Cost Reflective Pricing in Energy Networks

The nature of future tariffs, and implications for households and their technology choices

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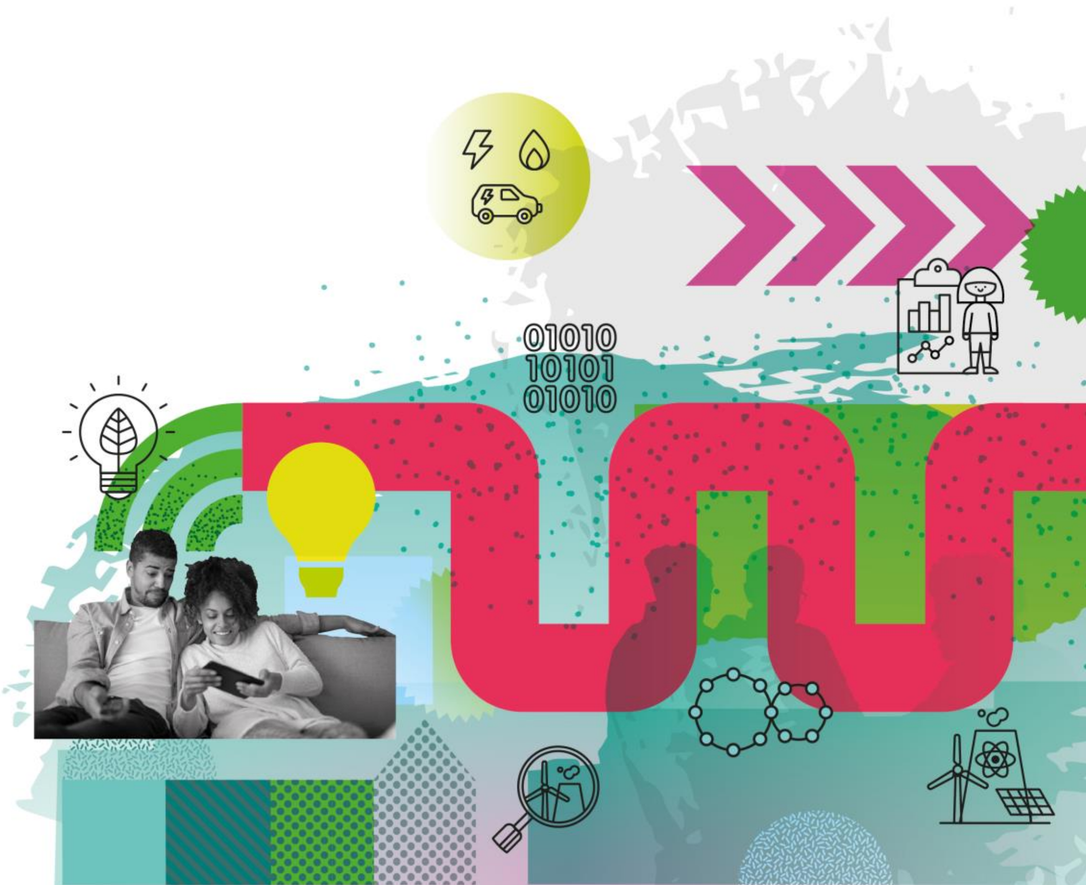

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1. Preface

1.1. Energy Systems Catapult

When considering prices throughout energy value chains, it is necessary to consider the issues from different viewpoints, including:

- **Economic:** The issues here include the ability of an efficient organisation in the supply chain to fund their activities, and the incentive properties on market participants in both short and long term. In particular, it is important that the incentives are aligned with the cost-effective investment in and operation of the energy system. This often leads to a particular focus on 'cost-reflective' pricing (i.e. aligning prices and the way they are structured with the underlying drivers of costs throughout different parts of the value chain).
- **Social:** The impact of energy pricing on customers, especially vulnerable customers, needs to be considered. For example, very high energy prices at the time of peak demand may have positive economic characteristics but be socially unacceptable to impose on those living in fuel poverty.
- **Environmental:** Decisions throughout energy value chains have environmental consequences, many of which are not fully reflected in market prices (most notably in terms of greenhouse gas emissions). Approaches to pricing can have an important influence on the achievement of environmental objectives.

Commonly, decisions have to be made balancing the imposition of greater costs on customers as a whole against other benefits such as reduced carbon emissions, improved security of supply or greater protection for vulnerable customers. Any intervention also carries the risk of unintended consequences by altering the incentives on market participants. While this process must involve judgement, it is important to have the best possible view of the additional costs and potential market distortions associated with different approaches to the structure of energy prices, including different approaches to 'cost-reflectivity'.

This report is intended to provide a backdrop to policy makers considering energy pricing by giving a clear description of the relevant economic analysis, including the underlying structure and drivers of costs, and its implications. This is then illustrated with examples of what the resultant "cost-reflective" tariffs would look like, based primarily on an economic logic, and a discussion of the incentive properties of these tariffs on customer decisions. While the discussion highlights some social/environmental issues, such as increasing costs for those consuming small volumes of energy or the potential use of a carbon tax, their resolution is beyond the remit of this report.

To summarise, this document should be viewed as an input intended to inform the debate on energy pricing, primarily from an economic perspective based around the concept of 'cost reflectivity'. It does not consider in depth the balancing of social and environmental objectives, so should not be interpreted as a set of policy recommendations.

1.2. Author's preface

This exercise began as an analysis of the cost structure of the three main utility networks relevant to the future of UK energy. It quickly became apparent that there were really two components to it. The first was primarily about the balance, in current tariffs for gas and electricity, between fixed and variable charges, and the arguments that a more cost reflective balance – essentially with a heavier weighting of fixed cost - would better promote general economic efficiency, including more efficient progress to low carbon policy objectives. This is not an entirely new issue, and the arguments are fairly clear. The precise allocations between fixed and variable network costs are often debatable, but the economic principles are clear, and a reasonable breakdown of current cost structures is readily available. It is a well-defined if imprecise technical exercise.

History also tells us that there are also large political and redistributive agendas around energy utility tariff structures. There are also opposing “camps” which, on redistributive or other grounds, oppose pure cost reflective approaches in favour of different forms of subsidy or cross-subsidy. These include so-called “lifeline” or progressive block tariffs, which provide for no fixed charge and a significant block of kWh at very low prices, subsidised by much higher prices for subsequent kWh. In focusing on a cost reflective approach, we mostly avoid these wider policy or political questions, but it is important to recognise their presence and that they will be an additional or continuing input to future policies.

The second component was to look more carefully at the future shape of the energy sector. This focuses largely on the power sector and its cost structure, and the implications, in particular, for low carbon technologies for use by households, the most relevant being for heat and electric vehicle (EV) charging. Immediately, the critical role of costs, prices and tariffs in the ecology of the energy sector takes over. Projections of future costs, apart from all the familiar uncertainties over fossil fuel prices (relevant to gas and CCS costs), can reflect alternative and plausible mixtures of different forms of generation, including nuclear, renewables, storage and CCS, and a wide variety of views on take-up and future costs. They also reflect interactions with the management of the behaviour of other consumer categories (commercial and industrial) in balancing power systems. This then leads into questions of whether consumers will expect the same or different service in respect of generally new technologies in consumption. Finally, there are multiple questions about how institutional structures and actual market processes might develop in the future, which will determine how tariffs are formed from the various cost building blocks, as well as policy driven interventions such as carbon taxation.

For all these reasons, analysis in this second component is necessarily speculative, although where figures are quoted for illustrative purposes, we have tried to use cost numbers that are prima facie credible and based on established or reputable assumptions and sources. What is more important in this second part, however, is the logic and the arguments that underpin the views we have taken of what will be the most important issues and developments. These include radical suggestions on how the nature of retail supply to households will need to change.

John Rhys

2. Summary for Policymakers

This paper deals with the key utility networks of gas and electricity, and potential future networks for heat distribution. Its primary purpose is to examine tariffs policies for household consumers, in the context of future issues and options relevant for the development of a UK low carbon economy. Among other issues it identifies features of current tariffs that are not fully cost reflective and have the potential to distort investment or consumer behaviour.

It then moves on to consider tariffs questions that deserve attention as the UK makes progress towards a low carbon energy sector. The most relevant factors are: first, the use of more accurate methods of charging, through real time metering, together with the potential of sophisticated metering, communications, IT and control systems, for example; second, the changing nature of power generation technologies (including decentralised own generation); and third the anticipated advent of new technologies in household energy use, if electricity plays a bigger role in heat (through heat pumps) and transport (electric vehicles).

2.1. Rebalancing Energy and Standing Charges

More cost reflective tariffs, rebalanced to higher standing charges, improve the overall efficiency of the energy sector, remove perverse incentives for wasteful consumer investments, and assist in promoting low carbon policies and innovative technologies. (Sections 3 and 4) These are immediate benefits.

The first part of the paper examines publicly available information on the composition of costs recovered through consumer tariffs (and benchmark costs for heat networks). A key question is the balance of fixed and volumetric (whether expressed as kW or kWh) charges in existing tariffs for domestic consumers. Historically domestic tariffs have been based overwhelmingly on revenue collection through per kWh charges for both gas and electricity, and this is widely seen as a fair and equitable method of recovering the very substantial fixed costs associated with these network industries. However, this implies that the kWh tariff charges to consumers will comfortably exceed the incremental costs of supply, whether measured in terms of short term marginal cost (SRMC) or long run marginal costs (LRMC).

One effect of this, in the power sector, is an excessive incentive for consumers to invest in their own generation (solar panels) and storage (battery) facilities. This is accentuated if consumers are also able to sell their excess production (above their own need) on the basis of a purchase tariff (or similar arrangement) which awards the same value to kWh sold back to the “system” as the rate charged in the retail tariff faced by the consumer.

If the kWh charge is higher than it needs to be, and more than can be justified on the basis of need to cover an incremental cost of supply, then it will also increase the running cost to an ordinary domestic consumer of charging electric vehicle (EV) batteries or using electric heat pumps. These are both technologies that are widely seen as an important part of a low carbon future in which low carbon electricity supplants the use of fossil fuels in transport and heat. It will therefore inhibit investment by individual households in EVs and in electricity based domestic heating systems.

2.2. Support for Social and Innovation Policies

Current electricity tariffs are also distorted by the burden of support for social and innovation support policies, which fall selectively on electricity as a fuel and not on own generation or on gas. (see section 4.4)

Examination of the cost structures also reveals a significant component of other costs, which we shall refer to as the policy burden. These are costs imposed on the electricity sector to support social programmes, or current and past support for innovation in generation technology. However, none of this burden falls on either consumer own generation or on the gas sector. In consequence it accentuates any distortion in favour of own generation and has the potential to inhibit the take-up of new low carbon usage technologies by the consumer, by raising prices and reducing any incentive for consumers to switch from gas.

2.3. Carbon Taxation

The case for more realistic levels of carbon taxation, rather than a discriminatory burden applied to electricity, is very strong. (see section 4.4)

A corollary of this concern with gas and (low carbon) electricity competition is to reinforce the case for a meaningful carbon tax, which would apply equally across sectors. The direction of energy policy is to encourage electricity, increasingly low carbon, and to discourage fossil fuel consumption, including gas. "Taxing" electricity but not gas is therefore perverse. Although the policy burden or "tax" on electricity, and carbon taxation, had or have entirely different rationales, the latter could be seen as a more efficient replacement for the former. The indicative number quoted in our analysis is the £65 per tonne of CO_2 that forms part of the CCC's High Renewables scenario.

The heat sector introduces problems particular to the heat sector. These relate to issues such as the funding of major city centre infrastructure schemes, issues of compulsion or choice for participation in heat network schemes, and tariff regulation. These are discussed in more depth in an Appendix.

The second part of the paper is necessarily more speculative. However, its aim is to anticipate some of the new issues that are likely with policies intended to promote low carbon energy use in heat and transport (EVs), and to identify ways in which cost-reflective tariffs will help resolve problems and create a more efficient and lower cost energy sector.

2.4. The Importance of High Load Factors

Future low carbon, high capital cost, systems place a high premium on pro-active and effective management, through tariffs, of the use of electricity for electric vehicle charging and domestic heating applications. (see section 6.)

Future low carbon systems, with high capital costs and a premium on flexibility in both supply and demand, will necessarily incentivise the achievement of high load factors, wherever possible and consistent with consumer needs, in order to reduce investment requirements, minimise costs to consumers and maximise economic efficiency.

2.5. Novel Approaches to Retail Supply

Novel approaches to retail supply are required, including "supplier managed" load, the ability to take different loads under different commercial arrangements and/or from different suppliers, and the ability to choose reliability standards. (see section 7.)

Electric vehicle charging, unless carefully managed, has the potential to create significant power system problems, both in terms of the adequacy of aggregate generation capacity and more local network capacity problems. There are useful measures, with the potential to substantially mitigate these problems, that can be based on a combination of cost reflective tariffs and changes in the way that electricity service is offered to consumers. Options include "supplier managed" load, in which, for example, a consumer, in exchange for a favourable kWh rate, would place an "order" for overnight (or some chosen period) delivery of kWh charge.

Heat pump technology currently suffers in comparison with gas heating in terms of its running costs. It would be helped by the rebalancing of fixed and volumetric charges, and by a "supplier managed" approach, its relatively low load factor, mainly due to the seasonal nature of heating, will most likely continue; this leads inevitably to an incremental cost to electricity suppliers of meeting heat load higher that is higher than average. This will be reflected into what the consumer pays through any genuinely cost reflective tariff mechanism. This can be mitigated to a significant degree if the consumer has a back-up, e.g. in the form of gas/ heat pump hybrids, which lop the peak heating loads and thereby improve electrical heating load factor.

Not least because of the growing significance of highly seasonal and weather dependent electrical heat load, and the continued prevalence of direct acting space heating, attention will need to be paid to managing periods of "system stress". There is a case for a carefully designed "red light" system which indicates very high prices for such periods.

2.6. Enhancing the Role of Retail Competition

The changes required enhance the role of retail competition in promoting innovative approaches to the supply service on offer to consumers. (see section 7.)

There is a major role for retail supply competition, potentially much more important than currently, to provide innovation in the nature of the service offering to consumers, and a choice between alternative types and levels of service and tariff. There are no technical reasons why a consumer might not take part supply from one supplier and part from others. Part of this choice should include differentiated forms and levels of supply service at higher or lower rates.

2.7. Network Costs

Network costs may increasingly be seen as a fixed cost, but with a significant element of more granular locational pricing. (see section 6.3)

Finally, we observe that there is very little firm empirical or theoretical evidence on the precise nature of the cost function for power networks, and distribution in particular. There are strong arguments in principle for assuming that future upgraded networks will have a cost, in aggregate, that is not very sensitive to changes in the volume of kWh or kW. There are also arguments for an approach that recognises the elements that are driven by the most important physical cost drivers, line length and geography, and introduces a more granular and locational element to pricing. These questions are not explored further but will ultimately be important in deciding how much of future network costs should be incorporated in kWh rates.

2.8. Implications

The development of the approaches outlined in this paper indicate some radical changes to the nature of tariffs and retail supply in the energy sector, particularly for electricity. They are entirely consistent with policy aspirations for a low carbon economy. (see section 8).

3. Introduction: Principles for the Formulation of Tariffs

This report aims to address the questions posed by the Energy Systems Catapult, a leading technology and innovation centre set up to help the UK navigate the transformation of the whole energy system. To do this efficiently, it is imperative that decisions on which technologies to install, and how to use them, should reflect the economics of the whole energy system. The aim therefore is to identify tariff structures that will as far as possible reflect the costs that individual customers impose on the various networks and incentivise choices that are consistent with the efficiency of the whole energy system.

Essentially this means considering what tariff structures are most likely to be appropriate to a UK low carbon future, in order to inform consumers with the right economic signals both in terms of the investments they choose to make and the way they choose to use energy on a daily basis. The investment choices include home insulation, selection of a main network source of domestic heating (including the option of combined systems), installation of own generation and storage facilities (eg solar panels or batteries) or buying an electric vehicle (EV). Behavioural or day-to-day choices may include decisions on when and how to charge EVs, modes of use for heating systems, and the usage of established appliances within the home, eg for laundry or kitchen purposes. These are decisions on two different timescales.

We begin in this introductory section by discussing general principles, and complexities, of building cost reflective tariffs, and also describing the processes through which, under current market and institutional arrangements, tariffs are formed. Sections 4. and 5. then describe how application of a cost reflective approach would change existing tariffs, taking 2016 cost and tariff data, and current assumptions on the characterisation of network cost, as a base. The analysis then proceeds in 6. and 7. to look further ahead and to explore a number of the new issues associated with formulating cost reflective tariffs in a low carbon future, paying particular attention to the changes associated with the greater penetration of electricity in new applications of electric vehicle charging and domestic heat pumps. This is followed by a short description of the characteristics that should be required of future efficient tariff structures. In 8., we consider how these ideas fit with general policy objectives and constraints, and with a number of particular technical and other questions. Finally, a number of related but subsidiary topics, explanations and illustrations are covered in boxes within the main text or within an Appendix.

3.1. Principles of Cost Allocation and Tariffs. A Summary

In a utility context a general requirement for tariffs to reflect (and cover) costs is usually taken as a given by economists (and others). It is often stated in a slightly stronger and idealised form, that wherever possible the tariff price for an increment of demand should reflect or even equate to the marginal cost of an increment of supply. A simple justification for this position is that prices significantly below marginal cost encourage excessive or "wasteful" consumption, and cost society more than the benefit for which people are prepared to pay. Conversely prices significantly above marginal cost reduce overall value within the economy by causing consumers to forego the enjoyment or benefit that additional consumption would have provided, at the same time only reducing costs (of production) by a smaller amount. In either case poor tariffs can result in poor investment decisions and significant misallocation of resources.

Overall, efficient tariffs are a necessary condition for an economically efficient system and should result in the best possible balance in the two objectives of providing the quality of services consumers want, at prices that reflect efficient or least cost[1] provision.

Multiple or Conflicting Objectives

In some instances, trying to produce tariffs that appear as "efficient" in more than one context will produce conflicts. This will happen, for example, if tariff features that appear to be necessary for the most "efficient" short term day-to-day decisions are incompatible with "efficient" investment decisions that involve longer timescales. The most obvious example of this arises in circumstances where the short run marginal cost (SRMC) of generation, from an overall system perspective, is zero (because all the investment in a renewable resource is a sunk cost, and maintenance is a fixed short term cost) but individual consumers with their own generation facility (e.g. a diesel generator) are able to generate power at a cost which is less than the tariff rate they are charged. The tariff rate has to cover the full costs (LRMC), including capital costs, both for revenue reasons and because "free" electricity would create inefficient use and unlimited demand. This renders the generators/suppliers vulnerable to consumer own production even when this is not an efficient outcome.

Revenue recovery is almost always a primary objective of tariffs policy and a necessary condition for a viable set of tariffs. It will from time to time be in conflict with strict interpretations of economic efficiency. Frequently in consequence, some of the argument will be about the least economically damaging means of collecting additional revenue (or very occasionally dealing with excess revenue[2]).

Idealised approaches to cost reflection also need to reflect practical considerations, which include the limitations on what can be effectively metered, and also the practical difficulties involved both for suppliers and consumers in creating, implementing and understanding tariffs, often described by economists as transactions costs.

Classification and allocation of costs

A starting point is to classify and allocate the different components of cost, according to whether they can be treated as fixed or variable, and how they vary in relation to increments of load, or in relation to other cost drivers, over the short term and over the longer term. This exercise, especially translated as allocation to tariff components, is necessarily imperfect because of the complexities of networks and power systems, limited information, a significant judgmental element, because more than one approach can sometimes be considered as legitimate, and because other practical and policy issues will impose constraints on what is possible. However, the main categories we shall use are as follows.

Costs that relate directly to connecting an ***individual*** *consumer to the network*. These are often covered by connection charges which can be customer and location specific, may be paid upfront, and do not necessarily have to be recovered through an ongoing tariff. In future these might include some of the additional local costs associated with installation of EV charging facilities or heat pumps.

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[1] Least cost provision should of course include externalities and social costs (cf carbon prices)
[2] This can occur if a utility faces high marginal costs but has a legacy of low cost plant.

*Costs that in aggregate may vary incrementally with the **number** of consumers but can be reasonably described as a fixed cost per consumer*. These include, for example, metering costs, and are obvious candidates for inclusion in the tariff as a fixed charge per consumer.

*Costs that in aggregate vary according to **volumes of energy/power** consumed*. However, for electricity in particular, this may need be measured in terms of both kWh and kW, i.e. both total energy consumed, and the power demand placed on the capacity of the system or the networks. It may also have a time dimension, by time of day, season, or simply by times of "system stress". This last does not necessarily equate to periods of highest consumer demand (since in the future these

Definition of LRMC for electricity tariffs and the relevance of load factor

"*Marginal cost is an engineering estimate of the effect upon the future time stream of outlays of a postulated change in the future time stream of output. There are as many marginal costs as there are conceivable postulated changes*." [1] (Ralph Turvey, one of the pioneers, with Boiteux, of LRMC theory in electricity.)

This quote forms the basis for practical application to electricity tariffs of LRMC principles. If we are talking about the LRMC calculation most applicable to domestic (household) load, then the "postulated change" may take several forms. It may simply mean more households with the same consumption pattern, in which case the deemed LRMC of supplying that increment of load over an indefinite future will equate to the deemed LRMC of the existing load.

However some of the new loads with which we are concerned will have very different characteristics from existing load and from each other, as will be discussed in some depth in this report, and one of the key concepts that we shall use is load factor, another term which needs an explicit explanation.

Load factor (over a year) can be defined simply as the ratio of average consumption to annual peak period consumption. The most relevant period for the calculation may be 30 minutes (to capture "instantaneous" peak) or it may be measured in terms of daily or monthly consumptions. The last case is instanced in this report as "seasonal load factor", the ratio of average to peak month requirements. In the context of particular loads (e.g. the past history of night storage heating) and overall system characteristics at any given time, the most relevant measure of load factor is consumption in relation to its contribution to the system peak, In other words it is the impact on the economics of the system that matters most, rather than the consumption/peak ratio for the individual category of load.

The importance for the incremental cost of meeting a particular type of load such as heat pumps for domestic heating, is that the most important element in that cost is the cost of additional capacity required to service the additional load. If the load factor is low then that capacity cost has to be recovered from a much smaller number of units (kWh) and will therefore be higher. The converse is the case for a high load factor. For any particular application, such as heat pumps, the higher the load factor, the lower will be the incremental per kWh cost of providing heat through the power system

Tariffs will, and should, on occasions be used to influence load factor. Night storage heaters were developed, with appropriate tariffs, because they make no contribution to peak and carry none of the associated capital cost. They improve the overall load factor of the system, and the much lower tariff price benefited consumers wanting to use this form of electric heating.

The load factor of an individual consumer is not normally a particularly relevant figure in tariff design. It is the categorisation and aggregation of loads that provides a useful basis for tariffs. Currently that essentially treats all residential consumer load as if it were the same. It is the clear differences that exist for some of the major new loads that provides one of the major themes addressed in this report.

1. ***What are marginal costs and how to estimate them?*** Professor Ralph Turvey, University of Bath, 2000.

may reflect periods of low renewables output rather than peak loads). These are often termed volumetric charges and are the most important variable element in costs.

We take the view, strongly supported by practice and experience, that variable cost in this context has to include costs that vary from a long-term perspective, i.e. this means including capital costs as a variable element wherever they vary with the projected volume of demand.

Costs that have to be covered in a functioning system but will be incurred regardless of the throughput of the system or the number of consumers and can therefore be described as ***fixed costs***. A priori we can expect these to be present and substantial wherever there are significant economies of scale, a standard feature of networks. (Telecomms networks are perhaps an extreme example of this.) These are fixed costs that have to be allocated, and this gives rise to a number of options. One is to allocate equally over all consumers. This is often regarded as inequitable (among other possible objections) and explains why these costs are in consequence often just averaged over all kWh.

Electricity, heat and gas are services provided with large fixed costs, as with many networks. The means to most efficiently recover these costs is the subject of a substantial theoretical literature. For example, both Hotelling (1939) and Coase (1946) take a standard position that price must be equal to marginal cost, as this allows the consumer to align marginal consumption decisions with the marginal cost of production. If this does not cover total costs, the remainder of the required revenue should be recovered either by general taxation (Hotelling, 1939) or by means of a fixed charge in a multi-part tariff. Hotelling (1939) argues that multi-part tariffs reduce the distortions and distributional consequences that might be associated with finance through general taxation; consumers of the service should pay for both the fixed and marginal costs as this ensures the willingness of consumers to pay the total cost of consumption. This is also consistent with the revenue objective of covering all costs including a return on capital.

A further development of approaches to finding a sensible allocation of fixed cost, is based on so-called "Ramsey Pricing". Ramsey-Boiteux[3] pricing posits that charging a mark-up inversely proportional to the price elasticity of demand is the least distortionary, highest social welfare approach (Ramsey, 1927). This allocation of fixed costs is sometimes described in transport economics as charging "what the traffic will bear". In principle it minimises economic distortions. In practice, estimation of the relevant elasticities may be quite inexact, and for any given tariff will not necessarily correspond perfectly to individual consumer preferences. Nor will it always be consistent with other objectives. It will also tend to imply a significant element of judgement and discretion in setting tariffs. However, we shall treat it as an important general principle for minimising distortions and as providing some important guidelines for the construction of tariffs. We should note that the application of Ramsey principles is consistent with differential fixed components of a tariff, as between different types of consumer, or alternatively may even be interpreted (not necessarily recommended) as an allocation according to some measure of individual consumption (eg a re-allocation per kWh).

One of our tasks therefore is to explore alternative means to allocate these costs either as a fixed component of a tariff, though this need not necessarily be the same for all consumers, or as variable kW/kWh related charges. The objective in this case is to determine what might appear as both more equitable and consistent with Ramsey principles.

[3] Boiteux was for many years President of EdF (1967-1987), was one of the architects of the French nuclear programme and was also strongly associated with an LRMC approach to tariffs.

Carbon taxes. These should be seen simply as the means by which the externalities, the damaging consequences of CO_2 emissions, are internalised as a cost within the energy sector. They should be seen as an essential part of ensuring economically efficient decision making, in production and consumption, consistent with the welfare of society as a whole. When levied through consumer tariffs, they fall on the volumetric kWh element in tariffs.

Costs that represent a policy burden. In recent years these have included costs incurred in support of innovation in renewables, as well as some social costs. Ideally these should not be recovered through charges to consumers since they have all the essential features of a tax, and potentially cause economic distortions, not least if they are carried by some fuels/ networks but not others. If they must be recovered through tariffs then they can be treated in the same way as fixed costs, for example with the application of Ramsey pricing principles.

There is a very strong case that general taxation is a more efficient means of recovering costs that should reasonably be borne by society as a whole. As well as avoiding distortions in the energy market, this provides more alternatives for sharing this burden in a fair and equitable way.

There may also be some elements of other costs that belong in this category or pose very similar questions. For example, some legacy costs associated with past investments and stranded assets might either be treated as a fixed burden to be recovered, not least for contractual reasons, or alternatively the corresponding assets might simply be written off. This may depend on both the nature of past commitments and the regulatory stance taken.

*Short run marginal costs (**SRMC**)*. These are a particular feature of electricity, reflecting real time needs to balance supply and demand. They matter in a tariff context because they are relevant to hour-to-hour decisions analogous to those involved in wholesale markets and merit order operation. They may for example affect "prosumer"[4] decisions on own generation, use of storage on the consumer side of the meter, and decisions on how to construct ToD or other types of tariff which aim to change the shape of consumer load. They are also very relevant to any purchase tariffs available to prosumers.

Direct application of SRMC measures, such as balancing price data, to tariffs is fraught with difficulties, particularly in a future low carbon system. One is that "true" SRMC is widely expected to be zero for most of the time. Another is that, with more variable generation, the periods of "system stress" may vary from day to day, inhibiting the construction of simple and easy to understand ToD tariffs. Moreover, it is uncertain whether the concept of SRMC can have full practical applicability in low carbon systems with complex operational constraints. This is because the real time decision to generate from particular facilities may need to be determined by operational constraints not reflected in a meaningful measure of SRMC. This negates the connection between SRMC as a "market price" and efficient system operation.

The need for tariffs to contain some significant acknowledgement of short run conditions is however apparent if one anticipates any role for tariffs in managing possibly severe shortages, either at times of peak demand or loss of supply from less firm sources of generation and discouraging certain types of load that could have a very negative effect. The definition of SRMC is sometimes extended to include the cost of lost load. Value of lost load (VOLL) is often taken as a measure that attempts to give some practical effect to this concept[5], and has in the past, and in

[4] We define a prosumer as any consumer who also exports to the local grid, either from own production or from stored power.

[5] VOLL is really an administration intervention that asserts what a market price "might have been".

combination with loss of load probability (LOLP), been used as a benchmark for setting prices at times of system stress and shortfalls in capacity.

3.2. Market Context: Price Formation in the Power Sector.

We need to understand the process of price formation as it currently operates in order to understand two things. One is the limitations and weaknesses it imposes on current tariff structures. The second is the changes in market and other institutional arrangements that might be necessary in order to move to tariff structures that are more cost reflective and therefore more efficient in future low carbon systems.

The fundamentals of the current system are determined by the unbundling of the separate functions of generation, transmission, distribution and supply. Supply tariffs for retail consumers are set by the supply companies who aggregate the costs of the upstream activities of generation, transmission and distribution, together with any other incidental costs and charges, and their own costs, before determining the basis on which they will set tariffs. Their tariffs will be designed to recover all their costs as suppliers, including their own profit margin, from consumers.

The suppliers purchase the energy for their customers in the wholesale market. They also pay for the transporting of that energy to their household customers through the charges levied by National Grid for transmission, under a transmission use of system (TUoS) tariff, and by the local distribution network operators (DNOs), under distribution system use of system (DUoS) tariffs. Taken together with the suppliers' own costs, and any impositions for social or environmental purposes, these constitute the most substantial cost components with which we need be concerned.

If we want to examine whether retail tariffs are sufficiently cost reflective from a system perspective, the three most important things to consider are therefore:

- *The basis on which the suppliers themselves transact for energy (and capacity if relevant)*. This is currently through energy market trading or direct bilateral arrangements which hedge future wholesale energy prices, and in which generators will necessarily try to capture their full costs. These contracts are commercially confidential, and so cannot be observed directly. In principle, and in a properly functioning wholesale market, they should in aggregate provide an approximation to the true cost structures of the "park" of generation as a whole.
- *The basis on which the suppliers are required to pay transmission and distribution charges relating to the loads, including the small retail loads, for which they are responsible*. The basis for network charges is described by the transmission and distribution use of system tariffs (TUoS and DUoS) set by the regulated monopolies responsible for transmission and distribution. The question is whether these network tariffs are themselves are adequately cost reflective or not. If they are not then it is impossible for suppliers to create retail tariffs that truly reflect network costs.
- *The way in which suppliers translate energy and network costs into retail tariffs*. Currently this is constrained mainly by the extent to which they can meter the consumption of small consumers. If this constraint is removed, then suppliers may still have to contend with other and administrative and practical considerations, including consumer response. With retail competition, the room for manoeuvre will also be conditioned by the tariff and pricing strategies adopted by their competitors, tending to constrain suppliers to stay close to their competitors and to reflect the generation and network costs as presented to them.

Supplier Translation into Retail Tariffs

As described above, any reflection of costs into retail tariffs must be mediated through suppliers who source wholesale power requirements and organise the payment of aggregate transmission, distribution and other costs and charges. But the metering of small retail consumers is mostly on the basis of analogue metering – meters read at infrequent intervals (often by the consumer) with very limited possibility of determining how much a given consumer has used during any particular time period of less than a few months. This severely constrains the ability of suppliers to reflect into tariffs either the complexities of their own wholesale contract terms or other wholesale market arrangements that reflect differential wholesale costs at different times. Similarly, it constrains any ability to reflect the complexities of peak demand (kW) contribution contained in TUoS and DUoS tariffs that form the basis of what they pay to transport energy to their customers.

Suppliers also have to set consumer tariffs within a particular market context. Even with the advent of more advanced digital metering systems, therefore, this will constrain what they are able to choose to do in a competitive environment. Their freedom of action to set "true" cost reflective tariffs will be limited partly by the basis, usually contractual, on which they are able to purchase generation in the wholesale market, and also the basis on which they are charged for transmission and distribution services.

In a competitive market, at least for a commodity such as electricity, it would normally be the case that suppliers are forced to adopt cost reflective pricing, reflecting the costs that they can observe and are required to pay. Failure to do so will result in their being punished by their competitors and consumers, and in particular by a process of adverse selection, in which the least attractive consumers gravitate to suppliers who fail to reflect their own costs. For example, if a supplier offers a tariff where the fixed component is "too high" and the variable component "too low", then that tariff will attract very high usage consumers, who will be unprofitable, and repel the low usage consumers who would have been very profitable. But the current UK structure provides no real incentive to suppliers to produce higher fixed charges in any case.

There are some corollaries. One is that suppliers in a competitive market are generally unable to make any cross-subsidies between different classes of consumer, if this is in respect of an identical service provision. Another is that if we design an optimal or idealised retail tariff providing the most efficient cost messages to consumers, its implementation through current market arrangements is likely to depend on key elements in the structure of that tariff being consistent with the structure of the upstream tariffs under which suppliers deal with their upstream purchases on behalf of consumers. For example, it will be difficult to put any part of network charges into a fixed charge per consumer, unless the DUoS and TUoS charges provide that same message in setting charges paid by suppliers, linked to the number of consumers attaching to a particular supplier. That seems unlikely to occur under current structures and arrangements, unless mandated by the regulatory authorities. A final corollary is that recommendations on tariff structures may imply (or depend on) significant changes to the overall sector structure, and arrangements for retail competition in particular.

4. Cost Reflective Tariffs based on 2016 Cost Data

This chapter presents an analysis of electricity, heat and gas cost structures, based on current (mainly as at 2016) information. In the case of gas and electricity this is based on actual tariffs and cost information. For heat we have simply used current estimates as a plausible indicator of the shape of hypothetical future cost structures. This enables us to understand better the issues involved in defining the drivers of cost and hence the nature of appropriate cost-reflective tariffs. The starting point is the decomposition of total costs into separate components, to the level of detail that is available. The components can then be linked to cost drivers such as kWh consumption (energy), measurements of kW demand (power) and numbers of connections.

4.1. Composition of Electricity Costs and Tariffs

The Office of Gas and Electricity Markets (Ofgem) is the UK's electricity and gas market regulator and provides the most comprehensive cost breakdown of electricity cost components. Since 2009 Ofgem has obliged the UK's six largest energy suppliers, that together serve 83% of the UK market (Ofgem, 2017a, 2017b), to produce Consolidated Segmental Statements (CSS). These summarise the companies' financial statements in a succinct and standardised format. Following regular reviews of these statements, Ofgem publishes aggregate data on the UK's energy market, prices and bills. These data constitute the backbone of the analyses offered by various other organisations. For 2016, we have analysed the CSS data for the 'Big 6'. We have aggregated each cost component for domestic electricity supply in Table 1, to show how total costs are broken down.

The breakdown of costs is under the main headings of wholesale energy costs; network costs (transmission, distribution and balancing services); metering and other supply related costs; and social and environmental policy costs. We rapidly arrive at the conclusion that the components that matter most for the design of power sector tariffs, and also present the most difficult issues for analysis and judgement, are wholesale energy costs and network costs, especially distribution costs.

The other significant element is the social and environmental policy burden. In common with others (Helm[6], 2017), we believe this is best excluded and not recovered through tariff charges to consumers.

[6] Helm, D. (2017). Cost of Energy: Independent Review [online]. Available: https://www.gov.uk/government/publications/cost-of-energy-independent-review

Table 1: 2016 Cost breakdown[7] by component			
Revenue	£	£	% of total
Sale of Electricity	12,452.40		99
Other revenue	86.20		1
Total Supplier Revenue - Domestic Electricity		12,538.60	
Cost			
Direct fuel costs (wholesale energy markets)	- 4,913.80		39
Network costs	- 3,557.30		28
Environmental and Social Obligation Costs	- 1,901.90		15
Other direct costs	- 135.20		1
Indirect costs	- 1,983.40		16
Total operating costs		- 12,491.60	
Net (balancing item)		47.00	

4.2. Generation Costs.

Since generation is a competitive market, it is reasonable to assume that, at least in aggregate and over a sufficient period of years, the costs incurred by suppliers broadly reflect long run marginal costs. Otherwise the generating businesses would not be financially viable. However, data for any particular period may also reflect surpluses or relative shortages of the capacity in that period and may not be a perfect guide to the future.

It is not possible to view the hedging arrangements made by suppliers, since these are essentially based on energy trading arrangements and commercially confidential bilateral contracts. In principle, and taken collectively, these can be expected to describe the overall structure of generation system costs as a whole, and this in turn might help to inform ideas of what an ideal and economically efficient tariff structure ought to reflect.

Information on capacity market outcomes, and on balancing prices in the wholesale market, can also provide a limited amount of information. Balancing prices are an imperfect measure of SRMC that may have some relevance to time of day (ToD) tariffs, and capacity markets may provide some clues to the incremental costs associated with peaking capacity.

In this analysis, we have calculated a uniform cost-reflective tariff. This is reflective of the average annual cost of energy generation in 2016 and is analogous to the uniform rate electricity tariffs commonly employed today. For the purposes of this initial definition of a cost reflective tariff, we have not attempted to create more complex time of day (ToD) or peak period energy tariffs, although it will in further analysis become increasingly clear that some such time differentiation of the energy (kWh) component of prices is important in principle for cost reflectivity, and to deflect some of the potentially very serious peaking issues associated with an "unmanaged" load such as direct (ie not via heat storage) resistive heating.

[7] Differences in reporting calendars result in some small discrepancies between these numbers and other OFGEM data, but these are of negligible significance.

4.3. Network Costs. Transmission and Distribution Tariffs

These use of system tariffs are usually referred to as TUoS and DUoS respectively. These are currently set, and will continue to be set, not in a competitive market, but by regulated monopolies. Current pricing structures offered by the network operators (and paid by suppliers on behalf of consumers) are clearly intended to provide important price signals that will influence the behaviour of consumers in the direction of reducing peak demand on the networks. Whether TUoS and DUoS tariffs provide price signals that are truly cost reflective is a more controversial question, but in the first instance we should describe how they currently operate, noting that many larger consumers will pay these charges directly.

Transmission tariffs

These apply to large and very large consumers as well as households, but their nature is nevertheless revealing. We note several important features of these tariffs;

- The current triad approach, described in the box below, together with the three-band approach for non-half-hourly metered (NHH) consumers, is an attempt to find a good approximator to how the load pattern of each consumer contributes to peak load on the system.
- Suppliers are charged in respect of the domestic load that they supply on the basis of assumptions about the load shape of domestic consumption as a whole. There is no means for direct measurement even of aggregate domestic load in any short period (half hour or even day), so charges are necessarily based on an assumed time profile for domestic load, viewed as an aggregate. This is turn reflects such statistical sampling research (load research) as is available.
- The peak load charges based on triad demand account for the greater part of the revenue requirement. Prima facie this is difficult to justify, purely in terms of reflecting incremental costs, for reasons that will be discussed further.
- They may induce behaviours not necessarily consistent with more efficient and equitable tariffs, may needlessly inconvenience the (large) consumers who practise them, and would be similarly inconvenient if extended into retail tariffs for households.

The implication is that simply trying to translate the **current** transmission network tariff structures into retail tariffs would not necessarily deliver efficient or properly cost reflective outcomes. An important inference is that current tariffs are substantially exaggerating the extent to which network costs should be seen as incremental with volumes of load. In consequence there is a strong argument that we should in future treat a major proportion of network costs as a fixed cost and need not necessarily be recovered through an incremental charge on additional kW at peak. In the context of small retail customers, the question remains open of how best to allocate it, for example per consumer, or by installed household capacity. The position adopted in this paper, however, is that the present approach, of recovery through a kWh charge based on notional peak contribution, is not satisfactory and may distort consumer choices.

Distribution Tariffs

Very similar considerations operate in respect of distribution charges, which have a very heavy emphasis on the three-band element of charging. The three-band approach has a higher price in the red band, corresponding to what are deemed to be peak usage periods. This is typically 16.00

to 19.00 on weekdays (although this varies between the separate distribution networks of the UK). The amber band is for other daytime periods and the green band (lowest rate) for night use.

The following extracts from Utility Week and other sources provide a useful summary of current practice in relation to **transmission tariffs**, and criticisms levelled at it.

Triad demand is measured as the average demand on the system over three half-hours between November and February (inclusive) in a financial year. These three half-hours comprise the half-hour of system demand peak and the two other half-hours of highest system demand which are separated from system demand peak and each other by at least ten days.

Consumers of electricity are split into two categories: half-hourly metered (HH) and non-half-hourly metered (NHH). Customers whose peak demand is sufficiently high are obliged to have a HH meter, which, in effect, takes a meter reading every 30 minutes. The rates at which charges are levied on these customers' electricity suppliers therefore varies 17,520 times a (non-leap) year.

The TUoS charges for a HH metered customer are based on their demand during three half-hour periods of greatest demand between November and February, known as the Triad. Due to the nature of electricity demand in the UK, the three Triad periods always fall in the early evening and must be separated by at least ten clear working days. The TUoS charges for a HH customer are simply their average demand during the triad periods multiplied by the tariff for their zone. [The transmission network is divided into separate zones for the purposes of transmission pricing.]

TUoS charges levied on NHH metered customers are much simpler. A supplier is charged for the sum of their total consumption between 16:00 and 19:00 every day over a year, multiplied by the relevant tariff.

"Energy users have a big incentive to switch from consumption to generation during the triads – and for that, they need to predict them. Conventional wisdom claims there is a pattern, with Tuesdays at 5pm being a favourite. But … if you apply the rules to winter 1972/73, you get a triad on a Sunday. Distribution-connected wind, asymmetry around interconnectors, falling demand and triad feedback have all changed the picture. It might be a while before we see another Sunday triad, but anomalies aren't anomalous; they're the norm.

The complaint that triad management is difficult has recently been swept aside by a new objection: triad management is too lucrative. Major investments have gone into the transmission network in recent years, and these have to be paid for. Meanwhile, peak demand has fallen – partly through successful triad management, and partly through energy efficiency. The numerator of the transmission charge has grown while its denominator has fallen. This makes triad management a must-do activity for most industrial and commercial energy users and small generators."

This is a cruder approach than that of the triad, since red band usage may be a poor proxy for contributions to either system or local peaks. It is currently under review. The current system has been criticised in the past for not correctly reflecting the incremental costs of reinforcing the network. As with TUoS the current system also led to a very high portion of revenue matching falling on the peak, insofar as this was reflected in the proxy measure of the "red" time band. The new DCP228 modification aims to scale these charges more accurately, so that charges are distributed across all three time-bands (green, amber and red).

The Office of Gas and Electricity Markets (Ofgem) have proposed regulatory changes to the way electricity distribution charges are calculated, significantly affecting most businesses. The proposed regulatory changes are currently known as "DCP228," and will be an amendment of the Common Distribution Charging Methodology (CDCM), the system which determines how distribution charges are calculated. These changes are scheduled to be implemented no earlier than April 2018.[8]

When the current charging strategy was implemented, a number of businesses implemented electricity demand management strategies to "load shift" energy consumption from peak times to cheaper amber or green time slots. Whether this merely shifts the burden of charges, as opposed to promoting a more efficient system, is open to question. In other words, distribution charging has been subject to some of the same criticisms as transmission charging. Again, the implication is that the impact of incremental load may have been exaggerated.

As with transmission tariffs, the details of these network tariffs are currently of limited direct interest to small consumers, including households, since they will not normally be metered in a way that would allow such tariffs to operate in respect of their supplies. They will however pay in respect of the collective responsibility of domestic consumers, with the charges being passed to them through their suppliers

If current tariffs over- emphasise peak periods, what is the real cost structure of networks?

Simple intuition suggests that the cost of building and maintaining a physical network infrastructure will be very heavily influenced by the overall line length, with its carrying capacity (the required "thickness" of the lines) a significant but secondary factor. There is no reason to suppose that this does not apply to UK networks.

However, we have as a matter of policy and institutional choices largely ignored the importance of line length in tariffs, except in exceptional circumstances or in relation to connection charges. This might deserve to be reconsidered in the context of network reinforcements to serve more remote areas, if a large reinforcement cost is required for a relatively small population, where heat load (for example) can prima facie be met more cheaply by other means. This is an argument for a more granular approach to network pricing.

A further unanswered question is estimating the incremental cost associated with incremental peak loading on networks. Network cost driven by capacity need, unlike in generation, is unlikely to be a linear or near linear relationship, and long run incremental cost will, other things being equal, decline as load increases. Recognition that there are economies of scale in relation to volume, for a given network length, and that these are very substantial, is in effect no more than a restatement of the observation that networks are often natural monopolies (absent such economies it would make

[8] The Energy Desk. 22 May 2017.

sense to duplicate the networks). Marginal cost being much less than average cost is, in this context, almost a necessary condition for a network to be described as a natural monopoly.

This makes a strong case for treating a much more substantial proportion of the total network cost as fixed, leaving a much more open question over how best to allocate those costs into tariffs, across the sector, e.g. on the basis of Ramsey or other pricing principles. Exactly how much should be treated as fixed may be a more controversial judgement.

To some extent these observations are also borne out by the analysis of forward looking plans for network companies. For example, UK Power Networks business plan[9] to 2023 has a load related capex of only £1.35 bn. (not all necessarily related to increase of aggregate load) out of a total of £7.23 bn.

Implications for the allocation of network costs

The above evidence suggests an over-emphasis on attaching a high price to peak load in networks. Network tariffs appear to implicitly over-emphasise or overstate the real long run marginal cost of network reinforcement. The quotes above suggest there can at least in principle be some quite serious economic distortions. An extreme version of an exaggerated response, for high or extra high voltage (HV or EHV) consumers, would be a factory that shut down every Tuesday in winter to avoid triads. And similar examples could be constructed for domestic load response if the incentives were excessive and they were passed through into tariffs.

Current estimates of network cost composition as fixed or variable

Network costs consist of transmission costs, distribution costs and balancing services use of system (BSUoS) costs. As the above discussion indicates, the characterisation of network costs as fixed or variable, and the extent to which they are driven by a large number of location specific needs, e.g. for network reinforcement, is a complex question. The following is a preliminary attempt at this, in the context of 2016 tariffs, based on a current OFGEM categorisation of costs into a forward-looking cost-reflective component and a residual component.

The ‘forward-looking’ components of network charges are designed to incentivise the efficient use of the network, and reflect network users’ impact on network costs, including current and future investment costs. Arguments can be made for attempting to make some of this component much more location specific, but this does not reflect current practice which includes a high degree of averaging, particularly in respect of distribution costs which are simply spread over all consumers within each of the main distribution network operator (DNO) regions. In relation to broad aggregates, therefore, as opposed to local situations, it is possible to argue that this overstates the incremental costs associated with a “right-sized” future system.

But in the first instance, and as an illustration, we show the effect of treating this forward-looking element of network cost as an expenditure driven by the costs of incremental capacity needed to meet increases in peak demands. OFGEM sources (Ofgem, 2017) suggest that about 20% of transmission costs, of total costs, and 50% distribution costs, might be put in this category. A potential measure, for tariffs purposes, of the impact of household consumers on network capacity requirements would be their consumption during peak periods.

The remaining “residual” component is the remainder required for these operators to recover their mandated revenue. Residual charges are intended for revenue recovery and are not meant to

[9] UK Power Networks. Business Plan (2015 to 2023)

incentivise specific actions by network users (Ofgem, 2017). This is therefore largely a fixed cost, unrelated to incremental provision on the network. Correspondingly therefore, the implication of the OFGEM estimates is that the residual components amount to c.80% of TNUoS costs and c.50% of DUoS costs. As these are unrelated to usage, they should be treated as fixed.

Overall network costs account for 28% of total costs. Of this 2% represent balancing services use of system (BSUoS) charges, 19.5% are distribution costs and 6.5% are transmission costs. In this analysis, it is assumed that contribution towards peak load drives the locational component of transport costs (20% of transmission costs and 50% of distribution costs). This is allocated according to kW peak, while the residual component is allocated by household.

4.4. Environmental and social obligation costs: Electricity.

Environmental & social obligation costs for domestic supply include Renewable Obligations Certificates (ROCs), Energy Company Obligation (ECO) and Feed in Tariff (FIT) costs. An efficient allocation of these costs should reflect the drivers of cost and the market failure for which these costs are implemented to correct.

If they are in place to correct an innovation market failure, then this cost is not to correct for inefficient generation but for inefficient R&D allocation. These costs should not be treated as forming part of an ongoing cost of electricity supply. In this context, financing this outlay via general taxation expenditure is preferable, as it removes the cost of correcting an under-investment in innovation from the energy consumption decisions. Furthermore, financing via general taxation allocates the cost to all households, in accordance with burden sharing principles for R&D expenditure allocation. Finally, it is also more progressive in a distributional sense, as it is financed by the taxpayer as opposed to the electricity consumer (because poorer people spend a higher proportion of income on energy).

An appropriate carbon price would be preferable. This would reflect the carbon content of current generation. Levying environmental and social costs per kWh consumed is a highly imperfect substitute for an appropriate carbon tax, and it does not track the carbon content of generation. The current imposition can create perverse incentives. For example, as the carbon content of electricity declines, it should become relatively less expensive relative to other fuels as the carbon tax levied falls, further incentivising fuel switching away from more carbon intensive alternatives. Charging the environmental and social cost in a non-cost-reflective manner does not allow for this price signal to be translated into the consumption decision. Furthermore, environmental and social levies do not incentivise fuel switching – to lower carbon alternatives - within generation.

So, it may be argued that recovery of environmental costs is most reasonably levied through general taxation. In a first-best world where there is a sufficient carbon tax to incentivise behavioural change and fuel-switching, these costs are reasonably considered as R&D investments and paid for through general taxation.

Similarly, social policy represents expenditure that does not influence the supply of electricity and therefore levying this cost on consumers influences the electricity consumption decision and creates economic distortions. This is a social concern and accordingly should be financed through general taxation.

The current arrangements are discriminatory against electricity (compared to gas). This is particularly perverse given the widely recognised importance of increasing the use of electricity in transport and heating applications.

4.5. Other direct costs and energy supplier margins

Other direct costs include expenditure on brokers' costs and sales commissions when the costs have given rise directly to revenue, that is, producing a sale. They also include Elexon and Xoserve market participation and wider Smart metering programme costs (Centrica plc, 2016). These are, largely, costs that vary with the volume of energy consumed and should form part of the volumetric charge.

Indirect costs

Indirect costs include a mixture of overheads and other fixed costs, which might be assumed to not vary much with kWh consumption. These are listed as including operating costs such as sales and marketing, bad debt costs, costs to serve, IT, HR, finance, property, staffing and billing and metering costs, including smart meter costs. (Centrica plc, 2016). This cost component does not vary directly with usage and each consumer might be assumed to make an equal contribution to the total. So, it would be reasonable to allocate indirect costs on a per household basis.

4.6. Electricity: alternative cost-reflective tariff for domestic consumers

Applying the above principles of cost reflectivity leads to a significant rebalancing of the typical electricity tariff. There are substantial variations between the different retail tariffs available to consumers in different regions and from different suppliers, but the table below sets out estimated average tariff rates for 2016, based on BEIS estimates, and compares them with our estimates of what a tariff based on cost- reflective principles would look like. The comparison has been made for a representative household which consumes 3,800kWh per annum, incurring a total annual charge of £600 and with a typical proportion of peak period consumption.

Table 2. Current vs cost reflective tariff for typical consumer (3800 kWh pa)				
Tariff	Volumetric rate p/kWh	Standing charge (£ pa)	Surcharge peak period (p/kWh)	Paid via general taxes (£ pa)
Current	14	69		
More cost reflective	7	184	9	90

The following points need to be made in relation to this table.

1. There is currently a very great variety of tariff rates in a competitive retail market, and these reflect not only any regional differences, e.g. in network costs, but different supplier profit margins, single fuel or dual fuel supply, and in some cases different metering arrangements such as Economy 7.

2. This variety also includes substantial variation in standing charges, with some companies offering tariffs with no standing charge, while others, according to some comparison sites[10], can be as high as 60p per day (ie comparable to the cost-reflective tariff). However, this figure is not typical and may reflect special situations or terms and conditions.
3. The table should therefore be interpreted as indicative of average or typical conditions currently prevailing in the retail market. It will not necessarily correspond to any individual consumer's experience.
4. The assumption in the more cost reflective tariff is that social and environmental costs averaging £90 per consumer are met through general taxation. This change, applied to the kWh charge for 3800 kWh would reduce the volumetric rate by approximately 2.4 p per kWh compared to the typical rate of 14.0 p/kWh.
5. The peak surcharge in the cost reflective tariff is based on the assumption that it applies to 18%[11] of load and is equivalent to an additional 1.8 p/kWh if averaged over the consumer's total consumption and applied to the volumetric rate.

It is important to note, therefore, that this table represents only a first step towards a cost reflective tariff. Its rebalancing is focused mainly on removing from the consumer the cost of the "policy burden", together with recognition that more than 50% of network costs could legitimately be shifted into a fixed charge.

The further elements in a truly cost reflective approach will ultimately need to reflect much more accurately the complex system cost structures of generation cost. These will be determined by the overall shape of future systems, including the mix of loads, both domestic and commercial/ industrial, and the composition of the mix of generation, as well as other factors. This is discussed in more depth in **6**. and **7**.

4.7. Gas Costs and Tariffs

The general considerations for gas are much simpler than for electricity, since it lacks many of the complex system choices that characterise the power sector. The dominant components will, as for electricity, be the wholesale purchase of energy and the network costs. The most significant differences from electricity are the higher proportion of wholesale energy costs and the much lower proportion of "policy burden" costs.

The wider longer-term issue for gas tariffs, and indeed for the commercial prospects for the gas sector, arises from the consideration of low carbon futures in which domestic gas consumption declines dramatically. This implies, in the longer term, that network costs have to be recovered over a diminishing volume of sales.

The approach used to disaggregate gas costs is essentially similar to that for the disaggregation of electricity costs. Each of the 'Big 6' energy suppliers provide a breakdown of total costs for domestic gas supply, through their Consolidated Segmental Statements (CSS). The aggregated sum of these costs is provided in Table 3. Costs are broken down according to the same categories employed for electricity. Many of the tenets of cost disaggregation used for electricity may be applied to gas and the most appropriate cost-reflective charging methodology develops from this.

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[10] UKPower.co.uk

[11] Based on OFGEM assumption. OFGEM. Regional Differences in Electricity Charges, par 5.16. October 2015.

Table 3._2016 Breakdown of costs, domestic gas. Typical consumption: 13,000 kWh.	£ mn.	£ mn.	Proportion of total revenue. %
Revenue			
Sale of Gas	10,608		99
Other revenue	74		1
Total Supplier Revenue		**10,682**	
Cost			
Direct fuel costs	4,550		43
Network costs	2,725		26
Environmental	187		2
Other direct costs	114		1
Indirect costs	1,827		17
Total operating costs		**9,403**	
Net total - supplier margin	1,279		12

Direct fuel costs

Wholesale gas costs are driven by the cost of acquiring the gas consumed. As with electricity, these costs should therefore be charged on a per unit consumed basis. As gas is essentially a commodity this cost is driven by the wholesale market price of gas. Real time or seasonal factor considerations for gas are much less important. A cost-reflective tariff should in consequence be expected simply to reflect the quantity of gas consumed on a standard per kWh basis.

Environment and Social Obligations

These are much less than for electricity since there is no equivalent to the support for renewables investment via ROCS and FiT schemes. Arguably the equivalent obligations in relation to gas might have included support for hydrogen or biogas technologies, but the same arguments as for electricity – that these are better financed through other means – would apply. The actual cost of current obligations for gas currently amounts to a relatively trivial percentage, certainly much less than would result from application of any significant level of carbon tax.

Other direct costs

As with electricity, other direct costs pertain to brokers' costs and sales commissions when the costs have given rise directly to revenue, i.e. an increase in sales. They also include Elexon and Xoserve market participation and wider smart metering programme costs. As these are directly related to the sale of energy, a cost-reflective tariff should incorporate these costs as part of the volumetric charge.

Indirect costs

Indirect costs are not driven by use. These include sales and marketing, bad debt costs, costs to serve, IT, HR, finance, property, staffing and billing and metering costs (including smart meter costs) (Centrica, 2017). These are appropriate for allocation to a fixed standing charge per household.

Supplier margin

Suppliers earned a 12% margin in 2016. This margin may largely be attributable to hedging activities and could therefore be regarded as a component of marginal fuel cost. (Supplier margins are intrinsically subject to year-to-year variations.)

Network costs

Network costs for gas prima facie are unlikely to change incrementally with marginal consumption or capacity requirements. In terms of capital they are largely sunk costs. It is not expected that there will be a general expansion of gas demand, although some capital expenditure may be required on a local basis. Again, this suggests the possibility of a more granular approach to network pricing. Network costs should not be recovered through the volumetric charge. Furthermore, capacity requirements are not reflected in peak usage to the same extent as for electricity pricing. Recovery through a fixed charge, allocated per household or on some other basis, represents the cost-reflective approach.

Cost-reflective tariff

Following the principles of more cost-reflective tariffs, the breakdown of the average bill should, as a result, be along the following lines (Table 4).

Table 4. Alternative tariff structures for gas	**Volumetric charge (p/kWh) (average)**	**Standing charge (£ pa) (average)**	**Paid from general taxation**
Tariff			
Current (2016)	3.8	86	
Cost-reflective equivalent	2.4	277	11

4.8. Heat Networks

This section attempts a similar approach to previous sections towards the composition of a cost-reflective tariff. It differs in that it depends mostly on estimates of the likely costs of hypothetical future systems, rather than being grounded in recent actual costs and tariffs. The intention is to identify a sample tariff for a number of benchmark household sizes participating in a non-bulk energy distribution heat networks. DECC analysis of heat network cost components is the primary basis for this analysis[12] (DECC, 2015).

The DECC analysis is comprehensive and emphasises the wide range of uncertainties and other questions surrounding an analysis of either current heat networks in the UK or future networks based around the promotion of low carbon policies for the heat sector. These include the fact that some current networks may enjoy legacy benefits of existing infrastructure or may have a quasi-social purpose that understates some of the costs. It also emphasises the scope for very wide

[12] Discussions have been carried out with Danish expert Morten Duedahl. However, DECC have carried out the most comprehensive estimation of costs in a UK context.

geographical and other variations in costs, for example between bulk and non-bulk schemes, as well as the very obvious factors of population density, scale and other considerations. Heat losses are another factor promoting large differences between schemes. For these reasons an indicative tariff is of quite limited value.

There are again two important components to a cost structure. The first is the treatment of the fixed costs of the heat distribution network, largely capital costs. The second is the full LRMC cost of the primary heat source. Since the latter has a number of different possibilities with very different cost characteristics, it is difficult to generalise. The possibilities include:

- Geothermal heat, which may have a very low incremental cost, at least if the heat supply is over-sized relative to the potential heat load on the network.
- Combined heat and power, in which case the aggregate energy cost will be the total cost of the facility less the value of the electricity produced.
- Heat from a conventional district heating boiler using waste material, biomass or gas.

In most instances heat would be metered and charged on a volumetric basis, with a rate per kWh of delivered heat that reflected the cost of the heat energy. This would again conform with the LRMC cost principles discussed earlier. In the case of combined heat and power there are some potentially complex interactions with the power system, since CHP schemes involve a trade-off between heat supply and electricity generation, but these are assumed in this context to be of secondary importance. There is a separate body of literature and experience on CHP schemes, which tend to vary very widely.

Principles of cost apportionment for network costs

The cost drivers in a heat network are the length of the network and associated capital costs; operating/maintenance costs and the quantity of heat delivered. Costs associated with the length of the network are driven by geography, notably household density and any difficulties associated with retrofitting in urban areas. For a new scheme, the network costs are essentially a fixed cost that needs to be allocated to all the households connected. To be viable, this may need a critical mass of households, and in some contexts, this may imply collective decisions, since partial participation in a heat network will raise costs substantially.

Network costs attributable to a given consumer typically represent the marginal additional cost imposed by connecting that consumer to the network. This may include connection and adjustments to the main network and are the main component of the fixed charge component in our suggested indicative tariff. Household-specific connection costs should be borne by the individual consumer. Expenditures that may benefit many consumers should be borne by all potential beneficiaries. If many households benefit from a given upgrade, for example, then they might be expected to bear this cost proportional to the benefit they incur, measured for example in relation to the size of property connected or the expected heat load. Such allocation may be relatively easy simple in a static context, for a single extension to the network. It may be more problematic in a dynamic multi-period context, for example where a major connection upgrade now might lead to benefits in future time periods for future households.

In this section, we outline cost component data and the calculation of sample cost-reflective tariffs. DECC (2015) provide substantial analysis and estimates of network costs. They have outlined operating costs for both bulk supply (e.g. for an apartment block) and for non-bulk supply (e.g. for individual dwellings). In this analysis we focus on the non-bulk setting. These costs are listed in Table 2. DECC (2015) calculate costs in £/MWh and £/unit. We use £/unit values, where possible.

Table 5: Heat network capital cost

Capital Cost		Average	Max	Min
Shared network capital costs per length	£/m	£468	£514	£422
Internal pipework costs per length	£/m	£169	£244	£94
Substations cost per kW capacity	£/kW	£35	£53	£16
Domestic HIU cost per dwelling (Domestic)	£/dwelling	£1,075	£1,326	£738
Heat meter cost per dwelling (Domestic)	£/dwelling	£579	£668	£491
(Thermal store	£ / MWh	£12	£12	£12)

Note: Costs pertain to 'non-bulk' heat networks, for example, a network supplying individual dwellings, not one supply for an apartment block. HIU is the Hydraulic Interface Unit. This is the physical interface through which the consumer accesses heat (for space heating and/or hot water) from the heat network.

Operating costs

Operating costs comprise operation and maintenance costs and energy generation costs. O&M costs are small relative to capital costs, and a case could be made for charging partly according to use and partly as a flat rate. As Table 8 shows, O&M costs may be broadly disaggregated according to operation/maintenance, staffing and annual business rates. Operation/Maintenance might be reasonably assumed to vary with use as wear and tear will drive much of this requirement. These may be subsumed into the per-unit charge Business rates and staffing costs will be largely invariant with use and therefore may be subsumed into the standing charge.

Table 6: Operating and Maintenance costs (£/MWh)

Scenario	Average	Min	Max
Maintenance	0.6	0.3	0.9
Management/Substation maintenance			
HIU Maintenance	9	2	16
Heat meter maintenance	3.4	0.1	9
Staff (Metering, billing, revenue collection)	16.9	0.1	34.8
Annual business rates	6	2	8
Fuel costs (O&M component only)	0.0752	0.05	0.10

Cost of heat

The cost of the heat input depends entirely on the source of the heat, and will be very different for, for example, conventional gas boilers, a geothermal source, biofuel or waste incineration, or combined heat and power. The DECC analysis indicates current fuel costs of around 5 p/kWh of heat supplied in the most favourable circumstances, but this is essentially a fairly arbitrary assumption. In terms of future costs and tariffs, the assumed heat source is critical. Moreover, it should, on the basis of an LRMC approach, include the capital cost of the facility that generates the heat. The most favourable assumption that could be made, other than perhaps for geothermal heat, would be based on a combined heat power scheme, wh**ere the capital cost of generation**

was already sunk or could be entirely attributed to the needs of the power sector. In this case the cost of heat would simply be the opportunity cost of the electricity production foregone.

The ratio of heat offtake to kWh lost can be described as equivalent to the coefficient of performance (COP) in a heat pump. (i.e. what is paid in electricity lost for what is taken out as heat). Some estimates place the COP as high as 6 or more under favourable operating conditions, ie significantly above the COP of domestic heat pumps. One assumption for future systems might therefore be to divide the estimated system or market value of winter electricity production by the assumed COP. This could lead to a significantly lower figure for heat costs, of the order of half the DECC figure.

Illustrative heat tariff

To provide a tariff illustration, we have taken a rather arbitrary network of 100 households with 2 km of shared pipework. Most city centre schemes envisaged in low carbon futures would be very much larger, but it is difficult a priori to determine whether this would result in significant economies or diseconomies of scale.

Table 7: Heat tariff for baseline case study

	Average	Min	Max
Volumetric charge (p/kWh)	5	2.5	*
Standing charge per month	£ 36.87	£ 16.92	£ 56.00
Total upfront capital cost	£ 2,161.00	£ 1,511.00	£ 2,726.00

Heat tariff for 2km network with 100 households. Standing charge per month represents the total shared network capital costs, apportioned among 100 households on the network and divided monthly over a 50-year lifespan of the installation. The tariff incorporates heat generation costs, HIU maintenance, heat meter maintenance and general maintenance.

*The alternative possibilities generate a very wide range. Significantly larger heat charges may be difficult to justify in a competitive environment, especially if gas is an alternative option. Equally geothermal heat might in some circumstances be associated with a very low incremental cost.

A significant question is whether the upfront costs of the scheme related to the household installation cost, would need to be recovered upfront or through the ongoing tariff. In the latter case this would add to the standing charge, but this calculation in turn depends on some very significant assumptions about asset life and cost of capital. With favourable assumptions this could be a relatively small addition.

5. The Benefits Flowing from Rebalancing Tariffs and Higher Standing Charges

In discussing the economic principles that should underpin the formulation of tariffs, the general case was made for observing the principle of cost reflectivity. In this section we explore some of the associated implications of such a rebalancing, and the recovery of fixed cost through a standing charge rather than a volumetric rate. These help to make the policy case for such a rebalancing, but we also need to address some of the counter arguments. The latter include some social policy or redistributive arguments, although this is not a main focus of this study, and these too are addressed, though only briefly.

5.1. Providing the right incentives for small consumers who already have their own generation and storage facilities, in deciding when to use them

In other words, the question is whether a rebalancing is likely to improve overall system efficiency in making sure that plant with the lowest operating costs is always used first (ie a merit order question).

In principle it does not make sense for an individual household to be given a per kWh tariffs incentive to run their own generator, e.g. a diesel generator, when the true SRMC for the system as a whole is much lower. This is inevitably a frequent occurrence with current tariffs, which are typically[13] set at around 14 p/kWh throughout the year, even though the marginal generating plant has a much lower or even zero marginal operating cost. When it happens, it will result indirectly in other consumers having to bear a higher proportion of the burden of fixed costs. It may also result in some other renewable generating plant being forced to "spill" production when there is a surplus supply.

Our proposal to reduce the allocation of fixed costs to the per kWh rate in the household tariff, both through removing any components of social and other policy costs, and through reallocating fixed network costs, would substantially reduce this distortion. Tariff rates, either on a seasonal basis or a time of day basis, will move closer to SRMC, but since they will ultimately need to be sufficient to cover and collect the LRMC costs of generation, they may still exceed SRMC for most of the time. Electricity tariffs will therefore still tend to overstate the value of own generation (to society as a whole), and confer excessive benefit to the consumer, to the extent that **any** of the fixed costs of the network, or LRMC costs of generation, have been allocated to kWh rates.

However, the distorting effect of this can be limited to the amount of own generation or battery installation and use that is economic for the household's own consumption. A corollary of identifying and dealing with this distortion is to remove the corresponding distortion from "purchase tariffs" available to consumers or "prosumers" to export to the grid any surplus production from own generation, and storage. This should normally be exported by the consumer/ "prosumer" on the basis of a purchase tariff that would reflect SRMC. This, it will be argued in 7. later, would also apply through periods of "system stress" when the value to the system was very

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[13] BEIS energy price statistics referenced earlier.

high, capturing the back-up value of own generation to the system overall. But it would provide much lower rewards for additional generation when there was a substantial capacity surplus.

5.2. Incentives for small consumers considering whether to install their own generation and storage facilities, but not to go completely off grid

This question flows in part from the above. The question is whether a rebalanced tariff would change the consumer decision at the investment stage decision as distinct from the operational/ behavioural decision above.

The answer also flows from the analysis of the previous question. Anticipation of a significantly lower revenue stream of income, from sales to the grid or cost savings, will very substantially reduce the incentive to install own generation facilities, unless these can deliver output at times when the price available for exporting to the grid is high. In the UK this would be most likely to affect investment in solar, which generally has much lower output during the winter seasonal peak periods. The proposal will, because it is much more cost reflective, be effective in deterring uneconomic investment.

Moreover, the current understatement of fixed costs also allows someone with their own generation to enjoy the use of the grid as back up, without paying their share of full costs. This increases the burden of those costs on the majority of consumers, including the poorest consumers.

Use by the consumer of EV batteries can be seen as a special case. The batteries will de facto be a sunk cost for the consumer as an EV owner. Moreover, this is one domestic electricity facility where the consumer is likely to be able, potentially, to exploit the much higher prices available in winter peak periods. Ability to exploit peak pricing in the purchase tariff provides a modest but real enhancement to the incentives to purchase an EV.

5.3. Effect on a consumer choice to go completely “off grid”?

To the extent that the proposal may provide significantly reduced revenue benefits to own generation from a grid connection, it might encourage some consumers in the choice to go “off grid”. As against this, the proposal to remove the burden of social and other policy costs reduces the incentive to sever grid connections.

There are some further, and possibly lesser effects. Rebalancing towards a fixed charge may, depending on how fixed charges are allocated, favour the larger consumers who are more likely to invest in their own facilities, and more likely to be tempted to go off-grid.

A bigger tariff issue for “off grid” choices could be presented by a more granular, locational approach to network pricing, though this is neither part of current practice nor analysed in any depth in this study. It may well make sense to shrink the gas and electricity grids in particular areas, and tariff incentives or disincentives might be a part of that.

There are also legal/contractual approaches which can be used by network operators to protect their position against the risks of losing substantial revenues and seeing their assets stranded. The biggest risk to the consumer in going "off grid" is essentially that of losing back-up, or any failure of own supply. Allowing an automatic "right of return" without penalty could then be seen as unduly favourable treatment imposing cost burdens on other users. There are contractual and other regulatory provisions relevant to this, on a spectrum between compulsory grid connection and contractual requirements for returners to commit to a minimum period.

5.4. Implications for the gas sector

Some of the issues associated with the potential for own generation in the electricity sector do not apply in the case of gas. The problem of uneconomic "bypass" (with own generation) does not arise. So the positive advantages, in terms, of tariff rebalancing towards a higher standing charge are less clear cut. In principle the recovery of costs through a higher fixed charge accords with the standard economic efficiency arguments presented earlier, but the argument is weakened to some degree by other practical and policy considerations.

One factor is that it is much easier for a low usage gas consumer, faced with a very high standing charge, simply to disconnect from the gas network. This introduces the risk of the so-called "death spiral" in which a fixed cost has to be recovered over a shrinking consumer base. Simply in commercial terms, therefore, gas suppliers may be much more reluctant to implement such a rebalancing.

A counter argument is that spreading the fixed costs onto the variable charge, as at present, is even more likely to cause larger users to abandon their use of gas, even more damaging to the commercial viability of the sector. Similarly, rebalancing tariffs for electricity but not for gas would be a further substantial change favouring the competitiveness of electricity for heating load. While this might be seen as a means to achieve a policy goal, it does not seem appropriate in a market environment; application of a carbon tax would be a more transparent, less interventionist and better economically justified means to the same end.

A further factor, considered in more depth in 5.5 below, is that a substantially lower volumetric charge would be contrary to other policy objectives, including that of reducing energy consumption and CO_2 emissions, and of encouraging higher standards of building insulation. This reflects the absence of effective levels of carbon tax, which should normally be considered the best means of reducing emissions.

Gas network viability

Maintaining the viability of gas networks is an obvious concern for the gas sector, given the widespread assumption that UK low carbon objectives will necessarily reduce gas volume sales. Higher standing charges and lower volume charges would better reflect the reality of the situation and hence require less re-calculation as gas demands fall (or rise). It would also reduce revenue volatility for the gas sector, since less of that revenue will depend on annual fluctuations in demand due to warmer or colder winters. These fluctuations are likely to intensify if the role of gas is increasingly that of a weather-dependent back-up to other forms of heating. This is a potentially significant benefit for the commercial management of the gas sector.

Another factor limiting the future loss of gas consumer connections is the potential importance of its role as a back-up. Stronger peak load pricing in electricity, one of the features of the idealised tariff structure proposed later in 7., is therefore a consideration that might discourage consumers from leaving the gas grid.

The other approach is to examine the cost base for the gas network, with a view to reducing the impact of the fixed costs. Once old pipes are finally replaced with plastic, ongoing replacement and maintenance costs should decline. The optimal solution might include a write-off on asset values,

However, it is also possible that the most efficient solution would include a partial shrinkage of the gas grid and continuation with a slimmed down remainder involving a much lower fixed charge and a reduction in the per customer burden. Bringing this about through tariffs, and a utility "death spiral" for parts of the network loaded with an increasing fixed cost burden, is not an attractive option, as it would reduce customer numbers across the network, but not be focused on the "high cost to serve" areas. A better way would be a coordinated cross sector approach, possibly involving the provision of alternative "back-up" for geographies deemed unsustainable for the gas grid.

5.5. Possible disadvantage of a reduced incentive for energy saving.

It can be argued that a higher kWh rate provides a greater incentive for energy saving, encouraging householders to improve their home insulation for example. This is an argument against our approach that is at first sight at least plausible. In the absence of a more effective carbon tax, this could be interpreted as a "second best" approach to energy efficiency and low carbon objectives.

However, there are a number of countervailing points. The first is that, historically, much "traditional" electricity load, by volume, and other than for heat, is fairly insensitive to price. Penetration into domestic heating is relatively small, and in many homes where electricity is the main source of heating, high levels of insulation will already have been applied. The low-price elasticity of traditional household load, and of EV charging applications, are also discussed later in 7.

The second is that the potentially more serious distortion of the future energy market is the bias induced by high volumetric charges against electric heat pumps as a substitute for gas in domestic heating. The lower volumetric kWh rate is a better fit with this and possibly a necessary condition to make it happen. Moreover, high levels of home insulation are often seen as a necessary adjunct to a heat pump solution.

The third is that, with an increasingly low carbon electricity sector, reducing consumption of electricity is not an end in itself. The normal economic argument for cost reflective pricing (see section 3.1) re-asserts itself.

5.6. Why retail competition has not already delivered cost-reflective tariffs. Preconditions for rebalancing.

Retail competition has not delivered cost reflective tariff structures of the kind we have described. In a competitive market, failure to reflect cost structures might have been expected to result in a process of adverse selection, as described in 1.2 above, compelling all suppliers towards a cost reflective approach. There are however a number of factors that operate to prevent this happening. One is simply the conventional assumption that spreading fixed costs over kWh is widely perceived as more equitable, and represents a traditional utility approach, and is well accepted by OFGEM, but there are others of greater practical significance.

One is the fragmentation of the industry. The network owners in transmission and distribution operate as regulated monopolies. They do not have a commercial incentive to offer strictly cost related tariffs and are unlikely to change unless explicitly mandated to do so. In addition, the network operator would need to have a measure of the number of customers associated with each supplier. Any attempt to have a differentiated standing charge, as suggested in 5.8 below, would further accentuate this issue.

The major factor has been the limitations of conventional metering. This not only inhibits the development of innovative approaches to supply (addressed later in 7). It creates a particular problem in relation to consumer switching. With meters read at relatively infrequent intervals, and often based on consumers' own estimates, any competitive moves in relation to changing standing charges would accentuate problems in consumer switching between suppliers. Some consumers would be able to time their switching to exploit tariff variations between suppliers in an opportunistic way, that suppliers would find difficult to monitor. Clearly this obstacle changes with the advent of half-hourly metering.

The preconditions for rebalancing along the lines we have suggested requires the removal of these obstacles. The first is not a technical issue but one of market structure and regulation. It will deserve attention in the wider context of other regulatory and structural changes required to adapt to a low carbon economy. The second, with introduction of smart meters, might be assumed to be already in train.

5.7. Heat networks.

The indicative numbers suggest that comparison with gas tariffs, and the current cost of gas heating as an alternative, may be the biggest issue. Other critical questions will be managing the level of capital costs, or at least the proportion that needs to be passed through into a fixed charge, and the matter of compulsion versus choice in joining a network – collective or individual decision making.

The energy source for the heat, and its treatment in terms of cost responsibility, is a second critical factor. The example given earlier in 4.8 presumed a situation where the capital cost of a generating plant with CHP could be assigned entirely to its value to the electricity system.

A perhaps equally likely interpretation is the construction of CHP plant (such modular nuclear) primarily to serve a heat network. A good approximation to the heat cost would then be given by looking at the total cost of the plant, followed by subtraction of the value of the electricity output.

A more general discussion of heat sector issues is given in the Appendix.

5.8. Social and equitable considerations

The focus of this study has been on what makes sense from a perspective of economic efficiency and sound energy policy. We have not therefore addressed or analysed in detail the issues associated with distributional and welfare objectives. However, we do not believe that an automatic presumption against standing charges is necessarily justified on social or redistributive grounds, for several reasons:

- current arrangements have conferred substantial benefits on wealthier consumers, most notably through the benefits accruing to own generation in electricity.
- low fixed charges benefit, among others, the owners of second homes.
- correlation of consumption with income is far from perfect, notably in relation to homes with electric heating
- there are plenty of other examples of fixed charges in a utility-type context, including TV licencing, and line rentals and other charges in telecommunications.
- the regressive content of a standing charge can be addressed, if necessary in other ways, either by exempting (subsidising) particular categories of consumer, or by alternative forms of standing charge, linked for example to property value.
- the more general economic argument that issues of redistribution are better and more effectively addressed through policies for general taxation and income support.

6. Issues for Tariff Design in a Low Carbon Future

The new factors in a low carbon future relate primarily to the electricity sector. This section aims to discuss a number of considerations relevant to the formation of future tariffs for household consumers, and to the potential outcomes for those consumers in terms of average p/kWh paid. Inter alia it argues that load factors, especially seasonal load factors are likely to be an important driver of outcomes (in average p/kWh) for different types of consumption, and that attention should be given to the reserve margins, another important cost driver, that it is appropriate to associate with different categories of load. It also considers whether a higher proportion of network costs should be treated as fixed for tariff purposes, and what factors might influence the means of collection of those costs.

6.1. Additional considerations in a low carbon future.

The first thrust of our illustrative tariffs was a drive towards rebalancing conventional tariffs, at 2016 levels, with a higher fixed charge and lower energy charge. On its own this would have some important consequences, and we believe it could help overcome some of the perversities associated with current tariffs.

However, an important part of this study has been to examine tariffs issues in the context of a prospective low carbon future for the energy sector. There are some important additional factors to consider, concentrated in the electricity sector as the main vector for low carbon energy. These relate both to the nature of most low carbon generation and to the very large increments of electricity load anticipated for heat and EVs. (Thermal demands of domestic and public/commercial buildings are estimated in a 2012 CCC report[14] at about 450 TWh pa; this compares to current total electricity consumption of about 300 TWh pa.)

In such a future almost, all new generation is from low carbon non-fossil sources, possible exceptions being either baseload CCS or a limited quantity of OCGT for use as an "emergency" reserve. It is also implicit that transport and heat represent very substantial additions to, and, taken together, are of comparable size with, "traditional" household load. Also implicit is the assumption that IT, communications, metering and control systems allow for very sophisticated real time interactions between system operation and consumer load.

First, for the electricity sector, future cost structures for generation are likely to be even more capital intensive, evidenced in BEIS analysis[15] of future generation costs. This will be an important factor in shaping system related questions, including tariffs. High capital costs place correspondingly high value on achieving high load factors.

A **second** factor is that the new types of load (e.g. heat pumps and EVs) are likely to give rise to very distinct time-usage patterns of consumer load. These loads are potentially more flexible in terms of the time and timescale over which they can be satisfied. This suggests that suppliers may take the opportunity to develop new concepts for the service the consumer requires, especially for but not necessarily confined to, the heat and EV markets into which electricity will penetrate. Tariff

[14] Decarbonising heat in buildings: 2030–2050. April 2012.

[15] The Department for Business, Energy and Industrial Strategy (BEIS) regularly updates estimates of the costs and technical specifications for different generation technologies used in its analysis. The report referenced here is Electricity Generation Costs, November 2016.

incentives, and the nature of the consumer offering, will need to reflect a balance of what consumers want in terms of cost and unconstrained instant satisfaction of some of their energy requirements. This will affect both their actual impact on system load shape and the amount of spare capacity that the system needs in order to cater for peak loads or periods of supply non-availability (the capacity margin).

A **third** factor is that it may be appropriate to revisit the judgements and working assumptions made earlier, notably on what should be treated as fixed and incremental costs in networks.

Fourth, differences in price elasticities of demand (ie sensitivity to price), suggests more attention could be paid to options suggested by the principles of Ramsey pricing. This is particularly relevant to judgements about the allocation of fixed costs, and the different methods by which they might be collected in tariffs.

These issues are concentrated in the first instance in the electricity sector but they will clearly have implications for, and interactions with the economics of heat and gas networks.

6.2. Future drivers of wholesale energy cost of electricity

We can get some idea of the cost conditions prevailing in this future from scenario projections prepared by the Committee on Climate Change (CCC)[16], and from the BEIS estimates of future generation costs and their capital cost component. The CCC projections, in their 2030 High Renewables scenario, suggest an average cost of generation of around 10 p/kWh, but an effective wholesale energy price of 7.8 p/kWh (difference explained by numerous adjustments for legacy effects). These figures imply a somewhat higher cost of wholesale energy than prevails today, although the gas commodity price is assumed to be very similar.

The BEIS figures indicate a range of fixed costs (capital plus fixed O&M) for the technologies considered for commissioning in 2025. Nuclear and offshore wind, for example, are presented as giving rise to fixed costs of between 8 and 9 p/kWh on a levelised cost basis[17] for these cost elements alone. The levelised cost basis represents what is achievable if there is a perfect match between what plant can deliver and what can be either consumed or absorbed into storage. It therefore allows an estimate of how sensitive actual average prices paid by consumers might be to load factor or load management considerations.

Long run incremental cost (LRMC) of supplying wholesale energy

The first of our four factors is essentially about the different LRMCs for different types of load. Reverting to the Turvey concept of LRMC for a postulated load (1.1), we should expect very different costs to be associated with supplying increments of load in three different categories – traditional domestic[18] applications, electric vehicle charging, and electric heating. Since low carbon generation is heavily dominated by capital costs, the wholesale cost of energy will be driven by the

[16] Energy Prices and Bills - Impacts of Meeting Carbon Budgets. Committee on Climate Change. March 2017. Fig 1.15 supporting tables.

[17] Levelised cost is usually defined as the total costs of generation from an individual plant over its lifetime, divided by the total kWh produced, assuming maximum potential production is allowed, and with appropriate time discounting.

[18] These are essentially lighting and a wide variety household appliance, although existing household load already includes a significant proportion of load for space and water heating which could be considered for classification with "new" heat loads. Current load is of course not homogenous although often treated as if it were.

capital cost of the plant mix deployed to satisfy demand, and the load factor associated with the consumer load in question (including any interaction with the intermittency characteristics of the chosen mix of generation supply).

On load factor, a reasonable working assumption is that flattening the daily load curve, or the more accurately stated objective of removing real time mismatches between supply and demand, is an attainable goal, given the tools available and the intrinsically more flexible nature of heat and EV charging load, making them very amenable to time shifting within day. The reducing cost of battery storage and increased technical potential for demand side measures are also important. This will however require tariff incentives if it is to be achieved, and we should expect tariffs to include differentiation over different time periods, most likely including seasonal, time of day (ToD) and some real time components. How this is expressed and the relative roles of, for example, automated response and supplier managed load, are likely to be part of the picture. However, seasonality presents a far more intractable problem. There are currently far fewer tools (absent cheap long-term energy storage) available for mitigating the marked seasonal pattern of traditional UK household demand and heating load. In the absence of technical solutions, seasonal factors set a limit on how far load factor can be improved.

Traditional household (domestic) load, as at present, has a seasonal load factor (defined as the ratio of average monthly consumption to January consumption) of about 80%.[19] There is no established daily pattern for use of electricity for heat (pumps) or EVs, and indeed the daily patterns are parameters that future policy, including tariff policy, should seek to influence, since this can dramatically reduce costs and improve economic efficiency.

For heat pump load, estimations can be made from National Grid data[20] on daily gas use through the year or from monthly degree day[21] data. The daily gas data (chart below) suggests that the annual load factor[22] of heating load could be as low as 35% (even assuming that this was based on a flat consumption over all 24-hour periods during peak season). As discussed earlier in relation to generation costs, this would tend to imply very high costs of maintaining sufficient capacity. However modest use of a back-up source of heat (e.g. gas), for peak lopping, raises this load factor substantially. Meeting 3% of heat need through an alternative source (gas) raises load factor to about 50%. A seasonal load factor of about 50% for heat load, ignoring within month variability, also corresponds closely to calculation based on monthly data for degree days (average monthly degree days as a percentage of coldest month degree days).

In practical and market terms, well-constructed electricity tariffs, that reflected the potentially very high cost of providing sufficient capacity to meet peak demands, would provide a very strong incentive for consumers to use gas as a back-up at times of peak or system stress. This in turn would incentivise the installation of heating systems that facilitated this kind of hybrid approach.

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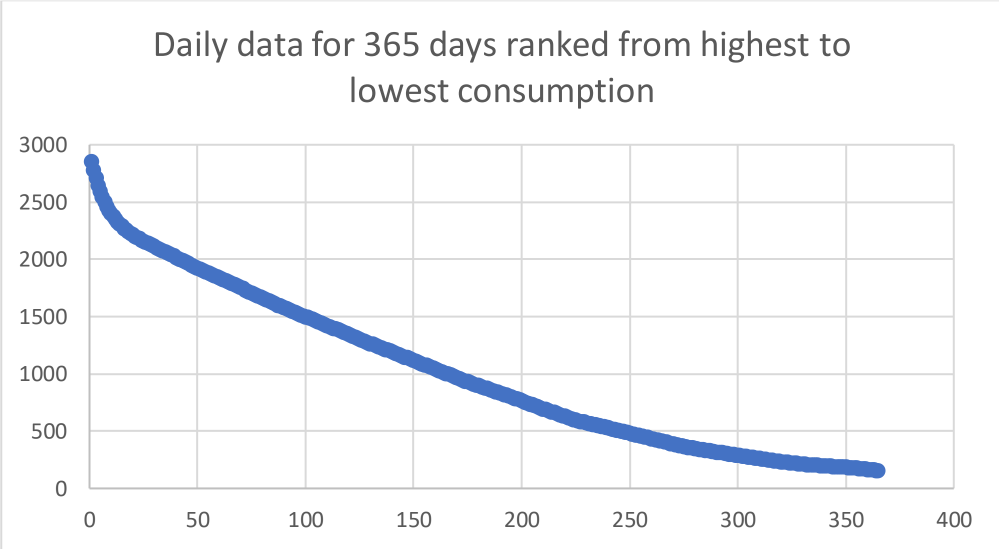
[19] UK energy statistics

[20] National Grid (2017). Electricity Ten Year Statement.

[21] Degree days are a common measure of heating need. One unit of heating degree days is the number of °C by which average temperature falls below a base level, typically 15.5°C. So, a 30-day month in which the daily average temperature is always 10.5°C would result in 150 degree days for that month. Monthly results are published by weather station as part of standard meteorological data.

[22] As defined earlier in the box in 1.1.



UK government statistics[23] suggest that the load factor for EVs can be assumed to be much higher. If within day variations are ignored, i.e. assumed to be flattened by careful management, it is potentially close to 100%. In fact, the statistics suggest that winter road transport demand (January to March) is significantly lower than the other seasons. This suggests that, at least in relation to costs of generation, EV charging might be managed with lower than average costs per kWh. If night time charging can take place entirely within the "night valley" of low demand[24], no additional capacity is required, and so there is little or no incremental cost to the system.

Reliability of supply is a very sensitive issue in public perception. However, since reserve margins are a driver of significant capacity costs (see box below), it will be important to recognise that the concept has different operational significance, and importance to consumers, for the different categories of load, for the reasons discussed earlier. Traditional load is usually seen as requiring the very highest standard of supply reliability, for instantaneous satisfaction of demand. The operational requirement of back-up for heat (especially when there is a back-stop such as gas) and EVs, which have some intrinsic storage, and where the consumer often has alternative means of satisfying transport need, are very different both from a system and a consumer perspective.

These marked differences between the three categories, in terms of load factor and required reserve margin, imply that, given any rational and sensible structure of tariffs, the outcome should be significantly different in average costs per kWh for the wholesale energy component of what consumers pay for their consumption in these categories.

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[23] UK Department for Transport. Road traffic statistics.
[24] This is a plausible assumption for an initial take-up of EVs but is less probable in the longer term as the night valley is filled, with heating providing additional competition to fill any dip in overall load.

There are two ways of thinking about this. In the first, a different price structure is developed for each type of load. In the second differentiated time of use pricing applies to all demand. So heating demand pays more because it takes more energy at times of high demand and EV charging costs much less on average over the year. This second approach makes the use of back up fuel an economic choice – using gas when it is cheaper than electricity. In a competitive market, suppliers would be exposed to costs in line with this second approach and would convert these into use-specific costs to attract customers

Supply reliability standards as a driver of wholesale energy costs/ prices

We can consider the relationships between the supply reliability, the cost of meeting peak load, and the so-called value of lost load (VOLL). There is a resurgent interest in how security standards should be set. This is a retreat from assumptions that an "acceptable" standard would emerge naturally from the interplay of market forces.

Within a centrally planned generation sector, the appropriate amount of capacity to construct could be in principle set by determining the point at which the last, "marginal", increment of (OCGT) peaking capacity was expected to have an annual utilisation factor that resulted in a levelised cost equal to VOLL; i.e. any additional capacity could not be justified by the value of the lost load "saved". High values of VOLL, equivalent to c £20 per kWh in today's money, were implicit in the old formal standard of generation security adopted by the CEGB (supply failure in not more than three winters per century) and justified by the CEGB by reference to the quasi-catastrophic nature of unplanned winter evening disconnections. More recent analysis[1] has also suggested quite high estimates.

In the UK, the 1990 arrangements maintained an obligation to supply (OTS) for the public electricity suppliers (PES) who retained a monopoly for a reducing fraction of the retail market. The obligation was to continue purchasing in the wholesale market, to meet demand in full, until such time as the wholesale market price reached a certain level, sometimes referred to as the value of lost load (VOLL). VOLL combined with a loss of load probability (LOLP), also set administratively, and based on system modelling. In principle this was intended to deliver the level of capacity adequacy that had previously been considered appropriate within the framework of state owned monopoly.

This was a clever device designed to unify the two separate market concepts of an energy only wholesale market, and a capacity element, into a single real time price. However, neither this mechanism nor the obligation to supply survived the NETA and BETTA market reforms in 2000. The latter were in turn criticised for failing to provide an adequate basis to remunerate "capacity per se" and hence new investment.

A VOLL lower than the implicit CEGB standard was adopted at the 1990 privatisation. Around £2 per kWh in the money of the day, or around £5 today, was deemed to be a more realistic estimate of consumer valuation. This figure was loosely attributed to earlier arguments and studies, which in turn had referenced: surveys of consumer willingness to pay, or a simple pro rata equation of lost load to loss of GDP, akin to some measures of the valuation of travel time in transport economics.

However, any future debate should be set in a much broader context of demand side participation which allows for direct discovery through tariff choices of how consumers might value supply reliability, and also very substantially mitigates the worst features of supply interruptions from earlier times. Inter alia the development of the demand side means much more opportunities for "market testing" what an acceptable standard really is, e.g. through offering different standards, and what consumers are willing to pay for.

Some caution is indicated however, in comparing with past periods, because the time profile of load, managed so as to eliminate peaks and flatten load curves, will make for very different loss of load probability simulations. Serious capacity shortages could therefore have much more serious consequences for ***the quantity of lost load***, as compared to the very limited duration shortages associated with "cold spell, early evening in January" peaks of the past.

1. The Value of Lost Load (VoLL) for Electricity in Great Britain. Final report for OFGEM and DECC. *London Economics*, July 2013

Short run marginal costs, operational factors, and peak periods

The lower costs and more economic efficiency associated with higher load factors and differentiated reliability requirements are only attainable if it is possible ***both*** to flatten the daily load curves (after allowance for supply intermittency) during the winter season, ***and*** to make operational the proposition that EV and heating loads can be associated with a lower reserve margin. This introduces a further dimension into the detailed design of tariffs.

The fundamental importance of managing consumer load is demonstrated by considering a hypothetical future in which there was no differentiation in the kWh charge by time of day or real time factors, such as might happen in the absence of efforts to manage large heating and EV load. Unconstrained by price or other factors, many motorists would tend to recharge their vehicles on return from work in the early evening, already a peak period. The problem with instantaneous direct acting space heating (DASH), with its very low capital cost to the household, and its use as a "top-up", is potentially even more severe. Historically it has always been recognised as having the potential to present a major capacity issue. The impact of inability to manage load on aggregate wholesale generation costs[25] for both heat and EVs would be very substantial, either in terms of very substantial additional low carbon capacity, or substantial additional battery storage, or both.

[25] Even more so than with conventional thermal generation, because there is no obvious equivalent in low carbon systems of mid-merit plant.

Inevitably this would feed back into much higher prices, discouraging progress towards these low carbon technologies.

At the same time attempts to base kWh rates solely around measures of SRMC are not really viable. The simplest statement of the issue is the "missing money" issue, that SRMC prices typically fail to cover LRMC, an effect exaggerated if SRMC is zero for most of the time. There are also serious questions around what validity SRMC wholesale prices would have in low carbon systems dominated by the management of plant inflexibilities and intermittency in supply. Possible measures to manage load shape include dynamic real time price signals with automated response, and management of the timing of consumption for particular loads by the supplier – so-called supplier-managed load. We can envisage a role for both these options. Both are consistent with the idea of competing suppliers offering a choice of different packages, and with households able to choose between packages that offer different levels of reliability and guaranteed reserve. However, in general the tariff rate applicable to consumption in any particular period will be higher than SRMC.

Our expectation is that tariffs would also include seasonal elements, so that the kWh rates would be significantly higher in winter than in summer. Time of day features would assist in shaping daily load curves (as part of a demand side management programme). Overall these should result in average p/kWh outcomes for consumers that reflected their mix of load. If markets and tariffs were operating with reasonable efficiency these outcomes should quite closely reflect expected values derivable from the load factors of the different types of load, and seasonal load factor in particular.

Implicitly this means that tariff structures have to be such that not only do they, in their aggregate effect, succeed in covering long run costs of generation, but also that they pay at least some attention to short run marginal costs, including the "scarcity costs" associated with periods of system stress and the risk of loss of load (where VOLL becomes a relevant measure). But an approach based solely on SRMC is unrealistic, not least because in practice it fails to cover full incremental costs.

6.3. Fixed and incremental costs of networks

In section 4 we quoted OFGEM observations on the nature of transmission and distribution costs, indicating a high level of fixed cost, up to 80% for transmission and 50% for distribution. These numbers still imply that a substantial part of distribution costs, in particular, should be treated as incremental with kW of load. This deserves further reflection, and consideration of what are the relevant measures of incrementality. We can argue that, in the context with which we are concerned, a much higher proportion should be treated as fixed in relation to incremental expansions in kWh or kW of domestic household load.

The first point is that there are different types of incrementality. Adding another 10 TWh of domestic load to a current 100TWh may have entirely different consequences for cost if it is attributed to the attachment of several new towns to the network, each requiring permanent additions of high and low voltage lines and transformers, on the one hand, or an expansion of 10% in demand from each and every existing household, on the other. But with current data it is not possible to distinguish clearly what investment is required for these very different types of expansion. Nor is it possible to distinguish between investment required because the system is expanding, in either sense, from essential replacement or upgrading of existing wires and transformers to improve quality, security and efficiency. Additionally, such evidence as we have from the investment plans of network companies implies a much lower percentage of future expenditure is attributable to load than is implied by the 50% figure for distribution.

The question, in a tariffs context, is essentially to determine the cost structure of the transmission and distribution networks as a function of the volume of kWh or kW throughput, ie the scale of aggregate consumption. Important parts of an overall cost function, such as line length, which may be by far the most important factor in comparing geographically separate networks, are largely irrelevant when a single tariff applies across a large region. Conceptually, one way to phrase the question is the following. If the total cost of a perfectly sized and designed network to meet a demand of X kWh is £ Y, then what is the total cost (Y+ ΔY) of a perfectly sized and designed network to meet a demand of (X+ ΔX) kWh? In principle this question, on the value of ΔY, could be addressed by asking a transmission/distribution engineer to evaluate the costs of wires, transformers and operations for a simplified hypothetical system.

Given how much of capital cost is typically tied up in civil works, and the "square root" economy of scale associated with pipes and wires, not to mention other fixed costs and scale economies, an intuitive answer is that the incremental cost of a kWh should be very small indeed. So, in the context of looking at hypothetical future low carbon systems it is possible to argue that we should heavily downgrade the importance of the variable cost component of network costs.[26]

It is worth emphasising that possibly the most important driver of cost, line length, is largely ignored in traditional approaches to distribution pricing, and is averaged over quite large geographies, between which it remains an important explanation of regional differences in cost. The possible option of substantially more granular locational pricing, in the context of retail consumption, is a possible cost-reflective option.

This rather startling suggestion, of very low marginal costs, may be blunted in looking at contemporary networks, for several reasons. First, the current valuation of networks assets probably represents a substantial write down on what would be a "replacement cost" starting from scratch, so that the cost of upgrading appears as larger in relation to current asset values than would otherwise be the case. Second, current networks are unlikely to be "right-sized" for a low carbon future in which aggregate household energy consumption could expand by 100% or more. So, there is a substantial and unavoidable future cost in upgrading existing networks. However, seen from the long-term perspective of an established network in a low carbon future, the marginal impact of additional load is likely to be very small. It is also quite credible to suppose that, while the networks do indeed need upgrading to cope with much higher levels of kWh throughput, some of this expenditure is necessary replacement expenditure in any case, and that this itself should be regarded as a necessary one-off fixed cost, within which the "marginal" or ΔY element remains very low.

There are of course substantial infrastructure costs associated with setting up domestic and neighbourhood charging points for EVs, but, for the purposes of this exercise, we have assumed that they will normally sit outside the framework of ongoing network charging.

Given that considerable effort will be expended in managing the load curve to meet generation cost objectives, with very large implications for wholesale energy costs, it would also seem less

[26] An alternative formulation of this argument is that the costs of upgrades would in theory tend to follow in steps as the next size of conductor was used. An upgrade is a large discrete (integer) decision for which an increased cost per kWh is a poor proxy? In other words, once society has invested in capacity, there is no sense in making a tariff a barrier to its use.

likely that much attention need be paid to time dependent pricing to reflect relatively small marginal cost considerations in transmission and distribution. If demand/ supply balancing has already been resolved, e.g. through "flattening" the load curve, there will be little purpose in small additional adjustments for network purposes, particularly if these in some cases conflict with the generation cost messages. Again, this could become more relevant in a more granular approach to network pricing.

Ramsey Allocations

Much of the earlier argument has been devoted to demonstrating that the electricity sector, and the network element in particular, is dominated by fixed costs, with incremental demand associated with small incremental costs. The justification of a cost-reflective approach then requires that these costs should be recovered through some form or forms of fixed charge levied within the tariff. There are counter arguments to justify "spreading" of fixed costs through the kWh charge. Loading the kWh rate on tariffs in this way is often seen as more equitable, and "fixed" or standing charges have generally been unpopular in the public perception of energy utilities.

Ramsey pricing is a sound principle from a perspective of economic efficiency, even if it is difficult to be precise about empirically verifiable estimates of relevant price elasticities (not least because we are discussing entirely novel forms of consumption). However, it can also create problems. For example, offering a lower allocation of fixed cost to consumers with their own generation opportunities (those consumers also discussed in 3.1) looks prima facie as if it might be justified by Ramsey pricing, but would be socially regressive. The principle also interacts with other policies to the extent that it can also be presented simply as an argument for loading fixed costs on places where they will create the least distortionary impact. It is a short step logically to argue for a more discretionary approach to fixed costs.

In the context of future household loads in a low carbon future, however, the most relevant implication of the Ramsey principle is that different types of load, rather than different types of consumer, have very different price sensitivities. Thus many household applications have a very low price sensitivity, at least in the short term with fixed technology, either because the usage is absolutely essential with no real alternative, eg lighting, or because energy consumption is a good that is complementary to other highly valued activities, eg home entertainment or laundry. Of the important future loads, heat is usually considered as much more price sensitive, especially in the context of competition from other fuels, while EV charging can be considered as much less price sensitive with transport normally being seen as a premium use of energy.

Whether and how these considerations might be reflected in tariff structures should be seen as an important question in future tariff design.

7. Features of efficient tariff structures

7.1. Enhancing consumer choice in a low carbon future

Section 6. set out some of the criteria efficient tariffs need to satisfy, and some of the areas open to discretion and judgement (on the allocation of fixed cost), but without exploring how that might be achieved within particular institutional and market frameworks, or in terms of practical systems of metering and measurement. In this exercise we note how some of these questions and their resolution might lead to an ideal system of more efficient tariffs.

There are clearly some difficult choices to be made. One of the options for example is the combination of the roles of distribution network operator and supplier. This has prima facie advantages in some circumstances, for example if network pricing were to be done on a much more granular basis and to take into account very localised constraints. The DNO then has all the relevant real time information about the state of the network, as well as wholesale energy market prices, and should be able to produce the most satisfactory outcomes in terms of system operations, and tariffs, without the need for complex trading structures and high local transactions costs. DNOs can then be required, through licence or other requirements, to meet additional policy requirements in the sector, as these might relate for example to the allocation of fixed costs. Arguably this also fits well with highly decentralised models or scenarios for a future electricity sector, in which a great deal of activity is "off grid".

However, the more important criterion when a majority of consumers are reliant on utility suppliers is to find the set of tariffs that presents the best choice to consumers. This is to meet the right balance between the nature and quality of the service they receive, and the total cost they have to incur. Moreover, different consumers will, in an ideal world, want to make different choices, just as they make trade-offs between quality and price in other sectors of the economy. This should be a legitimate expectation of a competitive retail supply market which should be expected and required to encourage substantial innovation in terms of the variety of tariff options between which consumers can choose. This is in itself a very substantial change from current structures where metering limitations prevent any very substantial differentiation in what is on offer to the consumer.

In looking at a low carbon future, we also need to recognise that we are looking at a digital future in which a number of important features transform the nature of the supply and metering services that can be offered. These features relate to much more frequent measurement of consumer load, communication of price or other signals to consumer premises, automated response at the other end and remote control by the supplier of certain load. Remote control would imply that certain loads were de facto supplier managed, either through price signals and automated response, or simply as one element in the tariff agreement. The form of remote control could be through either adjusting the rate of kWh delivery to the consumer (power adjustment), appropriate for EV charging, or through delaying the required kWh delivery (time adjustment), appropriate for applications involving a cycle. In principle this might reflect operational considerations in either management of generation capacity or in management of network congestion.

There is no intrinsic reason why it should not be possible or desirable for a consumer to purchase from two or more suppliers, or on the basis of multiple tariffs, each applicable to particular kinds of load, and associated with different price and service packages. This may appear excessively complicated, but it is much easier to envisage separate tariffs and separate suppliers for the very substantial loads that will be associated with heat and EV charging, both of which are likely to be associated in any case with separate circuits within the home (just as cookers, storage heaters and water heating are today). Retail competition could and should produce innovation and choice, and the degree of complication should ultimately be decided by consumers responding to the cost reflective tariffs that will be on offer. The option of a consumer having the ability to purchase from more than one supplier, or on more than one tariff, should encourage competition.

7.2. Suggested features and options for electricity tariffs

With these considerations in mind, we can envisage consumers having access to a menu of cost reflective tariffs, including the following features. The possibilities are intended to be illustrative rather than exclusive.

One or more options available for a default tariff

The default tariff would be very similar to today's standard tariff arrangements. It would have a degree of "shaping" in the form of seasonal rates, especially in terms of higher rates in the heating season, and perhaps also by time of day (ToD), but not attempt to equate to real time SRMC. The average p/kWh would, for the typical consumption of today's consumers, reflect quite closely the average cost of wholesale energy. There would be no restrictions on usage and no means by which the supplier could seek to control any individual consumer loads attaching to this tariff.

However, the default tariff rates would, for some particular uses such as heat and EVs, and for cost reflective reasons, necessarily result in significantly higher p/kWh outcomes, in comparison with the alternative "specialised" tariffs that would be on offer.

A "red light" system

Under a "red light" system, applied only at critical times of supply shortfall or excess demand, consumers would be charged a penal rate per kWh, for any kWh used above a threshold level. The purpose would be to reduce any non-essential uses, without actually curtailing supply. The red-light period kWh rate would reflect the degree of severity of the system stress, and would be based on a calculation combining the incremental costs associated with peaking plant used for very few hours and the value of lost load.

Consumers could protect themselves against these price spikes with an automatic control on non-essential appliances or circuits. Or they could opt for a higher standard set of prices as a default tariff option, in which case they would not be subject to red light period penalties.

Various forms of supplier managed tariff with different levels of service guarantee on offer

Tariff options of this kind would be targeted at particular markets, and their intrinsic characteristics in terms of flexibility, sensitivity to considerations of price, and other technical factors. They would be determined by the views that competing suppliers might take of what kind of supplier managed options are likely to be acceptable to, and welcomed by, consumers. The two largest and most obvious candidates are heating and EV charging load. In each case there is likely to be a very strong incentive on the sector as a whole to manage the threat of excessive addition to peak demand requirements, or other operational issues, from a great expansion of these loads.

It is worth summarising some of the issues discussed earlier in respect of these loads, since these help in understanding what kinds of tariff offering are likely to appeal to, and be appropriate to, consumers. This is done in the table below.

Category and Measure of Seasonality Factor.	Price elasticity, as impact on kWh consumption of price changes	"Time elasticity", ie the potential flexibility, and hence amenability to real time or ToD price signals, or acceptability of supplier managed load.	Required standard of reliability, or value attaching to *instant* satisfaction of need
Traditional household load. **80%**[27]	**Low elasticity.** Generally taken to be highly inelastic (other than for what is currently a relatively small proportion of heating load)	**Inflexible**, or quite limited flexibility for many applications. cf ToD and similar experiments.	**Very high standard** required because of disruption caused by supply failure. [high VOLL]
Heat Sector **50%**[28]	**High price elasticity**. especially if there is competition with other elastic fuels	**Generally flexible** within limits. Historical experience of storage heating relevant. Option of supplier management of load.	**Relatively low standard**, due to back-up options, and a degree of time flexibility
Electric vehicles **100%**[29]	**Low elasticity**. Because transport is a premium use of energy. [cf taxes on road transport fuels]	**The most flexible of the sectors**, due to nature of vehicle use. Potential for supplier management, with drivers using default option for time critical needs.	**Lowest standard**, arguably*, due to alternative travel options as well as intrinsic time flexibility. Plus charge already in battery.

* There will be exceptions. Alternative travel options may not be available to some elderly people or in remote rural communities. But many motorists will find methods to manage this risk comfortably, e.g. by maintaining a minimum level of charge, or be prepared to pay a penalty rate on the default tariff, if necessary. The occasional inconvenience of travel disruption is also arguably less dangerous than the risk associated with inability to heat the home

In the case of EV charging the problem of peak capacity would be most likely to arise as a result of many consumers tending to develop the habit of starting a re-charge immediately on return from work, for example. One of many possible tariff products, therefore, might be a promise of full re-charge by a given time the next morning, or a chosen number of kWh over a chosen number of hours, with power input and timing set by the supplier responding to supply/demand balancing or local network considerations. EV load, given its high seasonal load factor, will tend to cost significantly less to supply, and in aggregate demand will be relatively insensitive to price. Cost

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[27] Based on UK statistics for domestic load
[28] Based on degree day data.
[29] Assumed value based on Department for Transport traffic statistics. Road transport is actually lighter in winter months when electricity and heat demand peaks.

advantages may therefore need to be fully reflected in tariff kWh rates in order to persuade consumers to make the effort to sign up for this as an additional tariff. However current willingness to shop around between outlets for small savings in petrol or diesel prices suggests that many EV owners will be willing to do this.

The risk of (illicit) cross-over between tariffs would be obviated by the fact that a "managed" load would not be suitable for many or most of the applications required by consumers, such as lighting, cooking, or home entertainment.

For heat pumps the peaking problem arises mostly because of the well-established close seasonal alignment of heat requirements with system peaks. Heat pump technology works best with the semi-continuous delivery of heat over the day, and heat pump operation is likely to have different technical requirements so that a tariff targeted at the heat pump market, while still based around the concept of a supplier managed load, would probably need to offer a different service definition. Inter alia it would need to be built around the concept of 24-hour management.

At the same time heat load is potentially significantly more expensive to supply, reflecting its low seasonal load factor. Raising load factors wherever possible reduces overall system costs and provides a benefit to consumers in lower bills. Supply of electricity for heat is potentially much more sensitive to load factor, so suppliers would have an incentive to devise tariffs that enabled consumers of heat load to present a higher load factor and hence enjoy a lower tariff. This could be constructed from peak prices within the tariff, linked to those in the default tariff, or it might be related to the provisions the consumer was able to make for gas back-up, a feature described earlier/ later.

For any managed load, the consumer should have the option to override supplier controls and return temporarily to their default tariff (for example for the purposes of emergency EV charging), but in that case they would also be exposed to the higher rates in that tariff, including any red-light periods.

The potential effect of peak lopping on electrical load factor for heat pumps in residential heat load.

Load factor in relation to system peak requirements is a critical factor in estimating the incremental costs of a major new electrical load such as heating. The capacity requirement needed to meet peak will give rise to a lower average p/kWh cost if it is spread over more units supplied. This is particularly relevant in the UK because peak heating requirements in winter generally coincide with the system peak. This is due to the fact that heat, across industry and commerce as well as households, and together with lighting, already accounts for a significant percentage of established load.

The load factor of heat load can be estimated from a table presented by the National Grid in its Ten-Year Plan, which sets out the daily gas requirements for a cold winter, and which they use as a basis for planning. If we take these as a proxy for what heat pump load demands on the system might be, then calculation from this table gives a load factor of around 35 %, rather a low figure. Moreover, this takes no account of the possible deterioration in heat pump performance (COP) in exceptionally cold conditions.

However, this table also allows us to calculate very easily what the load factor of heat pump load might be if the load on the coldest days could be reduced down to a maximum allowable aggregate level, with the additional requirement being met by an alternative energy vector or storage, the prime candidate being gas. The calculations we make from the table indicate that quite small amounts of "peak lopping" can have a quite dramatic effect on load factor.

Thus use of gas to meet just 0.5 % of this heat load would raise the heat pump associated load factor to 42%. Using gas or other sources to "peak lop" and meet 3.1 % of this heat load would raise the load factor to just under 50%. Thereafter larger amounts of gas need to be "expended", and about 14% of heat load would need to be met by gas to get the load factor to 60%.

Clearly there is an optimal balance to be determined. For consumers using a hybrid boiler based on heat pumps and gas, the process could be automated, and linked to external temperature or to an internal algorithm that provided the most appropriate or least cost outcome for the consumer. Could also provide frequency response to the system.

The impact on generation costs of supplying a load with a 50% load factor, as compared to 35%, in a future where generation is dominated by capital costs, is clearly substantial. This also implies savings on heat pump and network capacity.

50% is a natural benchmark because it is also the heat load factor calculated from **monthly** degree day data (i.e. average monthly consumption as a percentage of peak month consumption. This indicates the necessity of the more granular, ie daily data, approach, in the context of more technical calculations. But an optimal balance might be struck at load factors higher or lower than 50%.

Options for allocation of fixed charge

There is a general issue of how best to deal with the fixed charge component of tariffs, and various alternatives can be discussed beyond having a simple standard rate per household. None are free of possible controversy.

One is basing the fixed charge on the fused capacity of the household. This ignores the relevance of diversity and the absence of any clear link between individual and system or collective peaks. It has the very unsatisfactory feature of imposing quite severe limitations on individual consumer behaviour, with no discernible economic benefit.

Other methods include linkages of the fixed charge to measures of property size or value. There are fewer objections to this on efficiency grounds, but it is a proposal driven primarily by a redistributive agenda, and as such would require discussion in the political arena.

The additional suggestion arising from our analysis and the table above is that one element in a charging structure could be to include an additional fixed charge for households with an electric vehicle. This would, first, be consistent with levying the fixed charge on the least price sensitive part of the market, and, second, could be taken as recognition that EV charging will require the creation of substantial infrastructure, even if this infrastructure is not in reality financed mainly through ongoing electricity tariffs. No additional fixed charge would be applied to individual households with heat pump installations.

Impact on Economy 7 and preserved storage heater tariffs

There are threats to conventional heating loads, largely because of increased “competition” from other loads capable of being served in the winter night valley. This would tend to raise off-peak tariff rates. One such “competitor” is EV charging. Another is heat pump load; low carbon policies are associated with the assumption that electric heating will be based on the much more energy efficient heat pump technology. In practice, while there might need to be some grandfathering of tariff rights when consumers have invested in storage heaters, there would necessarily be some possibly significant increase in Economy 7 off-peak rates and this would incentivise a move towards heat pumps with much lower running costs.

Purchase tariffs

Generation output exported to the system under a purchase tariff arrangement would be paid, not at the rates in the standard energy charge schedule, but at rates reflecting SRMC considerations. This would include the full “red light” rates above, which would be of particular interest to EV owners, but it might also include very long period of zero SRMC, especially in summer. Small retail-scale own generators would of course be free to enter into arrangements with aggregators who could trade in the market on their behalf. Existing owners would enjoy grandfathered rights established under feed-in tariffs.

8. Consequences and Implications of Proposed Tariffs

This section aims to interpret the ideas of earlier sections **2**. to **5**. both in the context of some of the major technologies for energy use that are currently anticipated for a low carbon future, and in terms of some other practical and policy questions that might be considered to flow from our analysis.

8.1. The economics of heat pumps.

Compared to conventional tariff approaches, tariffs designed along the lines suggested in 5. should lead to more efficient and lower cost provision of electricity to meet consumer needs in respect of choices to invest in heat pumps for domestic heating.

The capital intensive and less flexible nature of low carbon generation places a high premium on more flexible (less time-sensitive) load. Heat pump systems, it is widely assumed, will be designed around quasi-continuous delivery of heat to a household and maintaining a constant temperature, as compared for example to the rapid response associated with directing acting heating (DASH). As such it lends itself, particularly if combined with high standards of thermal insulation and possibly some limited on-premises heat storage, to a very significant degree of supply flexibility over (say) 24-hour periods. This strongly suggests tariffs policies, including supplier managed load, to exploit this intrinsic flexibility, benefiting both the operation of the power system and the consumer (through a better price).

However, heating provision suffers from an irreducible seasonality limitation, making it hard to improve an overall load factor above 50%, a little less than the current overall system load factor (for the power system as a whole) of over 60%. In terms of the cost of capacity provision, this should be at least partially offset by the greater options for back-up, through gas or (possibly) heat storage, allowing a significantly lower margin of capacity to be held against heat load (as compared to other domestic requirements). This should be reflected into tariff rates for heat pump load.

The key features of our analysis and tariff proposal that are relevant to heat pump technology and to its take-up are the following:

- Rebalancing of tariffs to provide lower volumetric (kWh) rates, substantially improves the position on running rates for heat pumps.
- Included in this is removal of the policy burden on electricity tariffs.
- Incentives in the tariff help to get the load factor for heat pump load as close to the optimal level as possible. Analysis of daily heat data (source: National Grid) shows that using gas to meet 3% of heat load, in order to lop the heating peaks, could raise the load factor for heat pump load from 35% to 50%, with a major impact on capacity need and hence cost. This has implications for the most appropriate choice of hybrid solutions.
- Managing daily balancing of supply and demand will also require very careful management of a potentially very large heat pump load. The best value (in p/kWh of heat) tariffs are likely to be from supplier managed load.
- Compared to "traditional" load or electric vehicles, our proposal would result in a much lower or minimal allocation of fixed costs, including fixed network costs, to heat pump load.
- Application of a carbon tax to residential gas use has a significant effect on the main heat market competitor – gas. Application of the CCC figure of £ 65 per tonne of CO_2 would add about 1.3 p/kWh to the cost of heat supplied through gas.

Taken together these factors bring the running cost of heat pumps much closer to that of conventional gas condensing boilers. To illustrate a comparison under different tariff conditions, the table below explores how different assumptions affect running costs for a standard/small heat pump consumer requiring 10000 kWh of delivered heat, assuming COP of 3 and 90% gas boiler efficiency. The first two rows show the effect of rebalancing 2016 tariffs to put all network costs in a fixed charge. The last two rows assume cost for heat pump use based on the average electricity wholesale price in the CCC 2030 High Renewables Scenario, and an unchanged gas price, with the last row adding the effect on gas of a carbon tax, again based on the CCC scenario.

This table shows the effect of different assumptions on competitive position of heat pumps (COP=3); gas 90% effcy; for home requiring 10000 kWh pa of heat	**ELEC p/kWh**	**HEAT PUMP Delivered heat; COP=3 p/kWh**	**GAS; heat delivered at 90% p/kWh**	**GAIN FROM ELEC HP £ pa**
Current tariff methodology. 2016 prices.	14.1	4.7	4.11	-59
2016 prices. Eliminate fixed cost and network cost to reduce kWh price for both electricity and gas.	6.8	2.3	2.67	+38
Indicative future electricity price on our heat pump load tariff and gas commodity price unchanged.	7.8	2.6	2.67	+7
Indicative future electricity price on our heat pump load tariff, and gas commodity price unchanged; plus 1.8p/kWh carbon tax for gas	7.8	2.6	4.00	+140

8.2. Gas/ heat pump hybrids and peak demand.

Without gas or other back-up for heat pumps, the capacity margin required for supply reliability would need to increase substantially to maintain an acceptable level of heating reliability. This would combine with a considerable worsening of load factor, as described in the earlier box in 7.2, so that the average p/kWh rates for heat pump use would need to be much higher. The real time component in the electricity tariff could be expected to impose a substantial penal rate, during peak periods and at times of system stress, which would discourage consumers from losing an existing gas connection.

One development suggested for heat pump design has been use of some direct resistive heating during very cold weather in order to boost heat output when the heat pump COP is diminished by the temperature gradient.[30] Our proposed approach would discourage this quite strongly, and this would correctly reflect the adverse effect this design would have on the system economics,

[30] The temperature gradient is the difference between the temperature in the external environment (from which the heat pump is extracting heat energy) and the desired output temperature the heat pump is providing. Low external temperatures mean the pump has to work harder, requiring a higher energy input, and hence reducing the coefficient of performance (COP).

imposing significant additional capacity requirements. Ultimately additional expenditure on capacity would feed through into tariff rates and impose higher costs on heat pump users.

Our analysis, relating tariffs to system economics effects, therefore tends to imply quite strong advantages for the development of hybrid systems.

8.3. Problems of large and unconstrained DASH (direct acting space heating).

A major feature of DASH is its very low capital cost to the consumer, and its potential load pattern with a major contribution to winter peak. This is particularly acute if DASH is used as a back-up to under-sized heating systems. Heating, especially DASH, is a major system concern when electricity meets a much higher percentage of heat requirements, with demand highly sensitive to temperature. The predominance of gas and other systems (including electric storage heaters) in the UK market has hitherto acted to limit this risk, but moves to decarbonise the heat sector, to a large extent through the vector of electricity, mean that its expansion could create problems.

This emphasises further the importance of including in tariff structures some component of real time pricing, at least to deal with periods when the system is under severe stress due to a shortfall in supply or very high demand. This is especially so in the absence of gas back-up. Given the scale of the issue, as electric heating takes hold, it is very important to resolve this. Very substantial (penal) tariff disincentives for consumption at peak periods are a part of the solution, and “red light” periods are part of the tariff proposal.

8.4. Electricity tariffs and their impact on EV owners.

There are two relevant considerations. The first consideration is simply whether the tariff will persuade EV owners to adopt charging practices that are consistent with the least cost provision, based on high load factor, that would result in the lowest costs and lowest prices. But our arguments suggest that there will be a strong financial incentive to adopt a “supplier managed” tariff option, at a very favourable rate of (say) 5 p/ kWh rather than fall back on a hypothetical default alternative with an average price of 8 p/kWh and possibly much higher peak charges.

Unless EV charging is managed to follow very flat profiles, then unconstrained reliance on, for example, early evening EV charging, would be likely to create new peaks, additional capacity requirements and a tariffs feedback to higher rates until a balance was reached.

A second consideration is that we expect aggregate demand in this market (as opposed to time flexibility) to be relatively insensitive to price.[31] This is a very firm and well established empirical finding from all experience with the road transport sector and is one explanation of why governments levy substantial fuel taxes. Transport is a premium use of energy.

Ramsey principles therefore suggest that EV charging could, unlike the heat pump sector, be a prime candidate to pay a substantial part of any fixed network or other costs. Moreover since, undeniably, there are substantial local infrastructure costs associated with local charging points anyway, this could be seen as a natural extension of the problem of financing that element of. One aspect of our hypothetical tariff therefore is that use of EV charging should attract a proportion of

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[31] As with petrol or diesel, consumers may still shop around and be very sensitive to price differences between competing suppliers, but their overall usage will be relatively inelastic.

the fixed charge, with a compensating reduction for standard tariffs applied to "traditional" load. This is obviously easier to enforce if there is a physically separate connection, but that need not be an essential condition. (Traditional water rates included a supplement for use of a garden hose.)

Finally, tariffs can play a role in exploiting the potential value of the storage capacity provided by EVs. This is discussed in 8.5 below.

8.5. Use of EVs as a storage option for system management

Our proposal for linking purchase tariffs to real time SRMC considerations is that it could provide, for some motorists, the possibility of selling stored power at a very substantial profit when the system is under stress (see below). This is a significant potential benefit to the power system and a source of income to the EV owner.[32]

This is a special case of the prosumer situation in relation to purchase tariffs, as described in 5.1 above. It differs, first because the consumer's investment decision (to own an EV with batteries) is already a sunk cost, and second because there is a realistic prospect of EV owners making regular windfalls by selling output from their batteries at times of system stress, at a substantial price. This contrasts strongly with the position of consumers trying to sell solar output during summer.

Potentially this is a very significant reservoir of kWh to assist the system at times of shortage. 10 million vehicles each with 40 kWh battery capacity amounts to 400 GWh, the equivalent of five Dinorwig pumped storage schemes. A very substantial, but fully justifiable, premium could persuade some owners to use their vehicles to support the electricity grid rather than remain available for personal transport.[33] This provides an additional illustration of the potential utility of a significant peak pricing component to the tariff.

8.6. The role of time of day (ToD) components in kWh charges for electricity.

Most existing studies relate to the impact of ToD tariffs with fixed time bands. They tend to indicate that load shifting on predictable ToD tariffs can be significant, but with some limits on what changes consumers are prepared to make to their behaviour. Further constraining factors for fixed ToD time bands in a low carbon system may also include:

- the variability of actual system conditions with more intermittent or variable sources of generation may inhibit the use of ToD rates that do not vary from day to day; unpredictability will significantly lower consumer response.
- cheaper battery storage options, on either side of the meter, may make the degree of price differentiation that can or should be offered in ToD tariffs lower than would otherwise be the case.

But we should be reasonably confident that some degree of differentiated pricing, part seasonal and part time of day, is likely to emerge and play a useful if not dominant role in managing power systems.

[32] In principle this could also be the subject of more complex agreements between supplier and consumer, such as ability to re-charge within a given time window.
[33] As road use is lower in the winter months, this may suit some consumers very well.

8.7. Role of a carbon price.

Conventional assumptions about the desirable level of the carbon price (typically based on the tipping point at which some renewable technologies were deemed to become competitive with fossil alternatives) have often been set at levels much less than £100/tonne. On the other hand, arguments based on social cost or the cost of sequestration could be used to suggest higher values, with £100 as a lower bound. This figure provides one possible benchmark to illustrate the potential effects, after translation into tariffs, of more effective carbon pricing. An alternative is the £65/tonne indicated in the CCC High Renewables Scenario for 2030.

£100/tonne translates into approximately 1.8p per kWh of natural gas consumed, or 3.5p per kWh of electricity (based on **current** structure of UK production delivered to the Grid, but very low or zero in future[34]. £65 /tonne translates into approximately 1.2p per kWh of natural gas consumed.

In the context of inter-fuel competition these are potentially highly significant adjustments. Looking to the future it is potentially of most significance in comparing the costs of gas for heating as against the alternatives of electric alternatives or provision through heat networks.

8.8. Potential for widespread consumer adoption of battery ownership.

Informal estimates[35] suggest a credible estimate of the future cost of lithium/ion batteries of around £100 per kWh capital cost, lower than ESME model assumptions. ESME model assumptions are for a life of around 15 years. Other estimates suggest round trip efficiencies of around 90%. If we combine these possibly optimistic estimates and consider how this might translate into a per kWh based on a daily cycle, then our estimate [based on a 5% real terms cost of capital] indicate a cost of 2.8p/kWh of load shifted through use of the battery, although this figure would be significantly higher if charge/discharge cycles occurred only in winter.

This suggests that load shifting through consumer response to tariffs could face serious competition from use of batteries in preference to dependence on consumer behaviour. This emphasises the simple point that battery storage and demand side management, either through tariffs or supplier management of load, are competing approaches to the time shifting problem and the flattening of the (net) load curve.

The case for batteries to be on the supplier side of the meter is that:

- Diversity implies a much lower total battery requirement.
- Correspondingly a much higher utilisation of the batteries and spreading of capital costs.
- Batteries owned and operated by the distribution network operator (DNO) can be mobile and moved around to meet local network problems.
- DNO batteries will be larger and so enjoy economies of scale.
- They can be used to meet local network problems flexibly at the discretion of the DNO without invoking complex and possibly dysfunctional tariff arrangements on the other side of the meter.

[34] Based on conversion factors recommended by Defra as part of its Environmental Reporting Guidelines. The natural gas figure is based on a physical constant, while the electricity figure is critically dependent on the means of production and is therefore entirely context specific.
[35] Attr. Peter Bruce presentations at Oxford Energy events.

For these reasons it seems unlikely that our tariffs should be expected to encourage or result in widespread battery ownership for load shifting, other than for vehicle batteries, where the cost has already been sunk by the owner in purchasing the vehicle.

8.9. The hydrogen economy

The primary concern of our tariffs discussion has been with small retail consumers, but some of our underlying assumptions have particular relevance to a hydrogen economy. The main reason is that any system currently envisaged for low carbon generation on the scale that includes substantial penetration into the heat market is likely to create some very substantial surpluses during summer months, amplified by past or current incentives for solar power. This provides what is almost a "free" energy input for electrolysis, so that, assuming the other costs of that process can be brought down, there may be a considerable comparative advantage to hydrogen in that process.

The utility of the hydrogen may be partly through direct use in the vehicle market, or injection to the gas grid, but more importantly in this context it provides a partial answer to the issue of seasonal storage and meeting exceptional peaks, through reconversion to electricity, a paradoxical result of having what is close to being a free primary energy input.

The price of hydrogen produced in summer months will eventually be the result of a market process that takes in demand from some peak generation, and possibly other usages, but may provide a lifeline for surplus generation in the summer months, including solar generation.

8.10. Purchase tariffs

Previous practice has encouraged the use of purchase tariffs as a means of encouraging new technology development. This would cease to be the case and a different approach would need to be adopted if required. Purchase tariffs would no longer "override the merit order" and investors in own generation would earn rewards more closely consistent with their value to the system.

9. Summary of Conclusions

Rebalancing of tariffs. The starting point has been examination of the current structure of costs and tariffs

1. More cost reflective tariffs in electricity should lead to a greater emphasis on the fixed charge component of tariffs. This will have some clear economic benefits in reducing the incentives for inefficient investment decisions, notably in relation to own generation, and in incentives for consumer adoption of new low carbon technologies.
2. For the gas sector, there is a similar strong case to be made for rebalancing tariffs towards a fixed charge. This will inter alia have some effect in reducing year to year volatility in the sector revenues and may be important if the role of gas is increasingly seen as a back-up.
3. Political and social concerns may conflict with this rigorous economic approach. However, any regressive effect of rebalancing can be addressed by other means to discriminate in favour of particular groups. One canvassed option is to link fixed charges to property or rateable values (cf water rates). But there are other approaches.
4. The allocation of fixed costs may also, purely in terms of economic arguments, take account of the price sensitivity of the different usages. This suggests, in the future, the possibility of reducing the fixed charge for households without EV charging, a higher charge for those with EVs, but no additional fixed charge for heat pumps.

Future Cost Structures and Cost Drivers.

1. The average wholesale cost of the energy component in retail tariffs in a low carbon economy is likely to be driven by the scale of capital costs, and by load factors of consumption, even more than is currently the case.
2. While tariff and other measures to shape the daily load curve will be important, it is likely to be the irreducible impact of seasonal load factor that is most important in determining differences in outcome average p/kWh prices for different categories of load, notably between heat and transport (EV charging).
3. Our arguments suggest that, as far as network costs are concerned, historically, tariffs have overstated the marginal impact of additional load, at least in relation to total load on the system, and that it is possible that the "true" level of what should be regarded as fixed is very high indeed. There is limited understanding and analysis of the "true" cost structure of these networks, which may deserve more attention.
4. Our analysis suggests different reliability standards, a significant driver of capacity requirements and hence cost, could reasonably be demanded by consumers for different categories of load, accompanied by a corresponding discount or premium in tariff rates. This argues for lower capacity margins, and hence some tariff benefit, in respect of heat and EV loads. But there is no reason in principle why consumers should not be offered a menu of tariffs offering different levels of supply reliability.
5. The allocation of fixed costs may also take account of the price sensitivity of the different usages. This suggests the possibility of reducing the fixed charge for households without EV charging, a higher charge for those with EVs, but no additional fixed charge for heat pumps.

Tariffs and Consumers

1. Given these factors it is useful to consider the three sectors of "traditional consumption", heat pump load, and EV charging individually, although the extent of separation in tariff terms is an open question.

2. We note that heat pump and EV charging may lend themselves to “spreading” over the 24-hour day to a much greater extent than traditional load, and this suggests the option of “supplier managed” load for these usages, as an alternative to complex tariff incentives.
3. This 24-hour “spreading” of heat and EV loads is a necessary condition to achieve the higher load factors consistent with the lowest possible wholesale energy costs, and tariffs will need to provide corresponding incentives, eg to participate in supplier managed delivery.
4. Tariffs will need to include some provision for setting very high prices, linked to a value of lost load (VOLL), at times of system stress - “red light” periods. This is necessary to strongly discourage use of DASH at such times, or other large unmanaged but non-priority loads.
5. Prima facie there is in consequence a strong case for allowing the possibility of EVs having some role in providing back-up at times of system stress.

Broader Policy Implications

6. Retention of the gas network has a valuable role in that its back-up function significantly reduces the standard of power supply reliability required for heat and hence capital costs in that sector. This may be an important factor in considering the ideal size of the gas network.
7. We have identified a number of general questions for heat networks, largely revolving around capital costs and retrofitting, and the options for the main energy source. A brief summary of wider issues is appended.
8. Although outside the scope of this study, the plausibility of low cost “surplus” generation in summer months suggests a possible role for electrolysis and hydrogen as an option for seasonal smoothing and peak demand management.
9. Imposing a policy burden on electricity consumers, for the recovery of social and other costs linked to innovation support, is a perverse incentive and should have no part in a low carbon future, not least because it does not apply to other fuels, including gas, or to own generation by consumers.
10. Our indicative numbers indicate the benefits of a realistic level of carbon tax, in this case applied primarily to gas. Inter alia this may be important, in relation to consumer choices on low carbon sources of heat.
11. The future role for innovation in supply competition needs to be a much more powerful driver of change in promoting new applications. This should include a wider range of tariff menus for consumers. We also envisage consumers being able to take different parts of their supply from different retail suppliers.

10. Appendix

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10.2. General Comments on the Heat Sector

Extract from a high-level perspective[36] *published by the Energy Technologies Institute (ETI) on conceptual approaches to a reformed framework for the governance and regulation of network infrastructure investment appropriate to a low carbon energy sector. This extract covers comments on the heat sector, including both heat networks and heat pumps.*

Features of the heat sector. Collective or individual solutions?

Relevant options for low carbon development of the heat sector are conditioned largely by geographical factors. For heat networks, or "district heating", these factors include proximity to geothermal heat sources, population densities, sufficient scale to deploy heat networks economically, and, under some scenarios, proximity to gas or CCS networks. Heat networks, in which heat is distributed from a common source, raise a number of diverse practical questions, but will necessarily operate essentially at local authority or city levels rather than as units within a unified national body.

Very large numbers of households will continue to make their own choices of heating system, independent of any local heat network, and their most important low carbon options are likely to be heat storage and electric heat pumps. Each of these has important, but very different, implications for the power sector, both at the level of balancing generation and load at aggregated levels, and for providing adequate capacity within local distribution networks.

Strategy for the heat sector therefore has to cover two types of development which will give rise to very different regulatory and practical challenges, in one case a "collective" solution typically initiated at a municipal level, and in the other case solutions mainly chosen and installed by individual consumers, but which may pose significant wider coordination and network problems of a different kind.

The scale of the heat sector is also a major factor. Decarbonisation of the heat sector is widely assumed to require a very substantial ability to use electricity as an important element in substituting for the direct consumption of fossil fuels such as gas. This is a big challenge primarily because meeting existing UK heat loads from electricity generation alone would require a very large expansion, even up to a doubling, of current kWh generation, and, given the seasonal and temperature dependent nature of UK heat loads, a proportionately larger expansion of capacity. Thermal demands of domestic and public/commercial buildings are estimated in a 2012 CCC report[37] at about 450 TWh pa; this compares to current total electricity consumption of about 300 TWh pa.

The same CCC report indicates future heat loads, taking into account UK population growth, of over 400 TWh pa in the period from 2030 to 2050, even on the assumption of high efficiency achievement. More modest assumptions on efficiency require much higher amounts, of up to 550 TWh by 2050. Ambitious energy efficiency rollout projections are therefore a very important part of strategy, but the scope for reducing UK buildings' thermal demands will ultimately be limited, leaving a remaining heat supply requirement that is still very large. Such a change in scale of kWh

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[36] Rhys, J.. March 2016 Markets, Policy and Regulation in a Low Carbon Future. *Policy and Regulatory Frameworks to Enable Network Infrastructure Investment for a Low Carbon Future.* Published by the Energy Technologies Institute and online at https://d2umxnkyjne36n.cloudfront.net/documents/2016-03-22-JR-Final-version.pdf?mtime=20161004120910

[37] Decarbonising heat in buildings: 2030–2050. Committee on Climate Change. April 2012.

supply is likely, a priori, to have very significant implications for local power distribution networks as well as for meeting aggregate demands.

Even if some of the heat need can be met through non-electric routes such as geothermal heat or biomass, and notwithstanding the useful energy gain from heat pumps, the interplay with the power sector is likely to remain substantial, with the possibility that heat choices, collective or individual, could be a dominant factor in the design and operation of power systems.

A further challenge is the potentially high cost of providing heat either through on premises electric heating methods, or through district heating networks, compared to "on premises" gas boilers. Although costs might be lower in favourable conditions, e.g. for heat networks in high density locations, or for further exploitation of current troughs in conventional electric load curves, low cost options are likely to be location constrained or supply limited. The high cost per kWh of heat energy is mainly due to the capital cost of additional generation capacity and/or new heat networks. This factor is accentuated by the strongly seasonal and temperature dependent nature of heating requirements, and further fuelled by the risk (for renewables) of low output at the seasonal peak. For electricity, these factors require an increase in kW capacity even larger than in kWh energy production, in order to meet heat loads.

A simple analysis of monthly long-term averages for recorded degree days[38] suggests that even if within day and within month heat storage were adequate to spread consumption evenly over days and months, heat load factors would still only reach about 54%[39]. This is before taking into account the need for significant margins to cover severe cold spell conditions, or imbalances within the day or the week. A 54% figure reflects a possibly optimistic assumption that short term variations in heat load can be quite easily accommodated.

A poor load factor matters a lot due to the impact on unit costs of capital intensive low carbon electricity generation. Electricity generation facilities (hypothetically) dedicated to providing the main or only means to heat provision would be likely to operate at most at 50% load factor, even for non-intermittent options. There is substantial scope for "in filling" of existing electricity load profiles through, for example, the established heating option of night storage radiators. But, although this is a potentially valuable contribution, it is ultimately limited; and other applications, such as electric vehicle re-charging, may be in competition for some of this "space" in the daily load pattern. It does not in any case deal with the seasonality factor. Poor load factor substantially increases the contribution of electricity capital costs, the dominating element in low carbon systems, to average kWh costs associated with meeting heat demand.

Reflecting the above considerations, some alternative low carbon or electric options for the heat sector are set out below, leading on to consideration of network, commercial and regulatory issues. All pose some specific challenges for regulation and for a coordinated approach to heat and to the energy system more widely.

The Collective Solution. Local Heat Networks.

Heat networks, for distribution of heat in order to warm buildings, are in an energy efficiency context often associated with options for combined heat power (CHP) operation, but historically and internationally they have also been associated with other formats, e.g. conventional boilers

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[38] Heating degree days are the number of degrees by which average temperature falls below a "base", e.g. 15.5o C, summed over all days for a given period. A similar measure, cooling degree days, can be applied

[39] Degree day statistics are readily available in official UK weather statistics.

fired by oil, coal or gas[40]. In principle future development could be in association with, for example, biomass or fossil fuel input with CCS, biomass without power generation, use of hydrogen fuel, dual firing, geothermal sources, or possibly as part of wider large-scale heat storage.

Non-electric low carbon options include geothermal energy, where lower cost options are likely to be geography specific. A second is use of conventional fossil fuels but with CCS. This in turn may be limited initially to sites adjacent to a relatively small and undeveloped CO_2 gathering network and carries the burden of the higher capital costs associated with CCS. A third is use of biomass or waste with CCS for firing district heating boilers. Once again biomass is likely to be supply limited and additionally has an important and possibly higher value in a competing use as input fuel for peaking or back-up plant[41] against renewables intermittency. Each of these non-electric options is therefore exposed to some form of supply limit.

The electricity linked solution for local heat networks is some form of combined heat and power production (CHP), with distribution of hot water as the heat vector. In this instance the source of the heat energy is thermal power generation plant. It is low carbon only for nuclear or for fossil plant with CCS. Biomass is a theoretical option, but as noted above, is subject to supply limitations and competing use constraints.

A general feature of district heat distribution is the large volume and large mass of water at relatively low temperatures, the last accentuated for CHP. This implies high capital and operating costs of distribution. In most circumstances, the most cost-effective means of transporting and delivering energy over significant distances are likely to be electricity by wire, gas by pipe, or through a hydrocarbon store as a liquid fuel, rather than as low-grade heat, with a low energy density, distributed through pipes to carry hot water. This factor is accentuated when the gas or electricity network is already in place or will be required anyway.

So the likely development of heat networks will be as local entities, without the development of national or large scale bulk transmission of heat. This strongly conditions approaches to developing and regulating heat networks. All district heating schemes will face the challenge of local capital costs in heat distribution and connection costs for individual households. A main problem is the cost and other issues associated with building new networks to distribute the heat.

The hard questions derive from the very obvious economies of scale in setting up a district heating network, and the alternative choices that consumers may want to make, if they have a free choice of heating method. Universal or near-universal participation may well be essential to the economics of many or most schemes. This is not necessarily a problem for “new build” situations. The equivalent of district heating schemes exist on a small scale, for example, in many large London apartment blocks, with an attendant lack of choice for residents. Typically, they pay a fixed charge and their heat consumption is not metered (although this is changing). But residents in this case have “chosen” this form of heating when they moved in.

Implementing larger schemes that involve major retro-fitting is much more problematic, and, in addition to technical and engineering considerations, depends either on an element of compulsion or on making the district heat option significantly more attractive than alternatives in terms of

[40] The widespread adoption of domestic gas condensing boilers has dramatically improved the efficiency of domestic gas heating, to a significant extent weakening the efficiency arguments for CHP.
[41] This is dependent on the implicit price of carbon and whether the target is 90% or 100% CO_2 reduction.

household heating costs, a matter whose economic and political ramifications need to be considered in setting out a strategy for the heat sector.

Compulsion or choice in the context of heat networks

If we assume near universal participation as a necessary condition for the viability of most heat networks, then we have to confront the problem that many consumers will be reluctant to incur the disruption or other "transaction costs" of joining a heat network. These are in many ways akin to the problems of implementing programmes for raising insulation to a high level across the housing stock as a whole.

Insulation of buildings and energy efficiency is usually assumed in longer term projections. The benefit is clear – lower aggregate heat and electricity requirements, and lower capital outlay and running costs. The negatives are issues relating to the retro-fitting of the existing building stock, chosen policy instruments, and transaction and disruption costs to consumers. Increasing take-up may be achieved by simple economic incentives and subsidies but administrative measures, amounting to a degree of compulsion, have also been proposed by some commentators.

There is therefore a case for finding ways to link the two initiatives in the public perception, not least to reduce the element of discrimination that might be felt in areas where a heat network was being imposed.

Compulsion in a formal sense is unattractive, although comparable historical examples might be cited, such as the imposition of smokeless fuel requirements to combat city pollution in the 1950s. In practice some combination of "carrot and stick" is likely. This might for example be a selection from or combination of the following:

- Consumers are put on notice that existing services, e.g. unrestricted mains gas supply, will not be available after a certain date, or only available at a substantially higher price.
- A direct subsidy towards the capital cost of retro-fitting to the consumer's own premises.
- Partial funding of the heat network through local taxes, so that householders recognise they are already paying part of the cost anyway.
- A guarantee that total future running costs will not exceed those of some benchmark calculation for the alternatives available to the consumer, e.g. electric storage heating.
- Ensuring that running costs for the alternatives fully reflect cost, including back-up energy per se. This would at least reduce the subsidies or the degree of compulsion necessary to induce near universal participation. Carbon pricing may be one element in this.
- Incentives through energy rating of buildings which might improve their value in selling or be reflected in local property taxes.

Operations of CHP schemes and interaction with power systems

Issues in CHP operations reflect the fact that there is normally a trade-off between heat production, expressed as the temperature of output heat, and the thermal efficiency of electricity generation. One question is therefore whether CHP could or should be wholly subject to central dispatch, thus enabling the SO to call for extra power at times when the system is under stress and additional capacity is required. This is a potentially complex question. First it further complicates an already difficult task for the SO. Second it creates difficult conflicts of interest and duty within the CHP scheme, ie whether its primary responsibility is to heat customers or to the national power supply, or to meet a financial target. Third, reducing heat output in severe winter weather, in order to increase electricity output, could induce compensating use of direct electric heating appliances by individual households, defeating the purpose or even producing an adverse system feedback.

In theory there might be a case for comprehensive optimisation by a central overall system operator, but the problems of possible multiple objectives and excessive centralisation are much more apparent than the benefits. It should be clear that the primary duty attaching to CHP schemes is to provide a secure supply of local heat.

This does not need to inhibit purpose specific contracts between the CHP facility and the SO. The operator of the heat network would deal directly with the SO and the CPA, and the basis for kWh sales would be some combination of negotiated contract and tariff terms, analogous to those for retail suppliers of power. Contract terms would need to reflect technical constraints on the CHP plant, the priority attaching to heat output in winter, and CHP design should aim to maintain flexibility in operations.

Organisation and strategy for heat networks.

The heat network sub-sector is potentially diverse. It could include for example new schemes for isolated but concentrated rural communities with relatively small-scale heat needs, conversions of established medium scale apartment blocks with communal heating, and larger and more controversial city wide schemes, including small scale nuclear generation. It is city schemes that are probably the most relevant to achievement of low carbon heat penetration in the ETI scenarios. A critically important factor is that of network economies of scale. Many schemes may only make economic sense with a sufficiently large number of dwellings at a fairly high density, possibly and controversially combined with near-universal participation.

In strategic terms, the intuitively obvious approach is to start with the "low hanging fruit", where costs are lowest, and where consumers are less likely to be resistant to a potentially disruptive change. This increases the chance for early success and provides an opportunity to learn from the technical and other obstacles encountered in the first projects, before proceeding to more challenging schemes. After the more obvious "new build" opportunities, the next category would perhaps be areas with high density of dwellings and a high proportion of rented property, where a primary responsibility rests with landlords, public or private. This reflects an assumption, possibly misplaced, that owner occupiers will object more strongly to the disruptions associated with retro-fitting heat networks.

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