Heating with steam methane reformed hydrogen – a survey of the emissions, security and cost implications of heating with hydrogen produced from natural gas

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Abstract

Hydrogen produced from natural gas with steam methane reforming coupled with carbon capture and sequestration (SMRCCS) is proposed as fuel for consumer heating and cooking systems. This paper presents estimates of the energy losses and methane and carbon dioxide emission and global warming across the whole gas to hydrogen heat supply chain – from production to consumer. Processed natural gas is typically about 95% methane which is a potent greenhouse gas with a global warming potential (GWP) such that, with 20 year and 100 year GWP horizons, about 4% and 8% leakage respectively will cause as much global warming as the carbon dioxide formed when burning the methane. Data on gas emissions and SMRCCS costs and performance are sparse and wide ranging and this presents a major problem in accurately appraising the possible role of hydrogen from methane. The survey indicates emissions between 50 and 200 gCO2eq per unit of heat (kWhth) for SMRCCS H2 heat depending on leakage and GWP time horizon assumed. The second part of the paper reviews gas supply pricing and security and presents a cost minimised configuration of a SMRCCS hydrogen heating system derived with a simple model. Uncertainty in SMRCCS greenhouse gas emissions coupled with a net zero emission target and the long term issue of the physical and economic security of natural gas supply, bear on the potential advantages of SMRCCS as compared to other options, such as heating with renewable electricity driving consumer or district heating heat pumps.

Contents

1. Introduction

The provision of heat in the UK consumes approximately 40% of delivered energy and produces 50% of carbon emission, a fraction that is increasing as electricity decarbonises but gas does not. Most heat is provided with natural gas, with electricity, liquid and solid fuels being minor. The supply of these fuels, both direct and indirect for electricity generation, engenders the emission of greenhouse gases (GHGs), of which carbon dioxide (CO2) and methane are most relevant to this paper.

A major part of emissions from imported gas occur outside the UK territory: some in international waters from LNG ships, some in transfer countries (e.g. between Russia and the UK), and some in the country extracting the gas. Plainly these emissions must be included in global emission inventories and somehow allocated to countries that can implement control strategies. Here it is assumed that all the emissions engendered by UK gas use are included, whether in the UK or outside from imports; this follows BEIS (BEIS, 2018).

Natural gas is a mixture, with a typical methane content of 85-95% depending on primary source and processing, with the remainder comprising other hydrocarbons (ethane, propane, etc.) and trace gases including CO2, some of which are also GHGs. One historic composition (1979) for the UK is given in the next Table. Some of the non-methane constituents cause global warming: CO2, and alkanes (ethane, propane, etc.) which have global warming potentials (GWPs) about 10-30% of methane (Hodnebrog, Dalsøren, & Myhre, 2018). To simplify the analysis, it is assumed throughout that natural gas is 100% methane which will give different results to using the real composition of natural gas - in particular methane will cause less CO_2 emission per unit of energy than natural gas, but more methane and associated global warming per fraction emitted. The overall conclusions of the analysis are not thereby changed, especially given the uncertainties in emissions.

Table 1 : Natural gas composition

Component	Volume %
Methane	93.63
Ethane	3.25
Propane	0.69
Butane	0.27
Other hydrocarbons	0.20
Nitrogen	1.78
Carbon Dioxide	0.13
Helium	0.05

Source: https://en.wikipedia.org/wiki/National_Transmission_System

UK and foreign natural gas is extracted, purified and transported to points of use in the UK via pipelines or as liquefied natural gas (LNG), and then to consumers where it is mainly used for heat, or to generators and other industry. At each stage energy is required, generally from the gas itself, leading to CO2 production, and leakage of methane and other constituents will occur.

A major option suggested for providing heat is to separate the hydrogen from the carbon in natural gas (mainly methane, CH_4) in a steam methane reforming (SMR) plant, producing hydrogen and CO2, a fraction of which is separated and piped to a sequestering store, such as a depleted gas field – this is termed carbon capture and storage (CCS): the integration of these processes is here labelled SMRCCS. The hydrogen is then distributed and used in boilers (or CHP plant, not considered here) to produce heat. Hydrogen for other purposes such as transport is outside the scope of this paper. Compared to direct natural gas heating, this hydrogen route reduces the emission of CO2 and the emissions of methane in the distribution and consumer systems, but increases upstream CO_2 and methane emissions to a lesser extent, and so reduces total GHG emission. This paper aims to analyse the emissions, security and economic aspects of this gas to hydrogen to heat delivery chain as shown schematically in the next Figure.

Figure 1 : Gas to hydrogen to heat delivery chain
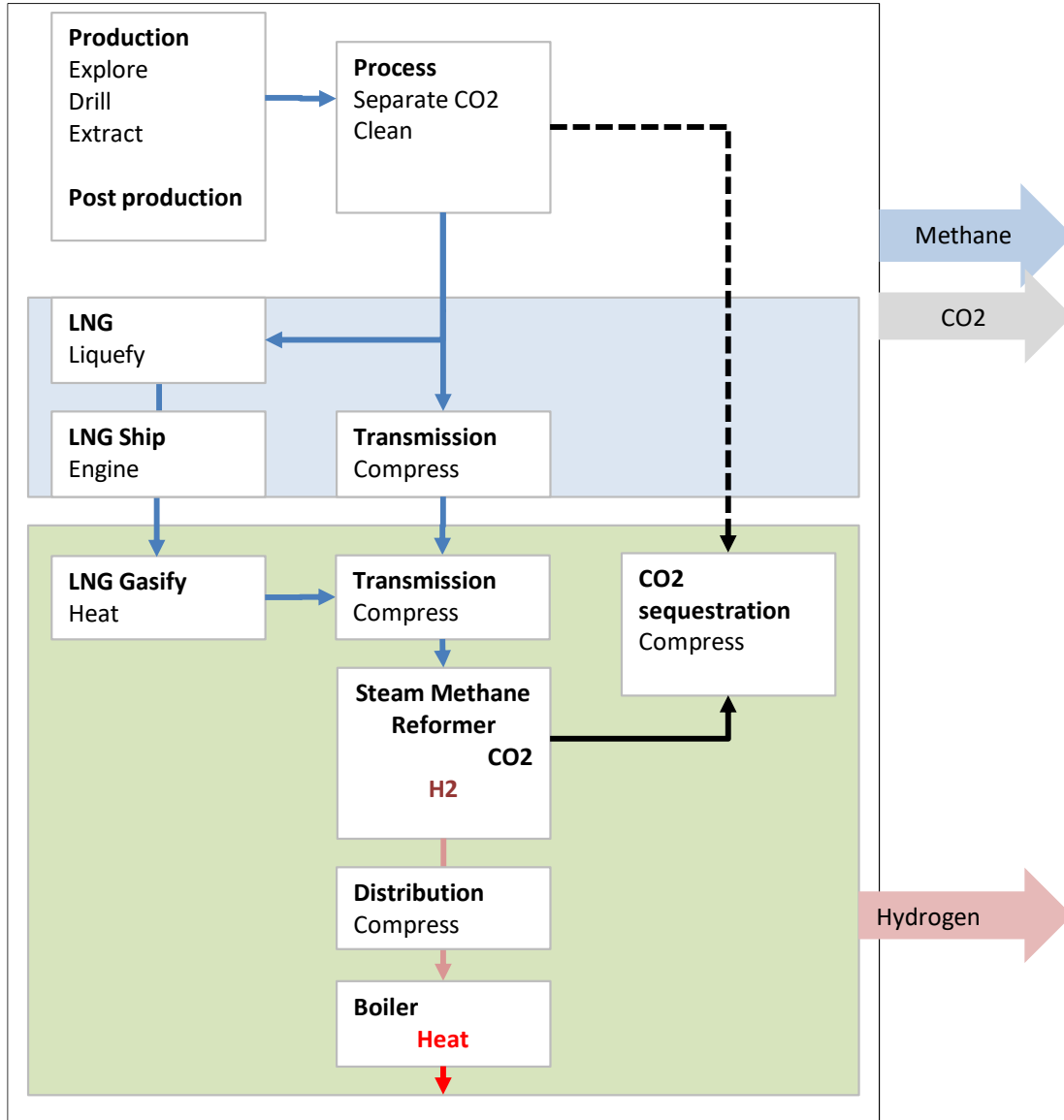
2. The gas supply chain – leaks and self energy use

2.1.1. Measurement of leakage

The primary objective is ensuring that methane leakage is controlled so as to attain high safety levels. Methane emissions of a few percent, if dispersed in the atmosphere, do not present a safety problem, but are significant for global warming. The gas industry has been adjusting to this additional objective.

A central technical and economic problem is estimating the energy use and methane and CO_2 emission from a system of thousands of gas supply components, mostly underground or underwater, stretching over 1000s of kilometres and several countries, leading to millions of consumer devices, power stations and so on. Some methane is leaked under normal operation (e.g. from a maintained compressor, boiler or engine), some from individually minor leaks (e.g. from faulty pipe joints) and some during rare but large leakage events, such as a gas well blowout. Small leaks may not be detected or reported, but methane leakage of just 1% is significant in global warming terms. Leakage will vary with time because of factors such as pressure and temperature. In general, the greater the gas throughput (mainly driven by demand) the higher the pipeline pressures and compressor use which will increase emissions. The emissions may still be significant with low or no throughput; this needs consideration when using the gas network for occasional energy supply, such as to back up heat pumps at peak demand times.

Small amounts of methane leakage are not easily detected and may be insignificant in terms of safety, and there are costs for reducing leakage. The International Gas Union (IGU, 2017) remarks: '… due to the expanse of natural gas infrastructure, the exact measurement of emissions is challenging and, in some cases, impossible.'. Added to this are uncertainties about newer technologies, particularly SMRCCS, as a replacement to consumers' direct use of methane. A further difficulty is that leakage data are often given as a combined figure for all GHG as CO_2 equivalent (e.g. CO2eq/kWh) so it is not possible to separate methane and CO_2 or other GHG emissions.

There are three basic approaches to measurement, each with problems:

i. **Meter.** Accurately measure total inputs and outputs of sections of the gas system. Natural gas is a gas (!) and so the volume of a given mass varies with pressure and temperature, making accurate metering difficult. Public data on methane emissions from consumer premises pipes and unburned methane in boilers and cookers are almost non-existent. Further, there are meter recording errors and theft. The millions of UK consumer gas meters should have an accuracy of 2%, but, for example, Which (Which, n.d.) report that 14% or more of consumer meters are found to be faulty when tested.

ii. **Sample.** Measure leakage from a sample of system components (pipes, compressors, boilers etc.) and then assume the sample accurately reflects the whole populations of components and their operating conditions.

iii. **Environmental**. Measure concentrations at different points in the air, water or earth near gas facilities. Compare these with background concentrations, and 'back calculate' with atmospheric or other medium models to estimate the sizes and locations of emissions. Remote sensing with satellites can be used to estimate atmospheric methane concentrations. However, environmental modelling is imprecise and there are many sources of methane apart from natural gas, some seasonally varying, such as animals and rotting vegetation.

There is a common view, e.g. Heath *et al* (Heath, Warner, Steinberg, & Brandt, 2015), that a large fraction of total emissions is from a few 'super-emitters' – such as well blow out, LNG storage loss, faulty compressors, or cracked pipes and so official inventories using 'normal' leakage underestimate emission. Further, the physical, environmental, technological, economic and policy context of gas systems varies widely from country to country, so measurements in one country may not be very relevant to others. Because of this, most literature found discusses approaches to emission monitoring, safety, measurement and control but gives no comprehensive, consistent emission estimates. Much emissions measuring and reporting is by the gas industry and this may lead to an underestimation bias.

For these reasons, estimates of methane and CO_2 emissions are tentative and greatly varying, with the only certainty being that they are not zero in any part of the system.

2.2. Whole system studies

There are several system studies that partially cover national systems, but few also extend to international and none found include consumer emissions. Very wide emission ranges are reported.

BEIS ("Digest of United Kingdom Energy Statistics 2018," 2018) Table 4.3 UK continental shelf and onshore natural gas production and supply gives estimates of self-use (where gas is combusted) for production, transmission and distribution; leakage for distribution only; and metering and statistical differences. These are shown for 5 years as percentages in the next Figure. One observation is the large range in estimates over a period of one or two years: leakage and distribution self-use range by over 2:1; metering and statistical differences range similarly. Concerning gas (methane) leakage, an estimate is only given for distribution (none here for transmission and production), and this varies between 0.19% and 0.39%, a range of 2:1.

This estimate is based on a National Grid Leakage Model for which the author found no accuracy estimate, but the report (Wales, Cadent, NGN, & SGN, 2018) says '*During the Winter where our network pressures are at their highest, we would expect to see an increase in Leakage Gas [...] whereas during the Summer we would see the opposite'* and that the model does not reflect this. These estimates are that about 70% of self-use is in production and 28% for distribution (for pumping and heating gas after expansion from the high pressure transmission system.) This illustrates the uncertainty and possible variability in self-use and leakage, and therefore CO2 and methane emission.

Figure 2 : UK gas industry self-use and leakage – DUKES
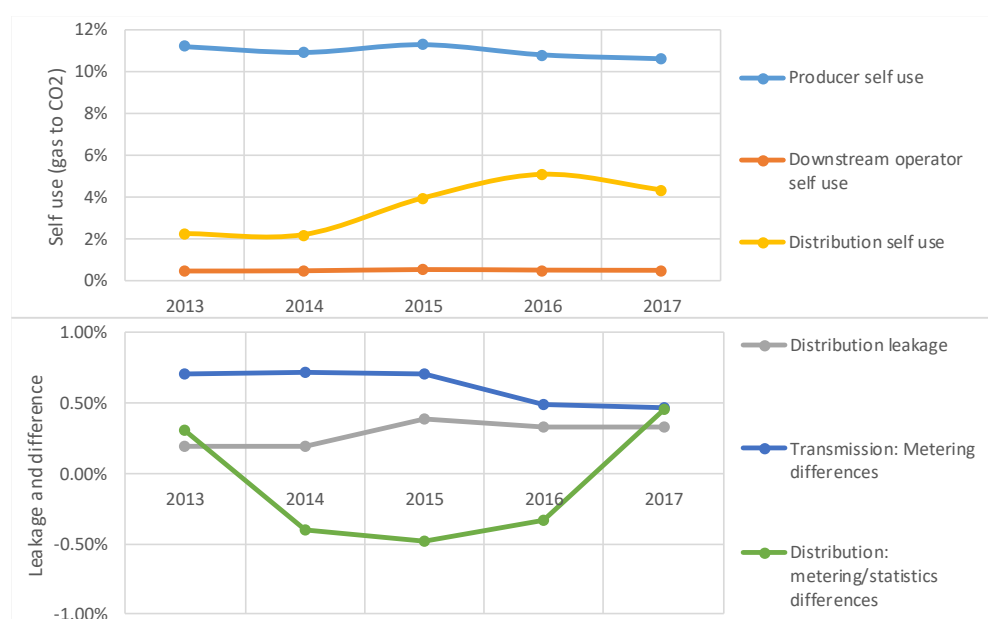
Balcombe *et al* (Balcombe, Anderson, Speirs, Brandon, & Hawkes, 2015) report a range of estimates, from exploration to distribution, of 0.2% to 10% of produced methane, a 50 fold range, but with most estimates of 0.5% to 3%, a 6 fold range. ConocoPhillips (ConocoPhillips, 2015) give a range 0.7 to 2.6%, with a central estimate of 1.5% arising from approximately 1.0% from production, 0.3-0.4% from transmission and storage and 0.1-0.2% from distribution. They quote top down (atmospheric, aircraft, satellite) studies ranging from 0.2% to 17.3 %. Alvarez *et al* (Alvarez *et al.*, 2018) estimate methane emission as 2.3% of gross US production. Heath *et al* (Heath *et al.*, 2015) partition emissions by four main segments of the natural gas industry: ~33% production, ~14% processing, transmission and storage ~33% and distribution ~20%; and approximately 43% of total methane emissions from compressors. The largest study found is the 550 page *Study on actual GHG data for diesel, petrol, kerosene and natural gas* (COWI, 2015). The focus is on gas for Europe, but it includes production in many non-Europe countries and transport to Europe. This gives a huge range of emission estimates from different parts of the systems in different countries.

2.3. Gas production

2.3.1. Conventional gas

Gas production involves exploration, drilling, extraction, gathering and processing, and then decommissioning. These processes require energy leading to CO_2 formation, some of which might be pumped underground with the remainder emitted, and a fraction of raw gas or its constituents is vented or flared (burned) and released to the atmosphere during normal or exceptional operations. Conventional gas can be produced alongside oil production, this is called associated gas, or it can be produced from 'dry' gas-only fields. UK production is currently around 70 TWh of associated gas and 40 TWh of 'dry' gas. For associated gas there is a problem of estimating and allocating emissions and energy use between oil and gas.

There is a variation in the composition of raw natural gas resources – the fractions of methane, other hydrocarbons, CO_2, hydrogen sulphide, etc. Emissions will vary with this and geology, technologies, operations and geography of delivery paths. Raw natural gas has to be processed such that gas for consumption meets specifications, meaning that some constituents have to be removed or reduced. This may include CO_2 which may or may not be sequestered. Variations occur: for example UK production methane and CO_2 emissions per unit of production apparently roughly doubled between 2000 and 2013 and thereafter declined (Calgary Partnership, 2017), though it is not clear if this is consistent with the DUKES data quoted above. These factors lead to wide variations in energy use and leakage per unit of gas delivered to consumers.

Kang *et al* (Kang *et al.*, 2016) and Riddick *et al* (Riddick *et al.*, 2019) review emissions from active and abandoned wells with the conclusion that wells can be substantial emitters and that USEPA emission factors are too low. An estimate considered on the high side by some researchers is by Howarth (R. W. Howarth, 2014): '*We concluded that 3.8% (±2.2%) of the total lifetime production of methane from a conventional gas well is emitted into the atmosphere, considering the full life cycle from well to final consumer.*'

It is provisionally assumed that the primary gas production emissions are the same for the UK as for other countries (e.g. Russia, Qatar) whereas they will actually differ; but that the different gas transport modes to the UK (pipe, LNG) from foreign countries have different energy and leakage losses.

After ceasing production, gas and oil wells are plugged. However, the integrity of the plugs may be compromised and there may be leakage through or around plugs; and disturbance of methane stored in natural materials around wells, leading to emissions of methane. This is discussed by Boothroyd *et al* (I. M. Boothroyd, Almond, Qassim, Worrall, & Davies, 2016) and Vielstädte *et al* (Vielstädte *et al.*, 2017), but no estimates as a percentage of production is given. Plainly such leakage can also occur in carbon sequestration.

2.3.2. Unconventional gas

Unconventional sources, principally shale and biogas, are not included quantitatively here. The indications are that leakage from non-conventional sources is of the same order or possibly higher than for conventional gas.

Shale. Currently the potential UK resource of shale gas that can be economically recovered whilst meeting environmental and public criteria is far from clear. Estimating methane leakage from shale gas is particularly hard to do because of its extension underground through fracturing, but indications are that its methane emissions are of the same order as conventional natural gas production, possibly higher. Most data and estimates concerning shale gas methane emission are from current USA production, ranging widely from around 0.27% to 0.45% (Barkley *et al.*, 2017) to 3.3% (R. Howarth, 2015). These data may not be very relevant to UK geology and technical extraction procedures, so estimates for the UK are very uncertain. Mackay and Stone (MacKay & Stone, 2013) estimate, with wide ranges, shale gas GHG emission to be 0–20% higher than UK conventional gas but about 10% lower than Non-EU piped gas or imported LNG.

Biogas. Biogas is complex because of biomass feedstock and process heterogeneity. In system terms: what would GHG emissions be if UK constrained biomass were not converted to biogas but used otherwise? For example, biomass such as wood or sewage sludge might be directly combusted in CHP plant rather than used for biogas production or used to make aviation fuel. Literature suggests a large range of leakage as a fraction of bio methane produced. Liebetrau *et al* (Liebetrau, Reinelt, Agostini, Linke, & Murphy, 2017) describe this complexity; of interest is they report methane slippage of 1% to 3% of CHP engine input.

2.4. Transport

As UK gas imports increase, the energy and methane losses and costs incurred by transporting gas longer distances will arguably also increase. Three primary sourced routes are explored here: 1. UK sourced gas, 2. Import by intercontinental pipeline, such as from Russia, and 3. Import via liquefied natural gas (LNG) from a country such as Qatar. The two long distance options are pipelines and liquefied natural gas (LNG).

Kavalov *et al* (Kavalov, Petrí, & Georgakaki, 2009) analyse the technical and economic aspects of long distance transport by pipeline and LNG . They report '*The typical energy penalty of delivering gas via pipelines is 10-15% (translating into an efficiency of 85-90%), while for LNG it is ≈25% (efficiency of ≈75%). However, when gas is delivered via pipelines from quite remote sources (e.g. over a distance of 7000 km), the energy cost comes close to that of LNG (24% versus 28% respectively)'.* These estimates depend greatly on the distance assumed, amongst other factors, but appear high compared to other sources.

2.4.1. Transmission and distribution pipes

Three tiers of transmission may be considered: intercontinental (e.g. from Russia), UK domestic high pressure transmission, and UK lower pressure distribution to consumers. Russia has 170,000 km of high pressure transmission. The Siberia-UK distance is 6000 km. The UK has 7600 km transmission, and 280,000 km of lower pressure distribution pipes. Compressors, mostly gas fuelled, emit CO_2 and methane and are used to push gas through the networks. Energy is also required to heat gas to maintain temperature to compensate for cooling during expansion from high pressure transmission to low transmission distribution.

Estimates of Russian transmission leakage are in the range 0.6% to 3.7%. For example, (Lechtenböhmer & Dienst, 2005) state 'We have made measurements in Russia along the world's largest gas-transport system and find that methane leakage is in the region of 1.4%. 'Leakage 0.6% of delivered'. In 2015, the European Commission said that 1.77 percent of Russian methane shipments are lost during transportation through the pipelines while Norway's supplies lose only 0.01 percent. The IEA (IEA, 2006) in its study of Russian gas estimated that 3.2% of gas was lost in (Russian) distribution (p49) and 3.7% in transmission (by ratios on p48); they also estimated that 6% of throughput was burned in compressors, and 2% was flared. McKain *et al* (McKain *et al*., 2015) estimate 2.7 ±0.6% emission from transmission and downstream in the Boston region.

Approximately, there is 30-40 times more distribution pipe length than transmission, with a larger multiple of joints, valves and meters and so on. In general distribution will be less closely managed than transmission because flows per pipe length are much smaller and it is less accessible. However, the pressure is lower and the greater proximity of distribution to people puts more emphasis on safety.

Boothroyd *et al* (Ian M. Boothroyd, Almond, Worrall, Davies, & Davies, 2018) estimate a methane emission of 62.6 kt/a from the UK transmission network: this is calculated to be about 0.11% of methane throughput. If we add this to the DUKES distribution leakages we obtain a range of 0.3% to 0.5% total leakage for transmission plus distribution.

2.4.2. Liquefied natural gas LNG

LNG is an alternative to pipes for transporting gas. There are four basic processes: liquefaction, storage, shipping and gasification. The energy, CO_2 and methane emissions depend on many factors: technological, operational and environmental. Data on these are again sparse.

Natural gas is liquefied by compression and cooling to a temperature of -162 $^{\circ}$C. This consumes a large fraction of gas energy throughput, ranging from 8.8% (Tagliaferri, Clift, Lettieri, & Chapman, 2017), to about 10% (Balcombe *et al.*, 2015) to as high as 20% (Anderson, Salo, & Fridell, 2015). Generally this energy will be supplied by natural gas with ensuing CO_2 emission vented or sequestered.

LNG is stored in pressurised, insulated tanks. These tanks absorb heat from the environment causing LNG evaporation or boil-off gas (BOG). Lowell *et al* (Lowell, Bradley, Haifeng Wang, & Lutsey, 2013) report 0.1 to 0.25% of LNG stored evaporation per day from large land based tanks. BOG causes the pressure to rise, and to keep the pressure below the tank limits, the BOG must be vented (emitted), re-liquefied or used as fuel. Lowell *et al* assume that all BOG from tanks at LNG origin will be reliquefied (but at an energy and CO_2 production cost) because they are near the liquefaction plant. BOG from the destination UK tanks can mostly be sent to gas supply. The transfer of LNG between tanks will also result in emissions, as will accidents.

LNG is transferred to LNG carriers – ships with large LNG tanks. A large fraction of LNG is currently imported to the UK from Qatar, a shipping distance of around 12000 km. After loading, the LNG will gradually warm up from its import side temperature, so BOG will increase during the ship's journey, with the possibility of gradually switching engine fuel from oil to BOG. Lowell *et al* (Lowell *et al.*, 2013) report that when at sea the ship can generally use all the BOG; if not, it is vented or re-liquefied but at an energy and CO_2 emission cost. When returning empty to the LNG source (e.g. Qatar) the ship will generally use oil or gas. Some methane input to engines is unburned – methane slip: Anderson *et al* (Anderson *et al.*, 2015) report engine methane emissions as a percentage of fuel into engines as 0.7% (full load) to 2.3-3.6% (part load). LNG carriers typically carry 100-200,000 m^3 of LNG. For a 160,000 m^3 (72 kt, 4000 TJ LNG) carrier, Rogers (Rogers, 2018) assume a speed of 19 knots and a fuel burn of 72 t LNG equivalent/day, which works out at about 43 TJ for the Qatar to UK journey – 1.1 % of the energy carried. Assuming the return trip uses 30% of that energy, the total ship energy is about 1.5% of energy delivered. If the ship fuel is assumed to be methane then an additional methane slip of 0.7% might be added.

The LNG is transferred from ship to UK LNG stores. The LNG is regasified for input to the transmission system by heating using gas - Tagliaferri *et al* (Tagliaferri *et al.*, 2017) report 3% of gas is used for gasifiying in the UK. Other heat sources such as low temperature heat from the sea may be used.

This indicates that 10% of energy is used for liquefaction, 1.5% for shipping and 3% for gasification – 14.5% in total; currently most of this energy will arise from gas combustion and CO_2 emission and it may be assumed that little of this will be sequestered. Information about methane emission from LNG land side processing or from ships is hard to find.

2.5. Consumer emissions

None of the studies of the emissions of the whole gas pathway, found so far, explicitly includes methane emission downstream of the consumer meter. In the UK there are some 23 M domestic and non-domestic consumer gas systems with perhaps 30-40 M boilers and other appliances using gas, and these devices will likely have less maintenance than the relatively small number of high throughput, large upstream public supply devices. Methane emissions and leaks from these devices and consumer gas systems (pipes, meters etc.) do not seem to be systematically measured *in situ* for large samples. The lack of data may be because methane emission from current systems is negligible in terms of safety and costs and so not worth measuring, and because it is too costly and invasive to measure in large enough samples in the systems of millions of consumers. However, the HSE (HSE, n.d.) has estimated that more than 4M homes - about 1 in 7 - had dangerous gas appliances which means gas leaks and a risk of explosion or incomplete combustion leading to poisonous carbon monoxide which indicates some unburned methane would also be emitted.

Data for the energy efficiency of gas boilers, engines and generators are available, but the emission factors for these as a percentage of fuel or gCH_4/kWh and other consumer devices such as cookers are harder to find and may not accurately represent real world operation. Data on gas appliances in normal operation are sparse. Normal operation emission factors for boilers seem to give estimates in the range 0.02% to 0.1% of methane input (Tsupari, Monni, & Pipatti, 2005) (BEIS, 2016). Emissions will vary with operation: Cernuschi *et al* (Cernuschi, Consonni, Lonati, Giugliano, & Ozgen, 2007) measure VOC emission, being about 70% CH_4 of 0.2 to 1.2 gCH_4/GJ at full load up to about 4 gCH_4/GJ at minimum load.

The odourant added to natural gas makes it detectable through smell at about 1% concentration (IGEM, n.d.) but diluted leakage might be undetected even if were a higher percentage than 1% of gas throughput.

2.6. Steam methane reforming

Steam methane reforming (SMR) is a process whereby methane is reacted with water to produce hydrogen and carbon dioxide, via two principal overall reactions involving the elements carbon (mass 12), hydrogen (1) and oxygen (16).

$$CH_4 + H_2O => CO + 3H_2$$

$$CO + H_2O => CO_2 + H_2$$
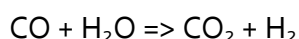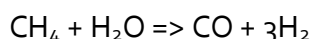
Overall, 1 molecule of methane produces 4 molecules of hydrogen; in mass terms, 16 g of methane produces 4 g of hydrogen and 44 g of CO_2. In SMRCCS, a fraction of the carbon dioxide is separated and pumped to a sequestration site. The percentage of methane converted to hydrogen depends on the temperature and pressure and may be close to but less than 100% (Rostrup-Nielsen & Rostrup-Nielsen, 2002), so some methane will remain in the raw syngas.

Figure 3 : Sample equilibrium composition of SMR
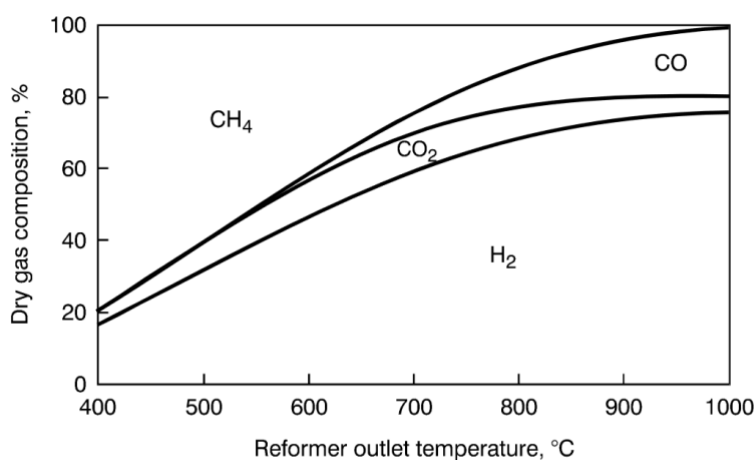

Fig. 3. Equilibrium composition out of a steam reformer at 26 bar with a feed steam to methane ratio of 2.5.

Source: (Rostrup-Nielsen & Rostrup-Nielsen, 2002)

Collodi *et al* (Collodi, Azzaro, Ferrari, & Santos, 2017) report 'Generally, the residual CH_4 in the product gas (un-shifted syngas) is in the range of 3.3 to 4% - dry molar basis'. The question is how much methane remains in the exhaust mixture of CO_2 and other traces, with presumably about 85% of this exhaust methane being captured and sequestered along with the CO_2. Some data on SMR methane emissions are given by E4Tech (E4tech, 2018) on p15. Additionally, SMR requires electricity input and this will engender some GHG emission. For actual operating SMRCCS plant or plant designs, no measured or theoretical data has been

found quantifying methane atmospheric emission. A 'placeholder' emission factor of 0.05% of methane SMRCCS input is assumed to leak to the atmosphere.

The key characteristics of SMRCCS required for analysis are energy efficiency, methane and carbon emission, and capital and operating costs. There are limited SMR with CCS (SMRCCS) plant operating with few basic technical or economic data for these available publicly. The three examples found are: Port Arthur (USA), a SMRCC plant without sequestration; Quest Canada.(Shell.ca, n.d.); and Japan (Tanaka *et al.*, 2017) but with little cost or performance data. SMRCCS performance and costs assumed here are taken from Collodi *et al et al.*, 2017) for five variant SMR systems. Based on their data, the annuitized capital and annual O&M costs and CO_2 removal are plotted against thermal efficiency in the next Figure. Costs increase and efficiency decreases as CO_2 removal increases so upstream emission increases as more gas is used. For the emission and optimisation below, a 70% efficient system with 85% CO_2 capture is assumed with capital costs of 1000 £/kW annuitized at 8%/a over a 25 year life. The energy for sequestration is assumed to be included in the SMRCCS efficiency. As noted: 0.05 % of SMRCCS methane input is assumed leaked as a mid emissions figure. CCS CO_2 emissions from the pipes and other equipment pumping CO_2 into storage, and from the storage, are assumed to be zero.

Figure 4 : SMR efficiency, capital costs and carbon reduction
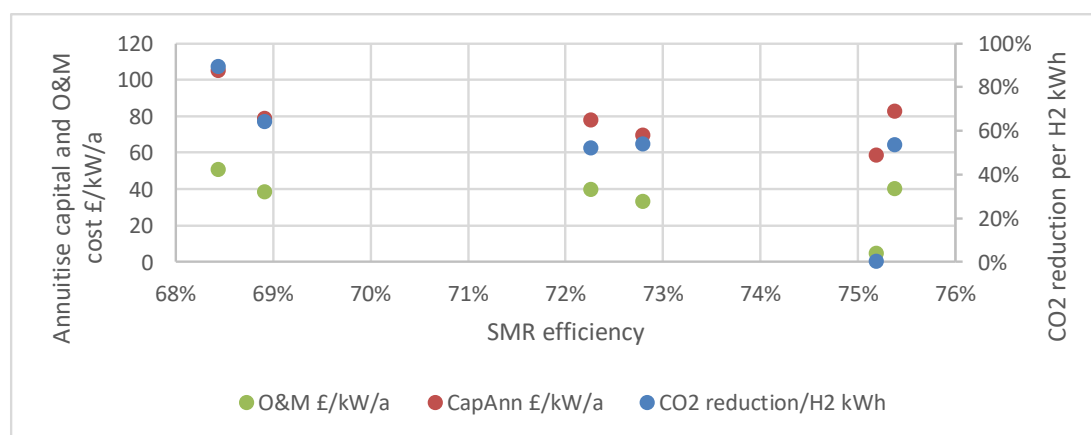
Source: (Collodi et al., 2017)

2.7. Carbon capture and storage (CCS)

CCS constitutes three phases, each of which require energy and will have some leakage to the atmosphere – separation, transport and injection:

1. **Separation**. Removal of a fraction of the carbon, usually as CO_2, from the fuel before, during or after combustion. The remaining CO_2 is vented to the atmosphere. This separation requires an amount of energy that increases non-linearly with the percentage separated, thereby decreasing overall energy efficiency and increasing energy consumption and upstream emission. For a power station, typical figures are 80-90% separation and a reduction of 10-20% in energy efficiency: for a power station this might mean a reduction of about 65-85% in gCO_2/kWhe compared to a station without CCS. The separated CO_2 may need to be cleaned to remove chemicals that might damage downstream pipes, pumps and etc.

2. **Transport to storage**. The separated CO_2 is transported, usually pumped through pipes into a depleted gas or oil reservoir, or other formation such as aquifers. The energy and leakage will depend on distance from capture to store and details of the store such as pressure and flow resistance. Transport by pipeline is discussed by several authors (Noothout *et al.*, 2014), Martynov (Martynov & Mahgerefteh, 2012) (Kaufmann, 2008), but it is not possible to give an estimate of CO_2 leakage for transport from the SMRCCS plant.

3. **Storage**. The CO_2 is injected into a reservoir and stored. Leakage will depend on the geological attributes of the reservoir, which will change with CO_2 injection and complex, regular or episodic geological processes, and details of the technologies used during storage. Estimates of long term (>100 years) leakage are generally zero or negligible, but these are based on site limited short term measurements or modelling. Some argue that leakage is more likely from around the pipes and other equipment injecting CO_2. If leakage occurs, it may be difficult to apply remedial measures. The EEA (European Environment Agency, 2011) says 'well selected storage sites are considered likely to retain over 99 % of the injected CO_2 over 1000 years.' URS (URS, 2007) state: 'Definition of long-term containment or an insignificant probability of physical leakage is a policy matter.'

The specific energy and CO_2 emissions in the transport and storage stages (2 & 3) of the SMRCCS chain are excluded from the analysis in this paper: it is assumed that the energy required is included in the SMRCCS efficiency, and that downstream CO_2 transport and storage leakage is zero, which is of course incorrect.

2.8. Hydrogen storage

Heat loads have a large variation across the year such that the annual load factor (average/peak), depending on heat load mix (residential, industrial etc.), might range 10-30%. For technical and economic reasons, the SMRCCS plant will not exactly follow this load, so some hydrogen storage will be optimal to smooth the load met by the SMRCCS and increase its capacity factor. Some storage by changing hydrogen distribution pipe pressure is possible, but substantial storage requires purpose built storage.

Some stores may be small and local and fabricated, others such as salt caverns may be more efficient and have lower capital cost, but have geologically limited capacity, and they may be more distant with more energy needed to transport the hydrogen to and from the store, and with associated costs for pipes and compressors. Energy efficiency (hydrogen energy out/hydrogen in) is generally in the range 85-98% and depends significantly on hydrogen compression ratios; see (Bossel & Eliasson, n.d.), (Maroufmashat & Fowler, 2017) and (Pellow, Emmott, Barnhart, & Benson, 2015). The costs and energy efficiencies vary widely with type of store. Leakage from these stores is probably negligible commercially and in terms of global warming.

Hydrogen storage parameters comprise the costs of input power capacity (£/kW), storage capacity (£/kWh) and efficiency. Estimating from piecemeal information, such as in (SGI, 2017), capital costs of 50 £/kW and 1 £/kWh are assumed, and a roundtrip efficiency of 93%.

3. Global warming

3.1. Global warming potentials

To compare the global warming caused by different mixes of emissions of atmospheric components (CO_2, methane, aerosols, etc.), a common metric is required. Greenhouse gases (GHG) change the radiation balance of the atmosphere, it is called radiative forcing (RF), and in general the effect of a particular GHG is dependent on the mix of GHGs. The Global Warming Potential (GWP) is a metric often used.

The IPCC (Myhre *et al.*, 2013) define the GWP and note:

1. p710; "The Global Warming Potential (GWP) is defined as the time-integrated RF due to a pulse emission of a given component, relative to a pulse emission of an equal mass of CO_2 …".
2. p 713 'The uncertainty in GWPs for gases with lifetimes of a few decades is estimated to be of the order of ±25% and ±35% for 20 and 100 years.'
3. p713; 'Gillett and Matthews (2010) included climate–carbon feedbacks in calculations of GWP for CH_4 and N_2O and found that this increased the values by about 20% for 100 years.'

The estimated global warming potential (GWP) of GHGs such as methane over different time horizons (10, 20,100, 500 years) is the result of complex science and modelling and as this changes so do, to a limited extent, the reported GWPs of methane. GWPs are given relative to CO_2 (called CO_2 equivalent or CO_2eq) per kg of pollutant over different time horizons (10, 20,100, 500 years), where CO_2 has a GWP of 1 for all horizons.

Generally the emissions of GHGs such as methane or CO_2 are not in pulses but continuous and varying according to patterns of demand and the evolution of energy systems over years. The total radiative forcing of the concentration of a GHG due to this stream of emissions and their gradual removal from the atmosphere has to be integrated over time to arrive at the total radiative forcing of the emissions over some time period. A further consideration is the possible positive feedback of processes like melting tundra releasing methane which places more benefit from early reductions to avoid the so-called tipping point of runaway climate change; then the short term impact of methane increases in importance.

A question then is: which time horizon to use for policy purposes? Unfortunately, there is no purely scientific logic directing choice of horizon, but SMRCCS hydrogen systems at scale would be a commitment for several decades, so a range of GWP horizons, 10, 20 and 100 years, is used here.

3.1.1. Methane

GWP20 (86) and GWP100 (34) values per kg of methane including climate–carbon feedbacks are from p714 of Myhre *et al* (Myhre *et al.*, 2013). Howarth (R. W. Howarth, 2014) quotes a methane GWP10 of 108 apparently from an IPCC 2013 report. The methane GWP reduces over longer time horizons because the atmospheric residence time of methane and therefore related atmospheric processes is short compared to CO_2. The choice of time horizon therefore substantially alters the balance between warming due to CO_2 and methane.

We want to express GWPs of methane for methane itself and as the CO_2 that would be formed by combustion of a given quantity of methane. The combustion equation is:

$$CH_4 + 2O_2 => CO_2 + 2H_2O$$
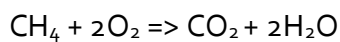
Using the approximate atomic weights of carbon (12), hydrogen (1) and oxygen (16), methane's molecular weight is (12+4x1 = 16) and CO_2 is (12+2x16 = 44). So 1 kg of methane produces 44/16= 2.75 kg of CO_2.

The gross calorific value (GCV) of methane per mass is 55.5 MJ/kgCH_4 (https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html https://en.wikipedia.org/wiki/) which, taking the reciprocal, is 0.018 kgCH_4/MJ or 64.9 gCH_4/kWh (0.018 x 1000 x 3.6). This forms 178.4 gCO_2/kWh (64.9 x 2.75). The emission factor for UK natural gas delivered is given as 183.2 gCO_2/kWh (BEIS, 2018), the difference being because natural gas is not just methane.

We then multiply 64.9 gCH_4/kWh by the relative GWPs of methane to arrive at the GWP of methane per kWh: e.g. for GWP20, 5578 = 86 x 64.9; GWP100, 2205 = 34 x 64.9. The GWP calculations and gCO2eq/kWh for different leakage rates are given in the next Table. We see that over 20 years a methane leakage of 3.50% will produce 195 gCO2eq/kWh (178.4/7100) which is about the same global warming (by GWP) as the carbon in the methane, over 100 years it is about 8% (178.4/2205).

Table 2 : Methane GWPs and leakage

CO2		Methane		
		10 years	**20 years**	**100 years**
GWP/kg	**1**	108	86	34
gCO2eq/kWh GCV	178	7005	5578	2205
Gas leakage		**Methane gCO2eq/kWh**		
0.50%		35	28	11
1.00%		70	56	22
1.50%		105	84	33
2.00%		140	112	44
2.50%		175	139	55
3.00%		210	167	66
3.50%		245	195	77
4.00%		280	223	88
8.00%		560	446	176

3.1.2. Hydrogen

Hydrogen is also a greenhouse gas due to processes described by Derwent (Derwent, 2018) with an estimate for GWP100 of 4.3. This is about 15% of the methane GWP per mass (kg). It is assumed that the radiative forcing consequences of hydrogen decline with time at the same rate as methane because the methane time constants dominate the time constants of the methane, carbon monoxide, nitrogen oxides, hydrogen and volatile organic compound species. So the GWP20 for hydrogen is GWP100(H_2) x GWP20(CH_4) / GWP100(CH_4) = 4.3 x 86 / 34 = 10.9.

Hydrogen leakage will be small upstream of the SMRCCS because there is little hydrogen in processed natural gas. There is little evidence as to the hydrogen leakage to be expected downstream of the SMRCCS plant in distribution, storage and consumer equipment. According to Graham's law, the rate of effusion of a gas through a given sized hole is inversely proportional to the square root of the gas' molecular weight (molar mass). Therefore hydrogen (molar mass 2) will leak from a hole in the ratio $(16/2)^{0.5}$ = 2.8 times faster (mass/time) than methane (molar mass 16), so since hydrogen will be deployed in similar technologies to methane, leakage might be 2.8 times higher. This is confirmed by the Leeds project report, (*Leeds City Gate: h21*, n.d.). So, for example, if methane leakage from a given distribution system is 0.5%, hydrogen leakage might be expected to be of the order of 1.5%. As for natural gas, safety would be a major reason to constrain leakage.

Frazer-Nash (Frazer-Nash, 2018) report concerns about leakage and materials degradation in consumer hydrogen components including boilers. Hydrogen flames will produce some nitrogen oxides (NOx) which is an air pollutant. These aspects require further investigation.

Given the low GWP of hydrogen compared to methane, and that 1 kg of methane produces 0.25 kg of hydrogen, the global warming due to hydrogen is likely to be a negligible fraction of SMRCCS hydrogen total gCO_2eq/kWh due to methane and CO_2. Further, hydrogen leakage is unlikely to greatly impact on the overall economics of SMRCCS hydrogen heating, so hydrogen leakage is ignored.

3.2. Greenhouse gas emission targets

If the world is to meet a target of 1.5 $^{\circ}C$ maximum temperature rise, emissions have to be reduced as fast as possible to near zero by 2050 and net negative emission thereafter: the UK has draft legislation for net zero emission by 2050. The optimal energy mixes that will meet this target will be heavily constrained. It is technically difficult and costly to reduce GHG emissions from some demands – notably aviation - and the costly capture and storage of atmospheric or marine CO_2 may be required to balance emissions from these sectors. In contrast, it is relatively easy to reduce emissions from heating, such as with renewable electricity and heat pumps.

3.3. Emission and global warming of SMRCCS hydrogen heating

The global warming of SMRCCS hydrogen heating depends on the methane and CO_2 emission estimates used, and the GWP time horizon. The methane and CO2 emission at each stage has GWPs applied, so building up the total global warming over the whole supply chain. Three sets of emission for each gas heat supply component have been assumed based on the surveyed data; these are called 'low, mid, high' though there no good defence of these labels given the uncertainty in emissions. Three GWP horizons (10,20,100 years) are later applied.

The individual and cumulative emissions of the system from production (Pro) to Delivered (Del) are shown in Figures 5 and 6.

Figure 5: Natural gas methane emissions – individual components
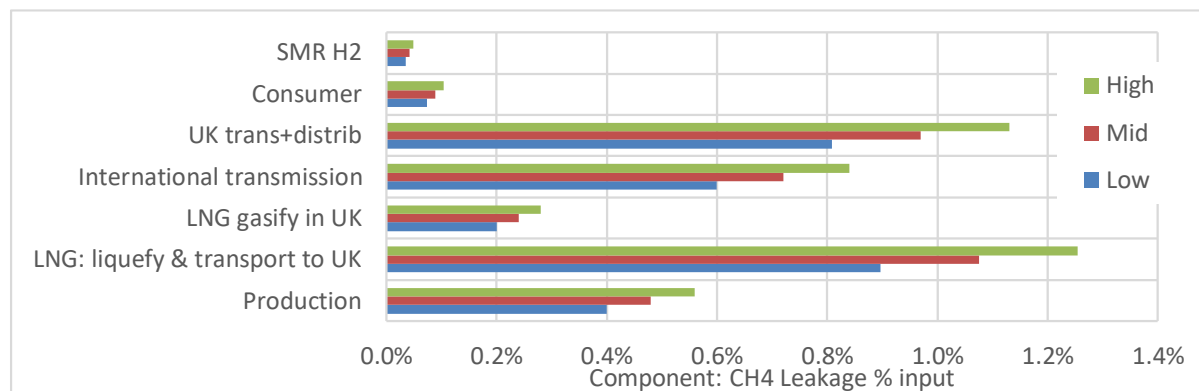
Figure 6: Natural gas delivery – cumulative emission to delivery
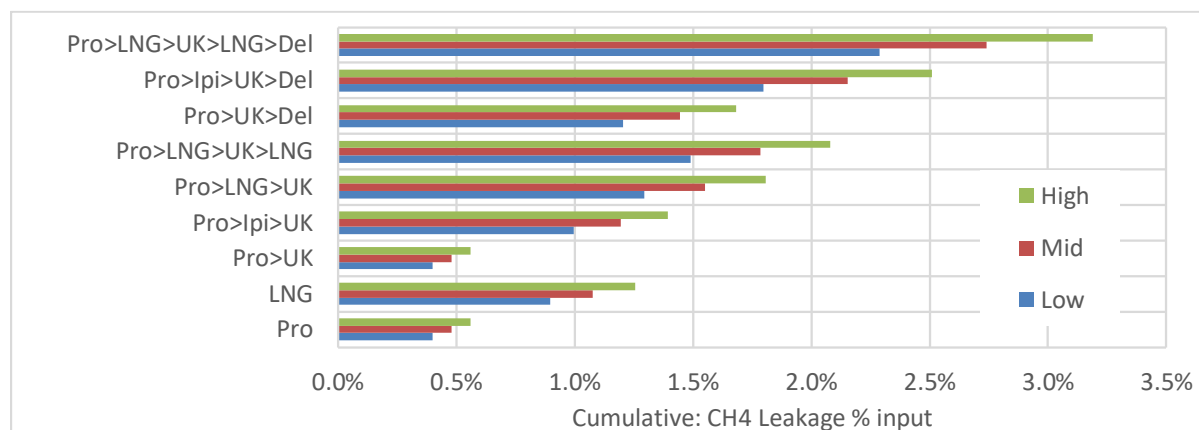
Using central (mid) assumptions, total methane emissions from production to delivery to consumers, as a fraction of total primary production, are estimated as 1.2%, 1.8% and 2.3% for the direct use of natural gas from the UK, transcontinental pipeline, and LNG imports respectively for heating. The global warming of gas heating is estimated for a 10, 20 and 100 year methane GWP. The CO_2 (not methane) GW for direct gas heating ranges from 226 to 260 gCO_2/kWh(heat) and for SMRCCS heating 48 to 54 gCO_2/kWh(heat).

SMRCCS eliminates downstream CO_2 and methane emission in distribution and at consumers, but increases emission of these upstream of SMRCCS by about 40% (1/0.7) because of the greater gas use caused by the SMR inefficiency.

Figure 7 shows cumulative emission for producing heat via the current pathway using natural gas directly in boilers, and for the pathway via SMRCCS.

Figure 7: SMRCCS heat global warming

Figure 7 continued…
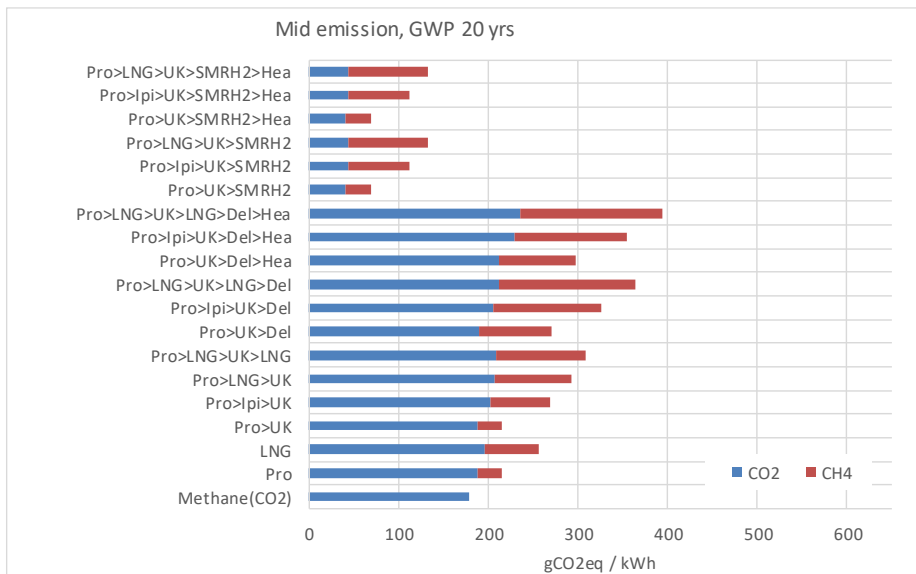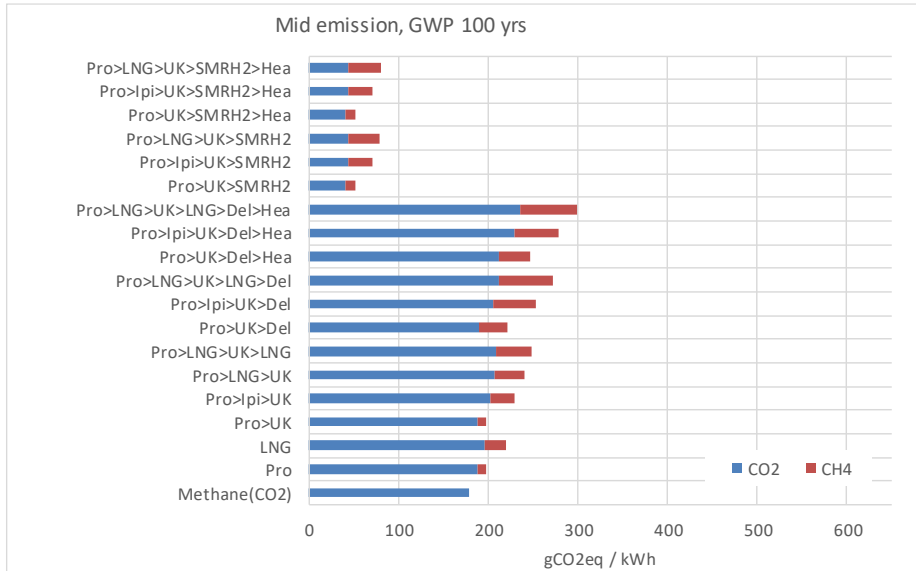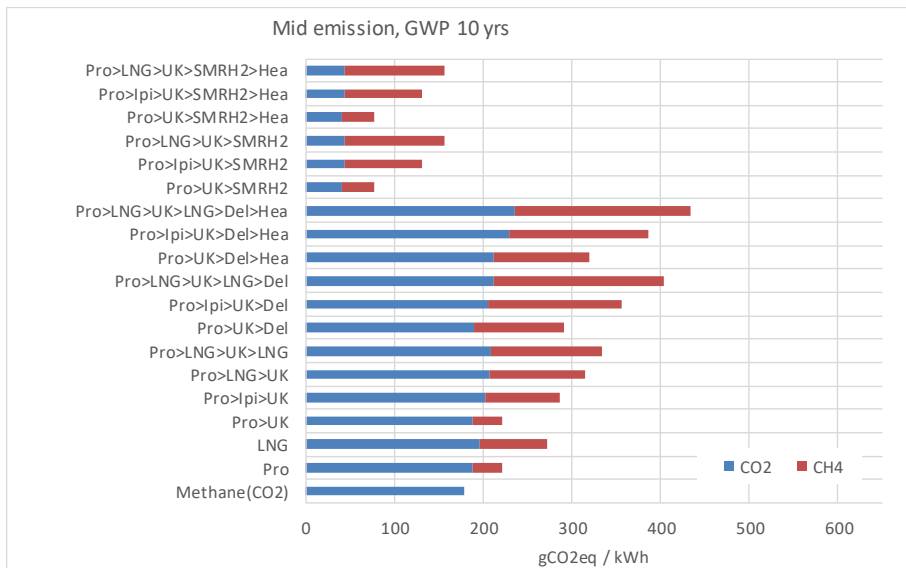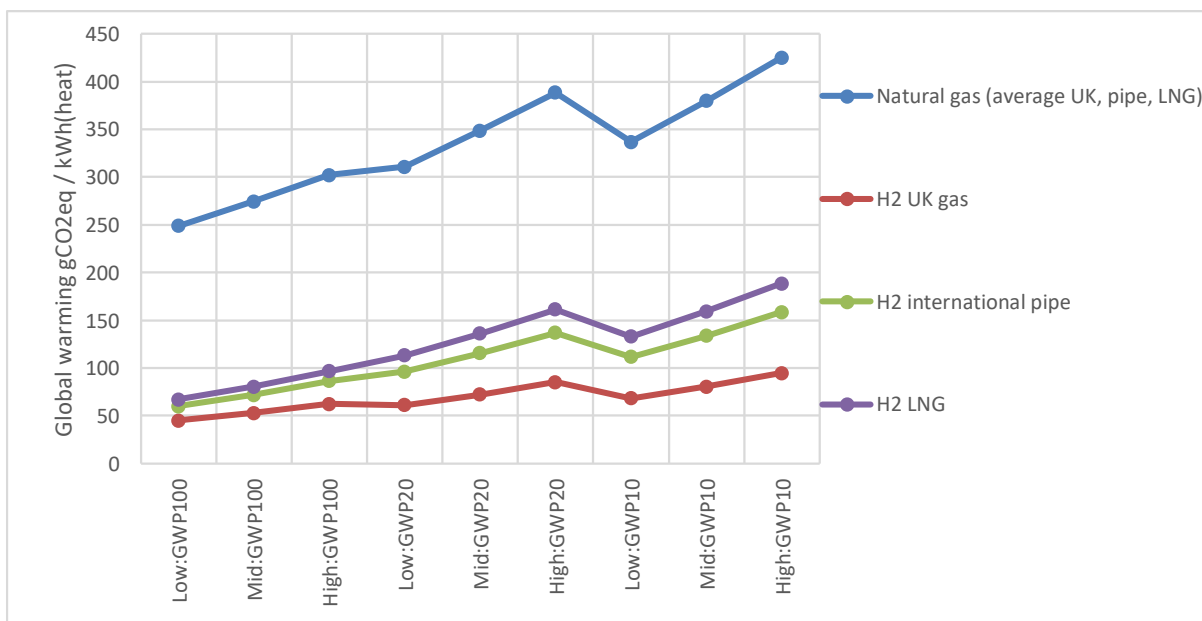

The next Figure shows the global warming of all nine combinations of long distance vector (UK pipe, international pipe, LNG), CO_2 and methane emissions (low, medium, high) and GWPs (10,20,100 years).

Figure 8 : SMRCCS hydrogen greenhouse gas emission – 9 combinations

Finally, the following Table gives details for CO_2 and methane for all nine combinations of emission and GWP.

Table 3 : Global warming (CO2eq/kWh) of gas chains – detail

	GWP100						GWP20						GWP10					
	Lo		Mi		Hi		Lo		Mi		Hi		Lo		Mi		Hi	
	CO2	CH4	CO2	CH4	CO2	CH4	CO2	CH4	CO2	CH4	CO2	CH4	CO2	CH4	CO2	CH4	CO2	CH4
Methane	178	0	178	0	178	0	178	0	178	0	178	0	178	0	178	0	178	0
Pro	184	9	188	11	191	12	184	22	188	27	191	31	184	28	188	34	191	39
LNG	190	20	197	24	204	28	190	50	197	60	204	70	190	63	197	75	204	88
Pro>UK	184	9	188	11	191	12	184	22	188	27	191	31	184	28	188	34	191	39
Pro>Ipi>UK	194	22	203	26	212	31	194	56	203	67	212	78	194	70	203	84	212	98
Pro>LNG>UK	197	29	207	34	218	40	197	72	207	86	218	101	197	91	207	109	218	127
Pro>LNG>UK>LNG	198	33	209	39	220	46	198	83	209	100	220	116	198	104	209	125	220	146
Pro>UK>Del	186	27	190	32	194	37	186	67	190	81	194	94	186	84	190	101	194	118
Pro>Ipi>UK>Del	196	40	205	48	216	55	196	100	205	120	216	140	196	126	205	151	216	176
Pro>LNG>UK>LNG >Del	199	50	211	60	224	70	199	128	211	153	224	178	199	160	211	192	224	223
Pro>UK>Del>Hea	**200**	**28**	**212**	**34**	**226**	**39**	**200**	**71**	**212**	**85**	**226**	**100**	**200**	**90**	**212**	**107**	**226**	**125**
Pro>Ipi>UK>Del> Hea	**210**	**41**	**229**	**49**	**251**	**58**	**210**	**104**	**229**	**125**	**251**	**146**	**210**	**131**	**229**	**157**	**251**	**183**
Pro>LNG>UK>LN G>Del>Hea	**214**	**52**	**236**	**62**	**260**	**73**	**214**	**132**	**236**	**158**	**260**	**184**	**214**	**165**	**236**	**198**	**260**	**230**
Pro>UK>SMRH2	35	11	40	13	48	15	35	27	40	32	48	37	35	34	40	40	48	47
Pro>Ipi>UK>SMRH 2	36	24	43	28	53	33	36	60	43	72	53	84	36	75	43	90	53	105
Pro>LNG>UK>SM RH2	37	30	44	36	54	42	37	77	44	92	54	107	37	96	44	115	54	134
Pro>UK>SMRH2> Hea	**35**	**11**	**40**	**13**	**48**	**15**	**35**	**27**	**40**	**32**	**48**	**37**	**35**	**34**	**40**	**40**	**48**	**47**
Pro>Ipi>UK>SMR H2>Hea	**36**	**24**	**44**	**28**	**53**	**33**	**36**	**60**	**44**	**72**	**53**	**84**	**36**	**75**	**44**	**90**	**53**	**105**
Pro>LNG>UK>SM RH2>Hea	**37**	**30**	**44**	**36**	**55**	**42**	**37**	**77**	**44**	**92**	**55**	**107**	**37**	**96**	**44**	**115**	**55**	**134**

| per kWhth heat delivered	GWP100			GWP20			GWP10		
Natural gas (average UK, pipe, LNG)	249	274	302	311	349	388	337	380	425
H2 UK gas	45	53	63	61	72	85	86	81	95
H2 international pipe	60	72	86	96	115	137	112	134	158
H2 LNG	67	81	97	113	136	161	133	160	189
H2 UK gas % red'n cf nat gas	82%	81%	79%	80%	79%	78%	80%	79%	78%
H2 international % red'n cf nat gas	76%	74%	71%	69%	67%	65%	67%	65%	63%
H2 LNG % red'n cf nat gas	73%	71%	68%	63%	61%	58%	61%	58%	56%

4. Energy Security

Energy security here is taken to include physical security – the availability of energy resources for the UK - and economic security in the sense of affordable services. A long-term view should be taken when planning large scale infrastructure. The lifetimes of existing infrastructure components and the capacities for investment, manufacturing and installation constrain the rates of energy system development. These lifetimes and capacities may be flexed to some degree, but there are tight constraints; for example, the social capacity for system installation is constrained by demography, labour skills and finance. A switch to 90% renewable electricity, or 90% electric vehicles, or 50% district or hydrogen heating might take the order of 30 years, and then these systems might be operated for 50 years or more. So we might consider the period 2040-2100 as appropriate periods over which to consider natural gas and hydrogen supply, costs and environmental impacts.

4.1. Gas supply

BP gives a global gas reserves/production ratio of 50 years (BP, 2017) so there is no imminent prospect of global gas shortages, but there will be increasing competition for dwindling resources. UK and European reserves are depleting rapidly and this, without reduction in gas consumption, can mean higher costs because of greater use of higher cost gas fields and infrastructure such as pipelines and LNG production and transport systems, forming a gas supply 'merit' order – UK sourced, Europe, Russian piped gas or Middle East LNG. European gas costs can therefore be expected to increase across the years and to be higher in winter (maximum consumption) than summer. At the same time, the UK departure from the EU may affect gas security.

The UK continental shelf (UKCS) currently (2017) supplies about 43% of UK gas demand, but the UK increasingly imports gas as its own reserves are depleted, as shown in the next Figure. These imports are imported by pipe from Europe with 23% of European gas originally from Norway and 35% from Russia. ("Where does UK gas come from? - British Gas," 2018). A further 13% comes from LNG with about 90% of this currently from Qatar (https://www.bbc.co.uk/news/business-43421431).

Figure 9 : UK gas import 1996-2016
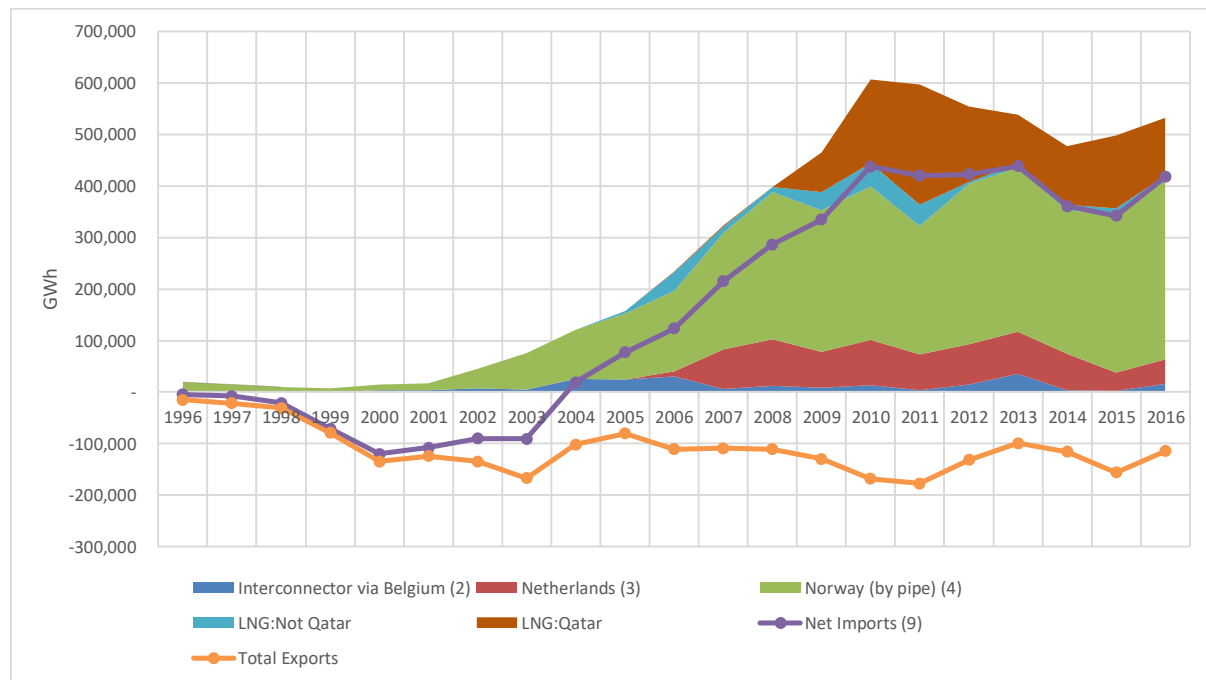
Source: DUKES https://www.gov.uk/government/statistics/dukes-foreign-trade-statistics

UK production is projected to decrease by 10-30% over 2017 to 2022 and by over 50% 2017-2035 (OGA, 2017). The consumption of gas will be a balance between drivers for increase, like population, and drivers for decrease like efficiency, renewable generation and electric heating, and less gas generation. BEIS scenarios (BEIS, 2017c) project gas consumption to reduce by about 17% 2016-2035, so, given a reduction of 50% in production, gas imports would increase significantly.

UK and European heat supply and electricity generation, and therefore gas consumed for these uses, is higher in winter than summer. Because UKCS supplies are limited, much of the winter-summer swing is currently met with Norwegian gas as shown in Figure 10.

Figure 10 : UK monthly gas supply

Source: OFGEM, https://www.ofgem.gov.uk/data-portal/gas-demand-and-supply-source-month-gb
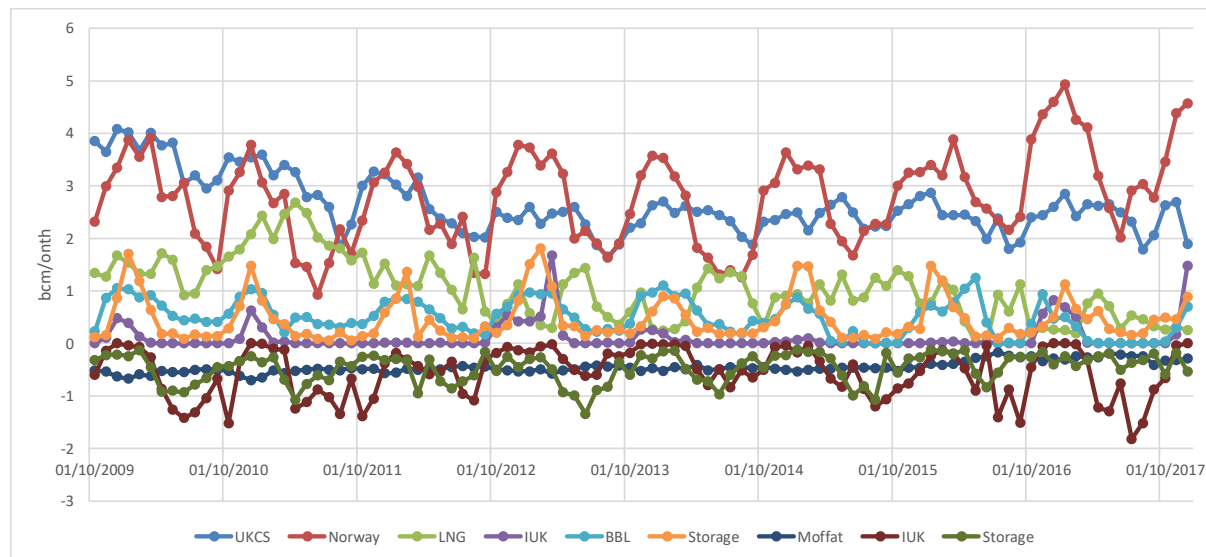
At the same time, UK storage capacity has fallen from 50 TWh to 16 TWh, about 10 days average UK consumption of around 90 GW (DUKES, Table 4.3, 2017), following closure of the UK's major gas store, the Rough field. This means the UK's primary gas supply, whether domestic or imported, has to follow demand more closely, though of course new storage can be built.
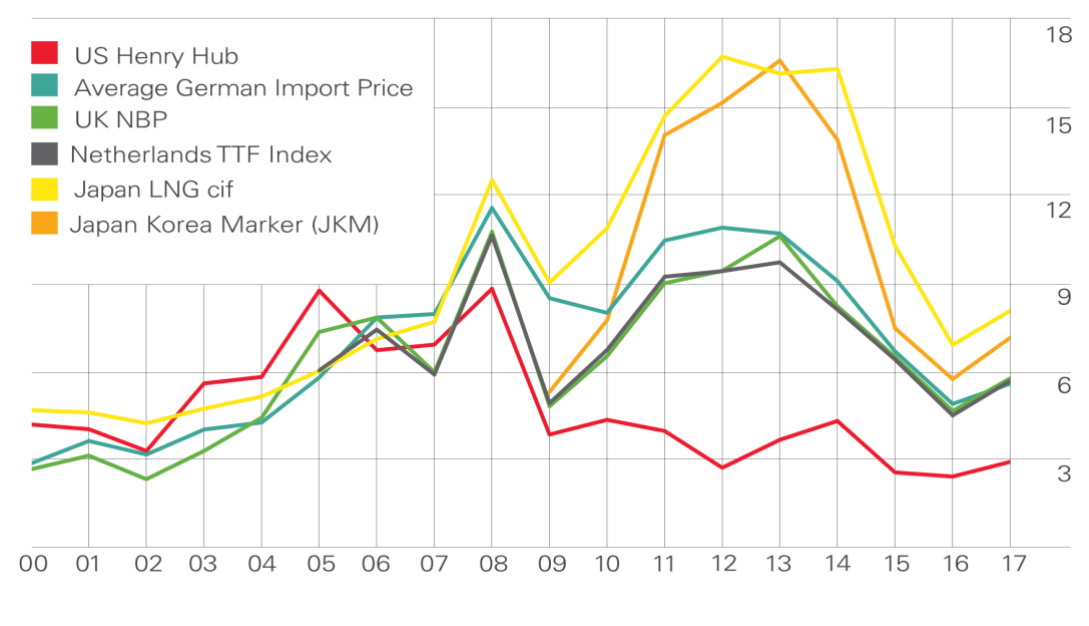
BP (BP, 2017) envisage global gas consumption growing at 1.6%/a with European production declining and imports from Russia and LNG increasing. In this context, the UK will become more vulnerable as its gas reserves decline and it is forced to import more from various sources, some of which may be subject to political pressures. Gas is an increasingly globally traded fuel because of reserves declining and the development of long distance pipe and LNG transport. Apart from Norway, the UK is distant from the main Eurasian reserves in Iran, Russia and the Middle East and there may well be increasing global competition for these reserves, such as from the great populations of China and India. Gazprom is nearing completion of a 2000 km gas pipeline from Siberia to China (Paraskova, n.d.)., with China projected to become the largest gas importing country by 2019 or soon thereafter. A problem with a major facility such as a pipeline or LNG store, whether because of equipment fault (Kottasová, n.d.) or attack ("Cyberattack Shows Vulnerability of Gas Pipeline Networkpipeline-," n.d.), could disrupt supply.

BEIS (BEIS, 2017b) consider gas security not to be problematic over the next two decades. Ofgem (Whitmarsh, Bojanowski, & Barber, 2011) appraise security of supply risks from shocks including LNG ship route constraints, problems with shale, nuclear crisis, and pipeline technical/political disruption. Ofgem also sees a low risk to security except in extreme demand and supply conditions. However, these appraisals are for the next decade or two with declining gas demand, whereas hydrogen heating needs horizons of 2040 to 2100 and each unit of natural gas replaced by SMRCCS hydrogen increases natural gas consumption by 40% in a future where gas becomes increasingly globally traded, and the UK therefore becomes more affected by shocks distant from the UK.

4.2. Gas prices

Gas prices during the period 2000-2017 have been volatile, varying by about 3:1 in the UK and Europe. Since 2009, USA prices have shown decline, largely because of shale, whereas Europe and particularly Japanese gas prices showed a large peak, partially because of the Fukushima disaster reducing Japanese nuclear output and replacing it with increasing gas generation using imported LNG, globally traded, and this has also influenced European prices.

Figure 11 : Gas prices – historic ($2017/mmBtu)

Source: https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/natural-gas/natural-gas-prices.html

UK power producers might be representative of large SMRCCS hydrogen producers in terms of bulk gas prices. During 2000-2017, the gas price to major UK power producers varied from 0.6 to 2.3 p/kWh, a range of nearly 4:1 – reported by DECC (Department of Energy & Climate Change, 2018)

As in the past, future gas prices will be determined by factors including consumption, production mix (conventional, unconventional) and infrastructure. Long distance gas transport by LNG and pipeline is costly in capital and operational terms. Given the past price variability and the increasing exposure of the UK and Europe to gas imports, variability in the future is to be expected.

Because of the rapid changes in historic gas prices, it is problematic to select a starting point for projections. The BEIS (BEIS, 2017a) forecasts are for gas prices to increase to 2030 and then remain flat to 2035. It is interesting to compare chaotic price histories with smooth forecasts: the high scenario for the gas price in 2035 is little higher than the peaks 20 years earlier in the period 2008-2013, and the low price forecast is about the same as the lowest price since 2004.

Figure 12 : Historic and BEIS gas price projections
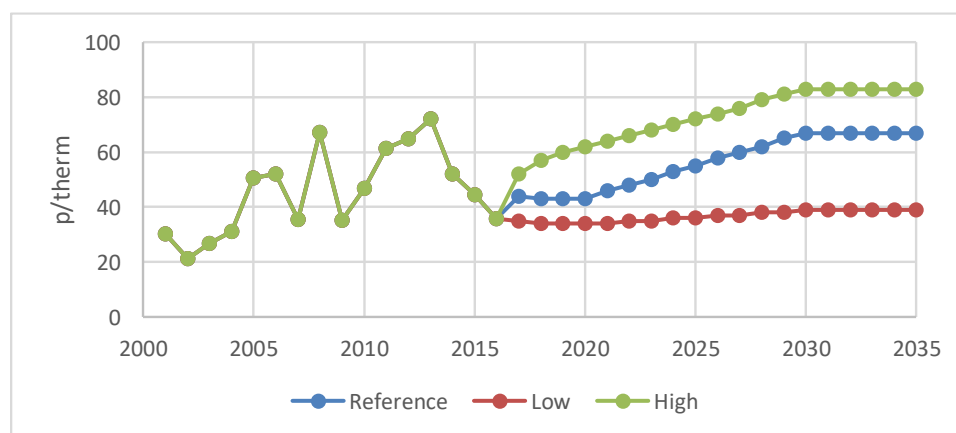
Source: (BEIS, 2017a)

As argued above, longer term forecasts are needed for long term infrastructure investments and quantification of possible consumer costs. European scenarios (EuropeanComission, 2016) are for gas prices to increase from 2016 by about 50% by 2030, and 75% by 2050.

Applying these proportionate price increases to the base 2017 UK price to major power producers (1.5 p/kWh) gives a projection 3 p/ kWh for 2050 which is adopted for the SMRCCS economic analysis: this is close to the BEIS high price forecast of 2.8 p/kWh for 2035.

4.3. Intra-year, seasonal gas prices

As supply costs increase with consumption which is maximum in winter, gas prices will generally be higher in winter than summer, and this is when SMRCCS hydrogen demand would be maximum. During 2004-2008, winter gas prices reached 20-40 p/therm (40-80%) higher in winter than summer; however since 2010, winter prices have generally been about 5-10 p/therm (about 10-20%) higher in winter than summer at the National Balancing Point (NBP). https://www.ofgem.gov.uk/data-portal/all-charts/policy-area/gas-wholesale-markets

Exceptional meteorology impacts on demand, but can also impact on hydro, nuclear, wind and solar generation and thence 'back up' gas consumption. The UK is already vulnerable to these and climate projections are that severe episodes may become more frequent. For example, in the 2018 cold episode:

- the Financial Times reported in February 2018:'Demand for gas soared to its highest level in five years on Wednesday as freezing weather gripped the UK, prompting fears supplies could get tighter over the coming days. Wholesale gas prices for same-day delivery soared to a 12-year high, jumping to 190p a therm on Wednesday morning, more than three times the average of 56p a therm seen so far this month.'

- For the same period' Reuters reported: 'In February, a cold snap across Europe dubbed the "Beast from the East" sent British wholesale gas prices to 10-year highs as traders scrambled to secure supplies to meet high demand for heating. Then, a summer heatwave across Europe, coupled with low wind power output and hydro levels ramped up gas demand from power plants during the months when storage stocks would usually be replenished.'

Such intra-annual variation adds further uncertainty and will strongly affect gas, widely used for space heating. The assumption is made that gas prices to the SMRCCS cost optimisation will vary from the average annual price by +10% in winter to -10% in summer.

5. SMR system optimisation

This section describes a simple optimisation model of SMRCCS aimed at determining the best combination of SMRCCS and hydrogen storage capacities. The SMRCCS hydrogen heating system comprises:

1. A heat load
2. Consumer hydrogen boiler.
3. Hydrogen distribution
4. Hydrogen storage
5. SMRCCS H2 production
6. Natural gas supply to the SMRCCS

Note that hydrogen heat delivery is assumed to be via boilers, whereas hydrogen fueled pumps or CHP would be more efficient, but more costly.

For a given profile of heat demand across the days of the year, the minimum cost of delivering hydrogen for heating will follow from some optimum combination of the capacities of SMRCCS (kW) and hydrogen storage (kW, kWh) given the efficiencies and unit capital and O&M costs of SMRCCS and hydrogen storage, and the time varying price of natural gas across the year. The network and boiler costs do not affect the optimum as they are assumed to be the same whatever the SMRCCS and storage capacities, but they will affect the relative costs of hydrogen as compared to other vectors such as district heating.

The total UK heat load, estimated for 2016 from ECUK (2017) is about 500 TWh, with low temperature heat the bulk of this – see Table 4. The future load will depend on the balance between drivers such as increased population and improved efficiencies of buildings and so on. For this exercise, the heat load assumed to be met with hydrogen is 300 TWh or 60% of the 2016 UK annual heat load: this might be representative of the UK urban high density heat load that is largely met with natural gas in networks which might be adapted to hydrogen. In fact, the optimised configuration in terms of SMR and storage capacity are scale independent under the assumptions made.

Table 4 : UK Heat load estimate

TWH	Space	Hot water	Low temperature process	High temperature process	Dry / separate	All		Low temperature	
Domestic	255	45	0	0	0	301	16%	301	16%
Services	76	11	0	0	0	86	5%	86	5%
Industrial	35	0	50	30	17	132	7%	85	5%
Total	366	56	50	30	17	519	28%	472	25%
	71%	11%	10%	6%	3%				

Source: Energy consumption in the UK, 2017. https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

Generally, economies of scale apply to all technologies and the unit costs fall with increasing spatial hydrogen (heat) demand density (kWh/km²/a) and load factor (peak/average demand). Thus a large system serving the high density core of a city or large industrial load centres will have lower unit costs than smaller systems; the costs assumed here are meant to reflect large systems with scale economies.

A major assumption is that SMRCCS can vary its hydrogen output as fast as required, say hour by hour. This is probably not correct for individual plant, but the heat demand assumed here requires a minimum 40 GW of SMRCCS and this capacity would comprise many plant. If plant shared load with common transmission, then then there is the possibility of turning off some plant during months of low demand. Hydrogen storage can reduce the requirements for the SMRCCS to follow the load hour by hour and month by month and to reduce SMRCCS installed capacity and thence total costs. Hydrogen storage parameters are discussed in section 2.8.

A simple sinusoidal variation in diurnal and seasonal weekly heat load profile is assumed, and a sinusoidal seasonal gas price. The heat demand (300 TWh/a) averages 35 GW and varies from 2 GW in the summer night to 111 GW peak winter. The annual heat load factor is 30%, which may be high. The delivered hydrogen input to a 90% efficient boiler follows these profiles as there is no consumer storage and hydrogen meets the whole heat load via boilers. Of course, these profiles do not reflect the impact on demand of the real world vagaries of the weather. In the simple model, distribution system hydrogen leakage is assumed to be zero.

Figure 13 : Heat and hydrogen demand (4 winter days, 52 weeks) and gas price
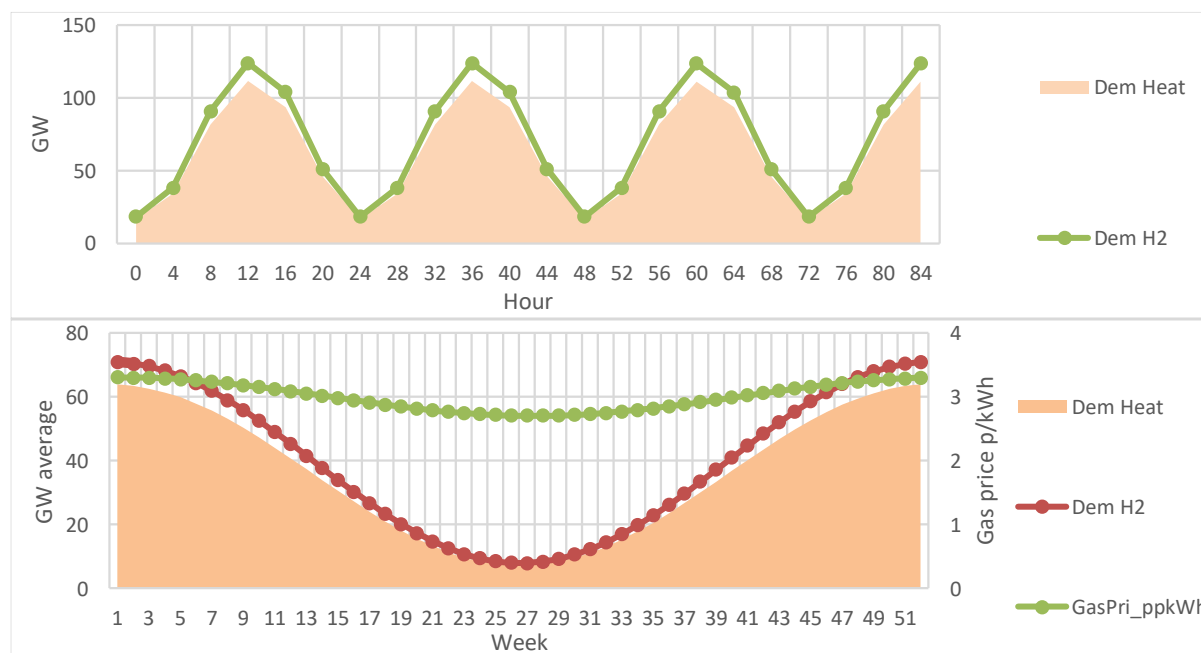
The objective function is the total annuitized cost of the system. The decision variables are just three: SMRCCS capacity (GW) and hydrogen storage power and energy capacities (GW, GWh). Frazer-Nash (Frazer-Nash, 2018) discuss the technical and cost issues relating to new, adapted and dual fuel hydrogen appliances.. There is uncertainty as to the costs of adapting natural gas distribution to hydrogen; a figure of 200 £/kW (consumer) is assumed - £1400 per consumer with a peak load of 7 kW. Costs for the distribution network and boiler are indicative and in any case are assumed constant and do not affect the simple optimisation.

The next table summarises the assumed performance and cost input data (in blue), and the optimum values for the (decision variable) capacities (in yellow) and associated costs. The cost of SMRCCS heat is 9.95 p/kWh. Natural gas constitutes about 50% of the total cost of heat, and SMR capital and O&M costs about 30% of the total cost. The SMR O&M costs (excluding fuel) are a large fraction of total SMR costs, maybe because of CCS operation, and this needs further research. For comparison, direct gas heating costs about 4.45 p/kWh, assuming gas distribution is amortised and so zero cost. Customer and network operational costs should be added, but are assumed not to vary.

Table 5 : SMR optimisation

			Inputs	Optimum capacity GW/GWh	Life yrs	Annuitised capital £/kW/a	M£/a	Heat p/kWh	Fraction heat cost	Direct nat gas	
										M£/a	Heat p/kWh
Natural gas		p/kWh	3				15,556	5.01	50%	10890	3.5
SMR CCS		Efficiency	70%								
	Capital	£/kW	1000	67	25	94	6309	2.03	20%		
	O&M	£/kW/a	40				2694	0.87	9%		
	CCS	CO2 %	85%								
H2 storage		Efficiency	93%								
	Cap: power	£/kW	50	50	25	5	233	0.08	1%		
	Cap: energy	£/kWh	1	6013	25	0	563	0.18	2%		
H2 storage	Distrib	£/kW	200	124	25	19	2316	0.75	7%		
	Boiler	Efficiency	90%								
		£/kW	250	111	15	29	3250	1.05	11%	2925	0.9
					Totals	Cap O&M	15,366	4.94	50%	2925	0.94
						Fuel	15,556	5.01	50%	10,890	3.5
						Total	**30,923**	**9.95**	**100%**	**13,815**	**4.45**

The next Figure shows 4 days' optimised system winter operation, and seasonal operation. It may be seen that the hydrogen storage, capacity 6013 GWh, is used to reduce diurnal and seasonal variations and its level is close to zero in late winter. SMRCCS runs at constant output in the winter and in the other seasons follows the average weekly demand.

Figure 14 : System operation – days and weeks
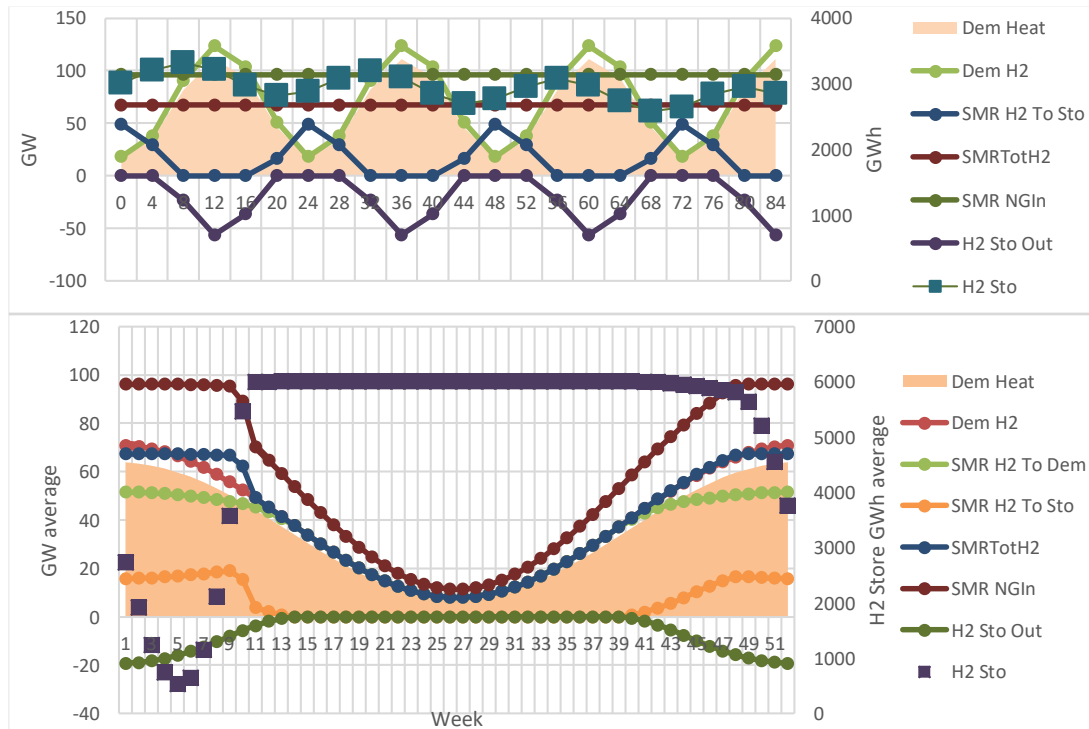
The (aggregate) SMRCCS plant has an annual capacity factor of 59%. Weekly natural gas input varies from a minimum 11 GW to a maximum 102 GW. Annual natural gas demand modelled is 500 TWh to meet 60% of UK heat demand: compared to some 550 TWh used for supplying perhaps 80% or 90% of 2017 heat demand. Thus the inefficiency of SMRCCS means gas demand for heating is similar to now (2018) for supplying 30% less heat.

Figure 15 : SMRCCS optimised system operation summary

	Peak GW	Annual GW	CapFac %
Heat	111	311	32%
Hydrogen	124	345	32%
SMRCCS	67	349	59%
Natural gas	96	499	59%

The model and optimisation are very simple. Elaboration and changing technology costs and efficiencies and gas prices will result in different optima. Further work would include a sensitivity analysis.

6. Discussion and conclusions

The preceding has constructed a framework for analysing the global warming of natural gas and SMRCCS pathways, and for optimising the configuration of SMRCCS hydrogen based heating. Throughout there has been a problem of poor input data for the analysis, most notably for gas supply methane leakage and energy consumption, where estimates can vary by a factor of three, five, or more; and there are no established, published data for the performance and costs of operational, commercial scale SMRCCS. Natural gas annual and seasonal prices in 2050 or beyond are necessarily uncertain. As an increasing fraction of UK gas is imported across great distances in future, it is likely gas prices will increase. It will be harder to control GHG emissions because much of these will be outside UK control but countering that will be improved leakage control.

The analysis of natural gas and SMRCCS hydrogen global warming impacts illustrated the uncertainty and complexity, but indicates that, for CO_2 only, SMRCCS heating produces about 50 gCO$_2$/kWh(heat) as compared to natural gas direct heating at 200 to 260 gCO$_2$/kWh(heat) depending on gas source, an 80% reduction, which is less than the CCS removes because the 70% efficiency of SMRCCS causes 40% more CO_2 emission upstream than direct gas use per unit of heat delivered. If methane emissions are added, then for GWP20, these figures are around 100 and 350 gCO$_2$eq/kWh(heat) for SMRCCS and direct use respectively, about a 65% reduction in global warming with SMRCCS.

To meet global targets, the UK has committed to net zero emissions by 2050. Compared to heating, it is relatively hard to reduce emissions in some sectors, such as aviation, cement and iron and steel and therefore services 'easily' decarbonised such as heat will, on economic grounds, require higher than average reduction. It is therefore difficult to see how SMRCCS hydrogen produced from natural gas can be used to fuel a significant fraction of heat, given the near zero carbon and other GHG emission alternatives of renewable and nuclear energy.

To widely implement SMRCCS hydrogen might take 20-30 years and, to make it a worthwhile investment, it should operate for, say, 30 or 50 years, taking us to 2050-2100; but before or by this time, because of gas availability, prices or tighter net greenhouse gas emission targets, heating might have to be switched again. Per unit of heat delivered, as compared to a gas boiler, SMRCCS increases natural gas consumption by about 40%, therefore increases imports at the margin. With the assumptions made, the simple model and optimisation result in a hydrogen heat cost of 9.95 p/kWhth, with natural gas cost constituting 50% of the total. The optimum system had 6013 GWh of hydrogen storage with the SMR CCS plant operating at 59% capacity factor.

A possibility is to balance SMRCCS emissions with environmental carbon sequestration – absorbing atmospheric CO2 and storing it – using processes such as plant biomass or in machines but this may have significant environmental impacts and costs. One option is Direct Air Capture and Carbon Storage (DACCS) though, because it's commercially unproven, published estimates of DACCS lifecycle costs range widely from around 50 to 2000 £/t CO_2 which is 0.005 to 0.2 p/gCO_2. If we assume this range and that SMRCCS heat emits between 50 and 200 gCO_2eq/kWhth then the DACCS cost addition to SMRCCS heat is between 0.3 and 40 p/kWhth as shown in the next table; this is in addition to the base cost of SMRCCS heat of about 10 p/kWhth calculated with the simple optimisation. DACCS requires considerable energy inputs of electricity and heat which would require more low carbon capacity build, with energy costs varying with location.

Table 6 : SMRCCS cost addition range of DACCS negative emissions

	SMRCCS emission	
	gCO2eq/kWhth	
	50	20
DACCS cost	**DACCS balancing cost**	
p/g CO2	p/kWhth	
0.005	0.3	1.0
0.2	10.0	40.0

This paper excludes any detailed consideration of other heating options, but some comments may be made.

Rather than consumer boilers, hydrogen could be used more efficiently in CHP (H2CHP), hydrogen fueled heat pumps (H2HP) or a combination of H2CHP, boiler and electric HP; and thereby reduce hydrogen demand and upstream emissions. Staffell (Staffell & Green, 2013) reported domestic scale fuel cell H2CHP capital costs then around 30-50,000 $/kW so this does not look a strong option. However, hydrogen or ammonia fueled CHP at district heat and cooling (DHC) scale would have lower costs per capacity (kW) and greater efficiency because of scale economies and could be sited near hydrogen or ammonia storage. DHC scale H2CHP could use a number of technologies - fuel cell, internal combustion, gas turbine or steam cycle. Some analysts propose that hydrogen used in consumer boilers for peaking alongside heat pumps would be a lower cost solution than heat pumps alone.

An alternative to SMRCCS hydrogen heating is renewable or nuclear electricity with life cycle electricity GHG emission around 10 gCO_2eq/kWh, driving a mix of district heating and consumer heat pumps, or for industrial high temperature heat (above about 150 ^{o}C), resistance heating. If electricity has a winter weighted carbon content of 50 gCO_2eq/kWh and the annual weighted heat pump coefficient of performance is 3, then heat is 17 gCO_2eq/kWh(heat) as compared to 50-200 gCO_2eq/kWh(heat) for SMRCCS. The electricity dominated route has hard problems, especially renewable variability, but electricity systems with connected storage and long distance transmission are being deployed to address these problems. All the technologies for a renewable electric heat route are commercially established and serve millions of consumers worldwide, and the costs of renewable wind and solar, because of fast development cycles and mass production, are falling steadily – a contrast with historic chaotic and projected increasing gas prices and cost uncertainties for SMR, hydrogen networks and boilers for which there are no scale systems globally. The renewable route is sustainable indefinitely, and once installed, there would be no need for further large scale system change, unlike for gas.

One can also consider gas fired CHP with CCS feeding heat to district heating and the electricity to consumer or DH heat pumps, or to meet other electricity demand - CHPCCS/HP. Let us assume the same 85% CO_2 removal rate for CHPCCS as SMRCCS. The CHPCCS might have an electrical efficiency of about 0.3 (including the CCS energy overhead) and a heat efficiency of 0.4 (including DH network losses), and the heat pumps a COP of 3. Then, assuming the CHP electricity is used in HPs, the overall efficiency of CHPCCS/HP heat is 0.4 + 0.3 x 3 = 1.3; whereas SMRCCS has an overall gas to heat efficiency of 0.7 (SMRCCS) x 0.9 (boiler) = 0.63. Assuming the upstream gas supply is the same in the SMRCCS and CHPCCS/HP cases, the emissions of SMRCCS will be 1.3/0.63 = 2.1 times that of CHPCCS/HP. CHPCCS/HP faces the same issues relating to meeting varying heat load, but gas and heat storage are proven at scale. Gas fired CHPCCS is also subject to the same gas import security issues of SMRCCS, but its greater efficiency reduces security problems in the ratio 1/2.1, i.e. about 50% less gas than SMRCCS for the same amount of heat.

Dispatchable CHPCCS fueled by stored fuel such as gas, or CHP without CCS fueled by biomass or renewable hydrogen or ammonia, may be important options for complementing variable renewables, at least until other system balancing storage and transmission options are sufficient. District heat offers efficiency and flexibility options as compared to hydrogen piped to boilers, with an advantage of heat pumps being that they can cool as well as heat and therefore provide flexibility in adapting to climate warming. District heat certainly requires new networks; it is not yet clear how much the existing natural gas networks would have to be adapted to use pure hydrogen, or electricity networks augmented, and what the costs of these might be.

We can outline approximations for the option of using hydrogen produced from electrolysis, at about 75% efficiency, in a boiler of 90% efficiency. With a COP of 3, the heat pump route would be about 4 times (3/(0.75 x 0.9)) as efficient converting electricity to heat as compared to electrolytic hydrogen, therefore requiring 1/4 of electricity supply from sources such as wind turbines. Assuming an average heat load of 35 GW (300 TWh/a) as in section 5, the average electricity supply required would be 14 GW in the heat pump case, and 60 GW in the electrolytic hydrogen case, with the peak depending on the storage capacity of hydrogen or heat.

A detailed analysis of this has been carried out. Gallo Cassarino and Barrett (2021) have developed nine designs of zero emission renewable energy systems in which heat is supplied using a mix of district heating, heat pumps and electrolytic hydrogen. The effect of climate change on heat demand is explored. The roles of storage and interconnector trade with Europe for system balancing are included. The energy flows and system costs are calculated in detail.

Apart from emissions, there is some gas supply risk in terms of availability and price in a globally traded fuel. History has shown the impact of non-gas generation reduction on gas demand and price – whether because of the Fukushima nuclear disaster, or low wind and hydro because of weather. Infrastructure failure and political action, such as when Russia restricted gas supply to Ukraine, are also possible. Currently the UK has less than 10 days' gas storage at average consumption – in winter it will be less. These factors make SMR hydrogen present some physical and economic vulnerabilities. This could cause hardship, particularly to an ageing UK population with fixed incomes, as happened when, for example, fuel poverty doubled between 2003 and 2007, partially driven by gas price increases (Bolton, 2010). Even if SMRCCS global warming is less than concluded through this analysis and costs are lower, and technologies such as Direct Air Capture are low cost to balance SMRCCS emissions, natural gas reserves will at some point deplete to levels where it is no longer an affordable primary source for heating. If adopted in the UK, SMRCCS might also be adopted more widely, thereby increasing gas demand in Europe and beyond. This emphasises the need for further comprehensive, comparative analysis of all the low emission heating options in the longer term to perhaps 2100. An advantage of the renewable-heat pump route is that it is indefinitely sustainable and has relatively well-known fixed costs and emissions that are domestically controllable.

Whole system dynamic modelling is required to accurately address the above possibilities.

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