element energy

Distributed gas sources

Final report

for

National Grid Gas Distribution Ltd

SGN

Wales and West Utilities

25 January 2017

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Executive Summary

The potential for distributed gas in the UK

Distributed gas from a range of sources is likely to meet a growing share of UK demand in the coming years. With the introduction of Renewable Heat Incentive (RHI) tariffs for biomethane injection, the market for biomethane to grid has grown rapidly in the past five years, and while commercial production of unconventional gas sources such as shale gas and coalbed methane has yet to be proven in the UK, the current government has a clear appetite to move towards a more diverse and secure gas portfolio, and envisages a ramp up of shale and coalbed methane production over the coming decades.

Based on industry estimates of reserves, potential production rates and policy targets, by 2030 between 5% and 34% of UK gas demand could be provided from the distributed gas sources considered in this report. Most scenarios predict production rates in the region of 7.5 Mscm/day, 6 Mscm/day, and 23 Mscm/day from biomethane, CBM and shale gas respectively. Due to their low production pressures, it is likely that biomethane and CBM will be injected mainly at the IP and MP tiers of distribution networks, with some injection at the LTS, whereas the predicted pressure and volumes of commercially produced shale gas mean that it is likely to be suitable for NTS injection, or LTS injection.

Opportunities to maximise distributed gas injection

A continued increase in the volumes of distributed gas injected to the grid would bring greater security of supply, as well as contributing to the decarbonisation of the gas grid. However, increased injection would also change the existing balance and geography of inputs and outputs to the network. The current operational and commercial environment may pose constraints to such changes, and as such, a combination of technical solutions and adaptation to the regulatory framework may be required in order to maximise the potential for injection and the benefits this could bring.

The growth of distributed gas injection fundamentally relies on there being a positive business case for gas producers. A range of factors affect the business case, including policy (such as the RHI, which currently brings significant revenues to biomethane producers injecting their gas to the grid), technical requirements for injection, and the capacity available for injection on the network. If a local network has very low demand, a gas producer will either only be able to inject a small amount of gas (which may not be enough to make a worthwhile business case for production) or will have to consider more costly methods to inject their gas (e.g. installing a pipeline to a location with greater downstream demand).

Due to the diminishing number of cost-effective injection opportunities on some networks, (which is compounded by the tendency for biomethane plants to be geographically clustered around various feedstock sources), more innovative methods of managing supply and demand across networks will need to be implemented to make capacity available and unlock the full potential supply of distributed gas sources. In addition, if the costs associated with distributed gas injection (including connection costs and various operating costs) could be reduced for future projects, this would help to make more projects viable in the future, ensuring that the benefits to the grid are maximised.

The main barriers for future injection of distributed gases, were identified through consultation with industry stakeholders involved in the process of injecting distributed gas to the grid. There is a focus on the barriers relating to distribution network requirements and conditions (commercial and regulatory aspects were considered in terms of the opportunities for distributed gas that potential changes could bring). The barriers can be summarised in order of estimated relative impact:

- Minimum CV requirements for injection to the distribution network, leading to high propanation costs
- Capacity constraints on the distribution network, leading to high connection costs in order to connect at a point with sufficient capacity
- Connection costs remain high, in part due to the lack of standardisation of GDN connection design specifications
- Long timescales for approvals during application for connections
- Lack of easily accessible information on connection opportunities

Table 0.1 quantifies the relative impacts of the major remaining barriers (in terms of the estimated cost for 20 new connections, which is the minimum number expected per year in line with the production scenarios), and indicates the progress that has been made towards addressing the barriers. The table also shows the estimated system costs associated with addressing these barriers. These costs are estimated in terms of the total system cost, so are not necessarily directly comparable with the impact of the barrier (which is per year).

Table 0.1 Summary of major barriers to gas injection and relative impacts

Issue / specific barrier	Impact (indicative additional cost for 20 new connections)	Progress to date	Potential system cost to address the issue
CV requirements and high propanation costs	£10-20 million **per year** across the network in propanation costs	Reduced propanation options (energy blending) offered today in certain situations, by some GDNs Implications of smaller charging zones (allowing lower propanation costs) will be explored 2017-2020 in a National Grid NIC project	Energy blending may lead to opportunity costs for subsequent injection plants £10s of millions possible total system cost for smaller charging zones
Capacity constraints	Up to £9 million **per year** for additional pipeline to access points with sufficient demand	Various solutions are being trialled and researched by GDNs (more details in Chapter 0)	£millions for field trials (or low £10s of millions e.g. if new commercial models are needed to share costs across multiple producers)
High connection	Estimated low £millions **per year**	Industry has identified key differences but has	Up to £100,000s for industry consultation

costs - contribution from lack of specification standardisation	in cost premiums for bespoke GEU designs	not quantified cost impacts Standardisation may be more feasible when tariffs are secured before injection (less time pressure)	to define details of possible cost savings, and creation of revised specifications

GDNs and producers are already starting to take steps to address the first two barriers, through various NIC funded projects and by exploring innovative methods such as energy blending, and ways to provide access to sufficient capacity. However, to maintain the growth of the biomethane injection market, and to support injection of shale gas, GDNs will need to engage with the industry and with regulators and policy-makers to ensure that the potential benefits of these gas sources at the system level are recognised and maximised in a cost-effective way. For the third barrier, further consultation between biomethane producers and GEU manufacturers is needed, to assess the specific cost impacts of particular differences between specifications, and the potential system costs of addressing these differences.

Table 0.2 breaks down the possible solutions to these key barriers in terms of the technical, commercial and regulatory opportunities that should be considered.

Table 0.2 Key technical, commercial and regulatory options to address barriers to distributed gas

Barriers	Possible technical solutions	Possible new commercial arrangements	Possible regulatory changes
CV requirements and high propanation costs	• Energy blending (the amount of propane required is minimised)	• Smaller billing zones for greater accuracy	• Non-directed sites (GDNs define the limits for CV) • Regulated differences in CV of sources could be relaxed
Capacity constraints	• Smart pressure management • Storage • In-grid compression to higher pressure tiers • Interconnection	• New pricing mechanism to incentivise injection at time of local demand • Pricing framework to allow GDNs to recover costs of technical solutions from all network users • Definition of ownership and flow restrictions /	• RHI tariff to incentivise injection at time of local demand • Framework & funding mechanism for GDNs to deploy solutions benefitting indeterminate stakeholders (and the system as a whole)

		conditions for storage	
Lack of specification standardisation	N/A	N/A	• Revisions to IGEM specification documents (TD/16 and TD/17)

Most of the technical solutions listed in the table have been trialled in the UK and/or internationally, with a view to maximising the cost-effective opportunities for gas injection. To inform the direction of further trials and longer term GDN strategy for distributed gas, this report estimates the costs and effectiveness of these solutions for different injection sources and injection points.

Finding cost-effective solutions to capacity constraints

The maximum injection capacity offered by GDNs to biomethane producers for injection is limited to the minimum demand downstream of the potential gas entry point. This varies a great deal at different points in the network, meaning that depending on the location of a distributed gas production facility, the closest network segment may not have sufficient capacity to allow injection.

Pipeline can be installed to carry the gas from the point of production, either to a higher pressure tier which has more downstream demand, or to a location where the network has sufficient capacity at that tier. However, pipeline costs (which are typically covered by the gas producer) can be very high, and can adversely affect the business case for connection and injection to the grid. In areas of low gas demand, with multiple projects seeking to inject gas to the grid, injection may become increasingly costly as a result of this. Without cost-effective solutions to capacity constraints, the growth of distributed gas is likely to be limited.

Various network management options, which optimise capacity by storing gas temporarily or by providing access to demand from other parts of the network, have been explored and in some cases implemented to address real constraints in the UK and elsewhere in Europe. The options considered in this report are summarised in the table below.

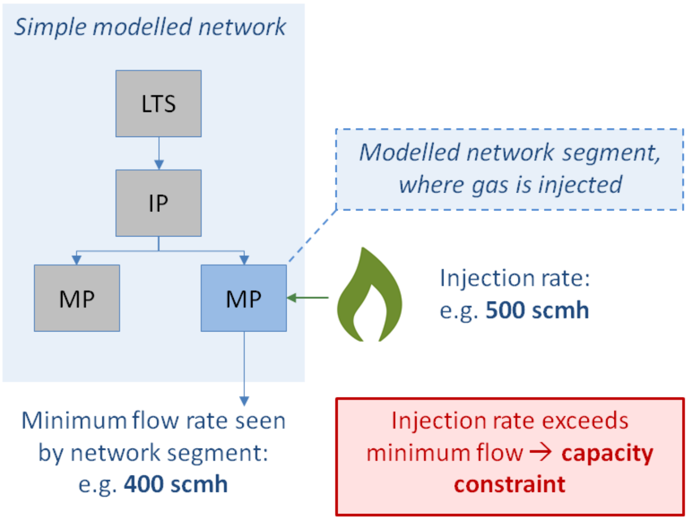
Table 0.3 Technical solutions to capacity constraints

Solutions to capacity constraints	Key principles	Use in the UK
Smart pressure management	The pressure in a segment of network is regulated to maximise the capacity available for distributed sources to inject their gas. Detectors monitor the pressure at network low pressure point(s) and communicate with automated regulators at pressure reduction stations (e.g. IP to MP). The system controls flow of gas from the IP to MP, for example, to allow MP-connected sources to inject, while always ensuring	This solution is now being trialled by National Grid Gas Distribution Ltd and Wales and West Utilities, in Cambridgeshire and Bristol respectively.

	adequate pressure to meet the demands of LP connected customers.	
Interconnection	Networks in close proximity could be interconnected to create a combined network of increased overall capacity. This solution is highly dependent on local network topology	Has been used to alleviate network constraints, but not specifically to enable producers to inject gas.
In-grid compression	At times of a constraint in a particular segment of the network, i.e. insufficient demand on the network to allow all gas sources to inject, compressors are operated to 'pump' gas to a higher pressure tier, e.g. from MP to IP or IP to LTS	Not used as a solution to date. NGGD is in the process of exploring possible costs and designs for in-grid compression, including an appropriate control system.
Energy blending	A process aimed at minimising the amount of propane that needs to be added to injected gas, whilst ensuring that gas supplied to customers remains within acceptable CV limits. The CV of the gas is measured downstream of injection, and propane is added accordingly. While this is not strictly a measure that explicitly addresses capacity constraints, energy blending could reduce the cost of injecting at higher tiers where there is more likely to be sufficient capacity, thereby making injection more financially viable.	Trialled by National Grid and SGN through various methods.
Storage	Excess gas produced by distributed gas sources could be stored across the low pressure network in dedicated facilities during low demand periods (as is already done on a national level along the NTS). On-site storage at the point of gas production could be an alternative to this.	No storage facilities on the network to date.

These solutions represent different ways of optimising the capacity available on the network as a whole, so that producers can inject gas at their desired injection rate, at a lower cost than might be possible without these solutions. On the basis of cost data provided by the industry (validated by National Grid, SGN and Wales and West Utilities), this study conducted a cost-modelling exercise to identify, for different levels of constraint on the network, which solutions would make the required capacity available to producers, at the lowest cost.

In assessing the effectiveness of each different solution, a highly simplified model of network demand was used to recreate a wide range of different scenarios for the minimum demand. Different levels of constraints were represented for various proposed injection rates, by ensuring that, in each case, the injection rate was in excess of the minimum demand at the proposed point of injection. An example is shown in the diagram below.



It should be noted that the conclusions from this exercise depend heavily on the assumptions made regarding costs and demand factors, i.e. the ability of the different solutions to effectively increase the demand seen at the point of injection. However, generalised conclusions have nonetheless been drawn out, regarding which of the solutions are most likely to cost-effectively resolve various capacity constraints, when the “baseline” option of using additional pipeline is too expensive.

Overall, the cost modelling indicated that different solutions can be the most cost-effective for producers, depending on the nature of the constraint. In many cases, the most cost-effective solution will be dependent on the specific characteristics of the network, which affect the resulting specific costs of pipeline installation, and the suitability of various methods. However, based on the assumptions of the modelling, the following broad conclusions have been made:

- For constraints which are not severe (i.e. where the minimum demand is not greatly exceeded by the injection rate) smart pressure management is likely to be the most cost-effective option.
    - However, if energy blending or another approach to propanation reduction can be used at the LTS**,** injection at the LTS is likely to be the most cost effective solution for constraints at the IP tier, even compared to using smart pressure management at the IP tier.
- For greater constraints, the most effective solutions vary, depending on the injection rate and the pressure tier. In-grid compression has the potential to accommodate large oversupplies and could provide cost savings over injection at the next tier, particularly

for relatively low injection rates requiring small compressors. UK trials of in-grid compression are needed to test the real-world viability and costs of this solution.

- In addition, costs of injecting at the LTS could be drastically reduced by minimising the amount of propane required. This could be facilitated through energy blending (albeit as a limited solution) or through the creation of smaller charging zones to enable billing that reflects different proportions of distributed gas injection. The wider system costs of this will be explored as part of an NIC project led by NGGD.

Recommendations for the industry

Based on the evidence set out in this report, the table below sets out the overall recommendations for distributed gas stakeholders, broadly in priority order, according to the size of the potential opportunities that could be unlocked for the distributed gas sector, and the corresponding benefits for the UK energy system. The specific actions relating to these recommendations are then set out below, grouped by estimated timescale for the action to occur.

Table 0.4 Overarching recommendations

<table>
<tr><th></th><th>Overarching recommendations for distributed gas stakeholders</th><th>Potential impact on future distributed gas market</th></tr>
<tr><td>A</td><td>Continue to explore options for reducing propane requirements.</td><td>Based on the evidence in this report, if reduced propanation could be achieved on a large scale, it could provide the largest net saving for distributed gas producers, even accounting for costs of commercial and regulatory change. As such, it could enable a large number of future projects.

Reducing propanation at the LTS could bring savings in excess of £20 million per year by 2020 (based on 20 applicable LTS connections in 2020), plus potential additional savings for IP and MP connections where reduced propanation is possible.</td></tr>
<tr><td>B</td><td>Trial capacity solutions, demonstrate feasibility and compare costs and benefits.</td><td rowspan="2">Difficult to estimate overall cost saving, as this will depend on the capacity solutions deployed, and the sources of gas seeking to inject. However, effective solutions or mitigation for capacity constraints will be essential to enable continued growth of distributed gas as the grid becomes more locally saturated with increasing distributed injection.</td></tr>
<tr><td>C</td><td>Seek policy changes that will reduce capacity barriers through:
i. Mitigating measures such as pricing / RHI tariff weighting, and/or:
ii. Policies supporting capacity management measures that can be installed in advance of requirements, with socialised costs.</td></tr>
<tr><td>D</td><td>Seek to minimise general connection costs and timescales.</td><td>This could bring savings of low £millions per year (based on 20 connections per year).</td></tr>
</table>

Next 6-12 months:

- A.1) Continue to use energy blending approaches in suitable situations.
- A.2) GDNs and industry to participate in consultation as part of stage one of NGGD's NIC funded "Future Billing Methodology" project.
- A.3) GDNs to share initial conclusions with implications for CV requirements, from existing projects including Future Billing Methodology (NG) and Real-Time Networks (SGN), as early as possible to inform next steps for industry and regulators.
- A.4) GDNs and industry could engage Ofgem to consider reviewing the approval process for CVDDs, to encourage more devices to seek approval.
- A.5) Producers should support activities by participating and investing in trials of new approaches to propanation, and sharing relevant data and experiences with the industry.
- B.1) GDNs should prepare to quote for providing in-grid compression for producers in connection agreements (National Grid has already started work on this).
- B.2) Producers using storable biogas feedstocks should assess the economic viability of optimising injection volumes on constrained networks by storing feedstock on-site.
- D.1) Industry should initiate a workshop to review the status of TD/16 & TD/17, compared to current requirements from individual GDNs, and determine whether these documents should be revised to reflect the latest lessons learned from different gas producers and GDNs. This could then lead to review of specifications, involving HSE.
- D.2) GDNs could offer the option for producers to pay for fast-tracked services such as connection enquiries and approval processes. GDNs could assess whether it would be feasible and cost-effective to employ additional staff, or (for connection enquiries) to build a self-assessment tool.

Next 1-2 years:

- A.6) GDNs and industry should continue to engage with the Future Billing Methodology" and consider the value of exploring other avenues outside the scope of the project. e.g.: to progress with the possibility of "Non Directed sites", the industry would need to define a framework for how this would be monitored and regulated by GDNs, including defining limits for what constitutes "low flow" sites. In addition, a detailed assessment of the system costs and benefits of this framework compared to the current one would be required, including quantification of financial impacts for customers, and to what extent these could be mitigated.
- B.3) GDNs and producers should trial in-grid compression to clarify the business case and identify any technical challenges.
- B.4) Industry grouping should identify emerging storage trends for different biogas production sources, and whether there is a need for aggregated storage on the network
- B.5) Producers should discuss the potential for sharing costs and benefits of technical solutions that have been trialled, in terms of capacity gained.
- C.1) Industry to engage BEIS to consider how best to support biomethane and other distributed gas sources from a network capacity perspective, to complement the support provided through the RHI.
    a. Industry to demonstrate costs associated with capacity constraints and the limits this could pose on the long term development of the market.
    b. Industry grouping to lead consultation on options to mitigate these limitations: a) possible changes to pricing or RHI tariff structure to incentivise injection at times of high demand; b) installation of new storage provisions as part of GDN portfolio, in advance of this being required from customers.

    c. Industry grouping to report findings of the above to BEIS and the regulator, defining possible forms of policy support.

- C.2) Industry to engage Ofgem to define framework defining ownership and input and output balancing arrangements for storage on the network.
- C.3) GDNs to explore scope for license obligation exemptions to facilitate implementation of new solutions beyond the trial stage.

Next 3-5 years:

- B.6) Shale producers could initiate and consider providing funding for investigation of future opportunities and likely costs for LTS interconnection alongside energy blending, in areas of known shale reserves.
- B.7) Explore practicalities and feasibility of LTS interconnection and energy blending, with support from shale producers.
- C.4) GDNs to work with BEIS and Ofgem to implement agreed policy changes around pricing and/or role in deploying capacity solutions.
- C.5) GDNs to work with Ofgem to develop framework to define conditions when socialising costs (e.g. through charging) is appropriate for different technical solutions.
- C.6) GDNs to engage Ofgem to introduce incentives / disincentives for the GDNs to ensure efficient and effective deployment and use of solutions.

While the most likely stakeholders to lead each specific action have been identified above, all of the actions outlined will require collaborative efforts and transparency between the different industry stakeholders, in order to bring down overall costs and maximise opportunities for injection of green and distributed gas. Costs (and practicalities) for the range of solutions available to maximise the injection opportunities on the network will be strongly dependent on particular network and source characteristics. As such, clear communication across the industry and GDNs will be essential to maximise learning for the system as a whole, and to draw out emerging trends around the suitability of different options.

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1 Introduction

1.1 Background

A number of distributed gas generation sources are set to be deployed in increasing numbers in the coming years, each with different characteristics, geographic distributions, and timescales for commercial production. With the introduction of Renewable Heat Incentive (RHI) tariffs for biomethane injection, the market for biomethane to grid has grown rapidly in the past five years. While commercial production of unconventional gas sources such as shale gas and coalbed methane has yet to be proven in the UK, the current government has a clear appetite to move towards a more diverse and secure gas portfolio, and envisages a ramp up of shale and coalbed methane production over the coming decades.

The widespread deployment of distributed gas injection could have a significant impact on the different segments of the distribution grid, and new commercial and regulatory arrangements may be necessary to support the transition away from imported, centrally injected gas towards an increasing proportion of distributed gas. This is likely to have profound implications for gas network stakeholders, in particular the Gas Distribution Networks (GDNs), whose networks will be expected to accommodate the majority of new distributed gas source connections.

The number of biomethane production plants seeking to inject their gas into the distribution network has grown rapidly over the last few years, and GDNs are increasingly facing challenges when it comes to providing connection points with sufficient capacity for producers to inject their gas. Producers also face various other economic and technical challenges in the process of preparing to inject gas to the grid, which, if not addressed, could impact the future deployment of distributed gas sources.

Three of the GDNs, National Gas Grid Distribution (NGGD), SGN and Wales and West Utilities (WWU), have commissioned this study to explore the future impacts of a continued increase of distributed gas on the network, and identify the most cost-effective measures that could be taken to support grid injection.

1.2 Objectives of the study

The findings of this study are intended to inform the approach of the GDNs towards distributed gas sources, by identifying priority actions that will support current and future injection in a cost-effective way. To achieve this, study has focused on achieving the following objectives:

- Establish likely scenarios for the deployment of distributed gas injection.
- Explore the technical and commercial barriers to the realisation of these scenarios, in relation to injection of this gas to the grid. Identify measures required to address these barriers, as well as measures which have already been taken.
- Assess the likely impacts of accommodating distributed sources on the distribution network, and identify available methods for GDNs to provide sufficient capacity for distributed sources to inject.
- Derive guidelines to help GDNs identify cost-effective measures to provide sufficient capacity.
- Identify the most cost-effective actions for GDNs to enable increased grid-injection in future.

1.3 Scope and approach of the study

Scope

This study considers deployment scenarios for biomethane, shale gas, and coalbed methane in the UK, with projections considered up to at least 2030. Hydrogen and synthetic gas (bio-SNG), two further potential distributed gas sources, are not considered in this report. However, it should be noted that a bioSNG demonstration plant project (which National Grid plays a key role in) began in 2013[1]. In addition, a consortium of stakeholders including National Grid has recently been awarded funding from Ofgem to support a Hydrogen project, HyDeploy, as part of which blended hydrogen will be injected to the UK gas grid.

The barriers and opportunities for injection of the above sources to the gas distribution network are explored, and as part of this, scenarios for injection are modelled to explore the possible constraints on the Medium Pressure (MP), Intermediate Pressure (IP) and Local Transmission System (LTS). Injection to the National Transmission System (NTS) is also considered, in order to compare the costs of injecting to the transmission system, with those of injection to the distribution networks.

Although this a UK-focused study, the consideration of possible solutions to current and future challenges for distributed gas injection draws on examples from the international experiences of distributed gas management.

Approach

An extensive review of existing literature on distributed gas sources in the UK and internationally formed the basis for the development of scenarios for UK deployment, and for the definition of key characteristics for each different source. The scenarios were developed through comparison and extrapolation of projections made in the literature. These scenarios were assessed and validated through consultation with producers, GDNs and other stakeholders. The consultation and literature review were also used to gather information on the costs and main barriers to injection of distributed sources, and on the international experiences of injecting gas into distribution networks and addressing some of these barriers.

Based on international experiences, and the solutions that are beginning to be trialled in the UK, a number of potential solutions to one of the key barriers (i.e. limits to the capacity of local networks to accommodate injection) were defined. The potential costs of these various solutions were then assessed, for various constraints on the network, which were represented by a simplified model of a distribution network. This model was informed by the results of the consultation and the literature review, with assumptions on demand and injection profiles based on the data gathered during this phase. Key trends were extracted from the cost analysis, to inform GDNs regarding the solutions which would be most likely to cost-effectively address future capacity constraints. The potential commercial implications of each solution for the network stakeholders were also considered, and a dedicated workshop with NGGD, SGN and WWU was held as part of this process.

Finally, the results of the cost assessment and commercial analysis informed recommendations for the industry to support increased grid injection of distributed gas sources.

[1] See http://gogreengas.com/ for more information

Figure 1 summarises the approach to this study.

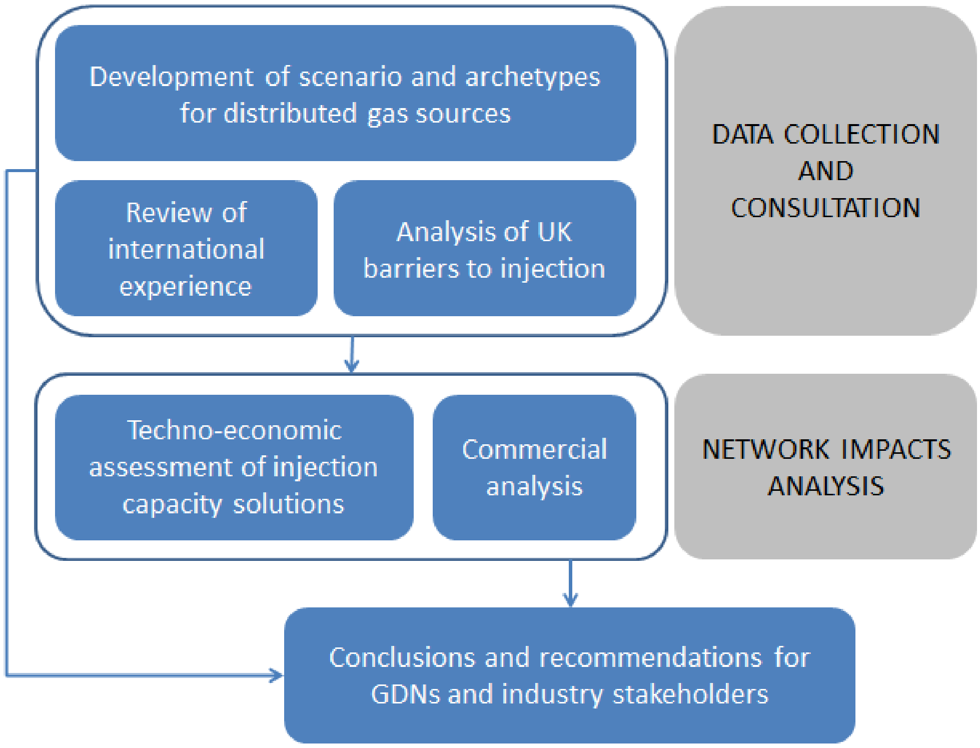


Figure 1 Summary of approach

1.4 Organisations involved

The organisations who contributed to this study are listed below.

Element Energy
CNG Services
Imperial College (Sustainable Gas Institute)
British Geological Survey
National Grid Gas Distribution Ltd
SGN
Wales and West Utilities

The authors of the study would also like to thank the following organisations for contributing to the consultation:

National Grid NTS
Third Energy
Future Biogas
Qila Energy
Cuadrilla Energy
Barrow Green Gas
SGN Commercial

2 Distributed gas production scenarios for the UK

This chapter describes the market status for distributed gas sources, and sets out characteristics and possible production scenarios, specifically for biomethane, coalbed methane, and shale gas.

2.1 Biomethane

Biomethane is produced mainly via anaerobic digestion of a range of feedstocks, including various agricultural wastes and crops, sewage, and food waste. These processes produce biogas, which can be treated to make biomethane that is suitable for injection into the gas grid.

2.1.1 Developments to date and market status

The Renewable Heat Incentive (RHI), introduced in 2011, provides subsidies to biomethane producers injecting gas to the grid, and has stimulated a fast-growing market. According to the latest data, by the end of 2015 there were 50 operational biomethane to grid (BtG) facilities, injecting approximately 2.5 TWh of biomethane into the gas grid (on the distribution network) each year. At least another 15 plants were expected to be completed in 2016[2].

Figure 2 shows the injection points for BtG projects that were completed in 2014, giving an indication of the spread of biomethane connections across the pressure tiers of the distribution networks. The data shows that in 2014, MP and IP injection were fairly evenly split and both more frequent than injection at the LTS.

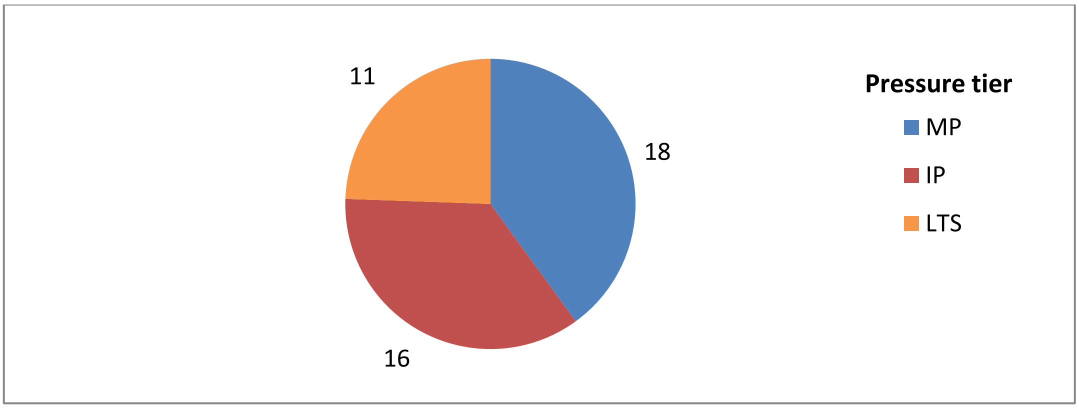


Figure 2 Biomethane injection facilities completed in 2014, by pressure tier of injection point[3]

The former Department of Energy and Climate Change (DECC) indicated that the RHI should continue to support biomethane to grid plants until at least 2020. However, the RHI tariffs that biomethane injection plants are eligible to receive have been reducing since 2013, and there is anecdotal evidence from manufacturers that this is beginning to slow the growth of the market. This has not yet translated through to data in terms of the numbers of plants built per year, but the total number of projects at the end of 2016 and in 2017 may provide some indication of this.

Figure 3 shows the proportion of projects in each GDN area, as shown on the map to the right.

[2] Renewable Energy Association, 2016, Renewable Energy View 2016
[3] CNG Services, 2014, Biomethane to Grid UK Project Review

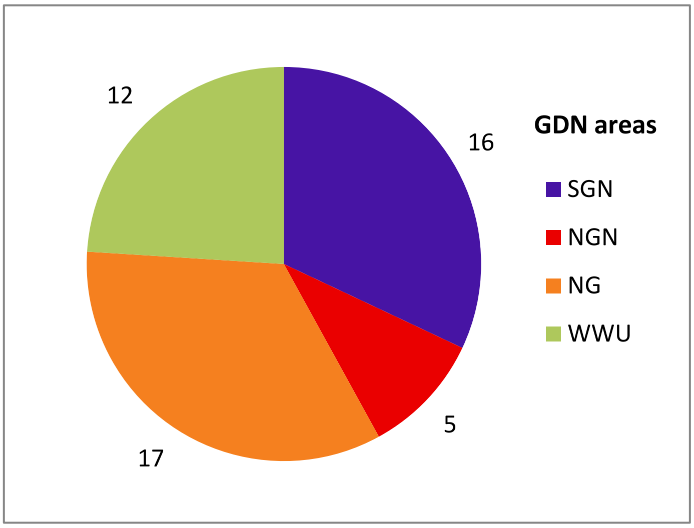


Figure 3 GDN areas and proportion of biomethane to grid projects in each area (Note that SGN includes Scotland Gas Networks and Southern Gas Networks).[4]

2.1.2 Characteristics of biomethane production and injection

Gas quality and Calorific Value

Biogas, the direct product of anaerobic digestion, has high concentrations of carbon dioxide, hydrogen sulphide and water and must be upgraded through various treatment processes, to produce biomethane.

The oxygen content of biomethane can be higher than that of natural gas. However a Health and Safety Executive class exemption (in 2012) changed the limit to 1% oxygen (molar) content, for gas injected into the distribution networks.

The calorific value (CV) of biomethane is about 37 MJ/m^3, which is lower than that of the gas transported in the NTS (around 39.5 MJ/m^3). To enrich the CV, propane, which has a much higher energy content, is added before injection.

Production pressure

As a result of the upgrading process, biomethane is produced at a pressure of at least 10 bar, so no compression is required for injection to MP or IP (maximum pressure of 7 bar).

Flow rates

Table 2.1 shows the range of production rates for UK biogas projects in 2015. This is a useful indication of the potential injection capacity for individual projects, although the actual injection rate will depend on the capacity for injection, and on the costs and benefits of injecting gas at different rates. One factor likely to influence the scale of biomethane injection facilities is that the highest tariff for biomethane is for the first 500 scmh of injection, and a lower tariff is received for additional injection beyond 500 scmh.

[4] CNG Services, June 2015, UK Biomethane Market Update; National Grid.

Table 2.1 Flow rates of biogas projects in 2015[5]

Biogas flow rate (scmh)	Number of projects in 2015	% of projects in 2015
0 - 400	4	6%
400 - 800	8	16%
800 - 1,200	29	58%
1,200+	10	20%

2.1.3 Scenarios for future biomethane to grid developments

Projected annual biomethane production profiles vary between different national energy scenarios, depending on the policy measures which are assumed to be in place. Scenarios for 2030 vary from a “failure” or no increase scenario (production of 0.6 Mscm/day[6]), to the highest prediction of 13 mcmd (millions cubic metres per day), which is equivalent to over a thousand BtG plants with a production rate of 500 scmh.

Figure 4 and Figure 5 show a range of scenarios for future biomethane production, based on existing literature. The first five scenarios were generated by extrapolation and interpolation of data from two reports: Green Gas Grids (EU project) UK roadmap[7], 2014 (UK scenarios, report data and spreadsheet data), and National Grid Future Energy Scenarios, 2015 (Consumer Power, Slow Progression and Gone Green scenarios)[8]. The final scenario was based on achieving the maximum potential for biomethane, as estimated by ADBA for 2020/2025, by 2030.

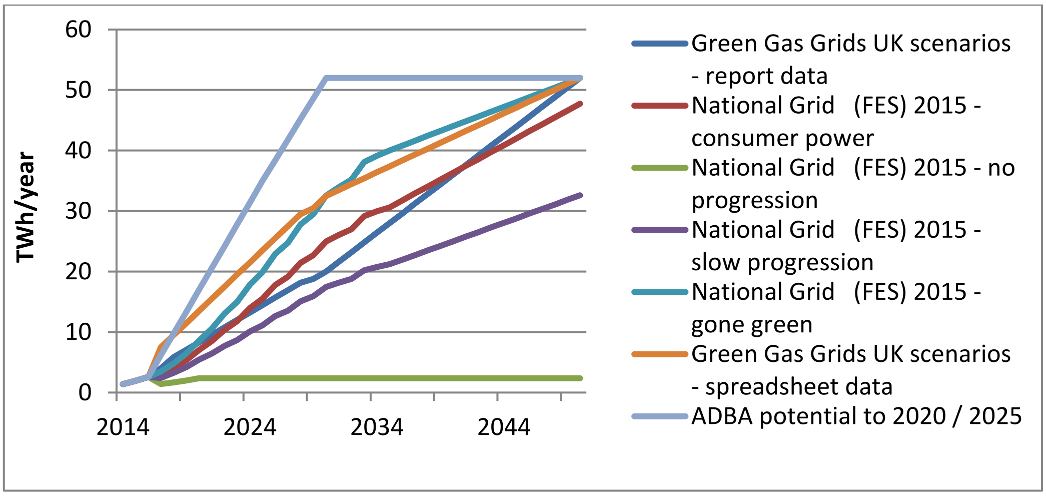


Figure 4 Biomethane production scenarios to 2050, in TWh/year

[5] CNG Services, June 2015, UK Biomethane Market Update
[6] In this report, Mscm refers to million standard cubic metres.
[7] Green Gas Grids – UK roadmap, 2014. Available from: http://www.greengasgrids.eu/info/downloads.html
[8] Future Energy Scenarios 2015, National Grid, July 2015

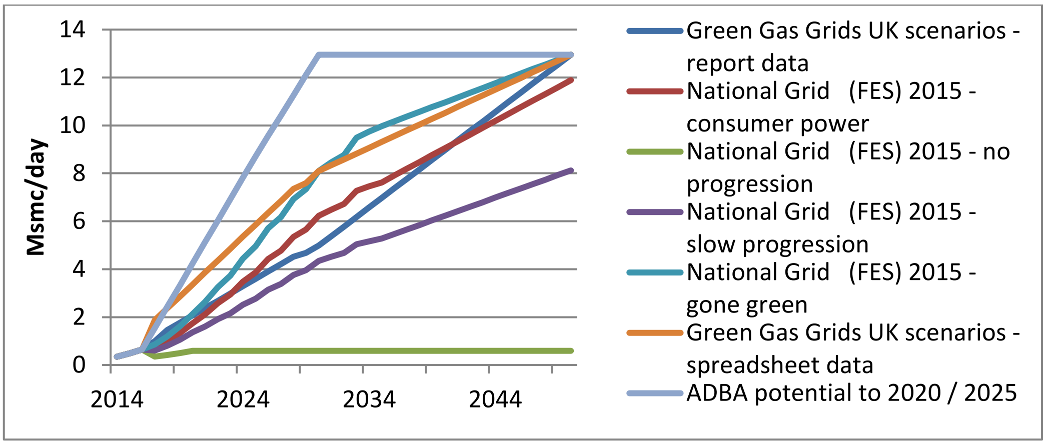


Figure 5 Biomethane production scenarios to 2050, in MCMD

Five of the seven scenarios predict production in 2030 to be close to 7.5 mcmd, which would be equivalent to 625 BtG plants injecting at 500 scmh. The “no progression” scenario is the lowest, assuming that there will be little increase from current levels of production of around 0.6 mcmd, and the ADBA potential scenario is the highest, assuming that the maximum potential of 13 mcmd is reached by 2030.

In 2014, total gas demand was approximately equivalent to 190 mcmd of biomethane (770 TWhr/year). Assuming a relatively flat demand profile between now and 2030, biomethane could account for a maximum of 7% of UK gas consumption by 2030. A more likely share, based on the scenarios above, would be around 4% (based on 7.5 mcmd).

2.2 Unconventional onshore gas sources

Coalbed methane (CBM) and shale gas are terms used to describe gas that is produced via different extraction methods to those used for conventional reservoirs. For coalbed methane, this involves pumping water out of a coal seam, to release the gas stored within the seam. Hydraulic fracturing (fracking), which is the main technique used to extract shale gas, may also be used in coalbed methane extraction. Hydraulic fracturing involves fracturing the impermeable rock holding the gas, using a pressurized fluid, to enable the gas to flow more freely.

Both of these extraction methods have caused controversy in their application worldwide, due to their potential negative environmental impacts, including risks of ground and surface water contamination, air and noise pollution, and the possible triggering of earthquakes. In the UK, hydraulic fracturing in particular has faced considerable public opposition and several potential shale gas projects have been stalled in the planning permission stage as a result of objections from the local public. However, the UK government is generally supportive of shale gas; in 2013, the tax rate on early profits from onshore oil and gas (including shale gas) was halved; in 2014 a £5 million fund was allocated to shale exploration, and future planning decisions regarding shale will be made by the Secretary of State, taking it out of the hands of local planning authorities.

2.2.1 Developments to date and market status

Production of coalbed methane or shale gas has not yet been achieved at a commercial scale in the UK. Test wells have been drilled in a number of areas, providing an initial indication of the viability of these production methods in the UK. However, until exploration begins on a larger scale, estimates of the total possible production volumes will be highly uncertain.

About fifty CBM wells have been drilled to date in the UK, as shown in Figure 6, which highlights the areas with potential for CBM and shale gas production, according to the British Geological Survey, and the wells to date.

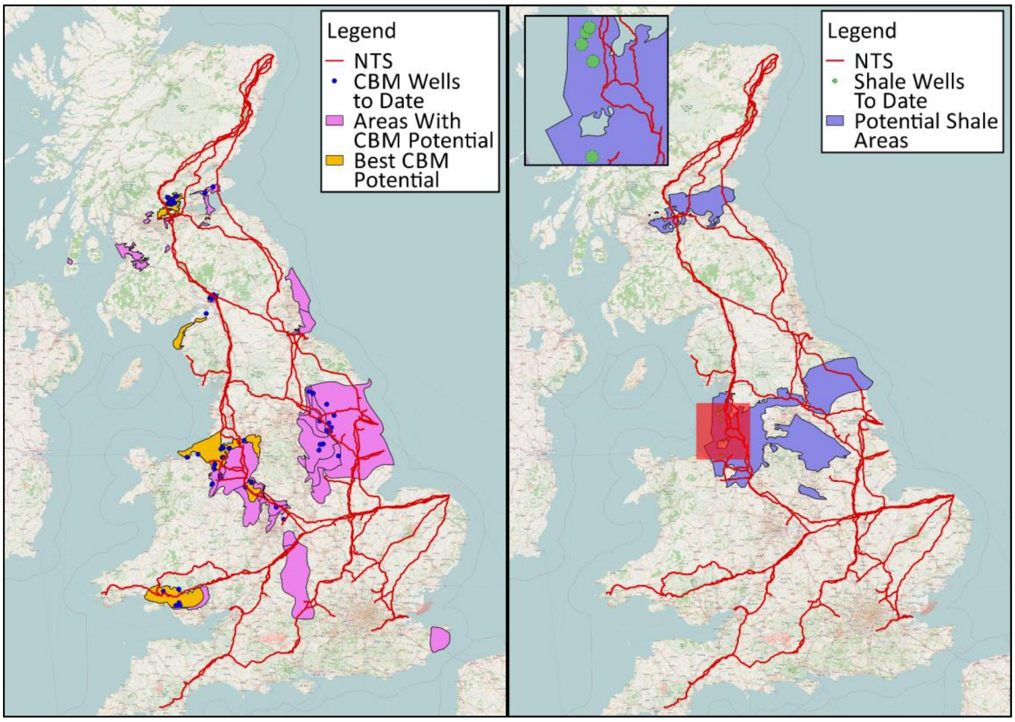


Figure 6 Areas with potential for production of coalbed methane (left) and shale gas (right), and wells drilled to date[9]

CBM production from the wells drilled to date has only progressed to the pilot stage in three locations: Doe Green (in Warrington), Airth (in Scotland), and Keele. Of these wells, only the gas produced at Doe Green has been fed into the gas distribution grid. The volumes produced from the Doe Green wells have been small, with a total of 297,000 scm being produced last year (equivalent to an hourly rate of 34 scmh, less than 10% of the typical injection rate for biomethane).

The British Geological Survey (BGS) estimated in 2004 that 2,900 billion cubic metres of CBM is in place in the UK, but that, due to low seam permeability, low gas content and resource density, it is likely that a maximum of 10% of this resource may be recoverable. This is low compared with recoveries in the US of 30-40%. Experiences to date suggest that technical challenges and public opinion are major barriers to coal bed methane, and the industry is not likely to reach a commercial level in the near future.

Although the first licenses for shale exploration were granted in 2008, very little shale gas has since been produced. A small number of shale gas test wells have been drilled by IGAS and Cuadrilla in the North of England, but none have been productive. Further exploration has been stalled by planning permission objections and rejections, but is more likely to go ahead in the future, following the Government's decision to leave planning decisions on shale to the Secretary of State.

The only successful production of shale gas in the UK to date has been at Kirby Misperton, on a site where there is existing production of conventional gas. Third Energy has taken over the license for the gas field and has hydraulically fractured a tight sandstone

[9] British Geological Society

hydrocarbon test well. The test well has produced 2.48 Mscm of gas in the last year (equivalent to an injection rate of around 300 scmh) and is expected to be productive over the next nine years. Shale gas production at Kirby Misperton is currently used to supplement the conventional gas production, which supplies a nearby electricity generation plant. However, in the future, subject to planning permission, more tests will be drilled, with the ultimate objective of launching production from as many as 70 wells simultaneously. If production is successful for multiple wells, the objective would be to inject this gas to the grid, either to the LTS or the NTS, depending on the production rate and the locations of suitable injection sites. A similar narrative of production ramping up over time can be expected for other potential shale production areas.

The extent of total UK shale reserves are very uncertain. BGS estimates 150 billion cubic metres of recoverable resource. However, the sum of the estimates of gas in place made by companies in their respective licence areas is 8.75 tm^3, and the IOD gives three possible recovery rates, 5%, 10% and 15%[10]. This leads to recoverable resource estimates of 438 billion cubic metres, 875 billion cubic metres, and 1.31 trillion cubic metres, respectively.

Overall, the outlook for shale is more positive than CBM: fewer technical issues are expected; license holders are more focussed on shale than CBM; and in successive statements the government has promoted the shale industry, most recently planning a Shale Wealth Fund to dissuade communities from blocking planning permission (which currently remains a major barrier to production).

2.2.2 Characteristics of production and injection

Table 2.2 summarises the characteristics of CBM and shale gas production which will be relevant to injection to the gas grid, estimated on the basis of discussions with producers.

Table 2.2 Production characteristics for CBM and shale gas

Source	Calorific value (MJ/m^3)	Production pressure (bar)	Expected production flow rate (scmh)
CBM	37.5-38.5	2	1,250
Pre-commercial shale gas (per well)	37.5-38.5	35 (individual well pressure will decrease sharply over time)	1,250 e.g. 5,000 for 4 wells
Commercial shale gas production (per well)	37.5-38.5	35 (individual well pressure will decrease sharply over time)	6,250 e.g. 125,000 for 20 wells

The production volumes and pressures for shale gas are estimates for one well, but it is likely that for injection to the grid, production from multiple wells will be combined to one injection point. This increases the total flow rate at the point of injection, and also means that the decline in production pressure that is expected for individual wells would have less of an impact, as production from wells at different stages could be combined, thereby

[10] Institute of Directors, 2013, Getting Shale Gas Working

maintaining the overall pressure and production rate. This will have impacts for injection costs; the higher the pressure, the lower the costs of compression.

CBM is produced at much lower pressures than shale gas. Due to the high costs associated with compression, this may mean that only injection into the distribution network (e.g. at IP or at the LTS) would be considered. For shale gas, both the high production rates (once multiple wells are combined) and the high pressures imply that injection to the NTS would be suitable. Injection to the LTS could also be appropriate for test wells, and for production small numbers of commercial wells.

It is likely that, as with biomethane, the addition of propane will be required prior to injection to enrich the CV of the gas to meet the value set by the relevant charging zone.

2.2.3 Scenarios for coalbed methane developments

Figure 7 and Figure 8 show a range of scenarios for future CBM production, based on the following assumptions:

- Case 1: No more wells drilled
- Case 2: 20 wells drilled per year
- Case 3-5: Models based on Australian Production, scaled to UK reserve estimates
- Case 6-8: Models based on US Production, scaled to UK reserve estimates

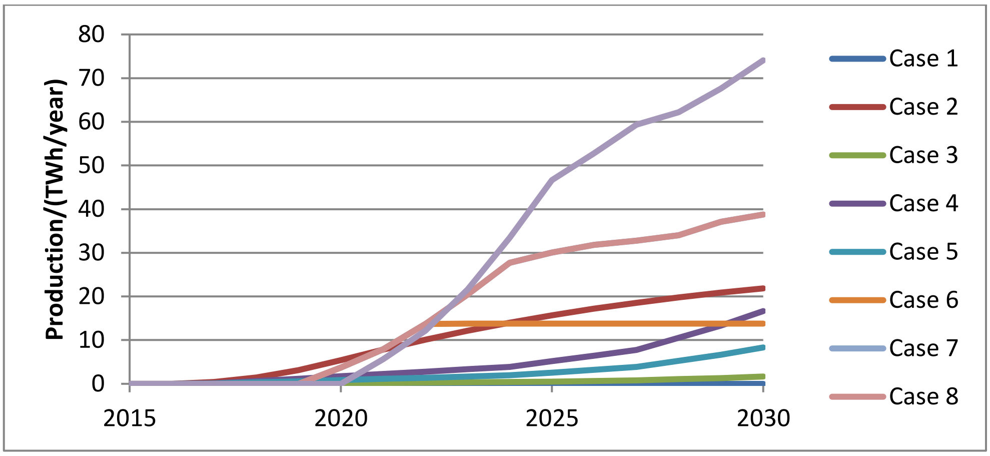


Figure 7 CBM production scenarios to 2030, in TWh/year

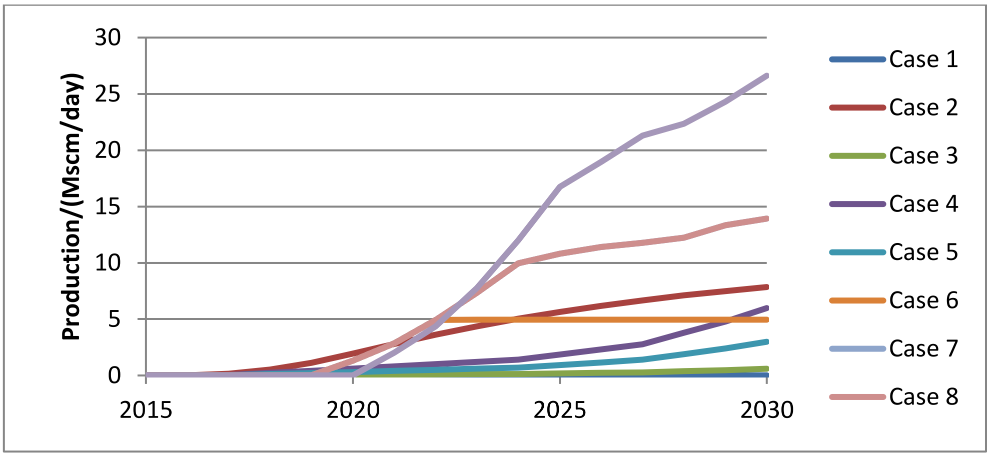


Figure 8 CBM production scenarios to 2030, in mcmd

Of the eight scenarios, six predict peak daily production rates of between 3 and 15 Mscm/day. Assuming that UK gas consumption remains close to 2014 levels, in 2030, this would account for at most around 10% of UK gas demand. However, given that the technical barriers have so far prevented CBM production from ramping up, it is also possible that commercial production will not be reached.

2.2.4 Scenarios for shale gas developments

Figure 9 and Figure 10 show a range of scenarios for future shale gas production, based on the following assumptions:

- Case 1: Following a ramp-up phase, 30 wells added per year.
- Case 2: Following a ramp-up phase, 20 wells added per year.
- Cases 3 and 4: US production trend, scaled to UK reserve estimates.
  - Case 3 - capped as annual production reaches 5% of reserves.
  - Case 4 – capped once production eliminates need for UK gas imports.
- Case 5: UK production follows US profile for shale use as a proportion of total demand. Capped once production eliminates need for UK gas imports.
- Case 6: Linear extrapolation of National Grid Future Energy Scenarios (Green scenario), which predicts 1 shale connection to the grid in 2020, and 100 in 2035 (note that this scenario exceeds the BGS estimated reserves).

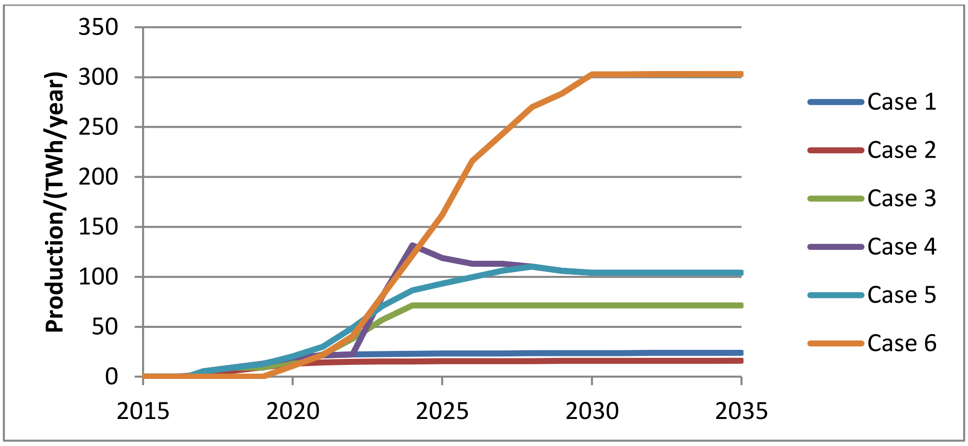


Figure 9 Shale gas production scenarios to 2030, in TWh/year

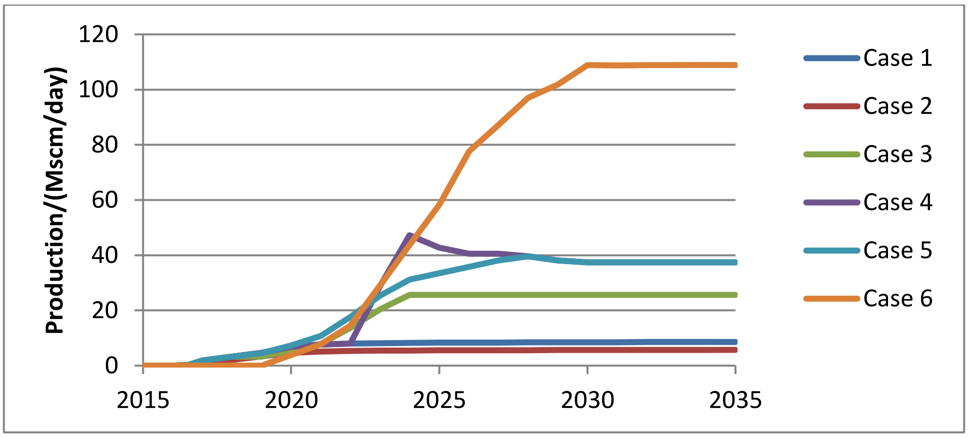


Figure 10 Shale gas production scenarios to 2030, in Mscm/day

The projected daily production rates for 2035 range from 5.7 to 37.4 Mscm/day, with an average of 23 Mscm/day from 2024 onwards. This would equate to 12% of the total gas demand, assuming that UK gas consumption remains relatively constant.

2.3 Overall predictions for distributed gas sources

Biomethane

Over the next few years, it is likely biomethane plants will increasingly penetrate the LTS and lower pressure tiers. Biomethane is most likely to be injected into the MP or IP pressure tiers. There may be some situations where it is preferable to inject into the LTS. The relative merits of injection at different pressure tiers will be discussed later in this report, in particular as part of the cost assessment in Chapter 6.

CBM and shale gas

Development of the CBM industry in the near future faces considerable barriers. If these barriers could be overcome, annual production could reach between 3 and 15 Mscm/day in 2030.

Based on the production characteristics and scenarios for CBM and shale gas, the latter is generally much more likely to be injected to the grid, as it is produced at a higher pressure and has the potential for higher production rates, and it is therefore less likely to require compression, and injection is more likely to be profitable. Due to the low production pressure of CBM, it is possible that only injection into the distribution network (e.g. at IP) would be considered, whereas for shale gas, both the high production rates (once multiple wells are combined) and the high pressures imply that injection to the NTS or LTS would be suitable.

Shale gas has better overall prospects for production than CBM, and if planning permission and other barriers can be overcome, annual production could reach up to 37.4 mcmd in 2035.

3 Opportunities to maximise distributed gas injection

Production scenarios for distributed gas in the UK, as discussed in the previous chapter, indicate that there is significant potential for increased injection of gas to the distribution networks. This would bring greater security of supply, as well as contributing to the decarbonisation of the gas grid. However, increased injection would also change the existing balance and geography of inputs and outputs to the network. The current operational and commercial environment may pose constraints to such changes, and as such, a combination of technical solutions and adaptation to the regulatory framework may be required in order to maximise the potential for injection and the benefits this could bring.

This chapter considers the possible circumstances for future gas injection to the distribution networks, and for existing injection. The potential limiting factors for injection (including technical and commercial/regulatory barriers) are then considered in the context of these scenarios. Opportunities to address these limitations are explored, including consideration of technical solutions and regulatory changes.

3.1 Comparing the characteristics of injection projects

Almost all distributed gas injection projects to date have been biomethane (with the exception of coalbed methane injection at Doe Green). Biomethane production resulted in the injection of around 2.5 TWh of distributed gas per year at the end of 2015. To put this in context, this is approximately equivalent to the annual domestic gas demand from around 100,000 homes (i.e. a large town). The total annual domestic gas demand for the UK is in the region of 400 TWh (approximately 40,000 million cubic metres)[11]. Volumes for a commercial scale shale bed could reach around 1,000 million standard cubic metres per year, which could make a significant contribution to gas supply.

As well as encompassing various sources and injection points, the "archetypes" for injection of distributed gas can be differentiated by factors that impact their feasibility under the current operational and commercial framework. One key aspect is downstream demand.

Currently, biomethane producers typically seek to inject at a constant rate (partly due to the way RHI tariffs must be claimed), and obtain a contract with the GDN which guarantees that they can inject the gas at this certain rate throughout the year, despite the seasonal variation in demand. The GDN can manage this to some extent, by varying the volume of gas flowing through the network from higher pressure tiers.

However, for a given injection point, the capacity that GDNs can offer is limited by downstream demand. The increased number of grid injection projects in recent years mean that in some cases, potential new projects cannot inject gas at their desired rate at a suitable injection point, due to there being insufficient "spare demand" on the network, particularly during low demand periods such as summer nights. Unless the industry develops and implements new methods of managing the overall balance of supply and demand across the network over time, this effect could significantly limit the amount of distributed gas injected in future. The industry is starting to explore various technical solutions that could help to address this, and as such, in order to maximise the opportunity for distributed gas, injection archetypes where there is "insufficient capacity" must also be considered as part of the potential range of options for future injection.

Table 3.1 shows the main variables that define the different injection archetypes. The injection rate and the pressure associated with the source of gas will inform the most suitable

[11] Renewable Energy Association, 2016, Renewable Energy View 2016

injection point, although this will also depend greatly on the specific network characteristics such as the downstream demand. Archetypes can be differentiated more broadly by the relationship between the injection rate and the minimum downstream demand, as indicated in Table 3.1.

Table 3.1 Key variables between injection archetypes

Source	Injection tier	Injection rate vs minimum demand (capacity at injection point)
Biomethane / Shale Gas / (CBM)	MP / IP / LTS	Below minimum demand (sufficient capacity) / Exceeds minimum demand (insufficient capacity)

The following section considers the potential limitations that may inhibit future injection of distributed gas, and how these may apply to particular injection archetypes. The opportunities to address these limitations, through potential technical solutions and through regulatory change, are discussed.

3.2 Limiting factors and opportunities to address them

The growth of distributed gas injection fundamentally relies on there being a positive business case for gas producers. A range of factors affect the business case, including policy (such as the RHI, which currently brings significant revenues to biomethane producers injecting their gas to the grid), technical requirements for injection, and the capacity available for injection on the network. If a local network has very low demand, a gas producer will either only be able to inject a small amount of gas (which may not be enough to make a worthwhile business case for production) or will have to consider more costly methods to inject their gas (e.g. installing a pipeline to a location with greater downstream demand).

The capacity issue arises from the fact that local gas demand and supply must be managed very closely over the course of each day, to ensure that pressure limits are adhered to. To some extent, biomethane projects to date have benefitted from relatively cheap "low hanging fruit" injection opportunities available within each distribution network area, resulting in a rapid deployment of biomethane injection projects between 2014 and 2016. Due to the "degression" aspect of the RHI, this rapid deployment has also led to significant reductions in tariffs available for new projects, and the combination of these factors could reduce the number of feasible projects post-2016.[12]

Due to the diminishing number of cost-effective injection opportunities on some networks, (which is compounded by the tendency for biomethane plants to be geographically clustered around various feedstock sources), more innovative methods of managing supply and demand across networks will need to be implemented to make capacity available and unlock the full potential supply of distributed gas sources. In addition, if the costs associated with distributed gas injection (including connection costs and various operating costs) could be

[12]However, in December 2016, BEIS (Department for Business, Energy & Industrial Strategy) announced an increase to biomethane RHI tariffs, and a revision to the degression mechanism to better align this with market growth. These changes are intended to help the further growth of the market.

reduced for future projects, this would help to make more projects viable in the future, ensuring that the benefits for the grid are maximised.

Table 3.2 indicates which of the current and future injection archetypes are impacted by the factors discussed above.

Table 3.2 Injection archetypes and potential limiting factors

	Source	Injection tier	Injection rate vs minimum demand	Possible limiting factors for business case
EXISTING INJECTION ARCHETYPES	Biomethane	MP or IP	Below minimum demand	Cost of connection Cost of meeting CV requirements Reduced RHI tariffs and high operating costs coming from requirement to add propane
	Biomethane	MP or IP	Exceeds minimum demand but injects on an interruptible basis, or pays for network to manage pressure to enable injection	Cost of connection Cost of meeting CV requirements Cost of implementing network management Reduced RHI tariffs and high operating costs coming from requirement to add propane
	Biomethane	LTS	Below minimum demand	Cost of connection Cost of meeting CV requirements Cost of compression Reduced RHI tariffs and high operating costs coming from requirement to add propane, and the need for compression
	Shale test well	LTS	Below minimum demand	Cost of connection Cost of meeting CV requirements High operating costs coming from the requirement to add propane

	Source	Injection tier	Injection rate vs minimum demand	Possible limiting factors for business case
NEW POTENTIAL INJECTION ARCHETYPES	Biomethane	LTS	Exceeds minimum demand	Cost of connection Cost of meeting CV requirements Constraints on injection volumes due to demand variation or reinforcement costs Reduced RHI tariffs and high operating costs coming from requirement to add propane, and the need for compression
	Multiple shale test wells	LTS	Exceeds minimum demand	Cost of connection Cost of meeting CV requirements Constraints on injection volumes due to demand variation High operating costs coming from requirement to add propane
	Commercial shale gas production	LTS	Exceeds minimum demand	Cost of connection Cost of meeting CV requirements Constraints on injection volumes due to demand variation High operating costs coming from requirement to add propane
	CBM	MP / IP	Exceeds minimum demand	Cost of connection Cost of meeting CV requirements Constraints on injection volumes due to demand variation High operating costs coming from requirement to add propane

It is clear from Table 3.2 that many of the factors limiting distributed gas injection can apply across the full range of archetypes, while some (such as capacity constraints) apply specifically to certain cases. To maximise the potential for distributed gas sources, however, all of these factors must be addressed.

The factors identified above (and the opportunities to address them) were explored in detail through the following processes:

- Review of literature on barriers for distributed gas injection in the UK and measures to address them, including evidence of the international experience of similar barriers.
- Interviews with market stakeholders (including producers and shippers), who were asked to identify the barriers most likely to prevent future injection to the grid, and where possible, to quantify the cost and impact of each of these barriers on their business case.
- Discussion of barriers, and possible measures to address them, with the GDNs.

Specific factors impacting the case for distributed gas

From the perspective of industry stakeholders, the specific barriers for future injection of distributed gases were identified as:

- Capacity constraints on the distribution network;
- Minimum CV requirements for injection, leading to:
  - High operating costs associated with adding propane to increase the CV;
  - High capital costs associated with CV determination devices, which must be approved by Ofgem.
- High connection costs, particularly for certain GDNs, partly due to the differences in connection design specifications between GDNs;
- Long timescales for approvals during application for connections;
- Lack of easily accessible information on connection opportunities.

These factors all play a part in undermining the business case associated with injecting distributed gas to the distribution networks. Their impacts, progress in addressing them, and technical and regulatory opportunities for the future are described in the following sections. This includes consideration of the policy framework for distributed gas. Alongside changes to the RHI in December 2016[13], which could be beneficial for the biomethane injection market, further policy changes could play a role in addressing some of the barriers.

The following tables explore in detail the specific factors that could limit the growth of distributed gas, and the opportunities to address them.

3.2.1 Capacity constraints

Issue	The maximum injection capacity offered by GDNs to biomethane producers for injection is limited to the minimum demand downstream of the potential gas entry point. The closest network segment to a distributed gas production facility may not have sufficient capacity for injection.
Relevant injection archetypes	Those where the minimum downstream demand is exceeded by the gas production rate. This is likely to occur for cases of biomethane injection to the MP, cases of biomethane injection to the IP or LTS where there are already multiple sites injecting, and shale injection to the LTS (especially for commercial production).

[13]Department for Business, Energy & Industrial Strategy (BEIS), December 2016. *The renewable heat incentive: a reformed scheme – Government response to consultation.*

Impact	The impact for a potential gas producer can be considered either in terms of the loss of revenues from the gas not injected, or in terms of the cost of a solution to achieve greater injection capacity. Currently, the most common means of accessing greater capacity is to pipe the gas to a point on the network where there is greater demand. As such, the annual cost of capacity constraints for producers can be estimated on the basis of the following assumptions: • Pipeline cost: £200,000/km at MP, £300,000/km at IP • Pipeline required to avoid a constraint: 2km at MP (vs 0.25km for "local" injection with no constraint); 3km at MP (vs 1km for "local" injection with no constraint) • Annual number of connections with constraints to avoid: e.g. 10 at MP, 10 at IP On this basis, the total cost incurred by producers in avoiding capacity constraints for new connections can be estimated as c.£9 million per year. The network impact of capacity constraints is likely to be a lower number of new projects injecting gas each year, due to the effect on the business case for injection.
Technical solutions	Various options could be implemented to manage the balance of supply and demand on the network in a more flexible manner. Some of these have been trialled for implementation with real constraints. Options include: • Gas storage during times of low demand • Smart management of network pressure • In-grid compression of gas to higher tiers • Interconnection of networks These methods, their technical constraints, and the scenarios they would be applicable to are discussed in detail in Chapter 0.
Obstacles to progress	There are few precedents in the UK for implementation of these capacity management options and therefore costs are uncertain and likely to be high initially. Pilot projects are required to understand the potential of these methods to reduce the costs of connection when there are local capacity constraints. Some of the options are likely to be capital intensive, even once proven, but are likely to have the potential for economies of scale. If multiple producers are likely to seek to connect in a certain area, a solution could be employed that would provide capacity for all of them, and in theory, costs could be shared across the producers (or socialised across the network) resulting in a lower overall cost than if the needs of each producer were met by a separate solution. For cases where costs could be allocated to those network users clearly benefitting from capacity solutions, GDNs could pass

	these costs onto producers through connection charges (capex) and pricing (opex and maintenance). However, there is currently no suitable charging framework or funding mechanism that would cover the costs of technical solutions in circumstances where it may be unclear who creates the demand for and/or uses the additional capacity provided by such solutions. This may particularly be the case for solutions such as storage, which could be installed ahead of requirements and used for the benefit of multiple stakeholders on the network.

Commercial and regulatory enablers	The potential benefits of future biomethane injection, as well as the government's commitment to support biomethane, suggest that there is a role for policy-makers in removing barriers at the network level, to complement their existing support through the RHI. Changes to high-level policy could be the most cost-effective way to support the mitigation of capacity constraints and implementation of solutions.
	
	In the latter case, as well as setting out commercial structures to allow implementation, regulatory change could enable the deployment of technical solutions to support multiple distributed injection projects at once, making them more cost-effective.
	
	<u>Regulatory changes to support technical solutions</u>
	
	• For solutions that would benefit multiple, indeterminate stakeholders, possible options to recover installation and operating costs could include:
	    o Framework for these costs to be recovered from customers using the network, e.g. based on their use of capacity (similar to the framework for Exit Capacity charges).
	    o Provision to be made through some form of government funding, to allow GDNs to include the installation of capacity solutions within their remit, as part of work to future-proof the network.
	• In either case, the installation of such solutions would need to take place under conditions approved by the government and Ofgem for the installation of "capacity solutions" in advance of the requirements of specific new connections. These conditions would need to define, for each technical solution a) the point at which it becomes appropriate to share costs across multiple producers (and potentially end customers across the network) and b) the terms through which the specifications of the solutions are defined (e.g. auctions for capacity in certain regions).
	• Incentives or disincentives for the GDNs could need to be put in place in order to maximise the effectiveness, efficiency and fairness of these measures.
	
	• In addition, if gas storage on the distribution network is to be introduced, this would require a specific framework setting out the ownership and responsibilities for storage facilities and flows in and out of these facilities.

	Modifications within daily commercial arrangements would be required to ensure that GDNs are permitted to hold gas for a certain period of time. • Depending on the specific solutions involved, the impact of technical capacity solutions on license obligations should be considered. For example, during early trials of technology such as compressors certain exemptions may be appropriate to allow for equipment failure. Suitable response scenarios for such circumstances would need to be defined. <u>Regulatory options to mitigate the need for technical solutions</u> • Price signals could be used to flatten gas demand (i.e. move demand out of peak times to times where demand is currently lower), in order to better match demand to the supply from distributed gas sources. There has been a great deal of interest in such time-varying price signals – 'time of use tariffs' – in the electricity sector in order to improve utilisation of network capacity and generating plant. To introduce time-varying pricing for gas consumption would require a change to the current network charging regime and roll-out of smart meters to provide improved temporal resolution of consumption metering. Increased thermal storage at customers' premises may also be required to increase the flexibility customers have to respond to pricing. • A new RHI tariff structure could reward higher volumes of injection at the time of greater demand. o This would rely on the feasibility of storage of gas or biomethane feedstock, or on the presence of alternative markets for the gas. Note that his may not be not ideal for some forms of biomethane production.

Recommended steps to maximise opportunities through regulation	<u>Next 1-2 years:</u>
	
	• Industry to engage BEIS to consider how best to support biomethane and other distributed gas sources from a network capacity perspective, to complement the support provided through the RHI.
	  o Demonstrate costs associated with capacity constraints and the limits this could pose on the long term development of the market.
	  o Industry grouping to lead consultation on options to mitigate these limitations: a) possible changes to pricing or RHI tariff structure to incentivise injection at times of high demand; b) installation of new storage provisions as part of GDN portfolio, in advance of this being required from customers.
	  o Industry grouping to report findings of the above to BEIS and the regulator, defining possible forms of policy support.

	• In parallel, industry to engage Ofgem to define framework defining ownership and input and output balancing arrangements for storage on the network. • GDNs to explore scope for license obligation exemptions to facilitate implementation of new solutions beyond the trial stage. Next 3-5 years: • GDNs to work with BEIS and Ofgem to implement agreed policy changes around pricing and/or role in deploying capacity solutions. • Ofgem and GDNs to develop framework to define conditions when socialising costs (e.g. through charging) is appropriate for different technical solutions. • GDNs to engage Ofgem to introduce incentives / disincentives for the GDNs to ensure efficient and effective deployment and use of solutions.
Relative system costs to address the issue	Costs to be accounted for could include: – Field trials through NIC projects to establish viability: £millions in total. – Costs of implementing new commercial models to share costs (including consultation): up to £millions in total In total, total system costs to prove and establish procedures for these methods could be in the region of £millions (or low £10s of millions) but, if effective, this could lead to annual savings of the same order of magnitude, and net system level savings in the long term.

3.2.2 CV requirements, propanation costs and determination devices

Issue	The Flow Weighted Average CV (FWACV) is the average CV of all gas inputs into the zone. However, to protect consumers, the billable FWACV is "capped" at: [Lowest Source in LDZ +1 MJ/m^3]. The difference between the actual energy delivered and the billed energy is the "Shrinkage". Implications of the FWACV cap include: • Customers may pay for less energy than they receive. • Shippers will lose out on the margin of the energy not billed. • Shrinkage cost of unbilled energy ends up with NTS, and is ultimately passed onto customers, meaning that customers incur (small) costs for energy used by someone else. Biomethane typically has a significantly lower CV than other LDZ inputs (i.e. gas from the NTS). Therefore, to avoid potentially high CV shrinkage caused by FWACV capping, before injecting

	gas to the distribution network, biomethane producers must add propane to ensure that the CV meets the local FWACV. Propanation costs can be prohibitively high for biomethane producers. For example, a single plant of 500 scmh could incur costs in the region of £150,000/year (or 0.3p/kWh of gas injected), assuming a CV of 37 against a FWACV of 39 MJ/m^3. This could equate to c.80% of the total annualised costs (see section 6.3 for more details). In addition, all gas entry sites, regardless of size, must measure the CV of the blended gas and communicate the data to the national system for gas billing. Currently, only Ofgem approved devices can be used to determine the CV (CV determination devices or CVDDs). These devices and the other associated equipment for measuring and communicating make a significant contribution to the capital costs of connection, and for low flow sites with lower revenues, this can be detrimental to the business case. One assessment, based on industry consultation, estimates that a saving of £100k could be achievable for each project if the requirement to measure and communicate the CV for the purposes of the national gas billing system was removed. This would remove the possibility of shrinkage costs being incurred to the system, but would mean that the degree of accuracy for billing for customers supplied with the injected gas would be slightly lower.
Relevant injection archetypes	All injection archetypes would become more feasible if the requirements to monitor, communicate and enrich the CV of injection gas were reduced. The possible exception is future commercial shale production sites, which could meet the demand for entire LDZs and would therefore not require enrichment.
Impact	Propanation costs will depend on the injection rate; from £150k/year for biomethane injected at 500 scmh, to around £1million/year for injection rates of 3,000 scmh. Reduced propanation techniques (such as energy blending) are more likely to be feasible for LTS connections, than for IP or MP connections. On the basis of 10 new LTS level connections per year, the total cost differential between injection with propane and without propane (or with minimal propane) could be in the region of £10-20 million, depending on the injection rate.
Technical solutions	Energy blending is an approach whereby propane is only added if the target CV is not met by blending the gas with the other network gas flowing through the injection point. This has been trialled for LTS injection at Severn Trent. Although this provides considerable savings for producers, this approach is limited, as under the current CV requirements it cannot be used for future connections in the same area (since the CV is already minimised

	by the energy blending plant). More details can be found in section 4.3.

Commercial and regulatory enablers	Options for regulatory change:
	
	• Currently, the gas chromatographs are the only CVDDs that meet Ofgem's accuracy requirements. Cheaper CVDDs are available, the use of which could slightly reduce capital costs for biomethane producers. Ofgem recently published a formal consultation proposal to relax the accuracy requirements for approved CVDDs[14]. Despite this, one apparent issue is that despite previous relaxation of accuracy requirements, manufacturers are not coming forward for approval, due to the costs associated with the approval process. A review of this process could result in a wider availability of affordable, compliant CVDDs.
	
	• However, addressing the limitations placed on distributed gas sources by CV monitoring, enrichment and requirements could be more comprehensively achieved by changing regulations so that:
	    ○ Small differences in CV within one billing zone can be permitted;
	    ○ CV is monitored over smaller areas to improve billing accuracy and avoid the issue of shrinkage costs.
	• It is possible that some or all of the above outcomes could be achieved by:
	    ○ Implementing smaller charging zones to make billing more accurate for LDZs with multiple gas sources. This could enable reductions to the amount of propane required for injection within these zones. NGGD recently secured NIC funding to explore this concept, as part of a project entitled "Future Billing Methodology".
	    ○ The removal of the requirement for Ofgem to "Direct" low-flow sites, i.e. delegating the CV regulation and monitoring requirements to GDNs so that accuracy can be lower, and costs of monitoring can be reduced.

Recommended steps to maximise opportunities through regulation	Next 6-12 months: • GDNs and industry to participate in consultation as part of stage one of NGGD's NIC funded "Future Billing Methodology" project. • GDNs and industry could engage Ofgem to consider reviewing the approval process for CVDDs, to encourage more devices to seek approval.

[14] https://www.ofgem.gov.uk/ofgem-publications/107513

	<u>Next 12-18 months:</u> • GDNs and industry should continue to engage with the 'Future Billing Methodology' project and consider the value of exploring other avenues outside the scope of the project, e.g.: ○ To progress with the possibility of "Non Directed sites", the industry would need to define a framework for how this would be monitored and regulated by GDNs, including defining limits for what constitutes "low flow" sites. In addition, a detailed assessment of the system costs and benefits of this framework compared to the current one would be required, including quantification of financial impacts for customers, and to what extent these could be mitigated.
Relative system costs to address the issue	If the requirement for propanation was reduced or eliminated through the introduction of smaller charging zones, costs to be accounted for could include: – Costs to GDNs – exploring the case for new billing arrangements via NIC funds: £millions – Costs to shippers / suppliers of making changes to billing: £millions – Cost of shrinkage due to different CVs within charging zones (likely to be relatively low for smaller charging zones) The total system cost of this approach would be in the region of £10s of millions. However, the savings that could be achieved could potentially exceed this, even on an annual basis, and on a system level, savings would easily balance the annual shrinkage costs.

3.2.3 High connection costs due to lack of standardisation

Issue(s)	The baseline capital costs for the design, build and installation of equipment for connection and injection of gas to the distribution networks are one significant cost component impacting the overall business case for distributed gas injection plants. In 2012, the EMIB consultation resulted in a common specification for biomethane connection and injection to the distribution networks. However, distributed gas facility operators consulted in this study contend that there has since been significant divergence from this specification. This is likely to be partly due to the time pressure to provide new connections (to enable producers to inject as quickly as possible, to secure the highest possible RHI tariffs). As a result of this, Grid Entry Unit (GEU) costs (a major component of capital costs) have

	increased, as GDNs have added additional requirements depending on the conditions of particular projects. Divergent factors highlighted by producers included[15]: • One GDN has a fundamentally different control system, with a separate PC controlling the Remotely Operable Valve (ROV). This adds around £50K to costs and means that the GEU design is specific to that GDN. • Changes to GDN functional specifications have taken place during or after the GEU design phase, which then can be expensive to adapt, and projects must therefore account for this possibility in budgeting. • One GDN will not allow flow with a Remotely Operable Valve bypass, while another GDN will not allow flow unless there is a Remotely Operable Valve bypass • One GDN requires the odorant system in a separate compartment, for ownership and operation by the GDN, which itself requires a specific GEU design for this GDN The fact that many GEU manufacturers are European rather than UK based has contributed to the absence of cost reductions, as the requirements of the UK market differ from those in European markets such as Germany and the Netherlands. The difference in requirements between different UK networks, and the evolving GDN specifications, has prevented the creation of a standardised solution for the UK, meaning that design work must be redone on an almost case-by-case basis.
Relevant injection archetypes	All injection archetypes would become more feasible if the costs associated with connection were reduced. This would be particularly supportive of injection at low-flow sites (i.e. biomethane) where capital costs are more significant to the business case.
Impact	The differences described above have prevented manufacturers from producing "standardised" GEU solutions for the UK biomethane market, and as a result units have a cost premium, either associated with the bespoke design modifications needed (independent to the cost of the components themselves), or will come at a price that reflects the most complex requirements of all the GDNs. As a result, a premium of up to £90k per connection is added to overall costs, some of which could potentially be avoided if some of the points above could be standardised across GDNs. For 20 connections, this could translate to a cost differential of £1.8 million per year.

[15] A full list of differences, compiled by the Renewable Energy Association, is provided in the Appendix

Progress to date	One UK based AD-plant manufacturer is producing their own GEU design. Most existing designs are from European manufacturers. The March 2016 RHI reform consultation proposed that the current system for securing RHI tariffs is revised, so that tariffs are secured before construction, once a project can provide evidence of funding. This could reduce time pressure on GDNs, and could allow more time to account for “lessons learnt” from previous projects (and/or those carried out by other GDNs) and identify possible savings to be made, and would avoid costly changes to specifications or requirements after design and construction have started.
Obstacles to progress	GDNs need to know specifically which design and specification differences lead to higher costs, and to what extent. More information is needed from producers and manufacturers before making potentially costly changes to GEU specifications.
Commercial and regulatory enablers	The IGEM documents that defined the initial specifications for connection of distributed gas (TD/16 and TD/17) were produced in 2014. Since then, over 30 new projects have connected to the gas distribution network. These documents could be updated to reflect the lessons learnt by different producers and GDNs, and to inform the requirements that should be imposed on new projects. This would include setting out requirements for specific situations, to avoid imposing these on projects where they are not needed.
Recommended steps to maximise opportunities through regulation	<u>Next 6 months:</u> Industry should initiate a workshop to review the status of TD16 & TD/17, compared to current requirements from individual GDNs, and determine whether these documents should be revised to reflect the latest lessons learned from different gas producers and GDNs.
Relative system costs to address the issue	Costs to be accounted for could include: – Consultation between producers and manufacturers – £10,000s – Alignment of GEU designs – £10,000s to £100,000s, depending on the nature of the changes required. A more detailed assessment of possible costs for the specific issues identified is needed to determine whether alignment of GEU specifications would be cost-effective. Producers and stakeholders working with producers to inject gas can build on previous work facilitated by the Renewable Energy Association to identify the potential cost savings that could be made through alignment of particular specifications.

3.2.4 Timescales of approval processes

This is considered to be a lower impact barrier than those described above, but it does lead to a small increase in the costs of injection, in some cases.

Issue	Timescales for various design approval processes can be several months long. G17 appraisal for system design may require multiple levels of approval at each stage, and changes to requirements imposed by GDNs may impose the need for additional approvals. In addition, project timetable dependencies vary between GDNs and there is often insufficient flexibility to allow several parallel processes.
Relevant injection archetypes	All
Impact	RHI tariffs are currently set after project commissioning, so approval and construction process should be as quick as possible to avoid losses being made as a result of lower than expected tariffs. Also, due to the fact that extra time may be needed, budgets cannot be tight – extra allowances in the region of £10k - £30k per connection must be made by producers to allow for additional time that may need to be spent pursuing approval processes. This could lead to annual costs in the region of £100,000s, based on 20 new connections per year.
Progress to date	The tariff guarantees proposed as part of the RHI update would lessen the requirement for rapid progression.
Obstacles to progress	As with GEU design, the GDNs need to know which stages of the process are prohibitively lengthy, and to what extent this impacts total costs. More information is needed from producers and manufacturers before making potentially costly changes to processes. In addition, some of the project dependencies causing delays rely on input from other parties and there is little flexibility to speed up these processes.
Relative system costs to address the issue	A more detailed assessment of possible costs for the specific issues identified is needed to determine whether taking steps to reduce approval timescales would be cost-effective. However, if the problem could be resolved through recruitment of additional staff, this could come at an annual cost of £100,000s.
Recommended steps to maximise opportunities	<u>Next 12 months:</u> GDNs could offer producers the option of paying a certain fee to speed up approval processes. Based on the level of demand for

	this service, GDNs could assess whether it would be feasible and cost-effective to employ additional staff.

3.2.5 Lack of information on connection opportunities

This is considered to be a lower impact barrier than the first three described in this chapter, but it does lead to a small increase in the costs of injection, in some cases.

Issue	It can take a long time for a producer to identify a suitable injection point with sufficient capacity for injection: the enquiry process dictates that specific inquiries are made requesting a certain capacity at a certain point on the network. It would be helpful to have an awareness of what the possible options might be, in advance of this, to speed up the process.
Relevant injection archetypes	All
Impact	Due to the fact that several months are needed to determine where the gas will be injected, project budgets cannot be tight – extra allowances in the region of £10k - £30k per connection must be made by producers to allow for additional time that may need to be spent submitting inquiries and considering offers. This could lead to annual costs in the region of £100,000s, based on 20 new connections per year.
Progress to date	Some GDNs have made available online maps of where pipes are located, as a starting point to work out connection options. It would be helpful to understand the impact of this in terms of how useful it has been for producers, and whether it would be worthwhile for all GDNs to make this information available.
Obstacles to progress	A capacity self-assessment tool (or "heat map" of availability) is unlikely to be helpful at GDN level, due to the constant change in network conditions (and therefore capacity), compared to on the NTS (for which such a tool is being created, as part of the CLoCC project). GDNs believe that this would be expensive to maintain, and not necessarily that helpful for producers, as network characteristics are very time and location dependent and each connection requires detailed modelling of the demand and capacity at that point. A system that could provide an accurate assessment of capacity would risk being too complex to be used externally.
Relative system costs to address the issue	The initial cost of creating a helpful capacity self-assessment tool covering all GDNs could be in the region of high £100,000s. Maintaining and updating this tool would be likely to have additional annual costs in the region of high £10,000s. Given that if effective, this could lead to annual savings in the region of £100,000s for producers, over time the savings could outweigh the costs.

Recommended steps to maximise opportunities	<u>Next 6 months:</u> GDNs could offer producers the option of paying a certain fee to speed up the enquiry process. Based on the level of demand for this service, GDNs could then determine the most effective way to use this funding, i.e. employing more connections analysts, or building a self-assessment tool.

3.3 Summary of key opportunities to enable injection

From the perspective of biomethane and shale gas producers, and with a focus on the barriers relating to distribution network requirements and conditions, the main barriers to increased injection of distributed gas can be summarised as:

- CV requirements and high propanation costs;
- Capacity constraints, and:
- Lack of specification standardisation

Table 3.3 breaks down the possible solutions to these barriers in terms of the technical, commercial and regulatory opportunities that should be considered.

Table 3.3 Key technical, commercial and regulatory options to address barriers to distributed gas

Barriers	Possible technical solutions	Possible new commercial arrangements	Possible regulatory changes
CV requirements and high propanation costs	• Energy blending (limited)	• Smaller billing zones for greater accuracy	• Non-directed sites (GDNs define the limits for CV) • Regulated differences in CV of sources could be relaxed
Capacity constraints	• Smart pressure management • Storage • Compression • Interconnection	• New pricing mechanism to incentivise injection at time of local demand • Pricing framework to allow GDNs to recover costs of technical solutions from all network users • Definition of ownership and flow restrictions / conditions for storage	• RHI tariff to incentivise injection at time of local demand • Framework & funding mechanism for GDNs to deploy solutions benefitting indeterminate stakeholders (and the system as a whole)

Lack of specification standardisation	N/A	N/A	• Revisions to IGEM specification documents (TD/16 and TD/17)

The actions for GDNs, producers and the wider industry to implement the solutions set out above and maximise opportunities for distributed gas sources are summarised in the following recommendations:

Recommendations for the next 6-12 months:

- GDNs and industry should engage with development of new billing methodology (NGGD project).
- Industry should initiate a workshop to review the status of TD16 & TD/17, compared to current requirements from individual GDNs.
- GDNs could offer option for producers to pay for fast-tracked services such as connection enquiries and approval processes.

Recommendations for the next 1-2 years:

- Industry to seek policy changes to reduce capacity barriers through:
    - Mitigating measures such as pricing / RHI tariff weighting;
    - Management measures that can be installed in advance of requirements, with socialised costs.
- Industry and GDNs to engage Ofgem to explore regulatory and commercial changes that may be needed to effectively implement storage and other solutions.

Recommendations for the next 3-5 years:

- GDNs to work with regulators and government to develop frameworks to define suitable conditions for capacity solutions benefiting multiple, indeterminate stakeholders.

The following three chapters explore in more detail the opportunities and possible impacts that could be provided through implementation of the technical solutions mentioned above.

4 Innovative measures for capacity constrained networks

As described in the previous chapter, network capacity constraints are one of the main barriers to further injection to the distribution network. However, there are a range of measures that can facilitate injection, by providing solutions to these capacity constraints.

This chapter describes the principles behind these innovative measures, provides examples of their use to date in the UK and elsewhere, and summarises the key obstacles to wider implementation, in support of an increasing share of distributed gas.

4.1 Baseline options for distributed gas injection

To minimise costs of pipelines for grid connection and injection, producers typically seek to inject their gas as close as possible to the point of production. For biomethane, this often means that the gas is injected at a nearby segment of the MP tier. Even this type of local injection will usually require some additional pipeline to be installed.

However, if the local pipeline cannot accommodate the injection, producers may investigate the economic feasibility of injection further from the point of production (referred to here as "alternative injection point"), where there may be a greater capacity to accommodate injection.

4.1.1 Local injection

Key principles of local injection	Injection at closest possible connection point.
Conditions required for this to be effective	Sufficient injection capacity available for the business case for the plant to be viable.

4.1.2 Alternative injection point

Key principles of alternative injection points	Gas is not injected at the closest possible point. Pipeline is laid to enable injection either: a) At another segment of the same pressure tier with greater demand downstream and more capacity for injection; b) At a higher pressure tier, where there is more demand downstream and more capacity for injection.
Conditions required for this to be effective	Feasibility depends on the cost of connection and of installing new pipeline, and hence on the distance required to reach a point on the network with sufficient capacity.
Commercial arrangements	Producers pay for the installation of new pipeline to carry the gas to the injection point. In rare cases, a pre-existing pipeline may be used, which reduces the cost to the producer.
Barriers	Installation of pipeline is very costly, and feasibility depends on the local environment (including existing infrastructure and developments).

4.2 Innovative measures for distributed gas injection

4.2.1 Smart pressure management

Key principles of smart pressure management	Over low demand periods (i.e. in the summer), the operating pressure of a relevant area of the network is lowered. Gas flow regulators are fitted at the feeder points (e.g. where the IP feeds into the MP) to the tier where distributed gas is injected. Low pressure points within the grid are fitted with pressure detectors which provide feedback to the flow regulators, ensuring that at times of low demand, the flow from higher tiers is managed and excess gas injected can be stored in the network (with the priority given to the distributed source). The effect is similar to that of linepacking at the LTS. This can provide a small increase in the injection that can be accommodated on the network. Pressure must be monitored in order to allow real-time warnings in case of failures.
Example	**In the Netherlands**, the Smart Green Gas Grid (SG3) project[16], amongst others, has tested this approach on a segment of local network. The setpoint pressure is changed twice per year, to operate at a lower pressure during the summer months. The approach has been found to be effective in networks with long, large-diameter pipes, and is considered to be the easiest and cheapest way to provide capacity during the low demand season. This solution is now being trialled by National Grid Gas Distribution Ltd and Wales and West Utilities, in Cambridgeshire and Bristol respectively.
Conditions required for this to be effective	Reasonable confidence in the location of the grid low pressure point; the network should not be too complex. Pressure monitoring is required at distributed gas injection points, to enable real-time warnings to producers in the case of pressure management failures.
Commercial arrangements to date	In the UK to date, where smart pressure management has been used to enable producers to access an increased injection capacity, these producers have paid for the costs of implementation.
Barriers	GDNs are likely to be reluctant to implement smart pressure management on complex networks due to the higher risk of failure of pressure management. In addition, this approach only provides marginal increases in capacity and as such it will largely only be appropriate as a solution for production plants seeking connection on networks with low levels of constraints.

[16] Based on discussion with Albert van der Molen at Stedin Netwerkt. See information at: http://www.sg3.nl/

4.2.2 Interconnection

Key principles of interconnection	Local capacity to accommodate gas injection is increased by interconnecting the segment where gas is injected with a segment of a neighbouring network at the same tier, enabling flow to the additional segments at times of low demand.
Conditions required for this to be effective	The network must be suitable for interconnection, i.e. the distance to the relevant segments cannot be prohibitively great (or obstructed by existing infrastructure) and the existing pipes must have appropriately wide diameters to minimise flow constraints. The pipeline between the two networks must itself have sufficient capacity to accommodate flow between the networks. Smart pressure management is also required to ensure that flows are managed across interconnected segments, and their connected higher and lower network tiers.
Commercial arrangements to date	Based on feedback from National Grid Gas Distribution Ltd and Wales and West Utilities, it is expected that, where interconnection would enable a distributed gas producer to inject their gas, the cost would be added to their connection costs. Distribution Network Operators have not yet defined the approach that would be taken if this enabled additional producers to inject at the relevant segment. However, due to the timescale between securing a connection point and making the first injection (usually a minimum of 6 months), it is possible that DNOs would have enough visibility of any upcoming relevant connections to enable the costs to be shared between several producers.
Barriers	It is not always possible to interconnect networks. Feasibility and cost will depend on the properties of the local network (e.g. some pipes may be too small and require reinforcement; distance between networks may be too great or obstructed by engineering difficulties.

4.2.3 In-grid compression

Key principles of in-grid compression	The segment where the gas is injected is fitted with a compressor to pump excess gas into higher pressure levels, e.g. from MP to IP or from IP to LTS. As such, the capacity is only limited by the capacity of the tier above, which in many cases will be much higher, due to the difference in the total downstream demand.
Examples	**In Germany**, in-grid compression is used as one of a range of solutions to capacity constraints which are employed

	depending on the situation at hand. At the Emmertsbühl biomethane plant, gas is injected at 500 – 800 mbar, into the low pressure network. At times of insufficient demand, gas is compressed from the low pressure network to the 40bar medium pressure network. The MP network is 5km away from the plant, whereas the LP network is less than 1km away. Due to the high costs of pipelines, injection at LP + compression is a more cost-effective option than injection at MP. **In the Netherlands**, the first in-grid compression project is in the planning phase. The compressor will compress excess gas from a local 8bar network to a regional 40 bar network, and is expected to operate for 200 hours per year during the warm summer nights. The installation is part of an innovation project, co-funded by the national government. **In the UK**, a pilot trial was conducted in Skipton over a short period to demonstrate the validity of the concept. However, this pilot was a simple network with no capacity constraint and in this case there was no control system used to determine when the compressor was used. Further tests would be required to demonstrate that this solution would be suitable for real situations with very low local gas demand and complex interplays between pressure tiers. NGGD is in the process of exploring possible costs and designs for in-grid compression, including an appropriate control system.
Commercial arrangements to date	Further testing of this concept for the UK could be funded through the following methods: a) Innovation competition funding (depending on relative system-wide costs and benefits, compared to other potential projects). b) Funded by distribution network (this would require evidence for the business case to be demonstrated internally). c) Funded by producer(s) who utilise the additional capacity provided by use of in-grid compression. This may be unlikely for the very first use of in-grid compression, as it will not have been tested in the UK and distribution networks may not offer it as a commercial product. However, once the concept has been proven, it is likely that GDNs will pass costs onto producers. If the concept is proven, in the long term, this solution will have the potential to provide sufficient capacity to enable multiple producers to inject. However, determining how costs should be shared between different producers may not be straightforward (as discussed in section 3.2.1).

	A long term solution could be for GDNs to absorb these costs and pass them on through transportation charges, which would ultimately be passed on to customers. However, this would involve making the case to Ofgem that in-grid compression would be beneficial at a system level. New commercial arrangements would be unlikely to be implemented for several years.
Barriers	The main barrier is the high capital cost associated with this solution, and the lack of precedent in the UK. The next step would be to undergo more detailed testing and analysis, e.g. as part of an innovation competition.

4.3 Energy blending

Key principles of energy blending	Energy blending is a process aimed at minimising the amount of propane that needs to be added to injected gas to remain within acceptable CV limits, thereby reducing operational costs to producers. As described in Section 3.2.2, for most distributed gas sources, propane is added prior to injection to enrich the CV of the gas. With energy blending, the CV of the gas is measured downstream of injection at a Remote Monitoring Point (RMP), and communicated back to the injection point. This enables the minimum amount of propane to be added, minimising costs to the producer while ensuring that the CV of the mixed gas flowing downstream remains within the limit for that charging zone. For injection at the lower tiers (i.e. MP and IP), higher savings will be made if there are larger volumes of natural gas from higher tiers, mixing with the injected gas. This means that the biggest savings are made when there are no constraints on capacity (i.e. when demand exceeds the rate of injection in the right ratios). In some cases, the reduction to operational costs can make the total cost of injection with energy blending at a higher tier (e.g. LTS), cheaper than injection at a lower tier but with full propanation (e.g. at IP), despite the fact that connecting at a higher tier tends to be more costly, and may require the gas to be compressed. As such, while this is not strictly a measure that explicitly addresses capacity constraints, energy blending could reduce the cost of injecting at higher tiers where there is more likely to be sufficient capacity.
Example	The Severn Trent biomethane plant at Minworth is one of the first facilities to inject into the LTS, and uses the energy blending approach described above. The decision to inject at the LTS was made on the basis of the savings that energy blending would bring. National Grid Gas Distribution Ltd

	worked with Severn Trent to agree the conditions for energy blending and set up the monitoring and feedback loop. SGN have set up a "Virtual Pipeline", whereby multiple biomethane producers truck their gas to one injection point, which is owned and managed by SGN. The site is also an offtake point, allowing SGN to blend the trucked biomethane with gas taken off the network, prior to injection. SGN can thereby ensure that the blended gas meets the FWACV for the charging zone, before it is injected.
Conditions required for this to be effective	Energy blending only enables reduced propane addition when the injection rate is exceeded by the flow rate (i.e., when there is some other gas flowing that can mix with the lower CV injected gas). In addition, due to the nature of energy blending (i.e., it ensures that the minimum amount of propane is added), the CV of the downstream gas will be at the minimum possible level. This inherently prevents energy blending for future distributed gas injection. Essentially, under current CV requirements for distributed injection, it is unlikely for facilitation of energy blending to be possible where it is already being done for an existing facility on the same network.
Commercial arrangements	At Minworth, Severn Trent (the producer) paid for the installation of the RMP and other necessary monitoring facilities. The costs of the feasibility assessment for energy blending were covered by Severn Trent as part of the capacity study. For SGN's "Virtual Pipeline", producers pay to transport the gas, and the injection facility is owned and operated by SGN, who have contracts setting out the arrangements for the revenues for the gas and the RHI tariffs. Depending on the success of this project, SGN may take this approach at other sites. It is possible that other GDNs may also adopt this approach, depending on appetite from producers. One particular future scenario to consider is the case where a large source of distributed gas (e.g. a shale gas well) seeks injection at the LTS, and supplies 100% of the downstream demand for the charging zone. In this case, where the injected gas is the only source in the charging zone, no propanation would be required, and the customers in that charging zone would be charged according to the CV of the injected gas.
Barriers	The fact that allowing energy blending at one point on the network prevents further nearby use of this approach indicates that it is not a long term solution to the challenge facing distributed gas producers from CV requirements. As discussed in Section 3.2.2, smaller charging zones could enable more differentiation of the required FWACV values, in

	accordance with how much distributed injection there is on a specific network. NGGD intends to explore smaller charging zones as a way to make billing more accurate, as part of the NIC "Future Billing Methodology" project, but implementation of these changes could require extensive updates to billing software for suppliers, and would be likely to lead to high costs.

4.4 Storage

Key principles of storage	In theory, excess gas produced by distributed gas sources could be stored across the low pressure network in dedicated facilities during low demand periods (as is already done on a national level along the NTS). On-site storage at the point of gas production could be an alternative to this. For example, biomethane producers could store feedstock on site during periods of low demand, and increase production at times of high demand.
Barriers	The majority of gas storage facilities for gas distribution networks have been decommissioned or (a minority) mothballed, partially due to changes in safety regulations since they were constructed. Existing natural reservoirs are too sparse and already used for NTS storage. Due to the changes in regulations around storage, there is a lack of data concerning possible costs of new storage facilities, but based on previous facilities it is likely that constructing new storage of the capacities required would be highly costly and may require new commercial arrangements (as discussed in section 3.2.1). The economic case for on-site storage (of feedstock or of gas) is also uncertain, as in most cases, plant capacity and production rates are carefully designed to enable injection to be maximised at all times. However, given that high costs are associated with many other solutions to capacity constraints, producers should consider exploring the economic feasibility of on-site storage in more detail. Diurnal storage during the summer could be cost-effective for low-level constraints.

5 Approach and assumptions for capacity constraints and cost modelling

5.1 Defining capacity constraints and overall approach

For gas injected on the distribution network, a capacity constraint occurs when the proposed injection rate exceeds the minimum flow rate seen by the segment that the producer seeks to inject gas into.

A simple modelled network, represented in Figure 11, was used as a basis to estimate the extent of possible capacity constraints and the effect of different solutions. Within the model, gas injection can be modelled at any LTS, IP, or MP segment (though Figure 11 shows injection at MP).

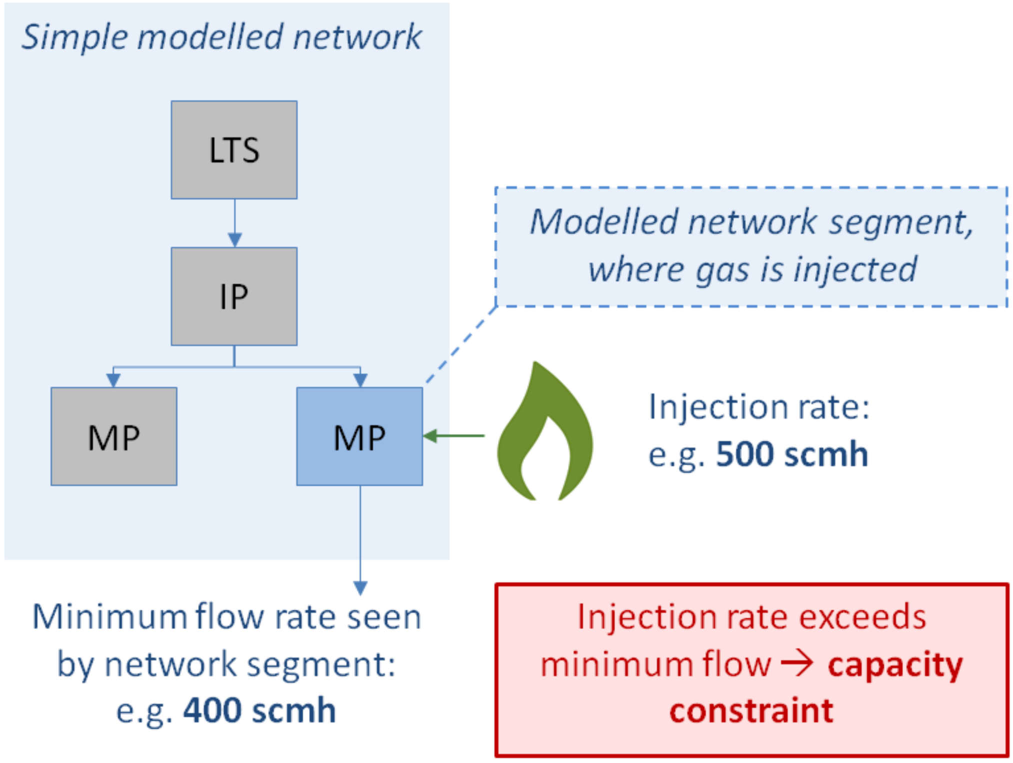


Figure 11 Representing capacity constraints on a simple modelled network

A number of capacity constraint scenarios were modelled, to explore the possible solutions to these constraints, and compare their costs. As indicated in Figure 12, the capacity constraint scenarios were set up by making simple assumptions for the characteristics of the network and the injected gas.

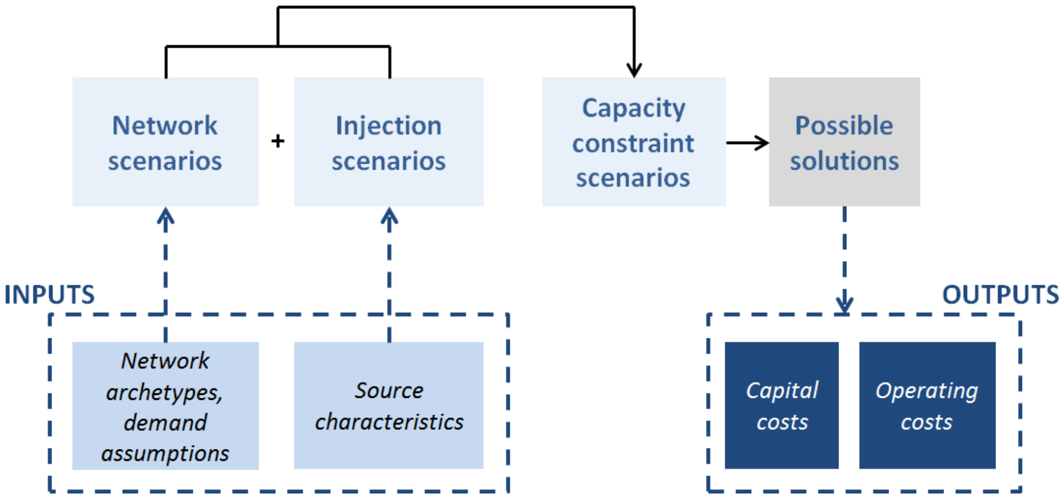


Figure 12 Summary of approach to modelling of capacity constraints and solution

5.2 Characterising the network

5.2.1 Network level demand

A simplified demand profile was used for the modelling, assuming a diurnal variation of **22%** across all segments of the network.

The graph in Figure 13 shows the modelled demand profile for the network, applied to August demand data for the National Grid West Midlands LDZ under seasonal normal temperature (SNT). The average daily demand in August is 4 mcmd (million cubic metres per day). With the 22% diurnal variation, in this specific case, the minimum hourly demand (during an August night) is 57,513 scmh (standard cubic metres per hour) for the whole LDZ.

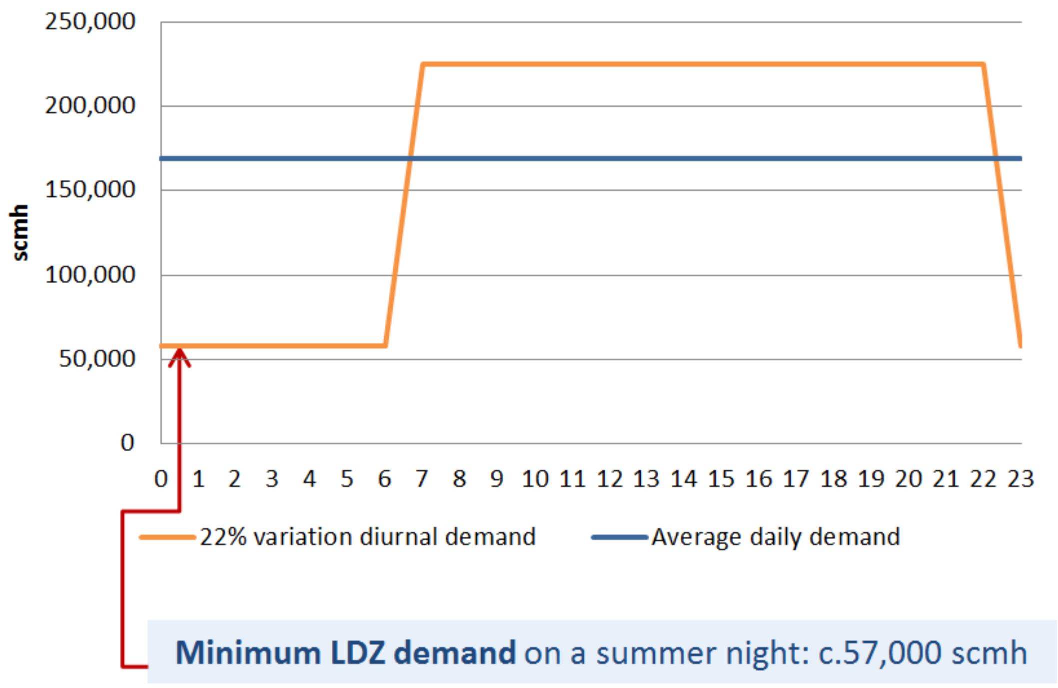


Figure 13 Example of a modelled LDZ demand profile on an average August day

5.2.2 Flow rates at modelled segments

Constraints depend on the flow at the network segment the gas is injected into (and also at the tier above, in the case of in-grid compression). Modelled flow rates at the relevant segments are based on:

- Overall LDZ flow;
- Assumed share of flow to modelled segments, which depends on the demand at each tier and the split between branches at each tier.
- The modelling considers various fixed “share of flow” options (shown in Figure 14 for the modelled segments, which are represented as blue boxes) and different levels of total LDZ demand, in order to simulate different constraints and explore the possible solutions. Figure 15 shows example flow rates with particular “shares” at each segment.

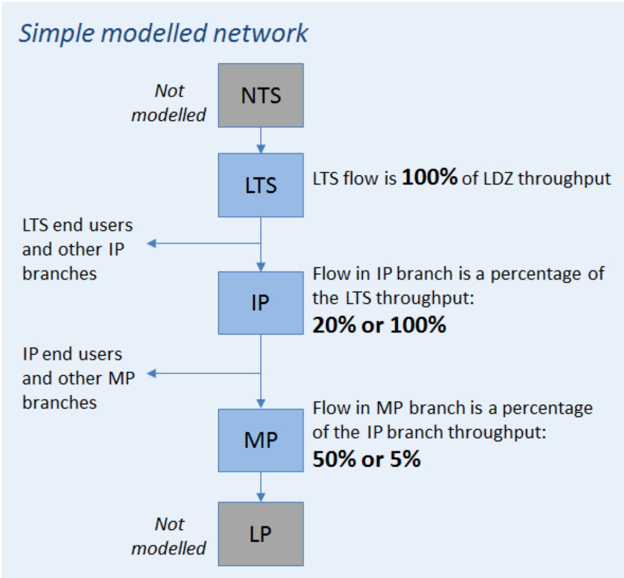


Figure 14 Simple modelled network and assumptions for flow at modelled segments

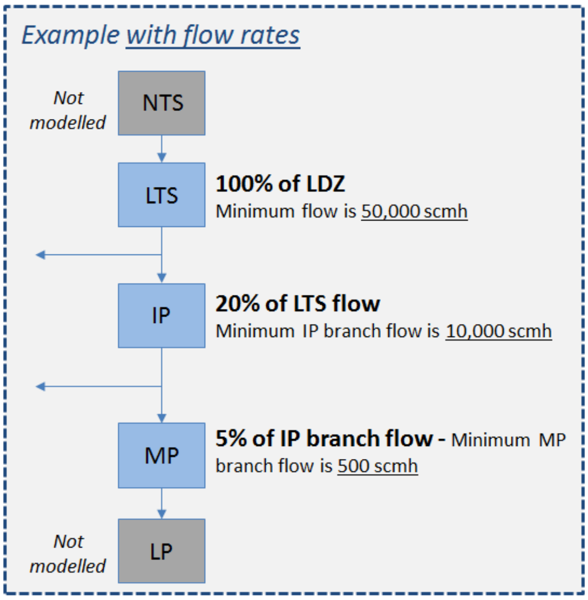


Figure 15 Example of flow rates in modelled network segments

5.3 Characterising distributed gas sources

Five different source archetypes were modelled, to account for different injection rates for two main sources: biomethane (with injection rates reflecting the current market) and shale gas (with rates reflecting possible flows from test wells and from large scale commercial wells – see discussion of production characteristics in Chapter 2). Figure 16 summarises the different source scenarios.

Biomethane
Shale gas

Scenario	Source	Injection rate
A	x 1 plant	500 scmh
B	x 3 plants	1,500 scmh
C	x 6 plants	3,000 scmh
D	Test well	5,833 scmh
E	Commercial well	125,000 scmh

Figure 16 Modelled source scenarios

For each of the source scenarios, a number of “constraint scenarios” were set up, using different network demand scenarios to reflect possible outcomes at different connection points.

5.4 Constraint scenarios

In each constraint scenario, the distributed facility operator (DFO) seeks to inject gas at a point on the network at which the minimum flow is exceeded by the injection rate. For example, a single biomethane plant with an injection rate of 500 scmh might seek to inject at an MP segment where the minimum flow is only 400 scmh, as illustrated on the left hand side in Figure 17 (the value in the blue box represents the minimum flow for that network segment). An equivalent example for a shale gas test well is also shown here, with injection on the IP.

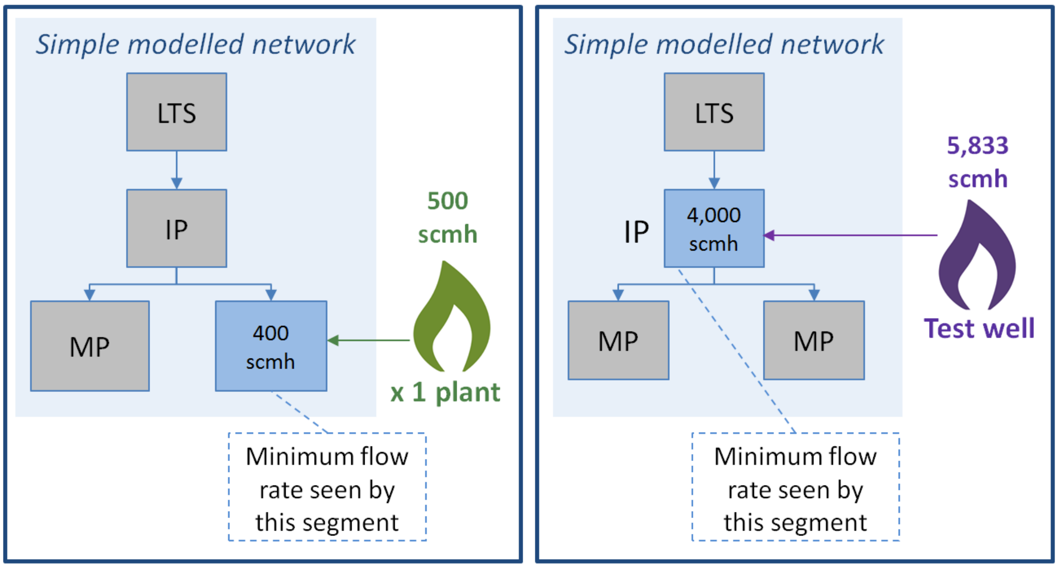


Figure 17 Illustrative constraint scenarios for biomethane (left) and a shale test well

For each constraint scenario, the model calculates the costs of “solving” this problem, with the following options:

- Assuming that only the gas that can be accommodated is injected, and calculating the "loss of potential revenues" associated with the rejected gas;
- Injecting at a higher tier or another branch of the same tier where there is sufficient demand downstream;
- Using innovative capacity measures such as interconnection, smart pressure management and in-grid compression.

Gas tends to be injected locally to the point of production, at the lowest tier with sufficient capacity (which is usually the cheapest option). As such, under the constraint scenarios, DFOs seek to inject at the highest tier where there is a constraint for that injection rate (the idea being that the various solutions will resolve the constraint).

For each source, the extent of the constraint (i.e. the exceedance of the minimum flow by the injection rate) is set at various levels, by varying the minimum flow seen by the segment where the gas is injected (as shown in Figure 18). This allows the modelling to show that the optimal solution may be different according to the nature of the constraint.

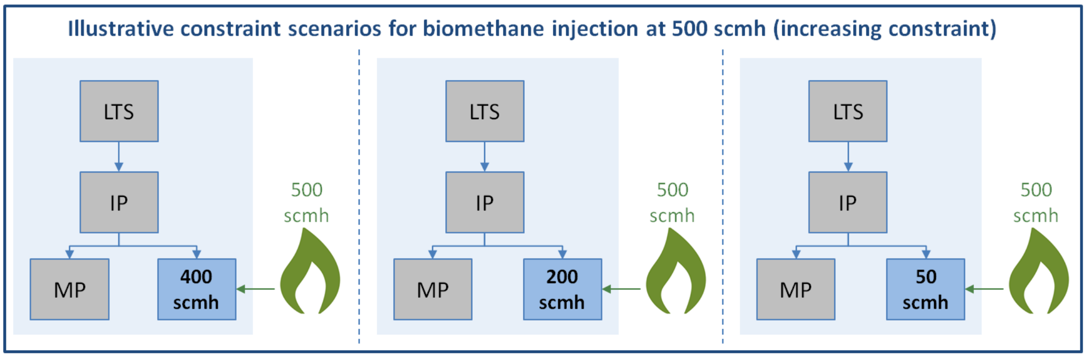


Figure 18 Varying constraint scenarios for biomethane injection

5.5 Modelling capacity solutions

For each constraint scenario, the model calculates the cost associated with different solutions. These solutions represent different ways of optimising the capacity available at different times and locations on the network, so that producers can inject gas at their desired injection rate, at a lower cost than might be possible without these solutions.

The modelling approach to reflect how each solution provides additional capacity is described below. In each case, the value in the blue box represents the minimum flow for that network segment.

Capped injection and loss of potential revenues

Only the maximum possible amount of gas is injected, and the remainder is accounted for in terms of the potential revenue lost. The "loss of potential revenues" associated with the rejected gas is also accounted for when alternative solutions described below cannot accommodate all of the gas. All cost assumptions can be found in the appendix.

Alternative injection point

A pipeline is laid to enable injection into another segment of the same tier. It is assumed that there is sufficient flow to accommodate injection, as this approach would only be taken where it is economically viable to lay a pipeline to a point with sufficient flow. The modelling assumes the following pipeline distances:

- 2km, compared to 0.25km for local injection (MP)
- 3km, compared to 1km for local injection (IP)
- 3km, compared to 1km for local injection (LTS)[17]

These distances are based on industry experiences, but in practice there is a great deal of variation in pipeline distances (and therefore costs). Assumed pipeline costs will have a strong influence on the relative costs of different solutions, and as such, cost comparison results should be interpreted with caution.

Interconnection

A pipeline is laid to connect the original segment to a nearby segment, so that some of the demand can be accessed in addition to the demand from the original segment. The nearby segment is assumed to have **twice the flow** of the original segment, as this increases the chances of an interconnection being worthwhile. However, on account of flow dynamics, only a maximum of **75%** of this can be accessed as demand for the injected gas.

The modelling assumes the following pipeline distances for interconnection:

- 2km (MP to MP)
- 3km (IP to IP)
- 5km (LTS to LTS)

As above, these distances are based on industry experiences, but in practice there is a great deal of variation in pipeline distances and costs. These assumptions will therefore have a strong influence on the relative costs of different solutions.

In addition to pipeline costs, the modelling for this solution accounts for the cost of installing smart pressure management equipment, as this is likely to be required for successful implementation.

[17] Based on discussions with National Grid, 3km tends to be the maximum length of new pipeline that will be considered on an economic basis.

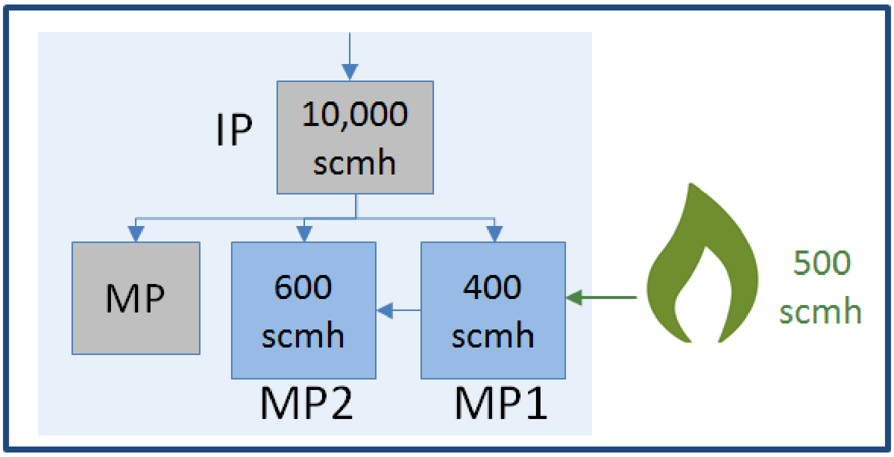


Figure 19 Example of modelling capacity gained from interconnection

Smart pressure management

Pressure and flow in the relevant segment is managed, enabling more gas to be packed into the segment at times of low demand without impacting the security of supply. This is modelled by increasing the minimum flow by **25%** (so up to 25% more gas can be injected at the time of minimum demand)[18].

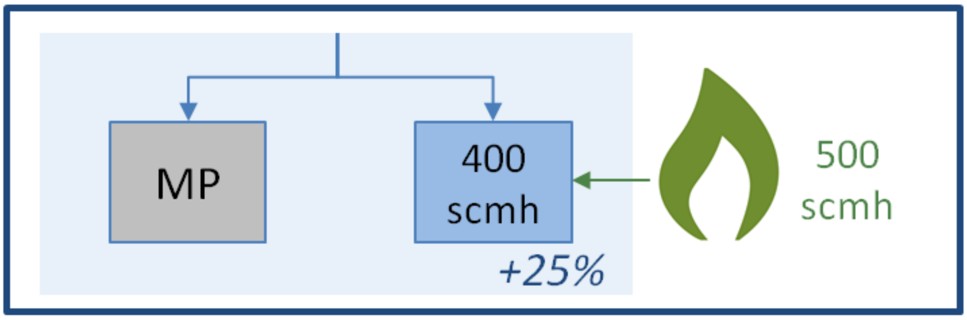


Figure 20 Example of modelling capacity gained from smart pressure management

Injection at next tier

A pipeline is laid to enable injection into a higher tier. As such, the capacity is only limited by the capacity of the tier above. Connection to a higher tier is usually more expensive in terms of connection costs. Assumed relative pipeline distances are as follows:

- 1km (IP) vs 0.25km for local MP injection
- 1km (LTS) vs 1km for local IP injection
- 1km (NTS) vs 1km for local LTS injection

[18] Based on discussions with GDNs, it is possible that more than 25% additional capacity could be provided, in some circumstances, through this method. However a conservative approach is used for the purposes of this modelling, reflecting the approach that GDNs would take when providing a contract for connection.

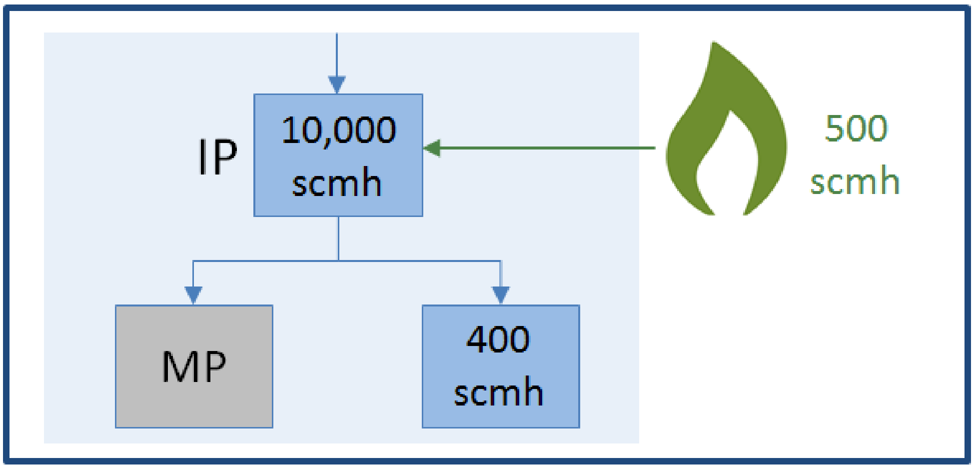


Figure 21 Example of modelling capacity gained from next tier injection

In-grid compression

The segment where the gas is injected is fitted with a compressor to pump excess gas into higher pressure levels, e.g. from MP to IP (as in the example) or from IP to LTS. As such, the capacity is only limited by the capacity of the tier above.

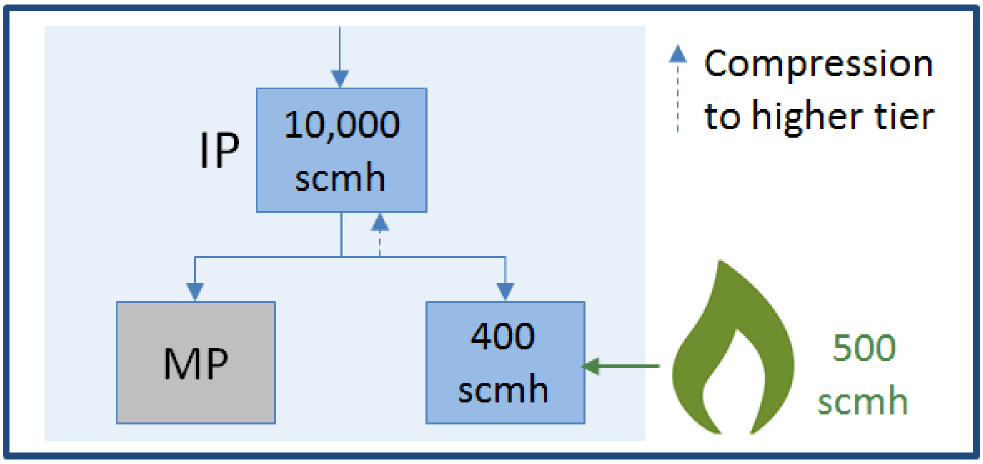


Figure 22 Example of modelling capacity gained from in-grid compression

The modelling assumes that for any scenario where the compressor is used for three months per year or more, a back-up compressor is required, and costs are accounted for accordingly. In-grid compression is assumed to use some of the energy of the gas compressed (2.5% for MP to IP, 2% for IP to LTS, and 2.5% for LTS to NTS).

Table 5.1 summarises the modelled conditions for the capacity solutions, as well as their potential impacts in terms of the minimum additional gas injection that can be accommodated, compared to the minimum flow at the local injection point.

Storage

Due to lack of relevant cost data, storage has not been included as a solution in the modelling.

However, given the high costs associated with some solutions to capacity constraints, there is a case for producer-led work to assess the costs of on-site storage in different constraint scenarios, so that the costs and benefits could be compared against those of other solutions. Storage of feedstock could be more cost-effective to implement than gas storage facilities on the network.

Table 5.1 Relative impacts and conditions for modelled capacity solutions

	Flow factor (minimum injection accommodated compared to local injection point)	Conditions
Local injection	1	-
Alternative injection point (same tier)	Sufficient	2km pipeline, compared to 0.25km for local injection (MP) 3km pipeline, compared to 1km for local injection (IP) 3km pipeline, compared to 1km for local injection (LTS)[19] Will only occur when sufficient capacity can be accessed cost-effectively.
Interconnection to same tier	1 + (2 x 75%) = 2.5	2km pipeline (MP to MP) 3km pipeline (IP to IP) 5km pipeline (LTS to LTS)
Smart pressure management	1 + 25% = 1.25	Will only be applicable for a relatively simple network
Next tier injection	Dependent on flow in segment above; likely to be sufficient in most cases.	1km pipeline to IP vs 0.25km for local MP injection 1km pipeline to LTS vs 1km for local IP injection 1km pipeline to NTS vs 1km for local LTS injection
In-grid compression	Dependent on flow in segment above	Connection to tier above (to receive compressed gas) relatively close to injection point.

[19] Based on discussions with National Grid, 3km tends to be the maximum length of new pipeline that will be considered on an economic basis.

5.6 Modelling energy blending

Costs of adding propane to the injected gas, to increase its Calorific Value (CV) to meet the network entry conditions, are also calculated as part of the modelling. The model also calculates the potential cost savings that could be achieved through energy blending, for some scenarios where this could be a possibility. The modelled conditions for full propanation and energy blending propanation are as follows:

- **Full propanation –** Propane is added prior to injection, so that all of the mixed injected gas has a CV of 39.
- **Energy blending propanation –** The minimum amount of propane is added each hour, as the flow demand in the segment varies over the course of each day, so that the mixed gas flowing through that segment always has a CV of 39. The different sources of gas include the modelled injected gas, and the gas entering the segment from the tier above, which is assumed to have a CV of 39.5.

6 Comparing system costs of injection capacity solutions

This chapter presents the results of the modelling introduced in the previous chapter, which aimed to assess illustrative relative costs for different solutions to capacity constraints. These solutions represent different ways of optimising the capacity available at different times and locations on the network as a whole, so that producers can inject gas at their desired injection rate, at a lower cost than might be possible without these solutions. The intention of the modelling is to identify, for specific constraints on the network, how the required capacity can be made available to producers, at the lowest possible cost.

It should be noted that the results depend heavily on the assumptions made regarding costs and demand factors (which have been validated by the GDNs). However, the results have been used to draw out general conclusions regarding which solutions are most likely to be appropriate in different situations.

Oversupply, loss of potential revenues and demand factors

To differentiate different levels of capacity constraint at different points in the network, this report uses the term "oversupply" to define the extent to which the minimum hourly demand at the point of injection is exceeded by the rate of injection of distributed gas. Specifically:

- **Percentage oversupply = Surplus injected gas × 100 / Minimum hourly demand (based on an August night)**

The surplus is equal to the injection rate minus the minimum hourly demand.

The objective of the modelling is to determine the least cost methods of addressing possible capacity constraints at different points on the network, for different levels of oversupply. There are several solutions to be compared, and these do not all have the same ability to increase the capacity of the point where the gas is injected (and thus reduce or eliminate the oversupply). As such, the model assumes that in the case that a particular solution does not enable all the injected gas to be accommodated, the remaining gas is accounted for in terms of the potential revenue lost. For biomethane, this is assumed to incur a cost of 6p/kWh gas, in lost revenues to the producer (including RHI tariffs). It is uncertain what the equivalent for shale gas would be, as this would depend on the existence of alternative markets for the gas. However, it is assumed that lost revenues would be similarly high.

The overall potential revenue loss depends on the quantity of gas that cannot be injected, which depends on the injection rate, and on the remaining level of oversupply after any solutions have been accounted for.

Using the modelled overall annual demand trends (based on NGGD data), we can determine for each level of oversupply how much injection is curtailed in total each year, and thus relate the level of oversupply to the overall potential revenue loss.

Table 6.1 shows indicative potential annual revenue losses for some of the distributed gas sources as characterised in the modelling.

Table 6.1 Potential annual revenue loss for various injection rates (revenue for shale assumed to be equal to that of biomethane = 6p/kWh)

Oversupply	500 scmh (1 biomethane plant)	3,000 scmh (6 biomethane plants)	125,000 (commercial shale plant)
5%	£6,000	£34,000	£1,432,000
20%	£25,000	£149,000	£6,195,000
50%	£80,000	£480,000	£20,002,000
100%	£141,000	£846,000	£35,242,000
200%	£244,000	£1,436,000	£60,967,000

To provide some context to the variation in oversupply percentages, Figure 23 indicates the levels of hourly demand at different times during the year, as used by the model, in terms of **the percentage by which it exceeds the minimum hourly demand on an August night**. This is based on the diurnal profile used in the modelling, which assumes that the demand is flat during the day and during the night (see Section 5.2.1).

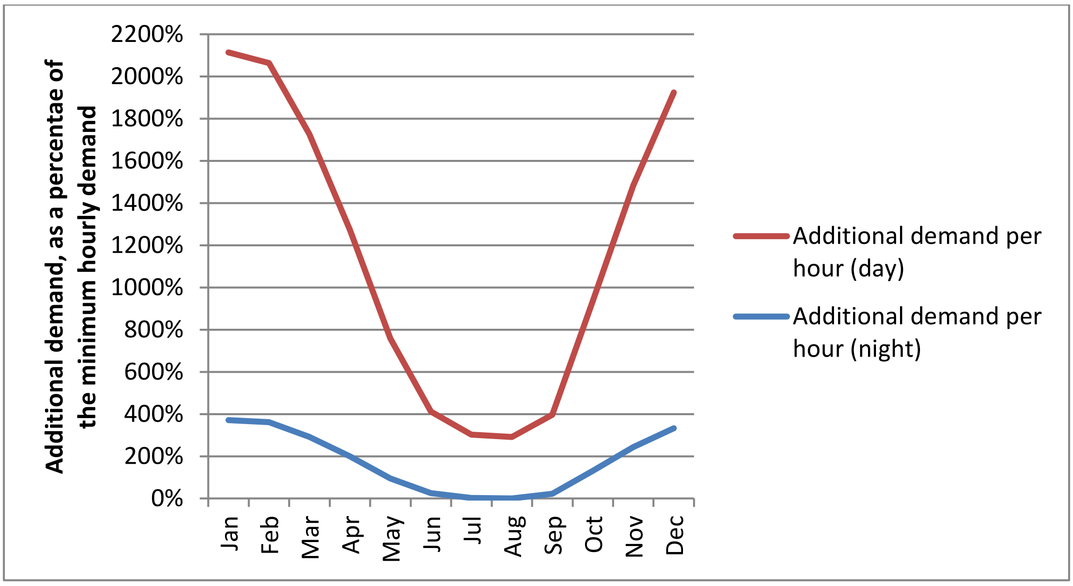


Figure 23 Annual variation in demand, relative to the minimum demand period (August nights). Based on National Grid Gas Distribution Ltd data for the West Midlands LDZ.

As shown in Figure 23, there is a huge variation in hourly demand over the course of a year. This means that, for constrained injection, even with an oversupply of 200% relative to the minimum hourly demand (an August night), there will be no excess injected gas (and no potential revenue loss) during the day, or during winter nights. However, even when there is only “excess gas” during summer nights (e.g. for an oversupply of 200%), it can be very costly in terms of potential lost revenues, as shown in Table 6.1.

Table 6.1 shows that potential annual revenue losses due to insufficient network capacity could be very high, even for low levels of oversupply. For comparison, estimated connection costs (a major component of the costs of injection) can be around £65,000 for local MP injection; a 20% oversupply for MP injection would lead to total revenue losses exceeding this in less than three years.

This serves to explain the fact that producers are unlikely to accept solutions where their desired injection rate exceeds the minimum capacity offered (which relates to the minimum demand). Exceptions to this could be where the oversupply is minimal and/or if savings can be made elsewhere (or if they have an alternative market for the excess gas). While producers have the option of injecting smaller volumes (or exploring solutions such as storing feedstock at times of low demand), there is a need for consideration of the range of solutions that could enable higher volumes to be accommodated, in order to maximise the total proportion of distributed gas in the network.

6.1 Solutions for marginal constraints

The first type of constraints considered here are those where all (or most) of the possible solutions are able to eliminate oversupply, i.e. “marginal” constraints. The assumptions for each of the different solutions were set out in Section 5.5, which describes the level of oversupply which can be accommodated by the solutions.

Figure 24 and Figure 25 show the annualised costs of the various solutions available for the following constraint scenarios:

- Figure 24: Injection at 500 scmh to a segment of MP network, where the minimum demand is 333 scmh, and the minimum LDZ level throughput is around 2.4 Mscm/day. The “oversupply”, i.e. the additional demand required to enable injection at this segment is **50%** of the current minimum demand level seen by the segment.
- Figure 25: Injection at 3,000 scmh to a segment of IP network, where the minimum demand is 2,857 scmh, and the minimum LDZ level throughput is around 1.0 mcmd. The oversupply, i.e. the additional demand required to enable injection at this segment, is **5%** of the minimum demand level.

These are both “marginal” constraints; defined here as having a maximum oversupply of 50% (as opposed to e.g. 100%, or up to 400%).

In Figure 24 and Figure 25, and all subsequent charts in this chapter, the capacity solutions are identified by abbreviations, as set out in Table 6.2 below. Common assumptions for the cost modelling are also set out in the table.

Table 6.2 Abbreviations used for solutions in this chapter, and key assumptions

Abbreviation	Solution
Base	Local injection
Base+	Alternative injection point (same tier)
Next tier	Injection at next tier
Connect	Interconnection
SPM	Smart pressure management

IGComp	In-grid compression
IGComp+	In-grid compression – higher costs (assumes that a back-up compressor is needed; also higher energy costs – see appendix for detailed assumptions)

Key assumptions common across solutions:

The economic assessment has been made over a 20 year period, assuming a discount rate of 10%, in accordance with typical project accounting (Element Energy, Sustainable Gas Institute).

One connection point per solution; for biomethane, this assumes that flow rates can be multiples of 500 scmh, but the costs of connection will be as for one injection point.

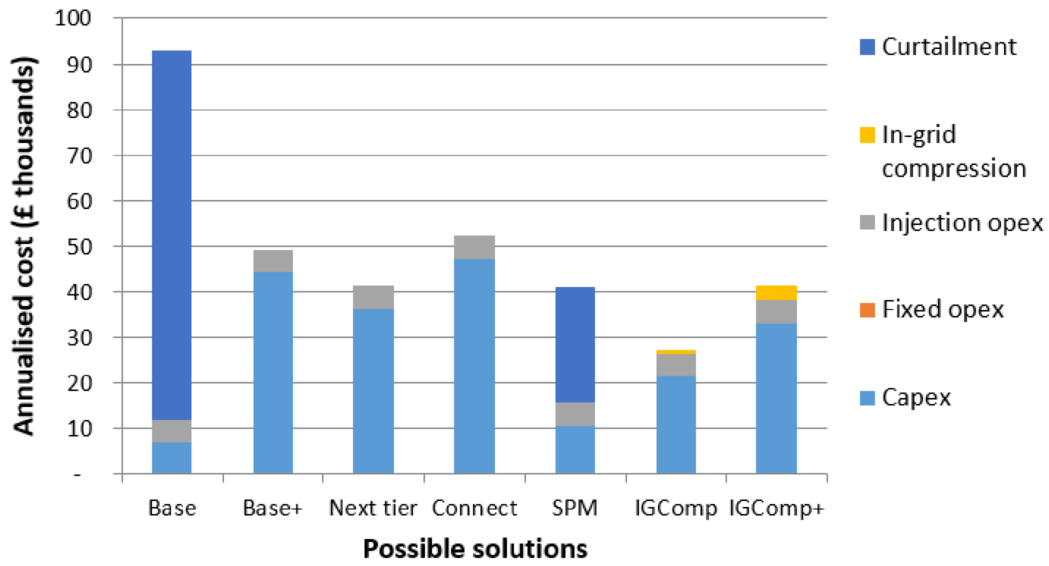


Figure 24 Annualised costs for injection at an MP network segment (injection rate 500 scmh, 1 biomethane plant) – minimum flow at MP of 333 scmh. Oversupply: 50%.

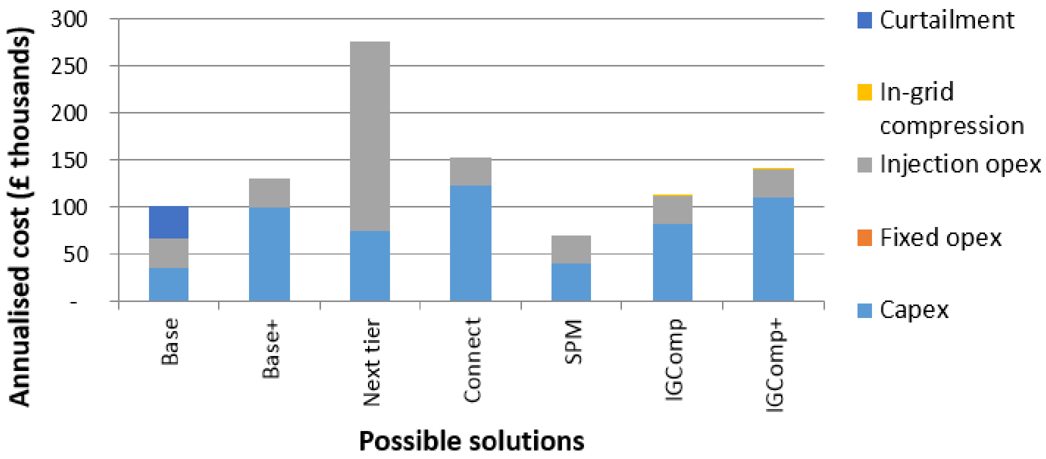


Figure 25 Annualised costs for injection at an IP network segment (injection rate 3,000 scmh, equivalent to 6 biomethane plants) – minimum flow at IP of 2,857 scmh. Oversupply: 5%.

At these relatively low levels of constraint, the operational costs of the different solutions are low (other than potential revenue losses) and as such, capital costs are the main factor determining which solution is the most cost-effective. Propanation costs are not shown here, as when there is no energy blending, propane costs are equal for all solutions (where there is no capping of gas injection). Potential savings from energy blending are explored in Section 6.3.

When the oversupply is below 25%, smart pressure management (SPM) can effectively accommodate the surplus gas without capping gas injection (e.g. as in Figure 25). This is under the assumption that this solution has a flow factor of 1.25. Smart pressure management is the lowest capex solution in both of the scenarios shown above (if we ignore Base, which represents the “local injection + capped gas injection” case).

The following sections explore the general cost trends for solutions to marginal constraints at MP and IP respectively. For LTS injection, any constraints that occur are likely to be high, based on the estimated sizes of potential sources; this will be discussed in Section 6.2.2.

6.1.1 Marginal constraints for MP injection

Figure 26 presents a generalised case for injection at MP with marginal oversupply, comparing the capex and opex of solutions for constraints at each pressure tier. The only operational cost figures shown are the differential opex values between solutions. For injection at MP (or IP, for "next tier injection"), the only differential opex is the cost of in-grid compression. Potential revenue losses are not shown here; these are addressed separately below.

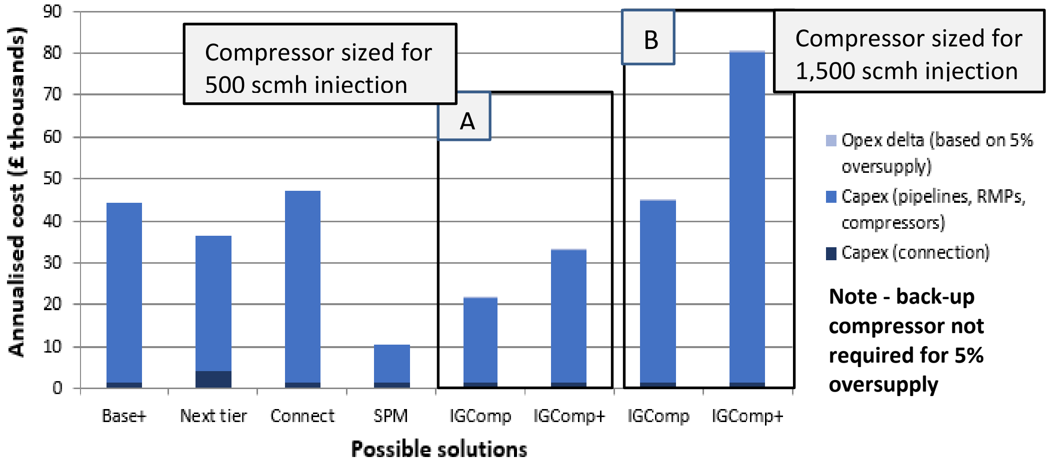


Figure 26 Annualised costs for 5% oversupply at MP. Capex figures shown are common to any injection rate, with the exception of compressor costs (which vary with injection rate, as indicated by the two examples shown). Note that in-grid compression has not been fully trialled in the UK.

For the first four solutions, the assumptions of the modelling imply that the **capital costs** will be fixed across different injection rates (and oversupply levels), and there is also no variation in opex across these options across different injection rates. The set of compressor costs "A", represent the minimum capex for this solution, where the compressors are sized for 500 scmh injection (biomethane plants are unlikely to inject if the flow is lower than this), and the set of costs "B" show the estimated cost of this solution appropriate to an injection rate of 1,500 scmh. The compressor opex would increase as the oversupply increases above 5%.

The results imply that for all constraints where smart pressure management can accommodate all oversupply at the point of minimum demand (i.e. there is no capping of gas injection), it is likely to be the cheapest solution.

- **Smart pressure management is likely to be the cheapest solution for MP injection, <u>if</u> it can accommodate the oversupply at the point of minimum demand (up to a maximum oversupply of 25%).**

When smart pressure management cannot accommodate injection at the point of minimum demand, some gas must be curtailed, which significantly increases the overall costs of the solution (as we see in Figure 24). In this case, the cheapest solution (as shown in Figure 24) may be in-grid compression or connection at the next tier. However, this will depend greatly on the particular situation, thanks to the following factors:

- The modelling assumes that in-grid compression requires a back-up compressor when it is needed for three or more consecutive months, to ensure that injection capping, and consequent revenue losses (due to compressor breakdown) are minimised. According to the assumptions of the modelling, this translates to an oversupply of 20% or more[20]. In addition, the cost of energy may vary depending on whether gas or electricity is used to power the compressor.
- In Figure 24 and Figure 26, IGComp accounts for the cost of a single compressor, with energy costs of 2.4p/kWh, and IGComp+ accounts for the costs of two compressors, with energy costs of 10p/kWh.
- In addition, as highlighted above, the cost of the compressors will depend on the amount of gas being compressed, as the compressor will be sized accordingly. The modelling assumes that the compressors are sized according to the injection rate, rather than according to the exact level of compression needed. This is a conservative estimate, which assumes that GDNs would choose to provide a high level of resilience to possible demand reductions.
- Compressor opex increases (and decreases) with the level of oversupply, which therefore also influences the results.
- The real capital costs associated with pipeline based solutions such as alternative injection points, interconnection and next tier injection are likely to differ from those presented here, which represent industry estimates of “mid-range” costs. In reality, these costs will vary significantly geographically, depending on the distance of pipeline required, as well as a range of other factors and constraints that will determine pipeline routing, dig costs and so on.

With this in mind, the modelling suggests that when smart pressure management cannot accommodate injection:

- **For the case of one biomethane plant (500 scmh injection) with an oversupply of up to 50%, in-grid compression is likely to be one of the cheapest solutions, even with a back-up compressor.**
- **For constraints on the MP, injection at the IP is likely to be one of the cheapest solutions, particularly in the case where the injection rate is above 500 scmh.**
- **The most cost-effective solution will depend mainly on the distance of pipeline required and the size of the compressor needed.**

6.1.2 Marginal constraints for IP injection

Figure 27 presents a generalised case for injection at IP with marginal oversupply, comparing the capex and opex of solutions for constraints at each pressure tier. In terms of operational costs, only the differential values between solutions are shown here.

[20] If the oversupply is less than 20%, then according to the modelled demand profile, the injection rate will only exceed the monthly minimum demand in two consecutive months (July and August), meaning that the compressor will only be used overnight in these two months, and a back-up is unlikely to be required.

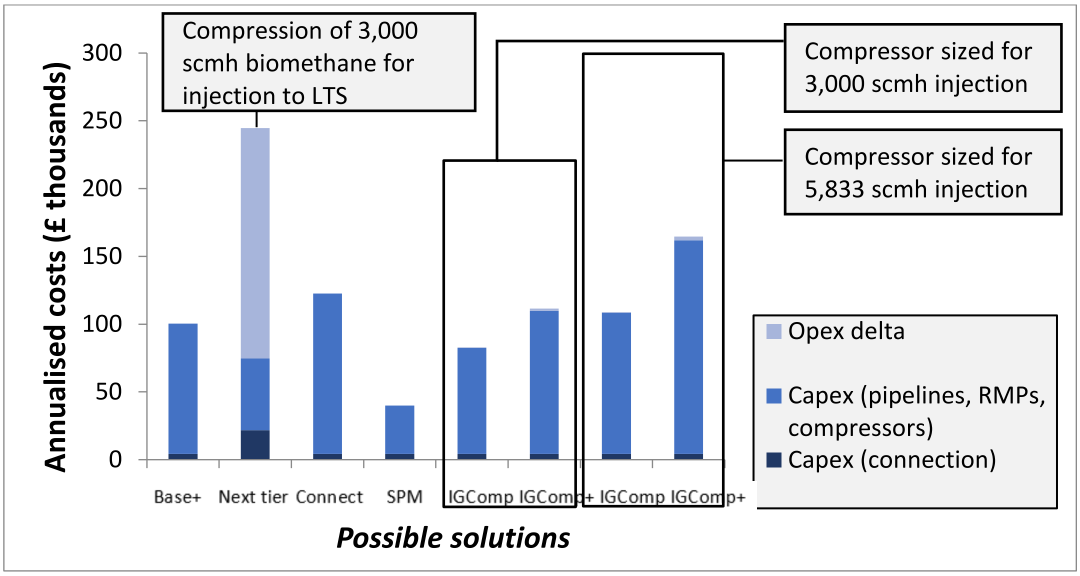


Figure 27 Annualised costs (excluding potential revenue losses) for 5% oversupply at IP. Capex figures shown are common for any injection rate, with the exception of compressor costs (which vary with injection rate, as indicated by the two examples shown).

As with MP injection, the capex of the first four solutions will remain constant regardless of injection rate or oversupply. However, for "next-tier injection" at LTS the modelling assumes that compression is required for biomethane, and therefore opex for this solution will increase in proportion with the injection rate.

Both the capex and opex of in-grid compression also depend on the injection rate. According to the modelling assumptions, a back-up compressor is required when the oversupply is 20% or more[21] (in which case the compressor capex follows the cases shown as IGComp+ in Figure 27). The opex will increase as the oversupply increases.

In terms of trends around the most cost-effective solutions, the results for marginal constraints at the IP are similar to those at the MP.

- **Smart pressure management is likely to be the cheapest solution for IP injection, <u>if</u> it can accommodate the oversupply at the point of minimum demand (up to a maximum oversupply of 25%).**
- **When smart pressure management cannot accommodate the oversupply, the cheapest solution for a small oversupply is likely to be one of the following:**
- **In-grid compression (more likely when the rate of injection is relatively low, so the compressor capex will be lower);**
- **Alternative injection point (more likely when the rate of injection and/or when oversupply is relatively high, and depending on the distance of pipeline required to reach a point with sufficient capacity).**

Next-tier connection is unlikely to be one of the most cost-effective solutions in this case, due to the requirement to compress the gas before injection and the high costs associated with this. However, as with MP injection, it will depend on the specific details of the network

[21] If the oversupply is less than 20%, then according to the modelled demand profile, the injection rate will only exceed the monthly minimum demand in two consecutive months (July and August), meaning that the compressor will only be used overnight in these two months, and a back-up is unlikely to be required.

and the location of the production plant. Interconnection is unlikely to be the best solution for marginal constraints, as it is typically more expensive than simply injecting in a different location.

Even in cases where in-grid compression would be more competitive with other solutions on a cost basis, to fully see the benefits, the costs of a single compressor would need to be shared between all producers who might benefit from the additional capacity. Arranging a retrospective cost sharing mechanism to enable this would itself incur costs at the system level, which would need to be assessed against to potential benefits system-wide.

6.2 Solutions for high constraints

As constraints increase to 100% and beyond, for some solutions, the likelihood that all the gas will be accommodated reduces. The modelling assumptions for smart pressure management and interconnection limit them to accommodating 25% and 150% additional injection, respectively, which in both cases, represents the best case scenario, according to the GDNs with experience in these areas. For in-grid compression and next-tier injection, the oversupply that can be accommodated is dependent on the difference in demand seen by the two relevant network segments.

Within the approach taken by the modelling, the only other difference in terms of costs for high constraint solutions, compared to low constraint solutions, is that opex values which are dependent on the level of oversupply increase. This includes potential revenue losses and the costs of in-grid compression.

Figure 28 and Figure 29 show two constraint scenarios for injection to the IP at 3,000 scmh (biomethane), and illustrate the cost differences for oversupply of 60% and 400% respectively.

Figure 28: injection of biomethane at a rate of 3,000 scmh to a segment of IP where the minimum demand is 1,875 scmh – equating to an **oversupply of 60%** (minimum LDZ level throughput is around 0.7 Mscm/day, and the IP segment takes around 20% of this).

Figure 29: injection of biomethane at a rate of 3,000 scmh to a segment of IP where the minimum demand is 600 scmh – equating to an **oversupply of 400%** (minimum LDZ level throughput is around 0.2 Mscm/day, and the IP segment takes around 20% of this)[22].

[22] Although it is unlikely that the LDZ total daily demand could be as low as 0.2 Mscm/day, a minimum flow of 600 scmh on the IP is possible, and the simple network model requires a very low LDZ demand to simulate this.

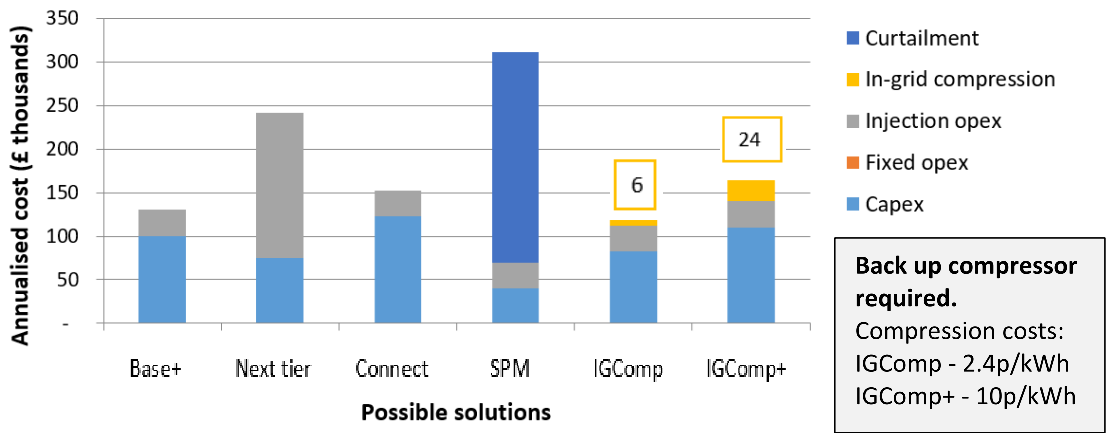


Figure 28 Annualised costs for injection at an IP network segment (injection rate 3,000 scmh, 6 biomethane plants) – minimum flow at IP of 1,875 scmh. Oversupply: 60%. The yellow boxes show the annual in-grid compression opex.

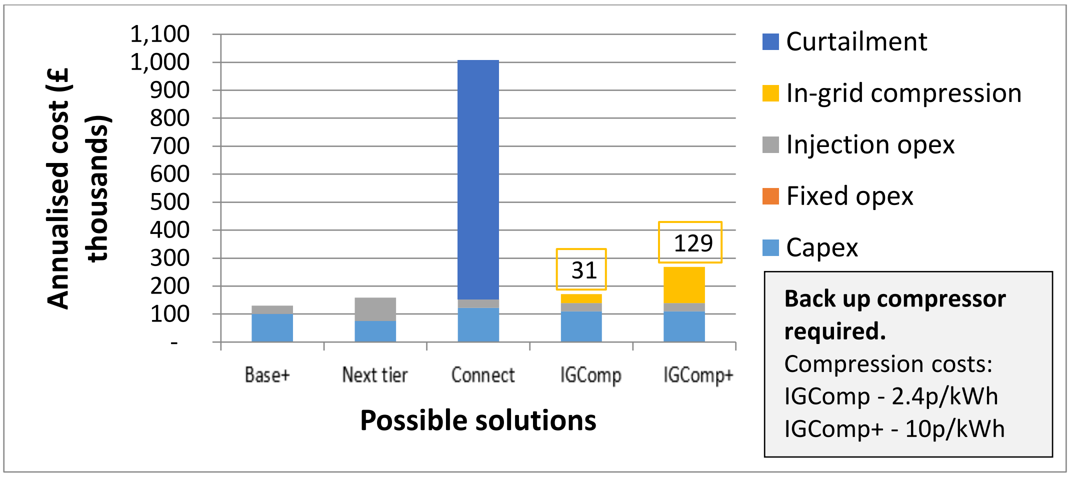


Figure 29 Annualised costs for injection at an IP network segment (injection rate 3,000 scmh, 6 biomethane plants) – minimum flow at IP of 600 scmh. Oversupply: 400%. The yellow boxes show the annual in-grid compression opex.

In the case of Figure 28, an oversupply of 60% effectively rules out smart pressure management (SPM) as an option, and there is little difference between the total annual costs of other solutions (although “alternative injection point” (Base+) comes out as the cheapest, as ever, this will depend on the specific details of a particular network).

An oversupply of 400%, as in the case of Figure 29, also rules out interconnection (Connect). In-grid compression costs also increase with this level of oversupply, and in the case of IP injection, this means that this solution is unlikely to be the most cost effective, although this will depend to some extent on the price of compression per kWh.

It should be also be noted that, while the modelled costs of Base+ and Next tier (alternative injection point and next-tier injection) remain unchanged between these two scenarios, in reality, for higher levels of oversupply it will be more unlikely that a connection point with sufficient capacity will be found at these costs. However, due to the huge variation in capacity across the network, it was not possible to quantify this precisely in the modelling.

Two general rules can be derived for higher levels of constraint:

- **The number of possible solutions that are likely to be effective decreases with higher constraint levels.**

- **When high oversupply is combined with a high injection rate, in-grid compression will only be the most cost-effective option if injection at an alternative location or a higher tier is particularly costly.**

The specific consequences of the latter, in terms of choosing the optimal solution, will vary between pressure tiers and injection rates.

6.2.1 High constraints for MP and IP injection

Figure 30 and Figure 31 present the generalised case for injection at MP and IP with high oversupply (100% and 60% respectively), comparing the capex and showing the differential opex values between solutions.

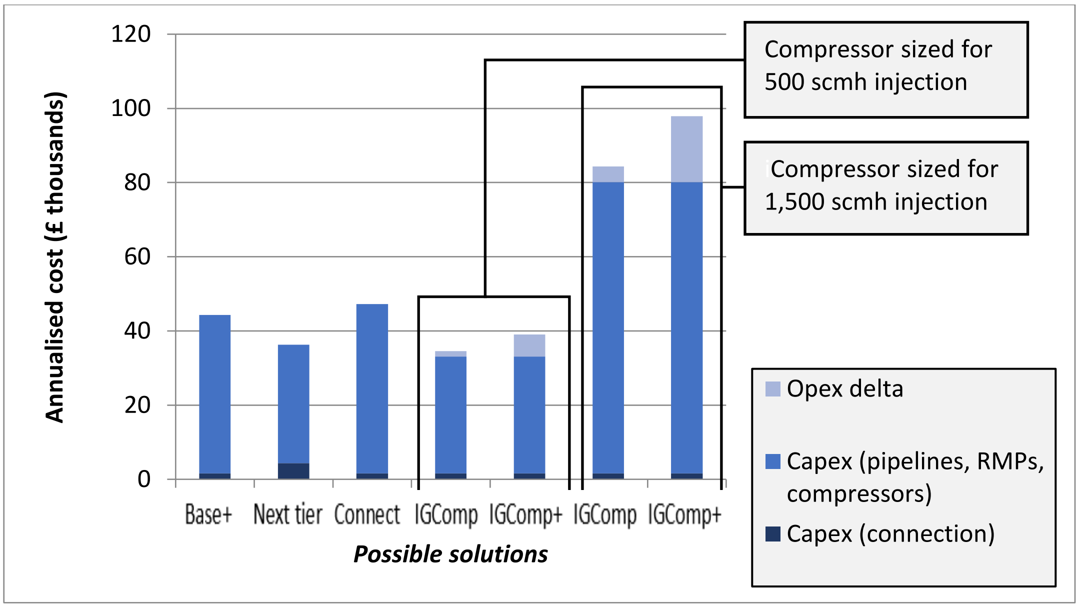


Figure 30 Annualised costs for 100% oversupply at MP. Capex figures shown are common for any injection rate, with the exception of compressor costs (which vary with injection rate, as indicated by the two examples shown). Only differential opex are shown.

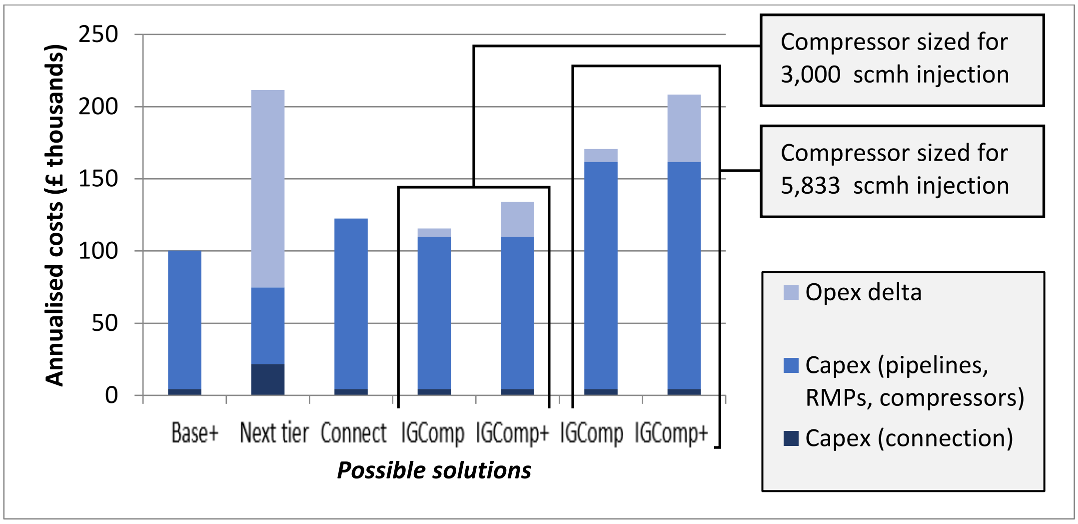


Figure 31 Annualised costs for 60% oversupply at IP. Capex figures shown are common for any injection rate, with the exception of compressor costs (which vary with injection rate, as indicated by the two examples shown). Only differential opex are shown.

The main difference between MP and IP solutions is that the next-tier injection solution is more expensive for IP constraints, as compression is required to inject biomethane at the LTS, whereas it is not required for injection at the IP. For gas produced at a shale test well, which is likely to be at higher pressure than biomethane, compression may not be required for injection to the LTS, and if it is required, the "differential opex" for compression would be proportionally lower than for biomethane, for the same injection rate.

The cost modelling shown leads to the following conclusions:

- **For high oversupply but relatively low injection rates (i.e. in very low demand networks), costs of in-grid compression are lower and therefore may be the most cost-effective solution.**
- **For high oversupply and high injection rates (i.e. higher overall demand networks):**
    - **At MP, next-tier connection is likely to be the most cost-effective solution, although this will depend on the local network characteristics.**
    - **At IP, connection at an alternative injection point is likely to be the most cost-effective solution. Interconnection may be more or less cost-effective, depending on the local network characteristics.**

It should be noted that, even if in-grid compression was more competitive with other solutions on a cost basis, to fully see the benefits, the costs of a single compressor would need to be shared between all producers who might benefit from the additional capacity[23]. Arranging a retrospective cost sharing mechanism to enable this would itself incur costs at the system level, which would need to be assessed against to potential benefits system-wide.

[23] Note that at some point, the demand seen at the pressure tier above could become a constraining factor

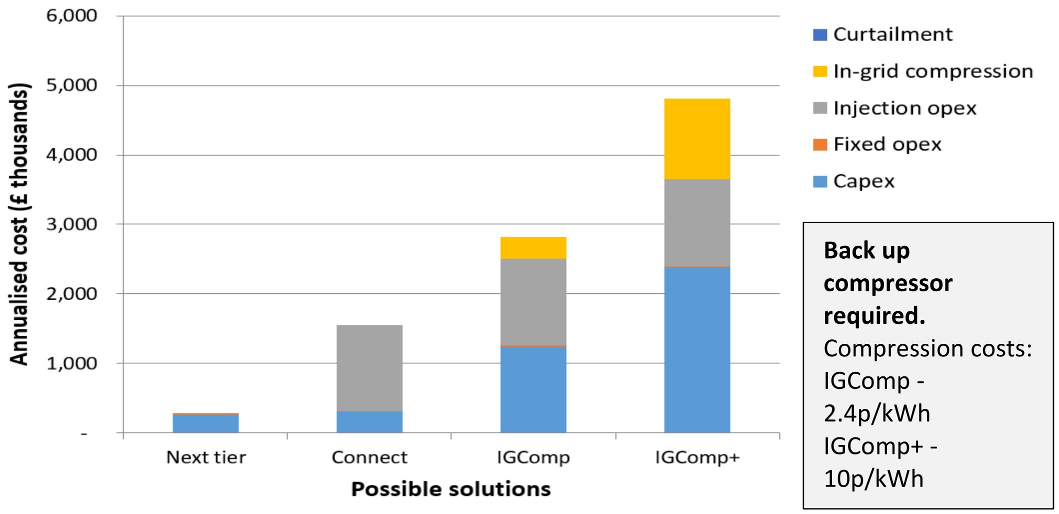
6.2.2 High constraints for LTS injection

It is likely that the majority of sources injected to the LTS will not be constrained. The minimum hourly demand for an LDZ is in the region of 50,000 scmh (although for some LDZs this could be as low as 8,000 scmh[24]), which suggests that one LDZ could accommodate a total equivalent of 16-100 biomethane plants injecting at 500 scmh, either injecting directly to the LTS or at lower tiers, in that charging zone. Assuming that for lower demand LDZs, there is only one "branch" of LTS that sees all the demand, production from a test shale well (in the region of 6,000 scmh) would have no constraints for injection at the LTS.

However, the case of commercial shale gas production should also be considered. The gas production rates for a successful shale development zone would translate to injection rates which would be likely to reach (and potentially exceed) 3 mscm/day, or 125,000 scmh. Without linepack, this would be equivalent to an oversupply of 150% - 1460%, depending on the minimum demand of the LDZ (8,000 – 50,000 scmh). Even if production rates only reached 1 mscm/day, this would still be equivalent to at least an 80% oversupply (with no linepack[25]).

For this reason, only high level constraints have been considered for injection at LTS, and as such, smart pressure management is not included in the cost comparisons.

Figure 32 shows the costs of solving the constraint where gas is injected from a commercial shale development into the LTS, at 125,000 scmh. An oversupply of 100% has been simulated, equating to a minimum demand of 62,500 scmh at the LTS. A linepack capacity of 11% has been assumed, which means that in periods of low demand, 11% of the total daily demand can be stored in the pipeline. This essentially increases the ability of the LTS to accommodate additional injection during periods of low demand, and means that the oversupply will be reduced during these periods.



[24] Based on NGGD and WWU demand data
[25] Linepack in the LTS enables some of the excess gas to be stored during periods of low demand, and effectively reduces the amount of oversupply.

Figure 32 Annualised costs for injection at an LTS network segment (injection rate 125,000 scmh, commercial shale production) – minimum flow at LTS of 62,000 scmh. Oversupply: 100% before linepack.

Annualised costs are only shown for next-tier (i.e. NTS) injection, interconnection, and in-grid compression, as the other solutions would be likely to require capping of injection. This includes alternative injection points on the LTS, as it would be unlikely for the minimum LTS demand to be higher than 62,500 scmh at another nearby point on the network. However, even for the solutions that could be effective without capping of injection, there is some uncertainty around associated costs and which solution is likely to be most viable. The cost components and challenges for each solution are explored below, within the specific context of LTS injection.

Next-tier (NTS) injection

As shown in Figure 32, the modelling indicates that injection to the NTS is by far the lowest cost solution to constraints to commercial shale injection at the LTS. This is particularly likely to be the case when the development area is close to a suitable point for injection, and a simple route for the high pressure pipeline can be identified[26]. Cost savings over other solutions include:

- No odorisation required for NTS (versus LTS injection)
- Propanation is unlikely to be required, as charging zones become separated downstream of NTS injection. Potential savings are considered in Section 6.3.

However, it should be noted that the modelling assumes that shale gas does not need to be compressed before injection to the NTS. Depending on the production pressure, it is possible that compression may be required, and the associated opex could dramatically alter the cost of this solution. Even assuming that 2% of the energy of the compressed gas is used, at a cost of 2.4p/kWh, this would translate to an annual cost of over £5.5 million, which would make this the most expensive solution. However, this is before taking into account potential propane savings (this will be discussed in Section 6.3).

Interconnection

Interconnection is likely to be cheaper than in-grid compression, due to significantly lower capex and opex; no compression is assumed to be needed for shale gas injection to LTS. In addition, there are none of the commercial challenges that would be associated with gas moving from the LTS to the NTS (see below).

Although there are existing interconnections and transfers between LDZs, there is no precedent for using them to balance out supply and demand in this context, and there is some uncertainty around whether it would be manageable. The costs of smart pressure management to facilitate this are included here, as this would be needed to manage flows between different segments.

The costs shown are for an interconnection between two segments. In theory, it could be possible to connect several LTS segments, to increase the maximum capacity during times of low demand, but this would be more costly and complex to manage. A two segment interconnection would need to be proven before this approach could be tested.

[26] Routing pipelines can be challenging, particularly in built up areas. Identifying suitable routes for high pressure pipelines can be especially difficult, and as such the feasibility of NTS connection will depend on the location of the gas production.

In-grid compression

Compression from the LTS to the NTS is likely to be very costly, and also challenging in terms of changes to commercial processes. The main cost differences compared to interconnection would be the large capital costs of the compressors needed, and the compression operating costs. Compressor costs would need to be much lower than assumed in the modelling, for this to be competitive with the other methods; this could be possible if the compressors were sized according to the maximum volume of gas needing to be compressed, rather than according to the rate of injection (in this case, this would reduce compressor capex by approximately 50%).

However, even if in-grid compression at the LTS was more competitive with other solutions on a cost basis, there would be significant barriers to implementing this solution. The compressed gas would be treated like any other source to the NTS and would therefore be subject to additional connection and transportation charges for the NTS (new commercial arrangements would have to be created for this to be avoided, which in itself would be a costly process for the NTS). In addition, the gas would need to be deodorised, following odorisation for injection to LTS.

Overall, it is unlikely that in-grid compression would be an effective and helpful solution for LTS injection.

- **LTS interconnection and direct injection to the NTS are likely to be the most feasible and cost-effective solutions to capacity constraints from injection of commercially produced shale gas.**
- **Costs and feasibility will be dependent on location, as identifying suitable routes for high pressure pipelines can be especially difficult.**

6.3 Propanation costs and potential savings from energy blending

The cost modelling so far has presented results without considering the costs of propane required in each different solution. However, as discussed in previous chapters, the requirement to add propane in order to meet the CV values for a particular charging zone imposes significant costs on biomethane producers seeking to inject gas, and for some solutions, savings could be made by using the energy blending approach and reducing the amount of propane added. The annualised costs of implementing energy blending have been estimated at around £30,000 per year, but for a propane cost of 1p/kWh of gas injected, savings are likely to be in the hundreds of thousands per year.

Figure 33 compares the annualised costs of the different solutions for the constraint presented in Figure 28 (3,000 scmh injected at the IP, with an oversupply of 60%), and shows the cost savings that could be possible if energy blending was used in parallel with injection at the LTS. “Next tier” shows the costs of propanation without energy blending for LTS injection, and next tier (blending) shows the significant cost savings that could be achieved through energy blending.

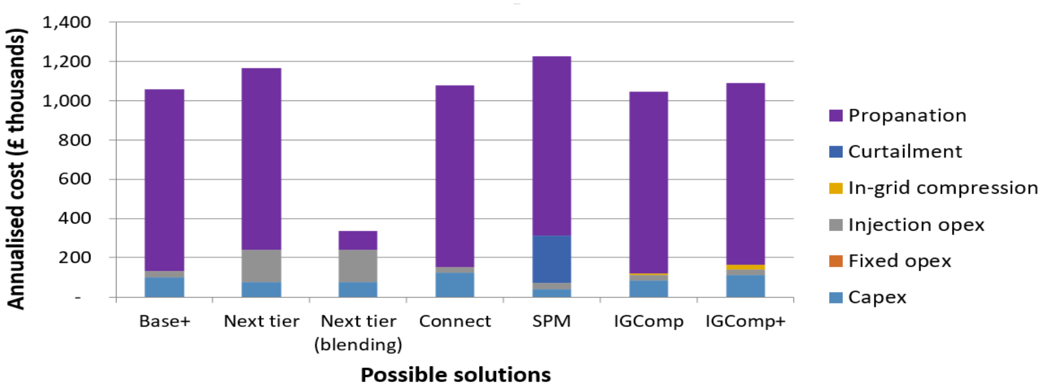


Figure 33 Annualised costs for injection at an IP network segment (injection rate 3,000 scmh, 6 biomethane plants) – minimum flow at IP of 1,875 scmh. Oversupply: 60%. Comparing propanation costs with and without energy blending.

The effect of using energy blending in this scenario is that injection at the LTS goes from being one of the more expensive solutions, to being the cheapest by far; it is clear that if energy blending was available as an option, this would be the clear choice for a producer. The same effect would be applicable in the majority of cases where energy blending can be applied, although the possible savings decrease as the demand oversupply increases. This is because the injected gas meets a larger share of the demand, and therefore more propane is required to meet the CV limit. Savings are slightly higher for lower oversupplies (for the same injection rate), which, based on the modelled costs, means that if energy blending is available at the LTS, injection at that tier will be preferable to any IP based solution, even if the oversupply is low enough to be accommodated through smart pressure management.

Figure 34 shows the relative costs of the solutions presented in Figure 32, this time including:

- Costs of propanation (for LTS injection-based solutions)
- Costs and savings for energy blending with interconnection
- Possible compressor operating costs for direct injection to NTS, for comparison with propanation costs.

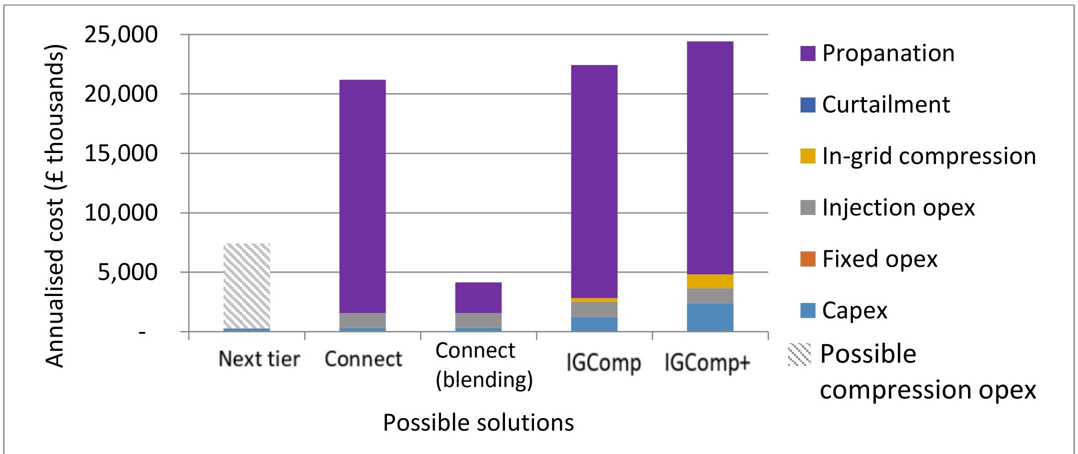


Figure 34 Annualised costs for injection at an LTS network segment (injection rate 125,000 scmh, commercial shale production) – minimum flow at LTS of 62,000 scmh. Oversupply: 100% before linepack. Comparing costs including propanation.

Propanation is not required at the NTS. As such, the modelling implies that, if full propanation is required at the LTS, direct NTS injection will be the cheapest solution for accommodating commercial shale gas, even if the gas does needs to be compressed. However, if energy blending can be used in conjunction with interconnection of LTS segments, this could then prove to be a cheaper solution, if compression is required for the gas to be injected to the NTS.

Energy blending has its own associated challenges. Under the current charging zones, it can only be used once in a particular network area, as it relies on minimising the amount of propane needed by blending with the other (higher CV) gas coming from the NTS. As discussed in Section 3.2.2, some of the GDNs are planning to explore the possibilities for alternative charging methodologies, and this may make it possible to reduce the amount of propane required for a greater number of producers. Methods such as the "virtual pipeline", where gas from a number of producers is blended at one injection point, will also help to maximise cost savings.

It is clear from the results in Figure 33 and Figure 34 that propane is the single largest contributor to overall costs for injection of gas to the grid. As such, prioritising possible cost reductions or commercial changes to enable such reductions should be a high priority to maximise the opportunities for distributed gas.

Summary of cost trends for capacity constraint solutions

The cost trends identified for different injection points and levels of oversupply (in bold text throughout this chapter) are summarised in Table 6.3.

Table 6.3 Cost trends for different solutions to capacity constraints for injection at various points on the gas distribution networks

Point of capacity constraint	Cost trends for solutions
All	• Smart pressure management is likely to be the cheapest solution if it can accommodate the oversupply at the point of minimum demand (likely to be up to a maximum oversupply of 25%). • The number of possible solutions that are likely to be effective decreases with higher constraint levels. • When high oversupply is combined with a high injection rate, in-grid compression will only be the most cost-effective option if injection at an alternative location or a higher tier is exceptionally costly.
MP Injection rate 500+ scmh	• For constraints that cannot be solved by smart pressure management, the most cost-effective solution, will depend mainly on the distance of pipeline required and the size of the compressor needed. • For the case of one biomethane plant (500 scmh injection) with an oversupply of up to 50%, in-grid

Point of capacity constraint	Cost trends for solutions
Minimum demand range[27] :10 - 15,000 scmh	compression is likely to be one of the cheapest solutions, even with a back-up compressor. • Subject to feasibility of connection, injection to the IP is also likely to be one of the cheapest solutions, particularly when the injection rate is above 500 scmh, and when the level of oversupply is high.

IP
 	
Injection rate 1,500+ scmh
 	
Minimum demand range: 1,000-50,000 scmh
	• **If energy blending or another approach to propanation reduction can be used,** injection at the LTS is likely to be the most cost effective solution, even compared to smart pressure management.[28]
	• **Otherwise:** When smart pressure management cannot accommodate the oversupply, the cheapest solution for a small oversupply is likely to be one of the following:
	  • In-grid compression (more likely when the rate of injection is relatively low, so the compressor capex will be lower);
	  • Alternative injection point (more likely when the rate of injection and/or oversupply is relatively high, and depending on the distance of pipeline required to reach a point with sufficient capacity).
	  • Interconnection (as above, depending on local network characteristics).

LTS Injection rate 8,000+ scmh Minimum demand range: 8,000-50,000 scmh	• LTS interconnection and direct injection to the NTS are likely to be the two most feasible and cost-effective solutions to capacity constraints from injection of commercially produced shale gas. • If compression were required to inject shale gas to the NTS, and energy blending or another approach to propanation reduction could be used in conjunction with interconnection of LTS segments, interconnection could be the most cost-effective solution. • If compression were not required for shale gas injection to the NTS, or if there is no opportunity for reduced propane injection at the LTS, then NTS injection would be the most cost-effective solution.

[27] Minimum demand ranges are based on feasible extremes, using 8,000 scmh as the minimum demand for a small LZD, and 50,000 scmh as the minimum demand for a large LDZ

[28] Note that energy blending is most likely to be feasible for injection to the LTS, rather than injection at MP or IP. When considering the options for constrained IP injection, the "pressure tier above" option is the LTS and therefore energy blending can be considered here (but not for any of the IP injection options).

7 Conclusions and recommendations

This report has presented the opportunities and barriers for distributed gas sources. Production scenarios for biomethane, shale gas and coalbed methane have been considered, and barriers to the realisation of these scenarios have been identified, through consultation with producers, shippers, GDNs and National Grid NTS. In parallel to this, the barriers and costs associated with possible solutions to capacity constraints were explored, to identify opportunities where innovative methods could prove to be more cost-effective than the approaches which are currently taken. Consideration of the costs, challenges and possible benefits of these potential solutions, and the commercial context, has enabled the identification of a number of recommended actions for GDNs and the industry, to support the future development of distributed gas injection.

7.1 Key findings

Based on industry estimates of reserves, potential production rates and policy targets, by 2030 between 5% and 34% of UK gas demand could be provided from the distributed gas sources considered in this report. Most scenarios predict production rates in the region of 7.5 Mscm/day, 6 Mscm/day, and 23 Mscm/day from biomethane, CBM and shale gas respectively. Due to their low production pressures, it is likely that biomethane and CBM will be injected mainly at the IP and MP tiers of distribution networks, with some injection at the LTS, whereas the predicted pressure and volumes of commercially produced shale gas mean that it is likely to be suitable for injection into the NTS or LTS.

RHI tariff degression means that reductions to grid connection and injection costs will be needed if the biomethane to grid market is to continue to grow. Based on initial cost estimates, the barriers with the greatest cost impacts for biomethane producers are: the high costs of propanation due to CV requirements; capacity constraints; and the lack of connection design standardisation. GDNs are already starting to take steps to address the first two barriers, through various NIC funded projects and by exploring innovative methods such as energy blending, and ways to provide access to sufficient capacity. However, to maintain the growth of the biomethane injection market and to support injection of shale gas, GDNs will need to engage with the industry and with regulators and policy-makers to ensure that the potential benefits of these gas sources at the system level are recognised and maximised in a cost-effective way. For the third barrier, further consultation between biomethane producers and GEU manufacturers is needed, to assess the specific cost impacts of particular differences between specifications and the potential system costs of addressing these differences.

Overall, the cost modelling of the various solutions available to address capacity constraints indicated that different solutions can be the most cost-effective, depending on the nature of the constraint. In many cases, the most cost-effective solution will be dependent on the specific characteristics of the network, which affect the resulting specific costs of pipeline installation and the applicability of various methods. However, based on the assumptions of the modelling, the following broad conclusions have been made:

- For constraints which are not severe (i.e. where the minimum demand is not greatly exceeded by the injection rate) smart pressure management is likely to be the most cost-effective option.
    - However, if energy blending or another approach to propanation reduction can be used at the LTS**,** injection at the LTS is likely to be the most cost effective solution for constraints at the IP tier, even compared to using smart pressure management at the IP tier.

- For greater constraints, the most effective solutions vary depending on the injection rate and the pressure tier. In-grid compression has the potential to accommodate large oversupplies and could provide cost savings over injection at the next tier, particularly for relatively low injection rates requiring small compressors. UK trials of in-grid compression are needed to test the real-world viability and costs of this solution.
- In addition, costs of injecting at the LTS could be drastically reduced by minimising the amount of propane required. This could be facilitated through energy blending (albeit as a limited solution) or through the creation of smaller charging zones to enable billing that reflects different proportions of distributed gas injection. The wider system costs of this will be explored as part of an NIC project led by NGGD.

7.2 Recommendations for the industry

Table 7.1 sets out the overall recommendations for distributed gas stakeholders, broadly in priority order, according to the size of the potential opportunities that could be unlocked for the distributed gas sector, and the corresponding benefits for the UK energy system. The specific actions relating to these recommendations are then set out below, grouped by estimated timescale for the action to occur.

Table 7.1 Overarching recommendations

	Overarching recommendations for distributed gas stakeholders	Potential impact on future distributed gas market
A	Continue to explore options for reducing propane requirements.	Based on the evidence in this report, if reduced propanation could be achieved on a large scale, it could provide the largest net saving for distributed gas producers, even accounting for costs of commercial and regulatory change. As such, it could enable a large number of future projects. Reducing propanation at the LTS could bring savings in excess of £20 million per year by 2020 (based on 20 applicable LTS connections in 2020), plus potential additional savings for IP and MP connections where reduced propanation is possible.
B	Trial capacity solutions, demonstrate feasibility and compare costs and benefits.	Difficult to estimate overall cost saving, as this will depend on the capacity solutions deployed, and the sources of gas seeking to inject. However, effective solutions or mitigation for capacity constraints will be essential to enable continued growth of distributed gas as the grid becomes more locally saturated with increasing distributed injection.
C	Seek policy changes that will reduce capacity barriers through: iii. Mitigating measures such as pricing / RHI tariff weighting, and/or: iv. Policies supporting capacity management measures that can be installed in advance of requirements, with socialised costs.	

D	Seek to minimise general connection costs and timescales.	This could bring savings of low £millions per year (based on 20 connections per year).

Next 6-12 months:

- A.1) Continue to use energy blending approaches in suitable situations.
- A.2) GDNs and industry to participate in consultation as part of stage one of NGGD's NIC funded "Future Billing Methodology" project.
- A.3) GDNs to share initial conclusions with implications for CV requirements, from existing projects including Future Billing Methodology (NG) and Real-Time Networks (SGN), as early as possible to inform next steps for industry and regulators.
- A.4) GDNs and industry could engage Ofgem to consider reviewing the approval process for CVDDs, to encourage more devices to seek approval.
- A.5) Producers should support activities by participating and investing in trials of new approaches to propanation, and sharing relevant data and experiences with the industry.
- B.1) GDNs should prepare to quote for providing in-grid compression for producers in connection agreements (National Grid has already started work on this).
- B.2) Producers using storable biogas feedstocks should assess the economic viability of optimising injection volumes on constrained networks by storing feedstock on-site.
- D.1) Industry should initiate a workshop to review the status of TD/16 & TD/17, compared to current requirements from individual GDNs, and determine whether these documents should be revised to reflect the latest lessons learned from different gas producers and GDNs. This could then lead to review of specifications, involving HSE.
- D.2) GDNs could offer the option for producers to pay for fast-tracked services such as connection enquiries and approval processes. GDNs could assess whether it would be feasible and cost-effective to employ additional staff, or (for connection enquiries) to build a self-assessment tool.

Next 1-2 years:

- A.6) GDNs and industry should continue to engage with the Future Billing Methodology" and consider the value of exploring other avenues outside the scope of the project. e.g.: to progress with the possibility of "Non Directed sites", the industry would need to define a framework for how this would be monitored and regulated by GDNs, including defining limits for what constitutes "low flow" sites. In addition, a detailed assessment of the system costs and benefits of this framework compared to the current one would be required, including quantification of financial impacts for customers, and to what extent these could be mitigated.
- B.3) GDNs and producers should trial in-grid compression to clarify the business case and identify any technical challenges.
- B.4) Industry grouping should identify emerging storage trends for different biogas production sources, and whether there is a need for aggregated storage on the network
- B.5) Producers should discuss the potential for sharing costs and benefits of technical solutions that have been trialled, in terms of capacity gained.
- C.1) Industry to engage BEIS to consider how best to support biomethane and other distributed gas sources from a network capacity perspective, to complement the support provided through the RHI.
    a. Industry to demonstrate costs associated with capacity constraints and the limits this could pose on the long term development of the market.

   b. Industry grouping to lead consultation on options to mitigate these limitations: a) possible changes to pricing or RHI tariff structure to incentivise injection at times of high demand; b) installation of new storage provisions as part of GDN portfolio, in advance of this being required from customers.
   c. Industry grouping to report findings of the above to BEIS and the regulator, defining possible forms of policy support.
- C.2) Industry to engage Ofgem to define framework defining ownership and input and output balancing arrangements for storage on the network.
- C.3) GDNs to explore scope for license obligation exemptions to facilitate implementation of new solutions beyond the trial stage.

Next 3-5 years:

- B.6) Shale producers could initiate and consider providing funding for investigation of future opportunities and likely costs for LTS interconnection alongside energy blending, in areas of known shale reserves.
- B.7) Explore practicalities and feasibility of LTS interconnection and energy blending, with support from shale producers.
- C.4) GDNs to work with BEIS and Ofgem to implement agreed policy changes around pricing and/or role in deploying capacity solutions.
- C.5) GDNs to work with Ofgem to develop framework to define conditions when socialising costs (e.g. through charging) is appropriate for different technical solutions.
- C.6) GDNs to engage Ofgem to introduce incentives / disincentives for the GDNs to ensure efficient and effective deployment and use of solutions.

While the most likely stakeholders to lead each specific action have been identified above, all of the actions outlined will require collaborative efforts and transparency between the different industry stakeholders, in order to bring down overall costs and maximise opportunities for injection of green and distributed gas. Costs (and practicalities) for the range of solutions available to maximise the injection opportunities on the network will be strongly dependent on particular network and source characteristics. As such, clear communication across the industry and GDNs will be essential to maximise learning for the system as a whole, and to draw out emerging trends around the suitability of different options.

Appendix 1 – Tables and assumptions

Summary of major barriers to gas injection and relative impacts

The table below quantifies the relative impacts of the major barriers (in terms of the estimated cost for 20 new connections, which is the minimum number expected per year in line with the production scenarios), and indicates the progress that has been made towards addressing the barriers. The table also shows the estimated system costs associated with addressing these barriers. This is estimated in terms of the total system cost, so is not necessarily directly comparable with the impact of the barrier (which is per year).

Issue / specific barrier	Impact (indicative cost for 20 new connections)	Progress to date	Potential system cost to address the issue
CV requirements and high propanation costs	£10-20 million **per year** across the network in propanation costs	Reduced propanation options (energy blending) offered today in certain situations, by some GDNs Implications of smaller charging zones (allowing lower propanation costs) will be explored 2017-2020 in a National Grid NIC project	Energy blending may lead to opportunity costs for subsequent injection plants £10s of millions possible total system cost for smaller charging zones
Capacity constraints	Up to £9 million **per year** for additional pipeline to access points with sufficient demand	Various technical solutions are being trialled and researched by GDNs (more details in Chapter 0)	£millions for field trials (or low £10s of millions e.g. if new commercial models are needed to share costs across multiple producers)
High connection costs - contribution from lack of specification standardisation	Estimated low £millions **per year** in cost premiums for bespoke GEU designs	Industry has identified key differences but has not quantified cost impacts	Up to £100,000s for industry consultation to define details of

		Standardisation may be more feasible when tariffs are secured before injection (less time pressure)	possible cost savings, and creation of revised specifications

Scenarios assessed in cost modelling and lowest cost solutions

Source	Injection rate (scmh)	Injection point	Minimum demand at injection point (scmh)	Share of throughput at injection point	Equivalent daily demand at LDZ (mcmd)	Oversupply at time of minimum demand	Most cost-effective solution
Biomethane (1 plant)	500	MP	333	1%	2,352,941	50%	IGComp
Biomethane (1 plant)	500	MP	250	1%	1,764,706	100%	Next tier / IGComp+
Biomethane (1 plant)	500	MP	24	1%	168,067	2000%	Next tier
Biomethane (3 plants)	1,500	MP	1,000	1%	7,058,824	50%	Next tier
Biomethane (3 plants)	1,500	MP	750	1%	5,294,118	100%	Next tier
Biomethane (3 plants)	1,500	MP	71	1%	504,202	2000%	Next tier

Biomethane (6 plants)	3,000	IP	2,857	19.8%	1,018,589	5%	SPM
Biomethane (6 plants)	3,000	IP	1,875	19.8%	668,449	60%	Base+ / Next tier (if energy blending is used at LTS)
Biomethane (6 plants)	3,000	IP	600	19.8%	213,904	400%	Base+ / Next tier (if energy blending is used at LTS)
Biomethane (6 plants)	3,000	IP	2,857	99.1%	203,512	5%	SPM
Shale test wells	5,833	IP	5,555	19.8%	1,980,477	5%	SPM
Shale test wells	5,833	IP	3,646	19.8%	1,299,688	60%	Next tier
Shale test wells	5,833	IP	5,555	99.1%	395,696	5%	Next tier
Shale commercial wells	125,000	LTS	62,500	19.8%	4,411,765	100%	Next tier (but not if compression is needed)

See next page for key to abbreviations.

Solution	Abbreviation
Local injection	Base
Alternative injection point (same tier)	Base+
Injection at next tier	Next tier
Interconnection	Connect
Smart pressure management	SPM
In-grid compression	IGComp
In-grid compression – higher costs (assumes that a back-up compressor is needed; also higher energy costs – see appendix for detailed assumptions)	IGComp+

Indicative costs of gas distribution network injection

	Cost components	Costs (£)	Unit
Baseline connection and injection costs			
Capex to connect and inject at MP (0.25km pipeline)	Connection and pipeline (£200,000 per km)	65,000	per connection
Capex to connect and inject at MP (2km pipeline)	Connection and pipeline (£200,000 per km)	415,000	per connection
Capex to connect and inject at IP (1km pipeline)	Connection and pipeline (£300,000 per km)	340,000	per connection
Capex to connect and inject at IP (3km pipeline)	Connection and pipeline (£300,000 per km)	940,000	per connection
Capex to connect and inject at LTS (1km pipeline)	Connection and pipeline (£500,000 per km)	700,000	per connection
Capex to connect and inject at LTS (3km pipeline)	Connection and pipeline (£500,000 per km)	1,700,000	per connection
Capex to connect and inject at NTS (1km pipeline)	Connection and pipeline (£500,000 per km)	2,500,000	per connection
Odorisation prior to injection	Odorant costs	5,000	per year, per 500m3/hr injected
Addition of propane prior to injection	Propane costs	0.01	per kWh injected
Compression for injection at LTS	Compression costs **Energy consumption:** 2% of gas compressed	0.024	per kWh
Curtailment costs (approximate lost revenue)	Lost potential revenue, per kWh biomethane not injected	0.06	per kWh curtailed biomethane injection
Costs of innovative solutions			
Smart pressure management capex	Remote monitoring point equipment installation	40,000	per connection
Smart pressure management opex	Remote monitoring opex	Negligible	
Interconnection at MP (2 km pipeline) capex	Pipeline and smart pressure management	440,000	per connection
Interconnection at IP (3 km pipeline) capex	Pipeline and smart pressure management capex	940,000	per connection
Interconnection at LTS (5 km pipeline)	Pipeline and smart pressure management	2,540,000	per connection
Interconnection opex (all tiers)		Negligible	

In-grid compression capex	Compressor plant installation Injection rate 500 scmh Injection rate 1,500 scmh Injection rate 3,000 scmh Injection rate 5,833 scmh Injection rate 125,000 scmh	(With / without back-up compressor) 135k / 245k 355k / 685k 432k / 689k 675k / 1,175k 10,889k / 21,604k	per connection
In-grid compression	Compressor opex	0.24 / 0.10	per kWh
In-grid compression from LTS to NTS	Deodorisation costs	Up to 50k Plus 20k	per 5,000 scmh injected per annum
Energy blending	Sensors and valves needed for energy blending	250k	per connection
Energy blending	Management and maintenance	Negligible	

Appendix 2 - International best practice for distributed gas sources

This Appendix reviews the international best practices, barriers and transferrable lessons for the UK regarding the injection of unconventional gas sources into gas grids. It also examines the historical development of unconventional gas industries. We consider the following case studies:

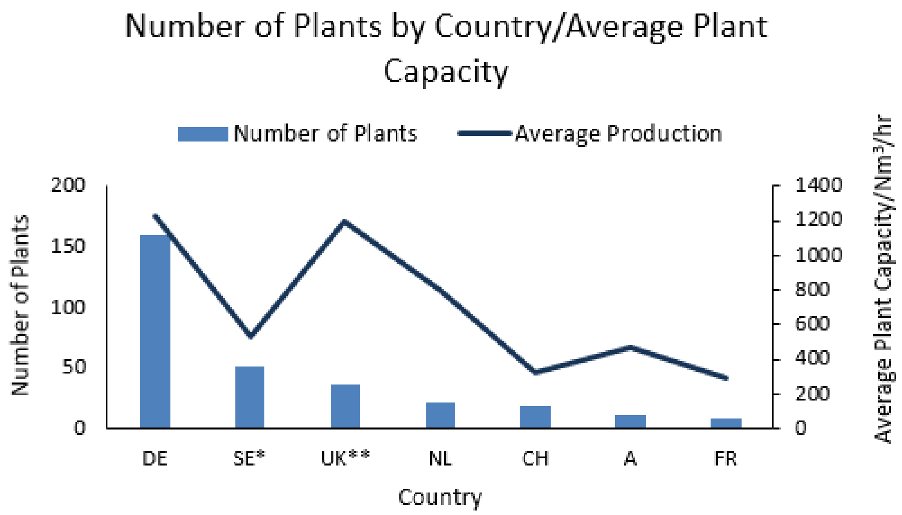
- Several innovative methods for management of distributed biomethane sources in Germany and The Netherlands;
- We review the development of CBM in Australia and the US, the world's foremost producers;
- Finally, we examine the 'shale-revolution' in the US.

Biomethane

Overview of biomethane production and biomethane to grid

Biomethane to grid (BtG) installations have only reached a modest penetration across Europe as the great majority of AD biogas is used for on-site heat and power applications. Germany is the European leader in BtG with 160 plants in operation and Europe's highest average plant capacity, 29,500m^3/day.

The largest gas network operators in Germany are Gasunie and VNG. Gasunie also owns the Netherlands gas distribution network.



Sources: DENA, http://www.iea-biogas.net/ (end 2014 data); ADBA; Green Gas Grid, Wikipedia, NNFCC

Key biomethane markets

The original intention of the international case studies work was to focus on France as a leading market for biomethane injection into the gas grid. However, on further investigation and discussion with GDF Suez, it became apparent that the biomethane market in France is not further advanced than in the UK.

More interesting case studies were identified in Germany and the Netherlands, hence these countries became the focus of the case study work. Some further details on the comparison between these markets is given below:

- In terms of the ratio of plants to population, Biomethane to Grid (BtG) in France (0.1 plants per million people (ppmp)) is relatively underdeveloped compared to the UK (0.6 ppmp).
- Furthermore, on average, French BtG plants have lower capacity than their UK counterparts.
- As one might expect from an industry that has achieved low penetration in France, there is little evidence of innovative approaches to BtG gas management, as consultations with GDF Suez revealed.

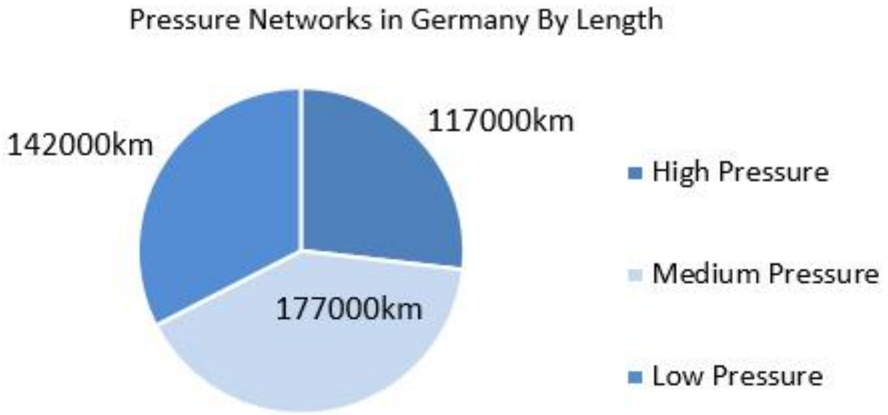
Hence, we investigated solutions in other countries:

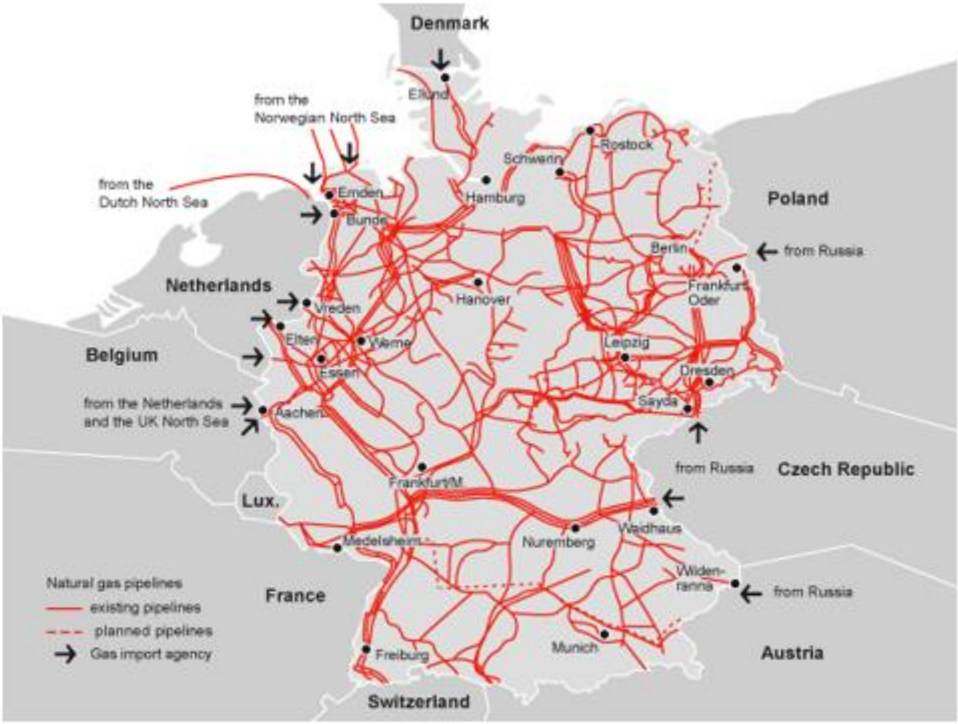
- Germany (2.0 ppmp) and The Netherlands (1.3 ppmp) have comparatively well developed BtG industries;
- Average BtG plant capacity in Germany is 1,230 m^3/hr, in the UK it is 1,190 m^3/hr and in the Netherlands it is 800 m^3/hr. These are significantly higher than the average French capacity: 300 m^3/hr. For this reason, not only are German and Dutch cases more similar to the UK, they are more likely to have capacity issues (and thus more likely to be investigating solutions).
- Several interesting cases of innovative grid management techniques being used in relation to biomethane injection facilities have been found in Germany and the Netherlands.

The gas network in Germany

The German gas network is characterised by regional variations in the gas quality (High and Low Wobbe index (roughly 97% and 89% flammable gasses respectively)). Accordingly, the degree of 'preparation' required for biomethane injection varies from site to site.

Operation of the 117,000km long high pressure grid is handled by 14 TSOs. The medium pressure grid is 177,000km long and the low pressure grid is 142,000km in length. Under the Gas Network Access Ordinance (GasNZV), **the German gas network operators are obliged to grant preferred grid access to biomethane producers on all pressure levels, with at least injection 96% availability** (on an annual basis). Access can only be denied if major technical barriers and/or excessive costs can be demonstrated to the regulator.





There currently are 165 biomethane-to-grid installations across Germany. The GasNZV ordinance specifies that 75% of the grid access costs need to be covered by the gas network operators (including up to 10km pipeline, compressors, gas metering and pressure measurement equipment), while the biomethane producers are liable for only 25% of these costs . The gas network operators retain the ownership of the grid access points and are responsible for their maintenance and operation.

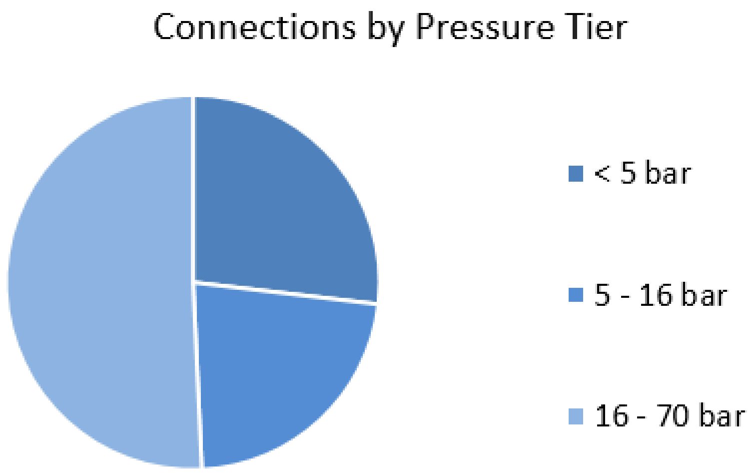
The costs incurred by the gas network operators for the provision of a grid access point and management of network are socialised via the gas transport tariffs.

Biomethane injection in the gas grid does not benefit from direct subsidies. Instead, a certificate system is implemented which carries a monetary value to biomethane traders as the sum of biomethane in power generation and domestic heat is eligible for direct compensation (respectively under the Renewable Energy Act (EEG) and Renewable Energies Heat Act (EEWärmeG)). In addition, plants up to a capacity of 350 Nm^3/h of upgraded biogas can receive a grant to recover up to 30% of the investment costs (Market Incentive Program). Hence, gas is purchased virtually: for example a customer can choose to buy 30% of their gas as Biomethane, and 70% as conventional gas.

Management of distributed gas in Germany

Injectors and operators negotiate to minimise costs and risks, and this framework appears to have resulted in case by case solutions to management issues associated with gas injection. **Typically, biomethane is injected into the intermediate pressure tier at around 16 bar**. In Germany injection of biomethane at this level requires propane enrichment and compression. Some plants injecting into low pressure tier are coordinated with additional sources of demand.

For example, in Ronnenberg a plant producing 300m³/hr connects to a grid of pressure 0.8 bar operated by enercity Netzgesellschaft. The plant connects via a 2.5km pipeline operating at 2 bar. The grid then moves the gas to CHP facilities on the outskirts of Hannover. This is not yet sufficient to buy all of the biomethane, and until more CHP facilities are connected some of the biomethane is sold to the market.



At Emmertsbühl biomethane plant, biomethane is injected into the local LP at a pressure of **500 – 800 millibar**. Gas leaves the processing plant at approximately 5 bar.

Normal natural gas in the grid has a CV of 11.3kWh/m³, and the biomethane has a CV of no more than 10.85kWh/m³. Conventionally, the CV would be increased via propane enrichment, but in this case **they allow a small amount of atmospheric air into the network along with natural gas reducing the system's average CV to 10.85kWh/m³**. This alleviates propane enrichment costs faced by the producer. The CV is monitored and recorded every three minutes to calculate the gas CV to adjust sale prices.

Much of the gas produced is used by local industry and the plant production often exceeds local demand (usually at weekends). To cope with this **gas flow may be compressed back to the 40 bar grid and LPG added, raising the CV to that of the MP**.

There are onsite CHP plants and a flare for use if the gas cannot be injected into the grid. Injection into the low pressure network was more cost effective than injection into the IP:

- Connection to the LP required an 800m pipeline, the nearest entry point to the medium pressure network was 5km away (injection into the LP had overall capital costs of 1.3 million €);
- Overall, compression costs were reduced: most gas only needed to be decompressed to 500 – 800mbar, only a small amount had to be compressed to 40 bar;
- Only the gas injected into the medium pressure network required propane enrichment.

The gas plant injects into the Blaufelden – Weisenbach local DN at an approximately uniform rate of 250 m^3/hr. The network operates at <1 bar and is 12 km in length. 278 private and five industrial customers are connected to this network.

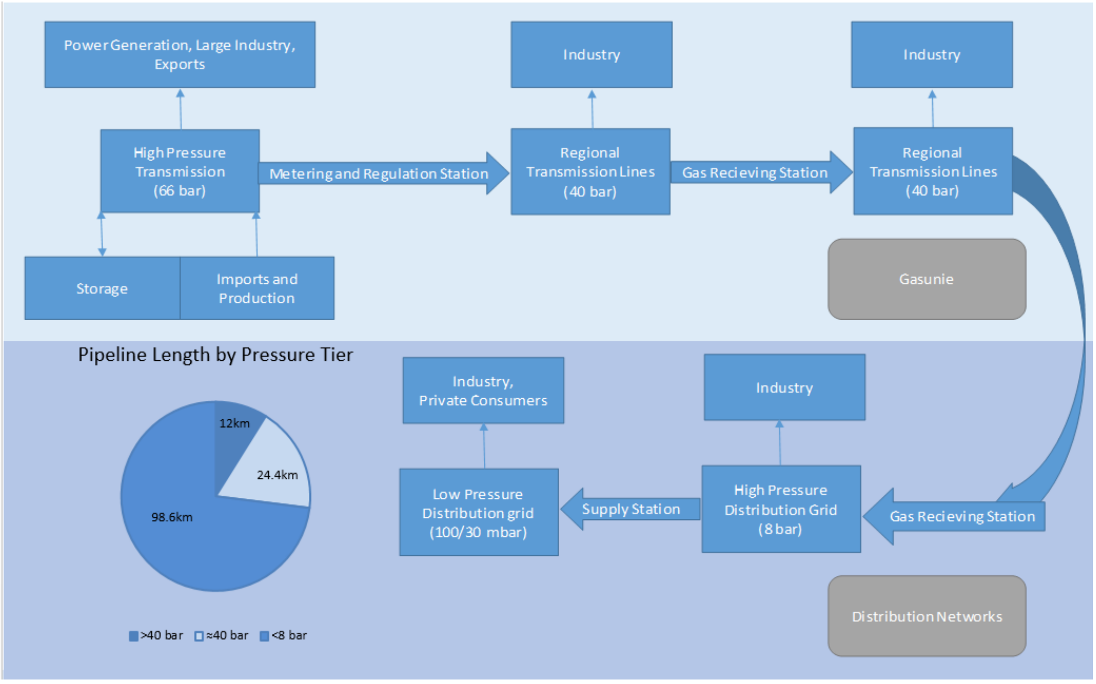
Peak demand in the area is in January, with weekday demand of around 700 m^3/h and around 500 m^3/h at weekends. Between May and November the average weekday demand is approximately 450 m^3/h, with a weekend demand below 200 m^3/h.

In Germany subsidies exist for power generation from renewables including biogas. Gas is purchased virtually: for example a customer can choose to buy 30% of their gas as Biomethane, and 70% as conventional gas. In 2012 the plant produced gas at a cost of 6.8 – 7.5€c/kWh, more than twice the price of imported gas. Consumers would buy the Biomethane and use CHP to generate electricity, thus profiting from the generation subsidy and using the heat for industrial processes.

The gas network in the Netherlands

The national transportation is owned by Gasunie. It operates between 40 bar (regional transportation) and 67 bar (main gas transportation). Two High pressure transmission lines run in the Netherlands, transporting low and high calorific gas. Nine DSOs operate the distribution grid (pressures of <8 bar).

Across the 135km of pipeline infrastructure: 8.9% operates above 40 bar; 18.1% operates at 40 bar; and 73% operates at low pressure (<8 bar). The high pressure grid is split into two networks carrying higher and lower energy content gas. Annual connection costs for Biomethane to the Distribution Networks are approximately 100,000€ and 300,000€ for the NTS.



Number of installations:

There currently are 25 biomethane-to-grid installations across The Netherlands. **All installations are injecting into the regional 7/8bar networks but for one producer also injecting at the higher pressure tier** (40bar) due to local capacity constraints.

The biomethane Wobbe index is typically higher than the grid average and thereby nitrogen is added to the gas before injection to ensure point-of-use safety (e.g. flame stability etc.).

Network access status:

Like in the UK, the Dutch gas network operators cannot refuse connection to biomethane suppliers and have to perform feasibility studies to inform capacity (e.g. a minimum number of full load operating hours the producer is guaranteed to be able to run) and connection cost offers. If the minimum load factor offered is too low, the GDN must provide an alternative connection offer. Connection capacity is offered on first-come-first-served basis. All connection-related costs are paid for by the biomethane producers.

Existing national regulations do not allow gas network operators to directly invest into network upgrading assets (such as compressors, storage, etc.) under purely commercial regimes. This implies that costs required to support biomethane injection capacity need to be paid by the biomethane producers if incurred.

Dutch regulations on this may change in the (near) future should the industry make a case for it. New solutions/network upgrade models would need to demonstrate cost effectiveness and quality of service (safety, etc.). Change of the national regulations would take a few years to become adopted.

Subsidies:

Biomethane-to-grid is supported by a national feed-in tariff scheme - this is the only subsidy/policy supporting biomethane in the country.

Pilot projects for distributed gas in the Netherlands

A number of pilot projects are under way to understand cost-effective options and opportunities for managing biomethane injections over periods of low gas demand across local networks.

The projects are paid for by the network operators as 'innovation' projects.

Active or planned projects aimed at managing local biomethane injections (selection)

A
- **Pressure regulation across a local network**: storage capacity in the local distribution network is created by lowering the local working pressure during low-demand periods (summer)

B
- **Gas compression**: excess gas is compressed from the local to the regional gas network to offer additional capacity whenever needed (e.g. when local demand cannot be sufficient)

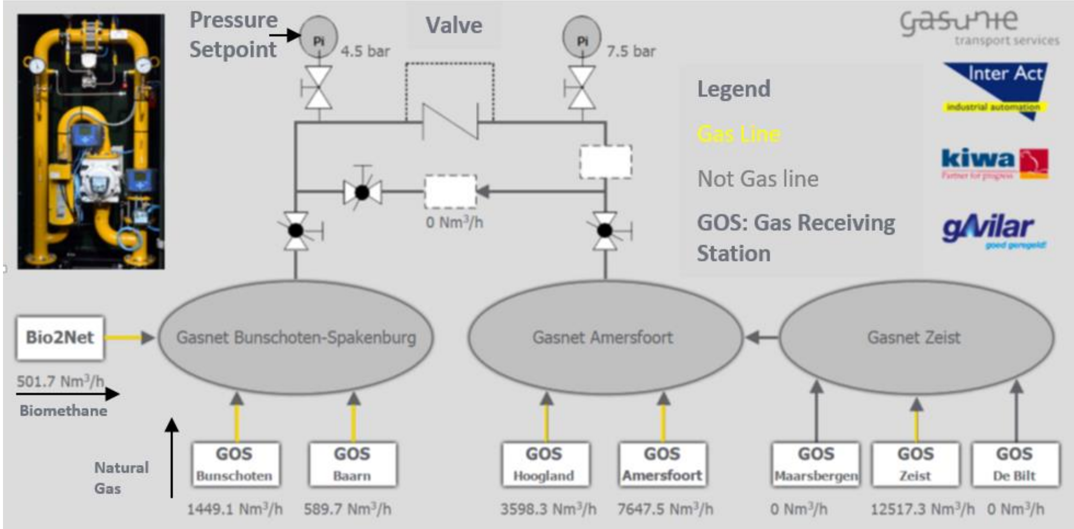
C
- **Intelligent local gas demand balancing**: a local network of baseload gas consumers, new gas consumers etc. works as a trading platform to support green gas consumptions year-round

D
- **Dedicated networks**: development of dedicated local biogas grids (mix of biogas and gas), potentially including adapted appliances (e.g. boilers) [*not discussed in this report*]

A – Pressure regulation across a local network

- A segment of the local (8bar) network is isolated from adjacent portions and operated at half the pressure (around 4.5 bar) temporarily during the periods of low gas demand (from April to September) to provide network storage capacity to a local biomethane producer, injecting at a rate of around 700 Nm^3/h.
- The pressure is monitored automatically but setpoint pressure is manually changed by technicians (twice per annum)
  - Currently considered the easiest and cheapest way to provide capacity during the low demand season
  - Works well in networks characterised by long and large-diameter pipes (e.g. long/large local networks)
  - Costs related to this pilot project are minimal – mainly related to fitting pressure monitoring devices (e.g. on the order of 10,000s€)
- In this area the network capacity was increased by a factor of 3.5 using this method. Calculations based on three other areas have shown similar increases (factors of between 2.5 and 3.5).
- Only minor issues were experienced. One consumer had to adjust their equipment: they experienced gas pressure changing between 4.5 and 8 bar. The emergency flare at the biomethane plant also had some issues due to the pressure change, but this was resolved by manual recalibration.
- A separate project is investigating scope for expanding this model across the national networks and automated pressure regulation options. Also, improving the

meshing of the local networks is being considered to provide greater capacity when adopting this technical solution.

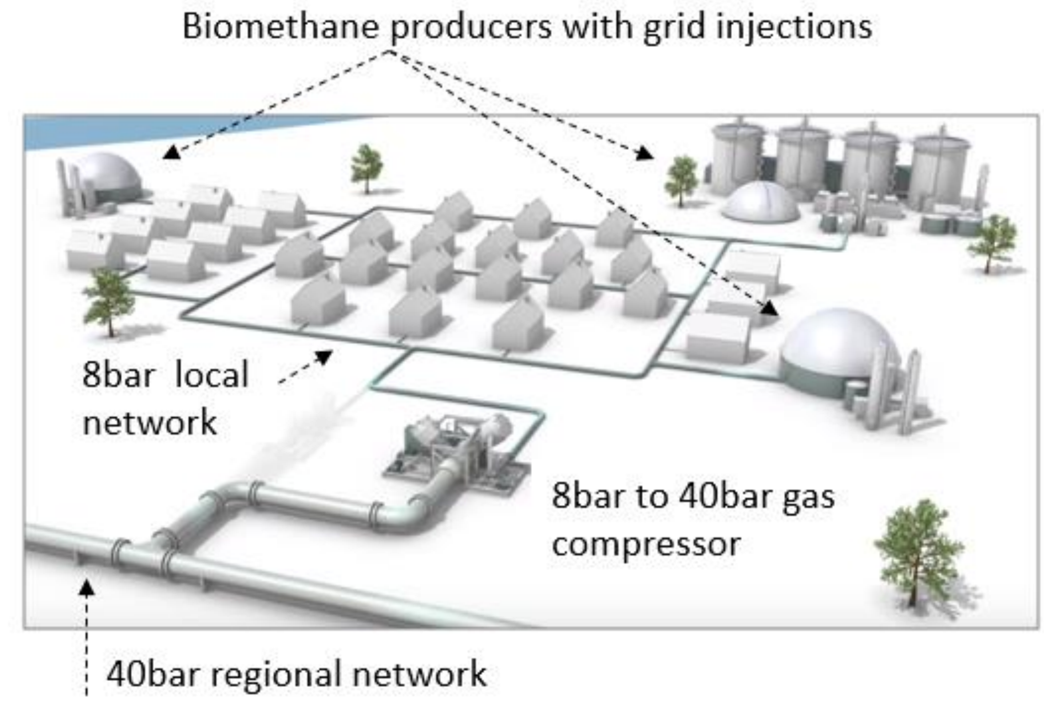


B – Gas compression

- The project will fit a compression station to compress excess gas from a local 8bar network into a regional 40bar network during periods of low-gas demand. The site will be chosen to include at least one biomethane injection plant.

Status and early insights:

- The project currently is on its planning phase and it is the first project of its kind in The Netherlands. It is projected to cost around 1.5 million € in total, including one compressor (likely between 500-700k €)
- The compressor will be 800 Nm3/hour, 7bar to 40bar capable and oil-free (this in order to avoid gas quality contamination issues)
- The compressor is expected to operate only 200 hours per year – this and its high capital costs have created delays in financing of the project
- The local gas network operator will fund the installation of the compressor as an innovation project (co-funded by the Dutch Government)



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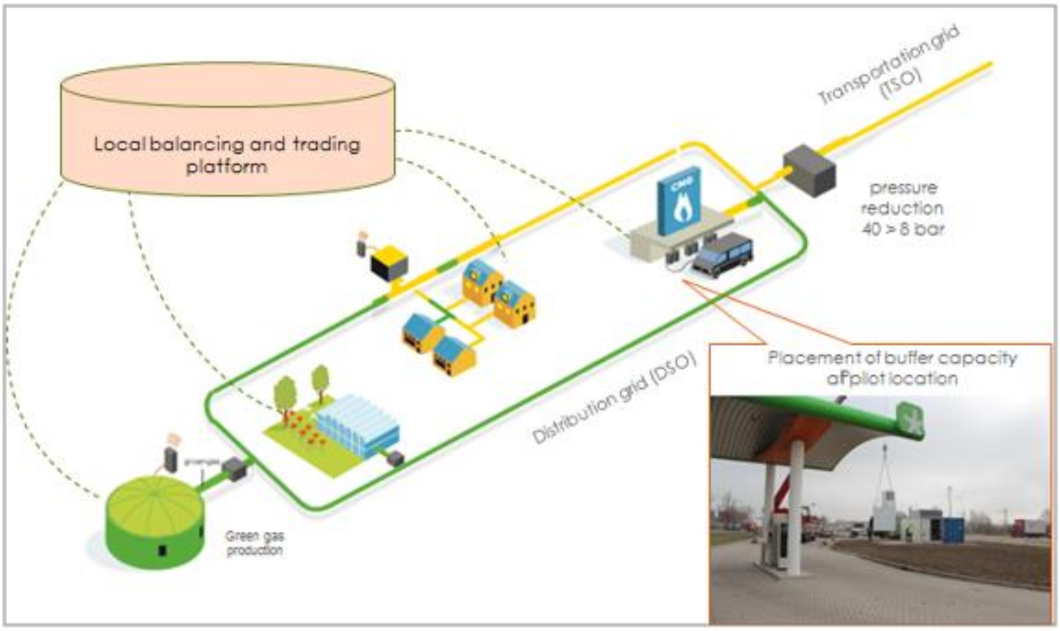
C – Intelligent local gas demand balancing

- Producers and end-users are involved in a common local gas trading and balancing platform which can turn gas demand on at times when curtailment of a gas producer becomes likely.
- For example, if the pressure on the distribution grid approaches 8bar, a message is sent to CNG filling station (or other users having local storage) to fill up gas storage (GDN facilitates data transfer)
- The gas network operator will balance the network by active pressure regulation and demand signalling
- The pilot will be conducted near Amsterdam where a CNG filling station will be adapted for providing demand response services (±1,000m^3 storage capacity per day)
- Pilot will be used to understand the business case and financials for scaling the solution. Partners will also perform a market consultation and regulatory studies
    - At present, regulation in the Netherlands prevents this project from being commercialised by grid operators.



Transferrable lessons from Germany and The Netherlands

Biomethane

- Dutch and German lessons are very useful for the UK because in all three cases, networks have significant obligations to connect biogas plants.
- Hence, several innovative and useful solutions have been/are being tried:

Germany

- New sources injecting into low pressure tiers are balanced with new CHP customers;
- Compressing additional gas and injecting upstream from low pressure into higher pressure systems at times of low demand.

Netherlands

- Smart grids that lower pressure in low demand periods to create more capacity;
- Upstream gas compression;
- Balancing surplus supply with CNG filling stations.

Bio-SNG and Power to Gas

Bio-SNG is derived by the application of a methanation reaction to a syngas that has been produced by the thermal gasification of solid biomass or waste-derived fuels. The bio-SNG produced is of high methane content and suitable for bulk injection into the gas grid.

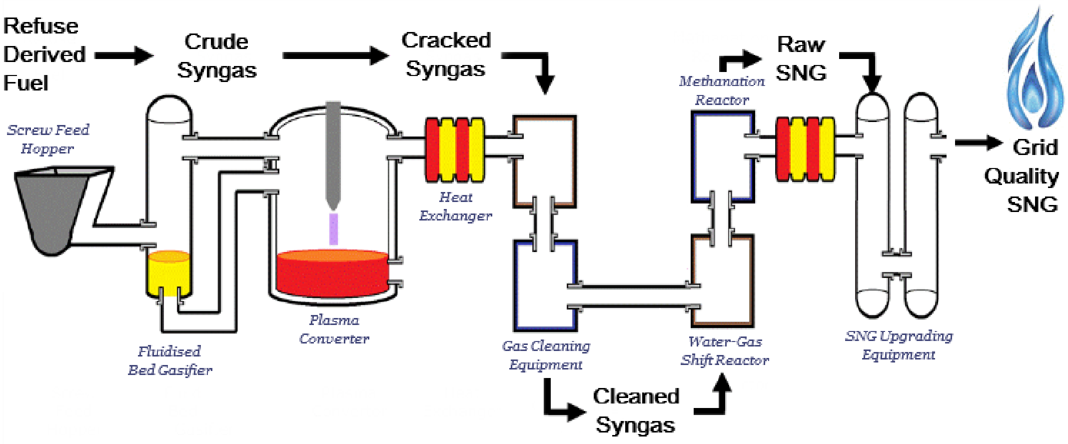
There are three main stages in the production of bio-SNG: (1) Gasification – the biomass or waste fuel is gasified to generate a syngas (mixture of H_2 and CO); (2) Methanation – the syngas is cleaned and processed in water-gas shift reactor to partially convert CO to H_2 and CO_2. This creates the necessary 3:1 ratio of H_2 to CO in the syngas for the methanation reaction; (3) Separation – a methane-rich gas is produced by the methanation reaction, but still has a high CO_2 content, which must be separated out. This can be done by a pressureswing adsorption process, resulting in a final gas of sufficient quality for injection into the gas grid.

There is currently relatively little experience of bio-SNG production in Europe. In the UK, National Grid, together with project partners, have been awarded NIC funding to build a first bio-SNG demonstration plant, utilising an existing waste-derived syngas source. This project will assess technical and economic feasibility of the technology. An illustrative process flow diagram for the National Grid demonstration plant is shown below[29].

Due to the limited current activity in bio-SNG it has not been a focus in this work.

The scale of plant is likely to be relatively large, e.g. 20 – 100MW, due to the economics of the gasification plant.

At this scale, injection is likely to be into the LTS (potentially NTS). The issues will be similar to those relevant to other large sources – capacity, CV and gas quality.



A further route to the production of synthetic natural gas is the methanation of hydrogen derived from a water electrolysis process. A schematic of the process is shown in the figure.

The synthetic gas produced is fully miscible with natural gas and can be injected directly into the gas grid, subject to the same gas quality and CV considerations as applied to other distributed gas sources. Alternatively the gas can be used as a clean fuel for CNG vehicles.

H_2 methanation is of interest as a power-to-gas technology, providing an outlet for surplus renewables production and relieving congestion on electricity distribution and transmission systems. The methanation of H_2 to SNG allows bulk injection into the existing gas grid, avoiding the issues associated with pure H_2 injection (e.g. the requirement for pipelines to be re-purposed and modifications to gas appliances).

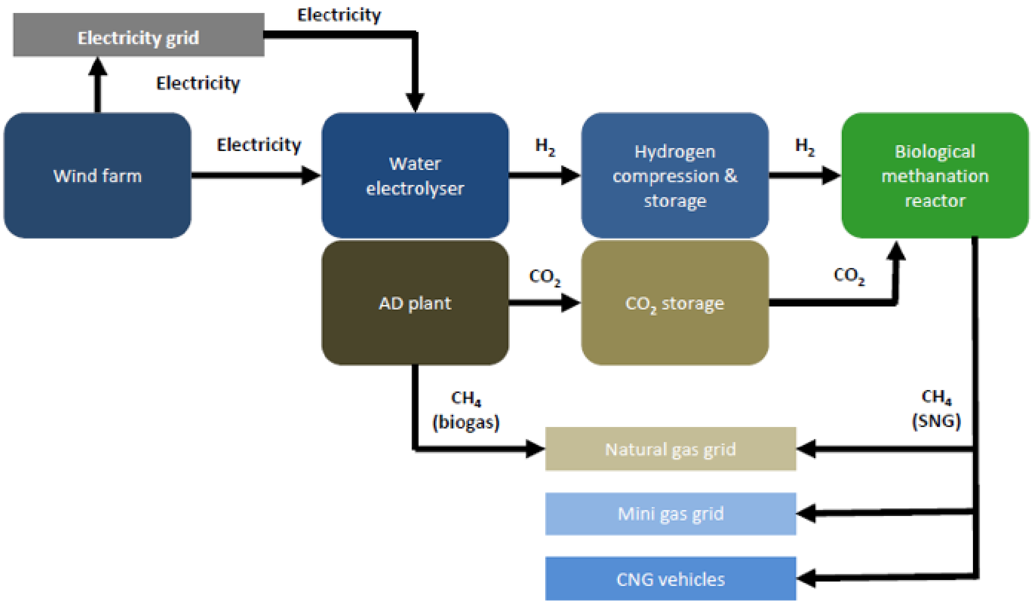
To-date, there has been limited activity in the field power-to-gas with methanation around Europe. A selection of currently operating plants are highlighted in the Figure.

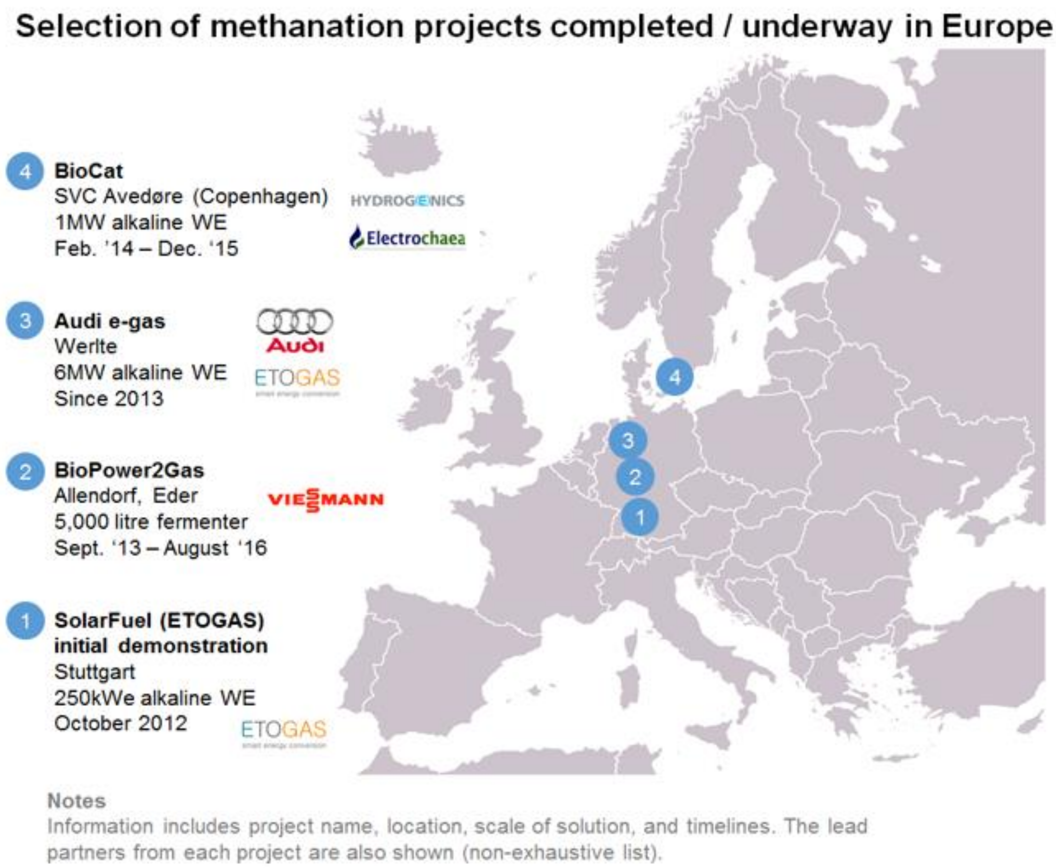
The economics of the power-to-gas with methanation are very challenging. The water electrolysis capex and opex costs are significant and the costs of the relatively novel methanation process are currently also considerable. At current capex and opex, the SNG is not able to compete with natural gas costs. Significant capital cost reductions and a very

[29]http://www2.nationalgrid.com/UK/Our-company/Innovation/Gas-distribution-innovation/NIC-Projects/BioSNG-Process-Diagram/

low cost source of electricity (potentially consistent with constrained renewable generation) will be required for the SNG to become competitive.

Injection issues are likely to be similar to biomethane. The location of the plant will be dictated by the sources of H_2 and CO_2 and in turn dictate the point of injection (LTS/IP likely to avoid compression costs)



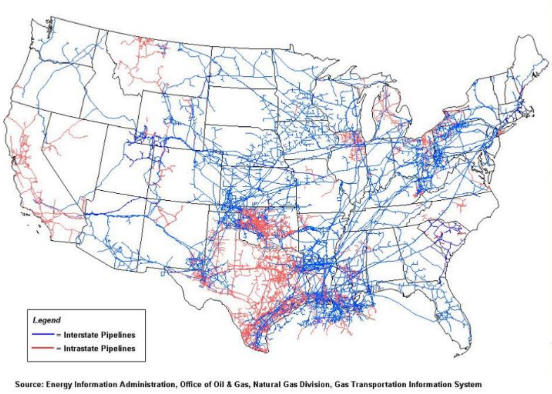


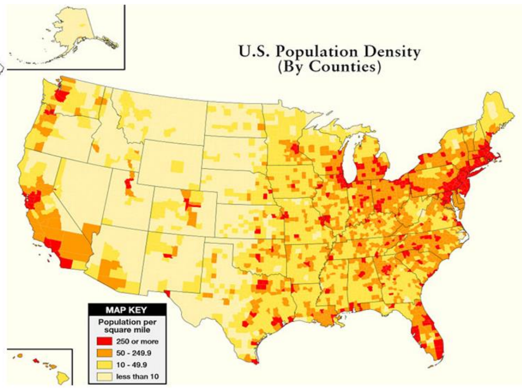
Coalbed Methane

The US and Australia are the two largest developers of coalbed methane.

CBM in the USA

The US is characterised by large gas developments often sited away from the largest gas consumers. **The total length of the American high pressure gas Network is 1,984,000km; 6.2m of pipeline per person**. Pipelines take gas from the production zones in the centre of the country to consumers in the northeast. They also link to export terminals in the Gulf of Mexico.



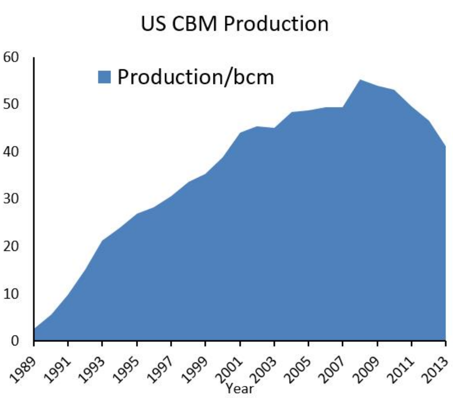


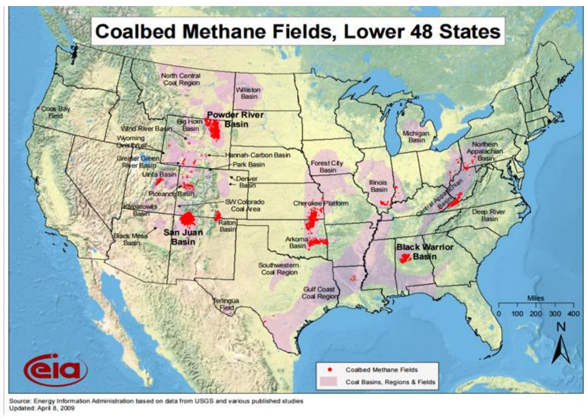
CBM was encouraged in the US in the early 90s. Prior to CBM reaching maturity, federal interventions such as tax credits encouraged the development of unconventional fuels with nearly 6,000 wells completed by 1994.

Access to existing infrastructure and deregulated energy markets facilitated rapid growth through the 1990s.

CBM proved reserves peaked in 2008 and one year later production peaked.

The outlook for CBM in the US is positive: they have rising gas prices, (comparatively heavy) pressure from carbon credits on the coal and oil industries, and depleted conventional gas resources and energy independence is a prominent political issue.





<u>CBM development example: the San Juan basin (The US's most prolific CBM development)</u>

The San Juan basin is sited across New Mexico and Colorado. It spans approximately 7,500 square miles and is the most prolific CBM basin in the US. CBM from this area supplied 4% of total U.S. natural gas demand in 2000.

The U.S. Geological Survey estimated (2002) a mean of 50.6 trillion cubic feet of undiscovered natural gas, 19 million barrels of undiscovered oil across the San Juan Province. The area was exploited for oil extraction since before the 1940s, but CBM production didn't flourish until the 1990s thanks to Federal tax credits.

The basin can produce over 50 million cubic metres/day of CBM from more than 3,500 wells. Wells in the area can reach peak production rate between tens of thousands (X0,000) to hundreds of thousands (X00,000) of cubic metres/day.

The basin is served by large capacity natural gas pipelines. One of the largest pipelines in the area can transport up to 176 bm^3 per day from production areas located in western Texas and San Juan Basin.

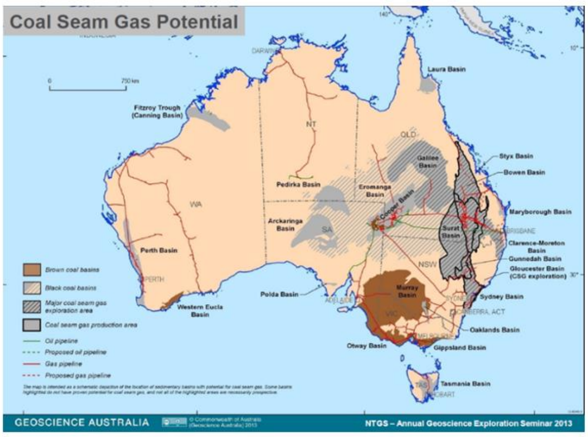
CBM production has fallen since 2006 (at an annualized trend-line rate close to 4.6%). NGI (a specialty sector analyst firm) attributes this to a lack of new drillings in the area and greater focus on new oil focused rigs.

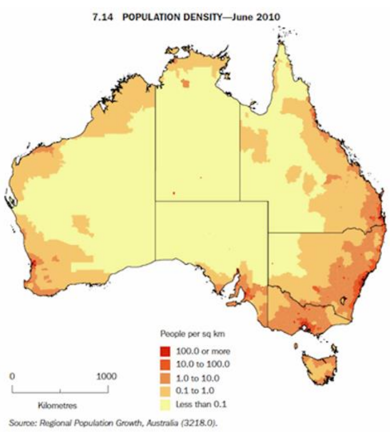
CMB in Australia

Australia has large scale, remote gas production, with extensive pipelines linking production to exports and consumers.

In Australia the high pressure pipeline length is 30,000km; 1.3m per person. As illustrated, the gas pipelines are built to serve the gas producers, and provide a link from remote production areas to urban centres. Additionally, the pipelines serve to link producers to export gates.

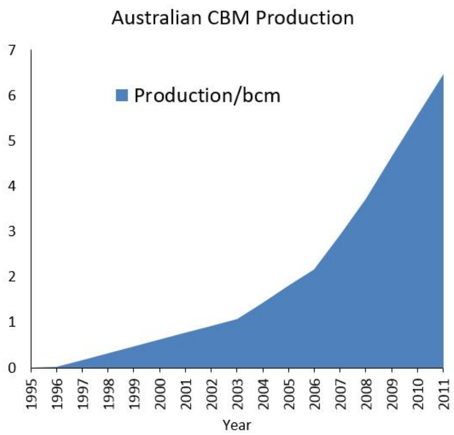
This compares to the UK NTS: 12,000km; 0.2m per person. In the USA and Australia onshore production takes place far from consumers and on a huge scale, so the grids are extended to reach producers.

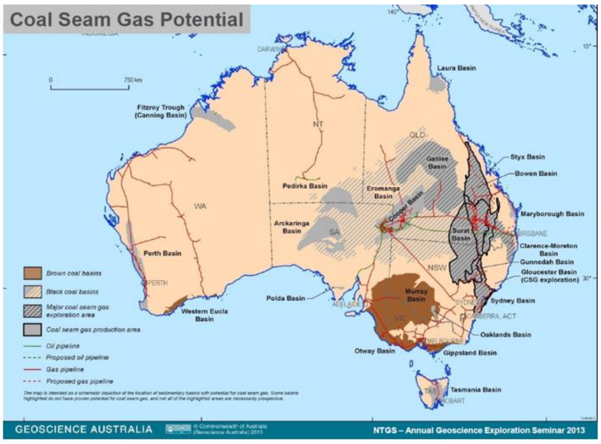




In contrast to the fiscal incentives in the US, the Australian CBM industry was driven by power generation and environmental incentives: rising energy demand, and attempts to switch from coal to gas, halving CO_2 emissions per unit energy.

The above drivers continue to be important, and Australia has large unexplored reserves. Moreover, the Australian export market is increasing in size and new LNG pipelines have been constructed to facilitate transportation to ports. Therefore, the outlook for Australian CBM may be very positive depending on foreign markets.





CBM production phases

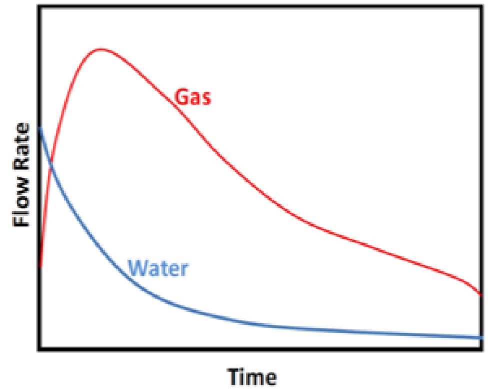
Pilot wells phase - general considerations based on the US and Australian experience

- Multi-well pilots are used to assess the potential (productivity and full-field development) issues of a CBM deposit with more certainty following initial surveys and drilling tests.
- The size of the pilot depends on the specific geological properties of the deposit. Generally speaking, pilots are both sufficiently large to allow for a representative estimate and sufficiently small to produce results in short times.
- Pilot developments typically consist of several closely spaced wells. Past projects suggest that the **number of pilot wells can be anywhere from a few units to a few tens of units per pilot** with **peak gas production volumes ranging from a few hundred (X00) to a few tens of thousands (X0,000) of cubic feet per day per well**. Pilots in very promising areas had wells producing a few million cubic feet per day.
- Pilot wells typically need to **produce for a minimum of 6 to 12 months to a few years** to demonstrate a promising development.
- The number of pilot wells can be expanded and/or their operation prolonged should the pilot demonstrate increasing but still uneconomic gas production rates. Staged approaches based on progressively expanding trials proved cost effective over the time taken to evaluate a CBM deposit.
- Multiple pilots may be required should the geologic properties of a same geographic area vary.
- Pilot wells may exhibit production ramp-up and decline rates as per commercial wells.

Commercial exploitation phase – general considerations based on the US experience

- **CBM wells produce low pressure gas (typically <1bar) which is usually compressed on-site (typically to >4 bar) and channelled into a local gathering pipeline system** connecting several tens to hundreds of wells together.
- The gas is transported to a central compression station and further compressed (to between 20 bar and 80 bar) before entering the regional or national transmission system. Compression before sale can be performed by site operators or third parties.
- Commercial developments may count several hundreds to thousands wells per exploited area.

- Wells can produce for between five and 15 years. Production rates per well depend on their distribution across the geological formation and spacing.
- Optimal wells reach their peak production capacity quite quickly (e.g. after one to six months of water removal) and then steadily decline over time (typically from less than 5% to more than 20% per year). Other wells may reach their peak capacity only after two to four years, making it difficult to predict decline rates.



Typical gas and water production profile for a CBM well (US EPA)

Gas grid connection and management

CBM (and conventional gas sources) have achieved such a scale in Australia that the transmission system comes to them. New pipelines are under construction to this date.

Typically, the gas is produced and then processed (to meet quality requirements) before it is sold to user parties. The transmission sector then pumps its gas to 'city gates' where the pressure is lowered (to lower than 10bar).

Expansion of CBM has given rise to the development of several processing plants around the production centres. This upstream processing infrastructure has been highlighted by stakeholders as a critical part of supply response and the two major Eastern processing plants have undergone considerable expansion in recent years.

At peak demand, pipelines may become congested. This is not a major problem **and network capacity trading policies reduce the risk associated with congestion**.

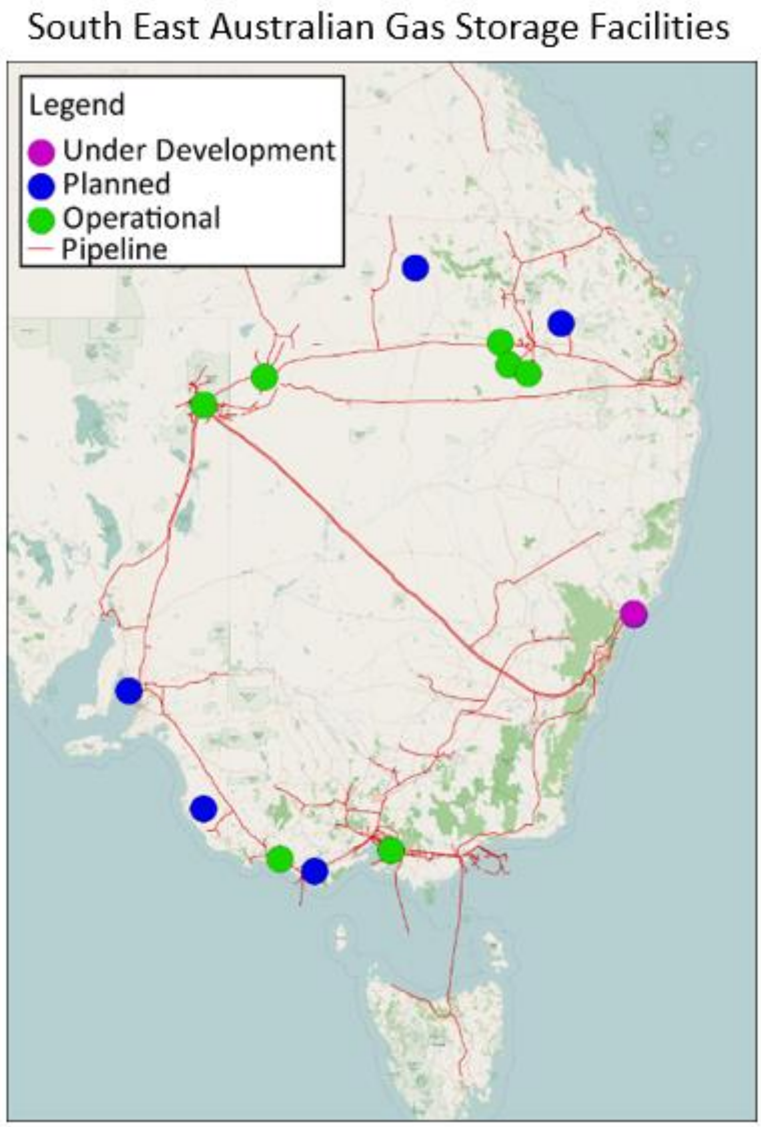
<u>Storage</u>

Storage is playing an increasingly prominent role in the development of the Australian grid. Producers are able to maintain a constant production profile – unhindered by demand fluctuations. Furthermore, storage facilities in close proximity to consumers enable distributors to adjust to demand changes and minimise risks of spikes in demand. **Strategies include line packing, re-injection into depleted fields, and small plants that temporarily convert gas to LNG**.

The Newcastle storage facility is an example of LNG storage and is scheduled to become operational imminently.

In order to supply gas fired power plants that back up renewable power generation, ensure security during peak demand and periods of supply disruption, the **facility can store approximately two weeks' worth of gas** (0.4 TWh) for the region. According to the developer, AGL, the facility will “develop critical energy infrastructure that… supports the emerging CSG industry in the Hunter and Gloucester regions”

Gas is liquefied by cooling to 111K. To facilitate the station, a 5.5km pipeline links the facility to a receiving station on the NTS. The estimated capital costs of the facility were £150 million.



Transferrable lessons from the USA and Australia

- Based on the US and Australia **we expect CBM pilots to produce low pressure gas** therefore, gas from pilots is **likely** to:
    - **Be injected to the LTS or low pressure networks to avoid compression costs or;**
    - **Not be injected at all**[30].
- In commercial phases flow rates from individual wells may be low compared to shale, but gas may be collected and injected on a larger scale, combining the produce of many

[30] Furthermore, in the NG’s FES, CBM is not anticipated to inject into the grid. They expect any CBM produced to be used for on site power generation.

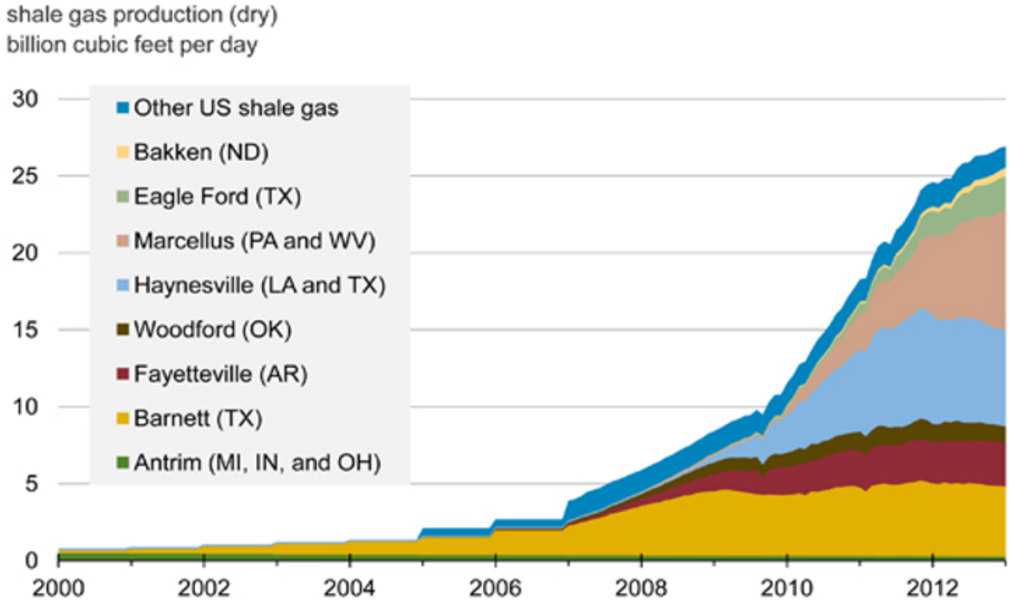
wells. This will require capacity at the injection point hence, **for big commercial developments, CBM injection into the NTS is more likely**.

- If large scale production of unconventional natural gas takes off, then storage on the NTS will become more useful: near production zones, and near population centres. The storage can be particularly useful to support renewables and provide supply security at times of peak demand.

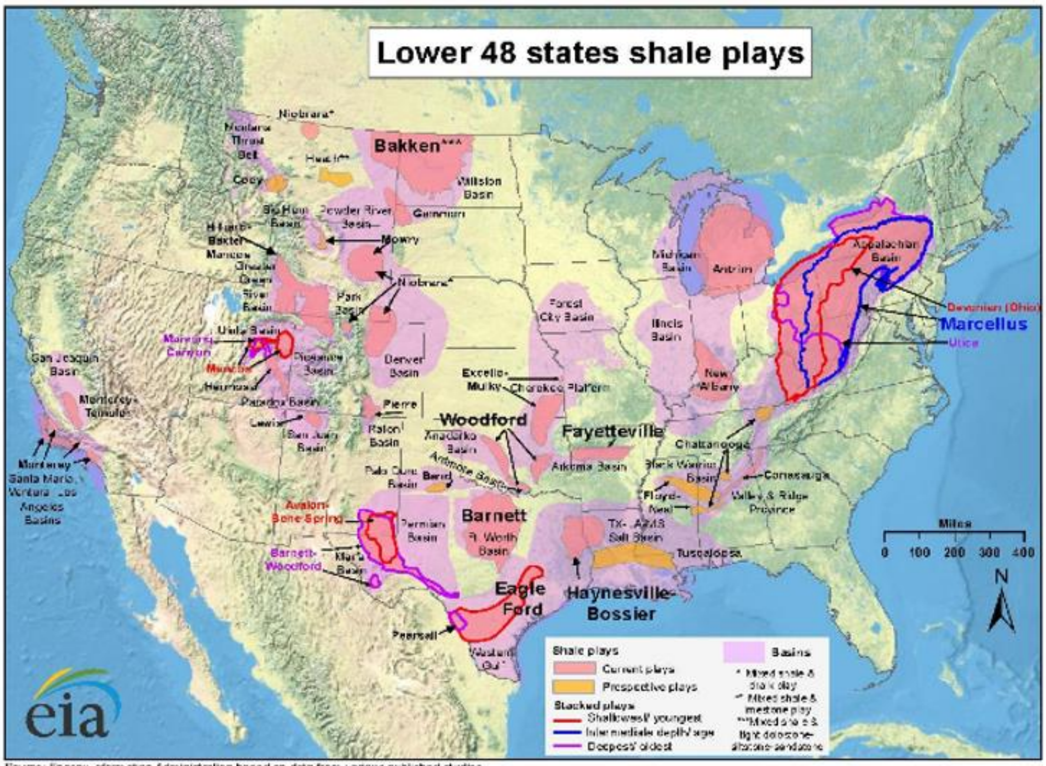
Shale Gas

Overview of the US shale gas revolution

- In 2013, shale accounted for 44% of US gas demand.
- The 'revolution' in shale gas occurred over the last 25 years, however, the most significant growth took place since the mid 2000s.
- US policy created excellent conditions for the shale industry, e.g. government tax credits accounting to 50 cents per million BTU and the Intangible Drilling Cost Expensing Rule (often financing at least 70% of capital costs for wells).
- The 'Haliburton Loophole' removed some environmental regulations from the path of development.
- Private land owners had rights to shale gas, reducing local opposition.
- The energy service industry in the US was highly competitive with many small companies working.
- High gas prices increased the economically recoverable resource – less profitable resources (e.g. those harder to process or connect to supply lines) became viable.



Sources: LCI Energy Insight gross withdrawal estimates as of January 2013 and converted to dry production estimates with EIA-calculated average gross-to-dry shrinkage factors by state and/or shale play.

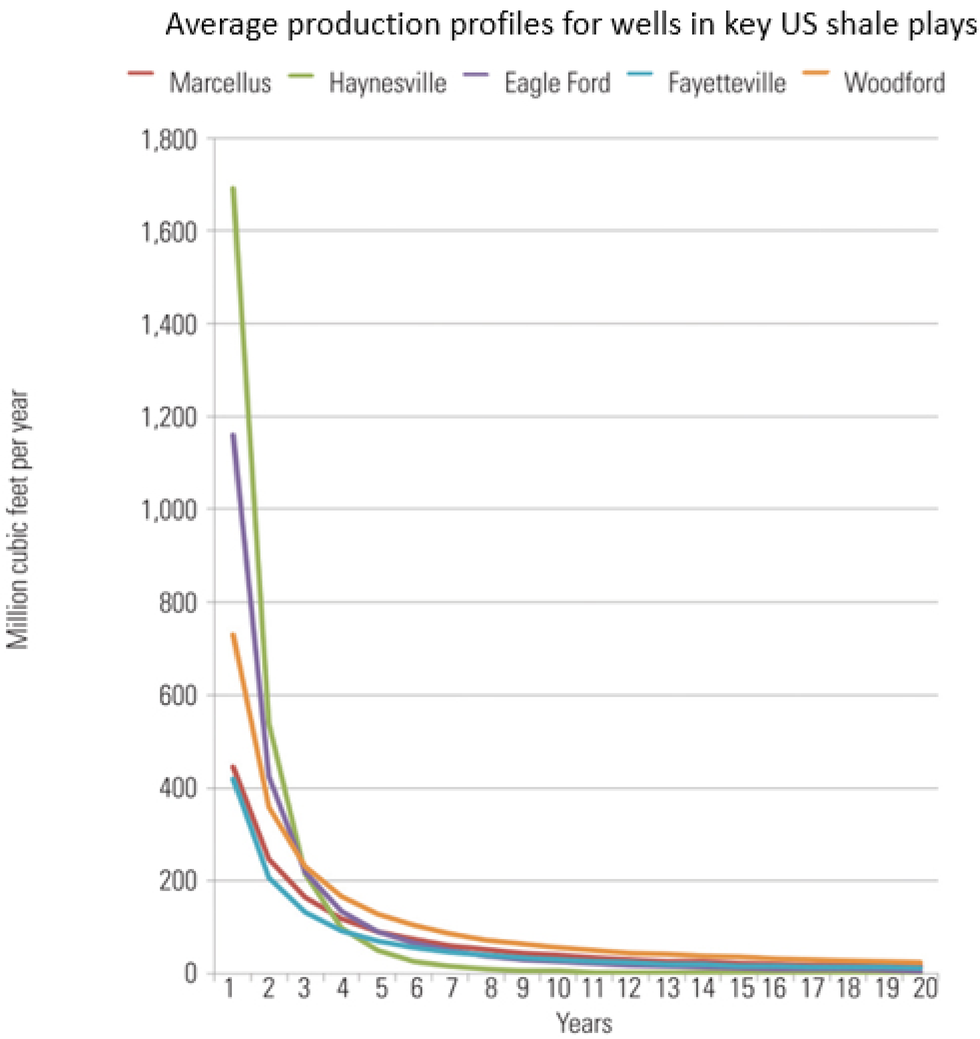


Source: Energy Information Administration based on data from various published studies
Updated: May 9, 2011

Shale gas production phases

<u>Pilot well phase</u>

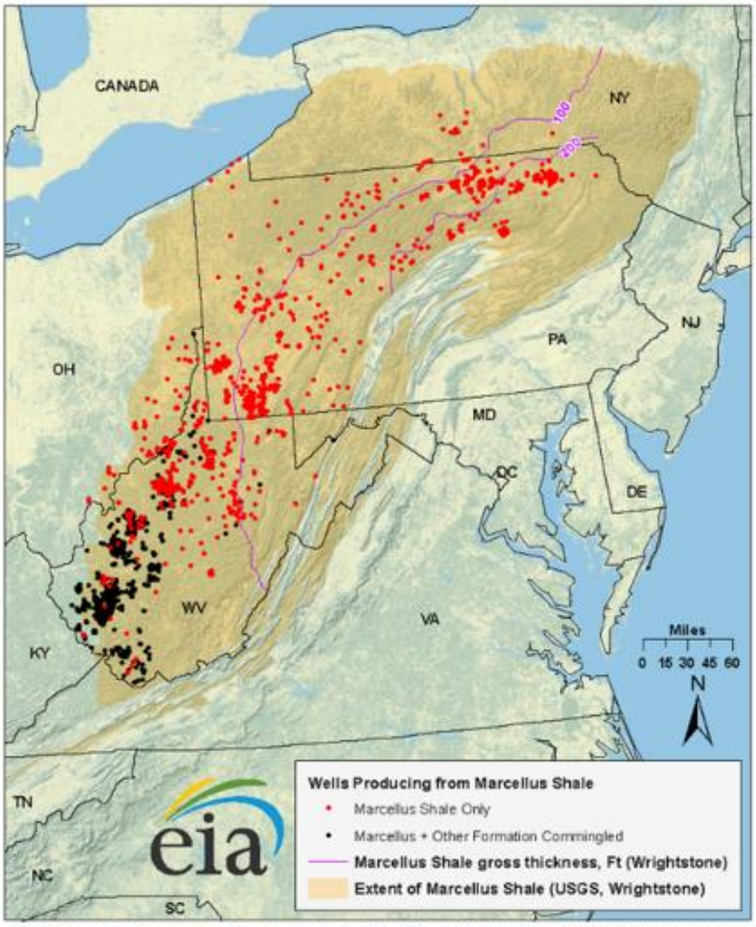
- Two or three exploratory wells are drilled to identify sweet spots of shale gas. Once a sweet spot is located the appraisal phase begins: **13 to 30 wells are drilled around the area in order to produce gas to assess the technical and commercial viability of the area**.
- **Appraisal can last for 9 months** in which gas is produced continuously – **typically the produced gas will be flared**.
- In the United States, infrastructure (including treatment and transportation) is constructed during ramp up, following appraisal.
- As the project ramps up, hundreds of wells are drilled.



Commercial Exploitation Phase

- **Initially, compression is not necessary with extraction pressures on the order of 70bar**.
- **Production rates and extraction pressure drop off quickly over the first year** of production.
- Due to the rapid decline of production from a well, to maintain a flat production profile, more **wells must be drilled consistently each year**, successful plays in the US consist of hundreds to tens of thousands of wells.
- Following production, the gas is taken via pipeline to a treatment centre where excess CO_2 and N_2 are removed, natural gas liquids are removed and the gas is compressed and injected into the grid.

Marcellus Shale Gas Play, Appalachian Basin



Source: US Energy Information Administration based on data from WVGES, PA DCNR, OH DGS, NY DEC, VA DMME, USGS, Wrightstone (2009). Only wells completed after 1-1-2003 are shown. Updated June 1, 2011

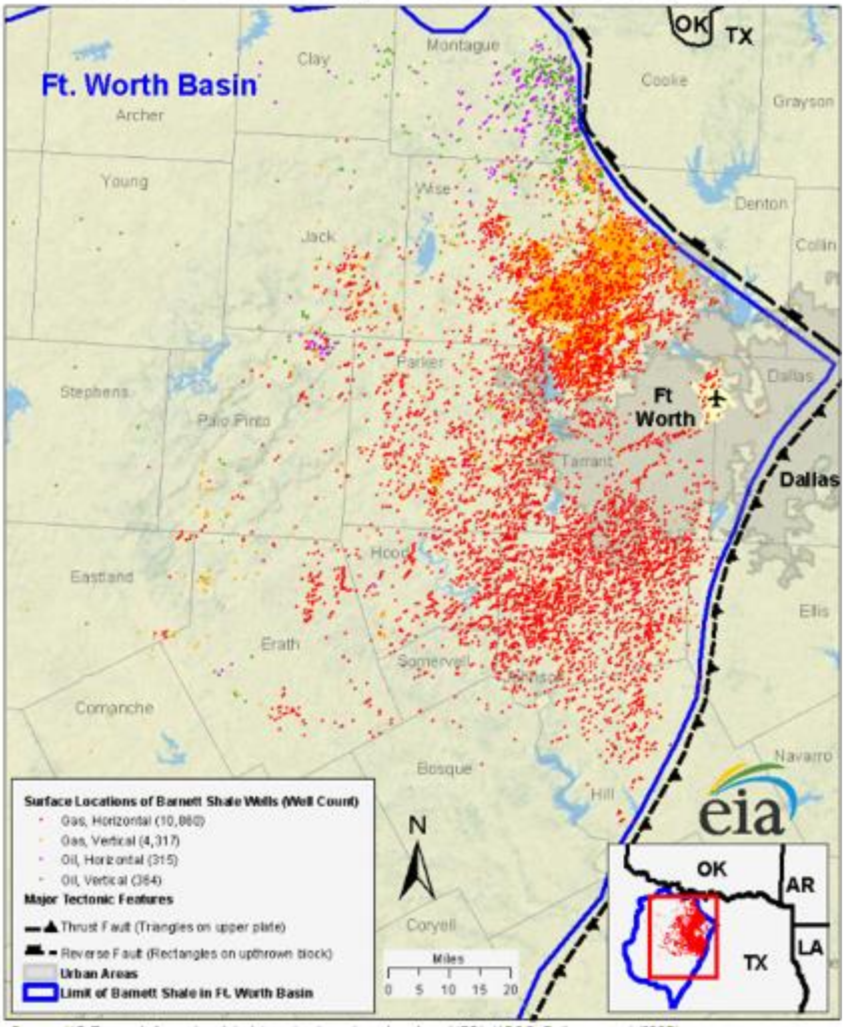
Shale gas development examples

<u>The Barnett Shale, the Grandfather of Shale Plays</u>

Much of US shale technology was developed when exploiting the Barnett Shale. Over the 2000s the annual production increased from negligible amounts to 42.5bcm. To keep up, the processing industry grew rapidly: some plants are able to process 30MMm^3/day. **As of 2012 the field had over 16,000 producing wells**.

Most plants remove CO_2, provide compression, separation and fractionation. For every mscf of gas, 3.5 gallons of natural gas liquids are produced. Gas quality varies across the play, with some wells exhibiting N_2 content above 7% (that would require removal). Rather than removing the nitrogen, the gas is blended with gas from other wells as a more economic solution.

Barnett Shale Play, Fort Worth Basin, Texas



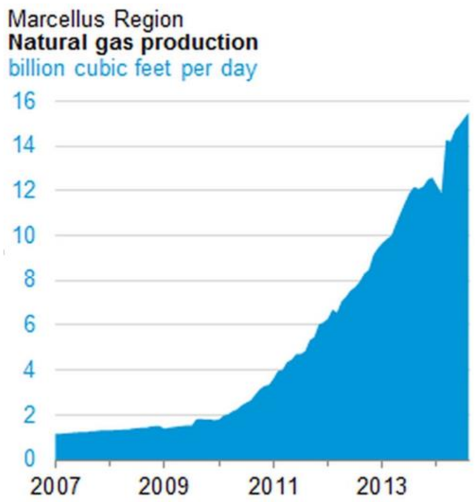
Source: US Energy Information Administration based on data from HPDI, USGS, Pollastro et al (2007)
Updated: May 31, 2011

<u>The Marcellus Shale</u>

The Marcellus shale was explored during the 1980s, and it was clear that it contained vast quantities of gas. However, at the low gas prices of the time and the undeveloped technology, the gas was not economically recoverable. Production took off after Range drilled a producing well in 2005, utilising processes developed in the Barnett Shale. Three more experimental wells were drilled by the end of the year.

Five years later (2010) 1,446 Marcellus wells were drilled in the Marcellus shale. Leasing prices reflected the success of the shale: between February and April 2008 lease prices went from \$300/acre to \$2,100/acre. Horizontally drilled wells appear to be producing at a rate of more than double vertical wells, and at a marginally lower cost.

At present, the Marcellus play produces 153 bm^3/year: around twice the annual gas consumption of Germany (approximately 81 bm^3/year).



Transferrable lessons from the US

- The US shale industry has grown extremely rapidly, but **there were many favourable conditions for shale in the US that are unparalleled in the UK today**.
- **High initial production rates and extraction pressures make injection of shale into the NTS likely**. Both decline rapidly, so compression is required at later stages.
- Gas properties and productivity vary across and within plays: CV can vary, and there may be a range of requirements for gas treatment.
- Large scale shale sites are advantageous: they benefit from economies of scale and if many wells are available, gas blending can provide a cheap alternative to removal of inert gasses.

Key conclusions

Biomethane

- In The Netherlands and Germany biomethane is usually injected into low pressure systems.
- Biomethane injection has risked exceeding demand in places.
- **Solutions to such issues range from smart grids that regulate pressure to create capacity in low pressure tiers; balancing biomethane sources with new customers (CNG filling stations and CHP plants); and upstream gas compression**.

CBM

- **CBM pilots have low pressure and low flow rates**, so may be injected into the LTS or not injected at all.
- In commercial phases, it is likely that the scale of production will make NTS injection more appealing with many CBM wells feeding into a collection pipeline. However, the National Grid Future Energy Scenarios report has indicated they do not anticipate any UK injection of CBM, and expect any CBM produced to be used for on-site power generation.
- Experience in Australia shows that natural gas storage near population centres may be useful for large scale unconventional gas production.

Shale gas

- **High pressure in shale gas pilots and high production volumes makes the NTS a likely option for injection**.
- Large scale production of shale is very advantageous. So, if they can get planning permission and overcome any technical barriers, UK projects may inject considerable volumes of gas.

Appendix 3 - REA list of differences to specifications between GDNs

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Biogas

Renewable Energy Association

Biomethane Injection to Gas Grid

Policy Differences

No names are used, just description of the issues

General Comment

The Biomethane to Grid industry has grown very quickly from 1 project in 2012, 2 in 2013 to around 25 in 2014 and 2015. A key issue during this time has been the absence of the ability to lock-in to the RHI tariff which has driven the requirement for shorter lead times. This has meant it has not been easy to take the time to review policies and make changes and as a result there has been significant divergence from the EMIB outcome of 2012. In practice, GEU costs have increased as GDNs have added additional requirements.

With lower RHI tariffs and the potential for tariff lock-in, it is a good time to review the details of the policies with the aim of implementing single model from 2017 with consequent lower costs.

1. Grid Entry Unit Design

- BNEF - Functional Specification V5.6 (14-05-2012) agreed as part of EMIB has been largely overtaken by GDN's deciding to implement different functionality and p0rovide additional details without any industry consultation.
- One GDN has fundamentally different control system with a separate PC controlling the Remotely Operable Valve (ROV), adds around £50K. Means GEU specific to that GDN and its a more complex system
- All the GDN's have various functional specifications that have an effect on cost e.g. requirement for ROV bypass valve (or not), RTU functionality.
    - One GDN has recently withdrawn their functional requirement specification making compliance from kiosk manufacturers difficult. Vagueness of some specifications take additional hidden time and resources to sort out after contract award. e.g. a GDN fundamentally changed their RTU functionality recently mid kiosk design.
- One GDN requires additional fast acting gas analysis equipment, hence additional costs
- One GDN requires pressure to be measured and tyransmitted downstream of the ROV
- One GDN will **not** allow any flow with an ROV bypass, one GDN will not allow any flow unless there is an ROV bypass.
- One GDN insists on taking ownership of the Odorant system and wants this in a separate compartment so the GEU design is specific to that GDN

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Renewable Energy Association

    - This leads to different testing regime for odorant system and significantly more complexity
- One GDN requires a different specification for valves that the others (high specification V6 valves for 7 bar)
- One GDN has a different pipework spec for 7 bar
- One GDN specifies the electricity supply to the ROV/RTU
- GDN's have different requirements and processes for back up communications and HPMIS (GMIST) data transfer.

2. Metering Calibration

- Two GDN requires a rotary meter to be calibrated on natural gas (expensive), two are ok with N2.

3. Gas Quality Analysis

- One GDN requires daily calibration of O2 and H2S monitors, irrespective of risk assessment.

4. Design Assurance

- Three GDNs require a G17 type approval and appraisal with 3 levels:
    - Designer
    - Approver (from specified list)
    - Appraiser (from specified list)
- One GDN requires 2 level appraisal (GL/5) on ROV/RTU only
- One GDN also carries out an additional review of the Appraised Design using an outside Design House
- One GDN requires an Appraisal of the Hazop carried out on the ROV/RTU design
- G/17 and GL/5 approach different for each GDN in addition to the points already noted.
- One GDN has replaced G/17 with another suite of documents (PS/5 and PS/6)

5. Costs in Connection Quotation

- Lowest cost £15-£20K
- Highest cost £90K

6. Project Timetable

- Two GDNs require all G17 to be completed prior to End to End (E2E) test
- One GDN requires 2 weeks from E2E to grid injection
- One GDN insists on carrying out the activities using linear approach with limited flexibility to change the process when circumstances change
- One GDN insists on having a deep level of technical information for items upstream of their adopted equipment and upstream of the GEU, which adds to costs and project time

7. Biogas and Biomethane Testing

- One GDN requires one biogas sample and 3 biomethane samples prior to flow to grid

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- One GDN requires just one biomethane sample

8. Commissioning

- All the GDN's have different requirements for testing and witnessing various activities. e.g. FAT, SAT, ME/2, ISO10723, End to End tests, etc.
- NRO requirements differ across the GDN's

9. LTS Connections

- One GDN allows LTS connections to be carried out using the Self-lay process for >7 bar and there have been 7 LTS projects in the past 18 months in that GDN area using this model
- No other GDN allows this approach which means that many biomethane projects with the LTS option have not been able to proceed due to cost and time

10. General Comments

- FWACV Daninit software is outdated (based on 1996 programme, 32 bit computers) and the Letter of Direction rules are not fit for purpose
    - Very limited industry knowledge of the Danint software, apparent reliance on one person in the UK
- The Danalyser (that has been used since 1996) appears to be towards the end of its life with technical issues arising and multiple failures of calibration accuracy
- The G17 process makes it expensive and time consuming to make any changes and this acts to stop innovation
- There is a lot of gas quality knowledge now and the risk analysis for gas quality (GQ/8) monitoring could be done without spending a day in review unless a new feedstock is used.

11. Proposed Way Forward

The REA Proposes that it sets out a proposal in all the areas above and asks the GDNs to respond, to agree or disagree. But the key is for the GDN to provide a written explanation that can be discussed.

For example, REA may propose ROV bypass with small rider pipework for pressurisation. The GDNs that insist on no bypass or full bore bypass can respond and provide their explanation. After discussion, aim would be to reach a consensus. This can be repeated in all above areas.

The aim of the exercise will be to reduce costs and complexity whilst ensuring safety is maintained and there remains compliance with Ofgem energy measurement requirements.

Date: 08/03/2016