Heat delivery in a low carbon economy

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Abstract

Recent energy scenario modelling suggests that electricity will play a majority role in the delivery of heat and other energy services by 2050. There are, however, potential issues associated with delivering a future energy system with such high utilization of electricity. This paper examines the implications of what may be described as the “all-electric” future with regards to: (i) growth in build rates associated with increasing electricity generating capacity; (ii) problems in the management of power flows and the transmission and distribution network; (iii) implications of intermittency given the high penetration of renewables; and (iv) consequences for end-users through the required modification of homes. Several of these issues are already of concern in the development of the power sector, and it is widely recognised that current energy market arrangements are not well-suited to the changes foreseen. For comparison, a vision of the 2050 energy system with an increased role for Combined Heat and Power (CHP) and District Heat Networks (DHN) is developed, reducing the burden of heat delivery on the electricity system. By increasing the efficiency of electricity generation through CHP the build rate for new generating plant may be reduced. Use of thermal stores and DHNs reduces the need for instantaneous power increases, limiting the impacts of peak demand. The flexibility of that thermal storage can also provide mechanisms by which intermittent generation can be managed. Issues of disruption for end-users can also be reduced potentially, since networked heat can be connected to homes through traditional radiator systems. The paper concludes that there are many ways in which increased diversity of heat delivery may facilitate the difficult move towards a decarbonised future. While the benefits of a decarbonised electricity system are compelling, many practical issues associated with delivering this system are not yet sufficiently understood. Efforts should be made, therefore, to keep open options which deliver synergistic benefits for both the delivery of energy to end-users, and the facilitation of the wider decarbonised energy system. The paper will explore briefly the implications of these messages for policy, and for the ongoing debate about energy market reform.

Keywords Heat technologies; Scenario analysis

1 Introduction

In 2008 the UK adopted legally binding targets mandating an 80% reduction in greenhouse gas emissions by 2050(OPSI 2008). Several scenarios of the energy system in 2050 have been developed recently, describing different paths towards this future, and different mixes of technology and resources at that point (CCC 2008; UKERC 2009). These scenarios investigate both the carbon emissions and economics of this transition. Amongst these scenarios some consensus has been built, with many envisaging a highly electrified future where demand for heat and transport is served by electric technologies rather than direct use of fossil fuels. We describe the agreement among these scenarios as the 'all-electric' future.

The all-electric future considers the challenges associated with electrifying heat in the energy system. Heat demand currently accounts for some 41% of final energy consumption and most heat loads are currently met through the direct combustion of fossil fuels, primarily natural gas (DECC 2009a). Heat is expected to remain a significant fraction of energy use in the future to 2050, giving rise to several questions regarding the delivery of heat in a low carbon future. As explained below, meeting high levels of energy service demand through electricity raises challenges relating to both electricity system expansion and end-users. It is also notable that the all-electric scenarios rely heavily on electricity-only thermal power stations, particularly fossil fired generation with Carbon Capture and Storage (CCS), with large amounts of primary energy lost as 'waste' heat.

The alternative, 'integrated' scenario developed in this paper explores how long term decarbonisation objectives can be met for heat delivery, whilst addressing the key challenges identified for the all-electric approach.

This paper reviews existing 2050 energy scenario analysis (Section 2). It then discusses some of the challenges associated with the all-electric future (Section 3). Section 4 introduces an integrated scenario for meeting heat demand in a decarbonised future. The paper concludes by discussing some of the key policy implications of such an integrated scenario (Section 5).

2 Decarbonisation scenarios and the 'all-electric future'

The UK Government's Low Carbon Transition Plan (LCTP) prepared by the Department of Energy and Climate Change (DECC) "sets out the UK's first ever comprehensive low carbon transition plan to 2020" (DECC 2009b). This white paper responds to the target set out in the Climate Change Act 2008, requiring CO_2 emissions cuts of 34%[1] by 2020 (OPSI 2008).

The conclusions of the LCTP are underpinned in part by several scenario studies, most of which use versions of the UK MARKAL model. These include work undertaken for the Committee on Climate Change (CCC 2008), the UK Energy Research Centre (UKERC 2009), the Department for Environment, Food and Rural Affairs (DEFRA) and DECC itself.

The all electric future has three themes. First, it focuses on the most cost effective measures – e.g. efficiency improvements, installing insulation in homes, etc, and this is mostly complete by 2020. Second, electricity generation is almost completely decarbonised by 2030. Third, it increases the proportion of heat and transport energy delivered through electricity. The net impact of these changes results in electricity increasing from 18% of final energy consumption in 2007 to 42% in 2050.

Recently the 2050 pathway analysis reinforced the orthodoxy of the all-electric future by pointing out that "a sustainable level of electrification of heating is needed" (DECC 2010a), whilst acknowledging that "heat from power stations may also be required" (DECC 2010a). Although the future reflected in the all-electric future may prove to be low carbon, there are

[1] All percentage emissions cuts are against 1990 emissions levels.

issues regarding the practicality of its implementation. To provide a point of reference, the CCC 80% reduction scenario is used here as a proxy for the all-electric future. To demonstrate the implications of this all-electric future the results of the CCC scenario are interpreted into the energy flow diagram presented in Figure 1. The practicalities associated with the transition to the all-electric future are discussed in the following sections.

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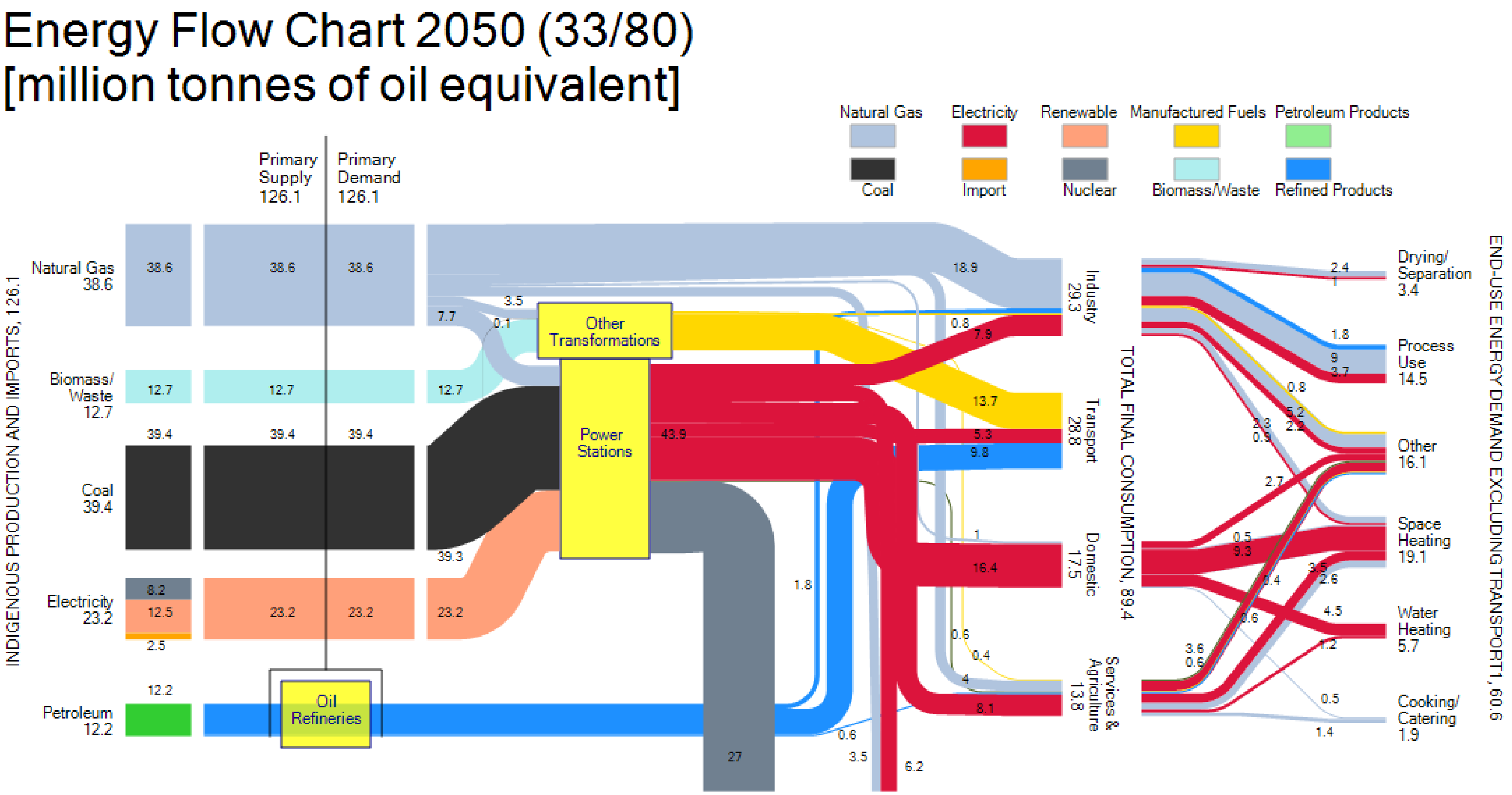
Figure 1: Energy flow diagram of Committee on Climate Change 33/80 scenario for UK in 2050



Assumptions:
1. Assumed that gas will meet total cooking/catering demand and the remaining gas would then be used to meet space heating end-use, 2. Proportionality of gas to electricity in final energy consumption of Industrial sector is used to estimate fuel mix in industrial end-uses, 3. Assumed that total petroleum product will be consumed in process end-use, 4. Assumed that energy available from other transformations will be consumed in other end-use, 5. Assumed that heat from CHP will be used in other end-uses of agriculture end-use

Footnotes:
1. Proportionality of 2007 end-use energy consumption is used to estimate final energy consumption, 2. Proportionality of 2007 Energy Industry Use, Non-Energy Use and Distribution Lossesis used to estimate, 3. Losses includes Power Station Conversion Losses and are estimated on the basis of difference between energy supply and final energy consumption, 4. Other Transformations includes fuel such as Biodiesel, Ethanol, Hydrogen (from Gas and Electrolysis), Bio-Waste, Solid Biomass, etc

This flowchart has been produced using the Results of Stage 1&2 of CCC MARKAL MED Ph 2_101108 for UKERC

3 Criticalities in the all-electric future

Higher electricity consumption under the all-electric future will affect all components of the UK electricity sector. If electricity can be entirely decarbonised, the positive aspects of such a system are clear. There are, however, several issues associated with the transition to an all-electric economy. The rate at which low carbon generation can be built, or the practicalities of insulating the building stock and retro-fitting electricity-based heating systems are fundamental challenges. Four main issues are discussed below.

3.1 Primary energy needs, system efficiency and roll out of low carbon generation

All of the low carbon scenarios presented in Section 2 rely on a high proportion of thermal generation of electricity from fossil fuels (with CCS) and nuclear power. This gives rise to a range of problems, including exposure to fossil fuel price volatility, the availability of primary resources and appropriate storage sites for CO_2 and nuclear waste. Most of these scenarios prioritise economic efficiency over resources efficiency. As a result they are all, to a greater or lesser extent, subject to the paradox that they use more fossil fuel than if the scenario were optimised to maximise energy efficiency and minimise losses in power generation. There are two main reasons for this. First, CCS consumes energy and reduces overall thermal efficiency. Second, the scenarios contain a substantial amount of thermal power generation (fossil fuels and nuclear power), but make very limited use of CHP to reduce thermal losses (waste heat from power stations). The use of electric heat pumps goes some way to compensate for the relative inefficiency of electric only power generation, since heat pumps extract ambient energy from the environment (air, ground or water), delivering more energy in the form of heat than is input in the form of electricity.

The ability of heat pumps to extract heat from surrounding ground or air (the *coefficient of performance COP*) may be as high as 4 to 1. However in practice the Seasonal Performance Factor (SPF) or Seasonal Efficiency, defined as the useful thermal energy delivered over the year divided by the electricity input over a year may be a more useful measure. This is typically lower than the COP measured at any one point in time. Dickinson (2009) cites results from a study of 217 heat pump installations in the US, assessed for total energy use throughout the year. On average the SPF was found to be approximately 2 to 1. There are alternative design options for heat pump systems to meet space heating and domestic hot water demands. It is possible to specify a heat pump system to meet the full demand, including peak loads. However heat pumps are not well suited to meeting instantaneous loads, and thus such systems require large water tanks and careful sizing and optimisation. As Dickinson notes, an alternative approach is to include an additional method of heating (typically a resistance heater) to meet building needs at times of low external temperature (when heat pump performance would be very low), to meet short term peaks and other supplementary needs. Meeting some portion of the load with an electrical resistance heater will reduce the overall SPF of the domestic system.

The all-electric scenarios also require major penetration of new low carbon *capacity* – nuclear power, fossil generation with CCS and renewables. The scale of development implies extremely aggressive build rates when compared to historical precedent.

The CCC 80% carbon reduction scenario implies total capacity increases of 74 GW between now and 2050. This includes:

- 13 GW of new nuclear power by 2050;
- 35 GW of new renewable wind capacity by 2050;
- 27 GW of coal generation with CCS in the period between 2020 and 2050;
- 13 GW of gas generation with CCS is built in the all-electric scenario; and,
- an extra 20GW of gas without CCS in 2050.

Dramatic build rates are not without precedent, 10 GW of gas-fired CCGT generation was built during the first four years of the 'dash for gas'(Winskel 2002). Build rates for wind power in excess of 3 GW per year have been delivered in many countries including Germany, Spain, China and the US (Bolinger and Wiser 2009; EWEA 2009; Li 2010). However, UK experience has not always been so favourable. For example UK installed capacity of nuclear power increased by 7 GW in the 33 years between 1974 and 2007 (ESDS 2009) and the period between 2004 and 2008 saw installed capacity of wind in the UK increase by just 2.5 GW (DECC 2009a). It is also important to note that some low carbon options are relatively unproven, with devices in the demonstration and testing stage of development. Large scale roll out will also require sustained support for innovation and deployment. The UK political landscape has recently undergone a major change with a new coalition government in place. Whilst policies are not yet fully developed, state support for nuclear new build seems unlikely, and indirect support (e.g. via developments in the planning system or risk management) are likely to reduce. Thus the challenges facing large scale private investment are significant.

Finally the sheer scale of the new electricity generation capacity implied by the 'all-electric' scenarios will have a major impact on the physical landscape, which may exacerbate problems already faced by new power generation projects in the UK. The development of large-scale renewable generation in the UK (primarily wind power) has been significantly hampered by local opposition, manifested through objections to planning applications, and the resultant delays in the planning approval process (House of 2008). The Planning and Energy Bills of 2008 and the changes to the obligations on local authorities(DECC 2009c; b) are an attempt to expedite the approval process for large scale generation projects (including large wind farms and nuclear), but this does not, of course, make potentially vociferous local opposition 'go away' – it merely provides a legal mechanism whereby such opposition can be given less weight in the decision making process.

3.2 Network requirements

The changing generation profile will require major reinforcements to electricity transmission and distribution networks. Investment in additional electricity transmission capacity will be needed in order to connect the large increase in generating capacity to centres of electricity demand. Investment will be needed also in the distribution grid, which will have to cope with increased load from heat pumps and electric cars, allow two-way power flows and control, and the connection of distributed generation. There may be a need for upgrading work in many areas, which has the potential to be disruptive to road transport and other services. Smart meter installation will contribute to the cost of this transition. National Grid has classified the UK in terms of required network reinforcements. Under this classification the

Scottish transmission network is already considered to be operating at capacity and is not currently fit to handle immediately anticipated electricity demand increases. Meeting future demand will require major reinforcements (NationalGrid 2009).

The Electricity Networks Strategy Group (ENSG 2009) set out a transmission reinforcement plan for 2020 that would be able to cope with all-electric scenarios. The plan concluded that the Scottish transmission network would need large investment in various areas of the transmission system in order to fulfil a scenario where 11.4GW of extra electricity generation were connected. An Ofgem consultation document estimated that required investment in the GB transmission and distribution network could be as much as £53.4bn between 2009 and 2025 (Ofgem 2009). This cost reflects the difficulties in transmission and distribution described above. In addition the report estimates the installation cost of smart meters with basic functionalities to be £10bn over the same period.

The scenarios reviewed in Section 2 may also require the installation of a smart distribution grid. Given the increased electricity demand associated with these scenarios, the grid will need the capacity to handle greater loads, and to manage peak loads. This includes the capacity to handle increased levels of distributed generation.

3.3 Peak loads and plant utilisation

Under the present mix of generation technologies, nuclear and renewable power plants with very low or negligible marginal costs will typically run whenever they are physically able to do so, and fossil-fired thermal plants will supply the remaining baseload and fulfil the load-following requirement to match the diurnal demand cycle (Gross *et al.* 2007). Achievement of a largely decarbonised, all-electric future has significant implications for the utilisation of generation capacity because a very large installed wind capacity will compete with nuclear for baseload supply (net of the flexible generation required to provide system balancing and reserve), leaving much fossil-fired generation running at very low, possibly uneconomic, average load factors. At times of high wind output and low demand, nuclear and/or wind power may also need to be constrained, which whilst technically possible, has major implications for their per unit generation costs.

In addition to economic implications of generators ‘chasing baseload’, the pattern of electricity demand may change. Heat demand, largely supplied by electricity, will add considerably to the peaks in electricity demand unless there are mechanisms (technical, economic or behavioural) to shift these peaks to lower-demand times in the diurnal cycle.

Air source heat pumps in particular have significant peak electricity demand, and relatively low SPF. Manufacturers typically install resistive backup (i.e. direct electric) heating in devices in order to meet peak loads rather than sizing the heat pump to meet them. This keeps costs down, as it minimises the size of heat pump required. It does not, however, reduce the peak electricity requirements of the heat pump system. This could have a profound impact on the electrical capacity needed to meet peak power demands. The peak power demand of a domestic heat pump would typically be around 7kW. However, the impact on peak grid demand will be much less, since UK heat pumps will not all be operating at peak simultaneously. Work recently carried out at Imperial College suggests that the aggregate effect may be 1.3kW per home, or 1kW in highly insulated homes (Hawkes 2010). This would mean an additional peak electricity requirement of tens of GWs for some of the more aggressive heat pump scenarios to 2050, where installation of 1 million units p.a. for the next 33 years is assumed (MacKay 2009). To provide some perspective, peak demand in Britain is currently around 60GW (National Grid 2009). Demand for heat also occurs when it is cold, and thus ‘heat pump peaks’ are likely in winter, which coincides with peak demands for electricity for other uses. If heat pumps are also operated on a time of day cycle similar to today’s central heating timers the additional demand would coincide with current morning and evening demand increments.

Of course the precise number, nature, rated capacity and utilisation of heat pumps in 2050 is a matter of speculation and it is possible that householders with highly insulated homes will be persuaded to alter the way they operate their home heating systems and avoid a time of day peak (see below). The precise impact on demand peaks is therefore difficult to quantify, but the potential impact is large. Further research is required to reduce these uncertainties, and also to guide future technical development work for heat pumps themselves.

3.4 End-user issues – behavioural obstacles to high penetration of domestic energy efficiency measures

The viability of an electricity-dominated energy future relies on achieving very substantial improvements in the end use of energy, notably on reducing demands for heating. In particular this will include the following key problems: (i) the need to achieve a major roll out of insulation in order to reduce demand and facilitate a move to electricity based heat systems; (ii) the potentially disruptive retrofitting of heat pumps; (iii) changes to demand patterns.

Insulation of buildings is an important step in order to reduce domestic energy demand and may be prudent in the attempt to decarbonise. In addition, given the relatively low output temperatures usually associated with ground and air source heat pumps, achieving a sufficient level of thermal comfort using heat pumps is contingent on a high level of building insulation.

The installation of heat pumps is another area potentially unpopular with end-users. The most efficient way to achieve sufficient thermal comfort is through the installation of under floor heating, increasing the thermal surface area of the heating system and improving heat delivery. Under floor heating may be relatively straight forward for new build, but obviously presents greater disruption for retrofit.

Installing insulation and heat-pump systems in modern homes or homes with cavity walls may be a relatively simple and non-disruptive process. However, around 80% of the 2050 housing stock is likely to be currently existing housing stock (Boardman 2007) and 7 million of these homes are of solid wall construction (EST 2009). Since internal solid wall insulation reduces the internal space of homes, and requires disruptive work, it may be difficult to persuade end-users to accept this transition.

Maximising the benefits of heat pump systems may require behaviour change which may also be an important factor in dealing with the issues of peak electricity demand discussed in Section 3.3. Given the efficiency characteristics of heat pumps, and the planned improvement to building envelope insulation, heat pumps could operate 24 hours a day, relying on the building fabric as a heat store -a capacity that innovative insulation materials may be able to enhance. This would maximize the efficiency of heat pumps, most efficient when operating continuously, and minimize the issues associated with peak electricity demand. However, evidence from behavioural studies does not clearly demonstrate whether end-users can be convinced to adopt this new pattern and how this relates to perceptions of thermal comfort (Upham *et al.* 2009).

4 An integrated scenario for meeting heat demand in a decarbonised future

The criticalities identified in Section 3 call for an analytical attempt to develop a scenario that meets the low carbon ambitions whilst reducing the risks identified. The objective for this scenario is to seek out opportunities to diversify heat provision and reduce thermal losses relative to the all-electric futures described in Section 2.The CCC 80% scenario is used as a 'base case'. Three questions need to be addressed when designing an integrated scenario focusing on heat delivery. First, which heat generation technologies could be used in the future and what are their efficiencies[2]? Second, which electricity generation and heat delivery technologies could be displaced? Third, to what extent could domestic and industrial heat demands be met through an integrated scenario?

4.1 Potential for CHP from biomass and CCS

Waste heat arises from three main sources of thermal generation: nuclear, coal, ; and gas-fired power stations. Since public acceptance of District Heat Networks supplied from nuclear power stations may be problematic, the possibility of utilising this waste heat is discounted in the integrated scenario. The potential to utilise waste heat from coal and gas-fired power stations, however, has a proven track record in many countries and was therefore deemed tractable for the integrated scenario.

The carbon emissions from coal or gas-fired CHP can be abated either by use of biomass derived fuels (including biogas solid waste or other solid biomass), or through carbon CCS technologies. We examine the potential for both of these decarbonised CHP options in turn below.

4.1.1 Biomass

The CCC 80% scenario prioritises biomass for the production of transport fuel. We assess the potential for additional biomass in 2050. The biomass/waste energy deployed in the CCC 80% scenario is 12.7 MTOE. There is evidence to suggest that there may be potential to make greater use of bioenergy than presented in the CCC 80% scenario. The 2007 UK Biomass Strategy (Defra 2007) estimated that the potential of the biomass resource in 2020 would be around 8.3 MTOE with predicted theoretical biomass resource of about 10 MTOE. Work for DECC on Biomass Supply Curves (DECC 2009c) estimates that the biomass resource from UK could reach around 10% of current UK primary energy demand by 2030, or 23.7 MTOE. Similar estimates are also made by the European Environment Agency (EEA 2006), who estimate the environmentally compatible bioenergy potential of the UK to be 13.5 MTOE in 2010, 19.0 MTOE in 2020 and 24.5 MTOE in 2030.

[2] MicroCHP technologies have not been considered here though should these technologies be provided with suitably low carbon fuels they could contribute to the heat and electricity demands of an 80% decarbonised future. The scenario also excludes the use of extra conventional (unabated) fossil fuel CHP plant.

This evidence suggests that sufficient biomass resource will exist to consider a fraction for CHP over and above the volumes going to transport in the CCC 80% scenario. There is potential to increase the role for bioenergy much further through importing biomass, but these additional inputs are not considered here. We therefore adopt the 2020 resource penetration potential from the UK Low Carbon Transition Plan and assume that this remains constant out to 2050, which results in bioenergy potential of 17.9 MTOE.

4.1.2 CHP-CCS

A combination of CHP and CCS technologies is increasingly discussed as a way of regaining some of the efficiency lost through the carbon capture process (Vattenfall 2009). First we must consider the conversion efficiency of such technologies in 2050. Integrated gasification combined cycle (IGCC) is a coal technology which can be fitted with both CHP and CCS functions. In this case combined efficiencies for both heat and electricity generation can reach approximately 58% (Ng et al. 2009) -compared to overall efficiencies for coal-fired CCS without heat capture of 32-40% (Damen *et al.* 2006; Descamps *et al.* 2008). Efficiencies for gas are considerably higher. Research suggests that natural gas combined cycle combined heat and power (NGCCCHP) can achieve 84-88% total efficiency (Kuramochi *et al.* 2009).

With the goal of improving whole system efficiency we assume that: (i) CHP technologies are combined with gas-fired CCS plant with efficiency of 86% and a heat power ratio of approximately 1:1; (ii) the displaced electricity generation is coal-fired; and (iii) the heat generated from CHP plants will substitute for electricity-based heat provision in houses and commercial properties using resistance heating or heat pump systems.

The focus on gas-fired CCS was chosen as it is most consistent with the objective to improve overall efficiency and reduce losses. CHP technologies could instead be added to coal-fired power stations first, though this may decrease the level of efficiency improvement. Future work could explore the potential for coal-fired CCS-CHP to reduce emissions and diversify the generation mix.

4.1.3 Modelling CHP-CCS with District Heating

Quantifying the potential role of CHP with CCS creates the practical problem of how to deal with carbon transportation. Where do the likely sequestration reservoirs exist and where will CCS-CHP plant be located? Many of the likely geological sequestration reservoirs are under the North Sea, off the east coast of the United Kingdom, and large population centres also exist along or near this coast. The project team therefore identified sites of existing power generation near the east coast of the UK, formed a view on the potential for generation in suitable locations to expand, and developed a methodology to assess the potential to link such CHP-CCS plants to heat loads in nearby conurbations. The geographical locations of the CCS plants in the all-electric scenarios are not specified. But by 2050 it is possible to envisage an integrated network of CO_2 pipelines running across the country. It is therefore possible for CO_2 pipelines to run from power stations located further west and hence to support the development of a larger array of CCS-CHP schemes. Investigating these possibilities would be an important opportunity for future work.

With regard to the domestic sector, we must define a proportion of that sector which can be serviced through DHNs. Current potential has been estimated as 14% of the UKs building heat demand, though estimates tend not to report future potential, particularly out to 2050 (Poyry and Faber 2009). There is a paucity of studies examining future potential of CHP and DHNs, and this is likely to be another valuable area for future work.

Having defined generation locations, estimates can be made of the catchments surrounding locations where CHP and DHN could be constructed. Modern DHNs have been constructed over distances up to around 30 km with complex local networks extending this range into population centres (Mattias 2009). DHNs constructed in Sweden demonstrate the feasibility of maintaining DHN temperatures over such distances and could provide a model for the UK. We can then apply an assumed network distance to the feasible catchments for future DHN networks in the UK. For the purposes of this study a 30 km radius is used. Based on population density data, these catchments can then be converted into estimates of DHN delivery potential.

A procedure similar to that outlined by the Institution of Civil Engineers (ICE) in a study of the near term potential for district heating (ICE 2009) is followed. DECC gas consumption data for England and Wales and existing and planned fossil fuel power plants have been incorporated into a GIS database. The above constraints are then implemented and 23 potential sites that meet conditions related to location of CCS infrastructure and presence of existing power stations are identified.

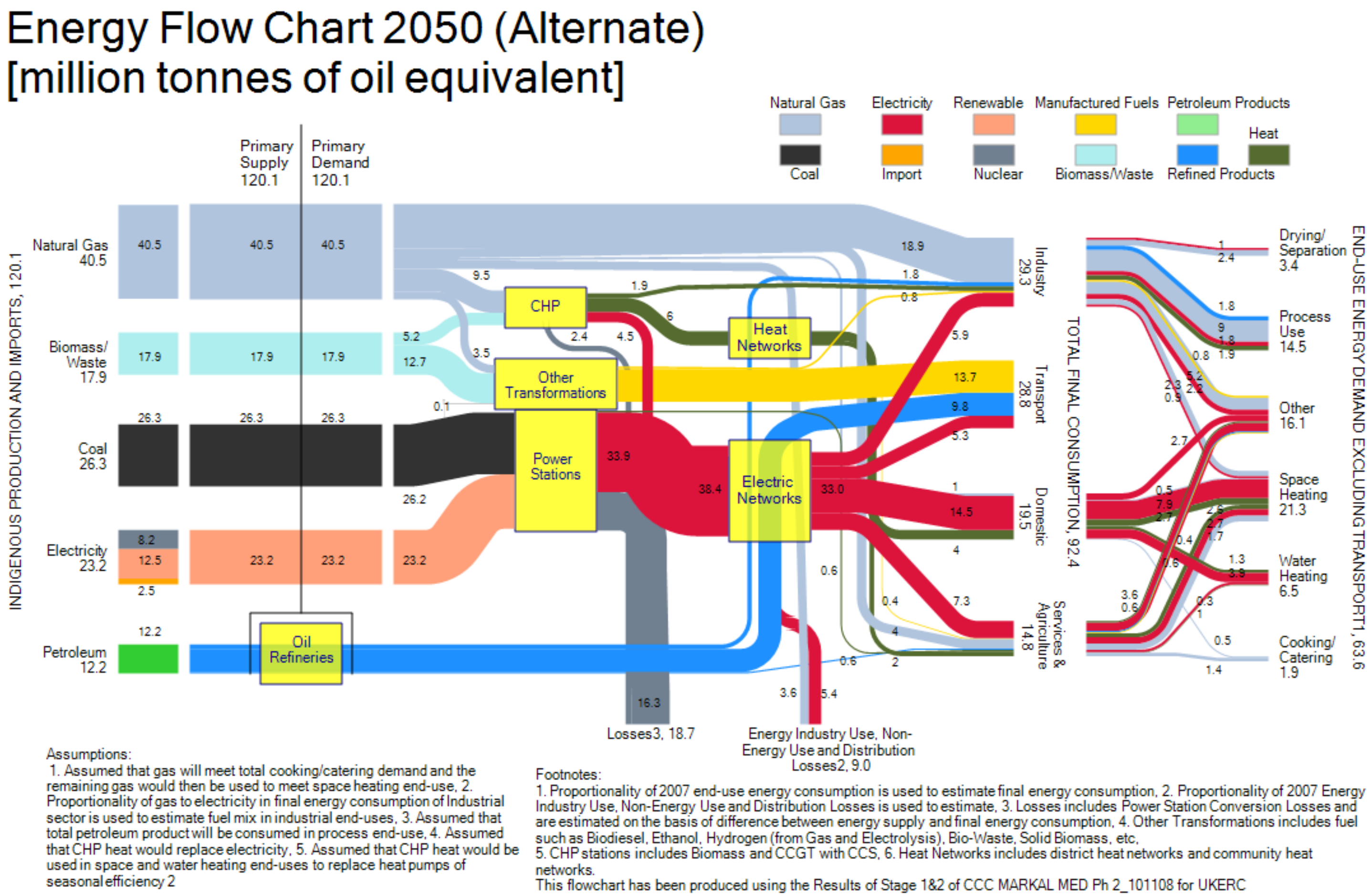
A circumference with a 30km radius is superimposed around each of the 23 power station locations on the GIS output. The heat demands from all population dense zones within each radius are added up. This method also replicates the procedure followed by ICE, with the modifications being the radius chosen (up to 10 km for ICE's 2020 study), and the number of sites considered feasible.

4.1.4 Industrial CHP

It is also possible for CHP systems to meet a fraction of industrial heat and electricity demand. Some estimates of current industrial CCGT CHP potential have suggested that as much as 16 GWe of extra CHP capacity could be installed (Poyry 2008). This estimate is based on analysis of existing industrial clusters and their electrical and heat demands. It seems reasonable to assume, therefore, that provided industrial planning policy focuses on the potential for CHP in all new industrial development we could reach at least this level of installed capacity in 2050. Taking Poyry's 'pessimistic assumption' about electricity and heat capacity and assuming a load factor of 60% leads to an industrial potential for CHP of 5.2 MTOE electrical and 3.8 MTOE thermal.

The magnitudes of waste heat utilisation and primary resource reductions can then be calculated through the assumptions regarding technological efficiency of CHP and the conventional thermal generation technology being displaced. The results are presented in Figure 2.

Figure 2: Energy flow diagram of the integrated scenario



4.2 Quantifying the integrated scenario

Based on the judgements, assumptions and methods described above, the integrated scenario unfolds as follows:

- By the year 2050, we have built large scale CHP facilities in 23 locations near the east coast of the UK supplying 4.18 MTOE of heat and 3.97 MTOE of electricity to the UK. This is efficient gas-fired plant with CCS providing a combined electricity and heat efficiency of 86%.

- DHNs have been constructed, delivering heat from our additional CHP plants to population centres, representing 14% of heat demand in the domestic sector. The availability of district heating for many consumers has reduced the demand for other heat delivery technologies such as heat pumps, reducing the domestic demand for electricity by 1.9 MTOE. In industry, electricity demand has also been reduced, and is now 2 MTOE less than expected under typical all-electric assumptions.

- Smaller scale biomass-burning CHP plant has been installed to service heat and electricity demand in areas not serviced by a CO_2 sequestration network. This plant will produce 3.67 MTOE of heat and 0.48 MTOE of electricity.

- By increasing the efficiency of the electricity generation system the scenario has been able to reduce demand for primary resources by 5%. As a further result of this efficiency increase, conversion loss has been decreased by 8 MTOE.

Overall, these reductions equate to a 13% reduction in electricity demand against the CCC 80% scenario. Since primary energy demand has been reduced, and CHP carbon emissions captured, system CO_2 emissions have remained within the constraint of the all-electric scenario, meeting current CO_2 emission reduction commitments.

The integrated scenario has changed only those conditions which pertain to the efficiency gains associated with applying CHP and DHN technology to biomass and CCS plants. Other scenario assumptions are held constant, and derived entirely from the CCC 80% scenario. This includes the completion of deep insulation to most building stock by 2030, the capture and storage of all feasible emissions from coal plant in 2050, and the installation of efficient heat pump technologies for most homes not connected to DHNs. There is also a role for small scale CHP, which constitutes 0.9 MTOE in the CCC 80% scenario. Future work could quantify the implications of relaxing certain assumptions for building stock efficiency in the light of the potential for CHP-DHN to reduce system wide emissions.

4.3 The benefits of an integrated approach

The integrated scenario encompasses a number of potential advantages which may provide some benefits in a highly electrified world. These benefits are discussed below.

4.3.1 Reduced demand for electricity

The integrated scenario has offset a proportion of the electricity demand required under the ‘all-electric’ scenarios by making use of CHP, district heating and biomass and reducing the use of electric heat pumps and resistive heaters. As a result, primary energy demand for power generation has been reduced by 6 MTOE. Demand for coal has been reduced by 13 MTOE, equivalent to 9 – 14 GW of coal-fired generation capacity displaced from the integrated scenario[3].

Reducing absolute electricity capacity has the principal benefit of reducing at least some of the highly ambitious electricity generation build rates implied in the all-electric scenarios (see Section 3.3). Moreover, replacing electric heat pumps with non-electric sources of low carbon heat has the potential to reduce the scale of heating-driven peak electricity demands as well as helping manage electric power flows in a number of other ways, as we now explain.

4.3.2 Managing energy flows

By utilising waste heat and installing heat networks in the integrated scenario, the system has the potential to provide a greater robustness and ability to manage power flows. The integrated scenario will provide 14% of domestic heat demand through DHNs. This represents 4 MTOE of heat delivered without the use of electrical heat systems such as heat pumps.

By relying heavily on electricity based heat solutions there will be an impact on peak power demand. Unless steps are taken to mitigate this, the current 60 GW winter peak electricity demand could increase by tens of GW. The integrated scenario has the potential to remove a fraction of the additional peak load. Urban or suburban districts were sought out in the district heating scenario. Since air source heat pumps also have highest applicability in urban areas, where installing ground source heat pumps is likely to be more difficult, the fraction of the demand peak removed as a result of the scenario is likely to be higher than the 13% of electricity displaced on an energy basis.

Similar implications can be drawn for the heat demand displaced by the 1.9 MTOE of networked heat going to industrial end-use, and the 2 MTOE of networked heat supplying the agricultural and service sector. By reducing peak electricity demand, requirements for electricity network upgrading, particularly at the distribution networks, may also be reduced.

- There are other prospective benefits for the management of energy flows afforded by the use of heat networks. DHNs can be (and often are) built in conjunction with large hot water storage systems. These systems are essentially large, heavily insulated hot water tanks, one UK example of which is in Pimlico, London (Citywest Homes 2009). These heat storage technologies can provide system management opportunities in several ways. First, by storing hot water during normal electricity production and providing that heat flexibly throughout the diurnal cycle heat can be delivered to end-users in a manner that may be able to smooth fluctuations in electricity demand. Second, during high wind weather events CHP can decrease its output, using stored heat to continue to satisfy heat demand. When wind production drops, the CHP plant can increase electricity and heat production in order to meet subsequent demand. This has been demonstrated in various countries and is the subject of a recent European FP6 project (DESIRE 2009). By utilising this flexibility the impacts of intermittency expected by a very high installed

[3] This range reflects assumed load factors for the displaced plant of between 50% and 80% (SKM 2008; Poyry and Faber 2009).

capacity of wind power can be mitigated. Third, CHP schemes and hot water stores can be 'co-fired' with electric boilers. It is possible to utilise these when electricity from intermittent sources is in plentiful supply (Baker 2009).

Overall, increasing the share of district heating and CHP, perhaps with electrical co-firing, offers a great deal of flexible demand that is otherwise not present in the all-electric scenario. It also decreases to a significant extent the absolute level of peak electrical demand arising from heating needs. As a result, the integrated scenario offers a substantial and potentially extremely valuable contribution to managing power flows on a low carbon electricity system.

4.3.3 End-user issues

Issues for end-users surrounding the implementation of low carbon heating alternatives are equally significant. The integrated scenario reduces the use of electricity for heating by delivering heat through DHNs. In the domestic sector and in many instances in the service sector this shift will obviate the need to install heat pump systems, with accompanying insulation and under floor heating. If a proportion of the 7 million solid wall properties potentially existing in the UK in 2050 (EST 2009) are connected to DHNs this could provide an additional path to decarbonisation for dwellings which are particularly hard to insulate.

5 Conclusions

The transition to a low carbon energy future presents the UK with some difficult choices, none more so than the choices around heat. Heat represents more than 40% of current energy demand and it is reasonable to assume that demands for thermal comfort and other heating services will endure, long after 2050. How then should its delivery be decarbonised? Many recent scenario modelling exercises envisage a largely all-electric future where electricity provides many of our energy needs, including the electrification of heat delivery. Several 2050 UK energy scenarios are highly decarbonised and, at least on the basis of the assumptions made in order to model them, cost optimal. However, in all cases a large fraction of primary energy is lost as waste heat from fossil fuel stations -with and without CCS- and nuclear power stations. Heat pumps help to restore overall system efficiency, but also give rise to challenges related to power flows, particularly in the winter peak demand periods. By presenting the all-electric scenario in terms of its energy flows, it has been possible to examine these implications. The all-electric scenarios also face several practical difficulties, requiring future developments that would be critical to a successful outcome.

The integrated scenario makes greater use of waste process heat in order to increase conversion efficiencies, hence meeting equivalent energy demands whilst reducing demand for electricity and consumption of primary resources. By building heat networks, heat can be delivered to buildings. By heating these networks with waste heat from CCS and biomass fuelled plant, the heat is sufficiently decarbonised that it remains compatible with deep cuts in emissions. The integrated scenario helps address some of the key criticalities, reducing peak electricity loads and helping manage power flows.

The legal framework for the adoption of the integrated scenario can be found in the EU CHP Directive and the Co-generation directive, which support cogeneration, which over the last few years has unevenly developed across Europe. For instance, market penetration of DH is unevenly distributed, being close to zero in some countries while reaching as high as 70% of the heat market in others. More than 5.000 DH systems in Europe are currently supplying about 556 TW h of heat, i.e. about 9% of total European heat demands with an annual turnover of €19.5 billion. The UK deficit compared with Denmark, the Netherlands, Germany and Finland in terms of CHP installations can be lessened by increasing CHP combined with CCS, as well as DH.

Although this paper provides only a snapshot of our future in 2050, we must also consider the transition journey to a low carbon future. Options which provide early cuts in CO_2 can reduce cumulative emissions between now and 2050, which recent climate research has highlighted as a key factor in avoiding dangerous climate change (Anderson *et al.* 2008). This includes technologies which are not sufficiently decarbonised to reach an 80% target but provide significant CO_2 savings in a period in which grid electricity and gas both remain carbon intensive. Fossil fuelled CHP at the small and micro scale may fall into this category. Another option may be the use of gas-fired CHP at medium scale, which may be used to support the development of heat networks. The networks could then be connected to large scale CHP with CCS or biomass fired CHP plant to help decarbonise heat sufficiently for demanding 2050 targets. This has the benefit of making early cuts to the CO_2 intensity of heat and supporting the development of district heating. By contrast, if we ignore opportunities to support DHN building in the near term, we will begin to lock ourselves in to a path towards another future which is less amenable to capturing the benefits associated with CHP-CCS and district heating.

This leads to a question of incentives. If we are to pursue a 2050 energy system with greater utilisation of waste heat, district heating and biomass CHP, how can this best be facilitated? The UK already has a CHP target of 10 GW by 2010 (Defra 2006), but the target will not be met, raising questions regarding barriers to CHP in the UK. Nevertheless, the 2010 consultation on National Policy Statements for energy presents a desire for the inclusion of CHP feasibility assessment for all electricity planning applications, which has the potential to increase the build rate of CHP.

In conclusion, the journey to a low carbon energy system will be difficult regardless of the path. This paper focused on the energy flows and 'criticalities' associated with a largely 'all-electric' future. It developed an integrated scenario which makes efficient use of primary resources, reduces the absolute requirement for electricity and reduces some of the problems associated with running an 'all-electric' system. The integrated scenario, however, presents challenges of its own, and policy-makers are presented with a choice: in which of these visions of the future energy system is there more value?

On one hand there is the all-electric scenario, which sees high dependence on electric heating in buildings. Is it possible to deliver an electricity system resilient to the difficulties of implied peak loads and transmission issues? Can enough generation capacity be built to supply this system? Are the environment, market and society prepared to accept the implications of increasing use of fossil fuel? Will end-users accept the disruption associated with both insulation and installation of heat pumps?

On the other hand there is the integrated scenario, which adopts a complementary and diverse mix of heating approaches, including both electric heat and more extensive use of heat from thermal power generation. This reduces some of the problems above, but introduces others. Will consumers and citizens be prepared to tolerate the disruption created in order to lay heat networks in existing urban areas? Again, will they tolerate the disruption to their homes associated with connecting them to heat mains?

Both scenarios involve dramatic changes to the energy system and neither have historical precedent. It is important to stress that they are by no means mutually exclusive. Indeed, bringing together elements of both has the potential to ameliorate some of the problems associated with each. As policymakers and energy industry consider the means by which to deliver a low carbon future it may be important to encourage diverse solutions. In the case of low carbon heat a variety of means are available and bringing them together in combination is likely to create a more resilient outcome and meet heat demands in a technically feasible, efficient and low carbon way.

6 Implications for policy

Since the market value of energy for heat does not yet make renewable heat attractive economically, the UK Government plans to introduce a Renewable Heat Incentive financial support scheme (DECC 2010b). The integrated scenario would require an extra 5.2 MTOE of bioenergy resource for CHP. There are at least three approaches that could help deliver this. First, the tariffs for large biomass CHP could be increased from the levels estimated by the Renewable Heating Incentive (NERA 2010) – which are currently set between 1.6 and 2.5 p/kWh for installations above 500kW. DECC proposed to provide the same tariffs for biomass CHP and biomass used for heat-only. However, biomass CHP might require a higher support level. This is because the cost of achieving the same CO^2 reductions for biomass CHP is higher than large-scale heat-dedicated biomass boilers. For this reason the higher range of incentive level – towards 2.5 p/kWh - may be more adequate for biomass CHP. As a result, the RHI would push renewable heat up by 15% by 2020, compared with the current 12% target with the overall average resource cost increasing from £31 MWh to £36 MWh. Second, the tariff life time for biomass CHP could be extended from 15 years to 20 years to reflect the high capital cost and time constraints associated with this technology. Third, biomass to CHP could be incentivised by applying tax credits.

With regards to new gas-fired CCS-CHP, incentives for this type of generation plant could be subtracted from incentives which will be allocated to heat pumps. The economic margins for reducing subsidies for heat pumps thanks to the decrease in electric heat in the integrated scenario can be derived from the DECC consultation document. The UK Government set out to incentivise small (below 45 kW) ground source heat pumps at 7 p/kWh for 23 years and air source heat pumps at 7.5 p/kWh for 18 years; medium (between 45 kW and 350 kW) ground source heat pumps at 5.5 kW/h and air source heat pumps at 2 kW/h, both for 20 years; and large (above 350 kW) ground source heat pumps at 1.5 kW/h for 20 years. Eliminating incentives for heat pumps would enable increasing incentives for biomass from 27% to 52% as proportion of total resource cost, whereas resources costs allocated to DH and CHP could be raised by 13% (from 3% to 16%) and 9% (from 7% to 16%) respectively.

DHN potential for delivery of the heat captured at locations could be fostered by incentivising DHN with fiscal exemptions for medium/large-scale CHP or heat-only boilers. The economic potential of such an initiative could be assessed in terms of expected system gains associated with reductions in supply thanks to heat for DHN against avoided system costs of peak loads which would occur under a highly electric heat delivery system. Current market arrangements are unlikely to allow cost recovery via the benefits that accrue. As such further research is needed into appropriate development of market arrangements to support wider uptake of district heating.

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