Title: Electricity Demand Reduction – Amendment to Capacity Market Clauses **IA No:** DECC0133 **Lead department or agency:** Department of Energy and Climate Change **Other departments or agencies:** N/A	**Impact Assessment (IA)** **Date:** May 2013 **Stage:** Final **Source of intervention:** Domestic **Type of measure:** Primary Legislation **Contact for enquiries:** Veeral Dattani Tel: 0300 068 6570
Summary: Intervention and Options	**RPC:** N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year (EANCB in 2009 prices)**	**In scope of One-In, One-Out?**	**Measure qualifies as**
£0.71 billion	N/A[1]	£m	No	N/A

What is the problem under consideration? Why is government intervention necessary?
Energy efficiency measures can reduce electricity demand, resulting in both private and societal benefits. On private benefits, they allow those who invest in electricity demand reduction (EDR) to benefit from electricity bill savings. On societal benefits, EDR can lower electricity system costs, assist with meeting security of supply goals, lead to air quality improvements and economic growth opportunities. Government intervention is necessary because there are a number of market failures which result in under investment in this market. These include misaligned incentives, imperfect information, undervalued energy efficiency opportunities and embryonic markets. The policy aims to overcome these barriers cost-effectively and encourage deployment that otherwise would not have occurred.

What are the policy objectives and the intended effects?
The key policy objective is to drive permanent electricity demand reduction (where it is cost effective) by overcoming market failures and barriers impeding the take-up of efficiency measures. The socially optimal deployment of energy efficiency measures could lead to the decarbonisation of the economy and achievement of security of supply goals at a lower cost than otherwise.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)
While this Impact Assessment considers non-financial options, its focus is on an examination of three market wide financial incentives: a Supplier Obligation, a Premium Payment and delivery through the Capacity Market. The analysis shows that these three market wide mechanisms should be broadly equivalent in economic terms. However, there are non-monetised benefits from pursuing a Capacity Market approach. The Capacity Market approach builds upon a framework and institutions already in development, and targets reductions at peak demand which are likely to deliver the greatest savings to society. Given the uncertainty involved and the need to develop a robust evidence base, we are considering testing the effectiveness of EDR participating in the Capacity Market through a pilot.

Will the policy be reviewed? If applicable, set review date: Yes – details to be confirmed					
Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** Yes	**< 20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:** -3.8		**Non-traded:** 0

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: .... Date: 21.V.13

[1] Administrative policy costs have been included in the total NPV calculations. These are assumed to be incurred upfront. It has not been estimated at this stage how these costs will fall directly to businesses as this will be dependent on the final policy design.

Summary: Analysis & Evidence Policy Option 1

Description: Achieving electricity demand reduction through a Supplier Obligation

FULL ECONOMIC ASSESSMENT

Price Base 2012	PV Base 2012	Time Period 2017-2034	Net Benefit (Present Value (PV) (£billion) 0.71		
			Low: 0.19	High: 2.10	Best Estimate: 0.71

COSTS (£bn)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	Optional		Optional	**0.09**
High	Optional		Optional	**1.02**
Best Estimate				**0.34**

Description and scale of key monetised costs by 'main affected groups'

The costs of EDR are primarily driven by the upfront costs of installing energy efficiency measures. There is also an administrative cost of running the Supplier Obligation. Additionally, if EDR results in reduced deployment of low-carbon technologies society will forego innovation benefits, since the learning effects that lower the capital costs of these technologies are determined by deployment levels. We assume for the Impact Assessment the same amount of financing and policy (administrative, monitoring and verification) costs are allowed for EDR under all three measures – the Supplier Obligation, the Premium Payment and the Capacity Market – resulting in identical monetised costs.

Other key non-monetised costs by 'main affected groups'

The Supplier Obligation route does not directly allow for EDR to be seen as equivalent to other capacity resources, thereby a direct trade-off between generation and demand reduction cannot occur. Furthermore, there is a concern that suppliers could lack the information and expertise to deliver energy efficiency improvements in the non-domestic sector which is heterogeneous.

BENEFITS (£bn)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	Optional		Optional	**0.29**
High	Optional		Optional	**3.12**
Best Estimate				**1.05**

Description and scale of key monetised benefits by 'main affected groups'

The benefits to society are driven by avoided costs in the electricity system. With a lower level of demand, there would be savings associated with generation capital costs (investment in new low-carbon and conventional generation plant). There would also be savings associated with electricity transmission and distribution networks. Given the reduction in conventional generation, costs incurred in their operation (such as fuel costs) would also fall. Correspondingly, the reduction in conventional generation would allow society to benefit from lower expenditure on CO_2 allowances incurred as part of the EU ETS.

Other key non-monetised benefits by 'main affected groups'

There are further externality benefits which have not been quantified. For example, there is potential for higher productivity from more energy efficient buildings and equipment, and lower running costs which would have a positive impact on economic growth. Investment in energy efficiency technology today can help to support future innovations and cost reductions that can make it cheaper and easier to invest in energy efficiency in the future. Furthermore, EDR should lead to a reduced requirement to import fuels, thus improving security of supply.

Discount rate (%)	3.5%

Key assumptions/sensitivities/risks

- A level of electricity demand reduction of 0.4% is assumed by 2030 in the central case, with sensitivities between 0.1-1.3%.[2]
- Upfront capital costs of electricity demand reduction measures are based on the original data sources used for the analysis of technical potential.
- Technical potential for electricity demand reduction uses the analysis undertaken with McKinsey and Co. in 2012 as a starting point. In response to feedback during the consultation, we have also sought to strengthen the evidence base by comparing this top-down analysis to UK data sources. Where sector specific UK data sources were judged to be more accurate, these have been used.
- The total costs and benefits of EDR are determined by the level of take up, with considerable uncertainty around the distribution of payback requirements, expected duration of savings and the level of additionality. The model developed for this purpose has been externally peer reviewed.
- Policy costs (administrative costs, sales/marketing cost, monitoring and verification costs) are taken from comparative international evidence, and tested against DECC policy costs. These are assumed to be the same for all three delivery mechanisms, ranging from £2-£7/MWh for the lifetime of the measure, with a central estimate of £4/MWh[3].
- Estimates are sensitive to gas and CO_2 prices, the requirement for and price of new conventional generation, the level of low-carbon generation displaced and the levelised costs of technologies.

BUSINESS ASSESSMENT (Option 1)[4]

Direct impact on business (Equivalent Annual) £m:			**In scope of OIOO?**	**Measure qualifies as**
Costs: N/A	**Benefits: N/A**	**Net:**	No	N/A

[2] Calculated as a percentage of final energy demand in 2030 (DECC Updated Energy & Emissions Projections, 2012). https://www.gov.uk/government/publications/non-co2-greenhouse-gas-emissions-projections-report-spring-2013.

[3] As these costs will be determined by the exact institutional design, reporting and governance structures, there is insufficient information at present to estimate differences in administrative, search and monitoring and verification costs between options.

[4] As per paragraph 3.75 in the consultation document (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66561/7075-electricity-demand-reduction-consultation-on-optio.pdf) funding for a Supplier Obligation is assumed to come from within the agreed Levy Control Framework, hence this option is assumed to be out of scope of OIOO.

Summary: Analysis & Evidence

Policy Option 2

Description: Achieving electricity demand reduction through a Premium Payment

FULL ECONOMIC ASSESSMENT

Price Base 2012	PV Base 2012	Time Period 2017-2034	Net Benefit (Present Value (PV)) (£billion) 0.71		
			Low: 0.19	High: 2.10	Best Estimate: 0.71

COSTS (£bn)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	Optional		Optional	**0.09**
High	Optional		Optional	**1.02**
Best Estimate				**0.34**

Description and scale of key monetised costs by 'main affected groups'

The costs of EDR are primarily driven by the upfront costs of installing energy efficiency measures. There is also an administrative cost of running the Premium Payment. Additionally, if EDR results in reduced deployment of low-carbon technologies society could forego innovation benefits, since the learning effects that lower the capital costs of these technologies are determined by deployment levels. We assume for the Impact Assessment the same amount of financing, and policy (administrative, monitoring and verification) costs are allowed for EDR under all three measures – the Supplier Obligation, the Premium Payment and the Capacity Market, resulting in identical monetised costs.

Other key non-monetised costs by 'main affected groups'

The Premium Payment does not directly allow for EDR to be seen as equivalent to other capacity resources, thereby a direct trade-off between generation and demand reduction cannot occur. There is also an inability to build on institutions and frameworks already in development.

BENEFITS (£bn)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low			Optional	**0.29**
High			Optional	**3.12**
Best Estimate				**1.05**

Description and scale of key monetised benefits by 'main affected groups'

The benefits to society are driven by avoided costs in the electricity system. With a lower level of demand, there would be savings associated with generation capital costs (investment in new low-carbon and conventional generation plant). There would also be savings associated with electricity transmission and distribution networks. Given the reduction in conventional generation, costs incurred in their operation (such as fuel costs) would also fall. Correspondingly, the reduction in conventional generation would allow society to benefit from lower expenditure on CO_2 allowances incurred as part of the EU ETS.

Other key non-monetised benefits by 'main affected groups'

There are further externality benefits which have not been quantified. For example, there is potential for higher productivity from more energy efficient buildings and equipment, and lower running costs which would have a positive impact on economic growth. Investment in energy efficiency technology today can help to support future innovations and cost reductions that can make it cheaper and easier to invest in energy efficiency in the future. Furthermore, EDR should lead to a reduced requirement to import fuels, thus improving security of supply.

Discount rate (%)	3.5%

Key assumptions/sensitivities/risks

- A level of electricity demand reduction of 0.4% is assumed by 2030 in the central case, with sensitivities between 0.1-1.3%.
- Upfront capital costs of electricity demand reduction measures are based on the original data sources used for the analysis of technical potential.
- Technical potential for electricity demand reduction uses the analysis undertaken with McKinsey in 2012 as a starting point. In response to feedback during the consultation, we have also sought to strengthen the evidence base by comparing this top-down analysis to UK data sources. Where sector specific UK data sources were judged to be more accurate, these have been used.
- The total costs and benefits of EDR are determined by the level of take up, with considerable uncertainty around the distribution of payback requirements, expected duration of savings and the level of additionality. The model developed for this purpose has been externally peer reviewed.
- Policy costs (administrative costs, sales/marketing cost, monitoring and verification costs) are taken from comparative international evidence, and tested against DECC policy costs. These are assumed to be the same for all three delivery mechanisms, ranging from £2-£7/MWh for the lifetime of the measure, with a central estimate of £4/MWh[5].
- Estimates are sensitive to gas and CO_2 prices, the requirement for and price of new conventional generation, the level of low-carbon generation displaced and the levelised costs of technologies.

BUSINESS ASSESSMENT (Option 2)[6]

Direct impact on business (Equivalent Annual) £m:			**In scope of OIOO?**	**Measure qualifies as**
Costs: N/A	**Benefits: N/A**	**Net: N/A**	No	N/A

[5] As these costs will be determined by the exact institutional design, reporting and governance structures, there is insufficient information at present to estimate differences in administrative, search and monitoring and verification costs between options.

[6] As per paragraph 3.75 in the consultation document (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66561/7075-electricity-demand-reduction-consultation-on-optio.pdf) funding for a Premium Payment is assumed to come from within the agreed Levy Control Framework, hence this option is assumed to be out of scope of OIOO.

Summary: Analysis & Evidence Policy Option 3

Description: Achieving electricity demand reduction through a pilot in the Capacity Market

FULL ECONOMIC ASSESSMENT

Price Base 2012	PV Base 2012	Time Period 2017-2034	Net Benefit (Present Value (PV)) (£billion) 0.71		
			Low: 0.19	High: 2.10	Best Estimate: 0.71

COSTS (£bn)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	Optional		Optional	**0.09**
High	Optional		Optional	**1.02**
Best Estimate				**0.34**

Description and scale of key monetised costs by 'main affected groups'

The costs of EDR are primarily driven by the upfront costs of installing energy efficiency measures. There is also an administrative cost of running the Capacity Market. Additionally, if EDR results in reduced deployment of low-carbon technologies society could forego innovation benefits, since the learning effects that lower the capital costs of these technologies are determined by deployment levels. We assume for the Impact Assessment the same amount of financing and policy (administrative, monitoring and verification) costs are allowed for EDR under all three measures – the Supplier Obligation, the Premium Payment and the Capacity Market, resulting in identical monetised costs.

Other key non-monetised costs by 'main affected groups'

There could be additional Monitoring and Verification challenges from running EDR through a Capacity Market, which could result in higher costs. This is minimised by using a pilot to test different approaches, and the additional burden these may place.

BENEFITS (£bn)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low			Optional	**0.29**
High			Optional	**3.12**
Best Estimate				**1.05**

Description and scale of key monetised benefits by 'main affected groups'

The benefits to society are driven by avoided costs in the electricity system. With a lower level of demand, there would be savings associated with generation capital costs (investment in new low-carbon and conventional generation plant). There would also be savings associated with electricity transmission and distribution networks. Given the reduction in conventional generation, costs incurred in their operation (such as fuel costs) would also fall. Correspondingly, the reduction in conventional generation would allow society to benefit from lower expenditure on CO_2 allowances incurred as part of the EU ETS.

Other key non-monetised benefits by 'main affected groups'

There are further externality benefits which have not been quantified. For example, there is potential for higher productivity from more energy efficient buildings and equipment, and lower running costs which would have a positive impact on economic growth. Investment in energy efficiency technology today can help to support future innovations and cost reductions that can make it cheaper and easier to invest in energy efficiency in the future. Furthermore, EDR should lead to a reduced requirement to import fuels, thus improving security of supply. With regards to the Capacity Market route, there is an option for a more direct trade off to occur between EDR and other capacity resources. This benefit has not been monetised. This route also offers the opportunity to build on frameworks and institutions already in development.

Key assumptions/sensitivities/risks	**Discount rate (%)**	3.5%

- A level of electricity demand reduction of 0.4% is assumed by 2030 in the central case, with sensitivities between 0.1-1.3%.
- Upfront capital costs of electricity demand reduction measures are based on the original data sources used for the analysis of technical potential.
- Technical potential for electricity demand reduction uses the analysis undertaken with McKinsey in 2012 as a starting point. In response to feedback during the consultation, we have also sought to strengthen the evidence base by comparing this top-down analysis to UK data sources. Where sector specific UK data sources were judged to be more accurate, these have been used.
- The total costs and benefits of EDR are determined by the level of take up, with considerable uncertainty around the distribution of payback requirements, expected duration of savings and the level of additionality. The model developed for this purpose has been externally peer reviewed.
- Policy costs (administrative costs, sales/marketing cost, monitoring and verification costs) are taken from comparative international evidence, and tested against DECC policy costs. These are assumed to be the same for all three delivery mechanisms, ranging from £2-£7/MWh for the lifetime of the measure, with a central estimate of £4/MWh [7].
- Estimates are sensitive to gas and CO_2 prices, the requirement for and price of new conventional generation, the level of low-carbon generation displaced and the levelised costs of technologies.

BUSINESS ASSESSMENT (Option 3)[8]

Direct impact on business (Equivalent Annual) £m:			**In scope of OIOO?**	**Measure qualifies as**
Costs: N/A	**Benefits: N/A**	**Net:**	**No**	**N/A**

[7] As these costs will be determined by the exact institutional design, reporting and governance structures, there is insufficient information at present to estimate differences in administrative, search and monitoring and verification costs between options.

[8] As per paragraph 3.75 in the consultation document (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66561/7075-electricity-demand-reduction-consultation-on-optio.pdf) if an EDR measure is included within the Capacity Market it will be subject to the cost control arrangements for it when they are finalised, according to its design and likely classification hence this option is assumed to be out of scope of OIOO.

1. Problem under consideration

1.1. Energy efficiency measures can reduce electricity demand, which would allow those who invest to benefit from electricity bill savings. There are also wider societal benefits from reducing electricity demand such as avoided electricity resource costs, lower exposure to security of supply risks, economic growth opportunities and potential air quality improvements. However, there are a number of market failures that result in under-investment in this market such as embryonic markets, misaligned financial incentives, information failures and undervalued energy efficiency opportunities. The proposed policy aims to overcome these barriers cost-effectively and encourage deployment that otherwise would not have occurred.

Background

1.2. The Electricity Demand Reduction (EDR) project is focused on delivering the White Paper's commitment to "assess whether there are sufficient support and incentives to make efficiency improvements in electricity usage and consider whether there is a need for appropriate additional measures". Analysis undertaken with McKinsey and Co[9] suggested that there is significant technical potential for further electricity demand reduction. In November 2012 the Government launched a consultation on options to capture this further potential, which closed on 31st January 2013.

1.3. It should be noted that the EDR project considers demand reduction and not demand response:

EDR refers to permanent reductions in electricity demand, through the installation and on-going use of more efficient equipment.

Demand Side Response (DSR) is the collective name for a range of actions that decrease or (more rarely) increase electricity demand temporarily to help balance the system. Typically these involve time switching (such as running industrial processes at other times of day to avoid peaks), turning demand down (such as reducing air conditioning loads) and switching to behind the meter generators to reduce demand on the grid.

2. Rationale for intervention

2.1. Evidence suggests that there is significant potential for demand reduction through cost effective energy efficiency measures. However, the existence of market failures and barriers to action result in a lower take-up of energy efficiency than is socially optimal. These market failures and barriers to action are described below.

Market failures

- *Misaligned financial incentives*: when the person responsible for making energy efficiency improvements will not receive the benefits, these investments are not prioritised. For example, a landlord may be responsible for funding an upgrade to a lighting system whereas the tenant would capture the benefits of lower bills. Since the landlord is unable to realise these benefits in monetary terms, the incentive for them to install the measure is reduced.

- *Information failures*: there is information available about overall energy consumption in the home and in business settings; however it can be difficult to relate this back to individual circumstances and identify opportunities to make energy efficiency improvements. In the absence of clear, trusted information organisations and households do not prioritise these investments.

[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48456/5776-capturing-the-full-electricity-efficiency-potentia.pdf

- *Undervaluing energy efficiency*: the lack of salience of energy efficiency increases the impact of hassle costs and behavioural barriers. There is also the issue of bounded rationality ("not front of mind"). Organisations and households make decisions about energy efficiency alongside a wide range of other criteria. Given the amount of information which has to be processed, it is not unusual for decision makers to revert to rule of thumb behaviour and make decisions based on a few critical parameters. Therefore energy efficiency, which is not a front of mind issue, may not be seen as strategic for a company and therefore not prioritised.

- *Embryonic markets*: whilst there are examples of companies focused on helping domestic and non-domestic consumers improve energy efficiency, the market remains underdeveloped. In the absence of a developed market, there is relatively little expertise on the supply or demand side for energy efficiency investment. This constrains the development of financial products to support this investment.

Barriers to action

- *Hassle costs*: these are non-financial costs faced by consumers such as searching for appropriate solutions, identifying reputable suppliers, shutting down production during installation or problems integrating new equipment. While hassle costs are not in themselves a market failure, they compound the impact of other behavioural barriers and therefore reduce the incentive for companies to invest even if a project is cost effective at market interest rates.

- *Hurdle rate/payback period*:[10] analysis undertaken with McKinsey identified that the rates of return for which many potential investors were looking were not achievable. Many respondents indicated they were looking for payback of around 2 years. On average, the measures considered have a payback of 3-5 years depending on the sector under consideration.

- *Risk and uncertainty*: this mainly applies to the industrial sector. Making changes to well-functioning equipment or processes in order to achieve energy savings brings risks, for example that the machinery will not restart or that a relatively untried technology will not prove to be successful. This reduces the incentive for businesses to invest.

2.2. The market failures and barriers described above result in deployment of energy efficiency measures below the socially optimal level. Increasing deployment of demand reduction technologies will lower the cost of meeting our decarbonisation objectives. Firstly by reducing demand, society will benefit from lower electricity system costs. This saving is made up of avoided generation costs (including operating, carbon and fuel costs), avoided capital costs (investment in new generation plant, consisting of both low-carbon and fossil fuel plants) and avoided transmission and distribution costs. Second, the potential impact on the amount of low-carbon capacity which needs to be built to meet our decarbonisation objectives could in turn reduce the level of low-carbon financing required.

2.3. The abatement potential offered by EDR is very cost effective. Analysis undertaken with McKinsey suggests there is 92TWh of potential across domestic, industrial and commercial sectors, most of which can be achieved at a negative cost to society.[11] Refined analysis suggests the available potential for EDR is closer to 32TWh – further details are provided below.

[10] The hurdle rate is minimum rate of return on a project required by an investor. The payback period is the length of time required to recover the cost of an investment.
[11] See annex for further details on the Marginal Abatement Cost Curve (MACC).

Box 1: Revised estimate of technical potential for EDR[12]

There is great uncertainty as to the level of potential for EDR, but even under conservative assumptions it appears significant. Preliminary research into the total potential for EDR across the economy was undertaken with McKinsey and Co. in 2012. That research estimated the total potential for EDR was around **92TWh** in 2030, after accounting for the impact of existing policy. This analysis provided a high level estimate of the total potential, on the basis of a top down methodology. As the EDR project moved from defining the strategic case for intervention to designing the policy, DECC has narrowed the focus of the analysis.

Following the consultation, DECC conducted a systematic review of all the sectors to strengthen the evidence base underpinning the technical potential estimates. As part of this process the following sectors were identified as being the most likely sources of demand reduction:

- Non-domestic building retrofit
- Non-domestic product and appliances
- Domestic products and appliances
- Industrial processes

Two sectors have been excluded from the analysis (new buildings and domestic retrofit) because most of their potential is likely to be captured by existing policies. This does not mean measures in these sectors would not be eligible for support under an EDR financial incentive.

There is a wide range of innovative approaches to delivering energy efficiency that could be eligible for support. The eligibility of different types of demand reduction project will be made at a later stage in the policy development process (and may be done on a project by project basis by the relevant authority). However, for the purposes of conducting the analysis we have focused on the sectors which are likely to deliver a significant majority of the demand reduction. This narrowing of the likely focus of the policy reduces the technical potential to **69TWh**.

In response to feedback during the consultation, we have also sought to strengthen the evidence base by comparing the top-down analysis to UK data sources. Taking a conservative approach, where sector specific UK data sources were judged to be more accurate, these have been used.

This adoption of UK datasets led to the estimate of potential being revised down to **32TWh**. The evidence therefore suggests that even under conservative assumptions there remains considerable potential for cost effective electricity demand reduction. The analysis of technical potential has been subject to external peer review, as explained in Annex G, but there remains considerable uncertainty around the level of potential. The table below presents the final estimate of technical potential for electricity demand reduction by sector.

12 The sources for these estimates are:
- The Non-domestic energy and emissions model (N-DEEM) for non-domestic heating lighting and building fabric
- Analysis undertaken with McKinsey and DECC internal analysis for the industrial processes, pumps and motors and non-domestic electronics
- AEA/Market Transformation Programme analysis for domestic products

Table 1: Breakdown of technical potential for EDR by sector

	Potential for EDR in 2030 (after impact of existing policy) in TWh
Domestic appliances and products	4.3
Non-domestic building fabric	1.0
Non-domestic heating and lighting	4.7
Non-domestic appliances and products	1.9
Pumps and Motors	11.3
Other industrial processes	7.2
Street lighting	1.7
Total*	**32.2**

*numbers may not sum due to rounding

2.4. The presence of market failures and the benefits in tackling these provide a strong rationale for intervention. A detailed examination of the costs and benefits of further action to reduce demand can be found in the section 5. There are also externality benefits, which are summarised below:

Externality benefits of further action to reduce electricity demand

2.5. There will be no additional carbon benefits from EDR measures[13] beyond those already captured through the European Union Emissions Trading System (EU ETS) and Carbon Price Floor. The potential effect of EDR on future caps in the EU ETS is not explored in this impact assessment.

2.6. There are a range of other external benefits which may result from a successful EDR policy:

- *Economic growth*: Installing energy efficiency measures has the potential to boost investment and employment and hence economic growth in the current economic climate. There are also long-term growth benefits in terms of higher productivity from more energy efficient buildings and equipment and lower running costs. Simple changes in energy use behaviour can also deliver some of these benefits with little up-front cost.

- Investment in energy efficiency technology today can help to support future innovations and cost reductions that can make it cheaper and easier to invest in energy efficiency in the future. Developing our innovative capacity in technology, materials or business models for energy efficiency opens up the potential for increasingly significant export opportunities for the UK as the global effort to combat climate change ramps up.

- *Security of supply*: an EDR policy should lead to a reduced requirement to import fuels, thus improving security of supply. It may also assist with ensuring strong capacity margins in the short- to medium-term where large volumes of coal plant are being retired due to environmental requirements.

- *Air quality benefits* should result from reduced generation even if the carbon costs are already internalised.

3. Policy objectives

3.1. The key objective of the proposed policy is to drive electricity demand reduction which reduces overall electricity system costs. In addition, the policy needs to meet the following objectives:

- Deliver value for money for consumers and taxpayers and be funded from within agreed DECC funding.
- Integrate with and complement the UK energy market and policy landscape.
- Not place undue regulatory or other burdens on business.

[13] EDR reduces emissions in the traded sector only, which is covered by the EU ETS cap.

4. Options considered

4.1. The initial EDR impact assessment published in November 2012 proposed further investigation of the following policy options:

Market wide financial

Premium Payment

Payment on a pence per kWh basis for the volume of electricity saved (Main variants FIT and CfD)

Capacity Market

Payment for demand reduction as an alternative to generation capacity

Supplier Obligation

Suppliers obliged to deliver a specified target of demand reduction

Narrow financial

Sector/ technology-specific schemes

Such as a scrappage scheme or a voucher scheme.

Non-financial

Information hub (industrial processes)

Disaggregated metering

Better labelling

Buyer's commitment

4.2. Market wide options provide a financial incentive for electricity demand, not taking into account the sector or product by which this is achieved. In comparison, narrow financial incentives only provide support to a predetermined sector or product group. Non-financial options do not involve incentive payments and are designed to tackle non-financial barriers such as lack of information.

4.3. This impact assessment firstly considers the 'do nothing' option, followed by a discussion of non-financial and narrow financial options. A detailed cost benefit analysis of these options is not provided in this impact assessment. The focus of this document is on the market wide financial incentives, which are analysed in detail in section 5.

Do nothing

4.4. There are a number of existing policies that contribute to tackling the market failures and barriers described above which were set out in detail in the consultation document published in November 2012.[14]

4.5. Our projections of electricity demand takes into account that current policies are expected to deliver 63TWh of electricity savings in 2020 and 55TWh in 2030 relative to the business as usual base case (Table 2). In the domestic sector, electricity demand reduction will be delivered through the rollout of smart meters, the Green Deal, building regulations and products policies (EU Ecodesign Framework Directive, EU Labelling Directive). In the commercial, services and public sectors the most important policies are smart meters, building regulations, Carbon Reduction Commitment (CRC) energy efficiency scheme and the Green Deal. In industry, savings are delivered through building regulations, products policy and climate change agreements. There are also a number of policies included in the baseline that continue to deliver energy savings. In the industry sector this includes the EU ETS which

[14] See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66563/7115-electricity-demand-reduction-initial-ia.pdf for further details. Annex A provides a summary of existing policies by sector.

places a price on carbon and incentivises energy efficiency where it delivers carbon savings. In addition, legacy savings from existing Climate Change Agreements (CCAs) which offer large energy users a discount on the Climate Change Levy in return for energy efficiency improvements are also included in the baseline. CCAs are estimated to deliver 38TWh[15] over the period from 2012 to 2020.

Table 2: Electricity Savings delivered through existing policies

Sector	TWh in 2020	TWh in 2030
Domestic (policies include CERT (20% extension and uplift), CESP[16], Green Deal, ECO, Smart Meters, 2010 Building Regulations, Zero Carbon Homes, Warm Front)	37	34
Commercial & public sector (policies include Green Deal, 2010 Building Regulations, CRC, Salix, SME Loans, Non‑domestic Smart Meters)	22	18
Industry (Policies included Green Deal, CRC, 2010 Building Regulations, SME Loans, Carbon Price Floor (indirect)) *Policies in the baseline:* ETS, CCA)	4	3
Total	63	55

Source: DECC, Updated Energy and Emissions Projections, October 2012.

4.6. In addition to the level of savings expected to be delivered by existing policies, there remains significant potential for demand reductions through EDR measures (see paragraph 2.3). The majority of consultation responses also supported action for EDR.[17] Given the cost effectiveness of this potential, avoided electricity system costs and potential for savings to low-carbon financing there is a strong case for intervention and therefore doing nothing is not the preferred option. However, if a new instrument is introduced it will have to be designed carefully to work with existing policies so that the interactions increase the take-up of efficiency measures. For example, information gathered under existing schemes could make it easier for firms to assess the potential for electricity demand reduction measures.

Non-Financial policies

4.7. The potential contribution of the following non-financial options was considered:

- Information hub – a web-based resource which would seek to bring together the best available expertise in industrial energy efficiency, such as recent research, energy efficiency solutions and tools, best practice training material etc.
- Disaggregated metering – support to help organisations install additional meters to give a more detailed understanding of their electricity use and so overcome information barriers.
- Additional labelling for non-domestic appliances and products. For example, the inclusion of information about lifetime electricity running costs to help inform decisions at the point of purchase.
- Buyers commitment which would recognise organisations that commit to only buy appliances or electronics with a high level of efficiency.

[15] Across all fuels.
[16] Community Energy Saving Programme
[17] https://www.gov.uk/government/consultations/options-to-encourage-permanent-reductions-in-electricity-use-electricity-demand-reduction

4.8. Further consideration and feedback from the consultation have confirmed that the policies listed above could be a useful complement to the existing policy framework, but we judge that alone will not generate a significant volume of electricity savings.[18] We will consider non-financial options further and report on these in the 2013 update to the Energy Efficiency Strategy. More radical policies with greater impact that are not listed above, face significant deliverability challenges or may not be desirable for wider reasons (e.g. unilateral action on products policy may run counter to the Single Market).

Narrow financial policies

4.9. Two general approaches to the mechanisms for delivering a financial incentive were considered as part of the consultation: broad and narrow approaches. A narrow financial incentive provides funding for a specific area of the market (e.g. replacement of industrial equipment with more energy efficient technology) or product group (e.g. an industrial pump). This option would focus finite resources on the areas of the economy with the most potential for reductions in electricity demand.

4.10. Two narrow financial incentives were examined: a scrappage scheme where a payment would be made to reduce the cost of replacing an existing piece of equipment with a new more electricity efficient version; and a capital grant scheme where a payment would be made to reduce the cost of a more electricity efficient piece of equipment (replacement of existing equipment would not be required).

4.11. One advantage of a scrappage scheme is its comparative simplicity, which implies monitoring and verifying savings would be comparatively straightforward. Additionally, it could be set up relatively quickly and it would be simple for people to participate in the scheme. However, a scrappage scheme lacks a strong mechanism to drive competitive price setting for EDR. Furthermore, by definition a scrappage scheme requires the recipient of the support to dispose of an existing piece of equipment. This rules out only rewarding behavioural change and subsidising the purchase of new equipment to optimise the performance of existing equipment. The scrappage scheme therefore has less flexibility due to the requirement to dispose of the existing piece of technology.

4.12. Like the scrappage scheme, a capital grant scheme would be constrained by its nature in the amount of potential that could be tapped. While straightforward, it also lacks a mechanism for competitive price setting.

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[18] Note that there are other non-financial policies which have resulted, and continued to drive, in substantial improvements in energy efficiency across the UK, such as products policy and building regulations. For example, the UK continues to encourage ambitious and proportionate action on products policy. Also the Energy Act 2011 enables Government to regulate to help ensure the take up of cost effective energy efficiency improvements in the Private Rented Sector. Our intention is that:

- From April 2016, domestic landlords should not be able to unreasonably refuse requests from their tenants for consent to energy efficiency improvements, where financial support is available, such as the Green Deal and/or the Energy Company Obligation (ECO); and
- From April 2018, all private rented properties (domestic and non-domestic) should be brought up to a minimum energy efficiency standard rating, currently likely to be set at EPC rating “E” (though this has yet to be consulted on and to go through Parliament).
- This requirement would be subject to there being no net negative costs to landlords. Where there are costs on landlords (such as time or hassle costs), we are committed to ensuring the benefits of energy efficiency improvements meet or exceed these.
- The intention is that landlords would have fulfilled this requirement if either the EPC rating reached “E” or if they carried out the maximum package of measures funded under the Green Deal and/or ECO (even if this does not take the property above an “F” rating).

4.13. In principle, one would be interested in a targeted scheme where there is a very clear and specific pocket of potential that warranted a tight focus. Our understanding of the opportunity for greater efficiency suggests that it is spread over a number of technologies and sector. For example, as shown in the table below, there are four different areas (pumps and motors, industrial processes, non-domestic lighting and domestic products) which account for at least a tenth of technical potential each. Each of these contains a different number of sub-technologies, for example the pumps and motors category contains five different processes/technologies.

Table 3: Share of technical potential by measure

Energy Efficiency Measure	Share of technical potential in 2030
Domestic products	13%
Non-domestic insulation	3%
Non-domestic heating and lighting	15%
Non-domestic products and appliances	6%
Pumps and Motors	35%
Industrial processes	22%
Street lighting	5%

(Numbers may not sum due to rounding)

4.14. It is likely therefore that a targeted scheme would considerably limit the existing opportunity for EDR. Furthermore, it lacks the flexibility to adapt to technological change and include emerging technologies that the broad options possess. Therefore this is not the preferred option.

Market wide financial policies

4.15. Market wide policies aim to provide an incentive to create energy savings across a range of sectors. There are potentially three types of broad financial policies that could be deployed: a Supplier Obligation, Premium Payment and EDR participation in the Capacity Market:

- **A Supplier Obligation for EDR –** suppliers could be obliged to deliver a volume of savings in the non-domestic sector. This could be delivered either directly though their customer base or potentially through a traded certificate scheme.

- **A Premium payment** – provides a straight payment per kWh of electricity saved. The lead delivery option would involve stand-alone auctions for EDR measures based around a desired volume of energy savings.

- **EDR participating in the Capacity Market –** permanent EDR could bid into the Capacity Market (either in a separate auction or a combined auction with other resources) and be paid for each kW of demand reduction.

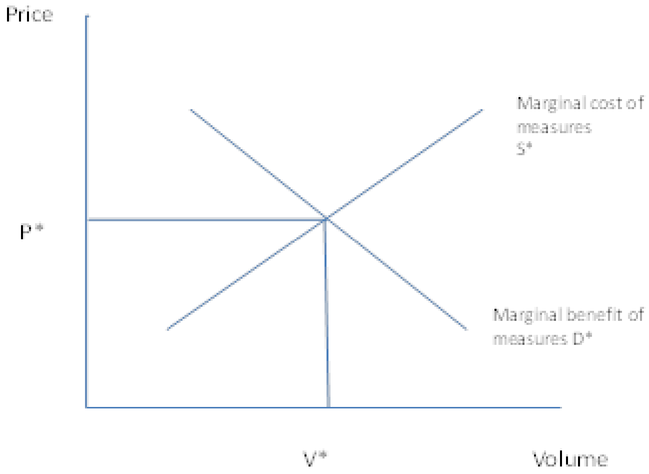
Economic case - which delivery mechanism?

4.16. As will be discussed in Section 5, the key benefits of EDR under all three delivery mechanisms are: the savings associated with generation costs (including operating, carbon and fuel costs), capital costs (investment in new generation plant) and transmission and distribution costs as a result of reduced demand. The key components of costs are: the direct cost of EDR investments, administrative policy costs and the foregone innovation benefit from reduced low-carbon generation. While there may be differences in the source of financing under the three mechanisms, for the purposes of this IA and the monetisation of costs and benefits, these financing source differences are not taken into account.

4.17. The economic modelling conducted for the purposes of this IA is based on the assumption that the amount of financing for EDR is the same for all three delivery mechanisms, with full information and perfect foresight from all market participants.[19] With these assumptions, economic rationale suggests that the three mechanisms should be broadly equivalent because:

- A Supplier Obligation which targets a volume (V*) will, as shown in Figure 1 below, lead to a price of P* and a direct EDR cost of V*P*.[20]
- A Premium Payment which pays a price P* would lead to the corresponding volume V* and a direct EDR cost of V*P*.[21]
- A Capacity Market auction which targets a volume (V*) will lead to a corresponding price P* and a direct EDR cost of V*P*.[22]

Figure 1: Market equilibrium



4.18. Based on the same direct cost of EDR and the same amount of EDR delivered, the gross societal benefits under the three schemes should also be equivalent. This breakdown of the gross societal benefits is presented in more detail in Section 5.

4.19. While in the three mechanisms the volume may be expressed in different units (e.g. MWh and MW), with the above assumptions, V* should be equivalent between the three. Similarly, the price could be expressed in different units (£/MWh, £/MW/year); again, P* should be equivalent between the three.

4.20. There is a simplifying assumption that policy costs (including administrative, search and monitoring and verification costs) under all three schemes are equivalent. As these costs, will be determined by the exact institutional design, reporting and governance structures, there is insufficient information at present to estimate differences in administrative, search and monitoring and verification costs between options.[23]

[19] The above argument is based on the assumption that all three mechanisms operate under full information and perfect foresight by all market participants. However, in a world of cost uncertainty, setting a price may lead to different volumes being delivered (Weitzman, M.L. (1974). Prices vs. quantities. *Review of Economic Studies* 41(4), 477-491). Weitzman argues that in a world of uncertainty and imperfect foresight, a price-based instrument is preferable when the marginal costs of measures are rising relatively steeply (compared with the marginal benefits).

[20] Alternatively, a Supplier Obligation for EDR could be combined with an obligation for other types of energy efficiency measures, the costs of which are known. This would in effect create an opt out price for the EDR measures.

[21] Alternatively a Premium Payment could be designed to deliver a specific volume (V*) through an auction, which would be delivered at the cost P*.

[22] The Capacity Market could also have a maximum price which is set by the price for alternative forms of capacity.

[23] It is possible that monitoring and verification costs could differ between the three mechanisms, and one uncertainty of using the capacity market is the extent of these costs. A pilot of the Capacity Market may be able to provide a better indication of these costs (see Section 6).

4.21. Despite the economic equivalence of the three mechanisms in theory, there are key non-monetised reasons favouring the choice of a Capacity Market tested through a pilot scheme, as explained in Section 6.

5. Cost benefit analysis

5.1. Under all three delivery mechanisms, EDR is estimated to have a net benefit to society. In order to reach this conclusion, there are three analytical components which are examined in this section of the IA:

(i) ***Estimation of level of demand reduction***: based on an assumed level of financial incentive, what is the expected uptake of EDR? This analysis builds upon information about the technical potential for EDR, associated capital costs and payback requirements.

(ii) ***Estimation of gross societal benefits***: these include savings associated with generation costs (including operating, carbon and fuel costs), capital costs (investment in new generation plant) and transmission and distribution costs as a result of reduced demand.

(iii) ***Estimation of gross societal costs***: in addition to the direct costs of EDR, this includes administrative policy costs under the delivery mechanisms and lost innovation benefits from pursuing low-carbon technologies.

Expected demand reduction from financial incentives

5.2. The analytical tool used to estimate the level of EDR delivered is the EDR take-up model. The results of this analysis are significantly affected by the assumptions used, as illustrated by the sensitivity analysis below.[24]

5.3. The EDR take-up model[25] was developed and tested using the following approach:

- The starting point is the technical potential for electricity demand reductions and the associated capital costs.
- There are number of additional costs associated with delivering electricity savings, over and above the capital costs, which have been included.
- An assumed distribution of minimum payback periods required to take action is used as a proxy for how responsive the EDR market will be to different level of support payments.
- The model is calibrated against a baseline level of take up.
- The outputs of the model are compared against international examples of similar policies, to check the results are broadly consistent
- The model has also been externally peer reviewed

<u>Duration of demand reduction and level of additionally</u>

5.4. Two factors that will have a significant impact on the final level of demand reduction are the length of the EDR contracts and the level of additionality. Both these factors will be affected by policy decisions made at later stages in the process. This analysis has therefore used some conservative working assumptions to illustrate the range of possible outcomes from implementing a financial incentive.

5.5. Theoretically, a measure that reduces electricity demand could be eligible for payments for its full lifetime. The average physical lifetime of measures included in the analysis is 11 years, with a range of

[24] The estimates of demand reduction exclude the rebound effect. This is where an energy efficiency measures lowers the cost of energy services, and in response the consumer increases demand for that energy service. For example in a business setting, a company may produce more output once energy costs of production fall. The evidence base in this area remains underdeveloped, and will need to be considered further in developing an enduring regime for EDR.

[25] Further details on the modelling can be found in Annex C.

2 to 45. In reality firms or aggregators will need to contract for a given period over which they will guarantee the saving. The length of these contracts will be decided as part of the detailed policy design, and may vary on a project by project basis. This analysis uses a working assumption that the contract will be for 5 years.[26] **This is an assumption used for modelling purposes only, and is not an indication of final policy design.**

5.6. Additionality refers to the proportion of EDR that is the direct result of the policy intervention. In some cases, payments may be made for measures that would have been installed anyway (in the absence of the policy). There are a number of processes that can be used to minimise the risk of payment for non-additional measures, but the exact level of additionality is often hard to measure. Correspondingly, there is little evidence of what the level of additionality would be under a financial incentive. For the purpose of this analysis a conservative assumption of 75% additionality has been used (meaning 1 in 4 projects funded through the policy would have gone ahead anyway). **This is an assumption used for modelling purposes only. In reality, the level of additionality will be affected by the monitoring and verification regime.**

Results

5.7. The total costs and benefits of EDR are determined by the level of take up of energy efficiency measures. One of the main factors that will determine the level of take up is the total spending under the policy. This analysis has used a range of illustrative scenarios to show how much might be available to EDR measures. The EDR model has been used to create a range of scenarios to illustrate:

- the level of take up at different levels of support; and
- the sensitivity of the results to the assumptions made.

5.8. Six policy scenarios have been modelled to illustrate the potential impact of different policy options. These scenarios are based on the different levels of funding that could be available and different assumptions around how the policies are ultimately implemented. The upfront payments for the different scenarios are illustrated in table 4, along with the central estimates of how much electricity demand reduction is delivered.

Table 4: Take-up of electricity demand reduction measures under different funding scenarios[27]

Scenario	Description	Electricity Demand Reduction in 2030 (TWh)	Percentage of 2030 electricity consumption[28]
1	Central scenario - funding at £10 / MWh with 5 year contract[29]	1.5	0.4%
2	Funding at £8 / MWh with 5 year contract	0.9	0.2%
3	Funding at £10 / MWh with 10 year contract	7.2	1.9%
4	Higher level of funding[30]	6.0	1.6%

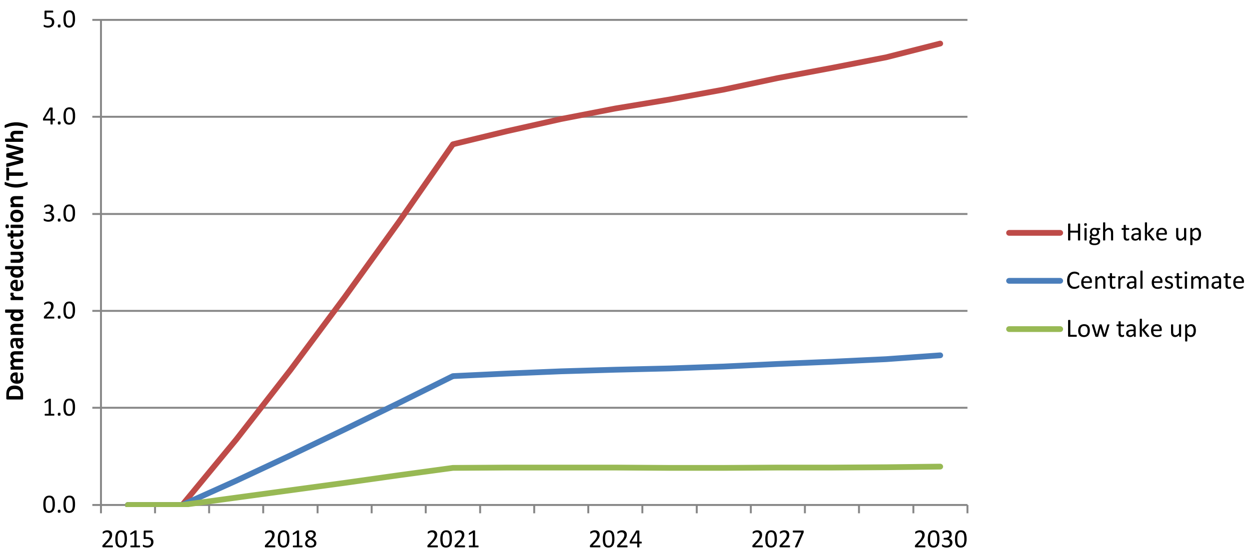
[26] This is based on international examples – see annex D for further details.
[27] Note that the levels of modelled funding available for EDR are purely indicative at this stage.
[28] Calculated as a percentage of final energy demand in 2030 (DECC Updated Energy & Emissions Projections, 2012).
[29] In the EDR modelling we have assumed our central scenario is based on a CM price of £40/KW year. This is based on an indicative assumption that financing available for EDR is the equivalent of the displaced cost of conventional capacity in the Capacity Market. The assumed price is based on estimates of the average capacity price in years in which additional capacity is brought on. Previous analysis [https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf] has shown the clearing price may be significantly lower or clear at zero prior to 2024. However, as the funding mechanism for EDR has not yet been agreed we have assumed this level of funding is available before this date in order demonstrate the potential impact of a financial incentive.
[30] This scenario assumes almost a tripling of financing resources available to EDR

5.9. There is considerable uncertainty around the estimates presented in table 4, which are significantly affected by the assumptions made. This uncertainty is illustrated in the sensitivity analysis, which focuses on scenario 1. The sensitivity analysis uses the following scenarios:

- **high and low take-up scenarios** to illustrate the impact of changing the assumptions about the distribution of payback requirements and the additional costs;
- **high additionally** scenario to show the impact of assuming that only 1 in 6 of the funded projects would have gone ahead without support, instead of the 1 in 4 assumption used in the central case;
- **high cost of finance** (cost of capital) to show the impact of aggregators and other firms having to apply a higher discount rate to future payments from the CM;
- **higher technical potential** scenarios, which use the original estimate of technical potential for the sectors likely to generate the majority of the demand reduction; and
- **calibration factor** scenario, which illustrates how sensitive the results are to the baseline level of take-up to which the model has been calibrated.

5.10. Figure 2 shows the level of EDR for scenario 1, using the high and low take-up scenarios. It illustrates that the payback distribution assumption has a significant impact on the results; the high scenario is 208% higher than the central and low scenario 74% lower.

Figure 2 – High, low and central estimate of electricity savings for policy scenario 1



5.11. Table 5 shows how the level of demand reduction delivered by 2030 in scenario 1 varies under different assumptions. It shows that the assumptions made have a significant impact on the projection of take-up (with the exception of the additionality assumption, which has a relatively minor impact).

Table 5 – Sensitivity analysis

Scenario	EDR in 2030 (TWh)	Percentage difference from central case
Scenario 1 (central)	1.5	0%
Scenario 1 (high take up) – high sensitivity scenario	4.8	208%
Scenario 1 (low take up) – low sensitivity scenario	0.4	-74%
Scenario 1 (higher additionality)	1.7	11%
Scenario 1 (higher cost of capital: 15%)	1.1	-27%
Scenario 1 (McKinsey potential)	5.2	240%
Scenario 1 (-50% calibration factor)	0.9	-43%
Scenario 1 (+50% calibration factor)	2.2	43%

International comparison

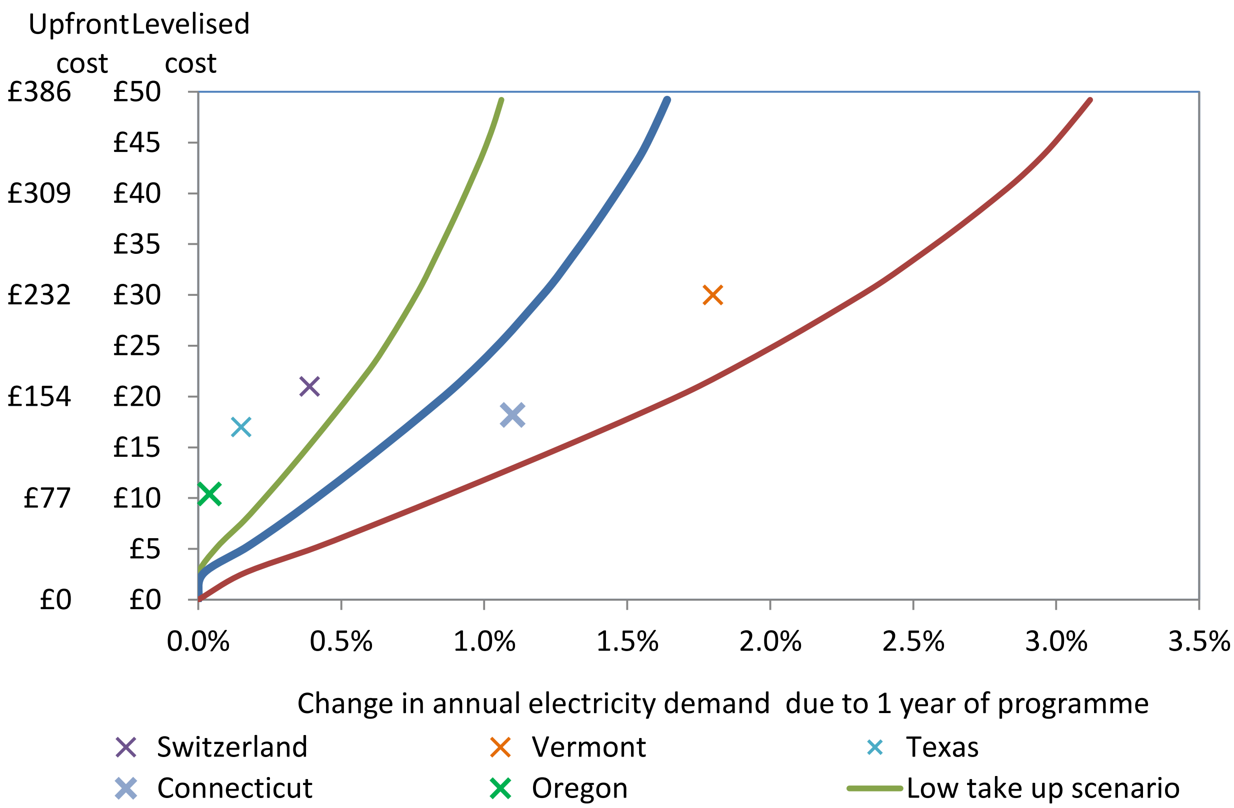
5.12. The outputs of the model have been compared with outcomes observed in a number of US states and Switzerland, where similar schemes have been run. Figure 4 shows the EDR model estimates of additional energy savings at different levels of subsidy.

- The y axis shows the both the upfront and levelised cost of EDR in £/MWh (assuming that the savings last for 10 years).[31]
- The x axis show the additional savings delivered per year, as a percentage of UK commercial, industrial and public sector electricity consumption.
- The lines illustrate the supply curve for EDR under different take-up scenarios
- The outcomes observed in other countries are shown as data points

5.13. However, drawing a direct comparison between schemes requires making a number of assumptions that are known not to hold in reality. These include:
- Energy prices are the same across countries/states
- The potential for electricity savings as a percentage of consumption is the same
- The market reacts to the introduction of a financial incentive in the same way
- The existing policy landscape is the same

5.14. These international comparisons should therefore be considered illustrative at best.

Figure 4: Comparison between modelled estimates of take-up and outcomes observed in other countries



[31] This assumption has been used to be able to compare to international examples. The take up modelling presented in the IA assumes savings last for 5 years.

Gross societal benefit of EDR

5.15. The gross societal benefit (i.e. resource cost saving) is driven by avoided cost in the electricity system. In particular, lower electricity demand leads to lower electricity costs in the following key areas:

- Savings associated with new low-carbon generation capital costs – with a lower level of annual demand, there is an impact on the amount of new low carbon capacity which must be built to meet demand over the long term.[32]
- Savings associated with new fossil fuel generation capital costs – with a lower level of peak demand, there is an impact on the amount of new conventional generation capacity which is required through the Capacity Market.
- Network costs – with a lower level of demand, there would be a savings associated with electricity transmission and distribution networks.
- Fuel costs – there would be reduced fuel consumption as fossil fired generation would be required to operate less often.
- CO_2 allowance savings – there would be lower CO_2 emissions within the traded sector, as fossil-fired generation would operate less often. This leads to savings in expenditure on EU allowances.

5.16. The estimates of the gross societal benefits are sensitive to the assumptions made concerning how much low-carbon generation is displaced, the levelised costs of the range of technologies displaced, the requirement for and price of new conventional capacity, and gas and CO_2 prices.

<u>Modelling of reduction in system costs</u>

5.17. DECC's dynamic dispatch model (DDM)[33] was used to estimate the reduction in system costs resulting from a lower level of demand. Demand is assumed to fall gradually over the period compared to the Energy Market Reform (EMR) base case. The expected level of demand reduction is based on the central scenario in the take-up modelling.

5.18. Consistent with the lower demand projection, the volume (in TWh terms) of both (i) renewable generation by 2020 and (ii) low-carbon generation throughout the period is assumed to be lower. The modelling assumes the following:

i) The renewable target is for 15% of energy demand to be met by renewable sources in 2020.[34] For every TWh decrease in electricity demand, the target volume of renewable demand across the whole economy, in absolute TWh terms, falls by 15% of the TWh decrease. In our modeling, we assume that all of this decrease in the target volume is reflected in a lower electricity contribution; for example a 1 TWh drop in electricity demand in 2020 would lead to a 150 GWh drop in the contribution from electricity.[35]

ii) In the modeling underpinning the EMR IA, the baseline for DDM analysis represents a plausible outcome of Electricity Market Reforms, characterised by a diversified supply mix[36] and an assumed carbon emissions intensity of 100gCO2/kWh in 2030, which is an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments[37]. In our modeling, we have continued with these assumptions.

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[32] This is used as an assumed benefit for the purposes of economic modelling in relation to EDR policy, and does not reduce the Government's ambition to support a sustainable UK renewable energy industry.
[33] See annex D for background information on the DDM model
[34] Heat and transport also contribute to the target.
[35] This is an assumption made for modelling and cost estimation purposes.
[36] Diversification reflects (in part) the objective of support for the development of a portfolio of low-carbon generation technologies, in order to reduce the technology risks associated with the decarbonisation objective for the power sector.
[37] Additional carbon emission intensities for the power sector in 2030 included sensitivities of 50gCO2/kWh and 200gCO2/kWh scenarios

5.19. As detailed in paragraph 5.15, there are five key areas that drive the gross societal benefit calculation. For these areas, we have assumed the following:

- *Savings associated with new fossil fuel generation capital costs* - With lower levels of peak demand, we have assumed that a lower volume of conventional generation capacity will be procured and commissioned. We assume the first 4 year ahead Capacity Market auction will be held in 2014 for delivery in 2018, and that the first 1 year ahead auction will be held in 2017 for delivery in 2018. It is assumed that a Demand Side Response (DSR) pilot will be held before 2018 but the exact detail of the pilot and its timing is still to be determined. In our modelling we have assumed that EDR has a value of £40/KW[38] year in the Capacity Market from 2016. **The modelling results are sensitive to this assumption.**
- *Network costs* - Based upon the IAG Toolkit[39], the resource saving associated with lower network costs resulting from lower levels of electricity demand is projected to be around £9/MWh (average over the period). This resource saving represent only around 30% of the network use of system charges, as around 70% of the revenue of the network companies is not directly influenced by the absolute level of demand. **The modelling results are sensitive to this assumption. If the saving is not as high as we assume, then the resource cost savings of EDR will be lower than assumed. In our analysis we have not explored this scenario.**
- *Fuel costs* – In our modelling, we have used DECC's 2012 central fossil fuel price projections[40]. **The modelling results are sensitive to this assumption. If the fuel prices are lower than we assume, then the resource cost savings of EDR will be lower than assumed. In our analysis we have not explored this scenario.**
- CO_2 allowance savings – In our modelling, we have used DECC's 2012 central CO_2 price projections[41]. **The modeling results are sensitive to this assumption. If the emission prices are lower than we assume, then the resource cost savings of EDR will be lower than assumed. In our analysis we have not explored this scenario.**
- *Savings associated with new low-carbon generation capital costs* - There is considerable uncertainty as to the future costs of low-carbon technology, and the rate at which they can be deployed. In the analysis underpinning the EMR IA, the baseline scenario assumed that a diversified range of technologies would be supported[42]. Up to 2020, onshore wind and offshore wind is displaced. Thereafter, a combination of onshore wind, offshore wind,

[38]In the EDR modelling we have assumed our central scenario is based on a CM price of £40/KW year. This is based on an indicative assumption that financing available for EDR is the equivalent of the displaced cost of conventional capacity in the Capacity Market. The assumed price is based on estimates of the average capacity price in years in which additional capacity is brought on. Previous analysis [https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf] has shown the clearing price may be significantly lower or clear at zero prior to 2024. However, as the funding mechanism for EDR has not yet been agreed we have assumed this level of funding is available before this date in order demonstrate the potential impact of a financial incentive.

[39] https://www.gov.uk/government/policies/using-evidence-and-analysis-to-inform-energy-and-climate-change-policies/supporting-pages/policy-appraisal

[40] DECC's 2012 Fuel Price projections can be found at https://www.gov.uk/carbon-valuation (update link)

[41] DECC's 2012 Fuel Price projections can be found at https://www.gov.uk/carbon-valuation

[42] https://www.gov.uk/government/publications/energy-bill-impact-assessments

It is assumed that EMR measures are generally deployed to achieve a least-cost decarbonisation pathway. However, in order to take account of uncertainty in the future costs of alternative technologies, for the purposes of modelling it has been assumed that EMR supports a broader diversity of technologies to 2030 than would be the case based purely on current central projections for generation costs, demand and fossil fuel prices to 2030. There is uncertainty about how the electricity sector will develop over the longer term and supporting a diverse generation mix in the medium term will help manage some of the technology risks associated with achieving the sector's share of the 2050 economy-wide 80% decarbonisation target, under a range of different future scenarios.

nuclear and CCS is displaced to maintain the diversified generation mix as per the EMR analysis.[43]

Box 2: Gross societal benefit calculation – illustrative example[44]

Taking 2030 as an illustrative example, benefits to society are broken down into the following:

- Displaced capacity savings (low-carbon and conventional generation): £33/MWh
- Displaced fuel costs: £48/MWh
- Lower network costs: £10/MWh
- CO_2 emission benefits: £8/MWh

This gives a gross benefit of £99/MWh. Each measure delivers benefits throughout the assumed lifetime of 5 years. To get to the gross societal benefit figure, this estimate is then multiplied by the level of demand reduction in that year (1.54TWh as in the central case). This leads to a gross benefit of approximately £152million. This calculation is then repeated for each year in the appraisal period, and discounted at 3.5%. The sum of these gives the discounted gross benefit.

5.20. Based on the estimated take up of the central scenario, the gross societal benefit of EDR measures delivered between 2017 and 2030[45] is estimated at £1.05 billion[46] over the period 2017-2034.The benefits of the policy continue until 2034, due to the above central working assumption that an EDR contract is entered into for 5 years[47.]

Gross societal cost of EDR

5.21. The gross societal cost is estimated to be £0.34billion[48] from 2017-34. This is driven by the cost of energy efficiency investments, administrative policy costs, and innovation benefits foregone when low-carbon technologies are displaced.

Cost of energy efficiency investments

5.22. In the central case, the central working assumption is that a contract is awarded for 5 years, and so benefits continue to accrue to this project in a cumulative fashion for every MWh of electricity reduced over that period. By contrast, the initial cost of electricity demand reduction works differently – it is only an upfront cost. In net present value terms this cost is only recorded in one single year, and is discounted at that year at 3.5%. The direct costs of EDR each year are therefore the incremental costs of new 5 year EDR projects. The analysis does not include potential demand reduction from behavioural measures, which will have a lower capital cost. The take-up of behavioural measures could therefore reduce the cost of delivering the demand reduction.

[43] The modelling indicates that a mixture of onshore and offshore wind could be displaced by EDR. In practice the displacement would be likely to be more complex and involve a wider range of technologies, given the difficulties in modelling real-world outcomes. Furthermore, DDM assumptions are being updated for the Delivery Plan, so the implications for different technologies might vary in reality.
[44] These are based on the assumption that a diversified generation mix is displaced.
[45] The cost benefit analysis was limited to the period 2017 to 2030 due to the level of uncertainty associated with projected outcomes beyond 2030.
[46] The benefits expressed in terms of £/MWh are then multiplied by the level of expected demand reduction in each year. These are then discounted at 3.5% in accordance with the Green Book, to arrive at the net present value.
[47] For example, a measure installed in 2030 will generate social costs in that year, but social benefits until 2034.
[48] Discounted to 2012

Administrative policy costs

5.23. There is an administrative cost of running a financial incentive scheme, which is supplemental to the financial incentive received by firms. These are assumed to be incurred upfront, in the first year of installation. The central estimate[49] of the upfront cost in the first year of installation is equivalent to an annual cost of around £4/MWh[50] across the assumed lifetime of 5 years[51]. This estimate is sensitive to the details and magnitude of the scheme. Though these estimates have been supported by international evidence, there is a wide range to the international examples and uncertainty around exactly which costs are included.

Disbenefits of reduced "Learning by Doing"

5.24. Increased deployment of low-carbon technologies results in learning effects that lower the capital costs of these technologies over time. These are also referred to as innovation benefits foregone[52]. In DECC's Dynamic Dispatch Modelling (DDM), it is assumed that for every doubling of capacity the capital cost of offshore wind falls by 12%[53]. This impact is implicitly accounted for in the DDM modelling.

Box 3: Gross societal cost calculation – illustrative example[54]

Taking 2030 as an illustrative example, costs to society are broken down into the following:

- Cost of energy efficiency improvements: £25/MWh
- Administrative policy costs: £4/MWh

This gives a gross cost of £29/MWh if the upfront costs are annuitised across the assumed lifetime of the measure.

However, for the purpose of the NPV calculation, the cost of energy efficiency improvements and administrative costs are incurred upfront and only once in the lifetime of each installation. This upfront cost is then multiplied by additional take up in that year (0.33 TWh in the central case) to give a gross cost of approximately £43million. This calculation is then repeated for each year in the appraisal period, and discounted at 3.5%. The sum of these gives the discounted gross cost.

[49] The low and high estimates of the NPV assume a cost of £30/MWh and £10/MWh in the first year of installation respectively. These are equivalent to an annual charge of around £7/MWh and £2/MWh for the lifetime of the measure.
[50] Discounted at 3.5%.
[51] For the NPV, this cost is assumed to be incurred upfront and so is only discounted in that year.
[52] Cost profiles of all other technologies (including hydro and tidal) are currently modelled exogenously and so would be unaffected by changes in UK deployment.
[53] This assumption is consistent with the analysis for the Renewables Obligation (RO) banding review and is originally based on the Carbon Trust (2008), *Offshore wind: Big Challenge, Big opportunity* and (2009) *Focus for success* reports. These looked at the level of innovation potential in the sub-categories of offshore wind and how they could be stimulated by Government support for offshore wind innovation, and suggested that in aggregate offshore wind capital costs could fall by 9% for every doubling in capacity under a BAU scenario, and 15% with very high levels of Government support for offshore wind innovation. DECC have assumed as a central assumption 12% reductions in capital costs for every doubling in deployment.
[54] The upfront cost in the first year of installation is £131/MWh, of which £20/MWh is the administrative policy cost.

Net Societal Benefit

5.25. The net societal benefit of EDR is detailed below in table 6. Sensitivities are provided to show the impact of changing the assumptions about the distribution of payback requirements which significantly affects take-up of EDR measures (see table 5). The low estimate assumes 0.4 TWh of demand reduction in 2030, and an administrative policy cost of £7/MWh. The central estimate assumes 1.5 TWh of demand reduction in 2030 and an administrative policy cost of £4/MWh. The high estimate assumes 4.8 TWh of demand reduction in 2030, and an administrative policy cost of £2/MWh.

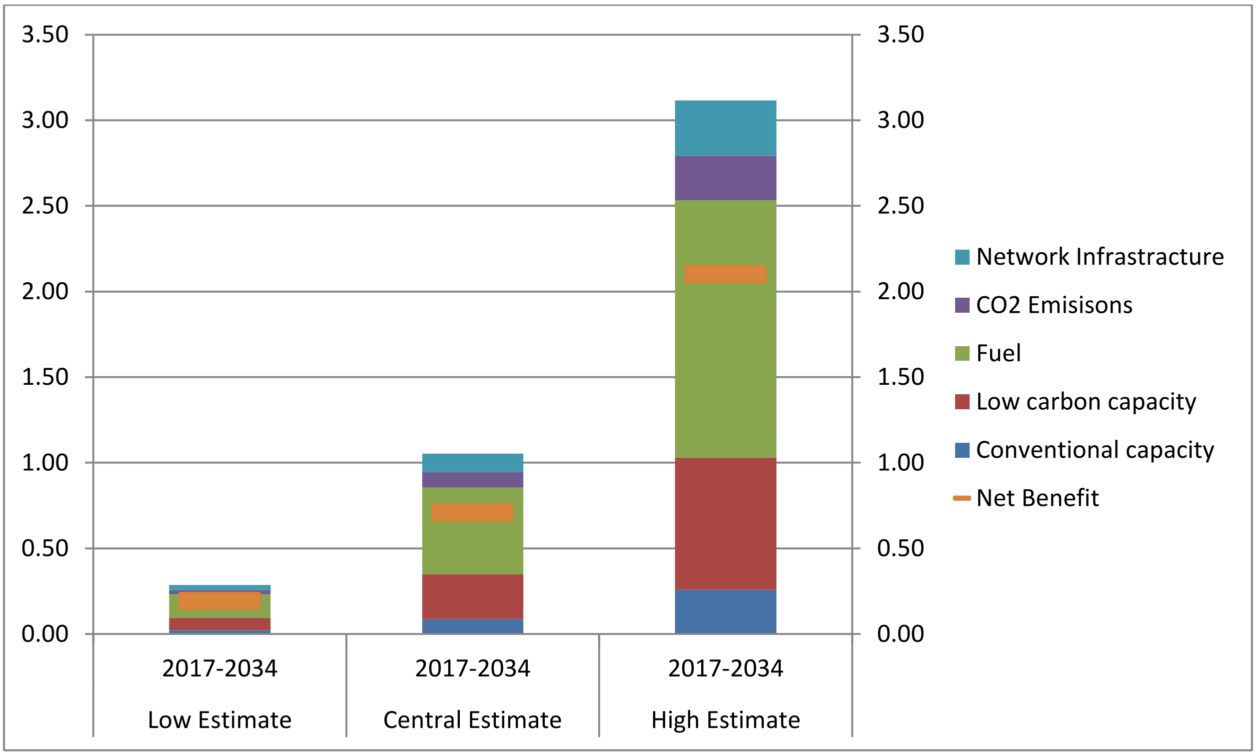
Table 6 - Net welfare breakdown of EDR under all three delivery mechanisms[55]

£billion, discounted to 2012	Low Estimate	Central Estimate	High Estimate
Conventional capacity	0.02	0.09	0.26
Low-carbon capacity	0.07	0.26	0.77
Fuel	0.14	0.51	1.50
CO_2 Emissions	0.02	0.09	0.26
Network Infrastructure	0.03	0.11	0.32
Gross Benefit	**0.29**	**1.05**	**3.12**
Gross costs	**0.09**	**0.34**	**1.02**
Net Benefit	**0.19**	**0.71**	**2.10**

(numbers may not sum due to rounding)

5.26. Figure 3 below details the central, low and high cases.

Figure 3: NPV (discounted to 2012, £bn) across low, central and high scenarios



55 Across the period 2017-2034

Implications for low-carbon support payments

5.27. The reduced cost of low-carbon generation shown here incorporates (i) an assumption of an acceptable limit of 100g/CO_2/MWh in 2030, (ii) an assumption of no new UK or EU targets for renewable electricity or energy use or generation beyond 2020; (iii) an assumption that Contract for Difference (CfD) strike prices or volume limits fall to reflect reduced electricity demand[56]. The estimated discounted value of savings in that scenario is around £230 million over the period 2017-2034.

5.28. It should be noted that, in line with standard practice, these assumptions reflect a 'current baseline' scenario for 2030. If, for example, CfD strike prices were left unchanged in this scenario, the percentage of low-carbon generation in the overall energy mix will be higher as a result of EDR. Estimates are also sensitive to assumptions about how much (and which) low-carbon generation is displaced, their associated strike prices, and the wholesale price – assumptions that in turn depend on progress made by individual technologies on reducing their cost.

6. Non-monetised benefits and costs

6.1. Sections 4 and 5 detailed the monetised costs and benefits of the three potential delivery mechanisms assessed: the Supplier Obligation, a Premium Payment and a Capacity Market. All were estimated to lead to equivalent net monetised benefits for EDR if the same funding level was provided. There are some key non-monetised reasons why a Capacity Market option has been chosen as the preferred option.

Rationale for Capacity Market

6.2. There are additional non-monetised benefits from pursuing a Capacity Market option over the other two delivery mechanisms. In particular it:

- *Builds upon framework and institutional arrangements already under development*: rather than setting up new arrangements, as would be required under a Premium Payment, or a new Supplier Obligation, EDR delivered through a Capacity Market can draw upon the framework and institutional arrangements as proposed for the Capacity Market. This route therefore reduces the deliverability risk by using arrangements and frameworks already being established.

- *Targets reductions at peak demand*:[57] the premise behind supporting EDR is that it can help reduce costs of meeting targets and ultimately decarbonising the UK electricity system. It does this by reducing overall system costs by incentivising demand reduction at times when it is most valued (i.e. peak times).[58]

- Enables Demand Side Response and Electricity Demand Reduction to be brought together in a single delivery vehicle enabling more effective, joined up delivery of both policies.

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56 This is consistent with the notion of moving down the supply curve for renewable technologies if demand is lower.
57 In practise, the ability to target reductions at peak will be determined by the monitoring and verification regime.
58 In this context, it has been raised that not all demand reduction has the same value for the electricity system. As with demand response, reducing electricity demand at particular times of day is likely to deliver more wholesale / upstream value than at other times of day. Limited evidence has been provided on this point, but understanding it further will be part of our forward work including around the potential pilot.

Supplier Obligation

6.3. A Supplier Obligation route for delivering energy savings has been implemented successfully in a number of international examples such as Denmark, Texas and Connecticut. There is, however, a disadvantage to such an approach. The non-domestic sector is heterogeneous and the "one-size fits all" approach of the domestic sector may be less applicable. There is therefore a risk that suppliers may lack the information and expertise to work with their client base on delivering efficiency improvements.

Premium Payment

6.4. The Premium Payment option has several advantages and has many similarities to the Capacity Market approach, through centrally auctioning a volume of EDR. It would enable a wide range of players to participate and enable competitive price setting for EDR if it incorporated an auction. This option also offers a high degree of transparency and greater simplicity as it would procure energy savings.

6.5. The option however does not provide the option for a direct a trade-off with the supply side as the Capacity Market option. It also contains similar risks, for example around effectively and fairly managing the interaction with the existing policy framework.

Risks of Capacity Market and rationale for a pilot

6.6. The preferred Capacity Market approach does have some notable risks and challenges to overcome. In particular:

- *Ability to generate take-up:* There is considerable uncertainty as to the price of capacity in the forthcoming UK Capacity Market. Internal economic analysis and some international evidence suggest that it may limit the funding available to EDR and that this may be insufficient to bring forward significant take-up, perhaps exacerbated by its perceived relative complexity.

- *Monitoring, Verification and Additionality (MVA) challenges:* all EDR approaches will require a robust MVA regime to ensure the validity and sufficient additionality of any intervention receiving funding. Integrating in the Capacity Market may raise the threshold of confidence on additionality and will likely require MVA to be relevant to peak demand

6.7. In light of the risks outlined above (including limitations of the available analysis and evidence) we are considering a pilot phase to gather the evidence required to allow for properly informed decisions to be made regarding long term financial support for EDR. In particular, a pilot approach would help in reducing uncertainty on the exact level of support required to bring forward meaningful levels of EDR. It would also help test the level of additionality, and whether monitoring and verification can be implemented in a way that does not deter projects.

7. Proportionality

7.1. This impact assessment provides an indication of the potential costs and benefits of an enduring support mechanism for EDR. A further impact assessment including learning from the any pilot would be published alongside any proposals to implement an enduring regime for EDR.

8. Risks and assumptions

8.1. The economic case for a policy of financial incentives for the deployment of energy efficiency measures has a degree of uncertainty, in particular around the following 5 areas:

- **Cost of energy efficiency measures:** the estimates of the capital cost of energy efficiency measures is based on the original data sources used for the analysis of technical potential. We assume that the "hassle" costs associated with the installation of energy efficiency measures are around 40% of the capital cost of the measure, but there inevitably remains a degree of uncertainty as to the cost of energy efficiency measures. A sensitivity has yet to be undertaken as how the attractiveness of EDR would change if costs were higher than the central assumption. However as discussed in Section 5, the CBA is highly positive under the central assumptions, and would be expected to remain strongly positive even if projected cost of the measures were higher.

- **The reduction in electricity demand achieved by energy efficiency investments:** though the potential for electricity demand reduction has been reviewed and revised down since the analysis undertaken with McKinsey in 2012, there inevitably remains a degree of uncertainty as the extent to which investment in an energy efficiency measure reduces peak demand and demand across the year as whole.

- **Avoided electricity system costs:** The CBA estimates are sensitive to the assumptions made concerning how much low-carbon generation is displaced, the levelised costs of the range of technologies displaced, the requirement for and price of new conventional capacity, and gas and CO_2 prices. The deployment of low-carbon capacity is assumed to be lower with lower levels of electricity demand, but there remains an issue around the timing of the low-carbon investment and the certainty of being able to achieve the assumed level of EDR. In our analysis, we assume the reduction in investment in low-carbon and conventional capacity occurs at the same time as the actual reduction in demand. We have not explored scenarios in which the benefit of lower investment is delayed, or in which the deployment of low-carbon generation continues unchanged from the baseline. Across the range of displacement scenarios considered, the CBA remains highly positive. In our modelling, we have assumed DECC's 2012 central fossil fuel price and carbon price projections[59], but no sensitivities to these projections have been explored.

- **The costs of running the scheme.** We assume that the cost of running a financial incentive scheme is equivalent to around £4 per MWh over the lifetime of the asset in the central scenario. This is low compared with the projected net benefit of EDR. Sensitivity to the assumed running costs of the different schemes has not been explored, but we would expect the CBA to remain highly positive.

- **The degree of additionality.** In our modelling, we assume 75% additionality i.e. that 1 in 4 projects funded through the policy would have gone ahead anyway. Whilst the issue of additionality is mainly a distributional issue, it does have resource cost implications, as there are costs associated with running the financial incentive scheme. However the cost of running the scheme is relatively low and a scheme with lower additionality would be expected to remain highly positive in NPV terms.

9. Direct costs and benefits to business calculations

9.1. High, medium and low estimates of administrative policy costs drawn from international evidence are £7, £4 and £2 respectively, per MWh savings over the expected lifetime of the measure[60]. These costs are assumed to be incurred upfront. It has not been estimated at this stage how these costs will fall directly to businesses as this will be dependent on the final policy design.

9.2. Due to the non-regulatory nature of options, costs to business do not fall within scope for OITO (One IN two OUT).

[59] https://www.gov.uk/carbon-valuation

[60] The equivalent upfront cost in the first year of installation is £10/MWh (low estimate), £20/MWh (central estimate) and £30/MWh (high estimate).)

10. Wider impacts

Competition assessment

10.1. EDR participation in the capacity market will neither directly nor indirectly limit the number or range of suppliers in the energy efficiency market. It is more likely that there will be new entrants to this market due to the investment opportunities a financial incentive will provide. In development of a monitoring and verification regime, further consideration will need to be given to ensure it does not limit the ability of suppliers to compete nor reduce suppliers' incentives to compete vigorously in this market.

Small firm impact

10.2. The preferred option does not place regulatory burden on small businesses. However, since the financial incentive could be available across all sectors it is likely that small businesses will choose to participate. As the policy design progresses, there will be a need to consider the impact of monitoring and verification requirements on small businesses that invest in energy efficiency measures.

Wider Environmental impact

10.3. The EDR policy is considered against the following questions for environmental impacts:

- Will the policy option be vulnerable to the predicted effects of climate change?
  No

- Will the policy option lead to a change in the financial costs or the environmental and health impacts of waste management?
  By incentivising the early retirement of existing products or appliances there could be an increased amount of waste.

- Will the policy option impact significantly on air quality?
  There could be a marginal improvement in air quality if demand reduction results in a reduction in the use of fossil fuels (specifically coal) for electricity generation.

- Will the policy option involve any material change to the appearance of the landscape or townscape?
  This will depend on the building measures, for example external solid wall insulation may change the appearance of buildings (this could be an improvement).

- Will the proposal change 1) the degree of water pollution, 2) levels of abstraction of water or 3) exposure to flood risk?
  Unlikely

- Will the policy option change 1) the amount or variety of living species, 2) the amount, variety or quality of ecosystems?
  Unlikely

- Will the policy option affect the number of people exposed to noise or the levels to which they're exposed?
  Building materials which aim to improve efficiency, such as insulation or double glazing, also help to reduce exposure to noise.

Greenhouse Gas impact

10.4. The electricity retail price already includes the pricing of carbon through the EU ETS price. Therefore there is likely to be no impact on this, but EDR will help to reduce the total cost of cutting carbon emissions in the UK as there is a reduction in emissions within the traded sector.

Health impact assessment

10.5. There is no reason why an EDR policy would have an impact on health as all the products that could be applied are already in existence. The potential health impacts have been considered against the health impact screening questions[61]:

10.6. Take-up in the domestic sector might have an impact on human health mainly through the installation of insulation in electrically heated homes (which evidence suggests should typically reduce the exposure to factors which can lead to risk of cold and indoor air quality-related illnesses). The policy is unlikely to have any impact on lifestyle related variables, such as physical activity, alcohol use or sexual behaviour. However, findings have suggested that a warmer household could reduce the risk of mortality, morbidity and stress within the home[62],. Findings do not exist for the working environment.

10.7. As the policy is focussed on electricity demand reduction, but without impacting consumer utility, there should not be an impact on the demand for health and social care services.

Human rights assessment

10.8. This policy should not have an impact on human rights especially as it aims to reduce electricity demand without affecting consumer utility.

Justice impact test

10.9. This will depend on the nature of the policy design (for example if there is a penalty regime) and will be considered further in future impact assessments.

Rural proofing impact

10.10. The majority of uptake is likely to be focussed on non-domestic and industrial organisations which are more likely to be found outside of rural areas. Therefore rural areas are less likely to benefit from these measures. Policies for domestic products and appliances should be shared equally across all households irrespective of their location.

Equalities impact assessment

10.11. It is unlikely that the preferred policy will treat different protected groups differently or impact areas of known inequalities (for example, access to public transport for disabled people, racist/homophobic bullying in schools).

Sustainable development impact

10.12. Intergenerational impacts – costs for policies are likely to be met by the current generation, whilst the long-run benefits associated with lower electricity demand may benefit future generations. At this stage it has not been possible to provide a more detailed sustainable development evaluation. This will be completed as the policy design progresses.

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[61] http://webarchive.nationalarchives.gov.uk/+/www.dh.gov.uk/en/Publicationsandstatistics/Legislation/Healthassessment/DH_4093617

[62] http://www.apho.org.uk/resource/item.aspx?RID=53281

11. Summary and Preferred Option

11.1. Supporting EDR in the Capacity Market builds on institutions and existing frameworks in development for the Capacity Market. It also provides an option for EDR to compete against supply more directly. However, there remains significant uncertainty, particularly on the level of support required to drive take-up, the clearing price of EDR in the Capacity Market, the additionality of financial support and the monitoring and verification (MVA) regime. In order to gather further evidence to support the design of an enduring regime for EDR, we are considering a pilot approach.

12. Implementation Plan

12.1. In light of the risks outlined above (including limitations of the available analysis and evidence) we are considering whether a pilot phase is the best way to gather the evidence required to allow for properly informed decisions to be made regarding long term financial support for EDR. In particular, a pilot approach could help in reducing uncertainty on the exact level of support required to bring forward meaningful levels of EDR. It could also help test the level of additionality, and whether monitoring and verification can be implemented in a way that does not deter projects.

13. Annexes

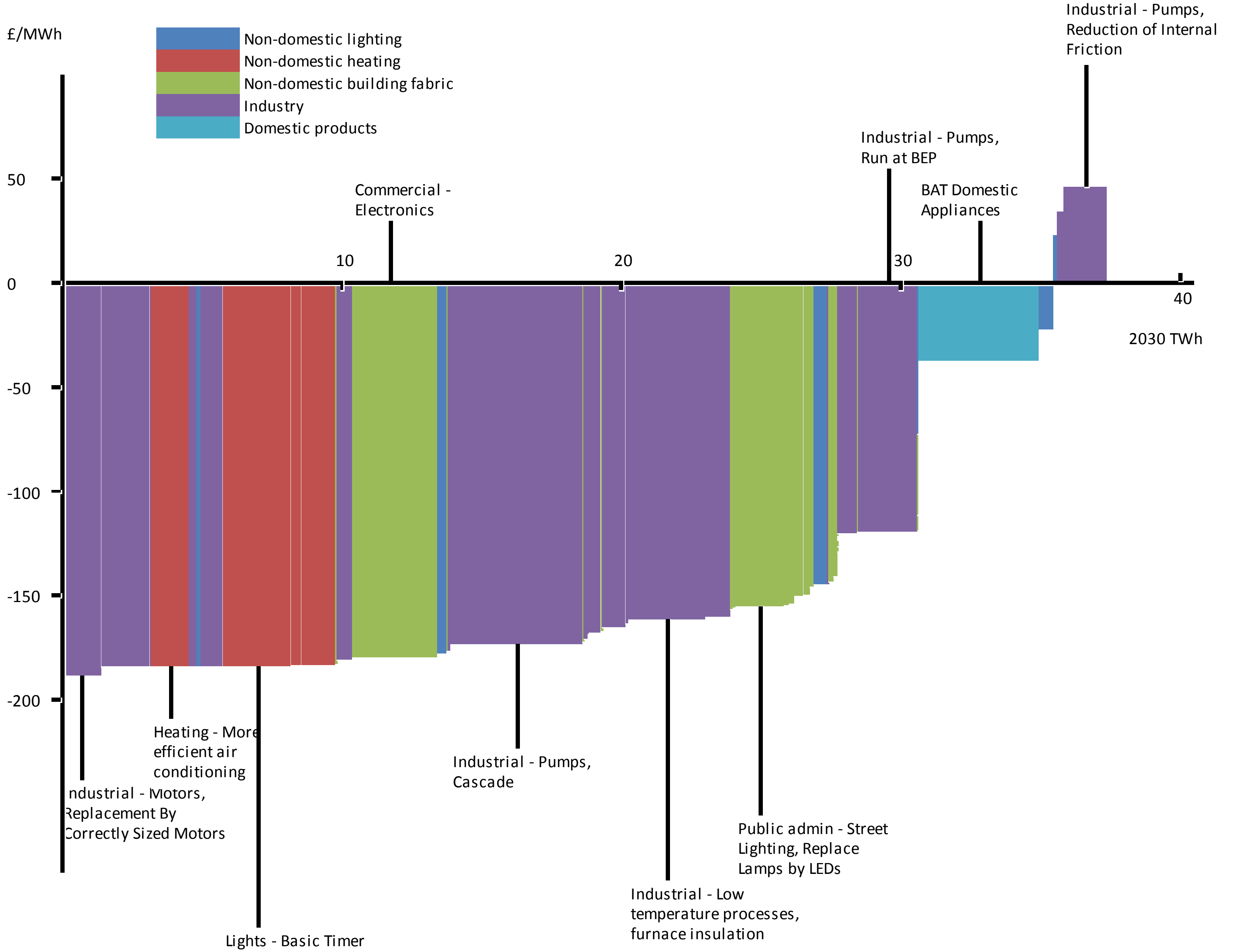
Annex A – Existing policies that impact on remaining potential for EDR

13.1. The consultation document published in November 2012[63] set out the existing policies that deliver electricity savings. A summary by sector is provided below:

Sector	Key existing policies
Domestic buildings	• Green Deal and ECO • Smart Meter Roll Out • Renewable Heat Incentive/Premium Payment • Building regulations
Non-domestic buildings	• CRC Energy Efficiency Scheme • Non-Domestic Green Deal • Enhanced Capital Allowances • Building regulations
Domestic products	• EU Ecodesign Framework Directive • EU Labelling Framework Directive
Non-domestic products	• EU Ecodesign Framework Directive • EU Labelling Directive • CRC Energy Efficiency Scheme • European Energy Star Programme
Industrial processes	• Climate Change Levy and Climate Change Agreements • CRC Energy Efficiency Scheme • Enhanced Capital Allowances • EU Ecodesign Directive

[63] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66561/7075-electricity-demand-reduction-consultation-on-optio.pdf

Annex B - Updated Societal Marginal Abatement Cost Curve (MACC) to reflect revised technical potential



Annex C – EDR demand model

Introduction

13.2. The EDR demand model was developed to provide a high level estimate of how much electricity demand reduction could be delivered under different assumptions. The main data inputs are the total technical potential for electricity savings and baseline level of take-up. The outputs of the model are significantly affected by the assumptions made, as demonstrated by the sensitively analysis presented in section 5.

13.3. There is currently insufficient evidence to provide a robust analysis of the possible differences in the impact of the different type of financial incentive (e.g. Supplier Obligation, Premium Payment). The analysis of the different mechanisms is therefore based on a qualitative assessment, while the EDR model is used to provide an illustrative estimate of the potential impact of a general financial incentive.

Overview of methodology

13.4. The EDR demand analysis uses the following process:

i. The starting point is the technical potential for electricity demand reductions and the associated capital costs.
ii. The responsiveness of the EDR market to a financial incentive is proxied using an assumed distribution of minimum payback periods required to take action.
iii. A number of assumptions are used to structure the analysis. These include:
    a. the additional costs associated with delivering electricity savings, over and above the capital costs;
    b. the duration of the energy savings in years; and
    c. the proportion of the saving supported by the financial incentive that is genuinely additional (i.e. would not have happened anyway without financial support).
iv. The model is calibrated against a baseline level of energy saving take-up.
v. The outputs of the model are compared against international examples of similar policies, to check the results are broadly consistent.

Technical potential

13.5. There are 69 different energy efficiency measures included in the model. For each measure the data provides an estimate of the costs and the total potential savings. For some measures (e.g. building fabric) these are based on the stock of savings available and so decline in line with the baseline take-up scenario. For others (e.g. pumps and motors) the cost and benefits are based on the capital replacement cycle. The potential savings from these measures therefore rise over time as more opportunities for energy efficiency improvements arise.

13.6. There is considerable uncertainty around the potential for electricity demand reduction. The analysis therefore includes a sensitivity analysis to illustrate the impact of different level of potential on the final results.

Modelling the take-up of EDR measures

13.7. The vast majority of the potential for energy efficiency is highly cost-effective, offering a high rate of return to investors. However, there is a wide range of complex barriers that prevents firms making otherwise cost-effective energy efficiency investments.

13.8. There is currently no evidence available on the cost of overcoming these barriers. However, it is reasonable to assume that providing a financial payment for electricity savings will lead firms to change their behaviour and make investments in energy efficiency measures. The central question the EDR demand analysis seeks to answer is how responsive the market will be to different levels of incentive.

13.9. The EDR model uses a proxy to simulate how responsive the EDR market is to changes in the level of support payments. The proxy used is a distribution of required payback periods[64]. Evidence suggests that firms typically require short payback periods in order to make energy efficiency investments.[65] By using this proxy, we are implicitly assuming these strict payback requirements capture the impact of the wide range of barriers to the take-up of energy efficiency measures.

13.10. The required payback period is assumed to be normally distributed across all the potential energy efficiency investment opportunities.[66] In the central scenario, the mean payback required is 2.5 years; the mid-point of McKinsey's finding that most firms require a payback period between 2 and 3 years.[67] The central scenario also assumes a standard deviation of 2 years, based on research into the willingness to pay by commercial sector organisations.[68] The table below illustrates the assumed mean and standard deviation of required paybacks for the central, high and low scenarios.

	Low payback requirements	Central scenario	High payback requirements
Mean	1.5	2.5	3.5
Standard deviation	1	2	3

13.11. These distributions determine the percentage of the potential for EDR that are taken-up for a measure with a given payback. By changing the payback of a measure, the financial incentive therefore changes the percentage of the potential that is taken-up.

13.12. The cumulative distribution curve determines the gradient of the EDR supply curve. For example, in the low payback requirement scenario (mean payback requirement of 1.5 with a standard deviation of 1), the gradient of the cumulative is higher, and so change in the percentage of potential taken-up for a given change in the payback of a measure is higher. The assumed distributions of required paybacks are illustrated in figure 4 and figure 5 which show the cumulative distribution (with the x-axis reversed).

[64] Payback excluding interest payment (cost/annual revenue)
[65] See Carbon Trust/ SPA Future Thinking research report here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66566/7028-design-policies-efficiency-elec-edr.pdf
[66] This is the same as assuming the required payback periods are normally distributed across firms and probability of having an opportunity for electricity demand reduction the same for all firms.
[67] 2.5 years is also broadly consistent with findings from research by Carbon Trust , Element Energy, ENWORKS
[68] Uptake of energy efficiency in buildings - element energy (2009) - commissioned by CCC

Figure 4: Assumed distribution of required payback periods

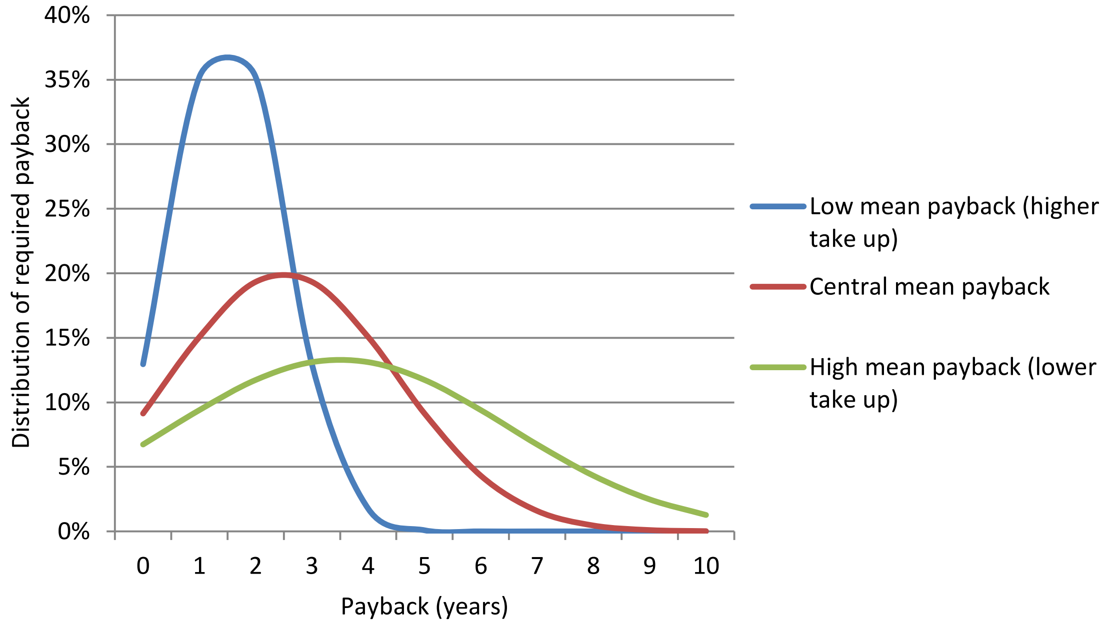
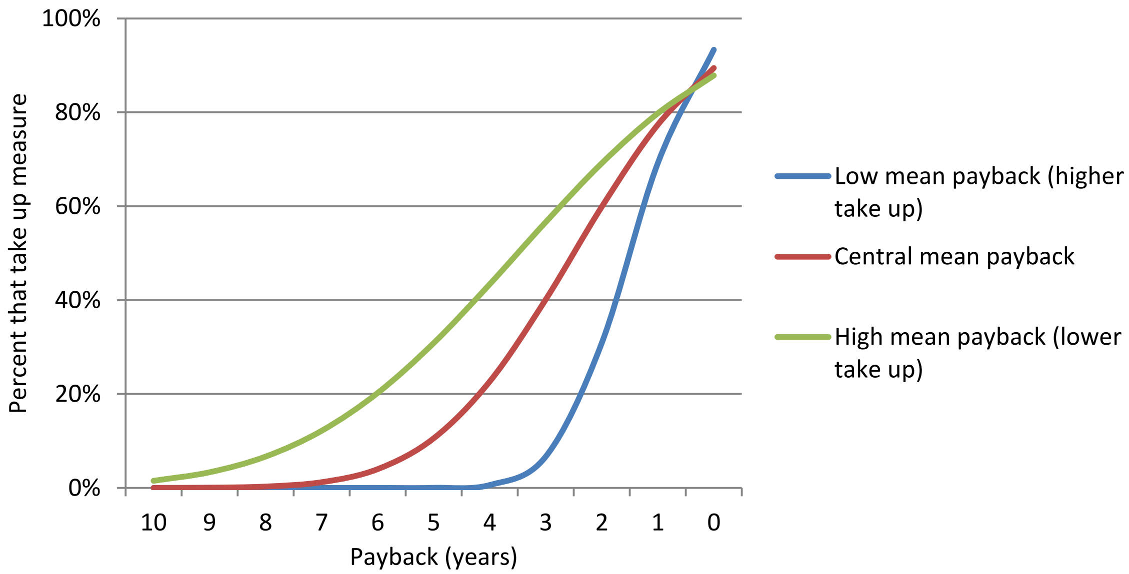
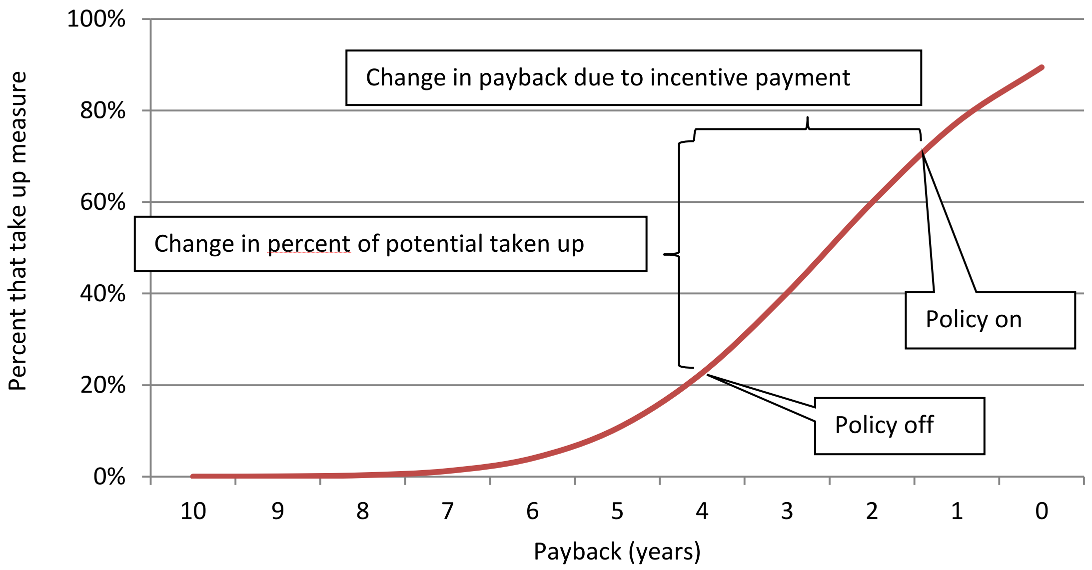


Figure 5: Assumed cumulative distribution of required payback periods



13.13. Figure 6 shows how the cumulative distribution is used to determine the impact of the financial incentive. As support payments increase, the payback period of measures falls. The impact of the policy is calculated as the difference between take-up of measures with and without support. In the example below, the financial incentive leads to the payback of the measure falling from 4 years to 1 year. This changes the percentage of potential being taken up from around 23% to around 77%. The take-up as a result of the financial incentive is therefore 54% of potential.

Figure 6: Illustration of how take up is calculated using the cumulative distribution of required payback periods



13.14. This modelling structure provides a way of testing the responsiveness of the EDR market to a financial incentive. It necessarily required a significant simplification of what is a highly complex set of decisions.

Input assumptions

Additional costs

13.15. There are a number of additional costs associated with delivering electricity demand reduction. These have been classified into two groups; those associated with delivering the actual savings and those resulting from the implementation of the policy.

13.16. The **hassle costs** have been reflected as 40% of capital costs with a high and low of 20% and 100%. These costs include the time firms' employees are required to spend on making the energy efficiency improvements. The additional policy costs (administration costs, sales /marketing cost to aggregators, monitoring and verification costs) are set out in the table below. These costs are assumed to be incurred upfront.

Table 2: Additional costs resulting from implementing the policy[69]

	Low cost	Central cost	High cost
Policy costs (£/MWh)	£10	£20	£30

Duration of savings and additionally

13.17. Two factors that will have a significant impact on the final level of demand reduction are the length of the EDR contracts and the level of additionality. Both these factors will be affected by policy decisions made at later stages in the process. This analysis has

[69] On an annuitized basis these are £2/MWh, £4/MWh and £7/MWh for the low, central and high scenarios. Note that for the purpose of the NPV calculation, the low scenario assumes a high policy cost. Similarly, the high scenario assumes a low policy cost.

therefore used some conservative working assumptions to illustrate the range of possible outcomes from implementing a financial incentive.

13.18. Theoretically, a measure that reduces electricity demand could be eligible for payments for its full lifetime. The average physical lifetime of measures included in the analysis is 11 years, with a range of 2 to 45. In reality firms or aggregators will need to contract for a given period over which they will guarantee the saving. The length of these contracts will be decided as part of the detailed policy design, and may vary on a project by project basis. This analysis uses a working assumption that the contract will be for 5 years, based on international example of similar schemes. **This is an assumption used for modelling purposes only, and is not an indication of final policy design.**

13.19. Additionality refers to the proportion of the demand reduction supported through a financial incentive that is actually a result of the policy. In some cases, payments may be made for measures that would have been installed anyway (in the absence of the policy). There are a number of processes that can be used to minimise the risk of payment for non-additional measures, but the exact level of additionality is often hard to measure. Correspondingly, there is little evidence of what the level of additionality would be under a financial incentive. For the purpose of this analysis a conservative assumption of 75% additionality has been used (meaning 1 in 4 projects funded through the policy would have gone ahead anyway). **This is an assumption used for modelling purposes only. In reality, the ability to assess the level of additionality will be affected by the monitoring and verification regime.**

Calibration

13.20. There is little evidence of the current level of take-up of the measures within the potential. The model is therefore calibrated against a policy scenario of takeup rate based on:

- The savings delivered by existing government policies that are relevant to the technical potential included in the model (for example, savings from new build and Smart Meters have been excluded); and
- The estimate of take-up under business as usual (for which the McKinsey and Non-Domestic Energy and Emission Model data sets already included projections).

13.21. The model calibration adjusts the modelled take-up in the “policy off” scenario so the average difference between baseline projection and the modelled take-up is zero. In Figure 7 below, the green line shows the baseline projection of savings. The blue line shows the savings in each year produced by the model before it is calibrated. Applying the calibration factor (which is the average difference between the blue and green lines) shifts the take-up in each to the red line. Figure 8 shows how this calibration affects the EDR take-up curve.

Figure 7: EDR model calibration processes

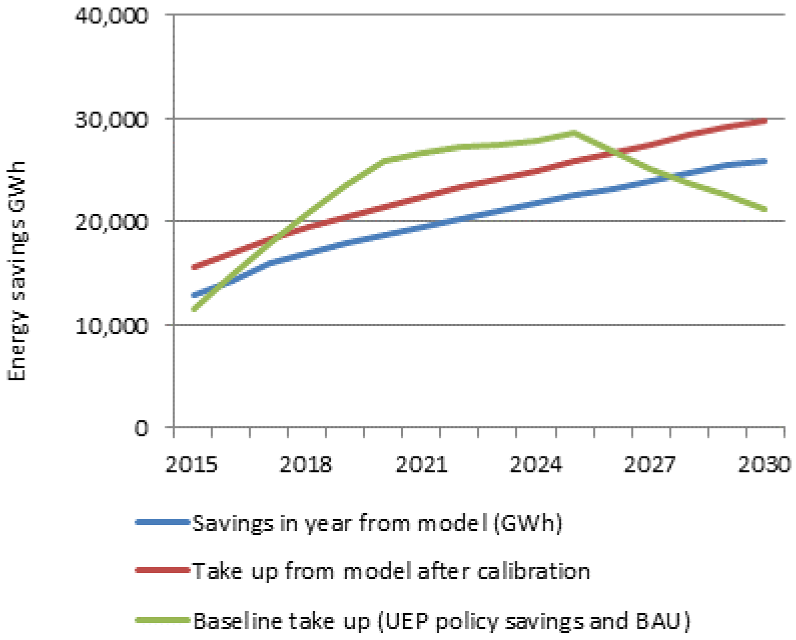
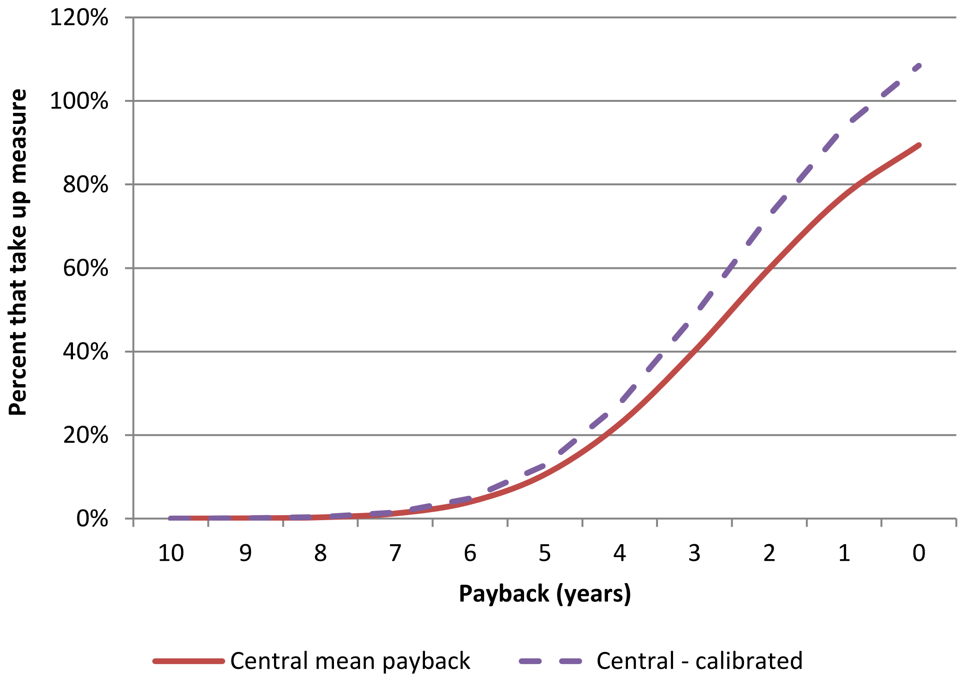


Figure 8: Impact of calibration on EDR take up curve



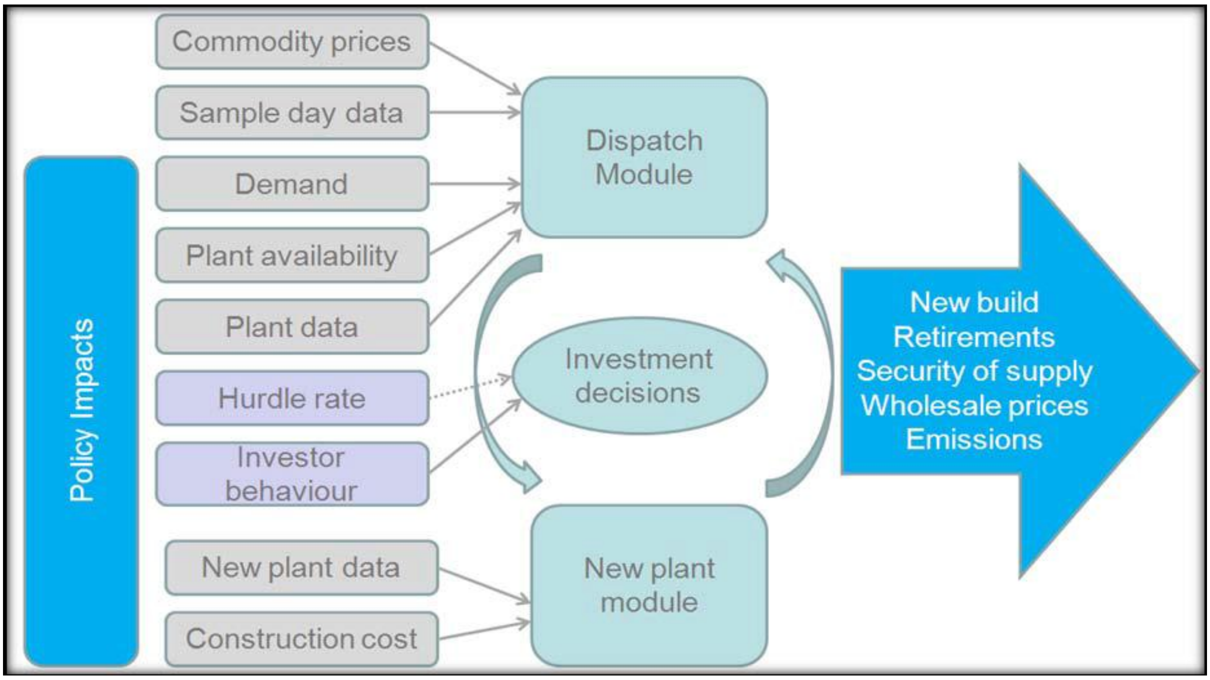
Annex D – Dynamic Dispatch Model (DDM)

13.22. The Dynamic Dispatch Model (DDM) is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from construction through to decommissioning. The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of supply and carbon emissions, and also outputs comprehensive and consistent Cost-Benefit Analysis results.

Overview

13.23. The DDM is an electricity supply model, which allows the impact of policies on the investment and dispatch decisions to be analysed. Figure 1 illustrates the structure of the model.

Figure 1: Structure of the Dynamic Dispatch Model (DDM)



The purpose of the model is to allow DECC to compare the impact of different policy decisions on capacity, costs, prices, security of supply and carbon emissions in the GB power generation market.

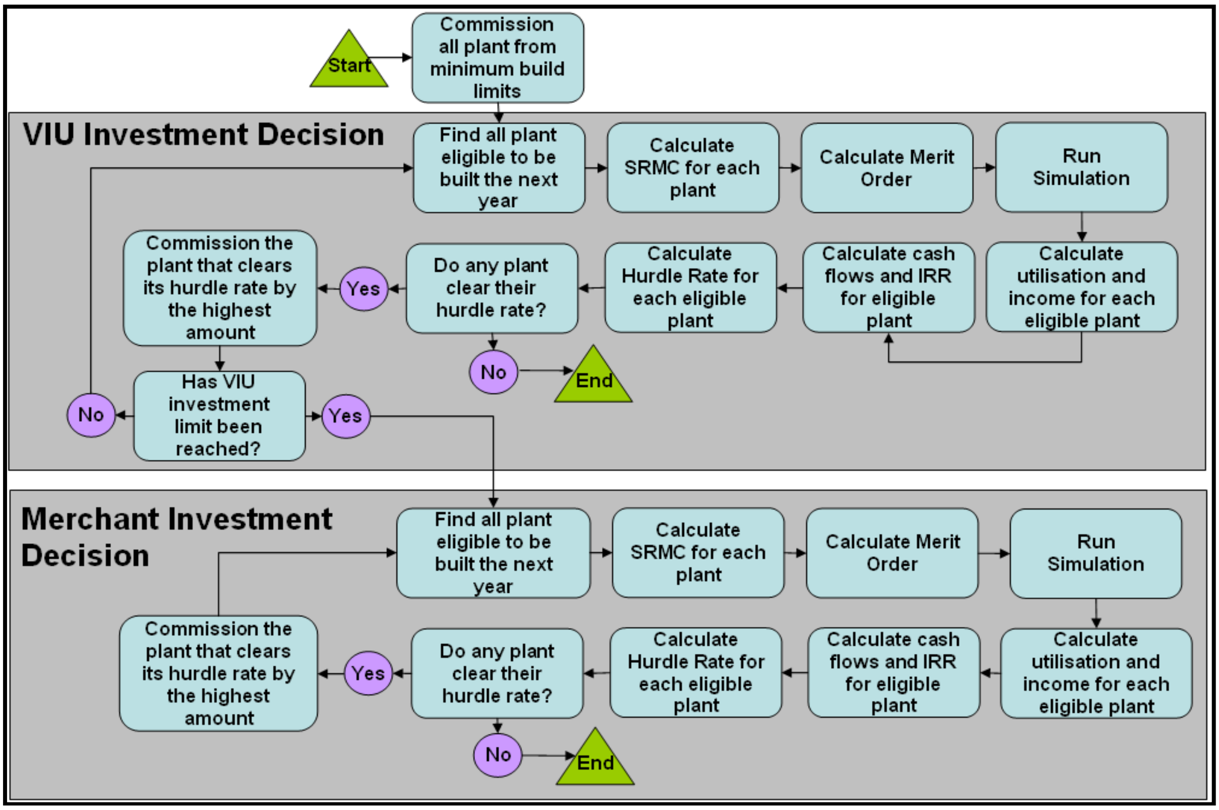
Dispatch Decisions

13.24. Economic, energy and climate policy, generation and demand assumptions are external inputs to the model. The model runs on sample days, including demand load curves for both business and non-business days, including seasonal impacts and are variable by assumptions on domestic and non domestic sectors and smart meter usage. Also, there are 3 levels of wind load factor data applied to the sample days to reflect the intermittency of on- and offshore wind. The generation data includes outage rates, efficiencies and emissions, and also planned outages and probabilities of unplanned outages.

13.25. The Short Run Marginal Cost (SRMC) for each plant is calculated which enables the calculation of the generation merit order. Demand for each day is then calculated taking wind profiles into account and interconnector flows, pumped storage, autogeneration and wind generation. Once the required reserve is calculated the system SRMC is calculated by matching the demand against the merit order and taking the SRMC of the marginal plant to meet demand. The wholesale price is equal to the system marginal price plus the mark up. The mark up is derived from historic data and reflects the increase of system marginal price above marginal costs at times of reduced capacity margins. Plant income and utilisation are calculated and carbon emissions, unserved energy, and policy costs are reported.

Investment Decisions

Figure 2. Investment decisions in the DDM



13.26. The model requires input assumptions of the costs and characteristics of all generation types, and has the capability to consider any number of technologies. In investment decision making the model considers an example plant of each technology and estimates revenue and costs in order to calculate an IRR. This is then compared to a user specified technology specific hurdle rate and the plant that clears the hurdle rate by the most is commissioned. This is then repeated allowing for the impact of plants built in previous iterations until no plant achieves the required return or another limit is reached. The model is also able to consider investment decisions of both Vertically Integrated Utilities (VIUs) and merchant investors, see figure 2. Limitations can be entered into the model such as minimum and maximum build rates per technology, per year, and cumulative limits.

Policy Tools

13.27. The model is able to consider many different policy instruments, including potential new policies as well as existing ones. Policies are implemented by making adjustments to plant cashflows which either encourage or discourage technology types from being built in future and impact on their dispatch decisions. The policy modelling has been designed flexibly and policies can be applied to all technologies or specific ones, only new plants or include existing plants and can be varied over time and duration. Policies can be financed through Government spending/taxation or charged to consumers.

Outputs

13.28. The model can be run in both deterministic and stochastic modes – this enables analysis to be carried out with different levels of randomness, allowing for more realistic treatment of uncertainty to be incorporated into the model outputs and better understanding of investment behaviour. The model outputs many metrics on the electricity market and individual plant that enables the policy impacts to be interpreted. Using these outputs a Cost Benefit Analysis is carried out on the model run including a distributional analysis.

13.29. The DDM therefore enables analysis to be carried out on policy impacts in different future scenarios, allowing DECC to consider and compare the estimated impacts of different potential policies on the electricity market.

Peer Review

13.30. The model was peer reviewed by external independent academics to ensure the model is fit for the purpose of policy development. Professors David Newbery and Daniel Ralph of the University of Cambridge undertook a peer review to ensure the model met DECC's specification and delivered robust results. The DDM was deemed an impressive model with attractive features and good transparency. For the Peer Review report see 'Assessment of LCP's Dynamic Dispatch Model for DECC' (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48385/5427-ddm-peer-review.pdf).

Levy Control Framework

13.31. On 23 November 2011, the Government agreed a Levy Control Framework (LCF) to 2020, which is set at a total of £7.6bn (in real, 2012 prices).[70] This will help diversify our energy mix by increasing the amount of electricity coming from renewables (from 11% today to around 30% by 2020), as well as supporting new nuclear power and carbon capture and storage commercialisation. It also helps to provide certainty to investors across a range of generation technologies and protection to consumers.

Scenario-based analysis

13.32. The baseline for DDM analysis represents a plausible outcome of Electricity Market Reforms, characterised by a diversified supply mix[71] and an assumed carbon emissions intensity of 100gCO_2/kWh in 2030, which is an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments.

13.33. Dispatch modelling is sensitive to a number of such assumptions (e.g. around inputs, methodology), which influence the capacity and generation mix realised under different scenarios (as discussed further in Annex C). This outcome therefore represents a

[70] https://www.gov.uk/government/news/government-agreement-on-energy-policy-sends-clear-durable-signal-to-investors

[71] Diversification reflects (in part) the objective of support for the development of a portfolio of low-carbon generation technologies, in order to reduce the technology risks associated with the decarbonisation objective for the power sector

specific state of the world and is not intended to be a prediction or forecast about what the future is expected to be.

13.34. Given the considerable uncertainty over how the electricity sector will develop to 2030, we are also developing different sets of assumptions to represent other potential future scenarios, which can then be modelled using DDM analysis. These scenarios reflect possible futures in which one low-carbon generation technology (nuclear, CCS, renewables) is deployed more heavily than the others. These recognise that there will be changes that we cannot predict in the supply chain, planning and grid constraints on deployment, technology costs and wider impacts of different technologies. Nevertheless, these scenarios include many common assumptions such as the modelling of EMR policies, fossil fuel prices, demand and the decarbonisation of the power sector to 100gCO2/kWh by 2030. These are being undertaken as part of the analysis for the draft EMR Delivery Plan, which is due to be published in July 2013.

Input assumptions

Fossil fuel price assumptions

13.35. DECC's fossil fuel price assumptions are used in the DDM as set out below to 2030. Details can be found at: https://www.gov.uk/government/publications/fossil-fuel-price-projections

2012 prices	Oil			Gas			Coal		
	$/bbl			p/therm			$/tonne		
	Low	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**
2011	115	115	115	58	58	58	124	124	124
2012	105	115	125	54	63	72	97	102	107
2013	103	116	128	51	70	87	94	110	121
2014	102	117	131	49	76	89	92	116	134
2015	**100**	**118**	**134**	**47**	**77**	**91**	**89**	**117**	**139**
2016	99	119	137	45	78	93	86	117	144
2017	97	120	140	43	75	95	84	118	149
2018	96	121	144	41	72	98	81	119	154
2019	95	122	147	41	72	100	79	119	159
2020	**93**	**124**	**151**	**41**	**72**	**102**	**76**	**120**	**164**
2021	92	125	154	41	72	103	76	120	167
2022	90	126	158	41	72	103	76	120	171
2023	89	127	162	41	72	103	76	120	174
2024	88	128	165	41	72	103	76	120	177
2025	**86**	**129**	**169**	**41**	**72**	**103**	**76**	**120**	**181**
2026	85	130	173	41	72	103	76	120	182
2027	84	131	177	41	72	103	76	120	184
2028	83	133	181	41	72	103	76	120	186
2029	81	134	186	41	72	103	76	120	187
2030	**80**	**135**	**190**	**41**	**72**	**103**	**76**	**120**	**189**

Carbon Prices

13.36. The DDM uses DECC's projected carbon price for the traded sector as well as the appraisal values of carbon, as set out below.

Projected EU-ETS carbon price for the traded sector, 2012 £/tonne of CO_2e

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central	6	6	6	6	7	7	8	8	9	9	9	10	10	10	11	11	11	12	12

DECC appraisal values for greenhouse gas emissions impacts in the traded sector, 2012 £/tonne of CO_2e

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central	6	6	6	6	7	7	8	8	9	15	22	29	35	42	49	56	62	69	76

13.37. In addition to this the Carbon Price Floor is included in the model following the trajectory set out in the government's response to the consultation on the Carbon Price Floor:

13.38. http://www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf

Carbon Price Floor, 2012 £/tonne of CO_2e

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
10	14	20	24	26	28	30	32	37	41	45	50	54	58	63	67	71	76

Technology Assumptions

13.39. Cost and technical data for new plant is taken from the 2012 PB Power study (for non-renewable technologies) and the Renewables Obligation Banding Review for renewable technologies. Details can be found at:

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65712/6884-electricity-gen-cost-model-2012-update.pdf
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42852/5936-renewables-obligation-consultation-the-government.pdf

Electricity Demand

13.40. The DDM uses Electricity Demand from the 2012 Updated Emissions Projection (UEP). These can be found in Annex C on following link.

https://www.gov.uk/government/publications/2012-energy-and-emissions-projections

Note: The UEP numbers are then adjusted downwards by 2.7% before use in the DDM model as they include Northern Ireland, while the DDM models Great Britain alone.

Annex E – Summary of International Evidence

Background

13.41. International evidence on the effectiveness of paid-for electricity efficiency schemes has been used to inform DECC's understanding of the potential impact of different levels of financial incentive on take-up of Electricity Demand Reduction (EDR) measures in the UK.

13.42. It is not possible to apply international evidence in order to make predictions about UK impacts – findings will be limited in their applicability due to a range of factors to do with the economic and policy context, such as the range of relevant efficiency measures. Findings from this international evidence gathering exercise are therefore only relevant as a component of the evidence base on potential UK take-up.

13.43. The schemes selected for further consideration in this study were chosen due to the relatively high quality of information and data available, and the willingness of colleagues working for these schemes to provide additional, detailed information. The sample of schemes is not in any way 'representative'.

Methodology

13.44. All available data for the case study examples was used to develop an understanding of the scale of financial payments made per MWh of electricity savings brought forward by financial incentive schemes, as well as the scale of administration and other scheme costs such as marketing. There have not been any attempts to estimate the scale of monitoring, verification and additionality costs specifically due to the limited information available, but the case studies were in part chosen because of the commitment of the schemes to ensure a basic level of additionality across their programmes. Overall, it is likely that there will be some free-ridership remaining, so the true costs of generating each MWh of electricity saving would be higher than quoted here.

Findings

13.45. Key findings from the main case studies are as follows:

Scheme	Cost of electricity savings (£/ MWh)	Total size of electricity savings brought forward as share of market size	Share of admin costs in total costs	Average ***retail*** electricity price[72] (2010)
Texas				
Texas Average (2011)	17	0.14%	c. 10%	9.34c/ kWh or c. £64/ MWh
Examples:				
Large Commercial Standard Offer Programme (Centrepoint)	17		10%	
Air Conditioning Market Transformation Programme (Oncor)	71		26%	
Vermont				
Vermont (2011) All programme costs	30	1.8%	38%	13.24c/ kWh or c. £90/ MWh
Vermont (2011)	17			

[72] http://www.eia.gov/electricity/state/

Incentives only				
Examples:				
Industrial process efficiency (incentives only)	8			
Cooking and laundry	15			
Switzerland				
2011 projects	21	0.39% (based on 2009 data)	No data collected	
2012 projects	15		No data collected	
American Council for an Energy Efficient Economy work				
Average value across 14 US states	16		24% (data for 6 States only)	
Range across 14 US states	15-29		8-38% (6 States only)	

Conclusions

13.46. The value of incentives paid varies between countries, time periods and programmes. In each of the countries and examples considered, there are projects being supported at different levels of cost.

13.47. It is difficult to draw any conclusions therefore about the level of incentives that would have to be paid in the UK to generate meaningful uptake of efficiency measures. It is only really possible to consider levels of financial support, and to use the international evidence to suggest whether or not such a level of support may be sufficient to drive take-up.

13.48. The data appear to suggest that a level of support worth in the region of £15/MWh or more would be expected to bring forward a meaningful level of take-up. This is worth between one quarter and one sixth of the retail electricity price (though note that much of the take-up is amongst commercial customers; data is not available on the prices paid by business customers for commercial reasons.).

Annex F – Review of the methodology to generate take-up curves by Vivid Economics

13.49. The peer review addresses the narrow question of whether the method of arriving at a "take-up" curve for EDR projects, starting from the MACC, is appropriate.

13.50. Our review does not provide a critical overall evaluation of the EDR nor does it consider the value for money of EDR compared with other decarbonisation measures. The review is based on the following information provided to us by DECC:

– two presentations of the methodology;
– a document explaining the EDR demand model;
– a document detailing the EDR technical potential; and
– a spreadsheet containing the underlying data and calculations.

13.51. The central conclusion of the review is that the methods used to develop the "take-up" curve are not implausible. We identified a range of methodological issues that can be improved upon, some of which DECC promptly addressed. In the absence of more solid empirical evidence, however, it is impossible to guarantee that large-scale spending on EDR will deliver the desired results.

13.52. The "take-up" curve rests on a range of assumptions for which there is relatively little available evidence. The evidence available to assess the advantages and disadvantages of this sort of intervention is limited. There is no previous UK evidence to assess the extent to which financial incentives can overcome largely non-financial barriers. Ideally, the EDR project would be set up as a controlled experiment to gather data on support levels and uptake in the UK, along the lines of the work of the Cabinet Office Behavioural Insights Team (Haynes et al., 2012). A first trial of the EDR project could be used to gather data and refine the estimates obtained from the theoretical modelling.

13.53. The current methodology would benefit by noting or addressing the following main points:

- non-financial incentives may be a more cost-effective way of overcoming non-financial barriers, and the EDR has to be seen in the context of wider energy efficiency programmes such as the Energy Efficiency Directive that are reducing information gaps;

- the policy assumed to model take-up may differ from the actual policy to be employed, rendering the take-up analysis hypothetical at the current stage. We realise that the uncertainty around the details of the policy details are inevitable given the current stage of the policy development;

- payback periods are a naïve proxy, which the internal assessment recognises and that, with more time and resources, the development of more appropriate proxies for different technologies is preferable;

- the estimation of additionality would benefit from further evidence gathering in a pilot project, as recognised by DECC;

- the technical electricity reduction potential is compiled from different sources, which improves the initial potential estimates by McKinsey as noted by Dr Nick Eyre of Oxford University. However, the adjustments are also associated with additional uncertainty; and

- the sensitivity analysis can be refined by allowing for ranges based on uncertainties associated with the aforementioned conceptual points.

Annex G – Review of technical potential for electricity demand reduction by Nick Eyre (Environmental Change Institute, University of Oxford)

13.54. This analysis of the scope for electricity demand reduction (EDR) in the UK represents a major improvement on earlier analysis undertaken with McKinsey, primarily because of the use of UK specific data and more careful technical analysis.

13.55. The technical potential identified (32 TWh/year) is a reasonable estimate based on the sectoral scope analysed, the technical potential identified in those sectors and an allowance for the potential expected to be delivered via existing policies.

13.56. The assessment is conservative. Different assumptions about sectoral scope, definition and potential would be likely to lead to much larger numbers, and this should be made clear in the presentation of analysis.