GLOBAL WARMING IMPACT OF A SWITCH FROM COAL TO GAS-FIRED ELECTRICITY GENERATION IN THE UK

EVIDENCE TOWARDS A BETTER SOLUTION

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EXECUTIVE SUMMARY

1. Combustion of natural gas for power generation produces less CO_2 per unit of energy than combustion of coal, and is being promoted by the UK Government as a 'bridging' solution to tackle climate change and fulfil the UK's legally binding climate change commitments, prior to a transition to zero-carbon energy.

2. A bridging solution is appropriate if:
(a) The time frame for a transition to a full and cost-effective system of renewable technologies, associated energy storage and advanced grid infrastructure is too long to justify making the transition directly,
(b) Greenhouse gas emissions from the bridging energy system are significantly lower than those from the existing energy system.

3. Natural gas consists almost entirely of methane, a powerful greenhouse gas with a Global Warming Potential (GWP) 87 times greater than an equivalent mass of CO_2 on a 20-year time frame. Thus, a switch from coal to gas is only beneficial if methane emissions from upstream operations are sufficiently small. If too much methane were emitted, this would nullify or reverse any climate change benefit from the switch to gas.

4. When DECC examined this issue in 2013 in relation to shale gas production (fracking), their published report underestimated the impact of methane emissions in two ways:

– it used an outdated estimate of GWP; the currently accepted figure is 44% higher,

– it estimated methane emissions from fracking based on limited ground-based data that are now known to significantly underestimate real emissions.

5. This paper examines two related topics. First, it critically reviews all of the relevant science currently available on methane releases from conventional and unconventional methods of gas production, and revises predictions of their global warming potential. Second, it critically revisits the key assumption underpinning the gas 'bridging' scenario, that zero-carbon energy technology is still decades away. The main conclusions of the report are as follows:

a. For gas to benefit climate change, total methane emissions from production, storage and delivery to the point of use must not exceed 2% of the gas produced.

b. Releases from conventional gas represent at least 1% of production, so this at least halves the supposed benefit to the climate of burning gas instead of coal.

c. The liquefaction of natural gas is energy intensive and reduces efficiency by 20-25%, leaving no climate benefit from burning LNG rather than coal.

d. Methane emissions from shale gas production are much higher than from conventional production. They represent in the region of 8% of total shale production; four times greater than the “break-even figure” of 2% that would be needed to benefit the climate. Not only will shale gas fail to reduce global warming, it will actually accelerate it.

e. The rapidly falling cost of renewable energy and storage, the growing use of electricity for transportation, and the risk of dangerous climate change are all economic drivers for a rapid transition to renewable energy. Such a transition is more beneficial to the climate and potentially cheaper than the gas bridging scenario. The gas bridging approach does not, in any case, satisfy either of the climate-related criteria noted in paragraph 2.

Conclusion

The UK Government needs to urgently review its energy strategy. Industrial production of shale gas in the UK would aggravate global warming and make it impossible for the UK to fulfil its legally binding climate change commitments. Furthermore, carbon capture and storage (CCS), even if commercially feasible, could not prevent the net warming effect of these methane losses into the atmosphere. As a result, a move towards shale gas production in England will undoubtedly result in legal challenges.

In view of the revised global warming limit of 1.5°C agreed at the UN Climate Summit in Paris in December 2015, an accelerated transition to greater energy conservation and renewable forms of energy is urgently needed so that 100% of UK electricity and at least 50% of total energy use can be sourced from non-fossil fuel technologies by 2030.

1. INTRODUCTION

Current UK energy/climate strategy includes a rapid shift away from coal-fired to gas-fired power generation. This shift is partly motivated by climate change reasoning, based on the fact that electricity generation using gas typically emits around half the amount of CO_2 emitted by electrical generation using coal. Gas is thus seen as a 'bridge fuel' for use during the period before renewables can take over as our main sources of low-carbon energy.

The above strategy carries risks and uncertainties in climate-change terms, as it is now accepted that gas production and distribution leads to the undesired emission of considerably more methane into the atmosphere than does coal production and distribution. Since methane is a much more powerful greenhouse gas than CO_2 this reduces, and may even reverse, the climate benefit of a switch from coal to gas.

These facts were noted in a report for HMG on fracking by MacKay and Stone in Sept. 2013 (which we refer to here as MS2013) [1]. The report provided quantitative estimates of the impact of methane emissions, based on then available data from the gas industry and DECC on emissions, and on the climate impact of methane from the Intergovernmental Panel on Climate Change (IPCC, Fourth Assessment Report (2007) [2]). The report strongly emphasized the need to monitor and minimize methane emissions from any future UK fracking-based energy production. On balance the report considered that there would be an overall benefit to the climate in switching from coal to gas provided that strict emissions controls were implemented. That conclusion appears to have been a significant 'green light' to HMG in backing a switch to gas.

Since the 2007 IPCC climate-change report and the early industry-informed considerations on methane emissions, the relevant scientific evidence has advanced considerably. First, the IPCC Fifth Assessment Report [3], released just after MS2013, shows that methane has a considerably greater potential for global warming than previously estimated (a best estimate of 44% higher potential than assumed in MS2013 over a 100-year time frame). Second, quantitative measurements of emissions from gas production and distribution in the United States now suggest that emissions are much greater than those foreseen in MS2013 (typically by a factor of 2-5). This double impact on MacKay and Stone's assessment is considered in this report. Calculations of the relative global warming effects of coal and gas production, previously provided by MS2013, are updated. In addition, we consider bridging scenarios where gas replaces coal for electricity generation for a limited number of years before the transition to zero-carbon energy is completed. In all cases we find that there is no prospect of ameliorating climate change by switching from coal to gas. Among the many impacts that would ensue, one legal issue would be the breaking of the UK's carbon budgets.

In the last few years it has become increasingly clear that global temperature rise could potentially destabilise Earth's climate in the relatively near term. Previously set carbon budgets, although challenging, are unlikely to be tough enough to reduce this risk to acceptable levels. In response, COP21 in Paris decided on an international effort towards achieving 1.5°C temperature rise. This would imply more than halving the world's remaining carbon budget and has significant implications for the UK's thinking on energy and climate policy. In a final section of the report we therefore discuss in some detail the option of skipping the 'gas bridge' and transitioning directly to renewables, as many comparable advanced economies, for example, Germany, are in the process of doing.

2. GLOBAL WARMING POTENTIAL OF METHANE COMPARED TO CO_2

2.1 Changes in methane-related climate parameters since MacKay and Stone's report on the climate impacts of fracking (2012)

The modelling data used in MS2013 were based on DECC and industry-sourced information on emissions and on climate related data from the IPCC Fourth Assessment Report (2007). The IPCC data have since been revised as a result of the considerable ongoing efforts in climate change research. The new data are presented in the IPCC's Fifth Assessment Report [3]. Updated parameters relevant for our report are as follows:

1. The methane lifetime in the atmosphere. This is now given as 12.4 yr (previously 12 yr).
2. Indirect effects: changes in stratospheric H_2O and ozone caused by methane emissions enhance the climate forcing due to methane by 65% (previously 40%).
3. The impact of fossil methane compared to natural methane. This is a few per cent higher as the CO_2 formed on destruction of fossil methane in the atmosphere also contributes to warming (previously neglected).
4. The effect of carbon-climate coupling on the effective climate forcing by methane (previously neglected). This effect is time dependent and leads to a roughly 20% enhancement of the 'global warming potential' over a hundred-year time-frame (at t=100 years after emission). This is an example of a positive feedback – the warming caused by methane emissions causes more methane to be released from natural systems. One such positive feedback is the melting of permafrost. The uncertainty here is very much on the upside: if such melting reaches a 'tipping point' the increase may be much larger [4] than the 20% used here[3].
5. Carbon cycle model parameters (describing the carbon-climate coupling effect on CO_2). These have been slightly revised in IPCC AR5.

The net result of all these changes is a large increase in the calculated global warming effect of methane.

[3] Whiteman et al. have reported in Nature magazine a significant risk of runaway methane release from several 100,000 km^2 of subsea permafrost beginning within the next 20 years as a result of current sea-ice loss over the Arctic continental shelf. They estimated this would lead to an additional global temperature rise of at least 0.6°C.

2.2 Global warming potential of methane relative to CO_2

Methane is a powerful greenhouse gas (GHG) whose global warming effect per kg emitted is about 120 times stronger than that of CO_2, according to the latest information from IPCC AR5. Fortunately, its lifetime in the atmosphere is much lower than that of CO_2 (12.4 years, compared to CO_2 a large part of which remains in the atmosphere for over 100 years with a tail stretching to 1000s of years in the absence of human intervention). Nevertheless, owing to its strong warming effect, methane has to be included in assessments of the climate impact of fossil fuels.

A useful 'rule-of-thumb' parameter for comparing methane and CO_2 effects on climate – also implicit in the 'CO_2 equivalent' quantities used in MS2013 – is the Global Warming Potential (GWP). This parameter compares the cumulative climate forcing at a given time after emission of a fixed mass of a GHG (e.g. methane), to the cumulative forcing at the same time after emission of the same mass of CO_2. It is expressed as a ratio between the methane and CO_2 effects at a particular time after emission. The GWP for methane using the IPCC AR5 parameters is shown in Fig. 1. The value of GWP at 100 years after emission, GWP_{100} = 36. This is 44% higher than the value of 25 assumed in the calculations in MS2013. Applying this correction has a significant impact on the results reported in MS2013, which was released just before publication of AR5.

A key feature of this result is that methane is an extremely powerful greenhouse gas when assessed on a timescale of a few decades after emission. This is important because certain 'tipping points' such as methane release from permafrost, melting of the Greenland ice-sheet, etc., may be irreversibly triggered on time scales of 20 – 50 years into the future, rather than the 100 years considered in MS2013. We will therefore consider a range of climate-relevant time scales in this report; notably 20, 50, and 100 years.

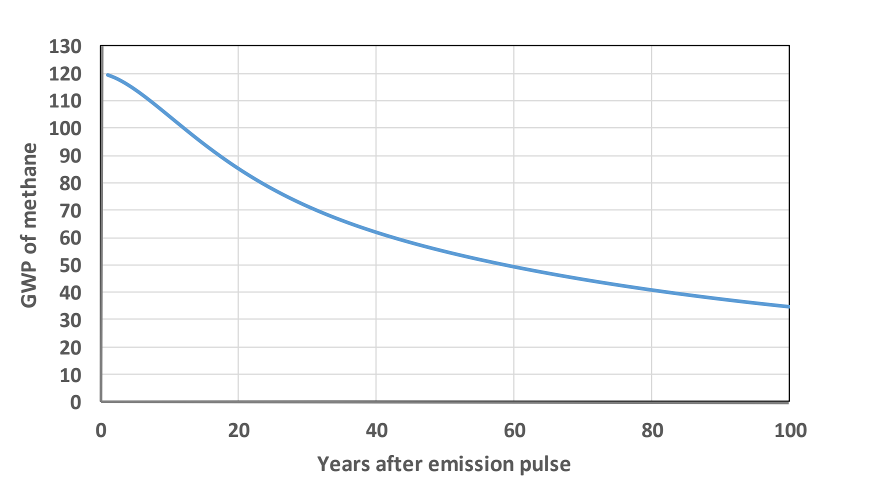

Fig. 1: Global warming potential for fossil methane shown as a time-dependent curve. The curve is based on the most recent (2013) dataset from the IPCC, known as AR5 [3]. It is customary to quote GWP values at 20, 50 or 100 years after emission. Based on AR5, GWP_{20} = 87, GWP_{50} = 54, and GWP_{100} = 36. GWP_{100} is 44% higher than the value of 25 used in MacKay and Stone's report.

2.3 Impact of the updated GWP on the results reported in MS2013

2.3.1 Comparison between various sources of gas

Fig. 6 of MS2013 (adapted here as Fig. 2) shows a comparison of CO_2-equivalent life-cycle emissions from various sources of gas, based on the GWP_{100} parameter from the 2009 IPCC AR4 report. The data are based on the assumption that 90% of methane released during well completion is flared, rather than escaping to the environment. This comparison enabled MacKay and Stone to conclude that unconventional gas has a (somewhat) lower carbon footprint than imported liquefied natural gas (LNG), and is the basis for Baroness Worthington's 2015 appeal for public acceptance of fracking in the UK as a means of mitigating climate change.

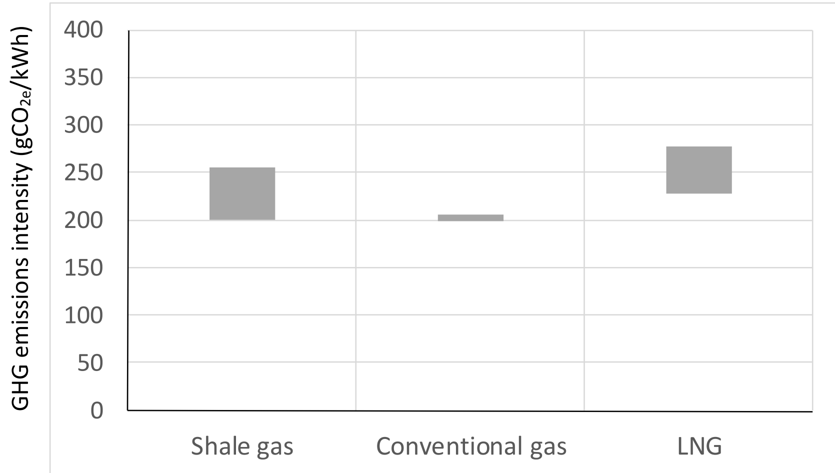

Fig. 2: Comparison of CO_2-equivalent life-cycle emissions from various sources of gas, based on the GWP_{100} parameter from the 2007 IPCC AR4 report. The data are based on data from MS 2013, including the assumption that 90% of methane released during well completion is flared rather than vented.

Fig. 3(a) shows the impact on those results of applying the IPCC's updated GWP_{100} parameter discussed above, *keeping all other parameters the same as assumed in MS2013*. Here we have applied the updated GWP_{100} to the well completion footprint, which according to MS2013 carries the largest methane emissions. Methane emissions from other phases of gas production considered in MS2013 have much less impact and are roughly equal for all sources of gas.

It can be seen from Fig. 3(a) that emissions from unconventional gas and LNG are now approximately equal, within the uncertainties in the data

Fig. 3(b) compares life-cycle CO2-equivalent emissions as viewed at 50 years after emission, again using the updated IPCC parameters. 50 years is an important time frame as major climate impacts are likely to have occurred, yet there will have been relatively little time for humanity to adapt to these impacts and/or successfully mitigate them. At this stage unconventional gas probably has a higher warming effect than that of LNG, and very much higher than that of conventional gas.

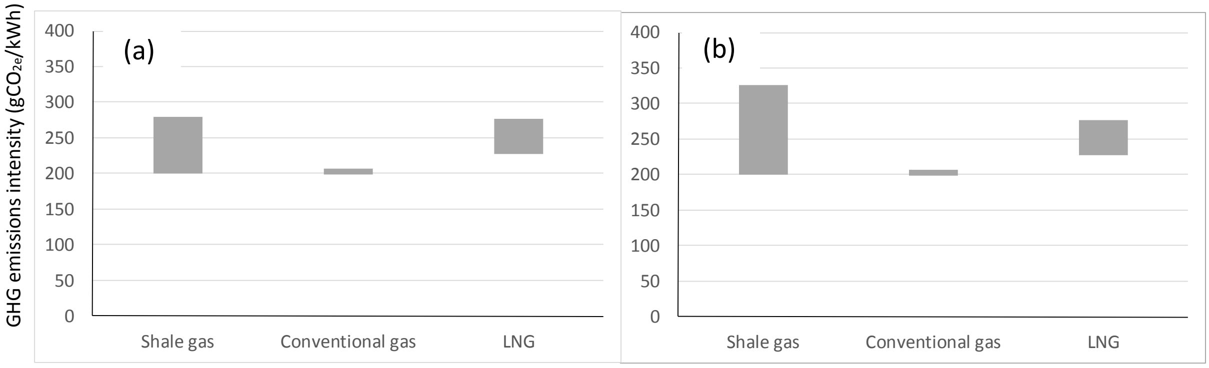

Fig. 3: Comparison of CO_2-equivalent life-cycle emissions from various sources of gas, based on the updated GWP parameter from the 2013 IPCC AR5 report; (a) GWP_{100} (b) GWP_{50}. Again, the data are based on data from MS 2013, including the assumption that 90% of methane released during well completion is flared rather than vented.

2.3.2 Comparison between various sources of gas and coal for electricity generation

Fig. 4a, as in Fig. 7 of MS2013, shows a comparison of CO_2-equivalent life-cycle emissions for the production of electricity from various sources of gas, and coal, based on the updated GWP_{100} parameter from the 2007 IPCC AR5 report. At 100-years after emission, the carbon footprint of shale gas is lower than that of coal but significantly higher than estimated in MS2013.

Fig. 4: Comparison of estimated CO_2-equivalent life-cycle emissions from various sources of gas, and coal, used for electricity generation. The data are based on GWP parameters from the 2013 IPCC AR5 report. (a) GWP_{100} (b) GWP_{50} (c) GWP_{20}. Again, the data are based on MS2013 including the assumption that 90% of methane released during well completion is flared, rather than vented.

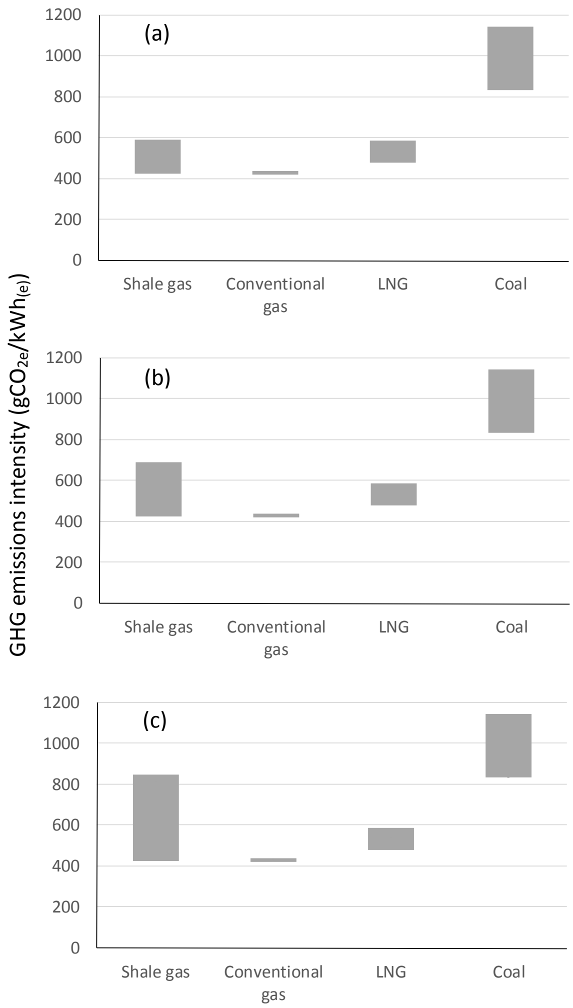

Fig. 4b and 4c show the life-cycle CO_2-equivalent emissions that are effective at shorter times; 50 and 20 years after emission, respectively. At 50 years the climate-change advantage obtained by using unconventional gas rather than coal is significantly reduced, and at 20 years the uncertainty ranges for shale gas and coal overlap.

Had MS2013 been published or updated a few months later, it could have benefited from the revised GWP data published by the IPCC in 2013. In that case the scientific input to policy would already have been significantly less favourable to unconventional gas development.

It is important to note that the graphs presented above *still rely on the methane emissions data used by MacKay and Stone in MS2013*, and follow their preference to exclude one of their reviewed data points considered to be an outlier [5]. As we will see in the next section, more recent measurement data show much higher emissions than reported in MS2013, closer in value to the rejected outlier.

We now go on to review recent research on emissions, and in Section 4 we present current best estimates for the global temperature forcing arising from gas and coal-based electricity generation. Section 5 summarizes our data on the impact of a coal-to-gas ‘bridging’ strategy, and Section 6 reviews plausible timescales and routes through the low-carbon transition.

3. LIFE-CYCLE METHANE EMISSIONS FROM GAS PRODUCTION

Since the publication of MS2013 a series of peer-reviewed scientific papers on methane emissions from oil and gas production have been published. Although much remains to be done, a broad scientific consensus is emerging that emissions are substantially greater than stated in national and international greenhouse gas inventories, and considerably greater than assumed in MacKay and Stone’s report.

3.1 Emissions from oil and gas production

The question of how much methane is emitted during unconventional gas production has been a highly controversial topic in recent years. Peer-reviewed published data on emissions from several oil and gas producing regions in the USA, obtained using ‘top-down’ (TD) measurements by a range of methods (aircraft-based, road-based, satellite-based, and measurements from fixed towers) have shown much higher emissions than expected from ‘bottom-up’ inventory estimates compiled from industry data, for example, by the US Environmental Protection Agency (EPA). Most of the published TD results to date [6], [7], [8], [9] have suggested emission rates well above the point at which there is a climate change benefit from switching from coal to gas.

Top-down measurements take a sample from the entirety of emissions from a specific region of interest. They extract information on methane from oil and gas production from a background arising from various sources including methane emitted by agricultural or natural processes, using a variety of techniques summarized in Ref. [10]. In contrast, bottom-up measurements are taken directly from each individual component of an oil or gas site and are then summed, at least in principle, over all components and all sites to obtain a total regional emission estimate. Official inventories, notably by the EPA, have traditionally been based on BU data only.

It has been thought for some time that part of the discrepancy between BU and TD data may arise because a few large emitters make a disproportionately large contribution to overall emissions. In this situation, BU measurements are likely to miss the most strongly emitting cases, leading to an underestimate of overall emissions. This view has been convincingly confirmed in a recent paper [10] that summarizes nearly a decade of research by the Environment Defense Fund (EDF), a US body part-funded by the oil and gas industry which collaborates with US universities and institutes. The paper presents an exhaustive study of BU and TD emissions in the Barnett Shale oil and gas producing region of Texas, taking to measure and statistically combine emissions from large as well as small emitting sites. As a result, the authors were able for the first time to reconcile BU and TD measurements from the same region and show the importance of large emitters.

The study also revealed the detailed distribution of the number of emitters as a function of their size. As this proves important for our further discussion, this paragraph briefly discusses the related physics. Fig. 6 shows the distribution of emission rates from individual sites as a function of their frequency (frequency meaning the fraction of sites with that particular emission rate at time *t*, averaged over all *t*).

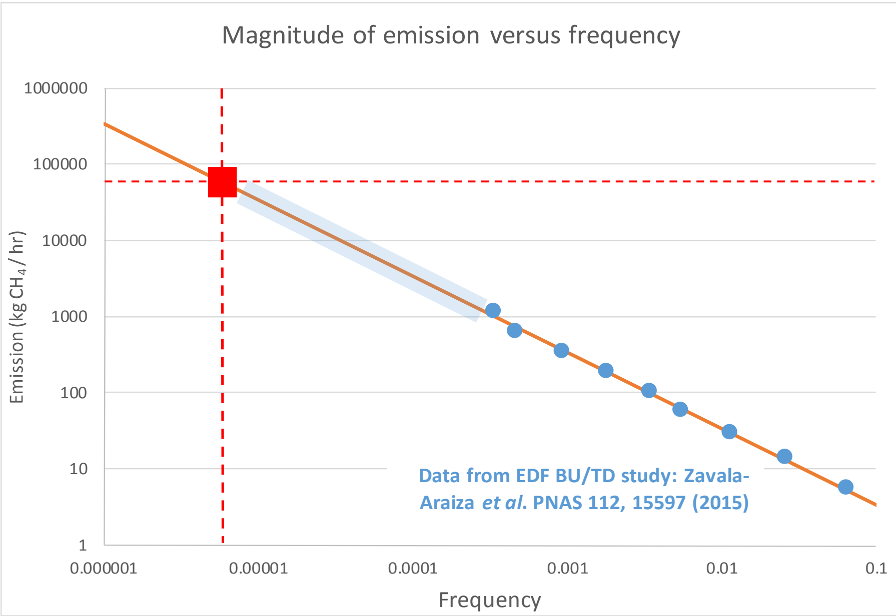

Fig. 6: Frequency scaling of methane emission rates from individual sources in the Barnett shale region reported by Zavala-Araiza (Environmental Defense Fund, Dec. 2015) [10]. The straight line through the data on this log-log plot is a 1/f distribution. The blue highlighted section of the curve represents larger, very low probability emission rates which are unlikely to be captured by short-term measurement campaigns, but will contribute significantly to overall methane emissions. The horizontal dashed line represents the huge emission rate from the damaged SoCalGas storage site near Porter Ranch, California. The vertical dashed line represents the inferred frequency, about 1/200,000, for such an event. Given the hundreds of thousands of emitting sites worldwide, events of this magnitude are statistically likely to occur and should be included in emissions estimates.

In order to display, in one diagram, the huge range of measured emission rates (ranging from about one to several thousand kg CH_4 /hr), and frequencies, the vertical and horizontal scales in Fig. 6 have been compressed so that so that each division represents a factor of 10 increase. Remarkably, the data summed over all emitting sites (wells, processing plants and compressor stations) cluster tightly along a curve (a straight line in this log-log plot) known as a 1/f distribution. The same curve is applicable to self-similar, or fractal, phenomena such as large-scale accidents and earthquakes where it is known as the Gutenberg-Richter Law.

Presumably in the case of large emission events, as with large-scale accidents, self-similarity arises through a balance between cost and perceived acceptable risk of events potentially occurring over a wide range of magnitudes.

By analogy with earthquake magnitudes, it may be convenient descriptively to define the emission magnitude, $M = \log_{10}$(emission rate/kg GHG/hr). In this unit an emission rate of 10 kg CH_4/hr) has magnitude 1, the largest emission rate measured in Ref. [10] has magnitude 3.5, and the emission rate from the recent Porter Ranch blowout had a peak magnitude of 5.2. In this description the magnitude M plays the same role as that on the Richter scale of earthquake magnitudes.

The 1/f distribution is an indispensable tool for the realistic estimation of methane emissions from statistical samples of experimental data on gas production. Total emissions result from events over the full range of possible magnitudes, and this range depends on the maximum cut-off magnitude that can occur. The maximum may be extremely large, as exemplified by the recent storage well blow-out at Porter Ranch near Los Angeles, which for several months has been emitting methane at a rate nearly 50 times faster than the largest emitter reported in the recent EDF paper; in fact, this is close to the total emission from the whole Barnett Shale region. As this is probably the highest-rate emission event that has occurred in the onshore gas industry to date, we take this as our estimated maximum magnitude. The blue highlighted section of the 1/f line in Fig. 6 then shows the inferred emissions in the range of magnitudes from the largest in the EDF measurement sample, up to the maximum cut-off value. The inclusion of the 'missing' large-scale emissions in the blue highlighted section leads to an approximately 60% upward correction to the total emissions estimated in the EDF paper. This correction quantifies the intuition voiced by many observers, that we have underestimated emissions by failing to take infrequent large-scale emission incidents into account.

Unfortunately, earlier publications have not provided enough information and analysis on emission magnitudes from individual sources to enable a similar quantitative correction to be applied. Nevertheless, some broad conclusions are possible. We assemble all the available data that appears to be of reasonable quality in Fig. 7; results where the dynamic range of measured excess GHG concentrations (i.e. ratio of maximum to minimum measured concentration) is less than 10:1 are discarded. This ensures that measurements that sample only the highest frequency / lowest magnitude portion of the frequency range, and are thus the least reliable, are excluded from the discussion. For completeness, the full set of available data, without selection, is discussed in Appendix A.

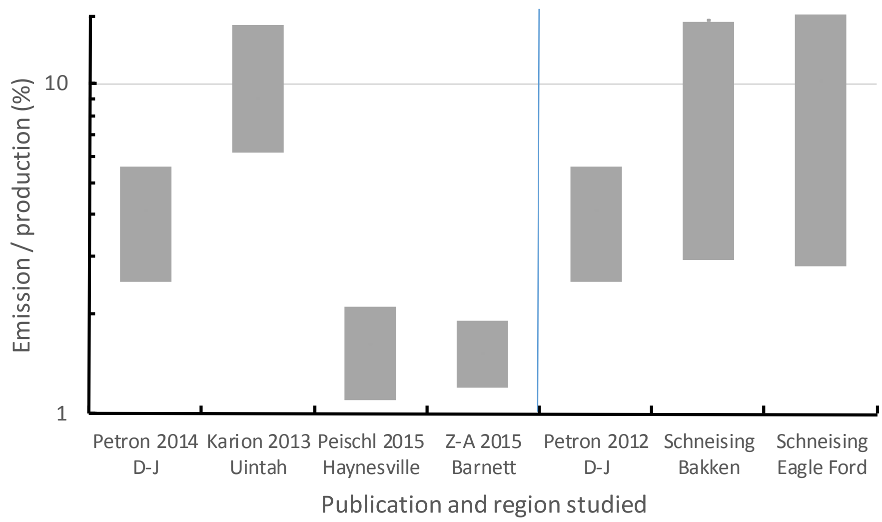

Fig. 7: Emissions data for several gas fields obtained from top-down measurements. Data bars to the left of the vertical line were obtained by short-duration measurements [10], [8], [7], [11], which potentially underestimate emissions (see text). Data to the right were obtained partly (Petron 2012 [6]) or fully (Schneising 2014 [9]) from long-duration measurements. D-J refers to the Denver-Julesburg region and Z-A 2015 refers to the 2015 EDF paper by Zavala-Araiza [10].

Several of the results in Fig. 7 were obtained by aircraft measurements of methane on just two separate days. As sampling is of such short duration, aircraft are likely to underestimate emissions as rare but large emission events, which may also be of short duration, will probably be missed. However, the dynamic range of the data is large enough to justify inclusion of the results. All the data in Fig. 7 obtained from road-based measurements and/or aircraft (data bars to the left of the vertical line) probably underestimate total methane emissions from production.

Fig. 7 also shows data obtained from measurements over long periods (data bars to the right of the dashed line). Petron et al. (2012) [6] used a hybrid approach, combining measurement data from a fixed tower collected over several years with extensive road-based measurement data collected during the summer of 2008. Schneising *et al.* [9] took spatially resolved data over a six-year period from 2006-2011 using the SCIAMACHY instrument on the ENVISAT satellite. Both approaches have a tendency to show significantly higher emissions than have been found using pure aircraft/road-based methods. Petron (2012) gives a best estimate of 4% methane emissions from the Denver-Julesburg Basin [6] and the satellite data give 10.1% from gas production in the Bakken region and 9.1% from the Eagle Ford region [9]. At least part of the reason for these higher values is that longer-term measurements (e.g. Petron 2012) capture a wider range of emission events, and long-term space-based observations (Schneising *et al.*) capture the sum of **all** emission events, including some that may only occur rarely but are of very large magnitude.

Even higher fossil methane emissions have been found in the LA Basin (17% emissions) but here the sources are less clearly identifiable and this data is not included in Fig. 7.

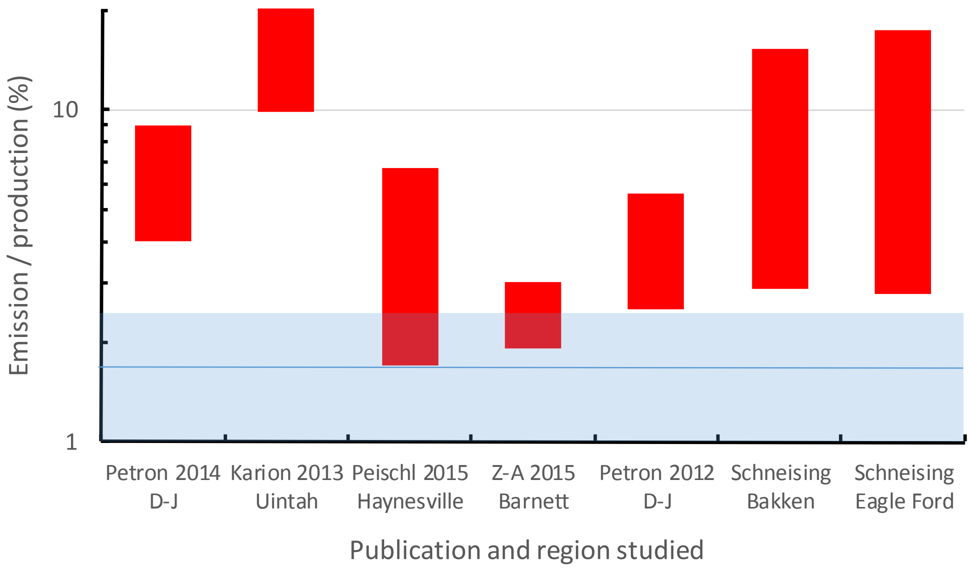

Fig. 8: Emissions data after correction; the four bars to the left in Fig. 7 have been scaled as discussed in the text. The blue horizontal line shows estimated worldwide % emission of fossil methane into Earth's atmosphere, obtained by analysis of the ^{13}C anomaly in the early 1990s – a time when only conventional gas production was taking place. The shaded area represents uncertainties in this estimated value. Methane emissions resulting from unconventional gas production are in most cases substantially (up to about 10x) higher than this.

Our 1/f analysis has shown that the most extensive and carefully analysed study to date using aircraft and road-based surveys – the 2015 EDF paper [10] – needed to be corrected by an enhancement factor of 1.6 in order to estimate realistic total emissions averaged over a long period. Previous aircraft/road-based surveys provided smaller statistical samples acquired over shorter times, and likely require larger corrections. We have therefore carefully assessed the quality of the earlier studies. Refs. [7] and [8] acquired quite extensive data but the data from Ref. [11] are relatively sparse, which is likely to bias results towards low emission values (see Appendix A for details).

We therefore choose to scale the results from Refs [7] and [8] by the same factor of 1.6 used with Ref. [10], but to scale the data accepted from Ref. [11] by a factor of 1.6-3.2, such that the lower bound on each data bar is multiplied by 1.6 and the upper bound by 3.2, reflecting the uncertain systematic bias in the data. The resulting adjusted emissions are shown in Fig. 8. The three right-hand bars were not subject to any correction as these were long-term measurements. The most plausible range of emissions appears is 2.5 – 12%.

Previous analyses have already indicated that real methane emissions from gas production are substantially higher than assumed in national methane inventories, with measured emissions ranging from 2 to 5 times EPA inventory estimates [7], [8], [9], [10]. Our correction to these analyses suggests that the discrepancy is even larger.

Among the above results the well characterised EDF data for the Barnett Shale region [10] gives the lowest value. The authors commented that this low value may be connected to the specific conditions in the Barnett region, which at the time of their measurements was already a mature field with a relatively low rate of drilling and well completions compared to more actively developing fields. This is important for the UK context, where the growth of unconventional gas fields would involve very high rates of drilling and well completions.

It is interesting to compare the above data from unconventional oil and gas production with historically measured global emissions which were dominated by conventional production, with a smaller added contribution from coal mining. Measurements and modelling of the isotopic methane anomaly $\delta^{13}C$ at the beginning of the 1990s have shown that fossil methane emissions were approximately 100 Tg/yr [12], roughly 1.8% of total gas production at that time. Since 100Tg/yr in 1990 corresponds to about 18% of the total methane flux, most of which is known to be biogenic [12], this figure cannot be a serious underestimate. Moreover, the 1.8% emission figure assumes that fossil methane emissions in 1990 were dominated by gas production, whereas in fact significant emissions may also have arisen from oil and coal. Clearly then, total global emissions from gas production and distribution have historically been in a range well below 2%. The much larger emissions from unconventional oil and gas production in the US in recent years, measured by several academic groups and institutions, clearly show that these high emissions are linked to the industrial application of *unconventional* oil and gas technology, rather than to the use of natural gas *per se*.

In Ref. [10] it was shown that production sites, processing plants and compressor stations all contribute less frequent, large magnitude emissions that are unlikely to be detected by standard bottom-up industry measurements, and were not considered in MS2013 [1]. Thus, it appears that multiple source types contribute to the large overall emissions of methane during unconventional gas production, in addition to well completion emissions discussed above.

3.2 Emissions from distribution to point of use

Measurements in Boston and New York indicate that approximately 2.7% of gas production is lost in the downstream components of the natural gas system, including transmission, distribution and end use [13]. This is a factor of 2.5 larger than national inventory estimates. In the case of distribution to power stations, where the required pipeline networks are less complex, we assume in the absence of reliable information a value of approximately 1%.

3.3 Summary of methane emissions for use in global warming estimates

Current evidence from experimental measurements and statistical analysis shows that the relevant methane emissions from unconventional gas production in the US represents 7% of production. An average of the results in Fig. 8 together with an additional estimated 1% from distribution gives a best estimate for total life-cycle emissions of about 8 % with lower and upper limits of 3.5% and 13%, respectively. While the UK situation may vary from that in the USA as a result of differences in regulation, geology and best practice, and while future improvements may be possible, we take the approach of applying available US results to the

UK situation as a preliminary guide to likely emissions. In the next section we use this approach to compare the climate forcing effects of unconventional gas and coal for electricity generation.

4. COMPARISON OF CLIMATE FORCING BY COAL AND GAS-BASED ELECTRICITY GENERATION

4.1 Estimates based on the concept of Technology Warming Potential

The direct use of the methane Global Warming Potential (GWP), discussed in section 2, to assess the relative merits of gas and coal is problematic for two main reasons. First, GWP refers to emissions after a short pulse of a particular greenhouse gas, whereas a 'bridge fuel' scenario implies emissions over an extended period, so that methane emitted at different times during this period contributes differently to subsequent global warming. Second coal bed methane may be released during coal mining, so for both gas and coal power a mix of CO_2 and methane is involved, as production and delivery of either fuel to the point of use carries a CO_2 and a methane footprint in addition to the CO_2 generated on burning for power generation.

Consequently, it may be more informative to use the concept of Technology Warming Potential (TWP), to compare cumulative CO_2-equivalent emissions from new gas-based power generation to the reference alternative of coal-fired power generation. TWP is expressed as a ratio of these cumulative emissions.

For illustration, we present TWP results for different emission scenarios in Fig. 9. This compares TWP results for three levels of emissions from unconventional gas production and distribution, assuming an overall scenario with 25-years of gas-based generation at constant power output. Parameters for coal and gas, including electricity generation efficiencies, are taken from Alvarez et al. [14]. The bottom curve labelled 'LOW' corresponds to the 3.5% lower limit of emissions estimated in section 3.3 above, the middle curve 'MID' corresponds to the 8% best estimate, and 'HIGH' corresponds to the 13% upper estimate.

The results show that a switch from coal to unconventional gas powered electricity for 25 years, intended as a bridge leading to a complete transition for carbon-free energy, will actually contribute initially toward an *acceleration* of global warming. Depending on the level of methane emissions the excess in warming potential could continue for many decades, and in the highest emission scenario well over 100 years. Under all realistic circumstances the widely promoted 50% reduction in GHG emissions on switching from coal to unconventional gas does not materialise.

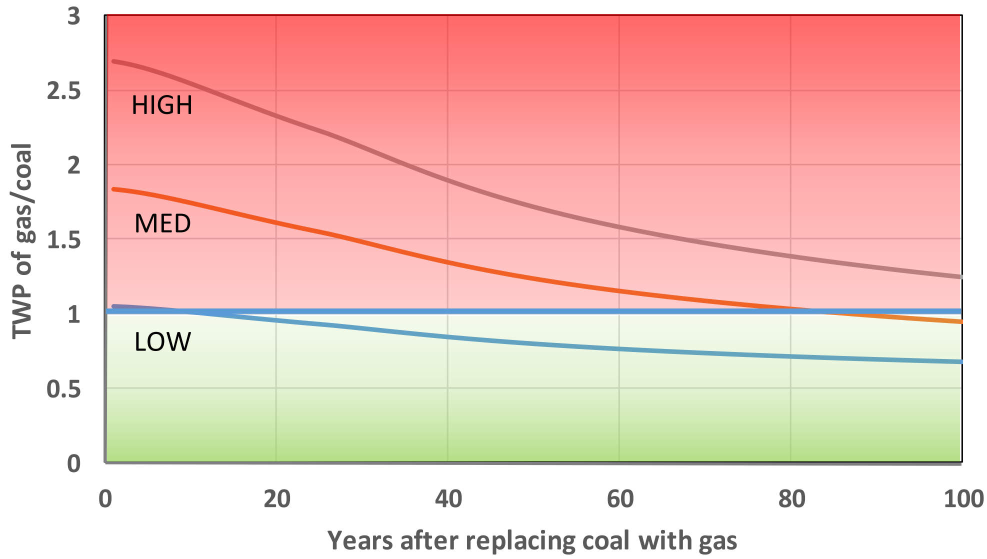

Fig. 9: Technology warming potential for gas-powered relative to coal-powered electricity generation, in a scenario involving a switch from coal to gas for a period of 25 years. Results are shown as time-dependent curves for three possible levels of life-cycle methane emissions from gas production and use: 'LOW' curve: 3.5% emissions, 'MID' curve: 8% emissions, 'HIGH' curve: 13% emissions. TWP values in the red area (TWP > 1) mean that the warming potential of gas is greater than that of coal.

4.2 Additional warming effects of a switch from coal to gas

In addition to the warming effect of methane a further, vitally important, process plays a role in the climate impact of a switch from coal to gas. Coal burning emits quantities of the gas SO_2 which after various chemical and physical processes in the atmosphere forms a sulphuric acid aerosol. This is a powerful reflector of incoming solar radiation and has consequently offset part of the global warming impact of CO_2 and other greenhouse gases, by bringing incoming and outgoing radiation fluxes through Earth's atmosphere closer into balance. Hansen has long referred to the continued use of coal as a 'Faustian bargain' as it raises atmospheric CO_2 steadily over time, to the point where it must be stopped and the full unabated climate impact of CO_2 then appears as the sulphuric acid aerosol dissipates [15], [16]. This is the situation that applies currently, except that *we are not yet proposing to stop all CO_2 emissions; only the ones (from coal) that supply mitigating SO_2*.

As sulphuric acid aerosols have a short lifetime in the atmosphere their effects are confined to the locality or region where coal is being burned, and thus their impact can only be properly modelled using climate simulation codes. In an investigation of the impact of a switch from coal to gas, Wigley has simulated scenarios in which coal-fired generation is gradually reduced to half over a period of 40 years and concomitantly replaced by gas-fired generation [17]. His results show that this gradual switch to gas has virtually no beneficial impact on global warming, even when life-cycle methane emissions from the use of gas are as low as 2%. The reason for this low threshold is the increase in incoming solar radiation caused by the decrease in sulphuric acid aerosol, together with the increase in greenhouse warming caused by the higher methane emissions from gas. At methane emissions above

2%, the switch to gas increases global warming far out into the 22nd century. It is self-evident that our average figure for methane releases from unconventional gas of 8% is four times greater than Wigley's "break-even" figure of 2%.

4.3 Carbon capture and storage

It is a commonly held view that carbon capture and storage (CCS) is an essential technology for climate-change mitigation [18], [19]. The EU's Energy Roadmap envisages 11 GW of CCS generated by 2030 and 100 GW by 2050 [20]. However, these numbers are small (around 0.5% and 5%, respectively) compared to Europe's rate of primary energy consumption which is around 2 TW (primary energy is relevant here as most future energy use will be based on generated electricity).

Predictably there is a very large gap between ambition and the reality of CCS, as pointed out by the Grantham Research Institute for Climate Change and the Environment [21]. Currently few CCS projects are under development in Europe and none are operating commercially. In addition, the Chancellor cancelled the UK's CCS research programme in 2015. There has been greater activity in North America with 13 projects underway and six more under construction. However, CCS reduces the energy efficiency of a plant by 20-30% and increases overall costs by between 50% and 130% compared with an unabated plant [21].

The Grantham Institute has calculated that a strike price of £140-190 /MWh will be needed for coal and gas-fired plants fitted with CCS to be commercially viable by the early 2020s. This compares with the strike price agreed with EDF for nuclear power from Hinckley Point of £92.5 /MWh. It is also similar to the estimated strike price for the Swansea Tidal Lagoon generation system [22], the technology for which is already available and does not require long-term (several thousand-year) storage of CO_2.

Alternatively, a carbon price of 355-360 euros /tonne CO_2 is needed before coal-fired plants would adopt CCS on commercial grounds, and 90-105 euros / tonne CO_2 for a new gas-fired plant. Currently the carbon price under the EU's Emissions Trading System is less than 10 euros /tonne CO_2. While the cost for gas-plus-CCS is lower than that for coal-plus-CCS, it should be borne in mind that CCS does not remove methane from the gas supply chain.

In summary, CCS is an extremely expensive and energy-intensive technology that has not yet been deployed at a commercial level. If used by the fossil-fuel industry to enable continued burning of coal and gas it will be of little or no benefit for global warming reduction. Moreover, there are further objections based on the short time frame for development of CCS before it is made obsolete by cheaper renewables (see also Section 6).

In the more distant future, CCS or other carbon-withdrawing technologies may be an important component of third way technologies for reduction of greenhouse gases, for example, by using them in conjunction with biomass energy plants. However, these carbon negative processes are still at an embryonic stage.

5. SUMMARY OF DATA ON SWITCHING FROM OIL TO GAS

In summary, there is no net benefit to the climate from a bridging scenario that phases out coal-fired power stations in favour of new gas-fired ones, whether fired by unconventional or conventional gas. Unconventional gas (shale gas) would greatly increase global warming with respect to the use of coal. Furthermore, it will take at least 10 if not 15 years before shale gas produced in the UK is available in significant quantities, by which time coal-fired plants will have already been phased out under the terms of the EU Large Combustion Plant Directive (LCPD, 2001/80/EC), superseded by the Industrial Emissions Directive from January 2016. So in practice UK shale gas will not be replacing coal but displacing renewables.

Conventional gas is readily available and would be less dangerous from a climate change perspective, but gas imports are already part of the UK energy mix. Both conventional and unconventional gas will avoid the substantial pollution arising from coal production and use. However, our data demonstrates that substituting one fossil fuel with another is no solution to climate change and may well make it worse, even in the unlikely event that carbon capture with storage becomes a viable option.

Under EU legislation the UK Government is committed to legally binding carbon reductions; namely a reduction of 20% in carbon emissions by 2020 compared with 1990, and 20% of total energy from renewables by 2020. In private communications the Energy Secretary, Amber Rudd, has admitted that the UK is likely to miss its renewable target for 2020. It is more likely to achieve its carbon target. However, this is because the UK has exported most of its manufacturing base abroad, notably to China. There is also EU legislation requiring an improvement in energy efficiency of 20% by 2020, but it is not clear how this will be achieved now that the Government has scrapped the Green Deal without replacing it.

By 2030, the EU has committed itself to a 40% reduction in carbon emissions, but the renewable target of 27%, after lobbying by the UK, is Europe-wide rather than country specific which makes it unenforceable. However, the UK Parliament is already committed to a reduction in carbon emissions of 80% by 2050 under the terms of the 2008 Climate Change Act, a figure which is now being adopted by the EU. The UK also in principle has a 'stepping stone' figure of 50% carbon emissions reduction by 2025 [23]. Our data show that the UK's legally binding carbon budgets are likely to be breached if the Government persists in its apparent hostility to renewables and promotion of fracking.

6. ALTERNATIVE STRATEGIES TO THE COAL-GAS SWITCH

If science tells us that the gas bridge fails on climate-change grounds, then an alternative strategy needs to be found. Perhaps the central question in choosing such a strategy is: "Can we assess with confidence the transition time for replacing fossil fuels with zero-carbon energy?". It can then be decided whether or not a bridging strategy is actually required. Clearly the elements of the renewables transition are already lining up as the costs of wind, solar and small-scale hydro generation, domestic and grid-scale battery technology, and electric cars with an acceptable range and charging time, are all falling rapidly. Moreover, the prospect of an electricity super-grid with high-voltage DC transmission over long distances (at European scale) offers a realistic endpoint where renewables will provide the UK with a robust, secure energy supply [24]. Here we look at the growth of three well-known energy generation technologies, wind, solar PV and hydro power, to estimate the timescale on which they may collectively contribute a substantial portion (say, 50%) of total UK energy consumption.

Fig. 10 shows the historical evolution of world energy consumption for the three technologies, together with fossil-fuel and primary energy consumption [25]. Solar PV in particular has shown a consistent pattern of exponential growth over many years, which has been attributed to an exponential *decrease* in manufacturing costs (Moore's Law) leveraged by technology improvements and efficiencies of scale. Fig. 10 shows an exponential projection for solar photovoltaic energy provided by Farmer and Lafond at the Institute of New Economic Thinking at the Oxford Martin School [26]. Their projection is grounded in arguments around the impact of technological innovation and assumes that growth is effectively unconstrained by 'road blocks' (see footnote).

During the last 15 years the doubling time for global solar PV has been about two years, that of wind about four years, and that of hydro about 20 years. We therefore match the exponential projection of Ref. [26] with projections for wind and hydro using these doubling times, as shown in Fig. 10. Finally, we follow the assumption made in a 2015 report by Bloomberg New Energy Finance (BNEF) [27], that energy efficiency developments will keep total world primary energy consumption constant over the next 2-3 decades.

Neglecting small contributions from other energy sources, consumption of fossil fuels is given by the difference between world primary energy consumption and total renewable energy consumption, thus fossil fuel consumption falls as renewables consumption rises. This leads to a crossover between renewable and fossil-fuel consumption in 2028, with the renewables transition essentially complete by 2030. A similar conclusion is reached in a paper by the US National Oceanic and Atmospheric Administration (NOAA) published in January 2016 in Nature Climate Change, which concludes that the USA will be able to achieve an 80% reduction in CO_2 emissions from its electricity system by 2030 based on wind and solar power [24]. An earlier report by BNEF, in 2015, predicted a crossover point before 2040. The International Energy Agency (IEA) and fossil-fuel companies predict longer time scales, but as their past projections have consistently underestimated subsequent renewables growth these predictions cannot be relied upon. In the political sphere, Democrat proposals in the US promise a much faster transition than the one outlined here.

A key assumption in Ref. [26] is that growth is not constrained by 'roadblocks' arising from external factors[4]. Arguably the most significant potential roadblock is the current absence of

[4] Potential roadblocks were a constant issue for the Moore's Law scaling of semiconductor technology of the last 40 years. In order to deal effectively with roadblocks *before* they impacted on growth, the industry set up the International Technology Roadmap for Semiconductors (ITRS). This has been a key institution behind the remarkable success of semiconductors, showing that careful planning allows effectively unconstrained exponential growth. Similar institutions, though with a shorter learning curve, exist in the wind and solar sectors.

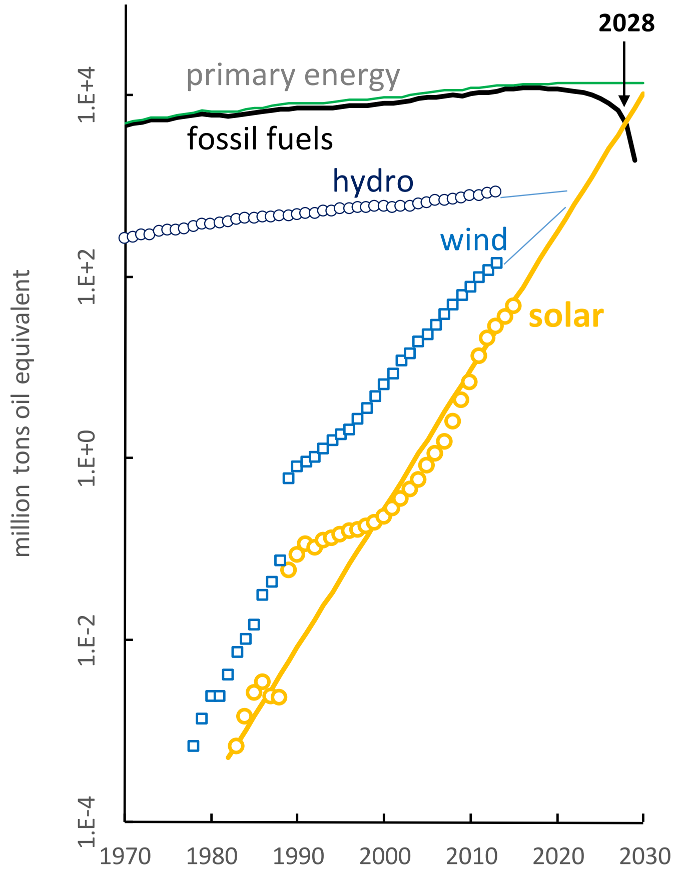

Fig. 10: World consumption of energy from various sources during the renewable energy transition. Historical data for wind and solar [25] are projected exponentially [26]. Primary energy consumption (grey line at top) is assumed to saturate as a result of energy efficiency measures [27]. The resulting total contribution from renewables reaches 50% of global primary energy consumption before 2030. The black curve shows the consumption of fossil fuels needed to balance demand; in this scenario the transition to renewables is largely complete within 15 years from the present.[5]

a continental-scale high voltage DC (HVDC) grid – infrastructure which is needed in order to smooth out the effects of regional weather variations on wind and solar energy output. Ref. [24] shows that the construction of such a grid will enable a full renewables based energy system in the US, and the same applies to the continent of Europe including the UK. Total renewables consumption can probably grow a further factor of 5 in the UK before this constraint begins to limit further growth, thus a potential roadblock arises in the early 2020s.

[5] Such rapid transitions are characteristic of paradigm shifts in industry, culture and society. Exponential scaling (Moore's Law) is of course well known in other technologies. In the microelectronics industry the number of transistors on a chip, cost per transistor, and other parameters have increased/decreased by twelve orders of magnitude in about 40 years by steadily doubling every two years. Exponential growth only slowed when the minimum dimension in a transistor (the gate thickness) approached atomic dimensions. Many other transitions have shown similar behaviour. In recent years the number of mobile phones grew exponentially until they equalled the human population, and in the context of infrastructure, the railway network grew exponentially in the 1840s until it obsoleted the established system of long-distance horse-drawn transport.

Current initial steps towards a European HVDC grid have involved the construction of bi-national connectors and EU research into super-grid configurations and construction. Assuming these actions are correctly timed and followed up, a full grid system will be rolled out across Europe during the 2020s. Meanwhile the arrival of an array of increasingly affordable energy storage technologies is opening up opportunities to smooth out variations in renewable energy output over a range of time scales, thus saving on fossil-fuel based back-up generation. We therefore propose that the transition time frame suggested in Refs. [24] and [26] is robust.

Based on these arguments we suggest that the time window for a bridging scenario using natural gas may be less than 20 years from the present. Moreover, it is plausible that the severe climate impacts which will already be taking place by 2030 will curtail any unconventional gas industry that has developed by then, leaving investments stranded and gas wells prematurely abandoned. In view of the capital costs of building an entire new industry and the short permissible time frame for its operation, it makes more sense to propose an immediate transition to renewable sources of energy. BNEF argues this case [27]; in advanced economies it is more cost-effective to make a fast transition to renewables with temporary ongoing supply from existing fossil fuel infrastructure. Most importantly, efficiency improvements, particularly in industrial processes, home insulation, and heating and electrical appliances, are a critical requirement as they represent the most cost-effective method of "keeping the lights on", and will substantially cut the cumulative use of fossil fuels during the transition period thus enabling the UK to meet its carbon targets.

Finally, it is important to note that synergy between government energy, industry, finance and environment policies through more aggressive carbon pricing is a powerful way to nudge industry along the transition pathway and fund essential low-carbon infrastructure.

In conclusion, the UK needs to fundamentally reconsider its pathway to a successful post-transition economy. It is all too easy to be 'left behind the curve' through caution and responsiveness to lobbying influences from traditionally established industry. With a suitable reorientation of UK policy, a suite of major new industries will quickly emerge from the country's strong science and engineering skill base. Embracing this transition will enable a secure energy future and full economic prosperity – climate change permitting.

Acknowledgement

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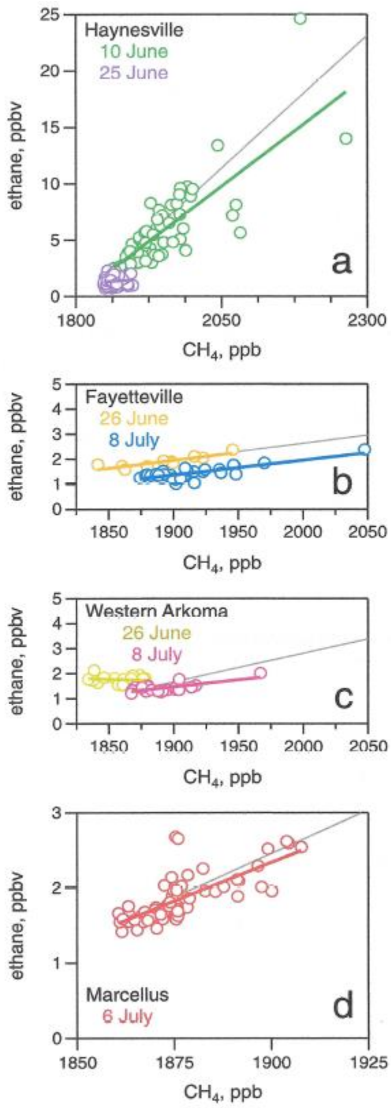
APPENDIX A: ON THE SELECTION OF TOP-DOWN EMISSIONS DATA

The top-down methane emissions data presented in Fig. 7 are based on a range of approaches including short-duration aircraft measurements, road-based measurements, fixed-tower measurements, and space-based measurements. Based on the most complete study reported to date [10], and from general considerations, we determined that methane emissions from the industry are rather accurately described by a 1/f distribution reflecting a relationship between the frequency of emission events and their magnitude. With a 1/f distribution, very large emission events are infrequent but contribute similar amounts of methane to the atmosphere over time as do smaller emission events.

This leads to a general prediction that, from a statistical perspective, observations that take place over long times and access information over an entire gas producing region are more robust than ones that are completed in short times and only sample a subset of the emitting region. Aircraft measurements, which are conducted in a short campaign of flights, each lasting only hours, pose a particular problem. The issue can be seen from Fig. A1 (a), which shows the results of two separate flights. Fig. A1 and its caption are reproduced under Creative Commons licence from Fig. 11 of Ref. [11].

Fig. A1: Scatter plots of ethane versus CH_4 in the boundary layer for the (a) Haynesville, (b) Fayetteville, (c) Western Arcoma, and (d) Marcellus study areas. The coloured lines are linear regression fits to the data. The grey lines represent the mean ratio of ethane to CH_4 in natural gas samples listed in the US Geological Survey database for each region. The shapes of the graphs maintain the same aspect ratio in the three panels, so that a direct comparison of the slopes can be made.



The figure plots methane emission data against corresponding ethane data (used to establish the component of measured methane that has come from the gas-field). What is of interest here is the spread of values along the horizontal direction, reflecting the measured methane concentrations in excess of the atmospheric background value of roughly 1800 parts per billion (ppb). First, methane data from the two flights show entirely different methane excesses and it would be reasonable to suppose that a third flight might have generated significantly different data again. Second, the spread of excess concentrations from each flight is limited: for the 10th June flight the range is from about 8-17 ppb above the roughly 1800 ppb background, just a factor of two, and for the 25th June flight the range is from about 12-93 ppb above background, a factor of about eight.

Concentrations do not *directly* reflect the underlying range of contributing emission rates; to extract this information requires more detailed measurement and analysis. However, a narrow range of measurement concentrations from aircraft flying directly over a gas-producing area does clearly indicate that a modest range of emission magnitudes is being sampled. In the case of Fig. A1 (a) we have chosen to accept the data on the basis that the two flights taken together provide a dynamic range of methane concentrations of just over 10. However, other data from Ref. [11] (A1 (b-d)) have been discarded because in our opinion the dynamic range of measured concentrations above baseline is too low (Fayetteville about 4; Western Arkoma about 6; Marcellus less than 3, based on only one flight). Substantially higher-quality aircraft-based data has been reported in work by Petron [8] and Karion [7] (both with dynamic ranges of the order of 100 above a more precisely defined baseline concentration). This dynamic range, as well as a 1/f-like decrease in frequency towards higher concentrations, is illustrated in Fig. A2, reproduced under Creative Commons licence from Fig. 4 (a) of Ref. [8], and appears even more clearly in Ref. [7] (permission requested).

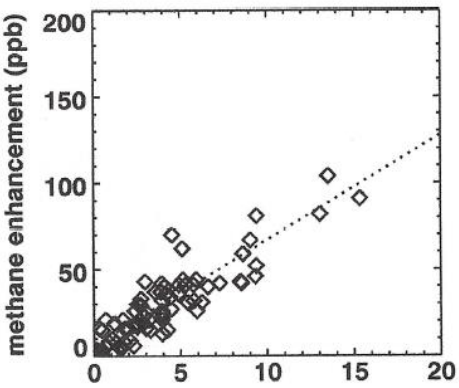


Fig. A2: A correlation plot of the methane versus propane mixing ratio in flasks sampled by aircraft in the boundary layer as described in Ref. [8]. The dotted line shows the correlation slope of the regression fit reported in the paper. The data come from the NOAA GMD multiple species analysis by GC-MS of discrete air samples collected with the aircraft on different days in the Denver-Julesburg Basin in May 2012.

In Fig. 8 in the main text of this report we have therefore applied the same correction factor of 1.6 to the data from Refs. [7] and [8] as we used with the data of Zavala-Araiza [10] to account for very large unmeasured events. However, owing to the lower quality of the data shown in Fig. A1 [11], we raise the upper limit on the "Peischl 2015 / Haynesville" data bar by twice this amount. This latter correction is of course arbitrary; a more scientifically rigorous choice would be to omit this point altogether, which would shift the weight of the overall data towards still higher emissions.