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Accelerating Transport to Zero Emissions

TRANSPORT SCOTLAND
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Opportunities for Biomethane as a Transport Fuel in Scotland

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Executive Summary

This report was commissioned by Scottish Enterprise and Transport Scotland to explore opportunities for the supply and use of biomethane as a vehicle fuel in both the heavy-duty (HGV) and agricultural segments. The work has been carried out by two specialist organisations working in partnership: NNFCC, focusing on the supply side, and Zemo Partnership, assessing the opportunities for GHG reduction, segment application, and overall vehicle demand. The report is therefore split into two sections reflecting this natural supply/demand separation, although findings are linked.

The supply-side analysis shows that while biomethane production from anaerobic digestion (AD) plants is a well-established technology in Scotland, the types and scale of potential feedstock would suggest significant opportunity to increase biomethane production to at least double the current level, without significant resource conflict. It is shown that industries already successfully operating in Scotland, including whisky production, brewing and agriculture, all offer significant potential to expand AD feedstocks and hence biomethane production. Examples of industries in these sectors already successfully operating adjacent AD plants are given. Operating economics of AD plants are examined, and shown to favour larger plants, suggesting some types of combination of operation would be most cost effective. This is especially true for the equipment required for upgrading biogas to biomethane either for transport or for grid injection. The supply-side analysis also assesses likely potential biomethane production vs. demands such as the existing natural gas grid, and finds that even with forecast reductions in natural gas from energy efficiencies and alternative technologies, the gas grid demand will significantly exceed any feasible biomethane production, giving very low risk of AD plants having no market for their product.

The demand side analysis shows the potential GHG savings for biomethane when used as a transport fuel, based on a rigorous well-to-wheel (WTW) approach, and assessing different production and supply methods for the biomethane. Different feedstocks are also assessed, using the data from the supply-side analysis, showing the benefits of using waste material, and in particular manure, rather than energy crops. Comparisons are given vs. a range of alternative energy sources, including mineral diesel, grid electricity and hydrogen, in different classes of vehicle, with the effect of different electricity grid GHG intensities also assessed.

The application of biomethane to different classes of vehicle is examined, especially in the heavy segment, both on an existing and projected basis, with rationale as to which sectors are expected to see ongoing demand or growth for biomethane as a fuel. As requested in the study definition, this is focused on the heavy-duty on-road and agricultural tractor segments. Both economic and technical factors are considered, as well as global trends in the industry, and activity from OEMs in various sectors.

Based on likely usage in various vehicle classes and segments, a model is then produced to project potential total biomethane demand for transport in the Scottish market over the next 20 years. This is shown as a central scenario, as well as different potential outcomes depending on the range of acceptance and hence penetration of competing zero-emissions technologies. This modelled demand is then compared to the projected AD production capacities and capabilities in Scotland, to assess the overall ability of Scotland to meet local demand for biomethane for transport from domestic sources, and how that demand may compare to existing gas demands such as heating.

It is found that Scotland has the capability to be effectively self-sufficient in biomethane for transport, give the likely supply and demand-side capacities projected.

Key Conclusions Drawn

1. Anaerobic Digestion (AD) to supply either biogas or biomethane is a well-established technology in Scotland, with a total of 84 sites known to be operating, spread across industrial, agricultural and commercial activities. Agricultural sites are the most numerous, representing around 66% of all operations, but also tend to be smaller, so in terms of gas capacity they are broadly equivalent to the larger industrial and commercial sites.
2. Total currently installed AD capacity is around 2 TWh/year, with around half of that being biogas for use in combined heat and power (CHP), and half being upgraded to biomethane for grid injection. It is estimated that actual biomethane supply is currently around 0.8 TWh/year.
3. Major sources of feedstock for AD include residues from distillation and brewing processes, as well as manure. 12 of the current plants are attached to either brewing, malting or distilling facilities, and others accept waste from these operations. Well recognised names such as Glenmorangie, Glenfiddich and Brewdog all operate AD facilities, with the latter two already providing biomethane for transport. William Grant & Sons, parent company of Glenfiddich, operate extensive AD facilities via their subsidiary Grissan.
4. Feedstock analysis carried out suggests that it would be relatively straightforward to increase AD capacity in Scotland to around 4 TWh/year, without significant trade-offs. Maximum theoretical capacity could be as high as 8 TWh, but beyond 4 TWh there is increasing competition for alternative uses and pathways for the bioresources.
5. Analysis of capital and operating costs for AD plants shows that profitability strongly favours larger plants, (7001200 m^3/hr), with smaller plants (c. 100 m^3/hr), as often found at agricultural sites, broadly only breaking even. Future development of AD capacity may therefore better focus on larger plants accepting waste from a variety of sources. This approach can incur higher energy demand for transporting feedstocks, but is viable over reasonable distances. Smaller numbers of larger plants can also simplify gas grid connections if suitably located.
6. Current total gas demand in Scotland is around 47 TWh/year, with an ambitious target to reduce this by 21 TWh by 2030, to leave c. 2527 TWh demand. In this context the total supplies of biomethane likely to be produced can readily be consumed within the grid.

7. Detailed Well-to-Wheel (WTW) analysis carried out, shows that biomethane from waste feedstock, the preferred source, typically offers around 8087% GHG reductions compared to diesel when combusted in an ICE HGV. This compares to around 95% for a BEV using current Scottish grid electricity. If biomethane is sourced from manure, GHG emissions can be net negative, in the range 200240% compared to diesel, due to the additional elimination of fugitive methane emissions from manure decomposition.
8. The sector of heavy vehicles forecast to show greatest growth over coming years is articulated tractor units, where biomethane is shown to be both technically and economically effective. Both CNG and LNG (liquified natural gas) applications are expected, with LNG often being preferred for the heaviest (44 T) applications.
9. Less certain is the growth of biomethane in the medium "rigid" sector, typically 12-26 T, where there is potentially more opportunity for fully electrified solutions, allowing a potential direct migration of this market sector from diesel to electric operation, particularly on shorter and less intensive operations. Battery cost and weight do however currently remain a significant barrier. Some growth is therefore projected for biomethane in this sector, although not as great as articulated units.
10. For the agricultural tractor market, only one OEM, New Holland, has to date brought a biomethane product to market, the medium-sized T6 unit. Vehicle performance matches the diesel equivalent model, and with optional gas storage capacity it can operate for up to around 6 hours between refuelling. Capital cost does however remain significantly above the diesel equivalent, potentially requiring support to achieve sales, and the ongoing "red" diesel rebate available to agriculture makes commercial biomethane fuel cost uncompetitive, although on-site generation and "side-streaming" may offer opportunities.
11. Modelling of the Scottish vehicle parc and usage, shows that projected demand for biomethane for these three classes of vehicle could peak at around 110 KT +/- 10% in the time range 2030-2034. Beyond this point it is expected that demand will decrease as alternative zero-emission solutions gain favour.
12. 110 KT of methane is around 1.5 TWh/year, therefore there is good scope for Scotland to effectively be self-sufficient in biomethane for transport applications well within the forecast 4 TWh/year potential AD & feedstock capacity.

Acronyms and abbreviations

AD	Anaerobic Digestion
BEIS	Dept for Business, Energy & Industrial Strategy
BEV	Battery Electric Vehicle
Bio-CNG	Compressed Biomethane
Bio-LNG	Liquified Biomethane
BMCS	Biomethane Certification Scheme
BRMT	Bioresource Mapping Tool
CHP	Combined Heat and Power
FCEV	Fuel Cell Electric Vehicle
GDN	Gas Distribution Network
gCO_2e/km	grams of CO_2 equivalent per km
GGCS	Green Gas Certification Scheme
GGSS	Green Gas Support Scheme
GHG	Greenhouse Gas
GoO or GO	Guarantee of Origin
GVW	Gross Vehicle Weight
HGV	Heavy Goods Vehicle
HVO	Hydrotreated Vegetable Oil
ICE	Internal Combustion Engine
IP	Intermediate Pressure
LCA	Life Cycle Assessment
LTS	Local Transmission System
LHV	Lower Heating Value
NTS	National Transmission System
REDII	Renewable Energy Directive
RGGO	Renewable Gas Guarantee of Origin
RHI	Renewable Heat Incentive
RTFC	Renewable Transport Fuel Certificate
RTFO	Renewable Transport Fuel Obligation
SIU	Scottish Independent Undertaking
TTW	Tank-to-Wheel
WTT	Well-to-Tank
WTW	Well-to-Wheel

1. Introduction and background

This work was commissioned by Scottish Enterprise, in co-operation with Transport Scotland, through an Invitation to Quote (ITQ 668573) issued in autumn 2021 entitled 'Invitation to quote for research into Scottish supply chain opportunities for biomethane in the low carbon transport sector'.

The Scottish Government's Climate Change Plan update (CCPu), published in January 2021, seeks (among other things) to reduce emissions in the freight sector. As part of this, the Scottish Government have pledged to work with the industry to understand the most efficient methods to remove the need for new petrol and diesel heavy vehicles by 2035. As a result, Scottish Enterprise and Transport Scotland are seeking to identify the key low carbon technology options and opportunities for Heavy Duty Vehicles (HDVs) in Scotland. The ITQ was for a market foresighting project, aiming to investigate the potential of biomethane as a lower emission fuel for use in the Heavy Duty Vehicle (HDV) sector.

After a successful bid, this work was carried out as a collaboration between Zemo Partnership and NNFCC.

Zemo Partnership is a not-for-profit, independent partnership, which has been in existence since 2003, with a unique membership structure of over 250 member-partners drawn from both national and local governments, academia and industry. Zemo members include the UK leading biomethane suppliers for road transport, CNG and LNG infrastructure suppliers and heavy-duty automotive manufacturers as well as trade associations such as the RTFA and REA.

NNFCC is a strategic business consultancy in the bioeconomy; analysing, explaining and de-risking the bioeconomy for clients. NNFCC's initial focus on the development of the rural economy through the development of industrial crop applications has widened over the years to cover all areas where biobased technologies are a key component of the low carbon circular economy, creating sustainable business opportunities and providing wide ranging societal benefits.

In the present work, the supply side of biomethane for transport was covered by NNFCC, while the demand side was covered by Zemo. NNFCC reported on biomethane production, bioresources used for biomethane, the economics of biomethane production, and competing markets for biomethane (section 2). Zemo reported on greenhouse gas savings (section 3), the use of biomethane as a transport fuel (section 4), and the demand for biomethane as a transport fuel (5).

2. Supply of biomethane

2.1 Summary of biomethane supply

Biomethane is produced using anaerobic digestion (AD), a biological process that generates a methane-rich biogas from bioresources such as manure and food waste. Not all biogas is used to make biomethane; some is used for generating heat or heat and electricity. There are currently 84 AD sites in Scotland, and only 19 upgrade their biogas to produce purified biomethane.

Biogas is 'upgraded' to biomethane by removing carbon dioxide and other contaminating gases. Biomethane is then typically injected into the gas grid (after odourisation and propane blending) for distribution to its point of use, which could be a biomethane vehicle fuelling station (or a home for use in domestic heat). For biomethane producers that are off the gas grid, a 'virtual pipeline' can connect the site to the grid or to a biomethane user.

Bioresources used for biomethane vary in terms of biomethane yield, cost, availability and source. Bioresources come from agriculture, industry, trade and local authorities. Examples of bioresources include crop and crop residues, manure, spent grains from brewing and distilling, fruit and vegetable peelings, expired packaged food from supermarkets and household food waste. Currently, Scottish bioresources used for AD are equivalent to around 2 TWh/year of biomethane, and this could be doubled to 4 TWh/year relatively easily. Total bioresources of at least 8 TWh/year are generated in Scotland but many are difficult to access, mainly owing to competing uses or easier disposal routes.

Two of the most available bioresources in Scotland are manure and residues from brewing and distilling. Distilling residues include the energy-rich draff, as well as more dilute materials like pot ale, lees and wash water. Distilleries and breweries are increasingly interested in generating biomethane on site as a transport fuel. For residues like draff, distilleries may miss out on income from animal feed, but for wastes like pot ale, this may save waste-disposal costs.

Manure is a particularly interesting bioresource owing to the greenhouse gas impact. When manure and slurry are left unmanaged, they naturally release methane - a potent greenhouse gas - into the atmosphere. However, when used for anaerobic digestion, this methane can be captured and valorised. Biomethane generated from manure is associated with a carbon credit and typically has a negative carbon footprint as a result. Nonetheless, it should be noted that the biomethane yield from manure is low, and typically needs to be supplemented with a bioresource higher in energy.

Several support schemes exist for biomethane production. For biomethane as a transport fuel, the Renewable Transport Fuel Obligation (RTFO) drives demand and prices. Nonetheless, small farm-based AD installations for biomethane generation are currently not economically viable, mainly owing to high operating costs and insufficient revenue from RTFO. However, agricultural bioresources including manure can be used in medium sized or larger AD sites, whether they are farm-based AD sites that take feedstock from multiple farms, or commercial waste-fed AD sites. Large commercial waste-fed AD sites typically generating additional income from the gate fee associated with disposing of waste, although many of their costs are higher than agricultural sites.

Non-transport uses for biomethane are in any sector where natural gas (methane) is used, particularly building heating and industrial process heat. Natural gas demand in Scotland is currently 47.4 TWh/year, and it is hoped this will reduce to 26.6 TWh/year by 2030. At a potential of only around 4 TWh/year, biomethane production is unlikely to exceed methane demand. Even in a future scenario where the gas grid is converted entirely to hydrogen, biomethane can be used for the remaining off-grid applications or converted into hydrogen using steam-methane reforming.

2.2 Introduction to biomethane supply

The supply of biomethane for transport considers the entire supply chain from bioresource production and collection through to biomethane production and distribution.

The supply section of this report starts with the production of biogas by anaerobic digestion (AD) as the core process in biomethane supply. It looks at the upgrading of biogas to biomethane, as well as the alternative uses for biogas, while looking at the existing Scottish AD industry. This section then goes on to describe renumeration and certification schemes for biomethane (both for transport and competing mechanisms), as well as the distribution mechanisms that allow the biomethane to reach the transport sector.

The next section takes a deeper dive into the bioresources used for biomethane production, looking at types, restrictions to their use, availability and sustainability issues. The final part of the supply section takes a closer look at the economics of biomethane production.

2.3 Biomethane production – anaerobic digestion

At the core of the supply chain of biomethane for transport is the anaerobic digestion (AD) process, which produces a methane-rich biogas from bioresources. An overview of the process is shown in Figure 1.

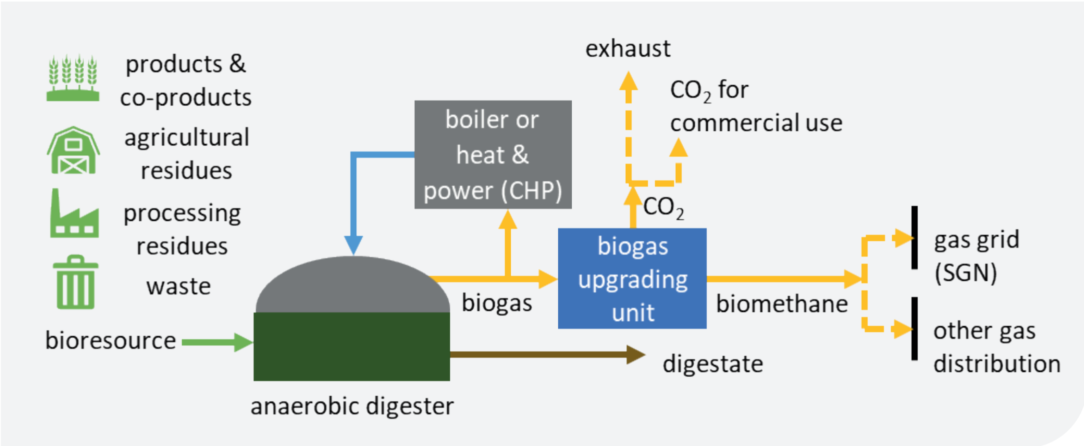


Figure 1: Overview of the production of biomethane as a transport fuel, showing a typical commercial AD plant (typical of recent years). Bioresources flowing into the digester are shown with a green arrow, while digestate flowing out is shown with a brown arrow. Gases are shown in yellow. Biogas leaves the digester and is upgraded to biomethane and/or used to generate process heat (or heat and power). Heat returning to the digester is shown with a blue arrow. Biomethane from the biogas upgrader is sent to the gas grid or to an alternative gas distribution system (e.g. virtual pipeline). Carbon dioxide rejected from the biogas upgrader can be vented into the environment or captured for commercial use or storage.

The AD process starts when bioresources such as food waste, manure and crops, are fed into the anaerobic digester. Often a bioresource pre-treatment step is needed, either to remove packaging materials (e.g. from supermarket food waste) or to make materials more available for biological breakdown.

The anaerobic digester itself consists of a tank (digester) or a series of tanks. The freshly added bioresource is mixed into the microorganism-rich liquid or slurry already present inside the digester tanks. The microorganisms break down the bioresource in a series of biological reactions, and the final reactions produce a combination of methane (CH_4) and carbon dioxide (CO_2), typically between 50 and 70% methane (depending on the bioresource). This gas is referred to as biogas and can be captured and further processed to biomethane.

2.3.1 Digestate – the undigested residue from anaerobic digestion

Only a portion of the bioresource that enters the anaerobic digester is converted into biogas, the rest leaves the digester as digestate. There are two main reasons for the existence of digestate: firstly, only carbon, hydrogen and oxygen are used to make biogas, so other elements such as nitrogen and phosphorous remain in the digestate. Secondly, parts of the bioresource are not easily digestible (e.g. because they contain high amounts of lignin), and will not totally digest.

Although the bioresources used for AD are typically waste, digestate can be used as a fertiliser in the same way as manure, provided it meets end-of-waste criteria laid out by SEPA by adhering to PAS 110 and Additional Scheme Rules for Scotland (ASRS)[1].

2.4 Use of biogas

Biogas from AD is typically used in three applications:

- **CHP:** biogas is combusted in a combined heat at power (CHP) unit to make electricity and useful heat;
- **Heat:** biogas is combusted to generate only heat (e.g. for the distilling process);
- **Biogas upgrading:** biogas is upgraded to biomethane, which can then be used for heating, transport or chemical processing.

Some AD plants use only one of these three biogas applications, while others use a combination of applications, generating energy for on-site use as well as for export.

2.4.1 Current uses of biogas in Scotland

In January 2022, Scotland had 84 AD plants in operation[2] and their biogas uses are shown in Figure 2. Most Scottish biomethane plants are CHP only and do not carry out any biomethane upgrading. However, most of these CHP-only sites are small, meaning that a greater proportion of the AD capacity in Scotland serves gas injection.

1 1 SEPA (2017) Classification of Outputs from Anaerobic Digestion Processes. SEPA Position Statement WST-PS-016, version 5 https://www.sepa.org.uk/media/219842/wst-ps-016-regulation-of-outputs-from-anaerobic-digestion-processes.pdf

2 NNFCC (2022) Anaerobic Digestion Deployment Database, Version January 2022. A version of database is released annually in April and can be found under the following link: https://www.biogas-info.co.uk/resources/biogas-map/

Although both electricity and biomethane are measured in kWh, the efficiency of generating electricity from biogas is different to the efficiency of producing biomethane. A CHP with an installed capacity of 350 kW electricity would require roughly 1000 kW of biogas to operate at full capacity. To allow sites producing biomethane to be compared to those generating electricity, a 'theoretical capacity' has been used in Figure 2, which converts the installed electrical capacity of an AD site to the equivalent in biomethane. Throughout this report, CHP-AD capacity has been referred to in equivalent biomethane capacity, where appropriate, to allow a comparison to be made.

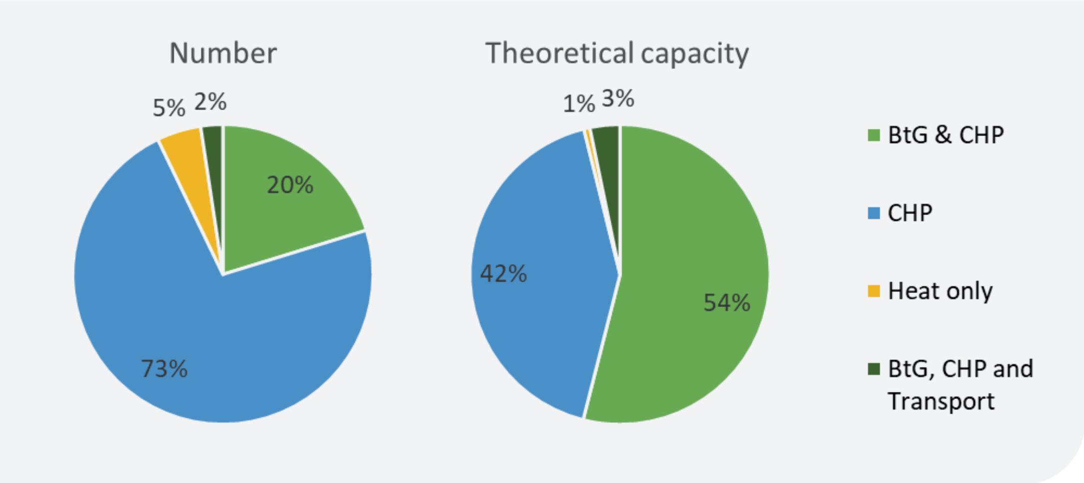


Figure 2: The 84 Scottish AD plants divided by their use of biogas, by number of AD plants and by theoretical capacity. Figure shows that most AD plants (73%) have only combined heat and power (CHP) biogas use, meaning they do not upgrade any of their biogas to biomethane. However, Scottish AD plants upgrading biogas to biomethane tend to be larger altogether, meaning that a greater proportion (54%) of the theoretical capacity of Scottish AD plants is in sites producing at least some biomethane to grid (BtG).

2.4.2 Biogas upgrading to biomethane

Biogas is upgraded to biomethane by removing the carbon dioxide and other contaminating gases (e.g. water vapour, hydrogen sulphide and ammonia). Several technologies exist for this, including membrane separation, pressure swing adsorption (PSA), amine scrubbing and water scrubbing. These technologies upgrade the biogas to around 95-99% biomethane. For injection into a local gas grid, biomethane is typically odourised and supplemented with propane to ensure the calorific value of the gas meets the grid standard.

2.4.3 Use of biogas for process heat or heat and electricity

It is important to note that, even on AD sites with biomethane upgrading, a portion of biogas is typically used in a CHP to cover the heat and electricity demand of the process.

However, it is important to note that this may change in the future. Electricity demand can be supplied from an external electricity source, which may make more economic and environmental sense in Scotland where renewable electricity is often readily available. In the future, it is possible that biogas is only used to generate process heat in a biogas boiler, rather than heat and electricity. Heat can also be supplied sustainably without biogas, for example by external heat pumps, although this is not currently carried out.

2.4.4 Use of carbon dioxide

The carbon dioxide that is removed from biogas during upgrading to biomethane is typically vented to the atmosphere. This does not count towards biomethane's carbon footprint because it is biogenic carbon. There is increasing interest in capturing this carbon dioxide, both because it can have market uses (e.g. for use in the fizzy-drinks industry, the horticulture industry or in livestock slaughter) and because it can potentially lead to a negative carbon footprint for the biomethane generated, further enhancing its decarbonisation potential. The latter is only true if the CO_2 is stored long term, or if it can be demonstrated that the use of AD-derived CO_2 displaces fossil CO_2 (which would be the case for most UK CO_2 markets, including the fizzy-drinks industry).

2.5 Biomethane support

Several incentives are available for biomethane production, outlined in **Table 1** and described in more detail below.

Biomethane application	Heat	Heat or non-transport use	Transport
Incentive scheme	RHI	GGSS	RTFO
2021 rate	**4.95** p/kWh (for first 40,000 MWh) **2.92** p/kWh (for next 40,000 MWh) **2.25** p/kWh	**5.51** p/kWh (for first 60,000 MWh) **3.53** p/kWh (for next 40,000 MWh) **1.56** p/kWh	**3.5** p/kWh (gas from products) **7.1** p/kWh (gas from waste)

Table 1: Overview of renumeration schemes for biomethane production.

***RTFO is not a fixed rate, it is open to market fluctuations. The 2021 rate is based on an estimated certificate price of 43p (per RTFC). The price also assumes the biomethane producer receives 60% of the RTFC price, although this is open to negotiation with the biomethane seller.**

2.5.1 Renewable Heat Incentive (RHI)

Until 2011, there was no government incentive for producing biomethane (as opposed to using biogas to make electricity, which was supported by the Feed-in Tariff, FIT[3]). In 2011, the Renewable Heat Incentive (RHI[4]) was introduced and provided a fixed-rate incentive for AD facilities upgrading their biogas to biomethane for grid injection. The fixed rate was guaranteed for 20 years and tariffs were tiered based on output, so the first 40,000MWh received a higher tariff and additional output received lower tariff levels.

As the RHI provides a financial incentive on a kWh basis, paid directly by the competent authority (Ofgem), the scheme provided vital reassurance to project financers that their investments would be paid back. The scheme closed to new applicants in March 2021.

2.5.2 Green Gas Support Scheme (GGSS)

Following on from the RHI closure, the Green Gas Support Scheme (GGSS)[5] was launched in November 2021 and will run till November 2025. Similarly to the RHI, it is a fixed-rate incentive, with direct payments made from the competent authority (Ofgem), collected through a Green Gas Levy (GGL) on licenced gas suppliers, with support guaranteed for 15 years from the date of accreditation. This scheme also provides reassurance to project financers that their investments will be paid back.

GGSS tariffs are again tiered, with the Tier 1 break being set slightly higher than in RHI, at 60,000 MWh to encourage slightly larger plants to develop.

2.5.3 Renewable Transport Fuel Obligation (RTFO)

Renewable transport fuels including biomethane are supported by a different scheme. Rather than directly subsidising renewable fuel at a fixed rate at point of production, fuel suppliers have a renewable transport fuel obligation (RTFO), which requires them to use an increasing percentage of renewable fuel. The fuel supplier must evidence the use of renewable transport fuel by presenting renewable transport fuel certificates (RTFCs), and in this way the RTFO drives a market for RTFCs.

[3] OFGEM (2021) Feed-in Tariffs (FIT) https://www.ofgem.gov.uk/environmental-and-social-schemes/feed-tariffs-fit

[4] OFGEM (2021) Non-Domestic Renewable Heat Incentive (RHI) https://www.ofgem.gov.uk/environmental-and-social-schemes/non-domestic-renewable-heat-incentive-rhi

[5] OFGEM (2022) Green Gas Support Scheme and Green Gas Levy https://www.ofgem.gov.uk/environmental-and-social-schemes/green-gas-support-scheme-and-green-gas-levy

The market price of RTFCs varies with supply and demand, but is limited by the buy-out price: this is where a supplier fails to redeem sufficient RTFCs to meet their obligation and they must pay the buy-out price, currently 50 pence per RTFC[6]. At the time of writing, the trading price of RTFCs was around 43 pence per RTFC. The RTFCs are not issued to biomethane producers, only to fuel sellers who are responsible for fuel at the duty point, so contracts must be in place between a biomethane fuel supplier and a biomethane producer. A typical contract would allocate around 60% of the RTFC to the biomethane producer and 40% to the fuel seller (the assumption used in **Table 1**), although contracts are subject to negotiation and vary considerably, usually based on risk and investment by both parties.

Although most biofuels are eligible for 1 RTFC per kg, biomethane is eligible for 1.9 RTFCs per kg if derived from bioresources that are considered as products or residues. If derived from waste, biomethane is eligible for 3.8 RTFCs per kg; this is known as double counting. More information on RTFOs and bioresource type can be found in section 2.6.1.

2.5.4 Claiming biomethane production on both RHI/GGSS and RTFO

If RHI has been claimed on a consignment of biomethane injected to the gas grid, then it is not possible to claim RTFCs on the same consignment as this would be double counting and double payment. Biomethane producers must therefore choose where to claim - this choice can be made on a quarterly basis at the time of making the scheme submissions.

Owing to the security of the RHI scheme and the initially inflexible regulations that prevented split-claims being made, most AD plants producing biomethane have historically claimed RHI only, despite the increasingly attractive transport-fuel market. However, since 2021, AD sites injecting biomethane into the gas grid have full flexibility to claim RHI (or, in the future, GGSS) on part of their gas injected and RTFCs on another part of their gas injected, provided both schemes are notified correctly and provided no single volume of gas is claimed to both schemes. This means that more AD plants are able to supply biomethane for transport and meet this growing demand, whilst retaining security of the RHI on their gas where necessary.

6 DfT (2022) Renewable Transport Fuel Obligation: Compliance 2022: 01/01/22 to 31/12/22 Guidance https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1042787/renewable-transport-fuel-obligation-compliance-guidance.pdf

2.5.5 Green gas certification

Further to the government-led incentives for biomethane production, there is also a market for guarantees of origin (GoOs) - or, specifically, renewable gas guarantees of origin (RGGOs). There is no government-run scheme, but there are two established UK schemes: the Green Gas Certification Scheme (GGCS[7]), operated by Renewable Energy Assurance Limited, and the Biomethane Certification Scheme (BMCS[8]), operated by Green Gas Trading Limited. While RTFCs are bought by transport fuel suppliers, RGGOs are aimed at consumers, allowing them to demonstrate that they are using green gas. These consumers include haulage companies, supermarkets and energy providers, for example.

The schemes issue RGGOs to producers for renewable gas (regardless of whether they have claimed RHI/GGSS or RTFO) and lists them in a register, along with information about when, where and how it was produced. The RGGOs can be transferred between owners in the registry, and are retired from the register when they are bought by a consumer. The scheme provides a mechanism to prevent double counting.

2.6 Biomethane distribution

Biomethane can be transported to its point of use via pipeline (e.g. injection into gas grid) or virtual pipeline (e.g. by road). Emissions associated with biomethane distribution are added to the GHG footprint of the biomethane. However, transport emissions represent a very small portion of the total GHG footprint of biomethane.

2.6.1 The gas grid

Biomethane is commonly distributed by injection into the gas grid. The gas grid consists of the Local Transmission Systems (LTSs), part of the Gas Distribution Network (GDN) which is operated in Scotland by SGN, and the high-pressure National Transmission System (NTS), which is operated by National Grid. The systems are connected to each other. The Scottish part of the NTS[9] is shown in Figure 3. It stretches from the St Fergus Gas Terminal in Aberdeenshire and crosses the Central Belt at three points: Glenmavis (Lanarkshire), Bathgate (West Lothian) and North Berwick. The NTS leaves Scotland at two points, one in Dumfries and Galloway, via the Moffat Compressor Station in Beattock, and the other in the Borders at Coldstream.

[7] Renewable Energy Assurance Limited (2021) The Green Gas Certification Scheme https://www.greengas.org.uk/
[8] Green Gas Trading (2021) Certification Scheme https://www.greengastrading.co.uk/certification-scheme/
[9] National Grid (2021) Network route maps https://www.nationalgrid.com/uk/gas-transmission/land-and-assets/network-route-maps

The LTS stretches further than the NTS, including all the way across from St Fergus to Inverness and on to Invergordon, covering various towns along the coast and further inland along the way. All major towns in the Central Belt are covered, with the LTS stretching to the Isle of Bute in the west. This is visible from the map of Scottish AD sites (Figure 4), which shows plants that inject into the gas LTS.

In addition to the NTS and the LTS, SGN operates five independent gas networks known as the Scottish Independent Undertakings (SIUs), located in Stornoway (Isle of Lewis), Campbeltown, Oban, Thurso and Wick[10]. Stornoway receives liquified petroleum gas (LPG) (via road tanker and ferry), which consists mainly of propane, butane and propylene, and is therefore not compatible with biomethane blending. The other sites use liquified natural gas (LNG) transported via road and rail, which is technically compatible with biomethane.

Additional local LTN capacity can be built as needed, for example to connect major industrial users[11] to the gas grid, although climate concerns may be limiting grid expansion[12].

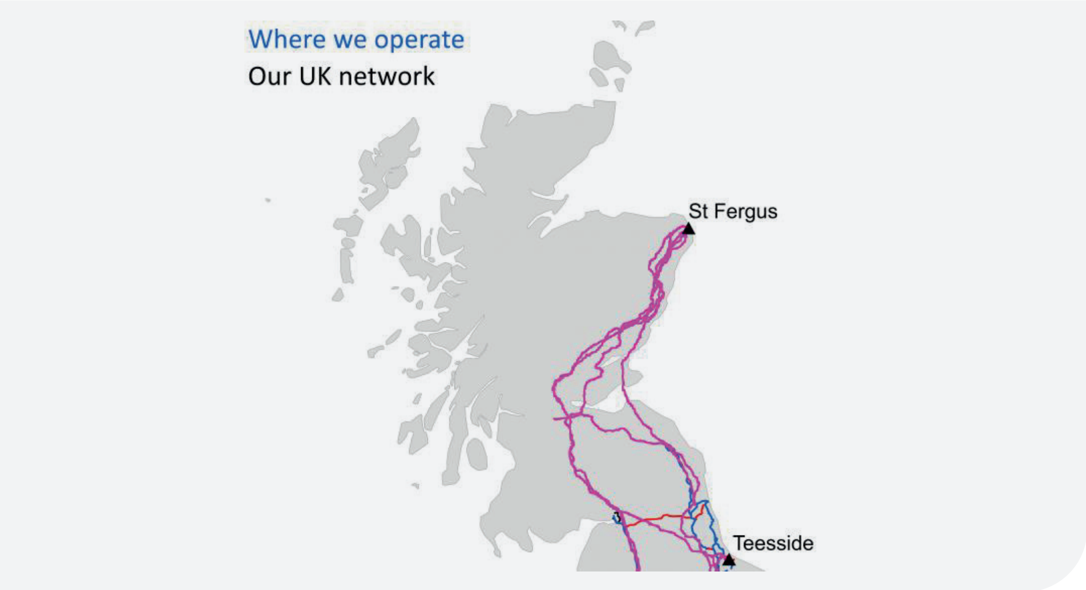


Figure 3: Map showing, in pink, the location of the high-pressure gas pipes of the National Transmission System (NTS) in Scotland. Black triangles represent gas terminals. Blue, red and black lines represent electricity overhead lines. Cropped from the National Grid UK 'Where we operate' map, available at https://www.nationalgrid.com/uk/gas-transmission/land-and-assets/network-route-maps.

10 SGN (2019) RIIO GD2 Business Plan Appendix Statutory Independent Undertakings December 2019 https://www.sgnfuture.co.uk/wp-content/uploads/2019/12/Appendix-017-SGN-SIU.pdf

11 Fulcrum (2012) Enabling major distilleries to reduce their carbon impact https://www.fulcrum.co.uk/our-stories/enabling-major-distilleries-reduce-their-carbon-impact/

12 Anon. (2020) Fort William gas plan turned off by climate concerns. Oban Times, 28/02/2020. https://www.obantimes.co.uk/2020/02/28/fort-william-gas-plan-turned-off-by-climate-concerns/

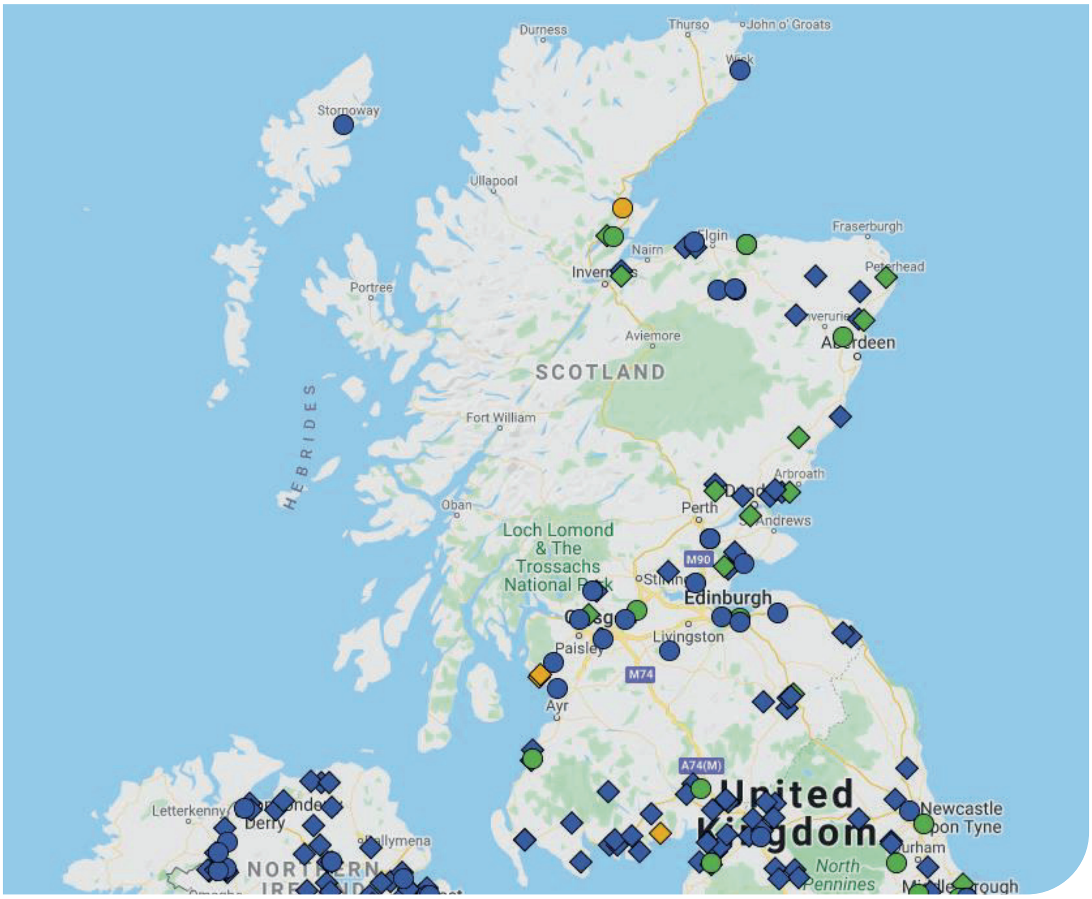


Figure 4: Location of AD plants listed in the 2021 NNFCC database. Diamonds represent farm-fed and circles waste-fed sites. Green symbols are sites producing biomethane for grid injection and blue symbols are sites with CHP only. Note that some site upgrades from late 2021 are not yet shown, such as biomethane production at Glenfiddich in Dufftown, Moray.

2.6.2 Disconnected local gas grids

Where national gas grid connection is not possible, for example in the Highlands and Islands, local gas grids are sometimes used to supply local industry and houses with gas. These are on a significantly smaller scale than the SIUs. Gas is supplied to these local gas grids via road (virtual pipeline). One example in the Highlands is in Tain[13] in the county of Ross.

[13] MacKenzie H (2019) Easter Ross distillery toasts 'virtual' gas pipeline as green drive stepped up. Ross-shire Journal, 09 August 2019. https://www.ross-shirejournal.co.uk/news/green-dream-a-step-closer-as-easter-ross-distillery-hails-gas-scheme-181246/

2.6.3 Biomethane injection to grid

Biomethane is typically injected into the LTS, provided grid capacity is available and has been agreed with the gas network. Biomethane can also be injected directly into the high-pressure NTS, although more energy is needed for gas compression. Typically, new biomethane AD sites require a new grid-entry point to be commissioned.

Similar to the renewable electricity market, gas is removed from the gas grid elsewhere and guarantees of origin are traded to evidence that renewable gas has been purchased. Biomethane in the grid can be used for a range of applications, including as a renewable transport fuel, for renewable heat, and for green chemistry.

Blending biomethane into the Scottish gas grid is consistent with the Scottish Government goal of decarbonising the gas networks[14].

2.6.4 Biomethane transport by virtual pipelines

Where local connection to the gas grid is not technically feasibly, biomethane can be sent by road vehicle to a grid-injection point. This is typically referred to as a virtual pipeline. Virtual pipelines can be a simple arrangement between a grid-disconnected site and an injection point (which may be at another AD site), or they can be between multiple AD sites supplying a central injection point in a hub-and-spoke model. Virtual pipelines are most economically feasible when large amounts of biomethane are being produced.

Virtual pipelines can also be used to allow biomethane producers to supply disconnected gas hubs directly (including to supply biomethane filling stations), bypassing grid injection entirely.

The term virtual pipeline is sometimes used to describe a system in which raw biogas is sent to another site for upgrading to biomethane. Biogas upgrading to biomethane can be costly, so this type of virtual pipeline has been considered to take advantage of the economies of scale of this part of the process. This model would be particularly suitable for small farm-based AD sites.

[14] Energy and Climate Change Directorate (2019) Scotland's electricity and gas networks: vision to 2030. Scottish Government, ISBN: 9781787814844 https://www.gov.scot/publications/vision-scotlands-electricity-gas-networks-2030/

2.6.5 Biomethane filling stations

Biomethane is typically fuelled into vehicles as compressed biomethane (termed bio-CNG), although liquified biomethane (bio-LNG) is also possible. Any filling station with a CNG filling point can become a biomethane filling station. Bio or conventional CNG as a transport fuel is not common in the UK, but it is more common in other parts of the world. For example, Italy - which has the largest CNG fleet in Europe by far - operated around 950,000 gas passenger vehicles in 2020[15].

Scotland currently has only a few operational CNG filling stations[16]: one is the new public filling station[17] operated by CNG Services at the Eurocentral Industrial Estate in Holytown off the M8, and the other is a private filling station operated by Air Liquide in Fourdoun off the A90. Both are bio-CNG only. It is likely that other private CNG filling stations exist in Scotland, but are not recorded on filling-station maps. For example, Glenfiddich reported in July 2021 that they had installed a bio-CNG gas fuelling station at its Dufftown site[18].

With many major brands like Waitrose, Asda, Hermes and Royal Mail expanding their CNG HGV fleets, the number of CNG filling stations is increasing rapidly.

Filling stations may be connected to the gas grid or supplied by virtual pipeline.

On-site filling stations (e.g. on farm)

It is possible to construct filling stations next to AD plants, supplied only by the local AD plant and not connected to the gas grid. This as a concept has attracted interest for on-farm AD sites in remote locations aiming to refuel local tractors and other vehicles.

However, a number of factors have limited their success. One is the cost of installing a single upgrading and refuelling unit, as well as the access to maintenance staff. Another limit is the lack of flexibility: when the AD plant is shut down (e.g. for maintenance or owing to a process problem), the filling station cannot be supplied, and when the filling station is shut down, the biomethane cannot be offloaded. In contrast, an AD site with biomethane offtake via grid or virtual pipeline has a greater flexibility of biomethane markets (i.e. heat and transport) it can supply to. In addition, a filling station that is often out of order will not inspire local uptake of biomethane as a transport fuel.

15 European Alternative Fuels Observatoory (2021) Alternative Fuel Passenger Cars https://www.eafo.eu/uploads/temp_country_/country-export-130121.pdf?now=1610518485025

16 Gas Vehicle Hub (2022) Station Map https://gasvehiclehub.org/

17 CNG Fuels (2021) Scotland's first biomethane refuelling station. Press release 25 March 2021. https://cngfuels.com/2021/03/25/scotlands-first-biomethane-refuelling-station/

18 Glenfiddich (2021) Glenfiddich fuels transport fleet with breakthrough green biogas made from its own whisky residues. Press release 27th July 2021. https://www.glenfiddich.com/uk/general/sustainability-press-release

2.6.6 Biomethane import and export

Biomethane can be imported from other countries. From within the UK, transport companies wishing to evidence their use of biomethane can simply trade RGGOs, as the RGGO registers cover the entirety of the UK. For biomethane from outside the UK, import of GOs is possible, particularly with neighbouring countries. This is currently associated with a high administrative burden because there is a lack of harmonised certification across the EU, let alone with the UK. Not every EU member state has a biomethane GO register, and those that have registers operate them independently from other member states. Nonetheless, trade of biomethane across Europe occurs, with national registers in the country of origin retiring GOs from their register for outgoing gas and national registers in the receiving country adding GOs for incoming gas, provided the biomethane complies with the requirements of both registers.

Harmonisation efforts are underway across Europe between national registers, in the form of The European Renewable Gas Registry, ERGaR. The UK imported its first biomethane on this scheme last year[19].

Imported biomethane from EU countries must be accounted for along the supply chain, and detailed guidance is available from Department for Transport (DfT)[20]. he additional transport creates additional emissions which must be accounted for, but the effect on the overall GHG footprint of the biomethane is typically very small.

The possibility of international biomethane trade also represents a future opportunity for the export of Scottish biomethane, taking advantage of varying market prices of biomethane in different countries.

19 ERGaR (2021) ERGaR has launched its Certificate of Origin Scheme. Press release, Brussels, 15/7/2021 https://www.ergar.org/2021/07/ergar-launched-certificate-origin-scheme/

20 DfT (2022) RTFO Guidance Update for Biomethane, Including as a Chemical Precursor. Valid from 01/01/22 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1042782/rtfo-guidance-for-biomethane-including-as-a-chemical-precursor.pdf

2.7 Size of AD

Various sizes of AD installation are possible, typically limited by feedstock type and availability. To compare the size of AD plants, it is typical to describe the installed capacity. As some AD plants make electricity (installed capacity in kW of electricity) and some make biomethane (installed capacity in m3 biomethane per hour), the units cannot be directly compared. To allow comparison in the following section, size has been given as equivalent total biomethane volume, even if some sites generate electricity alongside biomethane production, and others produce no biomethane at all.

Most AD sites in Scotland are small or medium sized, although medium, large and very large represent most of the installed capacity (Figure 5).

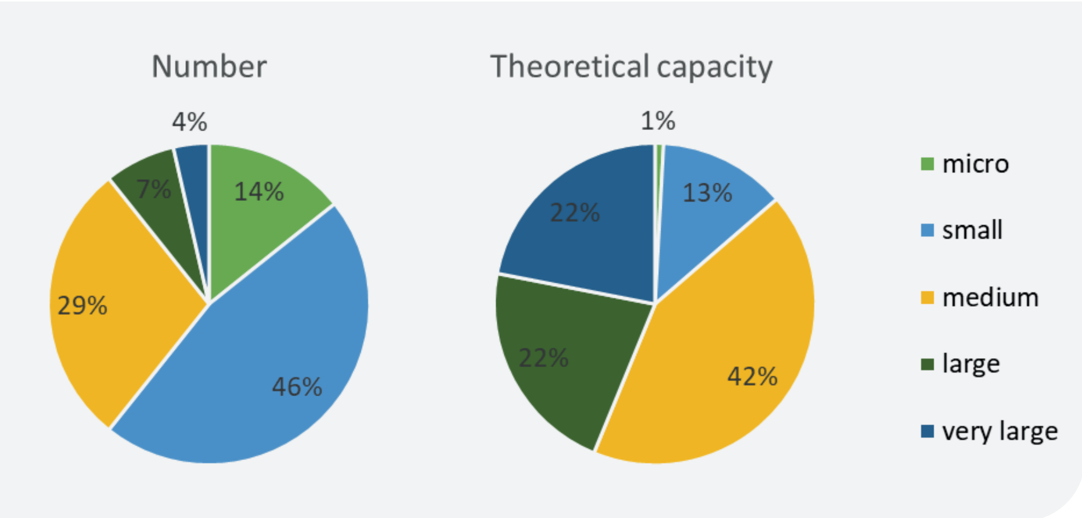


Figure 5: The distribution of Scottish AD plants by size, shown as the number of plants and their theoretical installed capacity.

The smallest type of AD is typically manure only and the biogas is used for heat only or CHP only, as biogas upgrading to biomethane is not economical at small scale. The maximum capacity of a micro AD plant is 100 kWe (typically 0.8 GWhe/year). This would be roughly equivalent to a biomethane capacity of 25 m^3/h (typically 200,000 $m^3/year$ or 2.1 GWhbiomethane/year). All micro AD plants in Scotland are on-farm AD plants.

A conventional small AD plant typically has a CHP installed capacity of up to 500 kWe (typically 4 GWhe/year), roughly equivalent to a biomethane capacity of 125 m^3/h (typically 2 million m^3/year or 10.5 GWhbiomethane/year). Again, biogas upgrading to biomethane is currently not carried out at this scale in Scotland and biogas generated at small scale facilities is used for CHP or heat only. Most (28) small AD plants in Scotland are on-farm AD, although 3 are commercial and 8 are industrial.

A medium AD plant would have an installed electrical capacity exceeding 500kWe (up to 2,700 kWe) or an equivalent installed biomethane capacity of up to 750 m^3/hr (typically 6 million m^3/year). This represents an annual biomethane production of just over 60,000 MWh, the upper limit of the tier 1 tariff the new GGSS. Of the 24 sites in Scotland of this size, 10 are CHP only and 14 are a combination of CHP and biomethane production. Around half of the medium-size AD plants is Scotland are farm-fed, and the other half are either commercial or industrial.

A large AD plant would have an installed electrical capacity exceeding 2.7 MWe or the equivalent of around 1250 m^3/hr (typically 10 million m^3/year), representing the upper limit of tier 2 on the GGSS. Of the 6 sites in Scotland of this size, half are CHP only and half are a combination of CHP and biomethane production. An equal number of large Scottish AD plants are on-farm, commercial and industrial.

Some plants are even larger, over 1250 m^3/hr (equivalent to 4.5 MWe). There are currently three in Scotland, one CHP only and two with CHP and biomethane production. Two are associated with distilleries and one is a commercial AD site.

2.8 Economic drivers of anaerobic digestion

2.8.1 Types of AD from an economic perspective

Although AD can use a wide range of feedstocks, in practice there are several types of AD plant: commercial or merchant AD plants, industrial AD plants and agricultural AD plants. As illustrated in Figure 6, over half of Scottish AD plants are agricultural, although they tend to be smaller so the total capacity is more evenly spread between agricultural, industrial and commercial plants.

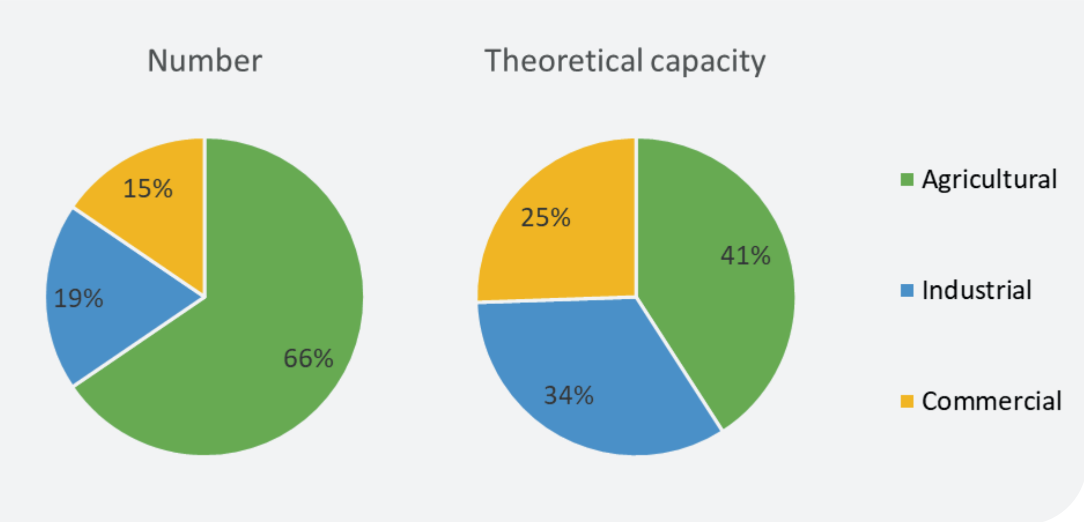


Figure 6: The distribution of Scottish AD plants by type, shown as the number of plants and their theoretical capacity.

The different types of AD plant are related to the bioresources used, technical limitations and regulatory distinctions. For example, different digester types may be used, depending on whether the bioresource is more like wastewater or more like food waste and manure. In addition, waste-handling sites typically need a very large de-packaging facility.

2.8.2 Agricultural or farm-scale AD

An agricultural AD plant will use manure in combination with purpose-grown crops, agricultural residues and sometimes waste animal feed or vegetable-processing waste. Bioresources used are often generated by the owner's farm and neighbouring farms, supplied under long-term supply contracts, although bioresources can also be bought from outside, on the open market or via short-term contracts.

The size of agricultural AD sites varies, with many being classified here as small (51%) or very small (22%), based on their installed capacity.

The drivers for building this type of AD are diversification for farmers and landowners, promise of renumeration (e.g. RHI/GGSS), or in-house heat and electricity demand, and improved manure management.

2.8.3 Commercial or merchant AD

A commercial AD plant typically uses whatever bioresource is available, with a big focus on food waste, either from local authorities or from retailers and markets. Bioresources are typically obtained through direct contracts with large generators (e.g. local authorities, supermarkets, food factories, etc) and through contracts with third-party feedstock brokers. Contracts are competitive, with AD sites typically offering lower gate fees for waste off-take than conventional waste handlers to secure materials. The size of commercial AD sites varies, although medium-sized plants (54%) are most common.

Drivers for this type of AD are decarbonisation, waste valorisation and commercial revenue potential, particularly through RTFO or RHI/GGSS, and gate fees for waste. A Scottish example of a commercial AD site is the Cumbernauld AD facility in Glasgow, operated by Energen Biogas[21].

2.8.4 Industrial AD

An industrial AD plant is typically attached to a particular factory. In Scotland, this includes 12 AD sites attached to breweries, distilleries or malting sites. Dairies can also be home to industrial AD sites. Another example of industrial AD in Scotland is the AD site attached to the GSK factory in Irvine[22] (CHP only, installed capacity of 1 MW).

The size of industrial AD plants depends on the size of the factory they are associated with and the bioresource available on-site. Of the 16 industrial AD sites in Scotland, 8 are classified here as small, 4 are medium, and 4 are large or very large, based on their installed capacities.

Drivers for industrial AD are reducing the cost of waste disposal and covering in-house energy demands. Increasingly, drivers for this type of AD also include either revenue from biomethane (e.g. RHI/GGSS) or provision of biomethane for transport, in particular to reduce the company's GHG emissions from their product transport to meet their decarbonisation commitments and improve their corporate social responsibility (CSR).

21 Energen Biogas (2020) renewable energy from AD https://www.energenbiogas.co.uk/

22 University of Strathclyde (2017) Cast Study – GlaxoSmithKline Irvine http://www.esru.strath.ac.uk/EandE/Web_sites/15-16/Industrial_Energy_Autonomy/case-study.html

2.9 Cost of biomethane production

To illustrate the cost of AD, three scenarios are shown: a typical small, medium and large AD plant (**Table 2**). Data were gathered through a cost survey of existing AD plants. Costs are indicative, as individual components vary hugely.

	AD size	Small	Medium	Large
	Approx. Biomethane Capacity - nm3/hr	100	700	1200
CAPEX	Pre-development £'000	1,150	3,200	5,500
	Construction £'000	1,900	6,600	9,500
	Additional/Other CAPEX £'000	950	3,000	6,000
	TOTAL CAPEX £ million	3.5	12.8	21.0
	Total CAPEX (with inflation) £ million	**4.0**	**14.7**	**24.2**
OPEX	Maintenance and Labour £'000/year	370	1,500	2,600
	Insurance, rates & fees £'000/year	350	550	800
	Digestate Management £'000/year	0	400	800
	Other £'000/year	20	160	220
	Costs incurred for residues £'000/year	0	270	500
	Costs incurred for products £'000/year	75	900	1,300
	Total OPEX & Feedstock Costs £ million/year	**0.82**	**3.78**	**6.22**

Table 2: Costs of building and running anaerobic digestion facilities, as well as revenue generated. Three different sizes are shown, representing small, medium and large AD plants. Sites are assumed to use biogas for biomethane upgrading (no CHP). All sites are assumed to use a mixture of 70% waste and 30% products. For the smallest site, all waste is manure, but for the medium and large sites a wider range of wastes is assumed. It should be noted that the smallest size represents part of a virtual biogas pipeline supplied by four sites of equal size or larger, as biogas upgrading to biomethane is not available at this scale.

The key assumption for calculating revenue were that the sites operate at full capacity for 8,000 hours a year and that 1 m3 of biomethane is equivalent to 10.5 kWh. For RTFO revenue, the assumptions are that the RTFCs sell for 43 pence each and that the biomethane producer receives 60% of the RTFC price (equating to 25.8 p per RTFC). As 1 kg of biomethane from products receives 1.9 RTFCs and 1 kg of biomethane from waste receives 3.6 RTFCs, and 1 kg of biomethane is equivalent to 13.9 kWh, this puts the RTFC price at 3.53 p/kWh for biomethane from products and 7.06 p/kWh for biomethane from waste. For biomethane revenue, a gas wholesale price of 3.41 p/kWh was considered, equivalent to 100 p/therm. Gas wholesale price is extremely difficult to predict in the current climate; in the last 5 years, natural gas in the UK typically traded between 20 and 60 p/therm, but in autumn 2021, spot prices exceeded 100 p/therm and were typically around 180 p/therm in winter 2021-2022, reaching prices of over 500 p/therm in March 2022. For renewable gas guarantees of origin, a selling price of 0.36 p/kWh was assumed.

It should be noted that the ‘small’ size of AD plant was costed as sending biogas (by pipeline or virtual pipeline) to a central location where it is upgraded with biogas from other smaller sites. This is because biogas upgrading technology and grid injection is not available at small scale. In this example, the ‘small’ AD plant is equivalent to a plant with a CHP of around 360 kWhe. As operating costs for the smallest AD site are only a little below the revenue, it is currently not economically feasible to build new small on-farm AD sites. Although many CHP-only AD sites of the ‘small’ size exist in Scotland, these were built when prices were considerably lower and support from the FIT and RHI was available at attractive rates; as AD has become a more mature technology, regulations and technical requirements surrounding AD have grown, impacting both OPEX and CAPEX of new facilities.

Both the medium-sized and large AD plants were costed as commercial AD plants using largely waste. A farm-based medium-sized AD plant would be somewhat cheaper to build and run, particularly as feedstock handling and pre-treatment (de-packaging) steps could be eliminated or simplified, licencing is easier for sites not handling waste (manure handling does not require a waste licence) and land costs are lower in rural areas. However, medium-sized agricultural sites would not receive income from gate fees. Operating costs for large waste-fed AD sites are higher, as are equipment costs, particularly as de-packaging and pasteurisation installations are needed. Nonetheless, commercial waste-fed AD sites are profitable as they typically generate additional income from the gate fee associated with disposing of waste.

2.10 Stranded assets

Currently, half of biogas in Scotland is used for CHP. These sites receive a feed-in tariff (FIT) for every kWh electricity generated, guaranteed for 20 years from the date of accreditation. The FIT is no longer available for new AD plants, as the scheme has ended. With many other routes to renewable electricity becoming available every year, there is little incentive for these sites to continue generating electricity after their 20 years of FIT, potentially leaving stranded assets.

2.10.1 Converting to biomethane

Many of these sites could be converted to biomethane production, even before their 20 years of FIT expire, as demonstrated by various distilleries currently switching off some of their CHP installed capacity and installing biomethane upgrading systems. Furthermore, the typical operational lifetime of a CHP engine is around 8-10 years, so as some of the ageing plants start to incur higher maintenance and equipment replacement costs, the option to switch to biomethane production becomes more attractive. Until recently, replacing engines was not permitted under the FIT regulations, without compromising the accreditation, so any site with a redundant CHP prior to 2021 may not have been able to replace it and retain their FIT, thus losing their main revenue stream for the remaining lifetime of the plant.

For small and micro AD plants, switching to biomethane production is unlikely to be feasible. Biogas upgrading equipment (to generate biomethane) is not available at small scale, and the cost of a new grid entry point would not be worth it. Even if several smaller farm-based AD sites were to get together to share biogas upgrading and grid entry infrastructure, this may be difficult to make financially feasible. However, such business models (which would enable small sites to contribute to the biomethane supply) are being explored in the UK. In such models, individual sites can be networked (physically or virtually) to a central upgrading and injection facility. This model would enable lesser output facilities and lower yielding feedstocks to be considered feasible options for switching in the future.

2.10.2 Alternative solutions for stranded AD assets

The alternative future use for AD CHP sites is to continue to provide electricity, but only to balance the grid during times when electricity generation from other renewables is low. This would involve increasing gas storage capacity on site, and doubling the installed CHP capacity. This approach is currently being used in Germany (in the so-called "flex bonus"), as the first German AD CHP plants are coming to the end of their 20-year tariff. However, no dedicated support mechanism is in place in the UK for this option at present, so additional costs and insecure revenue streams make it unfeasible at present.

2.11 Bioresource overview

AD is a very flexible process that can be configured in multiple ways, according to the inputs, outputs, site access, space and layout. The success of an AD facility and the resultant biomethane production plant is heavily influenced by the bioresources used to feed the process. Securing a reliable feedstock supply is fundamental to profitable AD and, if materials are to be bought from a third party, securing a long-term contract on acceptable terms is critical.

The bioresource does not have to be waste, any biodegradable non-woody plant or animal matter is a suitable for a digester. However, anaerobic micro-organisms cannot break down lignin, the complex polymer that gives plants their strength, which means that wood products, paper and straw will slow the digester.

The yield of biogas from a particular bioresource will vary according to the following criteria:

- dry matter (DM) content - this is the opposite of moisture content,
- the energy left in the material - if it has undergone prolonged storage it may already have begun to break down,
- the length of time the material spends in the digester,
- the type of AD plant and the conditions in the digester, and the purity of the bioresource - in particular, plastic or metal contamination will reduce the biogas yield.

Common bioresources include food and drink waste, processing residues, agricultural wastes and residues, crops and sewage sludge.

An AD plant diet is most typically made up of a combination of materials, but there are regulatory, technical, financial and availability constraints. An overview is shown in **Table 3**.

Regulatory considerations	
Site specific	**Waste** – sites using waste must be licenced for waste.
	ABP – sites using animal by-products (including food waste) must have appropriate equipment and license.
Renumeration specific	**Waste – RTFO: biomethane from some wastes are worth double RTFCs compared to residues and products. RHI/GGSS limits the amount of products that can be used.**
	Emissions – both RTFO and RHI/GGSS specify that biomethane is only considered renewable if emissions (e.g. from crop cultivation and transport) are low.
Technical considerations	
Water content	**Wet** – generally, wet bioresources (<20% DM) are used for AD as dry ones can be burnt instead.
	Watery – watery materials (<5% DM) have a low energy content and yield little biomethane.
Material properties	**Woody** – lignocellulose is difficult to digest. Wood is not suitable and straw requires additional technology.
	High nitrogen – the carbon-to-nitrogen ratio is a key parameter for AD, and high-nitrogen materials (e.g. slaughterhouse waste) can cause process problems.
	Floating & sinking – materials that float or sink can cause processing problems. Examples include bioresources like fat and straw, and contaminants like sand and plastic.
	Calorific content – similar to food, some bioresources have more / faster-releasing energy content than others.
Cost considerations	
Market demand	**Value** – the cost of a bioresource is typically directly proportional to its biomethane potential.
	Competing uses – bioresources with other uses (e.g. animal feed), are more expensive. Feed use is prioritised over AD in the waste hierarchy.
Distance	**Transport** – bioresource cost increases with transport distance. Watery feedstocks particularly affected.

Table 3: An overview of considerations affecting bioresource use for biomethane production.

2.11.1 Regulatory considerations

For biomethane sold for transport fuel, the RTFO rules impact feedstock choice. Firstly, biomethane from certain waste bioresources will receive double RTFCs compared with the same amount of biomethane made from processing residues and products[23]. This double counting is designed to encourage the use of waste and to limit the cultivation of crops for fuel production.

Secondly, biomethane is not eligible for RTFO unless it achieves a minimum greenhouse gas (GHG) emissions savings of at least 65%, against the fossil comparator. Similar (although subtly different) restrictions exist for biomethane claiming RHI or GGSS.

It should be noted that some bioresources used in AD will struggle to achieve the 65% emissions savings. Typical GHG emissions savings are shown in **Table 4**, although these figures do not take into account carbon capture, which presents an opportunity to bring emissions down to the 65% savings threshold for agricultural products like maize silage. Emissions can be further reduced, equivalent to an increased savings of up to 30% (percentage points) for biomethane made with carbon capture at the AD site.

Biomethane source	Typical GHG emissions savings	Default GHG emissions savings
Manure	190%	72–202%
Maize silage	52%	17–63%
Food waste	70%	20–80%

Table 4: Typical and default GHG emissions saving (versus the fossil fuel comparator of 94 gCO_2eq/MJ) for three main biomethane sources, according to the Renewable Energy Directive Recast (RED II)[24]. Emissions savings for manure are over 100% owing to the carbon credit associated with manure use.

Biomethane that does not meet the GHG criteria does not count as a renewable transport fuel, although it can still be sold as conventional methane. For this reason, biomethane with higher GHG emissions has not been considered in this report. The highest emissions savings considered in this report are 202%, for livestock manure. This corresponds to a GHG footprint of 95 gCO_2eq/MJ at the lowest and 30 gCO_2eq/MJ at the highest, depending on the livestock management system and accounting for the carbon credit associated with its use.

[23] DfT (2021) Renewable Transport Fuel Obligation (RTFO): feedstock materials used for creating renewable fuels. DfT Transparency data. https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-feedstock-materials-used-for-creating-renewable-fuels

[24] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (Text with EEA relevance.) http://data.europa.eu/eli/dir/2018/2001/oj

2.11.2 Technical considerations

Several key technical criteria are important to determine to what extent a bioresource is suitable for AD, relating to its chemical or physical properties.

Firstly, it is generally accepted that wet biomass is best suited to AD, both because some water is needed for AD biochemistry and because dry biomass can be combusted directly for heat or electricity, without the need for AD. This means that wood is not normally considered suitable for AD.

Although some water is essential, water content - or rather its inverse, dry matter (DM) content - is an important parameter for the economic feasibility of bioresources. Materials with a low DM, such as wastewater, will give a lower biomethane yield per tonne than materials with a higher DM.

The chemistry of some bioresources also limits their application. Lignocellulosic (woody) materials are slow to break down. Materials with a high nitrogen content, such as slaughterhouse residues, can cause process problems. However, both of these materials can be used in moderate amounts, if mixed with other materials. Additional equipment can be used to allow high volumes of these materials to be used.

Finally, some materials have inherently lower methane yields than others, in particular, bioresources in which a lot of biodegradation has already taken place. For example, household kitchen waste that has taken several weeks to arrive at the AD plant will have a lower methane yield than freshly-expired food waste from supermarkets. This is because uncontrolled biodegradation consumes some of the carbon that would otherwise be converted into methane.

2.11.3 Price, competing demand, waste hierarchy and transport

Competing demand varies between bioresource. Crops, agricultural residues and processing residues can typically be used as animal feed, although sometimes supply outstrips demand, especially for bioresources with a high moisture content. Bioresources should be used preferentially for animal feed over AD, as this is in line with the waste hierarchy[25]. This is also reflected in the RTFO in that materials with strong alternative markets such as animal feed do not receive double counting (of RTFCs), even if they are process residues.

[25] SEPA (2016) Food waste management in Scotland. SEPA Guidance | WST-G-049 | version 1 | issued December 2016 https://www.sepa.org.uk/media/219841/wst-g-049-food-waste-management-in-scotland.pdf

Prices typically reflect this, with materials that are well suited to animal feed often being prohibitively expensive for AD. In general, materials rich in energy (either as animal feed or for AD) and low in water are more expensive, and the bioresource price will roughly reflect the calorific value or biomethane potential of the material.

Generally, it is recommended to source bioresource locally, with transport distances below 50 km, both for cost and sustainability reasons. Bioresources with a high water content (i.e. low DM) have a low biomethane potential and it is therefore less attractive to transport them. In practice, many AD sites supplement their local bioresources with higher energy feedstocks from further afield than 50 km.

2.12 Bioresource availability

Bioresources can be categorised in various ways - here, bioresources have been divided by the sector from which they arise. A list of some important bioresources and their gas yields are shown in **Table 5**.

2.12.1 Bioresources from agriculture

Many crops are cultivated specifically for AD, including several cereals (harvested as whole crop, including stems and leaves) like maize and rye, as well as sugar beet ('energy beet') and grass silage. Cultivating crops for AD can provide additional flexibility to farmers in their crop rotation, and provide additional income for smaller farms in areas where small-scale livestock farms (and therefore local markets for feed) are dwindling. However, it is important to note that biomethane from agricultural products is only eligible for single counting as a transport fuel (see section 2.10.1), and some AD sites report difficulties finding buyers for biomethane (as a transport fuel) derived from these types of bioresources, which are regarded as 'products' in the RTFO guidance.

Many agricultural residues can also be used in AD, including vegetable leaves and tops as well as excess and reject vegetables, although often it is easier for farmers to plough reject vegetables back into the ground or to compost them on site, as collecting the materials is associated with additional costs and waste-handling paperwork.

Manures and slurries are also an important agricultural bioresource for biomethane production, see section 2.13.

2.12.2 Bioresources from industry

Many industries produce co-products, residues and wastes suitable for AD, notably breweries, distilleries, other beverage-production facilities, food-manufacturing plants, dairies, animal-feed-production facilities and pharmaceutical- or nutraceutical-production facilities.

Materials include co-products such as DDGS and whey, residues like spent grains and whey permeate, and wastes such as reject batches, fruit and vegetable peel, and wastewater or wastewater sludge.

2.12.3 Bioresources from trade and service businesses

Supermarkets and other businesses in the food (and feed) supply chain generate large amounts of food waste, often packaged food waste but sometimes unpackaged waste. Unlike food waste from households, these wastes are often sent to AD plants as part of direct contracts.

Food-service businesses (e.g. restaurants) also generate large amounts of food waste, typically not collected by local authorities but in contract with waste-management companies, who in turn send the materials to AD plants.

2.12.4 Slaughterhouse waste

Slaughterhouse waste (category 3 animal by-products) and some animal carcasses (category 2 animal by-products) can be used for AD in limited volumes. Regulatory and technical restrictions apply, particularly around the licencing and correct hygienic handling of these materials. The waste hierarchy[26] implies that these materials should preferentially be used for pet food production and rendering (i.e. the production of tallow and meat and bone meal), but with only 3 rendering facilities existing in Scotland, it may be cheaper and more convenient for some locations to send these materials to AD.

2.12.5 Bioresources from fishing, aquaculture and fish processing

The fishing, aquaculture and fish-processing industries generate large amounts of waste (category 3 animal by-product) and by-products in the form of reject fish and fish off-cuts. While many of these bioresources can be used for other purposes (e.g. pet food or animal feed ingredients), the remote locations of some of these sites limits the bioresource use options.

Fish that are suspected to have died of disease are category 2 animal by-products. The disposal of these fish 'mortalities' represent a significant

[26] SEPA (2016) Food waste management in Scotland. SEPA Guidance | WST-G-049 | version 1 | issued December 2016 https://www.sepa.org.uk/media/219841/wst-g-049-food-waste-management-in-scotland.pdf

challenge for the aquaculture industry. For this reason, it is typically possible to dispose of fish mortalities at category-3 licenced AD sites[27].

Seaweed or seaweed waste has been suggested as a feedstock for AD, although this is not currently common practice. Digesting high volumes of seaweed may be technically possible with systems that have been adapted to high-salt conditions.

2.12.6 Bioresources from municipalities and utilities

Local authorities generate bioresources including kitchen waste from household collection and sewage sludge from wastewater treatment plants. Other materials include trimmings from parks and sports fields, although often these are very dry and therefore better suited to composting than AD.

Feedstock type	What is it?	Considerations	RTFO classification	DM (%)	Methane yield (m^3/t_{VS})	Methane yield (m^3/t_{FM})	Indicative pricing (£/tonne delivered)	Competing uses
Crop products								
Cereal whole-crop silage	Silage made of whole maize, rye, etc. Earlier harvest. Grown for AD or feed.	Poor quality silage gives lower gas yield.	Product (single)	35%	330	110	38	Animal feed
Grass or clover-grass silage	Silage of grass (or a mix of clover and grass) from agriculturally managed grassland.	More lignified (straw-like) material gives lower gas yield.	Product (single)	35%	320	101	33	Animal feed
Beet	Sugar beet, fodder beet or 'energy beet'	High sugar levels can overwhelm the AD microbes, feed slowly.	Product (single)	18%	360	60	8	Animal feed
Agri-like waste								
Other grass	Grass other than agricultural grassland, e.g. from roadside verges, golf clubs.	Aged grass (roadside) has lower gas yield than green (golf).	Waste (double)	50%	100-200	43	-3	Few, potentially animal feed
Manures								
Cattle manure	Solid manure from cattle, typically containing bedding material. Farmyard manure.	More straw gives lower gas yield.	Waste (double)	25%	250	53	6	Fertiliser
Cattle slurry	Liquid manure from cattle, typically from situations where no/little bedding mixes in.	Unimpressive gas yield but adds buffer capacity to AD tanks	Waste (double)	10%	210	17	4	Fertiliser
Pig slurry	Liquid manure from pigs, typically from situations where no/little bedding mixes in.	Unimpressive gas yield but adds buffer capacity to AD tanks	Waste (double)	6%	250	12	3	Fertiliser
Poultry litter	Solid poultry manure, from both broilers and layers.	Only use limited amounts as high nitrogen content can inhibit AD.	Waste	40%	280	84	5	Fertiliser
Horse manure	Solid horse manure, typically containing bedding.	More straw gives lower gas yield.	Waste	27%	250	57	3	Fertiliser
Brewery								
Brewers' spent grains	Solid malt/grain residue after lautering/brewing.	Generally good gas yields.	Residue (single)	20%	460	90	30	Animal feed, human food
Waste beer	Expired beer, out-of-spec beer that is not suitable for animal feed.	High water content.	Waste (double)	4%	440	25	0	Few

27 Zero Waste Scotland (2016) Finfish Mortalities in Scotland. Project Code: 3RP005-502. https://www.gov.scot/binaries/content/documents/govscot/publications/research-and-analysis/2016/05/zero-waste-report-finfish-mortalities-in-scotland/documents/finfish-mortalities-in-scotland/finfish-mortalities-in-scotland/govscot%3A-document/finfish%2Bmorrtalities.pdf

Feedstock type	What is it?	Considerations	RTFO classification	DM (%)	Methane yield (m^3/t_{VS})	Methane yield (m^3/t_{FM})	Indicative pricing (£/tonne delivered)	Competing uses
Distillery								
Pot ale syrup	Thickened (evaporated) residue from distillation.	Generally good yields.	Residue (single)	43%	350	135	24	Animal feed
Pot ale (unconcentrated)	Liquid residue from distillation	High water content.	Waste (double)	5%	350	17	0	Few
Draff	Solid residue from whiskey making after mashing.	Generally good yields.	Residue (single)	19%	445	85	29	Animal feed
DDGS	A dried mixture of draff and other distillery waste.	Good yields.	Product (single)	90%	350	315	60	Animal feed
Dairy								
Whey	Liquid from milk after casein has been curdled for cheese. Contains sugars and proteins.	High water content.	Co-product (Single)	6%	420	24	40	Human nutrition, animal feed
Animal by-products								
Blood	Animal blood, removed at slaughterhouses.	High nitrogen content, combine with carbohydrates.	Waste (double)	13%	550	60	3	Fertiliser
Rumen	Rumen contents removed at slaughterhouses.	Gas yield depends on moisture content.	Waste (double)	15%	250	35	0	Few
Waste								
Commercial kitchen waste	Food waste from restaurants, catering and other commercial kitchens.	Gas yield dependent on composition.	Waste (double)	16%	350	50	3	Few
Household kitchen waste	Food waste from homes.	Gas yield dependent on composition.	Waste (double)	12%	300	30	3	Few
Packaged food waste	Packaged food waste from supermarkets and distribution centres.	De-packaging required. Gas yield dependent on composition.	Waste (double)	16%	300	30	-15	Few

Table 5: Common bioresources for AD, along with considerations and gas yields. DM refers to dry matter content (inverse of water content), VS refers to volatile solids (DM minus non-organic content such as potassium, phosphorous, calcium, etc, sometimes referred to as organic dry matter content), and FM refers to fresh matter (also known as wet weight).

2.13 Bioresources: a closer look at manure

Manures and slurries are an important resource for AD. Although they are not associated with high methane yields, their chemistry and biology provides stability to the AD process.

2.13.1 Environmental benefits of using manure for AD

The use of manures and slurries for AD is associated with several significant environmental benefits. Poor manure management is associated with methane emissions to the environment. Agriculture accounts for around 24%[28] of Scotland's GHG emissions, and methane emissions account for around 44% of that, although it is likely that only a fraction of this is attributed to poor manure storage. Using manure for biomethane production (and thereby avoiding poor manure management) is associated with a carbon

[28] Freeman D, Wiltshire J and Jenkins B (2020) Establishing a manure/slurry exchange in Scotland – a feasibility study. Ricardo Energy & Environment in ClimateXChange Publications http://dx.doi.org/10.7488/era/450

[29] BEIS (2021) Methods of calculating greenhouse gas emissions. https://www.gov.uk/government/publications/methods-of-calculating-greenhouse-gas-emissions

credit, which is 54 kgCO_2eq for every tonne manure used[29], assuming a water content of 90% in the manure (i.e. slurry). When calculated as part of the overall GHG footprint of the biomethane generated, using wet manure to make biomethane is associated with a carbon credit of around 112 gCO_2eq/MJ of biomethane.

In addition to causing methane emissions, poor manure management is associated with high-nitrogen farm runoff. Scotland's nitrogen-vulnerable zones (NVZ)[30] are in the areas with high manure arisings (Figure 7), including Moray and Aberdeenshire, Strathmore and Fife, Lothian and Borders, and parts of Dumfries and Galloway. The nitrogen content of manure remains in the digestate, so correct digestate management and application is essential to ensure high-nitrogen farm runoff is avoided.

2.13.2 Availability of manure

Estimates of manure and slurry arisings vary. The BRMT suggests around 14.5 million tonnes of manure arisings in Scotland. Around 89% of manure and slurry arisings are from cattle (dairy and beef).

Few competing uses for manure exist - manure is mainly used as fertiliser, but the fertilising value is retained in the digestate after digestion so this is not a competing use. Nonetheless, existing contracts and local arrangements exist, meaning that not all the manure will be available for AD. Furthermore, some manure may be geographically difficult to collect. Assuming approximately 60% of manure could feasibly be used for AD, around 280 million m3 of biomethane could be produced, equivalent to around 2.9 TWh.

	Slurry (liquid manure)		Solid manure	
	tonnes	*m^3 biomethane*	*tonnes*	*m^3 biomethane*
Cattle	2,568,163	43,145,144	6,827,085	341,354,257
Dairy	2,994,603	50,309,323	560,069	28,003,441
Pigs	357,426	2,460,881	378,652	31,806,737
Sheep	59,682	581,896	528,182	20,292,744
Poultry	-	-	133,834	11,242,066
Mixed	-	-	122,971	2,065,907

Table 6: Slurry and manure arisings in Scotland, derived from the Scottish Bioresource Mapping Tool (reference year 2015). Availability of manure for AD is likely to be around 60% of arisings.

30 Scottish Government (2021) Agriculture and the environment – Nitrate Vulnerable Zones. Policies, Agriculture and the environment. https://www.gov.scot/policies/agriculture-and-the-environment/nvz/

2.13.3 Feasibility of local biomethane generation from manure

Around 55 of Scotland's 84 AD plants are associated with a farm, and all 55 of them use some volume of manure.

However, it should be noted that the majority of these farm-based sites generate electricity and heat only, with only 10 upgrading biogas to biomethane. These 10 farm-based AD plants have biomethane production capacities of between 200 and 600 m^3/h. This is mainly because biogas upgrading is only economical for AD sites that are medium sized or larger, with small and micro AD plants (predominantly farm AD plants) unable to operate biomethane upgrading economically.

It should be noted that the average herd size in Scotland is small, around 200 for dairy cattle. The excrement from one dairy cow can generate biomethane at around 290 m^3/year[31], so a farm with 200 dairy cattle can generate almost 60,000 m^3/year, equivalent to a biomethane capacity of around 7 m^3/h. However, the smallest biogas upgrading units used in the UK have a biomethane production rate of around 100 m^3/h. For this reason, farm-scale biomethane production is challenging, unless multiple farms are supplying one AD site, or unless multiple AD sites are supplying raw biogas to one biogas upgrader.

For large AD sites associated with farms, biomethane

[31] FNR (2016) Faustzahlen [German-language rules of thumb for AD, provided by the German Agency for Renewable Resources] https://biogas.fnr.de/daten-und-fakten/faustzahlen

generation is feasible, although there are currently no farm-based AD sites with refuelling infrastructure in Scotland. Large agricultural AD sites are typically supplied with bioresource from a number of farms in their local area, and sometimes supplemented with additional materials from distilleries, particularly draff.

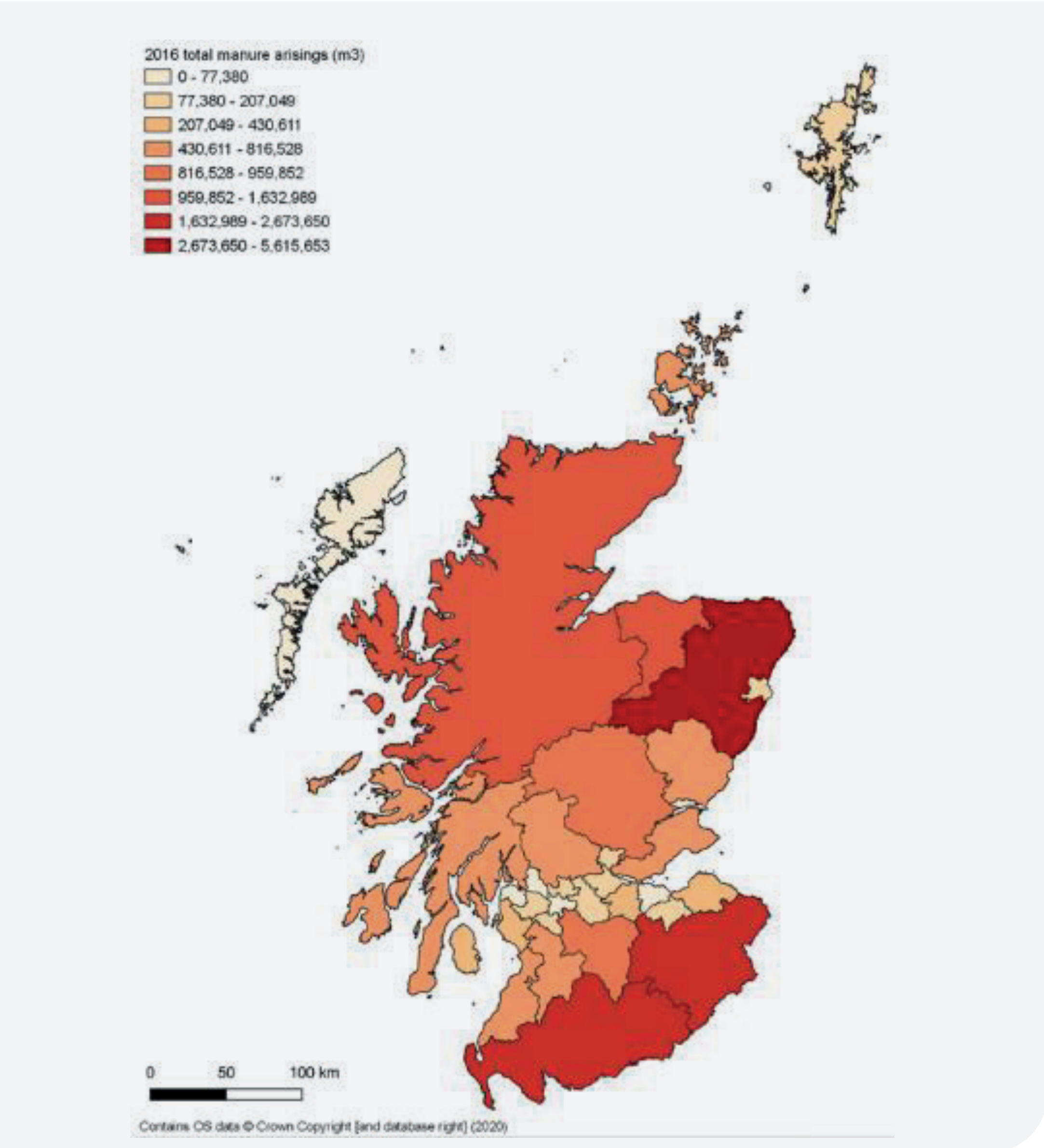


Figure 7: Heat map of manure and slurry arisings. Gross arising is shown, not taking into account how much is collected. Reproduced from Freeman D, Wiltshire J and Jenkins B (2020) Establishing a manure/ slurry exchange in Scotland - a feasibility study. Ricardo Energy & Environment in ClimateXChange Publications, available at http://dx.doi.org/10.7488/era/450,

2.14 Bioresources: a closer look at residues from distilling and brewing

2.14.1 Types of bioresource from distilling, brewing and malting

Residues from distilling, brewing and malting include spent grains (e.g. draff from whisky and brewers spent grains from beer), which are relatively dry at around 24% dry matter (76% moisture), and liquid residues like pot ale and lees, which have a dry matter content of around 5%. Wash water is also generated on these sites, which often contains a significant amount of organic matter. In addition, there may be reject batches of grain or beer, not used for quality reasons.

Distillery residues can be dried or concentrated, and sometimes pelleted. Pot ale syrup (around 45% dry matter) and DDGS (around 90% dry matter) are two examples of dried or concentrated distillery residues, and are typically used for animal feed.

2.14.2 Availability of bioresources from distilling, brewing and malting

The true availability of residues from distilling, brewing and malting are difficult to quantify and industry sources often say that all residues are already accounted for, with all draff and other spent grains going to animal feed. Spent grains are all allocated to animal feed in the BRMT. However, it is known that several AD sites in Scotland use draff and other spent grains.

In this report, it was estimated that 70% of pot ale and lees (whisky), and 70% of spent yeast (beer), can be (or is currently) used for AD, along with 60% of spent grain (including brewers spent grain and draff). As DDGS has other markets as animal feed and is treated as a co-product in the RTFO, only 10% of this material was assumed to be used for AD. The total biomethane potential from these materials is 50 million m^3/year, equivalent to around 0.5 TWh/year.

2.14.3 Feasibility of local biomethane generation from distilleries and breweries

Many distilleries already carry out AD on site. This may be at a very modest level as part of their on-site wastewater treatment plant, or it may be a larger installation using a wider range of their process residues. In particular, many distilleries carry out AD in order to generate heat or electricity and heat for their on-site demand.

It is feasible to generate biomethane at larger distilleries and breweries, particularly if the energy-rich residues like draff and brewers' spent grains are used in addition to pot ale, lees and wastewater. However, other biomethane uses at the sites should be considered, especially as biomethane or raw biogas can provide a good source of renewable high-temperature heat required for the distilling process.

Of the 84 current Scottish AD sites listed in the NNFCC AD database, 12 are associated with a distillery, brewery or malting site, and many more accept some volumes of distillery, brewery or malting residues. One distillery produces heat only, six operate a CHP only, while five carry out some level of biogas upgrading to biomethane. More distilleries and breweries have obtained or are in the process of obtaining planning permission for AD installations or biogas upgrading capacity. The Scotch Whisky Association has its own sustainability goals, including to reach net zero by 2040, and AD can help them achieve these goals.

Some examples of distilleries with AD installations are described below.

Glenfiddich

The Glenfiddich distillery in Dufftown (Speyside), owned by William Grant & Sons, has operated an AD plant since 2015, under the company Grissan Riverside Limited. Originally operating only CHPs at a total installed capacity of 3.5 MWe (roughly equivalent to an installed biomethane capacity of 950 m^3/h, or 80 GWh of biomethane per year), the AD plant is reported to use 100% of the site's waste and residues, around 80,000 t of bioresource (primarily, draff). Recent additional investment on site has allowed biogas to be diverted from CHP to produce biomethane for transport. In 2021, refuelling infrastructure was installed at the distillery to power its new fleet of bio-CNG trucks[32].

Girvan

The Girvan distillery in South Ayrshire, owned by William Grant & Sons, has operated an AD plant since 2011, originally with CHP only at an installed capacity of 7.9 MWe (roughly equivalent to an installed biomethane capacity of 2,150 m^3/h, or 180 GWh of biomethane per year). Some of this capacity has been converted to biomethane production and planning permission was granted in 2020 for biomethane refuelling infrastructure.

[32] Glenfiddich (2021) Glenfiddich fuels transport fleet with breakthrough green biogas made from its own whisky residues. Press release, 27th July 2021. https://www.glenfiddich.com/uk/general/sustainability-press-release

Glenmorangie

Although not supplying biomethane for transport, another interesting example of AD in distilleries is the Glenmorangie distillery in Tain, Ross-shire (Highlands), owned by LVMH, which has operated an AD plant since 2017. This was intended to only supply boiler heat to the distillery, generating 8,000 m^3/day of biogas (equivalent to approximately 200 m^3/h biomethane or 16.8 GWh of biomethane per year).

In addition, Glenmorangie recently installed a virtual pipeline to supply natural gas to the distillery, with the aim of displacing heavy fuel oil used on site. A 'daughter' gas-storage site located near the distillery is supplied with natural gas removed from the gas grid at a 'mother' station in Fordoun. In a separate project, pipeline developers Fulcrum (together with gas specialists CNG Services and gas company Air Liquide) are trialling a local gas grid connected to the 'daughter' station in Tain, to supply local households[33]. This project is also investigating the possibility of supplying biomethane from the distillery into the new local gas grid. This demonstrates the potential of mother-daughter virtual pipelines, which can also be used to supply biomethane fuelling stations.

Brewdog Biogas Plant

Currently still under construction, the AD plant at the BrewDog site in Ellon, Aberdeenshire, will operate a CHP to provide process electricity and heat, and is also aiming to produce 500 m^3/h of biomethane, treating 800 m^3/day of bioresource from their brewery. This site will capture the CO_2 from biogas upgrading to generate food-grade CO_2. The biomethane will be used to power a transport fleet and also for process heat.

2.15 Biomethane potential for Scotland

Previous estimates[34] for the total biomethane potential in Scotland are up to 8 TWh per year[35]. This is in line with the amount of available feedstock quantified in the Scottish Bioresource Mapping tool (BRMT)[36].

Based on the NNFCC AD database, current installed capacity for biomethane production in Scotland is around 120 MW, representing around 1 TWh per year. Actual production is likely to be below that at around 800 GWh. In addition, roughly half of all biogas generated in AD in Scotland is used for CHP, and the installed capacity is equivalent to another 1 TWh biomethane per year, meaning that roughly the equivalent of 2 TWh of feedstock are already in use for AD.

[33] Fulcrum Pipelines Limited (2017) Tain Innovative Gas Grid. RIIO Network Innovation Competition submission to Ofgem, project code FPLGDN01/1. https://www.ofgem.gov.uk/sites/default/files/docs/2017/11/fpl_tain_gas_nic_resubmission_with_redactions.pdf

[34] Bates, J (2019) The potential contribution of bioenergy to Scotland's energy system. Report by Ricardo Energy & Environment for ClimateXChange IQ11-2018. ED 11677, Issue Number 5. https://www.climatexchange.org.uk/media/3609/the-potential-contribution-of-bioenergy-to-scotland-s-energy-system.pdf

[35] Report divides bioresources into 'drier' and 'wetter' bioresources. Wetter bioresources (suited to AD) are said to have a potential of 3.2 TWh, but the report uses a biomethane conversion efficiency of 35%, when the correct efficiency is closer to 90%. For this reason, 3.2 TWh has been multiplied by a factor of 2.57 (90%/30%) to obtain correct biomethane estimates

At the very most, the amount of installed AD capacity in Scotland could quadruple to capture the full 8 TWh potential bioresource. However, a more realistic target is to double the installed AD capacity to 4 TWh. Accessing the full 8 TWh per year is challenging, partly because other more convenient disposal options are available for wastes (e.g. ploughing harvest and vegetable waste back into the soil, on-farm composting, disposing of wastewater to sea) and partly owing to risks of localised feedstock competition. It is also important to note that alternative avenues of bioresource valorisation are actively being pursued in Scotland including platform chemicals[37], food[38] and materials[39].

An overview of Scottish bioresources is shown in **Table 7**, along with their availability and their biomethane potential. Considerable volumes of biomethane can be generated from Scottish manure and distillery residues and waste.

	Arisings (t_{wet})	Available (t_{wet})	Biomethane available (m^3)	Biomethane available (TWh)
Slaughter and fish waste	300,000	150,000	4,800,000	0.05
Manure	14,500,000	8,500,000	280,000,000	2.94
Food waste	560,000	400,000	9,300,000	0.10
Fruit and veg waste	980,000	570,000	18,700,000	0.20
Whisky and brewery waste	3,400,000	2,100,000	51,300,000	0.54
Dairy	500,000	30,000	465,000	0.00
Other		200,000	12,200,000	0.13
TOTAL			**376,765,000**	**3.96**

Table 7: Overview of Scottish bioresource arisings and estimated availability for AD, along with the associated biomethane yield. Arisings are by weight in tonnes of wet/fresh material, as opposed to dry tonnage.

[36] Ricardo (2016) Scottish Bioresource Mapping Tool https://www.ibioic.com/scottish-bioresource-mapping-tool, Extract of BRMT kindly provided by IBioIC

[37] Celtic Renewables (2020) Celtic Renewables Biorefinery Sparks Boost For Scotland's Green Economic Recovery. Press release September 15. https://www.celtic-renewables.com/celtic-renewables-biorefinery-sparks-boost-for-scotlands-green-economic-recovery/

[38] ENOUGH (2021) ENOUGH raises €42m ($51M) Series B to supercharge sustainable protein. Press release 21st June 2021. https://www.enough-food.com/news-series-b

[39] Draff (2021) Draff – material. https://draff.co.uk/material/

2.16 Other demands for biomethane

2.16.1 Current gas market

Although biomethane is typically supplemented with small amounts of propane to meet the strict gas-grid calorific standards, fundamentally, biomethane (CH_4) is chemically equivalent to natural gas and can be used as a drop-in replacement. Assessing the current and future market for biomethane therefore considers the demand for natural gas, as well as the wider energy landscape.

Gas remains a major source of energy, providing around one third (47.4 TWh) of primary energy in Scotland in 2019[40]. Around 96% is used for heat, including building heating and industrial heating (e.g. heat for distilling). Natural gas is also used in power generation, where it plays an important role in balancing seasonal differences in demand.

In some markets such as home heating, moving away from gas is a logical decarbonisation path; in other markets such as industries currently using oil or coal, additional gas use will deliver environmental benefits[41]. Gas, combined with renewables, has helped reduce coal use in multiple countries. However, natural gas cannot be used in a net-zero world without capturing its emissions.

On a European level, the natural gas market is expected to increase over the next decade; it is the only fossil-based fuel expected to grow and peak beyond 2030. This is owing to the role of gas in replacing coal and oil in building and industrial process heat, as well as the role of gas in power plants, particularly those that can rapidly respond to dips in wind power. Owing to climate policies, a decline after 2035 will likely follow, although many in the industry expect the decline to be slow owing to the difficulties of replacing natural gas in some sectors, particularly domestic heat.

The biomethane industry is largely expected to continue growth. Greening the gas infrastructure is critical, and the two main options to decarbonise the gas supply are biomethane and low-carbon hydrogen. The Committee on Climate Change (CCC) has advised the UK government that both are required to reach net-zero.

40 Scottish Energy Statistics Hub (2021) Distribution of primary energy (indigenous production and imports). https://scotland.shinyapps.io/Energy/?Section=OilGas&Chart=PrimaryOilGas

41 CSIS. How Will Natural Gas Fare in the Energy Transition? https://www.csis.org/analysis/how-will-natural-gas-fare-energy-transition

In 2021, around 800 GWh of biomethane were produced in Scotland, from an installed capacity of around 1 TWh per year. As gas filling stations are very limited, it is likely that virtually all of this went to the gas grid and was used the same as natural gas. In 2019, an estimated 1.5% of Scottish gas consumption (711 GWh) was accounted for by biomethane blended into the gas grid, up from 0.3% in 2015[42].

By converting the remaining suitable CHP capacity to biomethane capacity, this could be doubled. Installing new AD facilities equivalent to doubling current installed capacity would bring the production of biomethane up to 4 TWh per year, still less than 10% of the current Scottish gas demand.

2.16.2 Heating industry

Of the 45.6 TWh of gas used per year for heat in Scotland, 29 TWh are domestic heat and 18 TWh are non-domestic heat. Gas provides heat in 81% of Scottish homes[43] and in many businesses.

The Heat in Buildings Strategy[44] foresees that GHG emissions from home and building heating will have all but disappeared by 2045. Improving efficiency is at the core of this Strategy, but the Strategy also recognises the need to replace fossil heating with low- or zero-emissions heating in the vast majority of off-gas homes and in around half of gas-heated homes by 2030. In combination with non-domestic heating targets, this aims to reduce natural gas consumption by 21 TWh (equivalent to around half of the 2019 Scottish natural-gas demand). The Strategy mentions heat pumps, heat networks and electric storage heaters as low- and zero-carbon heating solutions. Although biomethane is not prominent in the Strategy, biomethane and hydrogen blending into the gas grid are recognised as important:

> **"By 2030, we would like at least 20% of the volume of the gas in the GB gas grid to be alternatives to natural gas. Delivering blended gas to customers in Scotland will directly support decarbonisation of both heat and industrial demand still supplied by the gas network in Scotland in 2030."**

42 Minister for Zero Carbon Buildings, Active Travel and Tenants' Rights (2021) Heat in Buildings Strategy - achieving net zero emissions in Scotland's buildings. Publication – Strategy/Plan, 7 Oct 2021, ISBN: 9781802014464. https://www.gov.scot/publications/heat-buildings-strategy-achieving-net-zero-emissions-scotlands-buildings/documents/

43 43 Scottish Government (2020) Scottish house condition survey: 2019 key findings. Publications – Statistics, 1 Dec 2020, ISBN: 9781800043527 https://www.gov.scot/publications/scottish-house-condition-survey-2019-key-findings/pages/4/

44 44 Minister for Zero Carbon Buildings, Active Travel and Tenants' Rights (2021) Heat in Buildings Strategy - achieving net zero emissions in Scotland's buildings. Publication – Strategy/Plan, 7 Oct 2021, ISBN: 9781802014464. https://www.gov.scot/publications/heat-buildings-strategy-achieving-net-zero-emissions-scotlands-buildings/documents/

The heat target is ambitious, as it would involve low- and zero-carbon heat installation at a rate above natural boiler replacements. To date, progress in renewable heat has been difficult to achieve compared to renewable electricity, and Scottish 2020 targets were not met (Figure 8). UK 2020 targets fell similarly short. Of the renewable heat generated in Scotland in 2020, biomethane in the gas grid was by far the largest contributor (Figure 9) and biogas (used in CHP or biogas boilers) was also a major contributor.

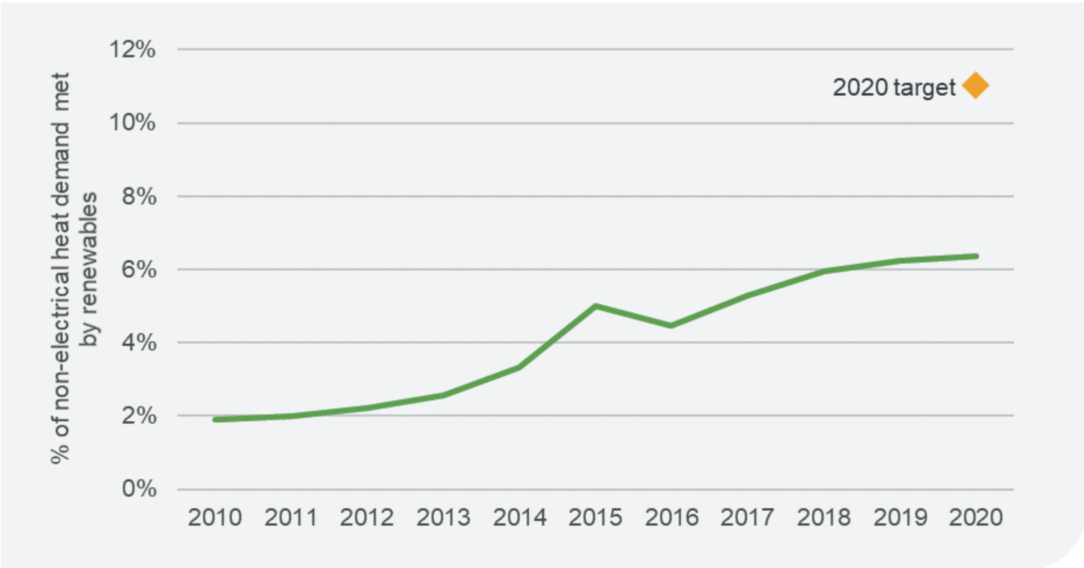


Figure 8: Renewable heat as a percentage of non-electrical heat demand in Scotland to 2020. Reproduced from Energy Savings Trust (2021) Renewable heat in Scotland, 2020. https://energysavingtrust.org.uk/report/renewable-heat-in-scotland-2020/

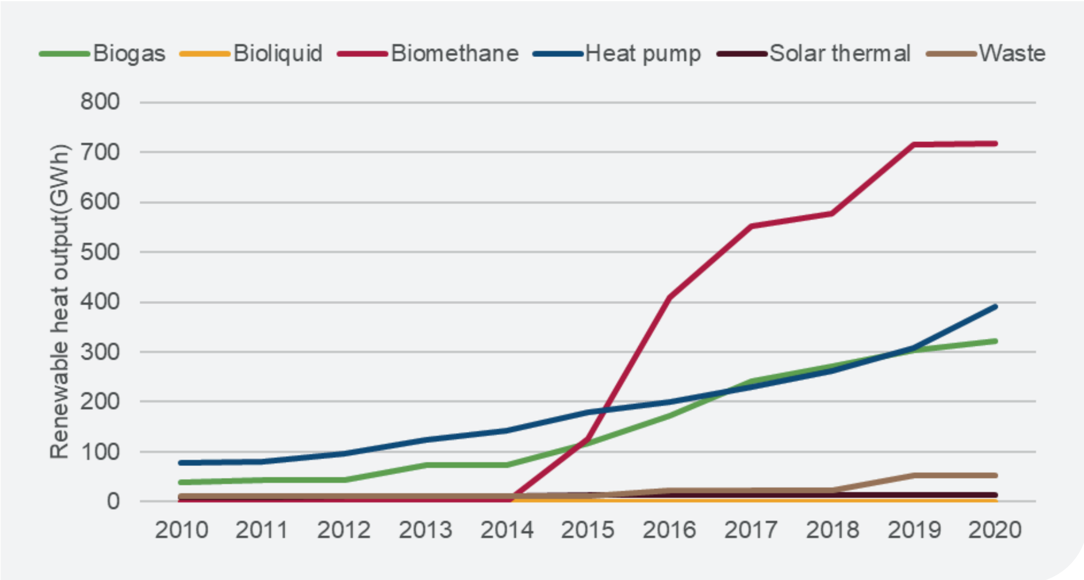


Figure 9: Renewable heat output in Scotland in to 2020, divided by source. Reproduced from Energy Savings Trust (2021) Renewable heat in Scotland, 2020. https://energysavingtrust.org.uk/report/renewable-heat-in-scotland-2020/

In the medium term, biomethane can readily be accommodated in the gas distribution pipeline system alongside hydrogen, which is expected to be blended at a rate of up to 20% (pending a UK government decision scheduled for 2023). In the longer term, however, gas distribution networks converted to carry 100% hydrogen would no longer be able to accommodate any amount of biomethane. Biomethane may therefore make its main longer-term contribution in regions where full hydrogen conversion does not take place, in off-grid properties unsuitable for electrification and as a transitional fuel for heavy transportation[45].

[45] Cadent Gas (2021) Our Green Print – Future Gas for Everyone. https://documents.cadentgas.com/view/908325570/30-31/

2.16.3 Hydrogen

Hydrogen is relevant to biomethane both as a competing green gas and as a use for biomethane. Hydrogen is differentiated according to its production source via the use of colours. Grey and blue hydrogen are obtained from natural gas, for example through steam methane reforming. Grey hydrogen currently dominates the market. Green hydrogen refers to hydrogen that has been produced from renewable sources and via technologies that do not emit greenhouse gases. There are currently two main processes being used for the synthesis of green hydrogen: water electrolysis using renewable electricity and biomass gasification. Hydrogen made from steam methane reforming of biomethane is also considered green hydrogen, and is widely considered a viable alternative use of biomethane should the market for hydrogen become more attractive than for biomethane.

2.16.4 Other

Biomethanol can be produced from biomethane, although this is not currently carried out in the UK. Biomethanol can be used both as a fuel itself and as a feedstock to produce other biofuels. It can also be a platform molecule to produce a range of products, including bio-MTBE, bio-DME, bio-hydrogen, synthetic biofuels, silicones, plastics, and paints[46].

Biomethane can also be used as a precursor for platform chemicals, although this is not yet carried out at industrial level. Via super-dry reforming of methane, carbon monoxide and syngas can be produced. Carbon monoxide is widely utilised for the production of critical compounds including methanol, acetic acid, phosgene, and hydrocarbons[47]. The use of biomethane in this way is not currently commonplace but signifies another opportunity for it to be used across the chemical industry.

2.17 Looking further ahead for gas

In the short term, Scotland intends to reduce natural gas consumption from its current 45.6 TWh per year by at least 21 TWh to, at most, 24.6 TWh by 2030. These figures do not take into account increasing gas demand from transport fuel. Realistically, Scotland will not be able to produce much more than 4 TWh biomethane using waste and residues, meaning that by 2030, gas demand will still outstrip biomethane supply.

[46] OCI (2021) Bio-Methanol as an Advanced Biofuel. https://www.oci.nl/sustainability/greener-fuels

[47] Journey M, Hutchings GS & Jiao F (2019) Carbon monoxide electroreduction as an emerging platform for carbon utilization. Nat Catal 2, 1062–1070. https://doi.org/10.1038/s41929-019-0388-2

[48] National Grid (2021) Future Energy Scenarios 2021. https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021

Predicting the demand for both natural gas and biomethane further ahead is challenging while there are significant technology and policy gaps for reaching net zero. National Grid's Future Energy Scenarios 2021[48] outline four different pathways for the UK's energy to 2050, depending on the route the UK takes to decarbonisation. Each pathway sees a wildly different role for biomethane, depending on the success of infrastructure roll-out like 100% hydrogen gas grids, as well as levels of individual action like domestic installation of low-carbon. Without major infrastructure and/or individual change, it predicts a major role for biomethane by 2050 (around 68.5 TWh across the UK).

2.18 Concluding remarks on biomethane supply

Anaerobic digestion is a mature technology that can deliver biomethane for use in heating and transport in Scotland, provide a sensible valorisation route for organic wastes and deliver revenue in the agricultural and waste-management sectors. The supply chains of anaerobic digestion are inherently local, with bioresources rarely travelling more than 50 km for AD. The use of biomethane can be anywhere across Scotland (or further afield) if the biomethane is injected into the gas grid. Biomethane refuelling stations can be located near AD plants, as demonstrated in 2021 at Glenfiddich, although refuelling stations are typically connected to the gas grid to guarantee a constant and reliable supply of biomethane in case of AD process interruption.

Currently, there is an installed biomethane capacity in Scotland of around 1 TWh per year, with around 0.8 TWh generated per year. In addition, there is another 1 TWh of biogas capacity in AD sites that currently generate electricity, although it would not necessarily be possible to convert all of these sites to biomethane generation.

Based on the available bioresources, it is feasible to generate up to 4 TWh per year. This would require new AD plants to be built, although some existing AD sites may be able to expand. More bioresource is available, up to at least the equivalent of 8 TWh of biomethane per year, but this would be difficult to access. More biomethane could be generated from crops, but these were not considered in this study as policy is moving away from using crops for fuel. The bulk of the available bioresources are in the form of manure and slurry; a total of over 8 million tonnes is available every year, mainly from cattle, and digesting 60% of this bioresource would generate 3 TWh per year of biomethane. The remaining 1 TWh comes from a range of food wastes, agricultural wastes and processing residues, including pot ale and draff from whisky distilling.

There are considerable environmental reasons to use manure for anaerobic digestion, in particular to avoid atmospheric methane emissions that occur when manure is not digested. Biomethane generated from manure is typically considered to have a negative carbon footprint owing to the avoided methane emissions from undigested manure, meaning this form of biomethane offers the greatest potential for carbon savings.

Challenges remain around manure digestion. The gas yield per tonne of manure and slurry is relatively low, meaning large amounts of manure need to be digested to generate significant biomethane volumes. Supplementing manure with other energy-rich feedstocks (including crops) is possible, but is associated with additional cost and may be limited by sustainability requirements. Furthermore, small farm-scale AD sites are not able to upgrade their biogas to biomethane as biogas upgrading equipment and gas grid entry is generally not available below a capacity of 200 m^3/h. While it may be technically possible in the future to link small AD sites together, sending their biogas to a central site with upgrading and grid injection, economic feasibility will have to be assessed on a case-by-case basis. Operating costs can be very high for small AD sites, particularly as the AD industry has matured and regulatory requirements have increased.

Biomethane is a direct replacement for natural gas. Current natural gas demand in Scotland is around 47 TWh per year, with 96% used for domestic heat, non-domestic heat and industrial heat. While it is hoped that natural gas demand will reduce to 27 TWh by 2030 through an ambitious roll-out of heat pumps, biomethane production in Scotland - which is likely to peak at 4 TWh owing to bioresource availability - will not be able to displace all of Scotland's natural gas demand. Redirecting existing biomethane production away from heat use and towards transport use is not difficult, although this would require other renewable heat solutions for Scotland to be implemented to achieve policy targets in this sector. In 2020, biomethane was responsible for almost half of Scotland's renewable heat output.

3. Greenhouse Gas (GHG) Savings

3.1 Executive Summary

In this study Zemo have modelled Well-to-Tank (WTT) greenhouse gas (GHG) emissions for a range of biomethane supply pathways and Well-to-Wheel (WTW) GHG emissions for a selection of biomethane and comparator vehicles.

The biomethane WTT results show that GHG emissions from the biomethane supply chain are much more dependent on the biomass feedstock than the method of distribution, or whether the biomethane is in gas or liquid form. Manure feedstocks deliver the greatest GHG emissions reductions due to the utilisation of the manure 'credit' for methane. Waste biomass feedstocks show lower GHG emissions than energy crop feedstocks. Compressed biomethane gas from a refuelling station with an on-site AD plant, and compressed biomethane distribution via a high-pressure LTS gas grid offer the lowest GHG emissions in terms of distribution and dispense.

The WTW GHG emissions results show that biomethane HGVs and tractors show significant GHG emissions savings compared to conventional diesel vehicles. When the biomethane is produced using manure feedstocks, the biomethane HGV can offer higher GHG savings than a battery electric vehicle (BEV) using renewable electricity, or a fuel cell electric vehicle (FECV) using green hydrogen produced via electrolysis with renewable electricity.

Where the BEV and FCEV are not powered by renewable electricity (either directly or by hydrogen from electrolysis with renewable electricity), their WTW GHG emissions are highly sensitive to the carbon intensity of the electricity grid used and the grid electricity GHG emissions factor used in the modelling. Whether a biomethane vehicle shows improved GHG emissions compared to a BEV or FCEV is likely to vary depending on the electricity grid and corresponding emissions factor.

3.2 Introduction

This study is focused purely on GHG emissions within the Well-to-Wheel boundary shown in the centre of Figure 10. WTW describes the in-use phase of the vehicle lifecycle. The GHG emissions are calculated by summing the Well-to-Tank contributions from the fuel or electricity production and the Tank-to-Wheel vehicle tailpipe emissions. WTW GHG emissions and energy are proportional to the vehicle fuel or electricity consumption.

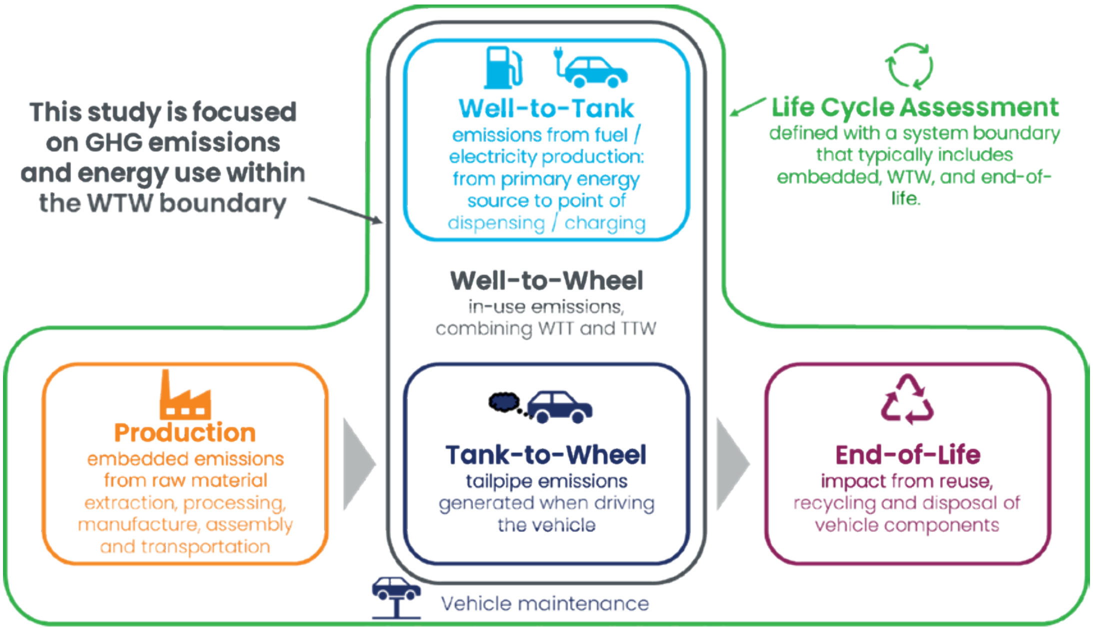


Figure 10. Definition of Well-to-Wheel and vehicle Life Cycle Assessment system boundaries

WTW differs from a full life cycle assessment in that it does not include the vehicle production and end of life. Also, LCAs may include a range of environmental impact categories, such as global warming potential, air quality, toxicity, land transformation, resource depletion, etc. Other environmental, health and economic impacts are not within the current scope of this study.

3.3 Methodology

WTW GHG emissions for biomethane fuelled gas trucks and tractors have been derived using WTT and TTW emissions factors and estimated vehicle fuel consumption data. Three different vehicle applications have been modelled:

1. 18t GVW truck with an urban delivery duty cycle
2. 44t GVW truck with a long haul duty cycle
3. Tractor

WTW GHG emissions were also derived for a selection of comparator vehicles and fuels: diesel, HVO, BEV and FCEV. The calculation for WTW GHG emissions and a list of assumptions made are shown in the Appendix, sections 4.1 and 4.2.

It is not the intention of this study to assess the feasibility of different vehicle powertrains for different applications, nor select an optimum.

3.3.1 WTT GHG emissions factors

Biomethane WTT GHG emission factors (gCO_2e/MJ) were calculated by Zemo for different supply pathways as shown in Figure 11.

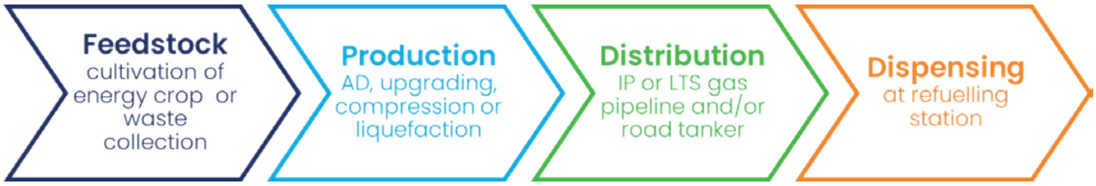


Figure 11. Biomethane WTT supply pathways

A selection of different biomethane supply chains were considered, including:

1. Three different feedstock options
    a. energy crop
    b. waste biomass
    c. manure
2. Biogas production via anaerobic digestion plant, with upgrading, storage, compression (for bio-CNG) and liquefaction (for bio-LNG)
3. Five different distribution options
    a. Bio-CNG via IP (intermediate pressure) gas grid
    b. Bio-CNG via LTS (local transmission system) gas grid
    c. Bio-CNG via a combination of LTS and road tanker
    d. Bio-CNG or Bio-LNG via road tanker
    e. Bio-CNG or Bio-LNG from an on-site refuelling station
4. Dispensing at the refuelling station

The WTT emission factors for the diesel and HVO vehicles were sourced from BEIS Company Reporting 2021 values[49]. For the FCEV, the hydrogen was assumed to have been produced via electrolysis and dispensed on-site at 350 bar. The WTT emissions factors for hydrogen were modelled using Zemo's in-house WTT tool (prepared by Element Energy)[50].

The analysis for BEV and FCEV includes three different options for the generation of the electricity used to power the BEV or produce hydrogen for the FCEV (via electrolysis):

1. On-site renewable electricity, e.g. from wind turbines, for which the WTT emissions factor is assumed to be zero gCO_2e/kWh.
2. Grid electricity based on the Scottish grid only. WTT emissions factor sourced from the Scottish Energy Statistics Hub 2019 data[51]. Note: the accounting method and assumptions behind this figure are not stated (for example, whether it includes WTT emissions from the production of fuels used in electricity generation, whether it is constrained, whether it includes transmissions and distribution losses, etc.).
3. Grid electricity based on UK grid, using WTW emissions factors from BEIS Company Reporting 2021 data.

Comparing the two different emissions factors enables the sensitivity to grid electricity factors to be demonstrated.

3.3.2 TTW GHG emissions factors

The TTW GHG emission factors for the biomethane and most of the comparator vehicles were sourced from BEIS Company Reporting 2021 values. The exception to this was the diesel trucks, for which the TTW emissions were based on Zemo vehicle emissions testing studies.

3.3.3 Fuel consumption

The HGV truck fuel consumption values used, have been primarily derived from Zemo vehicle emissions testing studies. At the present time there are relatively few hydrogen FCEV in operation in the UK, meaning that hydrogen vehicle consumption data is quite limited. The values used for HGV FCEV hydrogen consumption are from data collated by Zemo as part of a previous Hydrogen WTW study[52]. Tractor fuel consumption data was provided by CNH.

49 BEIS Company Reporting: https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2021

50 50 Zemo Low Carbon Hydrogen WTT Pathways Study: https://www.zemo.org.uk/assets/reports/Zemo%20Low%20Carbon%20Hydrogen%20WTT%20Pathways%20-%20Summary%20(2).pdf

51 Scottish Energy Statistics Hub: https://scotland.shinyapps.io/sg-scottish-energy-statistics/?Section=RenLowCarbon&Subsection=RenElec&Chart=GridEmissions

52 52 Zemo Hydrogen Vehicles WTW GHG and Energy Study: https://www.zemo.org.uk/work-with-us/fuels/projects/examining-hydrogen-production-pathways-and-use-in-vehicles.htm

Vehicle fuel consumption is highly dependent on a wide range of parameters, including driving style, vehicle speed, vehicle payload and weather. Ideally, when comparing vehicles powered by different fuels or electricity, the figures should be for consistent drive cycles or driving conditions, vehicle loading, etc. Unfortunately, this was not always possible due to limited data availability.

3.4 Model Results & Commentary

3.4.1 Biomethane WTT GHG emissions

Figure 12. Biomethane WTT GHG emissions (gCO_2e/MJ)

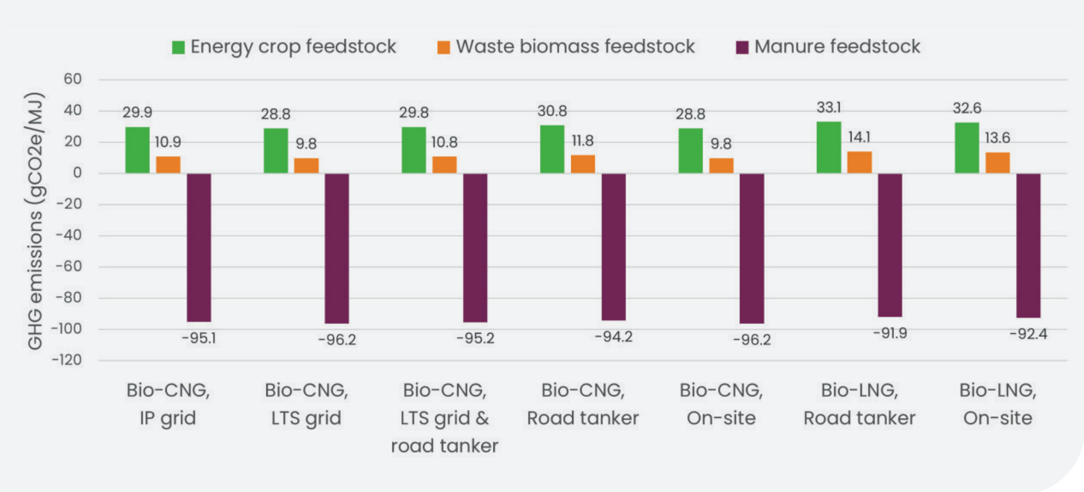


Figure 12 shows the WTT GHG emissions from producing biomethane from each of the three feedstocks and seven distribution-dispensing pathways modelled. The figure shows that GHG emissions are much more dependent on the biomass feedstock than the method of distribution or whether the biomethane is in gas (bio-CNG) or liquid (bio-LNG) form. For all pathways, manure feedstocks deliver the greatest GHG emissions reductions. The negative values arise from the utilisation of manure 'credit' for methane (CH_4) as per REDII[53]. Waste biomass feedstocks show lower GHG emissions than energy crop feedstocks.

The GHG emissions arising from liquefaction are higher than those from compression, meaning that bio-CNG shows lower GHG emissions than bio-LNG. Of the distribution pathways analysed, compressed biomethane gas from a refuelling station with an on-site AD plant, and compressed biomethane distribution via a high-pressure (LTS) gas grid offer the lowest GHG emissions. The high-pressure grid, being more energy efficient, results in a lower energy requirement for compression, and therefore carbon intensity.

[53] EU Renewable Energy Directive II: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=fr

3.4.2 HGV WTW GHG emissions

The WTW GHG emissions for the two HGV applications modelled (18t GVW truck with urban delivery duty cycle and 44t GVW truck with long haul delivery duty cycle) are shown in Figures 13 and 14. The comparator vehicles are shown on the left-hand side of each figure. The biomethane vehicles are shown on the right-hand side of each figure: the six biomethane supply pathways show the 'best case' and 'worse case' GHG emissions for each feedstock, based on the distribution-dispense pathways shown in Figure 12 ('best' being bio-CNG produced on-site and 'worse' being bio-LNG with distribution by road tanker). The percentage WTW GHG emissions savings of each vehicle, compared to the equivalent conventional diesel vehicle, are shown at the bottom of each figure.

Figure 13. WTW GHG emissions for 18t truck with urban delivery duty cycle (gCO_2e/km)

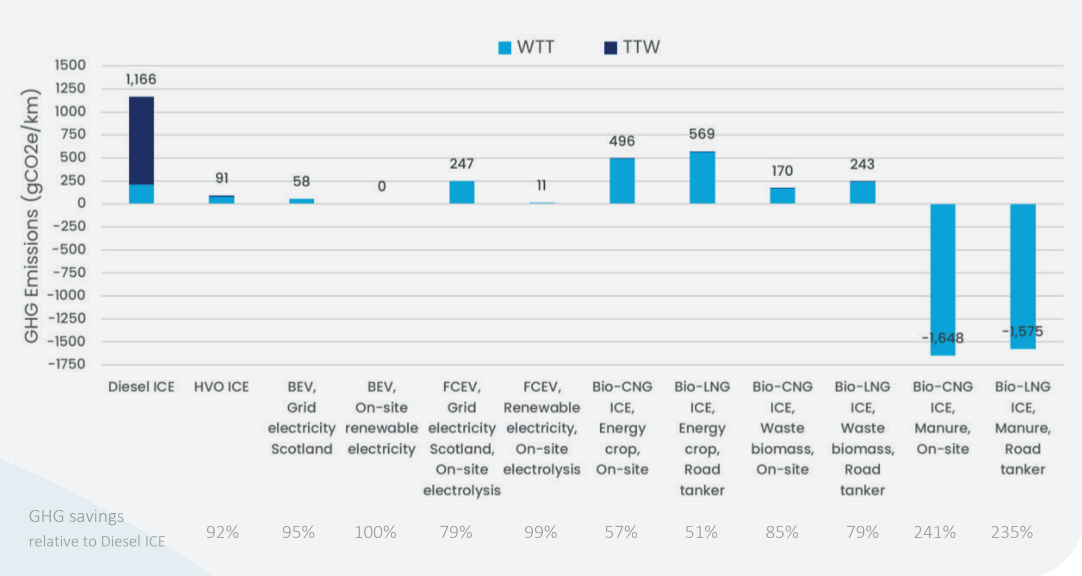
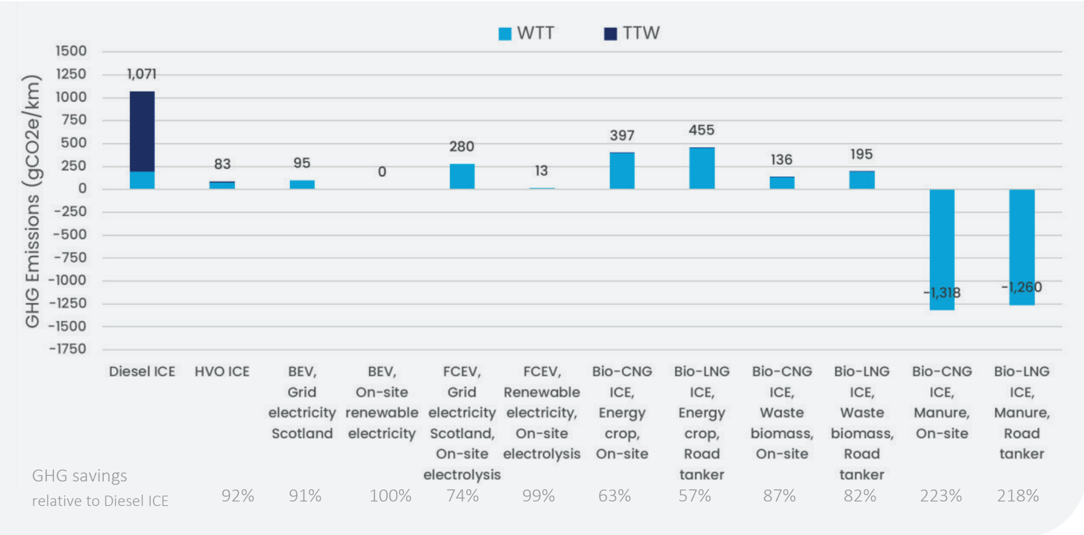


Figure 14. WTW GHG emissions for 44t truck with long haul duty cycle (gCO_2e/km)



13 and 14 show that trucks using biomethane produce less WTW GHG emissions than conventional diesel trucks. For supply chains using waste feedstocks, the biomethane vehicles show significant GHG emissions savings: in some cases, exceeding 80% compared to the equivalent diesel vehicle. For supply chains using manure feedstocks, the 'credit' applied for capturing methane that would otherwise be released into the atmosphere, results in negative GHG emissions and thus even larger GHG emissions savings. The biomethane pathways with manure feedstock show that these vehicles can outperform (in terms of GHG emissions) an equivalent BEV using renewable electricity and an equivalent FECV using green hydrogen produced via electrolysis with renewable electricity.

It is worth noting that some caution should be exercised when utilising carbon offsetting in GHG emissions accounting, to avoid inadvertent consequences such as promoting less energy inefficient scenarios or increased vehicle mileage. Bioenergy supplies are limited and it is recommended that they are allocated strategically to maximise GHG savings.

3.4.3 Grid electricity GHG emission conversion factors

GHG emissions from electricity consumption are calculated using emissions factors in gCO_2e/kWh and the consumption in kWh. The carbon intensity of the electricity grid is continually changing due to fluctuations in demand and supply (e.g. due to conditions for wind turbines). As such, emissions factors are typically based on the average carbon intensity over a year. Different sources quote different values for the grid electricity emissions factor depending on the methodology and data used. These can vary in terms of year, geographical location, accounting method and what is or is not included (WTT, distribution and transmissions losses, imports, curtailment, etc.).

The BEV and FCEV results shown in Figures 13 and 14 were calculated using a grid electricity WTT GHG emissions factor of 41.4 gCO_2e/kWh, based on the Scottish grid only and sourced from the Scottish Energy Statistics Hub 2019 data. To highlight the sensitivity of WTW GHG emissions to the grid electricity, the BEV and FCEV have also been modelled using an emissions factor of 291.3 gCO_2e/kWh, based on the UK grid and sourced from BEIS Company Reporting 2021 data. This source is traditionally used by Zemo for grid electricity GHG emissions factors (Scope 2 and Scope 3 values are combined, WTT and transmission and distribution losses are included). Note that these two sources of data are expected to differ in more ways than geographical region alone.

Figure 15. WTW GHG emissions for 18t truck with urban delivery duty cycle (gCO_2e/km) using different grid electricity GHG emission factors

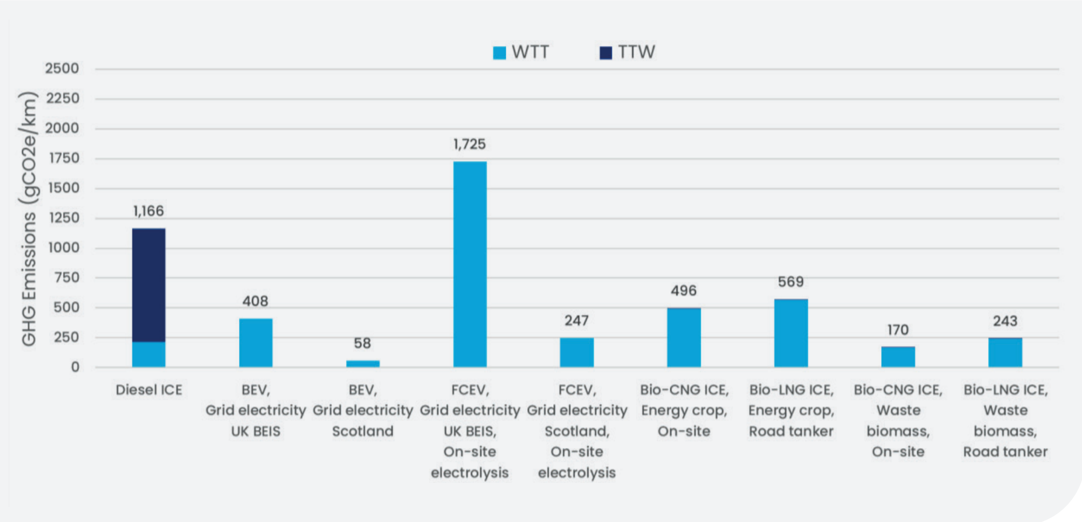


Figure 15 shows that the BEV and FCEV WTW GHG emissions results are highly sensitive to the grid electricity conversion factor used. The GHG emissions performance of the biomethane vehicles relative to the BEV and FCEV depends on which factor is used in the modelling. For example, the Bio-CNG vehicle with waste biomass feedstock shows lower WTW GHG emissions compared to the BEV with grid electricity using the data for the UK, and higher GHG emissions compared to the BEV with grid electricity using the data for Scotland.

Given the significant impact that the electricity grid carbon intensity factor used in calculating the WTW GHG emissions has, it is recommended that Government adopt a 'standard' set of conversion factors in carbon accounting to ensure consistency in the data sets used to inform decision making and policy.

3.4.4 Tractor WTW GHG emissions

Figure 16. WTW GHG emissions for tractor (kgCO_2e/h)

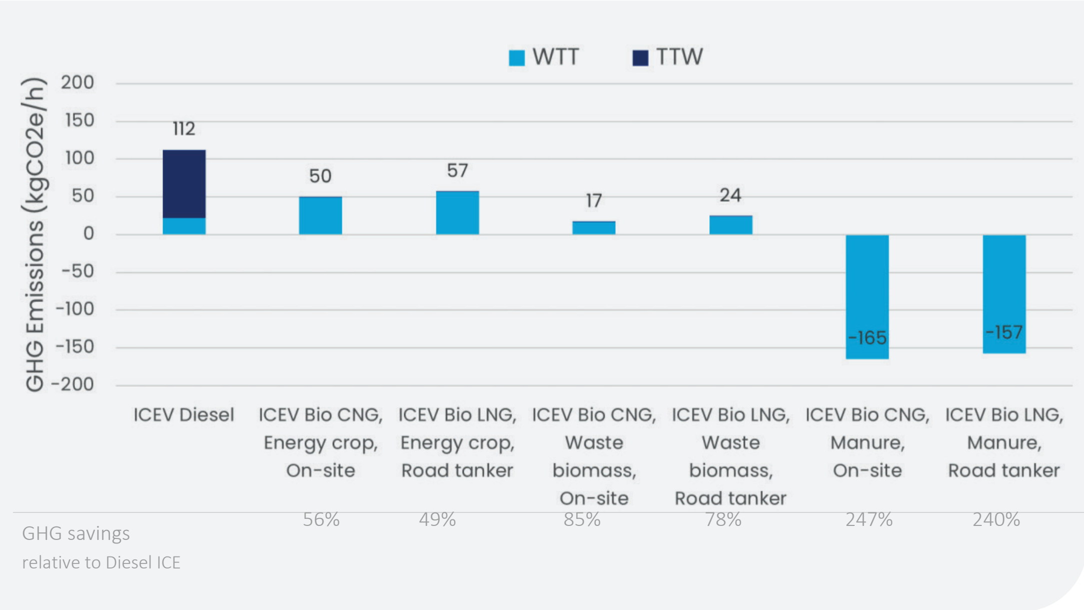


Figure 16 shows that tractors using biomethane produce less WTW GHG emissions than conventional diesel tractors. The percentage savings in WTW GHG emissions are broadly similar to those of the HGVs modelled.

4. Biomethane as a Vehicle Fuel

4.1 Terminology

Biomethane and natural gas are chemically identical, both being methane (CH_4). As such they can be used interchangeably and in any mixture as fuel for a vehicle designed to run on methane. Biomethane simply refers to methane gas derived from a renewable biological source, usually via anaerobic digestion (AD).

For use as a vehicle fuel, natural gas or methane must either be compressed to 200-350 bar (CNG) or liquified at c. -160oC (LNG) in order to provide sufficient quantities of gas onboard to give a vehicle the necessary range or endurance. Compression and liquefaction processes are identical, independent of whether the initial methane is of fossil or bio-origin. The majority of vehicle applications to date have made use of CNG, with LNG mainly being reserved for some specific heavy-duty, long-haul truck applications, which demand the higher energy density achieved with the liquefied gas.

4.1.1 Vehicle Technology and Applications.

CNG as a vehicle fuel is well established on both a global and European basis. Within Europe, around 1.2M, or slightly under 1% of vehicles, are designed to run on CNG. Vehicle types designed to run on CNG range from passenger cars (e.g. VW Golf TGI, Fiat 500, Panda, Punto), medium vans (e.g. Fiat Ducato, Iveco Daily Natural Power), through RCVs (e.g Mercedes Econic), service buses (Scania, MAN, ADL) and heavy trucks (Iveco, Scania, Volvo). This report will only consider applications to heavy vehicles.

In most applications, CNG is used as a fuel to replace petrol in positive (spark) ignition (SI) engines. Depending on the application these will adopt varying degrees of optimisation to suit the use of CNG and achieve maximum output and efficiency. Spark-ignition engines are also generally less expensive to produce than diesel variants, and can make use of significantly simpler and less expensive emission-control systems. In commercial vehicles however, the current large production volume of diesel engines, compared to SI types, does tend to offset this advantage. One notable exception to this approach is the Volvo truck application, which uses a compression ignition (CI) (diesel) engine in a dual-fuel approach, with diesel providing the pilot ignition, and CNG the majority of the energy, up to 90%.

Testing carried out for the LEFT trials showed that the efficiency advantage of the CI engine type was most marked in transient urban driving, with around 23% benefit over the SI derivative. In more stable driving the advantage decreased to around 8% on regional routes, and within 1% on long-haul motorway type work. The latest Iveco Stralis CNG truck, which is proving popular with large fleet operators (Amazon recently ordered >1000 for use across Europe), has a rated engine efficiency of 40% across the operating range from peak torque to peak power, which compares closely to a typical diesel engine at around 42%. In long-haul work the Volvo dual-fuel engine showed an actual energy efficiency benefit of 7% compared to the diesel comparator. On the basis of energy efficiency therefore, CNG/biomethane is best suited to trucks performing relatively long-distance rural and motorway type operation. The high energy demands of heavy-duty, long-haul operation, also make these vehicles the most difficult in terms of alternative, zero-emission, propulsion.

Technical advantages of CNG as a vehicle fuel include similar range and refuelling times to liquid fuel variants, with quieter operation and improved air quality emissions (mainly NOx and PM/PN) compared to diesel vehicles, especially prior to the EUVI emission standard in 2016. At the EUVI level, AQ emissions are broadly comparable and very low on both diesel and CNG (source LEFT trial 2020). These advantages have made CNG attractive as a fuel choice for vehicles operating extensively in urban locations, such as buses and RCVs. Italy, Spain and France all operate large fleets of CNG buses. In the UK, bus operators including Stagecoach, First and Nottingham City Transport have modest CNG bus fleets in operation (c. 350 vehicles), and Leeds, Liverpool and Sheffield have deployed small fleets of CNG RCVs.

In both bus and RCV markets however, electric propulsion is now overtaking CNG as the preferred low-emission alternative. Across Europe a significant milestone was achieved in 2021 when electric bus sales exceeded CNG for the first time (3282 vs. 3088, source: Sustainable Bus). In both Scotland and the UK the focus for new service buses is now almost exclusively on zero-emission derivatives.

In RCVs, Dennis Eagle, the market leader, is focusing on electric propulsion with their e-Collect vehicle, and in 2021, Mercedes, another major manufacturer, confirmed that they would be replacing their CNG version of the Econic RCV with an electric version. The Econic is based on the e-Actros rigid HGV, which went into serial production in late 2021, and signals Mercedes' intent to move the smaller rigid vehicles up to 27T into electric propulsion. Mercedes' strategy for their heavier tractor units is not yet clear, but early indications seem to be that they are exploring hydrogen fuel cells, but nothing yet close to production.

When interviewed for this report, Leyland-DAF trucks in the UK, confirmed that their focus is exclusively on electrification as the next generation of technology, with all R&D activity focused on this, and no intention of providing CNG alternatives. Similar to Mercedes, since early 2021, DAF now offers an electric version of the LF 19T rigid HGV, and also the CF rigid at 28T and the CF tractor at up to 37T. This is significant as DAF is by far the market leader in the UK, with around 31-33% market share.

Based on the declared direction of market leader DAF towards electrification, and evidence that Mercedes is also pursuing this as their primary approach for lighter, rigid, HGVs, our view is that the market for CNG in smaller rigid HGVs will remain fairly small, probably not exceeding 10% market share. (See modelling section).

As discussed in the modelling section, the rate at which the market shifts from diesel to electric derivatives in the smaller truck sizes, ahead of the 2035 mandate, remains open to a wide range of possible trajectories, largely defined by economics, especially battery prices, as all electric trucks are having to deploy extremely large batteries, typically in the range 300-400kWh. (DAF LF 282kWh, CF 350kWh. Mercedes Actros 300 + 400kWh option). Previous forecasts suggesting a steady decline in battery prices through this decade are currently being revised, as rapidly increasing demand in 2021 has actually caused a significant rise in prices. Until this is resolved via increased supplies, which may take several years, it seems likely that economics will favour a retention of diesel propulsion.

While the timing and rate of this shift from diesel to electric may vary between the "market enthusiasm" and "market reluctance" boundaries suggested in the modelling, the relatively low projected uptake of CNG (and hence biomethane) in the rigid segment, means that the overall impact on projected biomethane demand will be modest.

Manufacturers offering CNG/LNG versions of their tractor-units are IVECO, Scania and Volvo. Between them these three have around 36% of the UK market (2021), so are significant players.

4.1.2 OEM vs. Retrofit Market

Historically there have been several suppliers of aftermarket conversions of vehicles to run on CNG, based on both spark and compression-ignition engines. Increasingly strict emission regulations have however largely eliminated these, as the degree of control of the engine, and in particular the precise matching of the fuel delivery, required to achieve very low levels of pollutants, is very difficult to achieve without full OEM integration. A further concern with some of these earlier systems was that inaccurate control of the methane injection could lead to methane "slip" into the exhaust system. Methane is a relatively unreactive gas when passing through the catalyst system on an engine, and hence is likely to also emerge at the tailpipe. With a 100-year Global Warming Potential (GWP) of 28-36 compared to CO_2, even very small emissions of methane due to inaccurate control could lead to significantly higher total GHG emissions from the overall system. Testing conducted as part of the LEFT trials, and reported by Zemo Partnership in July 2020, showed that methane emissions from modern EUVI OEM CNG & LNG trucks were negligible, contributing 0-2% CO_2e to the overall GHG total. For these reasons we forecast that all future CNG products will be based on full OEM development and integration of the powertrain, rather than retrofits or conversions.

4.1.3 Range and Refuelling Requirements

For articulated truck tractor units, which currently, and are predicted in future to form the majority of the market for gas-powered vehicles, improvements in engine efficiency, together with improved gas tank design and higher pressures have enabled ranges to be improved significantly in recent years. CNG vehicles now typically achieve 350-400 miles on the most common 4x2 (single rear axle) artic types, depending on payload and driving type. Some variants are now approaching 500 miles. While this is still significantly shorter than diesel equivalents, the required range recognises that drivers are constrained by tachograph requirements, and that fuelling a vehicle can be undertaken in around 6-8 minutes, very similar to diesel.

On the heaviest duty (40-44T) trucks, the heavy payload combined with the requirement for a second rear axle (6x2 configuration), which constrains the space available for gas tanks, means that range with CNG is reduced to typically around 250miles/400km. While still suitable for many applications, this reduced range is not acceptable in every case, leading to all three OEMs offering LNG versions of their 6x2 (and 4x2) artic units. The higher energy density of LNG means that range is restored, with typically in excess of 400 miles/640km being achievable, frequently significantly more.

Refuelling for CNG trucks can be either at public access fuel stations, or dedicated facilities at depots. Depot facilities can be provided by a range of suppliers, including RoadGas, Air Liquide, BOC/Linde and GasRec. Zemo Partnership estimate that currently 60% of HGV refuelling takes place at depots (Zemo Renewable Fuel Report, March 2021). For public refuelling, CNG Fuels currently operate the largest network in the UK, with 23 stations planned to be in operation by 2023, including 3 in Scotland, although these are all in the central belt. Each station typically has a capacity for up to 500 trucks per day. GasRec operate a smaller network of facilities.

Public refuelling facilities for LNG trucks are currently very limited, with only two operational in the UK, so most LNG vehicles are currently using back-to-base depot facilities. The longer range achievable with LNG trucks allows this to be quite a feasible operating pattern, with less need for en-route refuelling. The same suppliers as operate for CNG typically provide LNG depot facilities.

Case Study:

Moy Park, a large food distributor based in Northern Ireland, commenced in late 2021 replacing their entire fleet of diesel trucks with 50 Iveco Stralis 6x2 LNG tractor units, which achieve a 400 mile range. These are used to supply both regional distribution hubs and directly to supermarkets. All will operate on a back-to-base system, with LNG refuelling facilities at two depots provided by RoadGas, and are expected to cover up to 100,000 miles per year. A further 70 trucks will be added by 2023 to complete the transition of the entire 120 unit fleet to gas power. As part of their zero-waste policy, Moy Park already send food waste to AD facilities, and all LNG supplied to the truck fleet will be bio-LNG from their own and other AD facilities.

Examples of other fleets known to be transitioning either entirely or partially to biomethane include:

- Amazon: 160 trucks - CNG (1064 across Europe)
- Asda: 1000 trucks - LNG
- B&Q - LNG
- Hermes: 160 trucks - CNG
- John Lewis Partnership: 600 trucks - CNG
- NISA - LNG
- Ocado: 80 trucks - CNG
- Royal Mail: 29 trucks - CNG
- Sainsbury's - LNG

4.2 Operating Economics

Beyond the significant environmental benefits achieved, and clearly a major incentive for operators to switch to biomethane, most operators also see significant operating cost savings, especially with high mileage fleets. Savings mainly arise from the fuel duty rates, which are set at 24.7p/kg for methane vs. 57.95p/L for road diesel. The methane rate is frozen until 2032, while diesel may vary in the nearer term , most probably upwards. As 1kg of methane will broadly replace 1L of diesel in operation, the resultant fuel saving is around 33p/litre. A further 1-2p per litre equivalent will be saved due to spark-ignition engines not requiring AdBlue.

For a truck covering 100,000 miles per year at an average consumption of c. 9MPG, the annual diesel fuel consumption will be around 50,000L, resulting in a fuel cost saving of around £16,500. A typical CNG truck costs around £25,000 more than a diesel equivalent, therefore payback in fuel savings can be as short as 18 months. LNG trucks are slightly more expensive, but payback can still be under 2 years. Lower annual mileages will extend this period, but in a typical operating life of at least 5-7 years, significant TCO savings should be achieved. In the Moy Park case study, the company expected to make sufficient saving over a 5-year truck lease to cover not only the vehicle costs but the LNG refuelling system also. The refuelling stations will have a life far greater than 5 years, so will not be a recurring cost, so future savings will be greater.

At the time of writing (February 2022) global methane prices are close to an all-time high, which has eroded some of the cost advantage for biomethane over diesel. However, there is evidence that the gas futures market is now projecting a significant reduction in wholesale methane prices, allowing the price gap to be restored. Ongoing announcements of fleets investing in CNG/LNG trucks also suggest that operators have confidence in the medium-term economics.

The fleet examples cited are all dedicated vehicles tied to one type of delivery. For the independent haulier bidding for individual contracts, the lower operating costs of biomethane-powered trucks should offer a potential pricing opportunity vs. competitors using diesel fuel. At 9MPG a truck travelling at 56MPH/90kph will be consuming around 28L of diesel per hour, so if the saving for CNG is the equivalent of 33p/L, then the saving is approximately £9.30/hour. With recent driver shortages having caused significant increases in pay rates for HGV drivers, the cost savings associated with CNG/LNG could be a significant offset, helping to maintain competitiveness. For contract hauliers operating in central and southern Scotland, it may be prudent to consider the opportunity from using CNG/LNG vs. diesel in order to maintain competitiveness vs. those from England and Northern Ireland who may also be using gas fuels.

4.3 Vehicle Construction and Modification Opportunities

As presented earlier, our view is that vehicles operating on CNG & LNG will require the rigorous engineering of the powertrain and chassis which only OEMs can provide. Furthermore, the level of reliability and service backup expected for HGV fleets can realistically only be provided by established players. These factors make it highly unlikely in our view that new entrants will enter the market for gas-fuelled vehicles.

In both the medium and heavy-duty sectors there are many companies developing final vehicles based on chassis' or donor vehicles from major manufacturers. Scotland is home to three good examples:

- Allied Vehicles - light and medium duty taxi, van and bus conversions.
- Alexander Dennis - buses based on diesel, electric and CNG chassis.
- Farid Hillend - waste & refuse handling vehicles (RCVs)

In the light and medium-duty markets in which Allied Vehicles operate, the clear trend is towards electrification, so ongoing and future vehicle developments should migrate to being based on electrified rather than ICE products.

Similarly in the bus market, where the clear direction is towards electrification, ADL are already the leading supplier of electric buses in the UK, based on a bought-in BYD chassis and drivetrain. They also supply a CNG version of the Enviro 400 based on a Scania chassis, so can continue to supply that if there is customer demand. The level of economic activity and value-add to build a complete bus on an electric chassis is judged to be very similar to doing the same on a CNG or diesel chassis, so we see little change in the ADL business as a result of this technology shift.

A previously outlined, the trend in refuse vehicles is also definitely towards electric and away from diesel or CNG, where previously there had been some take-up. In the case of Farid-Hillend therefore, the main economic opportunity will be to ensure that their completed RCVs are developed to suit electric chassis from major OEMs such as DAF, Dennis, Mercedes & Scania. Integrating major systems such as compactors into all-electric vehicles, and ensuring that energy demands of such systems are compatible with the more limited energy storage from batteries, could be key development areas.

4.4 Agricultural Vehicles

In a similar manner to HGVs, agricultural vehicles such as tractors present a difficult challenge for decarbonisation, due to high energy consumption rates and high levels of autonomy. In addition they are subject to extremely unpredictable usage patterns, ranging from many days of idle time to periods such as harvesting or soil preparation, when taking advantage of suitable weather-windows may require close to 24H operation. These factors in combination make the provision of zero-emission solutions such as electrification or hydrogen extremely difficult to achieve both technically and economically.

Several tractor manufacturers including John Deere and Fendt have therefore demonstrated prototype tractors developed to run on methane, and able to take advantage of the major CO_2 savings possible with biomethane, if a farm has a supply available. Despite various prototypes being shown, only Case New Holland (CNH) have actually brought a tractor to market, with their T6 model having been trialled in 2020 and early 2021, and formally launched in late 2021. CNH have a vision of the "energy independent farm", where a farm derives all their energy requirements from a mix of gas from AD plants, used to run vehicles including tractors, and electricity from PV or biogas-powered CHP generation.

The CNH T6 is a 180HP medium-duty tractor, with identical power and torque capabilities to the diesel equivalent, and all other controls and interfaces are also common, making operation a simple process. Onboard gas storage is 32 kg, equivalent to approximately 32 L of diesel, so this is significantly less than the 150 L of diesel in the standard tractor. Onboard storage can be augmented with an additional front-mounted storage unit holding a further 47kg, giving 79kg total capacity, still approximately half of the diesel capacity, but significantly increasing time between refuelling. At full power the total gas capacity could be exhausted in 22.5 hours, but in trials with more mixed use, CNH have found duration up to 6.5 hours.

New Holland T6.180 Methane Power tractor showing additional gas storage at front

When interviewed for this report, CNH confirmed that there is significant interest in the biomethane tractor in continental Europe, although highlighted that this is supported by significant grants, up to 40% in France and Germany as examples. CNH also identified three key factors in determining the potential uptake of biomethane tractors in the UK:

- Purchase price is currently at least 25% above the diesel equivalent, so some form of grant funding is likely to be required.
- The ongoing availability of the "red diesel" fuel duty rebate in the agricultural sector makes the cost of commercially-sourced methane or biomethane unattractive vs. diesel. Tractors used in non-agricultural roles (e.g. local authority maintenance vehicles) would not have this disadvantage.
- Farmers expect refuelling either on-farm or within very short distances, especially if operating duration is shorter on gas, so refuelling is more frequent.

Although all these elements are significant, it was stated that feedback from trials with farmers identified the on-farm refuelling as the most critical element to be resolved. If a farm or an estate has an existing AD plant providing gas to either the grid or to a CHP facility, then adding facilities to compress, store and dispense the biomethane can be achieved fairly readily. Companies such as RoadGas provide such installations currently. Even the smallest AD plants, of around 30 m^3/hr output, would provide sufficient gas for around 4-5 tractors, on an annual basis. However an AD plant is a continuous process, whereas tractor gas demand is intermittent, so a combination of sufficient gas storage, and an ongoing outlet for surplus gas to CHP or the grid, is required. The volume of gas produced, and feedstock required, supports consideration of the "clustering" approach, where one AD plant potentially receives input from, and supplies biomethane fuel to, several adjacent farms (see detailed AD report).

If an on-site supply of biomethane is not available, then distribution of compressed gas via road is feasible. As shown in the WTW Tractor analysis, road tanker distribution vs. onsite supply does inherently increase the energy and hence CO_2 impact of the overall process. For the example shown this is 7 $kgCO_2e$ additional per hour of tractor operation. Bulk tanker distribution of CNG to fixed onsite tanks is well established, with companies such as CNG

Services using this approach to provide fuel to distilleries in Scotland which are remote from the gas grid. To minimize compression requirements, a single high-pressure offtake point is utilised at Fordoun in Aberdeenshire, and gas is transported as far as Tain and Dalwhinnie.

For smaller applications, such as farms, which may not justify the cost of a fixed storage and refuelling facility, particularly during a possible transition phase, then containerised systems are available from companies such as CNG Fuels and RoadGas. These are either 20' or 40' ISO containers, holding both high pressure storage cylinders and dispensing equipment.

CNG Fuels Containerised Refuelling System

They can be taken to a public CNG refuelling facility to recharge, as shown here, or refilled onsite by a bulk tanker. A unit such as this could potentially be located in location such as a village accessible to several farms. Feasibility and economics of such systems require detailed study for specific applications.

Containerised refuelling system being refilled at public fuelling station. CNG cylinders visible.

5. Fuel Demand Modelling

The following sections summarise how the potential future demand for biomethane use in transport in Scotland has been estimated. The modelling methodology applied is described and the key assumptions and scenarios explained. The resulting demand profile and how it first rises (as new gas vehicles replace a proportion of conventional, diesel vehicles) and then falls (as sales and usage of zero emission technologies take over) is also presented.

5.1 Methodology

The Excel spreadsheet model developed for this work starts with baseline published data from the National Atmospheric Emissions Inventory (NAEI) for Scotland[54]. These data provide the most robust estimates of greenhouse gas (GHG) emissions from various heavy-duty transport sectors of interest. With the (completely reasonable) assumption that fuel use in such sectors is currently more or less exclusively diesel, these GHG emissions estimates have been used to generate estimates of overall diesel fuel demand in each sector, using standard GHG reporting factors[55].

The latest year for which NAEI estimates are available is 2019. We have assumed that the demand for diesel fuel in each sector calculated for 2019 applies also in 2021, which is the baseline year used in our model. While fuel demand in 2020 would inevitably have been significantly impacted by the SARS-cov2 pandemic, activity in 2021 is likely to have been close to pre-covid levels.

The second modelling step is to apportion each sector's overall fuel demand to the vehicles by age, i.e. what percentage of that fuel demand is consumed by new vehicles (up to one year old), by 1-2 year old vehicles, by 2-3 year old vehicles etc. In the absence of published data, to do this, a mathematical construct has been developed that reflects, for each sector, how long vehicles tend to remain in service and, from that, how steeply annual fuel use, on average, declines as each vehicle ages.

[54] https://uk-air.defra.gov.uk/reports/cat09/2106240841_DA_GHGI_1990-2019_Final_Issue1.2.xlsx

[55] 55 https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2021

This mathematical approach is based on a "Maximum Effective Life" (MEL) being assigned to each sector. The MEL for each sector is defined as the age of vehicles in that sector at which point 99.5% of that sector's overall fuel use is consumed by vehicles of that age and younger (i.e. just 0.5% of fuel is consumed by vehicles older than the MEL). Furthermore, the model assumes an exponential decline in fuel use as vehicles age such that in year x, the percentage of overall fuel used by vehicles of that age is determined by an equation of the form:

F = AeBx

Where F = fuel % for vehicles of age x and A and B are factors chosen to ensure the sum of all F's from x = 1 to x = MEL is ≥ 99.5%[56].

The net effect is that, as one would expect, vehicles that typically remain in service for many years have a flatter MEL curve than those with a much higher fleet turnover rate (Figure 18).

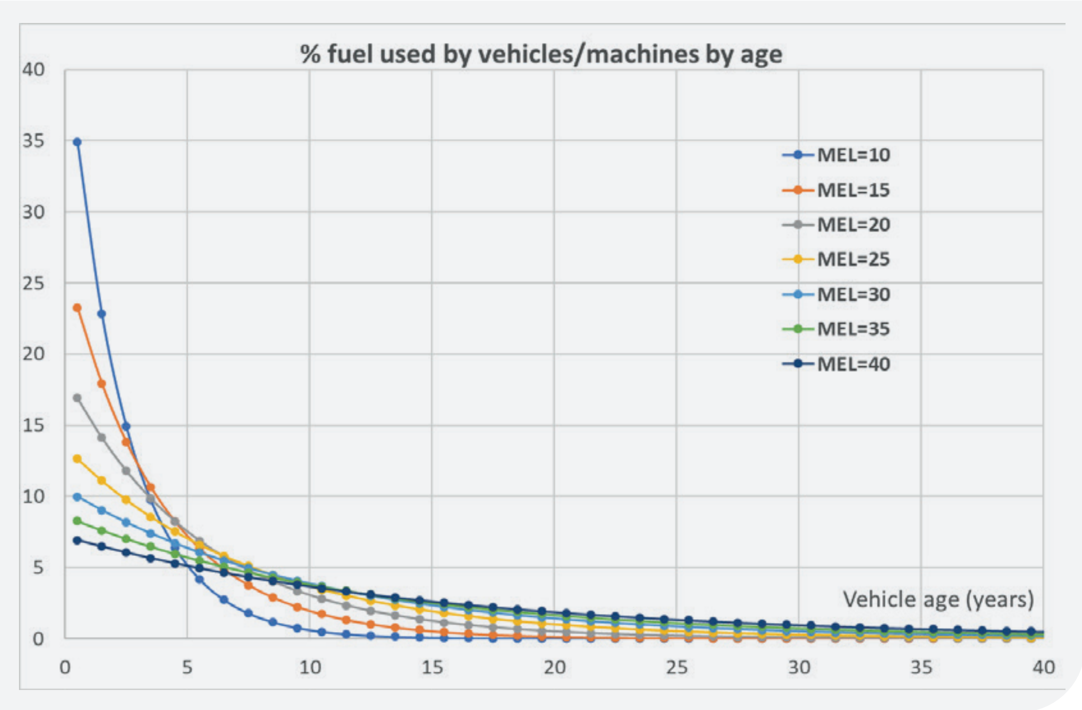


Figure 18. Variation of fuel use by Maximum Effective Life (MEL, ranging from 10 to 40 years)

[56] To properly represent all vehicles sold in any one year, the model uses x = 0.5 for vehicles up to 1 year old, x = 1.5 for those 1-2 years old etc.

As stated previously, more detailed estimates of how fuel use varies with vehicle age are largely absent from the published literature, but such information is essential for estimating how overall fuel use will change as new technologies take over from diesel.

The MEL curves used for this study are believed to be broadly accurate representations and, therefore, form a sound basis for making broad projections regarding overall fuel demand.

The third modelling step, again for each sector of interest, is to assign growth trajectories for zero emission technologies to, over the coming years/decades, completely displace sales of new combustion-engined vehicles and machinery. These “S-Curves” are inherently speculative but have been based on a combination of engineering knowledge and known regulatory frameworks (e.g. the UK Government’s recently confirmed plans to end the sale of all new non-zero emission HGVs > 26 tonnes gross weight by 2040, and lighter ones by 2035).

The S-curves used, again derived from exponential mathematical formulae, cover phase-out dates from 2030 to 2045, in five-year increments (Figure 19), from at or very close to zero in 2021 to 1.00 (i.e. 100% of sales) by the chosen date.

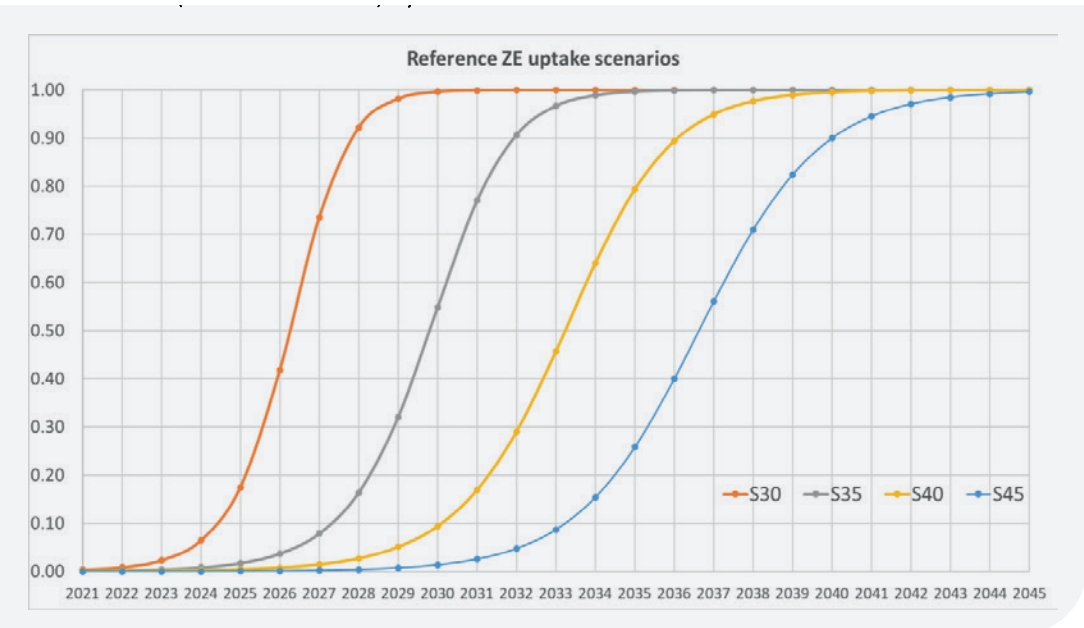


Figure 19. S-Curves to model uptake of zero emission technologies for new vehicle sales

5.2 Generating overall BAU projections of diesel demand

The above calculations and data have then been combined to provide overall estimates of how demand for diesel fuel in each heavy-duty vehicle/ machine sector of interest will fall as ZE technologies permeate into the fleet via increasing sales of new vehicles/machines. These thus represent "Business As Usual" (BAU) projections of diesel demand in the absence of any growth in bio-methane usage but with the full take-up of ZE technologies over appropriate timescales.

Furthermore, to reflect the inevitable uncertainties involved in forecasting future fuel demand and the sensitivities of our projections to the assumptions that underpin them, in addition to our "Central Scenarios", we have modelled two further scenarios. These have been named "Market Enthusiasm" and "Market Reluctance" and have been based on either shortening (Market Enthusiasm) or lengthening (Market Reluctance) the MEL estimates for each sector by 5 years. In effect, shortening the MEL simulates a scenario in which the cost savings and benefits of the new ZE technologies are so strong that owners/users of existing diesel machinery are motivated to bring forward their own fleet phase-out so that the incumbent diesel vehicles/ machines are retired from significant service ahead of the historical norm. Conversely, the Market Reluctance scenario is relevant in the situation that the ZE technologies, despite mandates effecting new sales, are perceived to be more expensive and/or less effective than the existing diesel technologies and so owners/users are instead motivated to hold on to their old equipment for longer than the norm.

The sectors modelled, and the MEL's and phase-out date S-Curves assigned to each, across the three overall scenarios are shown in 8.

NAEI Activity sector	Diesel fuel	Non-Zero Phase-out Date	Max Effective Lives (MELs, Years)		
			Central Scenarios	Market Enthusiasm	Market Reluctance
Articulated HGVs	DERV	2040	15	10	20
Rigid HGVs	DERV	2035	20	15	25
Bus & Coach	DERV	2030	20	15	25
Vans	DERV	2035	20	15	25
Non-Road Mobile Mach'y (NRMM)	Gas Oil	2040	20	15	25
Air-Support Vehicles	Gas Oil	2035	20	15	25
Railways	Gas Oil	2045	35	30	40
Agriculture	Gas Oil	2045	25	20	30

Table 8. Sectors and scenarios modelled for overall diesel fuel demand projections

5.3 Sectors relevant to biomethane usage, growth assumptions and rationale

To displace what would otherwise be the purchase and usage of conventional diesel vehicles or machinery, gas-powered alternatives will need to be available. For most of the eight NAEI activity sectors used for the above diesel demand modelling, such alternatives do not exist and are, in our expert view, unlikely to become available in the timescales being considered here. Our assumption is that this applies to the Vans, NRMM, Air-Support Vehicles and Railway sectors.

Dedicated gas vehicles/machines would require dedicated spark-ignition engines, as opposed to the compression-ignition diesel engines in widespread use now. We consider it highly unlikely, given the overall and universal thrust across all sectors to develop zero emission alternative technologies as quickly as possible, that vehicle manufacturers that do not already supply gas engines would divert significant resources to the development of dedicated gas engine-vehicles.

An alternative approach may be to develop dual-fuel technologies that can retain the diesel engine but combust a mixture of diesel fuel and gas (methane). While this option is technically viable, previous experience with it suggests that it is fraught with challenges, not least ensuring full combustion of the methane fuel. Methane is a very potent greenhouse gas, with a Global Warming Potential of around 30 over a 100-year period and as high as 80 or so over a 20-year period, meaning prevention of methane leakage to atmosphere is absolutely crucial to controlling global temperature rises in the period to 2050[57]. Trials of such (retrofit) technologies fitted to various HGVs found significant leakage from the tailpipe - known as methane slip[58]. We are not aware of any major programmes to further develop and improve dual-fuel retrofit diesel-methane technologies and, therefore, have also made the assumption that growth in biomethane usage can only be achieved through increasing sales of new dedicated gas vehicles/machinery directly by the major original equipment manufacturers (OEMs).

The one exception to this relates to articulated HGVs, where one major OEM (Volvo) does supply a form of dual-fuel diesel-methane vehicle. This technology requires a small amount of diesel fuel, compressed in the engine to provide the ignition source for the gas and has been found to be effective in improving overall tailpipe GHG emissions without appreciable methane slippage[59].

Of the four remaining sectors (Artic and Rigid HGVs, Bus & Coach and Agriculture), we have further assumed that there would be negligible take up of biomethane in the bus and coach sector. ZE technologies for buses, particularly battery-electric, are now well established with pressure increasing on bus operators to ensure any new vehicles they buy are fully zero emissions at the tailpipe. We are not aware either of any gas-powered coaches in current production. We therefore consider it unlikely that the bus and coach sector would switch to new gas vehicles in significant quantities.

This leaves the two HGV sectors and agricultural mobile machinery (e.g. tractors) as the sectors we believe do have meaningful potential for some switching to biomethane. Even in these sectors, however, the take up of gas vehicle technologies will inevitably be constrained, not least to only those OEMs with product available.

57 This issue was raised in one of the key outputs of the recent Glasgow COP26, the Global Methane Pledge.

58 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/581859/emissions-testing-of-gas-powered-commercial-vehicles.pdf

59 https://www.zemo.org.uk/assets/reports/LowCVP-LEFT_Dissemination_Report-2020.pdf

In the articulated HGV sector, three of the major OEMs have gas-powered vehicles available; Volvo (the dual-fuel technology described above), Scania and Iveco (both offering dedicated gas vehicles with spark ignition engines). These OEMs have between them about a 30% share of the UK new HGV market. We have therefore assumed that if very strong incentive mechanisms were in place, there is a maximum potential for 30% of all new combustion-engined (ICE) articulated HGVs to run wholly or predominantly on biomethane. Furthermore, we have assumed that it would take until 2030 to achieve that level of new sales share, starting from a near 0% share in 2021. Our modelling then maintains a constant 30% share of new ICE sales from 2030 onwards.

For rigid HGVs, only Iveco and Scania currently provide dedicated gas-powered vehicles. Testing by Zemo for the Low Emission Freight Trials indicates that gas-powered vehicles are best suited to regional delivery and long-haul operations at generally high and steady cruising speeds. Efficiency losses at low speed and in transient conditions such as encountered in more urban or city-delivery operations mean increased fuel consumption and the erosion of any significant running cost savings over diesel counterparts. Those trials also clearly demonstrated little to no air quality advantage for gas-powered vehicles over Euro VI compliant diesel equivalents. Our modelling therefore assumes that dedicated gas rigid heavy goods vehicles could achieve no more than a 10% share of new ICE vehicle sales, again by 2030 and starting from a near 0% base.

In the agricultural machinery sector, one OEM currently offers a dedicated gas vehicle option (CNH). CNH has roughly a 30% market share in the UK. Given that this sector will, after April 2022, also still be able to use duty-rebated red diesel (gas oil), it will be a potentially much more challenging sector to achieve a biomethane price that is attractive against diesel. That said, there are obvious synergies for some in the agricultural sector to use biomethane, especially if it is produced locally or even on their own farms. Overall, we have assumed that there is a maximum potential for 30% of new ICE agricultural mobile machinery sales to be gas powered but with the additional cost parity challenges, it is likely to take somewhat longer to achieve that level of penetration than for HGVs (2035).

For clarity, note that in the model, an x% market share for gas of new vehicle sales means that x% of the BAU diesel demand for that sector, in that year, is displaced by gas usage. How much gas those vehicles use in subsequent years is then modelled in the same way as the diesel vehicles (using the MEL curves).

5.4 Modelling results

5.4.1 Diesel demand, all sectors of interest

The resulting diesel fuel demand projections are shown in the Figures that follow. The first (Figure 20) presents a detailed breakdown of how demand in each sector falls over time, in the Central Scenarios. The second (Figure 21) highlights the overall sensitivity/uncertainty of the central projections by framing them in relation to those generated by the Market Enthusiasm and Market Reluctance scenarios.

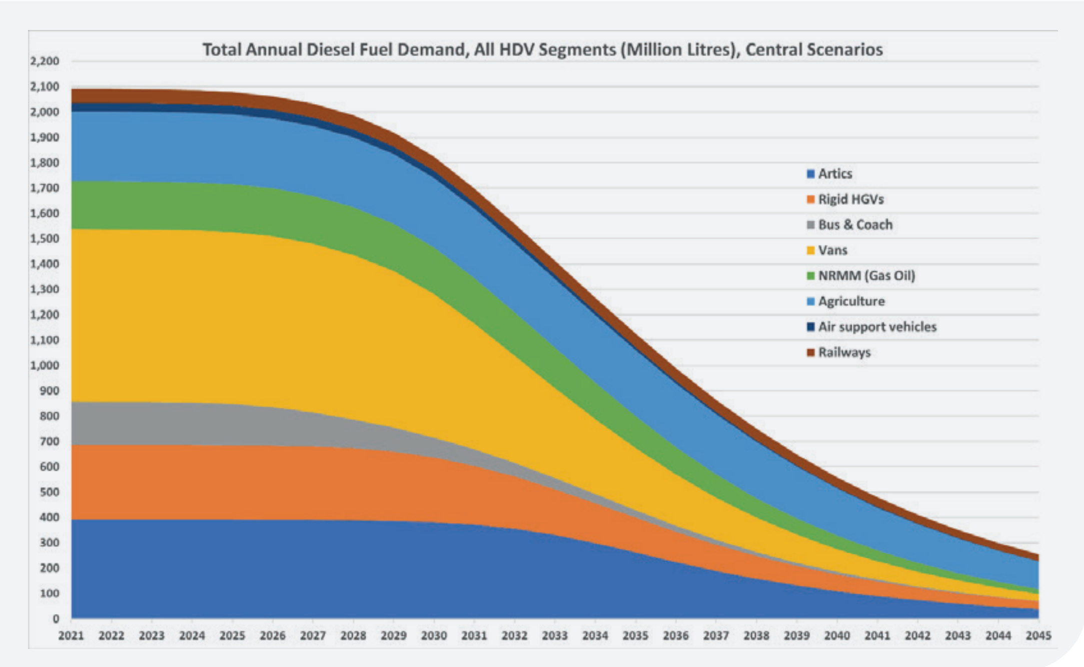


Figure 20. Annual BAU diesel fuel demand by sector (no biomethane growth), Central Scenarios

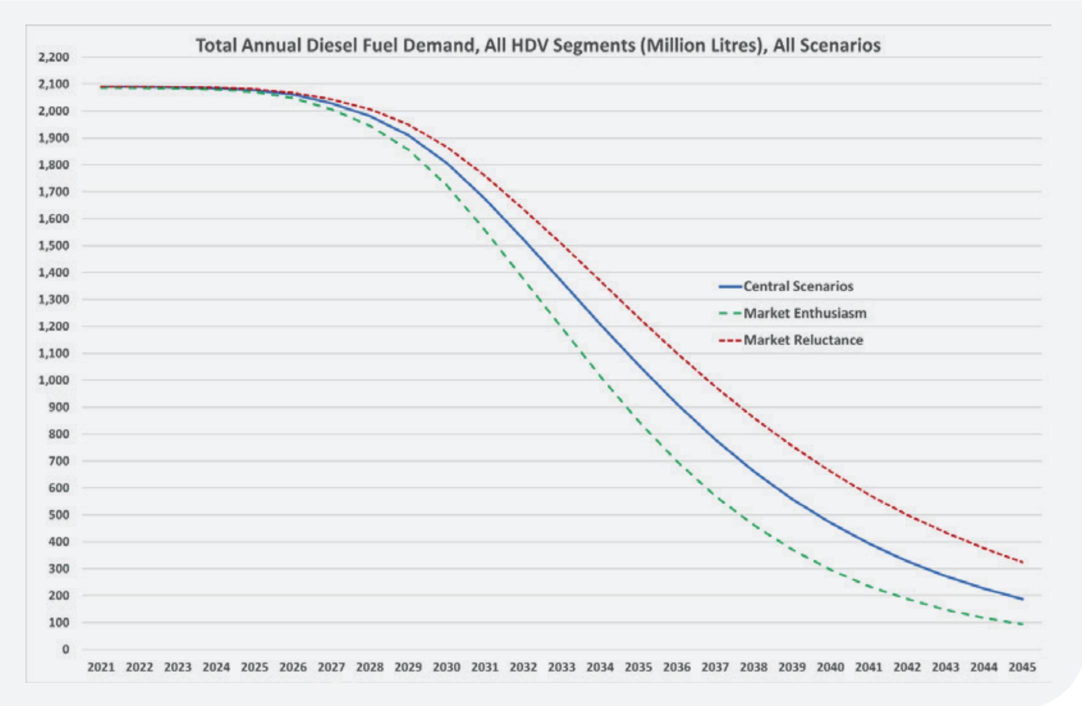


Figure 21. Projected diesel demand in three main scenarios

In total, annual diesel fuel demand across the eight sectors is projected to fall from its current 2.1 billion litres to between 1.7 and 1.9 billion litres in 2030 and then more steeply to around 0.8-1.2 billion litres by 2035 and just 0.3 - 0.7 billion litres by 2040 and 0.1 - 0.3 billion litres by 2045.

By 2045, the three key sectors of relevance to potential widespread biomethane uptake (rigid HGVs, artic HGVs and agriculture) are projected to account for around 60% of the diesel fuel use across all eight sectors (from around 45% in 2021).

5.4.2 Biomethane demand, HGV and agriculture sectors

The maximum potential annual demand for biomethane, if the 30%/10% new sales proportions are achieved by 2030/35, is shown in Figure 22, again across the three scenarios of market uptake (of ZE technologies). Previous testing by Zemo of gas-powered vehicles indicates that a good general rule of thumb is that, in appropriate applications, each kg of gas displaces very roughly 1 litre of diesel fuel, so for every Ml of diesel displaced it can be estimated that 1 ktonne of biomethane would be needed.

Overall, the modelling and associated assumptions described above generates a central estimate that demand for biomethane use in the Scottish fleets of HGVs and agricultural mobile machinery could peak at around 110 ± 10 kt between about 2031 and 2035 ± 1 year. Thereafter, demand is projected to fall back down again as ZE technologies gain pre-eminence, to around 40 - 60 kT by 2040 and 15 - 30 kT by 2045.

At and beyond the peak, this level of demand for biomethane would represent about a 20-25% displacement of diesel and, therefore, about a 20% cut in overall well-to-wheel GHG emissions if the diesel is assumed to remain predominantly fossil-fuel derived and the biomethane is assumed to have a near-zero net GHG impact.

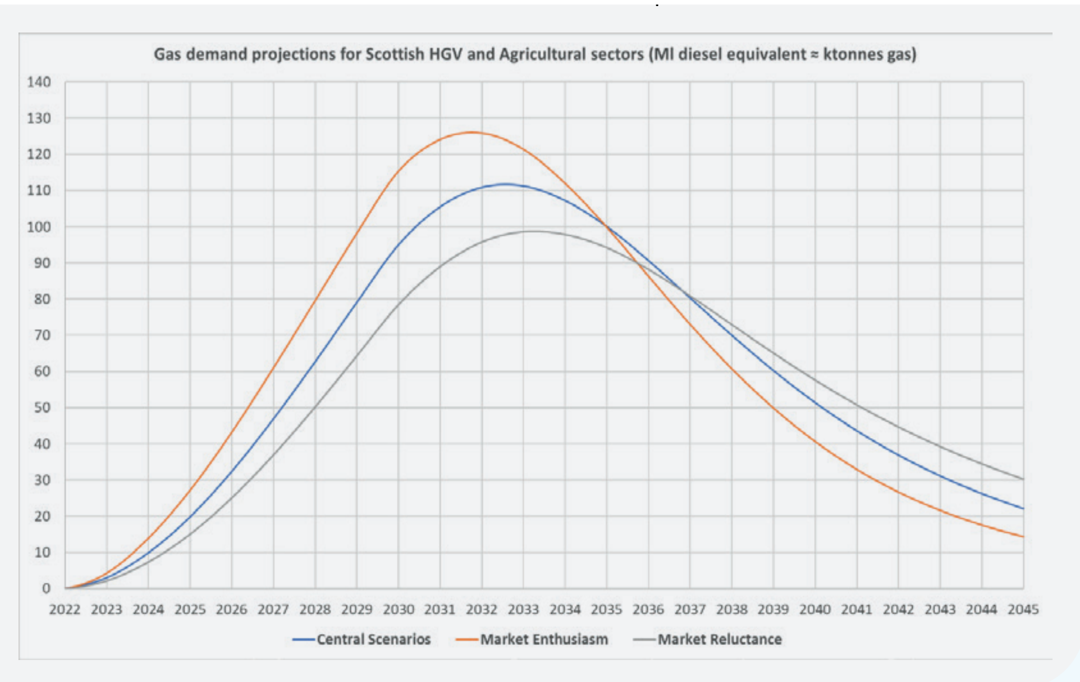


Figure 22. Modelled projections of biomethane demand across the three target sectors

6. Conclusions

1. Anaerobic Digestion (AD) to supply either biogas or biomethane is a well-established technology in Scotland, with a total of 84 sites known to be operating, spread across industrial, agricultural and commercial activities. Agricultural sites are the most numerous, representing around 66% of all operations, but also tend to be smaller, so in terms of gas capacity they are broadly equivalent to the larger industrial and commercial sites.
2. Total currently installed AD capacity is around 2 TWh/year, with around half of that being biogas for use in combined heat and power (CHP), and half being upgraded to biomethane for grid injection. It is estimated that actual biomethane supply is currently around 0.8 TWh/year.
3. Major sources of feedstock for AD include residues from distillation and brewing processes, as well as manure. 12 of the current plants are attached to either brewing, malting or distilling facilities, and others accept waste from these operations. Well-recognised names such as Glenmorangie, Glenfiddich and Brewdog all operate AD facilities, with the latter two already providing biomethane for transport. William Grant & Sons, parent company of Glenfiddich, operate extensive AD facilities via their subsidiary Grissan.
4. Feedstock analysis carried out suggests that it would be relatively straightforward to increase AD capacity in Scotland to around 4 TWh/year, without significant trade-offs. Maximum theoretical capacity could be as high as 8 TWh, but beyond 4 TWh there is increasing competition for alternative uses and pathways for the bioresources.
5. Analysis of capital and operating costs for AD plants shows that profitability strongly favours larger plants, (7001200 m^3/hr), with smaller plants (c. 100 m^3/hr), as often found at agricultural sites, broadly only breaking even. Future development of AD capacity may therefore better focus on larger plants accepting waste from a variety of sources. This approach can incur higher energy demand for transporting feedstocks, but is viable over reasonable distances. Smaller numbers of larger plants can also simplify gas grid connections if suitably located.
6. Current total gas demand in Scotland is around 47 TWh/year, with an ambitious target to reduce this by 21 TWh by 2030, to leave c. 2527 TWh demand. In this context the total supplies of biomethane likely to be produced can readily be consumed within the grid.

7. Detailed Well-to-Wheel (WTW) analysis carried out, shows that biomethane from waste feedstock, the preferred source, typically offers around 8087% GHG reductions compared to diesel when combusted in an ICE HGV. This compares to around 95% for a BEV using current Scottish grid electricity. If biomethane is sourced from manure, GHG emissions can be net negative, in the range 200240% compared to diesel, due to the additional elimination of fugitive methane emissions from manure decomposition.
8. The sector of heavy vehicles forecast to show greatest growth over coming years is articulated tractor units, where biomethane is shown to be both technically and economically effective. Both CNG and LNG (liquified natural gas) applications are expected, with LNG often being preferred for the heaviest (44 T) applications.
9. Less certain is the growth of biomethane in the medium "rigid" sector, typically 12-26 T, where there is potentially more opportunity for fully electrified solutions, allowing a potential direct migration of this market sector from diesel to electric operation, particularly on shorter and less intensive operations. Battery cost and weight do however currently remain a significant barrier. Some growth is therefore projected for biomethane in this sector, although not as great as articulated units.
10. For the agricultural tractor market, only one OEM, New Holland, has to date brought a biomethane product to market, the medium-sized T6 unit. Vehicle performance matches the diesel equivalent model, and with optional gas storage capacity it can operate for up to around 6 hours between refuelling. Capital cost does however remain significantly above the diesel equivalent, potentially requiring support to achieve sales, and the ongoing "red" diesel rebate available to agriculture makes commercial biomethane fuel cost uncompetitive, although on-site generation and "side-streaming" may offer opportunities.
11. Modelling of the Scottish vehicle parc and usage, shows that projected demand for biomethane for these three classes of vehicle could peak at around 110 KT +/- 10% in the time range 2030-2034. Beyond this point it is expected that demand will decrease as alternative zero-emission solutions gain favour.
12. 110 KT of methane is around 1.5 TWh/year, therefore there is good scope for Scotland to effectively be self-sufficient in biomethane for transport applications well within the forecast 4 TWh/year potential AD & feedstock capacity.

7. Industry Sources

Zemo Partnership and NNFCC wish to note and express our thanks for the contributions made by the following industry sources during the compilation of this report:

Case New Holland Ltd.
CNG Fuels Ltd.
CNG Services Ltd.
Leyland DAF Trucks
RoadGas Ltd

8. Appendix – Supporting information for section 3

8.1 Methodology

The calculations for WTW GHG emissions are shown in Figure 17.

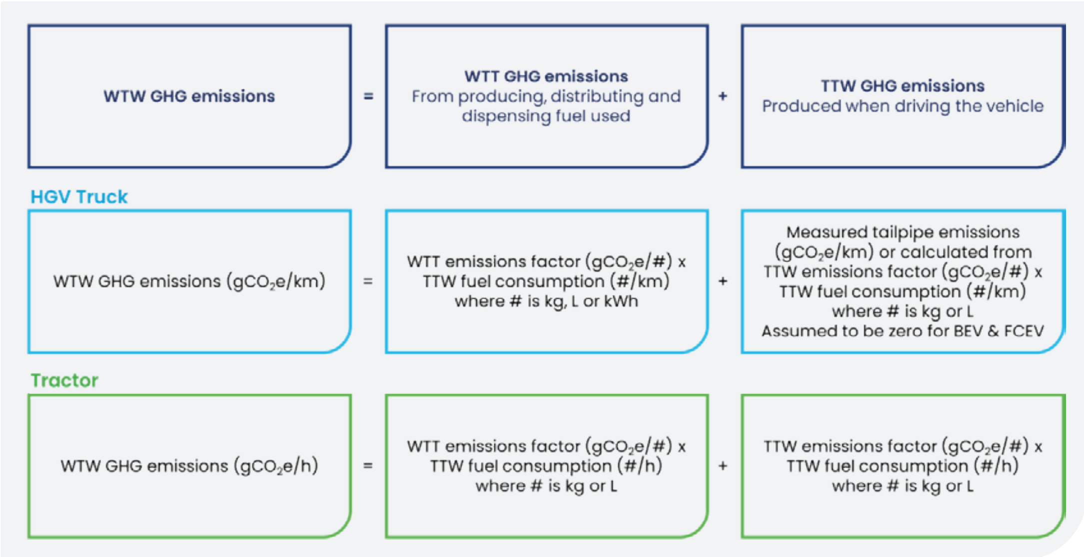


Figure 23. Calculations for WTT, TTW and WTW GHG emissions

Emissions factors in gCO_2e/MJ have been converted to gCO_2e/kg by multiplying by the lower heating value (LHV) of the fuel (MJ/kg).

8.2 Assumptions

Fuel supply

- WTT GHG emissions for hydrogen are derived from the Zemo WTT hydrogen supply model. The hydrogen is produced via on-site electrolysis with 350 bar dispense. For a more comprehensive list of assumptions behind the WTT hydrogen supply model please refer to the Zemo Hydrogen Vehicles WTW GHG and Energy Study report.
- BEV and FCEV results have been calculated using two different grid electricity WTT emissions factors: Scottish Energy Statistics Hub 2019 data and BEIS 2021 UK Government GHG Conversion Factors for Company Reporting.
- WTT GHG emissions for on-site renewable electricity are zero.

- WTT GHG conversion factors for comparator fuels are taken from BEIS 2021 Scope 3 UK Government GHG Conversion Factors for Company Reporting where available.
- Fuel densities and LHVs are taken from BEIS 2021 UK Government GHG Conversion Factors for Company Reporting where available.
- Diesel is a 'pump' blend and includes an element of biofuel (accounted for in the BEIS conversion factors).
- Vehicle consumption
- An effort has been made to use vehicle energy/fuel consumption values corresponding to a consistent drive cycle or similar real world conditions for comparator vehicles. However, this was not always possible due to limited data availability.
- Vehicle biomethane consumption is assumed to be the same for bio-CNG and bio-LNG: both are measured in kg/100km or kg/h and use the same emissions factors (gCO_2e/MJ) and LHV (MJ/kg) to calculate WTW GHG emissions.
- An ICE truck is assumed to have the same energy consumption when using diesel or HVO. Hence, due to the relative energy densities of the fuels (based on the LHVs), HVO fuel consumption is higher than that of the equivalent diesel vehicle.
- For BEV grid energy consumption is used: this accounts for any charging losses.
- The fuel consumption data assumes that the 18t GVW truck is operating at full payload and the 44t GVW truck is operating at 60% payload. In practice, a 44t HGV may use dual fuel technology (diesel and biomethane) but this has not been modelled in this study.
- No adjustments have been made for potential changes in payload between different powertrains (e.g. due to BEV battery size/weight or hydrogen storage tank size/weight).
- Vehicle deterioration factors have not been applied.
- In-use GHG emissions
- BEV and FCEV produce no GHG emissions in-use.

- TTW gCO_2e/km for diesel HGVs are based on Zemo emissions test data and experience (e.g. Low Emission Freight and Logistics Trial). An additional 3% is added to the tailpipe CO_2 to allow for other GHG emissions (CH_4 and N_2O):
- TTW gCO_2e/km = tailpipe CO_2 (g/km) x 1.03.
- For the other vehicles, TTW GHG conversion factors are used: taken from BEIS 2021 Scope 1 UK Government GHG Conversion Factors for Company Reporting where available.

Accelerating Transport to Zero Emissions

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