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A review of current and future costs and benefits of demand response for electricity

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ABSTRACT

Demand response can play a key role in bringing about a low carbon electricity system and more efficient allocation and use of electricity which will have both economic and environmental benefits. To ensure demand response, there is a need for infrastructure as well as the right institutional environment to ensure participation. Electricity market reforms can play a role in ensuring the right institutional arrangements to help encourage demand response and to reduce barriers to demand response. For regulators to have confidence in regulatory changes required to accommodate demand response for electricity, they must know the economic case for demand response This is the subject of the current paper. The paper firstly reviews and clearly outlines the different forms of demand response that exist and then goes on to assess the economic case for demand response through synthesis of five of the most relevant papers/reports assessing potential current and future costs and benefits of demands response in the UK. Quantification of all costs and benefits relating to various forms of demand response was not possible, but was for the majority. This study indicates that a positive economic case exists for most types of demand response. The positive case for demand response however relies upon at least a modest participation rate by energy consumers. For demand response to play its role towards energy security and a low carbon economy, the right environment needs to be developed to ensure consumer participation, as this determines the demand response related benefits for the UK and energy consumers who ultimately are likely to pay quite a large portion of the costs relating to DR (e.g. smart metering infrastructure etc).

1. INTRODUCTION

This paper brings together key literature relating to the costs and benefits of demand response (DR) for electricity in the UK. The paper aims to collate and provide estimates of the various costs and benefits and synthesise the economic case for demand side response for electricity[1]. The review does not enable comprehensive assessment of all benefits; from the literature it was found that benefit estimates for some aspects are currently not available. This paper does however attempt to quantify as many core costs and benefits as possible and report expected future costs and benefits as possible. It is hoped that by doing this one can identify the broad balance between costs and benefits for DR and highlight current uncertainties. The output will be used to guide DR related research and identify gaps that the University of Surrey, Reshaping Energy Demand of Users by Communication Technology and Economic Incentives (REDUCE) project could address.

The review is being conducted at a useful time, as the Department for Energy and Climate Change (DECC) is currently consulting on Electricity Market Reform (EMR). The proposed reforms of the EMR mainly relate to enabling the provision of new supply infrastructure to meet future electricity demand, ensuring energy security and at the same time enabling accommodation of more ‘low carbon’ generation (for example renewable and nuclear). Amongst other benefits DR has the potential to enable reductions in system infrastructure requirements, as well as accommodating more renewable generation. Strbac (2008) points out that an appropriate regulatory framework is essential in order to optimise the benefits of storage and demand side management within a liberalised environment (which exists in the UK). For regulators to have confidence in regulatory changes required to accommodate demand response for electricity, they must know the economic case for demand response in electricity markets. This is the subject of the current paper.

For this study, five of the most relevant papers/reports in assessing potential current and future costs and benefits of demand response in the UK are reviewed: DECC and Ofgem (2011a and 2011b), Ofgem (2010), Strbac et al (2010), Strbac (2008) and Seebach et al (2009). Details from other studies are incorporated where appropriate. The paper

[1] *Demand response is defined in different ways and this is discussed in the paper. Greening states that in the near term, demand side response is limited to changes in consumption in response to prices.*

starts by introducing and providing background on demand side management and demand response.

Demand side management (DSM) has evolved over the last three decades. Traditionally demand side management has been applied and generally restricted to efficiency and conservation programmes[2]. When developing such programmes electricity prices were taken as a given; this is said to have hampered such programmes. More recently however, programmes that emphasise price responsiveness have arisen (Charles River Associates 2005)[3]. Many authors refer to the latter as demand response.

Bilton et al (2008) discuss various forms of demand response and in the literature different definitions of demand response are used. Greening (2010 page 1519) states that:

"In the short run, the definition of demand side response is limited to modifications in consumption in response to prices"

Cappers et al (2010, page 1526) briefly look at how demand response is defined by others such as U.S. Department of Energy (2006) and Federal Energy Regulatory Commission (2006) and apply the following definition for demand response which is slightly broader than the one above:

"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardised"

This definition is a more concise version of the U.S. Department of Energy (2006) definition[4].

Building on a paper by The International Energy Agency (2003), Albadi and EL-Saadany (2008 page 1990) define demand response in a similar but slightly wider way to include energy savings:

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[2] For efficiency programmes, Spees and Lave (2007) report energy efficiency gains for nine studies, some of which include economic estimates;

[3] Spees and Lave (2007) provide further historical account.

[4] "Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized". (U.S. Department of Energy 2006 p.v)

"DR includes all intentional electricity consumption pattern modifications by end-use customers that are intended to alter the timing, level of instantaneous demand, or total electricity consumption"

Torriti et al (2010, page 1) define a similar boundary but in a somewhat different way. They state that:

"*Demand Response (DR) refers to a wide range of actions which can be taken at the customer side of the electricity meter in response to particular conditions within the electricity system (such as peak period network congestion or high prices)."*

Greening (2010 page 1519) states that[5]:

"The very broad definition of demand response includes both modification of electricity consumption by consumers in response to price and the implementation of more energy efficient technologies."

Greening (2010) notes that savings or benefits of demand response are highly variable depending on how DR is defined, and the types of programmes included in such estimates. In this study we broadly apply the definitions of Albadi and EL-Saadany (2008 page 1990) and Torriti et al (2010) when reviewing the costs and benefits associated with demand side response. This means we do not include energy efficiency improvements as a result of improved insulation etc. as a form of demand response.

It should be noted that the current study only uses published estimates of benefits and costs from DR as this increases the transparency of reporting; however as a result of this data aggregation was an issue for a few cost and benefit categories.

In this study, we firstly (section 2) review the core benefit categories from DR identified in the literature. Estimates of the value of benefits and any CO_2 reductions are then reported in section 3[6]. Section 4 briefly reports the main cost types relating to DR. Estimates of these costs are reported in section 5[7]. Discussion of costs and benefits of DR is conducted in section 6 and finally conclusions from the review are drawn in section 7.

[5] Greening (2010) seems to focus on price response, but as earlier noted response to incentives can also occur.

[6] Factors affecting level of response and potential barriers to demand side participation are the subject of further review and research in this project and are not a dominant subject or even heavily listed in this review.

[7] For costs and benefits the paper will attempt to provide likely estimates and where possible ranges, but will stop short of defining what the actual level of demand response (and hence expected benefits) will be from any action.

2 BENEFITS OF DEMAND RESPONSE

Greening (2010) identifies that estimation of benefits is determined by quite a number of factors such as: the elasticity of demand by various customers; the maximum level of response available during peak periods; the costs (fixed and variable) of the avoided generation, transmission and distribution; load profiles; pricing and incentives or penalties; cost of programme implementation. Given that Greening (2010) is referring to costs in determining benefits here, the current author assumes that Greening (2010) is referring to net benefits: remaining financial benefit after costs are deducted.

From all of the main studies reviewed, none seemed to identify whether benefits could or would result in net welfare gains. This is important to identify though, as different forms of demand response can vary in the extent to which they produce actual productivity and efficiency gains for the economy, the topic is investigated in the current paper. In welfare economics: Welfare is the sum of the producer and consumer surplus. Welfare gain can be defined as the net increase in consumer and producer surplus without regard to the distribution of the gains (as seen in Boisvert and Neenan 2003[8]). Wealth transfers do not result in an increase in the sum of the consumer and producer surplus, only a change in distribution of the surplus between producers and consumers. Please refer to Boisvert and Neenan (2003) for more information about welfare gains and demand response. In the current study a full welfare analysis is not possible but we attempt to identify whether benefits can result in a welfare gain, assuming benefits outweigh costs (ABOC)[9]. From section 2.1 onwards the term welfare gain is termed a net welfare benefit in order to keep consistency and fluidity in our use of language. A net welfare benefit is different from a net benefit which is any overall benefit that remains once reported costs (related to a demand side response investment e.g. smart metering) are deducted from benefits.

It was also found in the studies reviewed that the boundaries between different costs and benefits seem somewhat blurred at times and on occasions it is difficult to avoid overlap between potential benefits. In the current paper, particular care is taken to define benefits and where possible avoid overlap between benefits (and hence double counting). Where overlap is unavoidable, we note the potential for overlap.

[8] They look at social welfare implications of demand response programs in competitive electricity markets.
[9] Denoted by ABOC when we apply the assumption: benefits outweigh costs.

Sheffrin et al (2008) identifies the main potential benefits of DR as: lower wholesale electricity prices; maintaining system reliability (and avoiding forced outages) which financially is hard to quantify; reduction of costly additional transmission and generation infrastructure built, due to reductions in peak demand.

Different terminology are sometimes used for varying costs and benefits and sometimes reporting of benefits is quite complicated and repetitive. This review attempts to clearly and where possible simply present what the benefits from DR actually are. This is now conducted in sub section 2.1

2.1 The range of benefits from DR

Strbac (2008) was found to explain benefits in the most detailed way and provide quite good coverage of the range of benefits that can arise from DR. However, not all benefits are presented clearly and complexity remains. His study uses the term DSM, but the way the term is used by Strbac (2008) seems to generally fit with the definition of DR used in the current study. From reading this study and other literature, there seems to be roughly eight core benefits possible from demand response. The benefits of DR are now identified in accordance with the sub section in which they are discussed; as well as the studies later used to assess them, as seen in Table 1.

Sections	Benefit	Relevant studies	Quantification
2.2 and 3.3	Benefits from relative and absolute reductions in electricity demand;	DECC and Ofgem (2011a and 2011b)	Yes
2.3 and 3.3	Benefits resulting from short run marginal cost savings from using demand response to shift peak demand	Ofgem (2010) and DECC and Ofgem (2011a and 2011b)	Yes
2.4 and 3.4	Benefits in terms of displacing new plant investment from using demand response to shift peak demand;	Ofgem (2010) and DECC and Ofgem (2011a and 2011b)	Yes
2.5 and 3.5	Benefits of using demand response as 'stand by' reserve for emergencies/unforeseen events;	Strbac (2008)	Partial
2.6 and 3.6	Benefits of demand response in providing standby reserve and balancing for wind;	Strbac (2008), BERR (2004 and 2006), POST (2008), Seebach (2009)	Yes
2.7 and 3.7	Benefits of DR to distributed power systems;	Strbac (2008)	No
2.8 and 3.8	Benefits in terms of reduced transmission network investment by reducing congestion of the network and avoiding transmission network re-enforcement;	Strbac (2008), Mott MacDonald (2008)	Yes
2.9 and 3.9	Benefits from using demand response to improve distribution network investment efficiency and reduce losses.	Strbac (2008), Mott MacDonald (2008), DECC and Ofgem (2011a and 2011b), Strbac et al (2010).	Yes

Table 1: Demand response benefits identified from this review

More detail and discussion of each benefit is now conducted for the eight benefits identified in Table 1. It can be seen in the table that for most types of DR it was possible to attain a quantitative estimate. Where studies allowed estimation of average annual benefits, this was conducted to enable benefits to be compared in a more consistent and comparable form across studies, this helps discussion in Section 6.

2.2 Benefits from relative and absolute reductions in electricity demand

The current study defines electricity reductions as ‘relative’ or absolute. In this study relative is defined as on site (business) electricity reductions which result in decreasing electricity consumption per unit of gross value added (business). For households, a relative reduction in energy consumption is equivalent to a decrease in electricity use per unit of household income. In the latter situation overall usage of electricity could still increase. When absolute reductions in electricity result, there is an overall decrease in on site electricity demand (over a period of time) for a household or an organisation. These definitions follow similarly discussions on relative and absolute decoupling at an economy level as seen in Jackson (2009) [10].

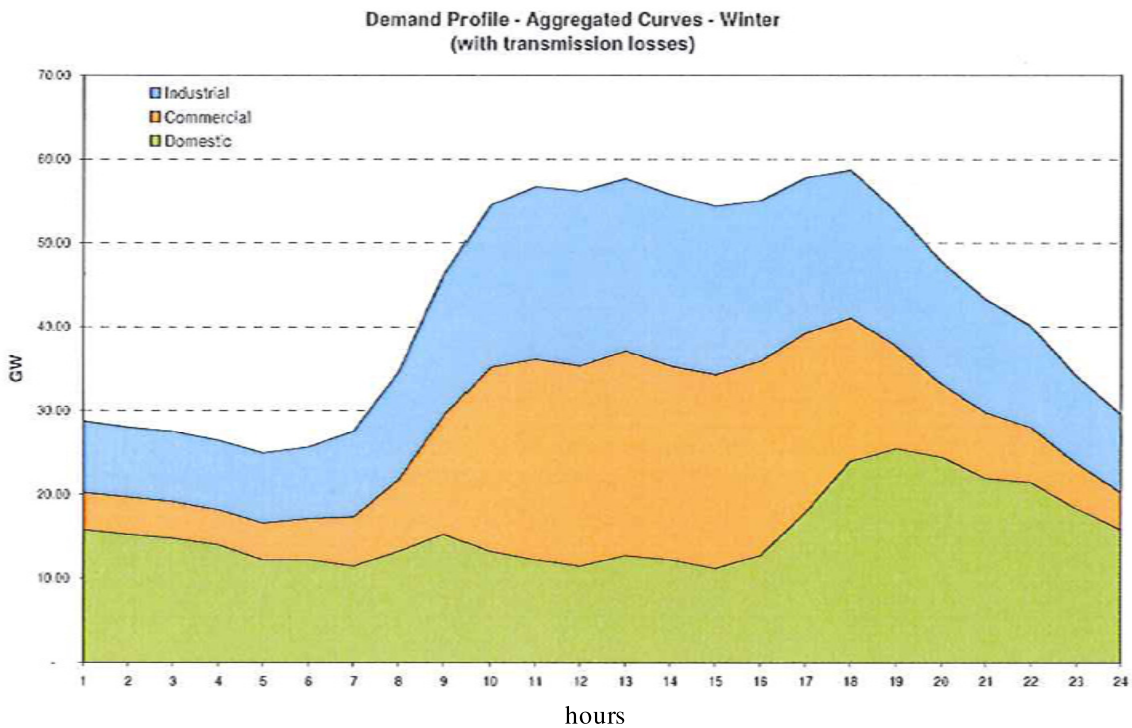
Reductions in electricity demand can result in reduced costs (through energy savings) to consumers and reductions in CO_2 emissions (relative or absolute) as well as reduced consumption of resources (relative or absolute) which has the potential to impact on resource scarcity (and the economy) when finite resources are used for electricity generation.

In order to look into some of these benefits the current study reports estimated electricity savings (and consequent benefits) from the introduction of smart meters. With the introduction of smart metering, there can be increased information and opportunity to help individuals save energy and reduce their electricity demand. Smart meters have been mandated by UK government for the domestic and small and medium non-domestic sector and will be installed over the next 20 years. As a result of this a number of publications are available that provide quantifiable indication and estimates of expected benefits from energy savings such as DECC and Ofgem (2011a and 2011b) as described in section 3.

[10] See Jackson et al (2009) for a review of relative and absolute decoupling of GDP and resources.

2.3 Benefits resulting from short run marginal cost savings from using demand response to shift peak demand

The nature of electricity demand is that it does not remain constant throughout the day, there are peaks in demand at the whole system level as identified in Figure 1. Such a profile reflects the aggregation of many millions of even 'peakier' load profiles at the individual consumer level.



Source: IHS Global Insight estimate. Commercial includes public administration.

Figure 1: UK System demand profile, estimated customer class contribution (IHS Global insight 2009).

Global Insight (2009) identify that the peak demand on the system over the whole year occurs on a cold winter weekday evening around 5 to 6pm.

This is because increasing residential load coincides with still high commercial and industrial demand as seen in Figure 1. Ofgem (2010) note that electricity is an unusual product, as it cannot be stored cheaply or in great quantities, therefore demand and supply have to balance in real time. As a result of the need for balancing, when very high (peak) demands are made on the electricity system, supply is also needed to respond in real time. When high demands need to be met, larger amounts of generation capacity are required to be available and operating.

In practice, the most efficient generators are likely to be running much of the time, but as demands on the system increase additional and sometimes less (economically and environmentally) efficient generators are required. This is a key factor in why the price of electricity per unit (kWh) increases during peak time. The high cost of generation to meet peak demand is ultimately passed onto the consumer. The logic goes, that by shifting some demands to outside of peak hours (where there is more efficient generation capacity available) this reduces the extent to which inefficient generation capacity is required, therefore reducing cost and environmental impact of electricity per kWh. If the peaks can be regularly and reliably reduced, then essentially the requirement for extra capacity can be reduced. This relates to the next benefit.

2.4 Benefits in terms of displacing new plant investment from using demand response to shift peak demand

There appears to be two types of situation where DR can aid the displacement of new plant infrastructure[11]. The first relates to displacement of extent of generation capacity required to meet peak demands. In this situation the idea is to use DR techniques to persuade some customers to ensure that peak demands are regularly and reliably lower than the peak would naturally be without DR[12].

It is believed that given that some generation capacity required to meet peak demands does not operate all the time, there may be some overlap (and therefore caution should be taken in avoiding double counting) between displacement of generation from reducing peak demand and the second situation: displacement of generation from customers willing to provide demand response as ‘stand by’ reserve for emergencies/unforeseen events. The second situation is now described.

[11] A third situation perhaps occurs when using DR for balancing for wind as seen in the next benefit.

[12] Sheffrin et al (2008) identify that of the studies they reviewed, demand response in the range of 5 to 15 percent of a system peak load can provide substantial benefits in decreasing need for additional resources and lowering real time electricity prices for all customers.

2.5 Benefits of using demand response as 'stand by' reserve for emergencies/unforeseen events

This relates to identifying and persuading some customers to forgo consumption relatively infrequently but at short notice, to provide the ability to the system to reduce demand quickly in an emergency. These customers would effectively be on 'stand by' support to surrender some of their demands on the network[13]. Using DR in this way would enable displacement of the need for infrequently used long term reserve generation capacity (Please see Strbac 2008 for more detail). 'Stand by' support effectively relates to the need to balance the system in emergencies.

2.6 Benefits of demand response in providing standby reserve and balancing for wind

It was earlier noted that in general electricity demand and supply have to balance in real time. This balancing will become increasingly difficult as the UK increases intermittent renewable generation such as wind and (possibly) inflexible generation capacity such as nuclear. With increasing intermittent supply, Strbac (2008) notes that the system will need to apply increased amounts[14] of reserve. He notes that this reserve will generally be provided by a combination of synchronised and standing reserve. In order for synchronised conventional generation to supply reserve, according to Stabac (2008) it must run part loaded. This part loading leads to inefficiency losses of 10-20%. He then notes that because the plant is running part loaded to provide reserve, additional generation capacity is then needed to be brought onto the system to supply energy originally allocated to the plant now running part loaded. Strbac (2008) notes that this usually means a higher marginal cost plant will be needed to run; this is a second source of inefficiency. It is said that in addition to synchronised reserve enabled by a part loaded plant, balancing also requires the support of standing reserve which can be supplied by a plant with higher fuel costs or by storage or DR. DR can perform the role of standing reserve as opposed to having flexible generation capacity on standby.

Strbac (2008) also notes that DR could provide a way of increasing the amount of wind power that the system can absorb as fewer generating units are scheduled to operate. It

[13] In this study we define this as 'stand by' support. Strbac (2008) terms it as stand by reserve. The reason we define this differently is in order to separate out benefits more clearly.

[14] The fact that the term ' increased' is used, would indicate that this is additional to the generation already used in the system and therefore avoiding double counting of avoided investment costs in reserve generation, used for peak demand and emergency stand by support.

is noted that this is particularly relevant in conditions of high wind, low demand. By increasing the amount of wind energy absorbed, this would allow a decrease in the amount of fuel bunt. The value of storage and DR when providing standing reserve can be calculated by analysis of the improvements in the system in terms of fuel cost and CO_2 emissions (Strbac 2008). In the current project we review quantitative benefits from balancing for wind that may result from the introduction Smart appliances (from Seebach et al 2009)

2.7 Benefits of demand response to distributed power systems

Similarly as for large scale wind, DR can bring benefits in the form of enabling greater use of distributed power generation. Benefits of DR in this context again relate to balancing, as achieving balance of demand and supply in a distributed supply system comprising different forms of renewable generation and different forms of combined heat and power (CHP) will be difficult (because it is not easy or desirable to modulate output of renewable or heat-led plants to follow a particular electricity load shape). DR could facilitate connection of more distributed generation by providing greater flexibility in balancing the system (Strbac 2008).

2.8 Benefits in terms of reduced transmission network investment by reducing congestion of the network

Strbac (2008) identifies that the advantage of the current UK operating philosophy (preventive, dominantly based around providing enough infrastructure to ensure security and minimising the chance of black outs for all times of the day) is simplicity of operation, but that this property emerges at the expense of increased operating costs and low utilisation of generation and network capacity with use of generation being at about 50%, and use of network capacity even below this. The author notes that recent advances in ICT could enable a change in the operating system philosophy from preventative to corrective. The alternative approach identified by Strbac (2008) is to operate the system at a lower operating cost including reduced network and generation capacity (therefore with higher utilisation), this is as long as overloads occurring after outages of circuits and generators, can be effectively eliminated by conducting suitable corrective actions, e.g. curtailing some loads at appropriate locations. It is said that DR programmes would be a core strategy in ensuring appropriate actions can be taken. This active approach would allow transmission network investment to vary while ensuring security of the system (Strbac 2008). It should be noted that regular peak demand shifting on its own can also result in a reduction in transmission network investment requirements, without changes in the electricity system management philosophy.

2.9_Benefits from using demand response to improve distribution network investment efficiency and reduce losses

Similarly, with regards to improving distribution network investment efficiency through a change in philosophy using DR, Strbac (2008) identifies a range of potential benefits as follows:

"(i) Deferring new network investment, (ii) increasing the amount of distributed generation that can be connected to the existing distribution network infrastructure, (iii) relieving voltage-constrained power transfer problems, (iv) relieving congestion in distribution substations, (v) simplifying outage management and enhancing the quality and security of supply to critical-load customers, and (vi) providing corresponding carbon reduction."

Again it should be noted that regular reductions in peak demand can result in reduced distribution investment needs, without having to change the electricity system management philosophy.

Now that the various core benefits of DR have been clearly identified, the literature is reviewed for reporting and quantification of these benefits.

3 VALUE OF BENEFITS FROM DEMAND RESPONSE

3.1 Introduction

In this sub section, reported estimates of benefits for each type of benefit are provided where possible. For those benefits where quantification is not possible, qualitative discussion of the potential extent of benefit is reported. We start with the first benefit identified in the previous sub section.

3.2 Benefits from relative and absolute reductions in electricity demand

As mentioned in section 1.2 to provide a quantification of the estimated benefits from energy savings, quantification of possible/likely electricity savings (and benefits) from mandatory introduction of smart metering in the UK are reported. Such benefits were found to be published separately for the domestic sector and small and medium non domestic sites by the Department of Energy and Climate Change (DECC and Ofgem (2011a and 2011b)[15]. We start by looking at domestic sites.

Domestic sector

DECC and Ofgem (2011) present estimated financial benefits in energy savings that result from electricity reductions as a result of the introduction of smart meters over a 20 year period. They investigate three scenario cases; a low benefits case, a central case and a high benefits case. For the central benefits case they assume a 2.8% reduction in UK domestic electricity. Using this central case £3140 million of financial electricity savings are made over 20 years[16]. Benefits over the 20 years are discounted at 3.5% as are costs.

The EU ETS permits savings in millions of tonnes of CO_2 saved equivalent for electricity are estimated to be 17.4 $MtCO_2e$ over 20 years for the central case scenario (Defra and Ofgem 2011).

If the value of energy savings over 20 years is divided by the number of years, then this leads to an annual average of £157 million (generated from present value estimates) for

[15] Earlier publications such as DECC and Ofgem (2009a and 2009b, 2010a and 2010b) were also reviewed.

[16] A value of £1538 million resulted from the low benefits scenario (1.5% reduction in electricity consumption for the UK) and £4618 for the high benefits scenario (4% reduction in electricity) over 20 years. DECC and Ofgem (2010a) were quite vague on the method of valuation used to value electricity reductions. So it is unclear how they are valued. This is also the case for DECC and Ofgem (2010b).

the central case scenario[17]. If CO_2 benefits are averaged over 20 years this leads to a figure of 0.87 millions tonnes of CO_2 equivalent saved for the central case scenario.

Small and medium non-domestic sector

Small and medium non-domestic sector estimates apply the same percentage electricity reduction assumptions as domestic. Again, estimates are made for a low benefits scenario, central case and high benefits scenario. The value of electricity savings for the central case is estimated at £674 million over the 20 years[18] (DECC and Ofgem 2011b). Discounting is again conducted at 3.5%. GHG reductions from electricity reductions (in the DECC and Ofgem 2010b report) are estimated at 4.9 $MtCO_2e$[19] for the central case scenario.

If the financial value of energy savings (present value) is divided over the 20 years of the project, then this leads to an annual average figure of £34 million in savings for consumers. If the same is done for GHG savings then this leads to an annual average of 0.25 million tonnes of CO_2e[20].

Key points with regards to domestic and non domestic benefits

Some of the above estimated energy reductions occur during peak time, so there maybe some overlap with short run marginal cost savings reported for peak shifting. This is however not thought to be the case as energy savings during peak shifting are subsequently used at a different time in the day but there is a small potential for some double counting. In terms of total overall physical energy reductions, it is believed that the way that DECC and Ofgem (2010a and 2010b) estimate CO_2 will result in peak time reductions forming a significant but not dominant part of estimated CO_2 reductions.

It is believed that CO_2 reductions can fall into the category of a net welfare benefit (ABOC), however the current study generally does not attempt to report monetary value of these savings in the main body of this document apart from when this is the only value

[17] It should be realised that annual average benefits do not in reality reflect the value of energy savings that can be obtained in a year from implementation of smart meters, as for the early years of the project benefits are a lot lower than they are in later years of the project when much of the implementation of meters has been conducted.

[18] For the low benefits scenario £330 million in electricity savings was estimated and £992 million for a high benefits scenario (again over 20 years).

[19] This is based on summing up traded (that falls under electricity) CO_2e in the table at the bottom of page 5.

[20] These benefits result from energy and CO_2 reductions directly from energy reductions of small and medium non domestic sector organisations and do not include benefits from reduced need for inefficient capacity (the same is so for domestic sector estimates). This was Confirmed with Pau Castells (15th March 2010). The same applies for energy savings from the domestic sector.

available. This stance is taken as financial values for CO_2 are generated from an estimate of financial value per tonne derived from emissions trading markets and these do not represent or reflect damage costs associated with the generation of a tonne of CO_2.

It should be noted that many of the electricity savings will not occur during peak times, for this reason it is believed that much of the value of energy bill reduction benefits from energy savings are unlikely to fall into the category of a net welfare benefit[21], but instead welfare transfers from producers to consumers. Although this is so, they are still real benefits to society and highly desirable as they help householders reduce and control escalating energy bills (and can reduce fuel poverty). One could also argue that reduced demand (if absolute reductions) will reduce resource scarcity if electricity is produced from finite resources, therefore reducing prices. An argument against this however is that reduced demand can reduce prices for the resource and reduced prices will result in an increase in demand.

3.3 Benefits resulting from short run marginal cost savings from using demand response to shift peak demand

With regards to this benefit, an early study that seems to attempt quantification of this benefit for electricity (on its own) for the UK is Ofgem (2010). They examine the potential wholesale cost savings associated with shifting electricity demand away from peak times. They examined two scenarios, shifting 5% and 10% of peak load. They estimate daily electricity wholesale cost savings to be £0.4 to £0.8m a day with a 5% shift and £0.7m to £1.7m per day for a 10% shift (depending on level of demand shifted and day examined)[22]. The authors state that estimates are indicative only and are likely to be conservative. Benefits for the Ofgem (2010) study are not discounted.

It should be noted that daily estimates (developed from three days) are said to not be applicable all year round. The authors note that wholesale cost savings are larger in winter, (and to a lesser extent) spring and autumn months than in summer months. The days chosen to calculate benefits were two winter days and an autumn day. For the 3 days, demand profiles were used to calculate wholesale cost savings from DR.

[21] ABOC.

[22] Shifted demands appear to be for both domestic and non domestic sectors (including larger commercial and industrial businesses).

According to Ofgem (2010), the cost savings identified above (short run marginal cost savings (SRMC)) were estimated by calculating the difference between the SRMC of the generation plant 'displaced' by DR and the 'replacement' generation plant. The 'replacement' (off peak) plant is expected to have a lower SRMC. This is because the study assumes generation plants used to meet demand run in ascending order of SRMC (Ofgem 2010).

The authors state that because wholesale prices are likely to capture the price of European Union Allowances as well as investment costs (in generation etc), there may be a level of double counting if adding costs for carbon emissions savings and investment savings (later dealt with in the current section) together with the daily wholesale cost savings. DECC and Ofgem (2011a and 2011b) treat with the issue of double counting of investment costs, but they state that in the short run (up to 2030), both benefits from utilising the existing capacity more efficiently (short run marginal cost savings) and reducing the need for investing in future capacity are realised. This suggests that double counting is not an issue in the short run.

Ofgem (2010) state that because wholesale cost savings are just an average for three days, the estimate should not be applied to estimate annual benefits.

DECC and Ofgem (2011a and 2011b) however build on this Ofgem (2010) work and estimate the annual short run marginal cost savings resulting from energy demand shifts over the life of the smart metering projects. They are however more cautious about their assumptions on how much demand will be shifted during peak time[23]. Estimates for demand shifts are conducted through assumptions about the uptake of time of use (TOU) tariffs. Their assessment is that in the short run 20% of current residential peak load is discretionary. They expect uptake of TOU tariffs to also be 20%. They assume that in the short run these customers will only shift their load for one in three times that they actually could. Taking their methods into account, the current authors estimate that this roughly equates to a 1.3% shift in peak domestic electricity demands[24]. For later years the study assumes that such customers will shift their load one in two times. Also, in 2030 they assume that discretionary load and take up of TOU tariffs increases to 24% from 20%. All these assumptions are for the central case scenario. Sensitivities are

[23] This was confirmed with Lienert (2011).
[24] (0.2*0.2*0.3333333)*100

said to be made on take up of TOU tariffs at 10%[25] and 40%[26]. For the small and medium non domestic sector, the same assumptions as for domestic are broadly applied, although slightly different. Broadly the same assumptions are applied, due to a lack of information. This gap in knowledge on the discretionary load from the non-domestic sector is potentially an area that the REDUCE project may attempt to address for service based sectors (using a case study of the University).

Based on DECC and Ofgem's (2011a) analysis they estimate that for the domestic sector benefits over 20 years will be £121 million (present value) for the central case[27]. As with all DECC and Ofgem studies looked at, a discount rate of 3.5% is applied over the 20 years. This equates to an annual average of £6.1 million per year. For the small and medium non-domestic sector benefits for the central case are estimated at £27 million over 20 years[28]. In annual average terms this equates to £1.4 million. A clear methodology of how short run marginal cost benefits were calculated (like Ofgem 2010 described) is not provided, further details have been requested.

Both Ofgem (2010) and DECC and Ofgem (2011a and 2011b) do not state whether short run marginal cost savings may result in a net welfare benefit[29]. Higher prices from the peak time may not be solely a result of use of less efficient capacity, they may also be the result of producers just increasing prices as they know that they can (because of very high demand). If the latter is the case, then less of the cost savings are likely to fall into the category of a net welfare benefit[30]. That part of the avoided cost that results from avoiding use of less efficient generation will be more likely to fall into the category of a net welfare benefit[31], but any part of the cost that is the result of a producers decision to increase wholesale price (just because they know they can) is not a net welfare benefit, but a welfare transfer from the producer to the consumer. If all of the cost savings really are real resource cost savings resulting from not having to use inefficient generation, then the values can fall into the category of a net welfare benefit[32].

[25] This is believed to equate to roughly a 0.7% shift in domestic electricity demands during peak time (0.1*0.2*0.3333333)*100.

[26] This is believed to equate to roughly a 2.7% shift in domestic electricity demands during peak time (0.4*0.2*0.3333333)*100.

[27] For the low benefits case it is estimated to be £64 million over 20 years. For the high benefits case £236 million is estimated.

[28] They estimate 14m for the low benefits case and 54 million for the high benefits case over 20 years.

[29] ABOC

[30] ABOC

[31] ABOC

[32] ABOC

It should however be acknowledged that even for that part of the benefit that is definitely not a net welfare benefit, such transfers from producers to consumers are a very desirable benefit as they reduce the cost of living for households (particularly those that suffer from fuel poverty) and ensure energy security for individuals[33]. From reading the methods of the studies it is believed that so long as price increases reflect genuine increases in the cost of production, then they have the potential to be a net welfare benefit[34].

The DECC and Ofgem (2011a and 2011b) estimates don't seem to indicate the same potential for benefits as indicated in Ofgem (2010), it is somewhat difficult to compare values however, due to use of different time frames and differing form in which values are reported (e.g. present values versus undiscounted current price values). Certainly the demand shift assumptions are more conservative in DECC and Ofgem (2011a and 2011b), this is the case even though Ofgem (2010) stated that they were being conservative.

Due to shifting demand to off peak times, there can also be CO_2 reductions. Ofgem (2010) state that providing carbon dioxide is priced appropriately (and all else being equal in terms of commodity prices), DR can result in a decrease in CO_2 emissions by displacing higher emitting peak generation[35]. With a 10% shift in peak load daily CO_2 savings are estimated to be between 800 and 2550 tonnes of CO_2 equivalent[36]. It should be noted that estimates of CO_2 and values of CO_2 reductions are based on modeling (and assumptions) by Ofgem (2010).

In line with their estimated demand shifts, DECC and Ofgem (2011a) estimate the financial value of CO_2 savings from demand shifts to be £2.4 million if present values for the 20 years (£47 million) is divided by the number of years (20). For the non domestic sector they estimate the value of CO_2 benefits to be £17 million over 20 years, which equates to an annual average (present value) of £0.85 million. Unfortunately the latter reports do not provide physical CO_2 values for demand shifts. It is important to realise

[33] There may be limits to this statement when considering absolute demand reductions as opposed to demand shifts, as if producers were to end up selling very small amounts of electricity then they may loose 'economies of scale' and therefore prices per unit of electricity may go up, ultimately impacting the consumer.
[34] ABOC
[35] The current author notes that even if CO_2 emissions are not priced appropriately, high energy costs may well still ensure that inefficient capacity will only be run during peak time.
[36] Converting CO_2 into monetary terms, this equates to between £11,200 to £35,700 in benefit.

that these monetary values for CO_2 do not represent damage costs of CO_2 which may be substantially different.

3.4 Benefits in terms of displacing new plant investment from using demand response to shift peak demand

In dealing with benefits relevant to reducing peak load, Ofgem (2010) provide estimates of the value of benefits from displaced peaking plant generation (and associated long term investment cost savings) as a result of reducing peak demand. They estimate that a 5% shift in peak load could result in £129m to £261m annual cost savings. A 10% shift is estimated to result in £265m to £536m in annual capital cost savings. Clearly these annual savings are quite substantial. If however added to annual wholesale price cost savings, some double counting may occur, as wholesale prices are likely to capture some part of investment costs, as discussed this issue is not seen as a problem in the short term by DECC and Ofgem (2011a). Similarly, the current author notes that reported cost savings are associated with new plant investment (not previous investment used for generation today) so is thought to not be such a problem if energy generators only factor in costs associated with generation investments already made.

Ofgem (2010) state that these cost savings should only be seen as indicative as they were estimated based on shifts during the three days assessed. The later report considers capital cost savings resulting from a reduction in new peaking plant investment to be evenly spread across the year, and they use this as a basis for justifying generation of annual estimates.

In line with their assumptions for demand shifts, DECC and Ofgem (2011a and 2011b) also estimate that for their central case benefits for the domestic sector will be £653 million[37] and for the small and medium non-domestic sector £20 million over 20 years. If converted into average annual figures then a value of 33 million is derived for the domestic sector and 1 million for the small and medium non-domestic sector.

These figures are in present values as opposed to undiscounted current prices for Ofgem (2010) figures, so this will lead to average annual DECC and Ofgem (2011a and 2011b) figures being lower. Clearly these benefits are however substantially lower than

[37] In the low benefits scenario domestic benefits are £341 million and £10 million for the small and medium non domestic sector over 20 years. For the high benefits scenario £1277 million is estimated for the domestic sector and £39 million for the small and medium non-domestic sector, over 20 years.

those of Ofgem (2010), in line with their more conservative assumptions for demand shifts and also due to estimates not including demand shifts for larger commercial and industrial enterprises. A clear methodology of how avoided generation investment was calculated is not provided by DECC and Ofgem (2011a and 2011b) so it is difficult to absolutely clarify in detail why estimates are so much lower. Annual investment capacity costs are said to be based on a recent Mott MacDonald (2010) report for DECC.

3.5 Benefits of using demand response as 'stand by' reserve for emergencies/unforeseen events

With regards to 'stand by' support for emergencies and unforeseen events, Strbac (2008) identifies that the value of DSM in these circumstances is determined by the cost of alternative provision which in the case of generation would be £250-£400/kW for a modern gas-fired-type plant. He notes that the value of DSM could however, considerably increase above the cost of generation due to difficulties and delays in the planning process linked with the construction of new power stations.

DR could provide an alternative form of reserve, Strbac (2008) notes that conventional solutions on (stand by) generation are likely to be inefficient and that value of DR is bound by costs of generation solutions. The current author sees that if such standby generation is also used in dealing with peak demand, then their are issues in adding displaced plant investment estimated from reducing peak load and those investment savings attributable to use of DR for 'stand by' support.

Strbac (2008) notes that this stand by support (termed standby reserve in his study) for balancing will be particularly relevant when increasing renewable resources in the generation mix. This brings us onto the next benefits assessed: Benefits of demand side participation in providing standby reserve and balancing;

3.6 Benefits of demand response in providing standby reserve and balancing for wind

A key problem in incorporating more wind power to provide generation capacity is the (sometimes) intermittent nature of this supply. The most dominant share of "intermittency cost" is associated with balancing costs due to imperfect forecast of wind (and potentially sun irradiation in the case of solar), transmission and distribution network costs are second (Strbac and ILEX 2002 as seen in Seebach et al 2009).

Seebach et al (2009) note that providing balancing services promises to provide considerable economic benefit, with benefits strongly increasing with further deployment of intermittent generation. The situation of high amounts of intermittent generation is a direction that the UK is heading in the near future, in addition to replacement and possible increase in nuclear (an inflexible type of power generation).

Strbac (2008) building on earlier work[38] report that when compared with traditional providers (generators) of standing reserve such as OCGT plants, the competitive advantage of DR is significantly reduced. Comparison with traditional providers such as OCGT plants shows the additional capital value of DR over OCGT to be less than £50/kW. Strbac (2008) states that this is unlikely to be enough to fund implementation of DR. Form their modelling it appears that these benefits relate to storage only.

A report by DTI (2004) identified storage (in a generation system with limited flexibility) as more valuable to the network operator than OCGT reserve, due to the reductions in fuel used and carbon dioxide emitted. The extra value was placed at between £60-£120/kilowatt. POST (2008) note however, that no large-scale storage technology has come close to meeting this cost. They site the Regenesys project and note that the break-even point for the project (providing arbitrage and reserve services) was £1200-1500/kilowatt, but the project was unable to meet this target[39].

POST (2008) note that in future, storage solutions will face competition with demand side management (termed DR in this study) technologies. It is noted that demand side management solutions have no efficiency losses and smaller capital costs. It is said that DSM is seen by market observers as an important development for future energy networks. POST (2008) however state that there is a need for significant roll out of smart metering and suitable appliances in addition to significant restructuring of electricity tariffs to be viable on a large domestic scale.

[38] Strbac and Black (2004) assess benefits of storage for balancing purposes. When modelling they assume 20% of demand is provided by wind.

[39] POST (2008) provide a useful overview of various storage technologies (http://www.parliament.uk/documents/post/postpn306.pdf).

Silva et al (2009)[40] conduct a literature survey on impact of intermittency in balancing costs (as part of their project). With regards to storage and demand side response, from review of Black and Strbac (2007) and BERR (2006) they report that:

"These studies presented storage as a promising technology, to deal with intermittency but it requires high investments, complex location and technological problems yet to be solved. Considering that DSM[41] presents some similarities to storage in the sense that it can provide additional flexibility on the demand side by shifting demand from one time period to another, the previous studies need to be extended to investigate the value of DSM."

After their literature review, the main focus of Silva et al (2009) was in reporting the value of managing the load represented by domestic appliances in order to provide balancing services. Seebach et al (2009) use this work in conjunction with other Smart-A project work and model the costs and benefits of smart appliances in Europe. The estimated benefits are now reviewed.

Specifically, Seebach et al (2009) estimate the value of benefits in 2010 and 2025 from the use of smart appliances for network balancing[42]. The benefits relate to providing 'stand by' reserve balancing, specifically the study states that it reports costs and benefits of network services (provided by a variety of appliances) that enable balancing[43]. It is noted that with regards to electric heating and electric water heater appliances, these can provide a form of storage[44]. So although focusing mainly on the role of smart appliances in reducing demand, a few appliances could potentially be classed as a form of storage.

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[40] In addition to studies earlier noted by Strbac (2008) and Strbac and Black (2004), Strbac is also an author in a report by Silva et al (2009).

[41] Demand side management.

[42] It is said that DR measures aim at influencing the load curve of an electricity system by reducing the load in total, or shifting the load.

[43] The project looks at the benefits and costs of using smart appliances for balancing.

[44] Seebach et al (2009) states that:

"Electric storage heating devices and electric storage water heaters have to be discussed separately in the context of smart appliances. Due to their high capacities and their capability to be operated in a smart way (in a form, this is widely done already for electric water heaters which are operated with a low price tariff during night) they are worth being covered by this study. On the other hand, substitution of electric storage heating devices and electric storage water heaters can be assumed to be strongly supported by political initiatives within the coming years due to their extremely low energy efficiency compared with technological alternatives. No roll out of a new really smart generation of electric heating devices can therefore be expected. Still, in order to demonstrate the relative potential of different appliances and corresponding costs and benefits, electric storage devices are addressed particularly for comparison within this study." (Seebach et al 2009, p.24)

Fuel cost savings, reduction in carbon emissions and reduction in wind curtailment are compared to a standard scenario without DR by Seebach et al (2009)[45]. Benefits according to different appliance types and countries are identified (with the UK being one of these countries). Cost savings are dependent on the national electricity system in place. The authors account for this and savings estimates are generated from relevant costs associated with a relevant regional electricity system. The methodology for classifying regional electricity systems and associated cost savings are provided by the EU project. Regional electricity systems are determined by a multi step classification and categorisation of national electricity systems (this is not conducted in absolute terms, but simplified according to whether the system falls into given categories and limits). Conditions and different costs are estimated for 2010 and 2025. Estimates are provided for a high fuel price and low fuel price scenario. Due to the fact that the different countries have different appliance penetration rates, countries were also classified according to current and predicted future appliance penetration.

Within the study Silva et al (2009) is cited in identifying that penetration of intermittent generation as a second decisive factor for the potential benefits of smart appliance, besides system flexibility. It is found that only a limited share of appliances are used for balancing services, therefore it is concluded that penetration rates (of appliances) are not the main driver behind potential value of smart appliances (given a sufficient share of smart appliances in the total stock of appliances).

For the year 2025, energy efficiency per appliance (energy use by the appliance itself) is usually assumed to increase by 20% compared to 2010. Typical technical values for appliances were developed by Silvia et al (2009) using literature such as Staminger et al (2008). Relevant household data and country penetration rates were applied to estimate total average load per household appliance.

It is identified by Silva et al (2009) that the benefit per capacity of DR load is quite heavily dependent on the total capacity of participating DR, marginal benefit generally decreases when DR capacity increases. Benefits are not generated linearly. In order to deal with this Seebach et al (2009) use scaling factors to downscale benefits according to the size of the modelled system according to the size of the European system. It is unclear whether this appropriately deals with the issue. The current author believes that it may not.

Energy reductions from smart appliances are assumed to substitute gas generation technologies, which are considered as a standard for the provision of spinning reserve capacities. Fuel costs and CO_2 emissions factors are in line with this assumption. Monetary benefit and fuel prices data (in conjunction with emissions factors) are used to calculate CO_2. Upper and lower price per tonne from the EU emissions trading scheme (ETS) are used to calculate carbon savings in monetary terms. Benefits and costs are not discounted as only two yearly estimates are provided.

Benefits are said not to consider benefits for individual market actors, but overall economic benefit (total) for the market system. It is stated that benefits represent avoided fuel costs by reducing wind spillage and so replacing conventional energy on the one hand and increasing the efficiency of part loaded plants through providing additional balancing capacity by smart appliances. Whether benefits (once any cost e.g. of the appliances etc. is subtracted) from fuel cost savings can be classed as a net welfare benefit[46] to society, depends amongst other things on whether there is any 'price lifting'[47] by producers captured in energy costs that does not represent a 'genuine' cost (e.g. labour or material etc). It is thought that gains could be classed as a net welfare benefits[48] as DR should enable a reduction in the running of inefficient generators.

Following Seebach et al (2009), total annual value of gross benefit from balancing capacity from 'best choice' DR penetration rates are reported. Results for the high price and low price scenario are presented. For the upper price scenario in 2010, UK benefits are just under 40 million euro. For the lower price scenario 2010 UK benefits are just over 20 million euro. For the upper price scenario in 2025 UK benefits are 344 million euros without including value of CO_2 reductions and 430 million euros when including value of CO_2 reductions. For the lower price scenario in 2025 UK benefits are 232 million euros without including value of CO_2 reductions and 256 million euros when including value of CO_2 reductions.

[46] ABOC
[47] Producers deciding to increase wholesale price just because they know they can and not due to an actual cost increase in their production.
[48] ABOC

Of the European countries looked at by Seebach et al (2009) the UK and Germany perform particularly well in terms of benefits. Benefits are highest for large systems with an inflexible generation structure and high wind penetrations. CO_2 reductions in physical terms were reported at roughly 200,000 tonnes per year in 2010 and 2,000,000 tonnes of CO_2/year in 2025. It is believed that CO_2 benefits may be classed as net welfare benefits if CO_2 avoidance is valued monetarily[49].

In order to make benefits of smart appliances comparable with reported costs, annual economic gross benefits are now reported for the UK in per kW DSM load (including avoided CO_2 emissions cost) for best choice DSM penetration rate in Table 2:

	Euro/kW DSM	
Year	lower price scenario[1]	upper price scenario[1]
2010	10	16-17
2025	80	130

[1] Some benefits vales were read from figures in published work so are not 100% exact numbers, but broadly correct.

Table 2: Annual economic gross benefits for the UK (including avoided CO2 emissions cost) for best choice DSM penetration rate (Seebach et al 2009)

In Seebach et al (2009) it is noted that net benefits of smart appliances can be considerably higher if account of additional applications of DSM through Smart Appliances is also accounted for (e.g. peak shaving or managing network congestions[50]). From this it can be concluded that it is likely that there is no overlap between benefits of balancing of wind with benefits earlier reported on the wholesale cost savings or later when looking at benefits related to the transmission and distribution network. There may be a small amount of overlap with benefits reported for energy savings of smart meters, although it is believed that this is probably not the case as DECC and Ofgem (2010a and 2010b) do not factor in the increasing future benefits from DR for wind curtailment.

To see more on how the assumptions and limitations of this study may result in under or over estimation, please see Appendix 1. This helps identify caveats about this work that better inform robustness of estimates of benefits.

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[49] ABOC

[50] It is reported that for these applications, no quantitative data on the benefits of smart appliances is existing within the Smart-A project.

3.7 Benefits of demand response to distributed power systems

Strbac (2008) state that the value of DSM for balancing demand and generation in such a system is thought to be very significant, but quantification of technical and economic performance of alternative implementation options in such highly distributed power systems is required before firm recommendations can be made (Strbac 2008).

3.8 Benefits in terms of reduced transmission network investment by reducing congestion of the network

Strbac (2008) state that their initial studies indicate the value of controlling the transmission network by DSM using a corrective philosophy could be significant[51]. However, the benefits from this are said to strongly depend on the level of existing transmission capacity and generation fuel cost differentials (the author refers to Strbac et al 1998). Operating and investment costs of the current preventative system approach are said to be the indicator of the limit of value of DSM. It is then reported that the average cost of transmission network reinforcement in the UK is about £300/MW km. It is said that the planning process in bringing about re-enforcement for the transmission network could increase this cost[52].

With regards to peak demand reduction, Mott MacDonald report that it is their understanding that costs in transmission will fall in the range of £50-80/kW from peak load savings (as a result of regular decreases in peak load reduction).

In line with the demand shifts assumed by DECC and Ofgem (2011a and 2011b), they estimate that the avoided investment in both transmission and distribution network from the uptake of TOU tariffs in the central case to be £29 million for the domestic sector and £1 million for the small and medium non domestic sector over 20 years[53]. These values are in present value terms. A clear methodology of how transmission network benefits are estimated is not provided in Ofgem and DECC (2011a and 2011b). It is stated that distribution investment figures are from Ofgem's Price Control Review 5. The reader

[51] Strbac et al (1998) – initial work.

[52] Strbac (2008) also notes that placing much renewable generation in the north of the UK could increase stress on the transmission network, therefore increasing potential corrective value that may occur from DSM in the south of the UK.

[53] In the low benefits scenario domestic benefits are £15 million and £0 million for the small and medium non domestic sector over 20 years. For the high benefits scenario £58 million is estimated for the domestic sector and £2 million for the small and medium non-domestic sector, over 20 years.

should note that these latter values relate to transmission and distribution benefits in moving to a corrective philosophy.

3.9 Benefits from using demand response to improve distribution network investment efficiency and reduce losses

With regards to quantification of these benefits, Strbac (2008) notes that the use of DSM for unlocking unused network capacity and the provision of system support services has not been widely considered and benefits are not well understood and quantified, it is noted that initial studies by Jayantilal and Strbac (1999) indicate them to potentially be quite significant. The article states that more analysis is needed to examine the value and practicalities of DSM for these purposes[54]. Ofgem and DECC as well as Strbac et al (2010) have recently conducted such further analysis and more detail is provided later in this section. Ofgem and DECC estimate distribution benefits as a result of peak load shifting (or as a result of reduced losses) where as Strbac et al (2010) estimate benefits relating to a move to a corrective, active control philosophy in the electricity system.

As a result of peak shifting, Ofgem (2010) identify that a 5% peak load shift results in £14 million in savings in network (distribution related) annually. A 10% shift results in £28 million of savings (distribution related). DECC and Ofgem (2010 and 2011) provide more conservative estimates relating to demand shifts.

DECC and Ofgem (2011a) report benefits in terms of reduced loses for electricity and gas to be £438m (over the 20 years of the project) for the domestic sector central case scenario as a result of smart meter role out. This equates to an annual average of £22 million, the annual average for the small and medium non domestic sector was estimated to be £5 million. Clearly these benefits are substantial.

Recently however, a more forward looking study by Strbac et al (2010) has looked at the future benefits to the distribution network from a paradigm shift in the electricity system operation philosophy that could be enabled by technology in conjunction with DR. They specifically look at benefits to the distribution system from changing the operating system philosophy from preventative to corrective. The work of Strbac et al (2010) is said to contribute to identifying the business case for a Smart distribution network. This

[54] Mott MacDonald (2007) assume that avoided investment (as a result of DR) costs resulting from peak load savings (as a result of peak load reduction) are at £25/kW for distribution.

is not assessed in the Ofgem (2010) or the DECC and Ofgem (2011a and 2011b) reports.

The modelling is based on future electricity network distribution scenarios. In future, the electricity system it likely to face a huge increase in loads due to the electrification of the heating and transport sectors. If the increase in load resulting from electrification of heating and transport sectors occurs, this could result in peak demand being a lot greater than its current level and this has huge implications for future transmission, distribution network and generation capacity requirements and efficiency.

The transport and the heat sectors however, are characterised by a significant inherent storage capacity therefore the electrification of these two sectors could also lead to unprecedented opportunities for using demand response to enhance the efficiency of the entire end-to-end electricity supply chain including generation, transmission and distribution (Strbac et al (2010). The latter authors state that coordinated management of responsive demand related to technologies that provide electric heat and transport requirements would enable system peaks to be significantly reduced. No quantification of benefits of such a change on transmission network and generation investment was quantified. Strbac et al (2010) however, do estimate benefits that would result to the distribution network from such a change in management philosophy.

Strbac et al (2010) consider a range of future development scenarios involving penetration of electric vehicles (EVs) and heat pumps (HPs) under two different network operation paradigms.

1. A preventative business as usual (BaU) approach and;
2. A corrective smart meter enabled active control (AC) approach.

The BaU approach is said to apply the present ‘unconstrained’ network operation philosophy where the distribution network control problem is resolved and dealt with in the planning stage by ensuring enough re-enforcement, so the distribution network is designed to accommodate any reasonably expected demand (and therefore preventative).

The smart meter enabled active control approach is different, it involves real time network management through optimising demand response. The paradigm involves a shift in network control philosophies that makes use of the advanced functionality of smart meters and an appropriate communication infrastructure to use demand response at the local level in order to manage network constraints and avoid or postpone network reinforcements (corrective and active appraoch). In this situation, demand response will be time and location specific. The latter approach and paradigm, allows one to examine more clearly the benefits from the unprecedented opportunities (as a result of electrification of heating and transport sectors) for the distribution network from using demand response to enhance the efficiency of the electricity system.

For this work a number of possible future development scenarios over the next 20 years are analysed. Specifically and most directly, the study attempts to quantify the order of magnitude impact on the UK electricity distribution network as a result of electrifying the transport and heat sectors under the two different distribution management paradigms as identified above. Future distribution network re-enforcement costs associated with two different distribution network management approaches resulting from the two different philosophies/paradigms are assessed[55]. Using comparative analysis, the study then assesses the benefits to the electricity distribution system from implementation of the corrective active control approach, this is done based on estimation of the avoided future distribution network re-enforcements costs[56].

In addition to electricity and heating sectors, Strbac et al (2010) also account for benefits to the distribution network from opportunities associated with demand shifts that are enabled by smart appliances. Therefore, the three categories of technology considered are: electric vehicles, heat pumps and smart domestic appliances[57]. It is said that the load impact from electrifying the heat sector can be mitigated by appropriately controlling loads due to the transport sector and vice versa. It is noted that this has not been considered in earlier studies.

[55] For consistency costs associated with reinforcement of individual network components are taken from Ofgem's Price Control Review 5

[56] The analysis conducted focuses on low voltage (LV) and high voltage (HV) distribution networks, as these assets dominate the overall distribution network costs.

[57] Analysis here focuses on three type of wet appliances: washing machines, dishwashers and washing machines equipped with tumble driers. There is said to be considerable potential to utilise demands of appliances to provide demand-side flexibility. Some analysis was conducted to demonstrate the capability of controllable smart appliances to reduce peak load in a distribution network.

The main steps in assessment are as follows: 1. Conduct future demand modelling: demand of electric vehicles, domestic electric heat pumps, smart appliances. 2. Conduct network operation and reinforcement modelling 3. Quantify the impact of EVs and HPs on distribution network under passive and active network control. 4. Quantifying the value of smart meter-enabled active control of UK distribution networks.

Other than the main two paradigms, key sensitivities assessed financially around alternative development scenarios were:

- Five different levels of penetration for EVs &HPs occurring during the years 2020 to 2030[58];
- Two alternative network re-enforcement strategies (like with like versus reinforcement based on inserting new distribution substations)[59];

From modelling it was found that as expected, the costs increase with the level of penetration of EVs and HPs, total costs are dominated by LV network costs.

With regards to the value of benefits derived from the AC approach compared to the BaU approach: NPV of the smart meter enabled active control paradigm under different scenarios of uptake is presented and compared to the BaU NPV costs. This represents a NPV of avoided investment costs. A discount rate of 3.5% is applied (consistent with a level often used for Government Infrastructure projects) when generating NPVs.

The main finding is that NPV benefits in terms of smart management of demand, enabled by an appropriately specified smart metering system, is between £0.5 and 10 bn across all scenarios considered. This is seen in the far right hand column of Table 3.

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[58] There are five scenarios for EV and HP penetration: 10%, 25%, 50%, 75% and 100% penetration. These scenarios occur during the years 2020 to 2030. See figure 6-3 in Strbac et al (2010).

[59] A very significant proportion of reinforcement cost is driven by loads either exceeding LV feeder thermal ratings or given rise to voltage variations outside statutory limits. For this reason two reinforcement scenarios are considered: reinforcing overloaded feeder sections while maintaining the number of distribution substations constant and (ii.) inserting additional distribution substations in order to reduce the lengths of LV feeders and hence eliminate overloads and inadequate voltages, while reducing the need to reinforce LV feeder sections. These two scenarios are considered to encompass the boundary of network reinforcement costs likely to arise in practice.

Scenarios	NPV costs LV (£bn)		NPV costs HV (£bn)		NPV Value of Smart (£bn)
	BaU	AC	BaU	AC	
SCEN 10%	0.75 - 2.48	0.30 - 0.98	0.06 - 0.20	0.03 - 0.08	0.48 - 1.62
SCEN 25%	1.90 - 6.26	0.70 - 2.32	0.20 - 0.66	0.04 - 0.13	1.36 – 4.47
SCEN 50%	3.76 - 12.4	1.48 - 4.88	0.30 - 1.00	0.13 - 0.42	2.45 – 8.10
SCEN 75%	5.08 - 16.72	2.47 - 8.12	0.34 - 1.11	0.22 - 0.71	2.73 – 9.00
SCEN 100%	5.85 - 19.27	2.91 - 9.59	0.37 - 1.21	0.26 - 0.85	3.05 –10.04

Table 3: Great Britain NPV of network reinforcement costs for two network control approaches and the associated value of smart meter-enabled active control.

In Table 3 above each cell containing values provides two estimates. The value on the right hand of the cell is for a situation of like for like distribution network re-enforcement, this provides an upper bound estimate of re-enforcement costs. The value on the left hand of the cell provides the lower bound estimate which represents a distribution network re-enforcement strategy based on inserting new distribution substations. Clearly the difference between estimates in each cell is very different, Strbac et al (2010) state that the potential financial benefits of reinforcement policy are potentially very significant and this is what the values in Table 3 suggest. Additionally, it can be seen that as expected, the costs increase with the level of penetration of EVs and HPs. Total costs are dominated by LV network costs. The authors observe that for the BaU control paradigm, total network reinforcement costs are 2.5 – 3 times higher than under smart, while this ratio drops to about 1.8 at higher penetration levels.

Strbac et al (2010) identify that it is important to note that optimal demand response is highly time and location specific with regards to distribution network benefits. If an active control philosophy and approach is to be implemented, then an appropriate infrastructure is required to facilitate real-time and location specific demand response, including smart meters with advanced real time functionality and appropriate communication systems. Less refined 'restricted hour' ToU tariffs would not deliver the optimum management of peak demand at the very local level, particularly due to the potential lack of diversity and 'lumpiness' of load associated with electric vehicles and heat pumps. These location specific attributes must be recognised in order to attain the full value of distribution network benefits resulting from demand response.

Another important point to bear in mind about findings in Table 3 is that the analysis does not consider distribution network asset replacements that would need to be conducted due to aging of equipment and which could be an opportunity to carry out strategic asset replacement of higher capacity in anticipation of higher network loading (Strbac et al 2010). The authors note that this would potentially reduce the benefits of active distribution management. Strbac et al (2010) however note that major renewals of HV and LV underground cable infrastructure due to degradation over the time till 2030 (time frame of analysis) is not envisaged.

Some additional sensitivities and analysis were undertaken and results from these are provided in Appendix 2 along with some other important points about the study. The paper now focuses on the costs associated with DR.

4 COSTS OF DEMAND RESPONSE

In this section the costs associated with demand response are firstly identified. A range of costs that can occur for DR are presented in Table 4.

Type of cost		Cost	Quantification
Participant costs	Initial costs	Enabling technology investment	Mainly
		Establishing response plan or strategy	No
	Event specific costs	Comfort/inconvienience costs	No
		Reduced amenity/lost business	No
		Rescheduling costs (e.g. overtime pay)	No
		Onsite generator fuel and maintenance costs	No
System costs	Initial costs	Metering/communication system upgrades	Yes
		Utility equipment or software costs, billing system upgrades	Partial
		Consumer education	Partial
	Ongoing programme costs	Programme administration/managment	Partial
		Marketing/recruitment	Partial
		Payments to participating customers	Partial
		Programme evaluation	No
		Metering/communication	Yes

[1]Ongoing program costs apply for incentive-based demand response programs and optional price-based programs only. For default-service time-varying pricing, ongoing costs are equivalent to any other default-service tariff offering. [2]Metering/communications costs can include dedicated wire or wireless lines leased from a third party telecommunications provider and costs to communicate pricing or curtailment information to customers or their energy service suppliers.

Table 4: Different cost categories for implementation and operation of a DSM system (developed from U.S. Department of Energy 2006)

Table 4 provides a concise overview of the various costs associated with demand response; it can be seen that there are a range of different types of costs and that these costs can fall directly on participants or the actors implementing the demand response system. In the far right hand column, it can be seen that from review it was not possible to find quantitative estimates for all costs, although a good number were quantified. Those that remain mainly un-quantified relate to inconvenience/rescheduling costs for customers[60]. For most other costs, quantitative estimates were mainly found.

With regards to enabling technology investments the current paper reports capital costs of smart meters from DECC and Ofgem (2011a and 2011b). Although believed to fall into the category of "enabling technology investment" participant costs, suppliers will be required to procure and install smart meters as part of a mandatory smart meter roll out for the domestic and small and medium non-domestic sector, so actually they are system costs; ultimately however this cost is likely to be passed on to energy consumers. Quantitative estimates of technology costs from Smart appliances are taken

60

from Seebach et al (2009). U.S. Department of energy refer to other enabling technologies as smart thermostats, peak load controls, energy management control or information systems fully integrated into a business customers operations. From review we only have annual UK estimates for smart metering and smart appliance technologies, but it should be noted that corresponding benefits of DECC and Ofgem (2011a and 2011b) and Seebach et al (2009) only relate to these technologies.

Other than technology costs the main costs to participants are related to response to reduce energy use. No quantitative estimates were found for the cost of “establishing a response plan or strategy”, this is also the case for costs of “comfort/inconvenience”, “reduced amenity/lost business” and “rescheduling costs and onsite generator fuel and maintenance costs”. Qualitative discussion of such costs was reported in the literature, for example Ofgem (2010) provide good descriptions and discussion of such costs. They state that costs of changing patterns of consumption are a particularly relevant issue for businesses. To participate in DR there may be a need to make new or change arrangements such as timing of working hours. As a result, costs in time and resources may result e.g. revising work schedules and paying overtime for later hours (Ofgem 2010). For consumers that actually participate in DR, one would assume that benefits of DR outweigh the costs for them personally.

To be involved in DR there may be time required in searching, choosing and switching to new tarrifs e.g. TOU or real time (Ofgem 2010). A report by Ofgem (2008) found that a majority of customers expressed that the level of expected savings from switching tariffs is too low and not worth the hassle of switching. Ofgem have been making strides to make it easier for people to change tariff (as seen in Ofgem 2010).

There are also costs (in terms of inconvenience) to the domestic sector from re-organising patterns of consumption and changing habits and norms of consumption. Ofgem (2010) note that inconvenience associated with changing electricity demand patterns involve varying the times at which activities are conducted e.g. appliance use cooking meals and washing etc. outside peak hours. They note that once automated devices become widespread and mainstream, then hassle associated with changing consumption should dissipate. Although this may be the case, the current author notes that the extent to which such automated devices avoid costs of inconvenience, is perhaps more unclear and something that REDUCE could investigate.

With regards to system costs, Figure 4 shows that a range of these exist. For a good number of the categories, estimates exist (from which average annual figures can be derived) from DECC and Ofgem's (2011a and 2011b) costs of roll out of smart metering. We now identify the specific system costs covered by the latter study. Total estimated costs for smart meters (electricity and gas) for the domestic sector in DECC and Ofgem (2011a) are reasonably comprehensive and include such things as: capital costs (display and meter, communications and infrastructure), installation costs, operating and maintenance (O&M) costs, IT costs, the cost of capital (10% per annum), energy costs from smart meter consumed energy (the latter is actually a participant cost), meter reading costs, disposal costs, Legal, marketing and organisational costs (Which include: marketing and consumer support costs, legal costs and other costs). Other costs include: data protection, ongoing regulation, assurance, accreditation, tendering, programme delivery, trials and testing (DECC and Ofgem 201la).

For costs described by DECC and Ofgem (2011b) for smart meter roll out for the small and medium non-domestic sector total, costs are said to include: Asset costs (advanced meter and smart meter costs, retrofit advanced costs, and display costs), cost of capital, installation and maintenance costs and costs of communication infrastructure (including a modem).

Costs reported for the domestic sector but not the non-domestic sector, are costs that carry across both domestic and small and medium sized non-domestic. This was found from discussion with Lienert (2011)[61]. Like for domestic, for the small and medium sized non domestic sector, some costs are broken down for electric metering in the DECC and Ofgem reports[62].

Although much of the system costs are covered by the DECC and Ofgem (2011a and 2011b) reports, for some costs coverage is believed to only be partial. With regards to the Table 4 category "Utility equipment or software costs, billing system upgrades", DECC and Ofgem do include tendering costs, but the current author is unsure whether this actually includes billing and settlement system costs. Similarly with regards to

[61] Lienert (2011) stated that when costs are shared between the domestic sector and small and medium non-domestic sector, then these costs are generally only reported for the domestic sector.

[62] For the advanced electric meter, asset cost are reported at £247 per meter, Installation costs £136 per meter and Maintenance costs: £6.1 per meter. For a smart meter electric costs are the same as they were for domestic.

consumer education[63], consumer engagement costs are included in the DECC and Ofgem reports but are believed to relate directly to engagement with smart metering and not necessarily specific demand response programmes run by energy companies. Also DECC and Ofgem (2011a) note that they are reviewing their cost estimate in light of conducting consumer engagement on a coordinated basis and the development of a consumer engagement strategy. With regards to the category “Programme administration/management” these are believed to be captured for the role out of smart meters but are not believed to be captured for specific demand response programmes although tariffs such as TOU and their management already exist and estimated peak demand shift benefits relate to these.

With regards to the quantified cost category “Marketing/recruitment” these are not necessarily captured for specific demand response programmes but are for the role out of smart meters. Costs for the category “Programme evaluation” in Table 4 have not been captured by studies reviewed.

Although some costs have not been fully captured, from review of cost estimates available for smart meters capital and installation costs dominate other types of costs, this indicates that system costs where only partial estimates are available are unlikely to dominate DR related costs.

We now report quantified costs of DR in section 5. We firstly identify costs of smart metering (section 5.1). Secondly, costs associated with the penetration of smart appliances are reported in section 5.2. Other quantified costs not reported when reporting costs of smart metering and smart appliances are reported in section: 5.3: Other costs.

[63] For example costs of educating on the time-varying nature of electricity costs, potential load response strategies and choice of tarrifs for demand response programmes available (U.S. Department of Energy 2006).

5 VALUE OF COSTS

5.1 Costs of smart meters

A breakdown of costs for the domestic and non-domestic sector implementation of smart meters for the life of the project (20 years) is provided below in Table 5. Electricity specific costs were not obtainable from Defra and Ofgem (2011a and 2011b), so cost estimates are aggregated estimates for electricity and gas meters but disaggregated by the domestic and small and medium non-domestic sector. Also, in both the domestic and non-domestic reports, quantification of certain costs was not possible and uncertainty is associated with some quantified costs.

Costs of smart metering in DECC and Ofgem 2011 (£million)		
Cost type	**Domestic costs 2011**	**SME costs 2011 (option 2)**
Capital	4005	265
Instalation	1596	96
O&M	692	39
Comms upfront	792	58
Comms O&M	1314	93
Energy	731	28
Disposal	15	3
Pavement reading inefficiency	238	8
Supplier IT	510	
Central IT	362	
Industry IT	154	
Industry set up	198	
Marketing	85	
Integrate early meter into DCC	65	
Total cost	**10757**	**590**

Table 5: Costs for smart metering for gas and electric – domestic and small and medium non-domestic sector from DECC and Ofgem (2011a and 2011b).

From Table 5, it can be seen that DECC and Ofgem (2011a) estimate the present value cost of putting in place smart metering for the domestic sector to be 10,757 million over the a 20 year period. For the role out of smart meters for the small and medium non-domestic sector, present value costs are estimated to be 590 million depending on which implementation option is chosen. So costs are substantially lower for the small and medium non-domestic sector[64]. Although this is so, it should be noted that some costs are shared across the domestic and non-domestic sector such as central set up costs.

Although in practice costs are not evenly distributed across the year, for consistency with other estimates, the current study takes the 20 year estimate of total costs and divides this by 20 to provide an average annual cost. When this is done for the domestic sector the annual average estimated costs are estimated at £537 million (best estimate, central case)[65]. For the non domestic sector total costs are approximately £29.5million for both options reported by DECC and Ofgem (2011b)[66].

An underlying assumption for the cost (and benefit) modelling purposes is that the metering technology deployed will provide the functionality required to achieve the wide range of benefits associated with smart meters[67].

It should be noted that both studies apply a cost of capital of 10% to fixed costs this is to take account of interest payments on loans that will be used to pay for smart metering[68]. This interest will obviously have inflated cost estimates. This is a fairly conservative but sensible approach. The small and medium non-domestic study also says it adjusts costs to take account of risk of optimism bias when assessing costs, this appears to be the case for the domestic sector too[69]. As a result of these latter procedures, cost estimates are thought to be on higher side of likely costs.

5.2 Costs of smart appliances

The quantitative costing of smart appliances for the UK by Seebach et al (2009), includes costs incurred by households that participate in use of smart appliances. These are said to include:

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64 Some individual components of the total cost of smart metering are reported for electricity metering. For example for the domestic sector costs of smart meters for electricity are reported at £43, and displays are reported at £15, communications and infrastructure for electricity are reported at £16 (DECC and Ofgem 2009a).

65 The average annual cost calculated here is different to DECC and Ofgem (2010a), possibly due to averaging a present value estimate.

66 The average annual cost calculated here is different to DECC and Ofgem (2010a), possibly due to averaging a present value estimate.

67 From reading it is believed that this is called ‘last gap’ functionality: the technical capability to alert networks when power supply is lost.

68 Attained from communication with Lienert (2011).

69 The domestic study states that all numbers are adjusted for risk of optimism bias unless otherwise stated.

- Annualised costs for smart appliances investment;
- Annualised costs for provision of smart functionalities by appliance (in the sense of additional operational costs); and
- Annualised costs for in-house command and control infrastructure.

For each of the cost categories, upper and lower cost scenarios are developed and applied in order to cover the range of costs that can be expected. The authors state that this is supposed to reflect the cost curve from 2010 (when the first smart appliances are supposed to be introduced) till 2025, when the market for smart appliances is deemed to be major (and hence production costs are substantially lower).

In Seebach et al (2009) pages 42 to 44 identify estimated upper and lower annualised additional costs for individual appliances (beyond non-smart appliances) for 2010 and 2025. It is stated that the methodology to estimate additional costs of smart appliances does not apply different additional investment costs per appliance type[70]. For this reason, annualised implementation and operation costs mainly differ depending on the expected lifetime of the appliance and the expected standby time for electricity consumption. Figure 2 identifies the annualised additional cost for implementation and operation of smart appliances, lower scenario for 2010, Figure 3 shows the upper scenario. Figure 4 shows the annualised additional costs for implementation and operation of smart appliances (lower scenario) for 2025. Figure 5 shows the upper scenario for 2025.

[70] The current author interprets this to be that Seebach et al (2009) assume that to make the appliance 'smart' it is the same cost across appliances.

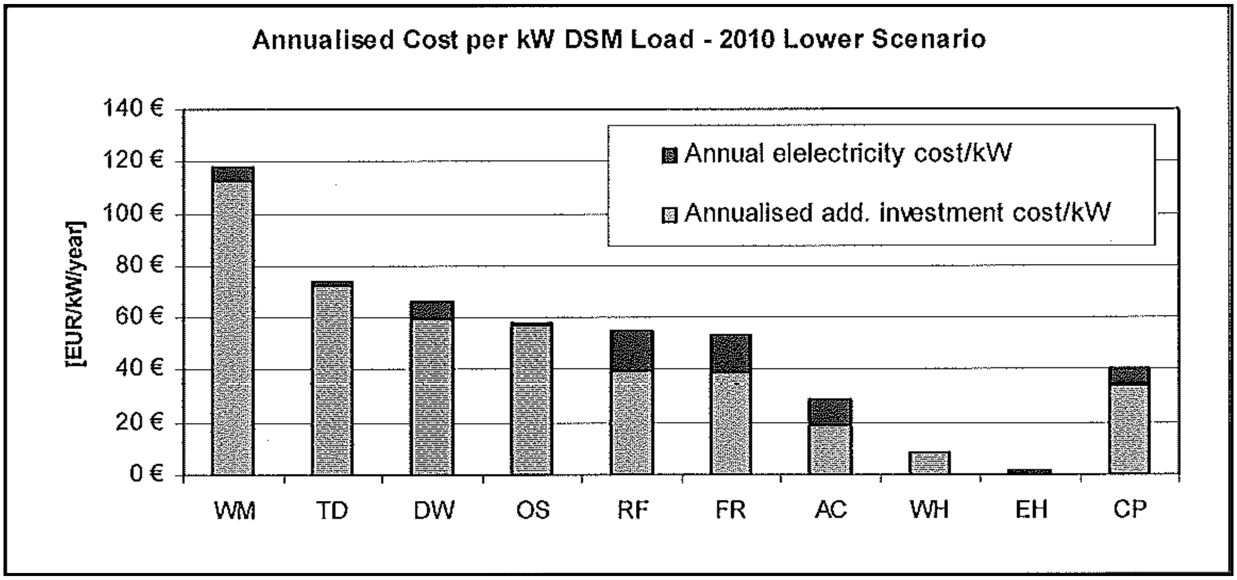
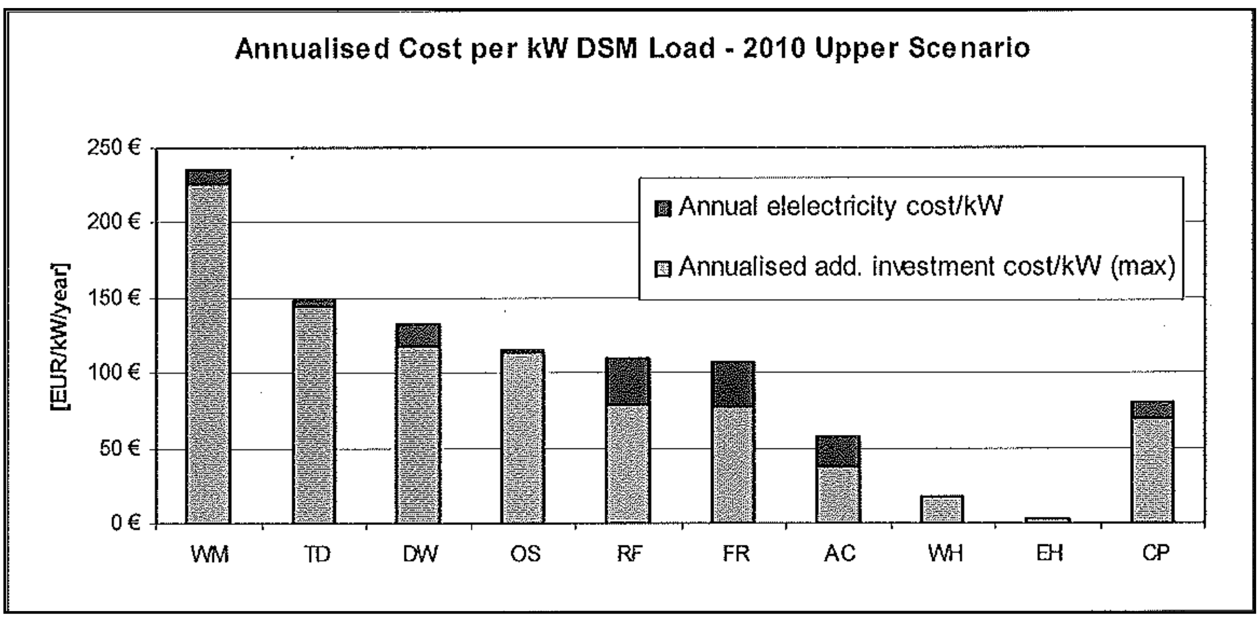


Figure 2: Annualised additional cost for implementation and operation of smart



appliances, lower scenario for 2010 (Seebach et al 2009)

Figure 3: Annualised additional cost for implementation and operation of smart appliances, upper scenario for 2010 (Seebach et al 2009)

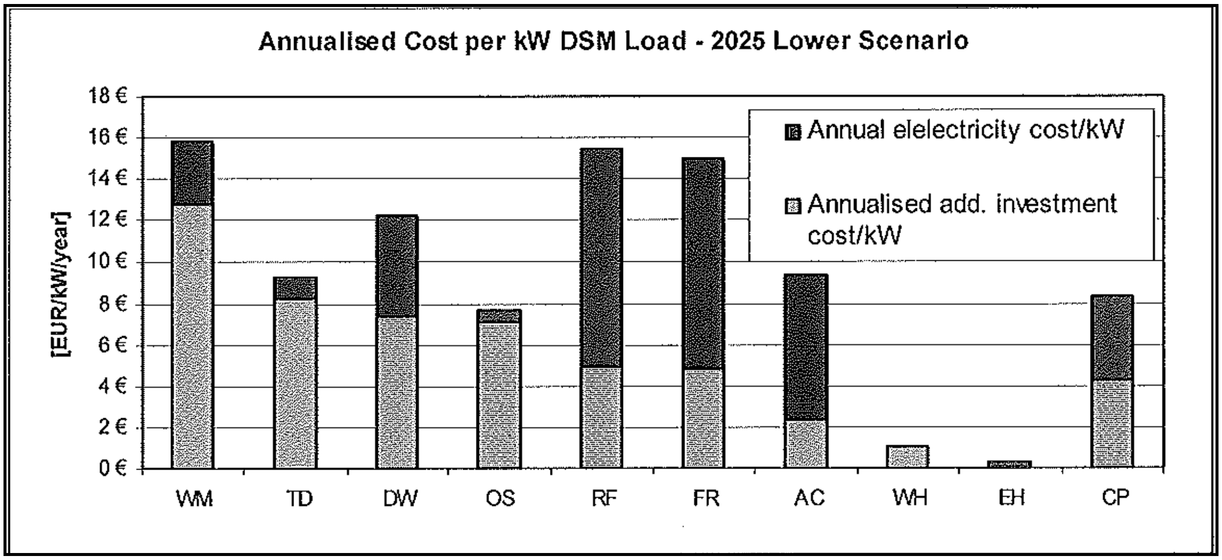


Figure 4: Annualised additional cost for implementation and operation of smart appliances, lower scenario for 2025 (Seebach et al 2009)

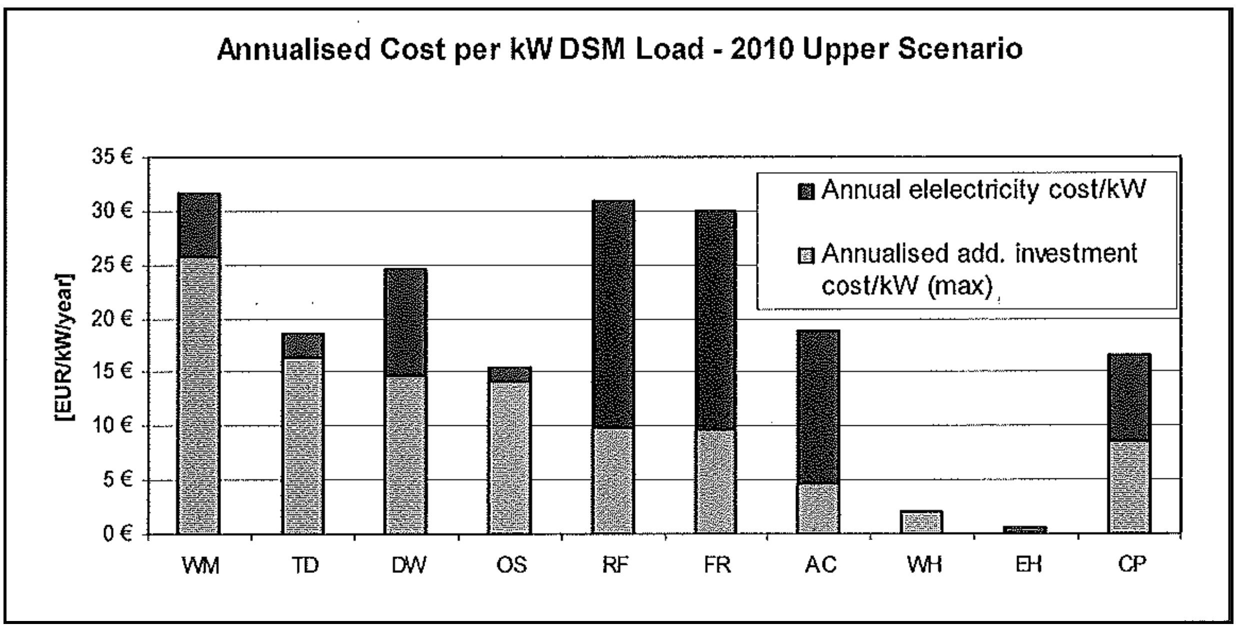


Figure 5: Annualised additional cost for implementation and operation of smart appliances, upper scenario for 2025[71] (Seebach et al 2009)

From the Figures (3,4,5,6) above, it can be seen that predicted additional annualised costs in 2025 are assumed to be a lot lower than in 2010.

The study also reports the expected range of annualised additional costs per kW of DSM load for smart appliances in 2025[72] for various countries. The expected costs for the UK

[71] In the figure it states 2010, but this is an error in the Seebach et al (2009) document.

in 2025 range from just under 10 euros/kW of DSM load to 30 euros/kW of DSM load. It is unclear whether these are an expected annual range by 2025 (e.g. based on the range of additional appliance costs leading up to 2025), or the expected annual cost range in 2025. From communication with the lead author, it is believed to be the latter. These costs neglect the costs of smart appliance for electric heating and water heating as smart appliance heating is expected to play only a marginal role in the future. Costs are not discounted as they are only provided for two separate years.

5.3 Other costs relating to DR

In this section remaining costs are reported as follows: Settlement system costs and billing costs.

Settlement system costs

A range of different tariff structures (or incentives) will be required in order to incentivise DR. Ofgem (2010) note that if very short and frequent settlement periods are needed (for example to capture changes during peak time) then the alteration and change of the settlement system for domestic and some SME customers may be required. Elexon (2008) as seen in Ofgem (2010) estimate that a change to the settlement system can entail costs up to £1 million dependant on changes required. Mott MacDonald (2007) report the same figure. Ofgem (2010) say these costs will arise regardless of a customer participating in DR. Although this is so, these are still costs associated with enabling and encouraging DR and will not occur unless it is decided that there should be a programme to increase and encourage demand response. From reading DECC and Ofgem (2010a, 2010b, 2011a and 2011b) it is not absolutely clear whether these costs are included (or relevant) in the most recent figures presented. It is thought that they are not as TOU tariff structures already exist and benefits and costs relate to this tariff.

Billing costs

Ofgem (2010) state that suppliers may incur additional costs due to changes required in their billing systems, as a result of introduction of new tariffs . The document also states that there will be costs incurred (to distribution network operators) related to re-designing and building parts of the network to allow DSR to facilitate an increasing proportion of variable and distributed generation on networks.

6 DISCUSION

This paper has so far attempted to review the range of benefits and costs associated with demand response. The paper now attempts (where possible) to provide average annual values for different types of costs and benefits described in the paper. From review it was sometimes difficult to achieve consistency in measurement across units, timescales and treatment for different costs and benefits due to use of estimates from different studies.

Although this is so, it is still useful to attempt to broadly compare costs and benefits. For this reason Table 6 presents estimates, mainly as annual average values (generated from present value terms and in a few cases non present value terms). Only quantifiable costs and benefits are presented and therefore initial discussion is generally restricted to these values[73]. Where possible, values of CO_2 savings in physical terms are provided in the table.

Form of DR benefit or cost		Benefit/Cost	Time period	Units	Domestic/ non domestic	Estimate of benefits/cost		Mt CO_2 (electricity)	Study
Energy reduction	*Benefits*	Reductions in electricity *(energy savings)*	Average annual	Present value Millions of £	Domestic	157		0.87	DECC and Ofgem (2011a and 2011b)
					Non domestic	34		0.25	
		Reductions in electicity *(CO_2 savings)*	Average annual	Present value Millions of £	Domestic	19		" "	
					Non domestic	4.2		0.25	
Peak demand shift		Short run marginal cost savings *(from shiting peak demand using TOU)*	Average annual	Present value Millions of £	Domestic	6.1		n.v	
					Non domestic	1.4		n.v	
		Displacing new plant investment *(Avoided investment from TOU)*	Average annual	Present value Millions of £	Domestic	33		n.v	
					Non domestic	1.0		n.v	
		Reduced transmission and distribution network investment *(avoided investment from TOU)*	Average annual	Present value Millions of £	Domestic	1.5		n.v	
					Non domestic	0.1		n.v	
		CO_2 reductions assocated with TOU demand shifts	Average annual	Present value Millions of £	Domestic	2.4		n.v	
					Non domestic	0.9		n.v	
Energy reduction and peak demand shift		Reduced losses as a result of the introduction of smart meters *(electricity and gas)*	Average annual	Present value Millions of £	Domestic	22		n.v	
					Non domestic	5		n.v	
Not DR related		Other non DR benefits resulting from smart metering *(electricity and gas)*	Average annual	Present value Millions of £	Domestic	445		n.a	
					Non domestic	26		n.a	
Balancing for wind		Benefits from balancing for wind *(value of energy and CO_2)as a result of smart appliances*	Value per unit in 2025	Euro/kW DSM	Domestic	lower price scenario[1]	upper price scenario[1]	2	Seebach et al (2009)
						80	130		
Balancing for a change in system managment philosophy		**Reduced** distribution network investment *(from a change to a smart corrective smart electricity system)*	Average annual (for the twenty years)	Present value Millions of £	Both	25-500		n.v	Strbac et al (2010)
Smart metering (electricity and gas)	*Costs*	Capital costs, installation costs, O&M costs, IT costs, the cost of capital, energy costs from smart meter consumed energy, meter reading costs, disposal costs, Legal, marketing and organisational costs	Average annual	Present value Millions of £	Domestic	538		n.a	DECC and Ofgem (2011a and
					Non domestic	30			
Smart appliances		Cost of the actual appliances	Value per unit in 2025	Euro/kW DSM	Domestic	lower scenario	upper scenario	n.a	Seebach et al (2009)
						10	30		

Table 6: Summary table of potential costs and benefits of demand response

[73] To see original values from which financial annual average values were derived please see appendix 4.

From Table 6 it can be seen that from the DECC and Ofgem (2011a and 2011b) work, energy savings generate the most significant demand response related financial benefits. These benefits are estimated to result from a 2.8% reduction in UK electricity use. DECC and Ofgem perform some sensitivities around this assumption, using alternative assumptions of 4% and 1.5% savings. When the 4% assumption is applied, value of electricity saved goes up from a value of £157m for the domestic sector to £237m. Therefore a modest increase in energy savings can have a significant effect on energy saving benefits.

Quite a lot of the value of these energy saving benefits are believed to be welfare transfers (from producer to consumer) and can therefore not fall into the category of net welfare benefits[74], as most of the reductions do not occur during peak times when inefficient generators are more likely to operate. CO_2 emissions reductions (if valued) however, could fall into the category of a net welfare benefit to society assuming economic benefits outweigh economic costs. DECC and Ofgem (2011a and 2011b) estimate an annual average financial value for these CO_2 savings as £23 million (domestic and non domestic sector combined). It should however be realised that this value does not reflect true benefit in terms of avoided damage costs of CO_2. It can be seen that the physical value of average annual CO_2 reductions associated with energy saving are quite high for both the domestic and non domestic sector. The 2.8% reduction in energy use is a conservative assumption and therefore benefits from energy savings and consequent CO_2 reductions in Table 6 are considered conservative estimates.

Shifting peak electricity demands as a form of demand response seems to produce large benefits (although less than energy saving) for the domestic sector. Of benefits relating to demand shifts (those associated with TOU tariffs) avoided investment in generation appears to be the largest benefit. Followed by short run marginal cost savings, the value of CO_2 reductions and then benefits in terms of avoided investment in the distribution and transmission network.

The finding that benefits from demand shifts (although significant) are not the largest demand response related benefits, contrasts with Spees and Lave (2007) assertion that

[74] ABOC

decreasing peak load (and consequent benefits) is most important in evaluating demand response[75].

If we look at the value of short run marginal cost savings (benefit) from demand shifts reported for the domestic and non domestic in Ofgem (2010) with those of DECC and Ofgem (2011a and 2011b), the latter studies estimates do seem very low. Table 7 provides values for Ofgem (2010).

Study	Benefit/Cost	Time period	Units	An estimate for		Tonnes of CO_2	
				5% shift	10% shift	5% shift	10% shift
Ofgem (2010)	**Benefits** -short run marginal cost savings from shifting peak demand	Range for two winter and one autumn day	Millions of £	0.4 - 0.8	0.7 - 1.7	560-1350 tonnes	800-2650 tonnes

Table 7: Short run marginal cost savings from shifting peak demand (Ofgem 2010)

Ofgem (2010) note that their average daily benefits from peak demand shifts cannot be scaled up to produce an annual figure as daily estimates are based on specific winter and autumn days. Even so however, potential benefits for just one day are very large even with the lower estimates, towards half a million a day with just a 5% shift (using the lower benefits estimate). This would seem to suggest that Spees and Lave (2007) are right in commenting that decreasing peak load (and generated consequent benefit) is most important for DR. One has to ask why the benefits from the Ofgem and DECC study so much lower? Well for a start the Ofgem (2010) estimates are believed to have been generated for domestic and non domestic (SME and larger C&I consumers) consumers where as DECC and Ofgem (2011a and 2011b) are for domestic and small and medium non domestic consumers. Also, the assumptions about how much electricity is shifted by DECC and Ofgem (2011a and 2011b) are much more conservative. Even with DECC and Ofgem's (2011a) high benefits scenario, using TOU tariffs they only assume roughly a 2.7% shift in demand. This compares with the 5% and 10% shifts estimated by Ofgem 2010 which are much more optimistic. Also the DECC and Ofgem (2011a) values are discounted, the daily estimates of Ofgem (2010) are not.

Comparison of DECC and Ofgem (2011a) and Ofgem (2010) is difficult due to values being presented in different forms (time frame, discounting and different assumptions on extent of energy shifts). Although this is so, due to the extent of difference it is believed that estimates of benefits from DECC and Ofgem (2011a) are very conservative and benefits may actually be greater in reality. Even the estimates of Ofgem (2010) are said

[75] Spees and Lave (2007) see energy efficiency as separate from demand response (which is generally the same for this study in terms of efficiency improvements from technical changes e.g. insulation).

to be conservative (in the study), but clearly they are more optimistic than those of DECC and Ofgem (2011a and 2011b)[76].

Importantly, it is also believed that short run marginal cost saving benefits associated with reducing peak electricity demand can result in net welfare benefits[77] as during peak times less efficient generators are more likely to be run. Daily CO_2 reductions that can result from shifting peak demand can be very high as seen in Table 7. If valued, these CO_2 reductions could fall into the category of net welfare benefits[78]. The DECC and Ofgem publications do not identify physical CO_2 benefits resulting from demand shifts of electricity.

Beyond short run marginal cost savings benefits, consistent, reliable and regular shifts in peak load can result in displacement of the need for new generation investment which results in investment cost savings. Tables 6 and 8 both identify that annual benefits from avoiding plant investment are substantial, assuming consistent reductions in demand can be sustained. Again it is difficult to directly compare estimates of Ofgem (2010) with those of DECC and Ofgem (2011a and 2011b) but the Ofgem (2010) estimates appear to be significantly higher.

Study	Benefit/Cost	Time period	Units	An estimate for		Mt CO_2 (electricity)	
Ofgem (2010)	**Benefits** - displacing new plant investment from shifting peak demand	Annual estimate	Millions of £	£129-£261m	£265 - £536m	n.a	n.a

Table 8: Generation investment savings from shifting peak demand (Ofgem 2010)

With regards to benefits from peak demand shifts relating to improved distribution network efficiency, DECC and Ofgem (2011a) are said to actually use the Ofgem (2010) annual estimate of £14 million. From viewing Table 6, these benefits are estimated to be substantially lower than those related to new plant investment and short run marginal cost savings.

Importantly, it is believed that both avoided generation and distribution investment benefits could fall into the category of net welfare benefits[79].

Beyond benefits associated with demand shifts, it can be seen in Table 6 that benefits associated with reduced losses are quite significant. This value does however contain

[76] Confirmed with Lienert (2011).
[77] ABOC
[78] ABOC
[79] ABOC

value from benefits for electricity and gas, as it was the only DR related benefit from DECC and Ofgem (2011a and 2011b) that could not be disaggregated for just electricity (from published values).

Just using the conservative DR estimates of DECC and Ofgem (2011a and 2011b), the entire demand response related benefits (domestic and non domestic) sum up to an average annual value of £286 million. It should however be noted that this is less than the value of other benefits at £472m (electricity and gas related) that do not relate to demand response but that result from the introduction of smart metering[80]. DR related benefits may be significantly higher in reality, given the conservative assumptions applied by DECC and Ofgem (2011a and 2011b).

Added together average annual benefits associated with the introduction of smart metering (electricity DR related and electricity and gas non DR related) are £758 million compared with average annual costs for electricity and gas smart metering at £567 million. It is important to realise that excluding reduced losses, DR benefits associated with gas are not included here (only electric) as the focus of this study is electricity demand response related benefits. Cost estimates however include costs relating to gas metering and electricity metering as it was difficult to separate out costs individually from DECC and Ofgem (2011a and 2011b)[81].

If conservative estimates of benefits of DR are considered in conjunction with non-DR related benefits then the economic case looks to be positive for DR resulting directly from the introduction of smart metering (in the sense that benefits outweigh costs). It should however, be noted that there may be some system costs related to DR programmes used in conjunction with smart meters that are not captured by DECC and Ofgem (2011a and 2011b), but it is thought that these elements will not dominate costs. This was identified in section 4.

The economic case for electricity related demand response in small and medium non domestic sector is clear, a positive net present value should be expected given that the value of electricity savings on their own (one DR related benefit) are greater than the value of smart metering costs. A caveat with regards to this finding is that some costs

[80] To see a full list of these benefits in the other (non demand response related) category, please see Appendix 3.

[81] Similarly the non DR related other benefits category includes estimates for gas and electricity as estimates were aggregated in DECC and Ofgem (2011a and 2011b).

that are shared for the domestic sector and small and medium non-domestic sector role out were reported in domestic sector costs.

This analysis of the economic case for electricity DR so far only considers DR directly associated with the introduction of smart metering. There are however a number of other electricity demand response benefits that could come forth as a result of the introduction of technologies such as smart appliances, electric vehicles and heat pumps, in conjunction with smart metering.

The introduction and penetration of smart appliances in the UK will bring forth opportunities for demand response that will enable improved ability to perform balancing for wind generation. Estimates of costs and benefits of smart appliances for balancing in Table 6 (Seebach et al 2009) are only generated for two specific years, so no discounting of cost and benefits occurs for these studies. Ideally one would have discounted costs and benefits over a number of years as occurred for smart meters.

In the case of this form of DR, Seebach et al (2009) estimate that benefits outweigh costs in 2025. Benefits are only estimated to be above costs in 2025 (and not 2010) due to costs being predicted to be lower by this year (as a result of the expected large markets for smart appliances) and also due to the prediction of more intermittent and inflexible generation in future (which increases expected benefits). Annual value of benefits was reported to be 256 million euros (energy and CO_2 benefits) for the low price scenario in 2025.

Given the lower price scenario seen in Table 6, benefits can be seen to be approximately 8 times greater than costs. Applying this benefit to cost ratio to the annual value of benefits would imply that costs are 32 million euros (lower price scenario)[82]. Given that benefits appear to substantially outweigh costs, the economic case for using smart appliances to provide demand response for balancing appears to be quite positive in 2025. This corresponds with Seebach et al's (2009) finding that of countries assessed, the UK was one of the countries where expected net benefits in 2025 were predicted to be highest. This signals good prospects for uptake of demand response in electricity system balancing (for wind) in UK. It should be noted that from above, the scale of these net benefits are indicated to be over 200million euros. Also, annual CO_2

[82] Annual total cost estimates were not provided, this is an estimate by the current authors based on data in Seebach et al (2009), therefore a level of caution should be held with respect to this estimate.

reductions resulting from the balancing of wind (shown in Table 6) are greater than all other quantified values of CO_2 reduction, an important finding from an environmental policy perspective. This is a result of avoided fossil fuel (gas) generation resulting from an increase in capture of wind generation enabled by balancing from DR.

Although this appears to be the case, possible costs associated with DR programmes used in conjunction with smart appliances are not captured in Seebach et al (2009) and may be encountered. Also, costs of smart appliances presented seem to be based on estimates of additional costs of appliances in 2025 (and hence being bought in 2025). In reality the current author believes that smart appliances penetration in 2025 will be the result of appliance brought in many of the years leading up to 2025, some nearer 2010. If costs occur in earlier years and benefits in 2025 then discounting would result in a lower benefit to cost ratio. For this reason the annual 2025 costs and benefits presented by Seebach et al (2009) may be more 'rosey' than in reality, once discounting of both costs and benefits relating to appliance bought in years leading up to 2025 is conducted.

Additionally, the current author has some doubts about one of the estimation methods used by Seebach et al (2009) as earlier reported in section 5. Although this is so, estimated benefits were said to be conservative and the reported benefits are much higher than reported costs, so net benefits (as reported by Seebach et al 2009) are to be expected in 2025 based on their analysis. The extent of future net benefits for the UK however, will rely on whether additional costs of smart appliances can be kept low (which depends on the development of large markets for smart appliances amongst other things) and whether the UK does in fact have the sort of generation system that is predicted e.g. a combination of high amounts of intermittent and inflexible generation (as this effects benefits estimates).

For these DR benefits reported, it is expected that value could fall into the category of net welfare benefits[83] (as opposed to transfers) as Seebach et al (2009) state that benefits represent avoided fuel costs by reducing wind spillage and so replacing conventional energy on the one hand and <u>increasing the efficiency</u> of part loaded plants through providing additional balancing capacity by smart appliances.

We now assess benefits to the distribution network that may result from a change in electricity system management philosophy. Strbac et al (2010) estimate the order of

[83] ABOC

magnitude benefits to the distribution network that would result from a change in electricity system management philosophy, enabled by demand response in conjunction with use of various technologies such as electric vehicles (EVs), heat pumps (HPs) and smart appliances. Table 6 shows that average annual benefits (developed from present value estimates over a 20 year period) are in the range of between £25 and £500 million per year, assuming that avoided costs of distribution network reinforcement occur in the twenty year timeframe. Estimated benefits result from avoided or postponed distribution network reinforcement costs.

Clearly, these benefits are very significant and have the potential to be as large or even larger than any other DR related benefit (from those quantified). The extent to which higher end predicted benefits will materialise is dependent on the penetration of EVs and HPs, and decisions on distribution network reinforcement e.g. whether like for like reinforcement occurs or whether a strategy is taken to insert new distribution sub stations (Strbac et al 2010). As with benefits values of DECC and Ofgem (2011a and 2011b) these benefits were discounted at 3.5%.

It is believed that these benefits could fall into the category of net welfare benefits [84]. There is also no overlap between benefits reported for balancing for wind generation as they relate to distribution network re-enforcement as opposed to avoided fossil fuel generation (due to incorporation of more wind generation). Clearly these benefits could be very significant but they depend on changing the current paradigm of management for the electricity supply system from the current business as usual preventative approach to a corrective active control approach. The current author foresees that such a change in electricity system management may entail organisational (and perhaps other) costs beyond those reported so far in the current review. Such cost considerations should be investigated when further considering the economic case for such a change in electricity system management philosophy. Although this is so, Strbac et al (2010) clearly show that the rewards from such a change enabled by DR could be great.

[84] ABOC

7 CONCLUSIONS AND FURTHUR RESEARCH

This paper presents a synthesis of the costs and benefits of demand response[85]. Uncertainties exist, but the relative scale of different costs and benefits is shown and the economic case is explored.

It was found that in the case of DR benefits directly related to introduction of smart meters[86] the value of electricity savings appears to be one of the largest benefits, even with the conservative assumption of a 2.8% reduction in electricity use.

When seen from a purely economic perspective however, some caution should be held about benefits from energy savings, as it is believed that much of the benefits from electricity savings can be classed as wealth transfers from the producers to the consumers (and therefore will not result in net welfare benefits in economic terms). Although this is believed to be the case, from a human welfare and equity point of view such transfers are highly desirable[87]. It should also be realised that consequent CO_2 reductions resulting from energy savings can be classed as a net welfare benefit (assuming benefits outweigh costs), such reductions also help the UK to meet its obligations with regards to GHG emissions targets.

As a result of the implementation of smart meters, additional demand response benefits are expected to come forth relating to peak load shifting. It was very clear from Ofgem (2010) that benefits have the potential to be very high, particularly short run marginal cost savings. It is believed that much of these benefits could be classed as net welfare benefits[88]. Some authors in the literature state that peak load reduction results in the main benefits associated with DR. Peak demand shift assumptions of DECC and Ofgem (2011a and 2011b) used in quantifying associated benefits are conservative[89], leading to benefits estimates being conservative. With this being the case, benefits for shifting peak load presented in Table 6 of this document may actually be significantly higher, particularly if some form of incentive is used to encourage energy saving.

[85] Where possible the study attempted to identify overlap between benefits as well as discussion of potential for net welfare benefit to the economy. From the review it was found to be possible to conduct some broad comparison of costs and benefits.

[86] Sensitivities by DECC and Ofgem (2011a and 2011b) showed that a modest increase in the percentage to 4% brings about much larger energy savings (average annual value of 237m just for the domestic sector).

[87] As they help consumers mitigate against rising energy prices and higher energy bills and can help ensure individuals energy security and reduce fuel poverty.

[88] ABOC

[89] This is seen from comparison with assumptions of Ofgem (2010).

Benefits from reduced losses as a result of DR were also seen to be significant as well as the value of CO_2 reductions from energy saving and peak demand shifts when valued financially. In total the conservative DECC and Ofgem (2011a and 2011b) electricity[90] DR benefits directly resulting from the introduction of smart metering presented in Table 6 amount to an average annual (derived from present value figures) estimate of £286 million per year. This compares with an average annual cost (derived from present value figures) for smart metering for electricity and gas of £567 million.

If one accounts for the fact that this cost estimate is a lot higher than it would be for just electricity alone (as it also includes gas metering), as well as the conservative approach to electricity DR related benefits by DECC and Ofgem (2011a and 2011b) then the economic case for electricity related DR (from introduction of smart meters) looks to be reasonably good (in the sense that benefits are likely to outweigh costs). This is especially the case if one considers the very high other (non DR) related benefits that will result with the introduction of smart metering. Consideration of system costs that may not be captured by DECC and Ofgem (2011a and 2011b) should however be made, although it was indicated that these are likely not to dominate costs.

Beyond these DR benefits and costs resulting from the introduction of smart metering, there are other DR benefits (balancing for wind generation and those relating to a change in electricity system operating philosophy) enabled as a result of changes in the structure of demand (from technologies such as electric vehicles, heat pumps and smart appliances) and electricity generation (wind generation).

We look firstly at the economic case for DR for balancing for wind generation enabled as a result of the introduction and use of smart appliances. The current author judges the economic case for DR associated with the use of smart appliances for balancing of wind to be reasonably positive, based on analysis of Seebach et al (2009), although reservations exist about some aspects of estimation methods used. The economic case depends on whether large markets for smart appliances develop, as well as whether the UK follows a path towards high proportions of intermittent generation and inflexible generation (which looks likely in the UK). The authors themselves are confident about

[90] A small amount of DR benefit (gas related) is present in the values of benefits from reduced losses.

net benefits, but note that they are only likely in 2025 (one of the two years that they assess). The estimated net benefits in this year are considerable, interpreted to be 224 million euros based on estimation using annual benefits value and benefit to cost ratios presented in Seebach et al (2009). It is believed that such benefits could fall into the category of net welfare benefits[91]. The economic case for using DR for balancing of wind presented here is based on DR via smart appliance technologies. It is likely that the economic case for DR for balancing would be different when using other technologies such as certain types of storage (as costs will be different).

With regards to distribution network benefits from a change in electricity system management from the preventative to the corrective and active control paradigm enabled by DR, potential benefits are considerable and in the range of an average annual (present value) of £25 and £500 million per year. Although not quantified there will also be benefits relating to the transmission network and avoided generation investment from such a change in electricity system management. From this work, the economic case looks likely to be reasonably good, but there should be more examination of potential additional costs relating to organisational change and possibly other areas in order to increase the robustness and clarity of the economic case for this type of change resulting from DR, as there are indications that additional costs may occur[92]. Again, it is believed that benefits could fall into the category of net welfare benefits, assuming that benefits outweigh costs.

Identification of the case for various types of electricity DR has now been reviewed for those areas of DR that it was possible (based on quantified estimates). In conducting a more holistic review of the economic case for DR it is also important to consider un-quantified costs and benefits.

In the case of some benefits such as those for distributed power systems, no quantified estimates of benefit were found, likewise for benefits from avoided transmission network investment (resulting from a different electricity system management philosophy) it was difficult to quantify this benefit. With regards to transmission and distribution network benefits from using DR to avoid costs relating to intermittency of wind, these were not

[91] ABOC

[92] Strbac et al (2010) state that real time network control that incorporates DR will have significant implications on the UK regulatory and commercial arrangements, as maintaining the present structure where supply and network businesses act independently of one another will lead to inefficient network investment.

quantified (avoided fuel costs from using DR as a form of standby reserve for balancing of wind were quantified).

With regards to un-quantified costs, studies were not found to quantify participant cost associated with changing consumption patterns. Costs of changing consumption patterns for the domestic sector relate to changing, searching for and identifying tariffs, re-organising patterns of consumption and changing habits and norms of consumption. Importantly, it is believed that REDUCE could provide information on some of these costs and how technology can reduce such costs. For businesses monetary costs relating to changing consumption patterns were also not quantified.

In summary, from quantitative estimates available, there appears to be a reasonable economic case for DR for electricity in the sense that for quite a number of forms of DR, benefits outweigh costs. It should however be realised that the actual economic case for DR for electricity will ultimately depend on ensuring participation in DR by consumers of electricity. Given that costs of changing consumption patterns were not quantified, this appears to be an important area for future research, especially as it was found that expected savings for individuals can often be low, there may be low incentives to participate in DR.

Although benefits can be low for some individuals, the current paper shows benefits for the UK as a whole can be very high. Also, the literature and estimates presented show that participation does not have to be huge in order to realise much of the benefits estimated, but none the less there must be a level of participation. The key to unlocking these benefits is then the persuasion and lowering of costs to (and for) consumers in taking part in DR and perhaps providing additional incentives beyond the value received from the market as a result of reducing or shifting demand. On this 'note' it is concluded that the REDUCE project has potential to investigate the use of persuasive techniques and incentives to help get people to participate with changing their consumption patterns and engagement with smart metering.

It is concluded that to maximise benefits from DR, it must be ensured that implementation of smart metering and other technologies is done in such a way as to ensure maximum acceptability and participation with DR. Government and suppliers should also take care with how implementation of smart metering is conducted, to ensure that people are comfortable with the technology and do not see the technology as invading privacy, lowering trust or generating ethical issues. If the role out of smart metering is conducted in a way that dissatisfies potential DR participants then DR related benefits that require participation may not be realised, then ultimately affecting the economic case.

In terms of regulation, Strbac (2008) points out that an appropriate regulatory framework is essential in order to optimise the benefits of storage and demand side management within a liberalised environment (which exists in the UK). Given that a huge investment in smart metering has been mandated (to initially be financed by suppliers but subsequently by energy consumers via cost pass on) and that this is one of the main costs (if not the main cost) relating to DR, the current Electricity Market Reforms must ensure that regulation does not result in barriers to DR (directly or indirectly) and that the system actively encourages demand response programmes so that electricity DR benefits (which have been shown to be significant) are maximised to negate the very large sunk costs associated with smart metering. This will help ensure that energy consumers (who are likely to ultimately pay the costs of smart appliances) see a fair return on the smart metering and other technology investments. This is particularly the case given the large benefits that suppliers will see from the smart metering investment even without DR. It may also be useful for the electricity market reforms to make similar considerations to ensure that regulatory barriers (direct or indirect) will not in future result for DR for balancing (with introduction of smart appliances and other technologies) and for the evolution towards a more preventative, smart active control electricity system management structure as future financial and particularly CO_2 reduction benefits associated with these types of DR are substantial.

Beyond the main conclusions, but as a result of writing this paper the current authors have a number of questions that it is believed could be important in understanding the economic case for demand response.

1. In future with European energy market integration and coupling, it has been suggested that we might see a smart international market (Ouden 2011), where electricity balancing in one country (due to the intermittent nature of wind generation) may be supplemented and addressed via transfer of electricity from wind generation of another country (at same time of day). In future, could this

type of balancing be more economic than using demand response (via use of smart meters etc.) in balancing?

2. In using DR to reduce the level of generation, transmission and distribution network infrastructure required at peak times, could demand response still respond to enable the required electricity reductions even in an extreme weather event such as a very cold freeze during winter? If not, then what is the cost as a result of demand not responding on such particular days? Does this diminish the economic case for certain forms of DR?

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Appendix 1: Potential effect of assumptions and limitations associated with Seebach et al (2009)

Assumptions and limitations of the approach that may lead to overestimation benefits:

It is stated that the modelling of appliances allows free shifting of all DSM load within the day. In reality, shifting potential for most appliances is more constrained, often between a few hours or minutes. The study additionally notes that Silva et al (2009) show that benefits of appliances depend on the available shifting period, smaller benefits are associated with appliances with short available shifting periods.

It is stated that as coordination of system balancing of European electricity systems is improved in future and current constraints of the European energy networks removed, levelling out of differences between neighbour countries will gradually occur and it is said that benefits of balancing services (from smart appliances) will therefore decrease.

When comparing the DSM load assumed for modelling in the Smart-A project, with overall load by household appliance in Europe, the authors state that actually in reality only a smaller share of appliances will be available for demand side management. From reading Seebach (2009)'s work, it is unclear whether this resulted in an underestimation or overestimation of benefits, but it is thought to be overestimation. They then go on to state that marginal benefit of smart appliances decreases with increasing DSM penetration rates, therefore a lower penetration has a higher benefit. The authors themselves also state that potential and total benefit of the whole system is probably overestimated.

Assumptions and limitations of the approach that may lead to underestimation of benefits:

Applying annual average load of appliance as a proxy for actual controllable load. The authors see this as a very conservative approach;

Applied modelling results only calculate benefits of smart appliances that result from avoiding marginal costs of balancing services. Full benefits calculation, including avoided costs from building of generation capacities would increase benefits reported by modelling. It is also stated that benefits associated with participation in kWh markets on power exchange (for e.g. peak shifting) and benefits associated with managing network congestion could further increase avoided costs.

Appendix 2: Additional sensitivity analysis and important points relating to the Strbac et al (2010) study.

Results for four important sensitivities are reported below:

1 A situation without heat pumps

The authors considered a situation without heat pumps (HPs) and observe that the total NPV for low voltage (LV) and high voltage (HV) networks for 10% and 25% electric vehicle (EV) penetration of different density mixes are in the range of about 0.25bn to 2.3bn. The authors state that this shows that the value of real time management of responsive demand is considerable, even in an extreme case of very low penetration for EVs and with the absence of heat pumps.

2. The impact of EV commuting patterns on re-enforcement of networks supplying business parks/towns and residential areas;

Strbac et al (2010) also analysed the potential impact of driving patterns associated with commuting to a town/business park area in the morning and making a return journey in the evening. This is said to lead to a heavy concentration of EV charging in the morning (e.g. 8-9 am) and evening hours (charging driven by typical home arrivals at 6-8pm). Results indicated a significant increase in morning peak demand under business as usual (BaU). It was however demonstrated that a very flat profile (with minimal increase in peak demand) can be achieved if charging is optimised, assuming demand is responsive to attempts for optimisation. Figure 2 shows the changes in electricity demand and local network peak load.

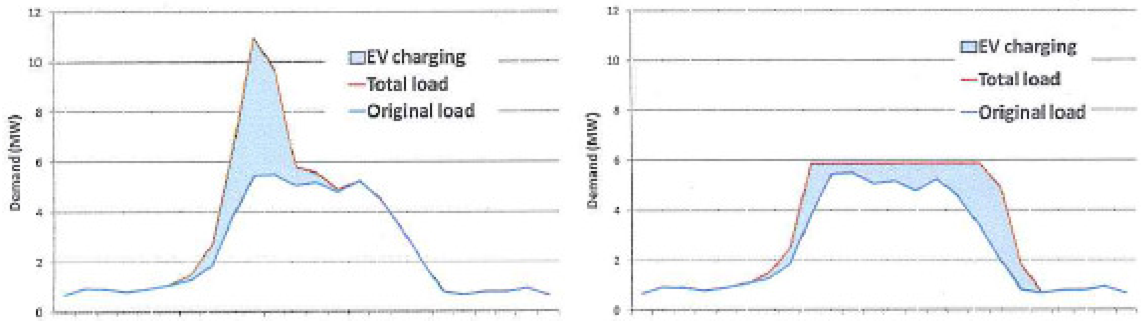

Figure 2: BaU (left) and Smart (right) demand profile in a commercial district (1km^2) driven by changing of 5,000 EVs following arrivals to work. (Strbac et al 2010, page 29)

The results in Figure 2 show that optimising demand response has the potential to result in a very considerable reduction in the system peak and therefore system reinforcement. The use of smart charging for EVs is critical to mitigating expensive network reinforcement. If such reinforcement is not avoided by the active control paradigm, there will massive under utilisation of network assets. Therefore, smart charging for EVs is critical to mitigate expensive network reinforcement that results indicate would be underutilised.

We now look at sensitivities associated with voltage limit constraints.

3. **Sensitivity to two voltage limit constraints (-6% and -10%);**

Strbac et al (2010) state that the required levels of network reinforcement for different levels of penetration of new loads (EVs and HPs) will be driven by both thermal ratings of equipment and network voltage constraints given the requirements enforced by network design standards. The latter authors conducted some sensitivity analysis by relaxing the voltage drop limits from -6% to –10%. By doing this, they state that they implicitly analysed the potential for decreasing network reinforcements through introducing LV voltage control facilities such as inline voltage regulators or distribution transformers with an on-line tap changing capability. Analysis by Strbac et al (2010) shows that a relatively significant proportion of network reinforcement costs may be driven by voltage constraints, especially in semi-urban/rural networks. Resulting cost savings however were not assessed.

4. **Potential conflict between supply and network-driven optimisation of demand response**

Strbac et al (2010) also provided analysis to highlight conflicts that may occur when a situation when high wind generation coincides with peak demand with dynamic pricing and an unconstrained trading philosophy are in place. On the one hand dynamic pricing would incentivise energy users to charge their EVs during peak time, because of the large amount of wind generation available and in terms of electricity generation this makes sense, but in terms of the network distribution this could result in significant stress on the system and overloaded network feeders and transformers. Their analysis demonstrated that an unconstrained trading philosophy may not be an optimal solution for the electricity system. Account of such issues would need to be considered when introducing dynamic pricing to achieve the type of demand response required for the active control approach of the electricity system.

Beyond this brief summary of Strbac et al (2010) there are some important points of further discussion surrounding the implementation of an active control system and the analysis of Strbac et al (2010). These are now provided.

Key Points and Uncertainties

It is important to note that optimal demand response is highly time and location specific with regards to distribution of network benefits. If an active control philosophy and approach is to be implemented, then an appropriate infrastructure is required to facilitate real-time and location specific demand response, including smart meters that have advanced real time functionality and appropriate communication systems. Strbac et al (2010) state that this is essential. It is also stated in the document that less refined 'restricted hour' ToU tariffs would not deliver the optimum management of peak demand at the very local level, particularly due to the potential lack of diversity and 'lumpiness' of load related to electric vehicles and heat pumps. These location specific attributes must be recognised in order to attain the full value of distribution network benefits resulting from demand response (Strbac et al (2010).

The latter authors state that it:

"is important to emphasise that analysis is based on diversified household load profiles and (historical) average national driving patterns applied to all local networks". (p.4 of Strbac et al 2010)

For individual circumstances, they note that significant deviations would be expected, e.g. it has been shown that the impact of driving patterns may be very significant. Additionally, with analysis based on fixed average load patterns, analysis does not capture the variability of particular lumpy loads, and the authors state that this results in the benefits of active network control being under estimated. Similarly, benefits are also understated due to the application of hourly time resolution and the assumption of fully balanced loading condition in LV networks.

It is further stated that: "This work does not consider distribution network asset replacements that may need to be carried out due to aging of equipment, as a major renewal of HV and LV underground cable infrastructure due to condition degradation over the period to 2030 are not currently envisaged." (p.4 of Strbac et al 2010)

If these replacements were to be conducted during the time period in which the study provides estimates, then they may have consequences for the estimated costs for the business as usual paradigm and hence expected benefits (as a result of cost avoidance) from the active control approach.

The active control approach leads to increased utilisation of the distribution network and would therefore lead to an increase in distribution network losses, particularly for higher penetration of EVs and HPs, however, the value of these losses was demonstrated and is said not to be material.

Other potential to increase benefits in future is discussed and identified for future study.

Appendix 3: Full list of benefits in the other (non demand response related) category

Other non DR benefits		
Type	**Category**	**Average annual value (developed from presant values)**
Customer	Micro generation	2
	Avoided site visit	159
	inbound inquireys	53
	Customer service overheads	9
	Debt handling	54
	Avoided PPM COS premium	50
	Remote (dis) connection	12
	Reduced theft	12
Supplier	Customer switching	80
	Reduction in customer minutes lost	2
	Operational savings from fault fixing	4
	Better informed enforcement investment decisions	6
	Avoided investigation of voltage complaints	2
Network benefits	Reduced outage notification calls	1
Total		**446**

Table 1: Breakdown of benefits in the other category

Appendix 4: Original cost and benefit estimates taken from DECC and Ofgem (2011a and 2011b) and Strbac et al (2010) to derive annual average values

Form of DR benefit or cost		Benefit/Cost	Units	Original estimate from studies	Domestic/ non domestic	Annual Estimate of benefits/cost (divide by 20 years)	Study
Energy reduction	Benefits	Reductions in electricity *(energy savings)*	Present value Millions of £	3140	Domestic	157	DECC and Ofgem (2011a and 2011b)
				674	Non domestic	34	
		Reductions in electicity *(CO_2 savings)*	Present value Millions of £	371	Domestic	19	
				84	Non domestic	4.2	
Peak demand shift		Short run marginal cost savings *(from shiting peak demand using TOU)*	Present value Millions of £	121	Domestic	6.1	
				27	Non domestic	1.4	
		Displacing new plant investment *(Avoided investment from TOU)*	Present value Millions of £	653	Domestic	33	
				20	Non domestic	1.0	
		Reduced transmission and distribution network investment *(avoided investment from TOU)*	Present value Millions of £	29	Domestic	1.5	
				1	Non domestic	0.1	
		CO_2 reductions assocated with TOU demand shifts	Present value Millions of £	47	Domestic	2.4	
				17	Non domestic	0.9	
Energy reduction and peak demand		Reduced losses as a result of the introduction of smart meters *(electricity and gas)*	Present value Millions of £	438	Domestic	22	
				90	Non domestic	5	
Not DR related		Other non DR benefits resulting from smart metering *(electricity and gas)*	Present value Millions of £	36+8567+46+86+115+43+21 = 8914	Domestic	445	
				7+446+19+35+12+9 = 528	Non domestic	26	
Balancing for a change in system managment philosophy		**Reduced** distribution network investment *(from a change to a smart corrective smart electricity system)*	Present value Millions of £	500-10000	Both	25-500	Strbac et al (2010)
Smart metering (electricity and gas)	Costs	Capital costs, installation costs, O&M costs, IT costs, the cost of capital, energy costs from smart meter consumed energy, meter reading costs, disposal costs, Legal, marketing and organisational costs	Present value Millions of £	10757	Domestic	538	DECC and Ofgem (2011a and
				590	Non domestic	30	