UK Government

Methane Emissions from Anaerobic Digestion – 2.0

Final Report

Department for Energy Security and Net Zero (2026)

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Abbreviations

ABP	Animal By-Products
AD	Anaerobic Digestion
BtG	Biomethane to Grid
BUU	Biogas Upgrading Unit
CA	Chemical Absorption
CAPEX	Capital Expenditure
CCUS	Carbon Capture, Utilisation and Storage
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSTR	Continuous Stirred Tank Reactor
CfE	Call for Evidence
DESNZ	Department for Energy Security & Net Zero
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
EBA	European Biogas Association
EGT	Exhaust Gas Treatment
EIGA	European Industrial Gases Association
ETS	Emissions Trading Scheme
FIT	Feed In Tariff
GEU	Grid Entry Unit
GGSS	Green Gas Support Scheme
GHG	Greenhouse Gas
GWP	Global Warming Potential
H_2S	Hydrogen Sulphide
HACCP	Hazard Analysis and Critical Control Point
HAZOP	Hazard and Operability Analysis
HRT	Hydraulic Retention Time
LDAR	Leak Detection and Repair
LNG	Liquefied Natural Gas
MS	Membrane Separation
NDRHI	Non-Domestic Renewable Heat Incentive
NREP	Non-Renewable Energy Potential
NMVOC	Non-Methane Volatile Organic Compounds
NO_x	Nitrogen Oxides
OCU	Odour Control Unit
OPEX	Operational Expenditure
OLR	Organic Loading Rate
PRV	Pressure Relief Valve
PSA	Pressure Swing adsorption
REDII	Renewable Energy Directive II
RTO	Regenerative Thermal Oxidation
VOC	Volatile Organic Compounds
WS	Water Scrubbing

Executive Summary

The Methane Emissions from Anaerobic Digestion (MEAD) 2.0 project synthesises the evidence base regarding the nature and impact of methane emissions from the UK's anaerobic digestion (AD) sector. Methane has a global warming potential (GWP) around 28 times greater than CO_2 over 100 years, meaning that even small fugitive losses can significantly affect both the carbon intensity (CI) and the commercial performance of AD facilities. As the UK scales biomethane production to support its 2050 net-zero targets, understanding and mitigating methane emissions is essential for ensuring environmental integrity, safeguarding revenue at AD plants, and informing future policy design.

Biomethane is expected to play a critical role in the UK's transition to net zero, with current production estimated at 7 TWh/year. Analysis for the 2023 Biomass Strategy suggested that 30-40 TWh/year of biomethane could be installed by 2050 to help meet Net Zero, although some industry projections suggest that even higher amounts of biomethane could be produced in certain scenarios. Prior evidence from MEAD 1.0 and other studies demonstrated that methane emissions from AD facilities can in some cases be much higher than previously assumed, ranging from 4% to 22% of total methane production at the sites investigated. Thus, highlighting the urgent need for a deeper investigation into emission sources and mitigation options.

MEAD 2.0 was commissioned to expand this evidence base by:

- Identifying mitigation measures for both point-source and area-source emissions.
- Establishing best practice in plant design, commissioning, operation, and maintenance.
- Providing detailed insight into methane slip from biogas upgrading technologies.
- Evaluating the effectiveness of post-AD digestate emissions abatement strategies.

This report integrates the findings from a literature review, UK market analysis, site sampling, stakeholder engagement and laboratory trials.

Common emissions points

Methane emissions can arise throughout the AD process, from feedstock reception and pre-treatment areas, during digestion and at biogas storage systems, at biogas upgrading units (BUUs), at CHP engines, across ancillary equipment (including pipework, seals, pressure relief valves (PRVs) and flares for example), and during digestate treatment and storage.

Feedstocks such as food waste, manures and sewage sludge may present a higher risk of methane generation prior to digestion compared to crops and crop residues (unless improperly stored). Best practice to avoid methane generation at this stage would include enclosed reception halls, rapid throughput of feedstock, temperature control, and the separate storage of high-risk materials.

Methane leaks are common at digester roofs, tank joints, membrane fixings and viewing windows. Site surveys carried out as part of the MEAD 2.0 study showed that half of the digesters

assessed exhibited methane leakage to some extent. Flexible double-membrane roofs were found to generally have fewer leaks than rigid concrete or steel roofs, although all types require rigorous and quality installation, and regular monitoring and maintenance in order to ensure normal operation.

Biogas upgrading is also a major potential source of methane slip, and the performance can vary depending on the technology used with typical reported values as a % of methane input to the upgrading unit documented as follows:

- Chemical absorption: <0.1% methane slip
- Membrane separation: 0.5-1% methane slip
- Water scrubbing: 1-3% methane slip
- Pressure swing adsorption (PSA): 1-5% methane slip
- Physical absorption: 2-4% methane slip

MEAD 2.0 sampling confirmed that there can be substantial variation in methane slip, with sites recording methane losses from biogas upgrading units where methane composition in the off-gas released to the atmosphere ranged from 0.13% to 9.05%, depending on configuration and operational conditions. CHP units can also incur methane slip, typically in the range of 1-3% of methane input into the engine, due to incomplete combustion.

Auxiliary equipment such as pipework, joints, seals, PRVs and flares can also be recurring sources of fugitive emissions. PRVs are particularly significant, with prior literature identifying leaks from PRVs at 53% of sites surveyed, and the MEAD 2.0 study at 5 out of 8 sites visited. In general, liquid-seal PRVs have been found to perform better than mechanical PRVs, but routine maintenance is essential for both.

Digestate exiting AD assets is a significant area of concern, as it can continue producing methane due to entrapped methane as well as residual biological activity occurring within the digestate. Laboratory trials during this study assessed multiple strategies for the abatement of methane generation post-AD, including pH adjustment, aeration, vacuum degassing, separation, and pasteurisation. Based on the results of this study, pH manipulation (alkaline or acidic) proved the only method capable of completely halting methane generation across all digestate types assessed, though other methods such as aeration, pasteurisation and extended process time also led to suppressed methane generation. Although it is important to note that future work in this area is critical given that some abatement methods and commercial technologies remain in their infancy and only specific conditions were tested for each of the abatement strategies tested, without optimisation trials conducted. The study also recognises that upstream AD optimisation and operations are anticipated to have an impact on post-AD emissions by reducing bioavailable carbon in digestates and on methanogenic community presence, potentially affecting the efficacy of downstream abatement strategies, which was not within the scope of the project and merits further investigation.

Leak detection and repair (LDAR) is central to emissions reduction at AD sites. For sites using standard fugitive methane values for Greenhouse Gas reporting under the Green Gas Support Scheme (GGSS), and for all permitted sites, routine monitoring is required to ensure methane emissions are identified effectively. While the costs of LDAR deployment can be considered significant for some operational sites, it offers economic returns from capture of additional

methane, alongside significant environmental benefits and reductions in health and safety (H&S) risks, making the investment worthwhile to protect site personnel and infrastructure. With regards to site design, preventing leaks requires high-quality welded pipework, gastight seals and corrosion-resistant materials, minimising joints and weak points, ensuring full access for roof inspection and maintenance. Furthermore, methane slip can be significantly reduced at the upgrading stage by selecting the most appropriate technology for site size and feedstock used, implementing off-gas treatment (e.g., CO_2 capture, combustion), optimising operational parameters and maintaining filter media for example.

Interviews with industry stakeholders active across the AD industry in the UK, including operators, installers, maintenance engineers and technology suppliers revealed that there was variability in the awareness of methane issues, particularly at exempt or older agricultural sites. Cost is often seen as a barrier to routine LDAR testing, despite the fact that methane loss directly reduces plant revenue. Operators with strong technical knowledge achieve substantially lower emissions and faster issue resolution.

The MEAD 2.0 project demonstrates that preventing methane emissions from AD is both technically feasible and economically beneficial to sites operating around the country. Three overarching conclusions emerge as a result of this work:

1. Methane losses are common but avoidable – leaks from digesters, PRVs, pipework and upgrading units routinely occur, yet can be identified and corrected through robust LDAR and asset quality improvements.

2. Technology choice and operational excellence matter – the difference between low and high emission AD sites derives largely from operator expertise, the quality of equipment installation, and proactive maintenance, more so than from feedstock type.

3. Digestate storage is a significant and under-addressed emissions source – laboratory evidence indicates that strategies such as extended process time, aeration and pH adjustment can reduce methane generation, although results are based on limited test conditions, and further research is needed to understand how effectiveness may vary with operating conditions and prevailing methanogenic communities.

Based on the findings of this study a number of key areas were identified for further action:

- Comprehensive training for operators and site staff, to be more aware of the need for effective monitoring and to understand when equipment requires maintenance, is failing or coming to the end of its effective life, and the impacts of this.
- Raise awareness among operators of the financial and environmental costs and H&S risks of methane losses and the benefits of reduction, prevention and capture.
- Provide clear guidance on what is required in terms of breadth, depth and frequency of an effective monitoring routine.
- Improved access to monitoring equipment or services at reasonable cost and in a timely manner, whilst also ensuring service provision is scaled alongside deployment, would help ensure effective and timely repairs can be carried out if/when issues are detected.

- Research gaps in digestate emissions abatement could be addressed with further research on innovative techniques that are not yet deployed at commercial scale in the UK, as well as linking efficiency of upstream AD operation to digestate emissions.

1. Introduction

The UK Government has set an ambitious target to achieve net zero greenhouse gas (GHG) emissions by 2050. To meet this goal, the UK must harness a wide range of renewable technologies, to decarbonise a number of sectors including energy, agriculture, transport and waste management. Biomethane, produced by anaerobic digestion (AD), is set to play an essential part in the UK's energy mix, offering a renewable, drop-in alternative to conventional fossil natural gas whilst also delivering benefits to the other sectors listed above.

Biomethane production capacity across the UK is currently around 7 TWh per annum[1] and with continued support from the UK Government via the Green Gas Support Scheme (GGSS), this was expected to increase to around 8 TWh by 2030.[2] The UK Government's Biomass Strategy 2023 highlighted biomethane's role in delivering cost-effective decarbonisation, estimating that around 30–40 TWh of biomethane by 2050 could help meet residual gas demand in hard-to-electrify sectors[3]. Similarly, the Climate Change Committee's Seventh Carbon Budget scenarios include biomethane as a key contributor to emissions reduction in heat, industry and transport[4]. The National Energy System Operator's (NESO) Future Energy Scenarios 2025 projected deployment of up to 36 TWh of biomethane by 2035 and up to 64 TWh by 2050, depending on the pathway[5]. When produced efficiently, biomethane can be considered a carbon neutral or even net negative alternative to conventional natural gas, provided that emissions from the AD process are effectively monitored, captured and prevented from being released to the atmosphere.

While the efficient production of biomethane is the objective of any AD facility, fugitive methane emissions can be an often unintended consequence of the biomethane production process. The extent of fugitive emissions can vary from site to site, but the loss of any methane is considered harmful to the environment – methane has a global warming potential (GWP) roughly 28 times greater than that of CO_2 over a 100-year time scale. Therefore, even small methane losses during digestion, upgrading, biogas storage or digestate storage can impact the overall carbon footprint of any biomethane generated by AD. Furthermore, methane emissions from AD can be detrimental to the commercial viability of AD facilities, as methane loss directly equates to lost production and profitability for owners and operators.

To investigate these concerns further, the UK Government's Department for Energy Security and Net Zero (DESNZ) commissioned the first of two "Methane Emissions from Anaerobic Digestion" (MEAD) studies in 2022.[6] This study, carried out by the National Physical Laboratory (NPL), inspected a small sample of AD sites and monitored methane losses at various points across the AD process. The study reported a wide range of methane emissions – between 4% and 22% of site methane production – which, when compared to previous estimates of between 0.05% to 2.5%,[7] was higher than UK Government assumptions at the time. Even though the upper end of this newly identified range was exceptional and could be attributed to failing

[1] Alder BioInsights, Anaerobic Digestion in the United Kingdom, 12th Annual Report, May 2025.
[2] Future Policy Framework for Biomethane Production, A Call for Evidence, February 2024.
[3] Department for Energy Security & Net Zero, Biomass Strategy, August 2023.
[4] The Seventh Carbon Budget - Climate Change Committee
[5] Future Energy Scenarios 2025: Pathways to Net Zero
[6] National Physical Laboratory, Methane from Anaerobic Digestion (MEAD) Study, April 2023.
[7] Ricardo Energy & Environment, Methodology to Assess Methane Leakage from AD Plants, 2016.

infrastructure, it does highlight that methane emissions can reach elevated levels if an AD site is not properly managed or maintained effectively.

To gain greater insight into the occurrence of methane emissions from AD, including the collection of evidence on mitigation measures and to make recommendations on good practice around plant design and operation (for both point and area methane emission sources), a second "Methane Emissions from Anaerobic Digestion" study (MEAD 2.0) was commissioned in 2024, with work undertaken through 2025.This report outlines the findings of said study.

1.1. About the MEAD 2.0 Project

The principal aim of MEAD 2.0 was to:

*"collect evidence on mitigation measures and good practice around plant design and operation for both **point-source**[8] and **area source**[9] **methane emissions**, linking to the core focus on sustainability of the Future Policy Framework for Biomethane Production and ultimately informing criteria for sustainable AD growth in the UK".*

To achieve this aim, the specific objectives were to:

- Define good practices in relation to asset selection, operation and maintenance that result in the minimisation of point-source methane emissions in AD sites and capture the expected wider environmental and public health impacts of these practices.
- Inform on methane slip from biogas upgrading technologies that are common in the UK.
- Capture previous evidence and field data on the efficacy of established and emerging abatement strategies for area emissions.
- Identify critical gaps in knowledge to abate point-source and post-AD area methane emissions on UK AD sites, making recommendations for addressing them.

The MEAD 2.0 project consisted of two parallel work packages (WPs):

- **WP1**: Good practice recommendations for point-source emissions abatement
- **WP2**: Effectiveness of abatement strategies targeting post-AD area emissions

The primary aim of WP1 was to evaluate point-source emissions from various elements and assets typically found in the AD and biomethane production process, and to identify practices relating to design, operation and maintenance that can help to reduce methane emissions. WP1 aimed to provide guidance on good practice relating to element and asset selection, installation, and operation and maintenance activities. Whilst the comprehensive findings are presented in this report, the good practice recommendations developed as part of this work are incorporated into a separate "Good Practice Guide" published alongside this report.[10]

During WP1, biogas upgrading was considered a key source of potential emissions, due to inherent losses in the form of methane slip often associated with biogas upgrading units (BUUs). As such, in addition to methane losses, this work package also sought to collect additional data

[8] **Point source emissions** originate from a single, identifiable location, such as a vent or pipe.
[9] **Area source emissions** originate from larger areas, rather than single point sources e.g., digestate lagoons.
[10] Methane Emissions from AD: Good Practice Guide for Point Source Emissions, 2025.

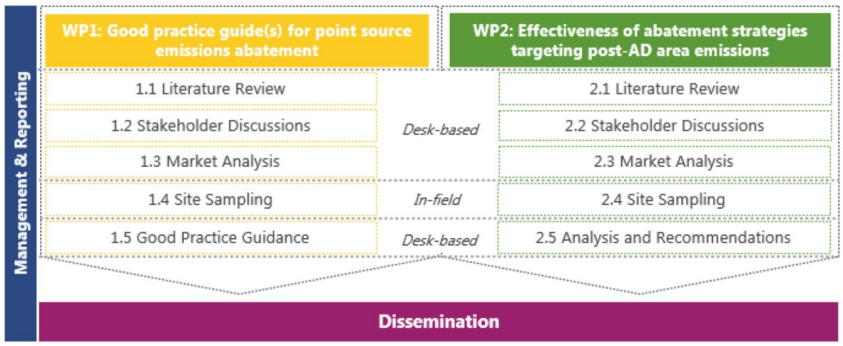
and information on other emissions and environmental impacts (e.g., H_2S, CO_2, NH_3, noise, odours etc.) from different upgrading technologies. This additional information is presented in Appendix H of this report.

The principal aim of WP2 was to investigate the effectiveness of abatement strategies targeting post-AD area emissions. Methane emissions post-AD can result from uncaptured methane trapped within digestate, as well as residual biological activity occurring post digestion, resulting in additional methane being generated. This work package reviewed previous evidence relating to methane abatement strategies and performed lab trials, aiming to replicate conditions and further investigate the efficacy of both established and emerging abatement strategies for post-AD area emissions. Where relevant, critical knowledge gaps were identified and recommendations provided to support future decision making in this area.

To effectively deliver this project, a combination of research methods, spanning evidence gathered from literature, stakeholder interviews and site testing was carried out. An overview of the project plan is highlighted in Figure 1, with each work package approached as follows:

- **Literature Review** – Existing literature evidence on methane slip, for both point-source and post-AD area emissions was gathered and assessed.[11]
- **Stakeholder Engagement** – Insight from stakeholders across the AD industry (e.g., industry bodies, site operators, equipment suppliers, maintenance engineers, and consultants) was gathered to inform on both point-source and post-AD area emissions.[12]
- **Market Analysis** – The site sampling strategies developed for the site testing components of the project were informed by analysis of the UK's AD market, to ensure that those selected for testing were representative of the wider biomethane industry.[13]
- **Site Sampling** – Point source emissions data was collected from a representative sample of sites. Post-AD area emissions abatement strategies were tested in a laboratory environment, using digestate collected from a representative sample of AD sites.[14]
- **Analysis and recommendations** – The findings from each work package were summarised and key recommendations provided based on insight gathered.

Figure 1: Overview of the MEAD 2.0 project plan.



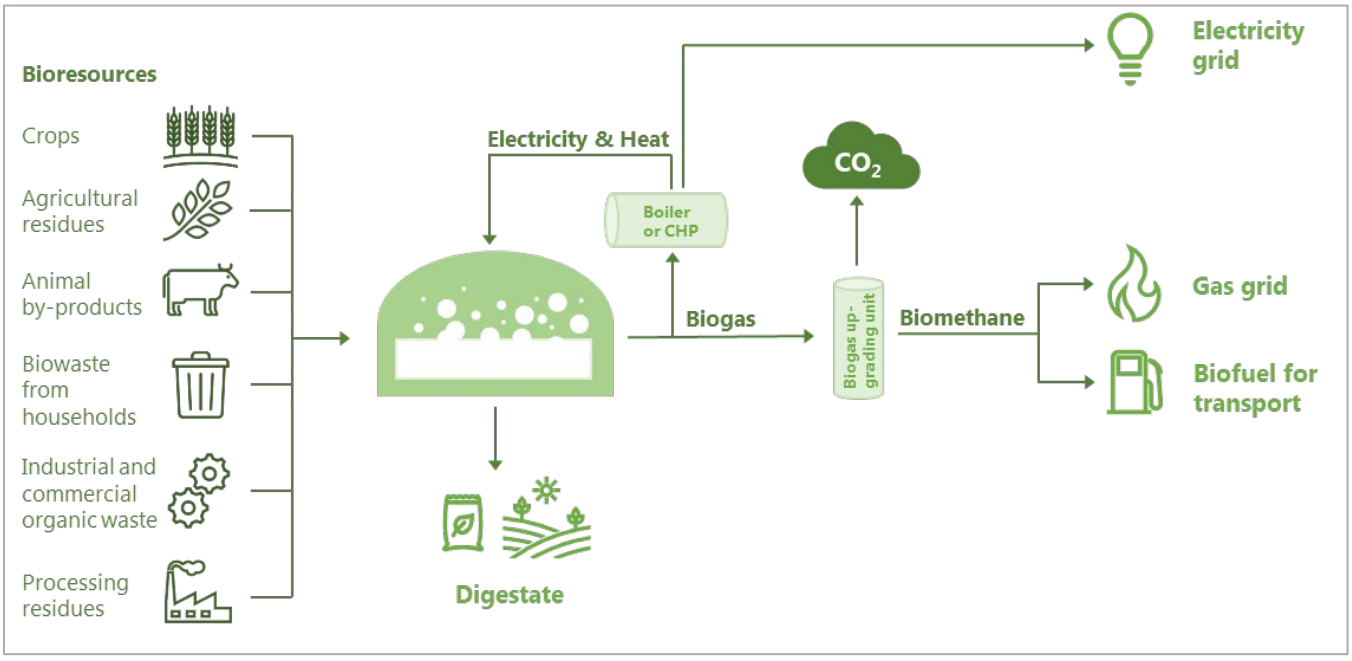
[11] The methodology used for carrying out the review of literature is outlined in Appendix A.
[12] Description of stakeholder types consulted during this project provided in Appendix B.
[13] Insight into the UK's AD market is included in Appendix C.
[14] The site sampling strategies used for work packages 1 & 2 are included in Appendix D and E respectively.

This report details the findings from each of the tasks outlined above, with recommendations provided as appropriate, and knowledge gaps identified where necessary.

2. Policy Context

Anaerobic digestion (AD) is a biological process which uses microorganisms to promote the breakdown of organic feedstocks (e.g., energy crops, livestock manures, crop wastes and residues, food waste and sewage sludge) in the absence of oxygen. The process generates biogas, a mixture of methane (CH_4) and carbon dioxide (CO_2), in addition to minor quantities of water vapour (H_2O), hydrogen sulphide (H_2S) and other trace gases. Biogas is typically either combusted in combined heat and power (CHP) units to generate electricity and heat (or in some instances in boilers to generate only heat), or upgraded to yield biomethane with a purity of over 95% by removing the CO_2 and other gases. Biomethane can be used as a drop-in substitute for fossil-derived natural gas and can be injected into the gas grid, used as a transport fuel, or as a substrate for chemical processing (Figure 2).

Figure 2: Overview of the anaerobic digestion production process for biogas and biomethane, outlining typical inputs and outputs (Alder BioInsights, 2025).



Over the past two decades, the UK Government has implemented various support mechanisms to promote the adoption of renewable energy technologies, reduce greenhouse gas emissions, and achieve net-zero targets. The two support mechanisms which have had the most notable impact on the UK's AD industry to date are the Feed-In-Tariff (FIT) and the Non-Domestic Renewable Heat Incentive (NDRHI), used to incentivise the generation of renewable electricity and renewable heat from AD respectively. Both schemes are now closed to new applicants, and the UK Government has since introduced the Green Gas Support Scheme (GGSS) as a mechanism to support biomethane generation for injection into the gas grid by newly

commissioned AD facilities in Great Britain. The GGSS opened in November 2021 and is set to remain open to applications until March 2028.[15]

With both the RHI and FIT schemes now closed to new applicants, and the existing GGSS closing to new applications in 2028, the future of biomethane support is now under review. It is not yet known how the next phase of support for biomethane will function, however, a range of potential mechanisms are being considered by DESNZ alongside a suite of appropriate evidence, gathered to inform decision making.

To calculate the GHG emissions associated with biomethane, a number of different emissions factors should be considered. Emissions factors refer to coefficients that quantify the amount of pollutant released into the atmosphere as a result of specific activities. These may include, but are not limited to:

- emissions from feedstock cultivation, collection and land use change
- emissions from the transport of feedstock and products
- emissions from processing, including pretreatment, digestion, and gas upgrading
- emissions from product distribution, including biomethane injection into the gas grid
- emissions savings from the generation of useful co-products (e.g., the replacement of fertiliser with digestate) and CO_2 capture.

In order to comply with GHG reporting requirements for the GGSS, the methodology set out in DESNZ's guidance should be followed[16]. This methodology is based on the EU's Renewable Energy Directive (REDII).[17] For full details on the calculations used, see Guidance produced by DESNZ under Regulation 12 of the Green Gas Support Scheme Regulations 2021.[18]

As indicated above, a range of emissions are typically associated with the AD process. However, ***fugitive methane losses are considered some of the most critical***. This is due to the fact that methane has a global warming potential (GWP) roughly 28 times greater than that of CO_2 over a 100-year time scale. Therefore, even small methane losses during digestion, upgrading, or storage can dominate the overall carbon footprint of any biomethane generated.

When calculating the GHG emissions associated with biomethane, component emissions factors should aim to be reported based on actual recorded data, but if this is not possible, default emissions values can be used. The default emissions values used by the previous NDRHI scheme and the existing GGSS are highlighted in Table 1 below.

[15] Further information on AD policies and incentives in the UK is provided in Appendix F.
[16] DESNZ, Methods of calculating greenhouse gas emissions: “actual value method” and “default value method”, 2024.
[17] 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.
[18] DESNZ, Methods of calculating greenhouse gas emissions: “actual value method” and “default value method”, 2024.

Table 1: Standard emissions values used for the NDRHI and GGSS.

Stage	NDRHI Standard Default Values[19]	GGSS Standard Default Values[20]
Anaerobic Digestion Site Leaks	**1%** of total biogas volume	**1%** of total biogas volume generated, if annual LDAR[21] is completed and repair log submitted. Otherwise, if no action is taken, **20%** of total biogas volume generated.
Slip from upgrading unit		**0%** of total biomethane generated, if off-gas is combusted. Otherwise, **3%** of total biomethane generated if off-gas is not combusted.
Whole Digestate storage	No default value reported.	**0%** of total biogas volume generated if gas-tight cover in place & annual LDAR inspection carried out. Otherwise, if no action is taken, **6%** of total biogas volume generated.

The NDRHI preceded the GGSS as a support mechanism for biomethane production. During this period, industry's understanding of fugitive methane emissions from AD improved significantly and the AD sector became more proactive at addressing issues relating to methane slip and associated losses, through improved site design, plant construction and site operation. It is therefore appropriate that the GGSS, as a more recent scheme, facilitates a more robust approach to reporting fugitive methane emissions. Table 1 highlights that the standard emissions values used for compliance with the GGSS are higher than those used for the NDRHI, unless measures are taken to ensure that methane losses are monitored and mitigated where possible on GGSS accredited sites. This, coupled with the fact that the GHG emissions threshold set for the GGSS is lower than for the NDRHI (24 gCO_2eq/MJ compared to 34.8 gCO_2eq/MJ) indicates that a more robust approach is now taken for reporting emissions under the GGSS.

The higher (no action) standard values adopted by the GGSS provide a greater incentive for the use of actual site data during sustainability reporting, if the conditions cannot be met to adopt the lower standard values (with evidence provided). This enables sites to demonstrate that they are below the GHG emissions thresholds by evidencing good practice through monitoring and reporting.

By providing detailed guidance on emissions reporting requirements for the GGSS,[22] the UK Government is signalling a need for AD plants to carry out routine emissions monitoring. It demonstrates the UK Government's intention to support the AD industry to produce greener, lower carbon intensity biomethane, through more routine monitoring, reporting and proactive implementation of mitigating measures against methane emissions.

[19] Ofgem, NDRHI: Sustainability Self-Reporting Guidance v2, 2024.
[20] Ofgem, Green Gas Support Scheme Guidance v2.2, 2025.
[21] Leak detection and repair (LDAR)
[22] DESNZ, Guidance for calculating fugitive methane emissions as part of the greenhouse gas criteria on the Green Gas Support Scheme, 2025

2.1. Monitoring Methane Emissions

Leak detection and repair (LDAR) refers to an environmental management practice used to identify and fix gas leaks, such as methane, from industrial equipment and infrastructure.[23] Key stages of an LDAR survey include:

- **Identification of potential leak sources** – define what constitutes a leak in the context of the site, and map potential leak points using the site's piping and instrumentation diagram (P&ID). Possible emission points can include plant assets (such as digesters, closed digestate tanks, and upgrading units, etc.) as well as specific elements (such as valves and flare systems, for example).
- **Detection** – use approved techniques to locate leaks e.g., visual and audio inspections, optical gas imaging (OGI) cameras, sniffer devices (i.e., flame ionisation detectors), and for hard-to-reach areas, drones with gas sensors.
- **Monitor** – conduct routine inspections monthly or quarterly (depending on risk level), after maintenance or operational changes, and during plant commissioning and decommissioning.
- **Repair and Maintenance** – repair leaks promptly, within a defined timeframe, replace faulty components if needed, and re-test to confirm leak resolution.
- **Documentation and reporting** – maintain LDAR records, including leak source, detection method and date, repair actions and appropriate evidence, emission estimates and mitigation steps.

As previously outlined, to avoid the use of restrictive, high (no action) standard values during GGSS sustainability reporting, LDAR is highlighted as a means of monitoring methane emissions at GGSS accredited sites to demonstrate good practice, allowing for lower standard values to be used (higher standard values can also be avoided by submitting actual values with appropriate evidence). Beyond GGSS accredited sites (e.g., RHI/FiT accredited sites), emissions monitoring is not a requirement for sustainability reporting purposes. However, any site operating under an Environmental Permit, regardless of support scheme accreditation, must provide evidence of emissions monitoring, in order to comply with The Environmental Permitting (England and Wales) Regulations 2016 (EPRs).[24]

Any AD site that uses waste feedstock must obtain an Environmental Permit, or a suitable exemption,[25] in order to operate within the confines of UK environmental law. Sites that do not utilise wastes (i.e., crop-fed facilities) do not currently require Environmental Permits in order to operate. Therefore, AD sites of this nature are not required to carry out emissions monitoring in order to comply with UK law, though they would still need to report emissions if supported under GGSS. As such, this demonstrates a potential discrepancy between permitted and non-permitted AD sites, regarding the level of methane emissions monitoring carried out across the

[23] Specific details of the LDAR survey protocols used by Bohr during the point source emissions sampling of the MEAD 2.0 project are included in Appendix D.
[24] The Environmental Permitting (England and Wales) Regulations 2016,
[25] Permit exemptions are usually limited to low-risk, often small-scale facilities (typically sites using agricultural feedstocks e.g., manures/slurries, crops and crop residues).

AD industry. However, it should be noted that many non-permitted sites are known to be routinely carrying out LDAR practices for their own operational benefit.

In order to address this discrepancy, Defra's recent Consultation on Modernising Environmental Permitting[26] noted that they are "minded to consult on making the anaerobic digestion of non-waste feedstocks [an activity] of the EPRs, requiring sites that meet certain thresholds to hold an environmental permit".

Nevertheless, this current lack of consistency across the AD sector regarding the need for LDAR, depending on legal definitions of who requires a permit and the requirements of those permits, creates a potential disparity in awareness levels of different stakeholders around the importance of monitoring emissions. This was particularly noticeable during the stakeholder engagement aspect of the MEAD 2.0 project, where newer AD sites accredited under the GGSS and older permitted sites operating under the RHI/FIT schemes, tended to be more conscious of fugitive methane emissions compared to older exempted farm-fed sites accredited under the RHI/FIT schemes. While most AD operators generally understood the impacts associated with methane losses, a number of those that were not required to carry out LDAR did not consider regular emissions monitoring a necessary part of operation and maintenance (O&M) activity. Key reasons these sites gave included:

- The lack of understanding of permit requirement to undertake LDAR and lack of understanding around what operators should do with regards to emissions monitoring, as options are numerous and costs can be significant if not focussed.
- A lack of awareness around the types of emissions monitoring services available to the sector, and the appropriateness of each option to different scales and types of plant.
- The potential costs associated with implementing LDAR programmes, and the financial benefits of successful implementation.

During stakeholder interviews, one site noted previously employing a third party to detect and monitor for methane leaks. However, upon review of the service's costs, and a lack of leaks found at this particular site, it was deemed an unnecessary practice by the stakeholder, as operational costs continued to increase elsewhere. As such, this particular site no longer continued to implement LDAR on a regular basis, although the permit required this.

Where sites did have LDAR systems implemented, it was typically carried out as part of routine inspections on a weekly basis, with checklists created to stay on top of the inspections, their findings and resulting actions. Where issues are found, they are generally fixed immediately, or as soon as replacement parts can be obtained. LDAR programmes may be carried out using a site's own equipment (e.g., cameras, sniffers, gas monitors etc.), or by third parties to conduct testing and monitoring.

[26] Defra, Consultation on modernising environmental permitting for industry, 2025. URL: https://consult.defra.gov.uk/industrial-emissions-team/consultation-on-modernising-environmental-permitti/supporting_documents/consultation-documentpdf

In light of cost being flagged as a key barrier for LDAR uptake (by AD sites that are not required to do so for permitting or for compliance with Government support schemes), indicative costs of common leak detection options as quoted by stakeholders include:

- **LDAR monitoring by third parties** – between £1,200-2,500 per day (depending on the scale or nature of monitoring). Depending on the extent of monitoring carried out, an LDAR survey may take between one half (smaller, less complex sites) to one full day (larger more complex sites). For more specialised monitoring, multiple days may be required.
- **OGI (optical gas imaging) cameras** – between £50,000-80,000 (capital cost). To conduct OGI monitoring on AD plants, certified operators should be used. Sites would not typically buy equipment of this nature themselves, but this reflects the costs incurred by third party LDAR service providers.
- **Methane leak detector "sniffer"** – between £1,000-5,000. Can be used by trained site professionals. A low-cost option available to use on site to identify if/where methane leaks may be occurring.

Without regular monitoring of site emissions at all AD sites operating in the UK, it may not be evident that methane leaks and losses are occurring – potentially resulting in unknown amounts of gas being lost to the atmosphere. While some quantification strategies appear costly, simple cost-effective strategies like frequent walking surveys with a sniffer can help identify leaks on site and trigger interventions for quick repair. However, permitted AD sites are required to undertake LDAR. Failure to do so may equate to lost productivity and profitability for site operators and have negative impacts on the environment. It also leaves the site open to enforcement action for lack of monitoring. As such, a key goal of this project was to demonstrate the benefits that emissions monitoring and mitigation can offer to the wider AD industry, to ensure that plant profits are maximised and operational practices are performed in a responsible and sustainable manner.

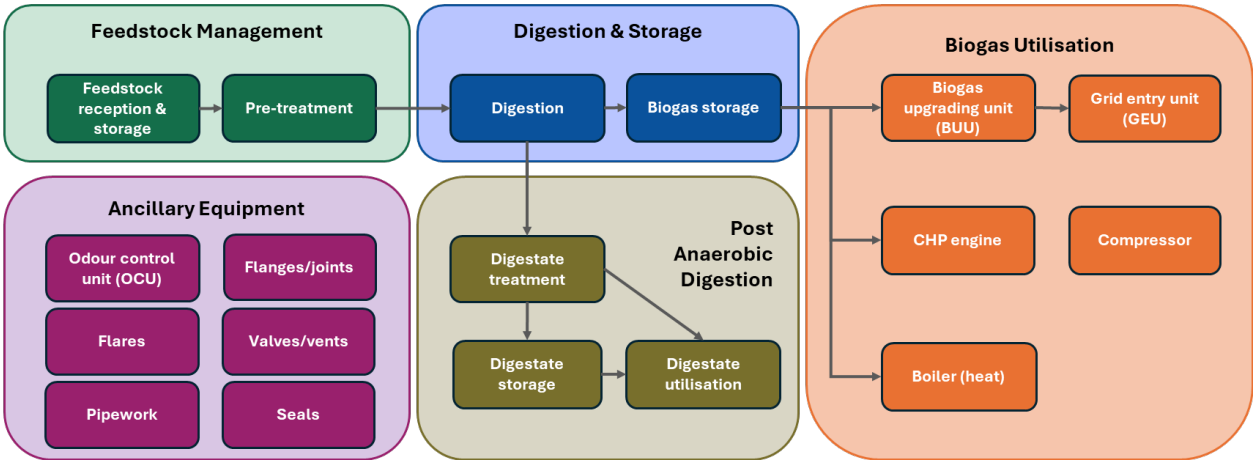
3. Methane Emissions From AD

Methane emissions from anaerobic digestion (AD) can arise at various stages of the biogas production process, including during:

- Feedstock reception, storage and pre-treatment[27]
- Feedstock digestion and biogas storage
- Biogas utilisation (whether upgraded to biomethane and injected into the gas grid, combusted in a CHP, or flared to the atmosphere)
- Post-digestion as part of digestate treatment, storage and utilisation.

Figure 3 illustrates these key stages, and outlines noteworthy ancillary equipment used throughout the AD process, as these can also be possible sources of methane emissions irrespective of the stage of the process.

Figure 3: Overview of the AD process, broken down by discrete stages and assets involved.



Methane emissions generated at AD facilities can be grouped into three distinct but related categories.

1) Emissions generated when the AD facility is operating within **'normal operating conditions' (NOC)**. The extent of these emissions is determined by design choices, the implementation of best available technologies (BAT) and decisions on what constitutes optimal NOC.
2) Emissions resulting from infrastructure, equipment or operational issues during **'other than normal operating conditions' (OTNOC)**. This group of emissions includes leaks from digesters or gas storage tanks, for example.

[27] Emissions created during feedstock procurement and management should also be considered here.

3) Emissions resulting from **temporary 'other than normal operating conditions' (OTNOC)**. A period of maintenance at an AD facility may disrupt NOC and result in methane emissions through the need to purge equipment or flare biogas/biomethane.

Understanding each category of emissions is important for the implementation of appropriate emissions measurement techniques, and the development of suitable mitigation strategies. Emissions from category 1 can be considered stable emissions, whereas category 2 emissions can be considered unstable, but they are often consistent when issues are identified. Category 3 emissions are temporary, which are often unpredictable. Should a temporary emission fall inside or outside of a measurement campaign, the extent of emissions could be over- or under-estimated, respectively.

Emissions from the first category (NOC) can be considered as baseline emissions reflecting minimal emissions based on optimised design, feedstock choice and operational decisions. It is known that differences in the physical and biochemical nature of AD feedstock influences emissions at the receiving and feedstock handling stage of the AD process as well as during the digestate handling and storage stages, whilst operating parameters (e.g. retention time) of the digestion process particularly impacts on emissions from digestate storage.

Throughout this research it is evident that significant differences are seen in methane emissions between AD facilities operating under normal operating conditions (NOC) and those deviating from normal operating conditions.[28]

The impact of other than normal operations (OTNOC) on methane emissions is also evident from the original MEAD study where four of the sites in the study were undertaking maintenance or had emergencies during measurement campaigns, thus impacting the results. Temporary emission peaks or high methane losses on whole measurement days were attributed to active pressure relief valves, flare ignition problems, leakages and/or stirring of not-gastight (open or covered) digestate storage tanks in this research.

The following sections discuss key areas where methane emissions may occur on an AD site, based on specific stages of the process and the key assets involved. Operation and maintenance considerations are also discussed as contributing factors, as well as the role that plant design and asset installation can have on emissions.

[28] Wechselberger et al., Methane losses from different biogas plant technologies. 2025.

4. Emissions from Feedstock Management

Methane emissions from AD can arise at various stages of the biogas production process, including upstream of digestion, during feedstock reception, storage and pre-treatment. Feedstock reception is a critical first step in the operation of an AD facility, where organic materials are received, inspected, and prepared for digestion. Typical components of a feedstock reception area include the weighbridge (for recording delivery weights), unloading area, hard standing (indoor or outdoor), hopper or bunker (for temporary storage before feedstock processing), and pretreatment equipment (e.g., shredders, de-packaging equipment, trommel screens, slurry tanks).

Emissions can arise during the feedstock management stage, but under normal operating conditions (NOC) these should ideally be minimised or prevented through good site design and operational practice. In addition to methane, emissions at this stage of the process may include ammonia (NH_3), non-methane volatile organic compounds (VOCs), odours, carbon dioxide (CO_2) and particulate matter (e.g., dust and particulates). The extent of any emissions occurring at this stage typically depends on the types of feedstocks being used. Regarding methane emissions, if feedstock has already started decomposing anaerobically during transport or prior storage, this could result in the generation of methane upon arrival at the AD facility (key examples include food waste, livestock manures, sewage sludge and fatty wastes). The likelihood of this further increases if the feedstocks have been stored for a prolonged period of time and/or under warm conditions.

Feedstocks that are easier to store and handle without the risk of uncontrolled emissions are generally less biologically active and do not rapidly degrade under ambient conditions. Key examples include crops (e.g. maize silage, grass silage or wholecrop cereals) and crop residues (e.g. straw or vegetable outgrades). This is not to say that emissions from the handling of these feedstocks will never occur, as poor feedstock management,[29, 30] long storage periods, or storage in warm, damp conditions can promote microbial activity and thus, result in methane formation.[31]

Table 2 outlines key feedstock types used by AD facilities in the UK, highlighting typical risk levels with regards to methane generation during the feedstock management stage.

[29] Good feedstock management should always be a priority for AD site operators. Guidance as set out in ADBA's Practical Guide to AD, gives an indication of good practice steps that should be followed.
[30] ADBA, Practical Guide to AD.
[31] Spence et al., Evaluation of anaerobic digestibility of energy crops and agricultural by-products. Bioresource Technology Reports. 2019.

Table 2: Methane emission risks associated with feedstock management of typical feedstocks used in the UK.[32, 33]

Feedstock Type	Risk of Methane Generation Pre-Digestion	Reasons
Crops	Low	Mostly stable, unless poorly stored
Crop Residues	Low	Mostly stable, unless poorly stored
Livestock Manures	Medium-High	Partially digested, microbial content
Sewage Sludge	Medium-High	Partially digested, microbial content, high moisture, anaerobic conditions.
Food Waste	Medium-High	Partially digested, microbial content, high sugar/fat content

The previous MEAD study also suggests that low levels of methane emissions are typically generated during feedstock reception and handling stages at agricultural sites, whereas higher emissions can occur at food waste facilities as illustrated in Table 3. Note that the data presented in Table 3 for commercial food waste is based on a single site, and so, firm conclusions cannot be made about the extent of emissions arising from the use of this feedstock type. The emissions factor data presented in the table below refers to percentage loss of total site methane production.

Table 3. Emissions from reception and handling of biomethane feedstock.[34]

Plant type	Feedstock	Feedstock (t/y)	Emission Factor % (standard uncertainty)
Agricultural	Maize, rye, grass and sugar beet	30,000	0.2 (0.2)
Agricultural	Maize, rye and manure	30,000	0.0 (0.2)
Agricultural	Maize, rye	22,000	0.1 (0.1)
Commercial	Food waste	48,500	4.4 (0.7)

Given that different feedstocks can generate varying levels of methane emissions when delivered to the reception area, it is essential that sites are designed accordingly at the outset depending on which feedstocks are planned for use. Proper site planning and feedstock management will ensure that emissions at this stage of the process are minimised or mitigated entirely.

[32] Spence et al., Evaluation of anaerobic digestibility of energy crops and agricultural by-products. Bioresource Technology Reports. 2019.
[33] Amon et al., Methane production through anaerobic digestion of various energy crops grown in sustainable crop rotations. Bioresource Technology. 2007.
[34] National Physical Laboratory, Methane from Anaerobic Digestion (MEAD) Study, April 2023.

In situations where feedstocks are at a moderate to high risk of generating methane emissions at the reception area, sites should consider the following:

- **Enclosed reception halls** – Fully enclosed buildings with negative air pressure to prevent gases from escaping.
- **Fast feedstock throughput** – Minimise the time that feedstock spends in reception; use automated conveyors or hoppers to move material quickly to preprocessing or storage.
- **Just-in-time delivery** – Schedule deliveries to match processing capacity; avoid stockpiling feedstocks, especially high-risk materials.
- **Temperature control** – Keep the area cool and avoid warm, humid conditions that promote anaerobic decomposition.
- **Leachate management** – Install sealed, sloped floors with drainage to collect leachate.
- **Separate storage for high-risk feedstocks** – Store higher risk feedstocks in sealed tanks or silos with gas-tight lids where necessary.

While more stable, lower risk feedstocks (e.g., crops and crop residues) may not require as stringent controls at the feedstock reception area, good feedstock management and sound operational practices are still necessary to ensure that methane emissions are not released.

With regards to pretreatment, certain feedstocks may require processing prior to digestion. Pretreatment aims to improve the digestibility, biogas yields, and handling efficiency of feedstocks, and may take the form of either mechanical, thermal, chemical or biological action. Mechanical pretreatment (including shredding, maceration, and high-pressure homogenization) generally results in low direct methane emissions, but decomposition can be accelerated if feedstocks are left exposed afterwards as organic waste stored in moist, poorly aerated conditions can develop anaerobic pockets which can result in methane generation.[35] Thermal pretreatments use heat to break down organic matter, potentially leading to the release of dissolved methane in feedstocks (e.g., sludges) if not properly contained.[36] Chemical pretreatment involves the use of acids or alkalis to hydrolyse feedstocks, potentially causing methane and VOC release if reactions occur in open systems, or if feedstocks are stored for too long afterwards.[37] Similarly, biological pretreatments are commonly employed to accelerate the hydrolysis stage of digestion, resulting in greater bioavailability of carbon for methane generation, which can start prematurely outside of the main AD reactors if the process is not suitably controlled, especially in warm, anaerobic conditions.[38]

Best practices to minimise methane emissions during feedstock pretreatment include:

- Sealed and enclosed pretreatment systems with gas capture and subsequent treatment

[35] Yasmin et al., Emission of greenhouse gases (GHGs) during composting and vermicomposting. Energy Nexus. 2022.
[36] Ruhl et al., Efficacy of thermal hydrolysis for boosting specific methane yield depending on temperature-normalized solids retention time in an activated sludge process. Environmental Science: Water Research & Technology. 2022.
[37] Ćwiertniewicz-Wojciechowska et al., Sewage sludge pretreatment: current status and future prospects. Environ Sci Pollut Res. 2023.
[38] Ferdes et al., Microorganisms and Enzymes Used in the Biological Pretreatment of the Substrate to Enhance Biogas Production: A Review. Sustainability. 2020.

- Steps to reduce methanogen activity in feedstocks until they enter the AD, e.g. cooling, acidification, aeration, stabilisation.
- Rapid transfer of feedstock to the digestion tanks after pretreatment.
- Emission detection tools like infrared cameras and flux chambers.

The feeding system used at the site may also impact on the release of methane emissions. For example, auger feeding and liquid feeding systems via hopper pumps have been reported by industry as potential sources of emissions. A robust auger system that can maintain a substrate plug in the infeed auger can, however, help to reduce methane loss – this essentially refers to a compacted mass of incoming feed material that sits inside the auger or feed tube and acts like a physical seal between the inside of the digester (where methane is produced) and the outside environment. Shorter augers are also preferable for improved seals, and longer augers should be emptied before restarts to avoid blockages and to prevent an interruption of flow. Some liquid feed systems are open to the environment, and so this should be considered and closed off where possible to prevent methane leaks and losses to the environment.

In general, however, anaerobic conditions are not as prevalent during feedstock reception, storage and pretreatment, compared to other key stages of the AD process.[39] Therefore, biological activity is not generally expected, and methane production does not usually occur at notable levels. This statement aligns with initial findings from the point-source emissions sampling carried out as part of the MEAD 2.0 study. In this study, feedstock reception areas were sampled using RMLD (Remote Methane Leak Detector) and AMLD (Advanced Mobile Leak Detection) devices and for all of the sites sampled, no methane emissions were detected in this area.[40]

Amongst stakeholders, the perception of risk of methane emissions generation during feedstock reception, storage and pretreatment was low. This was not typically an area of notable concern amongst site operators, based on both knowledge shared and experience. Provided that appropriate measures are put in place to mitigate methane emissions and that equipment is operated under NOC, fugitive methane at the feedstock management stage of the AD process *should* be minimal.[41]

Despite the low risk of methane emissions occurring during feedstock reception, storage and pretreatment, good feedstock management and sound operational practices are essential. An overview of good practice recommendations for the handling, storage and treatment of feedstocks is provided below.

[39] ADBA Practical Guide to AD (UK) notes: “Methane emissions from feedstock storage are negligible where storage times are short and aeration or mixing is provided.”
[40] Note that this statement applies only to the sites sampled, and widespread conclusions about a lack of methane emissions arising from feedstock reception areas should not be drawn based on this limited data. Furthermore, Bohr prioritised time and resources to ensure that survey efforts focussed on key emission areas. Since methane emissions do not commonly arise at feedstock reception areas, and the initial sampling indicated that no emissions were occurring at the sites surveyed, more detailed surveys were not conducted at this stage of the process.
[41] ADBA, Practical Guide to AD.

Good Practice Recommendations – Feedstock Management

- Consider the types of feedstocks that will be processed by the site; higher risk feedstock types may need more stringent controls in place for the management and mitigation of emissions.
- Ensure that sites are designed for the processing of selected feedstocks from the outset; methane emissions at this stage are more likely to occur outside of normal operating conditions.
- Ensure fast feedstock throughputs, minimising the time that feedstock spends in reception and storage areas. Consider the use of just-in-time deliveries and automated conveyors or hoppers for high-risk feedstock to move material quickly to preprocessing or contained storage, where appropriate.
- Consider enclosed reception halls with negative air pressures and gas capture.
- Avoid warm, humid conditions that promote anaerobic decomposition.
- Store high-risk feedstocks separately in sealed tanks or silos with gas-tight lids.
- Clean reception areas frequently to remove residues and prevent the buildup of organic material that could decompose anaerobically.
- Consider installing sealed, sloped floors with drainage to collect leachate.
- Install methane sensors in reception halls and ensure that feedstock reception areas are always included as part of methane emissions site monitoring plans, to determine whether methane loss is occurring in this area.
- Follow best available techniques (BAT) as set out in site permits and train operators to recognise the signs of decomposition (e.g., odours, heat, bubbling).

5. Emissions from Digestion & Biogas Storage

After the management and handling of feedstocks, the digestion process can begin. AD tanks, or digesters, lie at the heart of any AD process, as this is where organic feedstocks are digested to produce biogas. Site configurations may include the use of a single digester, or multiple digesters, as well as separate tanks or gas bags for the storage of gas. Key structural components of AD systems often include:

- **Tank base/foundations** – constructed using reinforced concrete and used to support the entire tank structure, as well as the contents of the tank. Must be watertight and chemically resistant.
- **Tank walls** – constructed using sectional steel, stainless steel, reinforced concrete, or composite materials. Used to contain the digesting material and withstand internal pressure. Often equipped with gaskets for sealing, insulation to maintain temperature, and corrosion resistant coatings such as epoxy or glass lined steel.
- **Tank roof/steel ring beam** – a rigid structure constructed using steel, concrete or composite materials, used for the tank's structural integrity. Enclosed tank roofs are used when gas collection is external or separate. Alternatively, steel ring beams act as open structural frames at the top of tanks, serving as attachment bases for integrated gas collection domes.
- **Gas collection dome** – flexible membrane dome either mounted separately above a rigid sealed roof or integrated as part of the tank's roof. As biogas builds up it flows into the dome either through open headspace (if the dome is part of the tank roof) or via pipes or vents (if the dome is external or separate).
- **Gas storage** – gas is stored either within integrated gas collection domes (as described above) or within separate external gas holders, such as double membrane domes (flexible, low-pressure) or rigid steel/concrete tanks (high pressure). External gas storage is generally able to store larger volumes of biogas and is therefore common in larger industrial or municipal facilities.
- **Digestion chamber** – the interior volume of the tank where the biological activity happens. It must be airtight to preserve anaerobic conditions, and it is typically equipped with mixers, heating systems and sensors.
- **Feedstock inlet/digestate outlet** – sealed pipes or ports used to feed material in and to remove digestate from the process.

Given that AD tanks are where biogas is produced, they are a possible source of fugitive methane emissions, along with gas storage containers. AD tanks must be airtight to preserve anaerobic conditions, therefore any methane losses at this stage are typically a result of 'other

than normal operating conditions' i.e., equipment damage, operational failures, or scheduled maintenance activities. Key leak points found during digestion and gas storage include:[42]

- Leaks in tank structures – cracks in walls, roofs or bases of tanks
- Unsealed or poorly sealed covers
- Flare system failures – if flares (used to burn excess biogas) fail or perform inadequately then methane may be vented directly to the atmosphere.
- Pipework and valve leaks – methane can leak from joints, flanges, valves and gaskets, with corrosion and improper installation increasing these risks.
- Site maintenance – during cleaning, repairs or emergencies, tanks may be vented and sometimes the roofs of digesters may be removed, releasing methane to the environment.

In some of these cases, fugitive methane emissions are a result of auxiliary equipment issues e.g., problems associated with pipework, flanges, gaskets, joints, valves and flares etc. Equipment of this nature is not used exclusively during digestion and gas storage, but rather, throughout the entire AD process. Therefore, emissions from auxiliary equipment are discussed in greater detail later in this report.

Site sampling found that tank roofs, however, are consistently found to be an area of methane emissions whether through joint leaks, membrane fixings, or tears in membranes themselves. Evidence based on experience of LDAR service providers indicated that leaks are typically more common in fixed/rigid roofs of digesters where roofs are constructed in sections i.e., emissions are more likely to escape from joints and seals between sections. Based on market analysis and consultation with installers, the most common roof types used in the UK are described below:

- **Flexible membrane covers** are the most common roof types, typically made from strong, durable, flexible materials like HDPE, PVC, and polyethylene. They are often dome-shaped, consisting of either single or double membranes. Single flexible membranes cover the digester and contain the biogas but typically do not offer significant storage capacity as they move with the gas volume. Double membranes are the most common flexible roof types; often tank mounted, consisting of an inner membrane that contains the biogas, and an outer membrane pressurised with air (often low-oxygen exhausts from an engine) by a blower. This pressurisation has a number of important functions including: keeping the outer membrane of the roof inflated, protecting the inner membrane, and regulating the gas pressure within the tank. Double membrane roofs provide integrated biogas storage, as the inner membranes can expand and contract to accommodate variations in gas production and demand. Key advantages include that they are cost-effective, offer integrated biogas storage, are flexible to accommodate gas volume changes, provide insulation, and are relatively easy to install. However, they can be susceptible to damage from wind, snow, or punctures if not properly designed and maintained.
- **Fixed/rigid covers** are solid roofs that are permanently attached to the digester tank. They are typically made from materials like concrete, steel (e.g., fusion-bonded epoxy

[42] Based on knowledge provided by key stakeholders, through decades of experience working in methane emissions testing.

coated stainless steel), and glass-reinforced plastic (GRP). As they are fixed and rigid, these roofs do not move with changes in tank pressure. Therefore, fixed/rigid covers typically require separate biogas holders (often a flexible membrane inside the tank or external gas bags), to ensure that optimal pressures are maintained during biogas production and offtake. Fixed/rigid roofs are common in older municipal wastewater treatment plants. Key advantages include that they are durable, robust, and good for structural integrity. They can be sealed effectively to prevent gas leaks and odour release. However, they do not offer integrated biogas storage, and can be more expensive to construct than some flexible options.

- **Floating covers** float directly on the surface of the digester's contents. They are typically made of metal (e.g., steel) and have a skirt that extends into the liquid to maintain a seal. Floating covers allow digester volumes to change depending on biogas production or consumption. They provide some degree of gas storage and prevent air from entering the digester. Key advantages include that they provide self-regulating gas pressure, and can adapt to changing digester liquid levels. However, they can be more complex to design and maintain, and require guide mechanisms to ensure proper movement.

Surveys carried out during the MEAD 2.0 study showed that 50% of the sites sampled demonstrated methane leakage to some extent directly from the AD tanks (not including PRVs). Table 4 summarises the key findings from this stage of the assessment.[43]

Table 4: Methane emissions arising from digestion tanks, as determined by point-source site sampling surveys.[44]

Site	Digester Type	Methane Emissions
1	Above ground – Rigid sectional concrete roof x1 Above ground – Double flexible membrane dome roof x2	The sectional concrete roof emitted methane from joints between the concrete segments. The maximum concentration of methane at this location was 324 ppm. A concentration of 246 ppm was also recorded at the perimeter of these concrete segments.
2	Above ground – Double flexible membrane dome roof x6	None from digesters directly.
3	Above ground – Rigid steel roof x4 Above ground – Double flexible membrane dome roof x1 Above ground – Double membrane gas bag x1	None from digesters directly.

[43] Details of each site outlined in Appendix C.
[44] Data collected from site sampling carried out as part of the MEAD 2.0 study.

4	Above ground – Double flexible membrane dome roof x2	None from digesters directly.
5	Above ground – Double flexible membrane pointed roof x5	Desulphurisation pump vent emitted methane with a maximum measured methane concentration of 10,984 ppm.
6	Above ground – Double flexible membrane dome roof x2	None from digesters directly.
7	Above ground – Rigid solid concrete roof x7 Above ground – Double membrane gas bag x1	Multiple overspill wells, integral to this type of digester, emitted methane with a peak methane concentration reading of 20,811 ppm.
8	Above ground – Double flexible membrane dome roof x2 Below ground – Double flexible membrane dome roof x2	A number of inspection pits were found to be emitting methane on a below ground digester. This was due to a leak in the concrete sidewall surrounding the viewing windows. The maximum measured methane concentration was 50,000 ppm.

The site sampling surveys carried out during the MEAD 2.0 study demonstrated that emissions from digesters are relatively common. This was also shown to be the case in literature, where a review of biogas sites across Austria, Germany, Sweden and Switzerland found that all digesters surveyed were subject to some form of leakage.[45] In the literature, an average of 5.1 leaks (median 2.0) were detected per plant (the average leakage rate was significantly higher than the median, due to one plant presenting with 30 leaks, of which 22 were related to deficient membrane fixings).

Table 5. Methane emissions from biogas production[45]

Leakage source	Frequency	Notes
Air-inflated double membrane domes	Leaks detected at 45% of 50 domes	The majority of leaks were found at membrane fixings (58% of 95 leaks), other leakage points were wires to adjust agitators (caused by insufficient lubrication), pipe leadthroughs (leaking gasket), pressure relief valves (leaking flange connection, open ball valve, missing water seal), fatigued inner membranes.
Concrete roof digesters	46% had at least one leak	The majority of leaks were due to cracks in the concrete (62% of 37 leakages). Others were due to leaking agitator gaskets and pipe

[45] Wechselberger *et al*., Methane losses from different biogas plant technologies 2023.

		leadthroughs (24%) and 2 were detected at pressure release valves.
Single membrane domes	Leaks found at 2 of the twelve digesters	Leaks at single membranes were similar to double membranes.

In the study described above, and the results shown in Table 5, membrane fixings were the largest source of overall leaks. But the emissions factors for these fixings were relatively low (<0.01-0.1% overall throughput[46]). Much higher levels of emissions were recorded for a crack in a concrete wall (a double membrane dome digester) (1.1% of gas throughput) and from a pressure relief valve (open ball valve) (1.0% of gas throughput).

For concrete roof digesters, the largest quantified leaks were found at a leaking lead through pipe (1.0% of gas throughput), at an agitator gasket (0.9% of gas throughput) and at a pressure relief valve (open ball valve) (0.7% of gas throughput).

MEAD 1.0 reported methane emission factors ranging from 0-12.9% from the digesters and gas storage, with emissions from digesters including leaks from the roof membranes and from pressure relief valves (Table 6).

Table 6. Methane emissions resulting from digesters at AD facilities sampled in the MEAD 1 project.[47]

Plant type	Feedstock	Feedstock (t/y)	Emission Factor % (% uncertainty)	Notes
Agricultural	Maize, rye and grass	30,000	0.9 (0.6)	-
Agricultural	Maize, rye, grass and sugar beet	30,000	0.5 (0.1)	-
Agricultural	Maize, rye and manure	30,000	3.8 (0.7)	-
Commercial	Food waste	48,500	0.0 (0.0)	-
Mixed	Food waste, crops and manure	40,000	12 (1.4)	This site had maintenance issues. Includes emissions from feeders although these are thought to be minor.

[46] Biogas throughput = the total quantity of biogas that passes through the AD system.
[47] National Physical Laboratory, Methane from Anaerobic Digestion (MEAD) Study, April 2023.

These examples of prior research and insight from MEAD 2.0 demonstrate that methane emissions can be a relatively common occurrence at digesters due to the very nature of biogas being generated at this stage. This was also highlighted during stakeholder engagement, with site operators, LDAR service providers, and experienced consultants operating in this space flagging that methane emissions can commonly occur at this stage of the process. When emissions do occur at this stage it is most often a result of sites operating at 'other than normal operating conditions'. Key examples include leaks from roofs through joints and fixings, cracks in concrete, and the possibility of faulty equipment (e.g., pressure relief valves and desulphurisation valves). Where equipment/infrastructure may not be operating effectively, this can be down to operational wear, or poor installation and management. The principal recommendation for emissions abatement in these cases would be for sites to implement an effective LDAR strategy in order to detect the generation of emissions at unexpected locations and to repair equipment/ infrastructure in a timely manner once detected.

In some cases, however, emissions at the digestion stage of the AD process may be due to 'normal operating conditions' but as a result of improper asset selection, installation or design flaws. Key examples here include emissions from valves (e.g., pressure relief valves and desulphurisation valves) where methane is released not strictly due to faulty equipment, but often because of poor quality or inappropriate asset selection. Emissions from overspill wells also fall into this category, where emissions generated due to a lack of covers on wells are an inherent consequence built into original site designs. Key recommendations here would be to identify where emissions are occurring despite normal operational conditions (e.g., through the use of LDAR) and consider the retrofitting of emissions points with methane capture technologies (e.g. covers) or the replacement of poor quality, ineffective equipment with assets that are better suited to the specific site in question.

An overview of good practice recommendations for the digestion and gas storage stage of the AD process is provided below.

Good Practice Recommendations – Digestion and gas storage

- Methane emissions at this stage of the AD process are typically a result of OTNOC, i.e., equipment damage, operational failures, or scheduled maintenance activities.
- Since emissions should not be expected, LDAR programmes should be put in place to regularly test all possible areas for leaks, including walls, roofs, bases, valves, flares and any areas where joints, seals, gaskets etc. are located.
- Ideally, any LDAR surveyor should have access to digester roofs meaning that surveys and general maintenance can be conducted more thoroughly. During site design, ensuring good roof access is a key consideration.
- Leaks are most common in areas with joints and seals, therefore site design and asset selection should minimise joints and seals where possible. This links closely to site design and installation considerations i.e., to factor in future site design/extensions where possible to avoid inefficient joints and seals as an example.

- Methane leaks are common around viewing windows in digesters due to the presence of seals. Installing inspection cameras instead of viewing windows would reduce risk of leaks here, to minimise break points and seals.
- Double flexible membrane roofs generally have fewer leaks than other digester roof types, where appropriately installed and maintained. Where site design, budget and site circumstances allow it, consider the use of these roof types.
- Test valves and flares for operational effectiveness. Where methane is released, either through asset design or through wear/faults, ensure that equipment is replaced or fixed.

6. Emissions from Biogas Utilisation

Following the production of biogas at the digestion stage, it can be used to generate electricity, heat, combined heat and power (CHP) or upgraded to biomethane for grid injection and/or use as a transport fuel.

Historically, the UK AD industry focussed on the generation of biogas for renewable heat and power, with roughly 85% of the existing UK AD market comprising CHP facilities. However, under the current policy framework, upgrading of biogas to biomethane for grid injection is favoured and supported, in order to promote a greener gas grid. As such, the bulk of this section will focus on emissions generated from the biogas upgrading pathway.

6.1. Biogas Upgrading Units (BUU)

Biogas upgrading units (BUUs) are another notable area of methane slip, with different levels of emissions arising depending on the upgrader type employed. This section will discuss biogas upgraders in detail, including how and why methane slip occurs. Other environmental impacts associated with these asset types are also discussed in Appendix H, to inform wider interests expressed by the Environment Agency.

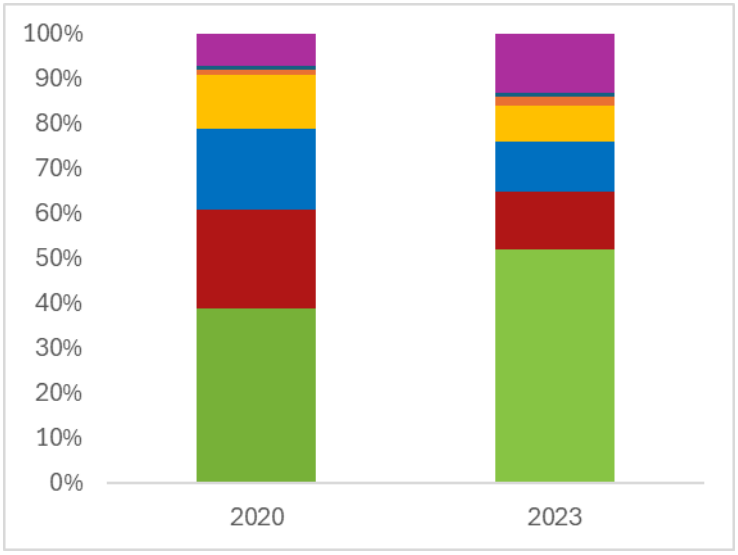
Biomethane emissions from biogas upgrading systems are referred to as methane slip when present in the off-gas vent stream as opposed to leakage. Methane slip occurs when a portion of biomethane escapes with the CO_2-rich gas stream during the upgrading process. The level of methane slip is dependent on the choice of technology and its operational parameters. The main commercial technologies for biogas-to-biomethane upgrading are:

- membrane separation,
- water scrubbing,
- chemical absorption with amine solvent, and
- pressure swing adsorption.

Physical absorption using organic solvents is also an available technology but is not widely used and cryo-separation, while suitable for biogas upgrading, is primarily used for CO_2 capture from the off-gas produced by the principal upgrading system. Biological upgrading is in the early stages of development, and there is no current evidence of the commercial deployment of this technology.

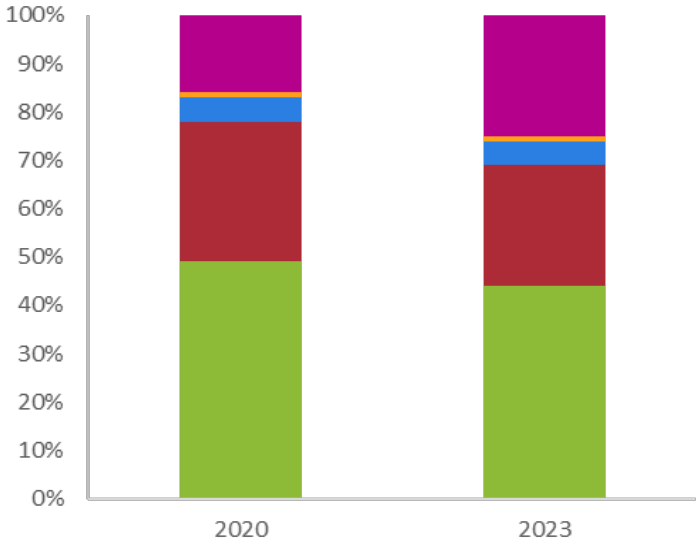
The European Biogas Association (EBA) published Europe-wide analysis of upgrader types deployed in respective regions. Figure 4 shows the different upgrader technology types and their prevalence across Europe. Membrane separation is the most widely deployed in Europe, and its share of the market has increased in recent years. It is also the most predominant technology used by AD sites in the UK. However, this is not necessarily the case for all countries across the EU. For example in 2023, Norway predominantly used chemical absorption as the principal

method for upgrading biogas, Sweden primarily used water scrubbing, and Austria's preference was for pressure swing adsorption.[48] The growth in membrane separation technology more generally across Europe has been driven mainly by an increase in on-farm and food waste sites due to the smaller, modular and relatively easy to use nature of the technology.



	2020	2023
Unknown	7	13
Cryogenic separation	1	1
Physical absorption	1	2
Pressure Swing Adsorption	12	8
Chemical Absorption	18	11
Water Scrubbing	22	13
Membrane Separation	39	52

Figure 4: The percentage distribution of upgrading technologies used by biomethane plants in Europe



	2020	2023
Unknown	16	25
Pressure Swing Adsorption	1	1
Chemical Absorption	5	5
Water Scrubbing	29	25
Membrane Separation	49	44

Figure 5: The percentage distribution of upgrading technologies used by biomethane plants in the UK.

The key biogas upgrading technologies and their different modes of action are discussed in more detail below.

Membrane Separation (MS) involves the use of synthetic polymer membranes, in the form of bundles of hollow fibres incorporated in stainless steel tubes (Figure 6), to separate biogas into biomethane and other gases. Typical polymer materials include polysulfone, polyimide or polydimethylsiloxane. The polymer membranes are permeable to CO_2, H_2O, and NH_3; less

[48] Adapted from the EBA Statistical Reports 2021 and 2024.

permeable to O_2 and H_2S; and largely impermeable to CH_4 and N_2. Due to these differences in permeability, as biogas is passed through the separator, CO_2, H_2O, and NH_3 move across the membrane in a flow termed 'permeate' while a methane rich gas, termed 'retentate' flows directly down the membrane fibres.[49]

Prior to membrane separation the raw biogas is passed through a scrubber to remove H_2O and H_2S. H_2S and other volatile organic compounds are removed from the scrubbed biogas using an activated charcoal filter and/or mixture of caustic soda, polyvinyl alcohol and water depending on the level of H_2S in the biogas stream.

The cleaned biogas is then compressed to 10-16 bar and sent to the membrane separation unit. Membrane separators are used in various configurations with multiple units giving the best separation efficiency, three phase separation through a polyimide membrane separation unit can achieve a ***methane recovery of 98%*** and ***methane slip below 1%***.[50]

Figure 6: Hollow fibres packed into stainless steel housing



Water scrubbing (WS) is based on the different solubilities of CO_2 in H_2O in comparison to CH_4. At 25°C, CO_2 has a water solubility that is 26-times greater than CH_4.[51] The solubility of a gas in a liquid is directly proportional to the partial pressure of the gas above the liquid, however gas solubility generally decreases as temperature increases. Therefore, the WS process operates optimally at low temperature and high pressures. While the water will absorb H_2S, high concentrations (up to 2500 ppm by volume)[49] can have detrimental effects on the scrubbing system. If the H_2S level is consistently high, then it is recommended that raw biogas is scrubbed to remove hydrogen sulphide.

The biogas is compressed to around 4-6.5 bar and then passed into a washing column which contains a packing material to increase gas-liquid mass transfer. The compressed biogas is introduced to the bottom of the column, meeting water injected from the top. CO_2 is absorbed by the water while methane flows out of the top of the column. The raw CH_4 gas is then passed through an activated carbon filter to remove non-methane VOCs and moisture. The CO_2 saturated water emitted from the scrubber contains roughly 5-6% of the methane content of the compressed biogas, which is recovered using a flash column, where a 2-4 bar pressure drop allows for methane recovery. The water is then passed through a desorption column at

[49] Gkotsis et al: Biogas Upgrading Technologies-Recent Advances in Membrane-based Processes. International Journal of Hydrogen Energy (2023) 48(10) 3965-3993.
[50] F.Ardolino G.F.Cardamone, F. Parrillo, U.Arena. (2021) Biogas-to-Biomethane Upgrading: A comparative review and assessment in a life cycle perspective. Renewable and Sustainable Energy Review. 139, 110588.
[51] Angelidaki, et al. Biogas upgrading and utilization: Current status and perspectives, Biotechnology Advances (2018) 36, 453-466.

atmospheric pressure with air used in counter-current flow, the regenerated water can be cycled back into the process. WS technology has a typical ***methane recovery of up to 98%*** and a ***methane slip in the range of <2%***.[51]

Chemical absorption (CA) is also a scrubbing technology, similar to water scrubbing, with the water being replaced with an organic solvent. Typically, an amine such as monoethanolamine, diethanolamine or diglycolamine is used. Amine solvents can absorb larger amounts of carbon dioxide (per unit volume) and therefore, smaller upgrading units can be used. Amine solutions can be designed to treat multiple contaminants in the gas stream and so H_2S scrubbing is not required upstream of the upgrader. However, off-gases will contain contaminants and therefore require scrubbing with activated carbon before the CO_2 rich stream is released to atmosphere.

Unlike water scrubbing, amine solvents do not require high pressures to achieve high efficiencies, typically operating at less than 1 bar.[52] Used amine solvents are recovered through a stripping column, which requires high temperatures above 120-150^oC, and then they are recirculated throughout the process[49]. CA technology is a highly effective biogas upgrading technology achieving ***methane recovery of >99%*** and ***methane slip below 0.1%.***[50]

Pressure swing adsorption (PSA) is based on the differential adsorption of gases into an adsorbent material based on molecular dimensions and their affinity to the adsorbent material. PSA relies on the ability of the adsorbent material to adsorb the target molecule under high pressures and subsequently release it under reduced pressure. Typically, zeolites or activated carbons are used, with cavities of ~0.37nm allowing the adsorption of carbon dioxide (0.34nm) while excluding methane (0.38nm). Consequently, carbon dioxide is adsorbed while methane is free to flow through the PSA unit. PSA follows four main stages: adsorption, depressurisation, regeneration and re-pressurisation.

Raw biogas is scrubbed to remove hydrogen sulphide (the presence of which can damage the adsorbent material), dried and then compressed to between 3-8 bar, before introduction to the PSA unit. The adsorbent will selectively retain CO_2, N_2, and O_2 while the methane is collected. In practice several columns are used to ensure continuous operation. The loaded adsorbent material is regenerated by a stepwise decrease in pressure to atmospheric pressure and flushing with biomethane to remove residual CO_2. The off-gas of the initial decompression stage will contain some methane and can be recycled to the raw biogas inlet. PSA technology achieves ***methane recovery of >96%*** with ***relatively high levels of methane slip, up to 4%***[49]

Physical absorption operates on the same principles as water and chemical scrubbing, but instead of water, an organic solvent is used for CO_2 and H_2S absorption. Commonly employed organic solvents are mixtures of methanol and dimethyl ethers of polyethylene glycol. An advantage of these solvents over water is their substantially higher CO_2 solubilities i.e., approximately three times more CO_2 absorption than water, resulting in reduced liquid input requirements and, consequently, smaller upgrading units.

[52] Personal communication: Ammongas uses a compression pressure of 200 mbar.

After scrubbing to remove hydrogen sulphide the raw biogas is compressed to 7-8 bar and cooled to approximately 20°C before being injected from the bottom of the absorption column with cold solvent introduced from the top of the column.

Post use, the organic solvents are regenerated using heat (~80°C) before being introduced to the desorption column where the pressure is reduced to 1 bar to remove the carbon dioxide. The removal of hydrogen sulphide from the solvent can require high temperatures due to its high solubility. Therefore, to avoid high energy requirements, it is recommended to remove H_2S before introducing biogas to the solvent. Physical absorption with organic solvents can achieve ***up to 96-98% methane recovery*** but has ***methane slip rates, in the region of 2-4%***.[49]

In these cases, the methane slip/loss is typically defined as the volume flow in the off-gas divided by the volume flow in the raw biogas and expressed as a percentage. The literature provides indicative figures for these values, but discrepancies can arise where the recovery and slip do not add up to 100%. The literature does not outline the nature of these discrepancies which could be linked to the nature of the technology, differences in configurations or operational inconsistencies.

Cryogenic upgrading is a relatively new technology and involves a gradual temperature reduction to target contaminants. Raw biogas is initially dried and then compressed to 80 bar prior to cooling. The temperature is reduced stepwise to initially remove H_2S and siloxanes, followed by further temperature reduction for the removal of CO_2. Temperatures can be further reduced to produce liquefied natural gas (LNG).

Different technology providers offer systems operating at different temperatures and pressures, depending on the required end use of the biomethane i.e. liquid methane or gaseous methane for grid injection. CO_2 can also be recovered in a liquid form as a saleable product. Cryogenic upgrading typically has a ***methane recovery rate of 97-98%*** and ***a methane slip of 2%***. However, high energy requirements and the technical complexity of the equipment required limit the use of this technology for biogas upgrading. [5151]

In practice, cryogenic technology is used in the UK as an add on to the primary upgrading system as a means of recovering CO_2 from the off-gas. The capturing of CO_2 increases the energy consumption at the site, in the region of 0.20-0.22 kWh/kg of liquid CO_2.[53] This method is generally only suitable for medium to large sites. As part of the stakeholder engagement aspect of the MEAD 2.0 study, discussions indicated that this technology would be limited to sites larger than 1000 m^3/hr of biogas generated,[54] with suppliers offering various size ranges for CO_2 liquefaction, ranging from 300-6000 kg/hr of liquefied CO_2.

The CO_2 stream from these upgrading technologies, except for water scrubbing due to high nitrogen content and low CO_2 concentration, is suitable for further processing and will be of sufficient quality to sell into the food and beverage sector. However, CO_2 derived from sites processing animal by-products (ABP) is not suitable for certain markets such as vegan, vegetarian or Halal products. Kerbside collected wastes also present hazard analysis and critical

[53] Information taken from HoSt website available at: CO_2 Recovery & Liquefaction | HoSt Group
[54] Personal communication with stakeholder site: This site currently captures CO_2 and conducted an economic assessment.

point (HACCP) challenges, as no control point is evident at source (resident or business). Similarly, CO_2 derived from wastewater treatment may find it difficult to exploit market outlets due to perception of the CO_2 origin. Several stakeholders consulted cited this as a reason for not capturing CO_2. The process had been considered but the lack of a ready market meant that the investment was not economically viable. These market issues are not specific to the separation process and are not isolated to specific technologies, as all CO_2 arising from the upgrading process would meet the required quality to be used in a range of different end markets.

The CO_2 can be captured from the off-gas, and be a saleable commodity, for the majority of upgrading technologies with the exception of water scrubbing which typically has a highly diluted CO_2 off-gas stream.

To summarise the technology types outlined in this section, Table 7 highlights key features of each, including methane loss, energy requirements and pre-treatment needs.

Table 7: Comparison of biogas upgrading technology. Adapted from Angelidaki et al[51], Lombardi and Francini[55], and Gkotsis et al[49]

	Membrane Separation	Water Scrubbing	Chemical absorption	PSA	Physical absorption
Electrical Consumption for raw biogas (kWh/Nm^3)	0.18-0.38	0.25-0.32	0.05-0.25	0.21-0.46	0.2-0.3
Heat consumption (kWh/Nm^3)	None	None	0.5-0.75	None	<0.2
Temperature required (°C)	NA	NA	100-180	NA	55-80
Cost	High	Medium	High	Medium	Medium
CH_4 losses (%)	0.5-1	1-3%	0.04-0.1	1-5	2-4
CH_4 recovery (%)	96-98	95-98	96-99	96-98	96-98
Pre-purification	Recommended	Recommended	Yes	Yes	Recommended
H_2S co-removal	Possible	Yes	Possible	Possible	Possible
N_2 and O_2 co-removal	Partial	No	No	Possible	No
Operation pressure (bar)	5-8	4-10	Atmospheric	3-10	4-8

During the MEAD 2.0 site sampling, seven upgraders were analysed for methane emissions. Of the seven sites four were membrane, two were pressurised water scrubbers and one was membrane with downstream cryogenic CO_2 separation. This spread of upgrader types is

[55] Lidia Lombardi, Giovanni Francini (2020) Techno-economic and environmental assessment of the main biogas upgrading technologies. Renewable energy. 156, 440-458

considered representative of those deployed in the UK (as per analysis carried out on the UK's AD market as part of this study) (Figure 5).

The results of the site sampling highlighted that there is considerable variation in the levels of methane loss to the atmosphere. Table 8 shows the average methane percentages measured in the off-gases of all the systems, as well as the high and low points recorded during the measurement phase. Furthermore, the surveyors were able to quantify methane emissions based on the flow rate. In the calculated flow rate, the bulk of the gas going to atmosphere will be CO_2.

Table 8. Average, high and low off-gas methane composition from test sites (total methane lost to atmosphere was calculated from the stated flow rate).

Site	Upgrader Type	Off-gas Methane Composition			Calculated Flowrate (NM^3/hr)	Average Methane Emission Quantification (NM^3/hr)
		Avg. %	High %	Low %		
1	Membrane	1.82	1.93	1.72	393.1	7.15
2	Membrane	0.97	1.37	0.00	368.8	3.58
3	Membrane*	9.05	12.04	0.00	452.0	40.91
4	Membrane	0.91	11.60	0.00	373.2	3.40
5	Pressurised water separator	0.32	3.18	0.26	530.0	1.70
6	Membrane	0.8	0.87	0.72	195.0	1.56
7	Pressurised water separator	0.13	0.18	0.00	245.0	0.32

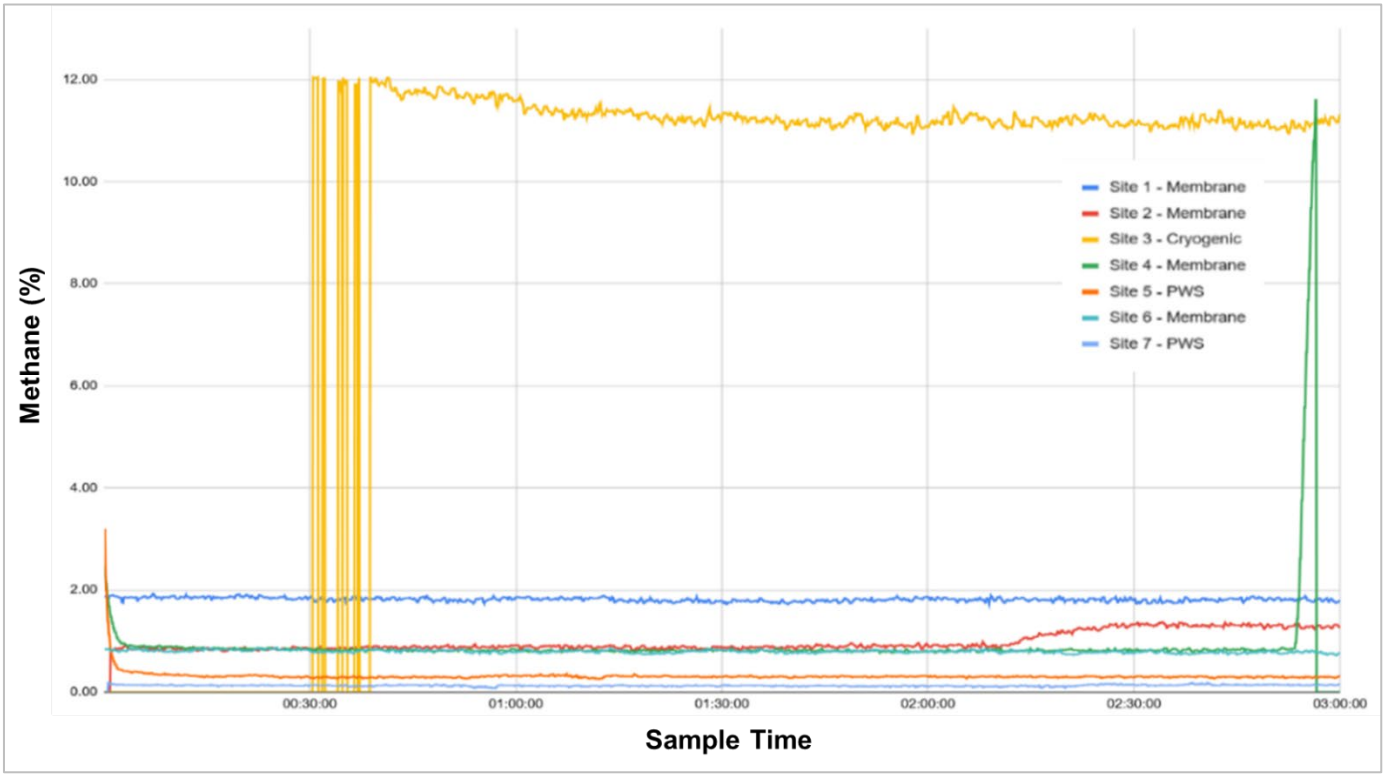
* *with off-gas sent to liquid CO_2 module for cryogenic separation.*

Site 1 had a consistent methane slip during the survey phase; however, an average of 1.82% is higher than quoted in the literature for membrane technology, indicating there may be some optimisation measures that could reduce methane losses.

Site 3 showed a high average methane slip, put down to post installation modifications of the upgrader which compromised the efficiency of the system. The loss of such high quantities of methane, the associated environmental impact and loss of revenue indicates that swift action is required to bring these emissions under control. It should be noted that the measurements were not taken immediately after the upgrader but after the CO_2 liquefaction stage, so it is not a direct analysis of upgrader losses.

Site 4 displayed a large disparity between the high and low points recorded. This can be seen in Figure 7, due to a spike towards the end of the testing period. Said spike is a normal part of operation when going through the start-up phase of the upgrader after a shutdown as was the case here.

Figure 7: Comparison of methane concentration (%) in off-gas stream exiting the upgraders at different biomethane facilities.



These testing events supply only a snapshot of the emissions from any given site; however, if a comprehensive testing regime is in place they can show key areas of concern. Loss of methane from upgraders can be kept to a minimum with good management, through using the right upgrader type for a particular site, and with good operator knowledge of the technology selected. By reducing methane slip from the upgrader, operators will reduce the site's environmental impact as well as reduce potential losses in revenue.

Literature research also provides further insight into methane slip from BUUs. In a study of methane emissions from 33 biogas sites across Austria, Germany, Sweden and Switzerland, researchers assessed emissions from a range of biogas upgrading units. Chemical (amine) absorption (four units) was shown to have the lowest emissions (emissions factor ≤0.1%), this emission level is similar to the methane slip of three units deploying additional exhaust gas treatment (EGT) after pressure swing adsorption or water scrubbing (EF≤0.2%). Without EGT two water scrubbers showed significantly higher methane slips of 2.0 and 3.9%.[56]

A separate study reported the methane emissions from seven sites in the UK. Due to the prevailing conditions and site layout, only 5 of the upgrading units were able to be measured (Table 9).[57] The emissions ranged from approximately 0.6% to 4.0%, with the main source of these emissions being the upgrade vent, which vents the carbon dioxide removed during upgrading. It was noted that in six of the seven facilities covered in the study, the upgrader off-

[56] Viktoria Wechselberger, Torsten Reinet, Johan Yngvesson, Deborah Scharfy, Charlotte Scheutz, Marion Huber-Humer, Marlies Hrad: Methane losses from different biogas plant technologies. Waste Management: (2023) 157, 110-120.
[57] National Physical Laboratory, Methane from Anaerobic Digestion (MEAD) Study, April 2023.

gas was vented directly to air without thermal treatment, the seventh facility captured carbon dioxide rather than venting this gas stream. The emissions factor in Table 9 is calculated as the emissions from the upgrader as a % of the total methane throughput of all potential end uses for the biogas i.e. BtG, CHP, heat and flare.

It was inferred that the unusually high emissions factors were as a result of inefficient separation; whether this was a technology and/or operator issue could not be determined.

Table 9. Methane emissions from biogas upgrading at five UK sites.[57]

Plant type	Feedstock	Feedstock (t/y)	GtG technology	Emission Factor % (standard uncertainty)	Notes
Agricultural	Maize, rye, grass and sugar beet	30,000	Membrane	2.5 (0.3)	This is an unusually high emission factor for membrane separation
Agricultural	Maize, rye and manure	30,000	Membrane	4.0 (0.3)	This is an unusually high emission factor for membrane separation
Agricultural	Maize, rye	22,000	Membrane	0.7 (0.1)	None.
Commercial	Food waste	48,500	Water-wash	1.7 (0.4)	None.
Mixed	Food waste, crops and manure	40,000	Membrane	0.6 (0.1)	None.

There is a critical need to ensure that the upgrading technology selected for use is suitable for the specific site in question. For example, the literature demonstrated that the emissions from an undersized water scrubber accounted for 75% of all methane losses identified across the site.[58]

Given that methane slip is inevitable due to the nature of the technology, the most effective way of minimizing the effects of methane slip is with off-gas treatment. The use of CO_2 capture units to capture any gases which would typically be emitted to the atmosphere following biogas upgrading was flagged as a beneficial technology by a number of stakeholders. During the upgrading stage, biomethane is separated from CO_2, but residual volumes of methane typically remain in the CO_2 off-gas, which is then vented to the atmosphere. During CO_2 capture however, this gaseous CO_2 stream is purified in order for it to be used in downstream applications, and any residual methane removed is fed back into the AD system meaning that it is not then lost to the atmosphere. One site operator stated that prior to installing the CO_2 capture equipment,

[58] Anders M. Fredunsland, Jorgen Hinge, Magnus A. Holmgren, Soren G. Rasmussen Charlotte Scheutz. (2018): On-site and ground-based remote sensing measurements of methane emissions from four biogas plants: A comparison study. Bioresource Technology 270, 88-95

roughly 0.6% of methane was lost from the membrane upgrader unit. This was subsequently captured following the installation of CO_2 capture equipment.

The choice of upgrading technology at a site can rest on several factors including cost, familiarity and perceived operational ease, intended location, plant size and the nature of the biogas being processed. In these technologies the highest energy users in the upgrading process are compressors and technologies which use higher pressures will have higher energy requirements in that area. Amine scrubbing has low pressure inputs for the biogas and therefore low electrical load; however, the regeneration of the amine solution requires heat which can use up to 0.75 kWh/m^3 in a worst case scenario.**Error! Bookmark not defined.** Much of this heat can be recycled but still needs to be generated and can come from a boiler consuming fossil fuels; however, the use of biogas boilers or offtake from a CHP can reduce this issue, as evident on a number of sites. There is no current evidence for the use of heat pumps to assist the amine regeneration process. However modelling studies have examined the use of heat pumps with amine-based CO_2 capture processes and suggest this may be a possibility in the future.[59]

Although upgrading systems can be modular, retrofitting additional units and the addition of CO_2 liquefaction will increase the OPEX of the site. If expansion is envisaged, then factoring in increased biomethane output at the design stage could reduce future OPEX of the system and overall energy consumption. The physical nature of the technology could be a factor in choice of upgrader. Typically, amine and water scrubbing systems will use columns which are over 10m tall. This may cause problems at the planning stage due to height restrictions in the planning consent.

Technology providers of upgrader systems are constantly looking to improve the efficiencies of their systems, with Table 10 showing current estimates of power consumption per technology and projected methane losses for each. Power consumption does not appear to be a major driver in technology choice, given that membrane separation is the most prevalent technology in the UK, and yet, has the highest energy consumption per m^3 of biogas processed.

Table 10: Typical manufacturer quotes for energy consumption (2025) (figures taken from promotional literature).

Technology	Energy usage kWh/m^3 Biogas	Projected CH_4 loss	Supplier
Membrane	0.28	<0.5%	DMT
PSA	0.22	<1.0%	Sysadvance
Amine	0.1	<0.05%	Ammongas
Water Scrubbing	0.22-0.23	<1.0%	Malmberg

[59] Electrification of amine-based CO_2 capture utilizing heat pumps

Site type can determine the choice of upgrader; the best choice for landfill gas will be a technology which can cope with additional contaminants which are more prevalent in landfill gas than in conventional AD, such as oxygen and nitrogen. However, through stakeholder engagement, it was apparent that cost, footprint, and familiarity with the technology were the main drivers for the rise in membrane upgrader technologies across the UK. Table 11 shows the capital and operating costs for various technologies. It should be noted that there are economies of scale associated with the investment costs as the large installation reduces cost per Nm^3 of biomethane produced. The operational costs provide a rough guide and will vary depending on several factors including size, energy source and the efficiency of the individual operation.

Table 11: Investment costs of the different upgrader types with representative operational costs. Adapted from Rodero et al.[60]

Plant size	Water scrubbing	Organic solvent scrubbing	Amine scrubbing	PSA	Membrane
Approximate investment costs (€/Nm^3/h)					
<250 Nm^3/h	4000-5000	4000-5000	4500-5000	4500-5400	4700-6000
Up to 500 Nm3/h	2500-4000	3000-4000	3000-4500	2500-4500	2700-4700
1000-5000 Nm3/h	1000-2500	1000-3000	2000-3000	1750-2500	1300-2700
Approximate operational costs (€/Nm^3/h)					
€/Nm^3/h	0.13	Not available	0.4	0.18	0.2

Based on the findings from the literature and sampling, good practice recommendations specific to biogas upgrading units are presented below.

Good Practice Recommendations – Biogas Upgrading Units

- Off-gas treatment is important to minimise methane emissions; this could be via off-gas combustion or further treatment of the CO_2 stream for CCUS. Liquefaction of CO_2 can reduce methane slip associated with the upgrading process. The use of this technology needs to be balanced with the extra energy usage for the site. The use of off-gas combustion (e.g., RTO) can remove any residual methane being lost to the atmosphere, but its use is not widespread at present due to high costs and energy use. However, as discussed above, where methane slip lower than the standard values are required for GHG compliance on GGSS and other schemes, this should be prioritised

[60] Rodero et al (2024) Membrane materials for biogas purification and upgrading: Fundamentals recent advances and challenges. Journal of Environmental Chemical Engineering 12, 114106

- For filter systems using activated carbon, the best quality carbon available and specific for particular contaminants should be used; do not use generic materials, as efficacy will be compromised.
- Optimise the process, working closely with the upgrader manufacturer and installer to ensure that the operation is set up and maintained in an efficient manner.
- In the event of feedstock changes, consult with the technology provider to ensure the upgrader will work efficiently and that there is nothing in the new feedstock which can damage or reduce upgrader efficiency if not adequately treated.
- Some sites have installed methane and H_2S monitoring linked to automated shut-down. Quick detection and action prevent the build-up of hazardous atmosphere and alerts operators to the presence of a leak. These measures are generally more effective in containerised systems such as membrane upgraders. However, larger companies are viewing methane loss and greenhouse gas emissions as an increasingly important aspect of the operation and are looking into sensor networks across the site to reduce emission events and reduce the environmental impact of the site as a whole.
- Forward planning can reduce energy requirements for future expansion. If the intention is for a site to expand in the future, then designing the specifications of the upgrader to account for future expansion could reduce the need for additional compressors and pumps associated with add on equipment which would present additional leak sources.
- Education of operators is invaluable. Stakeholder engagement has demonstrated that the more the operators and site staff know about the equipment and its operation the more engaged they are with the process. Expertise at this level means that potential problems can be diagnosed early and remedied thus preventing more serious problems.

6.2. CHP Engines

Methane slip is a common phenomenon when unburned methane escapes through exhausts due to incomplete combustion. This is particularly problematic in spark-ignition CHP engines, which are common at AD facilities, and it is estimated that between 1–3% of gas can escape combustion and be emitted as methane in these engine types.[61]

In order to reduce methane emissions from CHP engines, engine tuning and maintenance should be a priority to improve combustion efficiency and methane monitoring should be employed, with CHP a notable area of focus. Furthermore, in order to enhance engine performance, H_2S and siloxanes should be removed from biogas as part of gas quality controls. As a result of better performing engines, methane slip should be reduced. Oxidation catalysts

[61] de Zwart et al., Methane emissions from gas engines driving combined heat and power installations. 2012.

are devices installed in the exhaust systems of CHP engines. They facilitate the chemical conversion of methane and other volatile organic compounds into carbon dioxide and water through a process of catalytic oxidation, meaning that methane release is minimised. Operators should ensure that these catalysts are working effectively.

Regenerative Thermal Oxidation (RTO) is a technology that can remove both methane, and non-methane VOCs from the off-gas of CHP engines (i.e., a means of reducing methane slip). Note that this technology can also be applied at BUUs to address methane slip during the upgrading stage. It works by preheating contaminated air which then flows into a combustion chamber at a temperature between 750-850°C. This converts the contaminants to CO_2 and water vapour. While the system uses high temperatures, a series of ceramic heat exchangers can recover the heat making it 95% energy efficient.[62] However, this technology is relatively new to the AD market and is not widely used amongst stakeholders. One stakeholder indicated that it is currently being tested on their site, at a capital cost of roughly £250,000[63].

RTOs involve substantial capital expenditure, with reported total installation costs ranging from approximately £80,000 to over £1.5 million depending on capacity and configuration,[64] alongside significant operating costs dominated by fuel and electricity requirements to maintain high oxidation temperatures (typically between 800–1000 °C).[65] As such, its implementation at AD facilities may not be economically viable. However, stakeholder engagement as part of the MEAD 2.0 study did identify sites in the UK that are using or are considering the use of RTO to reduce emissions on their sites. Those with RTO employed included newer sites accredited under the GGSS, where emissions monitoring and management is encouraged. Where sites considered RTO without implementation, cost and energy usage were quoted as the main drawbacks of this technology. The GGSS GHG calculation requires that a default value of 3% methane slip is used where off-gas combustion is not used or actual values are not recorded[66]. This may, in some cases, be enough for sites to employ the technology if that value threatens the incentive revenue. The expectation however is that technologies, such as RTO, will be most economical at scale, i.e., large sites with high biogas volumes or significant methane slip may find the capital costs of these technologies within scope.

[62] Suez technical literature, available at: SUEZ Air & Climate in Spain | Thermal oxidation
[63] This site was RHI accredited and considered typical of such, with capacity to flow 650 – 750m^3 per hour to grid.
[64] Regenerative Thermal Oxidisers. 2024. URL: https://regenerative-thermal-oxidizers.com/what-are-the-costs-associated-with-rto-voc-control
[65] Regenerative Thermal Oxidizer VS Thermal Oxidizer: The Choice in Industrial Waste Gas Treatment. URL: https://regenerativethermaloxidiser.com/regenerative-thermal-oxidizer-vs-thermal-oxidizer-the-choice-in-industrial-waste-gas-treatment/
[66] DESNZ, Guidance for calculating fugitive methane emissions as part of the greenhouse gas criteria on the Green Gas Support Scheme, 2025

7. Emissions from Auxiliary Equipment

This section on emissions from auxiliary equipment discusses the role that assets such as joints, seals, gaskets, flares, valves, pipework etc. can have on subsequent methane emissions. These assets are often used across the entire AD process, rather than in one particular area, hence why they are discussed independently here. Key asset types relating to this category of equipment are discussed below.

7.1. Pipework, Seals & Joints

Pipework is used throughout a facility, to transport feedstock, biogas, biomethane, digestate, and other fluids associated with the AD process. Pipework is essential for maintaining a safe, efficient and hygienic environment at an AD site, and key types are highlighted in Table 12.

Table 12: Type of pipework used on AD sites.

Pipework	Materials Used	Purpose	Features
Feedstock pipework	Stainless steel, HDPE, PVC.	Transfer of feedstocks into the digester.	Often includes macerators or grinders to prevent clogging.
Biogas pipework	Carbon steel (coated), stainless steel, or specialised plastic (e.g. PE100).	Carries raw biogas from the digester to storage, treatment, or CHP units.	Must be gas-tight and corrosion-resistant. Includes pressure relief valves, flame arrestors, and condensate traps.
Digestate pipework	HDPE, PVC, or stainless steel.	Moves digestate from the digester to storage tanks or separation units.	Designed to handle abrasive and fibrous material.
Condensate drainage	Stainless steel or corrosion-resistant plastic.	Removes water vapour that condenses in biogas lines.	Includes traps and automatic drainage systems.
Air/ventilation pipework	Galvanised steel or plastic.	Supplies air to biofilters or venting systems.	Used in odour control and safety systems.

Typically, when methane emissions occur from pipework it is a result of poor sealing or mechanical failure at joints, valves, and other fittings. In other words, methane emissions arising from pipework are always a result of ‘other than normal operating conditions’ (OTNOC).

In the case of improper installation or assembly, misaligned flanges, over/under-tightened bolts, or the use of incorrect gasket materials, gaps or stress points can occur in pipework allowing gases to escape. Using materials that are not resistant to biogas components (e.g. H_2S, moisture) can further lead to corrosion or cracking, potentially leading to structural failure or pinhole leaks. Therefore, corrosion resistant materials should be prioritised, including carbon coated steel, stainless steel, or specialised polymer materials. Furthermore, without regular maintenance and monitoring, leaks arising due to poor installation can go unnoticed and

eventually worsen. Therefore, routine inspections are essential to identify leaks where they would not otherwise be expected.

As well as poor installation, faulty or degraded assets can also be a key cause of methane emissions from pipework. For example, over time, seals can degrade due to chemical exposure (e.g. H_2S), temperature fluctuations, pressure or mechanical stress. Temperature changes and mechanical vibrations (e.g. from pumps or CHP engines) can result in the loosening of fittings or materials fatigue. Furthermore, pressure surges or overpressure events can cause sudden changes in gas flow, potentially forcing gas through weak points, causing equipment malfunctions or triggering the use of pressure relief valves.

Best practices to prevent leaks from pipework include the use of welded joints where possible instead of flanges. Ensure the installation of gas-tight seals and corrosion-resistant materials. Inspection regimes must be rigorous. Conducting HAZOP analysis and keeping critical spare parts on site are key for effective planned maintenance and rapid repair in the event of failure. Implementation of LDAR programmes and monitoring with infrared cameras or methane sensors can also effectively and promptly pick up on leaks and losses from these elements.

7.2. Pressure Relief Valves (PRVs)

Pressure relief valves (PRVs) are another key auxiliary asset featured across different areas of an AD site. The primary function of a PRV is to protect equipment from overpressure (e.g., if gas production exceeds AD tank capacity or CHP capacity, or if a blockage occurs within the system). They also act to prevent vacuum collapse (often PRVs are combined pressure vacuum valves, PVVs) when gas is drawn out too quickly or during rapid temperature changes. For AD, the valve is often bi-directional, meaning that it opens inward under vacuum to allow air in, and outward under overpressure to let gas escape. PRVs are a critical safety measure on AD sites as they act as the last line of defence if control systems fail.

PRVs remain closed by a spring or weight, or liquid, until internal pressure exceeds a set point. When pressure rises above that point, the valve opens, releasing gas until pressure drops back to safe levels. The valve closes automatically when normal pressure is restored. However, when a PRV does not work effectively, it can result in the generation of emissions, as has been described widely in published literature. For example, a study of emissions from Danish biogas production by Fredenslund identified PRVs to be a common source of emissions; leakage was observed at 53% of the 69 plants assessed.[67] Table 13 outlines that PRVs along with gas storage components are key areas of methane leaks at an AD site.

[67] Anders M. Fredunsland, Jorgen Hinge, Magnus A. Holmgren, Soren G. Rasmussen Charlotte Scheutz. (2018): On-site and ground-based remote sensing measurements of methane emissions from four biogas plants: A comparison study. Bioresource Technology 270, 88-95

Table 13: Number and frequency of observed leaks/point sources across Danish biogas plants in Anders et. al (2018) grouped according to location. [68]

Location of observed leak/point source of emission	Times observed	Frequency of observation among plants[69]
Pressure relief valve	89	53%
Reactors – other leaks[70]	100	59%
Feedstock storage tanks[71]	129	67%
Gas storage units	7	12%
Other gas bearing components[72]	137	65%

PRVs have varied design mechanisms to relieve over pressurisation and reseat under normal pressure conditions. The key types are outlined below:

Mechanical PRVs – The valve contains a loaded spring which is "set" to hold a seat closed against the valve orifice until the pressure overcomes the set pressure threshold and relieves the biogas past the open seat. When pressure normalises then the valve spring closes the seat to retain the biogas in the digester. Key advantages include that they are relatively simple and affordable to produce, set and maintain. However, moving parts can be prone to wear or corrosion.

Liquid Level PRVs – Involves the use of a liquid (often water) column to maintain a seal under normal pressure. As the pressure builds up above the set threshold, the gas pushes through the liquid seal by displacement, resulting in venting of the liquid vapour. Key advantages include that they typically result in fewer methane emissions as liquid will be displaced instead during overpressure. However, this liquid level must be topped up and is often manually done, leading to the potential for human failure if PRVs are not routinely checked and topped up (especially during warmer months). Heat tracing is required on the PRVs if located outdoors to prevent freezing over the winter months.

PRVs were investigated as part of the MEAD 2.0 study. Typically, the PRVs found to release emissions were those consisting of a mechanical mechanism such as springs and weights. It was noted that the liquid barrier type (non-mechanical) was less likely to be a source of methane associated emissions.

[68] Times observed is the total number the type of leak was observed (several leaks were sometimes observed a single location (e.g. reactor).
[69] Frequency of observation is the fraction of the biogas plants, where the type of leak or point source was observed.
[70] Including all leaks observed at reactors apart from pressure relief valves, like inspection hatches, pipe connections, leaks in connection to wiring, leaks at soft covers and leaks near mixer axles.
[71] Including digestate storage (with and without gas collection), mixer tanks and storage tanks for substrate.
[72] Including leaks from gas engines, biogas upgrade units, compressors, gas pipes, filters, pipe connections, and more, but not engine exhaust or CO_2 exhaust from biogas upgrade units.

Table 14: Methane Emissions at PRVs[73]

Site	PRV Location	Type of PRV	Methane Emissions
1	Digester roof	Liquid	None directly from the PRV outlet. Emissions found at the flanged joint on 2 separate PRVs as they connected to the digester. Maximum methane concentrations of 629 ppm and 828 ppm respectively found.
2	Digester roof	Mechanical	Emission found on exhaust of digester main PRV. Maximum methane concentration of 2995 ppm found.
3	Unspecified	Liquid	N/A No PRV emissions found.
4	Upgrader PRV Vent	Mechanical	Emission found on outlet of a PRV vent stack from the BUU. Maximum methane concentration of 87383 ppm was found.
5	Unspecified	Liquid	N/A No PRV emissions found.
6	Unspecified	Liquid	N/A No PRV emissions found.
7	Multiple digester roofs	Mechanical	Emissions found on multiple digester PRVs. Maximum methane concentration as follows: 42920 ppm, 26988 ppm, 3665 ppm, 1200 ppm.
8	Digester 3	Liquid	Emission found on outlet of PRV. Maximum methane concentration of 1133 ppm was found.

Mechanical PRVs tended to leak more due to the possibility of wear of springs, linkages and sealing faces within the mechanical valve mechanism. Furthermore, biogas can have corrosive properties that can damage these components leading to the unwanted release of biogas and therefore methane. PRVs using a liquid level that do not rely on mechanical components for the pressure release setpoint of the valve are at less risk of wear in this area. However, discussions with stakeholders highlighted that unless properly maintained, liquid PRVs can still result in notable methane emissions, as the liquid level itself can leak leading to a loss of functional seal to keep methane contained.

A key recommendation in this regard is to prioritise the use of quality PRVs. While the use of cheaper valves may be appealing to many sites, this may come at the expense of quality (but is not always the case). Better quality equipment generally provides long term benefits.

[73] Evidence collected from MEAD 2.0 site sampling.

When using any PRV they must be designed, set and installed to the operational pressure of the process. For example, if set too high, the vessel, membrane roof, or pipework may be exposed to pressures beyond their design limits before the valve eventually opens, increasing the risk of structural damage or rupture, membrane tearing (e.g., for flexible gas holders), gas leaks or even catastrophic failures. Conversely, if the operational pressure of the valve is set too low, it may open during normal operation, causing frequent venting of biogas and the potential release of methane to atmosphere. PRVs must also be inspected and calibrated regularly by a qualified person.

Also relating to PRV function is the performance of an effective gas management system to ensure that venting does not occur unnecessarily. For example, where multiple tanks have variable gas levels with uneven pressure across the entire AD system, venting could occur from one tank due to high pressure, whilst other connected tanks are not at capacity. In this case, a PRV opening would be the result of an inefficient gas management system across all gas production and storage capacity. These systems should therefore be maintained effectively to ensure proper function.

7.3. Flares

Flares are designed to safely combust excess biogas or biomethane, methane and other volatile organic compounds (VOCs) into carbon dioxide and water vapour. This is preferable to venting raw methane, which is a potent greenhouse gas. However, flares can be a potential source of methane emissions due to incomplete combustion, overpressure events, flare pilot failure, low biogas pressure and emergency venting.

Table 15: Reason for methane emissions detected at flares.

Cause of Emissions	Reason
Incomplete combustion	Poor air-to-gas ratio, low flare temperature, or faulty ignition. Indicated by visible smoke or yellow/orange flame instead of a clean blue flame.
Overpressure events	Surges in biogas production (e.g. during feedstock changes or foaming).
Flare pilot failure	Pilot flame or ignition system fails, especially in cold or wet weather.
Poor maintenance	Blocked nozzles, corroded components, or sensor failures.
Low biogas pressure	Insufficient pressure to sustain flare operation.
Emergency venting	Safety systems trigger venting to flare during abnormal conditions.

During the MEAD 2.0 project, no emissions were detected at the flares. While this can be an area where emissions occur, it is not routinely noted as an area of key concern with leaks

generally only occurring with equipment failure, maintenance or in an emergency (rather than for a prolonged period of time).

In order to minimise or stop emissions at flares on AD sites, the focus should be on ensuring complete combustion, system reliability, and preventing unnecessary flaring. To ensure complete combustion a proper air to gas ratio should be maintained using automatic controls. The flare temperature should also be monitored and it should be ensured that it is above the required level (above 850°C for methane). Pilot flames or spark igniters should also be routinely checked for full functionality and to ensure they remain weather-resistant.

Regular maintenance of these assets is essential to ensure that they are working effectively. Including:

- Clean flare tips and nozzles – preventing blockages from soot or condensate.
- Inspect for corrosion or wear - replace damaged parts promptly.
- Test sensors and control systems - ensure accurate pressure and flow readings.

Furthermore, reducing the need for flaring through improved biogas storage capacity and through the efficient use of biogas (ensuring that CHP units, boilers, and upgrading systems are prioritised over flaring) is important. This largely comes down to improved operational practices, as well as installation considerations where flare use could be prevented through better site design.

7.4. Odour Control Units (OCU)

Some sites will have odour control units, such as activated carbon filters and biofiltration systems, to mitigate against odours. These units are more commonly found adjacent to the reception hall to minimise odour release from the pre-digestion stages of the process (i.e., treat the air from the reception area), in addition to other parts of the AD site like exhaust, buildings containing thickening or dewatering units for instance.

A study performed by Fredenslund *et al*., (2018) at four Danish biogas plants demonstrated the potential for methane emissions from odour control operations. The four plants all used manure as part of their feedstock mix. At one site the methane emissions resulting from building ventilation, through a biofilter for odour control, represented 26% of all onsite measured emissions (the largest being the CHP gas engine). The extent of the emissions was calculated based on the methane concentration at the inlet to the biofilter, and multiplying the concentration with the air flow determined from the specifications of the blower leading air to the biofilter.[74] The main sources of this methane flow were from two pipes located in the feedstock reception building (inlets from manure transport), while two other sources were ventilation from the gas building and the compressor building, accounting for 6.9% and 7.0%, respectively, of the combined emissions identified by on-site measurements. At another plant an IR camera leakage

[74] The choice to measure methane flow at the inlet to the biofilter as opposed to the outlet was done by the measurement team for practical reasons. The biofilter may potentially have some CH_4 oxidation capability. However, due to low retention of the gas in biofilters for odour reduction, CH_4 oxidation is expected to be minor, and thus the choice of measuring before the filter inlet is not expected to have led to any significant overestimation of this emission source.

search found 19 sources of methane emissions, four of which were ventilation air from a biomass receiving tank, a mixing tank, a heating unit and a biogas upgrade unit leading to a biofilter set up for odour control. On-site measurements showed that methane in the ventilation air leading to the biofilter accounted for 84% of the total sum of quantified on-site sources. Individual measurements for these four emission sources demonstrated that ~94% of the methane entering the biofilter was from the receiving and the mixing tanks.

During the stakeholder engagement aspect of the MEAD 2.0, the awareness of methane emissions from OCUs was low. This included site operators and OCU technology providers themselves.

In terms of the site sampling carried out during the project, only a small number of OCUs were sampled. This was due to the lack of adequate sampling points at the inlet and the outlet to make a confident assessment of the methane slip via the process. There were only three sites where a sample could be taken within the OCU stream. The data, containing the %vol of CH_4 & CO_2 along with the ambient temperature was recorded over a 30-minute timeframe for each site in the outlet. The results showed zero CH_4 for two of the sites and a peak of 0.02% CH_4 on the remaining one site. Thus, backing up the general view from stakeholders that methane emissions from this area are not a critical point of concern. However, more research across a broader sample of AD sites with suitable access to OCUs would need to be considered in order to make conclusions here.

8. Emissions from Installation & Maintenance

With regards to the installation of assets, a number of key measures should be considered from the early design and planning stages through to installation and commissioning, to ensure that fugitive methane emissions are minimised upon operation. Each of these aspects is discussed in more detail below.

8.1. Design & Planning

During the early design and planning stages, siting of equipment should be carefully considered to allow for easy access, maintenance and leak detection monitoring during operation. Access routes and clearances should be designed around all key assets, to allow for effective inspection, repair and emergency response measures. The use of compact system designs can help to minimise the length of piping, potentially leading to fewer joints and thus fewer leak points.

Site layout is highly bespoke, driven by site needs, space, location, access etc., but all designs should consider effective operation and maintenance.

The significance of site layout from a methane emissions perspective is about the complexity of pipework, length of runs and connectivity. Asset proximity and ease of connection should be considered at the outset, to minimise the need for additional boosting pumps, joints and valves where possible. These additions are often necessary where sites are expanded or additional equipment is integrated at a later stage, so early consideration of future ambitions and possibilities is advantageous.

A theoretical example of this is a small biogas site that has gained the investment and meets the legal requirements to produce liquefied carbon dioxide from the off-gas of an existing membrane BUU. To allow for the liquefaction plant, the only available space is utilised however, this is on the other side of the site. This would mean that lengthy pipelines must be installed to transfer the off-gas from the BUU to the liquefaction plant. The length of pipework requires an additional booster pump to enable delivery of the off-gas. Additionally, PRVs and valves are required to manage pressure and flow.

If the future ambitions and possibilities could have been considered at the time the plant was designed and installed, the need for lengthy pipework and additional plant could potentially have been avoided and the probability of fugitive methane emissions may have been reduced. However, it should be noted that optimisation is not always possible from the outset, noting that the political, regulatory and investment landscapes change over time.

During the site surveys, access to some key plant items such as digester roofs was challenging, thus highlighting how difficult digester roofs that did not have good access gantries and steps/ladders would be to maintain. Without being able to properly access these areas, it would

be difficult to identify leaks and even more difficult to repair them. One site had underground digesters with a roof at ground level that made the LDAR inspection a safer and simpler process, providing access to the most common leak points such as roof perimeter, connecting valves and pipework entry and exit points.

With regards to equipment selection, high-quality, gas tight materials should be prioritised to minimise methane losses. Key additional elements where methane leaks are common, as identified during the site surveys and also being frequently cited as emissions sources in literature, include:

- **Valves:** ISO-rated valves designed for gas service should be used, to ensure they are fit for purpose and effective during use.
- **Fittings:** fully welded joints should be favoured over flanged or threaded ones, and leak-proof seals and gaskets that are resistant to methane should be selected.
- **Corrosion-resistant materials:** stainless steel or HDPE materials should be considered for pipework, to reduce long-term leak potential due to corrosion or cracking.

Furthermore, the equipment located inside of digesters should be prioritized for low maintenance in order to ensure that tank opening is minimised as much as possible. For example, preferred mixing systems include those that can be serviced externally or removed without tank entry, such as retractable submersible mixers, or shaft mixers through fermenter walls. Additionally aim for mixers with a 5-to-10-year lifetime (e.g., horizontal or vertical paddle mixers ideally).

Upon installation, it is important that suitable, trained professionals are employed to install the relevant assets. All joints and fittings must be properly welded or sealed. Welded joints should be tested with non-destructive testing (NDT) methods like X-ray or ultrasonic inspection. Only seals and gaskets specifically designed for methane containing gases should be used. Furthermore, threaded connections should be avoided where possible as these are more prone to methane leakage as identified during the site surveys, and the use of temporary or makeshift joints should be avoided during installation or commissioning, as these are commonly identified sources of methane leaks, as evidenced by the literature and stakeholder discussions.

All installation and maintenance teams should be trained in gas safety and leak prevention, and commissioning checklists should be kept, with records of leak testing and any emissions minimisation steps taken – this is common practice according to installers and commissioning engineers consulted. Furthermore, project developers must also then ensure that the site complies with environmental permitting requirements, with particular care taken to ensure compliance with emissions limits during commissioning and regular operation. Environmental inspections can be proactively prepared for through the proper maintenance of detailed installation logs and test records. Fire and explosion risk assessments (e.g., DSEAR/ATEX compliance) must also be fully complied with during installation, as set out in industry and installer guidance, with the practice validated through discussions with stakeholders.

During site installation, gas monitoring should also be implemented, with methane detection systems (such as in-line analytical equipment or gas sniffers) located close to critical assets such

as the roofs of digesters, gas storage roofs, pipeline junctions, near CHP engines or biogas upgrading units. These should be used to detect leaks and losses that would not be expected during routine operation (e.g. not regular methane slip from upgrading). Infrared (IR) sensors offer high sensitivity to methane and are suitable for continuous monitoring with data logging and alarms. The use of flow meters and pressure sensors should be considered to monitor abnormal losses, pressure drops or flow anomalies. This can allow for the early detection of methane leaks, without relying solely on gas sensors. Finally, automated monitoring systems can allow for real-time alerting and remote shut down of key assets or gas transfer routes if emissions are detected. This can help to significantly minimise the impact of methane emissions as soon as they are detected.

During the site surveys, it was found that several CHP units had gas leaks from the fuel delivery system and the engine's cylinder head. In some cases, it was evident that the leak was likely present from the initial installation and commissioning of the unit, so this could have been detected and avoided sooner if gas monitoring had occurred at this stage. A full detection survey at handover would be prudent to identify such issues and to undertake remedial measures promptly.

8.2. Commissioning

Prior to site commissioning, it is evident from discussions with installers and commissioning engineers that all digesters, gas lines and storage systems will be pressure tested to detect any leaks that may result from improper installation or equipment defects. Digesters and gas lines are also then tested with inert gas (e.g. nitrogen) or water under pressure to check for leaks before introducing biogas.

Following site commissioning, a full LDAR review should be carried out, and this approach should continue routinely post-commissioning as discussed below. A number of tests can be used here as identified in the literature and during stakeholder discussions, including:

- **Handheld detectors:** Flame ionisation detectors (FIDs) or tunable diode laser absorption spectroscopy (TDLAS), providing high-sensitivity and real-time monitoring.
- **Optical gas imaging (OGI):** Infrared cameras to visualise invisible methane leaks across the entire asset, often from a distance.
- **Methane "sniffers":** Detect and measure concentrations around suspect areas.
- **Post-thermal cycling test:** After the system has experienced several temperature cycles, leak checks should be repeated, as seals and gaskets may expand/contract and develop new leak paths.

Any leaks found should be logged and dealt with as soon as possible.

8.3. Maintenance

Following the site surveys, it was apparent that maintenance of the biomethane sites and individual components within has a direct relation to the emissions discovered.

Typical maintenance types are summarised in Table 16 and further discussion on some key components is provided below.

Table 16: Maintenance types, by purpose and frequency, with examples.

Maintenance Type	Purpose	Frequency	Examples
Preventive Maintenance	To avoid breakdowns and ensure smooth operation	Daily, Weekly, Monthly	Checking gas leaks; Cleaning filters; Lubricating moving parts; Monitoring temperature and pressure
Corrective Maintenance	To fix issues after a fault or failure	As needed	Repairing broken components; Replacing faulty sensors; Fixing leaks in gas pipelines
Predictive Maintenance	To anticipate failures using data and analytics	Periodic (based on monitoring)	Vibration analysis on motors; Thermal imaging of electrical panels; Biogas composition monitoring
Routine Maintenance	Regular tasks to keep the system running efficiently	Daily to Weekly	Checking pH and tank levels; Monitoring gas quality and composition; Checking moving parts and mechanical components
Shutdown Maintenance	Major overhauls during planned downtime	As needed	Replacing worn-out components; Inspecting structural integrity
Emergency Maintenance	Unplanned repairs due to sudden failures	Immediate	Fixing burst pipes; Emergency gas flaring; Electrical short circuit repairs

Digesters – a combination of routine, preventative and corrective maintenance can prevent losses from tanks, roofs and associated equipment, identifying potential leaks and detecting issues early.

BUUs – a combination of routine, preventative and predictive maintenance can help to reduce losses and preventable leaks from the upgrading stage, with the type, nature and frequency of maintenance depending on the upgrader technology being used. With membrane upgrading systems for example, membranes can become saturated if not monitored and replaced in a timely manner; therefore, using predictive maintenance and monitoring usage can prevent this. Additional factors which would impact process efficiency and influence losses at this stage would also include failure to eradicate contaminants such as volatile organic compounds which stick to the surface of the membrane material or failure to operate within the design parameters of the BUU or incorrect configuration settings. Such failures would often cause an increase in methane slip where methane is passed through the free venting side of the membrane and passed into the atmosphere with the waste CO_2. Periodic maintenance of scrubbing devices within the BUU system such as activated carbon vessels could prevent the build-up of contaminants and therefore improve the efficiency of the membranes and drive down methane slip.

PRVs – a combination of routine, corrective and emergency maintenance is required to effectively manage PRVs and reduce losses and leaks due to functional issues or failures. PRVs must be regularly checked and maintained to ensure they function to the design pressure and prevent incidents from over or under pressure. This is a requirement under the Pressure Systems Safety Regulations (PSSR) legislation, applicable to larger scale biomethane facilities. It is also important to understand that a PRV opening too early can emit large amounts of methane to the

atmosphere unnecessarily. This would occur if the device were set to open below the operational pressure of a system, so biogas would be continuously passing through the valve. Periodic maintenance could identify incorrect set points and correct them to prevent potential detrimental effects to safety and the environment. Maintenance of the valve internals routinely can also prevent other failures related to their mechanical operation.

CHPs – a combination of routine, preventative, corrective and shutdown maintenance can reduce leaks and losses from CHP engines. Most existing and many new sites will include a CHP to provide heat and power to the site. Methane slip typically occurs from incomplete combustion, so mitigation techniques focus mainly on improving combustion performance. Monitoring performance is essential to minimising slip, and as CHPs require major overhauls periodically (every 5-10 years) shutdown maintenance is unavoidable; however, careful measurement, monitoring and prediction of replacement can be effectively coordinated with other shutdown activities to minimise losses and downtime. Routine maintenance of the CHP unit is also essential to effectively detect issues and allow timely repairs to minimise impacts.

Pipework and fittings – A combination of routine, preventative and corrective maintenance is required for effective leak reduction in pipework, seals, valves and flanges, for example. Missing gasket seals, open pipework, inadequate fastening and incorrect sealing methods are all examples of what was identified as a root cause to some of the emissions found during the surveying. It was apparent in some cases that inadequate maintenance was carried out, causing methane leaks. Routine checks should pay attention to such static components, as maintenance programmes are less stringent for such elements than they would be for key mechanical assets.

During the site surveys, it was identified that maintenance of plant items and in some cases the entire plant is often dealt with by a third-party contracting company. In these cases, maintenance according to the installation or operational guidance is adhered to but any static components that fall outside of such third-party contracts can be missed, and the whole site performance is not viewed in the same way as it would be by the site owner or operator. Furthermore, reactivity of maintenance and repairs was often observed to be immediate for plant owners and up to 2 weeks for the third-party service providers. It was often the case where a key plant item was maintained only by the manufacturer and the lack of availability of their maintenance team meant that methane leaks to atmosphere would continue until the manufacturer had availability to intervene. It is therefore important to consider an appropriate penalty or reward mechanism to encourage timely maintenance and repair, to optimise performance and to minimise impact.

9. Emissions from Digestate Storage

Following the completion of the AD process, a solid/liquid by-product, known as digestate is generated. Digestate can be a major source of methane emissions at the back end of the process, due to soluble and entrapped methane, as well as residual biological activity occuring in this material.

As part of MEAD 2.0, Marches Biogas undertook a series of trials focussed on investigating post-digestion emissions and potential abatement techniques for use in minimising those emissions.

In order to investigate this, samples were taken from sites falling into the following categories: agricultural (utilising energy crops, process residues such as whey, and/or animal manures), food waste (industrial and/or municipal) and wastewater treatment. These categories were used because experience shows that feedstock types are the largest determinants of chemical composition, physical characteristics, and the species of microbial populations. All of these are expected to potentially play a role in the effectiveness of abatement techniques.

The use of abatement techniques within the UK AD fleet is varied. Some techniques considered within this study have widespread usage (e.g. covered storage or solid-liquid separation), others are emerging and not fully in place yet (e.g. vacuum degassing) or have only been tested in small studies and not at site scale (e.g. pH adjustment). To provide a comprehensive evidence base for future biomethane and anaerobic digestion policy development, all available abatement strategies have been considered regardless of the current state of technology rollout.

Based on a review of literature, project specification, the market analysis undertaken as part of this study and engagement with key stakeholders, seven techniques were considered, with data and insight taken from both lab scale trials and site case studies.

- Extended process time – through either secondary digestion or covered storage connected to the biogas system.
- Aeration
- Vacuum degassing
- pH increase through dosing of alkaline additive
- pH decrease through dosing of acidic additive
- Separation
- Pasteurisation

To reflect the majority of the UK fleet, this study only considered mesophilic digestion (temperatures between 35–45°C).

While not all technologies are expected to be compatible with every AD site, this study aimed to consider as many configurations as possible. This work was designed to test each abatement

technique (7) on each site type (3), leading to 21 individual trials. In order to maintain a consistent baseline throughout these trials it was preferable to reduce the number of sites and therefore the variability in the initial control testing. As such, site selection aimed to identify a single site for each of the three site type categories (agricultural, food waste, wastewater). The primary purpose of this work package was examining the effectiveness of treatment techniques, rather than assessing the digesters from which samples were drawn.

Selected sites were chosen based on stability in feedstock composition, scale of production (kWe) as well as hydraulic retention time (HRT) and organic loading rate (OLR), all determined through the market analysis and subsequent engagement with sites. Practical considerations also had to be made, as digestate is known to produce significant gas immediately following discharge; where possible sites close to the laboratory were prioritised to minimise lost potential prior to testing. A summary of the selected sites can be found in Appendix C, Table C2. Digestate was subsampled to provide data on digestate parameters, site parameters were sourced from on-site recorded data at the time of sampling.

Two further sites were also then selected as specific case studies of solid-liquid separation (site D) and pasteurisation (site E). A summary of these sites can be found in Appendix C, Table C3.

9.1. Digestate Emissions Abatement Methods

The sampling and testing methodology is described in full in Appendix E with key findings for each of the abatement techniques considered discussed below.

9.1.1. Extended process time

The biological process of AD is comprised of four stages, each facilitated by a different group of microorganisms: hydrolysis, acidogenesis, acetogenesis, and methanogenesis. Hydrolysis and methanogenesis are the rate limiting stages, dependent on the ratio of hydrolytic bacteria to methanogentic archaea.[75]

The hydraulic retention time of a digester is calculated as digester volume (m^3) divided by feed rate (m^3/day). This determines how long the material is held in residence. Different retention times are required for different materials, as the breakdown of some takes longer than others.

Shi, et al. (2017) found that increasing the HRT of a straw fed digester from 20 to 60 days almost doubled the methane production per gram of volatile solids fed as the high cellulose content of straw had not fully broken down within 20 days.[76] Most wastewater plants are by contrast operated with a HRT between 15 and 30 days.[77] Alepu, et al. (2016) found that increasing retention time in the digestion of wastewater sludge from 10 to 20 days increased biomethane production rate fivefold, but increasing HRT to 30 days made comparatively little difference. Sites

[75] Ma et al., A simple methodology for rate-limiting step determination for anaerobic digestion of complex substrates and effect of microbial community ratio. Bioresource Technology 2013.
[76] Shi et al., Effect of Hydraulic Retention Time on Anaerobic Digestion of Wheat Straw in Semicontinuous Continuous Stirred-Tank Reactors. BioMed Research International, 2017.
[77] Alepu et al., Effect of Hydraulic Retention Time on Anaerobic Digestion of Xiao Jiahe Municipal Sludge. Internation Journal of Waste Resources. 2016.

therefore select HRT to maximise production, and to minimise cost. Hartmann and Ahring (2006) found that in municipal solid waste treatment, whilst highest production was attained at a lower HRT, due to continual refreshing of material, when accounting for the costs of waste and effluent treatment and the remaining downstream biogas potential, it was better to use a 30-day HRT.[78]

Purely in terms of residual biogas potential, this is always decreased by increasing retention time, and when using post-digestion storage, when that storage is heated.[79] Control samples were also utilised to inspect extended process time. As these samples were retained until gas production had plateaued with no other treatment undertaken, this could provide an indication of timeline for an extended process. Testing was undertaken at 20°C to represent ambient summertime conditions as well as 37°C to represent a heated vessel that would enable further digestion. The biogas production across each of the sites at both 20 and 37°C are presented in Figures 8 & 9 respectively.

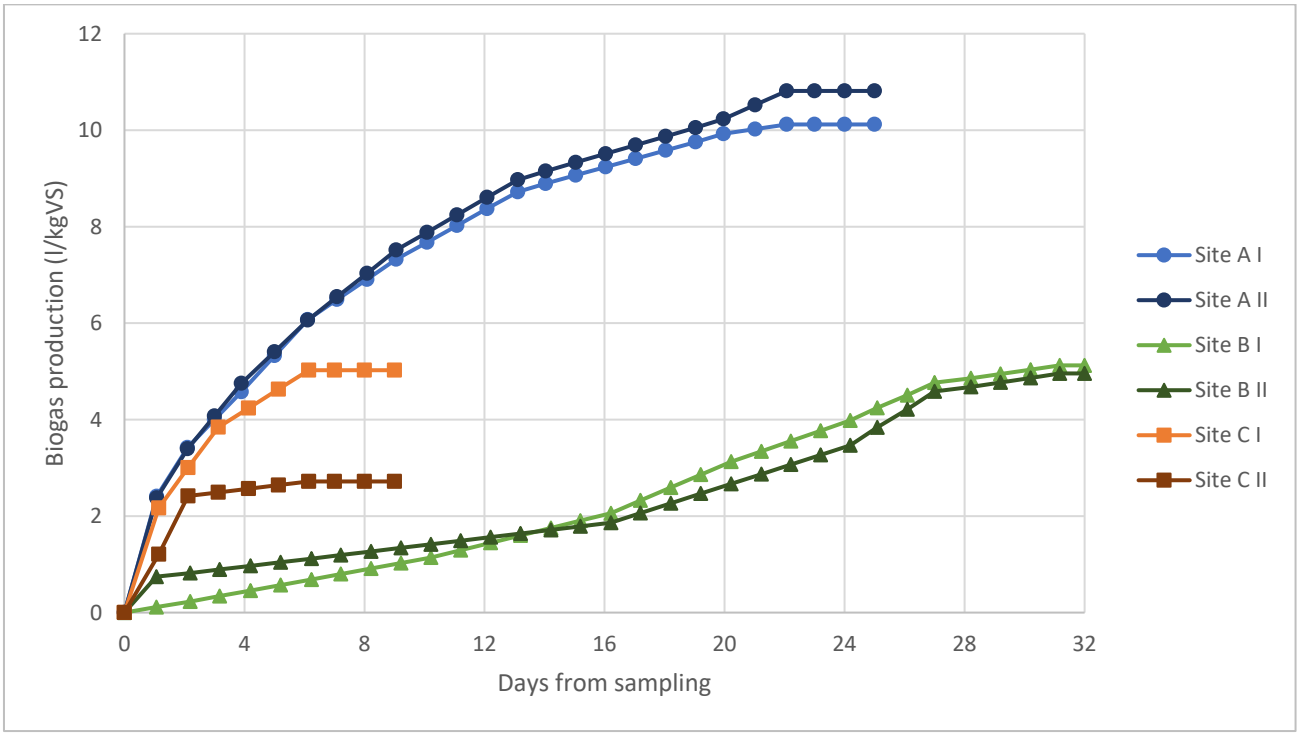


Figure 8: Biogas production over time for control samples, at 20°C. Repeats are denoted as I or II.

[78] Hartmann et al., Strategies for the anaerobic digestion of the organic fraction of municipal solid waste: An overview. Water Science and Technology, 2006.
[79] Astals et al 2020. Impact of Storage Conditions on the Methanogenic Activity of Anaerobic Digestion Inocula. Water. 2020.

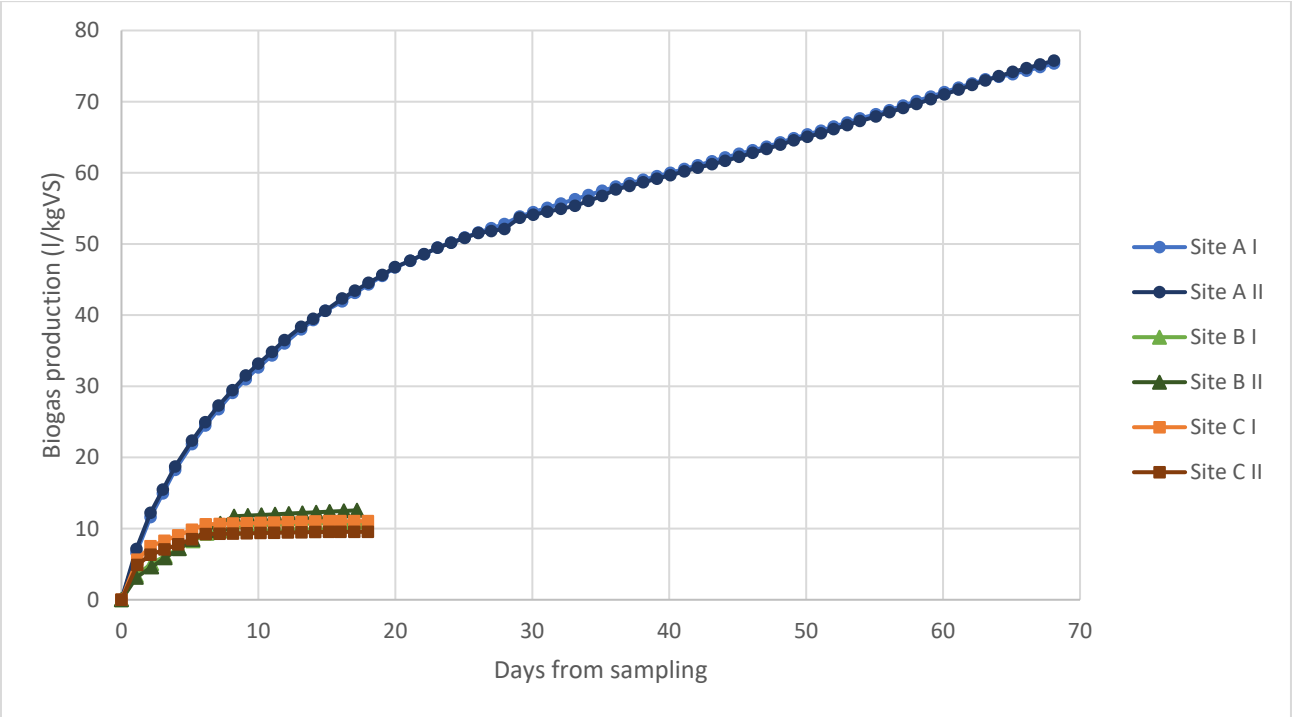


Figure 9: Biogas production over time for control samples, at 37°C. Repeats are denoted as I or II.

All site samples produced more biogas when stored at 37°C than at 20°C, and with the exception of site B, all production took more time to plateau at 37°C than at 20°C. Site B is an exception because at 20°C the sample showed a distinctive lag phase during testing. A lag phase is when the highest rate of production is not within the initial few days, for site B this lag was around 16 days, after which production then occurred at a more rapid rate until reaching its plateau.

There was no discernible cause for the disparity between the two samples from site C tested at 20°C. No leaks were identified in the apparatus, and a final mass check was performed confirming twice the loss in the higher performing replicate. This would indicate that something caused genuine drop off in the lower performing replicate, such as contamination during the sampling phase. As the cause was not identified both sets of data have been presented here, but only the higher/longer producing sample was used in further data analysis.

At 37°C, the sample from site A did not reach a plateau, even after 10 weeks stored at 37°C. Production had instead reached a steady state at around day 28 of 500-600ml/kgVS/day. The test was stopped at this point, as an additional 10-week retention time was considered beyond reasonable expectations for a site to implement. It should be noted that this is a single set of testing and other variables may lead to different results. For example, it is assumed that the CSTR is well mixed and freshly fed material is not entering the discharge in significant quantities; however, no mixing study has been completed at this site. When looking at site E for the pasteurisation case study, production from the unpasteurised digestate had not plateaued during the 4 weeks allowed for the testing, and testing at another agricultural site outside of this study showed production took 7-8 weeks to reach a plateau. These sites all had long retention times, but due to the nature of agricultural feedstocks, the digester retention time still left residual biogas within the digestate. The final biogas volume produced at each temperature for each site is

displayed in Table 17. This shows that storage at 20°C only produced 45-55% of the biogas released under storage at 37°C at sites B and C, and 10-15% of that at site A.

Table 17: Total biogas production, from each of the samples at each of the sites

Site		A	B	C
Temperature		Total biogas production (l/kgVS)		
20°C	Repeat 1	10.81	5.12	5.02
	Repeat 2	10.12	4.96	-
37°C	Repeat 1	75.76	12.57	11.04
	Repeat 2	75.35	10.91	9.54

This would indicate that samples stored at 20°C retain a higher biogas generating potential, and biogas could still be generated and released, either on a timescale beyond that within this testing, where immeasurable production for 3 days marked the end of testing, or should the circumstances under which the digestate is stored change to something more favourable.

The timescale for the end of production at 37°C was within 20 days for both sites B and C, as displayed in Table 18. Again, end of production here refers to the time after which no production could be measured for 3 days.

Table 18: Time to mid-point and end of production for each of the sites

Site	A	B	C	A	B	C
Temperature	Time to end of production (days)			Time to 50% of production (days)		
20°C	22.1	31.2	6.1	5.0	18.2	2.1
37°C	68.1*	17.2	15.2	13.13	4.2	1.2
***Test was stopped at this point, despite production not naturally plateauing**						

At 37°C there was no lag phase for any site, so 50% of the total measured biogas was released early. For sites B and C especially, this indicates there would be minimal potential for time to greatly reduce the residual biogas potential. Even at site A, adding two weeks to process time within the system would lead to a significant reduction in biogas potential.

Digestate from site B was taken from the discharge line of their unheated storage tank, which is covered and connected to the biogas system. Digestate is stored for 1-2 weeks dependent on demand. At the time of sampling the storage retention time was 11 days. Digestate was also sampled from the line between the secondary digester and the storage tank, in order to compare gas production between un-stored and stored digestate (Figure 10).

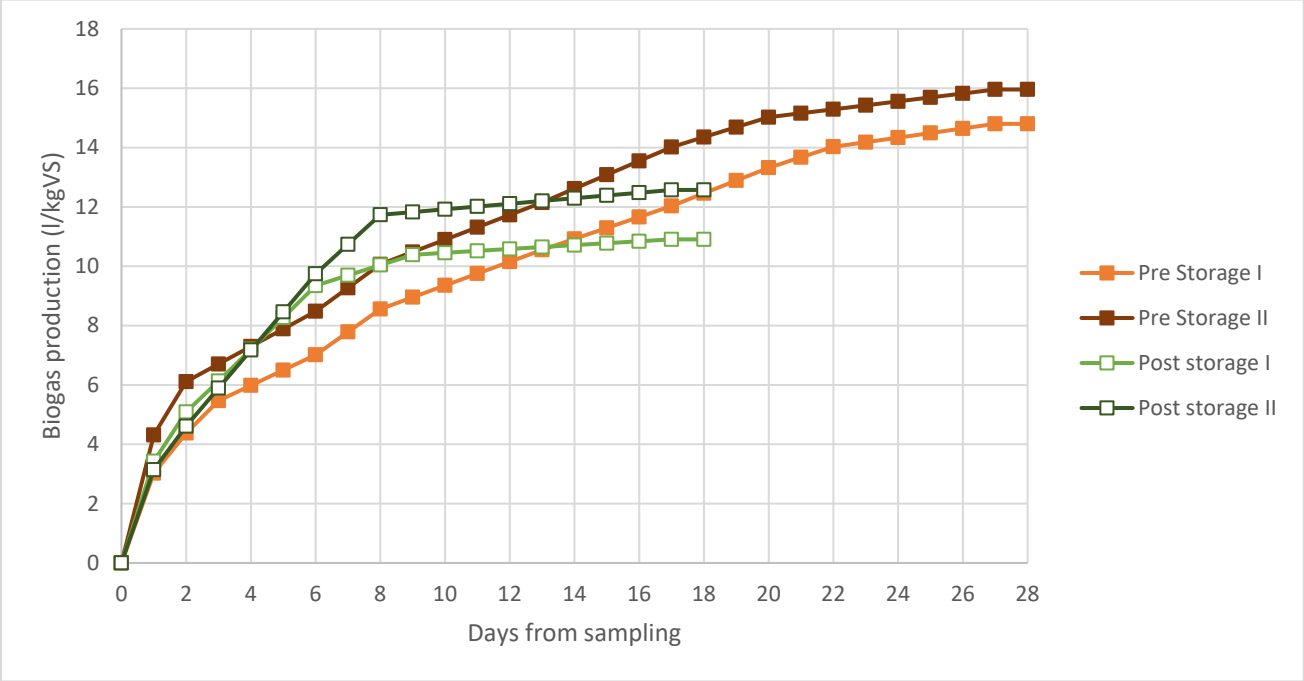


Figure 10: Biogas production at 37°C, from digestate pre- and post- storage time.

The total gas production pre-storage was reduced by 24% by its time within the storage tank, however this testing suggests that the post-storage digestate produced gas at a quicker rate, as seen between days 5-10, where the post-storage digestate was producing more than the pre-storage in all cases. The post-storage production then plateaued quicker. This suggests that the material within the storage tank is more readily available for conversion into biogas, possibly because it is further through the digestion process. Conversely, if the pre-digestion sample was still undergoing earlier digestion stages, new substrate would then become available to feed the biogas production process.

9.1.2. Aeration

Methanogens are a group of archaea, that are strictly anaerobic and obligate methane producers.[80] It is assumed because of this, that the introduction of oxygen to the methanogentic environment will prevent the production of biomethane. However, studies into anaerobic tolerance to oxygen have found that whilst exposure to air can reduce methanogentic activity, the effects are not guaranteed and if aerobic conditions are not maintained methanogenesis begins once more.[81, 82] This is likely because the tolerance of methanogens to oxygen differs

[80] Buan et al., Methanogens: pushing the boundaries of biology. Emerging Topics in Life Sciences. 2018.
[81] Kato et al., Anaerobic tolerance to oxygen and the potentials of anaerobic treatment of wastewater with high oxygen content. Water Science and Technology. 1997.
[82] Pedizzi et al., Effect of oxygen exposure on anaerobic digestion: A review. *Renewable Energy.* 2016.

between species. Kiener & Leisinger (1983) found that following 10 hours of aeration some species of methanogen had a 1% survival, but others were unaffected even up to 30 hours of exposure.[83]

At lab-scale, methanogen species have been found to be dependent upon temperature, pH, total ammoniacal nitrogen (TAN) and VFA concentrations (especially acetic and isobutyric acids).[84] However, at full scale, there has been found to be more diversity, and in fact this diversity is key to stable AD.[85]

Samples were placed in an 8l open bucket, and two aeration pumps added, putting through 150l/h each for a total air flow of 300l/h. This aeration stage was given 24 hours to maximise contact between anaerobes and oxygen (Figure 11).

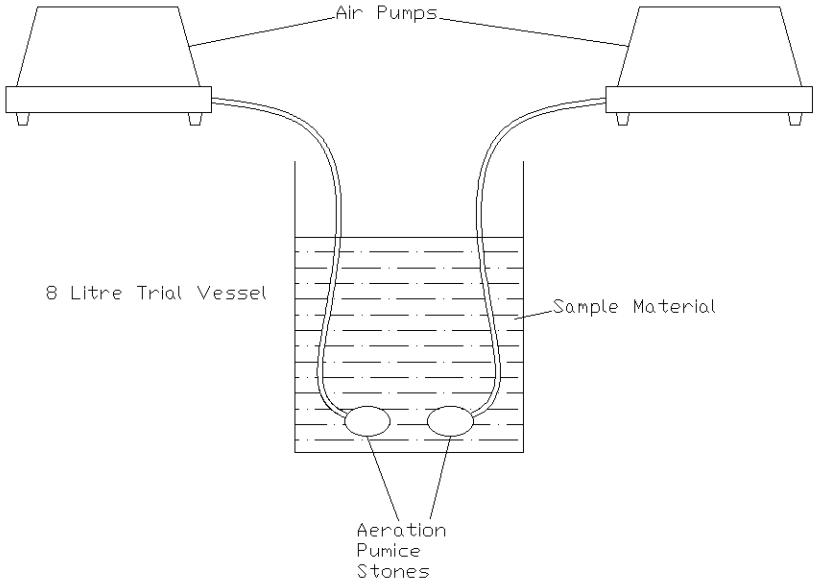


Figure 11: A diagram of the aeration testing set up.

Whole digestate at site A was highly fibrous, and as such the air pumped in during the aeration phase was insufficient to mix the digestate, and did not appear to diffuse through the sample. There was a clear visual difference in the formation of bubbles, which were large and across the full surface in the more liquid digestates, but only small and present in limited areas in the high-fibre digestate, suggesting the air potentially formed a stable “escape route”. As such separated liquor was sampled from site A, both for control and for aeration, and results from both sets of sampling were considered. The production from the aerated sample did not show significant variation from the control sample (Figure 12). Only one aerated sample was recorded, as the second repeat matched production for the first week before failing due to a broken seal in the gas collection apparatus.

[83] Kiener et al., Oxygen sensitivity of methanogenic bacteria. *Applied and Environmental Microbiology*. 1983.
[84] Ziganshin et al., Comparative Analysis of Methanogenic Communities in Different Laboratory-Scale Anaerobic Digesters. Archaea, 2016.
[85] Zhang et al., Substrate and environmental factors shape microbial community structure in anaerobic digestion systems: A review. Renewable and Sustainable Energy Reviews. 2019.

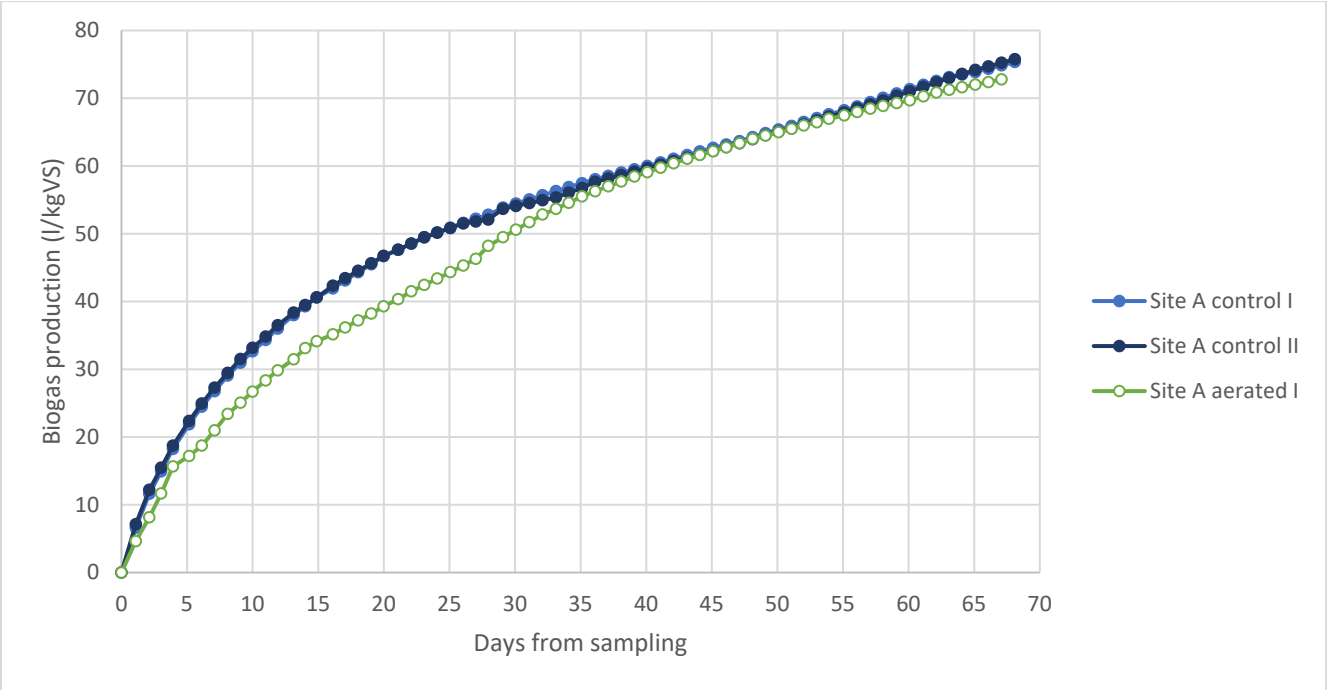


Figure 12: The results from aeration of whole digestate at site A

Site A had the ability to separate digestate, as such separated liquor (SL) was then also taken from the site to undertake the same testing. Over a 14-day period the aerated SL produced no measurable biogas. A control sample of SL was also taken to ensure the separation process was not responsible for the reduction, which it was not (Figure 13).

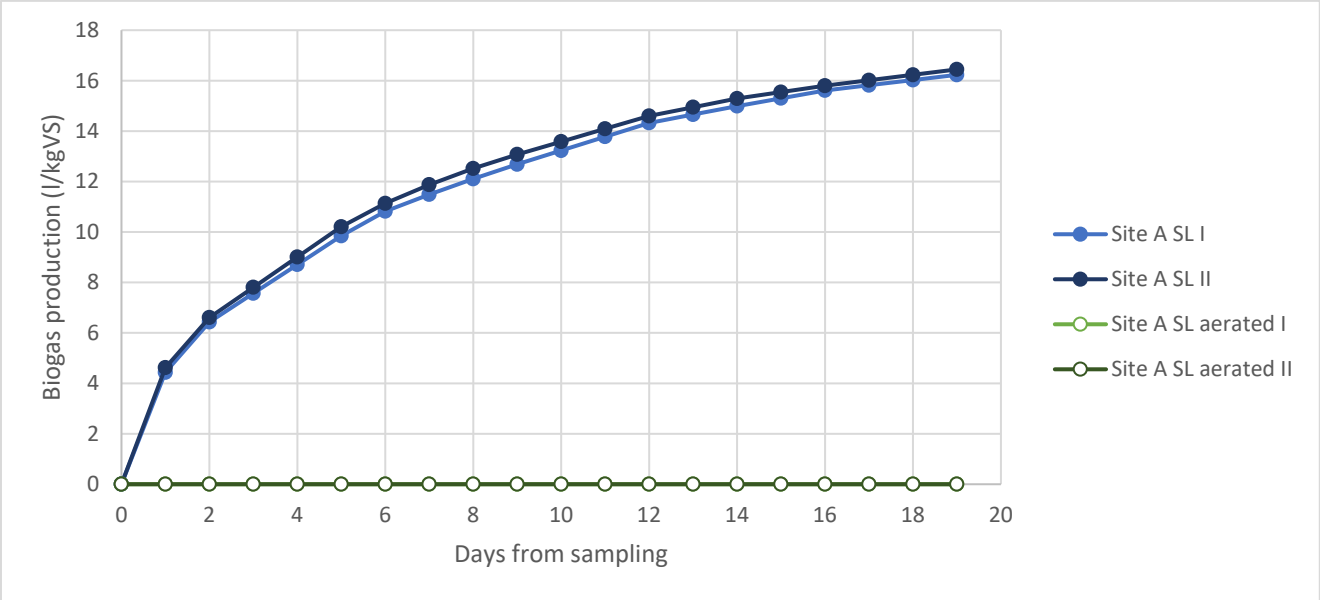


Figure 13: The results from aeration of separated liquor at site A

Digestate from sites B and C did not contain the same fibrous material. Site B produced no measurable gas over a 14-day period. Site C did not initially produce any gas, but after 8 days at 37°C in a sealed vessel with no new introduction of air, gas production began again (Figure 14).

At site C, total production was reduced by 28-30% compared to the control sample; however, gas released during the aeration process was not measured, and could account for some of that lost potential.

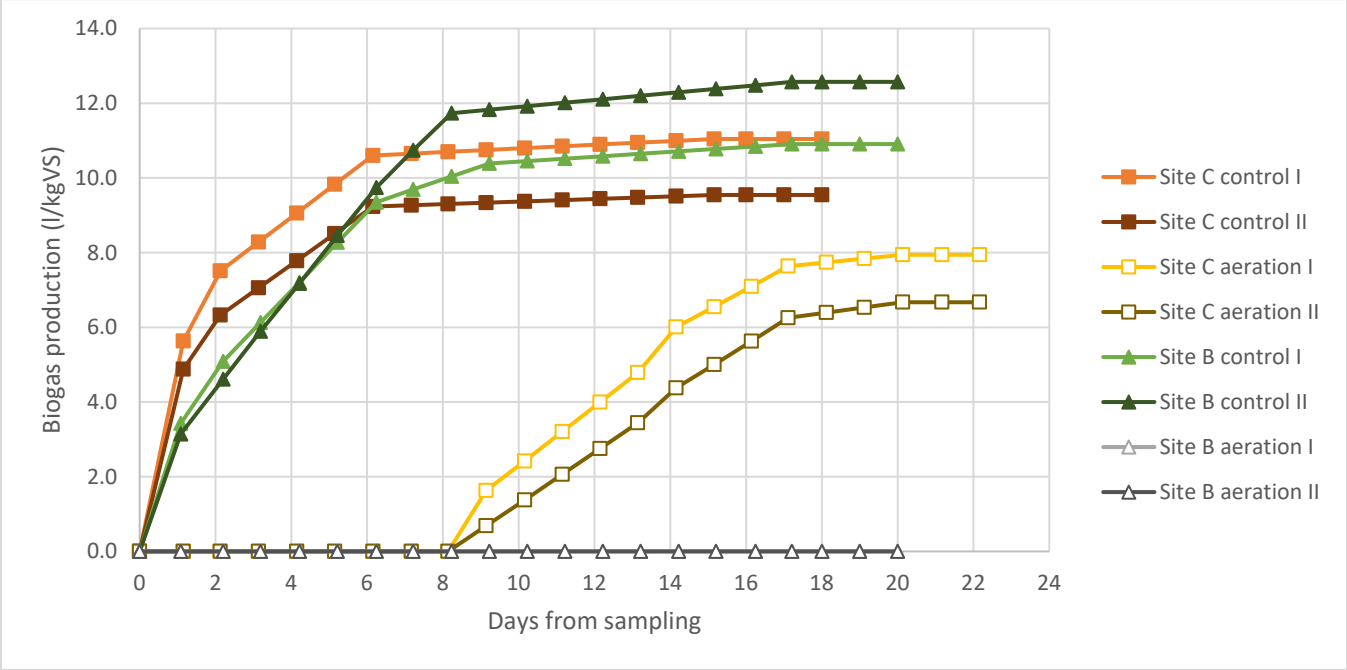


Figure 14: The results from aeration of digestate at sites B and C

It is hypothesised from this testing that site C had methanogen populations that were more resistant to the presence of oxygen. As discussed previously, there are some species of methanogen that are not inactivated by exposure to oxygen. A literature search identified temperature, pH, total ammoniacal nitrogen (TAN), and volatile fatty acid (VFA) concentrations as the key factors influencing methanogen type. All sites within this study were mesophilic, removing the possibility of a temperature difference. Both pH and TAN were significantly lower in the digestate at site C compared to A and B. VFAs were also lower, although around the same as the VFAs in site A's SL (94mg/kg in site C compared to 108mg/kg in site A's SL), as such this seems unlikely to be the cause for the difference.

It is also possible that due to the nature of wastewater treatment sites i.e. the use of both aerobic and anaerobic treatments in concert, the established colonies could be by necessity resistant to oxygen, and it is recommended that for any further work feedstock/site type is also considered. This work found aeration to be less effective on the wastewater sludges tested than other feedstocks, with higher efficiency recorded in samples from both agricultural and food waste sites, provided the physical properties of the digestate (e.g. dry solids, rheology) and the dynamics of the aeration (e.g. flow rate) allow for thorough aeration. It is, however, recognised that there can be great variability in methanogenic communities and hence in efficiency of aeration for a given feedstock between different sites, where a single site was sampled for each feedstock type.

9.1.3. Vacuum degassing

The use of vacuum treatments post digestion has primarily been for the recovery of entrapped gases within the digestate[86] and stabilisation of sludges.[87, 88] Little work has been undertaken looking at methane production following vacuum treatment; however, Gnida & Skonieczna (2020)[89] and Gnida & Niemiec (2025)[90] found that vacuum conditions had a negative effect on microbial activity, although they were looking at dehydrogenase, denitrifying, and phosphorous releasing activity, rather than methanogentic activity.

Samples were placed within a vacuum chamber and the chamber pressure reduced. The lab-scale vacuum pump allowed for reduction of -0.6 bar relative to atmospheric, i.e. absolute pressure of 0.4 bar. It is expected that commercial vacuum degassing technologies will be able to reach a stronger vacuum (i.e. absolute pressure <0.4 bar). This pressure was then held until the vacuum began to decay, which took between 15 and 20 minutes (Figure 15). Samples were then returned to atmospheric pressure to undergo biogas potential testing as described in Appendix E.

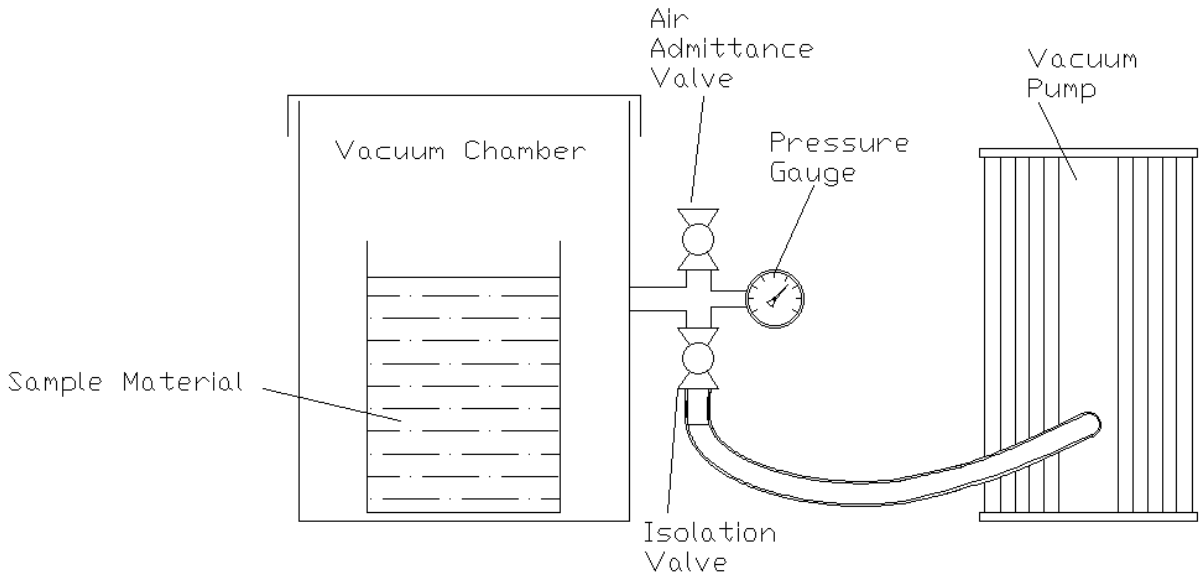


Figure 15: The experimental set up for the vacuum degassing test.

At each site the samples that underwent vacuum degassing showed no reduction in biogas production long term, once the digestate was moved into closed storage (Figures 16 to 18). Where vacuum degassing may remove entrapped gas from digestate, the treatment as described in this work does not impact the microbial populations in such a way as to inhibit their action once returned to normal conditions.

[86] Lee et al., Vacuum treatment for dissolved gas recovery from anaerobic digestate. Journal of Environmental Chemical Engineering. 2020.
[87] Gnida et al., Vacuum stabilization of sewage sludge: Effects on structure and odor. Water. 2021.
[88] Gnida et al., Vacuum conditioning of sewage sludge prior to further processing. E3S Web of Conferences. 2020.
[89] Gnida et al., Vacuum conditioning of sewage sludge prior to further processing. E3S Web of Conferences. 2020.
[90] Gnida et al., Impact of vacuum conditions on microbial activity in sewage sludge stabilization. Water. 2025.

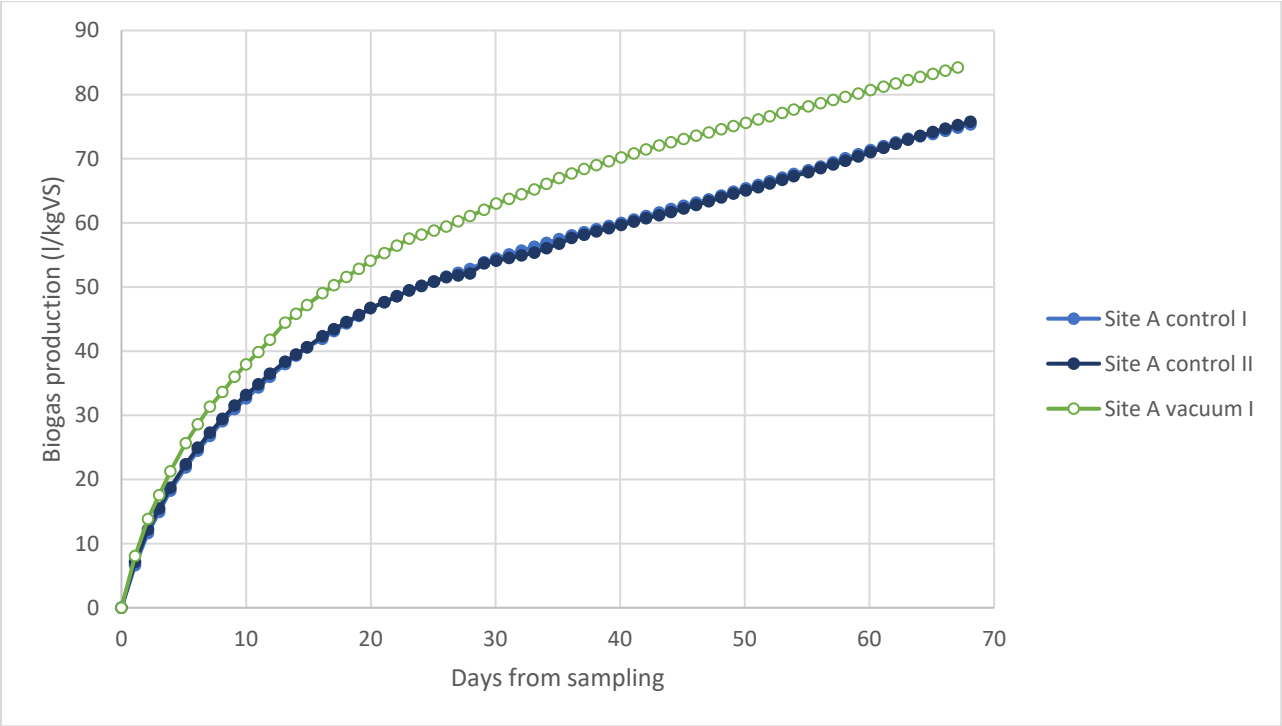


Figure 16: The results from vacuum degassing of digestate at site A.

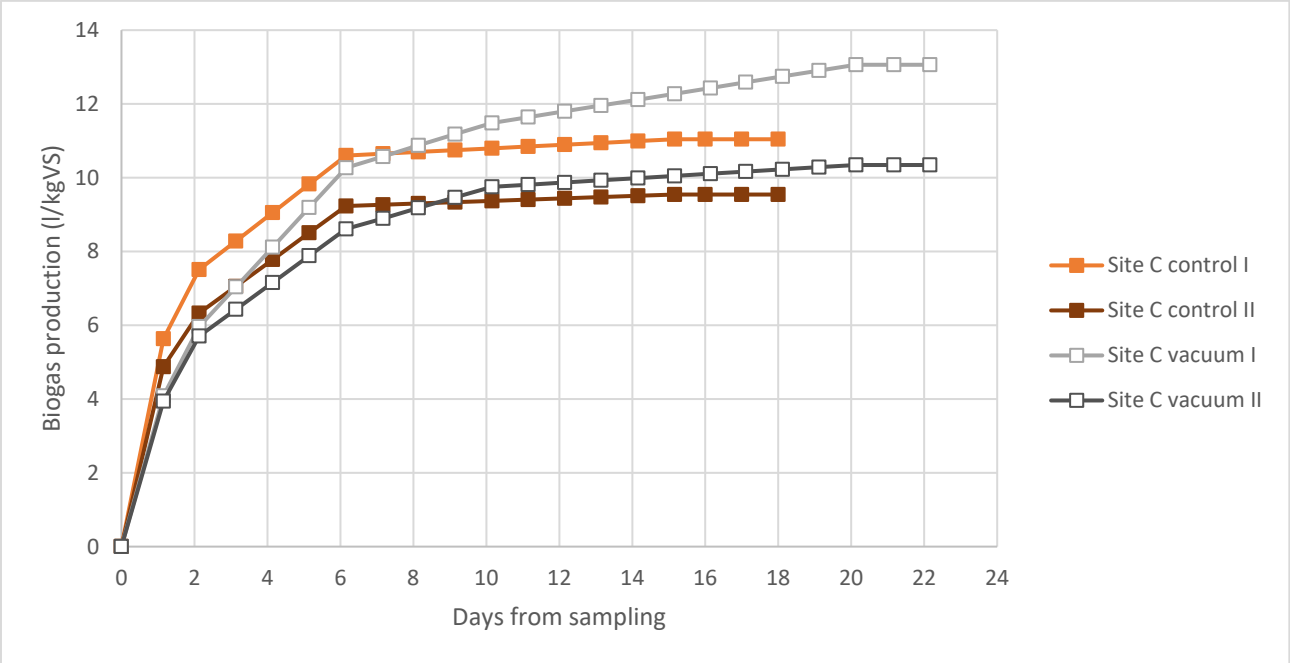


Figure 17: The results from vacuum degassing at site B.

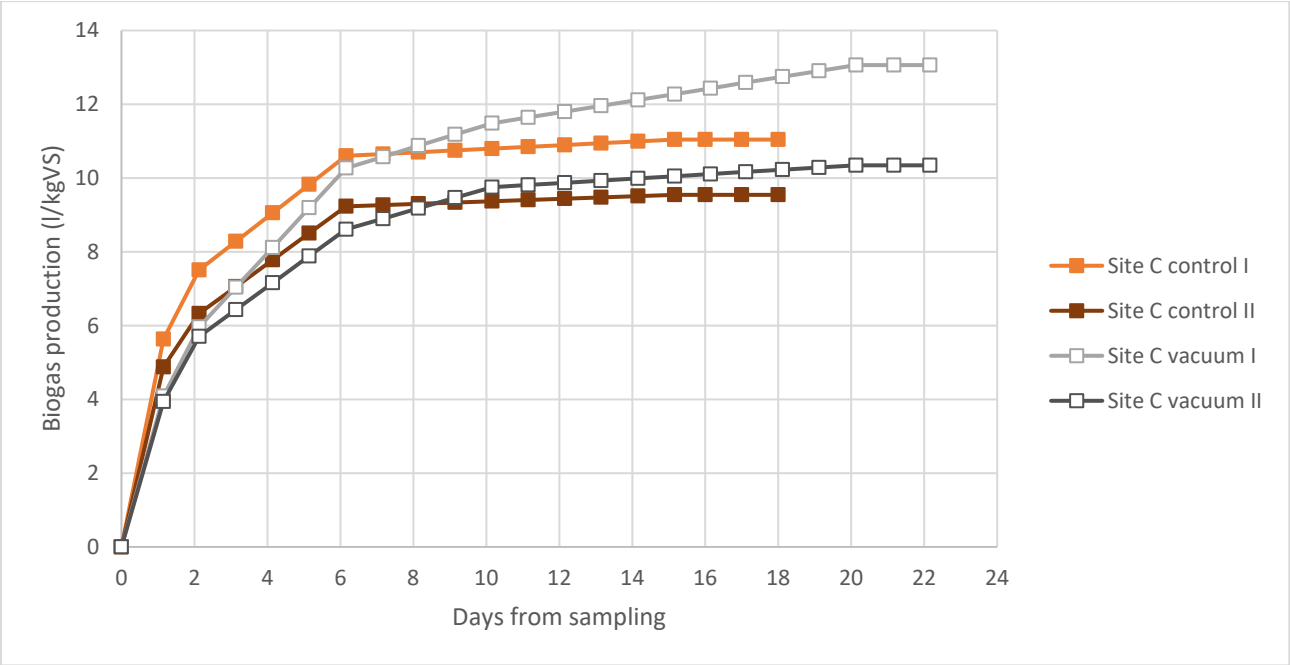


Figure 18: The results from vacuum degassing at site C.

At site A the second repeat failed early and was discarded; however, the successful repeat showed increased production over the control samples. Sites B and C also showed an overall increase in production following vacuum degassing treatment.

Table 19 compares the changes in production to the standard deviation in each case.

Table 19: Production averages and standard deviations.

Site	A	B	C
Average of control samples (l/kgVS)	75.55	11.74	10.29
Standard deviation of control samples (l/kgVS)	0.20	1.18	1.06
Results of vacuum treated samples (l/kgVS)	84.72	12.02 12.91	13.06 10.34

At Site A the vacuum treated sample produced more gas by 45σ, but at site B the samples were within 1σ of the control, and at site C one result was very close to average and the other within 3σ. As such only site A showed a significant increase in production following vacuum treatment.

Following vacuum treatment, samples from sites B and C also displayed an extended time for production to plateau. At site B production from the control sample slowed considerably after 8 days and had stopped entirely within 18 days; up to day 8 these samples outperformed those that had undergone vacuum degassing, but the vacuum treated samples then continued producing at a higher rate until 17 days had passed, and did not stop production until day 21. Although the timescales differ, the pattern is the same at site C.

These results suggest that vacuum degassing could have a side effect of increasing long term production. It was hypothesised that vacuum pressure could be causing mechanical breakdown of feed; however, Turner (1976) showed damage to plant cells beginning between 0.1 - 0.2 bar absolute, so the pressure reached in this vacuum may not have been sufficient to cause this damage.[91]

Vacuum degassing is a technology designed to remove entrapped gases, which can lead to downstream emissions upon release. This work does not examine the effectiveness of the removal of entrapped gas, but of the level of new biogas production following treatment. Vacuum degassing as undertaken for this work did not prevent new biogas production. This shows that the microbes were not suppressed by exposure to vacuum pressures.

9.1.4. pH increase

It is well established that the AD system is sensitive to changes in pH, with methanogens especially having a small range of optimal operation. This range is understood to be between 6.7 and 7.5;[92, 93] however, there is substantial evidence that methanogens can continue activity well beyond this range. Worakit, et al. (1986) found methanogens utilising H_2 with an optimal pH of 8.4 that could withstand pH up to 9.9.[94]

This continued activity is evident in works that look to suppress methanogenesis and stabilise sludges. Qiu, et al. (2023) found only a 23.8% suppression of methanogens at pH 8.5 compared to pH 7.0, and 92.1% suppression when that pH was increased to 10.0.[95] As with Worakit, et al. (1986), this work confirmed that it was hydrogenotrophic methanogens that were most likely to remain active, whilst acetoclastic methanogens were diminished. Whilst not looking at methanogens specifically, Williford, et al. (2007) found that when using lime to stabilise biosolids, raising pH to 10.0-11.0 would not sufficiently kill pathogens or prevent release of odours, recommending that the pH be increased to 12.0 for at least 2 hours.[96]

[91] Turner., Mechanical effects of vacuum on plant tissues. Journal of Experimental Botany. 1976.
[92] Clark et al., The pH tolerance of anaerobic digestion. Journal of Water Pollution Control Federation. 1971.
[93] Deublein et al., Biogas from Waste and Renewable Resources: An Introduction. 2008.
[94] Worakit et al., Methanogenic bacteria utilizing hydrogen at high pH. Applied and Environmental Microbiology. 1986.
[95] Qui et al., Effect of alkaline pH on methanogenesis and microbial community in anaerobic digestion. Bioresource Technology. 2023.
[96] Williford et al., Evaluation of lime stabilization for biosolids: Pathogen reduction and odor control. Water Environment Research. 2007.

Stabilisation has been undertaken on multiple occasions using lime as the alkaline additive,[97, 98] and sodium hydroxide (NaOH) has also been widely used as an alkaline post-treatment and found to decrease biogas yield.[99]

Initial tests were undertaken using lime as an alkaline additive due to its historic usage in stabilisation of digestates as found in the literature review; however, it was found that in quantities sufficient to raise pH for digestate from site A the mixture of lime and digestate formed a cement-like compound. It was determined that this would render the digestate unusable, and require significant disposal costs, so lime was replaced by sodium hydroxide (caustic soda).

Sodium hydroxide was added to the samples in small steps to bring the pH up to target level. Initially, as found in the literature review, pH of 12.0 was targeted; however, ability to spread to land prompted attempts to minimise pH change whilst still achieving cessation of methanogenesis.

The sodium hydroxide was added in steps between 0.1% and 1% of the sample mass, at a concentration of 98%, with step sizes altered depending on response of the sample. The sample was stirred, and the pH monitored continuously whilst the sodium hydroxide doses were measured and added. The samples were not left to rest at any point, and the dosing period was on the scale of minutes. Once the target pH was reached, the samples were immediately sealed.

Site A was tested in accordance with the advice from the literature review, i.e. with pH raised above 12. No gas was produced over the 14-day testing period, and when removed from the water bath pH was found to have increased from an initial sample pH of 7.98, with a final pH of 10.73. As gas production had not started it was determined that the target pH should be reduced.

Target pH was therefore reduced to 10.0 for site B, and further to 9.0 for site C. At no point was any gas produced from any of the treated samples (Figure 19) and all samples showed an increase in pH over the 14-day testing period (Table 20).

[97] Williford et al., Evaluation of lime stabilization for biosolids: Pathogen reduction and odor control. Water Environment Research. 2007.
[98] Mahdi et al., Effect of lime addition on anaerobic digestion and sludge stabilization. Environmental Technology. 2014.
[99] Romio et al., Effect of sodium hydroxide post-treatment on biogas yield and digestate characteristics. Waste Management. 2021.

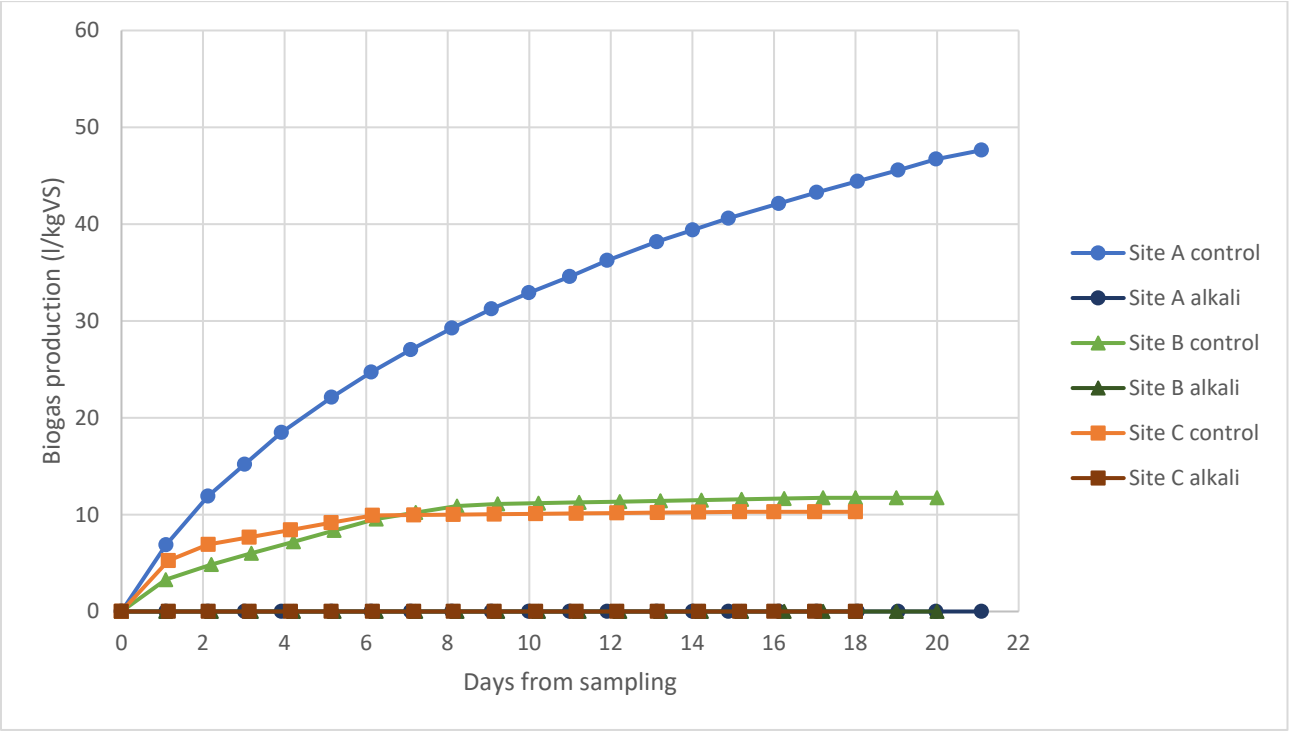


Figure 19: Production from controls compared to alkali treated samples. To reduce plotted lines, only average productions are displayed rather than individual repeats.

Table 20: pH readings of sodium hydroxide treated samples over the testing period

Site	A	B	C
Initial sample pH	7.98	8.70	7.32
Target pH	12.00	10.00	9.00
pH achieved	12.09	9.99	9.04
14-day pH	10.73	9.62	8.09

Despite pH returning to levels where methanogenic activity may be expected at site C, considering the final pH here is lower than the initial pH at site B, no such activity occurred, indicating that either the initial pH shock was sufficient to kill the methanogens, or that the active pH range of the methanogens at site C was particularly narrow. It is also possible that the addition of sodium hydroxide chemically removed the availability of acetic acid for utilisation by methanogens, as:

$$CH_3COOH + NaOH \rightarrow H_2O + CH_3COONa$$

$$Acetic\ acid + sodium\ hydroxide \rightarrow water + sodium\ acetate$$

It is also worth noting that site C was far more susceptible to pH changes. Figure 20 shows the amount of NaOH required (%w/w) to increase the pH of the sample. This shows that where sites A and B saw a similar rate of change, site C had a far sharper rise. FOS/TAC was measured for each sample, so TAC (alkalinity) was used as an indicator of buffering. This was 4,966mg/l at site C, compared to 29,361mg/l at site A and 24,212mg/l at site B. In the sampling team's experience this is typical for wastewater treatment sites, so far more sensitivity to pH changes is expected in wastewater digestates.

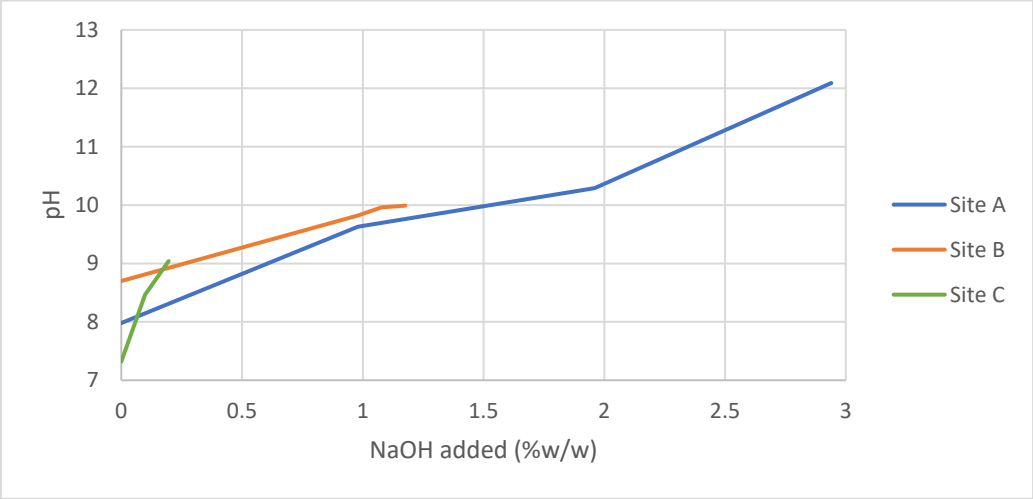


Figure 20: The change of pH for each site sample with addition of sodium hydroxide

There is concern that a large increase in the pH of digestate will lead to restriction on its use. Optimum soil pH for agriculture is between 5.3 - 6.5 dependant on crop and soil type.[100] Considering that pH did not need to be increased to 12.0 in this study to prevent methanogenic activity reduces the risk of the resultant product being difficult to use.

9.1.5. pH decrease

As with increasing pH, adding acid to reduce pH below the range of methanogenic activity would suppress methane production. Qiu, et al. (2023) found a reduction to pH 5.5 led to 71.7% reduction in methanogenesis, and to 4.0 gave 100% reduction.[101]

Within an AD facility there is a compounding effect, as hydrolytic and acidogenic bacteria operate at a lower range of pH than methanogens.[102] Inhibition on methanogens does not stop acid formation within the digester, and pH will then decrease further, leading to further inhibition.[103] However, there is also evidence that given sufficient time methanogens can acclimatise to a system of sustained low pH.[104]

Alum has been used for abatement of multiple emissions, primarily ammonia and methane.[105] Alum (aluminium sulfate/$Al_2(SO_4)_3$) was identified within the literature review as a suitable agent

[100] Agriculture and Horticulture Development Board, Nutrient Management Guide (RB209): Section 4 – Soil pH and Liming. 2023.
[101] Qui et al., Effect of alkaline and acidic pH on methanogenesis and microbial community in anaerobic digestion. Bioresource Technology. 2023.
[102] Deublein et al., Biogas from Waste and Renewable Resources: An Introduction. 2008.
[103] Fukuzaki et al., Effect of pH on acidogenesis and methanogenesis in anaerobic digestion. Journal of Fermentation and Bioengineering. 1990.
[104] Taconi et al., Methanogen acclimation to sustained low pH in anaerobic digestion systems. Water Research. 2008.
[105] Regueiro et al., Alum addition for ammonia and methane emission abatement during anaerobic digestion and digestate management. Journal of Environmental Management. 2016.

for acidification of digestate. As with increasing pH, the initial target was reduction to pH 4.0 following previous research; however, it was determined that bringing the final product closer to neutral pH would maximise available use of the product.

Site A was brought down to pH 4.0 in line with the literature review; however, when no biogas was produced the target pH was raised for both sites B and C.

Once the aluminium sulfate was added and pH decrease confirmed the samples were sealed and placed in the water baths. Over the course of a few hours (7 hours for both sites A and B, and 4 hours for site C) a significant amount of gas was produced. Upon testing this was discovered to be primarily CO_2, and indicated the chemical reactions were still occurring during that period (Table 21).

The CO_2 produced was insufficient to clear the headspace, so the majority of the measured gas was still air. There was a small amount of CH_4 present, which may indicate some biogas still being produced initially; however, even in the same early stages of the controls CH_4 and CO_2 were about equal in production, whilst in the acidified samples CO_2 was 15-20 times more abundant.

Table 21: The gas composition of the acidified samples compared to the control samples in the initial hours after chemical dosing (7 hours for site A and B and 4 hours for site C).

Site	A	B	C
With addition of acid			
CH_4 (%)	0.3	0.4	0.3
CO_2 (%)	5.9	6.3	5.0
CO_2:CH_4	19.67	15.75	16.67
Control			
CH_4 (%)	2.9	1.3	1.7
CO_2 (%)	2.8	1.3	1.5
CO_2:CH_4	0.97	1.00	0.88

Following the removal of the high CO_2 gas, production quickly stopped in the treated samples, with no further gas produced after the second day of testing (Figure 21). CO_2 is expected to have been produced during the addition phase, and it was noted that when mixing aluminium sulfate into the samples they developed a foamy texture. This texture remained and was still observed after the 14-day testing period.

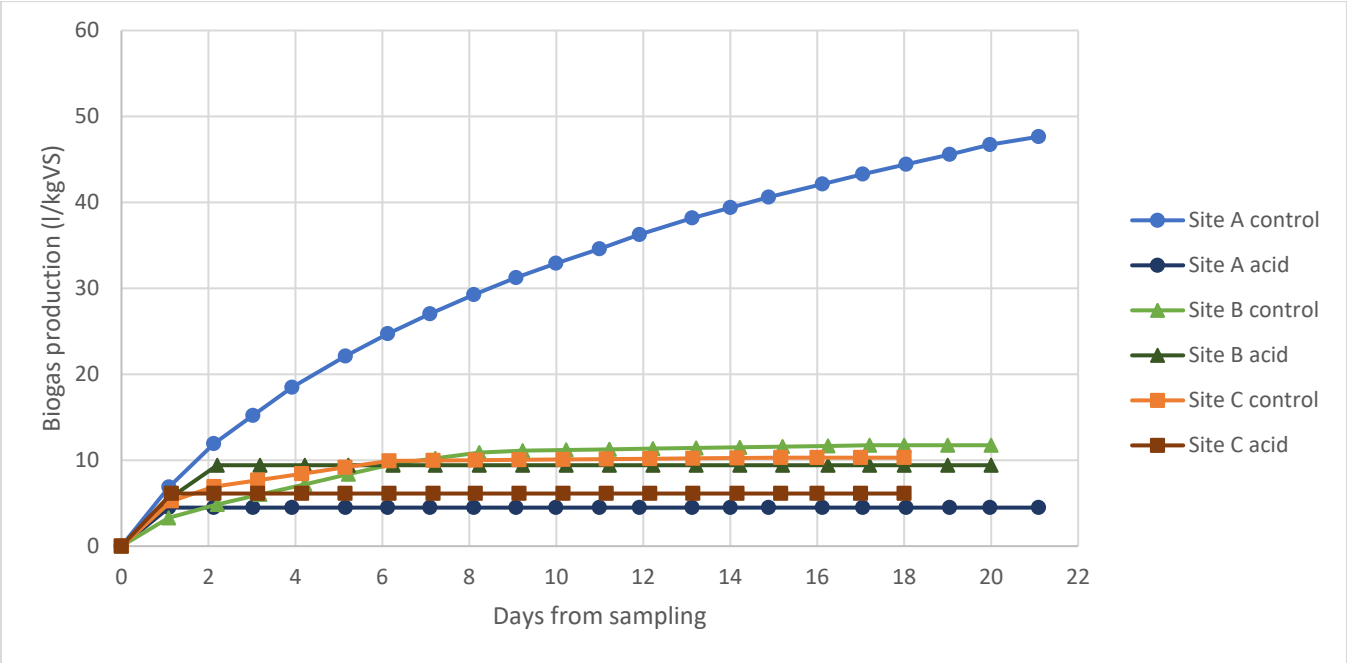


Figure 21: Production from controls compared to acid treated samples. To reduce plotted lines, only average productions are displayed rather than individual repeats.

As with the sodium hydroxide testing, pH did not remain constant over the course of the testing (Table 22).

Table 22: The pH readings of aluminium sulfate treated samples over the testing period

Site	A	B	C
Initial sample pH	8.06	8.64	7.09
Target pH	4.00	6.00	5.50
pH achieved	4.14	5.70	5.39
14-day pH	3.91	6.96	5.99

Site A showed further decrease in pH after the 14-day period, another indicator that the chemical reactions determining the pH change were still ongoing after the sample vessels had been sealed. Sites B and C, however, saw pH rising towards neutral, with site B's pH rising to well within the range of methanogenic activity. Again, this could be due to the specific site's range, the initial pH shock, or the chemical reactions that led to the reduced pH affecting substrate composition sufficiently to prevent methanogentic activity.

Site C also showed a sharper change in pH compared to the other two sites in pH decrease (Figure 22).

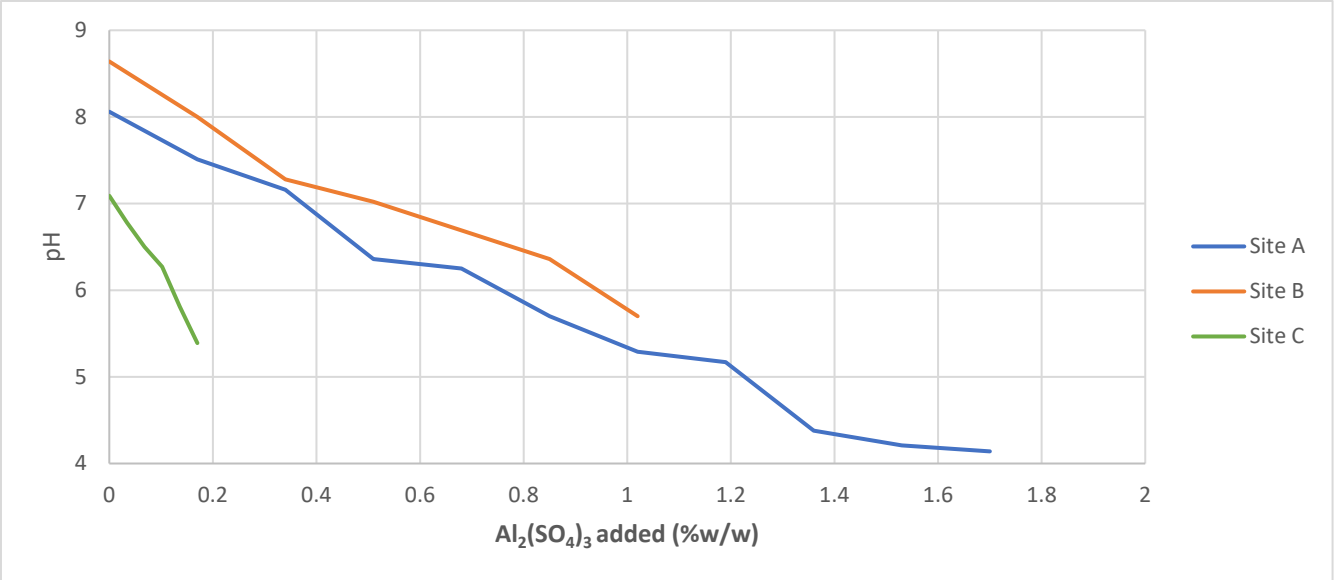


Figure 22: The change of pH for each site sample with addition of aluminium sulfate

9.1.6. Separation

Separation of digestate into solid and liquid fractions is considered an important part of digestate management as it reduces storage requirements,[106] transport costs and can also separate

[106] Vilanova Plana et al., Digestate separation and its impact on logistics and nutrient management. Agricultural Engineering International: CIGR Journal. 2016.

nutrients, which can make subsequent use easier where usage of whole digestate would otherwise be limited.[107]

When considering methane emissions from separated digestate, past studies have been inconclusive. Romio, Ward, & Moller (2024) found that when separated at laboratory scale the solid fraction of digestate from agricultural plants contained 60% of the methane potential of whole digestate, whilst 40% remained within the liquid fraction.[108] However, when tested at industrial scale the opposite was found, in this test the liquid fraction contained 60% of the methane potential of whole digestate. VanderZaag & Balde (2022) found that separation techniques that removed sufficient nutrients from the liquid fraction could completely eliminate methane production from liquids; however, the separated solids were not tested.[109]

Site D was used as a case study for separation. The specific equipment used at the site is a screw press slurry separator. This type of separator uses a purely mechanical pressing/filtration action to separate the digestate into fibre and liquor. No additives are used for this type of separation technology. The dry solids and volatile solids associated with each constituent are given in Table 23.

Table 23: The dry solids (DS) and volatile solids (VS) of the whole digestate and constituent parts at site D.

Constituent	Whole digestate	Separated liquor	Separated fibre
DS (%)	9.7	6.2	25.1
VS (% of dry solids)	75.6	67.7	86.4
VS (% of fresh)	7.3	4.2	21.7

As the study was designed to reflect the conditions of storage on site the 20°C water bath was used. The design of this storage is often based on the assumption that the separated liquor retains the majority of the biogas generation capacity; however, it was found that separated fibre also has potential (Figure 23).

The fact that the separated fibre (SF) did not produce any biogas within the first few days is likely a result of its on-site storage conditions. As found with the aeration testing of site C, sufficient aeration may suppress methanogentic activity without killing the methanogens, and in then moving the sample into a sealed anaerobic environment that activity can be allowed to start again. If this is the case, then good aeration of stored SF could be a possible strategy to reduce emissions.

[107] Cathcart et al., Nutrient recovery and utilization from separated digestate fractions. Journal of Environmental Management. 2023.
[108] Romio et al., Methane potential of separated digestate fractions at lab and industrial scale. Waste Management. 2024.
[109] VanderZaag et al., Impact of digestate separation on methane emissions and nutrient removal. Bioresource Technology Reports. 2022.

It should be noted that these results are displayed on a basis of volatile solids; however, on a fresh basis whole digestate (WD) had a higher production than separated liquor (SL) as well as the low producing SF sample (Table 25). There was no clear difference between the two SF samples that would account for the divergence in production, this difference was supported by a final mass check.

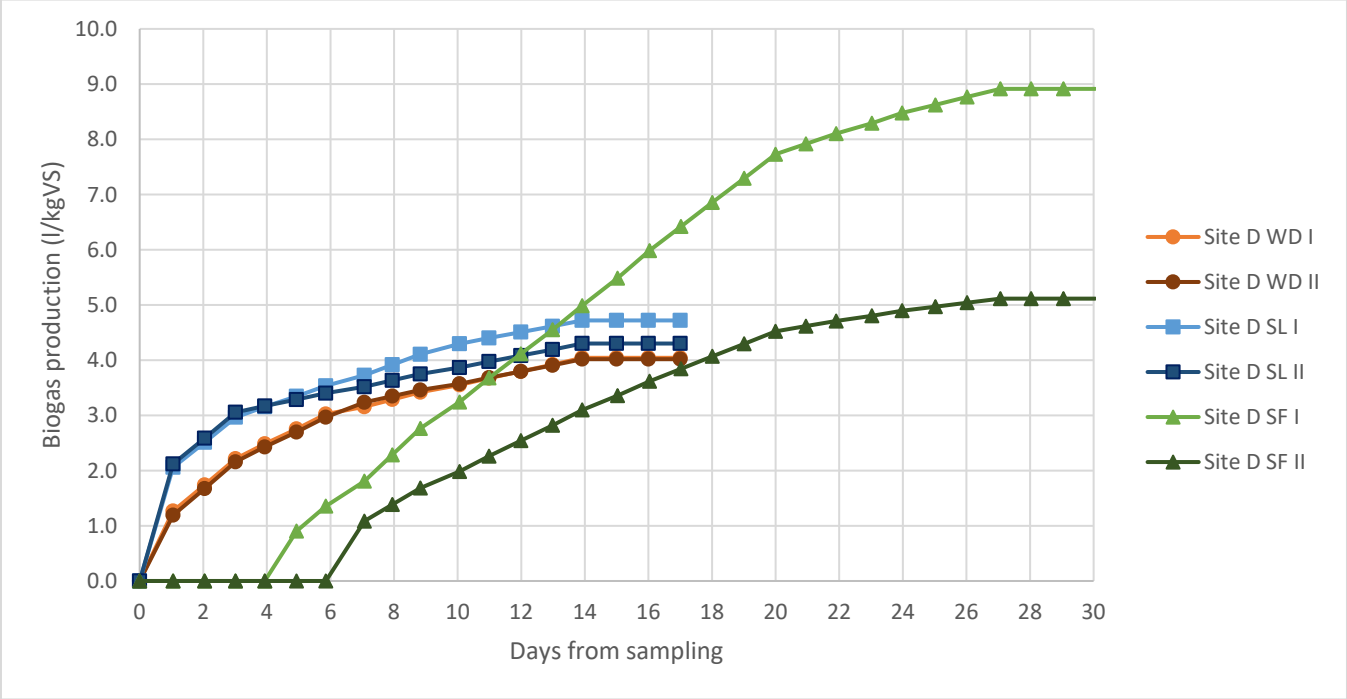


Figure 23: Biogas production from both whole and separated products at site D

As SL was collected for aeration trials at site A, a similar test was done to compare WD and SL when stored at 20°C and the results are shown in Figure 24. Here WD produced more biogas on both a fresh and VS basis (Table 25). SF was not readily available at this site, so was not tested. A screw press slurry separator is also used at site A. The dry solids and volatile solids associated with each constituent are given in Table 24.

Table 24: The dry solids and volatile solids of the whole digestate and separated liquor at site A.

Constituent	Whole digestate	Separated liquor
DS (%)	8.6	7.8
VS (% of dry solids)	76.3	70.8
VS (% of fresh)	6.56	5.52

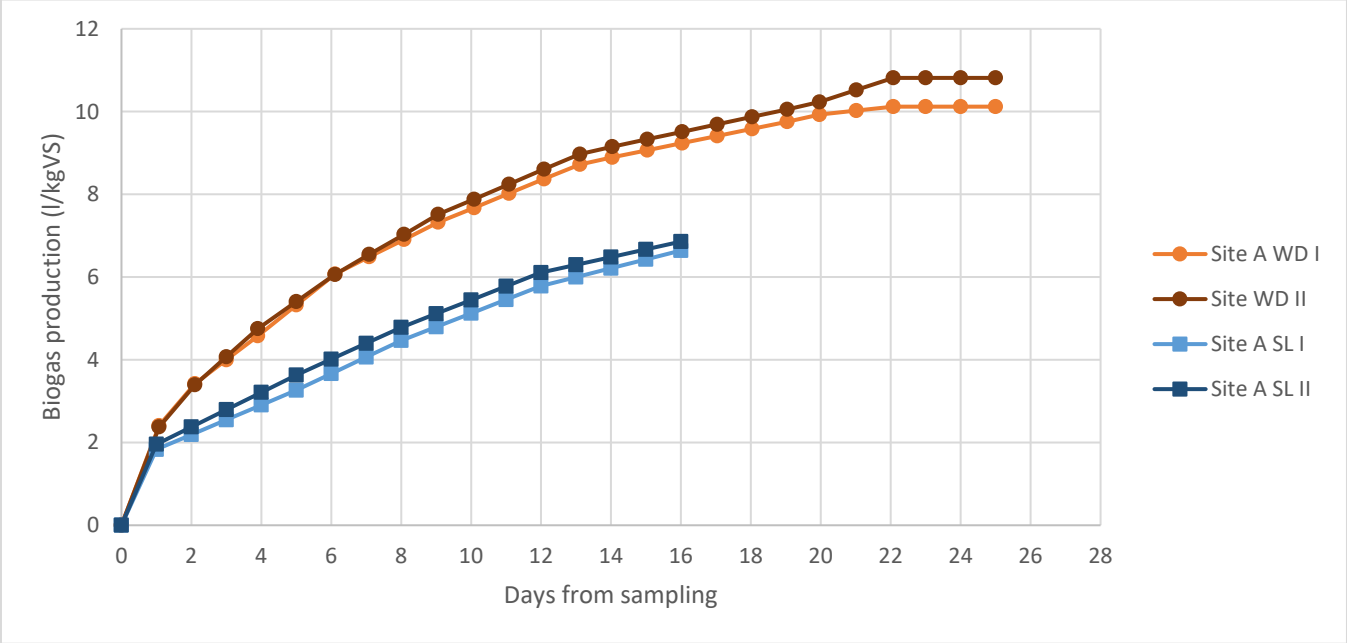


Figure 24: Biogas production from WD and SL at site A

The separation was more effective at site D, with a lower resultant DS and VS in the liquor compared to site A. On a fresh basis, the whole digestate produced more biogas at both sites (see Table 25). The efficiency of the separator may therefore factor into the resultant emissions from separated products.

Table 25: The total biogas produced on a fresh basis from both sites.

Site		A	D
Biogas production (l/kg fresh)	WD	0.69	0.30
	SL	0.37	0.19
	SF	-	0.65

9.1.7. Pasteurisation

Pasteurisation is often required on AD sites as part of treatment of animal by products,[110] or to gain certification under the Biofertiliser Certification Scheme (BSI PAS110). The primary purpose of this pasteurisation is the destruction of pathogens potentially harmful to human health. Depending on the requirements of the site, pasteurisation may occur prior to or post the digestion process.

Nolan, et al. (2018) tested both pre- and post-digestion pasteurisation at both the EU standard (70°C for 1h) and an equivalent Irish standard from DAFM (60°C for 96h), and found that methane continued to be produced from all samples, with the EU standard leading to an initial

[110] DEFRA, APHA, Animal by-products: Guidance for operators of anaerobic digestion plants. 2020.

spike in production over the first week, but all samples still producing methane 4 weeks after pasteurisation.[111] Zhang et al. (2020) only looked at pre-digestion pasteurisation and found that the pre-treatment could assist in breakdown of some specific compounds (e.g. starch in potato waste), but that there was no impact on methane production.[112]

Site E, an agricultural site with post-digestion pasteurisation, was selected as a case study for this. The pasteurisation treatment requires digestate to reach 70°C for 1 hour, and the comparison between pre- and post-pasteurised digestate is shown in Figure 25.

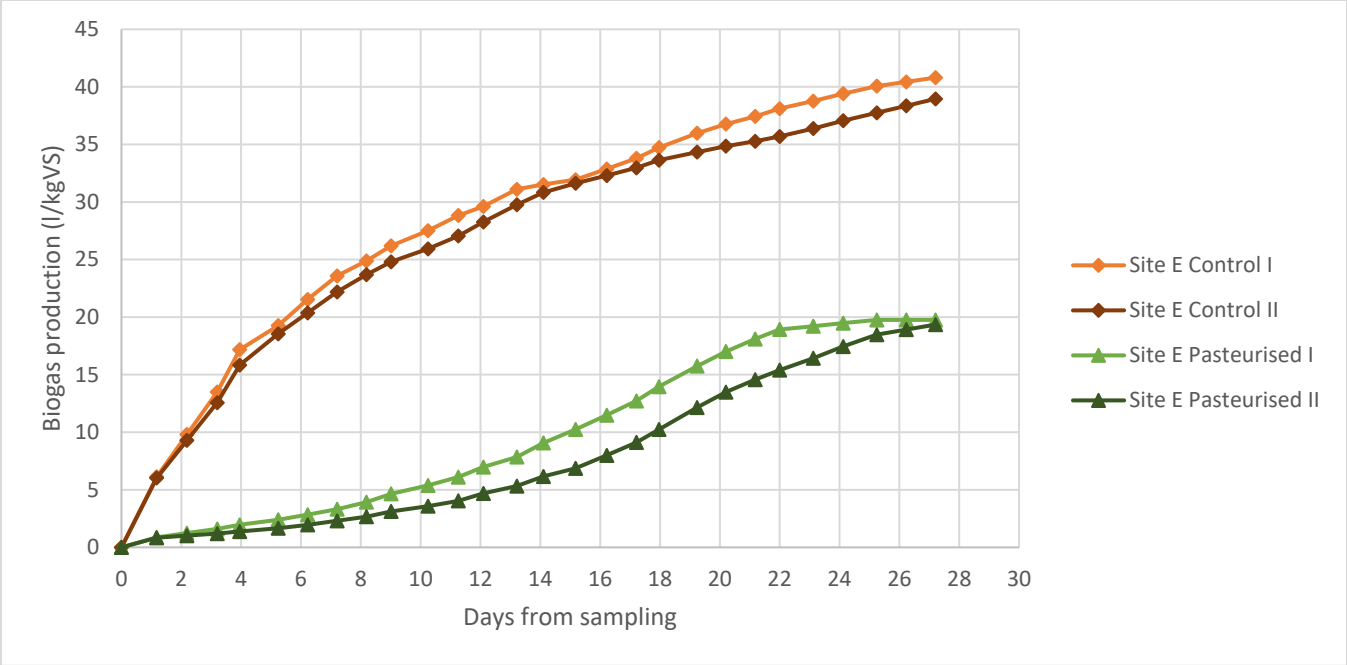


Figure 25: The biogas production from samples pre- and post-pasteurisation

At no point was production completely stopped by pasteurisation; however, it was significantly suppressed. The rate of production increased after a lag of around two weeks which matches the time scale for regeneration of methanogens at 5-16 days.[113] Following this time, daily production from the pasteurised sample increased in rate; however, production from both pasteurised and control samples slowed after three weeks, meaning that the pasteurised sample had a lower total production.

9.2. Digestate Emissions Abatement Summary

Of the methods tested within this trial, both the aeration and pH adjustment were able to completely stop methanogenesis from occurring. Aeration, whilst completely effective on separated liquor from site A and digestate from site B, was ineffective on whole digestate from site A, likely due to its physical inability to fully aerate high fibre material, and at site C only suppressed methane production temporarily. Therefore, use of aeration as a stop for

[111] Nolan et al., Impact of pasteurisation timing and temperature on methane production in anaerobic digestion. Waste Management. 2018.
[112] Zhang et al., Effect of pre-digestion pasteurisation on substrate breakdown and methane yield. Journal of Environmental Management. 2020.
[113] Deublein et al., Biogas from Waste and Renewable Resources: An Introduction. 2008.

methanogenesis is dependent on physical properties of the digestate and the storage conditions following aeration, and is potentially dependent on the populations of methanogens present.

Separation similarly was able to cause temporary suppression of methanogenesis in separated fibre, possibly due to some aeration occurring during the process and within storage, or due to removal of available carbon material into the liquor. Once storage conditions changed methanogentic activity began again.

The effect of pasteurisation is similarly able to supress methanogens, although not entirely stop methanogenesis, it is also dependent on post pasteurisation storage conditions being able to prevent the repopulation or reactivation of methanogens.

pH adjustment through use of a base was effective on all tested digestates, although further study as to the limits of pH is required to ensure the final product can still be used. Use of an acid was also effective, although consideration must be given to the produced CO_2, which would be another emission requiring abatement. As with use of a base, the final product must still have use and this is even more significant in this case, as most soils are acidic and therefore a basic digestate would have more use.

Extended process time could also be considered for reduction of biogas potential and therefore downstream emissions, should the timescale for biogas production to plateau be reasonable, as with sites B and C, but not site A.

Vacuum degassing led to higher biogas production long term and, at least on sites B and C, this appears to be due to extended production time, potentially indicating the treatment increased availability of substrate for methane production.

Due to the limitations in scope of this study several questions arose through testing that could not be answered in full. As such the following areas are suggested for further research with the potential to look deeper into the abatement techniques investigated.

- The testing for extended process time was a batch system. Whilst some digesters operate in batches, most are continuous processes. This means that new material would be introduced throughout the storage time, potentially changing the timescale on this treatment process.
- Only one method was used for testing of aeration. It may be possible that a method that incorporates mechanical mixing would have more effect on fibrous digestate, or that a method that allows for continued or intermittent aeration and monitoring of gas reveals more effective suppression.
- Similarly, only one method was tested for vacuum degassing. It is understood that vacuum degassing equipment being installed on sites can achieve a stronger vacuum and can treat digestate without exposing it to atmosphere. No site case study could be arranged but looking at these techniques in situ is highly recommended.

- There may be other substances that could achieve pH change. As environmental impact should be considered, substances should be checked not only for their effectiveness, but also for how they would interact with soils when spread to land.
- Combined treatments were not considered, either with each other or with options such as heat treatment.
- Throughout this study biogas production was used to indicate presence of active methanogenesis, however no microbial study was conducted. Such studies would better establish whether methanogens are killed by certain processes, or only shocked/inhibited with the potential for recovery.
- The mechanisms by which suppression of biogas production was achieved were not studied. Adjustment of pH will be caused by specific chemical reactions and these may vary depending on the initial composition of the digestate. Aeration may affect the redox of the digestate. Understanding these mechanisms may allow for more direct targeting and more effective suppression technologies.

Recommendations for abatement of post-AD area emissions from digestate

Of the tested potential methods of abatement:

- Extended process time is a potential option for sites where residual biogas potential is low enough to allow for reduction in a reasonable timescale. This is unlikely to be as effective on agricultural sites that are utilising energy crops, as these take a significant time for complete digestion; however, extended process time will always lead to some level of reduction in remaining methane potential. On sites with uncovered storage tanks, emissions reduction could be achieved by covering those tanks and connecting capture systems back to the biogas production and use system.
- The effectiveness of aeration is likely dependent on the physical properties and biological populations of the digestate, as well as the storage conditions post aeration. Aeration could be introduced through air mixing of stored digestate, providing the required properties are met. Further research is required to confirm these properties. Emissions during the aeration time were also not accounted for in this work.
- Vacuum degassing as tested here did not lead to a reduction in biogas production, and in one case caused higher biogas production over the testing period. This set-up was ineffective, although others should also be studied.
- Increasing pH stopped methanogenesis in all cases tested.
- Decreasing pH also stopped methanogenesis, although the use of aluminium sulfate led to production of carbon dioxide. Both pH adjustment techniques would likely require a dedicated vessel, and an input of additives, which may have economic limitations as well as environmental effects.

- Both separated liquor and fibre fractions were found to have residual biogas potential; again, storage conditions are important for mitigation of emissions.
- Pasteurisation reduced biogas production initially, potentially through either reduction or suppression of methanogen population; however, given time for the population to recover, production increased again.

10. Conclusions

Methane emissions from AD can arise at various stages of the biogas production process, including during:

- Feedstock reception, storage and pre-treatment
- Feedstock digestion and biogas storage
- Biogas utilisation (whether upgraded to biomethane and injected into the gas grid, combusted in a CHP, or flared to the atmosphere)
- Post-digestion as part of digestate treatment, storage and utilisation.

The MEAD 2.0 project aimed to collect evidence on mitigation measures and good practice around plant design and operation for each of these different AD process areas, with the intention of informing criteria for sustainable AD growth in the UK. To achieve this aim, the specific objectives of the MEAD 2.0 project were to:

- Define good practices in relation to asset selection, operation and maintenance that result in the minimisation of point-source methane emissions on AD sites and capture the expected wider environmental and public health impacts of these practices.
- Inform on methane slip from biogas upgrading technologies that are common in the UK.
- Capture previous evidence and field data on the efficacy of established and emerging abatement strategies for area emissions, and capture expected wider environmental and public health impacts of these strategies.
- Identify critical gaps in knowledge to abate point-source and area source methane emissions in UK AD sites, suggesting recommendations for addressing them.

This study aimed to flag key areas of emissions, identify the reasons for these emissions, and understand the level of awareness around different emissions areas. The study flagged that emissions can be generated across all areas of an AD facility, but they are typically most common in areas where biogas is produced and handled (i.e., from the point of digestion through to digestate storage).

Asset Selection and Maintenance

It is evident from this research that methane emissions often occur as a result of OTNOC, due to old or faulty assets (e.g., gaps in tank roofs, cracks in concrete, malfunctioning valves or seals etc) and as such, a key measure to identify and mitigate said emissions is through employment of regular monitoring and maintenance, with LDAR recommended on a regular basis. Active pressure relief valves have been identified as a key source of emissions across the AD process, with poor quality and malfunctioning equipment often causing unintended leaks. Stakeholders active in this area flagged the need for appropriate standards relating to the use of PRVs in AD. With so many different types available on the market, and a lack of awareness of the emissions generated from PRVs, this highlights the importance of high-quality components being

necessary and regulation or setting minimum standard requirements presenting as possible approaches.

To keep emissions to a minimum, it is essential that assets are designed and specified according to the intended scale and type of operation, and should expansion be considered, the suitability of original assets should be reconsidered to ensure they remain fit for purpose and effective for use. Equipment should be installed and maintained by suitably trained engineers, following an appropriate commissioning plan to ensure any leaks resulting from installation defects are identified immediately, and addressed before handover.

Biogas Upgrading

Alongside emissions caused by OTNOC, methane is also common as a result of NOC from biogas upgrading due to the inherent design of biogas upgraders. The action of removing CO_2 and other contaminants from biogas cannot be performed at 100% efficiency with the upgrading technology on its own. However, moves are being made to bring slip down closer to zero with new technology and operational innovation. As such, if the off-gas is not subsequently treated, it is expected that a small portion of methane will be vented to the atmosphere as part of this process. There are a number of different upgrading technologies currently available on the market, with membrane separation the most common in the UK followed by water scrubbing. The percentage of methane expected to slip from these technology types is typically in the region of 1-2%.

In order to keep slip to a minimum during commissioning and operation, it is essential the equipment is appropriately specified for the scale and type of plant on which it is being deployed, the recommended maintenance schedule is followed by appropriately trained engineers, and the equipment is included within the scope of the LDAR programme.

Off-Gas Treatment

Given that slip is inevitable due to the nature of the upgrading technologies, the most effective way of minimising methane slip is with off-gas treatment. The use of CO_2 capture units to capture any gases which would typically be emitted to the atmosphere following biogas upgrading was flagged as beneficial by a number of stakeholders, as discussed in the report. However, despite this positive result, this solution is not necessarily accessible to all biomethane facilities as the capital cost of purchasing such equipment was quoted as being around £1.5 - 2 million at the scale of a typical GGSS supported development. Furthermore, parasitic energy demand and resulting OPEX is high, and regulatory and perception barriers are still impacting market access for CO_2. Potential market interventions or regulatory reforms to provide stable and viable outlets for the captured CO_2 could benefit the economic case. The UK Emissions Trading Scheme (ETS) Authority issued a consultation[114] to recognise non-pipeline transport (NPT) of CO_2 to geological storage in the ETS. This would enable emitters sending CO_2 to permanent storage via NPT to deduct the amount of permanently stored CO_2 from their UK ETS allowance surrender

[114] UK ETS scope expansion - CCS: non-pipeline transport of carbon dioxide - GOV.UK

obligations.[115] This would further benefit the market, increasing the proposition for a broader customer base.

The use of technologies such as catalytic thermal oxidisers and regenerative thermal oxidation could be an effective method for treating methane slip from CHP engines and biogas upgraders, however, capital cost could be a barrier so a site-level cost benefit analysis would inform any future investment in this area.

Site Monitoring

Awareness around the potential impacts of methane emissions is generally well recognised across the UK's AD sector. Industry is becoming increasingly aware of the importance of capturing methane, not only from the perspective of boosting site revenue, but also in terms of minimising impacts on the environment. Methane is considerably more potent than CO_2 in terms of its global warming potential, thus there is a very real need to ensure that fugitive methane is reduced by the AD sector. However, despite understanding the importance of minimising methane emissions, LDAR programmes are not widely adopted. Where LDAR has not been implemented it is currently a breach of permitting conditions and the IED BREF BAT requirements, leaving operators open to enforcement for non-compliance.

Although noted for its value, both for economic and environmental gain, LDAR was not found to be an area being discussed widely by the sector, unless required by existing policy or regulation. As such, there is currently a disparity in awareness of need for LDAR across the wider sector with older sites generally applying less stringent monitoring measures. Within literature, higher levels of methane emissions were generally observed at smaller anaerobic digestion facilities, which may be attributable to lower investment in maintenance relative to larger facilities.

The primary reasons quoted for the lack of LDAR monitoring beyond the regulatory requirements across the industry focused on the costs associated with the implementation of such programmes, as well as a lack of understanding of what is required by, or available to the sector, due to limited official guidance in this area and a reduced number of companies active in this space. Many sites do not monitor methane emissions because it is neither deemed necessary for operation nor a regulatory or policy requirement. Some sites are also able to use default values for GHG reporting and still meet the GHG threshold as a result, when undertaking GHG calculations on RHI and GGSS. The GHG threshold approach currently provides no incentive for operators to go beyond this GHG limit from a regulatory perspective, so although they can use actual values, many still rely on standard values to reduce operational costs for monitoring and measurement, whilst at the same time minimising the administrative burden. However, in order to ensure that biomethane generation can effectively contribute to net zero targets by 2050, it may be beneficial for future AD support schemes to incentivise lower carbon intensity (CI) biomethane production.

[115] UK Government. UK Emissions Trading Scheme: Non-pipeline transportation of carbon dioxide.2024.

While most bespoke permits are now awarded with a requirement for an active LDAR programme to be developed and implemented, this is not representative of the wider AD industry established before these requirements became a requirement for newer sites.

Sites with LDAR programmes in place either owned their own equipment (cameras, sniffers, gas monitors etc.) or employed third parties to conduct testing and monitoring. Sites where emissions testing was not carried out, either in-house or by third parties, cited associated costs, and a lack of perceived need for it. For example, in one case, the site in question previously employed a company to detect and monitor for methane leaks. However, upon review of its cost and a lack of leaks generally found on site, it was deemed an unnecessary practice, as operational costs continue to increase elsewhere – as an exempt site, this facility did not require LDAR for compliance purposes.

Sites with LDAR systems implemented typically carried out routine inspections on a weekly basis, with checklists created to stay on top of the inspections, their findings and resulting actions. Issues can be fixed immediately, or as soon as replacement parts can be obtained. Despite the cost implications of LDAR widely quoted by others, the sites that did carry out monitoring were either required to do so as part of their permit requirements, or because they wanted to demonstrate improved carbon intensity on their sites.

In light of cost being flagged as a key barrier for LDAR uptake by the industry, some indicative costs provided by the stakeholders are:

- LDAR monitoring by 3rd parties ~ £1,200-2,500 per day (depending on the scale of nature of monitoring)
- Thermal imaging cameras ~ £50,000-80,000 (capital cost)
- Methane leak detector “sniffer” ~ £1,000-5,000 (capital cost)

A common theme appeared throughout this study around the apparent costs associated with the implementation of LDAR and other methane emissions mitigation measures. However, a key message to take away from this project is that by finding and fixing methane leaks at AD sites, the costs associated with monitoring and emissions reduction will be paid off over time, based on the value of methane saved and the additional revenue gained.

It is estimated that the loss of just 1m^3 of methane per hour at an AD site in the UK could lead to approximately £5,000 per year in lost revenue.[116]

A valuable consequence of adequate monitoring, identification of problem areas and timely action will be to improve site health and safety. By quickly localising leaks or faulty equipment the operator can reduce the build-up of dangerous atmospheres or explosion risks in confined areas and reduce operators’ exposure to toxic gases such as H_2S.

Digestate Storage

[116] ADBA, Pollutant gases: leak detection and repair. Guidance.

Uncovered digestate storage is recognised as being a significant source of methane emissions in literature, and the MEAD 2.0 study investigated measures to mitigate the generation of these emissions. Extended processing times were highlighted as a potential option to minimise emissions, by reducing residual biogas potential in the digestate prior to going to storage. Several operational stakeholders also flagged this as being a key measure employed on site for reducing emissions from digestate, as well as the use of digestate covers as a measure for capturing residual biogas, whilst continuing innovation in pH variation and aeration, for example, present positive opportunities for having effective options available in the future.

Covered digestate storage presents positive opportunities, to not only reduce odour but to also reduce methane as well as ammonia emissions from digestate. Gases generated by digestate can be collected by covers and flared off, or if located close to the AD facility, fed back into the system to ensure that no gases are lost.

On a similar note, wastewater treatment facilities are typically found to have high relative emissions, attributed to an absence of gas-tight digestate storage. However, this is due to the fact that the purpose of water treatment facilities has traditionally been to process/treat wastewater rather than to produce energy, which often influences effort to contain methane as a source of energy and revenue. However, stakeholder engagement with a number of key players in the UK's water industry indicated that emissions reduction at these types of sites is now becoming increasingly prominent, with the sector committing to being operationally net zero by 2030, and companies committing to net zero targets in a similar way. A number of commercial technologies have been rolled out and used to mitigate emissions from sites of this type demonstrating a market pull towards investing in methane mitigation measures.

Alternative emissions abatement techniques, beyond impermeable storage covers, are being investigated by the industry, as considered in WP2. The effects of techniques such as aeration, pH changes, vacuum degassing and separation were tested at small scale. The results showed potential for some techniques such as aeration and pH changes but these trials were limited in scope and would need further, detailed, work to prove efficacy at large scale. It is important to highlight here that the range of tested strategies considered throughout WP2 were not exhaustive, with other innovation strategies not considered during this project meriting further investigation in the future (e.g. use of bioadditives).

Further Action

Larger operators, portfolio managers and more recent installations tend to have a better understanding of the effects of methane losses and the benefits of maintaining the equipment to a high standard. However, there is still a significant portion of the industry that are not aware of the issues, resultant consequences and likely benefits. Key areas identified to be addressed are:

- Comprehensive training for operators and site staff, to be more aware of the need for effective monitoring and to understand when equipment requires maintenance, is failing or coming to the end of its effective life.

- Raise awareness among operators of the financial and environmental costs of methane losses and the benefits of reduction, prevention and capture.
- Provide clear guidance on what is required in terms of breadth, depth and frequency of an effective monitoring routine.
- Improved access to monitoring equipment or services at reasonable cost and in a timely manner, whilst also ensuring service provision is scaled alongside deployment, would help ensure effective and timely repairs can be carried out if/when issues are detected.
- Research gaps in digestate emissions abatement could be addressed with further research on innovative techniques that are not yet deployed at commercial scale in the UK, as well as linking efficiency of upstream AD operation to digestate emissions.

11. Appendices

11.1. Appendix A - Literature Review Methodology

A high-level systematic review of published international literature was undertaken to identify key factors influencing point-source and area emissions from AD facilities. The objective of the review was to capture data and analysis to understand the magnitude of methane losses, identify suitable monitoring methods, and assess the efficacy of existing or innovative mitigation strategies.

The review covered methane emissions across all operational stages of an AD facility with a focus on biogas upgrading to biomethane as the biogas utilisation option.

The review considered the source, publication date and robustness of evidence with a focus on recommendations for selection, design, operation and maintenance of elements and assets that are known emissions sources and abatement techniques.

The literature covered academic papers, research projects, technical specifications from equipment suppliers and installers, key policy documents and consultations, consultation responses and strategic industry position papers.

Literature was collated in a searchable Excel database. The database was organised into five sections.

- Emissions from anaerobic digestion (including digestion and whole process, from reception to digestate)
- Emissions from biogas upgrading
- Emissions from digestate
- Emissions from odour control units (OCUs)
- Emissions measurement

For each identified publication the following information was recorded: title, author, year, publication type, a summary of publication purpose/results, and a link to the original source.

Publications were identified using defined search strings and a limited number of search engines/databases. The search strings used were recorded in the Excel database; examples include:

- Anaerobic + digestion + methane + leakage
- Digestate + emissions + abatement
- Odour + control + units + methane + slip + anaerobic + digestion

The search engines and databases used were also recorded in the Excel database and include Google Scholar and Science Direct.

11.2. Appendix B - Stakeholder Engagement

Stakeholder engagement took place throughout the MEAD 2.0 project. The aim of this phase was to validate the findings from other work streams (i.e., the literature review and site sampling) and to gain valuable insight from key players active in the AD industry, both in the UK and internationally.

Companies active across a range of industry areas were engaged via stakeholder interviews, email correspondence, and discussions in-person at industry events. The aim being to understand the level of awareness around methane emissions sources and impacts throughout the industry, and to identify to what extent action is being taken to mitigate methane emissions at present.

98 stakeholders were engaged with throughout the course of the project including plant operators, technology providers/technology installers (e.g., tank suppliers, biogas upgrader suppliers, valve manufacturers etc.), consultants/researchers specialising in AD, servicing and maintenance engineers, and industry bodies representing the AD sector. The types of companies engaged with are highlighted in Figure B1 below, with AD site operators and technology providers making up over two thirds of the stakeholders consulted.

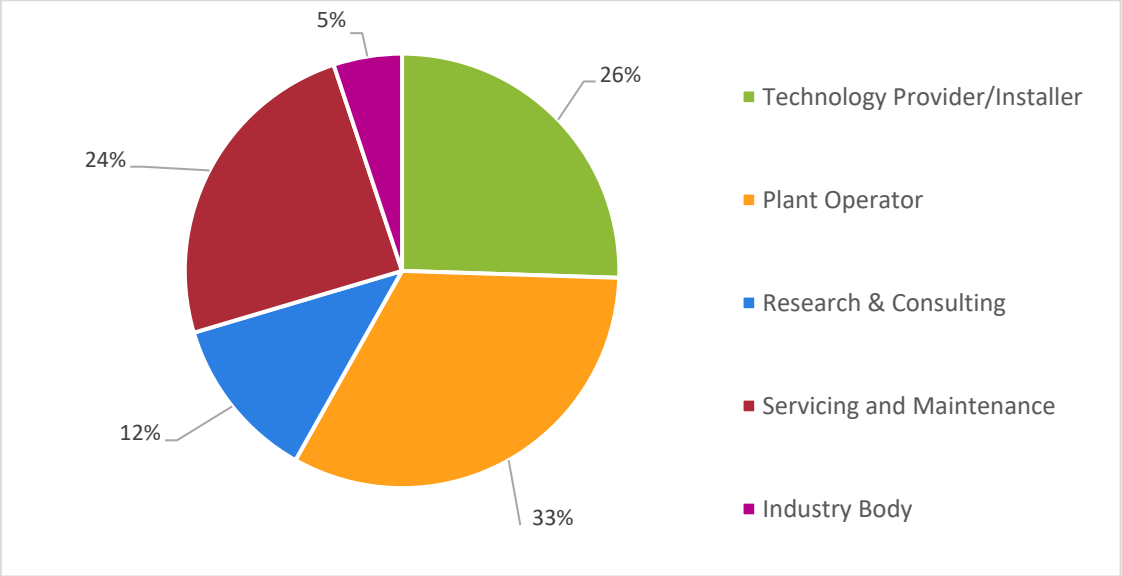


Figure B1: Stakeholder categories engaged with throughout the MEAD 2.0 project.

The insights gained from stakeholder engagement are discussed throughout the main body of this report.

11.3. Appendix C - AD Market Analysis

In order to target suitable sites for the sampling and analysis phase of the MEAD 2.0 study, high-level market analysis was carried out, to profile operational facilities, by type, scale, age and input. This initial market assessment was crucial for determining appropriate targets and suitable sample sizes.

To assess the current state of the AD and biomethane industry in the UK, data from Alder BioInsights' AD Deployment Database[117] was utilised. According to this database, there are 625 operational AD facilities in the United Kingdom, presenting a multitude of outputs. Of these, 421 sites are primarily farm-fed,[118] with a combined installed electrical capacity of 273.4 MWe, while 204 sites are waste-fed,[119] with a total installed capacity of 336.8 MWe. There are also understood to be an estimated 170 wastewater treatment facilities with AD capacity operating in the UK – bringing the total number of operational AD facilities to approximately 800.

Roughly 85% of the existing UK AD market consists of combined heat and power (CHP) facilities, generating heat and power for on-site and/or local use and wider distribution. Of these, 70 are micro-scale plants (0-102 kWe) with a combined capacity of 4.45 MWe, 214 are small-scale plants (103 – 499 kWe) with a combined capacity of 68.45 MWe, 187 are medium-scale plants (500kWe – 2,863 kWe) with a combined capacity of 199.34 MWe, 24 are large scale plants (2,864 kWe – 4,907 kWe) with a combined capacity of 84.81 MWe, and 8 are very large-scale plants (> 4,907 kWe) with a combined capacity of 56.20 MWe. It is understood that a further 150-160 wastewater treatment sites in the UK are also AD CHP facilities.

An additional 132 biomethane-to-grid (BtG) plants are also in operation in the UK, contributing 196.5 MWe of installed electrical capacity and 85,743 Nm^3/hr of biomethane capacity. Of these, 77 are medium-scale BtG plants (200 – 700 Nm^3/hr) with a combined methane capacity of 38,651 Nm^3/hr, 31 are large-scale BtG plants (701 – 1,200 Nm^3/hr) with a combined capacity of 28,908 Nm^3/hr, and 3 are very large-scale BtG plants (>1,200 Nm^3/hr), with a combined capacity of 6,150 Nm^3/hr.[120] A further 14 BtG facilities are based at wastewater treatment sites, with a combined methane capacity of roughly 12,000 Nm^3/hr.

Figure C1 illustrates the growth experienced by the AD industry over time, split by CHP and BtG facilities, since 2008. Over the past two decades, market growth has been driven primarily by the RHI and FIT schemes (both now closed to new applicants, but still supporting successful applicants prior to the schemes' closure for the duration of their 20-year accreditation period). The current Green Gas Support Scheme (GGSS) has not driven the same rate of growth in terms of plant numbers as these previous support mechanisms to date, being a shorter and more

[117] NNFCC, Anaerobic Digestion in the United Kingdom, 2024
[118] Installations where the contribution of agricultural feedstocks (e.g., manure; slurry; energy crops; crop wastes) towards the total feedstock requirement is greater than 50%.
[119] Installations where the contribution of municipal (e.g., food waste; green waste), commercial (e.g. food waste) and industrial wastes (e.g. brewery waste; animal processing wastes) towards the total feedstock requirement is greater than 50%.
[120] Note that the total number of plants categorised does not sum to the total quoted due to incomplete capacity information for eleven facilities. These plants have been excluded from the analysis of capacity distribution across the defined scales.

tightly defined scheme. Although it is worth mentioning that the GGSS tends to support larger developments, therefore relative capacity numbers are increasing at a slightly faster rate.

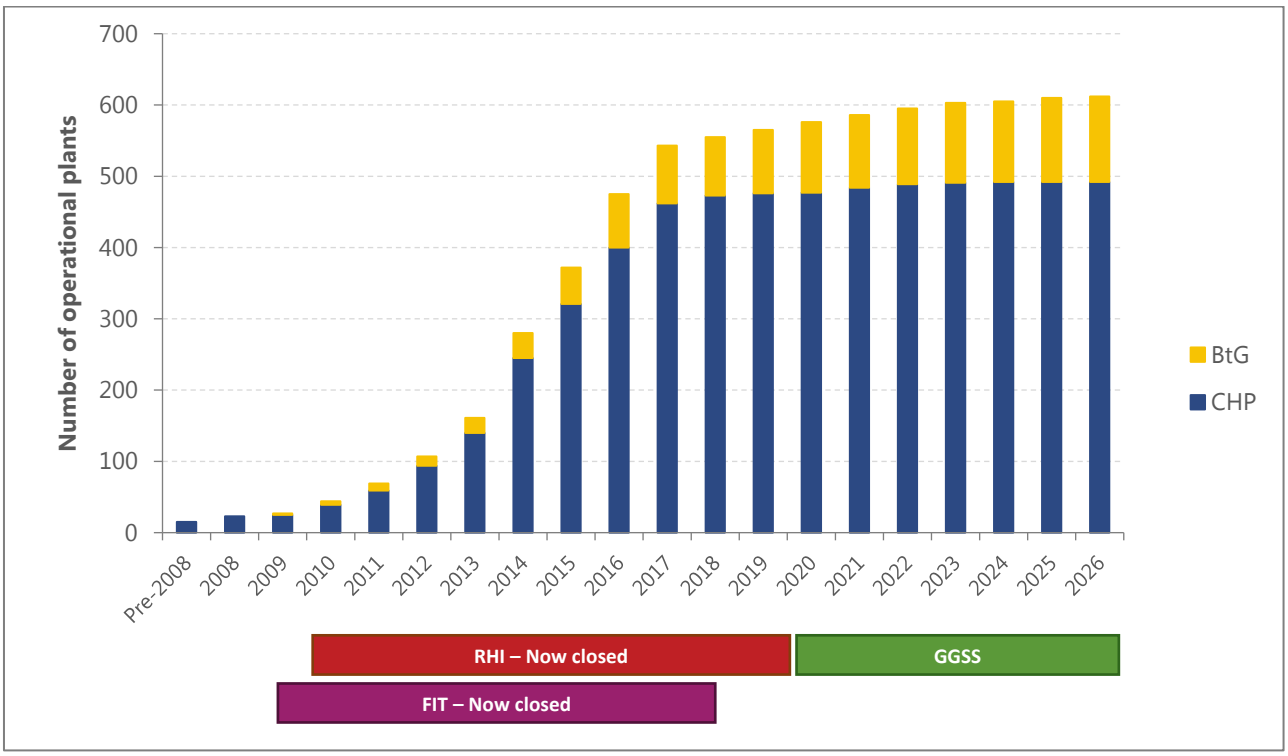


Figure C1: Cumulative number of AD plants, by type, in the UK.[121]

As already highlighted, the largest share of operational AD facilities in the UK are CHP plants, used to produce electricity for export to the electricity grid. However, current policy incentives favour the production of biomethane for gas grid injection. Therefore, only a limited number of CHP facilities are expected to become operational in the coming years, with the vast majority of new projects expected to be BtG plants. This aligns with the UK Government's estimates that around 8TWh per year of biomethane will be injected into the gas grid by 2030,[122] roughly corresponding to a 30% increase in capacity compared to 2022 levels.

Figure C2 illustrates the commissioning timeline of operational and anticipated BtG AD plants in the UK. It shows the total number of biomethane injection facilities commissioned or expected to commission each year. A peak in biomethane facility development occurred around 2016, coinciding with high tariff rates and a matured AD industry which facilitated an increase in development to meet a growth in biomethane demand. The steady growth in biomethane plants anticipated over the coming years, however, is attributed to current UK AD policy (the GGSS), which now favourably supports BtG developments. According to industry forecasts and available Government budget, by the time GGSS closes to new applications in March 2028, the scheme could potentially support the construction of 45-50 new biomethane plants, with an average biomethane capacity of over 750 standard cubic metres per hour (Sm^3/h).[123]

[121] The hashed 2025-2028 bars represent AD projects that are currently in the development pipeline, but not all are expected to go ahead given narrow support available under the GGSS at present.
[122] DESNZ, Future Policy Framework for Biomethane Production, 2024.
[123] ADBA Anaerobic Digestion Policy Report – April 2023

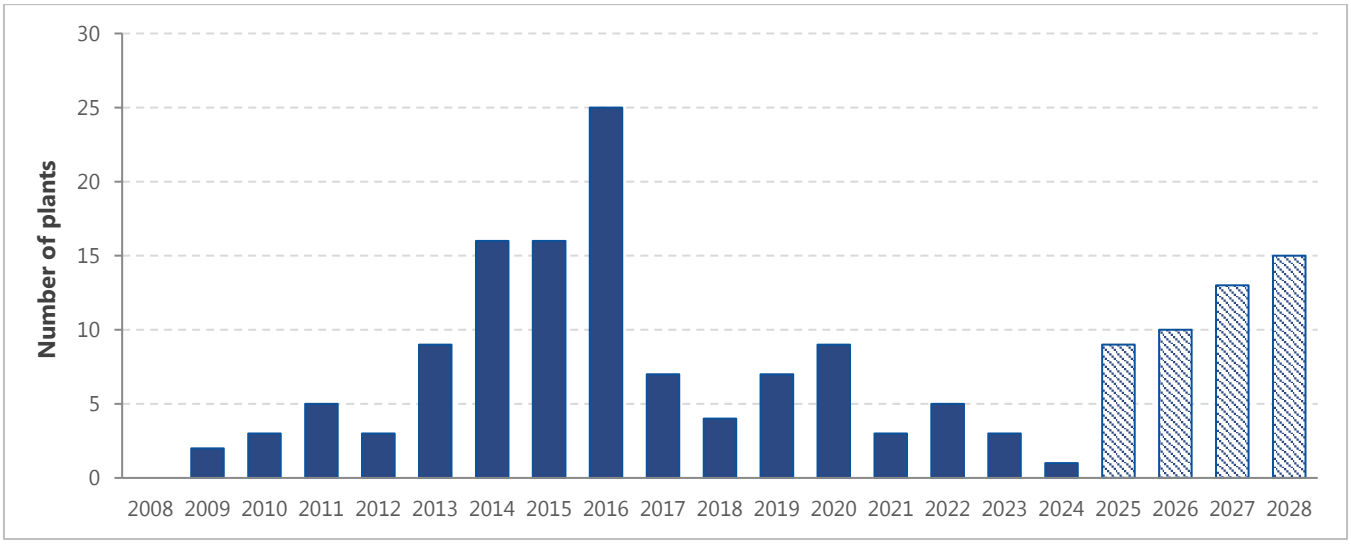


Figure C2: Completion dates (by year) for the operational, under construction, and application approved BtG facilities in the UK.[124]

Regarding feedstock use, operational AD plants across the UK currently have the cumulative capacity to process 17.9 million tonnes of feedstock per annum. This feedstock volume comprises 2,800 kilotonnes per annum (ktpa) of manure/slurry, 4,500 ktpa of crops, 6,000 ktpa of food waste, 730 ktpa of crop waste, and 3,800 ktpa of 'other' waste feedstocks[125] (Figure C3).[126]

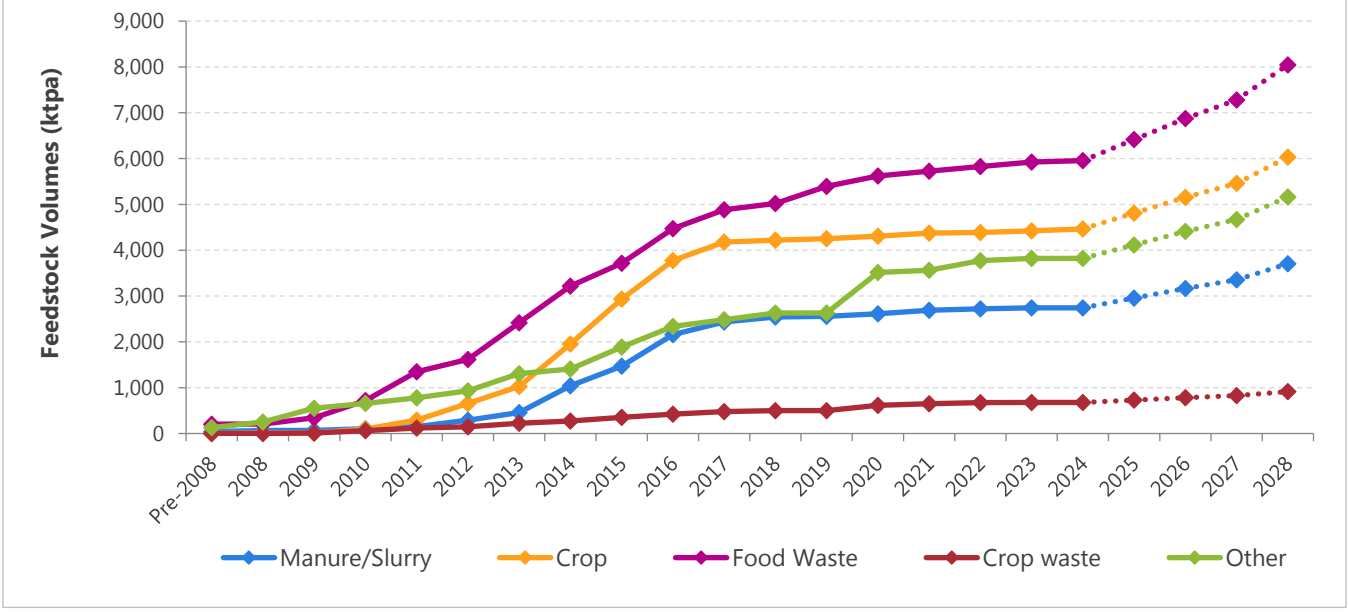


Figure C3: Estimated feedstock requirements for AD projects in the UK.[127]

When considering only BtG plants, 67 are classified as farm-fed facilities, 51 are classified as waste-fed facilities, and 14 are classified as sewage treatment facilities. Collectively, these sites have the capacity to process 7.8 million tonnes of feedstock comprised of 570 ktpa of manure

[124] The hashed 2025-2028 bars represent BtG projects that are currently in the development pipeline.
[125] Other refers to a range of alternative waste types (e.g., brewery wastes, bakery wastes etc.)
[126] NNFCC, Anaerobic Digestion in the United Kingdom, 2024
[127] NNFCC, Anaerobic Digestion in the United Kingdom, 2024

and slurry, 2,000 ktpa of crops, 2,900 ktpa of food waste, 340 ktpa of crop waste, and 2,000 ktpa of other waste.

Food waste remains the predominant input for the UK's AD industry. With the planned rollout of separate household food waste collections across England from 2025, it is anticipated that more food waste will be channelled to AD facilities nationwide. Consequently, the sector is poised for continued growth, with food waste expected to remain the dominant feedstock under the current policy framework.

With regards to asset types used by the AD market in the UK, a key variable in the BtG sector is the range of upgrader types deployed. Figure C4 highlights the spread of upgrader types used by BtG sites in the UK. Roughly two thirds of the current BtG fleet utilises membrane technology for biogas upgrading. Roughly one third of the current BtG fleet utilises water washing as an alternative upgrader type. Other, less common upgraders used in the UK include pressure swing adsorption (PSA), chemical wash, and cryogenic-based technologies.

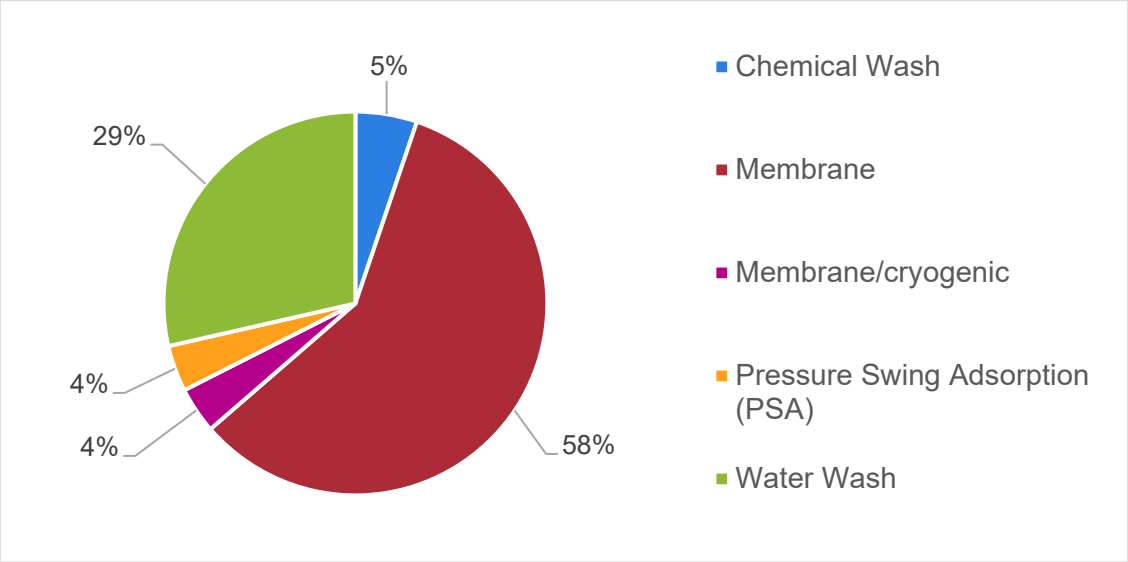


Figure C4: Upgrader types used in the UK.

11.3.1. Site Selection – Work Package 1

Market insight was used to inform site selection for the sampling of point source emissions at AD plants across the UK. Site selection focussed on BtG facilities, given that biomethane injection is the preferred use of biogas under the current policy framework, meaning that BtG deployment is expected to dominate the AD sector going forward.

Initially 10% of the UK's biomethane market was targeted for sampling. Sites were considered based on:

- **Size** (ranging from large to medium scale BtG).
- **Age** (recently commissioned and older facilities).
- **Site ownership model** (those operating under group/corporate ownership compared to individually owned and operated sites).
- **Feedstock type** (waste-fed, farm-fed or sewage treatment feedstocks).
- **Asset type** (where possible sites were selected with variable asset types e.g., upgrader types).

The full profile of sites selected for sampling is summarised below (Table C1). The sites demonstrate a reasonable spread in terms of site size, age, ownership model and feedstock type, offering a fair representation of the sector in terms of the types of sites considered. Furthermore, with regards to the upgraders used at each of these sites, the majority used membrane separation, while two used water wash. This is in line with the current spread of upgrader types presently used by the BtG market in the UK.

Table C1: Profile of sites selected for point source emissions sampling.

Site	Plant Size	Feedstock Type	Upgrader Type	Commissioning Date	Ownership/Operation
1	**Medium** kWe: 440; Nm^3/hr: 495	**Farm-fed** (22,500 tpa)	Membrane	2014	Group owned Group operated
2	**Large** kWe: 499; Nm^3/hr: 1,000	**Waste-fed** (95,000 tpa)	Membrane	2022	Group owned Group operated
3	**Medium** kWe: 3,176; Nm^3/hr: 850	**Waste-fed** (50,000 tpa)	Membrane	2011	Individually owned Individually operated
4	**Medium** kWe: 500; Nm^3/hr: 750	**Farm-fed** (51,000 tpa)	Membrane	2021	Group owned Group operated
5	**Medium** kWe: 500; Nm^3/hr: 375	**Waste-fed** (50,000 tpa)	Water wash	2016	Individually owned Individually operated
6	**Medium** kWe: 4,500; Nm^3/hr: 250	**Farm-fed** (20,000 tpa)	Membrane	2016	Group owned Group operated
7	**Large** kWe: 6,400; Nm^3/hr: 1,026	**Sewage** (396,000 tpa)	Water wash	2012 BtG in 2014	Individually owned Individually operated
8	**Large** kWe: 495; Nm^3/hr: 1,200	**Farm-fed** (110,000 tpa)	Membrane	2012	Individually owned Individually operated

11.3.2. Site Selection – Work Package 2

Market insight was also used to inform site selection for the sampling of post-AD area emissions at AD plants across the UK. Site selection focussed on AD facilities utilising different feedstock types, as this work stream took samples of digestate, which can vary in composition depending on feedstock type. The site selection captured data from three key feedstock groups:

- Agricultural (e.g., energy crops and manures/slurries)
- Food waste (e.g., municipal and commercial wastes)
- Wastewater treatment (e.g., sewage sludge)

All sites selected were representative of the most common digester types in the UK, being mesophilic continuous stirred-tank reactors (CSTRs). Selected sites were chosen primarily based on feedstock composition, but the following variables were also considered for each site: production capacity, operating temperature, hydraulic retention time (HRT) and organic loading rate (OLR) (determined through prior engagement with sites). Practical considerations also had to be made regarding site selection, as digestate is known to produce significant volumes of gas immediately following discharge. Therefore, sites close to the laboratories were prioritised where possible, to minimise potential methane losses prior to abatement testing. Table C2 highlights the characteristics of each site sampled as part of work package 2.

Table C2: A summary of each of the three sites chosen for lab-scale testing.

Site	A	B	C
Site Parameters			
Feedstock type	Agricultural (energy crops and chicken litter)	Food waste (municipal and commercial)	Wastewater
Site Description	Single CSTR for digestion of feedstock. Digestate is separated post digestion for storage.	Two CSTRs are run in series for digestion phase. Digestate is then pasteurised and separated before entering storage.	Two CSTRs run in parallel for digestion stage. Prior to digestion sludge undergoes several treatments including settlement and thickening.
HRT (days)	104	45	26
OLR (kgVS/day/m^3)	3.1	6.3	1.6
Production capacity (kWe)	250	1500	150
Operating temperature (°C)	37.4°C	39.8°C in digester Storage tank unheated	38°C

Digestate Parameters			
DS (%)	8.5	4.9	3.5
VS (%)	77.2	54.2	66.7
Total VFAs (mg/kg)	255	1,050	94
TAC (mg/l)	29,361	22,737	4,966
Ammonium-nitrogen (mg/kg)	3,781	5,553	1,026
Total nitrogen (%w/w)	0.79	0.80	0.26

Two further sites were then selected as specific case studies of solid-liquid separation (site D) and pasteurisation (site E). A summary of these sites can be found in Table C3.

Table C3: A summary of the sites chosen as more in-depth case studies

Site	D	E
Site Parameters		
Feedstock type	Agricultural – energy crops, chicken litter, and whey permeate	Agricultural – energy crops and chicken litter
Site type	Semi-plug flow digester. Digestate is separated through a screw press prior to storage.	Semi-plug flow digester. Digestate is pasteurised post digestion, then separated through a screw press prior to storage.
HRT (days)	57	73
OLR (kgVS/day/m^3)	5.9	3.4
Production capacity (kWe)	500	550
Operating temperature (°C)	39.7°C	41°C in digester >70°C in pasteuriser
Digestate Parameters		
DS (%)	9.7	8.8
VS (%)	75.6	77.4
Total VFAs (mg/kg)	<80	246
TAC (mg/l)	17833	24491
Ammonium-nitrogen (mg/kg)	2046	3422
Total nitrogen (%w/w)	0.65	0.72

11.4. Appendix D – Site Sampling Strategy (Work Package 1)

The testing of point source emissions was monitored by Bohr. The sampling strategy outlined in this section describes the survey approaches used for the testing of each site selected. The strategy outlines typical plant assets where emissions are expected, detection methods to locate emissions, and methods of quantifying methane slip from off-gases where applicable (e.g., biogas upgraders and odour control units (OCUs)).

The target areas tested were informed by a combination of Bohr's experience working with biomethane plants, a review of the site's piping and instrumentation diagram (P&ID), and a pre-site survey questionnaire sent to the operator, in addition to key areas of concern identified in the literature review aspect of the MEAD 2.0 project. Key examples of potential leak points include:

- Feedstock transport and storage[128]
- AD tanks
- Biogas storage
- CHP engines
- Flares
- Biogas upgrading units (BUUs)
- Grid entry units (GEUs)

To allow AD plant operators to act on or monitor specific leak indications identified during surveys, Bohr created a risk assessment matrix for sites that included: the area of leak (location and height); distance from operational areas; whether enclosed or in an open area; and leak size (concentration and flowrate).

A broad range of metadata was collected from each site to allow for reasonable interpretation and analysis, and to understand common themes arising from site visits. Metadata collected from each site included:

- Feedstock used
- Upgrader type
- Hydraulic retention time (HRT)
- Biogas/biomethane flowrate
- System pressure
- Site Age (full system and key components)
- Rated Capacity of relevant components

[128] The sampling strategy used by Bohr did not evaluate feedstock management and transportation, as methane emissions are limited and difficult to detect in these areas.

- Current production/site efficiency/availability/performance
- Maintenance schedule (full system and key components)

Each site survey was typically completed over a period of two working days. The methodology, as outlined below, required two survey technicians as a minimum to undertake the full sampling programme. The technicians were Gas Safety Certified and wore gas monitors at all times when on site.

11.4.1. Sampling Methods

Bohr used a variety of devices, to detect both fugitive methane emissions and methane slip. All areas that could be safely accessed were evaluated (both horizontal and vertical areas).

The core technologies used by Bohr are Tunable Diode Laser Absorption spectroscopy (TDLAS), Infrared (IR) and Optical Gas Imaging (OGI). Each device can be used across all areas of an AD plant, but each also has specific advantages when used at certain areas of the site.

Discover Tunable Diode Laser Absorption spectroscopy (TDLAS) - The Discover technology uses open path TDLAS with detection of methane at the parts per billion (ppb) level. It is vehicle mounted and detects and visually locates emissions on a GPS mapping position with an accuracy of up to 10 metres. Sampling coverage of the area is also included using data from a GPS and anemometer linked to detection software. The sampling frequency of the laser is 100 Hz and provides real-time leak detection feedback. The Discover also offers indirect quantification in (grams/hr or standard cubic feet per hour) with an uncertainty of +/- 70% for 80% of its detections. An estimated quantification of the leaks detected can be reported as a result.

The Discover TDLAS was mounted to an off-road vehicle and driven on the perimeter and through the AD site where possible. The survey protocol completes three runs (each run constitutes two passes in opposite directions) to be made at different times of the day or on an alternate day, if possible. Detections were carried out by the walking team to track down larger leaks. The post processing of results summarised all detections, locations and an estimated flowrate quantification.

Figure D1: Visualisation of the Discover TDLAS



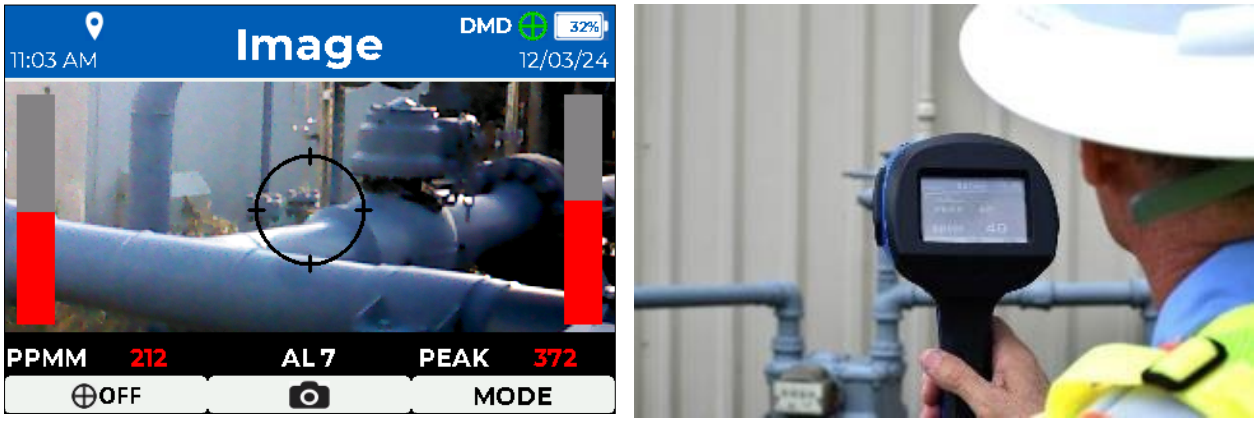
Optical Gas Imaging (OGI) – OGI cameras provide methane leak detection from 9 ppm and the quantification of leaks from 0.07 g/h. The device is handheld and includes a visual display which pinpoints the detected leaks as a heat map area on the image. The OGI camera is the device of choice for many gas producing facilities and allows emission points to be captured from distance, with a wider scanning ability due to the visualisation of the camera. This device can be used across a whole AD site and also offers wireless integration with leading LDAR software and quantification devices, allowing real-time component tag synchronisation and a simple association between components, images, and videos.

The site's P&ID was used to convert the AD plant into named sections, typically associated with its functional aspect. The scanned areas were also guided by the results of the Discover survey and the site questionnaire. The OGI camera focussed on larger items of the plant such as digesters, which can be difficult to access with more targeted devices. The surveyor conducted a walking survey around each site section, and the entire asset was scanned using the camera and display to check the areas covered. Emission detections were photographed and logged on the survey report and a coloured tag attached to each leak area so that it can be easily identified for repair or on-going monitoring purposes.

Remote Methane Leak Detector - Complete Solution (RMLD-CS) – The RMLD-CS is an open path TDLAS device with the detection of methane at the parts per million (ppm) level. The device is handheld and can detect emission points from up to 30 metres away. It is a mainstay of Bohr's walking surveys to pick up specific emission points from biomethane pipework in and around the digester tanks, CHPs, upgraders and the GEUs. The device has a display which can capture photographic evidence of the emission in terms of its ppm concentration, and it can be linked to an app which provides a breadcrumb trail of the route completed around the AD plant.

The site's P&ID was used to convert the AD plant into named sections, typically associated with its functional aspect. The scanned areas were also guided by the results of the Discover survey and the site questionnaire. The surveyor conducted a walking survey around each site section and scanned the entire asset using a laser pointer to check the areas covered. The focus of this scan was on pipework areas such as flanges, valves and PRVs. Emission detections were photographed and logged on the survey report and a coloured tag attached to each leak area so that it can be easily identified for repair or on-going monitoring purposes.

Figure D2: Visualisation of the RMLD-CS



Detecto Pak-Infrared (DPIR) – The DPIR is a close quarters infrared walking survey device with detection levels of methane ranging from 1 ppm to 100% gas in air. The device is handheld and uses a pump to draw the methane emission into the path of the infrared beam, thus measuring the concentration levels.

The DPIR was used in the categorisation of methane leaks. Information from the Discover and the RMLD-CS surveys was used to inform the DPIR sampling. The surveyor focused on the pipework element of the plant and directed the sampling attachment towards the leak to determine the size of the leak's concentration. The DPIR is sensitive down to 1 ppm and can discover smaller leaks not initially picked up by the RMLD-CS. Emission detections were photographed and logged on the survey report and a coloured tag attached to each leak area so that it can be easily identified for repair or on-going monitoring purposes.

Figure D3: Visualisation of the DPIR



ADvantage – In addition to fugitive methane leaks, methane slippage can also occur during the upgrading process i.e., via upgrader types where methane is not captured and is instead vented to atmosphere via the off-gas exhaust within the CO_2-rich stream. Bohr has designed, built and tested a portable analyser called the 'ADvantage' specifically to measure methane slip from the upgrader process, as well as for biogas compositional analysis for improved CHP utilisation, and possible measurement at OCUs.

The ADvantage portable sampling rig is a robust ready to use device which has been designed for the intermittent sampling of CH_4, CO_2 and H_2O within a biogas process. The sampling unit consists of a highly accurate in line NDIR analyser which has been integrated into a portable sampling enclosure to be connected directly to the off-gas pipeline. The analyser measures methane at levels of 0-5 vol% of gas, and if required the CO_2 at 0-100 vol% of gas. The ADvantage also contains process filtration, flow measurement and pressure regulation as standard. It can be fitted with a pump if the sample is to be returned into the process line. The unit includes a comms interface for data to be downloaded onto a PC.

The ADvantage was positioned in an area of the plant where it could be operated safely during the day by the Bohr sampling technician. The device requires a power source (located in a non-hazardous area) and connection to the off-gas pipeline using the required pipe fitting connection

and nylon tubing. On completion of safe installation, the ADvantage ran during the day whilst the Bohr team completed the leak detection surveys. The analyser took readings consistently, every 90 seconds during the course of the day. It is therefore a dynamic assessment and captured any changes to the processing conditions of the upgrader. The subsequent reports delivered comprehensive analysis of the levels of methane lost during a day's processing of biomethane, expressed as %vol of methane in the off-gas.

WP1 Sampling Strategy Conclusion

The potential emission areas of an AD plant when producing biomethane are across the full scope of the assets in use. In addition to known emission points such as safety relief valves, the strategy outlined here highlights other areas where emissions are likely to occur due to poor installation, operational and maintenance practices on the equipment.

This sampling strategy focused on the data collection throughout the biomethane production process – AD tanks, pre-treatment and OCUs where applicable, biogas storage, CHP engine, flare, BUU, and the GEU. The sampling strategy did not evaluate feedstock management and transportation, as methane emissions are limited and difficult to detect in these areas.

11.5. Appendix E – Site Sampling Strategy (Work Package 2)

The effectiveness of abatement strategies on post-AD (digestate) area emissions was tested by Marches Biogas.

While some abatement strategies have been rolled out across the UK (e.g., covered digestate storage, or digestate separation), other technologies are emerging and have not yet been widely adopted by industry (e.g., vacuum degassing) or have only been tested in small-scale studies (e.g. pH adjustment). Given that the MEAD 2.0 study intends to inform the development of future policy for the AD industry, it is important that promising abatement strategies are considered regardless of the current state of technology rollout.

Marches Biogas tested 7 techniques, as follows:

- Extended process time – through either secondary digestion or covered storage connected to the biogas system.
- Aeration
- Vacuum degassing
- pH increase through dosing of alkaline additive
- pH decrease through dosing of acidic additive
- Separation
- Pasteurisation

The greatest determiner of technology use for post-AD area emissions abatement is typically the feedstock type that the site uses. As such, three typical site types were considered which were deemed to be reasonably representative of the sector:

- **Farm-fed** (i.e. use of agricultural feedstocks such as energy crops, crop residues and animal manures)
- **Waste-fed** (i.e., sites which tend to utilise a mixture of commercial food waste and curb side collected waste)
- **Wastewater treatment facilities** (i.e., processing of sewage sludge feedstocks).

While not all techniques are expected to be compatible with every AD site, Marches Biogas aimed to consider as many configurations as possible. Marches intended to test each abatement strategy (7) on each site type (3), leading to 21 individual trials. In order to maintain a consistent baseline throughout these trials it was preferable to reduce the number of sites and therefore the variability in the initial control testing. As such, site selection aimed to identify a single site for each of the three site type categories. It should be highlighted here that the primary purpose of the work package 2 investigation was examining the effectiveness of abatement techniques, rather than assessing the digesters from which samples were drawn.

The site parameters which were used for selection are: feedstock composition, hydraulic retention time (HRT), organic loading rate (OLR), and plant production capacity (kWe). Table E1 outlines a selection of potential sites, known by the project team which were shortlisted based on the parameters outlined. The intention was to sample one site of each category, but several were shortlisted in case a) further testing proved useful and feasible, or b) unforeseen operational issues prevented the team from being able to sample from a site within a reasonable timeframe.

Table E1: Site selection for post AD area emissions

Site	Feedstock type and composition	HRT (days)	OLR (kgVS/ m^3/d)	Plant capacity (tpa)	Capacity (kWe)	Other site information
A	**Agricultural:** energy crops (maize, rye, beet), and chicken manure	100	3.0	6,500	250	Operate a CSTR with low annual input and output.
B	**Food waste:** commercial and council waste	24	6.0	25,000	1500	Operate primary and secondary CSTR digesters in sequence. HRT and OLR are here for primary, and the secondary digestion & covered storage are considered to be an abatement strategy for the purpose of this research. The site separates the digestate and stores separated liquor and fibre.
C	**Mesophilic AD WwTW site**	26.13	1.6	_	150	Gas mixed digestion. Site dug out, refurbished and recommissioned in 2018.
D	**Agricultural:** energy crops, chicken litter, and whey permeate	57	5.9	_	500	Semi-plug flow digester. Digestate is separated through a screw press prior to storage.
E	**Agricultural:** energy crops (maize, grass, beet), and chicken manure	72	5.5	9,000	550	Operating a semi-plug flow digester. The site separates the digestate and stores separated liquor and fibre.
F	**Food waste:** commercial ABP, curb side collection, capability to bolster with energy crops	29	4.7	64,000	2000	Operating two parallel semi-plug flow digesters. Only one would be selected for this research, based on stability. The site separates the digestate and stores separated liquor and fibre.
G	**Agricultural:** energy crops (maize, rye, beet), manures (chicken, cattle), and whey permeate	60	5.8	13,000	850	Operating a semi-plug flow digester. The site separates the digestate and stores separated liquor and fibre.
H	**Mesophilic AD WwTW site**	16.3	3.5	_	723	Gas mixed digestion. Site dug out and recommissioned in 2018.
I	**WwTW sludge** digesters with THP feed system.	12.4	5.5	_	1,998	Post Digestion Storage Tank with air mixing

* Blue shaded sites correspond with those eventually sampled by the MEAD 2.0 project, aligning with the site selection tables presented in Appendix C (Tables C2 & C3).

Samples were collected from each site via either a discharge line or overflow weir, depending on digester configuration. For lab-testing, control samples were taken and placed within the testing vessels on location, whilst sufficient digestate was then collected to process under each abatement technique at the same time, allowing direct comparison without needing to account for minor changes in biochemistry within the digestate over time. For case studies, all samples were collected and sealed at site, allowing for the full capture of biogas to begin immediately.

Each vessel was 2l in size and connected to a gas bag allowing for collection of biogas for analysis. Samples were taken in duplicate, and subsamples were also taken at this point for identification of dry solids and volatile solids content.

Unlike the RBP test developed for PAS110 testing, this test is done without the addition of inoculum, as it was expected that the methodologies tested could affect either the microbial populations or the biogas potential of the digestate or both. In the former case, introducing new microbes through inoculum would lead to increased biogas production that would not reflect the full-scale uses of these technologies.

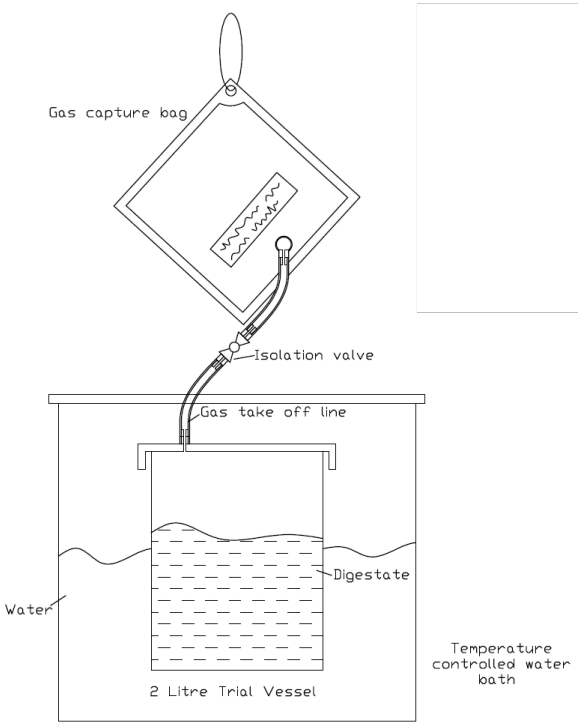


Figure E1: Illustration of experimental set up.

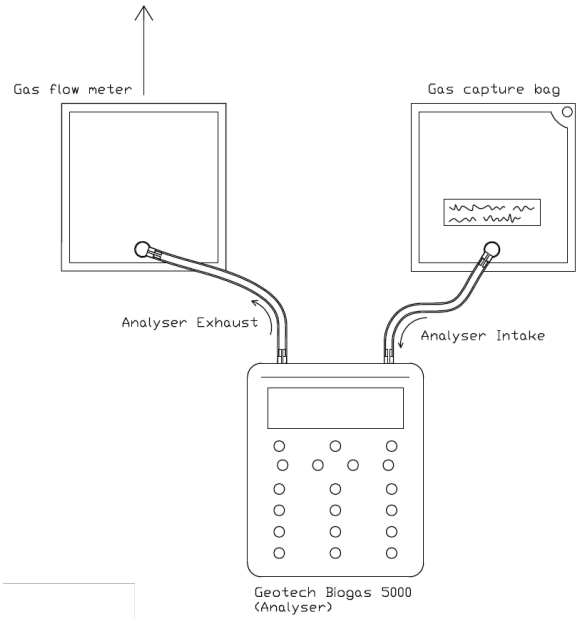


Figure E2: A diagram of the gas testing set up.

Biogas production was checked daily. A visual check was used to determine whether any gas had been produced, and if it was considered sufficient to allow for composition measurement. Composition was measured using a Geotech Biogas 5000. In order to accurately measure CH_4 and CO_2 volume the analyser is required to run for 10 seconds. Utilising a flow counter, the flow rate of this analyser was found to be 3.6ml/s, so at least 36ml of gas had to be produced for compositional analysis. This is below the flow rate expected by the manufacturer specification of 9.2ml/s and is possibly in part limited by the gas flow meter used to confirm the rate. However, the purpose of this testing is comparative rather than absolute, so these figures are informational but do not affect the conclusions reached.

Whilst composition was recorded where possible, the small amounts of gas produced sometimes meant that the 10 second minimum could not be reached in a reasonable timeframe. Additionally, whilst using both gas analyser and flow counter allowed for a check that the produced volume remained steady there was no check for composition. As such biogas volume was considered more accurate than methane volume, and so biogas production is reported instead of methane within this study. Biogas is expected to be 50-60% methane, variable dependent on feedstock input and process parameters, and where there was notable and confirmed deviation from this it is noted in the results.

11.6. Appendix F – Support for Anaerobic Digestion in the UK

Over the past two decades, the UK Government has implemented various support mechanisms to promote the adoption of renewable energy technologies, reduce greenhouse gas emissions, and achieve net-zero targets.

Two support mechanisms that have had the most notable impact on the UK's AD industry to date are the Feed-In-Tariff (FIT) and the Non-Domestic Renewable Heat Incentive (NDRHI), used to incentivise the generation of renewable electricity and renewable heat from AD respectively. Both schemes have now closed to new applicants. However, given that projects supported under said schemes receive payments for a total of 20 years from their accreditation date, a significant portion of the UK's AD industry is still supported by one, or both, of these schemes.

Both the FIT and the RHI were structured to offer different tariff rates depending on the scale of the installation. For the FIT, a high tariff was available for plants with a biogas capacity <250kWe, a central tariff for plants with a capacity between 250kWe - 500kWe, and a low tariff for plants with a capacity of between 500kWe - 5MWe. After April 2014, a flexible degression mechanism was introduced which enabled the Government to reduce tariffs for new applicants depending on rates of technology deployment, meaning that earlier developments received more beneficial tariffs than those commissioning later.

The RHI also offered fixed tariffs to AD projects where either the biogas was combusted to produce heat (for eligible uses), or the biogas was upgraded to produce biomethane and injected into the national grid. Again, tariffs were structured according to the scale of the installation. For biogas combustion plants, the tariffs were tiered based on capacity: a high tariff was available for plants with a capacity of less than 200 kWth, a central tariff for plants between 200 kWth and 600 kWth, and a low tariff for plants over 600 kWth. In contrast, tariffs for biomethane injection were based on output, with a high tariff for the first 40,000 MWh of biomethane injected into the grid, a central tariff for the next 40,000 MWh, and a low tariff for any additional gas above 80,000 MWh.

Following the closure of the FIT and the RHI to new applications in 2019 and 2022 respectively, the Government introduced the new Green Gas Support Scheme (GGSS) to support biomethane injection into the grid by newly commissioned AD facilities. The GGSS opened in November 2021 and is set to remain open to applications until March 2028. It operates in a similar way to the NDRHI for biomethane injection facilities, with tiered tariffs as shown in Table F1 below.

Table F1: Tiered tariffs for the Green Gas Support Scheme as of 1st October 2024 *(CPI adjusted annually on 01 April).*[129]

Tier Level	Scale (MWh)	Tariff Rate (p/kWh)
Tier 1	< 60,000	6.86
Tier 2	60,000 – 100,000	4.26
Tier 3	100,000 MWh – 250,000	3.98

The GGSS was introduced to support new AD facilities injecting biomethane into the gas grid, as this was deemed to be the most efficient and effective way of valorising biogas generated through AD. While there are a number of ways to generate renewable electricity (e.g., wind, solar, biomass power generation etc.), AD to produce renewable biomethane remains the only commercially available technology capable of greening the UK's gas grid. This is the principal reason why policy support for the UK's AD sector currently focusses on biomethane generation for grid injection.

With both the RHI and FIT schemes now closed to new applicants, and the existing GGSS set to remain open to new applications until 2028, the future of biomethane support is now under review. In February 2024, DESNZ launched a Call for Evidence (CfE) on the Future Policy Framework for Biomethane Production. This Call for Evidence, which was open until the end of April 2024 summarised the Government's initial thinking on future policy in this area and sought industry opinion on how the design and scope of this framework should take shape.

DESNZ is considering how best to support the industry to address a range of investment barriers, with further details to be provided in due course. DESNZ intends to provide a clear pathway that supports continued biomethane deployment, maintains investor confidence and avoids a hiatus in investment.

While we do not yet know exactly how the next phase of support for biomethane will look, it is understood that DESNZ are exploring biomethane's optimal role across the energy system and different possible approaches to support the industry to build upon the production capacity already established over the past two decades.

Adding to this, the Clean Flexibility Roadmap,[130] published in July 2025 by DESNZ, Ofgem and the National Energy System Operator (NESO), set out that a unified vision for a clean, flexible, and consumer-focused electricity system is integral to achieving the Clean Power 2030[131] targets and reaching net zero by 2050. This roadmap underscored flexibility as being essential for integrating a rising share of renewables, reducing energy bills, and enhancing the energy system's overall reliability. Biomethane is spotlighted as being not only a valuable heating fuel, but a flexible, low-carbon resource that can support a number of sectors, including transport,

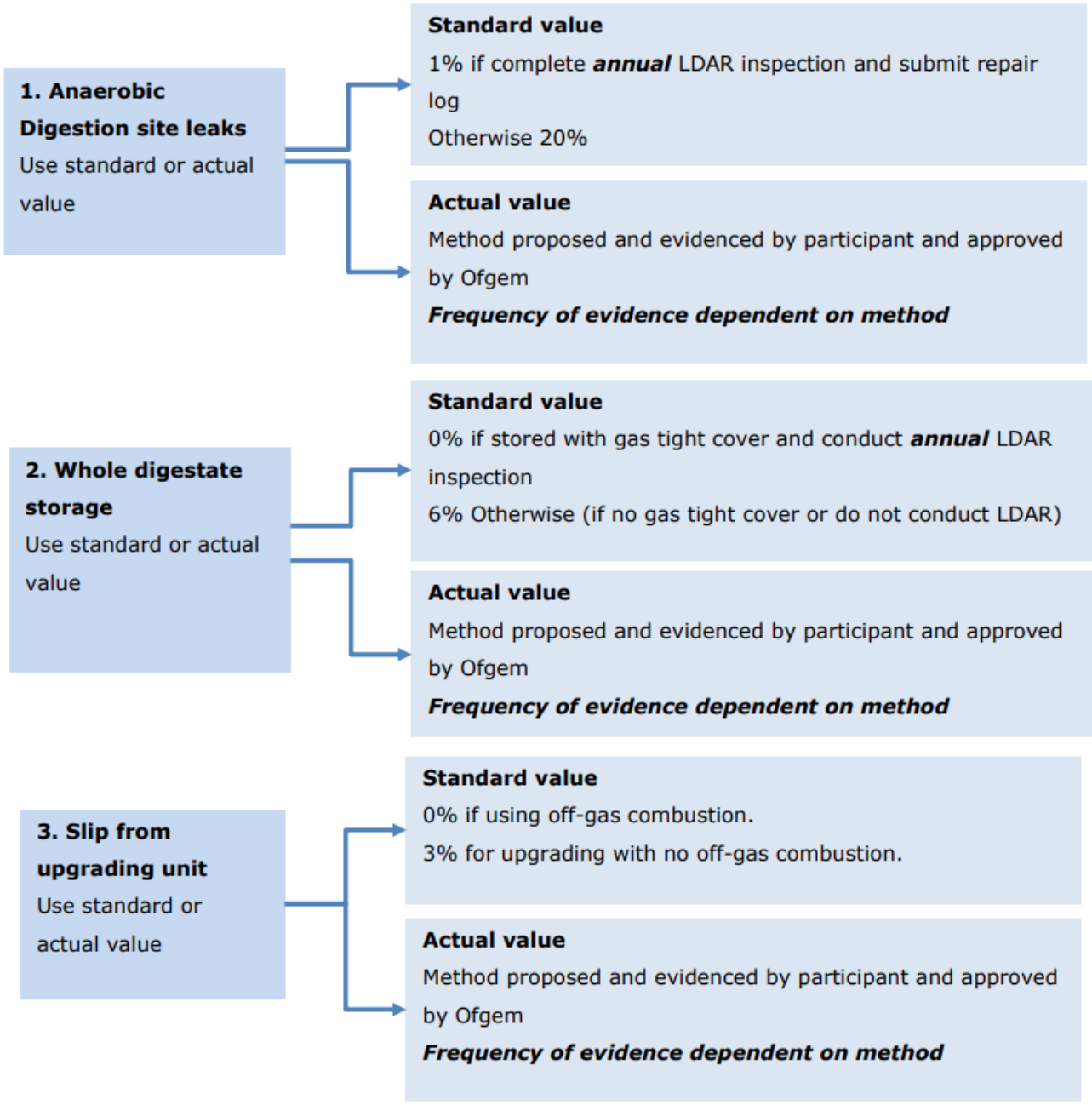
[129] DESNZ, 2024. *Green Gas Support Scheme (GGSS): Annual Tariff Review 2024*. [online] Available at: https://www.gov.uk/government/publications/green-gas-support-scheme-ggss-annual-tariff-reviews-and-tariff-change-notices/green-gas-support-scheme-ggss-annual-tariff-review-2024 [Accessed March 2025].
[130] DESNZ, Clean Flexibility Roadmap, 2025.
[131] UK Government, Clean Power 2030 Action Plan: A new era of clean electricity, 2024.

dispatchable power generation, and industrial sectors (e.g., chemical manufacturing). This is the first time a UK Government document has broadened the scope of biomethane use beyond domestic heating, recognising its value to many other sectors and formally framing it as being part of the solution to the intermittency of renewables, due to its ability to be stored and dispatched when needed. This highlights a drastic change in government thinking regarding the role of biomethane in the UK's drive to net zero recognising biomethane as a flexible fuel with potential in industry, transport and low-carbon dispatchable power.

11.7. Appendix G – Fugitive Methane Emissions Calculations

DESNZ guidance on the calculation of fugitive methane for GGSS sustainability reporting outlines three principal areas for the recording of emissions. These are highlighted in Figure G1, along with options for the reporting of real or standard (default) values. For more details on the conditions required for each approach, see DESNZ guidance on the Green Gas Support Scheme.[132]

Figure G1: Key areas of fugitive methane emissions, and options for the reporting of emission values (either actual or default). [133]



[132] DESNZ, Guidance for calculating fugitive methane emissions as part of the greenhouse gas criteria on the Green Gas Support Scheme, 2025.
[133] Ofgem, Green Gas Support Scheme Guidance v2.2, 2025.

11.8. Appendix H – Wider Environmental Impacts of Biogas Upgrading Units

Whilst considering the methane emissions impacts and mitigation strategies within this study, a broader question around wider environmental impacts specifically relating to biogas upgrading was also considered. This broader view is important to inform work being undertaken by the Environment Agency to determine Best Available Techniques (BAT) from an AD regulatory perspective. These findings from this wider research, undertaken via a literature review and further stakeholder engagement, are discussed in detail below.

11.8.1. Biogas Upgrading Units (BUU)

Biomethane emissions from biogas upgrading systems are referred to as methane slip when present in the off-gas vent stream as opposed to leakage. Methane slip occurs when a portion of biomethane escapes with the waste gas stream during the upgrading process. The level of methane slip is dependent on the choice of technology and its operational parameters. The main commercial technologies for biogas-to-biomethane upgrading are:

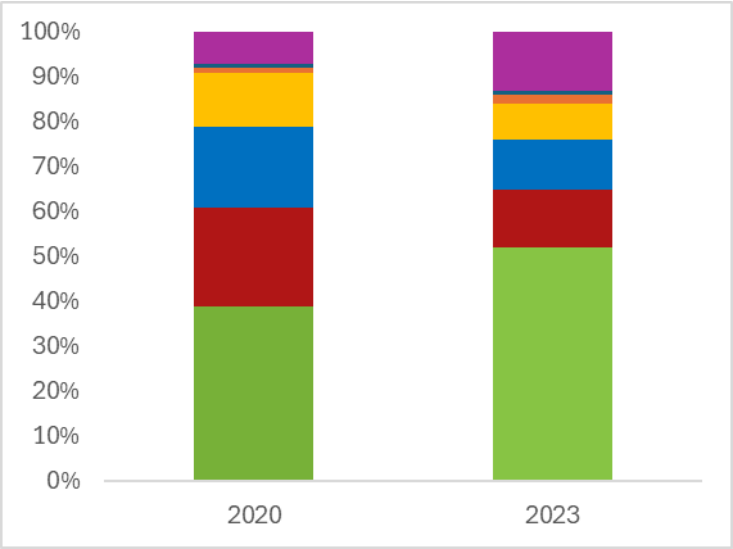
- membrane separation,
- water scrubbing,
- chemical absorption with amine solvent, and
- pressure swing adsorption.

Physical absorption using organic solvents is also an available technology but is not widely used and cryo-separation, while suitable for biogas upgrading, is primarily used for CO_2 capture from the off-gas produced by the principal upgrading system. Biological upgrading is in the early stages of development, and there is no current evidence of the commercial deployment of this technology.

The European Biogas Association (EBA) published Europe-wide analysis of upgrader types deployed in respective regions. Figure H1 shows the different upgrader technology types and their prevalence across Europe. Membrane separation is the most widely deployed in Europe, and its share of the market has increased in recent years. It is also the most predominant technology used by AD sites in the UK (Figure H2). However, this is not necessarily the case for all countries across the EU. For example in 2023, Norway predominantly used chemical absorption as the principal method for upgrading biogas, Sweden primarily used water scrubbing, and Austria's preference was for pressure swing adsorption.[134] The growth in membrane separation technology more generally across Europe has been driven mainly by an increase in on-farm and food waste sites due to the smaller, modular and relatively easy to use nature of the technology.

[134] Adapted from the EBA Statistical Reports 2021 and 2024.

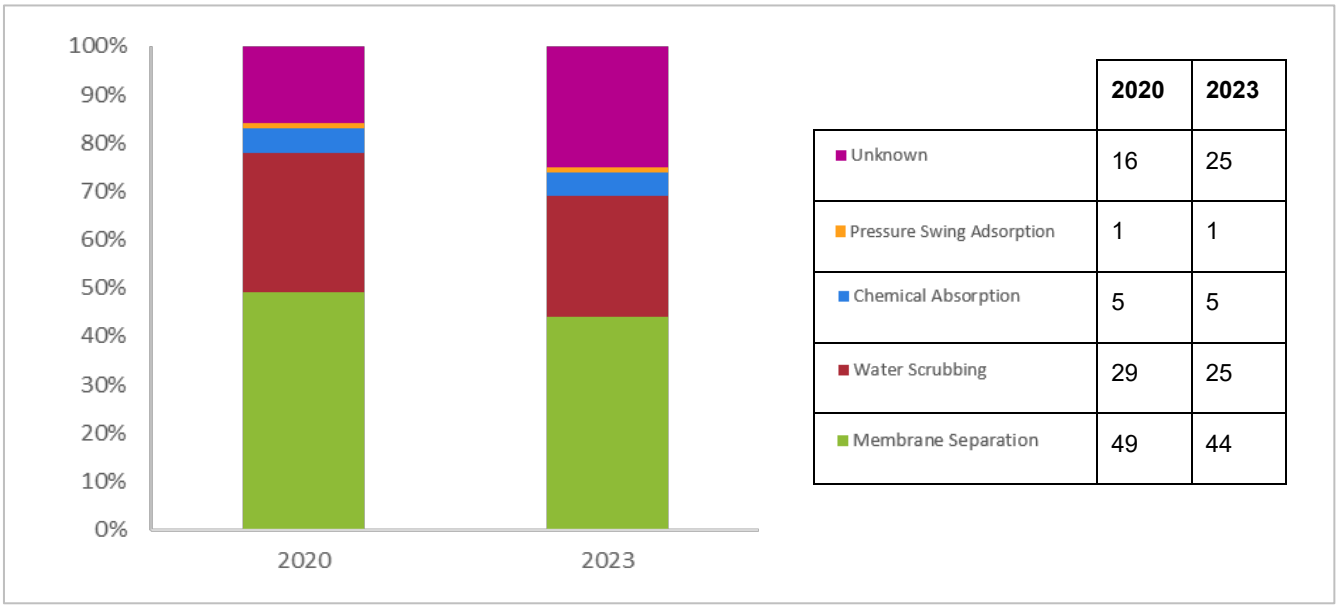
Figure H1: The percentage distribution of upgrading technologies used by biomethane plants in Europe.



[134]

	2020	2023
Unknown	7	13
Cryogenic separation	1	1
Physical absorption	1	2
Pressure Swing Adsorption	12	8
Chemical Absorption	18	11
Water Scrubbing	22	13
Membrane Separation	39	52

Figure H2: The percentage distribution of upgrading technologies used by biomethane plants in the UK.[134]



	2020	2023
Unknown	16	25
Pressure Swing Adsorption	1	1
Chemical Absorption	5	5
Water Scrubbing	29	25
Membrane Separation	49	44

The key biogas upgrading technologies and their different modes of action are discussed in more detail below.

Membrane Separation (MS) involves the use of synthetic polymer membranes, in the form of bundles of hollow fibres incorporated in stainless steel tubes (Figure H3), to separate biogas into biomethane and other gases. Typical polymer materials include polysulfone, polyimide or

polydimethylsiloxane. The polymer membranes are permeable to CO_2, H_2O, and NH_3; less permeable to O_2 and H_2S; and largely impermeable to CH_4 and N_2. Due to these differences in permeability, as biogas is passed through the separator, CO_2, H_2O, and NH_3 move across the membrane in a flow termed 'permeate' while a methane rich gas, termed 'retentate' flows directly down the membrane fibres.[135]

Prior to membrane separation the raw biogas is passed through a scrubber to remove H_2O and H_2S. H_2S and other volatile organic compounds are removed from the scrubbed biogas using an activated charcoal filter and/or mixture of caustic soda, polyvinyl alcohol and water depending on the level of H_2S in the biogas stream.

The cleaned biogas is then compressed to 10-16 bar and sent to the membrane separation unit. Membrane separators are used in various configurations with multiple units giving the best separation efficiency, three phase separation through a polyimide membrane separation unit can achieve a ***methane recovery of 98%*** and ***methane slip below 1%***.[136]

Figure H3: hollow fibres packed into stainless steel housing



Water scrubbing (WS) is based on the different solubilities of CO_2 in H_2O in comparison to CH_4. At 25°C, CO_2 has a water solubility that is 26-times greater than CH_4.[137] The solubility of a gas in a liquid is directly proportional to the partial pressure of the gas above the liquid, however gas solubility generally decreases as temperature increases. Therefore, the WS process operates optimally at low temperature and high pressures. While the water will absorb H_2S, high concentrations (up to 2500 ppm by volume)[135] can have detrimental effects on the scrubbing system. If the H_2S level is consistently high, then it is recommended that raw biogas is scrubbed to remove hydrogen sulphide.

The biogas is compressed to around 4-6.5 bar and then passed into a washing column which contains a packing material to increase gas-liquid mass transfer. The compressed biogas is introduced to the bottom of the column, meeting water injected from the top. CO_2 is absorbed by the water while methane flows out of the top of the column. The raw CH_4 gas is then passed through an activated carbon filter to remove non-methane VOCs and moisture. The CO_2 saturated water emitted from the scrubber contains roughly 5-6% of the methane content of the compressed biogas which is recovered using a flash column, where a 2-4 bar pressure drop

[135] Gkotsis et al: Biogas Upgrading Technologies-Recent Advances in Membrane-based Processes. International Journal of Hydrogen Energy (2023) 48(10) 3965-3993.
[136] F.Ardolino G.F.Cardamone, F. Parrillo, U.Arena. (2021) Biogas-to-Biomethane Upgrading: A comparative review and assessment in a life cycle perspective. Renewable and Sustainable Energy Review. 139, 110588.
[137] Angelidaki, I., Biotechnology Advances (2018), https://doi.org/10.1016/j.biotechadv.2018.01.011

allows for methane recovery. The water is then passed through a desorption column at atmospheric pressure with air used in counter-current flow, the regenerated water can be cycled back into the process. WS technology has a typical ***methane recovery of up to 98%*** and a ***methane slip in the range of <2%***.[137][135]

Chemical absorption (CA) is also a scrubbing technology, similar to water scrubbing, with the water being replaced with an organic solvent. Typically, an amine such as monoethanolamine, diethanolamine or diglycolamine is used. Amine solvents can absorb larger amounts of carbon dioxide (per unit volume) and therefore, smaller upgrading units can be used. Amine solutions can be designed to treat multiple contaminants in the gas stream and so H_2S scrubbing is not required upstream of the upgrader. However, off-gases will contain contaminants and therefore require scrubbing with activated carbon before the CO_2 rich stream is released to atmosphere.

Unlike water scrubbing, amine solvents do not require high pressures to achieve high efficiencies, typically operating at less than 1 bar.[138] Used amine solvents are recovered through a stripping column, which requires high temperatures above 120-150^oC, and then they are recirculated throughout the process.[135] CA technology is a highly effective biogas upgrading technology achieving ***methane recovery of 99%*** and ***methane slip below 0.1%.***[136]**Error! Bookmark not defined.**

Pressure swing adsorption (PSA) is based on the differential adsorption of gases into an adsorbent material based on molecular dimensions and their affinity to the adsorbent material. PSA relies on the ability of the adsorbent material to adsorb the target molecule under high pressures and subsequently release it under reduced pressure. Typically, zeolites or activated carbons are used, with cavities of ~0.37nm allowing the adsorption of carbon dioxide (0.34nm) while excluding methane (0.38nm)[135]. Consequently, carbon dioxide is adsorbed while methane is free to flow through the PSA unit. PSA follows four main stages: adsorption, depressurisation, regeneration and re-pressurisation.

Raw biogas is scrubbed to remove hydrogen sulphide (the presence of which can damage the adsorbent material), dried and then compressed to between 3-8 bar, before introduction to the PSA unit. The adsorbent will selectively retain CO_2, N_2, and O_2 while the methane is collected. In practice several columns are used to ensure continuous operation. The loaded adsorbent material is regenerated by a stepwise decrease in pressure to atmospheric pressure and flushing with biomethane to remove residual CO_2. The off-gas of the initial decompression stage will contain some methane and can be recycled to the raw biogas inlet. PSA technology achieves ***methane recovery of >96%*** with ***methane slip, typically up to 4%***.[135]

Physical absorption operates on the same principles as water and chemical scrubbing, but instead of water, an organic solvent is used for CO_2 and H_2S absorption. Commonly employed organic solvents are mixtures of methanol and dimethyl ethers of polyethylene glycol. An advantage of these solvents over water is their substantially higher CO_2 solubilities i.e.,

[138] Personal communication: Ammongas uses a compression pressure of 200 mbar.

approximately three times more CO_2 absorption than water, resulting in reduced liquid input requirements and, consequently, smaller upgrading units.

After scrubbing to remove hydrogen sulphide the raw biogas is compressed to 7-8 bar and cooled to approximately 20°C before being injected from the bottom of the absorption column with cold solvent introduced from the top of the column.

Post use, the organic solvents are regenerated using heat (~80°C) before being introduced to the desorption column where the pressure is reduced to 1 bar to remove the carbon dioxide. The removal of hydrogen sulphide from the solvent can require high temperatures due to its high solubility. Therefore, to avoid high energy requirements, it is recommended to remove H_2S before introducing biogas to the solvent. Physical absorption with organic solvents can achieve ***up to 96-98% methane recovery*** but has one of the ***highest methane slip rates, in the region of 2-4%***.[135]

In these cases, the methane slip/loss is typically defined as the volume flow in the off-gas divided by the volume flow in the raw biogas and expressed as a percentage. The literature provides indicative figures for these values, but discrepancies can arise where the recovery and slip do not add up to 100%. The literature does not outline the nature of these discrepancies which could be linked to the nature of the technology, differences in configurations or operational inconsistencies.

Cryogenic upgrading is a relatively new technology and involves a gradual temperature reduction to target contaminants. Raw biogas is initially dried and then compressed to 80 bar prior to cooling. The temperature is reduced stepwise to initially remove H_2S and siloxanes, followed by further temperature reduction for the removal of CO_2. Temperatures can be further reduced to produce liquefied natural gas (LNG).

Different technology providers offer systems operating at different temperatures and pressures, depending on the required end use of the biomethane i.e. liquid methane or gaseous methane for grid injection. CO_2 can also be recovered in a liquid form as a saleable product. Cryogenic upgrading typically has a ***methane recovery rate of 97-98%*** and ***a methane slip of <2%***. However, high energy requirements and the technical complexity of the equipment required limit the use of this technology for biogas upgrading. [135]

In practice, cryogenic technology is used in the UK as an add on to the primary upgrading system as a means of recovering CO_2 from the off-gas. The capturing of CO_2 increases the energy consumption at the site, in the region of 0.20-0.22 kWh/kg of liquid CO_2.[139] This method is generally only suitable for medium to large sites. As part of the stakeholder engagement aspect of the MEAD 2.0 study, discussions indicated that this technology would be limited to sites larger than 1000 m^3/hr of biogas generated,[140] with suppliers offering various size ranges for CO_2 liquefaction, ranging from 300-6000 kg/hr of liquefied CO_2.

[139] Information taken from HoSt website available at: CO2 Recovery & Liquefaction | HoSt Group
[140] Personal communication with stakeholder site: This site currently captures CO_2 and conducted an economic assessment.

The CO_2 stream from these upgrading technologies, except for water scrubbing due to high nitrogen content and low CO_2 concentration, is suitable for further processing and will be of sufficient quality to sell into the food and beverage sector. However, CO_2 derived from sites processing animal by-products (ABP) is not suitable for certain markets such as vegan, vegetarian or Halal products. Kerbside collected wastes also present hazard analysis and critical point (HACCP) challenges, as no control point is evident at source (resident or business). Similarly, CO_2 derived from wastewater treatment may find it difficult to exploit market outlets due to perception of the CO_2 origin. Several stakeholders consulted cited this as a reason for not capturing CO_2. The process had been considered but the lack of a ready market meant that the investment was not economically viable. These market issues are not specific to the separation process and are not isolated to specific technologies, as all CO_2 arising from the upgrading process would meet the required quality to be used in a range of different end markets.

To summarise the technology types outlined in this section, Table H1 highlights key features of each, including methane loss, energy requirements and pre-treatment needs.

The CO_2 can be captured from the off-gas, and be a saleable commodity, for the majority of upgrading technologies with the exception of water scrubbing which typically has a highly diluted CO_2 off-gas stream.

Table H1: Comparison of biogas upgrading technology. Adapted from Angelidaki et al[137137], Lombardi and Francini[141], and Gkotsis et al[135135]

	Membrane Separation	Water Scrubbing	Chemical absorption	PSA	Physical absorption
Electrical Consumption for raw biogas (kWh/Nm^3)	0.18-0.38	0.25-0.32	0.05-0.25	0.21-0.46	0.2-0.3
Heat consumption (kWh/Nm^3)	None	None	0.5-0.75	None	<0.2
Temperature required (°C)	NA	NA	100-180	NA	55-80
Cost	High	Medium	High	Medium	Medium
CH_4 losses (%)	0.5-1	1-3%	0.04-0.1	1-5	2-4
CH4 recovery (%)	96-98	95-98	96-99	96-98	96-98
Pre-purification	Recommended	Recommended	Yes	Yes	Recommended
H_2S co-removal	Possible	Yes	Possible	Possible	Possible
N_2 and O_2 co-removal	Partial	No	No	Possible	No
Operation pressure (bar)	5-8	4-10	Atmospheric	3-10	4-8

[141] Lidia Lombardi, Giovanni Francini (2020) Techno-economic and environmental assessment of the main biogas upgrading technologies. Renewable energy. 156, 440-458

During the MEAD 2.0 site sampling, seven upgraders were analysed for methane emissions. Of the seven sites four were membrane, two were pressurised water scrubbers and one was membrane with downstream cryogenic CO_2 separation. This spread of upgrader types is considered representative of those deployed in the UK (as per analysis carried out on the UK's AD market as part of this study).

The results of the site sampling highlighted that there is considerable variation in the levels of methane loss to the atmosphere. Table H2 shows the average methane percentages measured in the off-gases of all the systems, as well as the high and low points recorded during the measurement phase. Furthermore, the surveyors were able to quantify methane emissions based on the flow rate. In the calculated flow rate, the bulk of the gas going to atmosphere will be CO_2.

Table H2: Average, High and Low Off-gas methane composition from test sites. ***Total methane lost to atmosphere was calculated from the stated flow rate.***

Site	Upgrader Type	Methane Composition			Calculated Flowrate (NM^3/hr)	Average Methane Emission Quantification (NM^3/hr)
		Avg. %	High %	Low %		
1	Membrane	1.82	1.93	1.72	393.1	7.15
2	Membrane	0.97	1.37	0.00	368.8	3.58
3	Membrane*	9.05	12.04	0.00	452.00	40.91
4	Membrane	0.91	11.60	0.00	373.19	3.40
5	Pressurised water separator	0.32	3.18	0.26	530.00	1.70
6	Membrane	0.8	0.87	0.72	195.01	1.56
7	Pressurised water separator	0.13	0.18	0.00	245.00	0.32

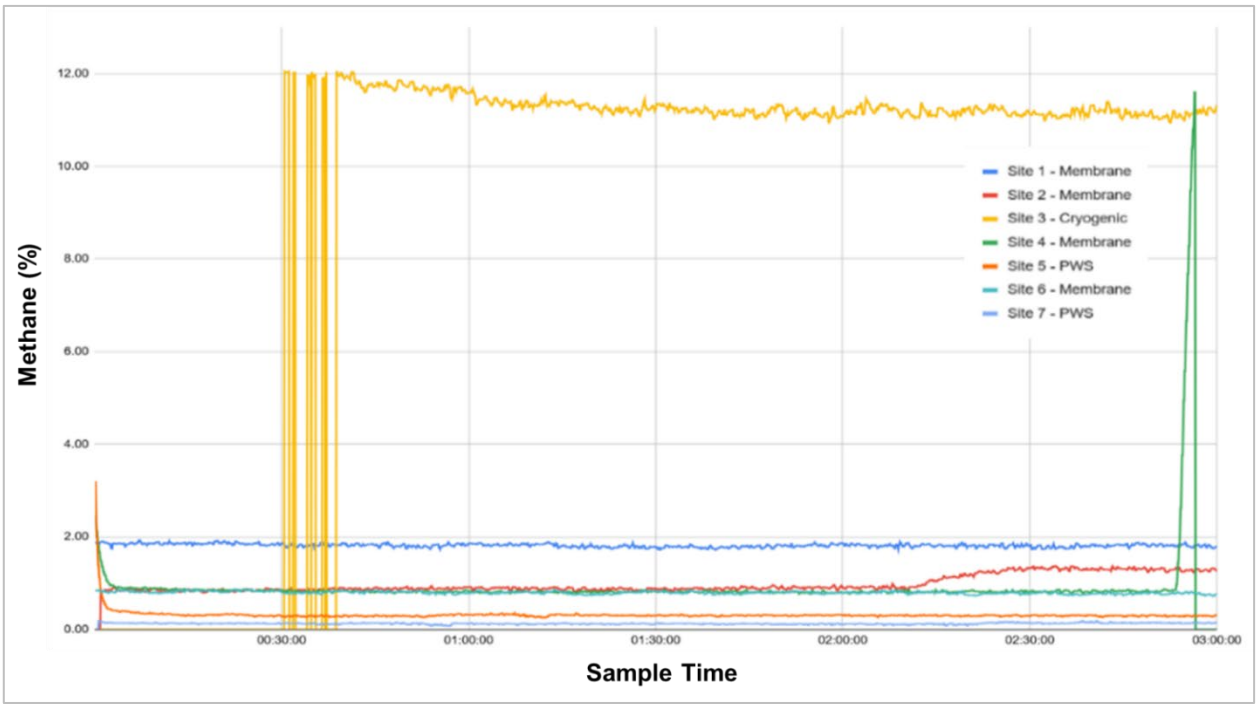
* *with off-gas sent to liquid CO_2 module for cryogenic separation.*

Site 1 had a consistent methane slip during the survey phase; however, an average of 1.82% is higher than quoted in the literature for membrane technology, indicating there may be some optimisation measures that could reduce methane losses.

Site 3 showed a high average methane slip, put down to post installation modifications of the upgrader which compromised the efficiency of the system. The loss of such high quantities of methane and associated revenue indicates that swift action is required to bring these emissions under control. It should be noted that the measurements were not taken immediately after the upgrader but after the CO_2 liquefaction stage, so it is not a direct analysis of upgrader losses.

Site 4 displayed a large disparity between the high and low points recorded. This can be seen in Figure H4, due to a spike towards the end of the testing period. Said spike is a normal part of operation when going through the start up phase of the upgrader after a shutdown as was the case here.

Figure H4: Comparison of methane emissions (%) generated at the upgraders at different biomethane facilities.



These testing events supply only a snapshot of the emissions from any given site; however, if a comprehensive testing regime is in place they can show key areas of concern. Loss of methane from upgraders can be kept to a minimum with good management, through using the right upgrader type for a particular site, and with good operator knowledge of the technology selected. By reducing methane slip from the upgrader, operators will reduce the site's environmental impact as well as reduce potential losses in revenue.

Literature research also provides further insight into methane slip from BUUs. In a study of methane emissions from 33 biogas sites across Austria, Germany, Sweden and Switzerland, researchers assessed emissions from a range of biogas upgrading units. Chemical (amine) absorption (four units) was shown to have the lowest emissions (emissions factor ≤0.1%), this emission level is similar to the methane slip of three units deploying additional exhaust gas treatment (EGT) after pressure swing adsorption or water scrubbing (EF≤0.2%). Without EGT two water scrubbers showed significantly higher methane slips of 2.0 and 3.9%.[142]

A separate study reported the methane emissions from seven sites in the UK. Due to the prevailing conditions and site layout, only 5 of the upgrading units were able to be measured (Table 9).[143] The emissions ranged from approximately 0.6% to 4.0%, with the main source of

[142] Viktoria Wechselberger, Torsten Reinet, Johan Yngvesson, Deborah Scharfy, Charlotte Scheutz, Marion Huber-Humer, Marlies Hrad: Methane losses from different biogas plant technologies. Waste Management: (2023) 157, 110-120.
[143] Howes *et al.,* 2023

these emissions being the upgrade vent, which vents the carbon dioxide removed during upgrading. It was noted that in six of the seven facilities covered in the study, the upgrader off-gas was vented directly to air without thermal treatment, the seventh facility captured carbon dioxide rather than venting this gas stream. The emissions factor in Table 9 is calculated as the emissions from the upgrader divided by the total methane throughput of all potential end uses for the biogas i.e. BtG,CHP, heat and flare.

It was inferred that the unusually high emissions factors were as a result of inefficient separation, whether this was a technology and/or operator issue could not be determined.

Table H3: Methane emissions from biogas upgrading at five UK sites.[144]

Plant type	Feedstock	Feedstock (t/y)	Upgrading technology	Emission Factor % (standard uncertainty)	Notes
Agricultural	Maize, rye, grass and sugar beet	30,000	Membrane	2.5 (0.3)	This is an unusually high emission factor for membrane separation
Agricultural	Maize, rye and manure	30,000	Membrane	4.0 (0.3)	This is an unusually high emission factor for membrane separation
Agricultural	Maize, rye	22,000	Membrane	0.7 (0.1)	None.
Commercial	Food waste	48,500	Water-wash	1.7 (0.4)	None.
Mixed	Food waste, crops and manure	40,000	Membrane	0.6 (0.1)	None.

There is a critical need to ensure that the upgrading technology selected for use is suitable for the specific site in question. For example, the literature demonstrated that the emissions from an undersized water scrubber accounted for 75% of all methane losses identified across the site.[145]

The choice of upgrading technology at a site can rest on several factors including cost, familiarity and perceived operational ease, intended location, plant size and the nature of the biogas being processed. In these technologies the highest energy users in the upgrading process are compressors and technologies which use higher pressures will have higher energy requirements in that area. Amine scrubbing has low pressure inputs for the biogas and therefore low electrical load; however, the regeneration of the amine solution requires heat which can use up to 0.75 kWh/m^3 in a worst case scenario.**Error! Bookmark not defined.** Much of this heat can be recycled but still

[144] Howes et al., 2023.
[145] Anders M. Fredunsland, Jorgen Hinge, Magnus A. Holmgren, Soren G. Rasmussen Charlotte Scheutz. (2018): On-site and ground-based remote sensing measurements of methane emissions from four biogas plants: A comparison study. Bioresource Technology 270, 88-95

needs to be generated and can come from a boiler consuming fossil fuels; however, the use of biogas boilers or offtake from a CHP can reduce this issue, as evident on a number of sites. There is no current evidence for the use of heat pumps to assist the amine regeneration process. However modelling studies have examined the use of heat pumps with amine-based CO_2 capture processes and suggest this may be a possibility in the future.[146]

Although upgrading systems can be modular, retrofitting additional units and the addition of CO_2 liquefaction will increase the OPEX of the site. If expansion is envisaged, then factoring in increased biomethane output at the design stage could reduce future OPEX of the system and overall energy consumption. The physical nature of the technology could be a factor in choice of upgrader. Typically, amine and water scrubbing systems will use columns which are over 10m tall. This may cause problems at the planning stage due to height restrictions in the planning consent.

Technology providers of upgrader systems are constantly looking to improve the efficiencies of their systems, with Table H4 showing current estimates of power consumption per technology and projected methane losses for each. Power consumption does not appear to be a major driver in technology choice, given that membrane separation is the most prevalent technology in the UK, and yet, has the highest energy consumption per m^3 of biogas processed.

Table H4: Typical manufacturer quotes for energy consumption (2025) (figures taken from promotional literature).

Technology	Energy usage kWh/ M3 Biogas	Projected CH_4 loss	Supplier
Membrane	0.28	<0.5%	DMT
PSA	0.22	<1.0%	Sysadvance
Amine	0.1	<0.05%	Ammongas
Water Scrubbing	0.22-0.23	<1.0%	Malmberg

Site type can determine the choice of upgrader; the best choice for landfill gas will be a technology which can cope with additional contaminants which are more prevalent in landfill gas than in conventional AD such as oxygen and nitrogen, for example. However, through stakeholder engagement, it was apparent that cost, footprint, and familiarity with the technology were the main drivers for the rise in membrane upgrader technologies across the UK. Table H5 shows the capital and operating costs for various technologies. It should be noted, there are economies of scale associated with the investment costs as the large installation reduces cost per Nm^3 of biomethane produced. The operational costs provide a rough guide and will vary

[146] Electrification of amine-based CO2 capture utilizing heat pumps

depending on several factors including size, energy source and the efficiency of the individual operation.

Table H5: Investment costs of the different upgrader types with representative operational costs. Adapted from Rodero et al.[147]

Plant size	Water scrubbing	Organic solvent scrubbing	Amine scrubbing	PSA	Membrane
Approximate investment costs (€/Nm³/h)					
<250 Nm³/h	4000-5000	4000-5000	4500-5000	4500-5400	4700-6000
Up to 500 Nm3/h	2500-4000	3000-4000	3000-4500	2500-4500	2700-4700
1000-5000 Nm3/h	1000-2500	1000-3000	2000-3000	1750-2500	1300-2700
Approximate annual operational costs (€/Nm³/h)					
€/Nm³/h	0.13	Not available	0.4	0.18	0.2

11.8.2. Carbon Dioxide Quality and Use

The predominant emission, by volume, from biogas upgraders is CO_2. Biogenic CO_2 is considered to be part of a short carbon cycle and, in principle does not contribute to CO_2 accumulation in the atmosphere. However, capture and use of that CO_2 would contribute to a reduction of atmospheric CO_2. [148]

The purity of CO_2 from biogas upgraders is variable based on upgrader type, feedstock composition and the efficiency of the digester. This means that it is difficult to point to a typical composition for the off-gas stream from an upgrader. Methane concentration as a contaminant is dependent on the upgrader type, as previously noted, and the efficiency of the upgrader which can be affected by maintenance schedules and suboptimal operational parameters. The literature is not primarily concerned with the full composition of the waste gas stream and concentrates on methane content, coupled with not being specific with where or how the gas is measured, it is difficult to get a true understanding of the nature of the gas stream that is vented to air.

Additional contaminants such as H_2S, and non-methane VOCs can be kept to a minimum with other abatement technologies such as activated carbon. These are primarily there to protect the upgrader and associated equipment. Some of these contaminants will still be present in the CO_2 stream and will show variation, also associated with upgrader type but also with feedstock type, digester performance and care and maintenance of upgrader equipment. Understanding of the

[147] Rodero et al (2024) Membrane materials for biogas purification and upgrading: Fundamentals recent advances and challenges. .Journal of Environmental Chemical Engineering 12, 114106
[148] Biogenic-CO2-from-the-biogas-industry_Sept2022-1.pdf

requirements of the upgrader and associated equipment is needed otherwise it can adversely affect the type and concentration of contaminants giving rise to an inconsistent gas stream.

A study by Arrhenius et al[149] compared the quality of the biogenic CO_2 streams from several sites with a view to capture and use, examples are shown in Table H6. Variations in the CO_2 stream were observed between upgrader types and between feedstock, even when using the same type of upgrader. Measurements were taken directly after the upgrading stage and do not necessarily represent the off-gas stream.

When applying these CO_2 sources to carbon capture and usage, Arrhenius stated that some further purification of samples would be needed to satisfy requirements of CCUS, in particular those for food and beverage grade. The study noted that water, methane and nitrogen were high in all samples, and H_2S was high in samples 1 and 4. They also noted that non-methane VOCs were high in samples that processed food waste and would also need further purification. Although other upgrader types were not presented here it is likely that they would have similar drawbacks with respect to minor contaminants. The exception would be cryogenic upgrading which can produce high quality liquefied CO_2

Table H6: Examples of composition of CO_2 streams from two upgrader types (adapted from Arrhenius et al 2025)[149].

	Site 1	Site 2	Site 3	Site 4	Site 5
Feedstock	Food waste and sludge	Fish waste sludge	Food waste and manure	Sewage sludge	Sewage sludge
Upgrader Type	Amine Scrubber	Amine scrubber	Amine Scrubber	Water Scrubber	Water Scrubber
Component					
CO2 %	97	97.2	97.9	99.1	92.7
Water %	1.5	1.3	1.1	0.5	0.9
Methane %	0.12	0.075	0.084	0.0920	4.7
Nitrogen %	0.55	1.3	0.7	0.25	1.3
Oxygen ppm	400	1000	0.15	<0.1	0.2
H2S ppm	50	<1	<1	260	<1

*CO_2 concentration and key additional contaminants for CCUS were noted.

[149] Quality of biogenic carbon dioxide stream from biogas plants including analytical method development

Given that methane slip is inevitable due to the nature of the technology, the most effective way of minimizing it is with off-gas treatment. The use of CO_2 capture units to capture any gases which would typically be emitted to the atmosphere following biogas upgrading was flagged as a beneficial technology by a number of stakeholders. During the upgrading stage, biomethane is separated from CO_2, but residual volumes of methane typically remain in the CO_2 off-gas, which is then vented to the atmosphere. During CO_2 capture however, this gaseous CO_2 stream is purified in order for it to be used in downstream applications, and any residual methane removed is fed back into the AD system meaning that it is not then lost to the atmosphere. One site operator stated that prior to installing the CO_2 capture equipment, roughly 0.6% of methane was lost from the membrane upgrader unit. This was subsequently captured following the installation of CO_2 capture equipment.

Possible biogenic CO_2 uses

There are a number of potential uses for biogenic CO_2 from AD, the primary, and most established use is in the food and beverage industry. In the European Union, the specification of CO_2 for use as a food or beverage additive is defined in Commission Regulation (EU) No 231/2012 and was carried over into UK legislation; this specification is reproduced in Table H7. Note that this only gives limits for three individual constituents: minimum CO_2 content and maximum content for both carbon monoxide and oil. Other properties are covered by tests for acidity and for reducing substances. These may not be particularly useful to a prospective user who wants to know what impurities are present in the material.

Table H7: EU specification for CO2 intended as a food additive[150]

Purity	Description
CO_2 concentration	>99%
Acidity	915 ml of gas bubbled through 50 ml of freshly boiled water must not render the latter more acid to methylorange than is 50 ml freshly boiled water to which has been added 1 ml of hydrochloric acid (0.01 N)
Reducing substances, hydrogen phosphide and sulphide	915 ml of gas bubbled through 25 ml of ammoniacal silver nitrate reagent to which has been added 3 ml of ammonia must not cause clouding or blackening of this solution
Carbon Monoxide	Not more than 10ul/L
Oil content	Not more than 5mg/kg

The European Industrial Gases Association (EIGA) noted that CO_2 is unique amongst other industrial gases, in that it is produced from many different sources and processes, each having

[150] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32012R0231

a different potential impurity profile. It gives recommendations on establishing levels of such impurities, even when they are not specifically included in the specification, taking account of variability in naturally sourced CO_2 or in source processes using natural feedstocks. Aligning with this interpretation of regulations by the industry body in Europe, commercial CO_2 suppliers aligned their product specifications to comply with the EIGA recommendations. An example of food grade CO_2 composition is outlined in table H8.

Table H8: adapted from BOC gases[151]

Component	Concentration
CO_2	99.9% v/v
Moisture	<20 ppm v/v
Ammonia	<2.5 ppm v/v
Oxygen	<30 ppm v/v
Total Sulphur	0.1 ppm v/v
Carbon Monoxide	< 5 ppm v/v
Total volatile HCs	< 50 ppm v/v
Nox (each)	< 1ppm v/v
Taste and odour in water	No foreign taste or odour

The requirements for CO_2 can vary depending on the application, each use will have its own requirements and will be able to tolerate different contaminants at different levels. The required CO_2 concentrations for different applications are outlined in Table H9. Purity and consistency are important, for example CO_2 used for welding requires a purity of 99.5% CO_2 to produce stable welds, whilst purity requirements for food and beverage uses relate more to quality and risk of contamination.

Table H9: requirements for CO_2 concentrations in different applications [152]

Application	CO_2 purity required %
Research	99.999
Supercritical fluid	99.998
Food	99.9
Beverage	99.9
Industrial	99.5

[151] Liquid_CO2_ES_CO2_data_sheet.pdf
[152] Carbon Dioxide (CO_2) Purity Grade Chart – CO_2 Meter

Cordova et al[153] conducted an analysis of other uses for CO_2 from biogas upgrading, including criteria such as the need for purification, energy requirements, net reduction in climate impacts and the effect on other environmental impacts. The results are shown in Table H10.

[153] What should we do with CO_2 from biogas upgrading? - ScienceDirect

Table H10: Potential uses for CO_2 with associated criteria

	Chemical (Methanol)	Mineral carbonates	Fuels	Methane	pH control	Liquefied CO_2	Biomass production
Purification needed	Yes	No	Some	No	Yes	Yes	Yes
Increase in Energy requirements	High	Low	High	high	Low	Low	Low
Capital and operational cost	High	Low	High	high	Low	Low	Low
Other environmental impacts	high	high	high	high	None	None	None
Net reduction of climate impact	High	Medium	Medium	High	High	High	Medium

While the application may not need purified CO_2 the issue can lie in the nature of processing, and the requirements of the equipment used for processing and transport can set the standard for purification.

A study was conducted by a Joint Industry Project designed to develop Industry Guidelines for Setting CO_2 specifications in CCUS Chains (2024)[154].[141] This study looked at the impact of impurities on key points in CCUS supply chains. The project looked at multiple sources of CO_2 streams, including biogas, and the potential contaminants expected. They noted the typical impurities and their effects on supply chains, such as:

- **Water** can have a corrosive effect as well as affecting choice of materials and seals for equipment.
- **Hydrocarbons** can accumulate on the surfaces of the internal flow path resulting in reduced compressor performance.
- **Non-condensable** such as, hydrogen, nitrogen, oxygen, methane and carbon monoxide can remain in vapour state during transport. In some applications these contaminants can change the density of the CO_2 stream and vary power requirements for pumping. In addition, hydrogen oxygen and carbon monoxide can impact material integrity and require appropriate material selection.

[154] Industry Guidelines for Setting the CO2 Specification in CCUS Chains | Wood

- **H2S and Acids** are toxic and aggressive compounds that can influence choice of seals and materials for compression and transport.

With regard to the effects of impurities in relation to compression and pumping, a number of typical indicative compositions from industry have been used to compare the requirements, relative to pure CO_2. The compositions considered representative for CCUS projects are described in Table H11 below.

Aramis and Peterhead are pipeline projects, and the figures below are for saturated CO_2 at 20°C and 1 bar. Northern Lights utilises ship transport for the CO_2 which is liquefied.

Table H11: Requirements of CO_2 purity for different CCUS applications.[154]

Indicative composition Mol%	Pure CO2	Aramis	Northern Lights	CCGT Peterhead
CO_2	99.198	94.607	99.956	99.196
H_2O	0.802	0.801	0.001	0.802
N_2	-	2.318	0.005	0.002
O_2	-	0.004	0.001	0.001
H_2	-	0.750	0.005	0.001
CH_4	-	0.992	0.010	0.000
CO	-	0.074	0.010	0.000

CO_2 from biogas upgrading can be used and there may be an increasing number of outlets; however, some form of treatment will be needed to provide industry with a consistent quality of product, with dehydration, excess methane and removal of some minor contaminants being likely.

The UK Emissions Trading Scheme (ETS) Authority have included a consultation to recognise non-pipeline transport of CO_2 to geological storage in the ETS. This would enable emitters sending CO_2 to permanent storage via non-pipeline transport (NPT) to deduct the amount of permanently stored CO_2 from their UK ETS allowance surrender obligations. This could provide more sites with the incentive to capture CO2 from the off-gas [155]

Environmental Impacts of BUUs

Techno-economic and environmental assessments reported in literature examined a number of upgrading technologies, including high pressure water scrubbing, amine scrubbing, pressure swing adsorption and membrane separation. The study is based around biogas production and upgrading from source segregated organics from municipal solid waste and reported per

[155] UK Emissions Trading Scheme: Non-pipeline transportation of carbon dioxide

functional unit which is 1 Nm^3 of raw biogas. A life cycle assessment was performed using the midpoint CML-IA baseline V3.05/EU25 method for 11 impact categories including global warming potential (GWP) in kg $CO_{2\ eq}$ and Human toxicity (HT) in kg 1.4-DB $_{eq}$. The study found that amine scrubbing showed the lowest GWP, lower than high pressure water scrubbing (by 13%), PSA (by 23%) and membrane separation (by 3%). However, for human toxicity, PSA showed the lowest impacts – lower than high pressure water scrubbing (by 7%), amine scrubbing (by 144%), membrane separation (by 9%).[141]141

The GWP for the upgrader elements was calculated by taking the $CO_{2\ eq}$ for each individual component for the processing of 1 Nm^3 of raw biogas and considered the impact contribution from:

- Avoided natural gas production and combustion
- Methane emissions
- Liquid waste treatment
- Transport
- Chemical usage
- Water usage
- Thermal energy
- Upgrading electrical energy
- Injection electrical energy

The major contributors to the overall GWP are shown in Table H12, expressed as a percentage of the total.

Table H12: Contributions to Global Warming Potential (GWP)[141]Error! Bookmark not defined.Error! Bookmark not defined.

Parameter	High pressure water scrubbing	Amine scrubbing	Pressure swing adsorption	Membrane separation
Electrical energy	7	4	5	8
Methane losses	12.5	0.7	18	6.5
Thermal energy	-	8	-	-
Avoided natural gas emissions	-79	-85	84	74

Even though amine scrubbing is affected by relatively high thermal energy consumption compared to other technologies, the GWP remains lower due to the reduced impact of methane losses. Recovery of the heat used in amine scrubbing and the use of renewable energy as the heat source will reduce the impact of this aspect.

Lombardi et al[141]Error! Bookmark not defined. modelled the effect of CO_2 capture on the GWP, assuming the recovered CO_2 substituted conventional CO_2 manufacture and found that the GWP for each site was reduced by 47% for amine scrubbing, 60% for pressure swing adsorption and 48% for membrane separation. CO_2 recovery was not applicable to water scrubbing due to the high levels of nitrogen in the gas stream.

The human toxicity values for the upgraders were relatively close with the exception of amine scrubbing. The major contributor to the toxicity impact for amine scrubbing was the production process rather than use of methyldiethanolamine (MDEA), which contributed 42.5% to the overall toxicity impact.

Ardolino et alError! Bookmark not defined. conducted a study to assess the environmental and economic impacts of key upgrading technologies, using a combination of life cycle assessment (LCA) with life cycle costing (LCC) to determine the sustainability of each technology.Error! Bookmark not defined. The life cycle impact assessment methodology used was Impact 2002+ with the main categories being, global warming potential (GWP), non-renewable energy potential (NREP) and respiratory inorganics potential (RINP). The study assessed the environmental impacts of direct and avoided burdens based on a functional unit of upgrading 500 Nm^3/h of raw biogas from the organic fraction of municipal solid waste to produce biomethane, compress the gas and use in road transport.

The study included environmental burdens such as power consumption and use of amine solvents and activated carbon, waste treatment, air emissions as well as the avoided impacts linked to biomethane utilisation as a substitute of fossil fuel, using diesel as the replaced product. Membrane separation showed the best performance in all three categories though with some limited differences. For RINP PSA showed the worst performance due to negative contributions from activated carbon and especially zeolite consumption. For GWP there were small contributions to direct emissions for membrane separation, water scrubbing and PSA related to methane slip. This was negligible for amine scrubbing but had a higher contribution relating to energy supply due to the high thermal energy usage in the regeneration phase. PSA again is impacted by the higher use of activated carbon and zeolite. For NREP the direct impacts are due to thermal energy requirements for amine scrubbing and material supply for PSA.

This study concluded that while all technologies provide a negative environmental impact in these areas compared to the non-renewable alternative, the results indicated that membrane separation showed the best performance with PSA being the worst. The authors did acknowledge that choice of upgrading technology will also need to take into account site specific conditions and commercial strategies, whilst also considering gains made elsewhere in a full comparative analysis.

Other Gaseous Emissions from BUUs

The bulk of the off-gas from the biogas upgrading process will be CO_2, but as has been pointed out previously, it is unlikely any technology will be 100% effective without additional abatement

actions, and each technology has a level of methane slip. However, with careful operation and preventative maintenance, emissions can be kept to a minimum.

With each of these technologies, the potential levels of fugitive H_2S are determined by the amount of H_2S in the raw biogas, the type of feedstock and the nature of any upstream treatment, such as ferric compounds in the AD tank or activated carbon scrubbers. Technologies which are less sensitive to contaminants, e.g. PSA, may be better suited to applications such as landfill gas which tend to have higher and more variable levels of contaminants.

The potential sources of gaseous emissions and issues that can occur in the most prevalent technologies in the UK are outlined below:

Water Scrubbing – Some methane will dissolve in the water used for scrubbing which is then liberated through the regeneration process and exits the system in an air stream along with CO_2. Until recently CO_2 capture from water scrubbing was not effective due to the air stream required in the off-gas. However, Malmberg have developed a technology, that can be retrofitted to recover the CO_2 from water scrubbing systems; this is a recent development and is not yet widely deployed. H_2S can also be absorbed in the water and will also exit with the air stream which will need treating, generally by post upgrading activated carbon scrubbers.[156]

Despite regeneration, the water will eventually become "tired" and will hold on to CO_2 and H_2S reducing the efficiency of the stripping process and increasing potential slip. Typically, there is a water exchange process so that fresh water is added to the system to maintain efficiency which, under normal conditions, with an H_2S concentration of 100 ppm, is approximately 0.09 L/Nm^3 of raw biogas. This is added in batches and requires that the water is pressurised to about 6 bar.[157]

Water scrubbing systems use packing materials to aid mass transfer. These packing materials can grow biofilms which need to be treated. Growth of the biofilm and poor maintenance will reduce the efficiency of the scrubbing system.

Chemical Absorption with Amine solvents – several factors can affect the level of methane slip. The type of amine used is important, as amines with high affinity for CO_2 will also trap some methane which will be lost in the regeneration stage. Inefficient regeneration of the chemical absorbent can lead to poorer efficiencies and higher methane emissions.

Amine can be used without pre-treatment for H_2S. However, when H_2S absorbs to the amine solution, higher temperatures may be required during the stripping phase and will need to be removed from the off-gas before release to atmosphere. Pretreatment is often advised especially for biogas with high H_2S concentrations, to reduce energy consumption in the regeneration phase.

Pressure Swing Adsorption (PSA) – methane can escape in the waste gas stream if adsorbers are incorrectly specified. PSA can use multiple adsorbers within the bed to achieve the correct specificity for the chosen gases being extracted. If the bed is incorrectly designed or the

[156] Malmberg CO_2 Harvester - Malmberg EN
[157] Malmberg technical literature

feedstock changes it may be that the ratio of contaminants changes and reduces the efficiency of the upgrader.

After saturation, the pressure in the bed is reduced to desorb the CO_2. During this pressure release and desorption phase, some methane can be released along with the CO_2, especially if the pressure drop is not optimised or if the desorption process is not complete.

Membrane Separation – while membranes are selective for CO_2 in preference to methane, they are not totally impermeable to methane. This means that a small amount of methane will go across the membrane and be lost in the vented gas stream. Cleaning up the CO_2 stream by recycling it back to the upgrader can be done and is technically done with PSA systems using multiple vessels, as the first pass will have sufficient methane in to warrant further treatment. For membrane separation there are already options for multiple membrane systems. To recycle the off-gas to the head of the system would require more cooling, compression and changing the upgrader specification for a larger gas flow, resulting in higher energy usage with limited benefits. The best approach would be to have downstream CO_2 capture technology which can produce CO_2 for industrial specifications for use or storage.

The system can be optimised to reduce methane slip by using the correct membrane materials, offering high permeance and selectivity. Optimising pressure and temperature in membrane-based systems involves finding the ideal balance for both feed and product pressures to maximise methane recovery and purity while minimising energy consumption and costs. The presence of H_2S can reduce the membrane's permeability and selectivity, meaning it may become less effective at allowing desirable gases to pass through while blocking undesirable ones. This can lead to a decline in the quality of the upgraded biogas, potentially requiring additional purification steps or even causing the system to fail. In the event of reduced membrane efficiency, it is possible to restore some of the membrane's capacity by physical, chemical or heat cleaning, but it will not return to maximum efficiency and will reduce the lifespan of the membrane.

11.8.3. Off-gas treatment

Effective removal of contaminants prior to the upgrader is the best way to protect the integrity of the BUU, reduce inefficiencies and improve longevity. This requires careful monitoring of H_2S and non-methane VOC extraction units, including the replacement of activated carbon before it becomes saturated, thus preventing excess contaminants from entering the upgrader. This is particularly important for membrane systems. Regular communication with technology providers and activated carbon specialists is recommended to make sure that no loss in efficiency of separation or increase in methane slip is tolerated.

Provided the upgrader is operating optimally then the methane slip will be kept to a minimum and in systems where H_2S and VOCs are removed before the upgrader then the level of contaminants in the CO_2 off-gas can be kept to a minimum. Regenerative Thermal Oxidation (RTO) is a technology that can remove both methane and non-methane VOCs from the off-gas. It works by preheating contaminated air which then flows into a combustion chamber at a

temperature between 750-850°C. This converts the contaminants to CO_2 and water vapour. While the system uses high temperatures, a series of ceramic heat exchangers can recover the heat making it 95% energy efficient.[158]

RTO can require high capital investment and uses a lot of energy, therefore, for most AD sites it would not be cost effective. However, stakeholder engagement as part of the MEAD 2.0 study did identify sites in the UK that are using or are considering the use of RTO to reduce emissions on their sites. Those with RTO employed included newer sites accredited under the GGSS, where emissions monitoring and management is encouraged. Where sites considered RTO without implementation, cost and energy usage were quoted as the main drawbacks of this technology. The GGSS GHG calculation requires that a default value of 3% methane slip is used where off-gas combustion is not used or actual values are not recorded[159]. This may, in some cases, be enough for sites to employ the technology if that value threatens the incentive revenue.

In general, sites with high methane slip (over 5-7%) or high levels of contaminants benefit from the use of RTOs. However, H_2S is not controlled by RTO technology, therefore additional or alternative treatment of off-gas may be needed upstream of the RTO to address this.[160]

11.8.4. Additional upgrader inputs/outputs

Depending on the type of upgrader selected for use, additional inputs may be required to support operation, and extra outputs may be generated. These considerations further contribute to the wider environmental impacts of the upgrader types employed. Key inputs/outputs are discussed below:

Activated carbon – the amount of activated carbon used on any site for H_2S and VOC removal will be determined by the feedstocks used, site throughput and the nature of H_2S treatment prior to the biogas upgrader. On a farm site with consistent feedstock, good H_2S monitoring and good H_2S control in the tank, the replacement of the carbon can be kept to a minimum. The level of replacement can increase dramatically on sites with variable and/or high sulphur feedstocks or poor in-tank control of H_2S. As an example, one technology provider indicated an activated carbon consumption of 33.2 kg for H_2S removal and 19.8 kg for VOC removal per day, based on a membrane upgrader designed to achieve between 590 Nm^3/hr and 1180Nm^3/hr. Carbon consumption will fluctuate based on actual contaminant levels and unknown components in the raw biogas might affect the consumption.

Activated carbon source and specificity for the chosen application will also influence the quantity used and therefore the frequency of replacement. General purpose carbons are available from relatively cheap sources and are produced from coal; however, by using specially tailored activated carbons from sustainable sources, where possible, the lifespan of the carbon bed can be increased, and the carbon footprint of the installation can be reduced. In addition, the carbon can be reactivated, via a thermal process, and reused. This means that there will be minor losses

[158] Suez technical literature, available at: SUEZ Air & Climate in Spain | Thermal oxidation
[159] GGSS Greenhouse Gas Calculator: user guide
[160] AB Energy technical literature available at: Regenerative thermal oxidizers (RTO) | Gruppo AB

from the system. The effect of activated carbon source on carbon footprint, and the benefits of reactivating the carbon are illustrated in Table H13.

Best practice is to use a lead-lag configuration where two vessels operate together as follows:

- **Lead vessel:** This is the primary or "worker" vessel that receives the incoming biogas and performs the bulk of the purification.
- **Lag vessel:** This vessel follows the lead vessel and acts as a secondary, "polishing" filter, providing a safety net to catch any contaminants that the lead vessel may miss.
- **Switchover:** When the lead vessel is spent and requires carbon replacement, the flow is diverted through the lag vessel first. The lag vessel is then promoted to become the new lead, and the vessel with the fresh carbon is placed in the lag position.

Activated carbon filters can be fixed or mobile. The advantage of mobile filters is that the contractor will bring in a new vessel with the appropriate carbon for the application and swap out the used vessel which is taken away for processing. This system is quicker and reduces on site handling and potential loss of carbons compared to fixed systems.

Activated carbons which are not reactivated will be disposed of via landfill or incineration, whichever is most appropriate to the nature of contamination.

Table H13: Comparison of activated carbon sources on emissions and the effect of carbon regeneration (adapted from Puragen data)[161]

	Reduction in CO_2 equivalents via reactivation %	Mt CO_2 equivalents/Mt activated carbon
Coal	93.22	6.72
Coconut	91.53	5.38
Wood	86.9	3.48
Reactivated	n/a	0.45

Oil and coolants – regular maintenance of upgrader components is vital for optimal BUU operation. Oil and coolant changes will be a factor in this process generating some waste which is usually disposed of by contractors. The quantities of these can vary. For example, for a system that uses high pressure and either larger or multiple compressors, oil residues may remain in the biogas, as well as trace amounts in the condensate. These will be relatively small amounts

[161] Reactivation | Puragen: Data supplied as part of stakeholder engagement.

and are not a frequent occurrence. In some systems such as water scrubbing, the compression is performed dry to prevent oil getting into the packing material.

According to a maintenance company during the stakeholder engagement, coolant is a minor issue and in practice, unless there are leaks in the system this does not need to be addressed. The major component in these systems is oil from compressors which may need some topping up depending on the compressor type but will also undergo a complete oil change once a year. This means that upgrading technologies which have a high demand for compression will also have a higher oil demand. In addition, those sites such as PSA which require multiple compressors will also have a high oil demand. For example, a large compressor may use 400 litres of oil while a small one can be in the region of 100 litres. The oil is typically changed at an annual service and is collected and disposed of through a certified waste oil collection service generally alongside that of the CHP engine.

Condensate – biogas contains moisture which needs to be removed, inevitably leading to the collection of a condensate. This condensate, while not deemed suitable to go back to the digester, will only have some minor contaminants, and it is disposed of via a grey water drain. A compact membrane system with a designed biogas flow of 1180 Nm^3/h will generate 9.4 L/h of condensate (e.g., DMT). A water scrubbing system will have higher levels of condensate from the gas, on average <110 L/h, which varies depending on the temperature and water content of the gas (e.g., Malmberg).

Absorbent inputs – in water and amine systems, topping up the solutions is necessary, primarily due to evaporative losses. The scale of additions will be determined by the biogas flow at the site and size of the scrubbing columns. Typically, an amine scrubber will lose 0.04 mL of amine per m^3 of biogas processed.[162] Typically, there is a water exchange process so that fresh water is added to the system to maintain efficiency. Under normal operating conditions with a H_2S concentration of 100 ppm is approximately 0.09 L/Nm^3 of raw biogas.[163] The effect on the toxicity impact of using amine scrubbing has been discussed previously. However, there is some concern over potential health impacts of amine getting into the atmosphere via the off-gas. The work to date has focused on carbon capture using amine on post combustion sites rather than AD sites. The results suggest that, in these situations with appropriate dilution factors the risk will be minimal[164]. The major risk to health is likely to be with operators handling amine solutions. Provided correct procedure and safety equipment is used these can be mitigated

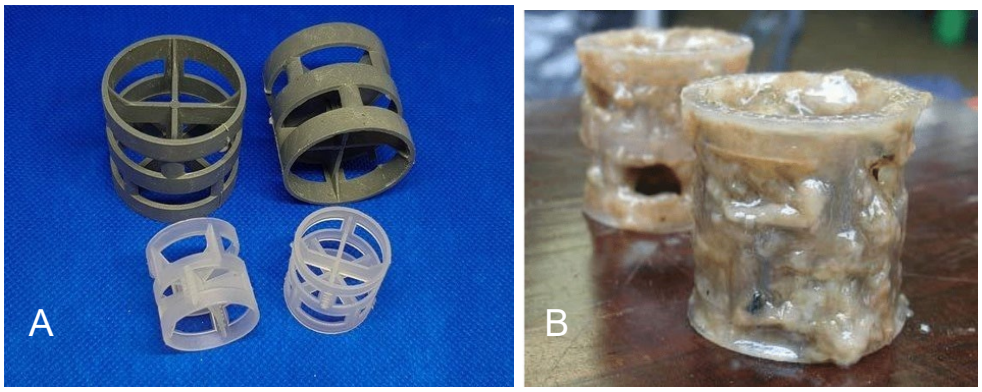
Water consumption - There is no direct water consumption for PSA or membrane separation as they are dry processes, and the aim is to remove as much water prior to the biogas entering the system. As mentioned above the water usage is highest in water scrubbing technology typically in the region of 0.1 L/Nm^3 of biogas processed. Lombardi et al[141] conducted a literature review of upgrading technologies and found values for water consumption varied widely from 0.01 to 0.6 L/Nm^3. Amine based upgrading systems use an amine solution of between 50% and 66% water. Due to the greater adsorption capacity of amine solution compared to water the

[162] Personal communication during stakeholder engagement
[163] Malmberg technical literature.
[164] Air pollution impacts of amine scrubbing for CO2 capture - ScienceDirect

systems can be smaller than water scrubbing and result in lower water consumption with 0.04 ml/Nm^3 (Ammongas)[165] of raw biogas processed or 150 micrograms Nm^3 CO_2 being lost in the CO_2 stream (Wartsilla)[166].

Cleaning solutions - wet scrubbing systems typically use column packing such as Pall rings, Raschig rings or wire mesh (Figure H5). Packing improves the mass transfer of gas to and from the absorbing solution. These materials, however, can act as a platform for biofilm growth which develops over time (typically within months) and can be monitored using sensors. As the biofilm develops the efficiency of the upgrader can be compromised due to interference with the mass transfer. The biofilm can be treated with biocides which are administered at regular, weekly, intervals. However, the main downside to this would be the gradual build-up of additional chemicals within the system.

Figure H5: (A) An example of the packing material (Pall rings[167]) used in wet scrubbing systems. (B) Pall rings with microbial growth.[168]



During the stakeholder engagement, an alternative to in-situ biocide treatment was employed at a site in the UK. The method used had additional sets of the packing materials which could be swapped in when required. The dirty packing can then be cleaned away from the upgrader, and all cleaning fluids disposed of through a contractor, most likely as hazardous waste.

Antifoams – wet systems may be subject to foaming which will reduce the efficiency of the upgrading process. In water systems it is typical to add a small amount of antifoam, 0.1mL/L to the exchange water. Antifoams can be silicon-based materials such as polydimethylsiloxane.

pH correction – while H_2S can corrode, damage and foul membrane units if not removed, wet systems are able to cope with H_2S in the raw biogas, and levels of 1000ppm can be tolerated. However, if these levels of H_2S are allowed to rise too high it can cause the system pH to drop and it becomes less efficient overall. Reducing the temperature of the liquid can reduce the rate of pH change but not stop it completely. To help prevent acidification from occurring, sodium bicarbonate can be dosed into the equipment to regulate the pH accordingly.

[165] World Biogas Association (WBA) | 10. Ammongas Amine Upgrading for biogas
[166] GAS SOLUTIONS FOR MARINE, ONSHORE & OFFSHORE PRODUCTS
[167] Image taken from Valumax engineering: Pall Rings - Valuemax Engineering
[168] Image taken from. Fredric Bauer, Christian Hultenberg, Tobias Persson, Daniel Tamm. Biogas upgrading-Review of commercial technologies. Swedish Gas Technology Centre, Rapport 2013:270

The specific additions relating to individual upgrading technologies are collated in Table H14. The extent to which each of these additions will affect an operation will be site specific.

Table H14: Additional requirements of various upgrading technologies

	Activated Carbon	Adsorbent	Oil	Coolant	Antifoams	Cleaning solutions
Membrane	Upstream processing	N/A	Compressors	To cool input gas and remove moisture	N/A	Potentially for cleaning membranes
Water scrubbing	Upstream and/or downstream processing	Water	Compressors	Cooling of process water is recommended for high ambient temperatures	Yes	Yes
Amine Scrubbing	Upstream/ downstream processing	Amine solution	Compressors	Input gas cooling Cooling of regenerated amine solution Post upgrading gas cooling, prior to grid injection	Yes Sporadically for foaming incidents	Yes
PSA	Upstream processing	Activated carbon/ Zeolite	Compressors	Input gas cooling and Moisture removal	N/A	N/A

11.8.5. Noise and odour environmental issues

Noise – noise nuisances are generally taken into account during the planning process for the site so that any equipment must adhere to the stipulated levels. The main source of noise from upgrading technologies comes from the compression systems. Noise levels quoted for a membrane system (e.g., DMT) was 88 dBA at 1m from the installation, and for a water wash system (e.g., Malmberg) the noise level was quoted as 75 dBA in the open air free field measurement 10m from the machine. Noise attenuation can be added by skid mounting membrane systems on rubber feet to reduce vibration or applying noise dampening to the container. For water wash systems, noise reduction can be accomplished by installing dampeners on ventilation openings and stripper fans, this will typically reduce noise by 6 dBA.

Odour – provided that the system is well maintained and that carbon filters are replaced efficiently then odour is not a notable concern for upgrading systems. The nature of biogas upgraders is that it is a pressurised system, in order to maintain the integrity of the upgrader the

seals must work well, under normal operation, no gas will escape, apart from the off-gas stream, and therefore odour issues are not typically an issue. Stakeholder engagement consistently confirmed that under normal operating conditions odour was not an issue for biogas upgraders. Operators were keen to point out that if odour should become apparent from the upgrader then it will be indicative of a malfunction in the system which needs to be addressed immediately. One stakeholder did note that the only odour issue that did occur was at the grid entry unit (GEU) due to leakage of the odouriser for the biomethane.

To summarise the content of this chapter on emissions/environmental impacts from the biogas upgrading stage of the AD process, good practice recommendations are presented below.

Conclusions

Over the past decade there has been a push for AD to move away from the development of CHP sites to produce electricity, to the production of biomethane for grid injection. An integral part of this process is the biogas upgrading unit.

As has been noted there are a number of competing technologies on the market, each with their own benefits and drawbacks. For example, membrane technology is relatively simple to use and is a familiar technology in the UK, however at larger scale it could be an issue. Amine scrubbing offers better efficiency with regard to methane slip but requires heat for the regeneration step.

With all these technologies it is important to develop good management and maintenance practices on site so as to not reduce the efficiency of the equipment and increase methane slip.

The carbon footprint of the site can be reduced if the CO_2 is captured, refined and used or stored, however there will be economies of scale and smaller sites may not be able to justify the cost. This option also gives the opportunity of reducing methane emissions as it can be captured and recycled. The recent consultation surrounding the Emission Trading Scheme and recognising non-pipeline transport of CO_2 for geological storage could provide an outlet and associated revenue for sites that struggle to find a market for captured CO_2.

Careful consideration needs to be given to the associated inputs and outputs of each system type, such as activated carbon, water, amine solution and oil for compressors. Appropriate capacity needs to be in place to cope with the demands of the system, and as such selecting the correct upgrading technology for any application will be site specific and failure in this aspect could lead to a system not being able to efficiently cope with the demands of the site, which could in turn lead to higher than anticipated methane losses.

Areas requiring further analysis.

While biogas upgrading is a maturing technology and is now being preferentially deployed on AD sites there are still a number of areas which require further work, especially in real world scenarios, to complete the picture. These are especially important for operators and developers to get a full understanding of how the technology fits into the site and can affect operations.

- The overall energy requirements for biogas upgrading can be highly variable depending on the technology used and the operational situation. A detailed study of a wide range of sites over a longer period of time would give a better picture of the energy used for different technologies and situations, monitoring how these vary over time. This would further enhance the understanding of the carbon footprint of biogas upgrading.

- While membrane is the most prevelent technology in the UK this is not the case for other countries. An assessment of why this is the case would inform a greater understanding of the different technologies available. In addition an assessment of which situations are best suited to each technology could assist in improved site efficiencies.

- Complete analysis of the off-gas has typically been of low priority beyond methane concentration. While there are some studies they are far from comprehensive. A thorough study of off-gas streams from each upgrader type and a diverse feedstock range would give a better understanding of the requirements for carbon capture.

- There have been some studies on techno-economic and life cycle analysis for biogas upgrading and these have shown that there can be variability as to which system is preferred. This is due to the variability of upgrading systems, feedstocks and operational conditions as well as the methodology used for the analysis. A more wide ranging study leading to a standardised model may inform developers which is the best upgrader for any given situation.

- Carbon capture and storage is an important aspect in lowering the carbon footprint of an AD site; however some producers find it difficult to access markets for the CO_2. A good deal of the issue is around perception of the origin of the CO_2, if this can be addressed it would open markets for a larger number of producers. In addition, a more coordinated approach at an industry level would be able to connect producers with end users to give AD sites confidence in investing in CO_2 capture.

- The importance of additional requirements for upgraders such as activated carbon, water use, coolant and oil can be overlooked or treated as a low priority. Greater analysis of these aspects with respect to the range of upgraders and feedstocks would improve the understanding of biogas upgrading carbon footprint.

Good Practice Recommendations – Biogas Upgrading Units

- Off-gas treatment is important to minimise methane emissions. This could be via off-gas combustion or further treatment of the CO_2 stream for CCUS. Liquefaction of CO_2 can reduce methane slip associated with the upgrading process. The use of this technology needs to be balanced with the extra energy usage for the site. The use of off-gas combustion (e.g., RTO) can remove any residual methane being lost to the atmosphere, but its use is not widespread at present due to high costs and energy use. However, as discussed above, where methane slip lower than the standard values is required for GHG compliance on GGSS and other schemes, this should be prioritised

- For filter systems using activated carbon, it is important to source the best quality carbon and be specific for contaminants rather than using generic materials. Modular systems with removable tanks are easier to work with and reduce handling of activated carbons
- Ensure proper disposal procedures are in place for additional outputs such as compressor oil or cleaning solutions.
- Optimise the process by working closely with the upgrader manufacturer, installer and maintenance engineers to ensure that the operation is the most efficient it can be.
- Ensure raw biogas filtering is optimised to reduce H_2S and non-methane VOCs (NMVOC) going to the upgrader. This will prevent unnecessary wear and tear on the upgrader unit and subsequent loss of efficiencies.
- In the event of feedstock changes, consult with the technology provider to ensure the upgrader will work efficiently and that there is nothing in the new feedstock which can damage or reduce upgrader efficiency if not adequately treated.
- Quick detection and action to prevent the build-up of hazardous atmosphere and alert operators to the presence of a leak is invaluable. These measures are generally more effective in containerised systems such as membrane upgraders. However larger companies are viewing methane loss and GHG emissions as an increasingly important aspect of the operation and are looking into sensor networks across the site to reduce emission events and reduce the environmental impact of the site as a whole.
- Forward planning can reduce energy requirements for future expansion. If the intention is for a new site to expand then designing the specifications of the upgrader to account for future expansion could reduce the need for additional compressors and pumps associated with add on equipment.
- Education of operators is invaluable. Stakeholder engagement has demonstrated that the more the operators and site staff know about the equipment and its operation, the more engaged they are with the process. Expertise at this level means that potential problems can be diagnosed early and remedied quickly.

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