Economic Viability of Farm Scale AD Biogas Production across Cheshire and Warrington.

For Reaseheath Enterprise Delivery Hub

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1.0 Executive Summary

The report presents the results of a study into the economic feasibility of different models of farm based AD development within the Cheshire and Warrington area. Farms in the study area are predominantly engaged in livestock enterprises, therefore the study focused on AD models with primary inputs from animal waste and potential secondary feed stocks being derived from off farm energy crops.

The financial models presented are based on three farm models of biogas supply:

- 150 head dairy unit and 30% energy crop
- Cluster (CAD) of three 150 head dairy units and 30% energy crop
- 300 head dairy unit and 30% energy crop

From these models, AD is still not financially viable for a 150 cow unit with 30% energy crop. To produce a 12% return, capital costs would need to fall from the present estimate of £450,000 to £108,000. The best income generation for this group would be local energy supply if there is adequate local demand.

A CAD (Central AD unit) of three farms working together with 150 cows each could provide a more viable economic option compared to individual on-farm units. Current levels of capital costs (with a 30% energy crop feedstock) delivering electricity to grid, would provide a 3.4% return on investment before interest. A 45% reduction in capital costs would therefore need to be seen to provide a return on investment of 12%.

A larger scale digester on a 300 cow unit with the addition of 30% maize silage could generate a return on investment of 3.2% before interest charges at the current capital development costs. As with the CAD examples a 45% reduction in capital costs would increase returns to 12%.

The modelling showed that capital costs are a major factor in farm AD viability; the larger the gas volume produced the more energy market options are available. If technology reduces in cost the viability of the various scenarios improves significantly.

The technology review within the study identified a number of new entrants to the AD market that are specifically targeting the livestock sector. This equipment is significantly cheaper than the more traditional AD systems available. As yet, most of the new micro AD systems are not fully market tested but they do show that the technology is beginning to meet the market demand. The report concludes that within the next few years capital costs will reduce to the point where significant returns can be achieved.

In addition to the more typical AD income streams associated with electricity and heat there is also potential to develop more coordinated AD infrastructure on farms that could supply gas to grid. Scale is the critical factor due to the present high costs

of gas clean up. To ensure financial viability, at present capital costs, gas production levels in excess of 200m^3/hr will be required. To produce this level of gas 4000 head of cattle with a 30% energy crop input would be required.

Through analysis of various models, it was shown that such high volumes of gas can only be produced by farm clusters that supply a number of centralised AD facilities within close proximity of the farms. From the AD plants, gas could then be transported to a single centralised Biogas to Grid (BtG) plant in advance of gas injection.

Technology development combined with reviews of regulatory controls associated with gas injection to grid could significantly reduce capital costs in the future. Existing BtG units producing 100m^3/hr presently cost over £600k. Within five years this could fall to around £250k. This reduction in cost would reduce the volume of gas required (and therefore cattle required) for gas injection to become viable.

In addition to the financial viability of farm based AD there are a number of critical constraints that need to be considered within site selection. Planning policy at a national and regional level is generally supportive although, at a local level, the issues associated with the change to unitary authorities combined with delays in the LDF planning process provide little information on local planning policy with regards to AD. Green belt areas could form the main issue due to the extent of green belt designations to the north of the study area.

The permitting process has, in theory, improved due to the introduction of both exemptions for small scale AD and Standard Permits for larger projects. Many locations may find it impossible to meet the requirements of Standard Permits due to the proximity of residential premises. If this is the case projects will have to apply for much more costly and time consuming Bespoke Permits.

NVZ restrictions are likely to be less of a constraint as the digestate analysis for each farm typology suggested that even with the addition of energy crops the land area available on the 'typical' farms will be sufficient under NVZ regulations.

In summary if capital costs of micro AD systems continue to fall, financial viability of slurry based AD is achievable for the typical Cheshire and Warrington dairy unit. In certain situations there will also be the potential for gas to grid opportunities but this will be reliant on significant reductions in capital costs of equipment and large numbers of cattle being located close to a centralised AD and BtG plant.

2.0 The Policy and Regulatory Framework for Farm Based Biogas Production

This study aims to identify the economic opportunity for farm based biogas generation within Cheshire and Warrington. The study was commissioned by Reaseheath College with funding from the NWDA, Centrica and National Grid. The consortium of Rural Futures (North West) Ltd, CNG Services Ltd and SKM Enviros have been brought together to investigate the options for farm scale AD Biogas production in Cheshire and Warrington.

The report aims to answer the following questions:

i) If a sustainable commercial market for farm scale biogas production at current prices and subsidies?
ii) The conditions that would be required for farm scale biogas to be viable in the future.
iii) The economic, social and environmental impacts of the different routes to market.

In order to establish whether there is a commercial market for farm scale biogas production, we identify the source and scale of supply potential in Cheshire and Warrington and the existing biogas markets which can absorb that supply. Section 3 reviews the biogas markets in the UK. Anaerobic digestion (AD) historically has focused on electricity supply to the national grid. However, there are other routes to market, namely, on farm use of biogas as fuel for heat, electricity generation, direct energy supply to local energy users, vehicle use after compression as well as direct injection of biomethane to the gas grid. Section 4 identifies the potential sources of supply of farm biogas in Cheshire and Warrington, given by the farm structure in the area, crudely, by the types of agricultural production and farm sizes. The report concentrates on livestock farms and, in particular, dairy farms which are currently the only producers of significant volumes of farm feedstocks. Using data from DEFRA's Agricultural Census and the Farm Business Survey of farm costs we present a series of business models for AD enterprises on two types of dairy farms in Cheshire: a 150 cow herd unit and a 300 cow herd unit. Beef and poultry farms were not considered because of the relatively smaller availability of slurry for digestion on beef farms and the small number of poultry farms in the area.

Technology supply is a crucial component of the AD business models. Inevitably the requirements will be for relatively small scale systems based around average sized farms or groups of farms (with a minimum of 150 cows). AD systems based on the European model of large scale energy crop input do not fit the requirements of farms in Cheshire and Warrington. For this reason an assessment of available technology based on a survey of AD technology suppliers in the UK is made in Section 3 of the report to establish whether the technology supply industry is meeting the requirements of this particular market.

The economic viability of the different business models is assessed in Section 4 of this report. The assessment is based on estimated capital and operating costs for AD

plants on the two types of farms identified, supplying electricity, heat and biogas to different markets, with a specific focus on gas injection to grid.

The intention of the modelling exercise is to establish whether any of the business models are feasible. However, even when they are found to be feasible it does not mean that the markets identified are available to any given farm in the study area. Every new AD project will be subject to a series of constraints which are typically geographically specific. Some of these constraints are economic, such as access to local markets for electricity, heat or biogas, or electricity and gas grid connections which cannot be changed in the short term. There are also social and environmental constraints to the development of on farm AD enterprises. These are embodied in environmental regulations, such as NVZ legislation, planning and licensing laws. Environmental incentives, on the other hand, in the form of subsidized prices for the supply of renewable energy and capital grants, will also affect the viability of any specific project. The report provides an assessment of the present position on all these factors. Where the review finds that economic viability cannot be achieved, it provides recommendations that may help to inform how these may be overcome.

Appendix B includes an overview of existing financial incentives and an overview of new policy initiatives presently under review. A full review of the relevant constraints is provided in Appendix C.

3.0 Biogas Markets and Technology Provision

3.1 Biogas Utilization Options and Technology Provision

Raw Biogas can be utilized in a number of ways:

- Burnt directly to produce heat
- Burnt in a boiler to produce hot water or steam
- Burnt in a gas engine that generates electricity with utilization of engine waste heat as a heating source
- clean-up and upgrade to biomethane and inject into gas grid
- Clean-up and upgrade to biomethane and then compress (or liquefy) for use as a vehicle fuel (CBM)
- Hybrid options such as injection to the gas grid with use for onsite vehicles or CHP with on site transportation use

The choice of utilization option depends on a number of factors including:

- Flow-rate of biogas (which depends on amount and type of feedstock)
- Location and capacity of electricity and gas grids
- Relative economics of Feed-in tariff for electricity with the Renewable Heat Incentive (RHI) for gas and the CBM as a vehicle fuel option taking into account the different capital and operating costs of the utilization infrastructure
- Availability of on-site vehicle use and of technology that allows vehicles to run on Compressed Biomethane (CBM)

In general small volumes of gas are likely to be used by more localised markets. This may be an on farm generator, farmhouse heat or hot water or a neighbouring user of heat. Small scale production requires less input material, a smaller less sophisticated AD plant and less energy supply infrastructure. The aim being to keep capital costs to a minimum.

As production levels increase more utilization options become viable, in particular generation of electricity and its export to the electricity grid.

In areas without electricity grid capacity to export electricity, there is the potential to have a biogas network which connects the biogas from a number of farms allowing larger volumes to be used for electricity generation at a point with grid access, or the gas can be cleaned-up and upgraded for injection into the gas grid.

Whichever utilization option is chosen, the financial viability will be a complex calculation based on input material costs, capital and revenue costs and transport requirements. Set against this will be the income from energy sales which will be set at a market rate for equivalent energy derived from other sources together with renewable incentives offered by the Government. For waste that is land filled, the Landfill Tax also provides a significant financial driver to underpin 'gate fees' for the disposal of certain categories of organic material.
The volume of material available on the ‘typical’ Cheshire farm together with the location and capacity of the energy networks will dictate the utilization options
The first stage of a review of utilization options starts with the AD technology itself and its associated costs.

3.2 AD Technology

The Anaerobic Digestion process involves three key phases.

- Hydrolysis – the phase that breaks down the long chain carbohydrates and other feedstock’s into soluble organic compounds.
- Acid Fermentation/Acetogenesis -Acetogenesis - Bacterial breakdown of the organic material. Hydrogen and carbon dioxide are produced as part of this process.
- Methanogenesis – hydrogen is then bound to the carbon to produce methane

The efficiency of the process is dictated by the technology utilised to control these phases. There is wide variation in the technology approach that can be taken. Temperature is the first. The systems can be Mesophilic operating in a temperature range of 35-45 ^{o}C or Thermophilic at between 50-60^{o}C. The systems can be wet (5-15% dry matter, DM) or dry (over 15% DM). Digesters can be large single tanks or multiples of smaller tanks. The tanks themselves can be either vertical or horizontal. Finally the process itself can be either on a continuous or batch system.

There are advantages and disadvantages to each system, highlighted below:

i) Mesophilic vs. Thermophilic - Shorter digestion period for Thermophilic (8-18 days) compared to Mesophilic (18-60days) therefore producing more gas in the same time period, less tank space for the same volume of input material, higher pathogen kill. The main disadvantages of Thermophilic are the higher capital and operating costs and increased labour requirement. Overwhelmingly, Mesophilic ADs are seen in operation in Europe.

ii) Wet vs. Dry – A wet system produces less gas and requires more tank space, is more costly and produces more waste. However, wet systems have by far the largest market share. Clearly, in a dairy farm area such as Cheshire, the organic material is likely to always include wet slurry and hence wet systems are likely to be built.

iii) Single vs. Multiple Tanks – More tanks tend to produce more gas although the space requirement increases. Single tank systems tend to be cheaper to build and operate.

iv) Vertical vs. Horizontal Tanks – Vertical tanks are much more common and take up less space. As a result they are presently cheaper. The main advantage with horizontal tanks is that the flow rate through the digester can be more accurately controlled providing for more efficient digestion.

v) Continuous Flow vs. Batch – Continuous flow produces more gas, lower cost and requires less management.

Based around these five basic parameters each technology provider then provides their own solution to both the input of material, control systems, material transfer and digestate treatment.

The basic requirements for a farm based system are provided below:

- Feedstock reception and storage (for the feedstock used within the analysis this will include a slurry storage system of sufficient scale to store the required slurry and a silage clamp for the maize)
- Weighbridge
- Some form of macerator that ensures a small enough particle size (providing the maize silage has been well shredded during harvest a separate macerator should not be required)
- Mixing tank for slurry and maize
- De-gritter
- Digester
- Gas condenser (water removal)
- Gas scrubber (H_2S removal)
- Gas engine driven electricity generation plant(if electricity to grid) with associated heat exchangers to recover waste heat
- Digestate storage and dewatering if required
- Gas flare

In order that gas yield is maximized there are a number of parameters that need to be considered.

Acidity – Bacterial activity takes place between a pH of 6.8 to 8.0. Acidity therefore needs to be carefully monitored. Too acid or too alkali will slow down the bacterial breakdown and potentially kill the bacterial colony altogether. Factors that impact acidity include the rate of mixing, batch delivery rate and level of protein within the feedstock although this will be less of an issue for slurry and maize.

Feedstock Mix – Changing the mixing rate and type of feedstock will impact on both gas yield and methane content within the gas. The 'freshness' of feedstock will also be a factor. Recently cropped silage will produce more gas than last season's crop. It is beyond the scope of this study but high protein feedstock produces more methane than carbohydrate based feedstock. This is due to the carbon / nitrogen mix within feedstock. Within a basic slurry/maize input the more maize the higher the biogas yield.

Moisture Content – The correct dry matter (DM) content is critical to the process. Too high a liquid content will require more heating and therefore reduce the system efficiency. It will also increase costs of dealing with digestate. Too dry a mix and there will be problems with mixing, pumping and circulation within the AD tanks. As slurry will comprise a large proportion of the overall mix the most likely scenario for the system analysed will be too high a liquid content rather than too low.

Retention Time – The longer the organic material is retained within the digester the more gas will be generated per unit of material inputted. The negative to this is that the higher the retention time the larger the capital cost for tanks etc. Technology suppliers strive to produce maximum gas yield based on minimum retention time. This will always be a balance between capital cost and income through gas. Each feedstock will produce gas at different rates. High protein feedstock produces large volumes of biogas in a short time with a rapid tail off. Feedstocks with high carbohydrate levels tend to require longer before reaching their peak yield. In the case of slurry and maize, peak biogas yield will be within four to eight days with a steady tail off to around thirty days. The efficiency of the gas yield will also be affected by the mixing process within the retention period. Most systems continuously add new organic material and remove digestate. When material enters a tank it will be mixed and a proportion of the recently added material will inevitably be lost. Again technology suppliers have different systems that aim to minimize this loss but it will be an inevitable inefficiency within most continuous flow systems.

3.3 Biogas Quality

Gas composition received from the AD process will be variable and dependant on temperature, feedstock and process technology. Typically would be in the following range:-

Methane CH_4	55 to 65%
$C0_2$	35 to 45%
Nitrogen N_2	up to 2%
O_2	up to 0.5%
H_2S	50 to 3000ppm, more likely 500 to 1500ppm

(Source: Task 37 Report into Biogas Clean up and Upgrading and CNG Services data)

This gas will be saturated with water. There should, in theory, be no Oxygen or Nitrogen in the AD as the process is anaerobic. However, small amounts of air are often added as part of the process of reducing H_2S content in the biogas.

3.4 Review of available AD technology

A survey of existing technology suppliers was undertaken for this study. Twenty seven technology suppliers were contacted and full details of our findings are provided in Appendix D. Of the twenty seven companies contacted fourteen responded. Of these only four stated that their technology would be suitable for the farm types identified for Cheshire, namely 150 and 300 cow herds. Of those who responded but stated that their technology was unsuitable, the volume of input material expected from these farms was significantly below their minimum plant size. This is not surprising as most of the plant suppliers have developed technology that fits the German model of AD based around German subsidy rates. These plants tend to operate with large volumes of energy crop rather than slurry. The growth in German AD has focused on plants at either 500kW or above. This level of electricity production far exceeds the levels predicted from the farm types identified from the Agricultural Census data for Cheshire. There are a now a number of larger plants coming on stream in the UK but they tend to be located on much larger farming businesses and often incorporate commercial food waste. The challenge for small scale AD technology provision is the ability to downsize and simplify the systems without impacting on the plants ability to deliver an efficient turnkey solution to the identified farm types.

Appendix D provides full details and costs for existing low cost solutions for smaller-scale-farm-AD for livestock farmers. The issue in the UK is that that there appears to be very few suppliers of such systems and they are not fully market tested. Manufactures of liners etc advertise systems suitable for biogas collection but there is a lack of ‘turnkey’ solutions available within the market place.

3.5 Biogas use in CHP

To protect downstream equipment both moisture and H_2S content should be reduced to acceptable levels, should this not be controlled excessive corrosion and reduced equipment life will be the result. For CHP this normally means reducing the H_2S level to below 250 ppm to avoid corrosion in combustion systems, exhausts and chimneys (data from: CNG Services Didcot Project for Thames Water/Scotia Gas Networks, project in process).

3.6 Clean-up and Upgrading of Biogas to make Biomethane for Gas Grid Injection

For gas to be injected into the gas grid, the moisture must be removed, all H_2S removed and the CO_2 content reduced to around 2%. In addition, at present there is a limit of 0.2% on the level of O_2 in the biomethane. The HSE will grant an exemption in respect of Oxygen provided the gas grid is dry. However, industry trade associations (REA and ADBA) are arguing for an amendment to the Gas Safety (Management) regulations to allow a higher level of Oxygen (up to 3% is possible in Germany). Nitrogen is usually present in a stoichiometric ratio to oxygen (i.e. 4 times as much). It is not in itself a problem (grid limit is 5%) but it has the effect of lowering the calorific value of the biomethane.

For injection into the gas grid, around 4% propane has to be added (12% by energy) in order that the calorific value of the biomethane matches the CV in the gas grid.

The most expensive processing plant is for removal of CO_2 from the biogas. The three main technologies are as follows:

- Water wash. Uses the properties of water to absorb and desorb CO_2.
- PSA. Pressure Swing Absorption. Uses the properties of a medium when pressurised/depressurised to absorb and release CO_2
- Chemical Wash. Uses an amine (or similar) solution which has high affinity for CO_2

There are two other technologies that are used on less than 5% of plants but have potential to grow market share:

- Membrane. Uses a membrane to separate CO_2 from CH_4
- Cryogenic. Chills the gas to around -65 deg C to extract CO_2 as a liquid/solid

All of these technologies effectively separate CO_2 but the PSA and membrane technologies also carry over significant level of methane into the waste CO_2 stream. The handling of this gas (typically 10% CH_4, 90% CO_2) is an important design consideration.

Options for a 10% CH_4/90% CO_2 stream are:-

- If gas engines to generate electricity are used and the CO_2 waste stream is no more than some 10% of the gas flow to the gas engines then the waste stream may be returned to the engine inlet without adverse effect on performance.
- If the CO_2 waste stream has an energy content of some 300kw per hour and a methane content of over 12% a micro-turbine CHP may be employed

- If the methane content is below 12% then it may be combusted in a low CV burner and the heat extracted.

If the methane content is below 1% the emission to atmosphere is likely to be permissible. Table 1 below summarises the technologies for CO_2 removal with number of plants in operation in EU:

Table 1 Comparison of biogas upgrading gas treatment technologies

Technology	Advantages	Disadvantages	Scale	Numbers in use
Water scrubbing	High gas quality Relatively low capex No pre-treatment Compact process Proven technology	CH_4 emissions Waste water disposal Drying of product gas required	80-2000 m^3/h	34
Chemical absorption	High gas quality Low methane losses Compact process Low emissions levels	Cost of loss of solvent Gas pre-treatment required High utility requirements Not extensively used at low scale Medium-high capital costs	300-4000 m^3/h	17
Pressure swing adsorption	High gas quality Dry product gas No water requirements No waste water disposal Proven technology Low emission levels Some adsorbents mitigate high oxygen levels in biogas	Gas pre-treatment required Medium capital costs Difficulty associated with waste gas stream (19% CH_4/90% CO_2)	80-1200 m^3/h	28
Cryogenic	Very high gas quality Compact process Dry product gas No water requirements No waste water disposal	Plant complexity High capital cost High utility requirements Not extensively used at low scale Novel technology	40-2400 m^3/h	2

	Re-use of removed CO_2 Some processes can remove oxygen			
Membrane separation	Compact process Dry product gas No water requirements No waste water disposal No moving parts (excl. compression)	Difficulty associated with waste gas stream (19% CH_4/90% CO_2) Gas pre-treatment required Membrane life	60-1100 m^3/h	9

It is important to note that there are no plants in operation of <50 M^3/hr, though a number of pilot/demonstration plants do existing at the 25 M^3/hr level.

Conclusions in respect to CO_2 removal are:

- CSL believes that acceptable technologies are Water Wash, Pressure Swing Adsorption, Chemical Wash and Membrane.
- Cryogenic technology is not proven at this stage.
- The best solution for any individual project will depend on:

a. Biogas flow-rate

b. Level of H_2S and Oxygen

c. Availability of waste heat

d. On-site electricity requirements

e. Ability to burn a methane-CO_2 waste gas stream for a useful purpose (e.g. in a boiler or CHP plant)

3.7 Injection into the gas grid

Cleaned biogas, now known as biomethane may be injected into the gas grid after the addition of propane to increase the calorific value (CV) of the biomethane to match that in the local grid (known as the Flow Weighted Average CV). Depending on the level of inerts (CO_2, O_2, N_2) it is possible that anything from 5 - 12% propane (by energy) is required.

In order for propane to be added to the biomethane there are a number of assets required:

i) Propane storage tanks (may be provided by propane supplier for small flows but will normally be one off tanks made specifically for the biomethane project).

ii) Propane vaporisation, control and mixing system to add the propane to meet the necessary CV.

For the vaporisation, control and mixing system the costs are in the region £50 - £100k with an annual O&M cost of around £3-5K.

The cost for the storage tanks depends on size, but indicative costs are provided below:

Table 2 Indicative Costs for Storage Tanks

Plant capacity m^3/hr	**Storage vol @ 4% injection refilling at 7 to 14 day frequency**	**Total Storage costs £**
100	3 Tonnes	9,000
250	8 Tonnes	15,000
500	16 Tonnes	30,000

Source: Renewable Energy Association paper to Uniform Network Code Review Group (Biomethane: CV Issues and Proposed Resolutions).

When propane is added to biomethane there is a 'Propane Value Loss', PVL:

PVL = cost of propane less value of wholesale natural gas at NBP

For biomethane, there is no seasonal swing, with the same amount of propane required all year round. There is some seasonality in propane prices. At a high level, propane prices are generally linked with oil.

It is estimated that the PVL looking forward is around 60 p/therm based on:

Propane wholesale price = $650/tonne= £425.tonne

There are 474 therms of propane in a tonne, so cost is around 90p/therm. In addition, there is the delivery charge and suppliers margin, taking the price to around 100p/therm at the moment. Natural gas price is around 40 p/therm so PVL = 60 p/therm.

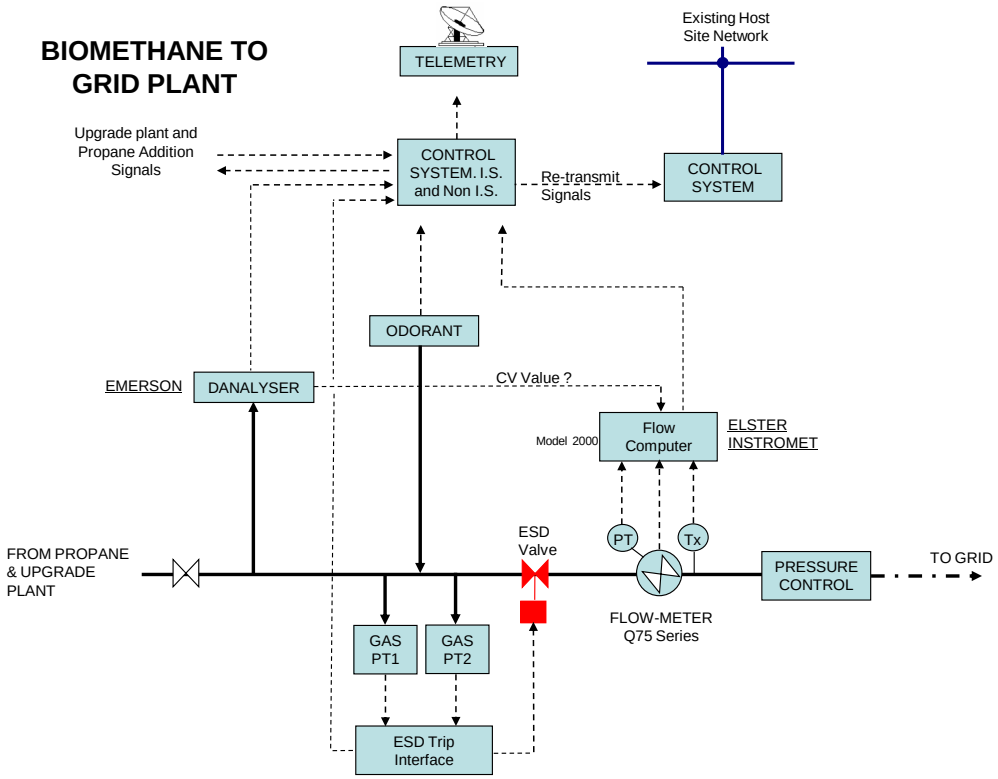
3.8 BtG Plant

Once propane has been added it is necessary to monitor gas quality, measure energy flow, add odorant, control pressure and have a telemetry system with the gas grid. Currently all this plant is very expensive.

A traditional 'north sea gas' BtG specification comprises:

1. Full gas chromatography to GS(M)R composition including total sulphur, Emerson type 500 Chromat, (Emerson type 700 now approved which has a lower cost), real time CV, Wobbe, H_2S and Oxygen measurement
2. Fiscal standard flow metering
3. Flow computer to fiscal standards and Ofgem-specified security (Siemens Micro-box)
4. Remote real time connectivity to High Pressure Metering Information System (HPMIS) and Flow Weighted Average CV (FWACV), inc. remote access by Ofgem
5. Odorant injection pumping system and controls
6. UPS/back up power
7. Remote Isolation valves
8. Controls and Telemetry and remote control with backup ISDN
9. Multi-stream Active-Monitor-Slam Shut Pressure control.
10. Sampling and purge points etc
11. Trip system (additional gas chromatographs)
12. Propane storage, mixing and injection plant
13. Civils work, utility supplies etc
14. Design and project management costs

Figure 1 Biomethane to Grid Schematic



There are 2 pilot projects underway which will shortly be commissioned on gas grids owned by National Grid (NG), the Adnams Project, and Scotia Gas Networks (SGN), the Didcot Project. The capital cost of the BtG plant on these projects is estimated to be in the £600 - £800K region.

The good news is that there are a number of clear opportunities to reduce capital costs and a biomethane compliant system for around £300K has been developed by CNG Services Ltd and a manufacturer.

In the medium term (2012 onwards) it is likely that further cost reductions will occur as competition is introduced in this supply chain, with estimated costs as follows (based on basic unit site producing 100 m^3/hr).

Table 3 Cost Reduction Predictions for BtG plants

Year	BtG costs £
2010	610k
2011	347k
2012	320k
2013	300k
2014	270k
2015	250k
2016	230k

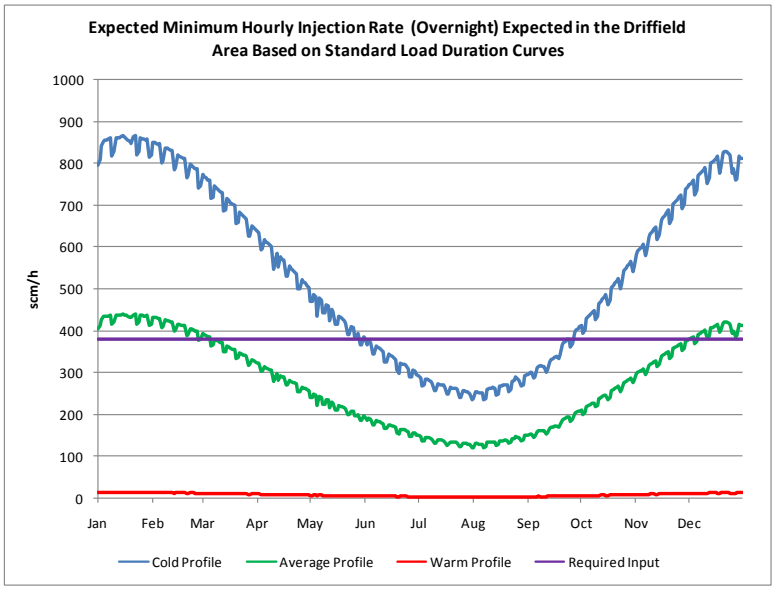
Source: CNG Services forecasts based on discussions with plant suppliers, Ofgem and a review of EU plant.

3.9 Gas Grid Connection Point

For injection of biomethane into the gas grid, there must be a gas grid nearby and it must have the capacity to absorb the biomethane flows. In practice, this means that local gas demand must be at least as high as the flow of biomethane.

The graph below illustrates how capacity to accept biomethane into a gas grid varies with the season. In winter, with high gas demand due to central heating load, it is possible to accept high flows of biomethane. In summer, domestic gas demand is limited to hot water mainly and there is very little demand during the night.

Figure 2 Seasonal fluctuation for gas grid injection



3.10 Potential Connection Points in Cheshire

National Grid reviewed their grid in the Warrington/Cheshire areas and identified 56 potential pipeline systems that could accept a reasonable flow of biomethane, i.e. 200 m3/hr of biomethane. (See Appendix G for mapped locations):

1. Holmes Chapel
2. Reaseheath/Crewe/Nantwich
3. Congleton to Stoke on Trent
4. Warrington
5. Chester - The Wirral

Outside these areas National Grid said that it was unlikely that there would be capacity to accept biomethane injection.

3.11 Vehicle Use

The main uses illustrated for biogas so far are CHP and gas to grid. Other options are biomethane as a vehicle fuel and, in theory, transportable gas. The addition of a vehicle fuel system to an existing biomethane production plant is straightforward. The system would need to be sized to cope with the fuel demand and the refuelling pattern needed. Systems may be "fast fill" where refuelling takes a matter of minutes, or "slow fill" where the vehicle is refuelled overnight. The cost of delivering fuel reduces with increasing capacity, the lowest capital cost but highest proportional delivery cost is with the small slow fill systems.

With the existence of a vehicle fill unit it is practical to charge up portable high pressure cylinders and transport gas to remote sites where gas is not available. This fuel source could replace liquid fuels such as kerosene, propane and butane in

burners and refill vehicles with the appropriate pressure booster systems. Capital costs are high but such a system could be viable.

If there is a large CHP plant then it is practical to employ a small scale biomethane production unit able to process some 30 - 40 m^3/hr of biogas as a slip-stream, using PSAS or membrane technology.

An increasing range of passenger cars, light and heavy goods vehicles are becoming available and able to run on biomethane or natural gas, there are also at least 3 farm tractors now offered, the scope is widening as the technology becomes mature.

3.12 Possibility for Biomethane - the Cheshire Option

A series of financial models were run to simulate biomethane production from livestock farms' feedstock and the results are presented in full in Appendix G. From the technology review in this section and the financial models we conclude that:

i. Technology is readily available to convert slurry/maize silage into biogas at a farm scale

ii. The technology to clean-up and upgrade biogas at scales <50 m^3/hr is not available at economic prices

iii. The cost of biomethane injection plant is expensive which makes plants <200 m^3/hr uneconomic

iv. There are limited areas of the National Grid gas network in Cheshire/Warrington with capacity to inject biomethane.

Given this, it appears that biomethane is not an attractive option in Cheshire/Warrington. However, this is not the case as there is an innovative option that can overcome the technology and cost barriers. We have called this the Cheshire Biogas Network Model and it is presented in section 4 of this report

4.0 Economic Feasibility of AD on Farms in Cheshire and Warrington

Section 2 of the report described the technologies associated with on farm AD and the access to different markets for farm biogas. Section 3 identified the potential markets for biogas available to farmers in Cheshire and Warrington. Section 4 now turns to the economic feasibility of biogas production for those markets on the types of farms found in the study area. The section begins with a description of the farm structure in the area in terms of livestock numbers and farm numbers using the latest Agricultural Census data available. However, critical to the adoption of AD is the average herd or flock size on any farm and the system of livestock production, given that this will the most important determinant of the scale of AD operation and therefore its potential profitability. Section 4.2 therefore develops 2 farm type models for farms in the study area that represent the majority of commercial farms with feedstock availability on farm. Section 4.3 discusses the particular characteristics of on farm feedstocks in the farm types identified in Section 4.2. Section 4.4 uses the models to assess the economic feasibility of different business models of biogas generation, clean up and sale.

4.1 Spatial Analysis of the Farming Sector in Cheshire and Warrington

As the first stage in assessing the potential of Cheshire and Warrington farm based AD, the location and distribution of the feedstock material was established. This required an analysis of livestock distribution and the location of the main crop production areas. The source of data on farm structure for the spatial analysis was DEFRA's 2007 June Agricultural Census at district level, updated to 2009 using the changes observed at the county level in the 2009 June Agricultural Census[1].The average herd size per holding is also critical since it will determine the scale of any AD enterprise based on it.

[1] The 2009 June Agricultural Census was only collected at county level. Our analysis needed

Figure 3 Local Authority Districts in Cheshire and Warrington

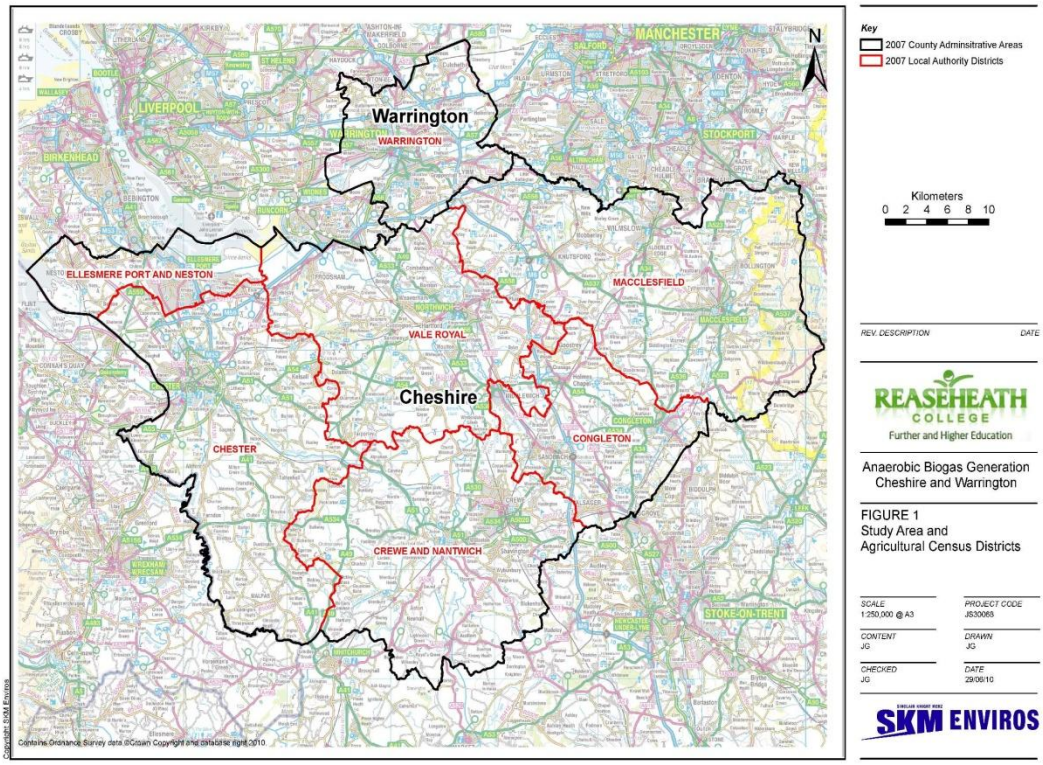
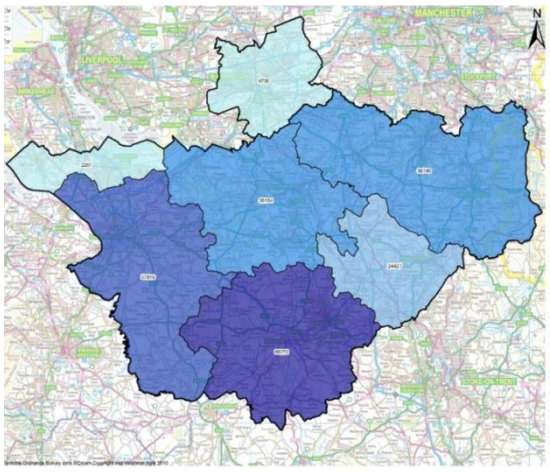
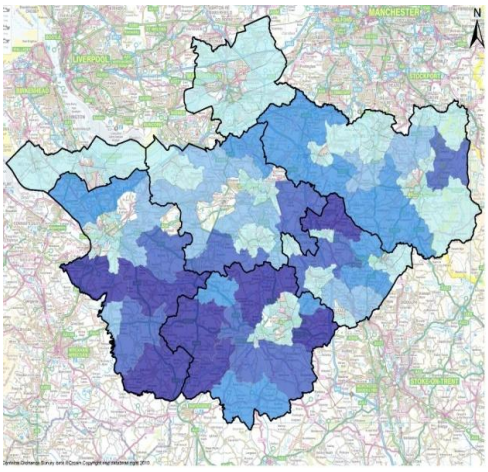


Figure 4 Cattle Distribution across Cheshire and Warrington by District and Ward. (estimated at June 2009)



4a Distribution by District



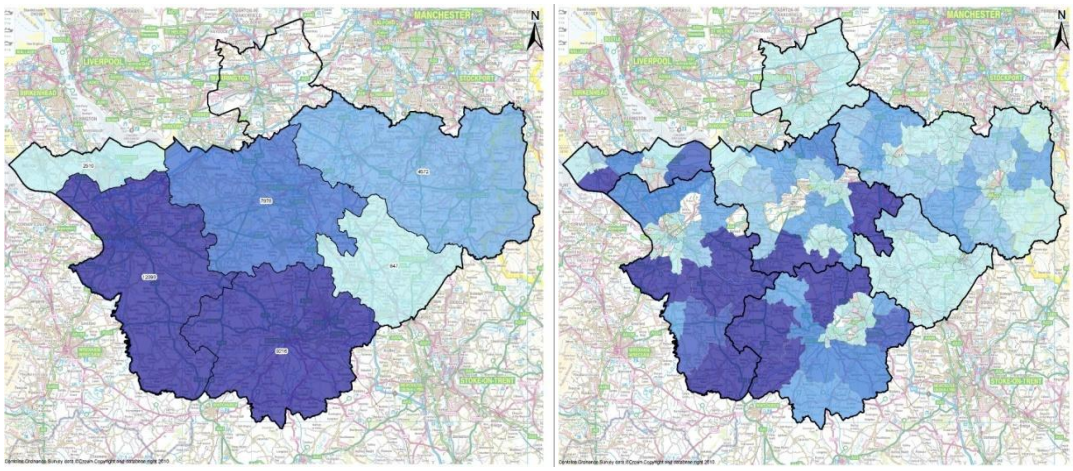
4b Distribution by Ward

Table 4 Number of Cattle and Cattle Holdings by District (estimated at June 2009)

Agricultural Census District	Total Numbers of Cattle	Total Numbers of Cattle Holdings
Warrington	4730	38
Chester District	57819	374
Congleton District	24427	210
Crewe and Nantwich District	66270	443
Ellesmere Port and Neston District	2201	24
Macclesfield District	36740	402
Vale Royal District	38184	316

The spatial analysis showed that the distribution of cattle is heavily weighted to the south west of the study area in the 'Crewe and Nantwich' and 'Chester' Districts. Examination at ward level showed that the greatest numbers of cattle lie in a more localised area running from Holmes Chapel in the north east to Winsford, Nantwich and Lower Kilmorton in the West, broadly corresponding to the lower lying Cheshire plains. A slight exception to this general pattern is the higher levels of cattle distribution to the East of Bollington on the lower slopes of the Peak District National Park.

Figure 5 Pig Distribution across Cheshire and Warrington by District and Ward. (estimated at June 2009)



5a Distribution by District **5b Distribution by Ward**

Table 5 Number of Pig and Pig Holdings by District (estimated at June 2009)

Agricultural Census District	Total Numbers of Pigs	Total Numbers of Pig Holdings
Warrington		
Chester District	12093	33
Congleton District	847	15
Crewe and Nantwich District	9216	38
Ellesmere Port and Neston District	2510	5
Macclesfield District	4572	51
Vale Royal District	7978	31

The distribution of pigs is largely similar to that of cattle but with a much stronger bias to the south west of the study area and some localised distribution in the areas surrounding Chester. The highest numbers are found between Crewe and Middlewich and between Nantwich and Chester. However, the total number of pigs is relatively low, such that a detailed assessment of biogas potential within the sector was not warranted.

Figure 6 Poultry Distribution across Cheshire and Warrington by District and Ward. (estimated at June 2009)

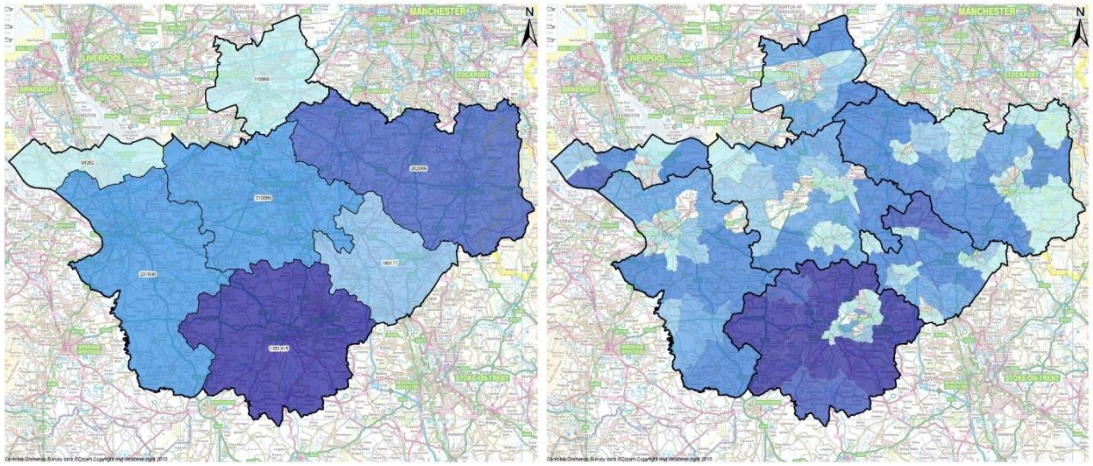


Table 6 Number of Poultry and Poultry Holdings by District (estimated at June 2009)

Agricultural Census District	Total Numbers of Poultry	Total Numbers of Poultry Holdings
Warrington	110989	29
Chester District	237836	143
Congleton District	180177	99
Crewe and Nantwich District	1351415	150
Ellesmere Port and Neston District	93262	16
Macclesfield District	262069	207
Vale Royal District	210869	116

Poultry distribution is very much concentrated to the south of the study area in the Crewe and Nantwich district although there is a significant concentration of poultry in the area north of Holmes chapel and between Macclesfield and Lymm.

Note that while the actual numbers of poultry in the Crewe and Nantwich district are significantly higher than other areas, the actual numbers of holdings is in fact lower than in the Macclesfield district indicating a trend to more large scale specialised poultry farming operations. Despite the existence of a small number of large poultry operations in this area, because of the relatively limited resources available for this study we will not include waste from these farms as a potential feedstock for AD.

Figure 7 Cattle Waste Distribution by District (estimated at June 2009)

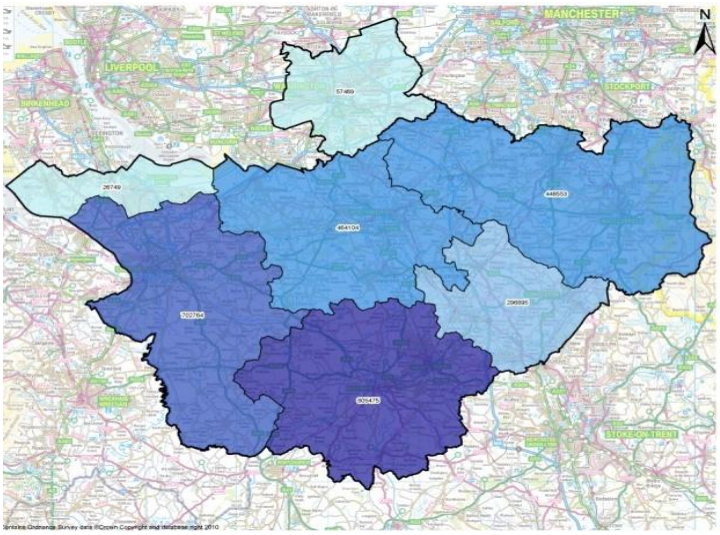


Table 7 Cattle Waste Distribution by District (estimated at June 2009)

Agricultural Census District	**Cattle waste (tonnes / Year)**
Warrington	57489
Chester District	702764
Congleton District	296895
Crewe and Nantwich District	805475
Ellesmere Port and Neston District	26749
Macclesfield District	446553
Vale Royal District	464104

Based on the total number of cattle head in each district, the tonnage of waste was calculated using a rough approximation of 51 kg of slurry per head. This is a very rough estimate based on slurry from dairy cows which in itself can vary by 50% depending on the size of the animal and the breed.
The estimate of 51kg is derived from Defra – Guidance Notes for Farmers in Nitrate Vulnerable Zones and ADAS – Managing Livestock Manures

Both contain a table which states
Dairy cow yielding > 9000l = 64kg manure/day
Dairy cow yielding 6000-9000l = 53kg manure/day
Dairy cow yielding < 6000l = 42 kg/day

This data was used to calculate the expected average slurry production of the cows in the study area using milk yield as a guide

Based on the Average yield of dairy cows in Cheshire, using FBS data, being 7190l – it was calculated that the expected slurry production would be 50.7kg as an average.

The distribution of waste of course, matches the distribution of cattle and therefore shows high concentrations to the south and south west of the study area. It is worth noting, however, that when the livestock are out at grazing the slurry is not available as an AD input. It is therefore necessary to identify which farms in Cheshire and Warrington are likely to have available slurry for digestion, as opposed to just keeping cattle, which we do later in this section.

Figure 8 Number of Farm Holdings by District and Ward. (estimated at June 2009)

Number of farm holdings *Number of farm holdings greater than 50Ha*

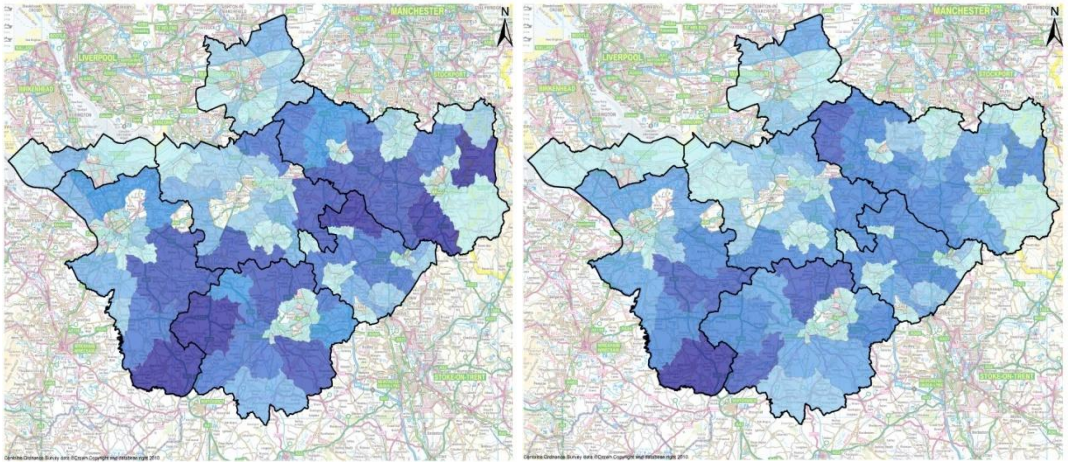


Table 8 Number and Size of Farm Holdings by District (estimated at June 2009)

Agricultural Census District	Total Number of farm holdings	Total Number of farm holdings >50Ha
Warrington	209	39
Chester District	925	241
Congleton District	545	105
Crewe and Nantwich District	856	199
Ellesmere Port and Neston District	115	7
Macclesfield District	1,080	194
Vale Royal District	676	135

The distribution of all farm holdings in the area is fairly even in the rural areas between the main urban centres, generally matching the overall pattern of livestock distribution. Overall, the areas surrounding Macclesfield, Chester, Crewe and Nantwich have the highest number of farms.

When looking at the larger farms greater than 50 Ha in size, there is a more pronounced concentration to the west of the study area with a concentration of large farms in the south west, in particular in the area between Whitchurch and Wrexham (Malpas ward – 48 holdings > 50 Ha) and to a lesser extent, in the Holmes Chapel

area north of Sandbach (Minshull ward – 43 holdings > 50 Ha) and the area between Lymm and Knutsford (High Legh Ward – 32 holdings > 50 Ha).

Figure 9 Cropped Area by Ward. (estimated at June 2009)

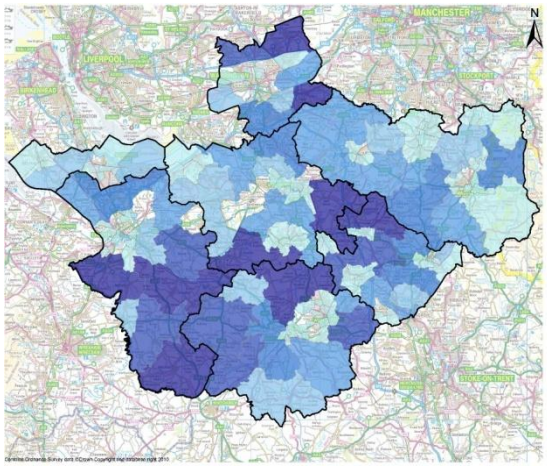


Table 9 Crop Area by District (estimated at June 2009)

Agricultural Census District	Crop Area (Ha)
Warrington	6892
Chester District	10786
Congleton District	4597
Crewe and Nantwich District	8233
Ellesmere Port and Neston District	698
Macclesfield District	6622
Vale Royal District	8165

The distribution of land under crops in the study area is largely concentrated in the band running from between Sandbach and Knutsford in the east to between Wrexham and Chester in the west. The largest concentration of crop area is in the Chester district to the west, but this is a largely rural district and so is unsurprising. Of note is the relatively high concentration of cropping area in the north of the Warrington district in a relatively small area to the north of the M62. Examination of aerial photography suggests this is an intensive area of cereal production compared to many

of the other areas which have a more mixed distribution of pasture and crop production.

Conclusions to the spatial analysis of livestock distribution and agricultural holdings in Cheshire and Warrington

1. Given the low density of livestock in the Warrington district we have disregarded the area for the purposes of this study assuming that feedstock availability for AD is limited.
2. Despite the high number of cattle in the area, it will only be farms which collect cattle waste, i.e. where the livestock is housed for at least some of the year, which will be able to use it as a feedstock for AD. Typically these will be dairy farms. For this reason, the development of farm type models to be used to assess the economic feasibility of on farm AD will be limited to dairy farms in Cheshire.
3. The highest concentration of cattle and larger holding sizes in the south and particularly south-west of the study area could provide an opportunity for small groups of farms to operate as a single AD business, increasing AD scale, minimising risk and sharing the management burden.

4.2 Farm Type Models for Cheshire

Table 10 shows the frequency distribution of dairy farms in Cheshire by herd size based on data from the June Agricultural Census 2007 (the latest data available at county level) and our projections to 2009 based on the percentage changes in cattle numbers and holdings observed in the North West since then.

Our projections for 2009 estimate that there were 884 holdings with dairy cattle in Cheshire. For the purpose of this study, holdings with 100 cows or less where discounted as it was acknowledged that they would not be operating as commercial dairy farms. Of all holdings with over 10 cows, 58% had herds of over 100 cows. Of those about 60% were of a herd size of between 100 and 200 cows, averaging 142, (which is only slightly higher than the national average), and the rest had herds over 200 cows, averaging 312 cows.

On the basis of this distribution we chose our two farm type models to be one of average herd size of 150 and the other 300 cows

Table 10 Frequency distribution of different dairy herd sizes in Cheshire from census data.

Herd size (number of cows)		<10	10<100	100:< 200	200 & over	total
Cheshire 2007	**Number**	693	18516	36741	42066	**98015**
	Holdings	257	323	263	141	**984**
	Average	3	57	140	299	100
Projection to 2009 on NW assumptions	**Number**	587	16411	33927	43640	94565
	Holdings	229	276	**239**	**140**	884
	Average	3	60	**142**	**312**	107

In order to create a full economic model of the farm types we used data for dairy farms in Cheshire from the Farm Business Survey for the 2008/2009 financial year. This data was necessary to create a realistic physical model of production where the dairy system of production could be identified in terms of feed use, land availability on the farm and costs.

Detailed analysis of these typical farms can be found in Appendix E.

4.3 Farm Feedstock's and Gas Yield

In theory any form of organic material can be utilised within an AD system. Any crop which has low levels of lignin can be utilised within AD. Wood or straw cannot be easily digested through an AD process so these inputs should be avoided. The more common crop inputs include maize, wheat, sugar beet and grass but manures, dairy washings and vegetable wastes can also be used. AD plants that use a combination of organic sources are the most common: typically, agricultural waste, crops and commercial food waste derived from food manufacturing and municipal food waste collection. This study has as its focus the feasibility of AD systems fed only with material derived from farms. The rationale for this narrow focus is that for the majority of dairy farmers, the AD enterprise needs to be integrated into the general management of the farm and the demands of managing the movement of imported feedstock's onto the farm are likely to be too onerous on family run farms.

The availability of input material on any one farm will dictate the size and type of AD plant, the gas yield and the most suitable means of digestate disposal. In turn, this will depend on the existing farming system, its location and the available crop area and number of livestock for producing input material. Larger volumes of feedstock need bigger plants, more storage and the ability to export more energy.

The biogas yields from feedstock's are subject to large variations. Central estimates are provided in a web tool developed by Andersons for the NNFCC: the "Anaerobic Digestion Economic Assessment Tool" and they have been used for this study. A few examples are shown in Table 11 below.

Table 11 Feedstock Yields

Feedstock	DM %	Biogas Yield m3/tonne	Value of Biogas £/tonnes
Cattle Slurry	10%	15-25	4.70-7.90
Pig Slurry	8%	15-25	4.70-7.90
Poultry manure	20%	30-100	9.50-31.70
Maize silage	33%	180-220	57.40-70.00
Grass silage	28%	160-200	50.50-63.40
Maize grain	80%	500	160
Whole crop wheat	33%	185	58

Within these input averages the main factors impacting on yield are dry matter content and the quality of the input material. If these vary then gas yield will also vary.

For the purposes of a 'typical' input scenario in Cheshire the report will focus on animal slurries derived from dairy cattle as the main input material with a secondary input from either maize or grass silage. Cattle slurry is a low yielding material compared to energy crops however it is provided at effectively a nil cost. The total tonnage of waste from the farm types identified for Cheshire is given below and it is based on the following assumptions:

- Slurry volume per cow – Within the available data there is a wide variation in the total volume of slurry available per dairy cow. DEFRA estimates range between 1.93m3 per month to 1.28 m3 per month for smaller dairy cows. Based on an analysis of the available data a conservative average has been provided of 51.51kg of slurry per day.
- Collected volume – The volume of collected material varies significantly based on the system employed. For the typologies of farm identified the assumption is based on the following systems.
- 150 head unit – Cattle housed for 6 months. During the outside period 30% of slurry will be collected during milking and yard movements.

- 300 head unit – Cattle housed for 6mths. During the outside period cattle are outside during the day but housed at night. The collection rate will therefore increase to 50% during this period.
- 3 X 150 head – as above for 150 head unit.

Number of Cattle	**Slurry volume tonnes per year.**
150	1854
300	4171

- Dry Matter - As with total volume, dry matter content will also vary depending on a variety of factors including feed type, levels of local rainfall, slurry system and the efficiency of the on farm dirty/clean water separation. Again the available data provides wide variation. For the purposes of the report an average dry matter content of 8% has been used.

In addition to the cattle derived slurry the waste within the slurry system will also include both rainwater and dairy washings. The volume of this material again varies significantly due to the efficiency of water use, areas of covered verses uncovered yards and type of slurry storage. In terms of maximising gas yield and minimising storage costs the most efficient system is to reduce the volume of water entering the system.

Slurry does not produce significant levels of gas as it has effectively already passed through an AD system within the cow. Expected biogas yields will rarely exceed 25 m3 per tonne (DECC & DEFRA AD Information Portal www.biogas-info.co.uk). It does however provide an excellent medium in which to add other higher gas yielding material such as energy crops.

The main issue with basing AD on slurry is the requirement for storage. An AD system based on the chosen farm types will have to operate through the summer period when the slurry volumes are significantly reduced as the cattle are outside. That said, the requirements of NVZ areas provided in Appendix C show that farms need to be able to provide up to five months storage. For this reason most farms should have the capacity to retain slurry over the outside period.

For energy crops the most likely scenario for dairy farm in Cheshire will be to use either maize silage or grass silage. In terms of gas yield they produce equivalent quantities and quality of biogas. As they are mainly ensiled they will be available year round.

There is the potential to use other Cheshire based energy crops such as grass silage, cereals and vegetable wastes. Grass silage and cereals will be readily available and may be in surplus on some farms. Gas yield for fresh silage and wheat is comparable to maize. If the farm incorporates vegetable production processing the waste may well save costs as the material can be used on farm rather than disposed of offsite. Gas yields are relatively low at around 70 m^3 per tonne. If the AD plant is located alongside glass house there may be other benefits through the use of excess heat and CO_2. For an individual farm these alternatives may be more appropriate.

One area of new development may be the use of sugar beet as an energy crop. Sugar Beet could potentially increase the effective gas yield per acre against maize but there are a number of inherent problems. Trials underway in Germany have shown that beet can produce up to 400kg of methane per kilogram of dry matter (KWS SAAT trials). This is 100 kg more than maize. This is due to the lower levels of lignum and cellulose compared to maize. The conversion rate of carbohydrate for beet can be as high as 95% compared to 70% for maize. The main issue with beet production is the level of contamination within the harvesting process and the rate of degradation of the beet crop compared to maize.

Research is presently underway to investigate various methods by which these issues can be overcome. These include beet hybrids that are specifically designed to boost both crop and gas yield and store for longer. Equipment is also being developed that will clean the beet during harvest to mitigate grit problems. Finally beet storage is also being addressed so that a year round supply is available.

Due to Cheshire's climatic conditions and shortage of land beet may well provide the best opportunity for a farm based energy crop supply but the technology is still in its infancy. For this reason the energy crop of choice will be maize.

4.4 Financial Modelling

The financial modelling of the various scenarios was carried out using the AD Economic Assessment Tool on the NNFCC website which calculates the rate of return on AD enterprises based on users' assumptions. A number of key assumptions were made during this process.

- There is a wide range of available data on gas production from various feedstocks. The standard data within the calculator was in the middle of this range and was therefore accepted for the financial modelling.
- The parasitic energy required to operate the plant varied substantially between technology suppliers. Again the default value in the calculator was within the range and was used for the modelling.

- FBS data was used to establish the average energy usage by typical dairy farms. This was established as being 400kW per year per dairy cow and was used as the figure for displaced farm electric.
- It was assumed that the typical dairy farms were utilizing all their available land for feed production for cattle.. The cost of energy crops can be dealt with in two ways. Firstly the costs of growing the crop can be incorporated within the overall economic model of the plant as the cost of production. This approach however ignores the potential loss of profit derived from using the same area of land for an alternative cash crop. The crop cost assumption also assumes that there is available land to grow the crop on the farm. As Cheshire dairy units tend to be relatively intensive this is unlikely. The ability of these units to swap fodder crop areas to energy crop without a detrimental impact on the existing farming enterprise will be a major factor. For this reason the report will base energy crop costs on the open market value. As maize is the most likely energy crop source the report uses a market value of £25 per tonne.
- The fertilizer value of the digestate was based on the improved nutrient value of digestate when compared to raw slurry. The financial value of this increase is based on current fertilizer costs.
- Using FBS data it has been established that the typical farms have sufficient land within their management to dispose of the digestate produced whilst still meeting NVZ requirements.
- Where the modelling looks at the Centralised AD option it was assumed that the slurry will be pumped by contractors from the farms to the AD plant and to pump digestate back to farms for spreading.
- The operating costs include the purchase of maize silage for feedstock, labour costs are based on industry standards for skilled staff , plant maintenance is the default in the NNFCC calculator, insurance based on industry standards, transport and pumping at current rates, laboratory and EA fees at current rates with an allowance for miscellaneous costs and finance costs.
- The breakeven point includes finance costs but the Return on Investment excludes finance costs as it is difficult to assess how much finance would be required in individual circumstances.
- For systems producing biogas rather than generating electricity it is assumed that the untreated biogas is sold to a third party for treatment and injection into the grid.

These assumptions were used to model a range of scenarios for the identified typical farms. Details of the physical parameters for the different models can be found in Appendix E along with data on revenue and expenditure for the different systems.

The capital costs were established for the various different farm models and the NNFCC calculator was used to establish the profit or loss for the system. The

calculator was then used to establish at what capital cost the various systems would break even.

Further analysis was then carried out to establish the capital cost at which the AD system would generate a 5% return on investment. It is important to note that using the NNFCC calculator the return on investment is before the cost of any finance as the level of borrowing will vary for every holding from a nominal bank loan to full financing of the project.

The main income source will remain the sale of energy and the associated financial incentives linked to power output. For smaller units the best returns will be achieved from a local supply network. This is due to the lower connection costs compared to grid connection and the higher direct supply charge that can be levied compared to grid supply. An energy supplier can effectively supply at the retail energy price rather than the wholesale energy price.

For a local supply to be viable a user needs to be located close to the AD plant that can use all the energy produced. The ideal model would be for the end user to still have a grid connection with the AD plant supplying the base load. This would allow for the inevitable fluctuation in supply from an AD system being compensated by additional grid supply. A typical scenario may be an industrial user located close to the AD plant taking all the AD electrical output then 'topping up' from the grid.

As the level of energy produced increases the more likely scenario will be for grid supply. Within the modelling, returns are provided for three market scenarios; local energy, grid connection and raw biogas. As the volume of biogas increases electricity to grid or direct raw gas supply becomes more viable.

For a capital project of this nature to be considered financially attractive a return on investment of 12% would be required. For the three different farm types, the financial modelling has been used to establish the capital cost at which this could be achieved.

The tables below summarise the findings for three farm level models: a single 150 cow unit, a CAD for 3x 150 cows and an on farm system for a 300 cow herd. These farms are assumed to supply energy to different markets as described above and on tables 11 to 13. More details on the detailed costs and income for the different models can be found in Appendix E.

Table 12 Capital costs and profit and loss projections for AD systems for a 150 cow unit.

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 5% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
150 cow unit	Slurry	Local electricity use	£250,000			£31,125	£15,543	-£15,582	-4.40%
150 cow unit	Slurry	Local electricity use		£72,750		£15,527	£15,543	£16	1.80%
150 cow unit	Slurry	Local electricity use			£53,500	£13,833	£15,543	£1,709	5.00%
150 cow unit	Slurry + 30% maize silage	Local electricity use	£420,000			£68,390	£58,796	-£9,594	-0.50%
150 cow unit	Slurry + 30% maize silage	Local electricity use		£310,750		£58,776	£58,796	£20	1.80%
150 cow unit	Slurry + 30% maize silage	Local electricity use			£227,500	£51,450	£58,796	£7,346	5.00%
150 cow unit	Slurry + 30% maize silage	Electricity to grid	£450,000			£71,030	£51,941	-£19,089	-2.40%
150 cow unit	Slurry + 30% maize silage	Electricity to grid		£232,750		£51,912	£51,941	£29	1.80%
150 cow unit	Slurry + 30% maize silage	Electricity to grid			£171,500	£46,522	£51,941	£5,419	5.00%
150 cow unit	Slurry + 50% maize silage	Local electricity use	£430,000			£87,446	£87,548	£102	1.80%
150 cow unit	Slurry + 50% maize silage	Local electricity use			£215,000	£77,326	£87,548	£10,222	5.00%
150 cow unit	Slurry + 50% maize silage	Electricity to grid	£460,000			£90,086	£76,196	-£13,890	-1.20%
150 cow unit	Slurry + 50% maize silage	Electricity to grid		£300,000		£76,006	£76,196	£190	1.90%
150 cow unit	Slurry + 50% maize silage	Electricity to grid			£221,000	£69,054	£76,196	£7,142	5.00%
150 cow unit	Slurry + equal quantity of maize silage	Electricity to grid	£590,000			£135,657	£137,060	£1,403	2.00%
150 cow unit	Slurry + equal quantity of maize silage	Electricity to grid			£445,000	£122,897	£137,060	£14,163	5.00%

Table 13 Capital costs and profit and loss projections for Central AD systems for three farms with 150 cows

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 5% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Raw biogas production	£535,000			£79,445	£35,823	-£43,622	-6.40%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Raw biogas production		£39,250		£35,819	£35,823	£4	1.80%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Raw biogas production			£28,750	£34,895	£35,823	£928	5%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Local electricity use	£550,000			£83,450	£45,806	-£37,644	-5.00%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Local electricity use		£124,500		£45,796	£45,806	£10	1.80%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Local electricity use			£91,500	£42,892	£45,806	£2,914	5.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Raw biogas production	£535,000			£127,380	£128,563	£1,183	2.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Raw biogas production			£402,500	£115,720	£128,563	£12,843	5.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Local electricity use	£565,000			£140,918	£186,245	£45,327	9.80%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid	£615,000			£145,318	£155,396	£10,078	3.40%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid			£535,000	£138,278	£155,396	£17,118	5.00%

Table 14 Capital cost and profit and loss projections for AD systems for a 300 cow unit

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 5% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
300 cow unit	Slurry	Local electricity use	£550,000			£65,356	£35,162	-£30,194	-3.70%
300 cow unit	Slurry	Local electricity use		£207,000		£35,147	£35,162	£15	1.80%
300 cow unit	Slurry	Local electricity use			£152,500	£30,351	£35,162	£4,811	5.00%
300 cow unit	Slurry + 1251t maize silage	Electricity to grid	£600,000			£107,673	£115,860	£8,187	3.20%
300 cow unit	Slurry + 1251t maize silage	Electricity to grid			£510,000	£68,478	£115,860	£47,382	5.00%
300 cow unit	Slurry + 1251t maize silage	Raw biogas production	£585,000			£113,401	£96,410	-£16,991	-1.10%
300 cow unit	Slurry + 1251t maize silage	Raw biogas production		£391,500		£96,373	£96,410	£37	1.80%
300 cow unit	Slurry + 1251t maize silage	Raw biogas production			£288,000	£87,265	£96,410	£9,145	5.00%

4.5 Conclusions from the economic feasibility analysis of farm AD on Cheshire dairy farms models

Tables 12 to 14 show that under current prices, financial incentives, capital costs and energy prices, the viability of different AD businesses on farm models for Cheshire is marginal at best. There are only four models which show a positive return on investment and only one of them is over 5%. In all cases slurry is supplemented to a significant degree with an energy crop in order to return a profit. For the single 150 cow herd model using equal quantities of slurry and maize silage a return of 2% is achieved through supply the electricity grid. The single 300 cow farm model using slurry and maize in equal proportions achieves a return of 3.2% also supplying the electricity grid. The only model to show a return of investment over 5% is the centralized model of three 150 cow herds supplying electricity to local users jointly which is estimated will generate a return of 9.8%. However, even this higher rate of return is unlikely to tempt a significant number of dairy farmers into AD. Table 15, therefore, estimates the reduction in capital costs necessary to provide a return on investment before interest of 12%.

Table 15 Viable financial models.

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 12% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
150 cow unit	Slurry + 30% maize silage	Local supply	£420,000			£63,390	£58,796	-£9,594	-0.50%
150 cow unit	Slurry + 30% maize silage	Local supply		£310,750		£58,776	£58,796	£20	1.80%
150 cow unit	Slurry + 30% maize silage	Local Supply			£108,000	£40,934	£51,941	£11,007	12.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid	£615,000			£145,318	£155,396	£10,078	3.40%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid			£338,000	£120,942	£155,396	£34,454	12.00%
300 cow unit	Slurry + 30% maize silage	Electricity to grid	£600,000			£107,673	£115,860	£8,187	3.20%
300 cow unit	Slurry + 30% maize silage	Electricity to grid			£321,500	£83,165	£115,860	£32,695	12.00%

For the 150 cow with 30 % slurry supplying local electricity, capital costs would need to fall by 74% from current prices to £108,000 to provide a 12% return on investment. New micro AD systems are starting to appear in the market that could achieve this level of cost reduction but as yet they are not yet market tested.

A CAD with three farms working together with 150 cows each provides a more viable economic option compared to individual on farm units. As the amount of energy will be significantly larger the most reliable market will be grid supplied electricity. At present capital costs with a 30% energy crop feedstock delivering electricity to grid a 3.4% return on investment will be provided. A 45% reduction in capital costs would need to be seen to provide a return on investment of 12%.

A larger scale digester on a 300 cow unit supplying electricity to grid becomes economically viable with the addition of 30% maize silage. This scale of plant would generate a return on investment of 3.2% before interest charges at the current capital development costs. As with the CAD examples a 45% reduction in capital costs would increase returns to 12%.

It can be seen from the analysis that capital costs are a major factor in viability. The larger the gas volume produced the more energy market options are available. If technology options reduce in cost the viability of the various scenarios improves significantly.

The preceding models have not attempted to double guess the development of AD and injection to grid technologies in the next few years, however there is an alternative model of biogas supply for which the technology is being developed and it is proposed below.

4.6 The Cheshire Biogas Network Model

There is a concept that will allow economic dairy farm ADs to be involved in the developing biomethane market.

- Anaerobic digester plants also have a size below which operation can become uneconomic so a figure of 100m^3/hr has been set based on the view of manufacturers.

- To limit the transport distance of raw materials the model is based on the concept of clusters of farms each feeding slurry to a local AD plant to produce biogas gas. Figure 3 below shows two options for transporting slurry to the centralised AD unit: pumping or road transport.

- The AD plants in turn pipe gas to the central Clean-up , upgrading, Enrichment and BtG plant at which point the gas would be injected into the gas grid.

It is estimated that slurry pipelines should be limited to around 4 Km in length for a 200 head dairy farm, but there is no limit on the biogas pipelines due to the ease of pumping biogas and relative low cost of polyethylene pipes laid by farmers across their own fields.

The concept is shown in Figure 10 below.

Figure 10 Biogas Network Model

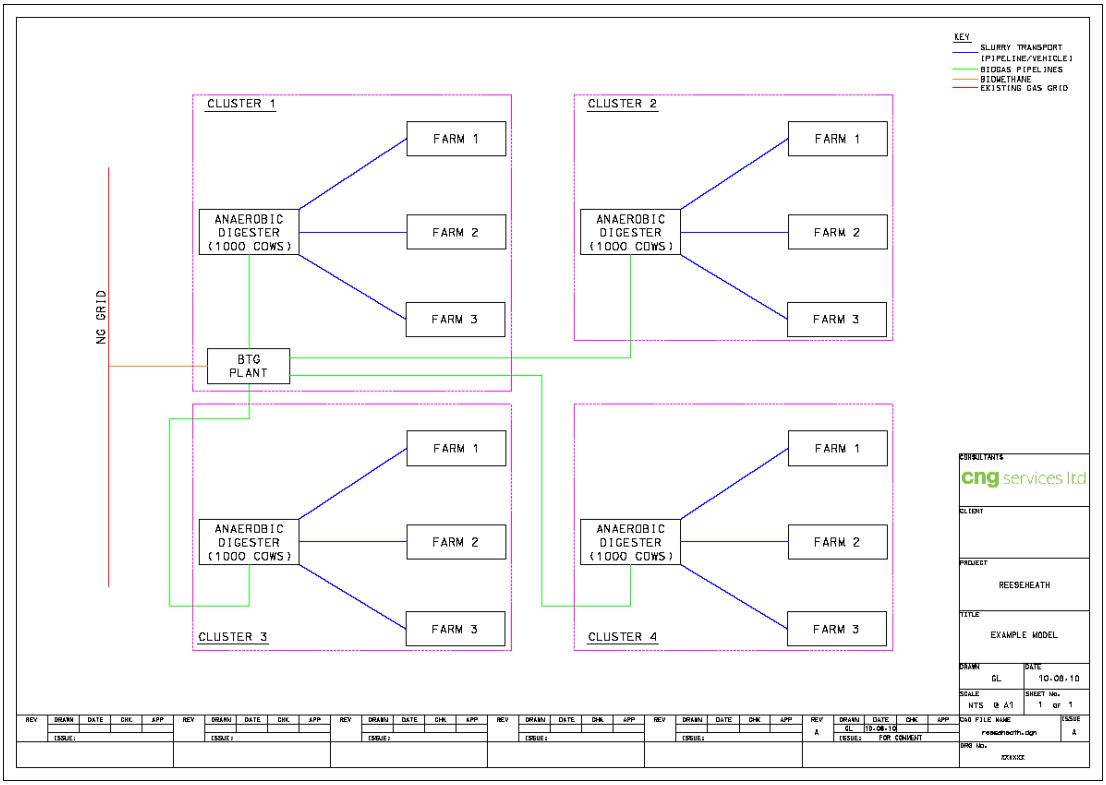
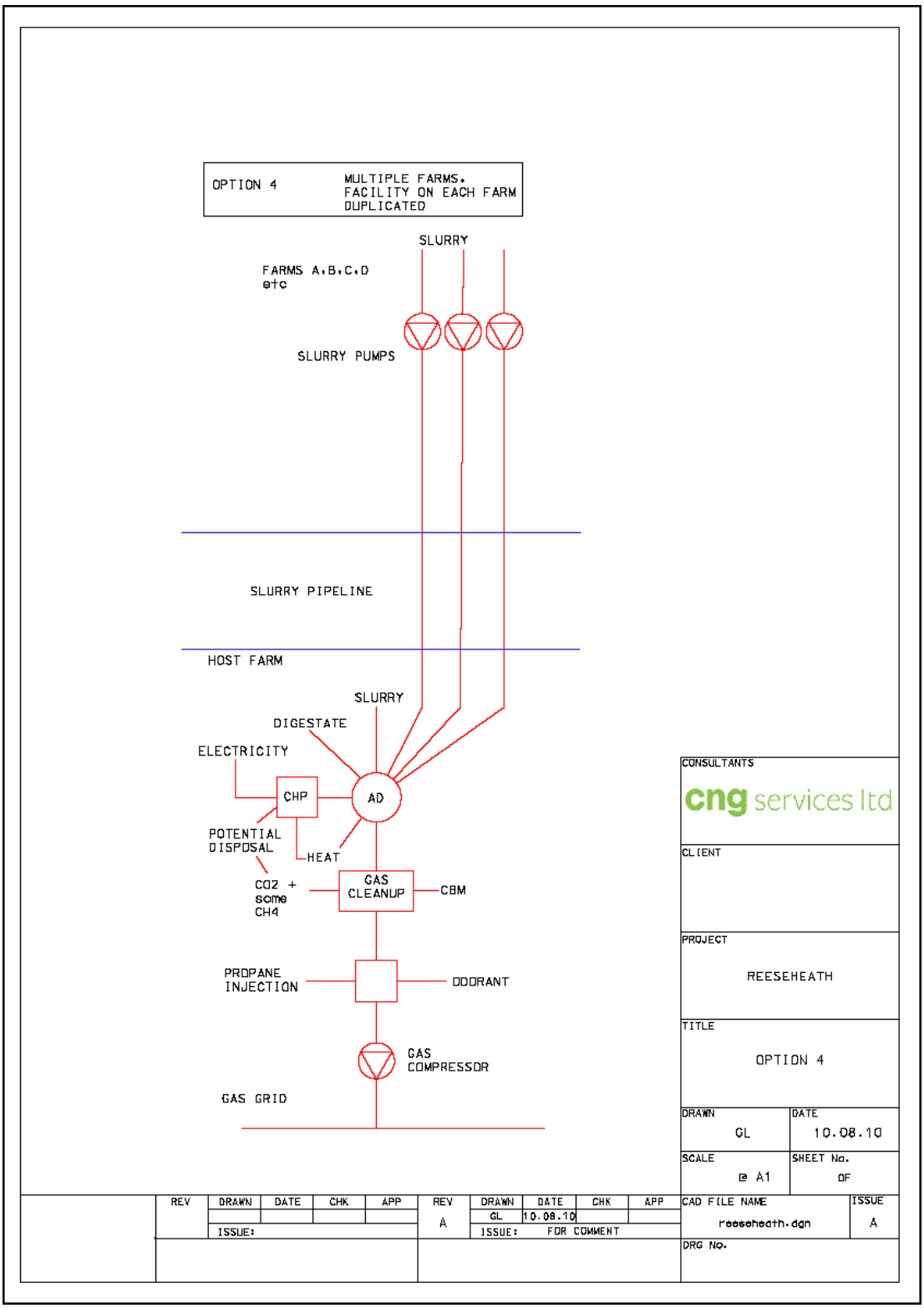
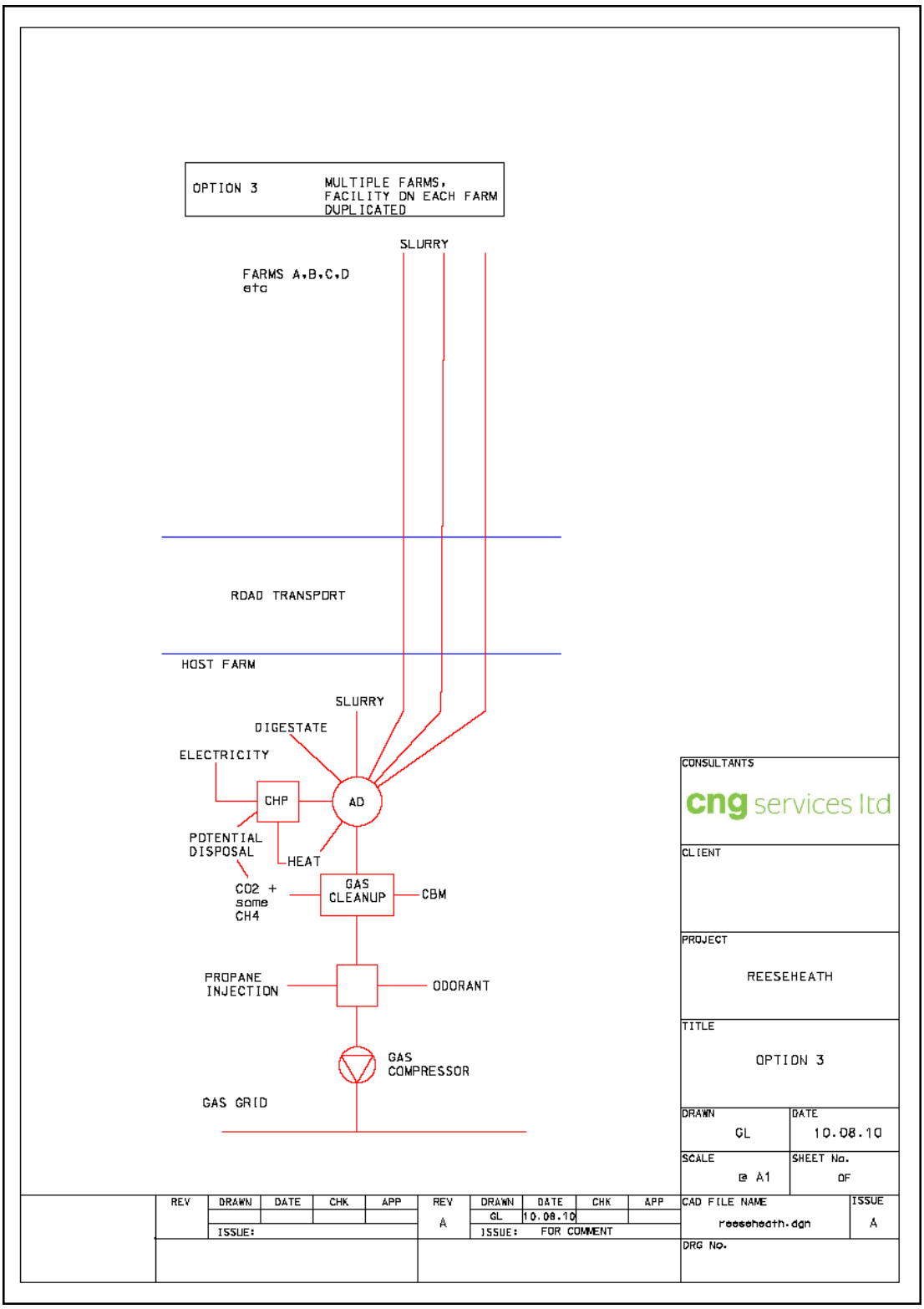


Figure 11 Cheshire Gas to Grid model




OPTION 3
MULTIPLE FARMS, FACILITY ON EACH FARM DUPLICATED
SLURRY
FARMS A,B,C,D etc
ROAD TRANSPORT
HOST FARM
SLURRY
DIGESTATE
ELECTRICITY
CHP
AD
POTENTIAL DISPOSAL
HEAT
CO2 + some CH4
GAS CLEANUP
CBM
PROPANE INJECTION
ODORANT
GAS COMPRESSOR
GAS GRID
CONSULTANTS
cng services ltd
CLIENT
PROJECT
REESEHEATH
TITLE
OPTION 3
DRAWN
GL
DATE
10.08.10
SCALE
@ A1
SHEET No.
OF
REV DRAWN DATE CHK APP
ISSUE:
REV DRAWN DATE CHK APP
A GL 10.08.10
ISSUE: FOR COMMENT
CAD FILE NAME
reeseheath.dgn
ISSUE
A
DRG No.

An additional advantage of pumping slurry and gas is that biohazard screening may be introduced so that the process is more secure in the advent of an outbreak of Foot and Mouth.

Centralised equipment of economical size operated on a commercial basis will reduce the need for farms to become involved in system operation (with the training and certification that may be required) and therefore allocation of their time.

A summary of the financial model for the proposed network is provided below. Further details are provided in Appendix G.

4000 cow + 30% energy crop model.

Abstract. This model assumes 9 clusters of 3 x 150 cow units with 30% maize crop feeding AD's which in turn feed a single gas cleanup plant.

CAPEX. £5,909k This includes AD's, slurry transport, H_2S, CO_2 and water removal, propane enrichment, odorant injection and monitoring of gas quality and assumes a 20% uplift for civils, mechanical works, electric supply, installation and commissioning. It also assumes that no additional gas compression is required for grid injection. In most cases gas entry points are at 4 Bar or lower, however those at Homes Chapel and Warrington are higher so will need additional compression. It also includes a low CV "Flox" burner to dispose of the gas waste stream and assumes no waste heat is required as the gas cleanup plant is located away from any AD process.

OPEX. £794k p.a for maintenance and electricity.

Propane cost is excluded. Biomethane producers are arguing that cost of propane should be paid by the gas company

Income.

Annual revenue generated from this model and based on gas price of £0.45 per Therm (£0.0153/kwh) and an RHI of £1.172 per Therm (£0.04/kwh) is £800,498.

The financial analysis based on present day capital costs shows that the model would only breakeven. If capital costs reduce and/or incentives for direct gas injection improve then gas injection from farm AD will become increasingly attractive.

Biogas networks are being developed in Sweden, Netherlands and the US. The Reaseheath Study with National Grid support has identified that Cheshire/Warrington would represent an attractive place to develop the UK's first biogas network feeding biomethane into the gas grid. If the initial capital costs reduce as predicted this option may become increasingly attractive to the gas market.

5.0 Summary and Recommendations

The report provides a comprehensive review of both the opportunity and ability of the Cheshire and Warrington livestock sector to deliver farm based micro AD projects. There is clearly a positive policy framework in place, including financial incentives, which aims to boost uptake of emerging technology.

The study area was analysed to ascertain the most likely farm scenarios where AD could be developed. The objective was to ascertain the potential for AD within the farm type's common in the study area rather than necessarily target farms that met the more common AD model for 500kW+ plants.

The report findings and details provided within the Appendices are summarised below:

5.1 Financial Modelling

Models were produced based on a variety of farm sizes, clusters of farms, different inputs, capital costs and energy supply scenarios. In order that the results were based on the same parameters the NNFCC calculator was used in all the scenarios provided. In addition cost analysis was also undertaken for fertiliser values, management costs and energy saving costs in the case of on farm energy use. Data was derived from both the NNFCC calculator and FBS data sources.
Key findings are listed below:

- Gas production increased significantly as energy crop percentage was increased
- To maximise returns a suitable energy use for heat must be found. This may be for on or off farm use.
- Gas injection produced significantly lower returns compared to electricity due to the value of raw biogas linked to the lower incentives available.
- Direct electricity supply to local users produces a 16% increase in return due to the higher direct supply price compared to grid supply.
- Cluster systems will not significantly increase labour and management costs.

For the three farm typologies the best return on investment is achieved through the following outlets:

- 150 head dairy unit and 30% energy crop – local energy supply
- 300 head dairy unit and 30% energy crop – grid energy supply
- Cluster (CAD) of three 150 head dairy units and 30% energy crop – local energy use

Capital costs are the critical factor. With the development of micro AD systems significant reductions in capital costs are being achieved. Within the next few years reductions in costs equivalent to those within the financial modelling are achievable.

Providing the equipment has been proved then there is no reason why small scale, farm based AD should not be a viable economic proposition.

5.2 Biogas Utilisation within the Gas Grid

A specific requirement of the study was to investigate both the technical, regulatory and financial potential of direct gas injection to grid rather than simply look at the more normal electricity supply model. The technology review identified that either water wash, pressure swing or chemical wash would be the most appropriate types of gas cleaning technology. At present capital costs are in excess of £1million for the required BtG and associated plant. This figure excludes any of the costs of either the AD plants or connection between AD plants and the BtG plant. In addition to the cost of the technology there would also be considerable regulatory and management issues associated with direct gas injection. The results showed that to justify the capital cost of gas cleaning equipment over 200 m^3/hr of biogas is required. This would only be provided by the most extreme model of 4000 cattle with a 30% input of energy crop. Development models based on farm and AD plant clusters have been provided. The most viable option would be for four separate AD plants each supplied by ten farms to link to a centralised BtG plant.

The report shows that the study area has the density of livestock to support such plants but the infrastructure requirements and gas grid connection points will limit the available locations for this type of development.

The technology review does indicate that BtG plant costs are likely to fall as new technology comes to market. There are also developments within the industry to provide more appropriate regulatory controls for gas injection from different sources. Combined these two factors will significantly reduce the volume of gas required to provide a reasonable return on investment. As a result the scale of required farm supply networks will also reduce.

5.3 AD Technology

There are many forms of technology solutions for AD. Within each niche there are a number of proven technology suppliers within the UK and Europe. The main problem with the available technology is that it has been designed on regulatory and financial models that do not fit with the identified farm typologies highlighted within the report. The technology supply sector clearly recognizes this problem and there are now a number of low cost solutions being brought to market that better fit the farm typologies within the study area.

For a number of the financial models a reduction of nearly 50% in capital costs will be required if attractive returns are to be achieved. Although this is a substantial fall the new generation of micro AD plants are approaching this level of cost reduction.

Once market tested and production levels increase there is nothing to suggest the required capital cost reductions cannot be achieved.

5.4 Policy and Financial Incentives

Despite the change in government AD still remains a priority for central government targets associated with a reduction in CO_2 emissions. A suite of financial incentives already exists to support micro renewables including ROCs and FiTs. There is still uncertainty over the delivery of the RHI due to the ongoing pressure on budgets. The farm typologies highlighted in the report are small and it is clear from the financial incentives available that economic viability is marginal at best. It therefore brings in to question the level of incentive provided under the existing schemes. FiTs for example is suppose to deliver a 12 % return on investment for generators based on technology type and scale of output. This is clearly not the case for micro AD.

To overcome the present low returns the RHI, or some form of additional farm capital support will be required.

Through a combination of reducing capital costs and an improvement in micro AD support through financial incentives the sector could see a rapid growth in farm based AD.

5.5 Constraints

AD development will inevitably be constrained based on a number of factors. Some of these will be logistical, some due to regulatory restrictions. A review of the study area identified four major constraints to AD development; planning, permitting, NVZs and energy distribution infrastructure. Planning requirements are site specific. Although the national and regional planning system tended to support micro renewable development at the local level there are many, and often conflicting planning issues that need to be considered. These include proximity to green belt, protected areas and additional local planning policy issues associated with farm diversification and renewable development.

Permitting also has localised issues that may contradict planning. For example under the new standard permitting system the AD plant needs to be located 200m from the nearest residence. This would include the farm house. As most farm houses are located alongside the farm buildings planning would require the new facility to be located within the same developed area. Permitting may preclude this. The costs and complexity of bespoke permitting may stop micro AD development where this is an issue.

Although the perception was that NVZ areas may provide a specific constraint to AD this was found not to be the case. Even with the addition of 30% maize the volume of digestate produced could still be accommodated within the farm areas provided by the FBS data.

The final major issue associated with constraints is the proximity of suitable, cost effective energy infrastructure. This could be grid connections for electricity and gas, or a more localised energy user, including the farm itself for micro generation. Again the energy infrastructure is site specific. Even where there is a readily available export infrastructure local network capacity may still preclude its use.

Constraints analysis is therefore critical to AD development. Each site will have different issues that will need consideration prior to investment. As the sector develops and policy support for renewable energy improves it can be assumed that many of the existing constraints will reduce in importance. In time on farm AD should form a normal part of farming operations rather than a new and unknown intrusion into the countryside.

5.6 Recommendations

Based on the report's conclusions the following factors would greatly increase the take up of 'micro' AD within the study area farms.

Technology:

- Work with the new generation of 'micro' AD technology suppliers to increase the speed of market testing and promotion of technology for the identified farm typologies.
- Encourage the development of 'turnkey' low cost low technology slurry lagoon systems.

Policy and Financial Incentives:

- Increase FiT levels for micro AD in order that the target 12% return can be achieved.
- Confirmation of RHI
- Direct capital funding through RDPE
- Clarification on state aid issues associated with capital funding and financial incentives.

Constraints:

- Highlight farm based AD as an acceptable farm diversification within the LDF process.
- Create a balance between green belt requirements and the advantages of farm based micro renewable energy generation. Micro renewables should meet the requirements of 'exceptional circumstances'.
- Create improved links within the permitting and planning system so that the two do not conflict.
- Reduce the costs of electricity grid surveys.

Gas Injection:

- Work with technology suppliers to reduce the costs of BtG plants for farm scale operations.
- Develop farm cluster groups for gas supply.
- Review of the gas injection financial incentives.

5.7 Conclusions

In relation to the original objectives of the report the following provides a summary of the key conclusions:

i) If a sustainable commercial market exists for farm scale biogas production currently.

'Micro' AD technology suitable for the identified farm typologies is available but at present this technology is not fully market tested. Markets do exist for the end product, be that electricity or gas. The issue will be the distance and therefore cost of transport and the associated post AD processing requirements that would be required to meet the identified markets.
Based on the limited volumes of gas being produced within the identified farm typologies the financial modelling suggests that at present capital costs economic viability can only be achieved through larger farms and/or clusters of farms delivering larger volumes of gas.

ii) The conditions that would be required for farm scale biogas to be viable in the future.

At present capital costs for small scale AD units, the available technology is limited and untested. When ancillary equipment such as CHPs and electricity connection costs are added financial viability is poor. To improve viability either capital costs need to fall or incomes improve. In reality it will probably require a combination of both.

The AD and BtG technology sector is already developing viable solutions that meet the required capital costs necessary to generate attractive returns on investment. What would further boost uptake would be improved financial incentives for small scale AD production through FITs and RHI.

If this can be achieved farm based AD could become an attractive investment option for many of the areas livestock farmers.

iii) The economic, social and environmental impacts of the different routes to market.

Regulatory controls are often a constraint to AD development in rural areas. At present planning and permitting still lags behind the wider national policy framework

for renewable energy and carbon mitigation. Environmental considerations still focus on landscape ahead of CO_2 reductions at the local level. These factors often work against even small scale renewable power generation in rural areas.

As the renewable sector develops local resistance to new projects will reduce. The hope would be that farm based AD will be regarded as a 'normal' farming operation in the future. If this can be achieved, through farm based AD, rural communities will generate new income streams, reduce national CO_2 levels and create new opportunities for local energy supply networks that bind communities together.

Farm scale AD is now a realistic option for livestock farmers. The potential benefits to the rural economy and the wider environment are considerable. The question will be the ability and willingness of the farming sector, the technology providers and the regulatory bodies to deliver on this potential.

Appendix A - Glossary of Terms

For the purpose of this document, the following definitions apply:

Anaerobic Digester (AD) – Reactor in which the digestion process takes place.

Biogas - produced by anaerobic digesters, composition 60% methane, 35% carbon dioxide with contaminants (H_2S and Siloxanes) and water. Not suitable for burning in gas engines or injecting into the gas grid. Partial processing (Siloxane removal and some removal of H_2S and water) required to meet gas engine specification for electricity generation.

Biomethane – renewable methane, 97-98% methane with water, H_2S, siloxanes and majority of CO2 removed. Suitable for use in electricity generation plant, vehicles and for injection into the gas grid (after BtG plant).

Bi-fuel CNG – car or van that runs on CNG or CBM and can also run on petrol

BtG Plant – Biomethane to Grid plant comprises the following:

- Odorant storage and injection
- Propane storage and injection
- Gas quality monitoring
- Gas CV measurement
- Gas flow measurement
- Pressure control
- Telemetry

The BtG plant is located after the Clean-up and Upgrading Plant and before the gas grid.

Calorific Value (CV) - that number of Megajoules produced by the complete combustion at a constant absolute pressure of 1.01325 bar of 1 Cubic Metre of gas at a temperature of 15°C with excess air at the same temperature and pressure as the gas when the products of combustion are cooled to 15°C and when the water formed by combustion is condensed to the liquid state and the products of combustion contain the same total mass of water vapour as the gas and air before combustion; and for the avoidance of doubt calorific value shall be REAL as defined in ISO 6976-1:1995(E)

CBM – compressed biomethane gas – vehicle fuel (200 or 250 bar pressure)

CHP – Combined Heat and Power. This is biogas fuelled electricity generation plant that uses some of its waste heat for the Anaerobic Digestion Process

Clean-up and upgrading Plant – plant that cleans up biogas and upgrades it into biomethane with removal of water, CO_2 and H_2S. There are 5 main technologies for Clean-up Plants:

- Pressure swing adsorption (PSA)
- Water wash
- Chemical absorption
- Membrane
- Cryogenic

CNG Trailers – a trailer containing High Pressure Gas Storage cylinders. There are 4 types of trailer:

- Type 1 – Constructed completely from metal only, typically steel
- Type 2 – Metal liner (Aluminium or steel) hooped wrapped with composite material, typically carbon
- Type 3 – Metal liner (Aluminium or steel) fully wrapped in composite material, typically carbon, often with fibre glass overwrap to offer additional wear resistance
- Type 4 - Polymer liner fully wrapped in composite material, generally a combination of carbon and glass fibre

Dedicated NGV – only runs on natural gas or biomethane in a spark ignition engine, which has no petrol or diesel capability.

Digestion – Anaerobic degradation of organic matter under the influence of specific bacteria.

Dual fuel NGV – truck with a diesel engine that runs on a mixture of 60% biomethane, diesel 40%

Energy Measurement – the measurement of Calorific value and Flow that together are used to calculate the amount of energy flowing into the Gas Grid. The standards of Energy Measurement must meet the requirements in the Gas (Calculation of Thermal Energy) Regulations, defined in the Network Entry Agreement.

FITs - Feed in Tariff

Flaring – burning of biogas because there is no other use for it, e.g. when electricity generation plant is being maintained or if Clean-up and Upgrading plant is not available

FWACV - Flow Weighted Average CV

Gas Grid – the natural gas distribution system(s) in the UK owned by National Grid, Scotia Gas Networks, Wales and West Utilities and Northern Gas Networks Ltd

Gas Grid Capacity – the capacity of the Gas Grid to accept injection of biomethane. This will normally be higher, the higher the pressure tier and will be lower in summer due to lower local gas demand

Gas Safety (Management) Regulations 1996 ("GS(M)R") – the regulations that define the gas quality requirements for gas entry into the UK gas grid (covering such things as H_2S, Wobbe, Oxygen)

Gas Quality Monitoring – plant required to measure the quality of biomethane prior to injection into the Gas Grid to ensure it meets the GS(M)R requirements

Gas (Calculation of Thermal Energy) Regulations – sets out the required standards for CV and flow measurement

GT License – Gas Transporters License

High Pressure Gas Storage – CBM is held in high pressure gas cylinders

Kg of Biomethane – equal to approximately 0.45 of a therm and worth around 20 pence as 'normal gas'. A new 3 bed semi will burn around 400 therms in a year

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LDF – Local Delivery Framework

Local Operating Procedures (LOPs) – these are part of the NEA and define day-to-day procedures for such items as: Notification of intended gas flows

- Confirmation of actual gas flows
- Site security
- Management of flow rates, pressures and gas quality
- Emergency arrangements
- Maintenance arrangements

Network Entry Agreement (NEA) - a Network Entry Agreement (NEA) sets out the technical and operational conditions for the connection and is required by the Uniform Network Code (UNC). The NEA is an agreement between the Biomethane producer and the Gas Grid Owner and includes such items as:

- The point of entry (marked on a diagram).
- The plant and equipment, and its ownership.
- Responsibilities for maintenance and operational control of equipment.
- Gas quality specification
- Measurement arrangements
- On-going charges
- Local Operating Procedures (LOPs)

NGV – Natural Gas Vehicles, which can operate on CBM.

Odorant – chemical added to biomethane to give it the characteristic smell of natural gas (necessary for injection into the grid)

PPG – Planning Policy Guidance

Pressure Tiers – the 4 different gas pressure tiers within the Gas Grid:

Low pressure (LP)	<0.5 bar
Medium pressure (MP)	0.5 – 2 bar
Intermediate pressure (IP)	4 – 7 bar
Local Transmission System (LTS)	7 – 50 bar

Note - biomethane will usually be injected into the MP or IP networks and consumed within a few km of where it is injected

Propane enrichment – small volume of propane (typically 5%) added to biomethane so that is meets the calorific value target set by the local Gas Grid owner (included in the BtG Plant)

PSA – pressure swing absorption

Renewable methane – gas from an AD, can be used to generate electricity (earn ROCs), or fuel vehicles (earn RTFO's) or injected into the gas grid (earn Renewable Heat Incentive Payments)

Renewable Energy Directive – new EU Directive that includes support for renewable methane

Renewable Heat Incentive (RHI) – legislation has been passed in the December 2008 Energy Act to enable the incentive of a reward payment for biomethane injected into the Gas Grid.

ROCs – Renewable Obligation Certificates – financial incentive to encourage renewable electricity generation. Currently worth around £40-£50/MWh**.**

ROC banding – from April 2009 a new AD earns 0.5 x ROC for its electricity, a new AD using commercial waste earns 2 x ROCs. An existing sewage gas supplied CHP plant will continue to earn 1 x ROC

RSS – Regional Spatial Strategy

RTFO's - Renewable Transport Fuel Certificates – financial incentive to encourage renewable transport fuels (mainly biodiesel and bioethanol, but includes biomethane). Scheme started 1 April 2008, value not known but buy-out price is 15 p/kg from 2008/9 to 2010/11 when it will rise to 30 p/kg

RDPE – Rural Development Plan England

Safety Case – Required pursuant of regulation 3(1) of the Gas Safety (Management) Regulations

Therm - An imperial unit of energy. Largely replaced by the metric equivalent: the kilowatt hour (kWh). 1 therm equals 29.3071 kWh.

Virtual Pipeline – name given to use of trailers to move gas. A virtual pipeline contains 3 main elements:

- Gas compression plant
- Trailers
- Pressure reduction plant

Wobbe Index (WI) - indicator of the burning characteristics of natural gas. If VC is the higher heating value, or gross calorific value (GCV), and GS is the specific gravity, the Wobbe Index, IW, is defined as

$$I_W = \frac{V_C}{\sqrt{G_S}}.$$

Appendix B - UK Biogas Summary

B1.0 What is Biogas?

Biogas is the generic term used for gas derived from organic sources. It forms part of the group of gases more normally referred to as 'Natural Gas'. Natural gas is produced from the decay of organic material. It is primarily composed of methane which is the simplest and shortest of the hydro-carbon molecules. Methane (CH_4) burns readily and completely.

As methane comprises 25% hydrogen and 75% carbon it produces very low levels of CO_2 compared to other fossil fuels. In comparison, by mass petrol has 13.4% hydrogen and LPG (Liquid Petroleum Gas) 17.4%. As a result natural gas produces more energy than other hydro-carbon fuels and lower carbon emissions.

Natural gas from fossil fuels was produced following the decay of organic material millions of years ago. As these sources cannot be replaced they cannot be viewed as 'renewable'. Natural gas in the form of biogas can however, be derived through anaerobic digestion and fermentation of existing organic material. As the organic material from which biogas is derived is grown, processed then decomposed the original source material is replaceable within our current time frame. For this reason biogas is considered to be a renewable source of energy.

As well as being a source of renewable power, burning methane derived from organic waste has significant beneficial impacts on climate change. Methane is twenty three times more damaging as a green house gas than CO_2. As methane is produced from the decomposition of all organic material it would be naturally produced from landfill sites, decomposing agricultural manures etc. By trapping the gas released and burning the methane the result is harmless hydrogen and water, and less harmful CO_2.

Biogas is commercially produced from various organic sources including manures, agricultural crops, sewage sludge and other biodegradable wastes. In the UK it is estimated that 24 terra (trillion) watt hours (TWh) of biogas are produced. The main source of biogas in the UK is derived from land fill gas; the second largest source from the waste water industry. This makes the UK one of the largest producers of biogas in Europe.

The greatest potential growth for biogas production in the UK is through the development of dedicated anaerobic digestion (AD) facilities. AD is the technology used within the waste water industry to process sewage sludge however the same process can be used to convert other organic feed stocks into biogas. These include agricultural organic wastes such as manure, agricultural crops, municipal organic wastes and commercial organic wastes.

B2.0 UK AD Potential

It is estimated that the UK presently produces over 100 million tonnes of organic waste annually. This underutilised resource could potentially generate up to 7% of the total UK energy requirements if investment was to be made in suitable Anaerobic Digestion (AD) technology. DEFRA estimates that if all the available organic waste were treated through AD it could provide a further 10-20 TWh of heat and power.

The UK AD industry is still in its infancy. Despite significant investment and promotion by UK government, uptake of this technology has been slow to develop. At this point in time there are still only a handful of fully commercialised plants within the UK. This compares to Germany with nearly 5000 plants.

The scale and range of input materials that can be utilised within AD will dictate both the technology required and the main focus of the appropriate business model. The majority of AD projects presently underway in the UK are associated with the treatment of organic waste from both the public and private sector. In addition there is strong interest and significant potential associated with farm based AD developments that employ either crop or animal waste feed stocks. In Germany it is this sector that has rapidly expanded due to the incentives provided by central government towards crop based inputs. These incentives are not replicated in the UK. As a result, and despite significant public sector investment, the farm based model for AD has yet to be fully proven in the UK market.

B3.0 National Policy on AD

Under the coalition agreement AD is specifically highlighted as an area for development. The agreement states that measures will be put in place "*to create a huge increase in energy from waste through anaerobic digestion*". Although details of new AD policy from the coalition government are still in their infancy their commitment is clear. On the 6th July Climate Change Minister Greg Barker and Environment Minister Lord Henley chaired an Anaerobic Digestion Round Table with industry.

Greg Barker stated that "t*urning waste into something usable is a no brainer! So I want to investigate how we can be far more ambitious in our use of anaerobic digestion. In the face of the challenge to build an economy that cuts carbon emissions, which ensures energy security, and which creates green jobs to help bring back economic prosperity - anaerobic digestion ticks all of these boxes. Plus it has the added benefit of reducing waste going to landfill*."

Following the meeting DECC and Defra will jointly draw up an action plan, looking at the economic capacity for the anaerobic digestion industry.

The new coalition have yet to commit to the previous governments announcements on AD but they have agreed to take forward the DEFRA policy statement provided within 'Accelerating the Uptake of Anaerobic Digestion in England: an

Implementation Plan' published on 25 March 2010. The Implementation Plan provides a framework for action by Government and stakeholders to facilitate the uptake of anaerobic digestion in England. The Plan is based on the recommendations of the Anaerobic Digestion Task Group, and also includes further actions that have been set in motion since the publication of the Task Group report. The key recommendations within the report are provided below.

- **Creating the Economic Framework**: The Government's objective is to ensure that the right long-term economic framework is in place to enable the market to deliver the increase needed in renewable energy.

- **Creating the Regulatory Framework:** To ensure a regulatory framework that strikes an appropriate balance between encouraging cost-effective growth in the use of anaerobic digestion and ensuring protection of the environment and those operating anaerobic digestion facilities.

- **Building Capacity:** The need to ensure the cost effective and environmentally beneficial uptake of anaerobic digestion by increasing awareness and understanding of the use of the technology and its products.

- **Research: Improving Our Understanding:** The need to continue to improve knowledge of the use anaerobic digestion technology and its products in order to make the most of the potential benefits.

- **Sharing Global Experience:** The need to learn from and share experience with other
countries, some of whom have much more experience with using anaerobic digestion than the UK.

- **Assessing Progress:** To identify where actions are working or where changes are needed, DEFRA will set up a comprehensive system of monitoring and reporting of progress. This will include a new online geographical information systems (GIS) tool.

The new coalition government has yet to state if it will follow through with the initial recommendations of the AD task Group however in July DEFRA also published a further report entitled '**Developing an Implementation Plan for Anaerobic Digestion'.** The report identifies the priority actions and recommendation required to deliver large scale AD investment in the UK. These are summarised below.

• **Recommendation 1**: The new feed-in tariff for small-scale low-carbon electricity generation and the renewable heat incentive should complement the existing Renewables Obligation and Renewable Transport Fuel Obligation so as to incentivise the most efficient uses of biogas, be clear on timescales and levels of support and recognise the relative costs of different scales of plant.

• **Recommendations 3-5 & 22**: Support and encourage separate collection of food waste through, for example, advice and guidance to local authorities and the private sector. Research and development on innovative collection technologies should be a priority.

• **Recommendations 13-15**: Clarify the regulatory framework for the co-digestion of sewage sludge with other feedstock's.

• **Recommendations 17-19**: Develop guidance on the gas regulatory regime and review requirements on calorific value and metering.

• **Recommendations 21-27**: Deliver a coherent research and development programme to support and promote the use of both the gas and the digestate products from anaerobic digestion.

• **Recommendations 32-33**: Deliver the Anaerobic Digestion Demonstration Programme as a priority and regularly review it to identify any further demonstration needs.

• **Recommendation 35**: Deliver the new web-based anaerobic digestion advice portal as a priority.

• **Recommendations 41-42**: Develop systems to monitor and report on the uptake of anaerobic digestion.

• **Recommendations 43-45**: Set up a central Government team to deliver the recommendations in the report and an independent stakeholder advisory group to support this team.

A number of these recommendations are already underway and will be reviewed later in this report but the fact remains that at present AD investment is still falling far short of its potential. ADBA (Anaerobic Digestion and Biogas Association) estimates that to meet the present target two plants will need to be commissioned every week for ten years. ADBA estimates that there is the potential for over 1,000 plants within the UK comprising of 750 'small' and 250 'large' projects. This alone will require an investment of between £2-£5 billion in AD technology.

Although there are estimated to be around 100 plants presently under construction or in development the UK is clearly falling behind within this sector. Policy rapidly needs to be converted to concrete actions on which the industry can base its economic forecasting. AD is a highly regulated sector that will require both financial and regulatory support for it to succeed. Until there is a degree of policy commitment and a viable model for development investment will remain sluggish.

B4.0 Financial and Regulatory Incentives

B4.1 Climate Change Levy

Climate change levy (CCL) is designed to encourage businesses to reduce their energy consumption or use energy from renewable sources. The CCL applies to supplies of the following:

- electricity
- natural gas supplied by a gas utility
- petroleum and hydrocarbon gas in a liquid state

- solid fuels, i.e. coal, lignite, coke - and semi-coke - of coal or lignite, and petroleum coke

Users of energy from these sources must pay the tax. The levy is imposed at the time of supply, so it will already be included in energy bills. Suppliers of these services collect the tax. Supplies for domestic use and to charity users for non-business purposes are excluded.

Rates
The levy is charged at an exact rate per unit of energy and increases broadly in line with inflation each April. The rates for 2010-11 are as follows:

Table 16 Climate Change Levy Rates

Commodity	Normal rate
Electricity	0.470 pence per kilowatt hour (kWh)
Gas supplied by a gas utility or any gas supplied in a gaseous state that is of a kind supplied by a gas utility	0.164 pence per kWh
Any petroleum gas or other gaseous hydrocarbon supplied in a liquid state	1.050 pence per kilogram
Any other taxable commodity, e.g. coal	1.281 pence per kilogram

Only renewable electricity with a Levy Exemption Certificate (LEC) is exempt from the levy. When an organisation buys renewable electricity with a Levy Exemption Certificate, they provide the Certificate to HM Customs and Excise.

For registered renewable producers Ofgem issues Certificates on a monthly basis to accredited generating stations. A single certificate represents the generation of 1 MWh of renewable electricity.

The climate change levy rate for this year is £4.56 per Megawatt hour (MWh) and rises in line with RPI year on year.

B4.2 Renewable Obligation Certificates (ROCs):

ROCs is the main support scheme for renewable electricity projects in the UK. It places an obligation on UK suppliers of electricity to source an increasing proportion of their electricity from renewable sources.

A Renewables Obligation Certificate is a certificate issued to an accredited generator for eligible renewable electricity generated and supplied to a licensed electricity supplier. One ROC is issued for each megawatt hour (MWh) of eligible renewable output generated.
The Renewables Obligation Order came into effect in April 2002. The Orders place an obligation on licensed electricity suppliers in England and Wales, Scotland and Northern Ireland to source an increasing proportion of electricity from renewable sources.

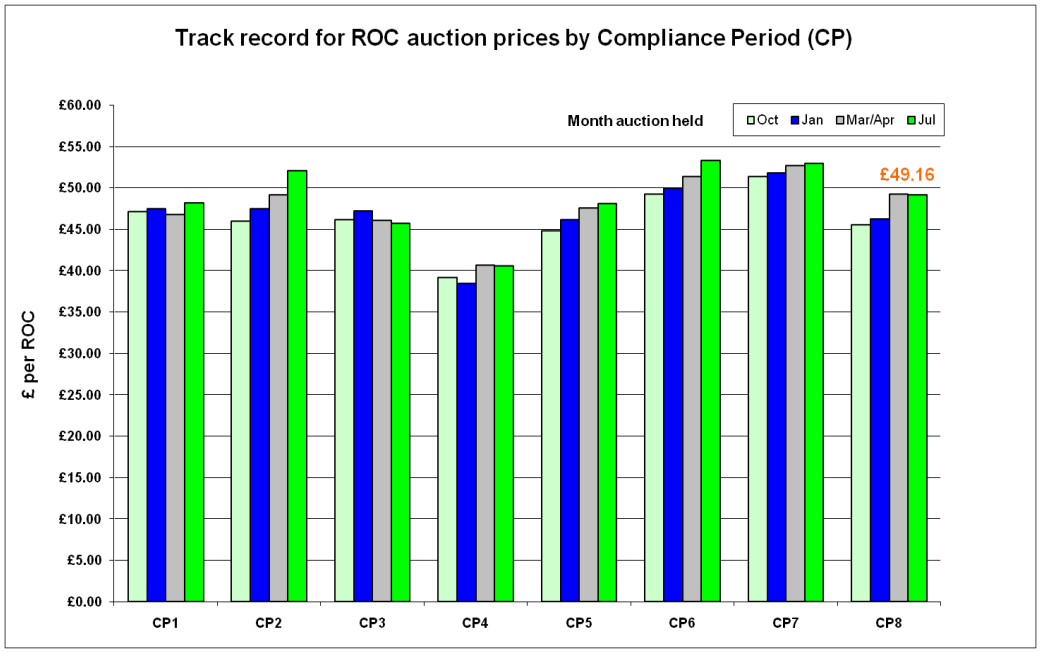
Suppliers meet their obligations by presenting sufficient Renewables Obligation Certificates (ROCs). Where suppliers do not have sufficient ROCs to meet their obligations, they must pay an equivalent amount into a fund, the proceeds of which are paid back on a pro-rata basis to those suppliers that have presented ROCs.

In April 2010, further changes included the RO being extended from its current end date of 2027 to 2037 for new projects, in order to provide greater long-term certainty for investors, and an increase in support for offshore wind projects meeting certain criteria.

The RO is administered by Ofgem who issue Renewables Obligation Certificates (ROCs) to renewable electricity generators. Previously, 1 ROC was issued for each megawatt hour (MWh) of eligible generation, regardless of technology. As of 1 April 2009, the reforms introduced mean that new generators joining the RO now receive different numbers of ROCs, depending on their costs and potential for large-scale deployment. For example, onshore wind continues to receive 1 ROC/MWh, offshore wind currently receives 2 ROCs/MWh, and energy crops 2 ROCs/MWh. AD also benefited from the new banding at 2 ROCs/MWh.

As ROCs are a tradable commodity the price has varied over time. ROC sales take place on a quarterly basis. The following graph provided by eROC shows the fluctuation over the past eight years. At an average of £49 per ROC this equates to a total income of around £100 MWh for AD.

Figure 12 ROC Auction Prices



B4.3 Feed in Tariffs

The Department of Energy and Climate Change (DECC) has used powers in the Energy Act 2008 to introduce a system of feed-in tariffs to incentivise small scale (less than 5MW), low carbon electricity generation.

The Feed-In Tariffs are based on the electricity generated by a renewable energy system. There is also an additional bonus for any energy produced which is exported to the electricity grid. The basic generation tariff levels are provided below.

Table 17 FITs Payment Rates

Technology	Scale	Tariff level for new installations in period (p/kWh) [NB tariffs will be inflated annually]			Tariff lifetime (years)
		Year 1: 1/4/10 – 31/3/11	Year 2: 1/4/11 – 31/3/12	Year 3: 1/4/12 – 31/3/13	
Anaerobic digestion	≤500kW	11.5	11.5	11.5	20
Anaerobic digestion	>500kW	9.0	9.0	9.0	20
Hydro	≤15 kW	19.9	19.9	19.9	20
Hydro	>15-100 kW	17.8	17.8	17.8	20
Hydro	>100 kW-2 MW	11.0	11.0	11.0	20
Hydro	>2 MW – 5 MW	4.5	4.5	4.5	20
Micro CHP pilot*	<2 kW*	10*	10*	10*	10*
PV	≤4 kW (new build)	36.1	36.1	33.0	25
PV	≤4 kW (retrofit)	41.3	41.3	37.8	25
PV	>4-10 kW	36.1	36.1	33.0	25
PV	>10-100 kW	31.4	31.4	28.7	25
PV	>100kW-5MW	29.3	29.3	26.8	25

PV	Stand alone system	29.3	29.3	26.8	25
Wind	≤1.5kW	34.5	34.5	32.6	20
Wind	>1.5-15kW	26.7	26.7	25.5	20
Wind	>15-100kW	24.1	24.1	23.0	20
Wind	>100-500kW	18.8	18.8	18.8	20
Wind	>500kW-1.5MW	9.4	9.4	9.4	20
Wind	>1.5MW-5MW	4.5	4.5	4.5	20
Existing microgenerators transferred from the RO		9	9.0	9.0	to 2027

The generation element depends on the type of energy produced and the capacity of the system. An anaerobic digestion system with a capacity of less than, or equal to, 500 kW would qualify for a generation tariff of 11.5 pence per kWh. An anaerobic digestion system with a capacity of more than 500kW would qualify for a generation tariff of 9 pence per kWh.

In addition the generator will be paid an export tariff for all the energy exported. A 'floor price' has been set at 3p/kWhr. You are entitled to receive this and it is index-linked to the retail price index. Generators also have the opportunity to opt out of this fixed price and try to negotiate a better rate with an electricity supplier. Each year the generator has the opportunity to decide whether to accept the fixed 3p rate or to opt out.

For AD the tariff is fixed for 20 years and will be index linked. Over the next few years the rate of tariff for some technologies will fall. This is known as degression. Whatever rate a new generator enters at will be guaranteed at that rate for the lifetime of the FITs scheme. For AD there is no degression.

B4.4 Renewable Heat Incentive

To meet the 2020 15% renewable energy target, the previous government wished to develop new ways of generating renewable energy in all sectors, including heat.

Some form of financial assistance is needed to expand renewable heat because other forms of heat are currently cheaper. Common examples of renewable heat technologies include: air- and ground-source heat pumps, biomass boilers, solar-thermal water heaters and combined heat and power (CHP) plants including AD.

Powers in the Energy Act 2008 allow the setting up of a Renewable Heat Incentive. On 1st February 2010, DECC published a consultation on the proposed design of the Renewable Heat Incentive (RHI) scheme, which it aims to introduce in April 2011. The consultation sought views on a number of aspects of the proposed scheme, including tariff levels. The consultation period closed on the 26th April 2010.

The main recommendations provided within the RHI consultation relevant to this study are provided below.

• The scheme should support a range of technologies, including air, water and ground-source heat pumps (and other geothermal energy), solar thermal, biomass boilers, renewable combined heat and power, use of biogas and bioliquids and the injection of biomethane into the natural gas grid.

• RHI payments to be claimed by, and paid to, the owner of the equipment.

• In small and medium-sized installations, both installers and equipment to be certified under the Microgeneration Certification Scheme (MCS) or equivalent standard, helping to ensure quality assurance and consumer protection.

• We propose payments will be paid over a number of years; annually for installations below 45 kW and quarterly for those above this level; and always subject to conditions such as continuing to operate and maintain the equipment.

• Tariff levels have been calculated to bridge the financial gap between the cost of conventional and renewable heat systems at all scales, with additional compensation for certain technologies for an element of the non-financial Tariff levels are proposed to provide a rate of return of 12% on the additional capital cost of renewables, with a lower rate of return of 6% given to solar thermal.

• Payments to be calculated on the annual amount of heat output, expressed in kilowatt hours (kWh). At the small and medium scale, the amount of heat generated by the equipment is proposed to be estimated (or "deemed") when installed in most cases.

• For large installations and process-heating, heat output to be metered, and the total annual support calculated from the actual energy generated, multiplied by the tariff level.

• Commitment that the RHI will remain open to new projects until at least 2020. Its design and tariff levels will be reviewed from time to time for new projects, so as to adapt to changes in technology costs and other circumstances.

• Eligible installations completed after 15 July 2009, but before the start of the RHI, to benefit from the scheme as if they had been installed on the date of its introduction.

• Ofgem will administer the RHI, making incentive payments to recipients and taking responsibility for auditing and enforcing the scheme.

Within the consultation the rates provided for AD are set at 5.5p/kWh for heat and 4p/kWh for direct injection to grid.

What is clear is that the consultation process has generated a significant level of controversy surrounding the RHI and the proposed tariff levels. In addition the new coalition government has yet to indicate its position relative to RHI. The present format of the consultation must therefore be regarded with a degree of caution.

B4.5 Capital Incentives:

The previous government provided a number of capital investment incentives to the renewable energy sector including both capital grant and low interest loans. For AD development funding tended to target three areas of activity; the promotion of recycling with AD grants targeting commercial and municipal waste, R&D funding and finally farm based AD. Some of these schemes were provided at a national level, others at a regional and even sub regional level.
Many of these programs have now closed. Those that are still operational are under review due to the present cut backs in government expenditure. In all likelihood it is unlikely that large scale capital funding will be available in the short or medium term.

Where capital funding is still available there also needs to be a degree of caution as many schemes will be regarded as double funding when set against the financial incentives provided by ROCs, FITs and RHI.

For farm based AD developments in Cheshire the most likely source of funding will be through Rural Development Plan England (RDPE). Under this program there are limited funds available under Measure 311 to support farm diversification. In theory the total level of grant could be up to £100k at a grant rate of 40%. In reality, and due to pressure on budgets between £20-£50k is more realistic. This fund operates to 2013 however the budgets are capped and it is likely that the present total budget may be exhausted before this point.
Also under RDPE the North West Regional Development Agency (NWDA) operated the Rural Carbon Challenge Fund (RCCF). This was targeted primarily at community based initiatives requiring a minimum grant level of £200k. Grant rates could be as high as 70%. The first round has now closed and it is unclear if there will be a second.

Under RCCF schemes AD would still be eligible for ROCs but not FITs or RHI. For the main RDPE scheme it is unclear if the same match funding eligibility would apply.

Appendix C - Cheshire and Warrington Biogas Constraints

In the siting of farm based AD plants there will exist a number of regulatory constraints that will need to be considered. These will include planning, permitting and Nitrate Vulnerable Zones (NVZ).

C1.0 Planning

C1.1 Planning Permission

Planning consent will be required for most AD installations because AD is not considered an agricultural operation. If the facility is going to use only feedstock from the farm and digestate will be spread only on the land of that farm, then it could be treated as permitted development (under part 6 of schedule 2 of the Town and Country Planning (General Permitted Development order 1995)). The final decision will be based on discussions with the relevant Local Authority. In most cases planning will be necessary.

The overall planning policy in England is presently under review. This has created a degree of uncertainty regarding the relevance of a number of planning policies. The old Regional and Local Plan policy framework was in the process of being phased out under the last government. This was being replaced with a new system of Local Delivery Frameworks (LDF). The speed of this change varies by Local Authority so many still operate under the old Local Plan Policy until such time as the detailed LDF documents are in place. To add further confusion the LDF process was based on a national and regional planning framework. This begins with the National Planning Policy Statements. Each region was then to produce a Regional Spatial Strategy (RSS). The RSS was then used to inform the LDF. Already the new coalition government has stated that the RSS system will no longer form part of the planning process however they have also stated that until the final structure of the new planning system is provided the old RSS can be used in support of planning submissions.

C1.2 Planning Process

Planning for AD will rarely be straight forward. Farm based schemes are likely to be located in rural areas where environmental, landscape and transport considerations will be more complex than in more industrial locations. Local opposition may also be more significant especially if the plant is to be located close to residential or other community buildings. For this reason the time and costs of planning submission should not be underestimated.

For project planning purposes the time and cost will be based on the planning requirements. These are dealt with more fully below but as a general rule the more information required the more time and cost will be involved. For a basic on farm AD project at least six months will be required. This will include the time required for pre planning advice, a basic level of community engagement, the completion of the planning application followed by submission and determination. The more

planning information required and the more sensitive the site the more time will be required.

In terms of cost the actual planning submission fee will depend on the Local Authority. Planning fees are established through the 'Town and Country Planning Fees Amendment Regulations 2008'. These were amended in October 2009. For the erection of buildings on land used for agriculture for agricultural purposes the fee will be dependent on total area.

Site area not more than 465m2 - £70
Site area between 465m2 and 540m2 - £335
Site area more than 540m2 up to 4,215m2 - £335 for the first 540m2 then £335 for each £75m2 thereafter
Sites are exceeding 4,215m2 - £16,565 +£100 for each 75m2 thereafter.

This means that for an average sized 500kW AD occupying 4000m^2 the total planning fee may be £15,790.

If the planning authority decides the application is an industrial operation it may fall under 'Erection/alteration/replacement of plant and machinery'. In which case, if the application is for the same 4000m^2 site, the planning fee will be £335 for each 0.1ha, in this case £1340. This rate applies up to a total area of 5ha.

The planning fee is only one part of the costs associated with planning. For most applications external planning support will be required. Costs will depend on the level of information required. As a basic guide the following provide estimates of likely costs associated with farm based AD projects.

- Elevation and plan drawings - £3000
- Completion of Design and Access and Planning Policy Statements - £2000
- Air Quality Assessment - £1500-£6000 (depending on planning requirements)
- Noise Impact assessment - £2500
- Phase One Habitat Survey - £1500
- Newt Survey - £2500 (Only available April to August)
- Landscape Impact Assessment - £1500
- Transport Impact assessment - £2500

Establishing Planning Requirements:
For the most basic farm based AD project the initial starting point will be to discuss the proposal with the Local Planning Authority in order to establish what will be required to support the application. Most of the projects to which this report is targeted will be associated with the use of on farm organic materials only. Depending on the location the Planning Authority will provide advice on what information will be necessary. A basic planning submission may include the following components:

- Completed drawings including elevation, block plan and site plan to the correct scale
- Completed planning application form

- Design and access Statement which identifies the main structures, building materials used, external landscaping, necessary car parking and highways access.
- Planning policy Statement which identifies the national, regional and local planning policies relevant to the proposal. The Policy statement may also include relevant economic or renewable policies that may be applied to the project.

In addition the Planning Authority may also require additional supporting information. At the extreme a Planning Authority may require a full Environmental Impact Assessment (EIA). This is unlikely but the planners may request certain components which would normally appear in an EIA. These may include one or more of the following.

- Landscape Impact Assessment
- Ecological Assessment especially if protected species such as great crested newts or water voles are known to exist in the local area.
- Business Plan establishing the economic viability of the proposal
- Traffic impact Assessment
- Air Quality Assessment
- Noise Impact Assessment
- Evidence of Community Engagement

C1.3 Planning Policy

The principal planning policies and issues to be considered within the planning application are as follows;

National Policy – Planning Policy Guidance and Statements
National government guidance on planning issues is contained in a number of Planning Policy Guidance Notes (PPGs), which are progressively being replaced by Planning Policy Statements (PPSs). As part of any application reference should be made to Planning Policy Statements.

A Summary of National Planning Policy Statements is provided below:
Relevant PPGs and PPS are outline below.

Planning Policy Statement 1 (PPS1): Delivering Sustainable Development, February 2005

PPS1 forms the backbone of the new national planning policy and sets out the Government's objectives for creating sustainable communities whilst ensuring a better quality of life for everyone, using the plan led system.

Whereas much of the guidance offered by PPS1 is of general or background relevance to AD development, the following specific points are noteworthy:

• Paragraph 3 of PPS1 identifies sustainable development as 'the core principle underpinning planning'.

• Paragraph 12 highlights pre-application discussions between developers and local planning authorities as being 'critically important'.

• Paragraph 8 reinforces the importance of the development plan in making decisions about development proposals.

Planning Policy Statement 10 (PPS10): Planning for Sustainable Waste Management PPS10, July 2005, and Companion Guide, June 2006

PPS 10 will only be relevant to those plants importing external waste. Guidance for all those involved in making decisions about the management of waste and relies on the waste hierarchy principle to bring waste management in line with the objectives of sustainable development.

Para. 1 of PPS10 states in this respect: -

"Through more sustainable waste management, moving the management of waste up the 'waste hierarchy' of reduction, reuse, recycling and composting, using waste as a source of energy, and only disposing as a last resort the Government aims to break the link between economic growth and the environmental impact of waste."

Relevant to the consideration of a planning application's suitability against the policies of PPS10 are the criteria set out in paragraph 21.

Planning Policy Statement 4: Planning For Sustainable Economic Growth.
PPS 4 was introduced in December 2009. It clarifies many of the issues relating to rural development and replaces the older PPG 7. The relevant sections are as follows.

PolicyEC2: Planning for sustainable economic growth

EC2.1 Regional planning bodies and local planning authorities should ensure that their development plan:

POLICY EC6: Planning For Economic development in Rural Areas

EC6.1 Local planning authorities should ensure that the countryside is protected for the sake of its intrinsic character and beauty, the diversity of its landscapes, heritage and wildlife, the wealth of its natural resources and to ensure it may be enjoyed by all.

EC6.2 In rural areas, local planning authorities should strictly control economic development in open countryside and set out the criteria to be applied to planning applications for farm diversification, and support diversification for business purposes that are consistent in their scale and environmental impact with their rural location

PolicyEC12: Determining planning applications for economic development in rural areas

EC12.1 Re-use of buildings in the countryside for economic development purposes will usually be preferable, but residential conversions may be more appropriate in some locations and for some types of building. In determining planning applications for economic development in rural areas, local planning authorities should:

b.support small-scale economic development where it provides the most sustainable option in villages, or other locations, that are remote from local service centres, recognising that a site may be an acceptable location for development even though it may not be readily accessible by public transport

Regional Guidance

North West Regional Spatial Strategy,
Regional Spatial Strategies (RSS) and Local Development Frameworks (LDF) are currently being implemented under the Planning and Compulsory Purchase Act (2004). These are replacing the previous system of Regional Planning Guidance (RPG), Structure Plans and Local Plans. The North West Regional Spatial Strategy was adopted on September 30th 2008. As previously highlighted the new coalition government has already cancelled the RSS as the framework for regional policy however it has also stated that the RSS is still relevant policy in the determination of planning application.
A Summary of the relevant regional Planning Policy statements are provided below.

Policy DP 3
Promote Sustainable Economic Development
It is a fundamental principle of this Strategy to seek to improve productivity, and to close
the gap in economic performance between the North West and other parts of the UK. Sustainable economic growth should be supported and promoted, and so should reductions
of economic, environmental, education, health and other social inequalities between different
parts of the North West, within the sub-regions, and at local level.

Policy DP 7
Promote Environmental Quality
Environmental quality (including air, coastal and inland waters), should be protected and
enhanced, especially by:

- *promoting policies relating to green infrastructure and the greening of towns and cities;*
- *maintaining and enhancing the tranquillity of open countryside and rural areas;*
- *ensuring that plans, strategies and proposals which alone or in combination could have a significant effect on the integrity and conservation objectives of sites of international importance for nature conservation are subject to assessment, this includes assessment and amelioration of the potential*

impacts of development (and associated traffic) on air quality, water quality and water levels.

Policy DP 8
Mainstreaming Rural Issues
The rural areas of the North West should be considered in a way which is integrated with

- *The problems of rural communities (such as housing affordability, economic diversification,*
- *The positive interaction between rural and urban areas should be promoted when appropriate.*

Policy DP 9
Reduce Emissions and Adapt to Climate Change
As an urgent regional priority, plans, strategies, proposals, schemes and investment decisions should:

- *contribute to reductions in the Region's carbon dioxide emissions from all sources,*

including energy generation and supply, buildings and transport in line with national targets to reduce emissions to 60% below 1990 levels by 2050

- *take into account future changes to national targets for carbon dioxide and other*

greenhouse gas emissions;
Measures to reduce emissions might include as examples:

- *facilitating effective waste management;*
- *increasing renewable energy capacity;*
- *focusing substantial new development on locations where energy can be gained from*

decentralised supply systems;

Policy RDF 2
Rural Areas
Plans and strategies for the Region's rural areas should support the priorities of the Regional
Rural Delivery Framework and:

- *maximise the economic potential of the Region's rural areas;*
- *support sustainable farming and food;*

Exceptionally, new development will be permitted in the open countryside where it has an

- *essential requirement for a rural location, which cannot be accommodated elsewhere*
- *is needed to sustain existing businesses;*
- *is an extension of an existing building; or involves the appropriate change of use of an existing building.*

Policy EM 15
A Framework For Sustainable Energy In The North West

Plans and strategies should promote sustainable energy production and consumption in
accordance with the principles of the Energy Hierarchy and within the Sustainable Energy Strategy. In line with the North West Sustainable Energy Strategy the North West aims to double its installed Combined Heat and Power (CHP) capacity by 2010 from 866 MWe to 1.5 GW, if economic conditions are feasible.

Policy EM 17
Renewable Energy
In line with the North West Sustainable Energy Strategy, by 2010 at least 10% (rising to at
least 15% by 2015 and at least 20% by 2020) of the electricity which is supplied within the
Region should be provided from renewable energy sources. To achieve this new renewable
energy capacity should be developed which will contribute towards the delivery of the
indicative capacity targets. In accordance with PPS22, meeting these targets is not a reason to refuse otherwise acceptable development proposals.

Local planning authorities should give significant weight to the wider environmental, community and economic benefits of proposals for renewable energy schemes to contribute towards the capacities set out in tables 9.6 and 9.7 a-c; and mitigate the causes of climate change and minimise the need to consume finite natural resources.

Policy EM 18
Decentralised Energy Supply
Plans and strategies should encourage the use of decentralised and renewable or low-carbon
energy in new development in order to contribute to the achievement of the targets.

Local Planning Policy

Cheshire and Warrington local planning documents are presently under review. The old Local Plan documents produced be each of the old Local Authorities have now been merged within the more recently formed unitary authorities of Cheshire East and West. At the same time the Local Planning Structure has been radically reformed through the Local Delivery Framework (LDF) process. The LDF process aims to replace the old plan lead system with more flexible needs based assessment of what the area requires. The LDF is in fact a series of documents based around the Core strategy. For the purposes of AD development on farms the Core strategy will then be supported by a series of Supplementary Planning Documents which might include documents relating to both rural development and renewable energy generation.
In most councils the LDF process is behind schedule. As a result the Supplementary Planning Documents are not yet in place. Where this is the case many of the old Local Plans, or parts of these plans have been retained. This creates added confusion within the new unitary systems as the retained Local Plan documents are still based on the original Local Authority boundaries. For example in Cheshire East the Congleton Rural Development planning policy has been retained as part of the

Cheshire East Supplementary Planning Documents but it only relates to the Congleton area. Neither the old Crewe and Nantwich nor Macclesfield Councils produced an equivalent.
For this reason it is still not possible to identify specific policies that relate to AD however unitary Supplementary Planning documents relating to both economic development, rural development and sustainable development will all be produced over time. For AD developments taking place prior to these documents being available applicants should utilise the old Local Plans where relevant. It is unlikely there will be any specific reference to AD so applications should be dealt with as farm diversifications and focus on the relevant policies that relate to this sector.
For Warrington Unitary Development Plan the situation is more straight forward as the original Plan is still in place. The relevant policy is provided below.

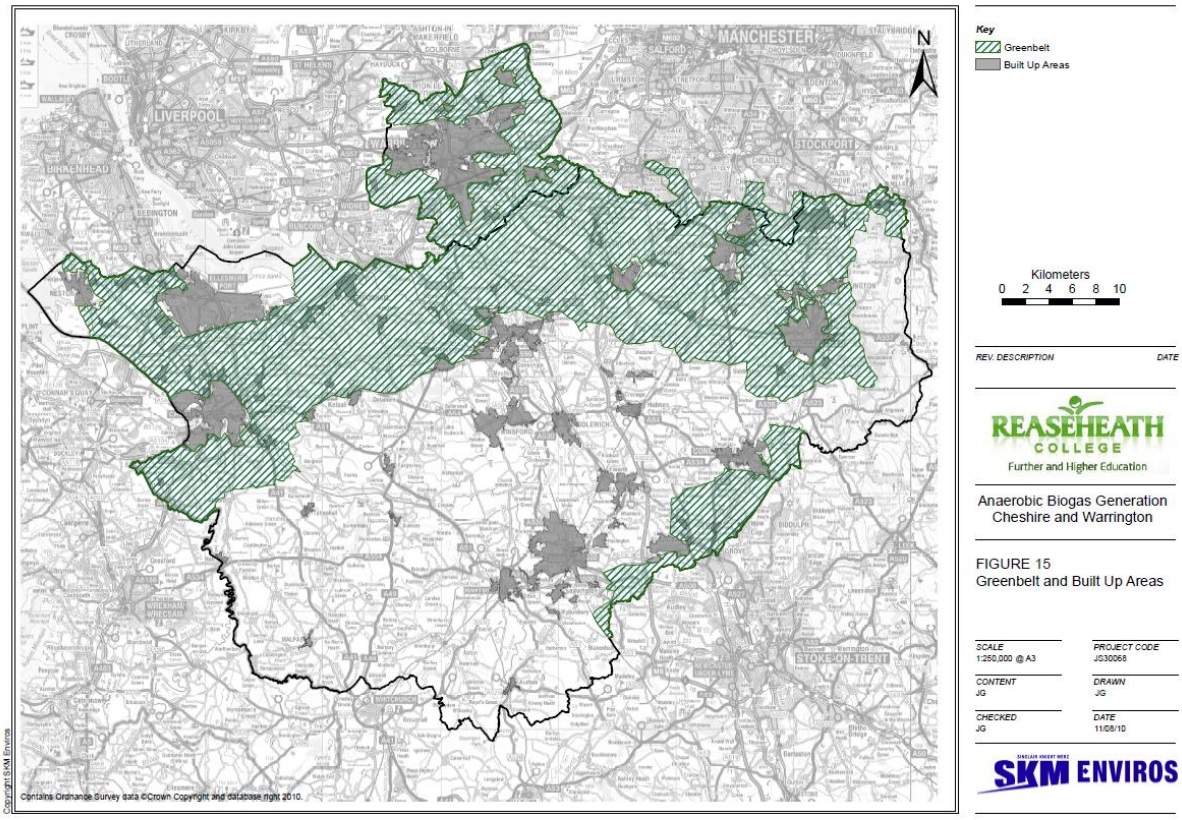
EMP10 DIVERSIFICATION OF THE RURAL ECONOMY

Proposals for the diversification of farm enterprises such as farm shops and tourism will be permitted provided that they:

1. *Help to secure the long-term viability of the agricultural holding;*
2. *Do not result in the severance or fragmentation of the farm holding;*
3. *Do not result in the loss of the best and most versatile agricultural land;*
4. *Do not conflict with policies for green belt or adversely affect the character of the surrounding countryside;*
5. *Do not have a detrimental impact by virtue of increased traffic flows on local roads;*
6. *Do not adversely affect the amenity of nearby residents or other sensitive land uses within the locality; and*
7. *Utilise existing buildings wherever possible. Where this is not feasible and new buildings are proposed, these will be subject to policies for the green belt. The scale, layout and design of any new buildings should not have a detrimental impact on the character or amenity of the surrounding area or the openness of the green belt.*

Each site will create specific challenges under the Warrington policy. Proximity to residential properties will be a major factor as will green belt. This will be the same issue across Cheshire. The map below identifies the green belt within the study area.

Figure 13 Cheshire and Warrington Green Belt



Green belt comprises 41% of the total area. Although farm diversification may be supported within green belt the majority of planning authorities will require the new activity to take place within existing buildings. If all the input material is derived from the farm the argument would be that the AD system is a 'normal' farming activity and therefore eligible. Once material starts moving between farms this will not be the case. For this reason the argument will have to be based on 'exceptional circumstances'. The requirements to prove 'exceptional circumstances' will be specific to each planning authority and will be dependent on local constraints such as proximity to sensitive sites such as private residences, schools etc.

At both the local and regional planning level there will be specific planning constraints associated with both environmental and heritage sites. Although Cheshire and Warrington has relatively few large nationally designated sites such as AONB's there are a many smaller sites that that will impact on the potential to deliver AD systems due to constraints within both the planning and permitting system as previously outlined.

The two figures below highlight the main environmental and heritage sites across the study area.

Figure 14 Environmental Constraints

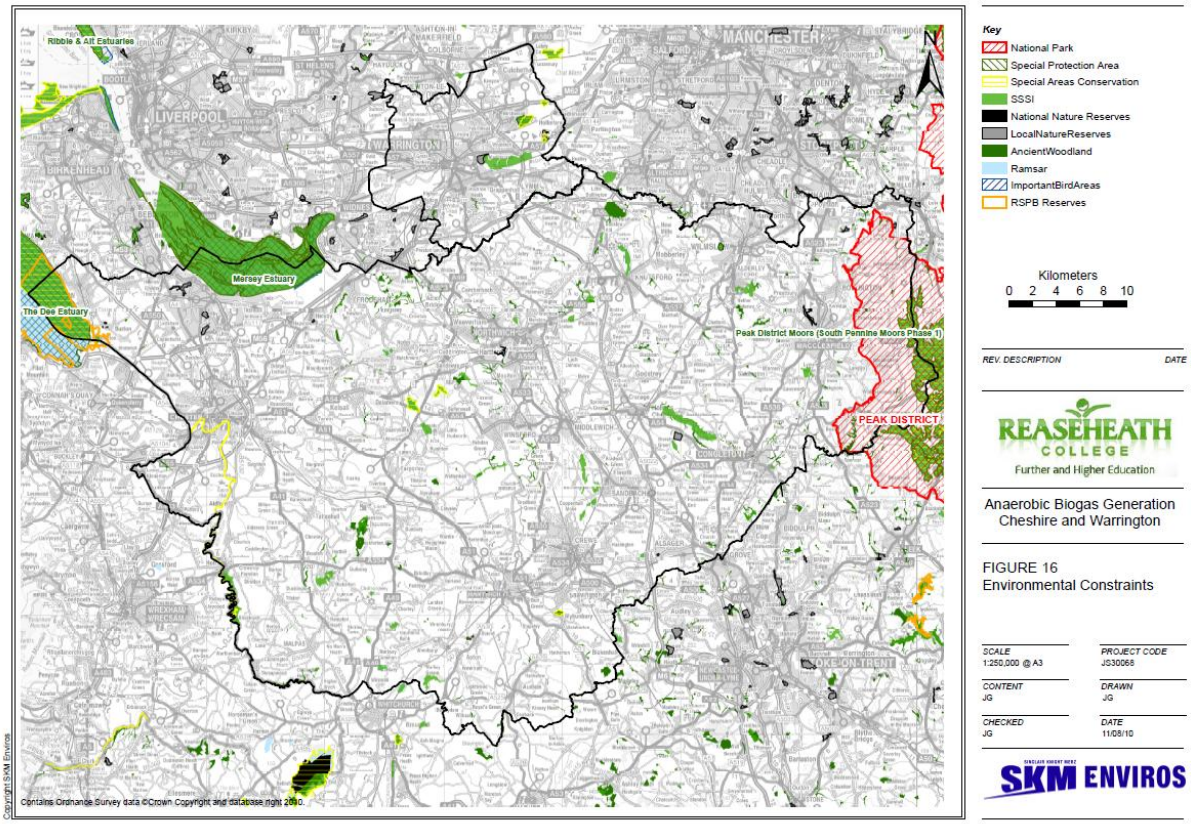
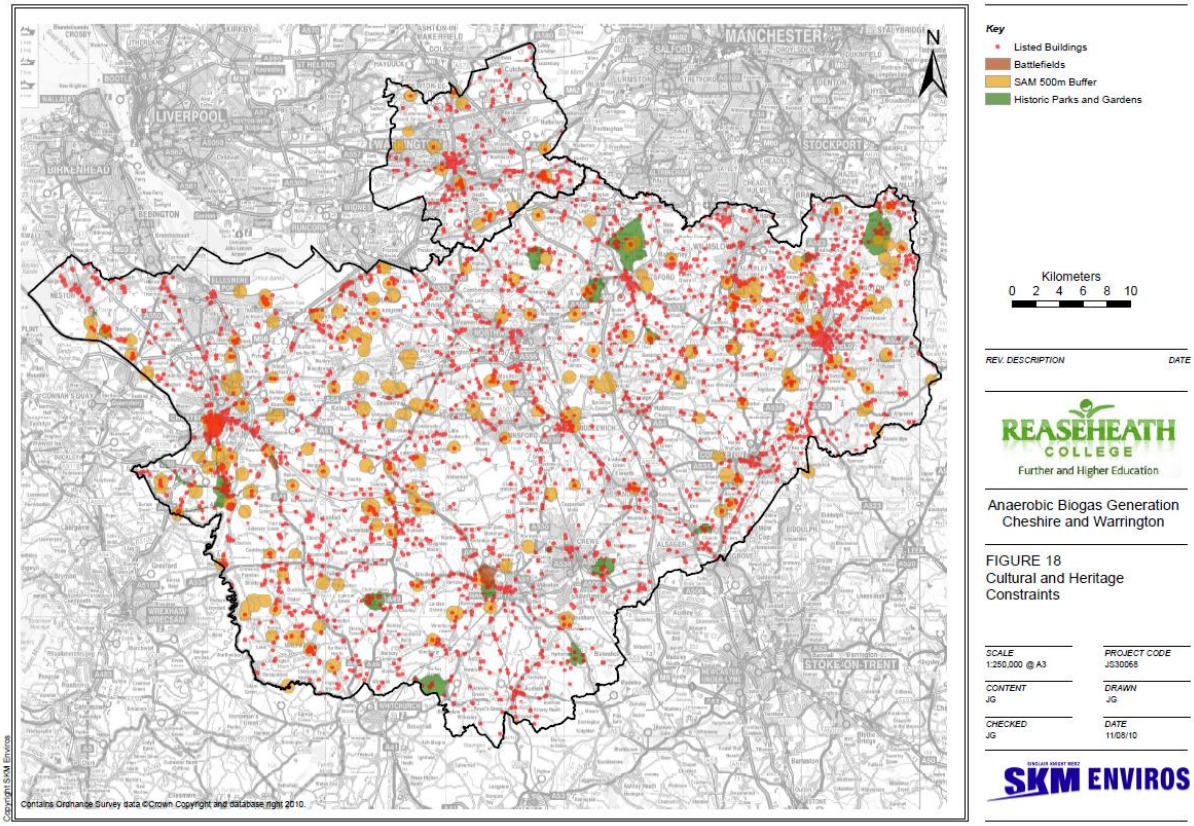


Figure 15 Heritage Constraints



The Scheduled Ancient Monument (SAM) sites identified on the Heritage Constraints map expands to an area of 500m around each site as this is the consultation zone associated with individual developments.

C2.0 Permitting

Anaerobic digestion is considered a treatment that is applied to organic substrates and for
the purpose of anaerobic digestion, substrates put into and through a digester are considered as controlled wastes by the Environment Agency (EA).

In April 2010 the EA published a Standard Permit entitled *SR2010No16 On-farm anaerobic digestion facility including use of the resultant biogas.* The permit allows '*an operator to operate an anaerobic digestion of wastes and also use of the biogas, in compression and spark ignition engines, with an aggregate rated thermal input of up to 3 megawatts. The rules also allow use of standard commercial gas turbines, fuel cells or treatment followed by injection into the gas grid'.*

The main preconditions are as follows.

The activities shall not be within:

- 500 metres of a European Site, Ramsar site or a Site of Special Scientific Interest (SSSI);
- a specified Air Quality Management Area (AQMA);
- 200 metres away from any off-site building used by the public, including dwelling houses;
- 10 metres of a watercourse;
- 50 metres of any spring or well, or of any borehole not used to supply water for domestic or food production purposes;
- 250 metres of any borehole used to supply water for domestic or food production;
- a groundwater source protection zone 1.

If a site cannot meet one or more of these conditions it will have to apply for a bespoke permit. For the standard permit an application fee of £1590 is payable with an annual fee of £510.

The main limitations for an SR2010No16 permit are as follows.

- All activities must be carried out on premises used for Agriculture.
- Treatment of waste shall include shredding, sorting, screening, compaction, baling, mixing and maceration.
- Digestion of wastes including pasteurisation and chemical addition
- Gas cleaning by biological or chemical scrubbing.
- Gas storage and drying
- Treatment of digestate including screening to remove plastic residues, centrifuge or pressing, addition of thickening agents (polymers) or drying.

- Composting and maturation of digestate
- The total quantity of waste accepted at the site shall be less than 75,000 tonnes a year.
- The use of combustible gases produced as a by-product of the anaerobic digestion process as fuel
- Except for the auxiliary flare, the aggregate rated thermal input of all appliances used to burn biogas shall be less than 3 megawatts.
- Use of an auxiliary flare required only for short periods of breakdown or maintenance of the facility.

It is acceptable to import agricultural waste from one farm to another under the standard permit. It will not allow for the import of any non-farm waste.

The burning of biogas is also a permitable activity depending on the scale to which it is
undertaken. Relevant to the identified farm typologies.
• Appliances rated between 0.4MW (400 kW) and 3MW (3,000 kW) burning biogas are not classifiable as a part A or B installation but are classed as a waste operation and requires regulation under the Environmental Permitting Regulations 2007
• Appliances below 0.4MW (400 kW) do not require permitting. Low cost systems operating at an ambient temperature are unlikely to reach this level

Exemption
Agricultural AD systems that have a net rated thermal input of less than 0.4Mw fall under exemption T24. Allowable activities include the following

- Anaerobically digest manure and plant tissue waste in a dedicated AD plant to produce a digestate.
- Burn the biogas produced by the AD process to produce energy to provide power on your farm or export to the national grid.
- Sort, screen, cut, shred, pulverise and chip the waste to aid the AD process.

The main limitations include the following:

- The waste must remain in the AD plant for a minimum of 28 days.
- You can store or treat up to 1,250 cubic metres of waste at any one time.

This storage limit does not include on-farm manure and slurry pits used to store waste prior to treatment. If you import manure and slurry from other farms and store it before it is fed into your AD plant, the storage of this waste is included within the 1,250 cubic metre limit.
When manure and slurry is mixed with plant tissue waste the 1,250 cubic metre limit will include the storage of plant tissue waste, the digester and the storage of the resulting digestate.

Under most of the farm typologies identified within the report the exemption will allow for most situations although the technology may not. Some of the systems reviewed have very short residency periods that may fall outside the exemption.

C3.0 Nitrate Vulnerable Zones

Defra has designated areas as NVZs, in accordance with the EC Nitrates Directive, in order to reduce nitrogen loss from agriculture to water. Farmers within NVZs are required to comply with measures in the Nitrates Action Programme.

The NVZ rules affect the management of nitrogen fertiliser on farms. Nitrogen fertiliser includes all materials applied to land that contain nitrogen compounds. It includes manufactured nitrogen fertiliser, and all types of organic manure, including livestock manure. The Nitrate Pollution Prevention Regulations 2008, which provide the legal basis for the NVZ designations and rules, come into force from 1 January 2009.

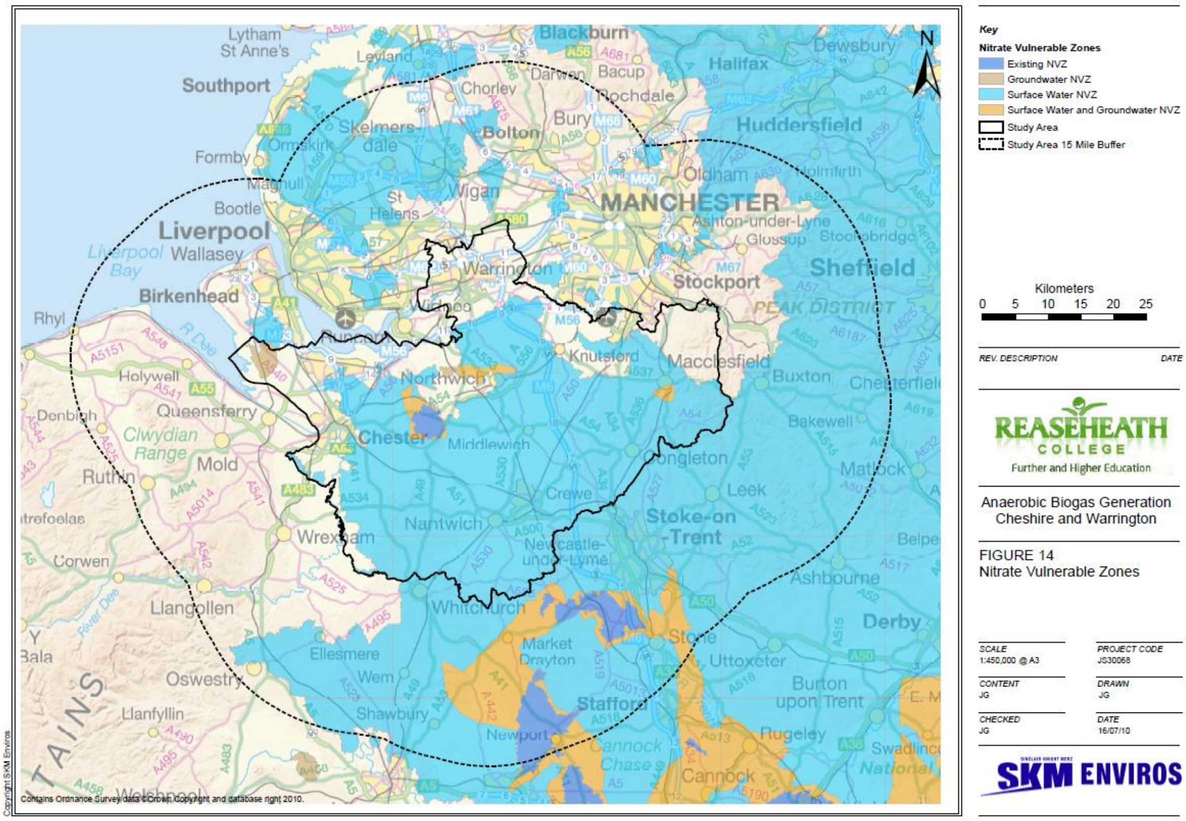
A list of NVZ requirements can be found within the DEFRA guidance note at http://www.defra.gov.uk/environment/quality/water/waterquality/diffuse/nitrate/documents/leaflet2.pdf

AD has often been suggested as a means by which disposal of farm waste can be used to overcome NVZ obligations. This is not the case for a number of reasons.

- If energy crops are added the total available nitrogen will increase significantly compared to the original slurry based nitrogen.
- A digester cannot be used as a store throughout the closed periods because it will be full at the start and full at the end of the closed period.
- Storage in the closed period is necessary for the entire digestate, not just that from livestock manures.

Within Cheshire the map below indicates the established NVZ areas.

Figure 16 Cheshire and Warrington NVZ Areas



The table below shows the percentage of NVZ designations across the study area.

Table 18 NVZ Designations

NVZ	Area Sq m	Area Sq Km	% of Study Area
Existing NVZ	17684380.73	17.68	0.77
Groundwater NVZ	17193470.53	17.19	0.75
Surface Water and Groundwater NVZ	33326869.8	33.33	1.46
Surface Water NVZ	1505470323	1505.47	65.74
Total NVZ Area		**1573.68**	**68.72**
Total Area of Study Area		**2289.93**	

As will be shown within the farm modelling, based on the farm sizes identified and the volume of digestate produced the conclusion within the report is that providing no additional material is added beyond the proposed use of maize all the farm models will be able to accommodate the digestate within the holding area. There will not be a requirement to move digestate off site or out of the NVZ areas to non NVZ areas (see Appendix E).

C4.0 Energy Supply Infrastructure

Depending on site location a major cost of setting up an AD plant will be the cost of supplying energy to the final end user. Grid connections for both electricity and gas to grid can be cost prohibitive. Costs of grid connection will be dependent on both distance and volume of supply. These can be as high as 10 to 15% of the overall capital cost of the project.

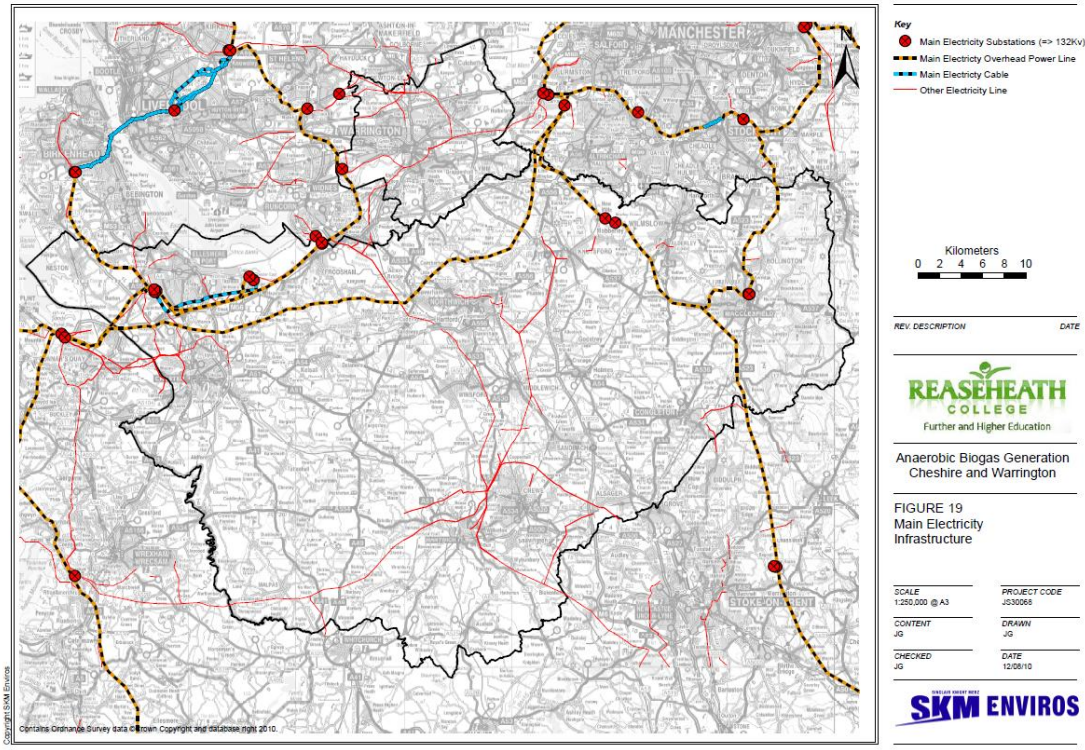
For electricity the cost of connection depends on two factors, the setup of an electrical substation and the cabling. As a guide, the substation cost for an average size plant (500kW) is circa £50,000 plus cabling. This will vary depending on the maximum amount of electricity on the peak load. Depending on wattage the cable size may also need upgrading. This also assumes that three phase is readily available.

In addition there may be other costs associated with way leaves requirements and in sensitive locations cabling may need to be underground. There may be other physical issues such as road and river crossings.

The final major hurdle will be the capacity of the local grid to accommodate the additional load. This will be site specific and will require a survey to be undertaken by the District Network Operator (DNO) to establish the potential. There is usually a cost associated with the survey. Once this is completed the DNO will provide a quotation for connection.

An overview of the main supply network across the study area is provided below. The localised low voltage network and substation locations are not publicly available and must be assessed as part of the DNO assessment

Figure 17 Main Electricity Supply Network



A full assessment of gas grid connection issues are dealt with in Appendix H.

Appendix D - AD Technology Review

D1.0 Available AD Technology

As part of the study a review of existing technology suppliers was undertaken. A Full list of available technology suppliers contacted is provided below.

ArrowBio	Biogen	Bioplex	CAMBI	Dranco	Entec
Biogas Environmental	Power Corp	Farmatic	Fre-Energy	Haase	Herhoff
Hirad (Dranco)	Komptech	Kompogas	Kruger	Monsal	OWS
Passavant	Paques	Portagester	Preseco	RosRoca	
Schmack Biogas		Schwarting	UTS Biogas	Wehrle	
Xergi					

For contact details see following web link:
http://www.anaerobic-digestion.com/html/anaerobic_digestion_worldwide.html

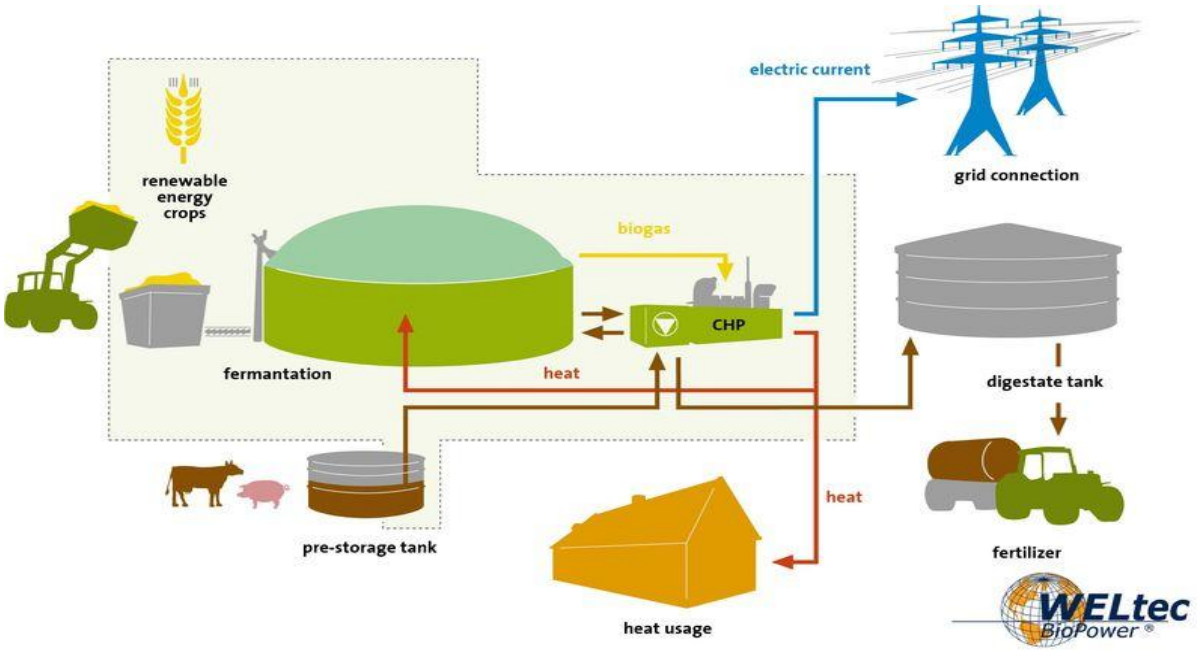
Of the twenty seven contacted only fourteen responded. Of these only four stated that their technology would be suitable for the typologies identified. The main reason for the low rate was due to scale. Of those that responded but stated that their technology was unsuitable the volume of input material was significantly below their minimum size. This is not surprising as most of the plant suppliers have developed technology that fits with the German model of AD based around German subsidy rates. In addition the plants tend to operate with large volumes of energy crop rather than slurry.

The growth in German AD has focused on plants at either 500kW or above. This level of electricity production far exceeds the levels predicted from the typologies identified in Cheshire. In the UK there are now a number of larger plants coming on stream however they tend to be located on much larger farming businesses and often incorporate commercial food waste. A typical example of the larger farm based AD plant is provided by WELtec of Germany. Although this scale of plant may not fit with the study area typology requirements a review of this scale of technology assists with the identification of the issues associated with smaller scale plants. 500kW plus plants are highly complex engineering structures that have sophisticated management systems. The issue for small scale AD technology provision is the ability to downsize and simplify the systems without impacting on the plants ability to deliver an efficient turnkey solution to the identified farm typologies. A review of a typical large scale plant helps to identify the problems.

WELtec BioPower Case Study:

WELtec BioPower plans and produces complete biogas plants made of stainless steel and distributes them world-wide: With more than 50 employees WELtec has constructed more than 200 plants all over Europe, the United States and Japan. The technology used within the plants is detailed below.

Figure 18 WELtec BioPower



Fermenter Made from Stainless Steel

The gas composition is very aggressive when forming and attacks many materials. That's why only resistant materials are implemented in the biogas area of WELtec systems. The material of choice for tank construction and internal components is stainless steel.

The Roof

The air-tight impermeable cover is UV-resistant and is pre-stressed to approx. 3 bar with a supporting blower fan. An inner diaphragm buffers the variable volume for the formation of gas such that an additional gas tank is not normally necessary.

The Thermal Efficiency

The biogas process depends on a constant temperature control. This is achieved by a stable thermal efficiency with an amply dimensioned tubular heating system in the bottom third of the fermenter and external insulation with moulded polystyrene

boards. The heating output usually facilitates the thermophilic process at approx. 55°C.

Mixing technology

A refined agitator technology is decisive for a reliable and efficient mixing of the fermenting substrates and forms the basis for an even yield of gas. Depending on the individual fermenter size a combination of long arm and submersible agitators are used.

Long arm agitator

The task of a long arm agitator is to mix the substrate evenly and carefully. At approx. 40 rpm it creates a flow in the vessel and ensures that the gas creating bacteria will have continuous and optimal conditions. The electric excitation is done by a frequency inverter, which, depending on the fed substrate can be adjusted. The motor and bearing support is located outside the fermenter and is guided at an angle into the vessel.

Submersible agitators

In addition to the long arm agitators Weltec also use submersible agitators. These agitators ensure a fast and targeted mixing of substrates and are used to maintain a minimum crust formation in the digester.

One pump for the whole system

WELtec BioPower use a progressive cavity pump.
This solution provides several advantages:

- Only one pump for the whole system
- Self-priming
- Also suitable for viscous substrates with a higher dry matter
- The pump is combined with a dry-run protection, under- and over-pressure protector and a flow meter
- Flexible application for further areas like pasteurisation, supply of drying plants, etc.

Of the suppliers of larger scale plants the typical input is in excess of 30,000 tonnes per annum with capital costs of around £2mill depending on the level of imported waste and front end separation technology. This far exceeds the largest of the identified study area typologies. It does however show the complexity of the equipment associated with even basic farm scale AD. The question is can the farms identified within the study area be provided with turnkey technology solutions at the low input feedstock levels provided within the modelling?

D2.0 Sub 10,000 tonne Technology Case Studies

The available technology for sub 10,000 tonnes of input material per annum is limited. Based on respondents to the technology assessment four technology suppliers have been assessed in relation to the identified typologies. All four are relatively new entrants to the market but this does show that there is recognition within the industry that this end of the market is as yet underdeveloped. In addition a fifth option, known as Low Cost Low Technology Solutions is provided.

i) Bioplex Technologies

Bioplex, based in Bristol have developed a portable digester known as the Portagester. The Portagester effectively acts as the first stage digester.

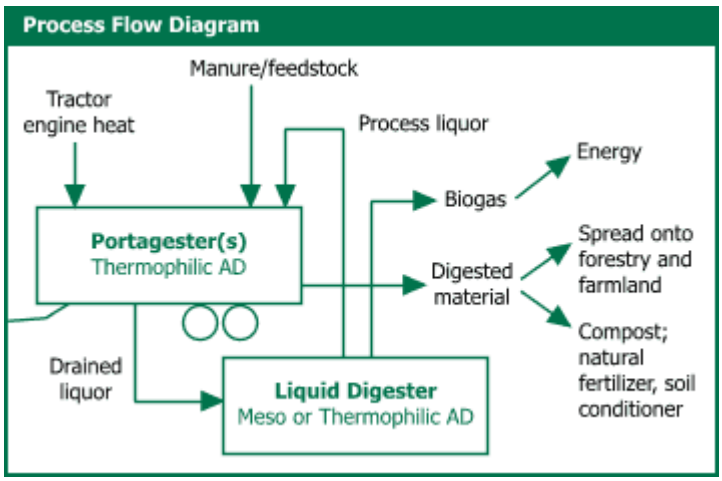
The Portagester is a mobile and modular anaerobic fermenter, which can hygienically treat waste material in less than four days.

It uses the process of mesophillic or thermophilic fermentation to pasteurize feedstock and naturally separate it into solid and liquid fractions.

The Portagester can collect the feedstock from one location, travel to a central location where the contents, still in the Portagester are treated and then transport the treated material to the end user. This reduces materials handling and the risk of spillages.

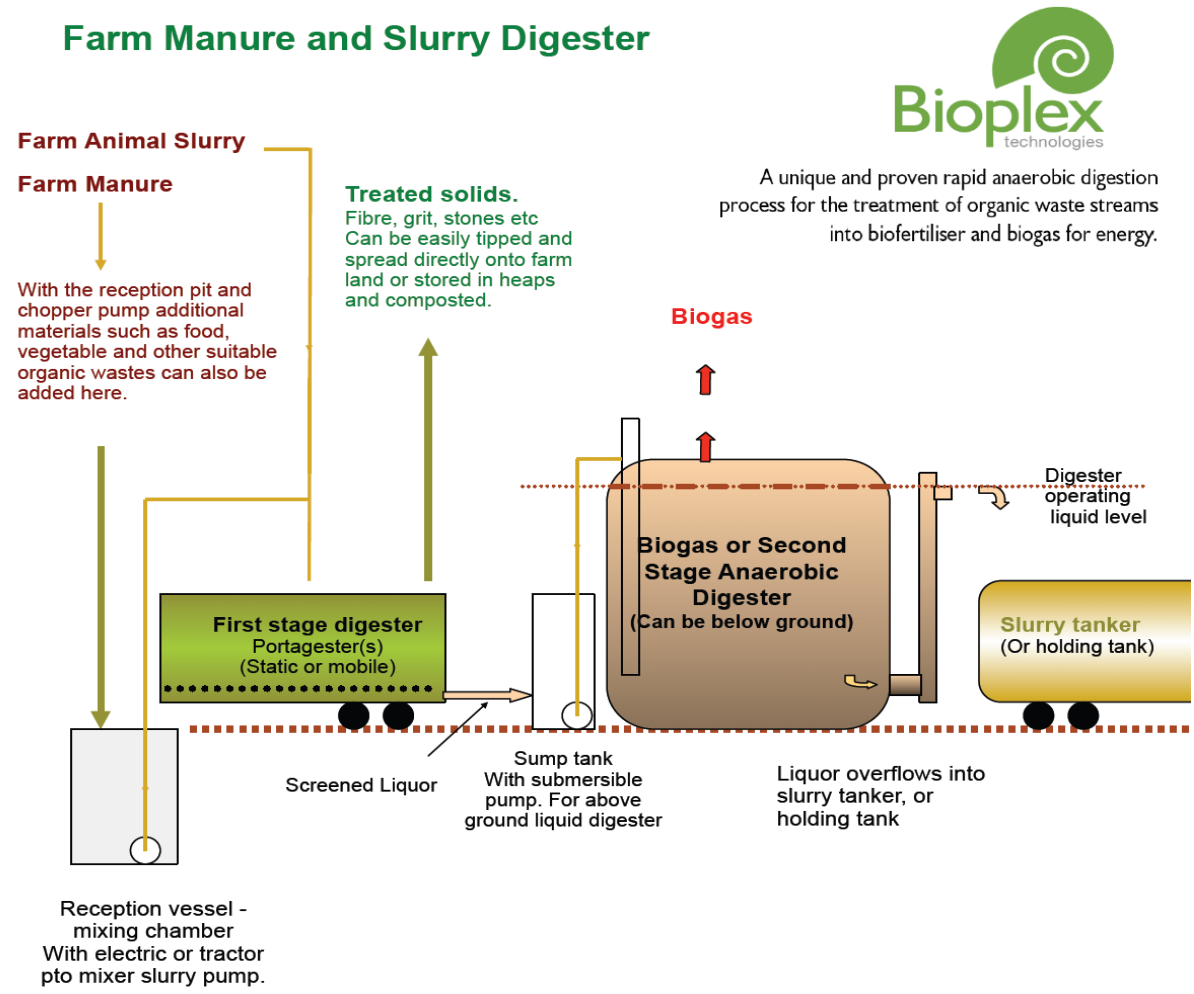
At the end of the process period, the liquid is screened, drained out and used within a fixed second stage AD tank. The biogas may then be used in a boiler or an engine to generate electricity and heat - and which in a fully operational unit, can be used to help keep the Portagester at the correct temperature.

Figure 19 **Bioplex Technologies**



A single Portagester can utilise up to 2,500 tonnes of material per annum. A further development of the process is the use of multiple Portagesters operating in parallel. This approach makes the system modular, so that it can be used in a range of sizes and expanded if the waste processing demand at one site is increased.

Figure 20 Bioplex Schematic



The following CAPEX estimates were provided by Bioplex. These exclude costs for CHP or gas cleaning equipment. The costs also assume a suitable digestate storage facility.

Scenario 1: 2,000 - 2,500 tonne per annum - 60 tonnes per week

1 Portagesters - first stage digester. Stainless steel within. Separator and dewaterer.
1 Control room, within a 20ft steel container. Dual fuel CHP generator and biogas boiler
• Anaerobic Digester control system with process heater and liquor heat exchanger.
• Pumps for heating and liquor transfer etc.
• Digester process monitoring and instrumentation.
• Biogas holder and level sensor
• All electrical and piping within.
• Data logging c/w direct link.
Second stage (biogas) liquid CSTR Digester . Biogas storage.
Piping to connect plant

Total £370,000

Scenario 2: 5,000 tonne per annum - 100 tonnes per week

2 Portagesters - first stage digesters. Stainless steel within. Separator and dewatered.
1 Control room, 1 Plant room. Dual fuel CHP generator and biogas boiler
• Anaerobic Digester control system with process heater and liquor heat exchanger.
• Data logging c/w direct link.
• Pumps for heating and liquor transfer etc.
• Digester process monitoring and instrumentation.
• Biogas holder and level sensor
• All electrical and piping within.
Second stage (biogas) liquid CSTR Digester. Biogas storage.
Piping to connect plant

Total £500,000

Scenario 3: 7,500 tonne per annum - 150 tonnes per week

3 Portagesters - first stage digesters. Stainless steel within. Separator and dewatered.

1 Control room, 1 plant room. Dual fuel CHP generator and biogas boiler

- Anaerobic Digester control system with process heater and liquor heat exchanger.
- Data logging c/w direct link.
- Pumps for heating and liquor transfer etc.
- Digester process monitoring and instrumentation.
- Biogas holder and level sensor
- All electrical and piping within.

- Second stage (biogas) liquid CSTR Digester. Biogas storage.
- Piping to connect plant

Total £700,000

The stated Bioplex Process advantages include the following:

- **The digester can be modular and transportable.**

There is no economy of scale. A 2,000 tonnes per annum system may cost the same as a 25,000 or 40,000 tpa system per tonne installed.

- **Grit removal: Separation of heavy fragments and grit**

Most material treated by a digester contains grits, sand, gravel and other heavy particles, which has caused many expensive digester failures.

With the Bioplex process, due to the retention time of 2 days, in the first hydrolysis tank, the heavy particles separate and precipitate from the fibre and sink to the bottom of the vessel. The low speed agitator guarantees that most of these residues will remain at the bottom and will not be pumped to the final stage digester except for fine silt.

The fine silt layer in the final stage digester will be very thin and may be constantly removed with the outflow of digestate. If this fine silt does cause a problem, occasional cleaning may be required. The doors in the wall make it very simple to remove the residue when necessary. No interruption of the digestion process is required.

- **Patented High Rate Process.**

In the first two process steps of the biogas production – hydrolysis and acidification – low pH values prevail. This has the biological acids which dissolve the molecular structures of celluloses and other fibres found in grass and similar high fibre materials.
These fragments can then be transformed by bacteria in the later process to produce biogas.

- **Advanced Process Control.**

Unlike the traditional one-stage biogas plants whose performance is variable, the two-stage Bioplex Process can control the biogas production within a 30 minute period. This unique feature can optimize energy production whilst preventing biogas waste.

- **Solid materials as input material for the biogas plant**

Farm Yard Manure (FYM) was one of the first input materials to be used in the Bioplex. Solid manure is rarely used in conventional digesters as it causes problems regarding mixing, grit/sand/stones accumulation and solid layers.
With the two-stage biogas plant a high solid manure share of up to 50% can be processed completely trouble-free.
The higher front end temperatures ensure pathogen, parasite, weed seed and odour control.

The use of high solids materials can lead to no excess liquid to deal with - a major advantage.

- **Low parasitic load (10% electrical 40% heat)**

As the unit is mobile the siting of the unit is critical in determining the final parasitic load.

ii) Hirad

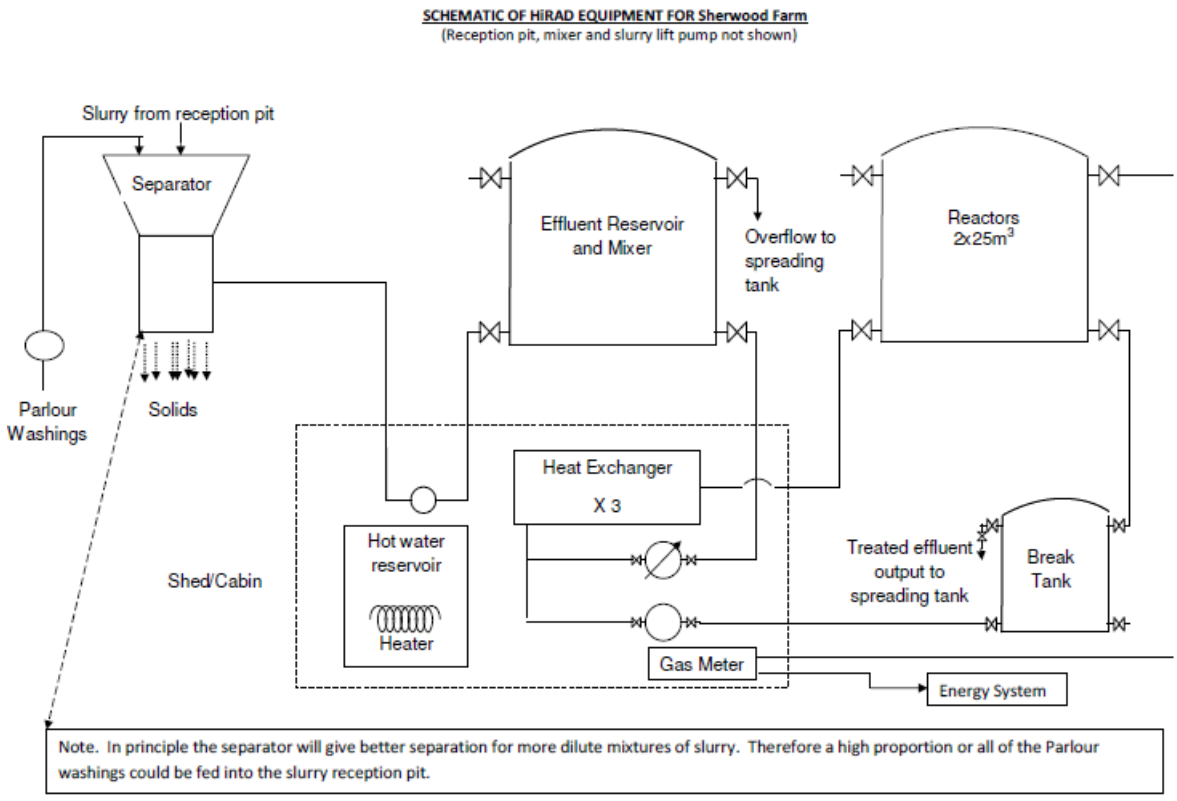
Hirad, based in Lancashire, is a new entrant into the market with its first trial plants due to be operational in the autumn of 2010**.** Unlike conventional systems Hirad look to extract the volatile solids from the input material prior to digestion. For this reason slurry, which has a low DM content is ideal. The target market is for single input, low DM content material. Although the system can cope with the addition of energy crops within the mix additional front end processing would be required. For this reason the main area of development will be slurry only systems based around herds in excess of 250 head.

The system known as the Hirad Energy Farm is a slurry processing system developed from traditional Anaerobic Digestion Technology simplified and improved by HIRAD using rapid rate anaerobic digestion.

The system is quick, converting a day's slurry production within a day. It is typically installed adjacent to the farm's existing storage facilities giving minimal disruption. Unlike old style AD systems, it does not necessarily require an energy crop or external waste stream.

The process just removes the volatile compounds. The nitrates that the farmer wants are left in the liquid producing a fertiliser that is much safer to store and spread.

Figure 21 Hirad Schematic



The most important difference between the Hirad Energy Farm and all other slurry AD systems, is the price. The Hirad system is designed to just process the farm waste. The smallest system will process the slurry from only 125 head of dairy cattle. With a separator included with each system it will also help reduce the farms storage requirements by up to 20%.

Capital costs based on cow numbers have been provided below. Maintenance costs would be on annual basis. These figures are based on a simple burner/boiler model.

150 head – 5kW system £60,000

300 head – 12kW system £80,000

900 head – 35kW system £100,000

Hirad's business model also offers a leasing option. For a one off payment Hirad will install a system suitable to the size of the farm and then set up a power export agreement and give the farmer a share of the electricity produced by the system. As part of the agreement Hirad will also undertake the majority of the maintenance costs. No lease costs are available at this time.

iii) Muckbuster

Based in Ringwood, SEaB market the Muckbuster range of products. A recent entrant into the market there is only one unit presently operational within the UK. MuckBuster is a self-contained anaerobic digester, set up to process smaller quantities of animal manure or septic waste. They offer two sizes to suit most private and small commercial installations. The MuckBuster converts various forms of organic waste into biogas. The biogas can be used to heat water or create electricity. In addition, the MuckBuster unit provides a source of organic fertiliser and the dry mulch that can be re-used as animal bedding.

Figure 22 Muckbuster containerised AD plant

MuckBuster Organic is designed for horse stables and farmyard waste. Material is added by way of a hopper fitted with a macerator flowing into a small mixing tank. This feeds into the processing tank. The output of this tank, gas and fertilizer, is moved into the storage tank, while the water is recovered into the mixing tank. Biogas and fertilizer are collected. Muckbuster conserves water by recycling water in the anaerobic digester unit. The spent digestate is processed through a dewatering unit to remove the lignin mulch and condense the digestate while recycling the water to mix into the incoming waste stream. The system outputs are thickened/condensed digestate and damp warm mulch.

The system operates on a batch process over four weeks so up front storage of input material will be required.

Units are modular so additional capacity can be added if required. Capital cost excluding CHP is as follows.

- 400 litre unit MB400 £22,000
- 800 litre unit MB800 £44,000
- 1200 litre unit MB1200 £66,000
- 1600 litre unit MB1600 £88,000
- 2000 litre unit MB2000 £110,000

Based on the identified typologies two MB2000 would have sufficient capacity to meet the needs of the smaller 150 head dairy units. The units need 6 monthly servicing and come with a 5 year guarantee.

MuckBuster provide the following calculations for the MuckBuster 400.

Cost	£22,000
CHP	£3000
Total	£25,000
Max Biogas per day (80% capacity)	25.08m^3
Electricity per day (35% efficiency)	138kWh
Annual electricity	14296kWh
FIT @ 9p/kW	£1,858
Electricity @ 14p/kW	£1,286
Total	£3,145
Payback	7.9years

The quoted electricity production levels are lower than those predicted by the NNFCC calculator for the identified input material.

iv) Fre-Energy

The Fre-Energy system has been developed by a new start business, Farm Renewable Environmental Energy Ltd. Based at Holt near Wrexham. The system has been specifically designed for farm use combining slurry with available energy crops.

The system unlike the previous examples is a more traditional AD design but constructed at a reduced scale.

Figure 23 Fre-Energy Trial Plant

The first trial unit is now operational at Lodge Farm, Holt.

v) Low Cost Low Technology Solutions

In addition to the four technology providers listed there is also the potential for other Low Cost Low Technology Solutions to be applied at the farm level. Research undertaken by Aardvark for Cornwall Development Company identified three options.

Option 1 - Covered Anaerobic Lagoons

Description Costs

An impermeable UV resistant liner is placed over the top of the lagoon to capture and trap the biogas resulting from the natural breakdown of the slurry in the lagoon. The liner is held down on the surface of the lagoon by weighted uPVC pipes filled with water.

Gas is collected and pumped to a boiler or engine for energy generation. No additional heat or control measures used, occasional stirring. Lagoons need to be deep, 4m ideally with steep sides. The technology has been used in farm applications in the US, NZ, Asia and Europe.

Comments

- Liner attachments are either dug in to lagoon bank with a key trench to prevent gas escaping, or floating boom type curtain to the base of the lagoon.
- Low gas yield as works on ambient temperatures.
- These lagoons will need stirring.
- Has benefit to prevent excessive rainfall on to lagoon area, benefitting NVZ requirements, simple water pump can be installed to pump away clean surface water from the surface of the liner.
- Potentially difficult to remove, floating system may be easier to move.

- Lagoons systems need to be large scale > 1000m3 to make AD effective using this method, long retention times ~ 200 days

Costs
Liner costs installed ~£15 to 20 per square meter
Potential limited life 10 yrs depending on location.
Estimated costs for a 4 kW system range £25,000 to £50,000

Option 2 - Flexible Reactor Anaerobic Lagoon Tanks

Description
Similar principle to the covered lagoon, except gas capture is via a series of smaller flexible tanks created within the lagoon using neoprene type material. Each tank has a separate gas capture system and allows limited heat to be circulated through the tank with a heat exchanger from the CHP engine to improve gas yield.
Each tank has a ridged floating top frame which hangs the insulating curtain sides to the base of the lagoon. Gas is collected and pumped to a boiler or engine for energy generation.

Comments
- Avoids costs of large constructed tank and extensive civil work – tank within a tank principle.
- Flexible tanks are a novel concept but as yet not proven technology.
- To build, flexible tanks are technically feasible and potentially low cost.
- Offers the potential to utilise the excessive low grade heat from a CHP unit to improve gas yield.
- Anchoring and lagoon maintenance would need to be addressed, e.g. stirring could damage tanks.
- Low gas yield as works on ambient temperatures but could utilise waste heat to improve gas yields.
- Has benefit to prevent excessive rainfall onto lagoon area, benefiting NVZ requirements, simple water pump can be installed to pump away clean surface water from the surface of the flexible tank.
- With heat, shorter retention times ~ 100 days, but at ambient temperatures similar to a Covered Lagoon above.

Costs
Tank costs for 45m3 installed ~£1400
Potential limited life 10 yrs depending on location.
Estimated costs for a 4 kW system range £20,000 to £60,000

Option 3 - Fast Rate Liquid Anaerobic Reactors
Description
Slurry is separated and pressed via standing belt press systems to produce a high strength liquid – Chemical Oxygen Demand of up to 10,000mg/l COD.
This is then digested in a series of small up flow liquid reactors on a rapid basis – 7 to 14 days. This is a mesophillic system and requires heat recovered from the CHP unit.
Gas is collected and pumped to a boiler or engine for energy generation.

Additional cost of civil work and for reactor tanks, ex farm or redundant farm equipment could be used to create reactors.
The technology has been used in farm applications in the US, NZ, Asia and Europe.

Comments

- More engineered and stable solution, overcomes the problems of maintaining gas production in low temperatures and allows the slurry liquid to be stored and used as a fuel.
- Offers the potential to utilise the excessive low grade heat from a CHP unit to improve gas yield.
- Tank costs vary, but standard tanks are available for up 60m3 free standing

Potential limited life 10 yrs depending on location.

Costs

Estimated costs for a 4 kW system range £45,000 to £75,000 depending on location.

The identified low cost solutions all provide theoretical solutions to the issues faced by individual livestock farmers. The issue in the UK is that that there appears to be very few suppliers of systems. Manufactures of liners etc advertise systems suitable for biogas collection but there is a lack of 'turnkey' solutions available within the market place. If such solutions were available they would be available at considerably lower cost than the more high tech sub 10,000 tonne options available. That said the output from lagoon systems is also less. Based on the typologies identified the smallest electrical output from a 150 head slurry only system will be 75,013kWh pa. The lagoon systems produce less than half of this.

Appendix E - Farm Typology and Financial Modelling

E1.0 Farm typologies in Cheshire and Warrington.

- An initial scoping exercise was carried out to establish the most frequent farm types in Cheshire and Warrington to enable the study to focus on relevant scenarios. This exercise was carried out using the Agricultural Census Data and supported by data recorded in the Farm Business Survey.
- The Agricultural Census Data indicated that there were only a small number of commercial pig and poultry units within the Cheshire and Warrington area. The units that were identified were of an insufficient scale and number to consider for the development of AD.
- The 2009 Agricultural Census illustrated that there are only a small number of commercial dairy farms in Warrington and that the sample farms were too small to use for this study. Therefore the sample farms used in the report are based on data for holdings in Cheshire alone.
- The Cheshire census data indicated that there were 884 holdings with dairy cattle. For the purpose of this study, holdings with 100 cows or less where discounted as it was acknowledged that they would be too small to allow for the development of an on-farm anaerobic digester.
- The most frequent herd sizes for dairy farms in Cheshire indicated 150 cows and 300 cows. The data was analysed to establish that there were 239 holdings with an average of 150 cows and 140 holdings with 300 or more cows. From this analysis it was established that the study should focus on these two herd sizes as "Typical Cheshire Dairy Farms".
- Census data from 2007 provided a breakdown of holdings in each herd size group. This data was used to establish the proportion of farms in each group. The 2009 data was not broken down into herd size groups so the model for 2007 was used to project the number of farms in each size group for 2009 also taking into account national changes in herd sizes.

Table 19 Illustrating average dairy herd sizes in Cheshire using census data.

		<10	10 <100	100 <200	200 & over	total
Cheshire 2007	**Number**	693	18516	36741	42066	**98015**
	Holdings	257	323	263	141	**984**
	Average	3	57	140	299	100
Projection to 2009 on NW assumptions	**Number**	587	16411	33927	43640	94565
	Holdings	229	276	**239**	**140**	884
	Average	3	60	**142**	**312**	107

Analysis of Farm Business Survey (FBS) data was also used to confirm these farm typologies. The data was analysed to identify the typical physical and financial parameters of these two farm types.

Table 20 Physical data for typical dairy farms in Cheshire

	150 cow herd	300 cow herd
Land holding		
Owner occupied area (ha)	35.45	43.82
Full Agricultural Tenancy (ha)	4.99	39.59
Farm Business Tenancy (ha)	51.76	68.53
Other		10.12
Average utilised agricultural area (ha)	**92.20**	**162.06**
Cropping		
Permanent grass	65.11	95.16
Temporary grass	9.30	39.75
Forage and whole crops	15.27	24.69
Other	2.52	2.46
Total crop area	**92.20**	**162.06**
Staffing		
Average full time staff	1.57	3.25
Regular part time staff	0.43	1.50
Dairy enterprise		
Average dairy cows	155.20	317.00
Average milk yield per cow (litres/year)	7,055.40	7,325.90
Average in calf heifers	17.10	19.40
Average females 1-2 years	21.00	21.75

Table 21 Financial parameters for typical dairy farms in Cheshire

	150 cow herd	300 cow herd
Variable costs		
Livestock costs		
Concentrates	77448	189468
Bulk feed/coarse fodder	6723	14426
Vet & medicines	11244	25887
Other LS costs	21926	66487
Total livestock variable costs	**117341**	**296268**
Crop costs		
Seeds	1616	4177
Fertiliser	14149	30797
Crop protection	1817	5157
Other crop costs	1249	2712
Total crop variable costs	**18831**	**42843**
Other costs		
Wages - paid	20915	78021
Contract work	19349	22829
Machinery repairs	8288	20013
Machinery fuel	5439	12061
Building repairs	3656	9767
Electricity	3697	11512
Heating fuel	32	176
Water	4375	10096
Insurance	3605	5861
Professional fees	2396	5477
Bank charges	667	1103
Other general costs	3405	4695
Fixed costs excl rent, depreciation and interest	**75824**	**181611**
Finance		
Average loan capital	63969	201674
Debt as % of total assets	8.84%	15.07%

E2.0 Capital costs for AD technology for typical Cheshire Farms

A number of AD equipment suppliers were contacted and asked to provide an estimation of the capital cost to develop an AD system for a number of scenarios. The base line was for a system to digest the slurry from 150 dairy cows. The amount of waste to be processed was based on industry averages for dairy cows and using data provided by DEFRA for the NVZ waste management calculations. Assumptions were made that dairy cows from herds with 150 head would be indoors for 100% of the time for six months in the winter and indoors for 30% of the time for the summer months. The amounts of waste were calculated for 150 cows, 150 cows + 30% crop input, 50% crop input and an equal amount of crop and slurry input.

The waste output data was then calculated for a proposed Central Anaerobic Digester (CAD) taking waste from three farms with 150 cows based on just slurry and then slurry + 30% maize silage. This scenario included contractor costs to pump slurry from the farms to the CAD and to pump digestate back to the farms.

The final data set was based on holdings with 300 cows making the assumption that the cows are housed all the time for six months and then for 50% of the time for the rest of the year. The scenarios were for a 300 cow holding using slurry only and then using slurry with 1251t of maize silage. Following the technology review an assessment of capital costs for a range of project sizes was carried out. Whilst the review identified a wide range of costs for different systems the cost for typical equipment was identified and used in the financial analysis.

E3.0 Assumptions made in financial analysis

The financial analysis was carried out using the AD calculator on the NNFCC website as agreed in the study contract. The data supplied by equipment providers indicated a wide range of expected gas yields from the feedstock's identified, with the standard data in the NNFCC calculator falling within this range. It was decided to carry out the financial analysis using the expected biogas outputs entered as defaults in the calculator.

The amount of energy required to operate the AD plant varied dramatically from one supplier to another. Again in this situation the NNFCC calculator figure was in the middle of this range and therefore used as an acceptable parameter.

FBS data was used to establish the amount of electricity used on dairy farms in Cheshire. This equated to 400 kWh per cow place on the sample of Cheshire dairy farms. Within the calculator no account has been taken of farm house usage within the sum for 'displaced farm electric'. The rate per kWh of electricity used on farm was set at 7.5 pence which is comparable to the market rate for a business tariff.
On detailed examination of FBS data for dairy farms in Cheshire less than one third of the holdings grow forage maize. It has been assumed that maize silage to be used as a feedstock would be purchased off farm so as not to take up land already being used to produce animal feed. A number of agricultural commodities suppliers were contacted and it was established that maize silage is usually readily available for £25 per tonne.

The analysis of the digestate within the NNFCC calculator has been used to calculate the added value of spreading digestate as opposed to slurry due to its enhanced nutrient value. Current fertiliser prices were entered into the calculator to arrive at a cost benefit of using digestate to reduce the quantity of inorganic fertiliser required for growing crops. It has been acknowledged that the majority of the study area is within a designated Nitrate Vulnerable Zone (NVZ). With this in mind an analysis of the average farm sizes using both Census Data and FBS Data has been carried out to establish the availability of land on which to spread the digestate. Farms with an average of 155 cows were identified as managing an average of 92 hectares. Holdings with an average of 317 cows managed an average farm size of 162 hectares.

Operating costs include maize silage purchased for feedstock, labour, plant maintenance, insurance, transport and slurry pumping, laboratory testing fees and EA fees, an allowance for miscellaneous costs and finance costs. The NNFCC calculator assesses maintenance costs as a percentage of capital costs so that when estimates were being made for the break even capital cost of a plant the calculation showed a dramatic reduction in maintenance costs. The operating costs for the CAD system includes the costs of employing a contractor to pump slurry from farms to the CAD and then to pump digestate back to farms.

Where the system produces biogas rather than generating electricity the costings assume that the untreated biogas is sold to a third party for scrubbing and injecting to the grid. It will be necessary for large amounts of biogas to be processed through a central point due to the capital cost of scrubbing equipment.

E4.0 Data analysis

The data has been analysed into a number of tables describing the potential feedstock's for the AD plants and then providing details of the expected outputs both in physical terms and expected economic returns. The potential energy production for the different farm types has been analysed for a range of feedstock's. The findings have been presented in tables for each of the three farm types; 150 cow dairy unit, a Central AD unit for three farms of 150 cows and an on farm unit for a 300 cow dairy herd.

Wherever possible the analysis has explored the potential for generating electricity to be supplied to local users, for electricity to be exported to the National Grid and for biogas to be produced which would be pumped to a third party for clean up and injection into the grid.

For each system the project returns have been calculated based on the current capital costs for development. Further analysis has been carried out to establish the capital cost at which the project reaches break even and to establish at what capital cost the project would generate a 5% return on investment. This return on investment is prior to any interest charges as it is not possible to accurately predict the level of finance required in a particular scenario.

E4.1 Physical inputs and digestate data

Table 22 Farm types, feedstock and digestate data.

Farm type	Feedstock	slurry t/pa	maize silage t/pa	Digestate Analysis total Kg/M^3 in digestate			Digestate volume (t)	Min land required for spreading in NVZ (ha)	Fertiliser value of digestate (£)
				N	P_2O_5	K_2O			
150 cow unit	Slurry	1,854	0	6.19	0.31	2.06	1800	44.5	2936
150 cow unit	Slurry + 30% maize silage	1,854	556	6.32	0.32	2.11	2290	57.9	5125
150 cow unit	Slurry + 50% maize silage	1,854	927	6.45	0.32	2.37	2590	66.8	6502
150cow unit	Slurry + equal quantity of maize silage	1,854	1,854	6.45	0.32	2.37	3450	89	10200
CAD 3x 150 cows (slurry pumped to central location)	slurry	5,562	0	6.19	0.31	2.06	5400	133.6	7695
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	5,562	1,668	6.32	0.32	2.32	6870	173.6	14949
300 cow unit	slurry	4,171	0	6.19	0.31	2.27	4050	100.2	6583
300 cow unit	Slurry + 1251t maize silage	4,171	1,251	6.32	0.32	2.32	5150	130.1	11203

This table illustrates the range of AD inputs which have been used to produce data for the identified farm typologies. The quantity of digestate produced from differing levels of feedstock is demonstrated along with the expected analysis when feedstock's are adjusted.

The fertiliser value of the digestate has been derived from the NNFCC calculator along with the minimum land required for spreading at these levels of nutrient composition within the NVZ areas. This is based on the maximum amount of nitrogen which can be applied from organic manures.

The nutrient composition is of a higher value than unprocessed slurry so that it would be possible to reduce the amount of inorganic fertiliser usage on the holding. The value of the digestate in financial terms can be seen in the last column and is arrived at by assessing the increased nutrient value which offsets the cost of inorganic fertiliser. The value of these nutrients is linked to current fertiliser prices.

Key Findings

Once the slurry has passed through the AD process there is a notable increase in the nutrients available for growing crops when compared to untreated slurry. This increase in nutrient availability will reduce the need for artificial fertilisers which is a cost saving to the farm business. Based on the FBS data the farm typologies illustrated in this study will have sufficient land available to spread digestate whilst still remaining within the NVZ regulations.

Table 23 Energy production potential for a typical 150 cow farm

Farm type	Feedstock	Energy output	electricity produced kWh e	parasitic demand kWh e	electrical output kWh e	revenue from electricity incl FiTs (£)	heat produced from CHP kWh t	parasitic heat demand kWh t	heat sold elsewhere kWh t	revenue from heat (£)	Income from energy produced (£)	Fertiliser value (£)	Total income from AD and energy operations (£)
150 cow unit	Slurry	Local electricity use	75,013	11,124	63,889	12,042	94,141	31,067	56,485	565	12,607	2936	15,543
150 cow unit	Slurry + 30% maize silage	Local electricity use	302,973	14,460	288,513	51,390	380,231	125,476	228,139	2,281	53,671	5125	58,796
150 cow unit	Slurry + 30% maize silage	Electricity to grid	302,973	14,460	288,513	44,534	380,231	125,476	228,139	2,281	46,815	5125	51,941
150 cow unit	Slurry + 50% maize silage	Local electricity use	455,083	16,686	438,397	77,619	571,129	188,473	342,677	3,427	81,046	6502	87,548
150 cow unit	Slurry + 50% maize silage	Electricity to grid	455,083	16,686	438,397	66,268	571,129	188,473	342,677	3,427	69,695	6502	76,196
150cow unit	Slurry + equal quantity of maize silage	Electricity to grid	835,153	22,248	812,905	120,571	1,048,117	345,879	628,870	6,289	126,860	10200	137,060

Table 23 indicates the projected electrical and thermal output from AD using slurry and maize silage. The different scenarios demonstrate the potential outputs using just cow slurry or slurry with varying amounts of maize silage as a feedstock.
In each case electricity is supplied to the farming enterprise and then costings illustrate the outcome from selling to a local user or selling on the wholesale market via the National Grid. It is clearly beneficial to sell directly to a local user at a higher price than to sell electricity at wholesale rates. All revenue for electricity includes the Feed in Tariffs as provided by the government.

Key findings
When electricity is generated using a CHP engine more heat is generated than electricity. To achieve the maximum output the business needs to identify an end user for the heat. This could be the farmhouse, other neighbouring residential properties or an industrial property. The proposed Renewable Heat Incentive will also increase revenue when introduced.
Electricity sold directly to an end user will command a higher retail price than electricity sold to the grid which is valued at a wholesale price.
Using slurry alone as a feedstock produces relatively low levels of biogas and thus lower levels of electricity are generated. In order to develop a viable enterprise it will be necessary to include other feedstock's – maize silage has been used as the example feedstock in this report.

Table 24 Energy production potential for a Central AD system producing raw biogas.

Farm type	Feedstock	Energy output	biogas produced m3	parasitic demand (13.8% output) m3	biogas output m3	revenue from biogas (25ppm^3) (£)	Income from energy produced (£)	Fertiliser value (£)	Total income from AD and energy operations (£)
CAD 3x 150 cows (slurry pumped to central location)	slurry	Biogas Production	112,519	15,528	96,991	24,248	24,248	7695	35823
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Biogas production	454,459	62,715	391,744	97,936	97,936	14949	128563

Table 24 illustrates the scenario where untreated biogas is produced which would then be pumped to a central processing unit where it could be cleaned and injected into the National Gas Grid. For this scenario to be viable there would need to be a number of production sites which would all produce biogas to be pumped to a central scrubbing unit. The biogas needs to be cleaned and odorised before it can be injected into the grid.

Key findings

The production of biogas which would need to be processed off site before injection into the grid currently offers lower returns than the generation of electricity due to the value of the upgraded gas and lack of external incentives.

Table 25 Energy production potential for a Central AD system producing electricity for local use or for the National Grid.

Farm type	Feedstock	Energy output	electricity produced kWh e	parasitic demand kWh e	electrical output kWh e	revenue from electricity incl FiTs (£)	heat produced from CHP kWh t	parasitic heat demand kWh t	heat sold elsewhere kWh t	revenue from heat (£)	Income from energy produced (£)	Fertiliser value (£)	Total income from AD and energy operations (£)
CAD 3x 150 cows (slurry pumped to central location)	slurry	Local electricity use	225,039	33,372	191,667	36,417	282,423	93,200	169,454	1,695	38,112	7695	45,806
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Local electricity use	908,919	43,380	685,539	164,452	1,140,693	376,429	684,416	6,844	171,296	14949	186,245
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid	908,919	43,380	685,539	133,603	1,140,693	376,429	684,416	6,844	140,447	14949	155,396

In this scenario the biogas is used to power a CHP with the electricity generated being utilised by local users or being sold to the National Grid. At this level of output the local network would need to have a continuous demand for power in the form of a business user as domestic requirements fluctuate dramatically and this cannot be mirrored by output from the CHP.

Key findings

The direct supply of electricity to local users shows a 16% higher income for the business. However the end user needs to have a level requirement for electricity as the CHP will have a continuous output. If this is not possible a grid connection will be essential.

Table 26 Energy production potential for a 300 cow unit producing raw biogas.

Farm type	Feedstock	Energy output	biogas produced m3	parasitic demand (13.8% output) m3	biogas output m3	revenue from biogas (25ppm^3) (£)	Income from energy produced (£)	Fertiliser value (£)	Total income from AD and energy operations (£)
300 cow unit	Slurry + 1251t maize silage	Biogas Production	340,834	47,035	293,799	73,450	73,450	11,203	96,410

To enable this type of holding to develop a viable project producing biogas it is necessary to include maize silage at a rate of 30% of cow slurry. As in Table 26 above the raw biogas would need to be pumped to a central scrubbing plant for processing before it can be injected into the gas grid.

Key findings

It is essential to add a supplementary feedstock to cattle slurry to achieve viable yields of biogas.

Table 27 Energy production potential for a 300 cow unit producing electricity for local use or for the National Grid.

Farm type	Feedstock	Energy output	electricity produced kWh e	parasitic demand kWh e	electrical output kWh e	revenue from electricity incl FiTs (£)	heat produced from CHP kWh t	parasitic heat demand kWh t	heat sold elsewhere kWh t	revenue from heat (£)	Income from energy produced (£)	Fertiliser value (£)	Total income from AD and energy operations (£)
300 cow unit	slurry	Local electricity use	168,759	25,026	143,733	27,309	211,792	69,891	127,075	1,271	28,580	6583	35,163
300 cow unit	Slurry + 1251t maize silage	Electricity to grid	681,669	32,532	649,137	99,525	855,494	282,313	513,297	5,133	104,658	11203	115,861

For an AD system operating on a feedstock of cattle slurry the electricity could be used on farm and by other local users. The addition of maize silage will enhance the electricity production but this level of output is likely to mean that a grid connection is essential to cope with the power produced.

Key findings

If the electricity is to be used locally from an AD plant of this scale it will be necessary to have a large business user if the electricity is not to be sold to the National Grid.

Table 28 Operating costs for potential AD plants on typical Cheshire dairy farms

Farm type	Feedstock	Labour (hrs/day)	Labour (£/yr)				Insurance	Transport & Pumping	Testing fees	EA fees	Misc costs	Rent & rates	Finance	Total operating costs
				Depreciation	Maintenance									
					AD Plant	CHP								
150 cow unit	Slurry	1	5475	12750	4900	750	200		800	1500	250		4500	31125
150 cow unit	Slurry + 30% maize silage	2	10950	21250	8300	3030	300		1200	1500	400		7560	54490
150 cow unit	Slurry + 50% maize silage	3	16425	22000	8400	5006	500	500	1200	1500	1000		10643	67174
150cow unit	Slurry + equal quantity of maize silage	4	21900	30500	11400	9187	500	1000	1200	1500	1500		10620	89307
CAD 3x 150 cows (slurry pumped to central location)	slurry	3	16425	28250	10700	2475	500	9000	1200	1500	1500	2000	9900	83450
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	4	21900	32250	11700	9998	500	10000	1200	1500	1500	2000	11070	103618
300 cow unit	slurry	2	10950	28250	10700	1650	500		1200	1500	500		9900	65150
300 cow unit	Slurry + 1251t maize silage	2	10950	30750	11700	7498	500	500	1200	1500	1000		10800	76398

The labour hours identified for the different systems has been established using the experience of operational sites using similar feedstock's. Maintenance of the AD plant is costed at 2% of the capital cost and maintenance of the CHP is costed at 1p per kWh generated.
Insurance costs have been estimated based on experience of typical farm based costs for slurry management systems and equipment.
Transport and pumping costs cover the cost of transporting maize where applicable and for pumping slurry and digestate between holdings where necessary. Testing fees and EA fees are appropriate to the scale of the project and miscellaneous costs cover administration costs.

Rent & rates have been included for the CAD projects as it is anticipated that this would operate as a separate business and therefore will attract ground rent charges and rates as a none agricultural business.
Finance costs are as produced using the NNFCC calculator assuming 90% of the capital cost was funded via a bank loan with interest at 3.5% above bank base rate.

Key findings
None of the Ad plants examined in the project will require a huge labour input with only the more complex CAD system requiring 4 hours per day. It is anticipated that the hours required could be accommodated by existing farm staff. The majority of the labour cost is associated with the addition of the maize feedstock but this is more than covered by the increased biogas production.
The operational cost of transporting slurry and crops to a CAD is also worthy of note.

Table 29 Capital costs and profit and loss projections for AD systems for a 150 cow unit.

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 5% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
150 cow unit	Slurry	Local electricity use	£250,000			£31,125	£15,543	-£15,582	-4.40%
150 cow unit	Slurry	Local electricity use		£72,750		£15,527	£15,543	£16	1.80%
150 cow unit	Slurry	Local electricity use			£53,500	£13,833	£15,543	£1,709	5.00%
150 cow unit	Slurry + 30% maize silage	Local electricity use	£420,000			£68,390	£58,796	-£9,594	-0.50%
150 cow unit	Slurry + 30% maize silage	Local electricity use		£310,750		£58,776	£58,796	£20	1.80%
150 cow unit	Slurry + 30% maize silage	Local electricity use			£227,500	£51,450	£58,796	£7,346	5.00%
150 cow unit	Slurry + 30% maize silage	Electricity to grid	£450,000			£71,030	£51,941	-£19,089	-2.40%
150 cow unit	Slurry + 30% maize silage	Electricity to grid		£232,750		£51,912	£51,941	£29	1.80%
150 cow unit	Slurry + 30% maize silage	Electricity to grid			£171,500	£46,522	£51,941	£5,419	5.00%
150 cow unit	Slurry + 50% maize silage	Local electricity use	£430,000			£87,446	£87,548	£102	1.80%
150 cow unit	Slurry + 50% maize silage	Local electricity use			£215,000	£77,326	£87,548	£10,222	5.00%
150 cow unit	Slurry + 50% maize silage	Electricity to grid	£460,000			£90,086	£76,196	-£13,890	-1.20%
150 cow unit	Slurry + 50% maize silage	Electricity to grid		£300,000		£76,006	£76,196	£190	1.90%
150 cow unit	Slurry + 50% maize silage	Electricity to grid			£221,000	£69,054	£76,196	£7,142	5.00%
150 cow unit	Slurry + equal quantity of maize silage	Electricity to grid	£590,000			£135,657	£137,060	£1,403	2.00%
150 cow unit	Slurry + equal quantity of maize silage	Electricity to grid			£445,000	£122,897	£137,060	£14,163	5.00%

Capital costs were established for the various scenarios and the NNFCC calculator was used to establish the profit or loss for the system. The calculator was then used to establish at what capital cost the various systems would break even. The calculator reduced the maintenance costs in

proportion to the initial capital cost which is shown in the lower operating costs for these systems. The breakeven capital cost was established to the nearest £250 in order to produce a positive cash flow.

A further analysis was carried out to establish the capital cost at which the AD system would generate a 5% return on investment. It is important to note that the return on investment shown is before the cost of any finance as the level of borrowing will vary for every holding from a nominal loan to full financing of the project.
The revenue costs includes a value for the displaced farm electricity, for electricity and heat sold and for the fertiliser value associated with spreading the digestate to land as opposed to untreated slurry.

Key findings
It is necessary to add at least 50% maize compared to the volume of slurry to enable projects to breakeven at current capital costs.
To achieve a 5% return on investment for most schemes it will be necessary for the capital costs to be reduced by around 50% on current prices.

Table 30 Capital costs and profit and loss projections for Central AD systems for three farms with 150 cows

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 5% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Biogas Production	£535,000			£79,445	£35,823	-£43,622	-6.40%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Biogas Production		£39,250		£35,819	£35,823	£4	1.80%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Biogas Production			£28,750	£34,895	£35,823	£928	5%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Local electricity use	£550,000			£83,450	£45,806	-£37,644	-5.00%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Local electricity use		£124,500		£45,796	£45,806	£10	1.80%
CAD 3x 150 cows (slurry pumped to central location)	Slurry	Local electricity use			£91,500	£42,892	£45,806	£2,914	5.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Biogas Production	£535,000			£127,380	£128,563	£1,183	2.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Biogas Production			£402,500	£115,720	£128,563	£12,843	5.00%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Local electricity use	£565,000			£140,918	£186,245	£45,327	9.80%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid	£615,000			£145,318	£155,396	£10,078	3.40%
CAD 3x 150 cows (slurry pumped to central location)	slurry + 30% maize silage	Electricity to grid			£535,000	£138,278	£155,396	£17,118	5.00%

In this case the breakeven capital costs have been established for Central AD systems using the same process as for the 150 cow units. In this case it can be seen that up to 30% maize silage has to be added to the slurry to achieve breakeven on current capital costs.

Key findings

A CAD system with three farms working together provides a more viable economic case than individual units being constructed.

Table 31 Capital cost and profit and loss projections for AD systems for a 300 cow unit

Farm type	Feedstock	Energy output	Current capital cost	Breakeven Capital cost	Capital cost to generate 5% return on investment	Operating costs incl feedstock	Revenue	Profit/ loss	Return on investment
300 cow unit	Slurry	Local electricity use	£550,000			£65,356	£35,162	-£30,194	-3.70%
300 cow unit	Slurry	Local electricity use		£207,000		£35,147	£35,162	£15	1.80%
300 cow unit	Slurry	Local electricity use			£152,500	£30,351	£35,162	£4,811	5.00%
300 cow unit	Slurry + 1251t maize silage	Electricity to grid	£600,000			£107,673	£115,860	£8,187	3.20%
300 cow unit	Slurry + 1251t maize silage	Electricity to grid			£510,000	£68,478	£115,860	£47,382	5.00%
300 cow unit	Slurry + 1251t maize silage	Biogas Production	£585,000			£113,401	£96,410	-£16,991	-1.10%
300 cow unit	Slurry + 1251t maize silage	Biogas Production		£391,500		£96,373	£96,410	£37	1.80%
300 cow unit	Slurry + 1251t maize silage	Biogas Production			£288,000	£87,265	£96,410	£9,145	5.00%

For systems on a 300 cow unit the capital costs are shown above for a system using only slurry with a local electricity use and then for a system using slurry and maize silage producing electricity for the grid and for a plant producing biogas for further processing.

Key findings

A larger scale farm digester on a 300 cow unit as opposed to a 150 cow unit becomes economically viable with the addition of 30% maize silage compared to slurry.

With the addition of 30% maize silage it is possible to develop an AD plant which provides a return on investment of 3.2% on current capital costs.

Conclusion

At current capital costs and with the present support system in the form of FiTs, on farm AD is not economically viable without adding substantial quantities of an energy crop such as maize silage.

The current market value of biogas does not make its production a viable proposition at current capital development costs. The biogas would need to be scrubbed at a central location before injection into the grid. The gas scrubbing technology is gradually reducing in price and government incentives will help to drive an increase in the price of biogas.

Upcoming developments in AD equipment will substantially reduce the capital costs for smaller on farm developments. This new technology is currently being trialled and indications are that substantial cost savings can be made.

Appendix F - Existing Gas Upgrading Plants and Technology Suppliers.

Table 32 Established Examples of Gas Upgrading Plants

Place	Substrate	Utilisation	CH4 require-ments (%)	Technology	Plant Capacity (Nm3/h raw gas)	In Operation Since
Austria						
Bruck/Leitha	Biowaste	Gas grid	97	Membrane	180	2007
Margarethen am Moos	Energy Crops & Manure	Gas fuelling	>95	Membrane	70	2007
Pucking	Manure	Gas grid	97	PSA	10	2005
Reitbach / Eugendorf		Gas grid & gas fuelling	97	PSA	150	2008
Canada						
Berthierville, (QC)	Landfill gas	Gas grid		Membrane		2003
France						
Lille	Biowaste	Vehicle fuel	97	Water scrubber	2600	2007
Germany						
Bootrop				PSA	120	2008
Burgrieden (bei Laupheim)		Grid injection		PSA	600	2008

Darmstadt - Wixhausen		Grid injection		Water washing	300	2008
Godenstedt		Grid injection		Chemical absorption	600	2008
Graben		Grid injection		PSA	1000	2008
Jameln	Manure, energy crops	Vehicle fuel	96	Selexol scrubbing	140	2006
Ketzin		Grid injection		PSA	400	2008
Könnern		Gas grid		Water scrubber	1250	2007
Mühlacker		Gas grid		PSA	1000	2007
Pliening	Energy crops	Gas grid		PSA	920	2006
Ronnenburg (bei Hannover)		Gas grid		Organic washing	650	2008
Schwandorf		Gas grid		PSA	2000	2008
Schwandorf II		Flared		Chemical absorption	200	2007
Straelen	Energy crops, manure	Gas grid		PSA	1000	2006

Iceland

Reykjavik	Landfill gas	Vehicle fuel		Water scrubber	700	2005

Japan

Kobe	Sewage sludge	Vehicle fuel	97	Water scrubber	100	2004
Kobe	Sewage sludge	Vehicle fuel	97	Water scrubber	2300	2007
The Netherlands						
Beverwijk		Gas grid	88	Membrane		2006
Collendoorn	Landfill gas	Gas grid	88	Membrane	375	1993
Nuenen	Landfill gas	Gas grid	88	PSA	1500	1990
Tilburg-De Spinder	Landfill gas	Gas grid	88	Water scrubber	2100	1987
Wijster	Landfill gas	Gas grid	88	PSA	1150	1989
Spain						
Madrid		Vehicle fuel	96.5	Water scrubber	4000	2007
Vacarisses (Barcelona)	Landfill gas	Vehicle fuel	>85	Chemical absorption	100	2005
Sweden						
Bjuv	Biowaste, manure	Gas grid	97	PSA	500	2007
Boden	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	200 (360)	2007
Borås	Biowaste, sewage sludge	Vehicle fuel	97	Chemical absorption	300	2002
Bromma	Sewage sludge	Vehicle fuel	97	PSA	300	1996
Bromma	Sewage sludge	Vehicle fuel	97	PSA	300	2000

Eskiltuna	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	330	2003
Eslöv	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	80	1999
Falkenberg	Sewage sludge, biowaste, energy crops	Gas grid	97	Chemical absorption	800	2008
Falköping	Sewage sludge	Vehicle fuel	97	Water scrubber	200	2008
Göteborg	Sewage sludge, biowaste	Gas grid	97	Chemical absorption	1600	2007
Helsingborg	Biowaste, manure	Vehicle fuel and gas grid	97	PSA	350	2002
Helsingborg	Biowaste, manure	Vehicle fuel and gas grid	97	Water scrubber	650	2007
Helsingborg	Sewage sludge	Gas grid	97	Water scrubber	250	2008
Henriksdal	Sewage sludge	Vehicle fuel	97	Water scrubber	600	2003
Henriksdal	Sewage sludge	Vehicle fuel	97	Water scrubber	800	2006
Jönköping	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	150	2000
Kalmar	Sewage sludge, manure	Vehicle fuel	97	Chemical absorption	200	2008
Kristianstad	Biowaste, manure, sewage sludge	Vehicle fuel	97	Water scrubber	300	1999
Kristianstad	Biowaste, manure, sewage sludge	Vehicle fuel	97	Water scrubber	600	2007
Laholm	Biowaste, manure	Gas grid	97	Water scrubber	500	2007

Linköping	Sewage sludge, biowaste	Vehicle fuel		PSA	200	1992
Linköping	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	660	1997
Linköping	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	1400	2002
Malmö	Sewage sludge	Gas grid	97	PSA	500	2008
Norrköping	Sewage sludge	Vehicle fuel	97	Water scrubber	275	2004
Norrköping	Distiller's waste, Energy crops	Vehicle fuel	97	Water scrubber	240	2006
Skellefteå	Sewage sludge	Vehicle fuel	97	Water scrubber	250	2007
Skövde	Sewage sludge, slaughter waste	Vehicle fuel	97	PSA	100	2003
Trollhättan	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	400	2002
Trollhättan	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	140	1996
Ulricehamn	Sewage sludge	Vehicle fuel	97	PSA	20	2003
Uppsala	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	500	2002
Västerås	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	650	2004
Örebro	Sewage sludge	Vehicle fuel	97	Water scrubber	300	2007
Östersund	Sewage sludge	Vehicle fuel	97	Water scrubber	250	2007

Switzerland

Bachenbülach	Biowaste	Gas grid and vehicle gas	96	PSA	200	1996
Berne	Sewage sludge	Gas grid		PSA		2007
Bischofszell	Sewage sludge	Gas grid		Genosorb		2007
Jona	Biowaste	Gas grid	96	Genosorb	55	2005
Lucerne	Sewage sludge	Gas grid	96	PSA	75	2004
Obermeilen	Sewage sludge	Gas grid		Chemical absorption		2008
Otelfingen	Biowaste	Vehicle gas	96	PSA	50	1998
Pratteln	Biowaste	Gas grid	96	Genosorb	300	2006
Romanshorn	Sewage sludge	Gas grid		Genosorb		2007
Rümlang	Biowaste	Vehicle fuel	96	PSA	30	1995
Samstagern	Biowaste	Gas grid	96	PSA	50	1998
Widnau	Agricultural co-digestion	Gas grid		PSA		2007

USA

Cincinatti (OH)	Landfill gas	Gasgrid	PSA	10000	1986
Dallas (TX)	Landfill gas	Gas grid	PSA	10000	2000
Dayton (OH)	Landfill gas	Gas grid	Krysol (methanol)	6000	2003
Houston (TX)	Landfill gas	Gas grid	Selexol	9400	1986
Los Angeles (CA)	Landfill gas	Vehicle gas	Membrane	2600	1993
Pittsburg - Monroeville (PA)	Landfill gas	Gas grid	Membrane	5600	2004

Pittsburg - Valley (PA)	Landfill gas	Gas grid		Membrane	5600	2004
Renton (WA)	Sewage sludge	Gas grid	98	Water scrubber	4000	1984+1998
Shasnee (KS)	Landfill gas	Gas grid		Physical absorption	5500	2001
Staten Island (NY)	Landfill gas	Gas grid		Selexol	13000	1981
Stephenville, Texas	Manure, biowaste	Gas grid				

United Kingdom

Albury	Landfill gas	Vehicle gas		PSA/Membrane	2008

Suppliers of Gas Treatment Process Equipment

The following suppliers of gas treatment equipment are believed to be active in the UK market:

1. Water Scrubbing

Chesterfield Biogas

Chesterfield Biogas is a UK company based in Sheffield that works in partnership with Greenline-Flotech, an international company that originated in New Zealand supplying to the compressed natural gas industry that now operates in a number of countries selling gas treatment equipment specifically for biogas upgrading to bio-methane.

Malmberg Group

Malmberg is an independent Swedish environmental technology company that offers water scrubbing gas treatment processes for biogas upgrading to biomethane. The utilisation of biogas either directly or as bio-methane is widely practiced in Europe and Malmberg have supplied a number of gas treatment units covering a wide range of sizes.

Dirkse Milieutechniek, DMT

DMT is a Netherlands based company specialising in the manufacturing of odour control and biogas upgrading technology. Their main product is a gas desulphurisation process, Sulfurex. They also offer a biogas gas upgrading process based on water scrubbing. Their UK representative is a company called Heat and Power Services Ltd, based in Hull.

Clarke Energy – Haase

CHP supplier - Clark Energy are UK agent for German company Haase's water wash scrubbing technology.

2 Pressure Swing Adsorption

CarboTech Engineering GmbH
Carbotech are based in Essen, Germany and offer pressure swing adsorption units utilising carbon molecular sieve adsorbents for biogas upgrade as well units for H2S removal, enrichment and odorant injection. They have extensive experience of working on biogas clean-up projects for EON.

Xebec (formerly Questair)
Xebec is a Vancouver based developer and manufacturer of PSA gas purification systems for production of hydrogen (for oil refining and industrial usage) and biogas upgrade to bio-methane.

Cirmac
Cirmac offer a vacuum Pressure Swing adsorption with CO2 removal by Carbon Molecular Sieves (CMS). Working pressure approx. 5 barg

3 Chemical Wash

Carbotech
Carbo-tech also offer a chemical wash product

Lackeby Water (Purac)
www.lackebywater.se
Water treatment services and contracting company that produces gas upgrading equipment in Sweden. Upgrading system called Lp Cooab

Cirmac
LP-Cooab (Low pressure CO2 absorption). CO2 removal by chemical absorption in an absorption liquid (Cooab). The CO2 can be removed again from the Cooab at higher temperatures. Working pressure: atmospheric

MT-ENERGIE
The company holds the licence rights for the production and operation of plants using the BCM® process of non-pressurized amine washing by DGE GmbH, Wittenberg, and functions as licensee.

3 Membranes

Cirmac
CO2 removal by permeation through high/mid pressure membranes working pressure 5-10 barg

4 Cryogenic

Gas Treatment Services
GTS are based in the Netherlands and offer gas treatment packages for biogas cleanup (drying, sulphur and silicones removal) for CHP use as well as upgrading packages to produce bio-methane. The upgrade process is cryogenic and consists of a

combination of low temperature and filtration to remove contaminants followed by cooling to around -78oC to remove carbon dioxide as a liquid. The first commercial plant has been completed in Q1 2009 in the Netherlands.

Appendix G - Gas to Grid Modelling, Technology and Regulatory Assessment

G1.0 Farm Models and Delivery Options for injection of gas to grid

The main purpose of this section of the report is to ascertain at what level of biogas production would the processing and injection of gas to grid become economically viable. Eleven model versions have been considered to establish at what level of gas output a gas injection system would become viable. A summary of the model parameters and results are provided below.

Model 1
150 cow unit, no maize silage. Net gas energy output 19kw, electrical energy requirement 1.0kw.

- Not viable

Model 2
150 cow unit, with 30% maize silage. Net gas energy output 80kw, electrical energy requirement 4.0kw.

- Not viable

Model 3
300 cow unit, no maize silage. Net gas energy output 45kw, electrical energy requirement 2.0kw.

- Not viable

Model 4
300 cow unit, 30% maize silage. Net gas energy output 180kw, electrical energy requirement 9.0kw.

- Not viable

Model 5
Combined 3 off 150 cow units. Net gas energy output 60kw, electrical energy requirement 3.0kw.

- Not viable

Model 6
Combined 3 off 150 cow units, 30% maize silage. Net gas energy output 240kw, electrical energy requirement 13.0kw.

- Not viable

Model 7
1000 cow input. Net gas energy output 132kw, electrical energy requirement 7.0kw.

- Not viable

Model 8
1000 cow input, 30% maize silage. Net gas energy output 535kw, electrical energy requirement 28.0kw.

- Not viable

Model 9
2000 cow input, 30% maize silage. Net gas energy output 1069kw, electrical energy requirement 56.0kw.

- Not viable

Model 10
3000 cow input, 30% maize silage. Net gas energy output 1604kw, electrical energy requirement 84.0kw.

- Not viable

Model 11
4000 cow input, 30% maize silage. Net gas energy output 2139kw, electrical energy requirement 112.0kw.

- Viable

Assumption within the analysis and commodity values used are provided below.

Assumptions

- CHP efficiency <100kwe 32%. 100 to 500kwe 36%. >500kwe 38%
- CHP heat output capacity 1.4X kwe output (i.e. 100kwe generates 140kwh)
- NO CHP currently available <30kw 3phase, 43A per phase.
- Heat required for AD 13.8% of energy produced
- Electrical demand for AD 4.5% of energy output
- G83 grid connection 16A per phase may be variable to 6kw per phase. See Western Power Distribution document.
- G59 grid connection > 6kw/phase
- Minimum economic size for a biogas to grid plant is approx 250m3/hr
- Minimum economic AD plant needs to have an output of 100m3/hr. Commented on by two AD manufacturers.
- Farm machinery - Farm owned and not contracted in.

Table 33 Gas to Grid Financial Assumptions.

Electricity export	p/kwh	4.5
Electricity ROC	p/kwh	4.5
Electricity LEC	p/kwh	0.43
Electricity prime cost	p/kwh	16
Electricity off peak cost	p/kwh	7
Electricity average cost	p/kwh	13.75
CHP Oand M value	£/Mh	10
Biomethane sales	p/Therm	45
Biomethane RHI	p/Therm	117.2
Natural gas cost	p/therm	45
Compressed biomethane fuel duty	£/kg	0.2360
Compressed biomethane fuel value	£/kg	0.5606
Compressed biomethane RTFO certificate	£/kg	0.1500
Value of white diesel fuel (exc VAT)	£/L	0.9500
Diesel hydrocarbon duty	£/L	0.5719
Value of red diesel fuel (exc VAT)	£/L	0.5500
Red diesel hydrocarbon duty	£/L	0.1055
Propane cost	p/kg	19.79

Scheme layouts showing combinations of systems

Scheme Options

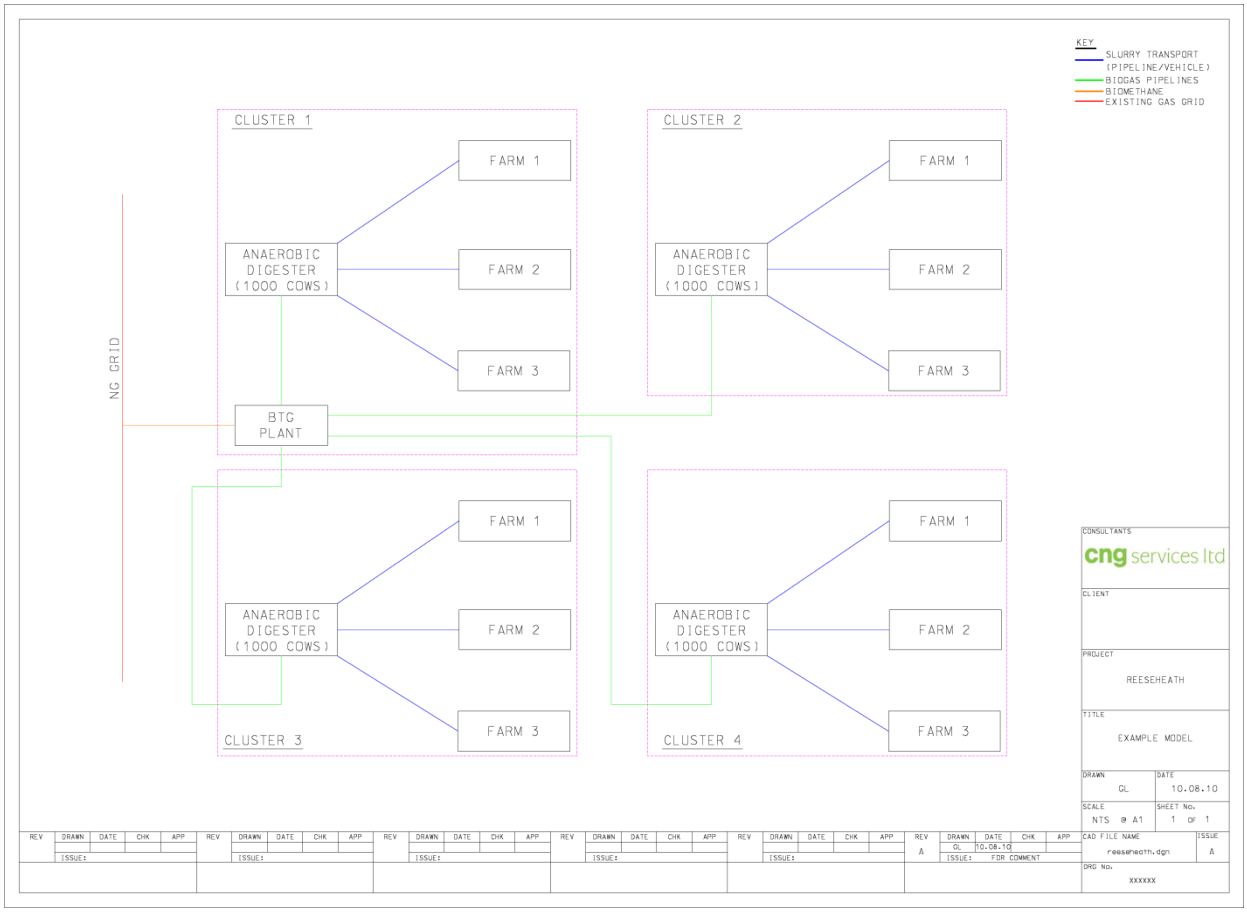
The advantages and disadvantage of the options proposed for utilising the energy available in farm gas biomethane are as follows:-

Option 1 - AD on satellite farms, pipe biogas, AD + cleanup + BtG on host farm

Advantage	Disadvantage
CHP possible	CBM available only on central farm
CHP waste heat	On farm equipment maintenance necessary. AD and CHP
Digestate on all farms	Limited scope to recycle scrubbed CO2
Minimal vehicle movement	
Low slurry spill risk	
Low cost pipeline to transfer gas	
Central gas cleanup and BtG system	

Whole system concept. This shows a number of farms each supplying slurry and energy crop to an anaerobic digester, the digesters then deliver gas to a central biogas to grid plant.

Figure 24 Central BtG plant for Farm Cluster

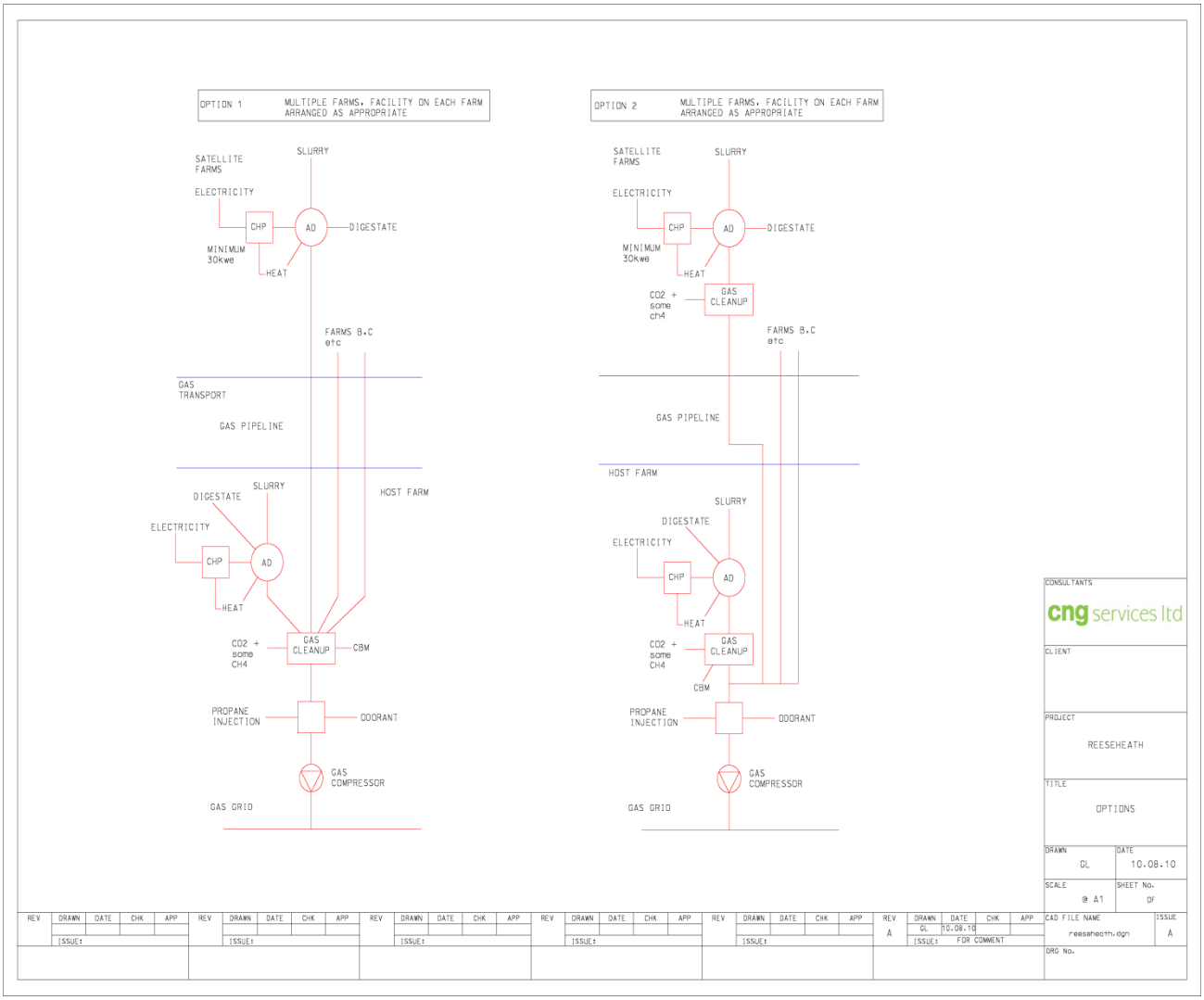


Option 2 - AD and gas cleanup on all farms, pipe biomethane, BtG on host farm

Advantage	Disadvantage
CHP possible	
CHP waste heat possible	On farm equipment maintenance necessary. AD and CHP
Digestate on all farms	High maintenance
Minimal vehicle movement	Limited scope to recycle scrubbed CO2
Low slurry spill risk	
Low cost pipeline to transfer gas	
Multiple gas cleanup and BtG system	
CBM available on all farms	

Slurry is processed through an on farm AD plant, either as biogas or cleaned to biomethane then pumped to a BtG facility.

Figure 25 Single Farm Gas Clean Up.

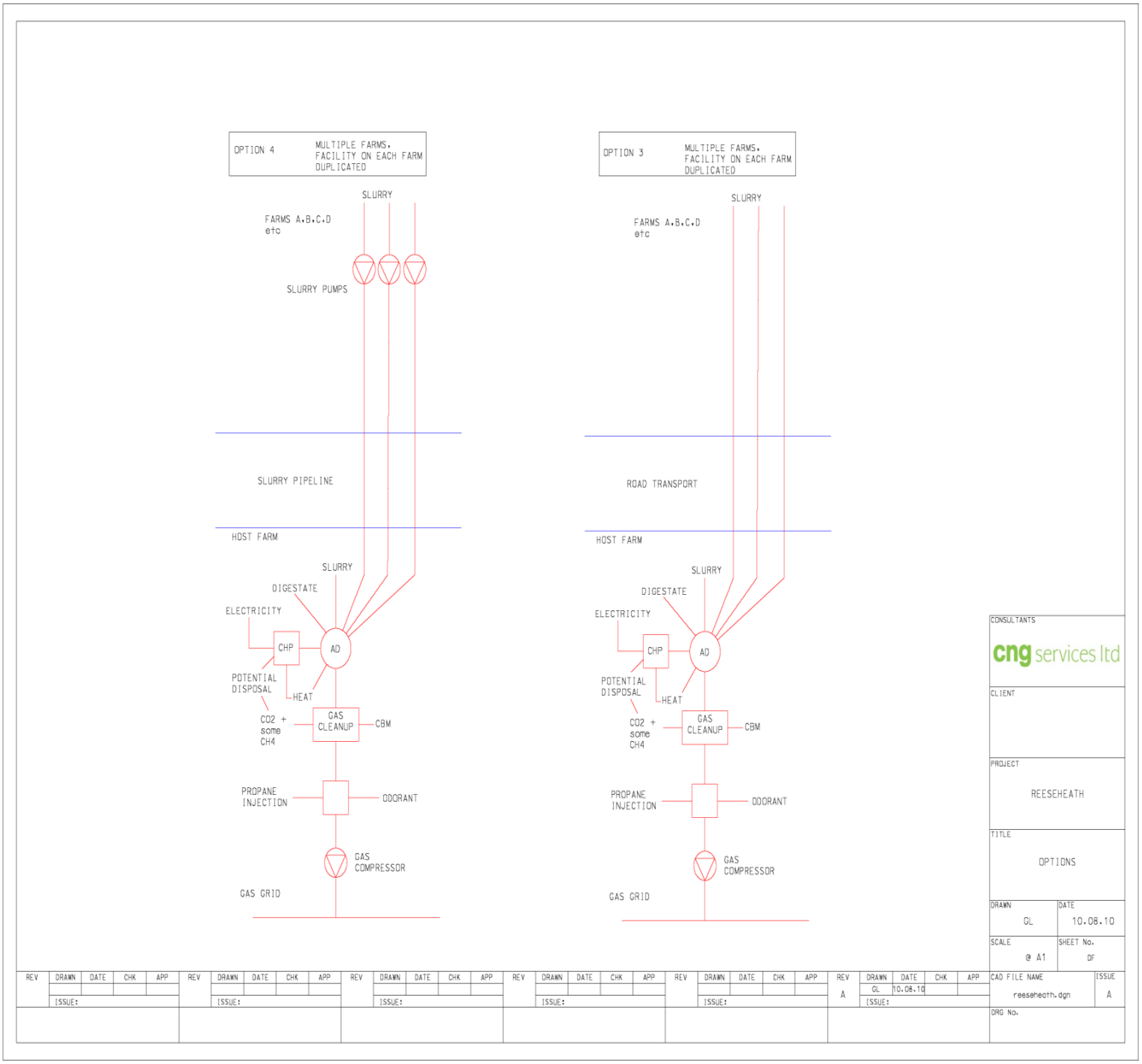


Option 3 - Central AD, gas cleanup and BtG on host farm - Slurry transported by road from satellite farms

Advantage	Disadvantage
CHP possible – electricity revenue	Increased digestate transportation
CHP waste heat possible	Slurry transportation
Single gas cleanup and BtG system	High slurry spill risk
CBM available on central farm	
All plant maintenance minimised	
Improved scope to recycle scrubbed CO2	

Slurry is moved from the farm to a local AD plant

Figure 26 Slurry Transfer Scheme.



Option 4 - Central AD, gas cleanup and BtG on host farm - Slurry pumped by pipeline from satellite farms - See Figure 26 Above

Advantage	Disadvantage
CHP possible – electricity revenue	Increased digestate transportation
CHP waste heat possible	Slurry pump systems technically challenging and prone to blockage
Single gas cleanup and BtG system	
CBM available on central farm	
All plant maintenance minimised	
Low slurry spill risk	

Biomethane for Vehicles

- The smallest biomethane generation unit has a flow capacity of some 50m^3/hr of biogas input (33 m^3/hr biomethane output). This would be too small for a BtG facility but capable of supplying a reasonable sized vehicle refuelling unit. Equivalent to approx 750L of diesel a day

- A modern large tractor will use up to 300L of diesel per day, representing a storage need of at least 1200L of CBM. There is insufficient space on board for this volume of cylinders so refuelling would need to occur 2 to 3 times a day. A small-scale refuelling unit would not achieve this, requires overnight filling

- Refuelling commercial or domestic vehicles from a facility located at a central BtG unit is entirely practical and CBM flows of 5m^3/hr upwards could be installed

- If biomethane is piped to farms through a private grid (if fossil gas is not already available) this can be used for all energy purposes including vehicle fuel

- Other farm vehicles can be made to operate on biomethane such as Quad bikes etc.

G2.0 Biogas Clean Up Plant and Technology

Design basis

The Biogas clean-up and upgrading plant would incorporate the following elements:-

- Hydrogen sulfide removal
- Carbon dioxide removal
- Moisture removal
- Waste heat recovery (from clean-up and upgrading plant) supplemented by raw biogas from the AD plant to provide heat for the AD plant using a waste heat/raw biogas boiler
- Measurement of gas quality at plant outlet (Hydrogen sulfide, water dewpoint, calorific value and wobbe index)

Required Biomethane specification

In order for gas injection to be achieved the biogas needs to meet the specifications of the grid network

Table 34 Biomethane Specification

Composition	Units	Required specification
Water dew temperature at 1.01325 bar	^{o}C	-40
Gross calorific value	MJ/m^3	See Notes 1, 2
Wobbe Index	MJ/m^3	See Note 1, 2
Methane	mol%	See Note 2
C2+ Hydrocarbons	mol%	0
Hydrogen	mol%	no more than 0.1
Carbon Dioxide	mol%	No more than 2.5 See Note 2
Nitrogen	mol%	See Note 2
Oxygen	mol%	No more than 1, preferably no more than 0.2 See Note 2, 3
Hydrogen Sulphide	mg/m^3	no more than 5
Ammonia	mol%	0
Alkyl halides	mg/m^3	no more than 1.5
Siloxanes	mg/m3	0

Notes:

1. Gross calorific value and Wobbe index are specified at reference conditions of 15°C (combustion) and 15°C, 1.01325 bar (metering).

2. The biomethane is intended to be suitable for injection into the UK natural gas distribution system and, after enrichment with propane and odorisation, be compliant with Schedule 3 of the Gas Safety (Management) Regulations, 1996, which require a minimum Wobbe index of 47.2 MJ/m^3. It is anticipated that, depending on the content of inert gases (nitrogen, oxygen and carbon dioxide) propane addition will be required to ensure Wobbe index and gross calorific value requirements of the Gas Grid Owner. In order to optimise overall gas treatment and enrichment the concentration of inert gases in the biomethane exiting from the gas treatment process and in particular the fate of nitrogen and oxygen in the biogas feed will be an important factor for consideration of tenders.

3. Schedule 3 of the GS(M)R requires that oxygen content is no more than 0.2 mol%. It is accepted that, depending on the oxygen content of the biogas feed, this level may not be possible to achieve and discussions with the Health and Safety Executive are being held to discuss this issue.

Technology Review to Meet Gas Specifications

Biogas arising from anaerobic digestion can vary in composition depending upon the substrate being digested. Typically, biogas from Sewage Water Treatment contains around 60 mol% methane and around 35% carbon dioxide, with smaller amounts of nitrogen (1.5 mol%) and oxygen (0.5 mol%), together with trace amounts of contaminants such as hydrogen sulphide. Some silicone-containing species may also be present, which may need to be removed so as to avoid formation of silica during subsequent combustion.

Removing carbon dioxide from biogas increases its calorific value and, when most of the carbon dioxide has been removed, the gas remaining (usually in excess of 95-97 mol% methane) is termed "biomethane". Depending upon the inert gas content, biomethane may be technically suitable for direct injection into some natural gas distribution systems. Often however, some degree of enrichment (typically by adding a small amount of commercial propane) will be required. In addition odorisation (adding a very small amount of usually sulphur-based odorant) is required in order to impart a distinctive and characteristic odour to the gas.
Gas treatment processes only for contaminant and carbon dioxide removal and drying are considered at this selection stage, since there is little practical variation in technology for subsequent enrichment and odorisation steps.

Acceptable technologies for Biogas Clean up are listed as follows:

- Water Scrubbing,
- Chemical Absorption Process
- Pressure Swing Adsorption

- Membrane technology
- Chemical Wash
- Cryogenic

Water Scrubbing Processes

Water scrubbing exploits the higher solubility of carbon dioxide and hydrogen sulphide in water compared with methane. The absorption process is physical and no chemical reaction occurs between the vapour and liquid phases. Absorption of carbon dioxide and hydrogen sulphide is enhanced by increased pressure and low temperatures and is most often carried out at pressures around 8-10 bar and temperatures around 8-10^{o}C.

Biogas is pressurised and fed to the bottom of a packed column where it comes into contact with water that is fed from the top of the column. The counter-current flow and packed column ensure high rates of dissolution of carbon dioxide and hydrogen sulphide. The water exiting from the packed column is often recycled after regeneration by depressurisation, often in conjunction with air stripping. If a cheap ready supply of fresh water is available then scrubbing without water recycle is possible, provided adequate systems for dealing with the discharged water are available. This could be the case at sewage treatment works.

Chemical Absorption Processes

Chemical absorption is similar to water scrubbing except that a solvent other than water is employed. The solvents employed vary; the proprietary solvent Selexol (a dimethyl ether of polyethylene glycol) and refrigerated methanol (developed jointly by Linde and Lurgi for the Rectisol gas treatment process) are perhaps the most widely known in gas treatment at large scale. Refrigerated methanol has been employed in the US for landfill/biogas gas treatment. By using solvents with high solubility for carbon dioxide and hydrogen sulphide, some process intensification is possible resulting in smaller, cheaper columns. However, the solvent itself is more expensive and the choice of water or other solvent will often be dictated by the scale of operation. The high cost of solvent also means that regeneration and recycling is always practiced. Stripping is generally carried out with an inert gas, steam or treated product gas.

Like water, both Selexol and methanol are physical solvents. A third type of solvent often used in gas sweetening and acid gas removal are the amines (of which monoethanolamine, diethanolamine and dimethyldiethanolamine are the most commonly employed). With amine solvents there is chemical reaction with the removed gases.

Pressure Swing Adsorption Processes

Pressure swing adsorption (PSA) exploits the selective adsorption or de-sorption of carbon dioxide on a solid adsorbent, typically in pellet form in a packed bed. In its simplest form biogas is pressurised and fed to an adsorbent bed and as it flows through the adsorbent carbon dioxide is removed and a product containing low concentration of carbon dioxide emerges. Eventually the capacity of the adsorbent for carbon dioxide is exceeded and when breakthrough of carbon dioxide is imminent, flow of gas is switched to another bed and the first bed is regenerated by reduction in pressure with a small flow of treated product gas to remove the desorbed

carbon dioxide. When the second bed is close to breakthrough gas can be directed to the first bed and the second be regenerated.
In practice more than two beds are often employed in mixed series/parallel configurations so as to make better use of pressure released from one bed following the adsorption step and reduce gas compression costs and improve process efficiency. Final regeneration using vacuum is also widely practiced.
Two types of adsorbent have been employed in landfill or biogas gas treatment: zeolites, which selectively absorb carbon dioxide; and activated carbon, which adsorb both methane and carbon dioxide, but desorb them at different rate when pressure is reduced.

Cryogenic Processes

Cryogenic processes exploit the different liquefaction temperatures of each component in the raw biogas. By cooling the biogas to low temperature at elevated pressure, unwanted components liquefy and are removed in a coalescing filter and/or separator vessel. In general chilling and separation is carried out in two steps: (a) chilling to around -25oC, between 16-25 bar to liquefy water, hydrogen sulphide, siloxanes and other components, followed by filtration; and (b) further chilling to around -70oC to liquefy and remove carbon dioxide.

Membrane Processes

Membrane processes exploit the different rates at which different components of biogas diffuse through a membrane. By selection of a suitable membrane, polar molecules such as carbon dioxide, moisture and hydrogen sulphide can be selectively removed from the gas stream. In order to increase the rate of removal a large membrane surface area is employed, typically by use of bundles of narrow hollow fibres down which the process gas passes.

Two types of membrane system are employed;

- High pressure gas-gas separation

  Biogas is compressed to around 36 bar and after filtration to remove particles, hydrocarbons, hydrogen sulphide and compressor oil vapour before passing into a membrane module. In the membrane module a pressure drop across the membrane provides the driving force for diffusion of molecules through the membrane to the low-pressure side. Treated product exits the membrane module at high pressure and waste gas rich in carbon dioxide exits at low pressure.
- Low pressure gas-liquid adsorption

  Biogas enters the membrane module at typically atmospheric pressure and components in the biogas preferentially diffuse though the membrane into a liquid solvent flowing on the other side of the membrane. The solvent chosen for the liquid phase are usually amine-based.

Membrane technology is not widely used in Europe but an Enhanced Membrane Separation Process for Biogas Upgrading, has recently been developed and installed to inject bio-methane into the Austrian Grid at Bruck/Leitha.

The normal drawback of membranes is that the CO2 extracted from the biogas contains around 7% methane.

G3.0 Assessment and Ranking of Gas Treatment Technologies

Technology assessment

Table 1 below lists the advantages and disadvantages of each technology type.
Water scrubbing currently accounts for the largest market share, particularly at the lower gas throughputs. Although not producing the best quality gas output, it is straightforward, proven technology with reasonable capital and operating cost.
Pressure swing adsorption produces a high quality gas output, but does feature a more complex plant layout. However the technology does have a relatively large market share and is also robust and proven technology.
Chemical adsorption processes are proven technologies at the large scale in natural gas and process industry applications, but less proven at small scale Utility requirements can be higher than water scrubbing because of the more severe solvent regeneration requirements. If there was waste heat on site then this would be more attractive.
Cryogenic processes offer potential for higher gas purity and some interest is now being shown for biogas upgrading. This technology appears to have attractions but it is still novel with the first plant being commissioned by end 2008.

Up to now, **membrane processes** have been relatively expensive, particularly at the high scale because the technology tends to scale linearly and offers little economy of scale. In principle this ought to offer advantages at the small scale. However, the lack of significant uptake in biogas applications and uncertainty over membrane life may offer unacceptable risk to the project. It has been used at the GasRec Albury facility to remove nitrogen (at that plant, CO2 was removed with a PSA).
An Enhanced Membrane separation process for biogas upgrading has recently been installed in Austria for feeding bio-methane into the grid and will warrant further investigation.

Capital and Operating Costs

Capital and operating costs have been obtained for each of the above technologies. A discussion of these costs is contained within the main report.

Emissions and Discharges

In general the potential for gaseous emissions and liquid discharge will reflect the nature of the raw biogas since all of the processes effectively produce a bio-methane of similar composition, consisting of in excess of 97 mol% methane with the balance as inert gases (nitrogen, oxygen) and trace amounts of hydrogen sulphide.
Methane is not completely retained in the product stream and methane slip and subsequent emission to the atmosphere is now becoming more of a concern in Sweden. Swedish permits now require that low emissions of methane from the gas treatment process. This has been a factor in the decline in use of Water Scrubbing processes in Sweden and increased use of PSA and now Chemical Absorption, although vendors of water scrubbing processes now provide an option for post-combustion of the waste gas stream to meet the more strict permit requirements

(believed to be similar process to catalytic removal of methane used as a vehicle fuel).
Removed carbon dioxide is emitted to the atmosphere during solvent regeneration in water scrubbing and chemical absorption processes. Similarly carbon dioxide is emitted to the atmosphere during vacuum regeneration of the adsorption beds. Cryogenic processes have potential for removed carbon dioxide to be discharged as a liquid and there may in some circumstances be a market for this product, which is generally of high quality. The volumes however are relatively small and there is also resistance in the food industry to use of waste derived carbon dioxide.
Removed hydrogen sulphide is captured in a preliminary filtration stage in CarboTech's PSA process and the spent adsorbent is removed and disposed by specialist contractor. In water scrubbing and chemical absorption processes, hydrogen sulphide is emitted to the atmosphere during the solvent regeneration stage.
The table below provides a summary of the pros and cons of each technology;

Table 35 Comparison of biogas upgrading gas treatment technologies

Technology	Advantages	Disadvantages	Scale	Numbers in use
Water scrubbing	High gas quality Relatively low capex No pre-treatment Compact process Proven technology	CH_4 emissions Waste water disposal Drying of product gas required	80-2000 m^3/h	**34**
Chemical absorption	High gas quality Low methane losses Compact process Low emissions levels	Cost of loss of solvent Gas pre-treatment required High utility requirements Not extensively used at low scale Medium-high capital costs	300-4000 m^3/h	**17**
Pressure swing	High gas quality	Gas pre-treatment	80-1200 m^3/h	**28**

adsorption	Dry product gas No water requirements No waste water disposal Proven technology Low emission levels	required Medium capital costs		
Cryogenic	Very high gas quality Compact process Dry product gas No water requirements No waste water disposal Re-use of removed CO_2	Plant complexity High capital cost High utility requirements Not extensively used at low scale Novel technology	40-2400 m^3/h	**2**
Membrane separation	Compact process Dry product gas No water requirements No waste water disposal No moving parts (excl. compression)	Relatively high methane losses (but can be burnt in boilers) Gas pre-treatment required Membrane life	60-1100 m^3/h	**9**

A full list of technology providers and installation is included in Appendix F.

Technology Conclusions

From the review it has been concluded that Cryogenic technology is not proven and as therefore not been considered as a solution.

The Chemical Wash process uses a 'liquid chemical" wash system to remove CO_2 which requires significant heat (steam) to regenerate, requiring around 20% of the biogas to be burnt to provide the heat for regeneration. After CO_2 removal the gas is wet and it uses a PSA for drying. This technology has the advantage of removing all the CO_2 which means less propane is required but it may not be the most economic due to the heat that goes up the chimney from burning biogas to make heat.
The PSA technology uses a medium that adsorbs CO_2 at high pressure (10 bar) and gives up the CO2 at low pressure (a slight vacuum). This plant is small and relatively low operating costs. However, the drawback is that the separated CO_2 contains around 10% methane and hence it cannot be burnt. An attractive option sometimes adopted is to mix this waste CO_2/methane with biomethane to make a gas with around 30% methane which can be burnt in a boiler or CHP plant.

The review recommendation is therefore based on the following technology types for the Cheshire application:-

- Water Wash
- Pressure Swing Absorption
- Chemical Wash

G4.0 Cost estimates for BtG Plant

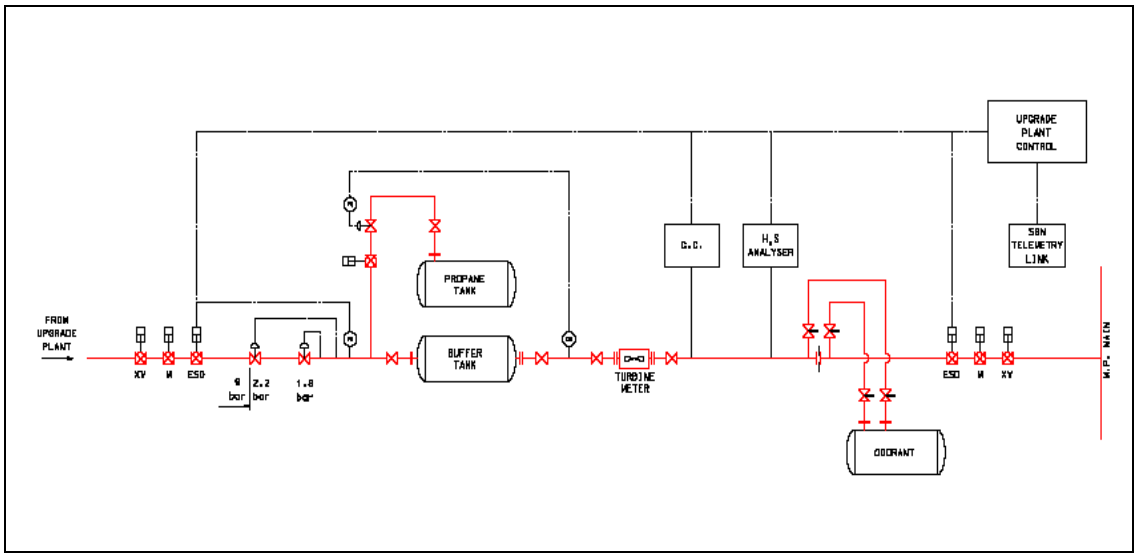
Design basis

The BtG equipment incorporates the following elements:-

- Odorant storage and injection
- Propane storage and injection
- Gas quality monitoring
- Gas CV measurement
- Gas flow measurement
- Pressure control
- Telemetry
- Integrated control and alarm systems
- Local control panels and alarm systems
- Provision of an ongoing plant monitoring service
- Provision of ongoing maintenance service

The above process is represented diagrammatically as follows:-

Figure 27 BtG Plant Schematic



For injection into the gas network, additional costs should include those for;

- Gas metering
- Gas quality analysis and CV measurement
- Odorant injection
- Propane injection
- Pressure control
- Connection pipeline
- Telemetry

These costs should be constant and independent of which upgrading technology is selected.

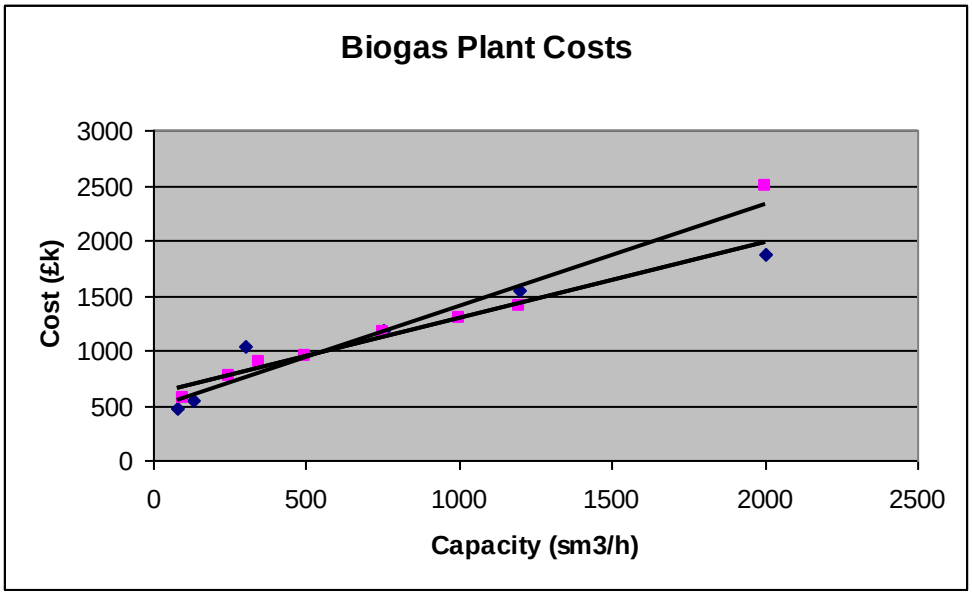
A minimum functional specification was prepared for the cleanup technology and this was issued to 3 suppliers. An indicative summary of the Capital and Operating costs of each technology is contained in the following table:

Table 36 Opex / Capex Clean up plant

Summary of Capex and Opex Costs		
Technology	Capex £million	Opex £thousand
Water wash	1.2 to1.5	118 to 154
Chemical wash	1.0 to 1.4	116 to 432
PSA	1.1 to 1.5	210 to 269

In addition data drawn from a number of plants provides the following cost analysis of gas cleaning by volume for various process designs.

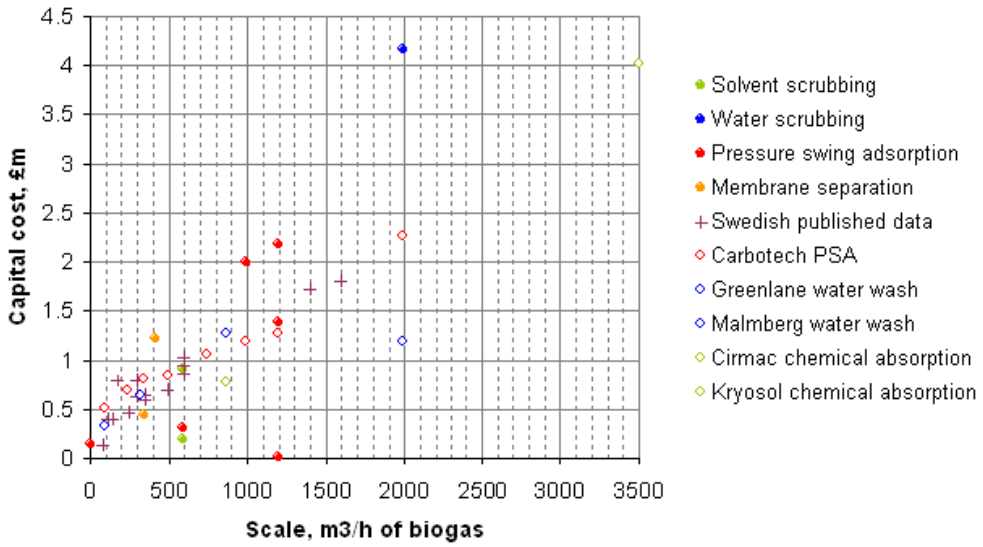
Figure 28 Biogas Cleaning Costs



The choice of a gas scrubbing plant would be between the MICRO 40 (40 -80 Nm^3/h) model and the MICRO 80 (80 -130 Nm^3/h) model, depending upon the maximum design rate.

The figure below is an extract from a cost comparison exercise that was carried out between the principal suppliers and technologies and can be compared with the most recent comparison carried out above.

Figure 29 Gas Cleaning Technology Supplier Costs



Summary of Investment Costs

The Short Term cost of installing BtG plant is within the range £500k - £750k however in the medium term it is anticipated that the costs will reduce to within the range £200k -£300k.

G5.0 Biomethane to Grid Injection in Cheshire and Warrington

Grid Capacity

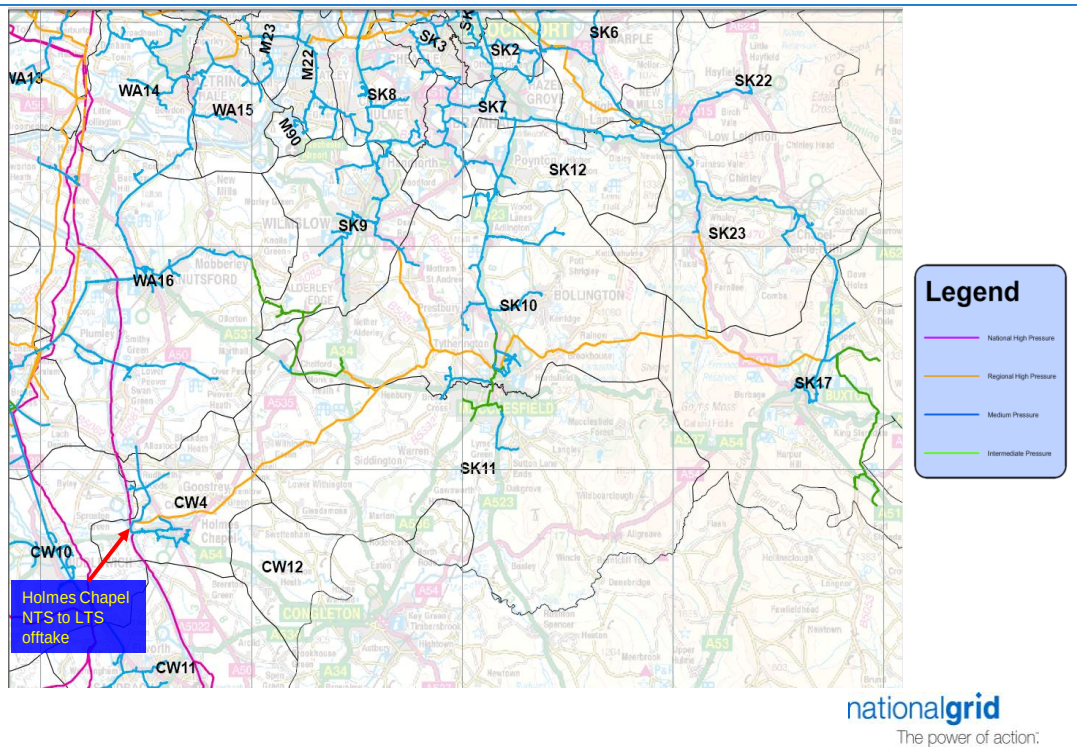
Injection point location diagrams

National Grid provided gas network plans complete with an indication of a possible injection point within the study area. The exact location of the injection point should be seen as flexible, with once again the limiting factors being the size of the mains in the network and the level of network integration.

Injection option 1 - NTS to LTS off take Holmes Chapel

The Holmes Chapel NTS off take supplies gas into the 42 bar LTS pipeline feeding the Macclesfield and Buxton area. There are a number of large non-domestic users in the area, five of which are sufficiently large to be Daily Metered Sites under Unified Network Code. It might be possible to inject bio-methane via the Holmes Chapel off take and make use of the existing metering and odorant equipment, potentially reducing costs. The 42 bar network is used as part of the storage system to provide diurnal storage in the form of linepack and therefore lends itself well to accepting bio-methane at a constant rate. The likely injection rate is 9,000 scmh.

Figure 30 Option 1- Holmes Chapel



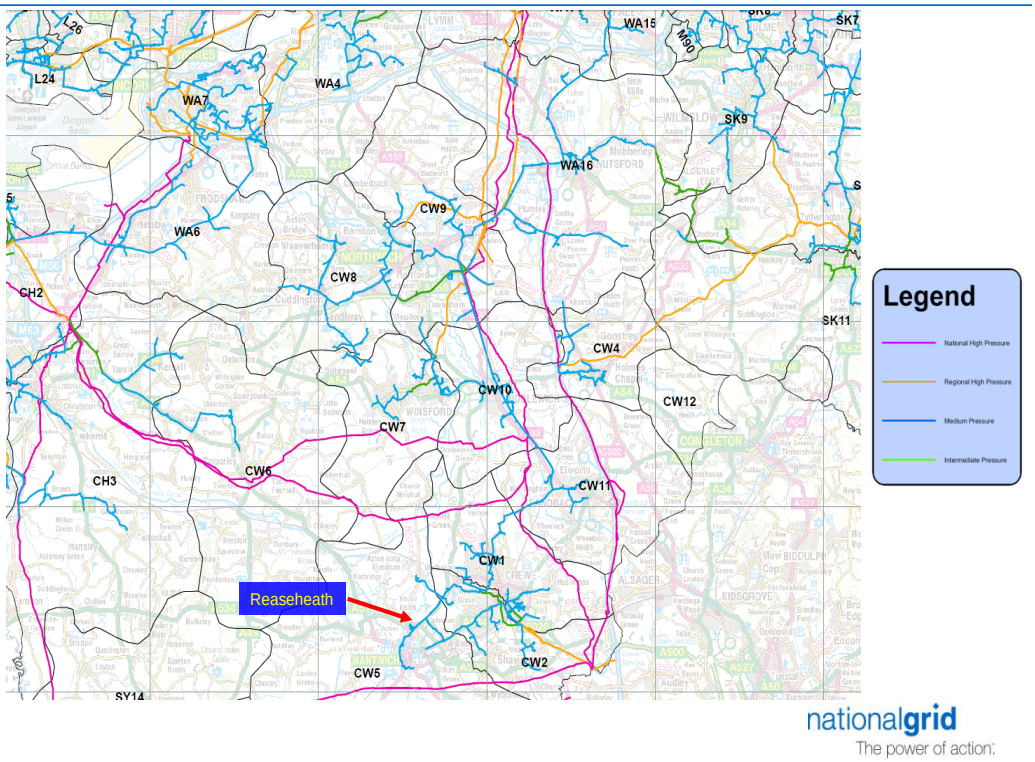
Injection option 2 – Reaseheath MP network Crewe

There is a medium pressure network in Crewe/Nantwich operating at approximately 1 bar and located relatively close to the Reaseheath College campus. Some chargeable work would be required in order to change the configuration of the network in Crewe, but assuming that this could be completed, it would be possible to accept bio-methane into the network at this point.

There is no storage capability in the medium pressure network and so the limiting factors are the size of the mains in the network, the level of integration of the network and the size of the loads connected to it. There are seven non-domestic users in the area that are sufficiently large to be Daily Metered sites under Unified Network Code.

The available injection rate could be 600 scmh or considerably higher, depending on the behaviour of the large non-domestic users, particularly with regard to their usage during the overnight off-peak period, especially in the summer.
National Grid is in the process of replacing many of the medium pressure mains in the area and this may result in the level of network integration being significantly reduced, which could in turn reduce the bio-methane injection rate that might be accommodated.

Figure 31 Option 2 – Reaseheath Crewe/Nantwich

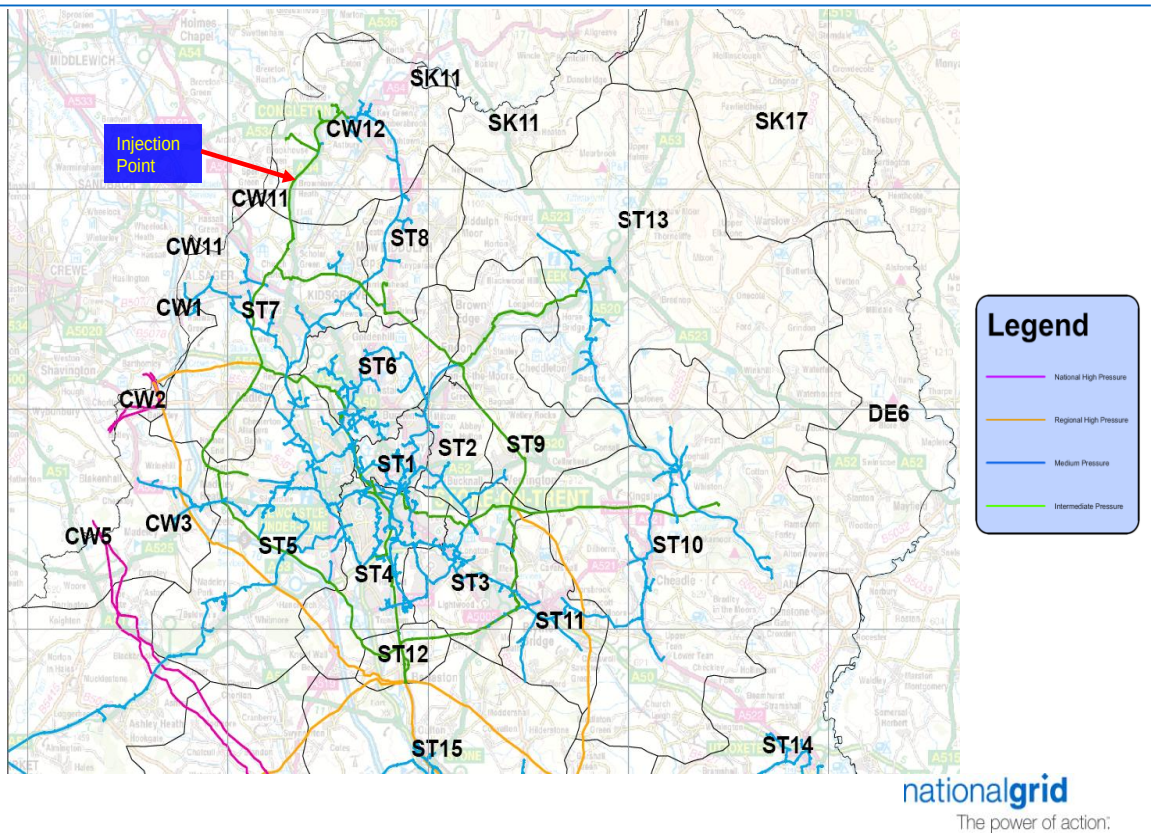


Injection option 3 – Congleton to Stoke on Trent

Stoke on Trent is served by an intermediate pressure ring main, which extends out to Congleton. The extensive nature of the IP system makes it ideal for injection of bio-methane. There are no plans for major works on the IP network, which means that it is likely to remain integrated and therefore ideal for bio-methane injection into the future.

There are a large number of non-domestic loads in the area, eighteen of which are sufficiently large to be Daily Metered under Unified Network Code.
The available injection rate could be 1,600 scmh or considerably higher, depending on the behaviour of the large non-domestic users, particularly with regard to their usage during the overnight off-peak period, especially in the summer.

Figure 32 Option 3 – Congleton to Stoke on Trent

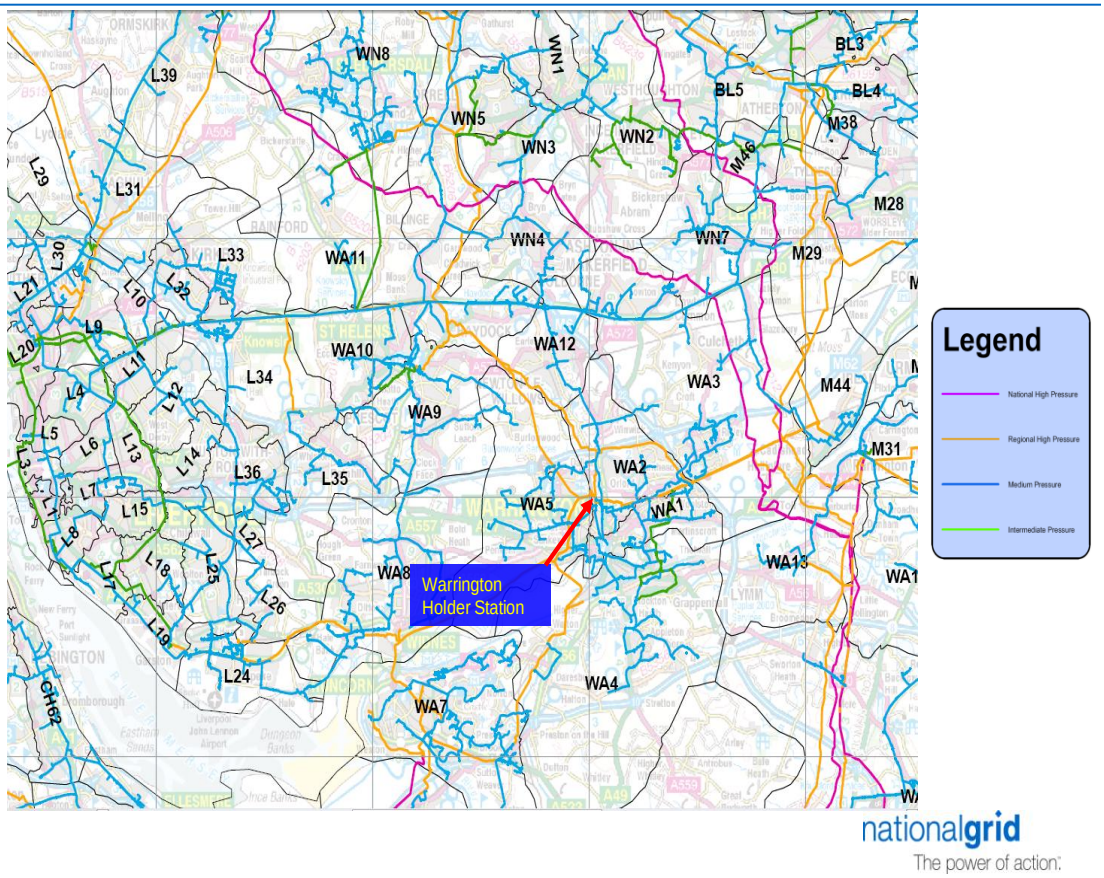


Injection option 4 – Warrington Holder Station

One of the main feeds for the Warrington area is at Warrington Holder Station. There is a supply from the Holder Station to the North and West, potentially feeding gas as far as the outskirts of Liverpool under low demand conditions.
Here again there is no storage capability in the medium pressure network and so the limiting factors are the size of the mains in the network, the level of integration of the network and the size of the loads connected to it. There are sixteen non-domestic users in the area that are sufficiently large to be Daily Metered sites under Unified Network Code.

The available injection rate could be 1,300 scmh or considerably higher, depending on the behaviour of the large non-domestic users, particularly with regard to their usage during the overnight off-peak period, especially in the summer.
National Grid is in the process of replacing many of the medium pressure mains in the area and this may result in the level of network integration being significantly reduced, which could in turn reduce the bio-methane injection rate that might be accommodated.

Figure 33 Option 4 - Warrington



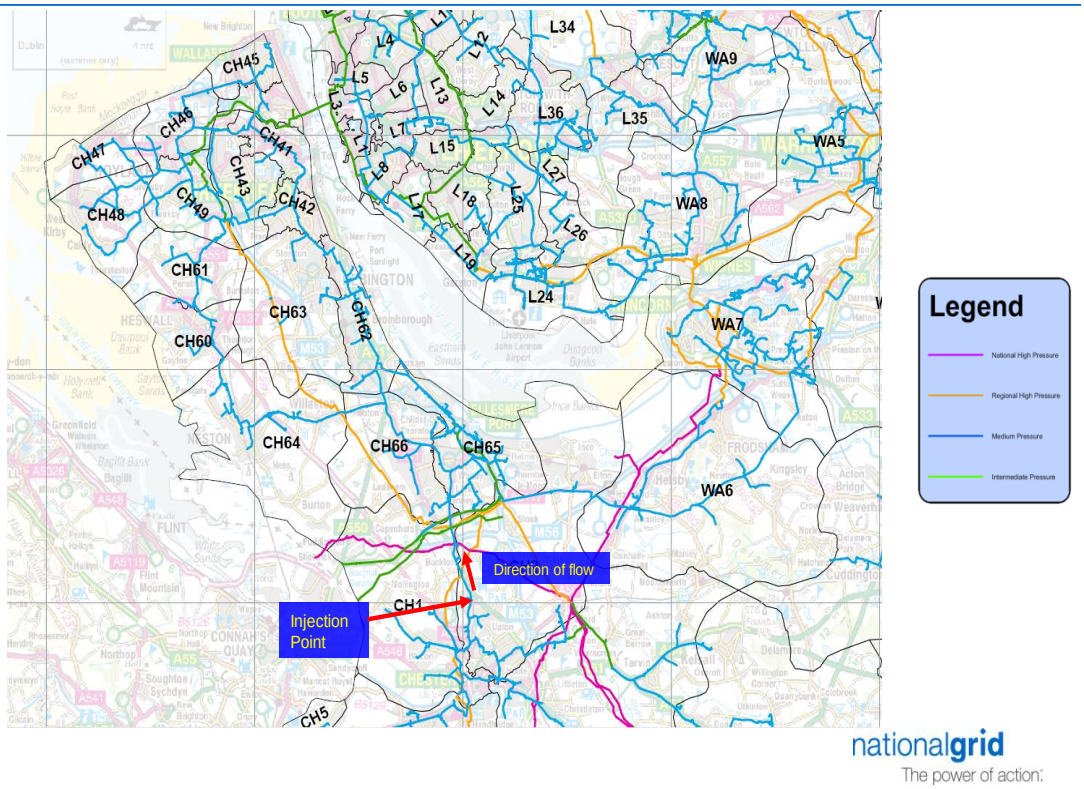
Injection option 5 – North of Chester to The Wirral

There is a medium pressure network to the North of Chester which is connected to the medium pressure network supplying a large part of The Wirral. Once again, there is no storage capability in the medium pressure network and so the limiting factors are the size of the mains in the network, the level of integration of the network and the size of the loads connected to it.

There are five non-domestic users in the area that are sufficiently large to be Daily Metered sites under Unified Network Code. The available injection rate could be 1,000 scmh or considerably higher, depending on the behaviour of the large non-domestic users, particularly with regard to their usage during the overnight off-peak period, especially in the summer.

National Grid is in the process of replacing many of the medium pressure mains in the area and this may result in the level of network integration being significantly reduced, which could in turn limit the bio-methane injection rate that might be accommodated.

Figure 34 Option 5 – Chester The Wirral



A number of factors need to be considered prior to injection

Compression: Depending on the pressure tier level at the point of injection there may be limited capacity in the NG gas distribution network to convey biomethane to gas consumers. This matter is currently under investigation and a design concept is being investigated to provide compressors to export gas across ascending pressure tiers in the NG network.

Gas Specification: It's important to make the general point that all the bio-methane injection rate figures quoted in the scenarios above assume that the gas is FULLY compliant with GSMR, particularly with regard to oxygen content and CV. If this is not the case then options for blending with 'network' gas would need to be considered and may greatly reduce the allowable bio-methane injection rate, unless blending can be avoided by obtaining an appropriate exemption from GSMR. For example, if the bio-methane contained 1% oxygen, then this would need to be blended with 'network' gas in the ratio of at least 4:1 to reduce the oxygen content of the blended gas to below the GSMR limit of 0.2% oxygen. Depending on the location, it may not be possible to achieve sufficient blending to accept the design gas injection rates.

In addition to these issues there are a number of high-level technical and commercial challenges for getting biomethane to grid in UK. These are provided in more detail below.

i) Oxygen specification

UK GS(M)R specification for Oxygen is 0.2%, a long standing value originally set at a level that UKCS always meets. The level needs to be at least 1% (in Germany it is 3%). As part of Didcot IFI Project, SGN commissioned a report from GL which indicates that there are no significant issues or risks with higher O_2 levels though there may be higher levels of corrosion in metal mains were the gas is wet. DECC have not agreed to look at the GS(M)R level for Oxygen, relying on exemptions in each case from HSE. This is time consuming and expensive.

ii) Grid Capacity

In the UK, biomethane will normally go into an MP or IP main. If biomethane flow is 300 m3/hr, then demand on the network needs to also be at least 300 m3/hr. Low demand hours in summer can be lower and hence the grid does not always have capacity. NGN have completed the first part of an IFI Project that shows this can be resolved by using compressors installed within the grid to export gas from MP to IP to LTS systems for short term periods, and that this is economic and technically feasible.

Also, the gas grid operator could adjust network regulator settings but they would incur costs and at present they have no incentive to do this.

CSL estimates that there is a capacity problem for around 40% of Biomethane projects.

Any compression plant would have to be owned, operated, and financed by the grid company as it would be embedded in their grid. A cost reflective charge could be levied to the biomethane producer that had requested the service (which needed compression).

CSL is discussing an innovation project with a gas distribution network operator that would address this issue.

iii) CV targeting

It is reasonable that the biomethane has to meet the Flow Weighted Average CV to ensure equality and consistent energy billing for gas consumers located next to AD plant (who could receive at 37 MJ/M^3 but would pay as if CV was 39.5 MJ/M^3. This is not fair, and is overcome by addition of propane in exact measured amounts.

The issue is who should fund the propane. If gas grid company funds, then RHI would be lower. But there are different trade-offs based on upgrading technology - chemical wash and cryogenic removes all CO2, add much less propane. If Grid Company pays, cannot do the full economic analysis and select best overall solution

iv) Specification (and hence cost) of the BtG plant

There is only one approved supplier of CV measurement equipment (Emersons) and only one contractor to put the Emersons chromatograph into a complete system (Orbital). In the UK it costs around £600k - £700k for CV measurement , monitoring, metering, telemetry, odorant, propane. In the Netherlands, the equivalent cost is

around £200,000 with simpler equipment proportional to BM flows and gas composition that meets the same objective.
To reduce the costs needs the regime to recognise that the rules for large gas flows are not appropriate for very small flows (daily processes as well as accuracy levels and levels of data security).
In addition, the projects need to have a standard solution and not be 'engineering projects' which they are for NTS (but only 2 new NTS entry points in last 15 years)

v) Plant Ownership

There are a number of options for ownership of BtG plant:

- DN funds, owns, maintains
- DN builds, charges full costs, DN owns and maintains
- DN specifies, customer builds, owns , operates, integrates with other plant (single civils, electrical, instrumentation, piping contractors rather than duplicating all of these)
- Biomethane producer has GT License and takes care of initial entry issues, CV , GS(M)R etc

It may be that the most efficient model is for Option iiii) where the DN to specify what the plant has to do (compliance with GS(M)R and Gas Thermal Energy Regulations) but for biomethane producer to finance, build, own and operate. This is similar to Option iv but in this option the biomethane producer is the GT and sets the specification to satisfy HSE and Ofgem. This would be exactly the same as the NTS entry arrangements at Beach and storage terminals. There is no consensus on this; all DNs have a different approach based on varied interpretation of obligations and regulatory incentives.

The big technical and financial benefit from Options iii) and iv) above would be that the BtG plant can be incorporated into the entire Clean-up and Upgrading and Enrichment Plant. One civil contractor, one mechanical, one Electrical and Instrumentation, single point accountability for safety etc. In Netherlands and Sweden and Switzerland the plant is all integrated, with lower cost and reduced duplication. In Germany, the grid company pays for the BtG plant which leads to much higher costs.
This would also mean that the same technical solution was likely to apply to all sites in GB as opposed to having 4 different solutions, one for each DNO.
Note - there is also an issue in that at present if a biomethane producer owned the plant (Option iii) it is likely that they would need a GT License or Exemption. DECC have said they are consulting on GT License Exemptions this summer as the present exemption regime expires in April 2012

vi) Network Entry Agreement

The contract between the BM producer and the DN needs to reflect the simpler procedures required for very small flows, the nature of unmanned sites, and the principle that security of supply is not an issue as BM flows will only displace existing fossil gas flows.

There have been no new NEAs since DN sales and only a handful of sites have gas flowing directly into a DN (WWU have Avonmouth, NG have Partington and Holford, SGN have Isle of Grain, Glenmavis and Wytch Farm, and NGN have none). The lack of Entry activity means there is no agreed specification and generally little experience in the DNs which may have the effect of making the BtG plant more expensive.
The key issue relates to specifying the capacity obligation. If it is very firm with liabilities, the DNO will indicate lower amounts of capacity. If it is too loose there may not be sufficient incentive to satisfy banks that there is capacity

vii) NTS Charges
At present biomethane pays NTS Exit charge even though it does not go into NTS. This unreasonably and unnecessarily increases entry costs with demonstrable impact on BM project economics. The Unified Network Code required specific provisions for smaller gas supply sites that directly connect to the lower gas grid tiers.

viii) Incentives on DNs
The gas grid owners are all supportive of biomethane but they have no financial incentive to provide this support. This means that they have no incentive to make capacity available by making adjustments to the way the lower pressure grid tiers are operated, or to install compression plant within their networks.

The DNs do not have the same process for new biomethane producers (e.g. some require funding for capacity studies)
The IFI Projects underway are very helpful at identifying issues and barriers, without them there would be no activity in 2010 as RHI only introduced in 2011 and level not yet finalised.

G6.0 Legislative and Licensing Compliance:

Gas Regulations associated with Biomethane Injection into the gas grid.

This note summarises the regulatory situation in the UK regarding gas quality and how this impacts on biomethane gas quality requirements.

Regulatory Framework

The primary legislation affecting natural gas quality is the Gas Act 1986 and the Health and Safety at Work etc Act 1974.

Underneath these Acts, there are two main pieces of secondary legislation (Statutory Instruments or “Regulations”) that refer specifically to natural gas quality:

(a) The Gas Safety (Management) Regulations 1996 (Statutory Instruments 551, known as the GS(M)R); and

(b) The Gas (Calculation of Thermal Energy) Regulations 1996 (Amended 1997).

The Gas Safety (Management) Regulations 1996

The GS(M)R set out the framework for health and safety regulation of the gas transportation industry following its privatisation in 1986.

Regulation 8 deals with the content and other characteristics of gas and paragraph (1) of this regulation places an obligation on the gas transporter "… subject to paragraphs (2) to (4), not to convey gas in a network unless the gas conforms with the requirements specified in Part I of Schedule 3". Paragraphs (2) to (4) provide for the situations of a gas supply emergency such that "The network emergency coordinator may, where it is necessary to prevent a supply emergency and in accordance with the arrangements specified in his safety case pursuant to authorise gas not conforming with the requirements of Part I of Schedule 3 to be conveyed in the network if the gas conforms with the requirements specified in Part II of that Schedule".

The requirements of Part 1 of Schedule 3 are set out in Table 1 below. The first requirements of Part I of Schedule 3 cover the content of hydrogen sulphide, sulphur, hydrogen and oxygen.

H_2S

Raw biogas contains significant sulphur predominantly as hydrogen sulphide well in excess of the requirements of the GS(M)R and gas treatment is required in order that the gas complies with the requirements of Schedule 3.

O_2

In addition oxygen is likely to exceed the minimum level (0.2 mol%) permitted by the GS(M)R. Most of the available gas clean-up technologies do not remove oxygen. This means that the oxygen content rises following carbon dioxide removal. This potential issue is important in the UK and whilst elsewhere in Europe does not appear to be a problem, in the UK either the requirements of the GS(M)R will need to be changed, or an exemption granted on a case by case basis.

Contaminants

The requirements regarding contaminants or not particularly onerous and conventional filtration is normally sufficient. However, for gas from sewage biogas, there is likely to be siloxanes present in which case it may be appropriate to have a siloxanes specification depending on downstream customers for the gas (e.g. if it feeds a CHP plant)

Hydrocarbons

Higher hydrocarbons are not present in biogas and hence hydrocarbon dewpoint is very low and not an issue.

Water

Biogas is usually saturated with water and hence drying is required to achieve a suitable raw point. The GS(M)R do not specify an absolute value for water dewpoint but the figure generally specified in Network Entry Agreements by the gas transporter is –10°C at 85 bar (the indicative value set out in the gas transporters'

Long Term Development Statements). Biogas gas treatment processes provide for drying prior to grid injection.

Wobbe Number, Incomplete Combustion Factor and Sooting Index

The final content or characteristics are Wobbe Number (WN), Incomplete Combustion Factor (ICF) and Sooting Index (SI). Together, these three parameters define an area on a "gas interchange ability diagram", which indicates gas may be freely interchanged without concern for the safe operation of gas appliances.

Generally, biomethane will be close to the lower limit in WN, either just below if inert (carbon dioxide, nitrogen or oxygen) content is relatively high, or just above if inert content is relatively low. In practice this means that if nitrogen and/or oxygen content is significant then carbon dioxide removal needs to be supplemented with propane enrichment to ensure the biomethane product is compliant with the GS(M)R requirements. Note that the GS(M)R lower WN limit of 47.2 MJ/m3 is relatively more stringent than that employed elsewhere in Europe. However, consumer billing requirements in Europe usually result in some degree of propane enrichment in calorific value anyway. In the UK, the biomethane has to be enriched which takes it into an area of the interchange ability diagram which is acceptable.

Odorant

For gas transported at pressures of 7 bar and below, the gas must be odorised. The odorant used in the UK is odorant NB, a blend of t-butyl mercaptan (78%) and dimethyl sulphide (22%) at an addition rate of 6 mg/m^3. This level is not mandated by the GS(M)R but set out in the gas transporters' safety case and hence is a condition for their gas transporter's licence and is hence not likely to be relaxed in a Network Entry Agreement.

The Gas (Calculation of Thermal Energy) Regulations 1996 (Amended 1997)

These regulations are enforced by Ofgem and deal with the basis upon which gas consumers are billed for the gas they consume. They essentially cover the measurement of the quantity of gas delivered to point of use and determination of the calorific value of the gas. The product of the two results in the energy consumed for billing purposes.

A relatively small number of gas consumers receive bespoke supplies of gas direct from the NTS, but the vast majority of gas consumers receive gas through the lower pressure systems. Transfer of gas from the higher-pressure NTS to the lower pressure distribution systems occurs at around 140 NTS Off takes throughout the country. Great Britain is divided into twelve charging areas (known as Local Distribution Zones, or LDZs) and most consumers are billed on the basis of the calorific value of gases entering (through the NTS off takes) the LDZ in which they are located. Each Distribution Network is associated with one or more Local Distribution Zones (LDZs).

Each day the UK Transmission business of National Grid, on behalf of the Distribution Networks, calculates for each LDZ a charging area calorific value, based on the daily average calorific value determined for the inputs to (and in some cases, outputs from) the LDZ. The manner in which the daily average calorific values are determined, and the charging area calorific value is calculated, is set out in the Gas (Calculation of Thermal Energy) Regulations 1996 and Amendments 1997 and 2002. The area calorific values calculated each day by UK Transmission are passed on to

Shippers and then on to gas suppliers who use them to calculate the final consumers' gas bills.
For most consumers, daily charging area calorific values are calculated using the flow-weighted average calorific value (FWACV) methodology, which requires that charging area calorific value is the lower of;

- The flow-weighted average of all daily average calorific values determined for all relevant inputs to and outputs from the LDZ, and;

- The lowest daily average calorific value determined for all relevant inputs to the LDZ, plus 1.0 MJ/m^3.

This second value caps the charging area calorific value to no more than 1.0 MJ/m^3 than the lowest source of gas to the LDZ for a particular day. The cap was introduced in the Gas (Calculation of Thermal Energy) Regulations Amendment 1997 to limit the disadvantage to some consumers.
Application of a CV cap can lead to an in-balance in the energy entering and leaving the NTS leading to what is commonly called CV shrinkage. The cost of CV shrinkage is borne by the gas transporter and the Shippers and because of the large volumes of gas entering charging areas each day, results in significant cost. There is therefore considerable incentive for the cap not to come into play. Gas transporters generally will apply a target CV in their entry agreement if risk assessment indicates that a new source of gas is likely to lead to significant capping of the FWACV. UK Transmission generally sets the target CV daily in advance at the forecast FWACV, less 0.5 MJ/m^3.

CV Measurement

It is not clear whether Ofgem would wish a Letter of Direction at the proposed injection points. This is likely to depend upon the interpretation of relevant energy input and relevant volume input in Regulation 4A(3) of the Gas (Calculation of Thermal Energy) Regulations (Amendment). This should be discussed with Ofgem. If Ofgem directs NGN to determine CV of the biomethane delivered from the Quarrington site then the CV measurement will have to be performed with equipment approved by Ofgem. Currently this is believed to be limited to the Daniels model 500 process analyser (the "Danalyzer") and two models of direct combustion calorimeter (Cutler-Hammer and Cambridge-Thomas). There may be other devices – need to be confirmed. The Danalyzer is designed to cope with the large quantities of gas passing through terminals and major NTS off takes and costs approximately [£120,000] plus £10,000/year in operation and maintenance costs. The capital cost to install one of these represents a disproportionate cost for small biomethane flows.

Options for directed CV measurement will need to be discussed with Ofgem, as (because of the low daily volumes of gas injected) measurement provisions represent a significant fraction of the installed cost of an injection point. If Ofgem directs NGN to determine CV of the biomethane delivered from the Quarrington facility – then, if not enriched, the biomethane would become the lowest source for the SE charging area and hence would have significant impact in the frequency of capping of flow weighted CV. Under this scenario, application of a target CV achieved through enrichment of the treated gas with commercial propane is necessary to put the Didcot facility CV at around Flow Weighted Average – 0.5 MJ/M^3.

If Ofgem deems the injection of biomethane to be an input into the SE charging area then daily volume would have to be determined to an accuracy requisite to the calculation of the Flow Weighted Average CV. Currently it is believed that NGN policy is for such daily to be measured to an uncertainty of 1.0% (in converted volume) and 1.1% (in energy). Given that this policy is set in the context of significant daily gas volumes (e.g. NTS off takes of around 1 million m^3 or more), a more appropriate accuracy such as that from installation to IGEM/GM/8 may be acceptable. Options for these measurements should be discussed with Ofgem.
There is a Daily Calorific Value Review Group being established under the UNC. It may be that this Review Group can be used to allow a change to requirements for small injection of biomethane. For example, if annual flow is less than 10 million therms it would be reasonable to have a more appropriate device for measuring CV and flow.

Table 37 Requirements of Schedule 3 of the Gas Safety (Management) Regulations 1996

Part 1 Requirements under normal conditions	
1. The content and characteristics of the gas shall be in accordance with the values specified in the following table.	
Content of characteristic	Value
Hydrogen sulphide content	5 mg/m^3;
Total sulphur content including H_2S	50 mg/m^3;
Hydrogen content	0.1 % (molar);
Oxygen content	0.2 % (molar);
Impurities	Shall not contain solid or liquid material which may interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a consumer could reasonably be expected to operate;
Hydrocarbon dewpoint and water dewpoint	Shall be at such levels that they do not interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a consumer could reasonably be expected to operate;
WN	51.41 MJ/m^3, and μ 47.20 MJ/m^3;
ICF	0.48
SI	0.60
2. The gas shall have been treated with a suitable stanching agent to ensure that it s a distinctive and characteristic odour which shall remain distinctive and characteristic when the gas is mixed with gas which has not been so treated, except that this paragraph shall not apply when the gas is at a pressure of above 7 bar.	
3. The gas shall be at a suitable pressure to ensure the safe operation of any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a consumer could reasonably be expected to operate.	

G7.0 Gas to Grid Conclusion

Biogas to Grid.
For a system to be viable it is important to locate a gas grid connection that can both take the volume of gas produced at all times and within reasonable distance from the raw material.
The cost of cleaning biogas to grid quality is very dependent on flow rates; there are a number of fixed cost items that do not vary with scale. A model with a nominal 250m^3/hr flow has been taken as a target to develop and represents the lower end of the scale of systems.

To limit the transport distance of raw materials the model is based on the concept of clusters of farms each feeding a local AD plant to produce gas. These in turn would pipe gas to the BtG plant, pipeline distance not being limited in the same was as slurry transfer.
It is estimated that slurry may be economically pumped from farms with over 200 dairy head to an AD unit over distances of some 4000+ meters. Should pipes be trenched in (a slurry feed and digestate return) other pipes containing gas and communications and electrical cables may also be laid. A network of energy, gas and communication can then be economically established.

Suggested farm scale model

This study suggests that to get the benefit of scale a number of farms need to work together. It requires a cluster of farms to feed a digester, produce biogas that in turn combines with other clusters to feed a biogas cleanup and grid injection plant. Slurry and energy crops can be delivered to an AD plant by road tanker or pipeline and have digestate returned by pipe or tanker. Where trenches are dug to install slurry pipes, there is a distinct advantage to lay extra pipes for water and gas also communications cables (fibre optic, LAN, etc) may also be installed creating a network for energy transfer and communications. A BtG plant may be located conveniently for injection to their respective grids. In principal labour time and maintenance should be minimised wherever possible, leaving plant maintenance to professionals and farm activities to farmers.

The study considered models from a150 cow unit to a 4000 cow combined units with 30% maize silage.

There are a series of operational and practical breakpoints as follows:-

- Need 150 cow unit + 30% maize slurry or 600 cows
- Need input from 1000 cows + 30% maize silage or 3500 cows
- Need input from 4000 cows + 30% maize silage or some 13000 cows before Biogas to Grid becomes practical.

This concept suggests a grid system collecting slurry from some 10 farms feeding a central AD plant with four CAD plants feeding a central BtG plant. Slurry pumping distances may require pump way stations.

Appendix H - References

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Appendix I – Useful Information

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Cultural and Historic Designations –English Heritage - www.english-heritage.org.uk/professional/archives-and-collections/nmr/spatial-data

Department for Environment, Food and Rural Affairs www.defra.gov.uk

Department of Energy and Climate Change www.decc.gov.uk

Electricity Network – National Grid - http://www.nationalgrid.com/uk/LandandDevelopment/DDC/GasElectricNW/undergroundcables/shape/

England's Official Anaerobic Digestion Portal – www.biogas-info.co.uk

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NNFCC Biocentre York Science Park, Innovation Way, Heslington, York YO10 5DG, www.nnfcc.co.uk

OFGEM www.ofgem.gov.uk 9 Millbank, London, SW1P 3GE

Ordnance Survey 1:50,000 vector mapping
http://www.ordnancesurvey.co.uk/oswebsite/products/vectormap/district/index.html

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Renewable Energy Association REA – www.r-e-a.net 17 Waterloo Place, London, SW1Y 4AR

RSPB Nature Reserves and Important Bird Areas – www.rspb.org.uk/ourwork/science/datazone/index.asp

The Biomethane Transport Forum – www.environmental-protection.org.uk/transport/biomethane-transport-forum

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