BIOMETHANE REGIONS

Introduction to the Production of Biomethane from Biogas
A Guide for England and Wales
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1. Introduction to the Opportunity

The conversion of biogas to biomethane will offer clear advantages and opportunities at some anaerobic digestion plants – both existing and proposed. The core of this guide is a review of the current readily available technologies that take raw biogas and enrich it to the point that it approaches pure methane – in order that it may be used in vehicles (as compressed natural gas) or injected into the natural gas grid. This introductory section discusses the circumstances where biomethane production may be appropriate.

The most significant advantage in producing biomethane, as an alternative to the standard model of producing electricity and heat from a combined heat and power (CHP) unit, is one of efficiency of the energy production process. Where all or most of the heat from the CHP unit is effectively utilised then the argument for biomethane production is significantly reduced, because the efficiency of use of the energy in the biogas is high. Where little or none of the heat from the CHP unit is used to good effect (apart from the sacrificial heat load on the digester) then the efficiency of energy conversion will be only between 30 and 40%. By comparison, most modern natural gas appliances have very high efficiencies.

Many AD plants are sited in locations remote from major heat users, and it is not at all unusual for it to be impractical or extremely expensive to construct heat mains to the nearest heat users. If those users are domestic properties then the demand for heat is far from constant. Under these circumstances it would be best to consider the feasibility of converting all or part of the biogas to biomethane. Although, putting some of the biogas through an engine might still be sensible in order to cater for the sacrificial heat load of the digester.

There are, however, significant constraints in developing a gas-to-grid project and these constraints need to be considered very early in the project’s conception phase:-

- All gas-to-grid cleaning and injection technologies are expensive, with some elements of the cost accelerating very little with increased scale. This renders smaller scale projects uneconomic as things stand at present.

- Although piping gas is nowhere near as expensive as piping heat, there are limits to economic viability in terms of distance to the gas grid. The costs, or even the possibility, will also depend upon land ownership and the nature of the ground to be crossed. Digging trenches in roads is costly and can involve complex interactions with other utilities.

- The gas grid into which the gas is to be injected has to be able to handle the amount of gas to be injected. A low pressure grid with limited demand for gas in the summer, for instance, may not be suitable for injection (although trials are being run at present that may provide a partial solution to this issue in some circumstances).
The use of the biogas-to-biomethane calculator developed under this project will enable approximate calculations of cost to be ascertained in respect of the upgrading. The location and suitability of the local gas grid will be ascertained only via consultations with the appropriate gas grid operator.

The remainder of the first part of this document (prior to the case studies) was produced by the Technical University of Vienna, and provides detailed guidance on currently available technologies.

2. Introduction and Overview of the Technology

Biogas upgrading and the production of biomethane nowadays is a state-of-the-art-process of gas separation. A number of different technologies to fulfil the task of producing a biomethane stream of sufficient quality to act as a vehicle fuel or to be injected into the natural gas grid are already commercially available, and have proven to be technically and economically feasible. Nevertheless, intensive research is still in progress to optimise and further develop these technologies as well as to apply novel technologies to the field of biogas upgrading. All technologies have their own specific advantages and disadvantages, and this review shows that no technology is the optimal solution to each and every biogas upgrading situation. The right choice of the economically optimal technology is strongly dependent on the quality and quantity of the raw biogas to be upgraded, the desired biomethane quality and the final utilisation of this gas, the operation of the anaerobic digestion plant and the types and continuity of the used substrates, as well as the local circumstances at the plant site. This choice is to be made by the planner and future operator, and this report is structured to act as a supporting guide during the planning phase of a new biomethane production site.

Biogas upgrading is a gas separation task, finally yielding a methane-rich product gas stream with a certain specification. Depending on the raw biogas composition this separation task comprises the separation of carbon dioxide (and thus increasing the heating value and Wobbe-Index), the drying of the gas, the removal of trace substances like oxygen, nitrogen, hydrogen sulphide, ammonia or siloxanes as well as the compression to a pressure needed for the further gas utilisation. Furthermore, tasks like odourisation or adjustment of the heating value by propane dosing might have to be performed. To give a short overview of the separation task, and the involved gas streams, a basic flowsheet for the biogas upgrading process is given in Error! Reference source not found..
The raw biogas basically is split into two gas streams during biogas upgrading: the methane-rich biomethane stream and the carbon-dioxide-rich offgas stream. As no separation technology is perfect, this waste-gas stream still contains a certain amount of methane, depending on the methane recovery of the applied technology. Whether this gas stream is legally permitted to be vented to the atmosphere or has to be further treated is dependent on the methane content, on the methane slip of the upgrading plant (amount of methane in the offgas relative to the amount of methane in the raw biogas) and on the legal situation at the plant site. The following sections will describe the technologies available for the most important tasks in biogas upgrading (desulphurisation, removal of carbon dioxide, drying). The removal of trace components will be discussed briefly and the possibilities for offgas treatment will be presented at the end of this section.

The following table contains typical gas compositions of biogas and landfill gas, and these values are compared to Danish natural gas. The quality of this natural gas seems to be quite representative for the available natural gas qualities throughout Europe.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Biogas</th>
<th>Landfill gas</th>
<th>Natural gas (Danish)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane [vol%]</td>
<td>60-70</td>
<td>35-65</td>
<td>89</td>
</tr>
<tr>
<td>Other hydrocarbons [vol%]</td>
<td>0</td>
<td>0</td>
<td>9,4</td>
</tr>
<tr>
<td>Hydrogen [vol%]</td>
<td>0</td>
<td>0-3</td>
<td>0</td>
</tr>
<tr>
<td>Carbon dioxide [vol%]</td>
<td>30-40</td>
<td>15-50</td>
<td>0,67</td>
</tr>
<tr>
<td>Nitrogen [vol%]</td>
<td>up to 1</td>
<td>5-40</td>
<td>0,28</td>
</tr>
<tr>
<td>Oxygen [vol%]</td>
<td>up to 0,5</td>
<td>0-5</td>
<td>0</td>
</tr>
<tr>
<td>Hydrogen sulphide [ppmv]</td>
<td>0-4000</td>
<td>0-100</td>
<td>2,9</td>
</tr>
<tr>
<td>Ammonia [ppmv]</td>
<td>up to 100</td>
<td>up to 5</td>
<td>0</td>
</tr>
<tr>
<td>Lower heating value [kWh/m³(STP)]</td>
<td>6,5</td>
<td>4,4</td>
<td>11,0</td>
</tr>
</tbody>
</table>

### 3. Raw biogas desulphurisation technologies

Although carbon dioxide is the major contaminant in the raw biogas during the production of biomethane, it has been shown that the removal of hydrogen sulphide can be of crucial importance for the technological and economic feasibility of the whole gas upgrading chain. Of course, this behaviour strongly depends on the sulphur content of the AD substrate used, and the continuity of the fermentation process. Hydrogen sulphide is a hazardous and corrosive gas that has to be removed from the gas prior to any further utilisation, whether it is grid injection or CNG fuel production. A number of technologies are readily available to fulfil this task. Depending on the local circumstances of the anaerobic digestion plant and the biomethane production unit, one technology or a combination of two or even more technologies for biogas desulphurisation have to be applied to realise a technically stable and economically competitive solution. The most important methods
are presented in the following section; the standards required for biogas upgrading for grid injection have been taken into account for this assessment.

a. **In-situ desulphurisation: Sulphide precipitation**

The addition of liquid mixtures of various metal salts (like iron chloride or iron sulphate) to the digester or the mashing tank prior to the digester results in a precipitation of the sulphur content of the substrate by formation of almost insoluble iron sulphide within the biogas fermenter. The iron sulphide is removed from the fermentation together with the digestate. This technology also allows ammonia to be removed from the biogas, in addition to the hydrogen sulphide. Furthermore, it has been reported that an improvement of the liquid milieu for the involved microorganisms can be achieved because of the reduction of toxic substances in the medium. This effect results in an increasing methane yield.

Sulphide precipitation is a relatively cheap desulphurisation method needing minimal investment. Existing anaerobic digestion plants can be retrofitted with ease and the operation, monitoring and handling is uncomplicated. On the other hand, the degree of desulphurisation is hardly controllable and pro-active measures are not possible. The effectiveness and the achievable biogas quality regarding hydrogen sulphide are clearly limited. This technique is typically used in digesters with high hydrogen sulphide concentrations as a first measure, together with subsequent desulphurisation stages, or in cases where high amounts of hydrogen sulphide in the biogas are allowed.

b. **Biological desulphurisation: biological scrubbing**

Hydrogen sulphide can be removed through oxidation by chemoautotrophic microorganisms of the species Thiobacillus or Sulfolobus. This oxidation requires a certain amount of oxygen, which is added to the biological desulphurisation via a small amount of air (or pure oxygen if levels of nitrogen have to be minimised). This oxidation can occur inside the digester by immobilising the microorganisms already available in the natural digestate. The alternative possibility is to use an external apparatus through which the biogas passes after leaving the digester. This is the only alternative if biogas upgrading for the production of natural gas substitute is desired. The applied external apparatus takes the form of a trickling filter with a packed bed inside, which contains the immobilised microorganisms as a biological slime. Biogas is mixed with the added oxidiser, enters the trickling filter and meets a counter flow of water containing nutrients. These microorganisms oxidise hydrogen sulphide with molecular oxygen, and convert the unwanted gas compound to water and elemental sulphur or sulphurous acid, which is discharged together with the column’s waste water stream. The investment needs for this method are moderate and operational costs are low. This technology is widespread and the plant availability is high.
c. Chemical-oxidative scrubbing

The absorption of hydrogen sulphide in caustic solutions is one of the oldest methods for gas desulphurisation. Nowadays, typically sodium hydroxide is used as a caustic and the pH is carefully controlled to adjust the separation selectivity. The task is to create and maintain a plant operation with maximised hydrogen sulphide absorption and minimised carbon dioxide absorption in order to minimise chemical consumption (carbon dioxide is to be removed with a more efficient technology). The selectivity of hydrogen sulphide versus carbon dioxide can be further increased by the application of an oxidiser to oxidise the absorbed hydrogen sulphide to elemental sulphur or sulphate, thus increasing the rate of hydrogen sulphate removal. Usually hydrogen peroxide is used as an oxidiser in biogas upgrading plants. This technique shows favourable controllability and stable operation even under strong fluctuations of raw biogas quality and quantity. Hydrogen sulphide content as low as 5ppm can be reached during stable operation. Usually, the most economic operation is to control the content of the purified gas to reach around 50ppm; the remaining hydrogen sulphide is removed by means of adsorption on metal oxides. This technology requires elaborate process control and knowledge of dealing with the chemical agents used. It has been reported that the specific costs of this technology are highly competitive with other existing desulphurisation technologies. This technology has to be considered if high or strongly fluctuating hydrogen sulphide contents are expected at a biomethane production site.
**d. Adsorption on metal oxides or activated carbon**

Hydrogen sulphide can be adsorbed on the surface of metal oxides like iron oxide, zinc oxide or copper oxide, or on activated carbon, and removed from the biogas with excellent results. During the adsorption on metal oxides the sulphur is bound as metal sulphide and water vapour is released. As soon as the adsorbent material is loaded it is removed and replaced by fresh material. The adsorption of hydrogen sulphide on activated carbon is usually performed with a small addition of oxygen in order to oxidise the adsorbed gas to sulphur and to bind it more strongly to the surface. If no oxygen dosing is allowed, a specially impregnated activated carbon material is applied. This desulphurisation technique is extremely efficient with resulting concentrations of less than 1ppm. Although the investment costs are relatively low, the overall specific costs of this technology are considerably higher, with the result that this method is typically applied only for final or less onerous desulphurisation tasks (typically up to 150ppm hydrogen sulphide in the raw biogas).

**4. Biogas upgrading and biomethane production technologies**

Currently, a number of different technologies for the major biogas upgrading step are commercially available. This major step comprises the drying of the raw biogas and the removal of carbon dioxide, and thus the enhancement of the heating value of the final gas produced. These proven technologies will be presented in the following section. The removal of minor or trace components from the raw biogas will be discussed subsequently. Typically, these removal steps are already included in any commercially available biogas upgrading plant.

**a. Absorption**

The separation principle of absorption is based on differing solubilities of various gas components in a liquid scrubbing solution. In an upgrading plant using this technique the raw biogas is forced into intensive contact with a liquid. A scrubbing column is filled with a plastic packing in order to increase the contact area between the phases. The components to be removed from the biogas (mostly carbon dioxide) are typically far more soluble in the applied liquid than methane and are removed from the gas stream. As a result, the remaining gas stream is enriched with methane and the scrubbing liquid leaving the column is rich in carbon dioxide. In order to maintain the absorption performance, this scrubbing liquid has to be replaced by fresh liquid or regenerated in a separate
step (desorption or regeneration step). Currently, three different upgrading technologies embodying this physical principle are available.

i. **Physical absorption: Pressurised water scrubbing**

The absorbed gas components are physically bound to the scrubbing liquid, in this case water. Carbon dioxide has a higher solubility in water than methane and will therefore be dissolved to a higher extent, particularly at lower temperatures and higher pressures. In addition to carbon dioxide, hydrogen sulphide and ammonia can also be reduced in the biomethane stream using water as a scrubbing liquid. The effluent water leaving the column is saturated with carbon dioxide and is transferred to a flash tank where the pressure is abruptly reduced and the major share of the dissolved gas is released. As this gas mainly contains carbon dioxide, but also a certain amount of methane (methane is also soluble in water, but to a smaller extent) this gas is piped to the raw biogas inlet. If the water is to be recycled back to the absorption column, it has to be regenerated and is therefore pumped to a desorption column where it meets a counter current flow of stripping air, into which the remaining dissolved carbon dioxide is released. The regenerated water is then pumped back to the absorber as fresh scrubbing liquid.

The drawback of this method is that the air components – oxygen and nitrogen – are dissolved in the water during regeneration, and thus are transported to the upgraded biomethane gas stream. Therefore, biomethane produced with this technology always contains oxygen and nitrogen. As the produced biomethane stream is also saturated with water, the final upgrading step typically is gas drying, for example by the application of glycol scrubbing.

![Figure 4: Flowsheet of a typical biogas upgrading unit applying pressurised water scrubbing; picture of the upgrading plant Könnern, Germany with a raw biogas capacity of 1,250m³/h (Source: Malmberg)](image)

ii. **Organic physical absorption**

Using a basic similar concept to water scrubbing, this technology uses an organic solvent solution (e.g. polyethylene glycol) instead of water as a scrubbing liquid. Carbon dioxide shows higher solubilities in these solvents than in water. As a result, less scrubbing liquid circulation and smaller apparatus are needed for the same raw biogas capacity. Examples of commercially available biogas...
upgrading technologies implementing organic physical scrubbing are Genosorb®, Selexol®, Sepasolv®, Rektisol® and Purisol®.

### iii. Chemical absorption: amine scrubbing

Chemical absorption is characterised by a physical absorption of the gaseous components in a scrubbing liquid, followed by a chemical reaction between scrubbing liquid components and absorbed gas components within the liquid phase. As a result, the bonding of unwanted gas components to the scrubbing liquid is significantly stronger, and the loading capacity of the scrubbing liquid is several times higher. The chemical reaction is strongly selective and the amount of methane also absorbed in the liquid is very low, resulting in very high methane recovery and very low methane slip. Due to the high affinity of especially carbon dioxide to the solvents used (mainly aqueous solutions of Monoethanolamine MEA, Diethanolamine DEA and Methyldiethanolamine MDEA), the operating pressure of amine scrubbers can be kept significantly lower compared to pressurised water scrubbing plants of similar capacity.

Typically, amine scrubbing plants are operated at the slightly elevated pressure already arising in the raw biogas, and no further compression is needed. The high capacity and high selectivity of the amine solution, although an advantage during absorption, turns out to be a disadvantage during the regeneration of the scrubbing solution. Chemical scrubbing liquids require a significantly increased amount of energy during regeneration which has to be provided as process heat. The loaded amine solution is heated up to about 160°C where most of the carbon dioxide is released and leaves the regeneration column as a considerably pure offgas stream. As a small part of the scrubbing liquid is lost to the produced biomethane due to evaporation, it has to be replenished frequently. Hydrogen sulphide could also be absorbed from the raw biogas by chemical absorption, but even higher temperatures during regeneration would be needed. That is why it is advisable to remove this component prior to the amine scrubber.
b. Adsorption: Pressure swing adsorption (PSA)

Gas separation using adsorption is based on different adsorption behaviour of various gas components on a solid surface under elevated pressure. Usually, different types of activated carbon or molecular sieves (zeolites) are used as the adsorbing material. These materials selectively adsorb carbon dioxide from the raw biogas, thus enriching the methane content of the gas. After the adsorption at high pressure the loaded adsorbent material is regenerated by a stepwise decrease in pressure and flushing with raw biogas or biomethane. During this step offgas is leaving the adsorber. Afterwards, the pressure is increased again with raw biogas or biomethane and the adsorber is ready for the next sequence of loading. Industrial scale upgrading plants implement four, six or nine adsorber vessels in parallel, at different positions within this sequence in order to provide a continuous operation. During the decompression phase of the regeneration, the composition of the offgas is changing as the co-adsorbed methane is released earlier (at higher pressures) and the bulk of carbon dioxide is preferentially desorbed at lower pressures. Thus, the offgas from the first decompression stages is typically piped back to the raw biogas inlet in order to reduce the methane slip. Offgas from later stages of regeneration could be led to a second stage of adsorption, to the offgas treatment unit or could be vented to the atmosphere. As water and hydrogen sulphide contents in the gas irreversibly harm the adsorbent material, these components have to be removed before the adsorption column.

Figure 6: Flowsheet of a typical biogas upgrading unit applying pressure swing adsorption; picture of the upgrading plant Mühlacker, Germany with a raw biogas capacity of 1,000 m³/h (Source: Schmack CARBOTECH)

Membrane technology: Gaspermeation

Membranes for biogas upgrading are made of materials that are permeable for carbon dioxide, water and ammonia. Hydrogen sulphide, oxygen and nitrogen permeate through the membrane to a certain extent and methane passes only to a very low extent. Typical membranes for biogas upgrading are made of polymeric materials like polysulfone, polyimide or polydimethylsiloxane. These materials show favourable selectivity for the methane/carbon dioxide separation combined with a reasonable robustness to trace components contained in typical raw biogases. To provide sufficient membrane surface area within compact plant dimensions, these membranes are applied in the form of hollow fibres, combined to assemble a number of parallel membrane modules.
After the compression to the applied operating pressure the raw biogas is cooled down for drying and removal of ammonia. After reheating with compressor waste heat the remaining hydrogen sulphide is removed by means of adsorption on iron or zinc oxide. Finally, the gas is piped to a single- or multi-staged gas permeation unit. The numbers and interconnection of the applied membrane stages are not determined by the desired biomethane quality, but by the requested methane recovery and specific compression energy demand. Modern upgrading plants with more complex design offer the possibility of very high methane recoveries and relatively low energy demand. Even multi-compressor arrangements have been realised and proved to be economically advantageous. The operation pressure and compressor speed are both controlled to provide the desired quality and quantity of the produced biomethane stream.

d. Comparison of different biogas upgrading technologies

It is hard to give a universally valid comparison of the different biogas upgrading technologies because many essential parameters strongly depend on local circumstances. Furthermore, the technical possibilities of a certain technology (for example regarding the achievable biomethane quality) often do not correspond with the most economic operation. The technical development maturity of most biogas upgrading methods nowadays is typically sufficient to meet any needs of a potential plant operator. It is mainly a question of finding a plant design providing the most economic operation for biomethane production. As a result, it is strongly recommended to perform a detailed analysis of the specific biomethane costs to be expected and to account for all possible upgrading technologies. As a guiding tool to fulfil these tasks the “BiomethaneCalculator” has been developed during this project and will be updated every year. This tool models all relevant upgrading steps and upgrading technologies and allows for a qualified estimation of specific biomethane production costs to be expected.

The following table summarises the most important parameters of the described biogas upgrading technologies, applied to a typical raw biogas composition. Values of certain parameters represent averages of realised upgrading plants or verified data from literature. The price basis used is from March 2012.
Membrane technology offers the possibility to widely adapt the plant layout to the local circumstances by the application of different membrane configurations, multiple membrane stages and multiple compressor variations. This is why a certain range is given for most of the parameters. The first number always corresponds to the simpler plant layout (“cheaper” and with low methane recovery) while the other higher number corresponds to a high recovery plant layout.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Water scrubbing</th>
<th>Organic physical scrubbing</th>
<th>Amine scrubbing</th>
<th>PSA</th>
<th>Membrane technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>typical methane content in biomethane [vol%]</td>
<td>95-99</td>
<td>95-99</td>
<td>&gt;99</td>
<td>95-99</td>
<td>95-99</td>
</tr>
<tr>
<td>methane recovery [%]</td>
<td>98</td>
<td>96</td>
<td>99.96</td>
<td>98</td>
<td>80-99.5</td>
</tr>
<tr>
<td>methane slip [%]</td>
<td>2.0</td>
<td>4.0</td>
<td>0.04</td>
<td>2.0</td>
<td>20-0.5</td>
</tr>
<tr>
<td>typical delivery pressure [bar(g)]</td>
<td>4-8</td>
<td>4-8</td>
<td>0</td>
<td>4-7</td>
<td>4-7</td>
</tr>
<tr>
<td>electric energy demand [kWhel/m³ biomethane]</td>
<td>0.46</td>
<td>0.49-0.67</td>
<td>0.27</td>
<td>0.46</td>
<td>0.25-0.43</td>
</tr>
<tr>
<td>heating demand and temperature level</td>
<td>-</td>
<td>medium</td>
<td>high</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>desulphurisation requirements</td>
<td>process dependent</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>consumables demand</td>
<td>antifouling agent, drying agent</td>
<td>organic solvent (non-hazardous)</td>
<td>amine solution (hazardous, corrosive)</td>
<td>activated carbon (non-hazardous)</td>
<td></td>
</tr>
<tr>
<td>partial load range [%]</td>
<td>50-100</td>
<td>50-100</td>
<td>50-100</td>
<td>85-115</td>
<td>50-105</td>
</tr>
<tr>
<td>number of reference plants</td>
<td>high</td>
<td>low</td>
<td>medium</td>
<td>high</td>
<td>low</td>
</tr>
<tr>
<td>typical investment costs [€/(m³/h) biomethane]</td>
<td>10,100</td>
<td>9,500</td>
<td>9,500</td>
<td>10,400</td>
<td>7,300-7,600</td>
</tr>
<tr>
<td>for 100m³/h biomethane</td>
<td>5,500</td>
<td>5,000</td>
<td>5,000</td>
<td>5,400</td>
<td>4,700-4,900</td>
</tr>
<tr>
<td>for 250m³/h biomethane</td>
<td>3,500</td>
<td>3,500</td>
<td>3,500</td>
<td>3,700</td>
<td>3,500-3,700</td>
</tr>
<tr>
<td>typical operational costs [ct/m³ biomethane]</td>
<td>14.0</td>
<td>13.8</td>
<td>14.4</td>
<td>12.8</td>
<td>10.8-15.8</td>
</tr>
<tr>
<td>for 100m³/h biomethane</td>
<td>10.3</td>
<td>10.2</td>
<td>12.0</td>
<td>10.1</td>
<td>7.7-11.6</td>
</tr>
<tr>
<td>for 250m³/h biomethane</td>
<td>9.1</td>
<td>9.0</td>
<td>11.2</td>
<td>9.2</td>
<td>6.5-10.1</td>
</tr>
<tr>
<td>for 500m³/h biomethane</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
e. **Removal of trace components: water, ammonia, siloxanes, particulates**

Biogas is saturated with water vapour when it leaves the digester. This water tends to condense within apparatus and pipelines and, together with sulphur oxides, may cause corrosion. By increasing the pressure and decreasing the temperature water will condense from the biogas and can thereby be removed. Cooling can either be realised using the ambient surroundings (air, soil) or by active cooling (i.e., refrigeration). Water can also be removed by scrubbing with glycol or by adsorption on silicates, activated charcoal or molecular sieves (zeolites).

Ammonia is usually separated when the biogas is dried by cooling, as its solubility in liquid water is high. Furthermore, most technologies for carbon dioxide removal are also selective for the removal of ammonia. A separate cleaning step is therefore usually not necessary.

Siloxanes are used in products such as deodorants and shampoos, and can therefore be found in biogas from sewage sludge treatment plants and landfill gas. These substances can create serious problems when burned in gas engines or combustion facilities. Siloxanes can either be removed by gas cooling, by adsorption on activated carbon, activated aluminium or silica gel, or by absorption in liquid mixtures of hydrocarbons.

Particulates and droplets can be present in biogas and landfill gas and can cause mechanical wear in gas engines, turbines and pipelines. Particulates that are present in the biogas are separated by fine mechanical filters (0.01µm – 1µm).

**5. Removal of methane from the offgas**

As mentioned before, the offgas produced during biogas upgrading still contains a certain amount of methane depending on the methane recovery of the applied gas separation technology. As methane is a strong greenhouse gas, it is of vital importance for the overall sustainability of the biomethane production chain to minimise the methane emissions to the atmosphere. It should be noted that the emissions of methane from biogas processing plants is restricted in most countries. Additionally, higher amounts of methane in the offgas increase the specific upgrading costs and could inhibit economic plant operation. But it is never so simple, as there is a trade-off in selecting a certain methane recovery value because a higher methane recovery always increases investment and operational costs of a certain upgrading technology. As a result, the most promising plant layout in terms of economics usually accepts a certain amount of methane left in the offgas and applies a certain treatment of the gas prior to venting it to the atmosphere.

The most common technique for removing the methane content in the offgas is oxidation (i.e., combustion) and generation of heat. This heat can either be consumed at the anaerobic digestion plant itself (as this plant often has a heat demand), it can be fed to a district heating system (if locally available) or it has to be wasted by cooling. Another possibility would be to mix the offgas with raw biogas and feed it to an existing CHP gas engine. Either way, the layout of the plant has to be planned carefully, since the offgas of a modern biogas upgrading plant seldom contains enough methane to maintain a flame without addition of natural gas or raw biogas.

Alternatively, the methane in the offgas can be oxidised by a low-calorific combustor or by catalytic combustion. A number of manufacturers already provide applicable technologies on a commercial
basis. These systems provide stable combustion even at methane concentrations as low as 3% in the combustion mixture with air. The treatment of offgas containing even less methane is increasingly difficult, as not enough energy is provided during the combustion of this gas, and raw biogas or biomethane have to be added in order to reach a stable oxidation. This is why it does not always make sense to choose an upgrading technology with a methane recovery as high as possible, because you always have to deal with the offgas. The integration of the upgrading plant into the biogas production facility and the overall concept of the biomethane production site are much more important. Only a very few upgrading technologies with extremely high methane recovery rates provide an offgas that is permitted to be directly vented to the atmosphere.

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BEST PRACTICE CASE STUDIES

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BIOMETHANE PRODUCTION FACILITIES

EMMERTSBÜHL BIOGAS PLANT, GERMANY

ZALAVÍZ WATERWORKS COMPANY, HUNGARY

BRUCK/LEITHA BIOGAS PLANT, AUSTRIA
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Case studies were produced following surveys / site visits undertaken between 2011 and 2012 and information is therefore relevant for operating conditions at the time of visit only. Some plants may now operate under different conditions to those specified within the case studies.

Authors

<table>
<thead>
<tr>
<th>Authors</th>
<th>Institution</th>
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</tr>
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<tbody>
<tr>
<td>Tim Patterson and Sandra Esteves</td>
<td>UoG</td>
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<td>Annegret Wolf, Heinz Kastenholz and Andreas Lotz</td>
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<td>Technical University of Vienna</td>
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Emmertsbühl Biogas/Biomethane Plant, Germany

INTRODUCTION / OVERVIEW

The biogas / biomethane plant is located at an arable farm in the village of Emmertsbühl, which is approximately 120 km to the north east of Stuttgart in the Baden-Württemberg region of Southern Germany. The farmer and AD plant operator originally developed an AD plant at the site in 2005 with wheat being the primary feedstock and biogas utilised in a CHP plant, although there was no local user for the excess heat generated at the plant. By 2008 the operator was exploring options for the expansion of the plant and wished to increase the utilisation of the biogas generated. In collaboration with the energy company EnBW Vertrieb GmbH, a scheme was developed whereby the plant could be extended, and biogas production would be sufficient to allow the upgrading of biogas to biomethane with injection into the local gas grid. This included a novel means of utilising the local low pressure gas grid as the injection point, with excess gas being exported – via the low pressure grid – to the medium pressure gas network.

PLANT DESCRIPTION

Feedstocks for the anaerobic digestion plant are grown on the plant owner / operator’s 500 hectare farm. The primary feedstock is whole crop maize and wheat silage, with a small tonnage of grass silage also utilised. Part of the farm, i.e. 70 ha, is also used to grow winter wheat and maize in rotation, as a supplementary feedstock. Total feedstock production is approximately 20,000 tonnes of silage per year.

Pre Treatment

Prior to storage, feedstocks are chopped to approximately 10 mm particle size. Feedstocks are stored in covered silage clamps on-site, and approximately 50 t per day of feedstock is added to an automated solids feeder, which adds feedstock to the primary digesters. Surface water runoff from the silage clamps and digestion plant is collected in a below-ground concrete tank to provide all necessary process water for the digestion plant.
**Anaerobic Digestion**

The current configuration of the site has evolved since the construction of the original plant in 2005, and as such comprises a number of tank designs and volumes. The original 2005 plant was constructed by Lipp GmbH and is of dual seam stainless steel construction. An additional tank of concrete construction was later added by Novatech GmbH. In 2010, the expansion of the plant was completed by the plant operator and included the construction of additional digesters and digestate storage tanks of concrete construction.

The anaerobic digestion plant therefore now comprises two primary digesters, with volumes of 1,600 m$^3$ and 1,200 m$^3$ respectively. The primary digesters include one new concrete vessel constructed in 2010 by the plant operator, and the concrete vessel constructed by Novatech GmbH prior to expansion. The bases of both vessels are approximately 2.0 m below ground level to reduce tank height and heat losses. The newer of the vessels is fitted with a flexible dual membrane gas storage roof system. Both primary digesters are operated at approximately 40–45°C and are mechanically mixed. Micro-nutrients including cobalt, manganese and selenium are added to the digesters on a daily basis. Iron salts are also added in order to reduce H$_2$S content of the biogas through precipitation of sulphur.

Each primary digester is followed by a secondary digester (1,100 m$^3$ and 1,000 m$^3$), which are also heated to 37–40 °C and mechanically mixed. The original tanks constructed by Lipp GmbH are now utilised as the secondary digesters.

**Digestate**

From the secondary digesters, material is passed into two digestate storage tanks of concrete construction (2,000 m$^3$ and 2,600 m$^3$), which were constructed in 2010. These are not heated but include flexible dual membrane roofs for gas storage for the plant. It is estimated that 2-3 % of overall gas production is via biogas generated within the digestate storage tanks themselves. Overall retention time within the total system (primary digester – secondary digester – digestate storage) is approximately 130 days.

Mixed digestate is separated into solid and liquid fractions. The liquid fraction is stored on site in a covered tank prior to utilisation on the farmer’s land as a fertiliser. Separated solids are sold to adjacent farmers for use as a soil conditioner.
Biogas Production and Utilisation

The anaerobic digestion plant produces biogas at a rate of approximately 500 m³/hr that has a methane content of approximately 52–54%. In the original (2005) site configuration, biogas was utilised in 2 CHP plants (170 kWₑ and 250 kWₑ), although heat from the CHP plants was not utilised other than for heating the digesters on site. Therefore, in order to maximise the utilisation of the biogas produced at the site, a biogas upgrading plant was developed adjacent to the AD facility. The CHP plant remains on-site and can be utilised in the event that the upgrading plant is not available (e.g. maintenance or repair periods).

The biogas upgrading plant was developed and is operated by EnBW Vertrieb GmbH. As such the company has signed an agreement with the AD plant operator, who will supply the upgrading plant with a specified quantity and quality of biogas at an agreed price. The upgrading plant was supplied by Schmack Carbotech GmbH.

Raw biogas enters the upgrading plant via a 3 m³ storage vessel, which is at a few millibars less than atmospheric pressure. The biogas is then compressed to 6 bar, following which the gas temperature rises to approximately 86 °C. Gas is cooled from 86 °C to 46 °C by a tubular (shell in shell) gas to gas heat exchanger. A second stage water-cooled heat exchanger then cools the biogas from 46 °C to 23°C before a refrigerant-cooled heat exchanger cools the gas from 23 °C to 6 °C, to produce a dried biogas. The dried biogas is then heated to approximately 46 °C using the counter-current from the first stage heat exchanger.

From here, the dried biogas passes through an activated carbon filter for removal of hydrogen sulphide, at a pressure of approximately 5 bar. H₂S is precipitated on the carbon filter as elemental sulphur, and it is estimated that activated carbon will require replacement approximately once every two years. In order to maximise the efficiency of the activated carbon filters, a small volume (approx. 300 l/hr) of air is added into the gas mixture.

Following desulphurisation, the gas temperature is again reduced to 26 °C, as this has been found to be the optimal operating temperature for the CO₂ / CH₄ separation technology used: Pressure Swing Absorption (PSA). The plant utilises 6 PSA vessels packed with activated carbon ‘molecular sieve’ materials (from Carbotech AC GmbH). Gas enters the bottom of the vessel and is pressurised to just over 5 bar. CH₄ molecules are allowed to pass through the molecular sieve material, resulting in a high CH₄ content gas leaving the top of the PSA vessel. CO₂ molecules are retained within the molecular sieve, but are released when the pressure is decreased, to generate a CO₂-rich gas that leaves...
the bottom of the vessel. The plant comprises 6 vessels in total that operate in three pairs such that two vessels are pressurising, two are at full pressure and are generating biomethane, and two are depressurising to generate the CO₂-rich off-gas. In this way, a constant output of biomethane is achieved. Each pair of vessels takes approximately 230 seconds to run through its pressurisation – production – depressurisation cycle. The CH₄ content of the product gas is monitored at this point, and if at any time the quality is below the necessary requirement, product gas can be recycled through the PSA system. The plant has a capacity to output a maximum of 320 m³ biomethane per hour with a CH₄ content of 98% - and is therefore currently limited by the production capacity of the anaerobic digestion plant (500 m³/hr raw biogas).

Biomethane generated at the plant is stored in a buffer tank at a pressure of 4.2 bar. From here, the gas is odourised and its quality is measured using an in-line gas chromatograph, which measures CH₄, CO₂, H₂S, H₂ and O₂. The volume of biomethane exiting the plant is metered.

The biomethane is injected to the local low pressure (500 to 800 millibar) gas network, owned and operated by EnBW Gasnetz GmbH, which supplies approximately 300 end users including domestic and industrial customers. The distance to the low pressure network is approximately 800 m. Customers on this low pressure grid purchase their gas on a volume basis in combination with its calorific value (the calorific value is measured every 3 minutes and is calculated to a one month average). As the common natural gas in the gas grid has a calorific value of about 11.3 kWh/m³ and the injected biomethane only has a calorific value of max. 10.85, natural gas entering the low pressure grid is mixed with a small volume of atmospheric air to reduce the calorific value to 10.85 kWh/m³. Standard practice in Germany and elsewhere would be to increase the calorific value of the biomethane to match that of natural gas by adding liquefied petroleum gas (LPG) e.g. propane, however in Emmertsbühl natural gas calorific value is reduced to save on LPG costs.

A significant proportion of the gas in the low pressure grid is utilised by a small number of industrial customers. When demand from these customers is reduced (notably at weekends), the low pressure network does not have sufficient capacity to accept all of the gas supplied by the Emmertsbühl plant. At these times, the gas flow is reversed towards the junction between the low pressure and medium pressure (40 bar) grid. Here, a second plant compresses the gas from the low pressure grid up to 40 bar, and LPG is added to standardise the gas with that already in the medium pressure grid. Gas in the low pressure grid (i.e. biomethane) is then injected into the medium pressure pipeline.
An enclosed gas flare is present on-site for use in the event that biomethane cannot be injected to the gas grid. In addition, as described previously, in the event that the upgrading plant is unavailable (e.g. maintenance periods), the biogas can be utilised by the on-site CHP plants.

The conventional model would have been to inject the biomethane directly into the medium pressure grid at 40 bar in order not to exceed the capacity of the low pressure network. However, the advantages of the model employed are that:

1. Distances for new pipelines were reduced to 800 m, whereas a new connection to the medium pressure pipeline would have required approximately 5 km of new pipeline.
2. Compression costs are greatly reduced. The majority of gas is added to the grid at 500 to 800 millibar, with only excess gas at weekends requiring compression to 40 bar.
3. Propane addition is also reduced as the majority of gas is utilised in the low pressure grid, which operates at a lower calorific value. Only gas injected to the medium pressure network requires propane addition to reach the calorific value of the natural gas in the pipeline.

This approach means that biogas upgrading plants (or other renewable sources of gas) could be sited in locations that previously were considered unsuitable due to limited capacity of the local gas grid.

**Emissions Treatment (Water, Wastewater, Exhaust Air)**

The CO₂-rich off-gas from the PSA plant still contains approximately 2-4% CH₄, and should therefore not be released directly to the environment. At the Emmertsbühl plant, a vacuum pump moves the off gas to a small storage vessel, after which it is compressed before being burned in a combustor specifically designed to burn low calorific value fuels (by eflox GmbH). In order to achieve a stable flame, compressed air and a small volume of raw biogas is also required. The off-gas combustor generates approximately 115 kW of thermal energy. Around 100 kW of this is utilised to heat the fermenters of the AD plant and the remaining 15 kW is used for general site heating. Off gas from the combustor is treated via a catalytic oxidiser.

**Visual / Local Impacts**

No adverse visual impacts of the plant have been described. It is noted that the majority of ancillary plant is located within ISO standard steel containers.

**ENERGY USE, COST AND ECONOMICS**

**Energy Balance**

<table>
<thead>
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<th>Description</th>
<th>Value</th>
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<td>Electricity Demand of Digesters</td>
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</tr>
<tr>
<td>Electricity Demand of Upgrading Plant</td>
<td>~105 to 115 kW</td>
</tr>
<tr>
<td>Electricity Produced by CHP (Backup Only)</td>
<td>420 kW</td>
</tr>
<tr>
<td>Heat Demand of Digesters</td>
<td>110 kW</td>
</tr>
<tr>
<td>Heat Demand of Upgrading Plant</td>
<td>None</td>
</tr>
<tr>
<td>Heat Generated by off-gas combustor</td>
<td>150 kW</td>
</tr>
</tbody>
</table>

**Cost & Economics**

The upgrading plant and configuration of the grid injection model is possible due largely to the legal requirement of energy companies to provide renewable energy to their customers, and the way in which the energy industry is structured and regulated in Germany.
First of all, the developer of the biogas upgrading plant (EnBW Vertrieb GmbH) had to negotiate with the biogas producer to supply the plant with a guaranteed volume and quantity of raw biogas each year. It is understood that a 20 year contract to provide 20 to 24 million kWh (approx. 3,600,000 m$^3$ raw biogas) per year is in place. The biogas plant operator himself had to be sure that he was getting a fair price for the gas generated, as he had to meet the cost of producing the raw feedstock (silage of maize, grass and winter wheat), as well as the additional capital cost of the plant expansion.

The upgrading plant developer then had to negotiate with the network owner and operator (EnBW Gasnetz GmbH) to establish the optimum model for injecting to the gas grid. In this case, the cost of the additional compression and calorific adjustment plant at the low $\rightarrow$ medium pressure junction also had to be met by the gas grid operator. This had an estimated capital cost of €1.8 million. This had to be balanced against the alternative, which was to construct a 5 km pipeline directly to the medium pressure grid, rather than the 800 m required to connect to the low pressure grid.

![Schematic showing the grid connection layout](source: J. Darocha, EnBW Vertrieb GmbH, April 2012)

Only once these agreements were in place was the upgrading developer in a position to procure the upgrading plant. The investment cost for this was approximately €3 million (including buildings and foundations).

The upgrading developer also had to ensure that the market would pay an appropriate price for the biomethane produced. There is no direct subsidy for the injection of biomethane to the gas grid in Germany, and therefore all costs must ultimately be met by the customers. In Germany there are only subsidies for electric energy produced from renewable sources (i.e. solar, water, wind and biomass, including biogas). In this case, the majority of the biomethane produced is being utilised by a small number of industrial end users who use the biomethane in CHP units, for producing electricity and thermal energy. They therefore benefit from subsidies paid for the electric energy fed into the public grid, whilst the thermal energy is used for their production processes.
Production costs of biomethane in Germany have been estimated by the upgrading plant operator (in April 2012) as:

- **Cost Price for Raw Biogas**: 5.0 – 6.5 €c / kWh
- **Cost Price for Upgrading**: 1.0 – 1.8 €c / kWh
- **Total Cost Price of Biomethane**: 6.0 – 8.3 €c / kWh

This compares to the border price (i.e. excluding taxes, profit, etc) of natural gas imported into Germany of approximately 2.73 €c / kWh. As such, the upgrading plant operator estimates that the cost price to the consumer of purchasing 100% biomethane is approximately twice that of purchasing natural gas.

Customers do not physically purchase the gas produced at the Emmertsbühl plant, but can buy the green gas virtually. To make sure the balance between injected and sold biomethane is even, the biomethane quantities are certified by the German Energy Agency. Customers therefore have the option to purchase a certain value, or a certain percentage of their gas consumption, as biomethane. For example, an end customer may wish to substitute 30% of their total gas usage with biomethane, and therefore purchase gas from the energy provider (EnBW Vertrieb GmbH) that consists nominally of 30 percent biomethane and 70 percent common natural gas.

**DISCUSSION AND CONCLUSION**

This case study demonstrates a number of points. Firstly, it shows that the technology is readily available to generate raw biogas and upgrade it to biomethane, in this case using PSA. With over 70 upgrading plants in Germany alone (as of April 2012) this is nothing new, although to date the majority of upgrading plants have been attached to larger AD plants with good grid access where economies of scale make development straightforward.

More importantly, this case study highlights the way in which negotiations between a number of parties, backed up by a legislative and regulatory framework that allows some flexibility, has allowed the development of an innovative scheme where gas flows within a local low pressure gas grid can be reversed to provide gas to the medium pressure grid during periods of low demand. It also demonstrates that this can be achieved economically, with costs to end users and payback time to investors within acceptable limits. This opens up the prospect of developing upgrading plants at locations previously considered as being sub-optimal.

**ACKNOWLEDGEMENTS**

The authors would like to thank the plant owners and operators including EnBW Vertrieb GmbH for allowing access to the plant and for providing additional information included within this case study.
INTRODUCTION / OVERVIEW

The biogas / biomethane plant is located at a waste water treatment facility, treating waste water from Zalaegerszeg, a large conurbation in the South West of Hungary. The treatment works occupies an area of approximately 1 hectare and does not operate a clarification tank, but uses a 3 stage Phoredox (A2/O) activated sludge treatment process. This is similar to a conventional activated sludge system with an anaerobic zone ahead of the aerobic basin, but also includes an additional anoxic zone following the anaerobic zone. The anaerobic digesters were installed in order to treat surplus activated sludge and were commissioned in December 2009. The wastewater treatment plant (including the digestion plant) was designed by UTB Envirotech Company Ltd and constructed by Ökoprotec Ltd. The plant treats approximately 50,000–60,000 m$^3$ of surplus activated sludge generated on site, and sewage sludge imported from other local wastewater treatment plants.

Biogas produced at the plant can be used to generate electricity and heat (via a CHP plant) and can also be upgraded to produce a biomethane vehicle fuel. The upgrading plant was commissioned in 2010 and uses water scrubbing technology designed by DMT Environmental Technology, Holland, and supplied locally by Ökoprotec Ltd. The refueling technology was provided by Fornovogas, Italy. The rationale behind the development of the upgrading plant was to reduce the presence of contaminants within the raw biogas in order to extend the operational lifetime of the gas engines. The installation of an upgrading unit also allowed the diversification of end uses to include vehicle fuel. The upgrading plant and refuelling station occupy an area of approximately 500 m$^2$.

PLANT DESCRIPTION

The anaerobic digestion plant was designed to treat approximately 50,000–60,000 tonnes per year of surplus activated sludge and normal sewage sludge, generated from the on-site municipal wastewater treatment plant and also imported from other local wastewater treatment plants a maximum of 30km distance from the AD plant.

Two feedstock samples are recovered each week and analysed in an off-site laboratory on one week turnaround for total solids (TS), volatile solids (VS), total carbohydrates, total lipids, total proteins, heavy metals and light metal ion content. Analysis is undertaken in accordance with local standards (MSZ 318-3 :1979, Hungary).

Pre-Treatment

The site does not have the facility to store feedstocks on site. Site-generated and imported sludge is fed directly into the process with no further pre-treatment.

Anaerobic Digestion

The anaerobic digestion plant comprises two digesters of ferro-concrete construction, insulated with 15 cm of polystyrene and covered with weather protection cladding. Each digester has a volume of 1,460 m$^3$, giving a total digester volume of 2,920 m$^3$. The digestion process operates at mesophilic temperatures (36–38 °C). Heat for the process is provided by the lost heat from the on-site gas engines and boilers, which is delivered to the process via pipe-in-pipe water/sludge heat exchangers. Material in the digesters is stirred mechanically (by Scaba agitators with pan facility) with drive motors mounted on the digester roof. Sludge is also mixed by recirculation.
Sewage sludge enters the digestion process at approximately 5% total solids content (with 70% volatile solids) and the process has a hydraulic retention time of 20 days. Sludge is continuously fed into the digestion tanks via an Archimedean screw pump.

The digestion process is monitored by collecting the following data:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Frequency</th>
<th>Sampling</th>
<th>Method</th>
<th>Location</th>
<th>Turnaround</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature</td>
<td>Continuous</td>
<td>On line</td>
<td>-</td>
<td>At plant</td>
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<tr>
<td>pH</td>
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<td>Total Solids</td>
<td>Weekly</td>
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<td>Next Month</td>
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<tr>
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<td>Weekly</td>
<td>Manual</td>
<td>MSZ 318-3 :1979 (Hungary)</td>
<td>Laboratory</td>
<td>Next Month</td>
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<tr>
<td>Volatile Fatty Acids (VFAs)</td>
<td>Weekly</td>
<td>Manual</td>
<td>MX-7:2008 (Hungary)</td>
<td>Laboratory</td>
<td>Next Week</td>
</tr>
</tbody>
</table>

Digestate

A 500 m³ digestate storage tank is present on site. Digested sludge has a total solids content of approximately 3.8% and digestate is mechanically stirred within the storage tank to prevent sedimentation. Digestate storage does not include residual biogas collection.

Digestate solid / liquid phase separation is carried out using a cylinder compressor (for pre-compress) followed by a sludge centrifuge (for dehydration) manufactured by Alfa-Laval. This produces approximately 35,000–40,000 m³ / yr of liquid phase effluent and 8,000–10,000 tonnes / yr of residual solids with a dry matter content of approximately 20%.

Solids material is transported in 9m³ trucks, approximately 2-3 times per day, to a sludge storage facility approximately 5km from the plant. The material is finally deployed on agricultural land used for the production of forage crops in accordance with national legislation (50/2001 (IV.3) Government Regulation, Hungary). End users of the material have reported a 30–40% increase in crop production as a result of utilising the product in place of synthetic fertiliser.

Liquid phase digestate cannot generally be treated directly in the wastewater treatment plant due to high ammonia concentrations. Therefore, in order to treat the liquid to an acceptable level a DEamMONification (DEMON) process for nitrogen removal has been installed. The plant, commissioned in 2010, has a treatment capacity of 160 m³/day, equivalent to approximately 160 kg/day of NH₄ → N conversion. It utilises a multi-stage biological de-nitrification process developed by Innsbruck University (Austria). Nitrifying bacteria in the first stage oxidise part of the ammonia to nitrite. A second group of bacteria uses the nitrite and the remaining ammonia to produce nitrogen gas which is liberated from the liquid. De-nitrification of the digestate reduces ammonia concentrations from around 800 – 1000 mg/l to approximately 100 mg/l, which allows around 150 m³ of digestate to be recirculated back through the treatment process.
Digestates are monitored for the following parameters:

<table>
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<th>Parameter</th>
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<th>Sampling</th>
<th>Method</th>
<th>Location</th>
<th>Turnaround</th>
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</thead>
<tbody>
<tr>
<td>Nutrients &amp; Trace Elements (N, P, S, Fe, Co, Ni, Mo, Se, Cr, Pb, Mg, Mn)</td>
<td>3 times / yr</td>
<td>Manual</td>
<td>MSZ</td>
<td>Laboratory</td>
<td>Next Week</td>
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<tr>
<td>N / kg FM digestate</td>
<td>Weekly</td>
<td>Manual</td>
<td>MSZ 318 (Hungary)</td>
<td>Laboratory</td>
<td>Next month</td>
</tr>
<tr>
<td>Volatile Fatty Acids (VFAs)</td>
<td>Every two weeks</td>
<td>Manual</td>
<td>MX-7:2008*</td>
<td>Laboratory</td>
<td>Next month</td>
</tr>
</tbody>
</table>

*Note: MX-7:2008 is a site specific method that has been accredited by the plant lab.

Biogas Production and Utilisation

Approximately 1,000 – 1,200 m³/day of biogas is produced from the digestion process. This can be utilised for either the production of electricity and heat, or can be upgraded and utilised as a vehicle fuel. It is understood that this represents approximately 30% of the total production capacity of the AD plant. This under-capacity is due to a lower than anticipated throughput of waste water through the treatment plant, resulting in a lower input of partially stabilised sludge to the digesters.

Raw biogas contains approximately 68.94% methane, 31.02% carbon dioxide and 0.4% nitrogen and is stored on site in a 1,000 m³ gas storage bubble (manufactured by Satler). Prior to utilisation, the gas is dried and compressed to approximately 60 mbar.

Details relating to the electrical generating plant and boilers utilising the biogas have not been provided; however, it is known that the electrical output of the generating facilities is approximately 1,200 – 1,700 kWh/day.

Biogas upgrading comprises two primary processes. Firstly, hydrogen sulphide concentrations are reduced from approximately 75 mg/m³ in the raw biogas to <1.5 mg/m³ by means of an activated carbon absorber. The carbon material has not thus far required replacement since the beginning of operations in 2010.
Secondly, carbon dioxide is removed from the gas stream by utilising a pressurised water scrubbing system (Figure 1) designed by DMT Environmental Technology, Holland, and supplied locally by Ökoprotec Ltd. The plant has a capacity of 50 Nm³/hr. This system includes the recirculation of process water in order to minimise overall water consumption. Total water consumption in 2011 is reported as just 60 m³. Following gas upgrading, gas quality is approximately 99.15% methane and 0.85% carbon dioxide. Biomethane production is approximately 15-20 kg per day, which is approximately 1.5 – 2% of the total biogas that could be produced on-site. Upgraded biogas is compressed to 200 bar and stored on-site in 25, 80 litre gas storage bottles. Fast fill vehicle refuelling infrastructure has been provided by Fornovagas of Italy. The facility is controlled by a webscada-based management system with a graphical user interface (Plate 4). The upgrading and refuelling facility meets the demand of 10 CNG vehicles (approx. 30 m³/day). Methane losses at the upgrading system have been quantified at approximately 0.1%.

Due to the high pressure gas storage, the plant is designated as an explosion proof area and compliance with the District Mines Inspectorate and the Hungarian Trade Licensing Office’s Regulations (Hungary) is essential.

**Emissions Treatment (Water, Wastewater, Exhaust Air)**

Wastewater treatment facilities for treating the separated digestate liquors are described above. No other emission treatment facilities are required at the plant.

**Visual / Local Impacts**

No adverse visual impacts of the plant have been described. It is noted that the majority of ancillary plant is located within ISO standard steel containers.

**ENERGY USE, COST AND ECONOMICS**

**Energy Balance**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Demand of Digesters</td>
<td>20 kWh / day</td>
</tr>
<tr>
<td>Electricity Demand of Upgrading &amp; Refuelling Plant</td>
<td>55 kWh / day (if in continuous operation)</td>
</tr>
<tr>
<td>Electricity Produced by biogas elec. generator</td>
<td>1,200 – 1,700 kWh / day</td>
</tr>
<tr>
<td>Heat Demand of Digesters</td>
<td>3,600 – 6,000 kWh / day (150 – 200 kW)</td>
</tr>
<tr>
<td>Heat Demand of Upgrading &amp; Refuelling Plant</td>
<td>0 kWh / day</td>
</tr>
<tr>
<td>Heat Generated by biogas boiler &amp; CHP</td>
<td>3,120 kWh / day (Approx.)</td>
</tr>
</tbody>
</table>
Cost & Economics

Capital and operational costs of the upgrading facility have been estimated by the operator as follows:

<table>
<thead>
<tr>
<th>Cost</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost</td>
<td>600,000 – 700,000 Euro</td>
</tr>
<tr>
<td>Annual Operational Costs</td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>1,000 Euro</td>
</tr>
<tr>
<td>Annual Explosion Poof testing &amp; certification</td>
<td>13,700 Euro</td>
</tr>
<tr>
<td>Calibration &amp; Customs payments</td>
<td>1,700 Euro</td>
</tr>
<tr>
<td>Replacement of activated carbon</td>
<td>6,700 Euro</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>1,700 Euro</td>
</tr>
</tbody>
</table>

Local maintenance of the upgrading facility is undertaken by just one employee. Minor operational problems have been encountered since commissioning the plant, primarily associated with the onset of cold weather and the activation of low temperature sensors in the water stream; however, these issues are believed to be relatively simple to address.

DISCUSSION AND CONCLUSION

This is the first biomethane filling station in Central and Eastern Europe. Planning activities for the facility included a communication strategy so that appropriate information could be provided to the public and media. As such the plant operator – working with local government, and the distributors of the CNG vehicles utilised at the site – has greatly raised the profile of biomethane and wider environmental issues in the region.

The initial reason for the development of the upgrading facility was to eliminate contaminants from the biogas stream and hence to prolong the operational lifetime of the electricity and heat generating plant at the site. However, the ability to operate a fleet of vehicles will bring additional environmental and economic benefits.

It is noted that the plant operators are currently evaluating the potential for installing a pasteurisation unit at the site, which would allow the treatment of additional high organic content materials containing Animal By-Products at the plant (e.g. abattoir waste).
INTRODUCTION / OVERVIEW

The biogas / biomethane plant is located in an arable region approximately 40km to the east of Vienna, in the federal state of Lower Austria in the eastern part of Austria. The biogas plant is operated as a co-digestion plant and utilises organic waste material to a large extent for the production of a high-quality biogas. The plant was commissioned in 2004, and initially produced electricity and heat for the local district heating grid using CHP gas engines. In 2007 the biogas plant was complemented by the erection and commissioning of a biogas upgrading plant producing biomethane for natural gas grid injection. A part of this gas is consumed in the local low-pressure grid; the remaining part (especially in summer and during the night) is compressed to 60bar and injected into the regional high-pressure gas grid. The manufacturer of the upgrading system was Axiom Angewandte Prozesstechnik GmbH, and the complete biogas/biomethane production facility is operated by Biogas Bruck/Leitha GmbH.

PLANT DESCRIPTION

Feedstocks for the anaerobic digestion plant are basically organic residual materials of varying origin. These comprise organic residues from agricultural processes and food production, date-expired packed and unpacked food, lecithin fractions from biodiesel production, organic waste material from separated collection at households and local commerce sites, fat separator residues, cooking oil and fat, dairy wastes and slaughterhouse wastes. Total feedstock consumption is approximately 28,000 tonnes per year.

Pre-Treatment

Depending on the type of feedstock different pre-treatment steps and storage methods are used. Liquid material is stored in two medium sized buffer tanks. Solid organic material is stored in a clamp silo at the plant. Packed material (time-expired and refused food) is unpacked mechanically and washed into the liquids buffer tank. Surface water runoff from the digestion plant is collected in a tank to provide all necessary process water for the digestion plant. The feedstock is mashed up together with this water in one of two mashing tanks, and the dry matter content is adjusted. During the automated pumping into the two primary fermenters, the solid fraction is chopped to approximately 10 mm particle size. Around 100 tonnes of feedstock are transported to the fermenters every day.
Anaerobic Digestion and Digestate

The feedstock is directly pumped from the mashing tanks to the primary digesters. Currently, three digesters of 3,000 m³ each are operated at the site. Two of these vessels are of dual-seam stainless steel construction; the third one is significantly newer and is made of sealed concrete. All digesters are operated at a constant temperature of 38 °C, which requires vessel heating (around 200kW mean heat load over the whole year). Mechanical stirring is performed both by slow agitation, via a central propeller, as well as high speed agitation at three points around the tank perimeter. Micronutrients as well as iron salts for H₂S reduction are added to the digesters on a daily basis.
Each primary digester is followed by a secondary digester (5,000 m$^3$ each), which are also heated to 38 °C and mechanically mixed. Both vessels are fitted with a flexible dual-membrane gas storage roof system. Additionally, these vessels act as digestate storage. Digestate is not fractionated into solids and liquids, and is utilised by local farmers as a fertilizer (roughly from April to November only). It is estimated that 2–3 % of overall gas production is via biogas generated within the secondary fermenters.

Overall retention time within the total system (primary digester → secondary digester → digestate storage) is approximately 50 to 60 days.
Biogas Production and Utilisation

The anaerobic digestion plant produces biogas at a rate of approximately 800 m$^3$/hr, which has a typical methane content of 60–64%. The main fraction of this biogas is utilised in two CHP gas engines (GE Jenbacher, 836 kWel each) producing 12 GWh of electricity and 15 GWh of process heat on an annual basis. Electricity is exported to the grid, receiving a (green energy) feed-in tariff of around 8.5ct/kWh (yearly average value). The heat (around 1.2 MW) is delivered to the local district heating system of the town of Bruck/Leitha (network length around 11 km), supplementing the heat generated by a local biomass combustion plant (6 MW). Thus, around 800 households are provided with biomethane-derived heat, covering approximately one third of the heating demand of Bruck/Leitha. A small amount of the heat produced by the CHP gas engines is directly utilised at the anaerobic digestion plant to heat up the digesters to operating temperature (around 200 kW as a yearly averaged value). The overall electricity demand of the biogas/biomethane production site is around 1 GWh per year.

In the year 2007 a biogas upgrading plant was installed and commissioned, having a production capacity of 100 m$^3$/h of biomethane, for injection into the adjacent natural gas grid. For this purpose a partial flow of 170 m$^3$/h of biogas is taken in parallel to the installed CHP engines. The biomethane facility was Austria’s first industrial-scale upgrading plant with grid injection, and has been in regular operation since 2008.

The biogas upgrading plant was designed and erected during a substantial research project (“Virtual biogas”: www.virtuellesbiogas.at) under the cooperation of leading gas companies, universities (Vienna University of Technology, University of Natural resources and Life sciences Vienna), the AD-plant operating corporate body and the plant constructor. This plant applies the innovative technology of membrane separation (gas permeation) for the primary task of carbon dioxide removal and gas drying. It has been designed and constructed by the company AXIOM Angewandte Prozesstechnik GmbH, and operated since 2008 by the AD-plant operator Biogas Bruck/Leitha GmbH. The whole upgrading plant has been mounted inside a standard 30 foot container by the plant constructor, and was transported whole to its final location in Bruck/Leitha. A number of plants also applying similar technology have been commissioned in Austria and Germany by the plant constructor since then, and the technology is commercially available.

The key advantage of the membrane gas permeation technology is its stable and continuous operation, and thus its ease of control. Furthermore, no expensive regeneration or chemical consumables are needed. The whole process becomes very simple, straightforward and compact. The separation technique uses a high-density polyimide membrane with different solubilities and diffusivities for the various gas species contained in the raw biogas feed. As a result, the driving force for separation is the difference in the partial pressures of the various species between the feed phase and the permeate phase. A high flux through the membrane can be realised with high pressure on the feed side and a low pressure (near to atmospheric pressure) on the permeate side of the membrane. Using this membrane material, most unwanted gas species are quantitatively removed from the feed stream and transported through the membrane to the permeate stream. Only nitrogen shows similar behaviour to methane, and therefore cannot be removed by this technique but remains in the product gas stream, as the so-called retentate.

Sufficient product gas quality and quantity can easily be reached only if sufficient membrane area and adequate operating conditions are provided. The greatest advantages of this process compared to others are its continuity, compactness, simultaneous drying and removal of traces of hydrogen sulphide and ammonia. Since the mixture of NH$_3$, H$_2$S and very humid gas can jeopardise the membrane material, some gas processing before the gas permeation is necessary.
The membranes are constructed as hollow fibres with the high pressure feed/retentate stream on the inner side of the tube and the low pressure (almost atmospheric) permeate on the outside of the tube. Many of these fibres are assembled to form a membrane module that is fed with pressurised biogas.

In the upgrading plant at Bruck/Leitha the raw biogas from the fermentation vessels is mixed with the permeate of the second membrane stage, and it is subsequently compressed and water is condensed out at gas temperatures below +7°C. Afterwards, the biogas is heated up again using waste heat from the compressor, in order to attain the optimum temperature for the subsequent separation steps. After that, the hydrogen sulphide is removed by means of adsorption and the pre-treated gas is fed into the two-stage membrane separation process.

In order to minimize the methane losses, two stages of membrane modules have been suggested. The permeate stream from the second stage, which contains significantly higher amounts of methane compared to the permeate of the first stage, is brought back for recompression. Due to the recycling of this permeate, a non-linear dynamic behaviour of the process is expected. The methane quality of the produced gas from the retentate of the second stage is controlled by a proportional valve that is located at the retentate outlet of the second stage. The position of the valve is adjusted by a PID controller, which influences the pressure in the feed channels and, at the same time, the methane content of the produced gas. Using this control strategy gases with various methane contents can be produced (e.g. from almost a ‘raw gas’ composition of 70% to 99% or more). Additionally, the volume flow of the biomethane product can easily be adjusted with an enhanced PID controller, manipulating the rotating speed of the compressor using a frequency converter.
Like any other separation technique, gas permeation cannot transfer all of the methane in the raw biogas feed to the produced biomethane. As a result, the carbon dioxide-rich offgas still contains small amounts of methane (usually 2 to 3% of the produced biomethane) and other separated substances. In order to achieve a zero-emission strategy regarding methane the upgrading plant is perfectly integrated into the existing biogas plant and the offgas is delivered back to the existing gas engines (CHP with raw biogas). Thus, the remaining methane is not emitted to the atmosphere, but is burned and its chemical energy is used to produce heat and power.

After concise online analysis of the relevant gas species (methane, carbon dioxide, oxygen, hydrogen sulphide, water vapour) the produced gas is transported to the gas distribution station via a 2.8km long pipeline. If the quality of the gas – relating to any parameter mentioned in the Austrian grid laws – does not meet the statutory obligations for grid injection, the supply is interrupted immediately and the gas is instead transported back to the gas engines of the biogas plant. The control system will then try again to improve the quality of the produced gas and to re-adopt the supply to the grid. The calorific value of the injected gas is approximately 10.86 kWh/m³ and is compliant with the Austrian gas grid standard. Additional LPG dosing for increasing the calorific value is not, therefore, necessary. The “green” natural gas is sold to the grid operator on a virtual basis.

The supplied bio-methane is transported to the nearby town of Bruck/Leitha (Population: 7,600) via the public natural gas grid, which has a pressure of up to 3 bar. The annual demand of approximately 800 households is covered by the injected amount of biomethane. During the winter months the entire supply of bio-methane is used to satisfy the gas demand of this settlement (with additional natural gas being required). During the summer months the gas demand is only a fraction of the produced gas, and the excess biomethane is compressed to 60 bar and fed into the regional high pressure natural gas grid. This approach enables constant operation of the biogas upgrading facility year-round, and therefore an optimised workload and cost structure.

A very important cleaning step during biogas upgrading is the removal of hydrogen sulphide, which is specially treated at the biomethane production site in Bruck/Leitha. The raw biogas produced at this AD-plant typically contains up to 1,000 ppmv of hydrogen sulphide; peak concentrations of up to
2,000 ppmv have also been monitored frequently (depending on the type of feedstock utilised). Also, steep gradients in hydrogen sulphide concentration have been reported. Due to its toxicity and corrosive effects, only a very small amount of hydrogen sulphide is allowed in the gas. The current process design incorporates four desulphurisation technologies, for specific purposes.

The first one is the in-situ-desulphurisation, by addition of special chemical substances (liquid mixtures of metal salts) directly into the fermenter (sulphur precipitation). As a result, the produced biogas typically contains 100 to 500 ppmv of hydrogen sulphide at the exit of the gas storage tanks.

The second is the microbiological treatment of the gas by means of the chemoautotrophic bacteria *Thiobacilli*. It results in reduction of hydrogen sulphide down to around 50 ppmv. The microorganisms use the H₂S for their metabolism and convert the gas to water and elemental sulphur or sulphurous acid, which is discharged and treated together with the waste water stream. The microorganisms need oxygen for this oxidative conversion of hydrogen sulphide. Before the biogas upgrading plant was included this biological desulphurisation had been operated with air as an oxidiser. Due to the fact that air comprises around 80% nitrogen, and nitrogen cannot be removed from the biogas stream with the gas upgrading technique utilised, this desulphurisation step has been retrofitted with pure oxygen injection.

It has been shown that the biological system is not able to guarantee stable desulphurisation (specifically, stable H₂S content in the sweetened gas stream) during phases of highly fluctuating raw biogas quantity and quality, as the micro-organisms need time to adapt to the changed conditions. Therefore, an additional desulphurisation technology has been applied especially for the gas flow used for biogas upgrading. This novel technology involves a chemical-oxidative scrubbing step, where the sour gas is washed with a caustic solution (NaOH) to absorb the H₂S from the gas. Subsequently, the absorbed H₂S is oxidised with hydrogen peroxide in order to enhance the removal selectivity against...
carbon dioxide, and the loading capacity of the scrubbing liquid. The application of this concept to biogas desulphurisation is new, and a pilot plant with a raw gas capacity of 300 m³/h has been designed, erected and optimised during a two-year research phase. The plant has been in regular operation since 2010 and is now commercially available. It has also been applied to another Austrian biogas upgrading and grid injection plant.

The final decrease in hydrogen sulphide occurs in the third stage, where adsorption by means of iron oxide or zinc oxide is implemented. This is used for final removal of H₂S only (from 70 ppm to lower than 3.3 ppmv, required by the grid injection standards).
An enclosed gas flare is present on-site for use in the event that the produced biogas stream cannot be utilised in the CHP engines (e.g. maintenance periods) and the biomethane production is also unavailable.

**Emissions Treatment (Water, Wastewater, Exhaust Air)**

The CO$_2$-rich off-gas from the biomethane production plant still contains approximately 2-4% CH$_4$ and is not allowed to be directly released to the environment. As already mentioned, this off-gas is mixed with raw biogas and piped to the CHP gas engines. Since the biogas upgrading is only applied to a partial flow of the produced biogas, this option is viable and the most cost effective. If no CHP engines are available at an AD-plant and the biogas upgrading would cover the whole produced raw biogas, a special off-gas treatment plant (typically combustion, low-calorific burner or catalytic oxidation) would be applied. The generated heat would be used to partially meet the thermal heat demand of the digesters.

**Visual / Local Impacts**

No adverse visual impacts of the plant have been described. It is noted that the majority of ancillary plant is located within ISO standard steel containers. Additionally, the distance from the AD-plant to residential areas is relatively great.

**ENERGY USE, COST AND ECONOMICS**

**Mass and Energy Balance**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feedstock for AD-plant</td>
<td>28,000 t/a</td>
<td>(approx. 3.3 t/h)</td>
</tr>
<tr>
<td>Produced biogas</td>
<td>6,800,000 m$^3$/a</td>
<td>(approx. 800 m$^3$/h)</td>
</tr>
<tr>
<td>Biomethane grid injection</td>
<td>800,000 m$^3$/a</td>
<td>(100 m$^3$/h)</td>
</tr>
<tr>
<td>Electricity demand of AD-plant</td>
<td>1,000,000 kWh/a</td>
<td>(approx. 120 kW)</td>
</tr>
<tr>
<td>Electricity demand of Upgrading Plant</td>
<td>296,000 kWh/a</td>
<td>(approx. 37kW)</td>
</tr>
<tr>
<td>Electricity produced by CHPs</td>
<td>12,000,000 kWh/a</td>
<td>(approx. 1,400kW)</td>
</tr>
<tr>
<td>Heat Demand of AD-plant</td>
<td>1,700,000 kWh/a</td>
<td>(approx. 200 kW)</td>
</tr>
<tr>
<td>Heat Demand of Upgrading Plant</td>
<td>none</td>
<td>none</td>
</tr>
<tr>
<td>Heat produced by CHPs</td>
<td>15,000,000 kWh/a</td>
<td>(approx. 1,750 kW)</td>
</tr>
<tr>
<td>Heat delivered to district heating</td>
<td>10,200,000 kWh/a</td>
<td>(approx. 1,200 kW)</td>
</tr>
</tbody>
</table>

**Cost & Economics**

First of all, it should be stated that currently no regulated feed-in tariff for biomethane injection exists in Austria. Plant operators injecting biomethane to the grid have to set up individual contracts with individual tariffs and contract durations with the relevant grid operating company. There is still no system comparable to the green electricity tariff (as of 2012).

The plant was erected as part of a research project, with 50% funding by national and federal agencies and the remaining 50% being contributed by three big gas and energy companies of eastern Austria. The injected green gas was supplied to these companies by the AD plant operator free of
charge during the research project’s lifetime. Afterwards, the upgrading plant was transferred to the AD-plant operator without any additional costs for this company.

The investment costs for the AD-plant have been calculated to be in the region of 6.5 Mio. €; the ongoing operational costs have not been reported and are difficult to assess. The overall specific production costs have been estimated to be in the region of 0.30 €/m³ of raw biogas.

The investment costs for the biogas upgrading plant were in the region of 800,000 €. Specific production costs, considering investment in the biogas upgrading unit only (equivalent annual cost), the complete operational costs of upgrading, plus maintenance and personnel, have been calculated to be around 0.25 €/m³ of biomethane.

Since the production of 1 m³ biomethane requires 1.7 m³ of raw biogas, the total specific costs including raw biogas production and upgrading add up to 0.76 €/m³ (of which 67% is raw biogas production, and 33% is biogas upgrading). If the calorific value of the biomethane end product is taken into account, the overall specific production costs convert to around 7 €ct/kWh. All costs are calculated based on stable plant operation data during 2012.

Customers do not physically purchase the gas produced at the Bruck/Leitha plant, but can buy the green gas ‘virtually’ as mentioned before. To make sure the balance between injected and sold biomethane is even, the biomethane quantities are certified by TÜV Austria Services GmbH. Customers therefore have the option to purchase a certain value – or a certain percentage – of their gas consumption as biomethane.

Local maintenance of the AD-plant and the upgrading facility is undertaken by just one employee. After the optimisation phase of the applied biogas upgrading process, no significant operational problems have been reported.

**DISCUSSION AND CONCLUSION**

This case study demonstrates a number of points. Firstly, it shows that the technology is readily available to generate raw biogas and upgrade it to biomethane, in this case using membrane separation gas permeation. It is shown that applying this technology for biogas upgrading allows for an economic natural gas grid injection operation, even at smaller scales. Nowadays, typical operating grid injection plants have a production capacity several times higher than the plant described in Bruck/Leitha. Also, the membrane technology benefits from the effects of economy of scale; it has to be assessed individually which technology best suits each case of a proposed biomethane production facility. Nevertheless, one has to be aware that biomethane is not directly competitive with imported natural gas, and the prices charged for this renewable product have to be higher.

The operators of the biogas/biomethane plant in Bruck/Leitha are very satisfied with the operational behaviour of the combined plant. Currently, they are assessing the possibility of extending the upgrading capacity to 800 m³/h of raw biogas. This would consume the total quantity of available biogas, thus making the CHP gas engines obsolete, and decommissioning of the machinery likely. The reason for the likely switch in emphasis is the ending of the contracted green electricity feed-in tariffs.

**ACKNOWLEDGEMENTS**

The authors would like to thank the plant owners and operators at Biogas Bruck/Leitha GmbH DI Gerhard Danzinger and DI(FH) Wolfgang Allacher for allowing access to the plant and for providing the additional information included within this case study.
Consenting Requirements for AD Plant in England and Wales

The following text is largely as it appears on the web site of the Wales AD Centre (University of Glamorgan and partners to the Biomethane Regions project) – see www.walesadcentre.org.uk

Town and Country Planning Consent

In the vast majority of cases Planning Permission will be required in order to develop an AD scheme. It is recommended that any scheme is developed in close consultation with the Local Planning Authority who can provide guidance on the exact requirements of the planning process. General points of good practice that could contribute to a successful planning application for an appropriately located facility include:

- Holding **discussions with the local community** at an early stage. This can help to prevent any misconceptions associated with the scheme and can also identify potential additional benefits such as heat users or local markets for digestate.
- A full **Environmental Impact Assessment (EIA)** may be required for large schemes or those in sensitive locations. Identifying possible environmental issues at an early stage allows more time for collection and preparation of data that can contribute towards an EIA, or can be used to address specific environmental concerns without the need for a full EIA. You should consult The Town and Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 and/or the Town and Country Planning (Environmental Impact Assessment) (Amendment) (Wales) Regulations 2008.

Refer to policy documents such as the relevant development plans for the local planning authority concerned and relevant central government planning guidance from either the UK or Welsh governments. (A list of potentially relevant documents for Wales is given on the AD Centre web site).

Any development of a waste treatment facility within or adjacent to a community is likely to cause concern, and anaerobic digestion is no different in this regard. The most common concerns raised by the public to date are:

- Odour
- Noise
- Increased traffic movements
- Visual impact of structures

Good design and house-keeping measures as well as engineering solutions exist to mitigate the majority of concerns regarding odour, noise and visual impact of structures. An appropriate road infrastructure and site access must be available to accommodate both the import of feedstocks and the export of digestates. It may be possible to suggest routes for vehicle movements in order to avoid any sensitive areas. Communication and engagement with the local community to foster trust has proved to be fundamental to the success in the planning process. A Communication guideline for AD plants was produced under the Biogas Regions project and can be found at [http://www.swea.co.uk/downloads/Comm_Guideline.pdf](http://www.swea.co.uk/downloads/Comm_Guideline.pdf).

Planning applications for AD plants should include a number of information documents such as:

- Detailed site plan – showing the development site, other land within the applicant’s control and neighbouring dwellings and other sensitive buildings
- Plans, elevations and sections of the buildings and structures
- A full description of the processes to be employed e.g. waste reception, processing, digestion and energy generation
- Description of the feedstocks, its origins, transport routes, delivery vehicles used etc.
- Description of the solid and liquid digestate and end use or disposal
- Energy output and utilisation
- Environmental advantages of AD including carbon emissions offset
- Plans for (or preferably already commenced) consultation with community
- Economic/social advantages for the region – employment etc.
- Potential emissions (which may include modelling of emission dispersion) and related mitigation measures for odours and air pollution, noise and visual impact, ground and water courses pollution
- Site management measures during the construction phase

**Environmental Permitting**

The Environmental Permitting Regulations (2007) came into force in 2008 to unify the former Waste Management Licenses and Pollution Prevention and Control (PPC) regimes. The Regulations have since been superseded by the Environmental Permitting, England and Wales Regulations (2010) which incorporate all of the provisions of the 2007 Regulations. The regulating body for Environmental Permits is the Environment Agency (EA) whose primary role is the protection of the environment and human health. There are three primary options available to the EA with regard to permitting of AD plants:

- A Standard Environmental Permit
- A Bespoke Environmental Permit
- An Exemption from the Environmental Permitting Regime

1. **Standard permits**

For operations that have been assessed to meet generic risk assessments (GRA) based on operation rather than a particular site. If the plant complies with the standard set of rules developed to meet the requirements of the GRA, as set out under the permit, and providing that planning permission is in place, then a standard permit can be issued. Standard permits are available for a range of AD plants and digestate storage and use. Standard permits should be quicker and less costly to obtain than bespoke permits. Standard Permits relevant to AD plants and associated operations include:

<table>
<thead>
<tr>
<th>No.</th>
<th>Title of Standard Permit</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>BIOLOGICAL TREATMENT OF WASTE</strong></td>
<td></td>
</tr>
<tr>
<td>SR2010No14</td>
<td>Composting Biodegradable Waste (in open and contained systems)</td>
<td>500 t (10 t / day of animal waste) at any one time of biodegradable material not used as solvents. Includes ABP material.</td>
</tr>
<tr>
<td>SR2010No15</td>
<td>AD facility and use of resultant biogas</td>
<td>Pre treatment and AD of up to 75,000 t/yr of biodegradable material that have not used as solvents (&lt;10 t / day of animal waste). Includes treatment of digestate (centrifuge / pressing / thickening) and biogas storage, drying and use. Biogas burner &lt; 3 MW thermal input in aggregate. Limits set on stack emissions.</td>
</tr>
<tr>
<td>SR2010No16</td>
<td>On farm AD facility and use of resultant biogas</td>
<td>Pre treatment and AD of up to 75,000 t/yr of biodegradable material not used as solvents. Includes treatment of digestate (centrifuge / pressing / thickening) and biogas storage, drying</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Code</th>
<th>Activity Description</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>SR2010No17</td>
<td>Storage of digestate from AD plants</td>
<td>Temporary storage of up to 75,000 t of waste in a lagoon or container for up to 3 years. Solid and liquid digestate. Containers must be fit for purpose, lagoons have a freeboard of 750 mm.</td>
</tr>
<tr>
<td>SR2009No4</td>
<td>Combustion of biogas in engines at sewage treatment works</td>
<td>Burning of biogas from digestion of sewage sludge in appliance(s) with aggregate thermal input of up to 3 MW. Limits on stack emissions set.</td>
</tr>
</tbody>
</table>

**RECOVERY OR USE OF WASTE ON LAND**

- **SR2010No4** Mobile plant for landspreading (Not applicable if digestate complies with Quality Protocol / PAS110) Storage of up to 3,000 t of waste for 12 months. The use of mobile plant for spreading materials stated in the rules for agricultural benefit. Includes digestate from AD plants (up to 250 t / ha).
- **SR2010No5** Mobile plant for reclamation, restoration or improvement of land Storage of up to 3,000 t of waste for 12 months. The use of mobile plant for the addition of up to 5,000 t / ha of the materials stated in the rules for agricultural / ecological improvement. Compost and digestate from non source segregated sources are to be used on brownfield land not intended for agricultural use only.
- **SR2010No6** Mobile plant for landspreading of sewage sludge Storage of up to 3,000 t of waste for 12 months. The use of mobile plant for the treatment of land using the substances listed for the improvement of agriculture / ecology. Includes non agricultural land and agricultural land used for the production of non food crops not grown in short term rotation with food crops. Application of up to 250 t / ha / yr. EA notification required prior to spreading. Sludges from treatment of urban waste water only.


2. **Bespoke permits**

For operations which do not meet the rules set out in standard permits. For operations that are generally more complex, larger or have potentially higher risks due to the nature of the operation or site location. The Environment Agency will set specific conditions with which the operations must comply.

3. **Exemptions**

Where specific low risk activities are being undertaken these may be exempt from an Environmental Permit. Exempt activities must usually be registered with the Environment Agency and this can be done on line from the Agency’s website.

Exemptions are set out in the Environmental Permitting, England and Wales Regulations 2010. The table below briefly describes the exemptions that are most likely to be applicable to anaerobic digestion and associated activities.
<table>
<thead>
<tr>
<th>No.</th>
<th>Title of Exemption</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>U6</td>
<td>Use of sludge for the purposes of re-seeding a waste water treatment plant</td>
<td>Storage of use of up to 1,000 m³ of sludge from a WWTP in order to re-seed the receiving WWTP. Can use sludges from treatment of urban wastewater, and sludges from biological treatment of industrial waste water other than those mentioned in 190811 (i.e. contaminated). It is understood that this exemption does apply to AD plants.</td>
</tr>
<tr>
<td>U10</td>
<td>Spreading of waste on agricultural land to confer benefit</td>
<td>Spreading of up to 50 t/ha and storage of up to 200 t of digestate produced from a process operating under a T24 or T25 activity. A mobile plant license is required where U10 is not applicable.</td>
</tr>
<tr>
<td>U11</td>
<td>Spreading waste on non-agricultural land to confer benefit</td>
<td>Spreading of material for physical, chemical or biological land improvement. Includes digestate from T24 or T25 process at a rate of 50 t/ha with up to 200 t storage. Compost also included. A mobile plant license is required where U11 is not applicable.</td>
</tr>
</tbody>
</table>

**TREATMENT OF WASTE**

<table>
<thead>
<tr>
<th>No.</th>
<th>Title of Exemption</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>T13</td>
<td>Treatment of waste food</td>
<td>Decanting, unwrapping, bulking up, sorting of food waste and its packaging. Does not include ABPR material destined to be fed to animals or any further treatment of the waste. Store or treat up to 30 t of waste at any one time. Can be stored for up to 7 days.</td>
</tr>
<tr>
<td>T23</td>
<td>Aerobic composting and associated prior treatment</td>
<td>Storage and treatment of up to 80 t at any one time at the place of production and where compost is to be used. ABPR needs Animal Health approval. 60 t if transporting material to or from facility.</td>
</tr>
<tr>
<td>T24</td>
<td>Anaerobic digestion at a premises used for agriculture and burning of resultant biogas</td>
<td>Storage or treatment of up to 1,250 t at any one time of manure or plant tissue waste for AD with a minimum retention time of 28 days. Storage of material derived on farm in manure or slurry pits is excluded from the 1,250 t. Imported manure / slurry is included in the 1,250 t. Biogas must be used to produce energy with a thermal rating of less than 0.4 MW. Plant tissue waste and farmyard manure &amp; slurry only.</td>
</tr>
<tr>
<td>T25</td>
<td>Anaerobic digestion at a premises not used for agriculture and burning of resultant biogas</td>
<td>Storage and treatment of up to 50 m³ of waste for AD with a minimum retention time of 28 days. Biogas must be used to generate energy with a thermal input of less than 0.4 MW. Includes ABPR but must comply with regs.</td>
</tr>
</tbody>
</table>

Information on all of these exemptions and others that may be relevant to your operations can be found at the Environment Agency website [http://www.environment-agency.gov.uk/business/topics/permitting/115492.aspx](http://www.environment-agency.gov.uk/business/topics/permitting/115492.aspx)

Consolidated permits may be available to operators with multiple facilities. But this is only available if the facilities are on one site, i.e. there is more than one type of permitted activity on one site.

Establishing which permit is relevant for your facility and demonstrating compliance with the various requirements of either Standard and Bespoke permits or Exemptions will require direct consultation with the Environment Agency and it is recommended that you contact your local EA permitting officer. There is information and guidance on environmental permitting of AD plants on the Environment Agency’s website [http://www.environment-agency.gov.uk/business/sectors/37338.aspx](http://www.environment-agency.gov.uk/business/sectors/37338.aspx)
4. Duty of Care

The Duty of Care is set out in section 34 of the Environmental Protection Act 1990 and associated regulations. It applies to anyone who is the holder of controlled waste. Persons concerned with controlled waste must ensure that the waste is managed properly, recovered or disposed of safely, does not cause harm to human health or pollution of the environment and is only transferred to someone who is authorised to receive it. The duty applies to any person who produces, imports, carries, keeps, treats or disposes of controlled waste or as a broker has control of such waste.

The Environmental Protection (Duty of Care) Regulations (with amendments) set out the framework within which waste should be appropriately held and transported. Specific requirements of the Duty of Care Regulations include:

- That you identify, store and transport your waste appropriately and securely;
- That your waste is collected, transported and handled by companies or people that are authorised to do so:
  - All businesses or individuals that collect or transport waste on a professional basis must be registered with the Environment Agency to do so.
  - Similarly all businesses or individuals who arrange for the collection or disposal of waste (e.g. brokers or dealers) must also be registered with the Environment Agency.
- That any transfer of waste between two separate bodies are recorded on an appropriate Waste Transfer Note, with such records being kept for a minimum period of two years.

DEFRA has recently undergone a public consultation on the Revised Waste Duty of Care Code of Practice (April 2009) which provides a good overview of how to comply with the Regulations. Further information can be found at the Defra website.

Animal By-Products Regulations

The Animal By-Products Regulations 1774/2002 came into force in 2003 and covers the use/disposal of any wastes that contain meat or animal by products. The Animal By-Products (Wales) Regulations (ABPR) 2006 is the enforcing legislation in Wales. They contain the national standards for AD plants as well as powers for inspectors, approval controls and appeals procedures.

Animal by products (ABP) are classified into three categories:

**Category 1** – Highest risk materials and international catering waste. This material cannot be treated using anaerobic digestion and needs to be incinerated or rendered.

**Category 2** – High risk animal by products. This material cannot be treated using anaerobic digestion unless it has been pressure cooked to the European Standard (133°C/3 bar/20 minutes). However, although the following materials are listed as category 2 material they can be used in AD plants without ABP approval – Manure, Digestive Tract Content, Milk and Colostrum.

**Category 3** – Low risk animal by products. This material can be treated via a number of routes including anaerobic digestion. This material includes raw meat intended for human consumption, waste from food manufacturers and retailers, eggs, and other by products that do not show signs of transmissible disease. All UK derived catering waste (i.e. from domestic and commercial kitchens) where meat and non-meat fractions are combined is also covered as Category 3 material.
In order to treat Category 3 material an AD facility must be approved and incorporate a number of criteria. The following requirements are for anaerobic digestion facilities treating ABP to meet the Animal Health rules, other agencies such as the Environment Agency are likely to have additional requirements and will need to be checked:

1. Criteria relating to particle size, time and temperature as per the Table below:

<table>
<thead>
<tr>
<th>Closed Reactor Treatment Technology</th>
<th>National ABP Regulations, option for catering waste only</th>
<th>National ABP Regulations option for catering waste only</th>
<th>EU ABP Regulation 1774/2002</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Particle Size</td>
<td>50 mm</td>
<td>60 mm</td>
<td>12 mm</td>
</tr>
<tr>
<td>Minimum Temperature</td>
<td>57 °C</td>
<td>70 °C</td>
<td>70 °C</td>
</tr>
<tr>
<td>Minimum Time Spent at the Minimum Temperature</td>
<td>5 hours</td>
<td>1 hour</td>
<td>1 hour</td>
</tr>
<tr>
<td>Additional Requirements</td>
<td>Followed by storage for at least 18 days if digestate is made from catering waste that included meat</td>
<td>Followed by storage for at least 18 days if digestate is made from catering waste that included meat</td>
<td>No post treatment minimum storage time specified</td>
</tr>
</tbody>
</table>

2. Treat materials immediately without undue delay
3. Have cleanable and lockable reception areas
4. A non-bypass pasteurisation stage must be included within the plant, unless the time and temperature requirement can be met within the anaerobic digestion reactor
5. Incorporate procedures based on Hazard Analysis and Critical Control Points (HACCP) in order to identify and evaluate critical control points
6. Operate strict hygiene conditions including for vehicle movement and physical separation of clean and dirty areas or any sensitive adjacent land uses
7. Record and demonstrate pathogen kill procedures, pest control measures, cleaning procedures have hygiene inspections documented
8. Monitor, sample, record and check Critical Control Points
9. Ensure that all equipment is in good working order and that all measurement equipment is calibrated every three months
10. Carry out microbiological sampling

The Regulations state that an AD plant handling ABP material cannot be located on the same premises as livestock. This means that there needs to be a complete separation between the AD plant and the farm. A separate area has to be identified with separate access arrangements and no means of cross contamination.

The precise requirements under the ABPR are site specific and therefore early discussions with the Animal Health (the Government’s executive agency primarily responsible for ensuring that farmed animals in Great Britain are healthy, disease-free and well looked after) who are responsible for the issue of Animal By Product Approval is essential.

Contact details for local Animal Health offices can be found at: http://www.defra.gov.uk/animalhealth/about-us/contact-us/search/listall.asp.

Local Authorities actually enforce the ABP Regulations and carry out risk assessed compliance visits. If the plant is approved under the ABPR, the digestate can be spread on land as regulated by the ABPR. Where that land is pasture (land that is intended to be used for grazing or cropping for animal
feeding stuffs), livestock must not be allowed access to land to which compost or digestion residues have been applied for the following minimum time periods: (a) in the case of pigs, eight weeks; (b) in the case of other farmed animals, three weeks. Similarly, animals must also not be fed with anything cropped from land to which compost or digestion residues have been applied, for the same time periods (eight weeks for pigs, three weeks for other farmed animals). You should also consult the requirements for land spreading of digestate under the Environmental Permitting Regulations and the PAS 110.

In brief, here is the ABPR Approval Application Process:

1. Application made by site operator (or future site operator) to Animal Health UK. Of particular importance is the HACCP plan.
2. Animal Health undertake a desk assessment (and in some cases a site visit) based on the information provided in the application. This will lead to either a Yes, No or further advice to achieve compliance.
3. If ‘Yes’ the plant will be formally inspected by Animal Health. The plant must be operational but still cannot receive ABP material. It must be commissioned using material that mimics ABP. Following this a temporary approval is likely to be issued at which point the plant can receive ABP material. Operators may wish to consider commissioning their plant ahead of ABP approval but for non ABP material.
4. From this point all material (digestate) generated by the plant must be monitored and sampled (usually taking around 3 months)
5. Once Animal Health are satisfied that the plant is operating appropriately (on the basis of the monitoring results) the material can be released from site
6. Animal Health then undertake a full review of the plant and procedures
7. If satisfied, a full approval will be granted at this point
8. Under the full approval, not all batches of outputs need to be monitored
9. Any failures in complying with approval conditions are passed to the Local Authority for enforcement action.
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