Energy Policy 60 (2013) 305–316

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The future of the UK gas network

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HIGHLIGHTS

- We examine the long-term future of the UK gas pipe networks using the UK MARKAL model.
- The iron mains replacement programme will not lead to gas infrastructure lock-in.
- Bio-methane and hydrogen injection have only a small role in our future scenarios.
- The most cost-optimal strategy might be to convert the networks to deliver hydrogen.
- Adopting a long-term gas strategy could reduce the cost of providing heat in the UK.

ARTICLE INFO

Article history:
Received 19 November 2012
Accepted 9 May 2013
Available online 10 June 2013

Keywords:
Gas network
Decarbonisation
MARKAL

ABSTRACT

The UK has an extensive natural gas pipeline network supplying 84% of homes. Previous studies of decarbonisation pathways using the UK MARKAL energy system model have concluded that the low-pressure gas networks should be mostly abandoned by 2050, yet most of the iron pipes near buildings are currently being replaced early for safety reasons. Our study suggests that this programme will not lock-in the use of gas in the long-term. We examine potential future uses of the gas network in the UK energy system using an improved version of UK MARKAL that introduces a number of decarbonisation options for the gas network including bio-methane, hydrogen injection to the natural gas and conversion of the network to deliver hydrogen. We conclude that hydrogen conversion is the only gas decarbonisation option that might enable the gas networks to continue supplying energy to most buildings in the long-term, from a cost-optimal perspective. There is an opportunity for the government to adopt a long-term strategy for the gas distribution networks that either curtails the iron mains replacement programme or alters it to prepare the network for hydrogen conversion; both options could substantially reduce the long-term cost of supplying heat to UK buildings.

1. Introduction

The UK Climate Change Act 2008 requires the UK government to reduce UK greenhouse gas emissions in 2050 by 80% relative to 1990 levels (HM Parliament, 2008). Studies of UK decarbonisation pathways to meet this target, underpinned by the UK MARKAL energy systems model, have invariably suggested that the low-pressure gas pipeline network should be mostly decommissioned by 2050, with heating provided by either electric heat pumps or biomass boilers (e.g. Hawkes et al., 2011; Kesicki, 2012). Since the gas network currently supplies around 22.9 million customers (DECC, 2011b), including 84% of homes, this represents a profound change to the UK energy system.

Notwithstanding these studies, a 30-year accelerated iron mains replacement programme (IMRP) is currently underway to replace around 100,000 km low-pressure iron distribution and attached service pipes near buildings with polyethylene pipes for safety reasons (HSE, 2001). This represents a significant investment in the network infrastructure. Since gas pipes have long lifetimes, the capital stock from the replacement programme will be retired early if gas use is curtailed by 2050. One alternative would be to supply zero-carbon bio-methane, produced from biomass, instead of natural gas (National Grid, 2009). The UK government has yet to adopt a position on the long-term future of the gas system (DECC, 2011a, p. 34) but it has identified bio-methane and hydrogen as potential carbon-neutral sources of heat in future (DECC, 2012b). There is growing pressure from the gas industry for the government to define a clear long-term strategy for the gas networks, as evidenced by the publication of several recent reports (e.g. Arran and Slowe, 2012; Greenleaf and Sinclair, 2012; National Grid, 2009; Redpoint, 2010). In response, the government has recently decided to explore the future of the gas

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http://dx.doi.org/10.1016/j.enpol.2013.05.030

network through whole system modelling and through consultations with industry (DECC, 2013). Yet few academic studies have considered the long-term future of the network, with van Foreest (2011) a notable exception.

This paper examines the future prospects for the UK gas pipeline network. First, we address our concerns about the adequacy of the representation of the gas networks in the UK MARKAL model by greatly improving the model using a new estimate of the age of the network and recent data on the costs of investment in gas infrastructure. We then use UK MARKAL to examine whether the pipeline replacement programme will effectively lock-in use of the gas network in the future at the expense of other low-carbon technologies than could have been built instead at lower overall cost. In doing so, we highlight the limitations of MARKAL-type models in representing large network infrastructures and we perform sensitivity studies to test the robustness of the conclusions. We examine whether the supplied gas can be decarbonised through the use of bio-methane, hydrogen injection to the gas stream or by converting the existing network to deliver hydrogen instead of natural gas. Finally, we describe possible scenarios for the future of the gas network and consider policy issues for the UK government.

2. The past and uncertain future of the UK gas pipeline network

It is important to understand the context in which the future of the gas network is being considered. In this section, we provide a brief history of the origins of the network, describe its current use and composition, and examine various debates around its future.

Gas has been delivered by pipeline to buildings in the UK for the last 200 years. 'Town gas', which comprised a mix of hydrogen, carbon monoxide, methane and other gases, was manufactured from coal and provided lighting to replace candles and oil lamps. The principal advantage of gas lighting was economic, with gas costing a third of whale oil (Chandler and Lacey, 1949). Despite this incentive, residential buildings were not supplied with gas until the 1840s because the cost of laying pipes to small buildings with low demand proved prohibitive, particularly when there were often many companies in the same area, each with their own pipeline network.

Gas cookers were widely adopted from the 1870s and provided a market for gas as lighting was gradually electrified. Few households used gas for heating until the introduction of natural gas in the 1960s because of the imperfect combustion of town gas and the accumulation of soot and odours in buildings (Williams, 1981).

The gas industry underwent three major transitions in the twentieth century (Williams, 1981). First, the industry was nationalised in 1948 as 1062 gas companies were merged to create 12 regional Gas Boards overseen by the Gas Council. Second, in the 1960s, natural gas was discovered under the North Sea and the Gas Council decided to switch the entire country from town gas to natural gas. Since the energy content of natural gas is much higher than town gas, this required all gas appliances in the country to be converted in a national programme taking 10 years. A high-pressure national transmission network (the National Transmission System or 'NTS') was constructed to deliver North Sea gas across the country and linked to all of the local distribution networks. The third transition occurred in the 1980s, when the gas networks were privatised to create a transmission network and eight regional distribution network companies (Arapostathis, 2011). These assets are now owned by several companies and their prices and capital investment levels are regulated by Ofgem, an autonomous government regulator.

2.1. UK gas network composition

The NTS has a total length of 7600 km (National Grid, 2011a). Gas leaves the transmission network at 175 locations. Some large power generation and industrial consumers are supplied directly from the NTS but most consumers receive low-pressure gas from the distribution networks (Simmonds, 2000, p. 11). These networks are much larger than the transmission network with a total length in 2010 of 280,000 km (ENA, 2010). This comprises approximately 12,000 km of high pressure pipes, 35,000 km of intermediate and medium pressure pipes and 233,000 km of low pressure pipes (Transco, 1999).

Service pipelines link smaller buildings to the mains distribution networks. They are the narrowest and shortest pipes in the system, but they represent a substantial investment as there are approximately 23 million of them across the country.

2.2. Estimating the age of the UK gas network

Future uses of the gas network depend on how long the existing infrastructure can be expected to remain in good working order. We estimate the age of each part of the existing network in this section.

Construction of the NTS began in the 1960s and the majority of the current network was built over a 10-year period (Williams, 1981). Transmission pipes have an expected lifetime of 80 years (National Grid, 2011b) so we expect the existing network to become obsolete from around 2050.

The mains distribution networks have been constructed over many decades as the number of customers has gradually increased and some pipes are now more than 100 years old. We have estimated the development of the networks using data from several sources (DECC, 2011c; ENA, 2010; Gas Council, 1960, 1970; Mitchell et al., 1990; Transco, 1999; Williams, 1981). The total length of the distribution networks was approximately proportional to the number of customers until around 1960, when construction of higher-pressure distribution pipes commenced to reconfigure the previously fragmented system for national gas delivery. This development added 50,000 km of pipes while the customers totalled 13 million (Fig. 1). The introduction of natural gas also enabled the huge increase in domestic gas consumption per customer since 1960 that is shown in Fig. 2. Estimating the age of the network is more complicated than finding the total length because pipes are occasionally replaced before the end of their life. It was necessary for us to estimate the replacement level, particularly in the early years, as described in Dodds and McDowall (2012a). Nevertheless, we believe that the construction rates we have produced, in Fig. 3, are sufficiently accurate for the purpose of our study.

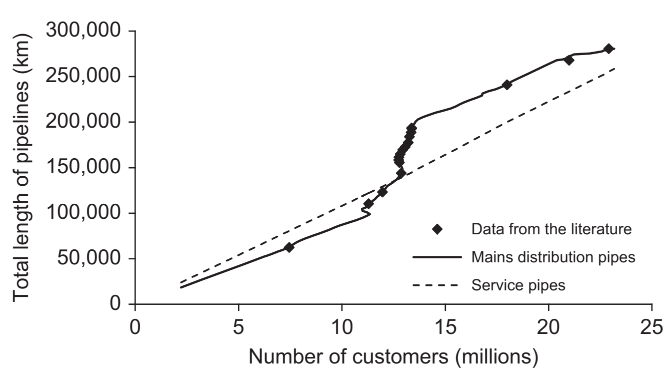

Fig. 1. Total length of the mains distribution and service pipes as a function of the number of customers. The points indicate data taken from the literature. The number of customers is taken from DECC (2011c).

A more uncertain factor is the lifetime of the mains distribution pipes, particularly as polyethylene pipes have been used instead of iron pipes since 1970. The 89,000 km of iron pipes that remain in the system have been in service for between 50 and 100 years (HSE, 2001). There are little data to determine the lifetimes of polyethylene pipes; Ofgem assumes 50 years for accounting purposes (CEPA and Denton, 2010, p. 71) but a review of the Dutch network, which has used PVC pipes for more than 50 years, concluded that they will continue in service for many years to come (Visser et al., 2008). We assume an average lifetime of 80 years for both iron and polyethylene low-pressure pipes in this study. We examine the consequences of this assumption in a sensitivity study in Section 4.2.

Little data are available about service pipes. Mitchell et al. (1990) estimate the total length using an average service pipe length of 11.3 m per customer and we have adopted the same approach. Service pipes are smaller than mains pipes and are more likely to be replaced due to changes to the built environment; for example, between 1970 and 1990, 64% of the service pipes were replaced compared to only 24% of the distribution pipes (Mitchell et al., 1990). We assume a shorter average lifetime of 60 years for service pipes in this study.

2.3. Current UK gas consumption

UK gas consumption can be split into four broad sectors: electricity generation, industry, domestic and other (government, commercial, agriculture, etc.). UK consumption in 2010 is shown in Fig. 4. Most electricity and industrial consumption is from plants connected to high-pressure transmission or distribution pipelines. Around half of the total consumption is used for low-temperature heating from the domestic and other sectors, which are supplied from the low-pressure mains distribution network.

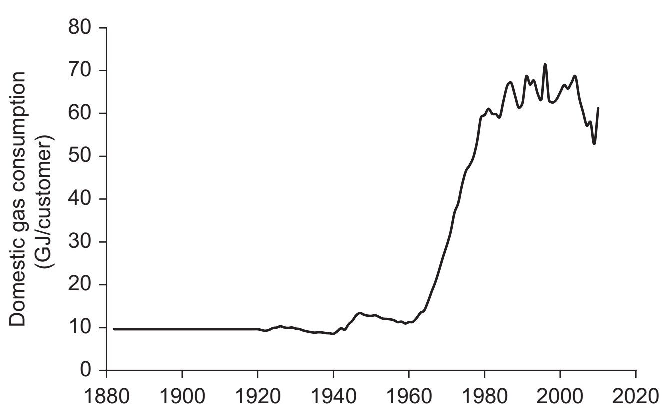

Fig. 2. Domestic gas consumption per customer in the UK, derived from DECC (2011c).

2.4. The uncertain future of the gas network

Previous studies (e.g. Hawkes et al., 2011) using the UK MARKAL energy system model, and other similar models such as ESME, have suggested that natural gas will be used purely for industrial purposes in the future and that the gas distribution networks will be switched off between 2030 and 2050.

Yet current regulatory policy, which controls prices based on asset values, assumes that the network will continue to be used many decades into the future (CEPA and Denton, 2010). Furthermore, policymakers are requiring significant new investment in gas infrastructure; in response to a number of accidents, the iron mains replacement programme (IMRP) commenced in 1977 to replace all iron pipes within 30 m of any building with polyethylene pipes (HSE, 2001). This programme slowed in the late 1990s but was then accelerated in 2002 with the aim of replacing the remaining 91,000 km iron pipes within 30 m of buildings by 2032 (CEPA, 2011). In 2004, an engineering survey revised the length of 'at-risk' pipes to 101,800 km in 2001, and the programme had reduced this to 89,400 km, approximately 32% of the total pipes, at the end of 2009 (CEPA, 2011). The programme will be revised again from 2013 to concentrate on the smaller 80% of pipes that are considered most at risk of failure (HSE, 2012).

The IMRP is a substantial investment in the UK energy system infrastructure that will substantially reduce the age and hence increase the value of the gas network by 2030. Such investments can cause infrastructure lock-in, where existing high-carbon infrastructure prevents alternative low-carbon technologies from entering the marketplace (Unruh, 2000). This does not prevent emission reduction targets from being achieved but it does

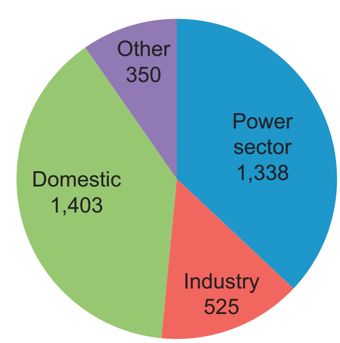

Fig. 4. UK natural gas consumption in 2010 (PJ). Data from DECC (2011b).

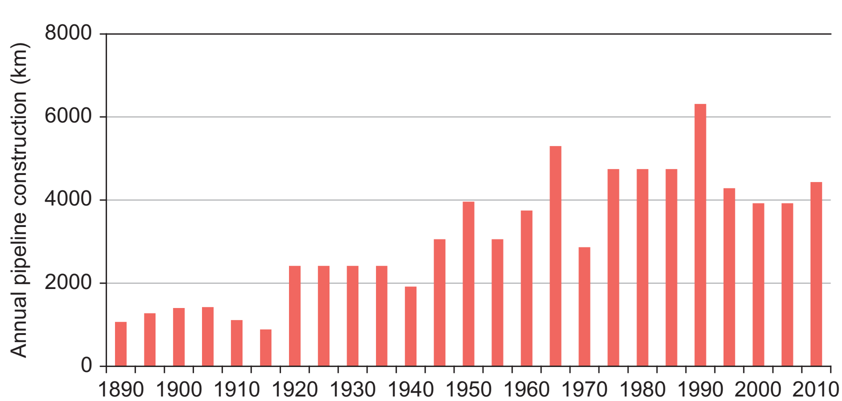

Fig. 3. Estimated annual pipeline construction rates over 5-year periods from 1890 to 2010. Both new and replacement pipelines are included in these data.

increase the overall cost of meeting these targets because the energy system evolves a non-optimal configuration.

The IMRP has been driven by safety concerns rather than by energy policy. However, it is important to examine the potential impacts of the programme on the ability of the UK to meet carbon targets at least cost. The cost–benefit studies used to justify the IMRP have not considered the risk that the programme may contribute to locking-in high levels of residential and service sector gas consumption decades into the future, with implications for the costs of reaching carbon targets. This study provides insight into the degree to which the investment associated with the programme may lock-in high gas consumption, resulting in higher decarbonisation costs elsewhere in the economy.

3. Using UK MARKAL to examine the future of the UK gas network

3.1. The UK MARKAL energy system model

MARKAL is a widely applied bottom-up, dynamic, linear programming optimisation model (Loulou et al., 2004). The UK MARKAL model (Anandarajah and Strachan, 2010; Kannan et al., 2007) has been developed over the last decade and portrays the entire UK energy system from imports and domestic production of fuel resources, through fuel processing and supply, explicit representation of infrastructures, conversion of fuels to secondary energy carriers (including electricity, heat and hydrogen), end-use technologies and energy service demands of the entire economy. It is calibrated to UK energy consumption in the year 2000. The initial energy service demands to 2050 are fully described in Usher and Strachan (2012).[1]

Analysis with MARKAL does not seek to predict the future. It identifies the energy system that meets energy service demands with the lowest discounted capital, operating and resource cost, subject to constraints such as carbon targets, and constraints that force the model to emulate a real-world energy system (such as requirements that the speed of transitions to new technologies reflects non-cost factors such as consumer preferences). MARKAL allows us to draw insights about the relative importance of different technologies, costs and policies in the energy system, but the results, as with all models, should be interpreted in light of the limitations of the model framework. We use the MARKAL elastic demand variant in this study in which welfare (defined as the sum of producer and consumer surplus) is maximised, and hence demand and supply reach equilibrium. Behavioural change in response to increasing energy costs is simulated endogenously using reductions in the energy service demands.

Carbon dioxide is the only greenhouse gas simulated in UK MARKAL. In both Usher and Strachan (2010) and Hawkes et al. (2011), the 80% emissions reduction target in 2050 is represented by a 90% reduction in CO_2 in the model. This additional effort recognises the uncertainties in the contribution of non-CO_2 GHGs, the emissions from land-use change and emissions from international bunker fuels (Usher and Strachan, 2010). The UK share of international aviation and shipping emissions is excluded from the 90% target in both studies. In this study, following Ekins et al. (2013), we use an 80% target to be consistent with UK policy and we do not include international aviation and shipping energy demands (and hence emissions) in any scenarios.

3.2. Revised representation of the gas sector in UK MARKAL

We reviewed and completely revised the gas infrastructure representation in UK MARKAL. We started with a revision of the modelled age and lifetime of gas infrastructure. The gas network that existed in the year 2000, the base year of the model, is termed 'residual' capacity and is made available to the model at zero cost with a fixed lifetime. The previous version of UK MARKAL assumed zero residual capacity by 2045 so new investment was required to maintain gas infrastructure beyond this date. For this study, we revised the residual capacity of the existing network based on our estimates in Section 2.2 of the age of the gas network and assuming 80-year lifetimes for the mains distribution pipes and 60-year lifetimes for service pipes.

Fig. 5 compares our estimate of the residual capacity of the mains distribution system (including the effects of the IMRP) with the residual capacity in previous versions of UK MARKAL. There is little difference until 2020 but the data diverge after then; our analysis suggests that parts of the system will still be operational in 2100 if the current iron mains replacement programme continues, while the previous UK MARKAL representation assumes that the whole network would be obsolete before 2050.

3.2.1. Revised representation of gas network structure

We revised the representation of the gas network in the model to enable the costs and capacities of different parts of the system to be more accurately depicted and to facilitate the introduction of gas decarbonisation options. Our revised structure of the gas system in UK MARKAL is shown in Fig. 6. The transmission network and the mains distribution and service pipes are all represented separately in the new model. Transport (for CNG vehicles) and agricultural sector consumers have high individual gas consumption rates so the cost of their connecting pipe to the mains distribution network as a function of their energy use is much lower than for the service and domestic sectors; this factor is represented in the model by connecting these sectors directly to the mains distribution network.

3.2.2. Revised gas pipe investment costs

UK MARKAL previously used pipeline costs from the US 9-region MARKAL model (US EPA, 2006). We estimated new costs

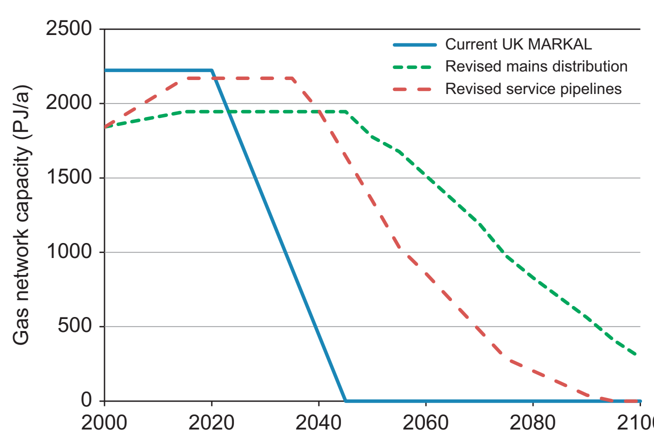

Fig. 5. Previous UK MARKAL residual capacity of the gas network compared with the revised capacities of the mains and service pipelines, assuming the iron mains replacement programme continues to 2032.

[1] In the present analysis, we extend the model time horizon to 2100, keeping all technology costs, energy service demands, and resource costs at the 2050 level. The reason for doing so is that analysis of large long-lived physical infrastructures such as gas grids requires an extended model time horizon, because of the slow rate of change. The results are not intended to represent a belief that such long-term predictions are possible, but rather aim to examine the long-run implications of energy system choices.

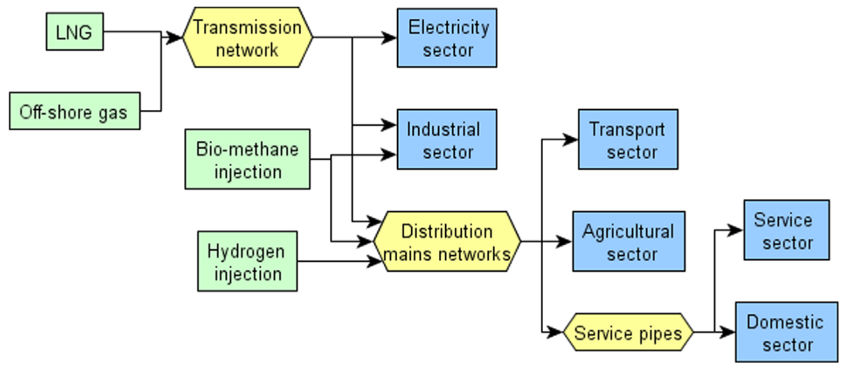

Fig. 6. Revised structure of the gas system in UK MARKAL.

Table 1
Revised investment costs for the gas system. All figures have units £/(GJ/year) with costs specified in year 2000 pounds.

	Previous UK MARKAL costs	Revised costs
Transmission network	8.0	3.0
Mains distribution networks	1.6	19.3
Service distribution pipes	0.0	10.0

for the UK gas networks using data from the IMRP, as described in Dodds and McDowall (2012a). The revised gas system investment costs are compared with the costs from previous UK MARKAL costs in Table 1. The revised cost for the transmission network is much lower, reflecting the high throughput, while the mains distribution network cost is much higher. The latter is an aggregate for distribution pipes at all operating pressures. The revised capital cost for connecting new buildings to the gas network is three times higher than the cost previously assumed in UK MARKAL, even after taking into account the different assumed lifetimes of the pipes (40 years previously and 80 years in this study).

3.3. *Revised representation of the heat sector in UK MARKAL*

The UK housing stock is represented in previous versions of UK MARKAL using two averaged groups: existing houses (in the year 2000) and new houses. A new version of the residential sector has recently been produced that disaggregates heat consumption into six types of house (bungalow, detached, semi-detached, terraced, converted flat and purpose-built flat). The heat technologies have also been fully revised in this version with new heat pumps, hydrogen boilers and micro-CHP engines and fuel cells, and updated capital costs for all technologies. The changes, and resulting impacts on the heat sector, are fully described in Dodds (2013). We used this new version, which also revises the service heat sector, as it allows us to more accurately assess changes in future gas consumption for the residential and service sectors.

3.4. *Representation of the hydrogen sector in UK MARKAL*

UK MARKAL has the option to build a dedicated hydrogen pipeline system to link hydrogen production facilities with fuelling stations and buildings. In this study, we used a revised version of the hydrogen sector described in Dodds and McDowall (2012b,c), with pipeline capital costs estimated using an approach consistent with the gas network capital costs described above. We extended the hydrogen sector by adding the option to inject hydrogen into the gas network and by allowing the gas network to be converted to deliver hydrogen instead of hydrocarbon gases in some

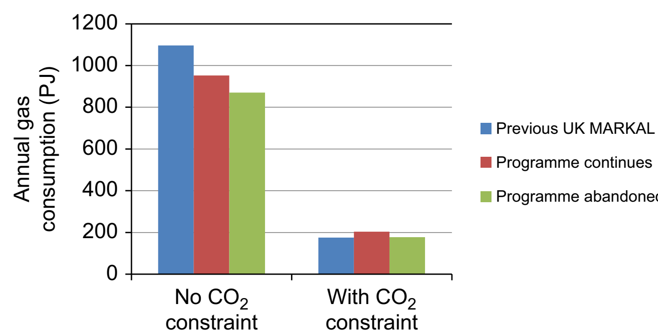

Fig. 7. Average annual residential and service sector gas consumption in the period 2050–2100. The graph shows the impact of continuing the Iron Mains Replacement Programme through to 2032 ('programme continues') vs. abandoning the programme in 2014 ('programme abandoned'). 'Previous UK MARKAL' shows results from the most recent published version of the model, as described in Hawkes et al. (2011).

scenarios. We prevented the model from building a low-pressure hydrogen pipeline network in parallel to the gas network so gas network conversion was the only method to enable hydrogen use within buildings in our study.

4. The impact of the iron mains replacement programme on the future of the gas network

The IMRP is planned to continue until 2030. To test whether the programme has any effect on the optimal gas network usage, we examined two scenarios:

1. Replacement programme continues as planned. In this scenario, the gas infrastructure residual is revised to include the effects of the mains replacement programme, as illustrated in Fig. 5. As a result of the mains replacement programme, new investment in gas infrastructure is locked-in until 2032.
2. Replacement programme is abandoned by 2014. In this scenario, the mains replacement programme is assumed to cease in 2014. As a result, the model has the freedom to choose whether to invest in new or replacement gas infrastructure from 2015 onwards.

Each of these scenarios was examined under a 'no carbon constraint' case, in which emissions of CO_2 are unconstrained, and a 'with carbon constraint' case, in which the model is required to reduce CO_2 emissions by 80% from 2050 relative to 1990.

4.1. Impact of the IMRP on residential and service sector gas consumption

Average annual residential and service (R&S) sector gas consumption over the period 2050–2100 is shown in Fig. 7 for the two gas infrastructure scenarios and climate policy cases, and for the previous UK MARKAL assumptions on the residual capacity of the network. Ceasing the IMRP in 2014 instead of in 2032 causes a small reduction in R&S gas consumption because the model responds to the gas network becoming obsolete more quickly by installing additional electrically powered air heat pumps. The overwhelming influence on R&S gas consumption is not the extended life of gas infrastructure, but rather it is the level of decarbonisation required to meet the carbon target. In the decarbonisation cases, the amount of gas consumed by the R&S sectors is around 80% lower from 2050. Continuing the IMRP does increase the annual average gas consumption (from 177 PJ per annum to 204 PJ per annum) and additional decarbonisation must take place elsewhere as a result. However, in the context of the energy system as a whole, the effect is negligible, and Fig. 7 shows that the assumed network lifetime in previous versions of UK MARKAL produced similar trends.

The implication of this finding is that the additional investment in new and replacement pipeline capacity associated with the mains replacement programme does not lock-in residential and service sector gas consumption in a cost-optimal decarbonisation scenario. As a result of this finding, we assume that the IMRP will continue as planned to 2032 throughout the rest of the paper.

The following subsections describe two sensitivity studies that examine the robustness of our finding to assumptions and limitations of the modelling approach.

4.2. Sensitivity study: assumptions about gas pipe lifetime

We mentioned in Section 2.2 that there is much uncertainty about the lifetime of pipes in the gas networks. We use a lifetime of 80 years in this paper but we tested this assumption with a sensitivity study using a 40-year lifetime for all three types of pipe (transmission, mains distribution, service), which is shorter than the 50-year lifetime used by Ofgem for gas network investment and accounting decisions (CEPA and Denton, 2010, p. 71). Table 2 shows that reducing the assumed pipeline lifetime decreases gas consumption by 46 PJ with a CO_2 constraint but has little impact with no CO_2 constraint in the period 2050–2100. Our results are robust to variations in the average pipe lifetime because the high capital costs are spread over a long period so the annualised costs do not change substantially even for a lifetime of only 40 years. This finding echoes the main finding that the IMRP does not lock in gas use, as it emphasises that infrastructure costs and lifetime are not the major determining factors in the cost-effectiveness of gas use for heating.

4.3. Sensitivity study: influence of model limitations on the results

In this sensitivity study, we examine the importance of limitations of the model in representing pipeline infrastructure. MARKAL-type models tend to poorly represent pipeline infrastructure because the capital costs are specified as a function of the energy throughput while the actual pipeline costs are more dependent on the geography of the country and the design of the network. Representing pipeline infrastructure in the model requires assumptions about the spatial pattern of demand as an exogenous input. For UK MARKAL, we calculate the pipeline investment cost as the average investment cost in new pipelines given the existing spatial structure and capacity of the network (using the maximum delivered energy between the years 2000 and 2010 as a measure of the total existing capacity). Using these costs throughout the model time horizon implicitly assumes that the pipeline length per customer and the energy demand per customer will not change in the future, and that the spatial pattern of gas demand is unchanged from today.

Table 2
Average annual gas consumption from the distribution networks in the period 2050–2100 with different gas pipe lifetime assumptions (all units PJ).

	No CO_2 constraint	With CO_2 constraint
80-year lifetime (base case)	952	204
40-year lifetime (sensitivity)	974	158

In reality, the energy demand per customer may reduce over time as energy conservation measures are deployed in existing buildings and tighter building regulations reduce space heating demand from new buildings. In UK MARKAL, we allow up to a 20% reduction per customer for the former and a 40% reduction per customer for the latter. As a result, the overall energy throughput will fall, but the system will remain the same in terms of the geographic extent of the network. Investments in pipeline renewal will thus cost more in terms of the units used by the model (£/(GJ/year)).

Furthermore, if many existing customers switch to other heating technologies (e.g. electric heat pumps) then the length of distribution pipeline per customer will increase, unless those switching are spatially clustered in particular regions for which the entire gas network could then be decommissioned. At worst, if customers switched randomly across the network then the total distribution network length would be unchanged. If the switch was managed and enforced in particular areas (for example, requiring larger, lower density houses to use electric heat pumps or other zero-carbon technologies), then parts of the gas network could be decommissioned and the increase in the length per customer would be lower.

Both trends (decreasing demand per customer and increasing pipeline length per customer) will increase the capital costs per customer over time, but the non-linear nature of these feedbacks makes them difficult to represent endogenously in a linear model such as UK MARKAL.

More subtly, assumptions about the future use of the network are also implicit in the specification of the residual network capacity in the model (i.e. the effective energy delivery capacity of the existing pipeline system without reinvestment). Firstly, the rate of physical deterioration of the pipes themselves is independent of their use, and as sections of the network reach the end of their life they are decommissioned in the model. However, the model thus implicitly assumes that those switching away from gas happen to be exactly those for whom the pipes have reached the end of their working life (which is unlikely, given that the decision to switch is influenced by many other factors), and that the residual network fully meets the needs of those preferring to use gas. Secondly, the residual network is assumed to operate perfectly with what would be effectively the random removal of sections of old pipeline. In reality, one might expect that, without reinvestment, the retirement of some segments of pipeline would leave other areas stranded and not connected to the network. As a result, if one assumes that no reinvestment will be forthcoming, the residual will decay more quickly than in a case in which reinvestment is expected.

4.3.1. Methodology

We examined the importance of these trends for the residential sector by iterating the model scenario with an off-line spreadsheet that recalculates the distribution and service pipeline residuals (i.e. the energy that the system supplies) as a function of the average gas consumption and the proportion of houses supplied by gas. The spreadsheet also recalculates the capital costs as a function of these trends but also taking account of the reduction in the network length that accompanies technology switching (represented as a fraction between 0, indicating random switching with the whole network remaining intact, and 1, indicating organised switching with pipes decommissioned as whole areas switch simultaneously.

4.3.2. Results

In the "replacement programme continues" scenario described in Section 4.1, with no CO_2 emissions constraint, gas delivery from the distribution networks increases towards 2050 but then gradually decreases towards 2100 (Fig. 8) as heat pumps are deployed in larger existing houses (detached, semi-detached and some terraced).

Gas consumption after 2040 is lower when the gas network residual and capital cost are altered to represent declining gas consumption (Fig. 8). This is unsurprising; major network infrastructures exhibit returns to scale, and as some customers switch away from using gas or reduce their consumption, the benefits of the network for the remaining customers' decline. The reduction in consumption is primarily due to the reduced residual capacity of the network rather than the increased capital costs, despite the latter increasing from £19/(GJ/year) to £50/(GJ/year) for the scenario with no pipe decommissioning. For this reason, the level of organisation of switching to other fuels has a relatively small influence on the overall trend, as shown by the small difference between the two treated cases in Fig. 8.

The same scenario produces a similar trend when run with an 80% reduction in CO_2 emissions (Fig. 9). After 2040, iterating the gas network residual and capital costs reduces gas consumption for heating to a niche technology for locations where other lower-carbon technologies cannot be deployed. The method of decommissioning the network again has little influence on the overall trend, despite the capital cost of the gas distribution network varying from £19/(GJ/year) in the organised switching case to £109/(GJ/year) with no pipe decommissioning.

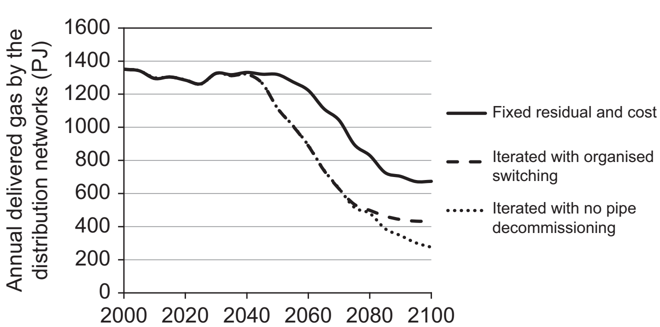

Fig. 8. Annual gas delivery from the distribution networks for the "replacement programme continues" scenario with no CO_2 emissions constraint.

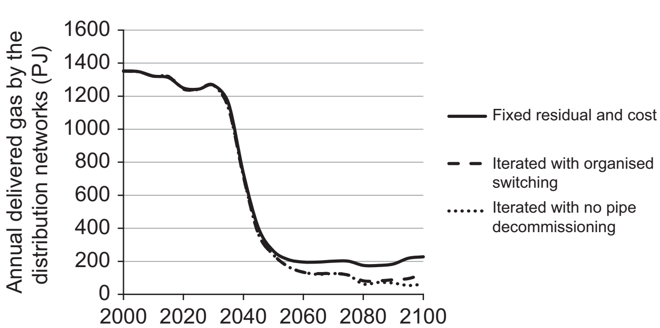

Fig. 9. Annual gas delivery from the distribution networks for the "replacement programme continues" scenario with an 80% reduction in CO_2 emissions in 2050.

4.3.3. Discussion

The results of this sensitivity study highlight two important insights into the future of the gas network.

First, decisions about optimal use of the network are sensitive to the development of alternative heating technologies and to the price of gas. Even with no carbon constraint, improvements in heat pump technologies could reduce the overall gas consumption of larger houses. The long-term wholesale price of gas in UK MARKAL, at around 62 p/therm, is similar to current market prices (DECC, 2012a, p. 6) and further increases or market volatility could further encourage consumers to switch away from gas. Since the gas network is most economical when it supplies many customers because the capital cost per customer is lower and because an extensive gas network is already in place, the result of some customers switching away from gas will be increased costs for remaining customers.

Second, MARKAL-type models that represent pipelines using the approach outlined in Section 3 are likely to underestimate any reduction in pipeline use because the reduced pipeline capacity residual and increased capital costs from such a reduction are not represented in the model. In other words, the returns to scale exhibited by large network infrastructures, a key cause of lock-in, are poorly represented. In Figs. 8 and 9, gas consumption in 2100 in the iterated case is around half that of the original scenario. This means that reductions in gas use throughout this study are underestimated and that the impacts of the decarbonisation options examined in the next section are likely to be overestimated.

However, under a decarbonisation pathway, the difference between the sensitivity study and the initial 'programme continued' scenario is small, with major reductions in delivered gas use in both cases. This suggests that our initial conclusion (that the mains replacement programme does not lock-in higher levels of gas consumption) is robust to the model limitations in representing returns-to-scale effects.

5. Decarbonisation options for the gas network

In Section 4, we examined whether natural gas delivered to residential and service sectors is part of a cost-optimal decarbonisation pathway for the UK to 2050, and we focused on whether the gas distribution network would continue to be used in the long-term. In this section, we examine alternative strategies in which heat continues to be generated from gas supplied by the mains distribution network.

Strategies that have been suggested to decarbonise the supplied gas include using carbon-neutral bio-methane, mixing the gas with small amounts of hydrogen or converting whole gas distribution networks to deliver hydrogen instead of natural gas. We examine each of these options in this section. We also consider their sensitivity to assumptions about the availability of carbon capture and storage (CCS) technologies (which are used to sequester the CO_2 from the production of hydrogen from fossil fuels) in the future; CCS technologies in UK MARKAL are assumed to sequester 85% of the CO_2 and are fully described in Kannan et al. (2007). Finally, we examine the impact of continuing to use gas for R&S heat in the long-term.

Table 3
Potential impact of gas decarbonisation options in the period 2050–2100.

	No carbon constraint	With carbon constraint
Total bio-methane consumption (PJ)	0	105
Bio-methane content of total gas consumption (%)	0	6
Bio-methane use in the R&S sectors (%)	0	0

5.1. Bio-methane injection into gas distribution networks

The owner of the gas transmission network and four distribution networks, National Grid, has identified bio-methane injection as a potential long-term decarbonisation strategy to prolong the lifetime of the gas network (National Grid, 2009). Bio-methane is produced by upgrading biogas, a product of biomass gasification and anaerobic digestion plants that is considered to be carbon neutral. The UK government is supporting bio-methane injection to the gas network in conjunction with gas network owners (Ofgem, 2011). A test plant has been opened at Didcot to upgrade and inject biogas from sewage (Baldwin, 2011) and future projects will be supported by the government's Renewable Heat Incentive (DECC, 2011d).

We use the same costs for upgrading biogas to bio-methane as Usher and Strachan (2010). Bio-methane is normally mixed with a small amount of non-renewable propane prior to being injected to the gas network to increase the energy content to a similar level to natural gas. UK MARKAL does not distinguish between different types of hydrocarbon gases so we ignore this process, assuming that a renewable source of propane will be used in the future if bio-methane injection is developed on a large scale. Government subsidies from the renewable heat incentive are not included in our model. We allow industry (including gas-fired electricity generators) to use bio-methane, assuming that bio-methane is generated from facilities adjacent to the industrial plant and thus requires no delivery infrastructure. Bio-methane is available to all sectors in the model so it is not necessary to separately represent injection to the transmission network as well as to the distribution networks.

5.1.1. Results

Bio-methane is only used by our model in scenarios with CO_2 emission constraints (Table 3) and is not introduced until 2030. Only 6% of the total gas supply comes from bio-methane and it is used exclusively in the industrial sector in all scenarios. Even with an 80% CO_2 emissions constraint, bio-methane accounts for only around 21% of total bioenergy consumption in the period 2000–2050. The bio-methane is all produced from sewage and waste plants; there is only limited production from other sources because there are more appropriate uses of biomass elsewhere in the economy, notably for electricity generation in co-firing CCS plants.

5.2. Hydrogen injection into gas distribution networks

Another gas decarbonisation option is to inject small amounts of hydrogen into the distribution networks. The level of hydrogen that can be safely added depends on the characteristics of the existing natural gas in the system and on the design of existing appliances (NaturalHy, 2010); for example, appliances have been successfully tested with 18–50% hydrogen by volume. In the Netherlands, a recently concluded four-year field trial used hydrogen and natural gas blends (with up to 20% hydrogen by volume) in off-the-shelf gas appliances and identified no serious problems in operation (Kippers et al., 2011).[2]

For hydrogen injection in UK MARKAL, we assume that the hydrogen volume cannot exceed 20% of the total gas volume in line with the Dutch field trial experience (Kippers et al., 2011). Since the volumetric energy density of hydrogen is substantially lower than that of natural gas, the maximum hydrogen injection in our study represents only 7% of the energy content of the blended gas.

Areas with large intermittent renewable deployments for electricity generation and with limited electricity transmission capacity to areas with high demand, notably wind farms in Scotland, occasionally generate more electricity than can be consumed or exported. When this happens, the system operator pays power generators for balancing services such as the curtailment of generation, and may pay high prices to wind energy generators to curtail generation. In other words, the system operator (and ultimately the consumer) on occasion pays high prices for energy that is not used. One mooted option for this excess electricity would be to produce hydrogen by electrolysis and inject the hydrogen into the gas network (Stiller and Stubinitsky, 2012; Teichroeb, 2012), a process called power-to-gas, and a project is examining the feasibility of this system in the UK (ITM Power, 2012). Unfortunately, the temporal resolution of UK MARKAL is inadequate to accurately assess the potential of making use of very low priced or otherwise constrained-off electricity during high-wind, low-demand periods.

5.2.1. Results

The model does not select hydrogen injection when there is no CO_2 emissions constraint. With an 80% reduction in CO_2 emissions, the maximum amount of hydrogen injection is introduced in 2035, but this averages just 14 PJ in the period 2050–2100 because gas consumption is very low and hydrogen injection is limited to 7% of the total delivered gas. Hydrogen injection peaks prior to 2050 when large quantities of natural gas are still being consumed because the price of hydrogen, while greater than natural gas, is lower than bio-methane. In this scenario, hydrogen injection is a niche technology which is most important during the transition to a low carbon economy.

The injected hydrogen is produced from coal gasification and steam methane reforming (SMR) plants with CCS. If hydrogen produced from renewable electricity during high-wind, low-demand periods (power-to-gas) were available at a lower cost, then hydrogen injection would be even more competitive, but UK MARKAL is not currently able to explore this option.

5.3. Conversion of the natural gas distribution network to hydrogen

As an alternative to blending hydrogen with natural gas, it may be possible to convert the low-pressure natural gas distribution network to deliver hydrogen instead of natural gas (Haeseldonckx and D'haeseleer, 2007; NaturalHy, 2010). The gas transmission network and the high-pressure gas distribution pipes are constructed of steel and would be unsuitable to transport hydrogen so a separate hydrogen transmission network would have to be constructed. However, the majority of the low-pressure distribution network will be made of polyethylene by 2030, which is suitable for hydrogen delivery in principle. There would be conversion costs for the gas network and also at the point-of-use to replace meters and convert appliances to hydrogen. The

[2] Note that the Netherlands and the UK have different gas standards, and therefore similar field trials would be required in the UK to confirm the possibility of injecting this hydrogen fraction into the delivered gas.

magnitude of these costs is uncertain. Such a conversion programme is not unprecedented, however, as the network was previously converted from town gas to natural gas over a 10-year period as described in Section 2. The cost of conversion on that occasion was lower than the book cost of retiring the many gas manufacturing plants early (Williams, 1981).

In this study we examine only the potential economic benefits of switching the gas network to hydrogen. We assume there are no insurmountable technical limitations that prevent conversion and we optimistically assume that the whole low-pressure distribution network can be switched to hydrogen at no cost. These assumptions are necessary given the uncertainty associated with such costs and technical barriers, and our results on the economic desirability of converting the network to hydrogen must be interpreted with these assumptions in mind. The conversion is introduced into the model using three constraints that allow the model to gradually convert parts of the network to hydrogen from 2030 while preventing reconversion back to natural gas. Hydrogen can be combusted in a condensing boiler, similar to existing natural gas boilers, or can be used to produce both heat and electricity in a micro-CHP fuel cell; both technologies are described in Dodds (2013).

5.3.1. Results

With no CO_2 constraint, the model converts 30% of the natural gas network to deliver hydrogen (Table 4). The partial nature of the conversion in this scenario would be unrealistic in practice because the complex integrated nature of the mains distribution networks would preclude switching only small parts of the network to deliver hydrogen. In contrast to previous scenarios, the gas network remains fully operational throughout the century in this scenario, supplying both existing and new buildings. It may be surprising that hydrogen plays a significant role in an energy system that is not subject to a carbon constraint. This is explained by the efficiency gain enabled through the deployment of micro-CHP fuel cells and the fact that the use of hydrogen enables the use of coal as a resource for residential heating, which is assumed to be cheaper than natural gas in the long-term. We assume a micro-CHP fuel cell electrical efficiency of up to 45% in the model and an installed cost after 2030 of £2200/kW electricity generation.

With a CO_2 emissions constraint, all the distribution networks are converted to deliver hydrogen. Although the annual consumption of energy from the gas network, 574 PJ, is 50% lower than the same case with no CO_2 constraint, it is substantially higher than the 204 PJ consumed in the no conversion case (Section 4.1). In this scenario, heat pumps dominate the heating market after 2050 in larger buildings (Fig. 10). Fuel cell micro-CHP deployment commences in 2030 in preference to hydrogen-fuelled boilers,

Table 4
Potential impact of converting the distribution network to deliver hydrogen on R&S consumption in the period 2050–2100. All figures have units PJ/year.

	No carbon constraint	With carbon constraint
Base case		
Natural gas consumption	799	1
Hydrogen consumption from converted pipelines	349	573
Total energy supplied by the gas network	1148	574
Sensitivity: heat pump cost unchanged in the future		
Natural gas consumption	859	0
Hydrogen consumption from converted pipelines	418	1024
Total energy supplied by the gas network	1277	1024

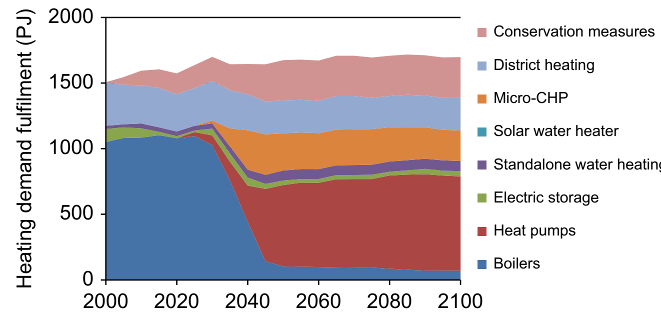

Fig. 10. Residential and service heating demand fulfilment by technology for an 80% CO_2 emission target with a zero cost conversion of the gas network to deliver hydrogen (base case). 'District heating' includes heat demand from all large service buildings.

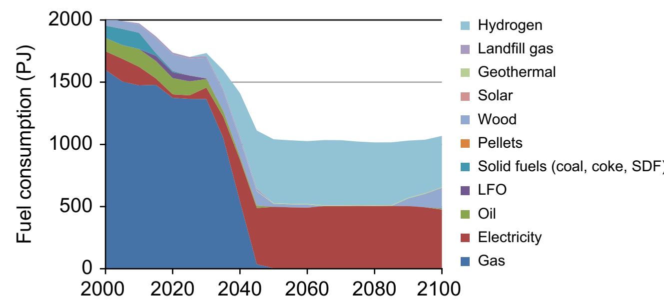

Fig. 11. Residential and service fuel consumption for heating for an 80% CO_2 emission target with a zero cost conversion of the gas network to deliver hydrogen (base case).

which are not adopted in any house types. Since micro-CHP generates most electricity during winter days, when electricity demand and prices are highest, the impact of installing micro-CHP is to depress the peak electricity price and the model responds by installing electric boilers in some houses; further research is required to quantify the potential impact of large-scale micro-CHP on electricity prices and the subsequent impact on the electrification of heat. All district heating is converted to use hydrogen. Hydrogen and electricity become the dominant heating fuels (Fig. 11), with hydrogen produced from coal gasification or gas SMR plants with CCS.

The scenario described above assumes that air heat pump prices will reduce from £700/kW to £525/kW and that the average COP of new installations will increase from 2.2 to 2.5 in 2030. We tested the sensitivity of our results to this assumption by assuming that the cost of air heat pumps will remain at current levels (£700/kW) throughout the model horizon. Table 4 shows that the annual hydrogen supply increases by 79% to 1024 PJ in this scenario. The model responds to the higher heat pump cost by deploying more micro-CHP and by switching some houses from heat pumps to electric boilers. We conclude that the potential economic benefits of converting the gas network to hydrogen are sensitive to both the cost and technical feasibility of conversion, and the relative costs and efficiencies of micro-CHP fuel cells and air heat pumps.

5.4. Sensitivity study: the importance of CCS

CCS technologies are unproven at present but are important to the results presented here for two reasons: (i) the use of biomass in co-fired CCS plants sequesters small amounts of atmospheric CO_2, relaxing the emission target for the model in other sectors; and, (ii) hydrogen is mostly produced from fossil fuels in industrial plants fitted with CCS. In this section, we perform two sensitivity studies to examine how the non-availability of CCS would affect

Table 5
Comparison of low-pressure gas network options. The changes in the welfare cost are relative to the first case.

Scenario	R&S emissions in 2050 ($MtCO_2$)	CO_2 marginal in 2050 (£/t)	Change in welfare cost (£bn)
Gas provides 85% of residential heat	44	374	
Gas network is converted to hydrogen	0	271	−56
Gas network is mostly abandoned	13	285	−40

our decarbonisation scenarios with and without gas network conversion to hydrogen.

5.4.1. Results

Despite the unavailability of CCS plants for electricity, average annual gas consumption across the economy is 1660 PJ in the period 2050–2100 for an 80% reduction in CO_2 emissions; this suggests that the gas transmission network will continue to have a long-term role in the UK energy system in all decarbonisation scenarios.

For the scenario with no conversion to hydrogen, R&S gas consumption in the period 2050–2100 increases by 62 PJ to 266 PJ compared to the scenario in Section 4.1. Fewer houses switch to heat pumps because the price of electricity is higher when CCS is not available. There is no hydrogen injection and the gas network is no longer converted to hydrogen when this option is made available because in the absence of CCS, low-carbon hydrogen is only available via electrolysis or expensive imports. However, we have not investigated whether the availability of hydrogen from power-to-gas would enable hydrogen injection in this scenario.

5.5. Impact of continuing current gas consumption in the long-term

Although decommissioning or converting the gas network are the least-cost methods of achieving the UK CO_2 emissions target in 2050, it is useful to compare these with a scenario where the UK continues to supply residential heat using gas from the low pressure network. We examined the impact of continuing gas use by constraining the model to supply at least 85% of residential heating in the future using gas.

5.5.1. Results

The three broad scenarios are compared in Table 5. Total emissions in 2050 are constrained to 118 $MtCO_2$ and continuing to use gas at the current level requires 37% of this limit. This figure does not include the estimated 5 $MtCO_2e$ emissions from methane emissions from the natural gas network. The marginal price of CO_2 in 2050 is £103/t higher in this scenario than if the gas network is converted or abandoned. Abandoning most of the network reduces the total welfare cost[3] in the period 2000–2100 by £40 bn, while converting the network reduces the welfare cost by £56 bn. The model results suggest that it is possible to meet carbon targets while continuing to use gas for R&S heat at the current level, but that higher emission reductions are required in other sectors and this comes at a greater overall cost to the UK compared to the other options.

[3] Standard MARKAL runs minimise the discounted energy system cost over the model time horizon. In the elastic demand variant used here, however, the model instead maximises the combination of discounted producer and consumer surplus over the time horizon. This represents a valid measure of societal welfare.

6. Discussion

We commenced this study with two concerns: first, that the assumptions underlying the representation of the gas pipeline network in UK MARKAL might be inadequate; second, that the IMRP would lock-in high carbon infrastructure in the future and increase the cost of decarbonisation by deviating from the optimal pathway.

The model improvements described in this paper eliminate the previous assumptions about the cost and residual capacity of the gas networks but have a fairly minor impact on gas consumption in our decarbonisation scenarios. While the high-pressure parts of the network continue to be valuable assets to provide gas to industry, and perhaps for a large expansion of hydrogen production via steam-methane reforming, the existing low pressure gas network still becomes obsolete with a rapid decline in R&S gas consumption after 2035.

The IMRP has a very minor impact on gas consumption for heat in the future when compared with ceasing the replacement programme in 2014. The programme does not appear to lock-in the use of gas in the future; it is a multi-billion pound investment that could be abandoned a few years after completion because natural gas must be regarded as a high carbon fuel in the long-term if the UK is to meet its CO_2 emissions target in 2050. This conclusion is from the perspective of a single social planner with perfect foresight, as embodied by the model, and the owners of the gas network are likely to see things differently.

6.1. Robustness of this analysis

6.1.1. Data robustness

There is uncertainty over the long-term cost of replacing or building new pipes. We calculated costs using data from the network owners and showed that the cost of the low-pressure network in particular is very high. The cost of constructing pipelines depends greatly on the topography, land use, labour and institutional costs, with materials accounting for only 25–40% of the total, and several of these factors are likely to increase in cost over time. We assume a constant cost in this study so we might have underestimated the capital cost in the future.

Gas pipes have long lifetimes but the exact length is difficult to assess because older pipes have a greater likelihood of failure so in practice the lifetime depends on the failure tolerance. The sensitivity study in Section 4.2 shows that the major findings are robust to pipe lifetime assumptions.

Heat pumps and micro-CHP fuel cells are most commonly selected to replace gas boilers in our decarbonisation scenarios but there is much uncertainty over the capital costs, performances and potential market penetrations of these technologies as highlighted in Section 5.3.1.

There are many uncertainties over the technical feasibility and cost of switching the current gas networks to transport hydrogen. In this study, we assess only the maximum economic benefits by assuming a no-cost conversion. More work is required to assess the technical feasibility and cost and we plan to revisit this subject in a future paper.

6.1.2. Testing the importance of limitations of the modelling approach

Representing variations in fixed high-capacity infrastructure such as gas networks is difficult in MARKAL-type models because the cost and capacity of the network depends very much on the geography and the pattern of energy consumption. Our iterated assessment of the model inaccuracy in Section 4.3 shows that UK MARKAL tends to underestimate the reduction in R&S gas consumption when the network gas capacity and capital cost are assumed constant. This means that R&S gas consumption in most decarbonisation scenarios in this study is overestimated. The exception is the network conversion to hydrogen scenario in which the gas networks continue to operate. Major changes to the model structure would be required to remove these assumptions but they would be unlikely to affect our overall conclusions.

UK MARKAL only accounts for CO_2 emissions from gas combustion. Mitchell et al. (1990) estimate gas leakage rates of between 1.9% and 10.8% from the gas distribution networks and the principal component of natural gas, methane, is also an important greenhouse gas. Methane leakages from the UK gas networks are estimated as 200 kT in 2010 (DEFRA, 2012) but these emissions are not considered by the model.

6.2. Scenarios for the future of the gas network

Several reports, sponsored by the gas industry or by Ofgem, have considered the future of the gas network and have presented potential scenarios (e.g. Arran and Slowe, 2012; CEPA and Denton, 2010; Greenleaf and Sinclair, 2012; National Grid, 2009, 2011c; Redpoint, 2010). These reports tend to focus only on particular sectors of the economy and so do not consider the role of the gas network and the optimum decarbonisation pathways within the whole UK energy system. We can envisage three possible future scenarios for the low-pressure gas network based on our study of the whole UK energy system.

6.2.1. Switch from gas to zero-carbon electricity

In our base scenario, natural gas becomes subject to economy-wide CO_2 emission taxes, making gas less competitive than other heating and cooking technologies. The loss of customers makes the gas network uneconomic and gas becomes a niche fuel for heating and cooking from 2045. The high-pressure network continues to supply large industrial users, particularly those with CCS facilities, but the low-pressure network is mostly decommissioned. If the decision to abandon the low-pressure network is made early enough then the IMRP is mostly abandoned.

6.2.2. Network conversion to deliver hydrogen

A decision to convert all or part of the gas network to hydrogen is made in the near future, following an appraisal of the technical challenges and potential economic benefits. The conversion cost is reduced by redesigning the iron mains replacement programme to make as much of the network hydrogen-ready as possible, over a period of decades prior to conversion. In this scenario, the existing low-pressure gas network remains in operation and is extended to new housing developments.

6.2.3. Business as usual

Gas continues to supply most of the demand for cooking and heating in the R&S sector. Air heat pumps become a niche technology for larger homes, particularly in rural areas, while district heating remains a niche technology in high-demand urban areas. There is a greater drive to insulate existing buildings in order to reduce fuel consumption and CO_2 emissions. This scenario might occur if: (i) the UK rescinded the Climate Change Act 2008 and abandoned the 80% reduction in CO_2 emissions; (ii) if the UK government decided to make larger cuts in CO_2 emissions in other sectors of the economy in order to allow continued use of gas in the R&S sectors (although this would be a non-optimum route to achieve CO_2 emissions, as shown in Section 5.5); or, (iii) if large-scale atmospheric carbon sequestration, for example biomass CCS generation plants, were deployed that relaxed the need to cut CO_2 emissions in other sectors of the economy.

6.3. Policy issues

The future of the low-pressure gas network raises a number of difficult policy decisions for the government and for the utility companies that own the networks. Two of the principal drivers of government energy policy, namely to reduce CO_2 emissions and to reduce fuel poverty, could conflict in the future over the use of gas.

Gas has recently been promoted by industry as a low carbon fuel (e.g. EGAF, 2011), but will be a high-carbon fuel in 2050 and the UK will struggle to achieve an 80% reduction in CO_2 emissions in 2050 while continuing to use gas for heating unless there are much greater emission cuts in other sectors or atmospheric CO_2 sequestration technologies are deployed.

The UK government has identified fuel poverty, defined as households that spend at least 10% of their income on fuel for heating, as a key priority area (UK Government, 2001). Ofgem (2012) has proposed connecting an additional 80,000 homes in fuel poverty to the low-pressure gas network to reduce their heating costs. Low-carbon alternatives to gas (e.g. air heat pumps, biomass boilers and district heating) are more expensive, particularly for up-front capital costs, and an enforced switch away from gas could force more households into fuel poverty.

Taking an early decision on the future of the network could substantially reduce costs in the long run. For example, if a decision was made now to make the network hydrogen-ready in all future maintenance works then the switchover to hydrogen in several decades time would likely be easier and achieved at a lower overall cost. It would be useful to assess the value of keeping the hydrogen switchover option open. If a decision was made to decommission the network in the 2040s then the pipe maintenance programmes, and in particular the IMRP, could be optimised to minimise costs, and the level of compensation payments from the government to the companies would likely be much reduced.

7. Conclusions

Previous studies have concluded that the optimal economic path to UK decarbonisation includes abandoning the low-pressure gas network by 2050. We have examined the robustness of this finding using an improved version of UK MARKAL that has a new representation of the gas network and a new disaggregated residential heat sector with revised end-use technologies. We broadly agree that new technologies, powered by alternative fuels, may offer a cheaper alternative to natural gas in the long term. The only economically optimal method of decarbonising the gas supply on a large-scale in our scenarios is to convert the network to deliver hydrogen, for use in micro-CHP fuel cells, instead of hydrocarbon gas.

The UK iron mains replacement programme is replacing much of the gas network with new pipes because of the safety risks associated with aging iron pipes,[4] yet these could be decommissioned shortly after the programme is completed. This investment will not secure the future of the gas network in the long term through infrastructure lock-in. Concerns have already been raised about the economic benefits of the programme (CEPA, 2011; Frontier Economics, 2011) and these will only intensify if the distribution networks are to be abandoned. This is one area where making a decision now about the long-term future of the network

[4] It is worth noting that the rationale for the iron mains replacement programme is of course partly based on the assumption that the entire network will continue to be used in the future. The safety risks associated with the non-replacement of iron pipes become substantially lower if the overall lifetime of the network is foreshortened by switching away from gas, and if many parts of the network are decommissioned.

could benefit the UK financially. Another option for the government is to alter the programme to prepare the network for conversion to deliver hydrogen, which could secure the long-term future of the network; however, more work is required to understand the technical feasibility and economic benefits of this option. The alternative, decommissioning the gas network to reduce CO_2 emissions, could increase fuel poverty and put two of the government's principal energy policies into conflict.

Acknowledgements

The long-term development of the UK MARKAL model has been supported by the UK Energy Research Centre (grant number NE/G007748/1), while the analysis reported in this paper was conducted as part of the EPSRC UK Sustainable Hydrogen Energy Consortium (grant number EP/E040071/1) and the EPSRC Hydrogen and Fuel Cell Supergen Hub (grant number EP/J016454/1). All these initiatives were funded by the RCUK Energy Programme. We thank two anonymous reviewers whose comments greatly helped us to improve the paper.

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