Bioenergy Review 2018

Call for evidence

Response from Advanced Plasma Power Ltd

1. ADVANCED PLASMA POWER

Company

Advanced Plasma Power (APP) is a UK-based sustainable energy company that has been operating for eleven years. During this time it has developed its Gasplasma® solution for converting municipal and commercial waste into advanced biofuels and electricity and has led the project development of several facilities based on its technology. This has culminated in the construction of the world's first plant to produce advanced biofuels from waste, which will start operation in 2018.

APP constructed a pilot plasma gasification facility in 2008 and used this this for research and development from 2009 until early in 2017. The plant has run for more than 3,000 hours over this time and has demonstrated production of power, substitute natural gas and hydrogen from a variety of feedstocks including refuse derived fuel, wood chips, auto shredder residue, straw and bagasse.

Gasplasma® Pilot Plant

From 2012 until 2014, APP was funded by the Energy Technologies Institute to develop a large scale waste to power project in Tyseley, Birmingham. The facility would have produced around 10MW of power from 16 tonnes per hour of municipal solid waste. APP set up a subsidiary, Tyseley Urban Resource Centre Ltd, to run the plant and this company submitted a bid in the October 2014 Contract for Difference Auction. Unfortunately, the bid was higher than the final strike price and the project was abandoned.

CAD Model of Commercial Plant

Since 2014, APP has focused on the production of advanced biofuels such as BioSNG and Biohydrogen from the syngas produced by the Gasplasma process. This resulted in a construction and operation of a pilot plant in 2015 and 2016 which clearly demonstrated the technical, environmental and economic feasibility of the production of BioSNG from wastes and residues.

BioSNG Pilot Plant

APP is now constructing a commercial demonstration plant that will convert 10,000 tonnes of waste per annum into 22GWh of natural gas. This plant will start full operations in 2018.

Equipment being installed at Commercial Demonstration Plant

APP has now started the development of large scale commercial BioSNG plants and is in discussion with a number of companies to use the Gasplasma technology to produce a syngas for conversion into hydrogen, aviation fuel, diesel and propane.

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2. GENERAL RESPONSE

APP is responding in detail to the Gasification sections of the consultation and in summary on other sections of the report.

Like all decarbonisation technologies, bioenergy will only ever be able to meet part of the UK's energy demand. A recent report by Cadent[1] shows UK feedstocks may be able to produce around 100TWh of renewable gas by 2050, around one third of domestic heating demand. However, bioenergy will play an essential role in helping the UK meet its carbon commitments for the following reasons:

- Bioenergy can address sectors that are very challenging to decarbonise in any other way such as off-grid heating, aviation, shipping and heavy goods transport.
- When combined with carbon capture and sequestration (CCS), it produces negative emissions that can be used to offset emissions from sectors such as agriculture that are difficult to decarbonise. Producing 100TWh of hydrogen with CCS for use in heating would save 56.5m tonnes of carbon dioxide (based on a saving of 565kg/MWh calculated in the Biohydrogen report[2]), around 13% of 2017 emissions.
- Biofuels are far less disruptive to consumers in some sectors than other low carbon solutions. For example, domestic heat customers are very resistant to heat pumps or heat networks but are happy to use biomethane because it does not require new heating equipment.

It is very easy to overlook the importance of bioenergy because it is limited by the availability of sustainable feedstocks and the challenges in analysing feedstock sustainability. However, it will be extremely challenging to meet 2050 emissions targets without a significant contribution from bioenergy.

The call for evidence rightly identifies sustainability, certification, GHG emissions, availability and best uses as key bioenergy issues and these are addressed in our response. There are two other key areas that are important to consider: affordability and fossil wastes.

The cost of biomass varies widely. Waste operators will pay a gate fee (currently around £30/MWh revenue) to facilities for processing domestic waste while conventional crops such as oil seed rape have a significant cost (currently around £30/MWh cost). The costs or revenues associated with feedstocks directly impacts on the cost of the fuels produced from them. This means that waste

[1] http://bit.ly/2CGD3xU

[2] http://gogreengas.com/wp-content/uploads/2015/11/Biohydrogen-Cadent-Project-Report-FINAL-3.pdf

feedstocks will be able to produce fuels cost effectively but crop and residue based fuels may struggle to compete.

The overall availability of biomass feedstocks will be driven by their economic value. Any assessment of the potential of bioenergy will require a good understanding of the cost of carbon as this will directly affect feedstock availability.

The call for evidence focuses on biomass resources and ignores another important low carbon resource. Residual household waste contain significant amounts of fossil material. It is not economically viable to separate the fossil and biomass fractions of this waste and landfilling the mixed material results in large emissions of methane, a gas with a high global warming potential. This means that combustion of the mixed waste results in the lower GHG emissions than other pathways, making the fossil fraction of mixed waste a low carbon, non-renewable fuel that can play an important role in meeting emissions targets.

Work by Defra[3] estimates that low carbon fossil wastes currently represent around 40% of residual UK waste with the potential to produce 15TWh according to the Cadent report. Given that the focus of UK policy and CCC committee work is on carbon reduction, the potential of this feedstock should be recognised and it should be included in the bioenergy review.

Finally, it is important to realise that the key technologies required to use bioenergy are mature. Gasification, catalytic conversion of syngas and anaerobic digestion have been used for more than 100 years. The Great Plains Synfuels Plant in the US has been gasifying lignite, converting the syngas to substitute natural gas and capturing carbon dioxide for more than twenty-five years. The key barriers to deployment of bioenergy are commercial rather than technical. If the correct support structures are put in place bioenergy could achieve its potential relatively quickly.

3. DETAILED RESPONSE

Questions 1 to 5 – GHG emissions and sustainability of imported Biomass

These questions focus on imported biomass but the issues raised relate to both imported and domestic biomass. The only difference between the sustainability assessment of domestic and imported biomass is the environmental impact of transporting the fuel or feedstock to the UK. This is particularly relevant for indirect land-use changes and wider market affects where, for example, any reduction in vegetable oil production for food in the UK might lead to increased palm oil production in Malaysia resulting in deforestation.

There are well developed methods of assessing the sustainability of feedstocks and fuels based on the Renewable Energy Directive. These can be used to assess the sustainability of any fuels and feedstock, wherever they originate. Both the Department for Transport and Ofgem have been assessing bioenergy sustainability for several years. The only element the analysis is controversial is the assessment of indirect land use impacts.

The Royal Academy of Engineering carried out a detailed assessment of the sustainability of liquid biofuels[4]. This addresses a number of issues raised in these questions and how lifecycle assessments can be used to consider the sustainability of biofuels. An important point raised by the report is the benefit of carrying our consequential life cycle analysis of biofuels in addition to attributional life cycle analysis.

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[3] http://bit.ly/2E7egzj

[4] https://www.raeng.org.uk/publications/reports/biofuels

Assessing the indirect impact of land use change is challenging. Ecofys, IIASA and E4Tech have produced a detailed assessment[5] of the indirect impact of biofuels consumed in the EU. For example, this estimates that the land use impact of palm oil is 231gCO_2eq/MJ, far higher than fossil diesel. The model developed for this report could be used to assess other feedstock such as US forestry.

DECC commissioned a detailed report than looked at North American wood pellets[6]. This showed that the pellets had low GHG intensities when produced from forest residues that would have been burnt as waste, but very high carbon intensities when produced from residues that would have been left on the forest floor. This shows how important it is to identify the correct counterfactual when assessing GHG emissions.

Assessing the sustainability and GHG impact of wastes is far simpler than crops and residues because by definition, true wastes do not have indirect impacts. The proposed use of a waste hierarchy[7] to determine whether biofuels can count for higher levels of support under the RTFO recognises the benefit of waste feedstocks. In the UK, household waste is the largest source of biomass and it should be the initial focus for bioenergy because its use does not have any indirect impacts.

Question 6-11 – Sustainability policy and certification

There are at least four sets of sustainability policies in the UK:

- The sustainability policies for renewable fuels, administered by the Department for Transport, are set out in the renewable transport fuel obligation guidance documents[8].
- The renewables obligation sustainability criteria, administered by Ofgem, are set out in the renewable obligation sustainability guidance documents[9].
- The renewable heat incentive sustainability criteria, administered by Ofgem, are set out in the renewable heat obligation guidance documents[10].
- The contract for difference sustainability criteria are set out in Annex 7 of the standard terms and conditions[11].

All of these are intended to apply the sustainability policy set out in the renewable energy directive[12] as amended by the indirect land use change directive[13]. All set sustainability criteria for crops and residues used to produce fuels or electricity and all set out methods of calculating the GHG emissions associated with land use, cultivation, transport and generation or production.

The DfT and Ofgem attempt to ensure that each of the sustainability criteria are consistent but they are constrained by the legislation setting out the various support mechanisms and by the time required to amend guidance.

This means that there are some significant differences. For example, transport biofuels made from waste are required to demonstrate that their GHG emissions are significantly lower than fossil fuels while electricity generated from waste does not have to carry out any GHG assessment. The

[5] http://bit.ly/1TO9896
[6] http://bit.ly/1V1VLyw
[7] http://bit.ly/2fRoQ4m
[8] http://bit.ly/2CsRxxf
[9] http://bit.ly/2vWduRW
[10] http://bit.ly/2lZe1ir
[11] http://bit.ly/2Aw6ywL
[12] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=EN
[13] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015L1513&from=EN

differences are confusing and it would be a lot simpler if there was a single set of sustainability and GHG criteria for all UK bioenergy.

In APP's opinion the renewable transport obligation sustainability represent the best practise at present. This is because the legislation they are based on is being updated to comply with the ILUC directive and they are tested more regularly than other criteria because transport fuels are the largest UK bioenergy market.

There are three major problems with the renewable energy directive GHG methodology:

1) It includes a set of defaults based on a best practise that may not be employed in an actual facility. For example, biomethane produced by anaerobic digestion has a default GHG saving of 73% if it is produced by municipal solid waste. However, if an AD facility does not control methane slip or if feedstocks travel a large distance to reach the facility the actual GHG saving could be far lower. Carrying out an actual GHG calculation is reasonably quick and inexpensive and it should be required for all bioenergy facilities to demonstrate they meet required GHG savings.
2) GHG calculations do not look at the actual counterfactual for the feedstocks used in a facility. Straw that is diverted from animal bedding has a completely difference GHG impact to straw that is left to rot in field. GHG calculations should look at the actual previous use of feedstocks and estimate the GHG impact of diverting them.
3) There is no agreed methodology for assessing the indirect land use impact of changing land use from food crops to energy crops. This has been addressed in the Globiom report discussed above but there is no consensus on how to assess the GHG impact. The problem has been side-stepped by limiting support for crop based biofuels but it needs to be resolved before energy crops can be deployed widely.

Changes to address points 1 and 2 of this list would be relatively simple to implement and are broadly compliant with the RED because they impose additional environmental protection above those set out in the RED. Resolving point 3 is far more challenging. It has been nearly 10 years since the problems were set out in the Gallagher Review[14] and there has been little progress in resolving them.

Question 12-17 – Bioenergy feedstocks

There are two reports that should be of interest to the CCC:

- E4Tech carried out a review[15] of global, European and UK availability and sustainability of wastes and residues for the Department for Transport in 2014.
- Cadent commissioned E4Tech and Anthesis to review[16] the availability of sustainable UK feedstocks in 2017.

Both reports provide credible estimates to 2050 broken down by feedstock type.

Neither report includes fossil waste in their final projections. As discussed in Section 2, the fossil fraction of residual municipal waste represents an important low carbon energy resource. Section 2.3.1 of the Cadent technical report forecast total residual waste arising, including the fossil portion. The central scenario forecasts total UK waste arisings of 14.6m tonnes in 2050. Figures from Appendix 1 of the report show that this contains 15TWh of low carbon fossil waste.

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[14] https://www.unido.org/sites/default/files/2009-11/Gallagher_Report_0.pdf
[15] http://bit.ly/1hfVWC0
[16] https://cadentgas.com/About-us/The-future-role-of-gas/Renewable-gas-potential

Question 18-22 – Scaling up UK sustainable supply

The key issue to resolve to allow large scale UK production of bioenergy is how use of land for energy fits with competing requirement for land for food, leisure and wildlife. At present there is no clear policy on how land should be used and this prevents landowners investing in energy crops.

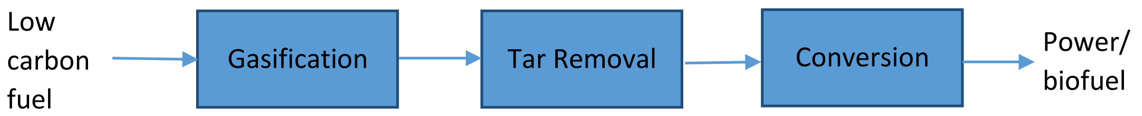
There are a number of questions that need to be addressed:

- What proportion of land can be used for energy? Are there any limits?
- Are some types of land preferred for energy production? For example, is marginal land preferred over highly productive land?
- How do we balance food, energy security and public access to land?

There will only be widespread production of energy crops if the Government sets a clear policy on land use that identifies situations where energy production is preferred.

Question 23a – Gasification Roll Out

Gasification is a combination of three connected technologies that work together to valorise biomass and other low carbon feedstocks. These are shown in the following diagram.



Each technology has the following function:

- Gasification converts the fuel from solid to a gas.
- Tar removal reforms or removes tars produced in the gasification process to create a clean synthesis gas (syngas)
- Conversion produces electricity through combustion in a gas engine or turbine or biofuels through catalytic conversion.

It is possible to generate steam through combustion of the crude syngas produced by the gasification step. This can be used in heating and power generation. However, this does not offer any fundamental advantages over raising steam through direct combustion or incineration of the fuel. For gasification to offer any real advantages over incineration it is necessary to reform tars to allow the syngas to be used in higher value applications.

Gasification is very well established technology with many hundreds of references around the world. E4Tech carried out a detailed review in 2009[17] which compares and contrasts difference approaches and details the development status of the technology. Since the report was produced the following has happened:

- Fluidised bed systems have flourished with tens of biomass systems entering operation.
- Dual gasification systems have seen some success with the large GobiGas facility starting operation in Sweden.
- Other technologies have struggled with most projects being abandoned.

Overall, the gasification step is ready for commercial deployment now.

[17] http://www.e4tech.com/wp-content/uploads/2016/01/gasification2009.pdf

Tar removal is a specific requirement for biomass gasification because of the low temperatures used. Technologies have been reviewed in several technical papers[18,19,20]. Currently, four technologies are at the commercial demonstration/first of kind plant stage:

- An oil based scrubbing system is used in the GoBiGas plant.
- A catalytic reformation system is used in the Andritz Skive plant.
- A thermal cracking and wet scrubbing approach used by Enerkem in their Edmonton plant.
- A plasma cracking system used by APP in their Swindon BioSNG facility.

Further plants based on these technologies are under development and expected to enter operation in 2021. This will establish the technical performance of each approach leading to further deployment later in the decade.

Conversion technologies can be split into three categories:

- Engines and turbines,
- Catalytic conversion,
- Fuel cells.

Engines and turbines are well established technologies on natural gas and diesel but there is far less experience of operation on syngas. Jenbacher have around 30 engines operating on syngas world-wide but other engine suppliers are unwilling to guarantee performance. Turbine manufactures are willing to guarantee performance but turbine efficiencies are low at the relatively small scales of bioenergy facilities. Overall, syngas engines and turbines are ready for deployment but struggle to compete technically or economically with generating electricity through direct biomass combustion.

Catalytic conversion of syngas is a very well established technology for fossil syngas. There are a large number of references for catalytic production of natural gas, methanol and liquid fuels. Biomass systems operate at smaller scales than the fossil plants but there are a large number of suppliers, such as Amec Foster Wheeler, Johnson Matthey and KBR, willing to guarantee performance of catalytic systems on tar free syngas.

Fuel cells offer high conversion efficiencies and carbon dioxide streams that are ready for capture. However, the integration of fuel cells with biomass gasification is at the conceptual stage at present and it is probably more than a decade from commercialisation.

Overall, the development of tar cracking technologies is the key technical block to the roll out of most gasification technologies. This is likely to be resolved early in the 2020's and there will be widespread deployment by 2025 is the right policies are in place to support the technology.

Question 23b – Gasification efficiencies and costs

Efficiencies and costs

[18] Reduction of tar generated during biomass gasification: A review (Biomass and Bioenergy 108 Rios, Gonzalez, Lora, Olmo 2018)
[19] The reduction and control technology of tar during biomass gasificiation/pyrolysis: An overview (Renewable and Sustinable Energy Reviews 12 Han, Kim 2006)
[20] Tar reduction in biomass producer gas via mechanical, catalytic, thermal methods: A review (Renewable and Sustainable Energy Reviews 15 Anis, Zainal 2011)

Details of the costs and efficiencies of BioSNG and biohydrogen can be found in reports[21] produced by APP, Progressive and Cadent.

The conversion efficiencies from feedstock to syngas will depend on the gasification and tar cleaning technologies deployed. The E4Tech report gives a range of efficiencies for a number of technologies. Broadly:

- Entrained flow systems have high efficiencies (90%) but require a significant amount of feedstock preparation which can reduce overall efficiency to 60%.
- Fluidised beds have high efficiencies 85% and require minimal feedstock preparation.
- Indirect gasifiers have efficiencies of 80% but require feedstock palletisation which reduces overall efficiency to 72%.

Both entrained flow and fluidised bed systems require oxygen to avoid a large nitrogen burden in the syngas. If this is take into account it would reduce efficiencies by three percentage points.

The technical papers referenced above discuss the efficiencies of different tar removal approaches. The overall impact is:

- Thermal cracking uses energy in the syngas to break down tars reducing efficiencies by 20% or more.
- Plasma and catalytic thermal cracking reduces the required temperatures for tar reformation so that efficiencies are only reduced by 5-10%.
- Tar scrubbing removes the energy in the tars and reduces efficiency by around 10%.

This results in an overall efficiency of the gasification and tar cracking steps of between 50% and 85%. Most of the lost energy report as syngas heat which can be captured and used elsewhere in the process or for power generation.

The efficiency of the syngas to product conversion step varies as follows:

- Syngas gas engines have efficiencies of around 40% in combined cycle. Turbine performance is worse than engines at biomass scales. This gives an overall gross efficiency of 20-34%.
- Catalytic conversion efficiencies depends on the product. For simple chemicals such as hydrogen, methane and methanol efficiencies are around 80% but for ethanol and liquid fuels efficiencies are around 40%, with large amount of energy ending up in co-products. This gives overall gross efficiencies of around 60% for simple products and 30% of complex products.
- Fuel cell efficiency is reported at 50% or higher. This would give gross efficiencies of 25-43%.

Each of the components of gasification systems are mature technologies and their costs are well understood.

The costs of producing BioSNG are set out in the BioSNG report and are summarised in the following table.

[21] See http://gogreengas.com/downloads/ for the Biohydrogen report and BioSNG Project Close-Down report.

	£m/MW Thermal Input	£m/MW BioSNG Exported
Capex	£1.63m	£2.57m
Opex	£0.15m	£0.24m
Gate fee	£0.16m	£0.25m

These figures are based on a plant converting 100,000 tonnes of feedstock per annum into 315GWh of natural gas. Typical plant availability is 85%.

The underlying costs of producing power or other biofuels will be depend on the capital costs of the conversion step. Broadly:

- The overall capex and opex of producing power is similar to producing BioSNG. However, as efficiencies are half that of BioSNG production the costs per MW of electricity are twice as high.
- Production of methanol and hydrogen is very similar to BioSNG.
- Propane production cost are similar to BioSNG but a natural gas co-product is produced. If costs are spread in accordance with energy content the biopropane cost is similar to BioSNG.
- Liquid fuel production is more expensive than BioSNG production because of the cost of refining and upgrading the biocrude produced by catalytic conversion. A range of co-products (predominately natural gas) are produced with liquid fuels which makes producing a cost per MW difficult. However, the cost is significantly (1.5 to 2 times) more expensive than BioSNG.

This would suggest that the best use of gasification technologies from an efficiency and cost point of view is production of natural gas, hydrogen, propane or methanol.

The main impact of plant economic of feedstock is the costs or revenues associated with that feedstock. Revenues from processing domestic waste can offset all of the operating costs of a facility while the costs of operating on biomass can double operating costs. However, biomass offers the following advantage over wastes:

- Household waste has high levels of incombustible ash which require capture and disposal, increasing capital and operating costs.
- Biomass has lower levels of heavy metals, chlorine, sulphur and other contaminants than wastes, reducing clean-up costs.

Biomass is completely renewable and all of the power and fuels produced from it will qualify for renewable incentives. Wastes are around 50% renewable and 50% low carbon fossil so that currently only 50% of the fuel or power produced from them qualifies for incentives. This means that biomass is generally preferred over wastes. This is perverse given that fuels from waste will generally have a far better GHG impact than biomass.

Cost reductions over time

Most of the equipment used in gasification facilities is already produced in reasonably large volumes and large scale deployment will not result in any significant savings. The key areas where there is likely to be cost reductions are:

- Tar removal equipment because this is not widely deployed at present.
- Catalytic conversion equipment which can be optimised for small scale operation.

- Project design and delivery costs which will fall as engineering contractors learn how to deliver gasification facilities.

Overall, these packages make up around 40% of overall project costs. Reductions in margin and learning effect could reduce then by 25% over time resulting in overall capex reduction of 10%.

Larger saving can be achieved through increasing plant scale. As confidence in the technology grows it will be possible to build larger facilities. Doubling the scale of the plant will reduce capital costs by around 15%. This would bring the plant size in line with current waste or biomass incineration plants. Further savings would be achieved for large plants.

There is less room for reducing operating costs without increasing scale. Increasing plant uptime could reduce costs by around 3% because fixed costs would be spread over great volumes of gas. Doubling the scale of the plant would reduce costs by 25% for similar reasons.

Future movements in waste gate fees and biomass costs will be driven by movement in supply and demand and Government policy. If policies do not change it seems likely that revenues and costs will remain relatively static. This has been the case for the last five years. Gate fees are tracked on www.letsrecycle.com and biomass pricing is tracked on http://www.fwi.co.uk.

Question 23c and d – Risks and Barriers to gasification deployment

The key barriers to gasification deployment are:

- **Economic**. The cost of fuels and power produced through gasification are currently higher than fossil fuels. Long term subsidies or carbon taxes are required for gasification to be economically viable. Unless investors believe that there will be long term support for the technology they are unwilling to invest in facilities.
- **Political**. Support is available for the technology under CfD's, the RHI and the RTFO. However, there is no overarching decarbonisation strategy setting out the role of gasification and the feedstocks it processes. Gasification is reliant on political support and currently there are conflicting messages about the technology from BEIS, DEFRA and the DfT which undermines stakeholder confidence.
- **Technical**. As explained above, technologies for tar removal are not yet mature and the risks around technology selection act as a barrier to investment.

Question 23e – Gasification policies and incentives

Currently gasification is supported for electricity production under CfD's, for BioSNG production the RHI and for all transport fuel production under the RTFO. This means there is currently no support for other biofuels used in heating such as biopropane used in off-grid homes or hydrogen injected into the gas grid.

It is highly questionable whether there should be any support for power production using gasification. There are lower cost pathways for decarbonising electricity such as wind and solar and low carbon fuels are better deployed in producing fuels, where there are few alternatives, rather than power.

The value of the renewable heat incentive is too low to support gasification projects. Tiering means that support drops of significantly after the first 40GWh of gas production but normal scale BioSNG plants will produce more than 300GWh so 260GWh receives very little support. In addition, the RHI is due to end in 2021 and gasification facilities that start development now are unlikely to complete commissioning in time to secure support.

The RTFO is due to be amended in 2018 to increase the supply of renewable transport fuels and offer high levels of support to BioSNG, hydrogen and liquid fuels produced from wastes and residues using gasification. However, the RTFO is a market driven support mechanism that doesn't offer any certainty to developers. This limits its ability to secure investment. The policy has led to development of projects producing BioSNG by APP and producing aviation fuel by Velocys and Fulcrum. The new policy will be shown to be successful if any of these project reaches financial close.

The Government should set a policy that clearly sets out the requirement for low carbon fuels for heating after 2021, identifies suitable feedstocks for fuel production and provides a mechanism to bridge the gap between the costs of fossil and low carbon fuels. This mechanism could be:

- An extension of contract of difference to low carbon fuels for heat or transport.
- An obligation on suppliers of natural gas to decarbonise, similar to the RO.
- An obligation on regulated gas distribution companies to reduce carbon emissions from gas in their network and allow them to invest in low carbon gas production.
- A carbon tax on fossil gas and other fuels set at a sufficient level to allow low carbon fuels to compete.

The cost analysis in the BioSNG Close Out report shows that first of a kind waste BioSNG plants require long term support of around £50/MWh (around £200 per tonne of carbon dioxide saved) for all of their output in order to compete with fossil gas. Similar support is required for biohydrogen or propane. Liquids would require higher levels of support to compensate for the lower efficiencies and higher costs of liquid production.

Question 24 – Bioenergy with Carbon Capture and Storage

The ability to sequester carbon dioxide produced through the gasification of low carbon feedstocks is a key reason for supporting gasification technologies. The negative emissions generated can be used to offset emissions from sectors that are challenging to decarbonise such as agriculture.

It is possible to design most gasification processes so that a high purity stream of carbon dioxide that is suitable for storage is produced. This means that the capture process is efficient and inexpensive. The BioSNG demonstration plant that APP is constructing in Swindon produces liquid carbon dioxide that is sold to Air Liquide for use in industry. If carbon sequestration infrastructure was available it would be possible to connect a BioSNG plant to it now.

APP has worked with Progressive Energy to produce a report on biomass hydrogen production[22]. This shows that 372kg of capture ready carbon dioxide are produced for each MWh of biohydrogen which compares to 255kg per MWh of BioSNG. These saving are independent of the feedstock.

Production of electricity using engines or turbines does not provide a capture ready stream of carbon dioxide because of the nitrogen loading from the air used in the combustion of the gas.

The key barrier to BECCS is the lack of any financial incentives to store carbon dioxide. None of the UK's main incentive reward the carbon savings achieved by carbon capture which means there is no reason to develop BECCS projects.

Question 26 – Advanced Biofuels

E4Tech and Ricardo recently carried out a review of advanced biofuels production for the DfT[23]. Section 2.14 summarises all of the possible pathways.

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[22] http://gogreengas.com/wp-content/uploads/2015/11/Biohydrogen-Cadent-Project-Report-FINAL-3.pdf

There are four gasification pathways – covering aviation fuel, ethanol, methanol, methane, hydrogen. Gasification has been discussed in depth in Question 23. A few other points are worth making here:

- APP is working with Calor gas on production of biopropane. Work on production of propane from fossil syngas is limited because of its low economic value. However, biopropane is a very good solution for decarbonising off grid heating and use in heavy goods vehicles. Production appears to be relatively simple and it is expected that the project will demonstrate the technical feasibility of biopropane production.
- Production of liquids such as diesel will result in production of a significant amount of methane, ethane and/or propane as a by-product. It is important that routes for use of these by-products as fuels is maintained because otherwise that are wasted when used for on-site power production.
- Gasification and pyrolysis are the only technologies that are omnivorous and can process all wastes, residues and biomass feedstocks. Other processes a limited to a subset of feedstocks such as sugars or oils. This means the potential production through gasification is far higher than other technologies. This is clearly shown in Figure 4 of the E4Tech report on sustainable feedstocks[24].
- Most processes compete for feedstocks. The exception are fuels from power which are produced through the electrolysis of waste to produce hydrogen. If required this can be catalytically converted with a pure stream of carbon dioxide to produce hydrocarbons. The economics of these processes depend on the relative cost of electricity and the fuels produced. In a well managed grid the cost of power should be close to the cost of production but imbalances may create an opportunity for fuels from power.

Unsurprisingly, APP's view is that gasification is the best route for advanced biofuels production. For gasification our view is that:

- Production of hydrogen is most efficient at around 73% (see the Biohydrogen report[25]) following by natural gas at 64% (see the BioSNG report[26]). Methanol can achieve similar efficiencies but other fuels (ethanol, diesel, kerosene) will only achieve efficiencies of around 35% but with significant production of by-products (methane, methanol etc) bring overall efficiencies to 60%. Biopropane appears to be cost-effective to produce but there are significant methane and ethane by-products.
- Residual waste (a low carbon mixture of fossil and biomass components) is the feedstock with the lowest greenhouse gas profile and the best economics.
- High efficiencies mean that biohydrogen and biomethane are the best products in the markets they can address, primarily grid heating and transport. Biopropane is a good solution for off-grid heating and transport.

Barriers, policies and incentives are discussed in in the answer to Question 23. The RTFO provides good support for advanced biofuels. However, natural gas will only be adopted as a transport fuel if there is certainty over the economics of fossil gas versus fossil diesel for use in HGV's.

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[23] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/637662/dft_f4c-feasibility_final_report.pdf
[24] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/277436/feedstock-sustainability.pdf
[25] http://gogreengas.com/wp-content/uploads/2015/11/Biohydrogen-Cadent-Project-Report-FINAL-3.pdf
[26] http://gogreengas.com/wp-content/uploads/2015/11/BioSNG-170223-1-Project-Close-Out-Report.pdf

The ETI produced a detailed analysis of the use of fossil gas in HGV's[27] which showed they have the potential to produce well to wheel GHG savings of 13%-24% by 2035. Dedicated natural gas HGV's have lower NOx emissions than comparable diesel vehicles and are more likely to meet Euro VI emission limits in real world conditions because their emission control systems and far simpler. Bypassing of Adblue systems may be a serious problem for diesel vehicles[28].

It is essential that the current fuel duty differential between gas and diesel is maintained for the long term in order to encourage adoption of natural gas vehicles if these savings are to be achieved. In addition, the route to low carbon gas production is much clear than the route to low carbon diesel production. Anaerobic digestion is a mature technology that produces large quantities or low carbon fuel. In future this will be complemented by BioSNG production. Production of low carbon diesel is several years behind BioSNG and the lower efficiency of liquid fuels production means that renewable diesel will always be more expensive then renewable gas.

[27] http://bit.ly/2Dj8UVb

[28] http://transportoperator.co.uk/2017/07/25/dvsa-check-roadside-emissions-cheating/