A perspective on the potential role of biogas in smart energy grids

Tobias PERSSON, Jerry MURPHY,
Anna-Karin JANNASCH, Eoin AHERN,
Jan LIEBETRAU, Marcus TROMMLER,
Jeferson TOYAMA

SUMMARY

This report documents the potential role of biogas in smart energy grids. Biogas systems can facilitate increased proportions of variable renewable electricity on the electricity grid through use of two different technologies:

- Demand driven biogas systems which increase production of electricity from biogas facilities at times of high demand for electricity, or store biogas temporarily at times of low electricity demand.
- Power to gas systems when demand for electricity is less than supply of electricity to the electricity grid, allowing conversion of surplus electricity to gas.

The report is aimed at an audience of energy developers, energy policy makers and academics and was produced by IEA Bioenergy Task 37. Task 37 is a part of IEA Bioenergy, which is one of the 42 Implementing Agreements within IEA. IEA Bioenergy Task 37 addresses the challenges related to the economic and environmental sustainability of biogas production and utilisation.

iea Energy Technology Network

IEA Bioenergy

A perspective on the potential role of biogas in smart energy grids

Technical Brochure prepared by:
Tobias PERSSON, Jerry D MURPHY, Anna-Karin JANNASCH, Eoin AHERN,
Jan LIEBETRAU, Marcus TROMMLER, Jeferson TOYAMA

Edited by David BAXTER

First printed edition produced in 2014
A catalogue record for this Technical Brochure is available from the British Library.
ISBN 978-1-910154-12-0 (printed paper edition)
ISBN 978-1-910154-13-7 (eBook electronic edition)

Published by IEA Bioenergy

Contents 3
Foreword 4
1. Introduction 5
1.1. The challenge to substitute fossil fuels 5
1.2. Biogas as a facilitator for increasing intermittent renewable electricity 6
1.3. The potential of the natural gas grid to store energy 6
1.4. The limited role of hydrogen in power to gas systems 7
1.5. End use of biogas 7
1.6. Objectives of report 7
2. Development of electricity generation in selected IEA countries 8
2.1 Germany 8
2.2 Sweden 8
2.3 Republic of Ireland 9
2.4 Brazil 9
3. Demand driven biogas plants to stabilize the electricity grid 10
3.1 Economic incentive for demand driven biogas 10
3.2 Biomethane: a route to energy storage 10
3.3 Co-operative approach to demand driven biogas 11
3.4 Demand driven biogas at a single facility 11
3.5 Case study: Sobacken biogas plant 12
3.6 The benefit of combining phased feeding with biogas storage 13
3.7 Biomethane storage through pressure variation in the distribution grid 13
3.8 Complexity and efficiency loss in demand driven biogas systems 14
3.9 Flexible bioenergy in the energy grid 14
4. Power to Gas; a means of storing surplus electricity 15
4.1 Electrolysis 15
4.1.1 Alkaline Electrolysis Cells (AEC) 15
4.1.2 Polymer Electrolyte Membrane cells (PEM) 15
4.1.3 Solid Oxide Electrolysis Cells (SOEC) 16
4.2 Power to methane 17
4.3 Catalytic methanation 18
4.4 Biological in-situ or ex-situ methanation? 19
4.4.1 Sequential processes of anaerobic digestion 19
4.4.2 Effects of adding H_2 to an anaerobic reactor 19
4.4.3 Biological methanation in the anaerobic biogas reactor (In-Situ Reactor) 20
4.4.4 Biological methanation in a separate reactor (Ex-Situ Reactor) 20
4.5 Can biogas upgrading be replaced by methanation? 21
5. Discussion 22
6. Conclusions and recommendations 24
References 25

Foreword

This publication describes a perspective on the potential role of biogas in meeting fluctuating demand for electricity, and in smart energy grids. The amount of variable renewable electricity produced in the world is rapidly increasing and so is the need to develop suitable technologies to balance uneven electricity production and utilisation. Demand driven biogas plants allow electricity generation specifically at times of peak electricity demand. Power to gas systems allow any surplus electricity to be converted to hydrogen at times of low demand. Power to gas systems can generate gaseous biofuel for transport (or for heat) from electricity that is in excess of demand, for example in regions with very high generation capacity from intermittent sources such as wind and solar.

It is shown that biogas:

- can be used to facilitate increased variable renewable electricity on the grid
- systems can be used to increase electricity production at times of low supply

And that:

- Power to gas systems convert electricity to storable gas when demand for electricity is low
- Power to methane systems can act as a means of upgrading biogas to biomethane

Biogas production systems have significant potential to facilitate increased proportions of variable renewable electricity in an integrated energy system. This is implemented either by demand driven biogas systems or through power to gas systems. Biogas systems typically produce electricity at a relatively uniform rate, unlike variable renewable electricity such as produced by wind turbines. Demand driven biogas plants can increase electricity production at times of high electricity demand and can reduce electricity production at times of low demand. This can be achieved through storing biogas and only using it to generate electricity when needed by the grid. This managed fluctuation of electricity production can be enhanced through varying the time, and rate, of feeding of the biogas plant.

Power to gas systems have a totally different role. In essence these systems involve converting electrical energy into gas that can be more readily stored. At times of low demand for electricity, electrolysis may be employed to convert surplus variable renewable electricity to hydrogen. Hydrogen is an energy vector of the future; the hydrogen infrastructure is not yet in place. Hydrogen may subsequently be converted to methane by catalytic or biological methanation. The methane may be used as a source of renewable gaseous transport fuel or renewable heat.

A model is proposed which combines these two concepts at biogas facilities allowing storage of variable renewable electricity, with co-production of electricity (at times of peak demand for electricity) and methane for gas grid injection (at times of low demand for electricity).

The authors of this report are members of IEA Bioenergy Task 37, which addresses the challenges related to the economic and environmental sustainability of biogas production and utilisation. IEA Bioenergy is one of 40 currently active Implementing Agreements within the International Energy Agency and has the aim of improving cooperation and information exchange between countries that have national programmes in bioenergy research, development and deployment. IEA Bioenergy's vision is to achieve a substantial bioenergy contribution to future global energy demands by accelerating the production and use of environmentally sound, socially accepted and cost-competitive bioenergy on a sustainable basis, thus providing increased security of supply whilst reducing greenhouse gas emissions from energy use.

Acknowledgements

The authors are grateful for the support from John Bøgild Hansen (Haldor Topsoe), Dominic Hofstetter (Electrochaea), Filip Smeets (Hydrogenics), Martin Ragnar (Energiforsk, Sweden), Camilla Till (Borås Energi och Miljö AB), Paul Deane (Environmental Research Institute) and Mathieu Dumont (Netherlands Enterprise Agency) for providing useful information for this publication.

1. Introduction

The aim of this report is to outline the potential role of biogas in stabilising the electricity grid in a future where more variable renewable electricity will be produced, for example from wind and solar. This report will not describe the technologies in detail, but instead present an overview of current technologies and a perspective on applications of biogas technologies for balancing electricity supply with demand in future smart grids. According to IEA (IEA, 2011), a smart grid is an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. Smart grids co-ordinate the needs and capabilities of all generators, grid operators, end-users and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimising costs and environmental impacts while maximising system reliability, resilience and stability.

This report presents various options for demand-driven biogas plants and power to gas. A model of an integrated demand driven biogas, power to gas system is proposed whereby increased electricity can be generated at times of peak demand while at times of low demand, electricity can be used for the production of biomethane which can be injected into the gas grid or used as a gaseous renewable transport fuel.

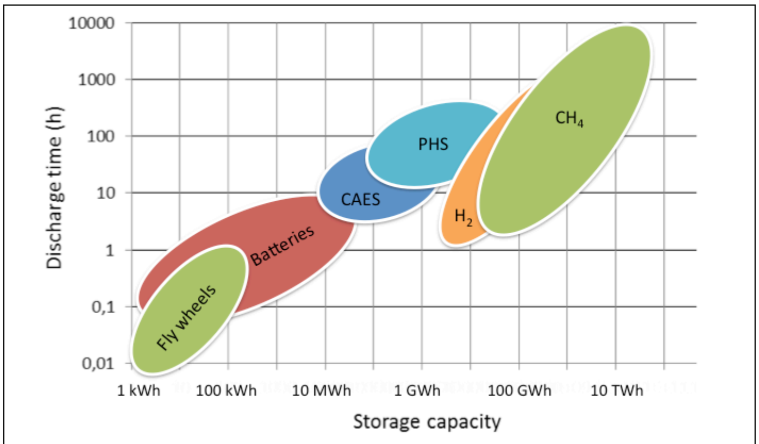


Figure 1: Comparison of various energy storage systems with respect to discharge time and storage capacity (modified from Specht et al., 2011).

1.1. The challenge to substitute fossil fuels

Climate change is the major driver for renewable energy technologies. The challenges for engineers and scientists include the development and selection of the best available technologies and integration of these technologies into the existing energy infrastructure. Energy systems will need to undergo dramatic changes to allow compliance with renewable energy targets and proposed reductions in greenhouse gas emissions. Fossil fuels will eventually have to be phased out; this however is not an easy task. Fossil fuels are still relatively cheap; for example fracking has significantly increased the resource of natural gas in the USA and reduced the price of gas. Power plant technologies are very well proven and efficient; natural gas combined cycle gas turbines (CCGT) can produce electricity at conversion efficiencies in excess of 60%. Most importantly fossil fuels can provide a constant reliable output of electricity. This is a challenge for renewable electricity, in particular when sourced from wind and solar, as the production tends to be variable or intermittent. As the portion of variable renewable electrical energy increases in the electricity supply system, it becomes very difficult to match production with demand. The potential for oversupply (and lower prices for electricity), and more crucially, undersupply (leading to outages) increases with increased levels of variable renewable electricity.

It is necessary to balance electricity supply and demand (or load) at all times within a defined electrotechnical framework; voltage stability is required for the protection of technical facilities. The balancing requirement is often at distribution grid level (low and medium voltage); this provides new opportunities for flexible energy supply and/or demand side management.

The question of how to deal with a high share of variable renewable power production (such as solar and wind) has to be addressed at TSO (transmission system operator) and DSO (distribution system operator) levels. Within the TSO networks a major balancing can be achieved through interconnectors between countries. The TSO-grids are often 110/380kV voltage grids. At this level, base load from big nuclear or fossil power plants feed into the grid. The DSO network distributes the energy from TSO networks to the customers. These grids are required to accept electricity feed in from renewable electricity production. This is challenging for the network operators, since the network was not originally built for the feed in of high shares of renewable electricity, but only for energy distribution. This can lead to reverse load flow between low and medium voltage levels, as well to overloads of network equipment or critical grid situations when operating parameters are not met.

Typically, electricity storage mechanisms include: flywheels; batteries; compressed air energy storage (CAES); pumped hydroelectric storage (PHS) and heat pumps in houses. These options are limited by short duration time of storage (Figure 1).

1.2. Biogas as a facilitator for increasing intermittent renewable electricity

Biogas systems can facilitate increased variable renewable electricity on the grid. One such system is demand driven biogas (Figure 2(a)). This is very relevant in countries such as Germany with an extensive biogas infrastructure. These plants may be operated in such a way as to increase production of electricity from biogas when the demand for electricity is high. This may be implemented by storing biogas until electricity demand is high and/or by feeding biogas plants in a pulse mode that produces maximum biogas output when electricity demand is high.

A second system is termed Power to Gas (Figure 2(b)). This involves converting renewable electricity to hydrogen (H_2) using electrolysis when the electricity production is high but demand is low. However the infrastructure and industry associated with hydrogen as a transport fuel, or as an energy vector, has yet to be widely employed. Distribution systems or end users are not in place. However the methane economy is mature and many countries have extensive natural gas (methane) distribution systems and methane end use is widespread, ranging from home heating to natural gas vehicles (NGVs) to combined cycle gas turbine power (CCGT) plants. The hydrogen can be used to produce methane (CH_4) through methanation in two ways: catalytic conversion or biological conversion. Both of these technologies will be explored in this report. Methane produced from surplus electricity via hydrogen may be injected to an existing gas grid; this allows for storage of the energy and also changes the energy vector from electricity to gas. The storage capacity and duration of storage of methane is in well in excess of most other energy storage systems (Figure 1).

The renewable gas (or green gas) can be used for renewable heat, as a renewable transportation fuel, or as a source of renewable electricity when demand increases again. Hence, this integration technology is a potentially key component of a future smart grid.

1.3. The potential of the natural gas grid to store energy

The existing natural gas grids have distributed natural gas since the 1950s and 1960s. The extensive gas distribution network in existence today also provides for large scale energy storage in the grid itself as well as through the connection to below-ground storage systems such as salt caverns and depleted gas reservoirs. The global working gas storage capacity for natural gas is about 319 billion normal m^3 (STP: normally referred to in the biogas and biomethane sectors as Nm^3) with more than 690 storage systems worldwide, of which two-thirds are situated in Russia and USA (LBEG, 2013). This storage capacity could potentially be utilized in power to gas systems. In power to methane systems, the produced methane can be injected into the gas grid for storage and/or associated storage systems. In terms of composition or quality there is little difference between methane from power to methane and natural gas in the grid; both are dominated by methane even though natural gas may have small quantities of higher hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) or pentane (C_5H_{12}). These higher hydrocarbons increase the energy value of natural gas. In several countries, such as Denmark, France and Germany, investigations have been performed that indicate that the natural gas grid is a very good option for storage of energy (Urban, 2013; Larsen and Petersen, 2013; Specht et al., 2011).

1.4. The limited role of hydrogen in power to gas systems

Hydrogen gas could also be fed into the existing gas grids to form a mixture of natural gas and hydrogen; this may be termed hythane. By injecting hydrogen into the grid, the volumetric energy density of the gas is reduced since hydrogen has a lower heating value (LHV) of ca. 10.2 MJ/Nm^3 compared with CH_4 with a LHV of ca. 35.5 MJ/Nm^3. The limitation in injecting H_2 to the natural gas grid is the low molecular weight and the potential for leakage of the H_2 from the pipework. Discussion prevails as to what portion of hydrogen addition would be acceptable in the gas grid. No definite answers are given in a European context, but a range from 2 to 20% is discussed. Use of compressed natural gas, with composition of H_2 in excess of 2%, may lead to corrosion in the high-pressure storage tanks of natural gas vehicles (NGVs). This may be a practical limit to hydrogen injection to the grid. From a historic perspective, it is of note that hydrogen-rich town gas once dominated the gas market. The first commercial town gas facilities were in Baltimore, USA (1806) and London (1813). These systems lasted well into the 1960s. As such, it is clear that hydrogen may be transported in the natural gas grid in low proportions and used for any purpose for which methane is used (e.g. heat, transport or electricity).

1.5. End use of biogas

The output of power to gas systems includes gas which may be used as a renewable gaseous transport fuel. This option can be attractive in Europe due to an amendment to the Renewable Energy Directive (RED, 2009) which allows double counting of energy used in the transport sector even when the gaseous fuel is derived from non-biological origins (such as power to gas). The double counting is part of the assessment for meeting the 2020 renewable energy supply in transport (RES-T) target (European Commission, 2014).

Another output is renewable electricity. The efficiency of conversion to electricity obviously has a significant impact on the overall efficiency of the energy balancing system. One of a range of power generation units can be used to produce electricity at a single biogas facility; these include four-stroke engines, micro turbines and Stirling engines (Kaparaju and Rintala, 2013). These have electrical efficiencies in the range 25-45%. Alternatively, if biomethane is added to the gas grid from numerous facilities, a large scale combined cycle gas turbine (CCGT) can achieve electrical efficiency above 60%. In any case, the electricity generation system must be capable of responding rapidly to changes in the variable electricity production from solar and wind. Gas engines can be started within seconds. A CCGT can start-up and reach full capacity within an hour (Kaparaju and Rintala, 2013).

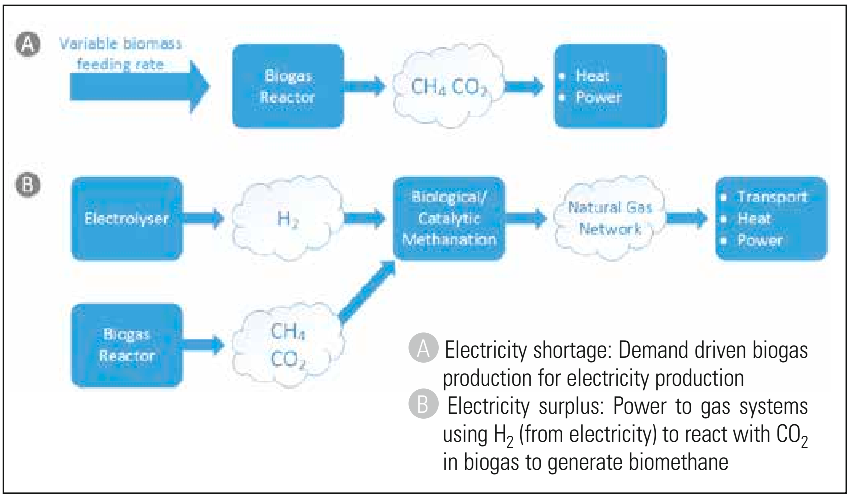


Figure 2: The role of biogas in the smart grid.

1.6. Objectives of report

This report has the objective of providing a perspective on the role biogas can play in balancing the electricity grid. When electricity demand is high, demand driven biogas concepts can be employed to increase electricity output (Figure 2 (a)). When intermittent renewable electricity production exceeds demand, power to gas systems may be used to convert electricity to methane (Figure 2(b)).

2. Development of electricity generation in selected IEA countries

2.1 Germany

The greenhouse gas emission target of the German government is 40% reduction from the 1990 level by 2020. The target rises to 55% by 2030 and to 80-95% by 2050. This is coupled with a target of 60% renewable energy in final energy consumption by 2050 and 80% renewable energy in final electricity consumption by 2050. Presently the share of renewable energy in electricity is around 22%. In Figure 3 it is shown that even at this level of renewable electricity, at times the renewable electricity production approaches the electricity consumption level. If the share of renewables is increased four times (as projected for 2050) it is clear that it will be hard to match consumption and production without the introduction of new technologies that can make good use of surplus electricity.

2.2 Sweden

Sweden is remarkable in that it has a very low carbon footprint in electricity production. Electricity in Sweden is sourced from hydroelectric power (45%), nuclear power (39%), CHP (11%) and wind (4%). Most hydroelectric power plants were built between 1910 and 1980. The nuclear power plants were built between 1972 and 1985. Although new investments are made in both nuclear and hydro-electric facilities on a regular basis, the fact that the capital investment for the bulk of this infrastructure was made a long time ago means that the cost of electricity production in Sweden is low compared to most other countries; 40 EUR/MWh is a typical figure.

Nuclear power provides a constant base of electricity production whilst the hydroelectric power is a very flexible asset for power regulation. As wind power makes up a small share of the total power production, power regulation on a national level is uncomplicated. However, wind power is growing rapidly and nuclear power could diminish in time. In addition, regional differences exist. For example on the isle of Gotland,

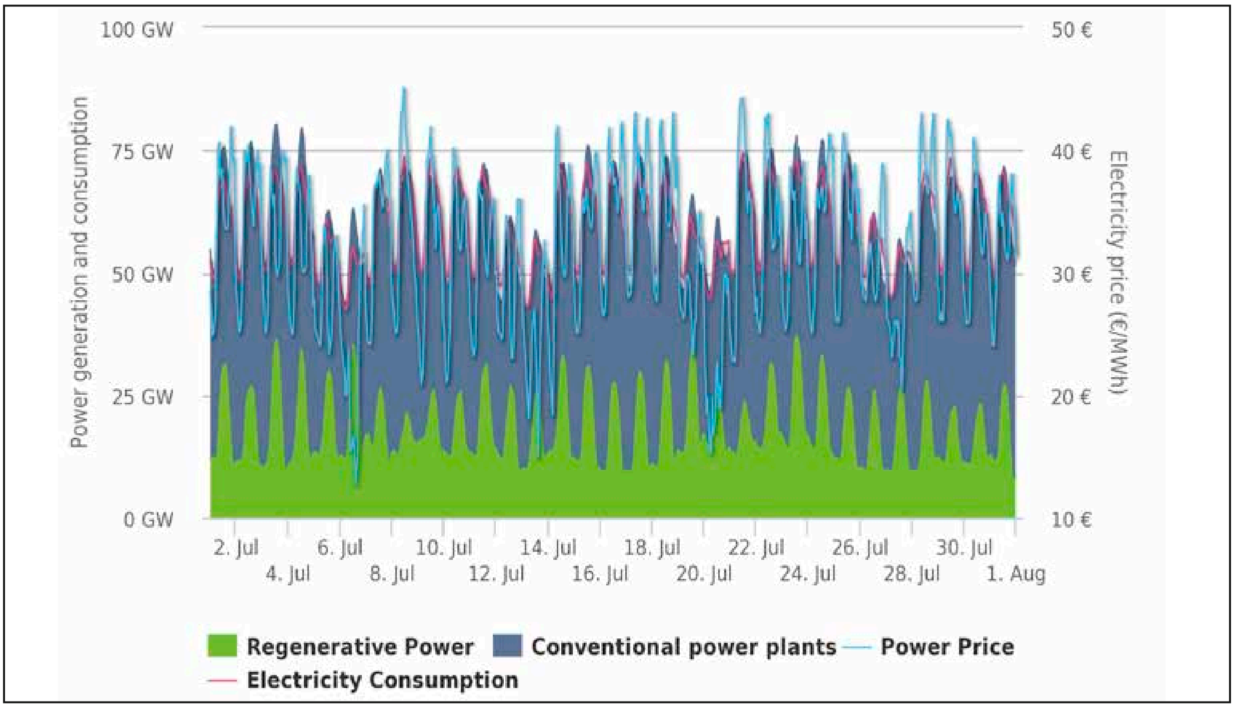


Figure 3. Generation and consumption of electricity in Germany in July 2014, also showing actual electricity consumption and electricity prices (Note: Regenerative Power includes renewable electricity from solar, wind, biomass and water) (Source: Agora Energiewende).

located in the middle of the Baltic Sea, wind power production is substantial and power cables so far only allow power to be transported from the mainland, not in the other direction.

Looking forward, Sweden's electricity production is already highly de-carbonised. Electricity price rises are hard to foresee in the next 10 years. The only threat of instability to Sweden is if it increases integration with European electric grids such that the regulatory function of the Swedish hydroelectric power is used for the benefit of other countries, and consequently lessening its capability to stabilise the Swedish grid.

2.3 Republic of Ireland

Ireland is an island off the west coast of Europe. This does not facilitate full integration of electricity distribution and production with its neighbours. Variable renewable electricity is much more challenging in an island grid (as on the isle of Gotland in Sweden).

The European Renewable Energy Directive (RED, 2009) set a target for the Republic of Ireland (hereafter termed Ireland) of 16% renewable energy share (RES) of gross energy consumption in 2020. The target is effectively equivalent to a combination of three national renewable targets of 40% renewable energy supply in electricity (RES-E), 12% renewable energy supply in heat (RES-H) and 10% for renewable energy supply in transport (RES-T).

Ireland's renewable energy supply was on track to meet targets as of 2012. In 2012, renewable energy was responsible for 7.1% of Ireland's gross energy consumption. This may be broken down as follows.

- RES-E (normalised) reached 19.6% of gross electricity consumption; the target for 2010 was 15%.
- RES-H was 5.2% in 2012; Ireland's target for 2010 was 5%.
- RES-T (including doubling counting for sustainable biofuels) was 3.8%; Ireland's target was 3% by 2010.

Electricity production from wind energy has increased to the point that it accounted for 81% of the renewable electricity generated in 2011. This fell back to 74% in 2012 due to the lower wind resource relative to 2011. Electricity generated from biomass accounted for 8% of renewable electricity in 2012. Biomass consists of contributions from solid biomass, landfill gas, energy from waste and biogas. Wind, hydro and biomass-generated electricity in 2012, respectively, accounted for 15%, 3% and 2% of Ireland's gross electricity consumption.

Looking forward, a study on the Irish electricity system (McGarrigle et al., 2013) found that the system non-synchronous penetration limit (related to the ability to operate the electricity grid with a given percentage of capacity on the grid from wind turbines) is expected to be 75% in 2020; in 2014 it was 50%. If this limit can be increased to 75% by 2020 it would necessitate 7% of renewable electricity to be curtailed (or be deemed surplus) by 2020. If this limit can only be increased to 60% then 14% of renewable electricity would need to be curtailed. Ireland needs to find a means of storage of this electricity and power to gas presents one such solution.

2.4 Brazil

Historically, hydro-electricity has represented the major part of the installed capacity in Brazil. However more recently, investments have been made in power plants fueled by natural gas and biomass. In 2013, 68% of electricity was sourced from hydro-electricity, 28% from thermal power plants (using natural gas and biomass), 2% from wind, 2% from nuclear power and a minor amount from solar-photovoltaic generating plants (ANEEL, Brazilian Electric Energy Regulatory Agency, 2014). Any negative impact on electricity prices are hard to foresee due to the high share of hydro-electric power.

The system of production and transmission of electric power in Brazil has multiple owners. By the end of 2020, the basic electrical transmission grid will have 142,000 km of power line (Ministry of Mines and Energy, 2011). The Brazilian Interconnected System (SIN) is a complex hydro-thermal system that is connected by a long transmission grid. Currently, only 2% of electricity production is not part of the SIN; these are isolated systems located mostly in the Amazonia area.

3. Demand driven biogas plants to stabilize the electricity grid

Figure 4. Water being bypassed at the hydro-electric power plant in Itaipu with a capacity of 14GWe

The operation of the Brazilian Electric Sector (BES) is highly regulated. The maximum supply of hydro-electricity is obtained by retaining the highest level in the reservoir. Due to the preponderance of power plants in the BES, mathematical models are used to find the optimal solution to balance the current benefit of water use and the future benefit of storage, measured in terms of expected fuel economy of thermal power plants.

To ensure optimal operation of the BES water is sometimes bypassed through smaller power plants to keep a stable water level in the dam of Itaipu (second largest hydro-electric power plant in the world). It would be possible to use this water in a more efficient way by producing hydrogen instead of just bypassing the power plant (see Figure 4). The power to gas concept could allow for balancing the water levels behind Brazil's dams in the future.

3.1 Economic incentive for demand driven biogas

For stable operation of electricity grids it would be of great benefit to be able to produce biogas and more importantly, electricity from the biogas at times best suited to the fluctuating electricity supply from wind and solar sources. However, for this to happen, there must be an economic driver for the biogas plant operators. Existing feed-in tariffs in several European countries ensure equal incomes for a producer of renewable electricity independent of whether the generated electricity is required at a specific time or not. This is not an optimal system, especially as levels of installed capacity of variable renewable electricity generation continue to increase; this potentially may lead to over supply at times of low demand, or vice-versa. It can be strongly argued that the support systems should be adapted to benefit producers who adjust the rate of electricity production according to periods of high demand or according to specific needs of the electricity grids.

3.2 Biomethane: a route to energy storage

Biogas produced through anaerobic digestion is often used as a source of combined heat and power (CHP), as shown in Figure 5(A). This is the dominant use of biogas in most countries, for example in Germany, South Korea, the UK and Denmark, amongst others. However Denmark's near neighbour Sweden uses the majority of the biogas produced as a source of transport fuel (Murphy et al., 2004, Persson and Baxter, 2015). For use as a transport fuel, or for natural gas grid injection (Urban, 2013), biogas must be cleaned (Petersson, 2013) and upgraded (Beil and Beyrich, 2013) to typically greater than 97% methane content (then known as biomethane). Inserting the biomethane into the natural gas grid allows for storage of the methane and later use as a fuel for heat, transport fuel or for power generation at times of peak demand, as shown in Figure 5(B). Another advantage is that the biomethane can be used to generate electricity in combined cycle gas turbines that can produce electricity from methane with efficiency above 60%. In Germany over the last few years a significant number of biogas facilities chose to inject gas into the gas grid (Bowe, 2013). However, CHP fed with raw biogas is still dominant in Germany.

3.3 Co-operative approach to demand driven biogas

Optimized electricity supply from renewables is the business case of some new companies in the electricity market in Germany since 2012. These power traders have developed portfolios of mainly renewable capacities comprising a lot of wind and solar power, but also biogas and fossil-based CHP. With the growth of a substantial share of renewables in Germany, the influence of renewables on power market prices has also grown. Consequently, a higher demand for flexibility in the power markets has evolved. Today the renewable electricity pools of these traders are offered on different power markets, especially the day ahead and intraday markets. In addition, balancing power, particularly secondary control reserve and minute reserve are also provided. Since 2014 even primary control reserve has been offered by one company. Thus these new players are taking over some of the functions of providing grid stability and security of energy supplies, which today is in large part supplied by fossil energy providers.

In cooperation with Ökostrom, Switzerland, several biogas plants are connected through a centralised control and regulation system. This system controls all CHP units so that the electricity production is adjusted to the actual electricity demand from one central location instead of at each individual plant (Mutzner, 2013). By connecting several units in such a joint control system the possibility of synchronising all biogas plants to produce electricity at peak demand times can be optimized.

3.4 Demand driven biogas at a single facility

Research and development is underway, particularly in Germany and Switzerland, to study the possibility of varying the rate of production of biogas to match demand of the electricity from the grid (Jacobi et. al., 2013; Mutzner, 2013). The concept is to operate CHP units and produce electricity when electricity is required and avoid production when demand is low.

Flexible electricity generation is possible by adjusting different components and operational strategies. The biogas plant can shift the time when it combusts biogas in the CHP, typically by a number of hours. As a result the biogas plant can adjust the time of production of electricity to the actual need of the electricity grid (Figure 6). The gas production rate, the gas storage capacity and the gas utilization rate define the flexibility of the plant. This flexibility always requires the storage of biogas but the gas storage capacity can be reduced if adjustment of the biogas production process provides additional flexibility. Demand driven power supply from biogas plants requires an increased capacity of the CHP unit in relation to the average output of the plant. The higher CHP capacity allows a plant to meet periodic higher than average electricity demand. It is noted that biomethane plants which inject upgraded biogas into the gas grid do not need separate gas storage, although a small storage may be suitable when services at the upgrading or injecting facility are necessary.

Another possibility to vary biogas production is to utilise two phase digestion (Nizami & Murphy, 2011) whereby liquors rich in volatile fatty acids are produced

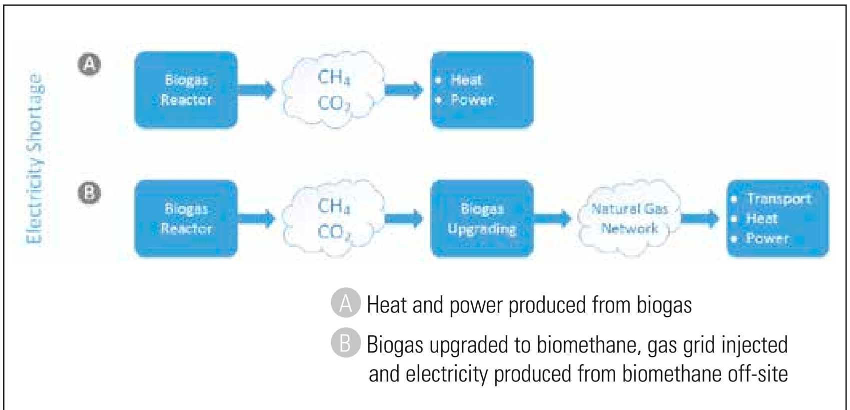


Figure 5: Two different pathways (A-B) for the role of biogas during electricity shortage.

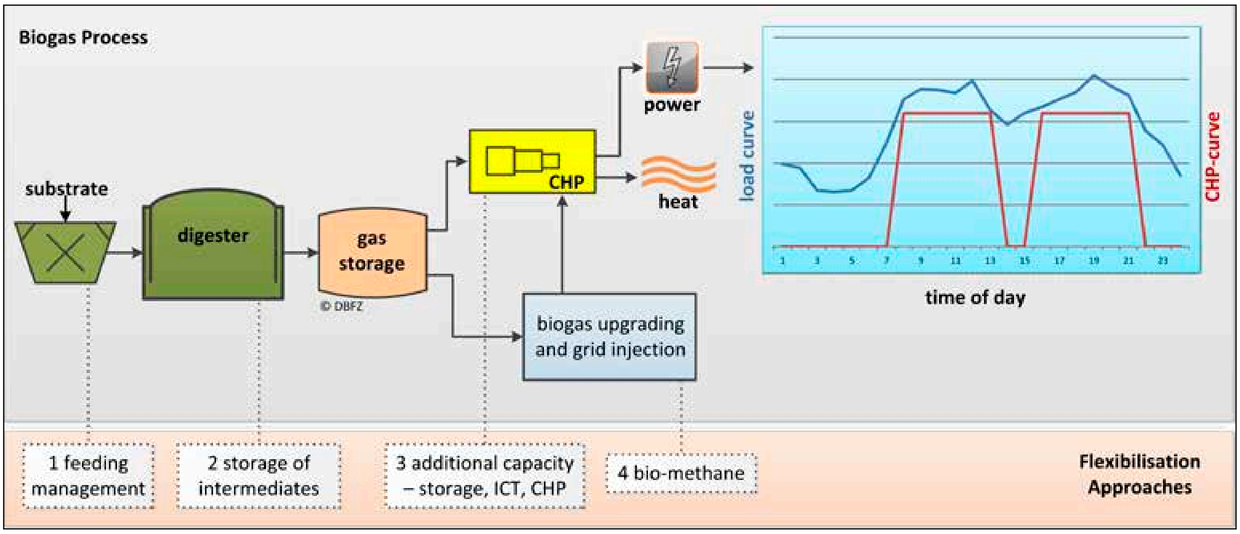


Figure 6: Approaches for biogas-based demand driven power production (Szarka et al, 2013)

in the first phase through hydrolysis and acidogenesis. Subsequently, the liquor is sent to a separate high rate methanogenic reactor at times of peak electricity demand.

3.5 Case study: Sobacken biogas plant

Loading of substrate to the reactor can be limited to particular times; for example feeding once per day to achieve high gas production during the daytime (and when demand is high) and a low gas production during the night (and when demand is low). Such a system has been in stable operation in the Sobacken biogas plant in Borås in Sweden since 2008. The substrate (source separated food waste and waste from the food industry) is fed to the digester in a discontinuous manner. The actual reason for this is not specifically to vary the gas production, but instead to fulfil the requirement for hygienisation, the process of minimising health risks from residues from the biogas production process. However, it is an excellent example of a full scale plant where the biogas production has been varied significantly each day while being able to maintain stable operation for 6 years.

The 24 hour daily cycle adopted at the Sobakken biogas plant is as follows. Every morning, at seven o'clock the flow of fresh substrate injection into the digester is started and this process is continued for ten hours. Thereafter, feeding is stopped and nothing is either injected or discharged for ten hours in order to allow for hygienisation to take place. During the final four hours in the 24 hour period digestate is discharged from the digestion vessel until the starting volume of digesting liquor in the digester is reached, i.e. the same volume as at the start of the 24 hour period. The volume of digestate in the digester and the biogas production rate are illustrated in Figure 7.

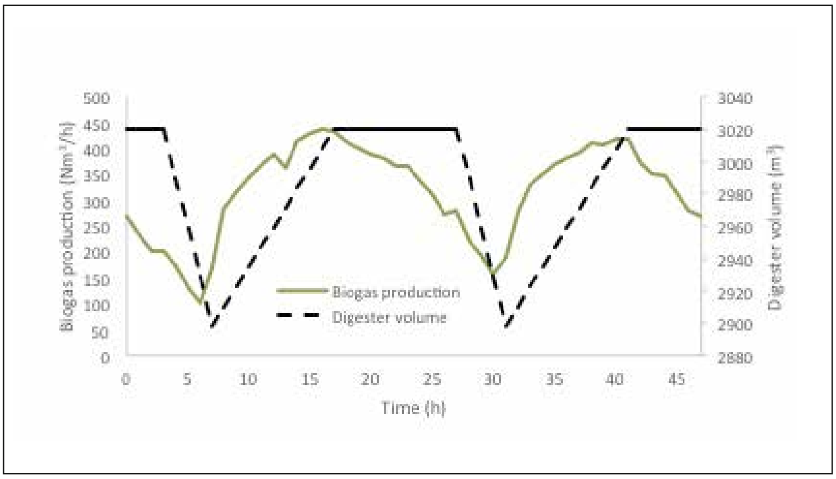


Figure 7: Biogas production and feed injection during a 48 hour period at Sobacken biogas plant in Borås. (Source: Borås Energi och Miljö)

The dashed black line in Figure 7 shows how the substrate volume varies in the digester during one day between 2900 and 3020 m³ (total effective volume is 3200 m³). The solid line shows how the raw gas production varies between 100 and 450 m³/h during the same day with the highest production in the middle of the day. The methane concentration in the biogas varies at the same time between 63% and 72%. This discontinuous operation of the process has not disturbed the microbiology performance in the digester to an extent so as to create a problem. Previously, the cycle was shorter and the loading was performed more rapidly which resulted in operational problems. One challenge that the operator has observed is that the operation is more challenging when gas production is high as several units are operating at the maximum of their capacity. Operational problems at maximum output are extremely costly as significant energy revenues can be lost. Uneven gas quality and the uneven gas flow have created operational problems for the downstream biogas upgrading unit based on water scrubbing technology. If a plant is operated in this way it is important to select a biogas upgrading system that is able to handle rapid changes in the gas flow rate as well as in the gas composition.

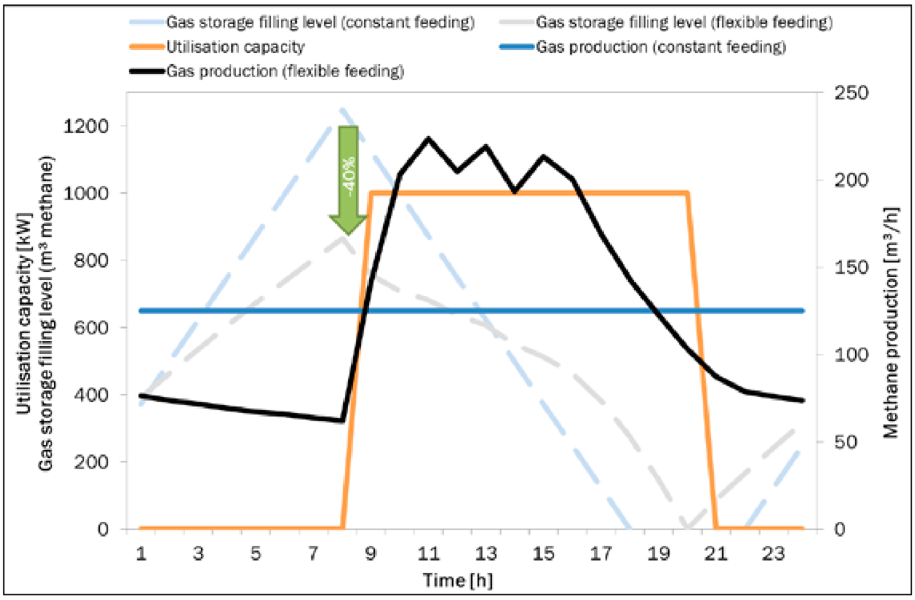


Figure 8: Cost reduction by means of lower gas storage need based on flexible biogas production (Jacobi et al, 2014a)

3.6 The benefit of combining phased feeding with biogas storage

Research results from Germany indicate that flexibility of biogas production can lower the need for additional gas storage capacity or increase the flexibility within the limits of plants designed to operate under constant conditions. The result is reduced costs for the provision of the flexible energy output (Trommler et al, 2012). However, this approach requires additional operational effort; feeding needs to be controlled to adjust the gas production process. In future scenarios the plant operator will require sufficient process control options to allow for flexible gas production according to the energy demand and flexible feeding regimes (Liebetrau et al, 2014). Figure 8 shows the potential reduction of biogas storage capacity for a flexible biogas production process (Jacobi et al, 2014a).

3.7 Biomethane storage through pressure variation in the distribution grid

Upgrading of biogas to biomethane, and production of electricity in a CHP-unit linked to the gas grid, increases flexibility of electricity output, due to the gas storage within the natural gas grid (Figure 5(B)). The storage capacity in the transmission grid is usually very large, but if the biomethane is injected into a distribution grid the storage capacity is often limited. A method of increasing the storage capacity in the distribution grid is to vary the pressure; use a lower pressure when the demand for electricity is high and a high pressure when the demand for electricity is low and the biomethane needs to be stored. Such a system was assessed by Stedin in the Netherlands.

Since 2012 Dutch DSO (distribution system operator) Stedin has performed field tests with dynamic pressure management. The principle is to apply variable pressure levels in the nominal 8 bar natural gas transport grid in order to create additional space for feed-in of pipeline quality biomethane and to reduce gas transport losses. The concept is called “Smart Green Gas Grid”, or SG3. The ambition of the work is to solve the problem of mismatch between local gas production and local gas demand. After a thorough theoretical analysis, SG3 was applied in the Netherlands. Real time information on pressure levels and gas flows were followed live on the internet. When the biomethane producer was offline, extra gas was fed into SG3 from the standard 8 bar gas grid. In this way the dynamic behavior of SG3 could be monitored within a limited amount of time. The SG3 field test highlighted a good match between theory and operational condition in the gas pipe. No negative effects were experienced in either the gas grid or end user appliances.

An alternative to SG3 is to compress the excess gas and feed it into a higher pressure part of the grid (e.g. 8 bar). However, this is not only expensive because of hardware but compression also requires extra energy. No additional hardware is required for SG3. Moreover, the biomethane producer saves energy because the gas can be fed into the gas grid at a pressure level below 8 bar.

3.8 Complexity and efficiency loss in demand driven biogas systems

The addition of a flexible biogas production process at a biogas plant increases the complexity of operation of the facility. It also results in additional costs and decreased capacity utilisation. Capital investment is required in extra power rating for the CHP system, in a gas storage system, in gas management systems, potentially a new transformer and possibly a new feed in point when the installed electric CHP-power is increased.

Conversion of an existing biogas plant to demand driven operation is costly and as such conversion needs to be compensated through higher financial return. Results from Germany (Schaubach et al, 2014) indicate that the costs of additional flexibility of biogas plants are sufficiently remunerated under the current framework condition (EEG-legislation, revenues from EPEX and balancing energy markets). However financial returns may not be sufficient for conversion to demand driven biogas if extra earnings from EPEX-Spot or balancing markets decrease (Jacobi et al, 2014b).

3.9 Flexible bioenergy in the energy grid

The flexibility from bioenergy-plants has positive effects for the grid and for the integration of additional shares of variable renewable power production. For the 50Hertz-TSO-region in Eastern Germany, research results show that a reduction of overall residual load can be achieved by flexible bioenergy; flexible bioenergy can be a major contributor to balancing energy (Tafarte et al, 2014).

It can be assumed, that flexible operation of existing bioenergy plants is an effective and cost efficient balancing option compared to electricity network upgrades and implementation of storage-alternatives (such as pumped hydro-electric schemes). Furthermore demand driven bioenergy plants and battery-storage can be seen as complementary; battery-storage is focused on short-term storage of energy whereas flexible bioenergy plants can supply electricity on demand within a short response time and from storage for up to 12-16 hours. By comparison, biomethane based CHP-units can utilise the gas at any point of time and consequently store energy for almost unlimited time.

Flexible bioenergy plants can be combined with power to heat and power to gas systems. Power to heat is currently used in Germany to avoid the shutdown of wind based power plants; surplus electricity is used for the provision of heat. Biogas plants can be combined with power to heat by shutting down the CHP unit in times of excess electricity production whilst heat demand of the biogas plant is provided by power to heat. This approach is not optimal from a greenhouse gas mitigation perspective. It is the authors’ opinion that surplus electricity from variable renewable electricity is better used in power to gas concepts.

4. Power to Gas: a means of storing surplus electricity

4.1 Electrolysis

The first step in a Power to Gas system is electrolysis and production of hydrogen. Electrolysis is an electrochemical reaction, where direct electrical current (DC) is used to split water into its constituent elements, oxygen and hydrogen, according to Eq. 1.

$$2\,H_2O\,(l) \rightarrow 2\,H_2\,(g) + O_2\,(g) \qquad \Delta H_r = 286\ \text{kJ/mole (at 25°C, 1 bar)} \qquad \text{[Eq. 1]}$$

The production of hydrogen and oxygen takes place in an electrochemical cell, which consists of two porous electrodes (anode and cathode), an electrolyte and a membrane (gas barrier) which hinders the recombination of the two product gases. As seen in Equation 1, water electrolysis is an endothermic reaction. Energy input is required to sustain the reaction. Hydrogen is formed via reduction at the cathode. Oxygen is formed via oxidation at the anode. The two electrodes are electrically connected via an external circuit and an ionic-conductive electrolyte. A typical electrolyser system comprises numerous (tens to hundreds) single cells, electrically connected in series, forming a so called cell stack. The performance of the electrochemical cell depends on its total resistance. In the case of water electrolysis, this resistance depends on the rate of the electrode reactions and the electrical resistance caused by the electrolyte and the external circuit. The resistance generally increases with increasing current/power. Temperature also has a large impact on the electrolysis performance.

There are, in principle, three different electrolysis technologies, which are either commercial or pre-commercial. They are named after the type of the electrolyte used. The technologies are Alkaline Electrolysis Cells (AEC), Polymer Electrolyte Membrane (PEM) cells and high temperature Solid Oxide Electrolysis Cells (SOEC). The characteristics of these cells are summarized in Table 1. Figure 9 shows a power to gas installation in Falkenhagen, Germany.

Figure 9: 2MW Power to gas unit based on alkaline electrolysis in Falkenhagen, Germany. The hydrogen is injected into the gas grid without methanation. (Source: E.ON)

4.1.1 Alkaline Electrolysis Cells (AEC)

The Alkaline Electrolysis Cells (AEC) technology is the most widely used. It has been in industrial use for decades and is also considered the most mature technology. It is generally used for small-scale applications, with typical production rates of 10-200 $Nm^3\ H_2/h$. Even though the majority of the alkaline electrolysers operate at a relatively low pressure (< 30 bar), systems operating at up to 200 bar (so called high pressure systems) have recently become commercially available. This high pressure technology is expected to be particularly attractive for large-scale applications (at MW scale) offering advantages such as low load operation down to 5-10%, somewhat higher efficiencies and more compact geometries. However, higher operation pressure leads to more complex safety and control systems which results in slower dynamic response times. This makes high pressure technology less suitable for variable power sources such as wind and solar.

4.1.2 Polymer Electrolyte Membrane cells

Polymer Electrolyte Membrane (PEM) cell technology has the ability to operate at four times higher power density than alkaline systems whilst simultaneously allowing operation at low loads (down to a few percent of rated capacity). Thus PEM electrolysis is well suited to variable wind and solar power (Carmo et al., 2013). This also leads to lower operation costs. However, it is a significantly less mature technology than the competing AEC technology. The installation cost is higher due to the expensive membrane and electrode materials. Another disadvantage of the system is that the membrane/electrolyte needs to be exchanged every 5 to 10 years (Benjaminsson et al., 2013).

4.1.3 Solid Oxide Electrolysis Cells (SOEC)

Solid Oxide Electrolysis Cells (SOEC) is the most promising technology, but the least mature. Similar to PEM technology, it can be operated in the reverse direction and produce power if desired. Due to its very high operating temperature (700-1000°C), the efficiency is potentially very high which should have a positive impact on costs. Firstly, in contrast to the low temperature technologies, a significantly larger amount of the energy needed for electrolysis is supplied as heat instead of more expensive electricity. Secondly, the rates of the electrochemical reactions are significantly faster at higher temperatures leading to an overall lower total cell resistance which gives better cell efficiency. Efficiencies of 90 to 95% are possible as compared to 60 to 70% for AEC and PEM technologies (Benjaminsson et al., 2013). The high operating temperature of SOEC enables not only production of pure hydrogen from water but also from synthesis gas (carbon monoxide and hydrogen) through co-electrolysis of steam and carbon dioxide. However, SOEC operation requires access to high-grade waste heat during start-up. This may be sourced from a power plant or more appropriately from an adiabatic catalytic reactor such as a catalytic methanation process.

In addition to hydrogen, oxygen is also produced during the electrolysis. Oxygen could be an additional valuable byproduct from the biogas plant and used for desulphurization by adding oxygen during the anaerobic digestion process or in separate desulphurization units before biogas upgrading. By using oxygen instead of air, nitrogen accumulation can be avoided which otherwise makes it very hard to reach the required purities during biogas upgrading to biomethane. The oxygen can also be sold to nearby industries. One such example is a gasification plant, using direct gasification that requires pure oxygen to produce biomethane without nitrogen input.

Table 1. Summary of the typical characteristics of different electrolysis technologies.

	AEC	PEM	SOEC
Type of electrolyte	20 – 30% KOH in $H_2O(l)$	Polymer, e.g. NAFION®	Ceramic of yttria-stabilized zirconia (YSZ)
Type of electrodes	Ni-based	Pt/C-based	Ni-based (H_2) Perovskite (O_2)
Type of membrane	Asbestos or asbestos-free polymer	Same as the electrolyte	Same as the electrolyte
Temperature	60 – 80°C	50 – 80°C	700 – 1000°C
Pressure	< 30 bars	< 30 bars	under evaluation
Power density	≤ 1 W/cm²	≤ 4 W/cm²	under evaluation
Part load range	20 – 40%	0 – 10%	0 – 10%
Efficiency[1]	60 – 70%, corresponding to the power consumption 4 – 5 kWh/Nm³ H_2	60 – 70% corresponding to the power consumption 4 – 5 kWh/Nm³ H_2	90 – 95%, corresponding to the power consumption 3 – 3.3 kWh/Nm³ H_2

KOH=potassium hydroxide, Ni=Nickel, Pt=Platinum, C=Carbon.

[1] Efficiency refers to the cell voltage efficiency based on lower heating values (LHV).

1 Nm³ H_2 has a LHV of 10.79 MJ or 3 kWh; thus for example 3 kWh electricity producing 2.85 kWh of H_2 yields an efficiency of 95%.

4.2 Power to methane

In examining the potential for power to methane the source of carbon dioxide (CO_2) is very important. The CO_2 can either be of fossil or renewable origin, extracted from the air or various industrial waste gases. However, capture of CO_2 is not cheap and clean concentrated sources of CO_2 are not abundant. It is not simply a case of collecting the flue gas from the stack from a power plant and mixing it with hydrogen. The cost of CO_2 capture is more expensive if the concentration of CO_2 in the gas is low. Thus CO_2 capture from the exhaust of a thermal power facility with low concentration of CO_2 is expensive. Estimates for the cost of CO_2 range from €7 – €75 per tonne of CO_2 captured, with coal plants at the lower end and combined cycle gas turbine plants at the upper end of this scale (Sterner (2010), IPCC (2005)). Alternatively, the CO_2 produced in other processes, such as in an ethanol plant or at a biogas facility, can be much cheaper. One example is the CO_2 from biogas upgrading (Ahern et al, 2015), which in most cases is free from contaminants.

Use of the power to gas concept at a biogas facility has great potential. When excess electricity is available, surplus electricity may be stored through the power to gas concept by producing hydrogen by electrolysis. The hydrogen can thereafter be combined with CO_2 to produce methane in a number of ways:

- Hydrogen is added to the anaerobic reactor and reacted with raw biogas within the biogas digester; this is termed in-situ biological methanation (Figure 10(A)). In this process it is unlikely that a biomethane standard (> 97% methane content) suitable for gas grid injection or for vehicle use will be achieved. Thus a smaller biogas upgrading step will be required if biomethane is the proposed end product.
- Hydrogen is added to and reacted with raw biogas after the biogas digester. This can be a biological ex-situ process in a separate biological reactor or a catalytic process (Figure 10(B)).
- Methanation may be post biogas up-grading (Figure 10(C)). This could be employed at a site where biogas upgrading is already in place and a very concentrated CO_2 stream is available.

A “disadvantage” of catalytic methanation is that impurities, such as hydrogen sulphide and siloxanes, have to be removed prior to the catalytic step. This is not the case for biological methanation. For catalytic methanation it may be more beneficial to perform the methanation with raw biogas (Figure 10(B) after remo-

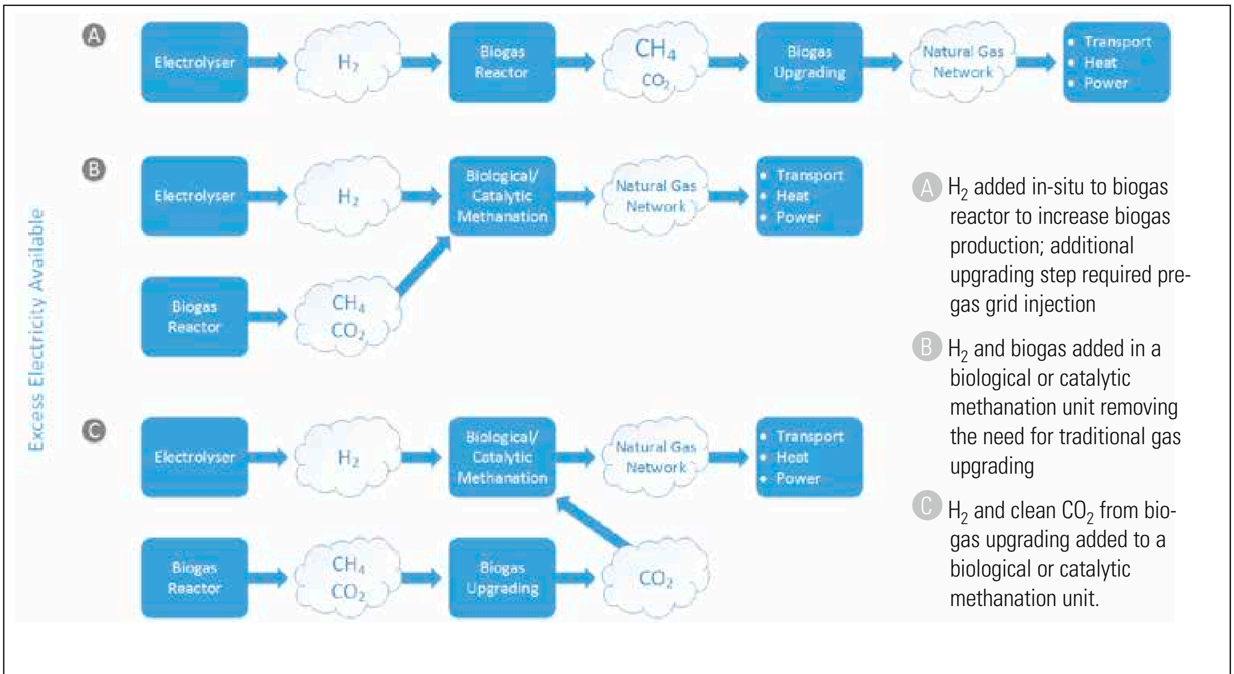


Figure 10: Three different pathways using power to methane concepts at a biogas facility

val of hydrogen sulphide, instead of pure CO_2 from the upgrading unit (Figure 10(C)). A larger catalytic surface will be required to handle the increased gas flow, but less heat will be produced per volume of gas; this facilitates a less complicated and less costly design. A major advantage of methanation with raw biogas is that the costs associated with biogas upgrading can be avoided. This is a significant cost saving and may be the only situation that allows a sustainable financial model.

There are a number of questions to be answered when combining a biogas plant with a power to methane application:

- For biological methanation, should hydrogen be inserted into the digester (in-situ) as in Figure 10(A) or is it more efficient to perform this operation in an ex-situ process as in Figure 10(B)?
- If methanation is performed ex-situ, is it more cost efficient to do this with a biological or a catalytic method (Figure 10(B))?
- Could the biogas upgrading plant be completely removed from the biogas plant if biological or catalytic methanation is applied (Figure 10(B))?
- If there is an existing biogas upgrading unit, should the CO_2 from the biogas upgrading unit be used instead of the biogas (Figure 10(C))?

None of these questions have a definitive answer because the industry is still developing and the answer will depend on variables including: the size of the facility; whether it is a new facility or an addition to an existing facility; if an existing facility whether the biogas was used in CHP or upgraded; the policy and tariffs of the country of operation.

4.3 Catalytic Methanation

The reactions involved in generating methane from carbon monoxide, carbon dioxide and water through catalytic methanation are shown in Equations 2, 3 and 4 (ΔH_r at 25°C). The reaction described in Equation 3 is termed the Sabatier reaction.

$$CO\,(g) + 3\,H_2\,(g) \rightarrow CH_4\,(g) + H_2O\,(g) + \text{heat} \qquad \Delta H_r = -210\ \text{kJ/mole} \qquad \text{[Eq. 2]}$$

$$CO_2\,(g) + 4\,H_2\,(g) \rightarrow CH_4\,(g) + 2\,H_2O\,(g) + \text{heat} \qquad \Delta H_r = -165\ \text{kJ/mole} \qquad \text{[Eq. 3]}$$

$$CO\,(g) + H_2O\,(g) \rightarrow CO_2\,(g) + H_2\,(g) + \text{heat} \qquad \Delta H_r = -41\ \text{kJ/mole} \qquad \text{[Eq. 4]}$$

The methanation reactions are thermodynamically favored by low temperatures and high pressures. In practice, the reactions normally take place in the presence of a nickel or a ruthenium-based catalyst normally at 300 – 500°C, with an overall energy conversion efficiency of 80% (Benjaminsson et al., 2013).

The methanation reactions are highly exothermic and generate significant quantities of heat (which could be used for high temperature Solid Oxide Electrolysis Cells (SOEC)). Temperature control is essential to favor methane formation and to avoid overheating and deterioration of the catalysts. There are different strategies for temperature control: several fixed bed adiabatic reactors with intermediate cooling (i.e. no heat is transferred to or from the reactor) or isothermal reactors (i.e. operating at a constant temperature) with integrated heat exchange cooling or combinations of these two. Depending on the flow rate applied, the reactors can be of fixed, bubbling or of circulating bed type. For methanation, fixed beds are the most commonly used since these enable the most efficient cooling (Kopyscinski, 2010). As of 2014 there are only a few companies that develop electrolysers integrated with catalytic methanation reactors. These are ETOGAS, Haldor Topsøe and Sunfire (Benjaminsson et al., 2013: Iskov and Rasmussen, 2013). These organisations are involved in the following projects:

- As of February 2014 ETOGAS was the only company that has sold and installed complete power to methane systems of industrial scale; they have installed three systems, all in Germany. The most recent one (completed late 2013) is the world´s largest power to gas plant. It has an estimated average methane production capacity of 25 GWh/year and a power capacity input of 6 MWe (suggesting a combined efficiency and capacity factor of 48%). Their technology is based on alkaline electrolysis and isothermal fixed bed methanation reactors. The carbon dioxide is sourced from an amine scrubber used for biogas upgrading. The heat required in the amine scrubber is supplied from the electrolysis and methanation equipment.
- Sunfire expects that they can offer complete power to methane systems in 2014. The first ones will be based on alkaline electrolysis combined with their own catalytic methanation reactor

concept, consisting of an adiabatic reactor followed by an isothermal reactor. However, from 2016, they plan to substitute the alkaline electrolyser with their own SOEC-technology, which potentially can increase the overall efficiency (from power to methane) from 55% to 80%.

- Haldor Topsøe plans to combine their SOEC technology with their catalytic methanation technology. They participate in several R&D projects using SOEC technology and a methanation technology called the TREMP® process (Topsøe Recycle Methanation Process). If starting with syngas originating from biomass or coal gasification, this concept is based on three catalytic fixed bed adiabatic reactors with intermediate cooling. However, if cleaned biogas is the starting point, the process can be simplified and only two reactors are needed.

4.4 Biological in-situ or ex-situ methanation?

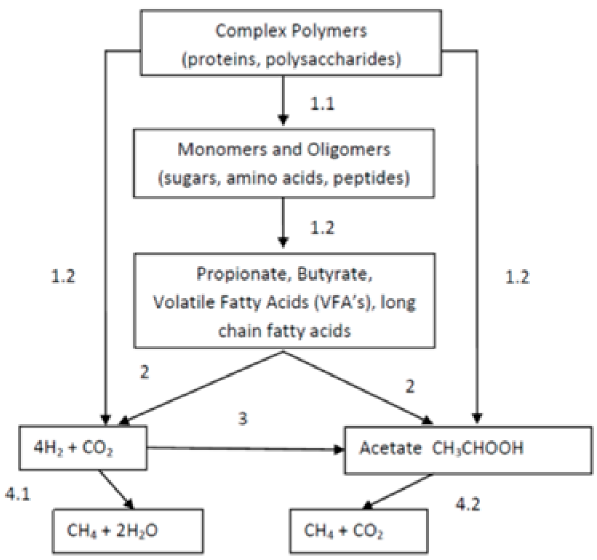
4.4.1. Sequential Processes of Anaerobic Digestion

The microbiology of anaerobic digestion is complex. It is dominated by four different trophic groups (Figure 11). It is a sequential process; the end products of one trophic group of micro-organisms are the food source of another trophic group of micro-organisms. This may be noted in degradation of ethanol as highlighted by Murphy and Thamsiriroj (2013) and Colleran (1991). Three separate species are required. Acetogenic bacteria (species 2) convert ethanol to acetic acid and hydrogen; in terms of thermodynamics this is not a favourable reaction (ΔG is positive). Hydrogenotrophic methanogenic species (species 4.1) have a high affinity for hydrogen (ΔG is negative) and thus assist the acetogenic species. The aceticlastic methanogenic species (species 4.2) convert acetic acid to methane and carbon dioxide.

Species 2	$CH_3CH_2OH + H_2O$	$= CH_3COO^- + H^+ + 2H_2$	$\Delta G = 5.95$ kJ/reaction	[Eq. 5]
Species 4.1	$2H_2 + 0.5CO_2$	$= 0.5CH_4 + H_2O$	$\Delta G = -65.45$ kJ/reaction	[Eq. 6]
Species 4.2	$CH_3COO^- + H^+$	$= CH_4 + CO_2$	$\Delta G = -28.35$ kJ/reaction	[Eq. 7]
Net	CH_3CH_2H	$= 1.5CH_4 + 0.5CO_2$	$\Delta G = -87.85$ kJ/reaction	[Eq. 8]

4.4.2 Effects of adding H_2 to an anaerobic reactor

Hydrogen can be converted to methane by the action of hydrogenotrophic methanogens; the reaction may be represented by Equation 3. The efficiency of biological methanation (just as catalytic methanation) is limited to a maximum of around 80% due to the energy released when this exothermic reaction takes place (Benjaminsson et al., 2013). Obviously addition of "extra" or "outside" hydrogen to an anaerobic digester



1	Acidogenic bacteria
1.1	Hydrolytic bacteria
1.2	Fermentative bacteria
2	Acetogenic bacteria
3	Homoacetogenic bacteria
4	Methanogenic archae
4.1	Hydrogenotrophic Methanogenic archae
4.2	Aceticlastic Methanogenic archae

Figure 11: Four trophic groups involved in anaerobic processes (adapted from Murphy and Thamsiriroj, 2013; Colleran, 1991)

has potential to disturb the operation of the sequential microbiological system. The problems are outlined below:

- CO_2 is very soluble; within the digester it reacts with hydroxide ions to form bicarbonate ions (HCO3-) which gives buffering capacity (Murphy and Thamsiriroj, 2013). Introduction of H_2 to a reactor consumes CO_2 and creates methane. This decreases the partial pressure of CO_2, reduces buffering capacity and causes an increase in pH, which typically has a negative effect on methanogenesis (Luo and Angelidaki, 2013a).
- Degradation of propionate and butyrate needs very low hydrogen concentration; generally lower than 10-4 atm (Fukuzaki et al., 1990). Adding hydrogen to a biogas reactor may increase hydrogen partial pressure, inhibiting VFA (propionate and butyrate) degradation (Luo et al., 2011; Siriwongrungson et al. 2007).

4.4.3 Biological methanation in the anaerobic biogas reactor (In-Situ Reactor)

Based on Equation 3, in theory, hydrogen should in principle be added to a biogas reactor at 4 times the quantity of CO_2. This is the theory and 100% efficiency is not easy to obtain. If the biogas comprises 50% $CH_4$and 50% CO_2, theoretically all CO_2 will react with H_2 and the exit gas will be 100% CH_4. In this simplified analysis the quantity of CH_4 produced will double. A crucial challenge with biological conversion of H_2 to CH_4 is the fact that H_2 is approximately 500 times less soluble than CO_2 at 60°C. Thus the requirement to put H_2 into solution and make it available for consumption by hydrogenotrophic methanogens is essential for an efficient in-situ process; this may be termed a gas liquid mass transfer criterion.

Luo et al. (2011) reported improved gas liquid mass transfer of the process through very high levels of mixing. However, up-scaling of such a system may result in very high parasitic energy demands and lower life cycle energy efficiencies. Insertion of H_2 by a ceramic diffuser with pores of 14 – 40 micron (Luo and Angelidaki, 2013a) or a hollow fibre membrane (HFM) with diameter of 284 microns (Luo and Angelidaki, 2013b) were also trialed and showed improvements in efficiency as exemplified by higher methane content and lower CO_2 and H_2 contents in the biogas. It is difficult to achieve maximum efficiency in an in- situ reactor; the methane content increases but H_2 and CO_2 are still present to varying degrees in the exit gas.

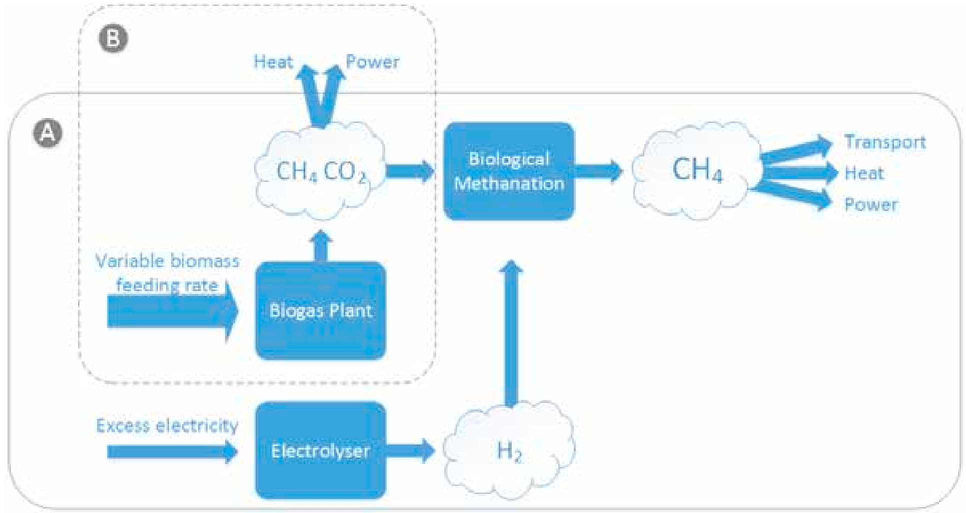
MicrobEnergy evaluated an in-situ methanation process in a pilot plant based on a conventional horizontal digester with high dry matter content. The high viscosity is important since it decreases the rising speed of the hydrogen bubbles that are added at the bottom of the digester. Thus far, the methane concentration has successfully been increased from 50 to 75% (Benjaminsson et al. 2013).

4.4.4 Biological methanation in a separate reactor (Ex-Situ Reactor)

In-situ biogas upgrading suffers from many technical challenges that can be avoided by using an external bioreactor optimized for the process. Luo and Angelidaki, (2013b) investigated an application of biological methanation to biogas upgrading in an ex-situ vessel enriched with hydrogenotrophic methanogens. They achieved very high consumption of H_2 and CO_2. Enriched thermophilic inoculum performed 60% better than enriched mesophilic inoculum. It is suggested (Luo and Angelidaki, 2013b) that the upgrading reactor volume is of the order of 11% of the original biogas reactor. It is possible to achieve gas grid injection specification from ex-situ biomethanation (Luo and Angelidaki, 2012).

An alternative to a stirred tank reactor is a trickle bed reactor. An advantage of this technique is that the energy required for stirring is avoided. In a recent study (Burkhart et. al. 2014) it was shown that a trickle bed reactor can operate without gas circulation, due to the formation of a three-phase system on the carrier surface. Burkhart and co-workers (2014) have achieved methane concentrations higher than 98%. Another technology investigated to avoid or decrease the energy consumption needed for stirring involves use of hollow fibre membranes to dissolve gas into the liquid phase (Benjaminsson et al., 2013).

MicrobEnergy, Krajete and Electrochaea are companies in start-up phase in the field of biological methanation. They all have pilot plants in operation. Krajete and Electrochaea focus only on biological methanation in a separate ex-situ reactor while MicrobEnergy also studies in-situ systems (Benjaminsson et al. 2013). The ex-situ reactor for biological methanation is in most



A Gas grid injection after biological methanation at times of low power demand

B CHP production at times of peak power demand

Figure 12: Co-location of CHP and biological methanation (from Ahern et al., 2015)

cases designed with hydrogen addition in the bottom of the continuously stirred tank reactor operated at 65°C (Benjaminsson et al., 2013). The stirring speed is very important in this type of system. A high stirring speed increases the hydrogen solubility and increases the methane yield but also the energy consumption.

Fraunhofer IWES, together with partners ZSW and Solarfuel are conducting an on-going evaluation of an ex-situ methanation process for biogas plants with a raw gas capacity of up to 50 m3/h. The study is located on the premises of the Hessian biogas research centre (Persson and Baxter, 2015).

In December 2013, Electrochaea was awarded a substantial grant to design, engineer, build, and operate a 1MW power to gas facility near Copenhagen in Denmark in a project called BioCat. A 1 MW alkaline electrolysis plant from Hydrogenics was scheduled to be installed and surplus electricity used to produce hydrogen. The hydrogen will be combined with raw biogas or CO_2 from a biogas upgrading plant and fed into an ex-situ biological methanation reactor. The produced methane will be injected into a nearby gas distribution system. Start-up is planned for July 2015.

4.5 Can biogas upgrading be replaced by methanation ?

Obviously the time over which electricity may be deemed surplus and used to produce hydrogen is finite and uncertain. Hydrogen produced from surplus electricity (which would be lost to the system without conversion to hydrogen) should in principle be significantly cheaper than hydrogen produced from electricity that is produced at a time where there is demand for electricity. Storage of hydrogen is also a significant cost consideration; an alternative would be to store biogas and react with hydrogen when it is available.

If the aim of the biogas plant is to produce biomethane over the entire year, the economics may be such that biogas upgrading at a specific biogas facility could be employed for both biological methanation through hydrogen upgrading (when electricity is surplus and hydrogen is cheaper), and a traditional biogas upgrading system when electricity supply is not surplus and hydrogen is more expensive. Thus one large advantage of biological methanation, savings in investment and operational costs for a traditional biogas upgrading system, may not be fully realizable. It is also yet to be proven which methanation systems are able to reach the level of specification of a traditional biogas up-grading system and again this may necessitate co-location of biological methanation and traditional biogas upgrading. A significant opportunity would be lost if the power to methane system does not replace (to some extent) the energy and cost of a traditional biogas upgrading system. However another option may be to produce biomethane when hydrogen is cheap due to low demand for electricity and produce electricity in a CHP system at times of high demand for electricity (Figure 12).

Figure 13: Biogas plant with adjacent wind park

Another solution may be to separate the concept of surplus renewable electricity storage from biological methanation. This may be exemplified by locating a wind park and biogas facility adjacent to one another (Figure 13) and by converting some of the electricity from the wind turbine to H_2 and use it purely as part of a gas upgrading system. Biogas may be stored until sufficient hydrogen is available for the biomethanation system.

5.Discussion

The perspective of IEA Bioenergy Task 37 is that biogas could and should have an important role in future smart energy grids for balancing increased amounts of variable renewable electricity generation. This may be achieved in two ways:

- Through use of demand driven electricity production from biogas plants in times of maximum demand for electricity and low supply; for example when there is little wind and wind turbines are not producing sufficient electricity.
- Through power to methane when the demand for electricity is less than supply of electricity. This has a serendipitous benefit of upgrading biogas to biomethane through use of CO_2 in the biogas.

Regulation of the electricity grid tends to be a function of National Government with Grid Operators generally responsible for implementation. Without clear framework conditions and endorsement from Government there is a risk that different market actors will regard each other, rather than themselves, as the ones to take the first step. The main actors include the power generators, grid owners and third parties involved in trade. Development of power to gas requires economic incentives, such as state subsidies, grants or electricity feed-in tariff regulated by the generation and consumption of electricity with higher feed-in tariffs when electricity is needed and vice versa.

Utilisation of smart grids and interconnection of the gas and electricity grids through the power to gas concepts provide a means of storing renewable electricity that would otherwise be lost to the system. The life cycle efficiency from electricity to methane is in the range of 48 to 76% taking the efficiency of electrolysis to be between 60 and 95% and methanation of around 80%. If power to methane to power is employed, net conversion efficiency in the range 19 to 45% would be expected; this assumes electrical efficiency between 40% (at small scale) and 60% (at large Combined Cycle Gas Turbine (CCGT) scale). One situation that should be avoided is generation of electricity from methane at the same time that surplus electricity is used to produce methane, in which case the overall effect is just a loss of electricity (Ahern et al., 2015). While close integration of electricity grids between countries should be able to minimise inefficiencies, power to gas is likely to be needed for grid balancing at the regional level and where insufficient interconnection is available.

Power to gas must be compared to alternatives as a means of energy storage. Pumped hydro-electricity schemes have life cycle efficiencies in the range 75 – 80%, however the potential for new sites are limited and the large scale of these systems means very long lead times for construction (Ahern et al., 2015). An added benefit and a differentiation between power to gas and other energy storage schemes is that power to gas changes the energy vector to gas. When it is considered that typically electricity is approximately 20% of final energy demand whilst transport and thermal energy tend to be of the order of 40% each (Murphy and Thamsiriroj, 2011), the benefit of changing the energy vector may be noted. This is highlighted by the weighting attributed to renewable energy supply in transport (RES-T) attributed to renewable gaseous fuel produced from non-biological origin in the proposed amendment to the EU Renewable Energy Directive (European Commission, 2014). The weighting of 2 to the energy content of the fuel is transferrable to extra green certificates in the biofuel obligation certificate scheme, which is for example the case in Ireland. This weighting makes biofuel production for transport financially viable in Ireland (Ahern et al., 2015). Thus it may be suggested that an optimal route for power to gas is to make renewable transport fuel for natural gas vehicles from surplus electricity.

The authors expect that many power-to-gas facilities that utilize CO_2 from biogas plants will be on the market within 5–10 years, especially in countries with numerous biogas facilities and large capacities for generation of variable renewable electricity, such as Germany, Denmark and The Netherlands. Biological methanation plants will probably be more competitive in smaller installations, while catalytic methanation may be more competitive in larger installations.

One uncertainty for the power to gas industry is whether there will be successful development of other methods and applications which use surplus electricity. This may increase the competition for, and the price of, surplus electricity. It may emerge that hydrogen could have a better economic return outside the energy sector. It should also be considered what will happen when the capacity of the electrical power system is in excess of electricity demand. Who will build new power plants? If there is no excess electricity production there may be little demand for power to gas facilities. It is reasonable to expect that the electricity grid owners will feel their major task is to invest in the electricity grid, rather than investing in capacity to dispatch electricity. Potentially there is scope for biogas facilities to invest in wind turbines and power to gas systems as a biogas upgrading system.

6. Conclusions and recommendations

The annual growth of variable renewable electricity is increasing and is projected to continue to increase in the period to 2050. Challenges associated with the intermittent character of wind, ocean and solar power will become more problematic. Today, there is little agreement on how variable renewable electricity will be balanced in the future and what developments will take place in the next 5–10 years. Islands such as Ireland are looking at electrical interconnectivity with France and the UK. A potential challenge for interconnectivity is that electricity will be purchased at a higher price than its cost of generation. Electrical interconnectivity may thus be expensive for a country. The gas grid may be seen as an alternative to electrical connection particularly for island grids. Policy is required at Government level to indicate the preferred route. It can be strongly argued that future feed-in tariff schemes should be designed to increase the support for producers that contribute to balancing the electricity grid and generate electricity when it is needed and/or store it when there is a surplus. This will create financial incentives for biogas plants to develop and build systems to achieve this target through demand driven biogas production and power to methane systems.

Biogas plants are more complex when less biodegradable substrates are used. Methanation as well as demand driven biogas production will further add to this complexity. There will be a need to increase system integration within the biogas plant; it might not be necessary to optimize every single unit operation, but instead the energy consumption and operational cost of the entire plant should be optimized. Within a Smart Energy Grid system the optimization may not be in the biogas facility itself, but the role it will play in a broader energy supply market.

Through this publication IEA Bioenergy Task 37 highlights the potential role of biogas in future smart energy grids. As of 2014 power to gas and demand driven biogas plants are developing technologies; there is no definitive optimal solution or technical layout recommended. IEA Bioenergy Task 37 will continue to produce publications to describe the development and future implementation within this field.

References

AHERN, E., DEANE, P., PERSSON, T., O' GALLACHOIR, B., MURPHY, J.D. (2015) *A perspective on the potential role of renewable gas in a smart energy island system.* Renewable Energy, 78 (2015) 648 - 656

ANEEL – *Brazilian Electric Energy Regulatory Agency (2014)* Available at http://www.aneel.gov.br

BEIL M., BEYRICH W., (2013) *Biogas upgrading to biomethane*, in: WELLINGER A, MURPHY J, BAXTER D, editors. *The biogas handbook: science, production and applications.* Woodhead Publishing series in Energy: number 52; 2013, ISBN 978-0-85709-498-8

BENJAMINSSON G., BENJAMINSSON J., BOOGH RUDBERG R., (2013) *Power-to-Gas A technical review*, SGC Rapport 2013: 284 Available at http://www.sgc.se/en/?pg=1445651

BOWE S. (2013) *Market development and certification schemes for biomethane*, in WELLINGER, A., MURPHY, J., BAXTER, D., editors, *The biogas handbook: science, production and applications.* Woodhead Publishing series in energy: number 52; 2013, ISBN 978-0-85709-498-8

BURKHARDT M., KOSCHACK T., BUSCH G., (2014) *Biocatalytic methanation of hydrogen and carbon dioxide in an anaerobic three-phase system*, Bioresource Technology, 178 (2015) 330-333

CARMO M., FRITZ L. D., MERGEL J., STOLTEN D., (2013) *A comprehensive review on PEM water electrolysis*, International, Journal of Hydrogen Energy, 38 (2013) 4901-4934

COLLERAN E. (1991) *Application of anaerobic bacteria to wastewater treatment and energy recycling*, Winter lecture series, the Institute of Engineers of Ireland, (unpublished), November 1991.

EUROPEAN COMMISSION (2014) *Proposal for a Directive of the European Parliament and of the Council amending Directive 98/70/EC relating to the quality of petrol and diesel fuels and amending Directive 2009/28/EC on the promotion of the use of energy from renewable sources,* Available at http://register.consilium.europa.eu/doc/srv?l=EN&f=ST%2010300%202014%20INIT

RED (2009) *European Renewable Energy Directive* (2009/28/EC) of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources.

FUKUZAKI S, NISHIO N, SHOBAYASHI M, NAGAI S., (1990) *Inhibition of the fermentation of propionate to methane by hydrogen, acetate, and propionate, Appl .Environ. Microbiol.*, 56(3) (1990) 719–723.

HVIDTFELDT LARSEN, H., SØNDERBERG PETERSEN, L., (2013) *Energy storage options for future sustainable energy systems*, DTU International Energy Report 2013, Available at http://orbit.dtu.dk/files/60269108/DTU_International_Energy_Report_2013.pdf

IEA (2011) *Technology Roadmap - Smart Grids, International Energy Agency/OECD*, 2011, Available at http://www.iea.org/publications/freepublications/publication/smartgrids_roadmap.pdf

IPCC (2005) *Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage*, Available at https://www.ipcc.ch/publications_and_data/_reports_carbon_dioxide.htm. [Accessed: 25-Feb-2014].

ISKOV H., RASMUSSEN N. B., (2013) *Global screening of projects and technologies for Power-to-Gas and Bio-SNG*, Danish Gas Technology Centre Report, ISBN 978-87-7795-373-6, Available at http://www.dgc.dk/publikationer/

JACOBI H.F., TROMMLER, M., MAUKY, E. (2013) *Flexible Biogasproduktion in der Direktvermarktung.* EDS THRÄN, D., PFEIFFER, D., *Konzepte für die Bioenergie der Zukunft Energetische Biomassenutzung*, 4. Statuskonferenz, Schriftenreihe des BMU-Förderprogramms Energetische Biomassenutzung Band 9, ISSN 2192-1806, pp. 146-151

JACOBI, F.H.; MAUKY, E. (2014): *Neue Ansätze zur Flexibilisierung von Biogasanlagen.* In: NELLES, M. (Hrsg.): *DBFZ-Jahrestagung Bioenergie. Vielseitig, sicher, wirtschaftlich, sauber?!* S. 81–87. Leipzig. ISBN 2199-9384.

KAPARAJU P., RINTALA J., (2013) *Generation of heat and power from biogas for stationary applications: boilers, gas engines and turbines, combined heat and power (CHP) plants and fuel cells*, in WELLINGER, A., MURPHY, J., BAXTER, D., editors, *The biogas handbook: science, production and applications.* Woodhead Publishing series in energy: number 52; 2013, ISBN 978-0-85709-498-8

KOPYSCINSKI J., S. T. (2010) *Production of synthetic natural gas (SNG) from coal and dry biomass – A technology review from 1950 to 2009*, Fuel 89 (8)(2010) 1763–1783

LBEG (2013) *Untertage-Gasspeicherung in Deutschland; Erdöl, Erdgas, Kohle, Landesamt für Bergbau, Energie und Geologie, Hannover*, Available at http://www.lbeg.niedersachsen.de

LIEBETRAU J., DANIEL-GROMKE J., JACOBI F., (2014) in THRÄN, D. (Ed.) : *Smart Bioenergy. Technologies and concepts for a more flexible bioenergy provision in future energy systems.* Springer-Verlag GmbH, 2014, Heidelberg. ISBN: 978-3-319-16192-1

LUO G., ANGELIDAKI I., (2013a) *Co-digestion of manure and whey for in situ biogas upgrading by the addition of H_2: process performance and microbial insights.* Appl. Microbiol. Biotechnol.,97 (2013) 1373-1381

LUO G., ANGELIDAKI I., (2013b) *Hollow fiber membrane based H_2 diffusion for efficient in situ biogas upgrading in an anaerobic reactor*, Appl. Microbiol. Biotechnol. 97 (2013) 3939-3744

LUO G., JOHANSSON S., BOE K., XIE L., ZHOU Q., ANGELIDAKI I., (2011) *Simultaneous hydrogen utilization and in-situ biogas upgrading in an anaerobic reactor.* Biotechnology and Bioengineering, 109 (2012) 1088-1094

LUO G., ANGELIDAKI I., (2012) *Integrated Biogas Upgrading and Hydrogen Utilization in an Anaerobic Reactor Containing Enriched Hydrogenotrophic Methanogenic Culture*, Biotechnology and Bioengineering, 109 (11) (2012) 2729-2736

McGARRIGLE E.V., DEANE J.P., LEAHY P.G., (2013) *How much wind energy will be curtailed on the 2020 Irish power system?* Renewable Energy, 55 (2013) 544–553

MINISTRY OF MINES AND ENERGY – MME, COMPANY OF ENERGY RESEARCH - EPE, (2011) *Plano Decenal de Expansão de Energia 2020*, Brasilia, MME/EPE, 2011. Available at http://www.mme.gov.br/mme/galerias/arquivos/noticias/2011/RELATxRIO_PDE_2020.pdf

MURPHY, J.D., McKEOGH, E., KIELY, G. (2004) T*echnical/economic/environmental analysis of biogas utilisation*, Applied Energy 77(4) (2004) 407-427.

MURPHY, J.D., THAMSIRIROJ, T., (2013) *Fundamental science and engineering of the anaerobic digestion process for biogas production*, in WELLINGER, A., MURPHY, J., BAXTER, D., editors, *The biogas handbook: science, production and applications.* Woodhead Publishing series in energy: number 52; 2013, ISBN 978-0-85709-498-8

MURPHY, J.D., THAMSIRIROJ, T. (2011) *What will fuel transport systems of the future?* Materials Today, 14 (11) (2011) 518-524

MUTZNER, S., (2013) *Energy from biogas as an operating reserve? Workshop "Biogas Process Optimisation"*, IEA Bioenergy Task 37, Bern, Switzerland; April 18th 2013. Available at http://www.iea-biogas.net/workshops.html

NIZAMI, A.S., MURPHY, J.D., (2011) *Optimizing the Operation of a Two-Phase Anaerobic Digestion System Digesting Grass Silage, Environmental Science and Technology*, 45 (17) (2011) 7561-7569

PERSSON, T., BAXTER, D., (2015) *Task 37 Country Reports Summary 2014*, IEA Bioenergy Task 37, Available at http:/www.iea-biogas.net/country-reports.html

PETERSSON A. (2013) *Biogas cleaning*, In: WELLINGER A, MURPHY J, BAXTER D, editors. *The biogas handbook: science, production and applications.* Woodhead Publishing series in energy: number 52; 2013, ISBN 978-0-85709-498-8

RASMUSSEN, N.B. (2013) *Bio-SNG and RE-gases: detailed analysis of bio-SNG technologies and other RE-gases*, Danish Gas Technology Centre Project Report, August 2013, ISBN 978-87-7795-367-5

SCHAUBACH, K., POSTEL, J., TROMMLER, M., NEBEL, E., DOTZAUER, M., (2014) *Leistungsfähigkeit von Biogasanlagen im Energiemix der Zukunft am konkreten Beispiel Honigsee*, DBFZ final Report, Leipzig.

SIRIWONGRUNGSON, V., ZENG, R.J., ANGELIDAKI, I., (2007) *Homoacetogenesis as the alternative pathway for H_2 sink during thermophilic anaerobic degradation of butyrate under suppressed methanogenesis*, Water Res., 41(18) (2007) 4204-4210

SPECHT, M., ZUBERBUHLER, U., BAUMGART, F., FEIGL, B., FRICK, V., STURMER, B., STERNER M., WALDSTEIN, G., (2011) *Storing Renewable Energy in the Natural Gas Grid: Methane via Power-to-Gas (P2G): A Renewable Fuel for Mobility,* October 2011, Available at http://www.etogas.com/nc/en/information/publications/

STERNER M., (2010) *Bioenergy and renewable power methane in integrated 100% renewable energy systems: Limiting global warming by transforming energy systems,* Kassel University Press, ISBN: 978-3-89958-798-2, Available at http://www.upress.uni-kassel.de/katalog/abstract.php?978-3-89958-798-2

SZARKA, N., SCHOLWIN, F., TROMMLER, M., JACOBI, H.F., EICHHORN, M., ORTWEIN, A., THRÄN, D., (2013) *A novel role for bioenergy: a flexible, demand-oriented power supply,* Energy, 61 (2013) 18-26

TAFARTE, P., DAS, S., EICHHORN, M., DOTZAUER, M., THRÄN, D., (2014) *Smart Bioenergy. Technologies and concepts for a more flexible bioenergy provision in future energy systems,* THRÄN, D. (Ed.) (in prep.) Springer-Verlag GmbH, 2014, Heidelberg

TROMMLER, M., JACOBI, H.F., MAUKY, E. (2012) *Flexible, demand driven biogas production – biological possibilities and economic considerations*, International Renewable Energy Storage Conference and Exhibition, Berlin, 2012

URBAN, W., (2013) *Biomethane injection into natural gas networks,* in WELLINGER, A., MURPHY, J., BAXTER, D., editors, *The biogas handbook: science, production and applications.* Woodhead Publishing series in energy: number 52; 2013, ISBN 978-0-85709-498-8

IEA BIOENERGY Task 37 – Energy from Biogas

IEA Bioenergy aims to accelerate the use of environmentally sustainable and cost competitive bioenergy that will contribute to future low-carbon energy demands. This report is the result of work carried out by IEA Bioenergy Task 37: Energy from Biogas.

The following countries are members of Task 37, in the 2013-2015 Work Programme:

Austria	Bernhard DROSG bernhard.drosg@boku.ac.at
	Günther BOCHMANN guenther.bochmann@boku.ac.at
Australia*	Bernadette McCABE bernadette.McCabe@usq.edu.au
Brazil	Cícero JAYME BLEY cbley@itaipu.gov.br
Denmark	Teodorita AL SEADI teodorita.alseadi@biosantech.com
European Commission: Task Leader	David BAXTER david.baxter@ec.europa.eu
Finland	Jukka RINTALA jukka.rintala@tut.fi
France	Olivier THÉOBALD olivier.theobald@ademe.fr
	Guillaume BASTIDE guillaume.bastide@ademe.fr
Germany	Bernd LINKE blinke@atb-potsdam.de
Norway	Roald SØRHEIM roald.sorheim@bioforsk.no
Republic of Ireland	Jerry MURPHY jerry.murphy@ucc.ie
Republic of Korea	Ho KANG hokang@cnu.ac.kr
Sweden	Tobias PERSSON tobias.persson@energiforsk.se
	Mattias SVENSSON mattias.svensson@energiforsk.se
Switzerland	Nathalie BACHMANN enbachmann@gmail.com
The Netherlands	Mathieu DUMONT mathieu.dumont@RvO.nl
UK	Clare LUKEHURST clare.lukehurst@green-ways.eclipse.co.uk
	Charles BANKS cjb@soton.ac.uk

* Australia joined Task 37 in 2015

WRITTEN BY

Tobias PERSSON
Anna-Karin JANNASCH
Energiforsk
Nordenskiöldsgatan 6
211 19 Malmö
Sweden

Jerry D MURPHY (corresponding author)
Eoin AHERN
Science Foundation Ireland (SFI)
Marine Renewable Energy Ireland (MaREI)
University College Cork
Cork
Ireland

Jan LIEBETRAU
Marcus TROMMLER
DBFZ – Deutsches Biomasseforschungszentrum gemeinnützige GmbH
Torgauer Straße 116
04347 Leipzig
Germany

Jeferson TOYAMA
Itaipu Binacional
Foz do Iguaçu
Brazil

EDITED BY:

David BAXTER
European Commission
JRC Institute for Energy and Transport
1755 LE Petten
The Netherlands

Published by IEA Bioenergy, December 2014

http://www.iea-biogas.net

IMPRESSUM: Graphic Design by Susanne AUER
ISBN 978-1-910154-13-7 (eBook electronic edition)

ISBN 978-1-910154-13-7

IEA Bioenergy