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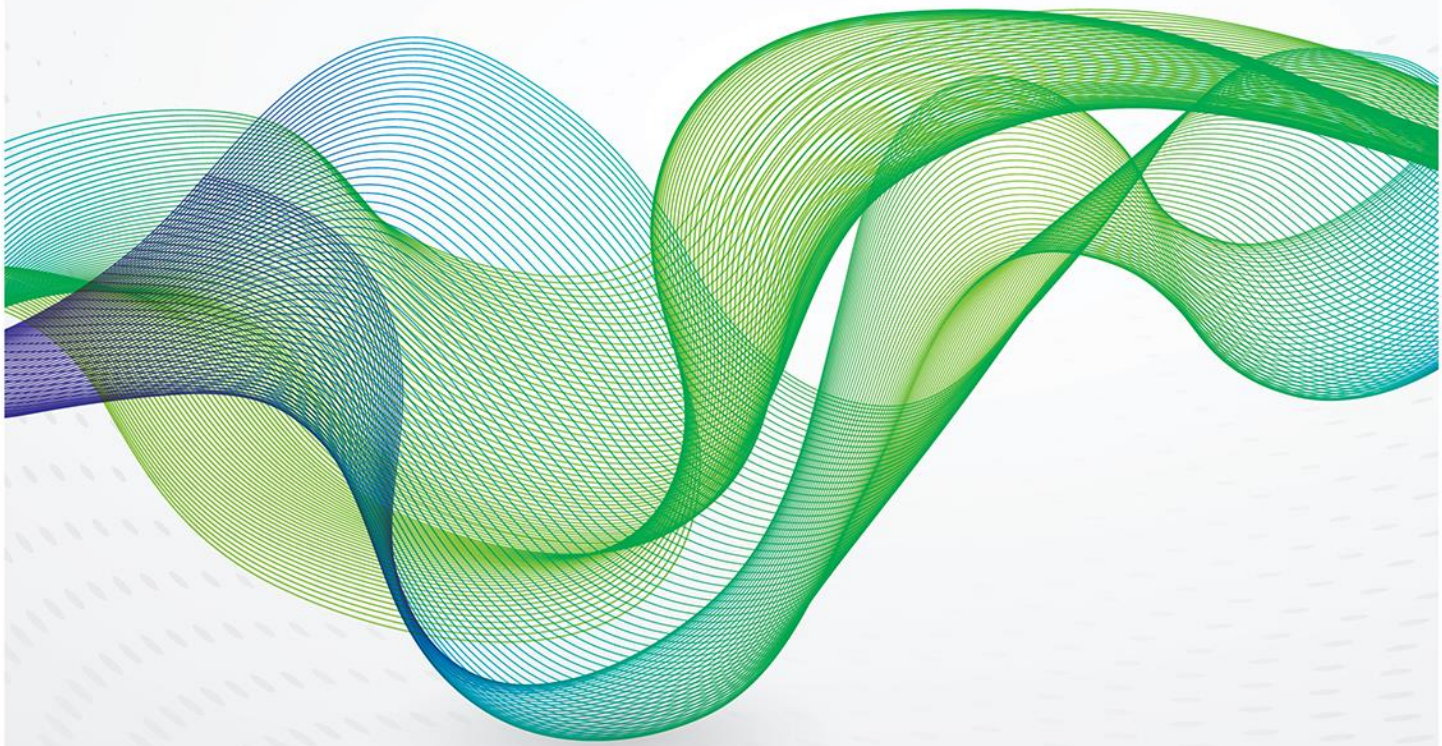
The Future of Gas in Decarbonising European Energy Markets:
the need for a new approach



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Preface

The future of gas in the energy mix is a topic of obvious interest to the Natural Gas Programme at OIES, but we believe that it is particularly relevant given that expectations about its role in Europe have been confounded over the past decade. The argument that gas is the cleanest fossil fuel and should at least displace coal in the energy mix, especially in the power sector, has had little if any traction with policy-makers in spite of the apparent boost to the fuel's prospects provided by the COP21 agreement in December. In fact over the past decade gas's share of the European energy mix has declined sharply in the face of a rise in renewable energy, while coal demand has remained remarkably robust.

A number of factors have contributed to this outcome. A low coal price, combined with an ineffective carbon price, has undermined the economics of gas-fired power generation; the importance of the coal industry as an important source of employment in a number of key European countries has discouraged attempts to reduce demand for it; concerns over methane leakage in the gas chain, as well as the debate over the exploitation of shale gas using fracked wells, have raised environmental concerns; and finally security of supply issues have been raised due to the perception of an over-dependence on Russian gas in the European market, in particular in light of the continuing crisis in Russia-Ukraine relations. Overall then, the potential benefits of gas as an energy source which can reduce short term CO2 emissions and complement the intermittency of wind and solar power have failed to gain acceptance from a variety of environmental, energy and political stakeholders.

In this paper Jonathan Stern reviews in detail the problems which gas continues to face in Europe, and also highlights the potential impact on all parts of the gas value chain. Indeed he suggests that it is the fragmentation of the gas industry, and the different incentives within each sector, which is partly to blame for the lack of a coherent message from the industry as a whole. His conclusion is a radical one, namely that in order to have a long-term future the gas industry needs to develop a de-carbonisation strategy. Furthermore, it needs to do it fast, because policy decisions made in the next few years will determine whether gas has a promising or declining outlook in Europe beyond 2030.

The paper is deliberately Euro-centric, because this is the region where gas appears under greatest threat. Nevertheless, Stern acknowledges that different regions will have different outcomes, and it does appear, for example, that in Asia the potential for demand growth is significant. However, the European example can provide a salutary lesson concerning the mistakes that can be made by an industry that is convinced by a logic which fails to persuade a wider stakeholder community. The challenges in China and India, in particular the threat from cheap coal, are not so dissimilar, and the outlook for gas there remains uncertain.

As a result, conclusions reached from the European example can provide useful pointers for the global gas market. The Natural Gas Programme at OIES will be exploring these in greater detail, both in a European and a global context, over the next months and years, as we embark on a research programme specifically focussed on the main demand, supply, environmental, commercial and geo-political issues which relate to the future of gas in the global energy mix. This paper lays the foundation for that work, and also hopes to catalyse significant debate amongst all those interested in the role of gas in a decarbonising world.

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Acknowledgements

My grateful thanks to colleagues at OIES for their comments and help with additional material and sources especially: Chris Le Fevre, James Henderson, Anouk Honoré, Malcolm Keay and Howard Rogers. I would also like to thank the participants at the October 2016 OIES sponsors' meeting for providing valuable comments and suggestions on an earlier draft. John Elkins provided his usual excellent editing suggestions and Kate Teasdale did everything else with her customary efficiency.

Perhaps more than for most publications I should stress that the views expressed, and any mistakes which remain, are solely my responsibility.

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Executive Summary

The European gas community has argued that it can play a major role in the transition to decarbonised energy markets because of the advantages of switching from coal to gas, and the role of gas in backing up intermittent renewable power generation. While this remains a logical approach for some countries, in others it has proved either not relevant, or generally unsuccessful in gaining acceptance with either policymakers or the environmental community. This has left gas in a position of continuing to be labelled a fossil fuel, where its carbon-related advantages over other fossil fuels are viewed in the longer term (2030-50) as, at best, questionable. It is not necessary to accept the credibility of carbon reduction targets and timetables that governments have set themselves post-COP21, to recognise that decarbonisation of European energy markets is ongoing and unstoppable. The key variables which will determine the long-term future of gas in Europe will be policy and technology, as well as economics – defined as the price of gas in relation to the costs and prices of other sources of energy, impacted by policy measures such as carbon pricing.

To ensure a post-2030 future in European energy balances, the gas community will be obliged to adopt a new message: `Gas can Decarbonise' (and remain competitive with other low/zero carbon energy supplies). In this context, there are several potentially different (but related) futures for the groups of companies in the gas value chain:

- commodity producers and exporters may either have to take the initiative on decarbonisation, or run the risk that governments and other value chain stakeholders may decide to pursue non-methane-related options;
- if non-methane-related options are adopted, owners of gas-fired power stations, LNG regasification terminals, and storages will run the risk that their assets will be stranded before they reach the end of their useful lives;
- failure to decarbonise is likely to mean that the gas business of wholesale and retail gas suppliers and traders will decline, but they will be able to reorient their business(es) towards electricity;
- owners of transmission and distribution networks can have different futures depending on decisions taken regarding the decarbonisation of the commodity and the use of the assets. Networks serving different regions may have different futures, depending on decisions to switch to hydrogen (whether produced from gas or renewables), biogas or biomethane. But if decarbonisation follows a path of electrification or district heating based on renewables, gas networks could be stranded.

The European gas community suffers from mismatches of commercial interests and time frames along the value chain; and mismatches between the time horizons of commercial decisions and government decarbonisation policies. The latter may result in policy decisions being taken in the next 5-10 years which will irreversibly impact the future of gas in the period 2030-50. A paradigm shift in commercial time horizons and gas value chain cooperation will be necessary for the industry to embrace decarbonisation technologies (such as carbon capture and storage), which will eventually be necessary if gas is to prolong its future in European energy markets.

The European gas community must adopt a new approach to its future in decarbonising energy markets. Specifically, it needs to devise and implement a strategy which will lead to the decarbonisation of methane starting no later than 2030. Failure to do so will be to accept a future of decline, albeit on a scale of decades, and to risk that by the time the community engages with decarbonisation, non-methane policy options will have been adopted which will make that decline irreversible.

Introduction

This paper examines the future of gas in the period up to 2050 and beyond, in the light of European government commitments to decarbonise energy balances and move away from fossil fuels. Its focus is on changes that will be needed if gas is to prolong its future in decarbonising European energy markets.[1] The approach taken by this paper is somewhat different to that of other literature where projections of gas demand, or the meeting of carbon reduction targets, are the main goals of the analysis. The aim is not to advocate the use of gas over other fuels, but rather to analyse circumstances in which gas could have a longer term future in decarbonising energy balances. The paper concentrates on three issues:

- the reasons for the decline of gas in European energy balances over the past decade;
- why policymakers and other key stakeholders remain to be convinced by the proposition that gas can (and should) play a key role in decarbonising energy markets;
- the general approach the gas industry will need to adopt, in terms of messages it will need to give to policymakers, and actions it will need to take, in order to prolong its future in decarbonising energy balances.

The focus of the paper is the future of gas *in Europe* with a brief consideration as to whether the trends identified in Europe may have wider geographical application.

This is a short `scoping', rather than a comprehensive research paper (although it is based on the conclusions of research published by the OIES Gas Programme and others) which deals with a very large subject. The conclusions are intended to indicate issue areas crucial to the future of gas in Europe (and elsewhere), and to provide a context for future OIES Gas Programme research.

The paper is structured in four sections: it first considers the reasons for the decline of gas demand in Europe over the past decade. The second section looks at five problem areas for the gas industry in the 2010s. The third section takes a brief look at decarbonisation issues for gas outside Europe. The fourth section draws some conclusions on: mistakes that the industry has made in its advocacy arguments; changes in messages and actions which will be needed if gas is to have a longer term future; and the possibility of different futures for different groups in the gas value chain.

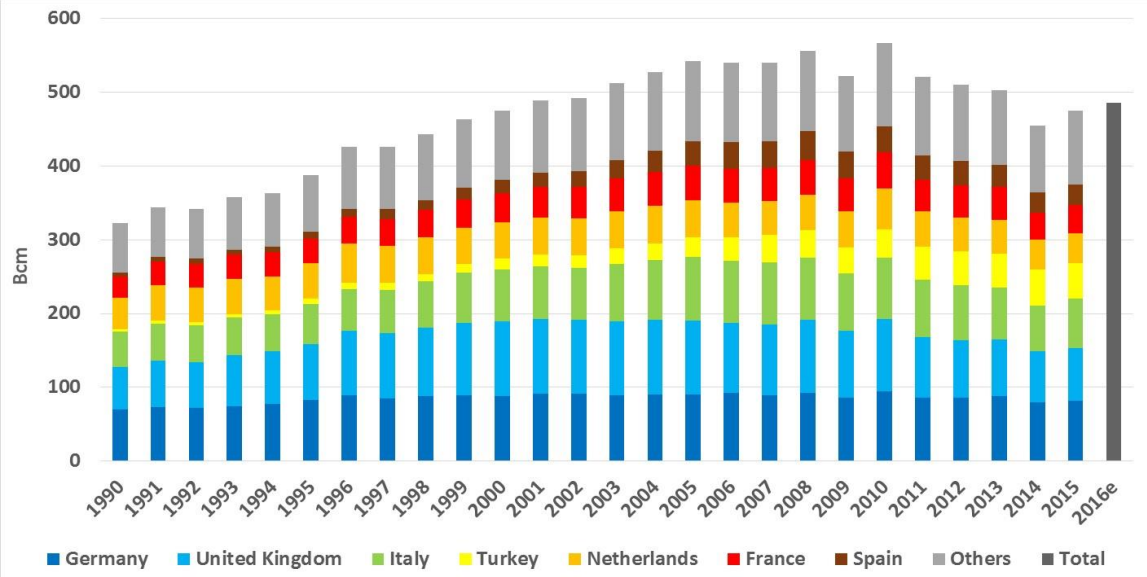
European Gas post 2005 – a gradual worsening of the demand outlook

In the mid-2000s, the European gas market reached the end of a 40 year period of almost continuous expansion (Figure 1). This was followed by a plateau of around three years and then a period of decline which has continued through 2015.[2] This decline had not been foreseen by an industry which had projected continuous future growth (albeit on a lower growth trajectory than previously). Although initially this was thought to be a consequence of recession and the decline in energy and power demand, by the mid-2010s the problem appeared more fundamental.

[1] This paper's focus is decarbonisation rather than air quality where gas has significant advantages over other fossil fuels which have (arguably) been ignored due to the concentration on carbon issues. For benefits achieved in European cities see IGU (2016).

[2] Figure 1 appears to show a recovery in 2010 and 2015 but this is because the data are not temperature-corrected. The increase in gas demand for the first 8/9 months of 2016 was in the range of 2.5-3%. IEA, *Monthly Gas Statistics*, November and December 2016, p.6. This may have resulted in the first temperature- corrected increase in demand since 2008.

Figure 1: European* Gas Demand 1990-2015 (Bcm)



*Europe of 35 countries; data is not temperature-corrected

Source: Honoré/OIES using data from IEA, *Natural Gas Information* (various issues).

For the majority of the European gas community post-2008 developments were completely counter-intuitive. Most had expected that once Europe had recovered from the 2008 recession, gas demand would resume its upward trajectory. They were encouraged in this view by a 2011 IEA publication which became known as `The Golden Age of Gas' scenario which posited that the success of North American shale gas development could be replicated elsewhere in the world at similar (or slightly higher) costs.[3] The summary of the publication finished: `Based on the[se] assumptions...from 2010 gas use will rise by more than 50% and account for over 25% of world energy demand in 2035 – surely a prospect to designate the Golden Age of Gas'.[4] Five years later, the outcome is that North America is indeed enjoying a Golden Age of Gas, but no other region is producing substantial volumes of unconventional gas and – with the exception of China and Australia – the Agency's more recent scenarios show this not happening before (and perhaps even after) 2030, partly due to commercial viability and partly to environmental concern and opposition.[5]

What has gone wrong for gas in Europe?

At every major gas conference (both in Europe and across the globe) in the 2010s, senior executives of energy companies continue to make speeches (usually to like-minded audiences) laying stress on the importance of gas in meeting carbon reduction targets, and how switching from coal-fired to gas-fired power generation, and using gas to back up intermittent renewable power generation are the quickest and most cost-effective way to reduce carbon emissions. For the analytical gas community (including the present author) these were reasonably persuasive messages[6], but they failed to provide a basis for reversing the fortunes of gas in Europe. Later sections of the paper go into more

[3] To be fair to the Agency, the title of the publication posed the question: `Are we Entering a Golden Age of Gas?', rather than making the statement, but this was quickly forgotten as everybody remembers the slogan but not the question which forms the title. IEA: *Are We Entering a Golden Age of Gas?*

[4] Ibid, p.9. Outside North America, the most significant unconventional gas production is coal bed methane in China and in Australia (where it is known as coal seam gas and provides the gas supply for several LNG projects).

[5] IEA: *World Energy Outlook 2015*, Figures 6.2 and 6.3, IEA/OECD: 2015, pp. 234-5.

[6] Although more in relation to fuel-switching than to back-up for renewables, where gas-fired generation may have advantages over other forms of generation which are able to perform this role, but is not an automatic choice.

detail on some of these issues, but it is worth briefly listing here the problems which gas has encountered in Europe in the 2010s:

Lack of traction of the `Gas Advocacy' message Gas industry trade associations have, over several years, mounted `advocacy' campaigns aimed at promoting the fuel particularly in relation to its environmental (particularly carbon-related) advantages in comparison with other fossil fuels.[7] Outside the fossil fuel community, and particularly in the policy and NGO environmental communities, the contention that gas is `still a fossil fuel', and that methane emissions (particularly from fracking) negate the advantages which gas claims to have over other fossil fuels (particularly coal), continues to resonate powerfully.

The price competitiveness problem of 2011-14 During this period, internationally traded gas prices outside North America reached historically high levels in Europe and Asia resulting in a determination of energy users and policy makers to move away from gas and embrace especially coal and renewables. Despite the fact that since 2014 international gas prices have fallen to between one half and one third of previous high levels, that period may have done lasting damage to the commercial image of gas in many countries.

The price competitiveness problem has led many European countries into a coal and renewables paradigm in the power generation sector: whereby governments provide financial support for renewables but tolerate, and even encourage, the burning of low cost coal in power generation. This proved highly popular with politicians who were able to boast about meeting renewable energy targets, while ignoring the fact that stable or rising coal burn, combined with falling gas burn, offset much of the carbon reduction benefit of renewables.

The failure of national and (particularly) EU policy to raise carbon prices to meaningful levels: carbon prices from the EU emissions trading scheme (ETS) have been in single digits for much of the 2010s, nowhere near sufficient to favour gas over coal. There is little optimism that EU ETS price levels will change significantly in the near, and perhaps even the longer, term future. This leaves the gas industry relying on national measures – such as the UK carbon support price which progressively advantaged gas over coal during 2015/16[8]; and emission performance standards (EPS) mandating standards for older power stations which only gas (among fossil fuels) can meet without significant additional investment.

Cost reduction and technological advancement of renewables and electricity storage The fossil fuel community has traditionally claimed that wind and solar are expensive sources of energy needing large scale subsidies. However substantial cost reductions in (particularly) onshore wind and solar power projects mean these claims are increasingly overstated and unpersuasive for politicians, particularly given the 2011-14 period of high oil and gas prices, and cost inflation for new fossil fuel projects. Debates about `subsidies' between fossil and low carbon communities have a tendency to descend into unproductive mutual accusations.[9] The fossil fuel community needs to recognise that it has been overly sceptical about the pace of development (and cost reduction) of both renewable energy and electricity storage technologies which can go some way towards addressing intermittency. It has also underestimated the willingness of governments to maintain, and customers to tolerate,

[7] For example: the International Gas Union, Gas Naturally (a partnership of six European gas trade associations) and the European Gas Advocacy Forum (an informal group of eight European upstream and midstream companies and suppliers of gas to Europe). More recently, the creation of the Oil and Gas Climate Initiative (OGCI) – an alliance of 10 upstream companies – is focussing on carbon capture technology and methane emissions reduction in the gas industry.

[8] By Q3 2016 coal-fired power had been reduced to negligible proportions in the UK. However, this relied on gas prices in the region of €/12-14MWh in the second and third quarters of 2016. By the fourth quarter these increased to €17-20/MWh, but international steam coal prices had also risen above $80/tonne.

[9] The issue being one of definition. The low carbon community regards, tax allowances on upstream production as a `subsidy' while the fossil fuel community regards the taxes which it pays on production and sales as a demonstration that it is net contributor to the economy.

substantial financial support for low carbon energy sources, with part of its attraction considered (not necessarily correctly) to be security of supply.

Security of supply One of the major contentious issues for gas in Europe has been the political controversy surrounding the import of Russian gas. This issue has been on the European energy (and in some countries national) security agenda for many decades both during and after the Cold War. But disagreements between Russia and Ukraine, which led to interruptions in European supplies in January 2006 and (particularly) January 2009, created a fundamentally different set of security concerns, reinforced by the Ukrainian political crisis and Russian annexation of Crimea in 2014.

In summary, the contention of advocates in the 2010s that natural gas is: "abundant, acceptable and affordable"[10] has met strong challenges to which it has not given answers considered satisfactory by many in the policy and environmental communities. This paper suggests that these challenges need to be urgently addressed.

Did COP21 change anything about the future of gas in Europe?

The 2014 IPCC 5th Assessment Report set out the framework for decarbonisation of energy systems in the following way:

> "To accommodate this reduction in freely emitting fossil fuels, transformations of the energy system rely on a combination of three high-level strategies: (1) decarbonisation of energy supply, (2) an associated switch to low-carbon energy carriers such as decarbonized electricity, hydrogen, or biofuels in the end-use sectors, and (3) reduction in energy demand…Bringing energy system CO_2 emissions down toward zero, as is ultimately required for meeting any concentration goal, requires a switch from carbon-intensive (e.g., direct use of coal, oil, and natural gas) to low-carbon energy carriers (most prominently electricity but also heat and hydrogen) in the end-use sectors in the long run."[11]

At the COP21 summit in Paris in December 2015[12], 196 parties (195 countries plus the EU) agreed to limit carbon emissions to a level which will restrict the global average temperature increase (relative to pre-industrial levels) to 2 degrees (and to `pursue efforts' to achieve 1.5 degrees) centigrade. This will be achieved by countries adopting Intended Nationally Determined Contributions (INDCs) which will be adopted and reviewed against actual performance every five years. Without full details of the INDCs it is difficult to make an assessment of their impact on the fossil fuel sector.[13] However, many European countries already have `carbon budgets' which set out how future carbon emissions must be reduced relative to a base year.[14] In general terms, in order to meet targets, European countries need to have substantially decarbonised their power sectors by 2030 and their heat sectors by 2050.

While it is easy to express cynicism as to the likelihood of these commitments being met, it should be a concern for the future of gas worldwide that an IEA report highlighted five energy sector measures (relying only on proven technologies and policies) which could help achieve an early peak in total energy-related GHG emissions, at no net economic cost. These measures, presented as a "Bridge Strategy" (and intended to be a bridge to further action) did not include switching from coal (or oil) to natural gas.[15]

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[10] For a typical example of such advocacy see the speech by Hans Riddervold of the International Gas Union, at the 4th Session of the UNECE (2011).
[11] IPCC (2014), p. 443.
[12] The 21st Conference of Parties under the United Nations Framework Convention on Climate Change.
[13] However, the sum of INDCs received in 2016 equated to a global temperature reduction of only 2.7^{0}C.
[14] For details of the UK carbon budget process see https://www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets/
[15] The five measures are: improving energy efficiency in the industry, buildings and transport sectors; phasing out the use of the least-efficient coal-fired power plants; further boosting investment in renewables-based power generation technologies (to $400

Furthermore, from the INDC submissions available on the UNFCCC website, the author was only able to find 20 countries mentioning greater use of natural gas as a way to reduce emissions.[16] Most of these are significant producers/exporters of oil and gas: Iran, Saudi Arabia, Nigeria, Algeria, Gabon, UAE, Yemen, Ecuador, Brunei, Trinidad and Tobago and Peru. These countries will combine fuel switching with reduction of methane and CO_2 emissions from venting and flaring. Smaller countries either planning to introduce imports or increase production of gas are: Afghanistan, Ghana, Israel, Morocco, Lebanon, Niger and Barbados. Only two large countries - China and Canada - mention fuel switching to gas as a potential major part of their INDCs.

The COP21 outcome can certainly be criticised in terms of enforcement potential i.e. if INDCs are not sufficiently ambitious or not achieved, the `naming and shaming' sanction on governments may not be sufficient.[17] However, it seems unwise to base the future of (fossil fuel including) gas industries on cynicism about government policies. Although it could be claimed that COP21 changed nothing in terms of the *specifics* of European energy or gas futures, it was an important declaratory statement signalling a time-limited future for fossil fuels without carbon capture and storage (CCS) capability. Therefore, unless the gas industry can achieve capture and storage of its carbon emissions, then natural (as opposed to other types of) gas can only be a transition fuel, and even the length of that transition is unclear.

The impact of technology advances on gas

Gas technologies and applications currently under development will be important for future gas demand, with renewed interest in the transport sector applications, particularly LNG in heavy trucks and marine transport. Transport is the best hope that the European gas industry has of a significant market expansion, albeit from a low base, but fuel switching from oil products to LNG or CNG is aimed principally at improving air quality rather than decarbonisation.[18]

Technological change in the electricity sector seems likely to be increasingly negative for the gas industry. Renewable cost reduction and advances in electricity (battery) storage have raised questions over both the future competitiveness of gas-fired power generation against wind and solar power, and the extent to which it will be required to back up intermittent renewables.[19] Renewable and storage technologies have far to go in relation to widespread application, and particularly their ability to deal with seasonal (as opposed to diurnal) storage requirements, but it cannot be ruled out that, as well as continued progress of existing technologies, new breakthroughs in both renewable energy and storage will reduce costs and increase capability.

In the heat sector, technologies related (but also potentially unrelated) to gas are also likely to make progress. In particular, there is the possibility of using existing gas networks to distribute hydrogen produced from decarbonised natural gas by a steam reforming process. Existing transmission and distribution networks (provided that they are equipped with polyethylene pipe) can be relatively easily converted from natural gas to hydrogen.[20] In the heat sector, household appliances can be converted from natural gas to hydrogen. In the power and transport sectors hydrogen networks would open up

billion in 2030); gradually phasing out fossil fuel subsidies; and, reducing methane emissions from oil and gas production. IEA, *Special Briefing for COP21*, p.6.

[16] http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx Accessed September 9, 2016. The IEA mentions `less than 30 out of 160 submissions'. IEA: *World Energy Outlook* 2016, p.169.

[17] For a general discussion of strengths and weaknesses of the agreement see Faulkner (2016). For COP21-related issues in respect of fossil fuels see *Oxford Energy Forum* (2016).

[18] Le Fevre (2014); EU 2016 reference scenario results are very pessimistic with only 7.5 mtoe of gas (10% of bunker fuel) being used in the marine sector in 2050. European Commission (2016), p.62.

[19] Reports in September 2016 of bids to build large scale offshore wind farms in Denmark at levelised costs of €60-75/MWh are by no means generalizable to other countries and locations, but may be indicative of trends in renewable cost reduction. Hirtenstein (2016).

[20] A video demonstration of how a large city could be converted from natural gas to hydrogen can be found at: http://www.teessidecollective.co.uk/watch-h21-leeds-city-gate-film/ See Appendix for more detailed consideration of UK prospects.

the possibility of power stations and vehicle refuelling stations being supplied directly from the grid. Salt caverns used to store gas can also be used to store hydrogen.[21] Aside from the costs of all of these conversions, the most difficult problem for gas conversion to hydrogen will be capture and storage of carbon from the steam reforming process.[22] An additional question concerns which corporate entities are most likely to invest in the different elements of the CCS process (to which we return below).

Production of hydrogen via electrolysis (using renewable energy) produces far less CO_2 emissions thereby avoiding the carbon capture and storage problem, but is more technically complex and therefore potentially more expensive.[23] However, both options open up the possibility that the future of existing gas networks – transmission and distribution – need not necessarily be the same as the future of the commodity. They also create different options for transmission, and particularly distribution[24], networks in the same country, which could in the future be transporting different products – methane, hydrogen, biogas (depending on CO_2 content) and biomethane or a mixture of these gases. Solutions are likely to be local rather than national, with different choices likely to be made by urban, suburban and rural communities.[25]

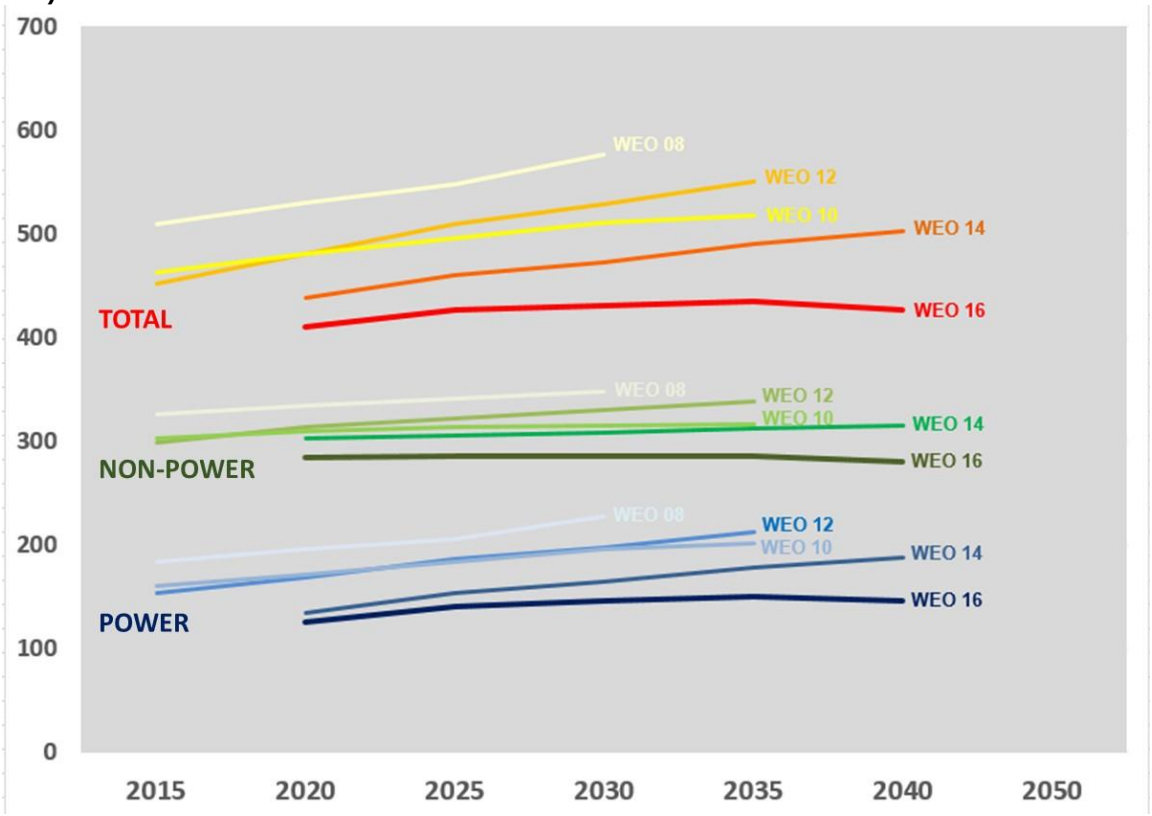
Non-hydrogen based solutions for decarbonising heat, such as electric heat pumps and district heating based on non-gas alternatives, are in the forefront of policy for many governments. Demand-side technologies which improve efficiency, both in relation to overall energy use and reducing peak demand, are also likely to make significant progress, potentially reducing the need for both power and heat supply. Progress in relation to demand-side management with smart grids reducing peak demand, would further reduce the problem of renewable intermittency and hence the need for back-up from gas (or other fossil fuel) generation.[26] This variety of pathways to decarbonisation underlines the fact that there are many non-gas supply and efficiency based options which can replace the traditional natural gas model.

Scenario Projections and Policy Assumptions 2014-40

Post-2008, consensus public domain scenarios for European gas demand over the next two decades were progressively scaled down. Figure 2 shows the IEA's `New Policies Scenario' projections for OECD Europe gas demand for the period 2008-16. Projections for total gas demand in 2030 have been reduced from 575 mtoe (684 Bcm) in 2008, to 431mtoe (521 Bcm) in 2016, with relatively flat demand in the 2030s.[27]

[21] MacLean et al. (2016), p.3.
[22] Also, the process captures only around 90% of the CO_2. KPMG (2016), p.20.
[23] IEA, *Technology Roadmap: hydrogen and fuel cells*, Figure 4, p.18.
[24] Despite the fact that he was referring to electricity networks, the following quote from the CEO of E.ON is also relevant to gas: `I think it would be prudent if politicians understand that the most important network for the future is distribution not transmission. The transmission network was important in the past because all the large power stations were linked to it and that's where the market happened…politics here in Brussels is still very often focussed on transmission. It underestimates the proximity our lower voltage networks have to the customer and to distributed generation and that's where the future lies'. Energy Post Weekly (2016).
[25] MacLean et al (2016), pp. 43-44.
[26] Up to a certain limit of load displacement potential, which varies across the year and differs between countries.
[27] IEA: *World Energy Outlook 2016*, p.566; and IEA: *World Energy Outlook 2008*, p.618 (reference scenario).

Figure 2: IEA 2008-16 `New Policies' Scenarios for Gas Demand in OECD Europe 2015-40 (mtoe)



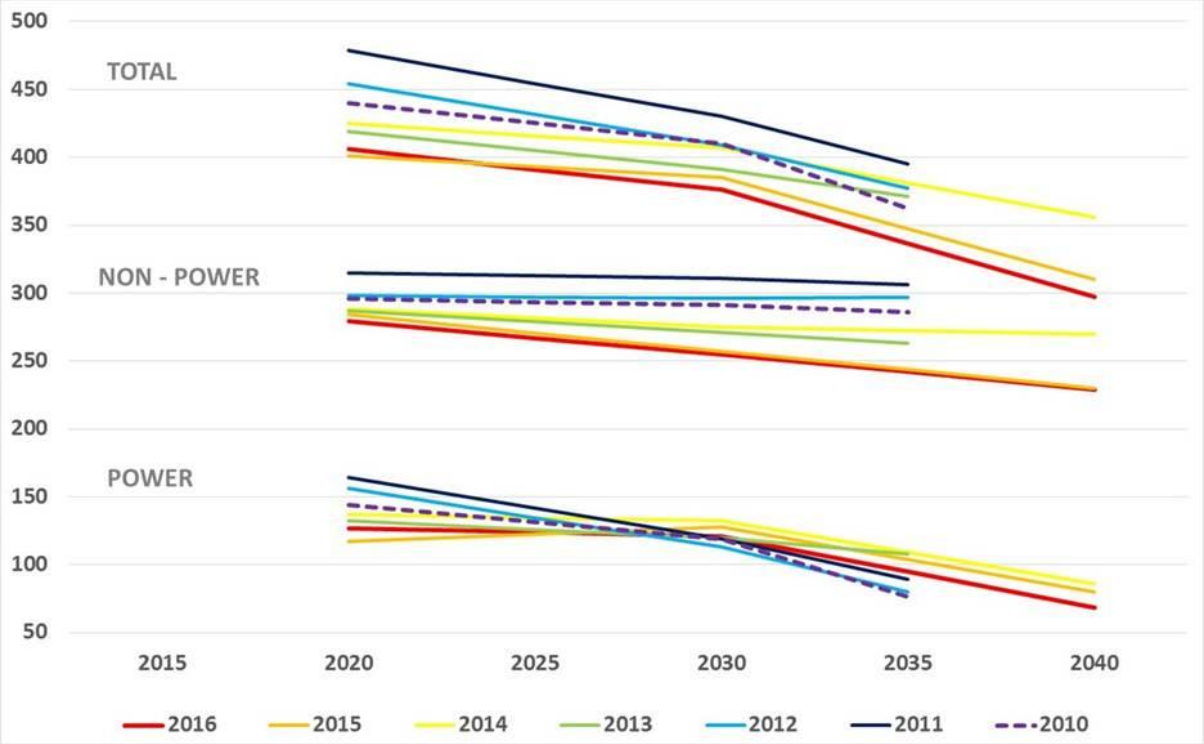
Source: Honoré/OIES using data from IEA, *Natural Gas Information* (various issues), *World Energy Outlook*, series 2008-16.

But the IEA's 450 Scenario projections (predicated on more aggressive decarbonisation policies) for the years 2010-16 (Figure 3) show a rather more dramatic picture.[28] The 2016 Outlook shows a fall of 36 (483-447) Bcm for total gas demand for the period 2020-30, but 94 (447-353) Bcm for the period 2030-40. For the later period, two thirds of the reduction is caused by the fall in power generation where gas demand falls by almost 50%, but in the non-power sector by only around 12%. It is significant that the `450 Scenario' projections for the 2030s fall sharply reflecting the need for accelerated decarbonisation if targets are to be met.

Somewhat more optimistically, the 2016 EU Reference Scenarios for Energy see only a slight decline in total gas demand during the same period with demand of 371 mtoe (441 Bcm) in 2030 and a similar level in 2050 but having increased to 394 mtoe (469 Bcm) in 2040. This is caused by gas-fired power generation falling up to 2030, but recovering in the 2040s.[29]

[28] IEA: *World Energy Outlook 2016*, p.567. The 450 Scenario assumes a set of policies where the international goal of limiting the rise in long term average global temperature to two degrees Celsius is achieved.
[29] European Commission (2016), Appendix 2, p.144. The reason for the recovery in generation capacity is to back up intermittent renewables (p.66), suggesting that if other solutions to the intermittency problem are found then gas demand may be lower.

Figure 3: IEA 2010-16 `450 Scenario' for Gas Demand in OECD Europe 2015-40 (mtoe)



Source: Honoré/OIES using data from IEA, *World Energy Outlook*, series 2010-16.

At the end of 2016, a reasonable generalisation was that European gas demand is expected to remain relatively robust up to 2030. But thereafter more aggressive decarbonisation policies would create strong downward forces on gas demand, especially in the power sector. And such policies will need to be put in place relatively soon in order to achieve the desired results in the 2030s. In order to retain its place in European energy balances these policies will require the gas industry to make significant progress towards decarbonisation.

The 2010s and beyond: five problem areas for gas in Europe

This section examines the problems which different gas value chain[30] groups have faced in Europe in the 2010s, and are likely to face over the next decade under five headings: commercial, security, environmental, business model and corporate fragmentation.

Commercial problems for utilities and upstream companies

As already mentioned, since 2008, energy demand in Europe has fallen substantially due to a combination of recession and improved efficiency. However, since that date gas has been

[30] The natural gas value chain from the `wellhead to the customer' comprises upstream (exploration and production/export), midstream (supply and trading) and network (transmission, distribution and – either separate or integrated storage) companies. Gas-related equipment (boiler and other heating equipment) suppliers and servicing companies could also be considered part of the value chain, as they are an integral part of gas usage.

disproportionately affected, and demand has not only failed to significantly recover,[31] but may even be continuing to decline in some countries. The main reasons for this are:

- The coal and renewables paradigm in power generation: in the period 2010-15 the share of gas in OECD European power generation fell from 23% to 17%, which reduced demand by more than 60 Bcm/year.[32] During the same period, the share of renewables increased while the shares of coal and nuclear remained relatively constant.[33] Gas was squeezed out of the power sector by a combination of lower priced coal, low ETS prices, and renewables supported financially by government. The high gas prices of 2011-14 contrasted sharply with falling costs in the renewables sector, and the apparent ability of international coal suppliers to undercut gas prices however low these fell. In the absence of significant European (EU ETS) carbon prices, this made the task of gas suppliers and gas-fired power plant owners – very difficult.
- Continued efficiency gains in the residential/commercial and industrial sectors, combined with sluggish economic growth (and therefore a lack of energy and gas demand recovery) resulted in demand continuing to fall in these sectors.

By 2016, the picture had changed somewhat, with increases in gas demand in the power sector in the UK, and the industrial sector in Central Europe and Germany, due to lower gas prices and much higher coal prices compared with the 2011-14 period. In the UK, a combination of a high carbon support price, a favourable combination of gas and coal prices, very old coal-fired generation plant (and some plant closures) and limited interconnections with other markets, led to a situation where throughout 2016 coal-fired generation was progressively replaced by gas-fired generation in the power sector.

Lower gas price levels post-2014 have caused problems for upstream companies considering new supply projects to deliver gas to the European market. 2016 price levels present a serious cost challenge for all energy mega-projects, and particularly for new greenfield gas and LNG projects. As these costs increased in the 2010s, the costs of renewable energy have been falling. European decarbonisation commitments raise difficult questions for upstream companies, notably whether new (pipeline or LNG) mega-projects may become uncompetitive, given what was said above about possible technological progress in the renewable and electricity storage sectors.

In addition, the difficulties arising from changes in European utility business models (see below) mean that the long term take or pay contractual framework, which has traditionally underpinned financing for upstream gas projects, may no longer be workable. This is a major problem for those upstream companies for which (even though they continue to be colloquially known as `oil' companies) gas now dominates their reserve portfolios. Future profitability of these companies will therefore be substantially dependent on their ability to monetise gas reserves, and for this reason the potential decline of European gas demand (and the possibility that this could be replicated in other regions) should be of serious concern.

Security problems versus perceptions

Another significant problem for European gas has been continuing and – in many countries – increasing concerns about supply security. There is a major disconnect between perceptions and reality in relation to the views of politicians and media commentators and the gas community. From a *political perspective*, a substantial consensus was created by the 2006 and 2009 Russia/Ukraine gas crises – and has strengthened greatly since 2014 and the Russian annexation of Crimea – that the overall and specific market dominance of Russian supplies constitutes the most important security

[31] In 2015, demand increased by 15 Bcm mainly due to colder weather in the first half of the year; in the first 8-9 months of 2016 gas demand increased around 2-3% compared with the previous year, possibly the first temperature corrected increase since 2008.

[32] Data for 2010-2015e, *IEA, Electricity information, 2016 Report*; estimates for 2015: Honoré/OIES.

[33] The share of coal rose and then fell, so the share in 2010 and 2015 was similar but not constant over the period.

problem for European gas markets.[34] In 2009, European countries lost supplies of Russian gas for more than two weeks and this caused significant problems in a small number of south east European countries (some of which were not EU members).[35] The 2014 Ukrainian political crisis and subsequent Russian annexation of Crimea, followed by US and European sanctions (and Russian counter-sanctions) not only resulted in a substantial deterioration of EU-Russia political relations but also renewed military and national security concerns. These developments created a political climate in which additional dependence on Russian energy – specifically gas supplies – and new Russian gas pipelines to Europe[36], became politically and strategically undesirable for some countries.

The problem with such views from a *gas perspective* is that they neglect the supply realities facing Europe in three important dimensions:

- the decline in European domestic conventional gas production;
- the failure of diversification of pipeline gas supplies and uncertainty about the duration of the current LNG supply surplus;
- that any restriction of Russian gas supplies – which have the lowest cost of delivery for substantial volumes of pipeline gas into Europe - will inevitably increase the price of the commodity in Europe.[37]

Declining European conventional gas production

The fall in (oil and) gas prices since 2014 has not yet had a significant impact on UK and Norwegian gas production because of the time lag between investments and field development. In 2016 average monthly hub prices were in the range €12-18/MWh/$4.0-6.0/MMBtu. However, if European gas prices remain significantly below €20/MWh (or $6.50 MMBtu at late 2016 exchange rates) then not only will it be difficult to develop new fields, but existing fields may be decommissioned on an accelerated basis.[38] Gas production in the Netherlands – the other major source of European conventional production - has been reduced due to government decisions resulting from environmental (subsidence) problems around the Groningen field.[39]

Shale gas, biogas and biomethane prospects

European shale gas development has encountered serious environmental opposition (see below) but it is highly doubtful whether – at 2016 price levels – it would be commercially viable on a large scale. By 2015-16, IEA scenarios (recalling the 2011 Golden Age of Gas study cited above) no longer included any significant unconventional gas production in Europe even by 2040.[40] Despite this situation, the reputation of gas in Europe is being damaged by opposition to unconventional gas development (especially fracking) which is in any case not happening. Partly because of this opposition and partly for commercial reasons, Europe is unlikely to produce any significant volumes of shale gas even in the 2030s.

[34] For a broader perspective on gas as a politicised commodity see Franza et al. (2016).
[35] Stern et al. (2009). The 2006 episode was of shorter duration and involved fewer countries. Stern (2006).
[36] Opposition to new gas pipelines is connected to EU political support for continued transit of Russian gas through Ukraine which will be reduced if new pipelines go ahead. For scenarios of how this could unfold see Pirani and Yafimava (2016).
[37] In 2016 Gazprom's shut-in production capacity (i.e. gas which could be produced if markets were available) exceeded 100 Bcm; unused transportation capacity to Europe (assuming greater use of the Ukrainian corridor) was around 40 Bcm. No other pipeline supplier to Europe is able to significantly increase deliveries. Some LNG suppliers are able to significantly increase deliveries to Europe but, aside from Qatar, none can compete on cost with Gazprom, although delivery costs are strongly related to the Dollar/Rouble and Euro/Rouble exchange rates. Henderson (2016).
[38] Due to substantial capital expenditure reductions reported by all companies since the collapse of oil and gas prices in 2014.
[39] Annual production at the Groningen field was reduced from more than 40 Bcm in 2014 to 24 Bcm in 2016, with no guarantee that it will not be further reduced in future.
[40] *World Energy Outlook 2015*, Figures 6.2, p. 234, had specific figures for North America, China, Australia and Argentina and then a bar for `Rest of World' (not specifying any figure for Europe) which amounts to about 100 Bcm in 2030 and around 175 Bcm for 2040. Discussion of European gas supply in *The World Energy Outlook 2016*, p. 188-9 does not mention unconventional gas.

The prospects for biogas and biomethane (which are classified as `renewables' rather than unconventional gas by many countries) are much more positive partly because many projects and plants are already in existence, and partly because the political and environmental reaction is mostly supportive. There are about 12,000 biogas plants in 12 European Countries (most of them are agricultural cogeneration plants producing heat and power).[41] Most of the biogas cogeneration plants are in Germany, Italy and Switzerland. In 2014, biogas energy output was about 18 Bcm mostly for the electricity sector. Biogas growth is slowing due to revisions of policy in Germany and Italy. In contrast to wind and solar, biogas plants have fuel costs and, as a result, rely on government financial support for construction and running costs. There are a wide range of different support schemes across Europe. The most popular are feed-in tariffs (FiTs) but tax exemptions, investment subsidies or priority grid access are also common.[42] The sector faces challenges from reduced government subsidies and future growth will be subject to political decisions in individual countries.[43] But if financial support continues then by 2030, biogas and biomethane could be larger sources of gas than conventional production in both the UK and the Netherlands.

Availability of non-Russian gas imports[44]

As far as alternative sources of pipeline imports are concerned, the prospects are relatively poor. *North African* supplies have been in decline for several years due to a combination of political instability, increasing domestic demand (largely due to low domestic prices) and lack of incentives to develop new fields (which required higher investment costs). While the region has huge gas reserves, and continues to have exploration success (especially in Egypt), it is doubtful whether current export levels from Algeria – the main regional exporter – can even be maintained (let alone increased) over the next decade.[45]

Southern Corridor pipeline gas from the Caspian region (Azerbaijan), Central Asia (Turkmenistan) the Middle East (Kurdistan and Iran) and latterly the East Mediterranean (Israel and Cyprus) which has been championed by the European Union, shows no sign of becoming a significant, competitive and secure source of supply for at least a decade (and probably longer). The start-up of Azerbaijan's Shah Deniz 2 development, which will deliver 6 Bcm/y to Turkey and 10 Bcm/y to other European countries from the end of this decade, is likely to be counterbalanced by the need to retain gas, currently being exported to Europe, for a growing domestic market.[46] It is also uncertain whether, unless other sources of Southern Corridor gas can be mobilised by the early 2020s, some of the 10 Bcm/y destined for Europe could remain in Turkey, where demand growth projections are higher than elsewhere in Europe. Nevertheless, for small markets in south east Europe, which have been completely dependent on Russian gas, a few Bcm/y of Southern Corridor gas would represent significant diversification.

In contrast to pipeline supplies, European *LNG* imports are likely to grow substantially given the huge wave of additional supply (mainly from Australia and the US) entering the global market in the period up to 2020, and substantial under-utilised capacity at European import terminals.[47] A combination of EU policy to support new infrastructure for security reasons, and global availability of larger volumes

[41] 177 of these are biomethane plants, where biogas is upgraded to a quality similar to natural gas. 128 of these plants inject biomethane into the natural gas grid, especially in Germany, Switzerland, the Netherlands and Austria. Eurobserv'ER (2015), pp. 42-49.
[42] http://www.greengasgrids.eu/
[43] For instance, plants running on biomethane receive €216.3/MWh in FiT in Germany under the current EEG law. Argus News and Analysis (2016). Eurobserv'ER (2015), pp. 42-49.
[44] For a detailed review of prospects from late 2014 see Stern et al. (2014).
[45] Aissaoui (2016). In 2016, Algerian exports to Europe rose by nearly 10% for reasons that are not easy to explain other than that the country may need additional short term funds.
[46] Pirani (2016).
[47] In 2015, the utilisation figure was 24%, Corbeau and Ledesma, eds. (2016), p.310.

of LNG has already enabled the Baltic countries and Poland to achieve a degree of diversification away from Russian gas. Expansion of existing (Greek) and new (Croatian) LNG terminals in south east Europe will assist diversification in that region. LNG security concerns arise from the experience of 2011-14 which showed that LNG can disappear very quickly from Europe because Asian countries, specifically Japan, Korea and Taiwan (because of their limited alternative gas supply options) will always be willing to pay higher prices than their European counterparts. However, the current consensus is that the global oversupply of LNG will last until at least 2020 and potentially up to 2025.[48] This would provide both competition for Russian pipeline gas and potentially also time to develop new sources of non-Russian supply; the main problems are not availability of reserves but (domestic and international) politics and commercial viability of projects.

However, as mentioned above, this overview reflects a gas industry perspective on supply security which is either not recognised or not shared by the wider political and media communities. Many European governments see gas security as a simple formula which can be expressed as:

GAS = GAZPROM/PUTIN = THREAT TO EUROPEAN (ENERGY/GAS) SECURITY

These views are extremely negative for the image of gas in Europe. European (as opposed to individual country) diversification away from Russian gas, widely promoted by the European Union and many national governments, is unlikely to succeed in the future except for the period while the global LNG market is in surplus. This will be a problem for the future of gas which cannot be controlled by the industry. There is extreme sensitivity to any problems – or even imagined problems – in relation to Russian gas supplies, but very little in relation to considerations of security of other gas (or other energy) supplies, defined as the reliability of supply from different sources.[49]

Russian gas supplies have always involved `high politics' (as did Soviet gas supplies during the Cold War period), and post-2014 the political and military conflict with Ukraine and Crimean annexation has raised these politics to a very high level on European foreign policy and security agendas. The question for the gas industry is how to respond to these concerns. The EU response, which is part of the Energy Union initiative[50], has been to fund the building of pipeline and LNG infrastructure, much of which is not commercially viable but will ensure that gas can reach potentially vulnerable countries in the event of a supply interruption. Beyond pointing to the existence of such infrastructure, there is little that the gas industry itself can do. The idea of setting a European or national limit on supplies of Russian gas – which was popular during the Cold War period but never workable even then – has been ruled out by the development of competitive markets where gas can flow in many directions. In the majority of European countries it has become impossible to know for certain the origin of gas which is being consumed in terms of exact percentages of demand or imports.

The essential point to be made in respect of security is that pipeline and LNG infrastructure exists (or will soon exist) which has improved diversification for countries most heavily dependent on Russian gas in the Baltic region and south eastern Europe. European Union initiatives to financially support the construction of additional supply and interconnection infrastructure should ensure that such regions will be able to cope with any serious interruption of gas supply from any source.

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[48] Ibid, p.564.

[49] To illustrate: there was no public consciousness or interest in the fact that Italy lost the entirety of its gas supplies from Libya for most of 2011, and that supplies have never recovered to pre-revolution levels. Similarly, there has been little publicity given to interruptions of Iranian and Azerbaijani supplies to Turkey. Supply problems in the North Sea – mostly caused by failure of ageing infrastructure - also attract no attention outside the trade press (which is mostly concerned with short term price fluctuations). The point is not that such interruptions have (thus far) caused serious security problems, it is that the political aspect of Russian supplies engages agendas which are much wider than gas and energy security.

[50] In February 2015, the European Commission adopted "A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy". This strategy was aimed at creating a new momentum to bring about the transition to a low-carbon, secure and competitive economy and to deliver on one of the 10 priorities of the Juncker Commission. For details see Buchan and Keay (2015).

Environmental problems

While the industry itself regards gas as an environmentally benign fuel, this is not how it is generally regarded by the political and environmental community. As decarbonisation has become an increasingly serious priority on political and energy agendas, gas has come to be regarded as `just another fossil fuel'[51] under environmental attack in two specific respects.

a) Methane emissions

Natural gas is subject to venting and flaring from exploration and production operations to greatly varying degrees and leakage from transmission and distribution pipelines. The difference between venting and flaring is important. Flaring produces CO_2 emissions; venting is more difficult to estimate and involves the release of methane which is a much more potent greenhouse gas than CO_2. The two major sources of methane emissions from the gas industry are from old low pressure distribution systems where cast iron pipes are still in use; and upstream (production) operations where gas is sometimes vented – rather than flared. In the minds of politicians and the media, emissions from upstream operations are directly connected with unconventional gas and what has been called `the fracking debate'. Fracking (hydraulic fracturing) has become a politically toxic issue in most European countries resulting in the opposite of the advocacy which usually accompanies locally produced energy. [52] Whether objectors are correct in their views of the risks/dangers arising from unconventional gas development, populations living in the vicinity of drilling sites have (despite the potential financial incentives offered by some governments) mostly opposed it, and politicians who require their votes are unlikely to disagree with them.

Despite the fact that the gas community believes that methane emissions from the gas chain have been substantially overstated, there is very little available documentation of emissions outside the US. Even within the US there are widely different estimates of methane emissions, some of the official estimates are high for some sources, with a significant range between high and low estimates.[53]

b) Carbon emissions

Although gas emits less carbon dioxide than oil or coal, its emissions are still significant. One solution to this problem of carbon dioxide emissions from fossil fuels is to remove them using carbon capture and storage (CCS) technology. There are a small number of gas fields around the world with a high percentage of CO_2 where carbon is captured and stored in nearby formations.[54] However, CCS application to power stations, and especially in the heat sector, has made limited progress anywhere in the world. In a European context, it was unfortunate that the UK government abandoned the funding of a CCS gas-fired generation demonstration project when the contract was close to being awarded.[55] While discussion of gas and CCS is generally related to the power sector, it can also play a role in the heat sector in terms of conversion to hydrogen if this is manufactured from natural gas (see Appendix).

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[51] For example the CEO of RWE's view that: "The gas society lost the opportunity to distinguish itself, and therefore it's all in one pot, and I don't know if it's even possible to get out of it. People see carbon -- if it's coal or gas, it's carbon." Gilblom (2016).

[52] In the UK, where unconventional gas development enjoys strong central government support, an October 2016 poll found that only 17% of respondents backed shale gas development (the lowest level of support since polling began in 2012) compared with 33% who opposed it and 48% having no opinion. http://www.climatechangenews.com/2016/10/27/uk-public-support-for-fracking-is-collapsing/ Opponents suggest fracking is likely to pollute water resources, emit dangerous gases such as radon, and in extreme cases is equivalent to the spread of nuclear weapons. See the Letters page of *The Guardian*, May 30 and August 11, 2016.

[53] Balcombe et al. (2015); U.S. Environmental Protection Agency (2016). This report increased the EPA's estimate of the contribution of the oil and gas industry to methane emissions by around 30% relative to its estimate in 2015. It also identified a small number of `super-emitters' such as the leak from the storage facility at Aliso Canyon in California from October 2015-February 2016. For an overview of the EPA study and other US estimates see *The Economist* (2016).

[54] The Heimdal and Snohvit fields in Norway, the In Salah field in Algeria, the Gorgon field in Australia.

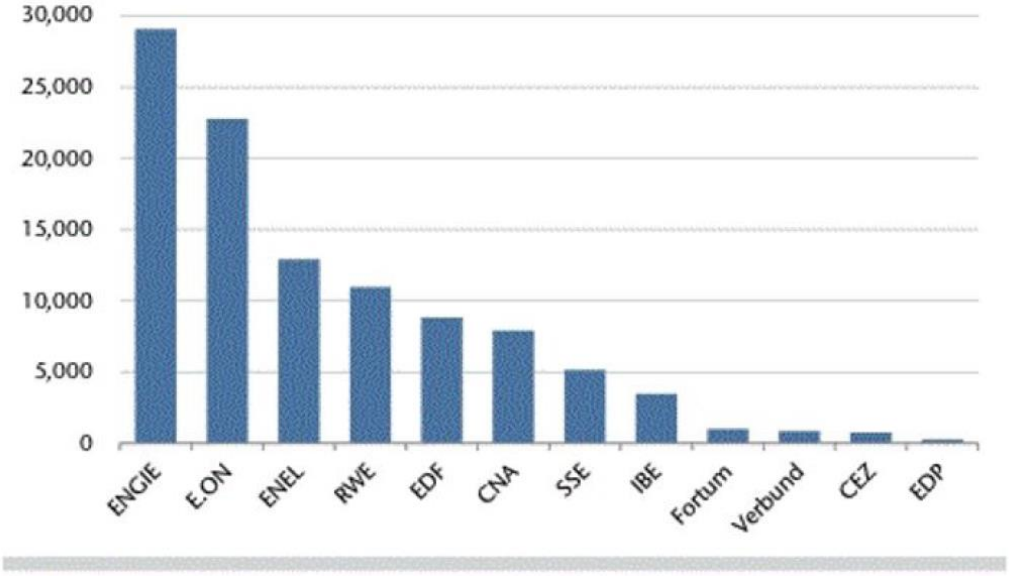
[55] Carrington (2015).

Business Model Problems

As noted above in the section on commercial problems European utilities – and particularly their gas businesses – are experiencing some of the most difficult times since the natural gas industry was created, because of a combination of the following factors:

- the decline of energy – gas and power demand – post-2008 combined with a substantial increase in competition in both sectors;
- the progressive disconnection of hub (spot) gas prices from oil-linked long term contract gas prices;
- the large scale introduction of renewable energy with government financial support which has reduced wholesale power prices and progressively rendered any new power generation investments impossible in the absence of long term regulatory support (i.e. feed-in tariffs, capacity charges and strike prices);
- reduced load factors for many gas assets – specifically gas-fired power stations and regasification facilities – to below 30% in the mid-2010s. This (combined with similar problems with coal generation assets) has resulted in write-downs (impairment charges) on these assets of €5-25bn per company (Figure 4) and substantial losses.

Figure 4: European Utility Impairments Since 2010-2015 by Company (€ million)*



*data include all (not just gas-related) utility assets
Source: Jeffries cited in Timera (2016).

These problems were well illustrated in an interview with the (newly appointed) CEO of Engie:[56]

> `[Engie] will sell €15bn of assets in E&P, coal fired plants and US gas plants. It will invest €22bn in renewable energy, energy services (heating and cooling) and decentralised energy technology…Engie will also try to find regulated, not market-based, energy contracts to protect itself from price fluctuations, `This is the way to create shareholder value at Engie…the question is less about how we expand the group internationally, but how we move away from a model which no longer works'.

In a similar vein E.ON, in its search for a new and more workable utility business model, demerged its fossil fuel assets from its low carbon business, the latter remaining with the parent company E.ON,

[56] Stothard (2016).

while the fossil assets were transferred to a new company Uniper.[57] The usual explanation for the demerger is that investors attribute different risks, and therefore different valuations to fossil and low carbon assets. By implication this suggests that fossil energy utilities will have a different business model to low carbon energy utilities. One possible conclusion, which is somewhat disturbing for the future of gas, is that the fossil fuel utility businesses should be regarded as `legacy assets', and their principal focus will be one of managing decline. This conclusion can be strongly questioned, particularly if governments reduce financial support for renewables and other low carbon technologies, and the latter fail to make rapid progress in terms of cost reduction. However, should the opposite be the case and renewable cost reduction and cost-effective electricity storage progress strongly over a 5-10 year period, then the German model may prove to be correct.[58]

The prospects for fossil power generation are further complicated by the Industrial Emissions Directive (IED) which sets minimum limits for emissions of sulphur dioxide, nitrogen oxides and dust to the air from large combustion plants with a thermal rating equal to or greater than 50 megawatts. At the time of writing, it was too soon to know the full impact of the IED, but potentially 50-100 GW of fossil fuel generation across the EU could be forced to close, starting in the early 2020s.[59]

Until a longer term workable business model for European utilities emerges, and emission performance standards and decarbonisation commitments become more specific - in relation to commitments arising from the IED and INDCs (resulting from COP21) - utility companies will remain strongly risk-averse in relation to new investment in any large scale, long term fossil fuel (including gas) related assets, even with regulatory support.

Finally, since 2008, utilities with existing long term oil-linked gas contracts have had an ongoing problem to keep these legacy assets `in the money'. After nearly 10 years of renegotiations and arbitrations, there is no sign that either side is seeking to terminate these long term contracts (although there are examples of contracts not being renewed, or only renewed on a short term basis once they have expired). In this situation, it is unlikely that buyers will commit to large volumes of gas under new 15-25 year purchase or ship or pay contracts, partly because they do not know their requirements in the 2030s and 2040s and will be reluctant to enter into binding financial commitments, even if they believe it will be possible to trade away surplus gas (and capacity). This creates additional problems and risks for upstream companies to invest in new gas developments, and the financing of pipeline and LNG related infrastructure needed to deliver that gas to markets.

Industry fragmentation problems

In the era of monopoly utilities up to around the early 2000s (late 1980s in the UK), the European gas industry comprised three relatively cohesive groups of companies:[60]

- national and international oil and gas companies (NOCs and IOCs). The most important national oil and gas companies were: Statoil (plus Norsk Hydro and Saga in Norway), Gazprom, Sonatrach and several LNG exporters of which Nigerian and Qatari companies were the most important. The IOCs were well known multinational companies with Shell, BP and Exxon being

[57] RWE also demerged into a company with the same name retaining fossil fuel assets, and a low carbon company, Innogy. This is opposite to the E.ON solution where the parent is the low carbon company and Uniper was demerged with the fossil fuel assets.

[58] It can also be argued that the German government decision (after the 2011 Fukushima nuclear disaster) to shut down all nuclear power stations by 2022 makes that country a special case which does not apply elsewhere in Europe.

[59] Estimate from Honoré/OIES. This capacity includes coal, but also old gas-fired plant. For coal-fired plant the date will depend to some extent on coal prices. Operators of combustion plants which chose to opt out ('limited life time derogation') cannot operate the plant for more than 17,500 operating hours after 1 January 2016 and not beyond 31 December 2023. Operators of combustion plants who chose to opt in, had two options: comply with new regulations by 1 January 2016 and run the plant, or sign the plant into a Transitional National Plan (TNP) and have 4 more years to comply with new regulation. From 1 July 2020, plants that were subject to a TNP will have to comply with new regulations (but there is a possibility of less strict emission limit values for plants operating less than 1,500 hours per year).

[60] These developments are set out in much greater detail in Stern and Rogers (2014), Chapter 2.

the most important in European gas production and supply. These companies sold their gas on 15-25 year contracts to…

- merchant gas transmission companies (MGTCs) of which the most important were: British Gas, Ruhrgas, Gaz de France, SNAM, Distrigaz, and Enagas. Each of these companies operated within their national (or regional) borders and sold their gas, through high pressure transmission pipelines which they owned, either directly to large (industrial and power) customers or to..
- local distribution companies (LDCs) which owned low pressure networks. In some countries (e.g. Britain and France) the MGTCs owned most or all of the LDCs; in others (e.g. Germany and Italy) there were hundreds of LDCs in local and municipal ownership.

With (privatisation and) liberalisation of utility markets resulting from national legislation and the EU First, Second and Third Energy Packages this structure changed fundamentally. By the 2010s, NOCs and IOCs were still recognisable (although fewer in number), still selling gas partly under long term contracts with utilities, partly directly to large customers and partly at market hubs. But merchant transmission companies had disappeared and been replaced by (or merged or demerged into) the following groups:

- Utilities holding gas (and power) assets mainly gas-fired power stations and regasification terminals[61];
- Mid-stream energy traders: trading gas, power and many other (energy and non-energy) products. These included the trading departments of the utility companies but also IOCs, NOCs, and independent traders without physical assets;
- Network companies: transmission system owners and operators (TSOs) and distribution system owners and operators (DSOs).[62] Many of the TSOs had been demerged from the MGTCs and then merged with each other (and electricity network operators) as had and did many of the DSOs. They are prevented from engaging in energy supply and are pure gas (and power) network companies;
- Local distribution companies (which, depending on their size, may or may not still own networks) which serve smaller customers in competition with a range of other suppliers;
- Storage owners and operators some of which are owned by TSOs and NOCs, and some in independent ownership.

The fragmentation of what was previously a vertically integrated and therefore relatively cohesive sector means that to a large extent, and despite the use of the term in this paper, it has become problematic and probably misleading to refer to a `European gas industry'. Companies involved in the European gas value chain in the 2010s can be divided into four functional groups[63]:

1) Producers and exporters of gas as a commodity;
2) Suppliers and traders of wholesale and retail gas;
3) Generation, regasification and storage asset owners;
4) Network owners (and operators).

A few companies are involved in all of the first three categories, and many companies are involved in categories 2 and 3. The commodity producers have similar – and in many cases joint – assets and businesses for both gas and oil. In the other groups many, if not most, companies in groups 2 and 4 have assets and businesses related to trading and transporting power as well as gas. Network ownership and operation – the product of regulatory requirements arising from the unbundling provisions of (especially) the Third Energy Package - does not overlap with any other group (except in

[61] IOCs and network companies also own regasification terminals.
[62] Owners and operators of these assets may be different.
[63] As noted above, gas-related equipment (boiler and other heating equipment) suppliers and servicing companies could also be considered to be part of the value chain, as they are an integral part of gas usage.

relation to regasification terminals) and these companies have a very different commercial and regulatory agenda to the first three groups.

Aside from the gas producers and exporters, these different industry groups have limited incentives to promote - or to lobby politicians or other decision-makers, in favour of - gas (and especially natural gas) over other forms of energy – e.g. coal, renewables, nuclear and electricity generally. To use a phrase borrowed from a different EU context, the European gas community is unable to `speak with one voice' about its future, because the commercial interests of the four value chain groups are different in relation to the priority they give to gas relative to the other products and services which they sell. This is potentially an important barrier to investments in technologies such as CCS which will require cooperation between all value chain groups.

Fragmentation of the value chain post-liberalisation constitutes a problem for the future of gas. It also highlights the fact that network and storage assets could have a future independent of – or only partly related to - the future of natural gas as a commodity, if hydrogen (either manufactured from gas or via electrolysis) becomes widely-used as a source of heat energy.

Mismatches of commercial interests and time horizons along the value chain

Along the value chain there is a major divide between producers and exporters which want to sell natural gas over long time periods (ideally underpinned by long term contracts), and network owners and operators which want to extend the life of their assets, not necessarily transporting just natural gas, but also potentially: biogas[64], biomethane, hydrogen (from natural gas or electrolysis) or some mixture of these products. While network owners also have a strong interest in a long time horizon for their assets, they need to maintain flexibility to respond to policy, technology and commercial change. The position of transmission companies may be different to that of distribution companies, because the latter may need to respond to local decarbonisation initiatives of various kinds.[65]

Somewhere between the producer/exporter and network owner positions are:

- the suppliers and traders of wholesale and retail gas which, if they are producer/ exporter affiliates will clearly be influenced by their parent companies. But most will be suppliers of power as well as gas, and (aside from producer affiliates) may not have strong feelings about how the balance of their sales should evolve in the future. An all-electric future may not constitute a significant problem for those without specific gas-related assets as they can simply switch to selling more power and less gas. These companies may be more concerned to adjust to the needs and wishes of their customers in relation to energy supply and services, including consumer preferences for non-fossil electricity.
- Owners of generation, regasification and storage assets have different interests and time horizons. Generation has the shortest asset life and has flexibility to form part of a renewable energy offering, but will be dependent on either a sufficiently high load factor or a capacity payment to remain commercially viable. Regasification assets have more in common with exporters in that they regasify LNG into conventional natural gas and are therefore dependent on the durability of that commodity even if is subsequently decarbonised further down the value chain. Storage asset holders are also dependent on continued natural gas utilisation and on the transmission networks to which they are attached, to continue to distribute natural gas.[66]

[64] Depending on its calorific value, it may not be possible to inject large volumes of biogas into networks carrying other types of gas. This would mean that biogas distribution would be possible, but limited to small distribution systems or discrete sections of large distribution systems delivering to communities not requiring a high calorific value product.

[65] For example, a power to gas project could work well for a small scale distributor which might then convert its network to hydrogen and disconnect from the gas transmission network.

[66] Salt caverns can be used for hydrogen storage; different views are expressed in the literature as to whether depleted fields and aquifers are suitable for hydrogen storage.

However, with advances in smart grids and battery (and other storage) technology enabling daily load shifting, their role seems likely to be increasingly restricted to seasonal load balancing.

Mismatches between policy and commercial time horizons

An additional problem is the mismatch between the time horizons of policy makers and commercial companies in the gas value chain. Post COP21, policy makers are coming under increasing pressure to deliver carbon reduction commitments for 2030 and 2050 via legislation and regulation. By contrast energy companies (particularly operating in a low-price environment) are focusing on time horizons which will deliver short term returns to shareholders, and avoid any investments which are not immediately necessary or not supported by current commercial conditions. The emphasis on short term trading and much shorter term contracts giving greater flexibility, means that managements have less incentive to think further ahead than a few years (or even a few months). In this commercial environment, it has become impossible for companies to consider a time frame as far distant as 2030 (let alone 2050) and therefore very difficult to engage in cooperation with other commercial parties to propose an investment in, for example, carbon capture and storage which is likely to result in gas and power costs in excess of prices anticipated in the late 2010s.

Difficulties of reaching a common national position

Fragmentation of the gas community means that finding a common position even in a single country, let alone across Europe, may be impossible. Because value chain configurations differ by country, and probably also by region and locality, the gas community in each country will need to see how much common interest there is in a natural gas-related future. It could be that although all value chain players will want to retain gas as a fuel in their business model, different parts of the chain will see a different future in relation to time horizon and type of gas, particularly in countries with highly fragmented ownership of the gas and power value chains.

Outside Europe: a different outlook for different regions (and countries)

While any kind of detailed appraisal of the future of gas outside Europe is well beyond the scope of a short paper, it is important to point out that other regions of the world have different energy and environmental priorities to those of Europe. In *North America*: low cost shale (oil and gas) production is more likely to mean that gas and renewables will prevail at the expense of coal.[67] However, opposition to fracking is limiting development of shale in some US states, and concern about methane emissions from shale operations (and natural gas operations more generally) may also place limits on development.[68] But North America is the OECD region where natural gas has the most promising future.[69]

Much of *Asia*, particularly China and India, has very significant domestic reserves of low cost coal and increasing energy (particularly power) demand. As a result, coal continues to dominate along with renewables in new power generation investment plans.[70] Natural gas – often based on imported LNG or (in the case of China) pipeline gas – is considered too expensive to be a large scale solution. The

[67] The IEA's New Policies Scenario for 2016 has only 7GW of new coal-fired generation being built in the Americas in the period up to 2040 compared with 296GW of gas-fired generation and 1183GW of renewables. IEA: *World Energy Outlook 2016*, Table 6.4, p.261.

[68] Boersma (2016).

[69] The IEA's 2016 New Policies Scenario has 197GW of new gas-fired generation being built in OECD Europe (although around one quarter will offset anticipated retirements during this period) and 79GW in OECD Asia Oceania in the period up to 2040. This compares with 35GW of coal and 666GW of renewable generation in Europe, and 36GW of coal and 209GW of renewables in Asia over the same period. IEA: *World Energy Outlook 2016*, Table 6.4, p.261.

[70] In the period up to 2040, the IEA (New Policies) suggests that China will add 298GW of new coal-fired generation compared with 132GW of gas and 1306GW of renewables; the corresponding figures for India are 300GW of coal, 92GW of gas and 443GW of renewables; and for South East Asia 136GW of coal, 106GW of gas and 142GW of renewables. IEA: *World Energy Outlook 2016*, Table 6.4, p.261.

fall in LNG prices and the increase in international coal prices in 2016, brought generating costs of coal and gas-fired generation much closer together. However, future priorities for gas may depend on how much damage was done by the image of imported LNG as an expensive source of energy during the 2011-14 period, and concern that building significant additional import terminal capacity may coincide with possible future price increases in the 2020s when global LNG supply and demand rebalances.[71] This period may have left governments with the impression that imported LNG will be unaffordable on a large scale, relative to domestic coal (and potentially also renewables).

Costs aside, Asian countries also consider domestically produced coal as a secure source of supply and, for countries traditionally dependent on gas-fired generation, diversification of energy sources. In South East Asia, countries which have traditionally depended heavily on gas-fired generation, nearly 30GW of new coal-fired generation is under construction (with an additional nearly 60GW permitted and pre-permitted).[72]

Africa is likely to be a similar story to Asia but with even less ability to pay high prices for imported gas and LNG. Therefore gas demand on the Continent will most likely be driven by low cost indigenous resources. But the IEA suggests that 160GW of new gas-fired generation will be built by 2040 which is around twice the projected new coal capacity.[73] In *Latin America*, the main gas developments have been based on indigenous gas development; gas utilisation tends to be strongly linked with back-up for hydropower during years of low rainfall.[74] Gas demand in the *Middle East* has increased substantially over the past three decades and this is likely to continue but at a slower rate, with renewables (especially solar power) and in some countries nuclear power, taking an increasing share of the power market.[75] *Russia and other former Soviet Union (FSU)* countries are already heavily gas-dependent and are relatively inefficient users of energy. Therefore Russia and other gas-rich FSU countries with limited alternative market opportunities, with growth potential mainly in the transport sector.

In most countries in regions outside Europe, the issues of affordability and security (defined as minimisation of import dependence) are higher up on the political agenda than the issue of carbon reduction. Affordability of imported gas should be a less important problem in the late 2010s and early 2020s when the global oversupply of LNG is expected to keep international prices at or below 2016 levels, but will become more important as the market rebalances in the 2020s. Many non-OECD markets will not be willing or able to pay prices for imported gas which exceed $6/MMbtu (and even this may be too high for some countries except at times of peak demand).[76] But in the absence of substantial cost reduction, many new greenfield gas projects may not be developed at prices significantly below $10/MMBtu. This will be a difficult problem for the gas industry in the 2020s, the resolution of which will be one of the important keys to its future globally. To the extent that the tension between costs of new supply and expected prices is not resolved, dependence on (particularly domestically produced) coal looks set to continue (and even increase) particularly in Asian countries. In countries where energy demand grows substantially, gas demand will also grow but will depend on development of domestic coal and renewables, unless air quality becomes an urgent political issue.

[71] This is particularly the case for land-based regasification terminals. Supply to floating terminals can be terminated if prices rise above certain levels as long as leasing contracts are appropriately flexible. Corbeau and Ledesma, eds. (2016), pp.180-206.
[72] Cornot-Gandolphe (2016).
[73] IEA: *World Energy Outlook 2016*, Table 6.4, p.261. Corbeau (2016).
[74] Honoré (2016)
[75] IEA: *World Energy Outlook 2016*, Table 6.4, p.261.The Middle East is the only region where the IEA sees more new gas-fired (213GW) than renewable (121GW) generation up to 2040 (although this includes 41GW of gas capacity retirements).
[76] Where gas is replacing diesel or other oil products (eg in small Island states), there may be willingness to pay higher prices.

Environmental priorities: air quality versus carbon reduction

It is a reasonable generalisation that outside Europe, the majority of countries have much lower sensitivity to climate change (and carbon reduction) issues. In many countries urban air quality is the most pressing environmental issue because of health effects. If this becomes a sufficiently high priority on the political agenda then it could provide a very significant opportunity for gas, particularly in large cities, because of the difficulty of installing sufficient renewable energy to have a rapid impact on urban air quality.[77] New `clean coal' plant can be expected to run with higher efficiency levels, fitted with sulphur and nitrous oxide removal. But not only is it unclear whether this will completely solve particulate emission problems (which are an important factor in air quality), it also addresses the carbon emissions problem only to the extent that the new power stations are more efficient than those they replace.

Conclusions

Mistakes that the gas community has made in Europe (and could make elsewhere)

Assuming that coal to gas switching is the `obvious' answer to cost-effective carbon reduction

The European gas community has misjudged government policy about the urgency and cost effectiveness of reducing carbon emissions. Many governments are not convinced of the value of coal to gas switching, despite the short term carbon reductions this could achieve by utilising gas-fired generation which has either been mothballed or has been running at low load factors, at the expense of coal. The lack of any significant carbon price resulting from the EU ETS – and little sign this will soon change – has led to accusations from the gas community that the EU commitment to decarbonisation has lacked seriousness. The fact that the UK's carbon support price (combined with low gas prices) substantially increased gas fired-generation in 2015/16 at the expense of coal-fired stations can be regarded as a demonstration of what can be achieved by policy measures.[78] Again this view, while analytically correct, has had little traction with policymakers across Europe.

For many governments – specifically in Germany and central/eastern Europe – low cost coal has significant advantages despite its CO_2 content and air quality consequences. Domestically produced coal has a high policy priority as it provides job creation/retention in regions which may be critically important for political leaderships.[79] Coal is viewed as more `secure' than imported (especially Russian) gas, and (with low carbon prices) had been more competitive than gas until 2016, especially where new coal stations are able to back up renewables. The proposition that gas is the best partner for renewable energy development is therefore not necessarily correct in countries with other forms of generation capable of backing up renewable intermittency.

Failure to recognise that gas has its own environmental problems

The gas industry needs to acknowledge that gas has its own environmental problems of which the most important is methane emissions. There are no reliable and comprehensive estimates of methane emissions from the gas chain outside the United States. In the US, there are widely differing estimates of these emissions due to the difficulty of obtaining reliable estimates at the level of

[77] For a study with European case studies of the potential contribution of gas to urban air quality see IGU (2016).
[78] Although it is misleading to take the UK, with significant numbers of very old and inefficient coal-fired stations as well as more efficient gas-fired stations, as an example of what could be achieved elsewhere in Europe where power generation fleet composition and age profiles are very different. Plus, as noted above, relative coal and gas prices remain important even with a high carbon support price.
[79] Domestic production of lignite far exceeds that of hard coal (the vast majority of which is imported); there are long-running issues of subsidies connected with European coal production. For an analysis of the German situation see Dickel (2014).

geographical location and stage of operations (exploration and production, transmission and distribution).

One important source of such emissions is leakage from pipelines and particularly cast iron distribution networks which have not been modernised. A second source is emissions from upstream operations which increased in importance and during the 2010s due to public concern about unconventional gas development and particularly hydraulic fracturing (fracking). Very high estimates of methane leakage from unconventional gas operations – which are mostly not possible either to confirm or to generalise even across a single country, let alone between countries - have already done damage to the image of gas as a `clean fuel' and are used as `evidence' by those arguing that gas has no environmental advantages over coal.

Failure to recognise/accept that the gas advocacy message has had little traction outside the industry

The industry continues to repeat at gas conferences the persuasive logic that gas represents the most cost-effective short term carbon reduction strategy for most countries. Two major gas advocacy arguments in relation to carbon reduction, have been the merits of fuel switching and carbon pricing. Over the past decade, the gas community has repeatedly stressed that much faster carbon reduction could be achieved by closure of coal-fired generation and its replacement by existing (and new) gas-fired generation. In the EU as a whole – particularly Germany, France, UK and Italy – a total of 50GW of gas-fired power generation has been mothballed (closed on a temporary or semi-permanent basis) in the 2010s[80]; many more stations have been running at load factors below (and often well below) 30%, including some of the most efficient power stations in Europe. From a gas industry perspective, the obvious carbon-related logic would be to use these power stations in preference to coal-fired power stations and to do so immediately. This would have the merits of reducing carbon emissions in the short term and therefore making an immediate contribution to decarbonisation.[81]

However, this logic is not shared by the low carbon community and policy makers which are focussed principally on long term (2030-2050) carbon emissions and:

- either see no advantage in reducing emissions over a shorter time scale (granted that this would still leave longer term emissions to be addressed)[82]; or
- elevate other agendas – principally security (defined as import dependence) and employment (aimed at protection of domestic coal industries) over environmental issues including both air quality and carbon reduction. This is a clear example of the power of advocacy for locally produced energy over environmental arguments.

A serious problem for incentivising the development of any low carbon technology is that the EU Emissions Trading Scheme (EU ETS) has failed to produce a significant carbon price, and no EU agreement on carbon pricing or carbon taxation which would do so is likely in the foreseeable future.[83] Gas industry arguments in favour of meaningful carbon pricing have been vindicated by the national carbon support scheme in the UK where the price has been sufficient to create a major switch from coal to gas.

Despite the logic of the case which the gas community has made for higher carbon pricing to create the incentive for coal/gas switching leading to carbon emission reductions, this has had little traction with the policy and environmental communities[84] which don't believe the message because of convictions that:

[80] Estimate from Honoré/OIES.
[81] This is discussed at a more global level in Franza et al. (2016).
[82] An example of this approach is McGlade, C. et al. (2016).
[83] By `significant' is meant a price in the range of €30-60/tonne.
[84] See Franza et al. (2016).

- fossil fuels which have not been decarbonised must be phased out;
- methane emissions mean that environmental impacts of gas could be as bad as (or worse than) coal;
- imported gas was expensive during 2011-14 (and these price levels could return) and, especially if it comes from Russia, it is undesirable on political and security grounds;
- fast growth of renewables is popular with the electorate, particularly if it can be shown that costs are falling rapidly.

The principal mistake that the gas community has made in relation to advocacy is therefore not one of logic or analysis, but failure to accept that its arguments have had little or no traction with other important stakeholder groups, and that this situation is unlikely to change.

What actions are needed from the gas industry to create a convincing message to prolong its future?

Given this situation, a logical next question is to ask what the European gas industry needs to do to create a convincing message for policy makers.

Methane emissions and the fracking issue

It is essential for the industry to develop credible and – on some level – independently verifiable methane emissions data, both from pipeline (transmission and distribution) and upstream operations.[85] The latter should distinguish between gas which is flared (i.e. burned) and methane which is vented into the atmosphere. Without such data it is impossible to counter the almost certainly overstated figures which are given wide media publicity. It is, in any case, in the interests of all stakeholders – industry, policy makers and NGOs - that credible and verifiable data is available.

Unconventional gas, and specifically hydraulic fracturing, has become a toxic subject which is detrimental to the overall future of natural gas in Europe. From a geological and commercial perspective its future is uncertain, and only in the UK does it command strong government (but not popular) support. Supporters and opponents of unconventional gas and fracking have massively overstated their case on the basis of selective examples from (mainly) North America with questionable applicability in a European context. However, the outcome is that the image of natural gas has been, and continues to be, damaged.

Biogas and Biomethane

The conventional gas industry has been distinctly lukewarm in its support for biogas and biomethane development which are politically popular, although in need of government and regulatory support to be commercially viable. This needs to change; despite the fact that its contribution is not likely to be substantial in the context of overall European gas demand, `green gas' needs a greater level of support and a strong indication of the size of the contribution which it can be expected to make.

Security of Supply

Security of supply concerns are a particular problem for politicians in European countries with heavy dependence on Russian gas.[86] In many countries, political distrust and fear of Russia – and specifically antipathy towards president Putin – remains widespread. The industry needs to be clear that where gas security is considered a problem, new (largely EU-funded) infrastructure should provide adequate protection against interruptions. There is nothing that the industry can do about political tensions between the EU and Russia. But in the late 2010s, the supply outlook suggests that Russia is the only country which has made investments in both resource development and

[85] There is also a methodological issue of how upstream emissions should be attributed. For example Hammond and O'Grady argue that upstream emissions from both pipeline gas and LNG imports into the UK should be attributed to the UK, rather than to the countries where the emissions actually occur. Hammond and O'Grady (forthcoming 2017).

[86] And even in countries (such as the UK) which import virtually no Russian gas.

transportation capacity to maintain and even increase gas supplies to Europe compared with current levels beyond the mid-2020s.

Carbon pricing/taxation

The only part of the existing gas advocacy message which continues to attract support is higher carbon pricing (or taxation) with the UK support price of £18 (€21/ton) as an example of how this could be implemented. Elsewhere in Europe, lower CO_2 prices provide a more muted signal which requires a lower gas price relative to coal for switching to occur. However, for coal to gas switching to make an early and significant contribution to CO_2 reduction it has to be physically possible to replace coal-fired generation by increasing the load factors on existing gas fired capacity, if not in the same national market, then at least in markets linked by interconnectors. Where this is not the situation, coal to gas switching requires new CCGT capacity to be built, relying (probably) on government or regulatory support. This becomes more difficult from a policy point of view as the use of state funds for CCGTs, rather than renewables or battery storage (and in some countries new nuclear plant), is politically difficult. For much of the 2020s and 2030s coal-fired or gas-fired generation will be required for base load and/or balancing purposes. Using public funds to ensure this is gas (rather than coal) is completely valid in a carbon reduction context, but a difficult proposition for policymakers for whom security (equating to domestically produced energy), employment and least cost supply all lead in the direction of coal.

Carbon capture and storage (CCS)

Despite being the only large scale solution to decarbonisation of gas, CCS remains largely undeveloped on a commercial scale and is not considered to be commercially viable by most governments and companies.[87] The UK is an interesting case study because the infrastructure configuration needed to support the conversion of gas to hydrogen may be favourable, and may be among the least cost options for decarbonising heat (see Appendix).

Changing the message for gas from fuel switching to decarbonisation

Given current policies and the possible low carbon technology paths which could evolve in Europe, there may be less than a 15-year window before carbon reduction commitments dictate a rapid and unstoppable decline for natural gas as a commodity without decarbonisation.[88]

However:

- decarbonisation could provide gas with a much longer life in the power sector, and eventually in the heat sector;
- gas transmission and distribution networks could have a much longer life transporting and distributing hydrogen manufactured either from decarbonised gas or from renewable energy via electrolysis, or biogas/biomethane (from low carbon sources) or (in the case of distribution) district heat.

The proposition that, in the absence of decarbonisation, gas can be a `bridging fuel' in the low carbon European energy transition is unconvincing, unless by `bridge' is meant a plateau or slow decline in demand up to 2030 and a faster decline thereafter. Accelerated decarbonisation policies (without CCS) could see gas demand in power generation fall by around 50% (compared to 2014 levels) to less than 70 Bcm by 2040.[89]

[87] There are strong arguments that CCS will favour coal-fired power generation as much or more than gas-fired generation about which this author is not qualified to comment. However, as noted above, CCS would be highly favourable to gas in the heat sector where (in most European countries) coal is not a significant factor.
However, given that CCS made little progress even during 2011-14, which was a period of very high fossil fuel prices, it will be difficult to revive its fortunes in a period of much lower prices.
[88] This is a major conclusion of McGlade et al. (2016) in relation to the UK.
[89] See Figure 3 – the data is for OECD Europe only.

Post-2020, this could cast doubt on the viability of new large scale investments in European natural gas markets requiring a payback period in excess of 10 years. Despite the anticipated fall in European natural gas production, this might particularly apply to new resource development aimed at supplying gas to Europe by pipeline.[90] New LNG projects with the ability to deliver to multiple markets would not be so vulnerable to European demand decline.

A New Message: "Gas Can Decarbonise"[91]

The logical conclusion of these arguments is that unless it can be demonstrated that decarbonisation of gas will be a commercially viable option which the gas community intends to actively pursue, then the fuel has a declining future in European energy balances. The switch of emphasis which methane gas therefore needs to achieve is from a position that it has lower carbon content than other fossil fuels, to a position that gas can – given time – decarbonise and therefore retain its position and relevance in European energy balances.

This is not a question that can be deferred for a decade. Unless policy makers can be persuaded that gas is making demonstrable efforts to become a much lower, on the way to becoming a zero, carbon source of energy supply, then different energy policies may be adopted at the latest by the early 2020s (and perhaps earlier).[92] There are three major elements to decarbonisation of gas:

- carbon capture and storage with distribution of hydrogen,
- biogas and biomethane,
- power to gas (renewable electricity producing hydrogen via electrolysis).

Only the first of these provides a solution for large scale decarbonisation of *natural* gas. However, the difficulty involved in creating incentives for different groups in the value chain to cooperate in developing carbon capture and storage (CCS) does not lead to confidence that this option will be adopted on any significant scale. A traditional response of the gas community is that CCS technologies are too difficult, long term and expensive to develop, and/or that it is up to governments to finance their development either directly or via higher carbon prices. The natural gas community needs to rethink its approach to decarbonisation of gas in the power and heat sectors – possibly as two separate projects - with power as a more immediate priority and heat as a project which will not start until around 2030 (but for which plans need to be made in the next 5 years).

Assuming that the carbon reduction commitments of European governments are to be met, the decline of natural gas in Europe seems inevitable without decarbonisation, starting in the power sector in the 2020s and in the heat sector in the 2030s. But if the gas industry can demonstrate progress towards decarbonisation, its long term future – while certainly not assured – will be significantly improved. However, in order to be developed on a large scale, decarbonised natural gas will need to demonstrate than it can become cost-competitive with heat and power generation from low/zero carbon alternatives.[93]

Different futures for different parts of the gas value chain

A key conclusion of this analysis is that there are different futures for the different groups of companies in the value chain.

[90] This is a point often made about projects such as Nord Stream 2 (see the comments by EU Energy and Climate Commissioner Canete in EUOBSERVER (2016)). However, the decline in domestic European conventional gas production makes it likely that as long as a project is commissioned in the early 2020s it can recover its costs even if natural gas is completely phased out by 2050.

[91] To be completely analytically correct, the new message should be that `methane can decarbonise' in order to make the distinction between methane and decarbonised gases.

[92] This was a major conclusion of: MacLean et al. (2016), p.49, – which is specifically focussed on the UK.

[93] A correct comparison would involve not just the cost of renewable and storage technologies, but also the cost of network expansion, demand side response technologies and other country-specific issues.

Upstream producers and exporters with natural gas to sell over the next several decades need to be concerned about the time-limitation of such sales because the owners of networks, which they need to transport their gas to customers, may cease to be willing to accept their commodity unless it is decarbonised.

The network sector of the value chain may begin to experience conflicts between transmission companies and distribution companies. Companies in different regions and different localities (cities, towns and smaller communities) may have different ideas as to the type of decarbonised energy to which they wish to transition, and different ability and willingness to pay. Networks may therefore experience a shift from national to local solutions, and from natural gas to other types of gas. In the heat sector, these initiatives may come from end-user communities rather than from government policies, although the latter will be influential in setting (and monitoring) overall `targets'. The key imperative for network owners will be to ensure that their assets continue to be utilised, whether transporting natural gas, biogas, biomethane, hydrogen or heat. District heating or electrification based on renewables (unless it includes large scale power-to-gas) could mean that gas networks will become decreasingly utilised and may become redundant by (or possibly before) 2050, stranding what (in many European countries) are huge national assets.

Although this paper has grouped *asset owners* - gas-fired power generation, storage and regasification plants - together, these assets have very different productive lives and potential for decarbonisation. On a timescale of more than a decade, many generation plants will probably be retired. Regasification and storage assets have longer lives but must rely on others up and down the value chain to initiate decarbonisation, without which their assets will become stranded.

European gas in 2030 and 2050: different time frames for commercial and policy decisions

Another conclusion of this paper is that the gas community has relatively limited time to develop a response to decarbonisation which policy makers, the environmental community and electorates consider appropriate and convincing. It has become clear that this is going to be very difficult even within one country because of:

- fragmentation of the industry into different groups with different commercial agendas;
- mismatches between the commercial interests of different value chain groups and..
- different decision making time frames of these groups.

This paper does not suggest that the European gas industry has reason to panic about its future up to the mid-2020s. Falling domestic production will mean that additional gas will continue to be needed (and will be available) from upstream producers and exporters, and will need to be supplied, traded and transported to customers. But in the event of static or falling overall energy and power demand, and a continued rise of cost-competitive renewables and electricity storage, this will not necessarily be the case by the late 2020s, and especially post-2030.

Do these conclusions apply to regions outside Europe?

These conclusions relate specifically to Europe, and cannot be generalised to other regions particularly those with access to low cost domestic production, such as North America, where large scale emission reductions can be achieved by switching from coal[94] and decarbonisation of gas may not be considered urgent. In other regions, significant increases in gas demand may also be dependent on low cost domestic resource development rather than higher cost imports. There is a risk that large parts of Asia will show a similar pattern to Europe, with coal and renewables dominating

[94] Assuming that methane emissions from unconventional gas do not outweigh the benefits of lower CO2 emissions.

new power generation and gas playing a role to the extent that prices of imports remain affordable, and/or where there is no alternative option to rapidly improve air quality.

Concluding messages: not all gloom and doom for gas in Europe

This paper is not suggesting that the future for gas in Europe is `all gloom and doom'. For the period 2015-30, projections from both the IEA and the European Commission are that, with the policies that governments have said they will introduce, natural gas demand will be relatively stable and declining only modestly even with more aggressive decarbonisation policies. Post-2030, that outlook changes potentially dramatically, particularly if decarbonisation policies become more aggressive; this initially impacts power generation and progressively the heat sector. This may seem to suggest that the European gas community has another decade to engage seriously with decarbonisation, but that would be a wrong conclusion.

Natural gas has always been a long term business because of large scale investments, long asset lives and long term contracts. Decarbonisation poses different long term challenges and potentially an existential threat. Continuing with current business models and arguments may result in a situation where, by the time the gas community agrees a solution to decarbonisation which is commercially viable and acceptable to governments, a combination of renewables and electricity storage will have taken over much of its market in both the power and heat sectors. The gas community needs to engage now with proposed government policies and targets for decarbonisation in a 2030-50 time frame, even if those policies and targets seem unrealistic and to ignore short term, low cost gains which can be achieved by switching from coal to gas in power generation.

The aim of this paper is to focus the attention of the European (and potentially wider geographical) gas community on the need for a different approach to a decarbonised energy future. Specifically the gas community needs to devise, and start putting into practice, a strategy for decarbonisation of methane as soon as possible but certainly within the next five years. The alternative is to accept a future of decline, albeit on a scale of decades, and the risk that by the time the community is ready for serious engagement, non-gas options will have been chosen which will make that decline irreversible.

Appendix

The UK: a gas market with favourable characteristics for decarbonisation with carbon capture and storage

In the UK there has been significant discussion of decarbonisation of the fossil generation and heat sectors but limited progress towards achieving this goal.[95] Decarbonisation needs to be addressed in relation to both power and heat. The UK record in relation to decarbonisation of fossil-fired power generation has been disappointing, with carbon capture and storage (CCS) projects having been abandoned.[96] Government policy in relation to decarbonisation of the heat sector has focussed principally on heat pumps powered by low carbon electricity, although other pathways are also under consideration and research is suggesting that a more diversified strategy would be prudent.[97] One of the possible paths to decarbonisation of the heat sector is the conversion (`repurposing') of gas networks to distribute hydrogen either derived from decarbonised natural gas or large scale electrolysis.[98] Discussion of how far (and how quickly) hydrogen could be blended into the current natural gas network is ongoing. Current regulations place a limit of 0.5% of pipeline volume but much higher percentages (potentially up to 20%) may be possible, prior to potential full conversion of networks to hydrogen.

The UK has a combination of gas market attributes not common to most European countries, specifically:

- one of the largest natural gas markets in Europe – with around 70% of all the heat used in UK homes coming from natural gas[99];
- an existing natural gas transmission and distribution network that covers a very high proportion of the population, and which is suitable for conversion to hydrogen;
- many offshore structures – including many depleted fields – which are suitable for carbon storage, and offshore pipelines leading from the shore towards these structures.

A 2016 Parliamentary report set out a route to CCS in some detail, including the creation of 5-6 hubs from which carbon would be transported to offshore storage locations.[100] It suggested the creation of an initially state-owned (later to be privatised) CCS Delivery Company (CCSDC), comprising two separate subsidiaries – PowerCo tasked with delivering the anchor power projects at CCS hubs, and T&SCo tasked with delivering transport and storage infrastructure for all sources of CO_2 at such hubs.

An alternative logistical configuration would be that gas arriving in the UK (from either domestic or international sources) could be decarbonised at the point of entry to the grid, and the carbon transported in existing pipelines to appropriate offshore structures. An alternative corporate model could be to attempt to unify the four groups of the gas community: producers and exporters; suppliers

[95] Beyond the government commitment to phase out coal-fired power generation by 2025 – although for commercial reasons this may anyway happen before that date.
[96] The cancellation of the Longannet CCS project in 2011, and cancellation in November of a CCS competition at a very late stage in the process. BBC News, `Longannet carbon capture scheme scrapped', http://www.bbc.co.uk/news/uk-scotland-north-east-orkney-shetland-15371258; Carrington (2015).
[97] Hannah et al. (2016) - a UKERC investigation of international experience of policies to promote low carbon heat supply was launched in 2016. See also: Department of Energy and Climate Change (2013); Eyre and Baruah (2015); Howard and Bengherbi (2016).
[98] Some of the literature suggests that the natural gas to hydrogen route to decarbonisation could be among the least cost alternatives: MacLean et al. (2016). A large scale shift to hydrogen is one of the measures considered in Committee on Climate Change (2016).
[99] Department of Energy and Climate Change (2013), p.98.
[100] Oxburgh (2016).

and traders; owners and operators of generation, regasification and storage assets; network owners and operators. This model could see producers and exporters which own the gas and the offshore pipelines, become involved in producing hydrogen from decarbonised gas at the point of entry (either at the processing plants which receive pipeline gas or at regasification terminals), and transporting the carbon offshore through pipelines to depleted gas fields (or other structures).[101] Hydrogen could then be purchased by existing gas suppliers/traders and owners/operators of existing gas-related assets (especially power plants), and transported through existing networks by the current network owners/operators.[102] An extensive hydrogen infrastructure could also provide a route to transport decarbonisation using the distribution network to supply fuel cell vehicles.

The commercial aspects of a hydrogen transition would be complex – given the costs related to: hydrogen production, offshore and onshore networks, storage structures, and conversion of power plants, industrial furnaces and household appliances. But an advantage would be the potential for many of the commercial actors currently involved in the gas chain to be incentivised to remain involved, and to play important roles in the transition.

The UK has substantial advantages for this model of decarbonisation given its offshore structures, and extensive onshore and offshore pipeline networks.[103] What has become a fragmented gas industry (due to the liberalisation of the sector) should have an interest in collaborating in a transition which could create the potential for the fuel to play a significant role in the country's energy balance beyond 2030, and potentially beyond 2050. Leaving it to government to take a similar initiative via state ownership runs the risk that none of this will happen.

[101] Norwegian gas exporters are reported to be studying a similar model. Van Renssen (2016).
[102] Hydrogen can be stored in salt caverns (as is the case currently with natural gas. There are differences of opinion in the literature as to whether it can be stored in depleted fields and aquifers.
[103] This is the theme of National Grid's `Future of Gas' project. http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas/

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