energy Outlook 2024, https://www.iea.org/reports/world-energy-outlook-2024

IEA (2020), Outlook for Biogas and Biomethane: Prospects for Organic Growth, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth

Trinomics (2024), Study on Energy Prices and Costs – Evaluating Impacts on Households and Industry's Costs: 2024 Edition, https://op.europa.eu/en/publication-detail/-/publication/78756c15-f263-11ef-981b-01aa75ed71a1/language-en

International Energy Agency (IEA)

Unless otherwise indicated, all material presented in figures and tables is derived from IEA data and analysis.

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/contact

Typeset in France by IEA - May 2025
Cover design: IEA
Photo credits: © Shutterstock

Revised version, May 2024
Information notice found at: www.iea.org/corrections

Outlook for Biogas and Biomethane

World Energy Outlook Special Report

Biogases play an important and growing role in energy systems. Produced locally using organic waste, biogas and biomethane can contribute to energy security, waste management, emissions reductions and agricultural development.

In recent years, demand for biomethane – also known as "renewable natural gas" – has grown rapidly in many countries, supported by dozens of new policies. As a low-emissions substitute for natural gas, the use of biomethane has been targeted across a wide range of sectors, including power, industry, transport and buildings.

This report presents a first-of-its-kind global geographical analysis of the untapped potential of biogas and biomethane from agriculture, municipal waste and forestry residues. Using detailed geospatial and production cost data, it assesses the potential, costs and suitability of over 30 types of feedstocks in more than 5 million locations worldwide.

More broadly, the report also analyses the current state of play of the biogas and biomethane sector, reviewing today's policies, business models, consumption patterns and supply trends. Additionally, it examines the environmental impacts of biogas projects, highlighting the importance of minimising associated methane emissions and responsibly managing organic waste streams. And it considers the latest technologies and innovations in the sector, plus the scope for reducing costs through higher yields or economies of scale.