Energy Bill Summary Impact Assessment

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Section 1: Introduction

1. The Government's energy and climate change goals are to deliver secure energy on the way to a sustainable low carbon future and drive ambitious action on climate change at home and abroad. It is critical that we address both security of supply and climate change challenges while maximising the benefits and minimising costs for consumers and taxpayers.

2. The Government is committed to ensuring sufficient investment in sustainable low-carbon technologies to put us on a path consistent with our 2020 renewables targets and our longer-term target to reduce carbon emissions by at least 80% of 1990 levels by 2050.

3. Moving to a secure, low-carbon energy system in a cost-effective way is extremely challenging, but achievable. It will require major investment in modern technologies: to renovate our buildings; to provide for the electrification of much of our heating, industry and transport; and to move to cleaner power generation. It will also require major changes in the way energy is used by individuals, by industry, and by the public sector.

4. Through this Energy Bill, the Government aims to further its objectives. It will:
    1. Enable a 2030 decarbonisation target range to be set for the electricity sector in 2016.
    2. Ensure a secure electricity supply through providing a diverse range of energy sources; ensure sufficient investment in sustainable low-carbon technologies and maximise benefits and minimise costs through its programme of Electricity Market Reform (EMR);
    3. Establish the Office for Nuclear Regulation as a statutory body;
    4. Enable the sale of Ministry of Defence (MOD) held assets, which supply aviation fuel to United Kingdom and United States airbases as well as some civilian airports - the Government Pipeline and Storage System (GPSS);
    5. Clarify the regulatory framework by being clearer about the Government's strategic direction and how Ofgem's regulatory decisions should be aligned with this direction through a Strategy and Policy Statement;
    6. Support Ofgem by taking powers to ensure consumers are on the cheapest deals for their preferences and have clearer and more accessible information to improve engagement with the market;
    7. Enable Ofgem to compel businesses to compensate those consumers who suffer losses from any licence or regulatory breach;
    8. Make provisions so that offshore wind generators constructing transmission assets can lawfully test and commission those assets, before transferring them to an Offshore Transmission Owner;
    9. Introduce a power for the Secretary of State to charge fees for services or facilities provided in the exercise of energy resilience powers.
    10. Ensure that costs can be recovered from industry for technical, financial and legal advice that DECC procures in relation to agreeing a Waste Transfer Contract (WTC) or agreeing a Section 46 (S46) agreement, and prior to the submission of a Funded Decommissioning Programme (FDP).

Section 2: Policy Proposals

5. The Energy Bill is legislating for multiple policy objectives and therefore brings forward a number of different measures. All of the policy proposals where costs and benefits have been identified have an individual Impact Assessment (IA) which discusses the options, rationale and costs and benefits in detail. A summary of the IAs is presented in Section 3 and the detailed individual IAs accompany this document.

6. The table below provides a summary of the policies included in the Energy Bill together with the rationale for the policy intervention.

Table 1: Policy Summaries and Rationale

Policy Measure	Rationale for intervention
Decarbonisation	Part 1 of the Energy Bill enables a 2030 decarbonisation target range to be set for the electricity sector in 2016. A decision to exercise this power will be taken once the Committee on Climate Change has provided advice on the level of the 5th Carbon Budget and when the government has set this budget, which is due to take place in 2016. If a target range is set, then in line with the regulatory requirements a full Impact Assessment (including consultation) will be undertaken. This would consider the costs and benefits to businesses and consumers across a number of scenarios representing different decarbonisation levels in 2030. The results of this analysis and subsequent consultation would then inform the level of the target that is set in law.

Electricity Market Reform (EMR): As set out in Planning our electric future: A White Paper for secure, affordable and low-carbon electricity (July 2011). This will ensure future electricity generation is affordable, secure, diverse and consistent with the UK's obligations to reduce carbon emissions and increase the use of renewables. Further details of the EMR policies are given in Table 2.	The current electricity market arrangements are not likely to deliver the required scale or pace of investment in low-carbon generation whilst ensuring adequate security of electricity supply and affordability to consumers. This is due to: • Cost characteristics of typical low-carbon capacity (high capital cost and low operating cost) mean that it faces greater exposure to wholesale price risk than conventional fossil fuel capacity, which has a natural hedge given its price setting role. • Carbon price being too low and its future level too uncertain to mitigate the risks associated with low-carbon investment. • Market imperfections posing risks to future levels of electricity security of supply. These effects are likely to be exacerbated when there are significant amounts of low-carbon intermittent and inflexible generation. • Market failures impede investment in Electricity Demand Reduction (EDR) measures. These include misaligned incentives, imperfect information, undervalued energy efficiency opportunities and embryonic markets.
Office for Nuclear Regulation (ONR): The Government intends to establish the ONR, the nuclear regulator, as an independent statutory body. It is currently an agency of the Health & Safety Executive (HSE).	The UK's nuclear regulator needs to be effective, independent, fully resourced, transparent and accountable. It must also be sufficiently flexible to meet future challenges in an industry that deals in long timescales. As a civil service body, the ONR is currently constrained in its capacity to develop the necessary recruitment and reward strategies to attract and retain highly skilled specialists in a competitive and increasingly international market. Transparency is also an issue in that the ONR performs statutory functions that are in law held by the Secretary of State, rather than by ONR itself. Such issues can only be resolved using legislative means.
Government Pipeline and Storage System (GPSS): A proposal which will allow the sale	The GPSS provides aviation fuel for both

of MoD-held assets that supply aviation fuel to UK and US airbases, as well as civilian airports.	military bases and commercial airports in the UK. MoD has reviewed the pipeline and concluded that it does not need to be owned by Government. There are currently restrictions on developing the system for greater commercial usage unless there is an underlying defence requirement. Legislation is required before the GPSS can be sold.
Ofgem Strategy and Policy Statement: As set out in the Ofgem Review Final Report, the Government intends to strengthen the current regulatory framework by bringing greater clarity and coherence to the roles of both Government and the regulator. To achieve this, the Government proposes to establish a new statutory 'Strategy and Policy Statement'. This Statement will set out the Government's strategic priorities for the gas and electricity markets, describe the roles and responsibilities of Government, Ofgem, and other relevant bodies, and define policy outcomes that Government considers Ofgem to have a particularly important role in delivering.	The context in which the Gas and Electricity Markets Authority (GEMA) and its executive arm Ofgem work has changed significantly since economic regulation was established in the 1980s. The role of the regulator is now much more complex than originally envisaged, with an important contribution to make to Government's wider policy goals for the energy sector such as climate change objectives. One consequence is that a lack of clarity over the respective roles of GEMA and Government has developed, which is causing regulatory uncertainty. There is a need to clarify these roles and provide confidence that there will be coherence between Government policy and regulation.
Consumer Tariff Amendments: Main tariff provisions: The Government intends to support Ofgem by taking powers to limit the number of core tariffs suppliers can provide, prescribe features of tariffs, mandate suppliers to move customers off poor value "dead" tariffs, require suppliers to provide personalised information on bills about the cheapest tariff and use a common tariff comparison metric.	Government intervention is needed to help inactive consumers benefit from cheaper tariffs and to prompt them to engage more widely in the market. The Government intends to support Ofgem in legislation to ensure Ofgem can implement the final, post consultation proposals, without any undue delay. The proposals will ensure that consumers are not left indefinitely on more costly tariffs and make it easier for consumers to compare tariffs across the market, and should encourage greater engagement and increase competitive pressure on suppliers.
Consumer Tariff Amendments: Third Party Intermediaries (TPIs): The Government intends to clarify existing powers to make specified activities licensable to make them expressly clear that they cover the activities of third party intermediaries, so that Ofgem is able to move quickly should it conclude that there is	Ofgem is launching a review of the regulatory framework for TPIs, which will consider whether there is a case for a more regulatory approach to TPIs' activities. Government intervention is needed to clarify that Ofgem has the power to apply to licence TPIs' activities so that Ofgem is able to move quickly should its review conclude that there

a case for such further regulation.	is a case for further regulation, without the risk of appeal on the basis it does not have the power to apply to regulate TPIs.
Consumer Tariff Amendments: Electronic Information: The Government intends to take powers to require suppliers to provide key information to customers in a form that allows smart phones to read and use it.	Government intervention is needed because suppliers may not have sufficient incentives to work voluntarily to provide consumers with their data in a format that will enable ‘frictionless’ cross market comparisons from accredited switching sites. This will provide certainty that appropriate action can be taken if necessary to ensure that consumers can take advantage of beneficial technological advances being applied to the energy supply sector. These changes, if applied, should aid quicker and easier switching, increase engagement and competitive pressure on suppliers, leading to lower prices for consumers.
Ofgem Consumer Redress: Introduce powers to allow Ofgem to compel businesses to compensate consumers for losses suffered as a result of a breach in licence conditions and other regulatory requirements.	Gas and electricity businesses have to comply with licence conditions (unless they are exempt) and other regulatory requirements. Breaches can result in consumer losses. In the event of a breach, Ofgem can fine a business up to 10% of its annual turnover. However, Ofgem has no powers to compel businesses to pay redress to consumers or other businesses in compensation for losses. This means that whether redress is paid will often depend upon individual action (e.g. through the legal system). Ofgem does seek to negotiate voluntary redress in appropriate cases, but energy businesses have sometimes resisted this option. Other regulators such as Ofcom and the Financial Services Authority already have powers that allow them to require redress.

Offshore Transmission Systems: An amendment to provide an exception to the prohibition of participating in the transmission of electricity during testing of offshore transmission connections.	Developers constructing offshore generating stations have the choice of also constructing the offshore transmission assets, to connect the electricity to the onshore grid, before transferring the assets to an Offshore Transmission Owner to own and operate them. The measure is crucial to ensure that UK offshore grid constructors can build and test this infrastructure to export power without committing a criminal offence.
Energy Resilience: Clause which introduces a power for the Secretary of State to charge fees for services or facilities provided in the exercise of energy resilience powers.	Government is committed to working with business and regulators to reduce the likelihood of disruption to energy security, and to ensure that contingency arrangements are in place to respond to emergencies when they do occur. In the event of a major disruption, Government could provide support for business in the form of specific services such as personnel, supplies, equipment and assets. This clause enables Government to set charges for providing such services.
Nuclear Sites: Decommissioning and Cost Recovery: Government intends to amend the current legislation to ensure that costs can be recovered from industry for technical, financial and legal advice that DECC procures: (1) in relation to agreeing a Waste Transfer Contract (WTC) or agreeing a Section 46 (S46) Agreement, and (2) prior to the submission of a Funded Decommissioning Programme (FDP).	The Energy Act 2008 currently allows DECC to charge a fee to a site operator in order to recover the costs of obtaining advice in relation to an operator's FDP, upon its submission to DECC. However, the Act does not allow the Government to recover: (1) The costs incurred by DECC for advice received in relation to agreeing a WTC or agreeing a S46 Agreement, and (2) the costs incurred by DECC in relation to advice received prior to the submission of the FDP i.e. for the period between a notification by the operator of its intention to submit an FDP and the submission date. Government intervention is required to amend current legislation so that costs can be recovered in relation to advice received in these areas.

The Regulatory Policy Committee (RPC) has had an opportunity to comment on the IAs where policies are regulatory in nature, and the final IAs reflect its comments.

Section 3: Summary of Impacts From Policies

Electricity Market Reform (EMR)

1. Our long-term vision for the electricity market is for a decreasing role for the Government over time, and to transition to a market where low-carbon technologies can compete fairly on price. This competition between technologies will drive down costs and allow us to meet our objectives in the most cost-effective way. EMR provides the tools for transition to get to this vision, and will provide the necessary support to low-carbon technologies that enables them to get to a level of maturity where they are able to compete on a level playing field. EMR is also designed to ensure security of supply in the short, medium and longer term.

2. The EMR objectives align with three objectives across the energy sector:
   I. Ensuring a secure electricity supply by providing a diverse range of energy sources, including renewables, nuclear, CCS equipped plant, unabated gas and demand side approaches; and ensuring we have sufficient reliable capacity to minimise the risk of blackouts.

   II. Ensuring sufficient investment in sustainable low-carbon technologies to put us on a path consistent with our EU 2020 renewables targets and our longer term target to reduce carbon emissions by at least 80% of 1990 levels by 2050.

   III. Maximising benefits and minimising costs to the economy as a whole and to taxpayers and consumers - maintaining affordable electricity bills while delivering the investment needed. EMR minimises costs compared to the current policies because it seeks to use the power of the markets and competition and reduce Ministerial intervention and support over time.

3. The EMR provisions in the Bill establish a framework for delivering these objectives. The proposed policy measures in the Bill relate to aspects of the EMR outlined in Table 2.

Table 2: Summary of EMR Policies

EMR Policy	Key Decision Documents	Key Conclusion from Impact Assessment
Feed-in-Tariff with Contracts for Difference (CfD)	EMR White Paper: Planning our electric future: a White Paper for secure, affordable and low-carbon electricity (July 2011); and accompanying Impact Assessment; Electricity Market Reform – ensuring electricity security of supply and promoting investment in low-carbon generation Impact	CfD is the preferred option: as it provides greater stability to returns whilst maintaining market incentives and minimising costs to consumers.

	Assessment 2012; Energy Bill 2013 and accompanying Impact Assessment	
Capacity Market	Technical update to EMR White paper: Planning our electric future, a technical update (December 2011); Capacity Market Impact Assessment 2012 Energy Bill 2013 and accompanying Impact Assessment	Administrative Capacity Market is the preferred form of capacity mechanism as it reinforces market signals to bring forward sufficient reliable capacity.
Electricity Demand Reduction (EDR)	Consultation on options to reduce demand: Government response Final Impact Assessment: Electricity Demand Reduction Energy Bill 2013 and accompanying Impact Assessment	A Capacity Market approach is the preferred option as it builds upon a framework and institutions already in development, and targets reductions at peak and so incentivises demand reduction at times when it is more valuable. 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.
Emissions Performance Standard (EPS) 450gCO_2 /kWh with grandfathering[1] of the level until 2045	EMR White Paper Planning our electric future: a White Paper for secure, affordable and low-carbon electricity (July 2011 EPS Impact Assessment); Energy Bill 2013 and accompanying EPS Impact Assessment	EPS to act as a regulatory backstop, supporting decarbonisation and giving certainty to the market. Grandfathering provisions give long term certainty to investors, particularly in relation to new gas generation that is needed to ensure security of supply.

[1] See the EPS section

Final Investment Decision (FID) Enabling	EMR White Paper: Planning our electric future: a White Paper for secure, affordable and low-carbon electricity (July 2011); Technical update to EMR White paper: Planning our electric future, a technical update (December 2011); Energy Bill 2013 and accompanying Impact Assessment	Our analysis shows that enabling early investment decisions delivers a more socially optimal generation mix out to 2030, both in terms of generation capacity, and in terms of capacity utilisation. The recommended preferred option is to issue early CfDs with price and contract terms conditional on any necessary state aid approvals being secured. This gives as much certainty as possible to low carbon investors who are ready to make a final investment decision before EMR has been fully implemented.
Renewables Obligation Transition	EMR White Paper: Planning our electric future: a White Paper for secure, affordable and low-carbon electricity (July 2011); Energy Bill 2013 and accompanying Impact Assessment	Government will continue to calculate the Renewables Obligation on a headroom basis until 31 March 2027, whereupon it will move to a Fixed Price Certificate system until the end of the RO in 2037. Moving to a Fixed Price Certificate system will give generators certainty over the incentive they receive, and investors the long-term visibility to provide debt financing with a longer term. It will also eliminate the potential rents.
Wholesale Electricity Market Liquidity	Energy Bill 2013 and accompanying Impact Assessment	Taking powers to improve liquidity, with constraints on using the powers, is the preferred option. It contributes towards reducing barriers to entry to electricity generation and supply, while limiting negative impacts on wider regulatory uncertainty.

Barriers to Independent Generation (PPA)	Energy Bill 2013 and accompanying Impact Assessment	The Secretary of State is taking powers in the current Energy Bill to reduce barriers to securing long-term contracts for electricity generation. Subject to further evidence gathering and analysis, Government intervention would be a valuable option if there are clear issues that require intervention.

3.1 Contracts for Difference (CfD)

4. The Government set out in the EMR White Paper in July 2011 its decision to provide increased revenue certainty to low-carbon generation through use of a Feed-in Tariff following the structure of a Contract for Difference (CfD).

5. Generators with a CfD will sell their electricity into the market in the normal way, and remain active participants in the wholesale electricity market. The CfD then pays the difference between an estimate of the market price for electricity and an estimate of the long-term price needed to bring forward investment in a given technology (the 'strike price').

6. This means that when a generator sells its power, if the market price is lower than needed to reward investment, the CfD pays a 'top-up'. However, if the market price is higher than needed to reward investment, the contract obliges the generator to pay the difference back.

7. In this way, CfDs stabilise returns for generators at a fixed level, over the duration of the contract. This removes the generator's long-term exposure to electricity price volatility, substantially reducing the commercial risks faced by these projects. As commercial risks are lower under the CfD, this lowers the cost of raising finance and ultimately, encourages investment in low-carbon generation at least cost to consumers.

8. The CfDs will take the form of long-term, private law contracts, providing generators with a clear set of rights and obligations, and recourse to arbitration processes to resolve disputes. This structure supports investor confidence in the arrangements and reduces the risk that the support payments might be reduced or removed in future; further reducing risk to investing and therefore costs to consumers.

Update on CfD Payment Model

9. The analysis presented in the EMR White Paper assumed that contracts would be bankable, to ensure that the necessary certainty to industry would be provided. Stakeholders raised concerns regarding the payment model that was within the draft Energy Bill that this might not be the case. This was a multiparty arrangement where effectively all suppliers were counterparty to a legislative instrument in place of a contract. Generators in particular were concerned that this was complex, about what would happen in a dispute, and whether this model fused public and private law in a way that could be off-putting to investors.

10. In response to such concerns from industry and others, the Energy Bill published in November 2012 introduced a single counterparty in the form of a Government owned company. The counterparty body will sign contracts with generators and collect monies from suppliers. This is a simpler system which creates a private law contract, a model that investors will be familiar with, and gives certainty through an enforceable statutory obligation that monies will be raised from suppliers. This creates a credible and investable model, as assumed in our initial analysis. Further details are provided in the accompanying Bill documents.

Updated CfD with Capacity Market Analysis

11. The Summary Impact Assessment (IA) published alongside the Draft Energy Bill in May 2012 stated that the analysis of the Contract for Differences (CfD) and Capacity Market would be revised in Autumn 2012 following the publication of DECC's annual updated assumptions on technology costs, fossil fuel prices, and demand. In addition, the modelling would be migrated to a DECC in-house Dynamic Dispatch Model (DDM) and would incorporate further methodological changes to enhance the robustness of the analysis assessing the Capacity Market.

12. The resulting EMR Impact Assessment (IA) published alongside the Energy Bill in November 2012 was based on an agreed set of assumptions, including technology costs and electricity demand at the time the analysis was undertaken, but with no affordability constraint. In addition, the analysis presented in the November 2012 Energy Bill Impact Assessment used $100gCO_2$/kWh in 2030 as an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments.

13. However, to reflect the decision to take a power to set a decarbonisation target range, and show the wider range of costs and benefits of EMR, the November 2012 EMR IA stated that the analysis would be updated early in 2013, to incorporate additional carbon emission intensities for the power sector in 2030 (50gCO2/kWh and 200gCO2/kWh), as well as a range of fossil fuel price scenarios. This would also allow for the modelling to reflect the impact of the Levy Control Framework, which was agreed in November 2012 for 2020/21.

14. An updated EMR Impact Assessment was published in January 2013. The results of that analysis are presented below, with a small difference to reflect updated administrative cost estimates.

Updated Cost Benefit Analysis (CBA)

Table 3: Net Present Value (NPV) – Impact of EMR policy package relative to basecases A & B, assumed emissions intensity of 100gCO2/kWh in 2030

<table>
<tr><th colspan="2"></th><th>2012-2030</th><th>2012-2040</th><th>2012-2049</th></tr>
<tr><td colspan="2">NPV, £bn</td><td>+£4.2 to £7.6</td><td>+£12 to £20</td><td>+£15 to £26</td></tr>
<tr><td colspan="2">Of which: Contracts for Difference</td><td>+£4.8 to £8.2</td><td colspan="2" rowspan="4"></td></tr>
<tr><td></td><td>Of which: Financing Impact</td><td>+3.0</td></tr>
<tr><td></td><td>Of which: Tech Mix impact</td><td>+£1.8 to £5.1</td></tr>
<tr><td colspan="2">Of which: Capacity Market</td><td>-£0.6*</td></tr>
</table>

*2030 NPV estimates also include expected administrative costs of approximately £0.7bn (estimates post-2030 do not); * the figure for the capacity market is based on assumption in counterfactual of perfectly functioning energy market (see below)*

15. In undertaking the cost-benefit analysis for the EMR with the CfD and a Capacity Market, the policy package is compared to a basecase counterfactual, without the EMR package. The policies Government might use to meet its decarbonisation ambitions in a world without EMR are unknown. To reflect the uncertainty over what policies might be used in practice, alternative ways of achieving the same decarbonisation ambition using

existing policy instruments (e.g. Renewables Obligation and carbon pricing) are modelled. Reflecting the uncertainty over the basecase, the impact of EMR is reported as a range.

16. In a scenario where power sector emissions are 100gCO_2/kWh in 2030, the Cost Benefit Analysis (CBA) suggests that EMR is a cost-effective way of decarbonising the electricity sector in comparison with using existing policy levers up to 2030 and beyond. EMR could lead to an improvement in welfare of between £4.2bn and £7.6bn up to 2030, with larger benefits up to 2050.

17. The key benefit of decarbonising using EMR is in terms of reducing financing costs for investors and minimising generator rents under high wholesale prices. The greater revenue certainty from the contracts for difference allows financing at a lower cost and our evidence set out in the EMR White Paper suggested this effect could be up to a 1.5 percentage point reduction in the cost of capital for developers, depending on the technology type. In the updated analysis we have used updated hurdle rate and hurdle rate reductions. With these updates we have valued this benefit to be around £3.0bn (including the expected administrative costs of CfDs).

18. There will also be impacts on the generation mix and including these effects the overall net impact rises to between £4.8 billion and £8.2 billion.

19. The overall net impact reflects a net loss from the Capacity Market of -£0.6 billion. However, this modelled figure measures the benefits of a Capacity Market against a perfectly operating energy market. In reality the market may not deliver the optimal level of investment due to a range of market failures, including market prices that do not reflect the full scarcity value of electricity and the difficulty investors face in making optimal investment decisions in the face of volatile electricity prices. This is reflected in the Capacity Market Impact Assessment.

20. The updated IA also includes an appraisal of EMR targeting a range of carbon emission intensities in 2030 (50gCO_2/kWh, 100gCO_2/kWh and 200gCO_2/kWh).

Table 4: Change in Net Welfare (NPV) – combined EMR impact (2012-2030), emission intensities of 50g, 100g and 200gCO2/kWh[2]

NPV, £bn (2012-2030, real 2012 prices)	Decarbonisation target in 2030 (gCO2/kWh)		
	50	100	200
EMR: Total NPV	**+5.3**	**+4.2 to +7.6**	**+1.9**
Contracts for Difference	**+5.2**	**+4.8 to +8.2**	**+2.4**
- Financing impact	+4.1	+3.0	+2.1
- Technology mix impact	+1.0	+1.8 to +5.1	+0.3
Capacity market	**+0.1**	**-0.6**	**-0.5**

Source: DECC modelling

2 Inclusive of administrative costs

21. This updated analysis indicates that EMR is a cost-effective tool for decarbonising the power sector across a range of decarbonisation levels in 2030. This is shown by the overall NPV for EMR being positive across all emission intensities, up to 2030 – £5.3bn for 50g, £4.2bn to £7.6bn for 100g and £1.9bn for 200g.

Updated Price and Bill Impact Analysis

22. Final consumer electricity bills are made up of wholesale energy costs, network costs, metering and other supply costs, supplier margins, VAT and the impacts of energy and climate change policies. Wholesale electricity prices, and therefore bills, are also strongly influenced by the prevailing capacity margin in the wholesale electricity market.

23. The EMR policy package affects electricity bills in three main ways:

- **EMR support costs:** CfD low-carbon payments and capacity payments which are assumed to be funded through electricity bills
- **Lower RO support costs:** less new generation will be covered by the Renewables Obligation
- **Wholesale price effect:** resulting from changed generation mix and capacity margins

24. The price and bill impact modelling assesses the net impact of these three effects. The table below presents the impact of EMR on average household electricity bills.

25. For domestic consumers, EMR has the potential to reduce average annual household electricity bills by between 6% and 8% (£38 to £53) over the period 2016-2030, relative to a basecase which achieves the same decarbonisation level of 100gCO_2/kWh using existing policy instruments. The impact on average bills for businesses and energy-intensive industries will be similar.

Table 5: Price and Bill impact – Impact of EMR policy package on domestic electricity bills, relative to basecases A & B (assumed emissions intensity of 100gCO2/kWh in 2030)

Time Period	Impact of EMR on domestic electricity bills, relative to basecases A & B (real 2012 prices)
2016-2030	-£38 to -£53 (-6% to -8%)

Source: DECC modelling

3.2 Capacity Market

26. Previous IAs for the Capacity Market – primarily December 2011[3] and November 2012[4] – have analysed the policy options that would best deliver our security of supply objective. The key conclusions from these previous impact assessments are:
    - A Capacity Market is the preferred instrument to mitigate security of supply risks compared to alternatives, including a strategic reserve and doing nothing.[5]
    - An Administrative Capacity Market is the preferred form of the capacity market compared with a reliability option.[6]

27. In theory, a perfectly-functioning energy market should provide sufficient incentives for investment in new capacity. In practice, we think there is a risk of market failure in the current GB market. Incentives for investment in new capacity may be insufficient as electricity prices cannot rise sufficiently at times of scarcity, and even if our balancing price were reformed to be more cost-reflective, investors could face difficulties building capacity on the basis of peaky prices earned at times of scarcity.

28. A market-wide capacity mechanism is preferable to a targeted capacity mechanism ("Strategic Reserve"), as it ensures sufficient incentives for investment in new capacity and helps to bring down financing costs.

29. While a Strategic Reserve can be an effective short-term measure to ensure existing capacity is on the system, it is less effective at bringing on new capacity. If the Strategic Reserve becomes an enduring feature of the market it can also create the risk of a "slippery slope", where there is pressure to use the reserve capacity outside of exceptional circumstances, dampening prices and necessitating an expansion of the reserve.

30. An Administrative Capacity Market is preferred over the Reliability Market, as an Administrative Capacity Market reinforces existing energy market signals for capacity to be reliable. A Reliability Market creates additional exposure to a volatile real-time price, potentially prompting parties to trade financial options around that price. However it is recognised that a Reliability Market could theoretically be cost-efficient, if cash-out is reformed in particular ways.

31. The latest Capacity Market IA presents updated energy modelling analysis and price & bill impact analysis for an Administrative Capacity Market only. As a result of the

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3 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf

4 https://www.gov.uk/government/publications/energy-bill-impact-assessments

5 This decision was first presented in the December 2011 Technical Update to EMR (http://www.decc.gov.uk/assets/decc/11/consultation/cap-mech/3883-capacity-mechanism-consultation-impact-assessment.pdf).

6 An Administrative Capacity Market is one in which capacity providers receive a payment for offering capacity which is available when needed, but are able to keep their energy market revenues. Under a Reliability Market, capacity providers receive a payment for offering capacity which is available when needed, but are required to pay back any scarcity rents earned in the energy market.

updated analysis, net welfare figures have changed from the estimates published alongside the Energy Bill in November 2012. However, the relative ordering of the policy choices has not changed.[7]

32. In addition to analysis based on a carbon emissions intensity of 100gCO_2/kWh for the power sector in 2030, which is consistent with previous Capacity Market IAs, the updated IA also includes analysis based on average emissions levels of both 50gCO_2/kWh and 200gCO_2/kWh in 2030.

Table 6: Change in Net Welfare (NPV) – Administrative Capacity Market, emissions intensities of 50g, 100g and 200gCO_2/kWh

NPV, £bn (2012-2030, real 2012 prices)	Decarbonisation target in 2030 (gCO_2/kWh)		
	50	100	200
Administrative Capacity market	+0.1	-0.6	-0.5

Source: DECC modelling

33. The impact of the capacity market varies across the three decarbonisation scenarios:
    - For 100g, the NPV of the capacity market is -£0.6bn;
    - For 200g – where it might be expected that demand for a capacity mechanism is lower than for a 100g scenario, given the less pressing need for low-carbon generation up to 2030 – the overall NPV is similar (-£0.5bn);
    - However, for a 50g target in 2030, the NPV of the capacity market is slightly positive (£0.1bn).

34. Our modelling suggests that an Administrative Capacity Market could lead to a small increase in bills of around £16/year[8] per domestic household and has a net cost to society (£0.6bn to 2030) in the central 100gCO_2/kWh case.

35. However this may understate the benefits as it assumes an efficient energy-only energy market, in which prices can rise to reflect consumers' Value of Lost Load (VoLL) and where investors have perfect foresight of demand up to five years out. This therefore understates the potential benefits of mitigating the security of supply risks that could arise if the energy market fails to bring forward sufficient capacity.

36. Sensitivity analysis presented in the IA published in November 2012 assuming a £500/MWh price cap and higher peak demand showed that a Capacity Market could provide a large net benefit (up to £4.2bn to 2030) by reducing blackouts and brownouts and by reducing the high electricity prices that might occur at times of scarcity.

[7] The conclusions on the relative attractiveness of the different options set out in previous IAs for the Capacity Mechanism are considered robust. Therefore, there is no need to update the full analysis on all the potential policy packages previously assessed. Instead this analysis updates and presents the impact of the lead option only (i.e. an Administrative Capacity Market).
[8] See Capacity Market Impact Assessment

37. However it should be noted that there is significant uncertainty around modelling the economic impact of a Capacity Market. The precise forecast impact is heavily dependent on a number of variables, in particular what level of capacity an energy-only market would have brought forward and how high prices go as capacity margins tighten.

38. There are also a range of factors that can significantly affect the economic impact of a Capacity Market which are not reflected in the modelling. These include:

- Whether the capacity auction is illiquid;
- The degree to which the Capacity Market can bring down investment financing costs for new plant;
- Whether the electricity market is reformed so that prices can rise to reflect scarcity, and whether investors will value potential "scarcity rents" when pricing into the Capacity Market; and,
- Whether the System Operator is more or less successful than the market in estimating the 'optimal' level of capacity needed four years ahead.

39. Given the uncertainties around the modelling, the overall conclusion from the analysis is that an Administrative Capacity Market is a sensible precaution against the risk of market failures leading to inadequate levels of security of supply.

3.3 Emissions Performance Standard

40. In the Coalition Agreement, the Government committed to the establishment of an Emissions Performance Standard (EPS). The EPS will provide a clear regulatory signal that coal-fired generation can only play a long-term role in the UK's energy mix if its carbon emissions are significantly reduced, supporting the existing requirement set out in the National Policy Statements (NPS). The EPS will also complement the economic signals provided by the Carbon Price Floor (CPF) and Feed-in Tariff with Contract for Difference (FiT CfD).

41. The EPS will be set at a level equivalent to 450gCO_2/kWh for all new fossil fuel plants. The first EPS IA, which accompanied the EMR White Paper, focused on the introduction of the EPS and the level of the EPS and discussed the principle of grandfathering[9] the emissions limit of the EPS. Two options were considered:

    1. Introduce an EPS as an annual limit on the amount of CO_2 a new fossil fuel plant can emit, equivalent to 600gCO_2/kWh for plant operating at baseload;

    2. Introduce an EPS as an annual limit on the amount of CO_2 a new fossil fuel plant can emit, equivalent to 450gCO_2/kWh for plant operating at baseload.

42. Both options assumed grandfathering of the EPS level for operational life for the purposes of the analysis.

43. Both options were considered to provide further clarity on the regulatory environment for fossil fuel-fired power stations in addition to existing consenting policy. The IA estimates that neither option impacts generators' investment decisions or pattern of generation compared to the baseline (the baseline includes all EMR policies except the EPS). However administrative costs have been identified. An initial regulatory exchange to establish the EPS value for each new fossil fuel-fired plant is estimated to cost approximately £5,000 in current prices.[10] There will also be operating costs of the EPS estimated to be approximately £50,000 per annum based on staff costs, IT costs and enforcement costs. Further work on the administrative costs of the EPS will be presented in the Impact Assessment that will accompany Secondary Legislation on the EPS.

44. Table 7 sets out the estimated Net Present Value of the policy:

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[9] Grandfathering provides clarity to developers over the emissions limits that their plant will face for a set period of time. This clarity will help developers when making a decision of whether or not to invest in the electricity market

[10] For NPV of the policy, see Emissions Performance Standard Impact Assessment https://www.gov.uk/government/publications/energy-bill-impact-assessments

Table 7: Summary of Societal Costs and Benefits, NPV 2011-2030

Costs	£0.6m
Benefits*	£0m
Net Benefit	**-£0.6m**

* No quantifiable benefits identified

45. The first EPS IA which accompanied the EMR White Paper confirmed the selection of the second option. Given that this option assumed grandfathering, this implied that the principle of grandfathering would be applied to the EPS emission limit.

46. The second EPS IA, which accompanied the Draft Energy Bill, focused on the details of the grandfathering provision. Three options were considered:

1. "Do nothing": introduce an EPS of 450gCO_2/kWh with grandfathering of the level for 30 years, which is the expected operational life of a CCGT plant[11];

2. Introduce an EPS of 450gCO_2/kWh with grandfathering of the level until 2018, which is one of the first review points of the policy;

3. Introduce an EPS of 450g/kWh with grandfathering of the level until 2045 after which the policy comes to an end.

47. The first option provides generators with the most clarity over the EPS. However it would not allow Government to control emissions from fossil fuel plants in the years before 2050, if the EPS was needed to help meet the 2050 carbon emissions target. By definition, a "do nothing" option has no costs or benefits compared to the baseline.

48. The second option provides a maximum of two operational years of clarity over the level of the EPS. Under this option, depending on the emissions limit of the EPS beyond 2018, the load factor of fossil fuel plants within scope of the EPS could be limited more than expected. This could potentially affect their revenue stream and hence the economic viability of the plants. Therefore it was considered that this option introduced regulatory risk compared to the baseline. Responses to the informal consultation indicated that investors would heavily discount any revenue gained once grandfathering had come to an end. It was proposed that under this scenario there would be no new investment in Combined Cycle Gas Turbines (CCGTs) once the EPS was in force, compared to the baseline. It was estimated that this would lead to a negative net change in economic welfare.

[11] As estimated by Parsons Brinckerhoff in their 2011 report http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/2127-electricity-generation-cost-model-2011.pdf

49. The grandfathering period provided by the third option diminishes, the later that the plant becomes operational. It has not been possible to accurately predict the impact of such grandfathering periods on investment decisions. Each developer will have a different appetite for risk, meaning that the investment case of some projects will not be altered, while it will be for others. It is recognised that while it has not been possible to accurately analyse this option, it may have costs compared to the baseline.

50. However this third option provides flexibility as it allows Government to take action to drive down emissions with an EPS to help meet the 2050 emissions target if needed. Yet, if we are on track to meet out 2050 targets, the amount of generation from gas is likely to be very low, and the EPS may be a redundant policy instrument. This important benefit is the reason why Option 3 had been chosen over option 1 even though it may have costs.

3.4 Renewables Obligation (RO) Transition

51. The Renewables Obligation (RO) is imposed on all licensed electricity suppliers which supply electricity in England & Wales, Scotland and Northern Ireland. Suppliers must submit, a certain number of Renewables Obligation Certificates (ROCs) in respect of each megawatt hour of electricity that each supplies to customers in England & Wales during a specified period known as an obligation period. Generators of electricity from eligible renewable sources are awarded ROCs for every megawatt hour they generate. These certificates can be sold to energy suppliers along with the electricity they buy or can be traded independently.

52. Throughout the Electricity Market Reform process, the Government has set out clear and transparent transition arrangements from the RO to the new support mechanism, with the aim of preventing a hiatus in renewables investment while the new arrangements are being put in place. The transitional arrangements will affect how the value of a ROC is determined from 2027. The precise date of implementation will be the subject of secondary legislation.

53. Currently, the value of a ROC to the electricity supplier is determined by the buyout price and the difference between the level of the Obligation and the number of ROCs surrendered to Ofgem (also known as "headroom basis"). In the EMR White Paper, Government set out its intention to continue to calculate the Renewables Obligation on a headroom basis until 31 March 2027, whereupon it would move to a Fixed Price Certificate system until the end of the RO in 2037.

54. It is therefore proposed that ROCs surrendered by generators will be bought by a purchasing body at a predetermined price. The purchasing body recovers costs from suppliers in the same proportion as their share of the electricity supply market. The policy intent is to introduce Fixed Price Certificates from 2027.

55. Although there may be some upfront administration costs incurred to set up the new system, costs are expected to remain the same under the Fixed Price Certificate system. Although there would be no buyout fund to recycle to energy suppliers, the purchasing body would have to incur additional costs in levying energy suppliers to recover the cost of purchasing certificates from generators. There is not enough information to calculate exactly how much administrative costs would change under the current option. Further evidence will be gathered to produce a more robust estimate for subsequent Impact Assessments.

56. Under current arrangements, the Obligation is set for the forthcoming financial year, and if ROCs generation is higher than the Obligation, generators receive a recycling payment. The Obligation is set at the forecast level of ROCs generation plus 10% 'headroom'. If ROCs generation is at the level forecast, then there will be recycling payments, boosting the value of individual ROCs to the avoided buyout price plus 10%. If the level of ROCs is more than 10% below the Obligation level, then the recycling fund will be bigger, and the value of each ROC higher; if it is less than 10% below the Obligation level, the value of each ROC will be lower. Over several years, if there is no

systematic bias to the error in forecasting ROCs generation, the ROC value should average out at the buyout price plus 10%.

57. There are two key risks inherent in the current system:

- If ROCs generation is more than 10% higher than forecast and hence exceeds the Obligation level, there may be a collapse in the value of ROCs, undermining investor confidence in the system. This is mitigated to a certain extent by the ability suppliers have to 'bank' ROCs from one year to be used towards the following year's Obligation.

- If ROCs generation is systematically overestimated (for example, it was overestimated in both 2010/11 and 2011/12), then electricity suppliers and generators will be overcompensated (with the sharing of this surplus dependent on the terms of their contracts). As these payments are unanticipated, they are essentially excess profit, and may not impact on deployment. Nevertheless if the ROCs generation is systematically overestimated there will be an impact on consumer costs, and hence consumer bills – removing the systematic overestimate could therefore reduce cost to consumers.

58. There are several factors which make it difficult to predict the level of ROCs generation in advance, which may cause investors to heavily discount, or disregard, ROC income from the latter years of the subsidy regime. This makes it more difficult to secure debt financing with a longer term, and therefore deployment of these types of project may be hampered.

59. Moving to a Fixed Price Certificate system will give generators certainty over the incentive they receive, and investors the long-term visibility to provide debt financing with a longer term. It will also eliminate the potential rents.

60. Table 8 sets out the estimated Net Present Value of the move to a Fixed Price Certificate system over the lifetime of the policy, under the two options. Given the uncertainty attached to estimating whether the costs are more or less significant than the benefits, it is expected that the change would be broadly neutral. This is based on the changes in administrative costs cited above, and not on any of the potential impacts on either consumer costs and / or deployment. Modelling of these is very uncertain.

Table 8: Summary of Societal Costs and Benefits, NPV 2011/12-2039/40[12]

	Fixed Price Certificate from 2017	**Fixed Price Certificate from 2027**
Costs	£ Positive	£ Positive
Benefits	£ Positive	£ Positive
Net Benefit	**£0 (central estimate)**	**£0 (central estimate)**

[12] See Renewables Obligation Transition Impact Assessment https://www.gov.uk/government/publications/energy-bill-impact-assessments

3.5 Final Investment Decisions (FIDs)

61. The Government is committed to working actively with relevant parties to enable early investment decisions in low-carbon plant to progress to timetable, including ahead of EMR, where eligibility criteria are met.

62. Developers that require FID before the EMR programme has been implemented will not invest until they have certainty over what it will deliver. Without Government intervention to provide such assurances, investments in low-carbon generation are expected to be delayed putting decarbonisation, security of supply, and affordability objectives at risk.

63. Our analysis shows that enabling early investment decisions delivers a more socially optimal generation mix out to 2030, both in terms of generation capacity, and in terms of capacity utilisation. By offering greater certainty on reforms to low carbon investors who are ready to make a final investment decision before EMR has been fully implemented, the Government will help deliver its decarbonisation ambitions in a more cost-effective way, and mitigate the risks of significant delay or cancellation of some projects.

64. Bringing forward low-carbon projects introduces a trade-off between carbon and generation cost savings, and earlier capital expenditure. Our central case suggests that there is a net welfare gain of £2bn (NPV)[13] associated with introducing an effective FID enabling product. This result is robust to changing fossil fuel prices and reductions in demand, in the case of lower economic growth for example.

65. In the IA three possible delivery options are considered:

    1. Do nothing. Under our central counterfactual, developers are risk averse and wait until EMR is implemented in 2014, with strike price and contract terms known, before reaching FID.

    2. A non-binding letter of comfort offering assurance covering, for example, eligibility, strike price banding, high-level risk allocation, and wider government action to support investments. The content of the letter would not be binding on the Government or the delivery body.

    3. An early CfD with a generator entered into by the Secretary of State ahead of full implementation of EMR, where the payment obligations are conditional on primary powers being secured (if entered into before the Bill is enacted) and any necessary state aid approvals.

66. By seeking the legislative provision through the Energy Bill, Government is ensuring that it can deliver necessary certainty for investors in eligible projects, thereby making final investment decisions in advance of EMR implementation more likely. Our analysis provides a justification for engaging with interested parties, recognising that the success of the scheme also depends on attracting projects that represent value for money for

[13] Electricity Market Reform (EMR) Final Investment Decision (FID) Enabling Impact Assessment https://www.gov.uk/government/publications/energy-bill-impact-assessments

consumers. Some projects may not find the terms of the investment contract on offer attractive and these projects will not be incentivised through the scheme.

3.6 Wholesale Electricity Market Liquidity

67. The GB wholesale electricity market suffers from low liquidity. This creates a barrier to entry to independent generation and retail supply and could also prevent the successful and cost-effective delivery of Government's security of supply and decarbonisation goals.

68. Poor liquidity may be explained by reciprocal externalities theory, a "market failure" whereby the market is stuck at a low liquidity equilibrium. Ofgem is currently developing proposals for interventions to enhance liquidity in GB wholesale electricity markets. However, there is a risk that Ofgem's interventions, if adopted, may not be sufficient or timely enough to meet wholesale electricity market objectives.

69. Government's objective in seeking to take powers is to gain certainty that appropriate action can be taken, if needed, to ensure cost-effective delivery of its decarbonisation and security of supply goals and contestable retail and wholesale markets. We aim to do this whilst minimising any potentially negative impacts incurred through the taking of primary powers.

70. Taking powers to improve liquidity, with constraints on using the powers is the preferred option. It contributes towards reducing barriers to entry to electricity generation and supply, while limiting negative impacts on wider regulatory uncertainty.

71. Direct costs of primary legislation could be increased costs of capital for investors in the energy sector, as a result of a perceived increase in regulatory uncertainty. Additionally, there could be impacts on Ofgem's reforms and an increase in rent-seeking activity. We judge these costs to be limited, since it would be clear that the Government is seeking back-stop powers and would work closely with Ofgem and ensure consistency with wider reforms.

72. Taking powers to support liquidity may be seen by potential investors and new entrants as insurance against the risk that market developments and Ofgem's interventions, if adopted, may not be sufficient or timely enough to allow them to appropriately manage the risks they face in the electricity market. It therefore contributes towards reducing barriers to entry to generation and retail supply, potentially reducing costs of capital, improving competition and ultimately reducing costs to consumers.

Table 9: Summary of Societal Costs and Benefits, NPV 2012-2019[14]

Costs	£0.26m
Benefits	0*
Net Benefit	**-£0.26m**

* No quantifiable benefits identified

[14] See Energy Bill 2012 Impact Assessment: Liquidity Measures https://www.gov.uk/government/publications/energy-bill-impact-assessments

3.7 Barriers to Independent Generation (Power Purchase Agreements)

73. For any power generation investment, investors will want to be certain that risks can be efficiently managed during the investment payback period. Some independent generators rely on long-term offtake contracts, known as Power Purchase Agreements (PPAs), to give lenders this certainty.

74. In July 2012 Government launched a call for evidence, now closed, aiming to improve understanding of the issues facing independent generation developers. Independent electricity generators have reported that they are finding it increasingly difficult to secure long-term contracts for sale of generation on bankable terms i.e. that costs are higher and fewer firms are submitting tenders.

75. The main rationale for taking enabling powers is that there may be market failures preventing an efficient level of investment in generation, and that these are not addressed sufficiently with existing primary powers.

76. Government's objective is to provide investors in generation with certainty that EMR will fulfil its objectives of delivering decarbonisation and security of supply goals at least cost, by ensuring efficient routes to market for independent generators. We aim to do this whilst minimising any potentially negative impacts incurred through the taking of primary powers.

77. The Secretary of State taking powers in the current Energy Bill to reduce barriers to securing long-term contracts for electricity generation is the preferred option. It can be seen as a valuable option for Government to intervene, should it become apparent, following further evidence gathering and analysis, that there are clear issues that require intervention.

78. The act of taking powers could lead to some increase in regulatory uncertainty for market participants, increasing costs of capital and potentially increasing the costs to society of meeting Government's decarbonisation and security of supply goals for the electricity sector. However, we believe such adverse impacts on uncertainty should be limited.

79. Taking powers increases the probability that Government can reduce barriers to entry to independent generation, increasing market contestability and potentially reducing the costs to society of meeting Government's decarbonisation and security of supply goals for the electricity sector.

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Table 10: Summary of Societal Costs and Benefits, NPV 2012-2019[15]

Costs	£0.26m
Benefits	0*
Net Benefit	**-£0.26m**

* No quantifiable benefits identified

[15] See Energy Bill 2012 Impact Assessment: reducing barriers to securing long-term contracts for independent electricity generation investment
https://www.gov.uk/government/publications/energy-bill-impact-assessments

3.8 Ofgem Strategy and Policy Statement

80. The Ofgem Review was a Coalition Agreement commitment. These clauses implement the main conclusion of the review: that Government will publish high-level policy outcomes for Ofgem to report against.

81. A new statutory ‘Strategy and Policy Statement’ will be established. This document will:

- Set out the Government’s strategic priorities for the gas and electricity markets
- Describe the roles and responsibilities of Government, Ofgem, and other relevant bodies, and
- Define policy outcomes that Government considers Ofgem to have a particularly important role in delivering.

82. The accompanying IA describes the rationale for intervention and explains how regulatory uncertainty has resulted from a lack of clarity over the respective roles of GEMA and Government and considers different options to reduce this.

83. The options considered in the IA are as follows:

    1. Do nothing. In this scenario, the legislative framework would remain with GEMA’s existing principal objective, statutory duties, the Guidance that the regulator must have regard to and the potential for Government, in extremis, to make specific changes to regulatory detail through primary legislation.
    2. Establish a new ad hoc ‘Power to Direct’; taking a power for the Government to define individual policy outcomes that GEMA would be legally bound to operate in line with whenever the Government saw fit and within the independence constraints imposed by the EU Third Package. The existing Guidance could be repealed.
    3. Establish a new ‘Strategy and Policy Statement’. This would mean Government periodically establishing a coherent set of policy outcomes that GEMA would be legally bound to justify their actions against, expected to remain stable over a Parliament. The existing Guidance would be repealed. This is the preferred option because it offers the most coherent, stable and predictable approach.

84. The impacts of the options are assessed on a primarily non-monetised basis, since actual costs and benefits will depend on Government policy and the regulatory decisions taken by Ofgem. This assessment is summarised below:

85. Option 1 would have a negligible impact on the issues around role clarity and accountability as, even if ways of working were improved, the underlying causes of the problems identified would remain.

86. Option 2 would, where the power is used, create greater confidence that the Government and the regulator are aligned and that this coherence would be enduring. It would also increase the regulator’s focus and, potentially, its efficiency in the policy area where Government has made the appropriate trade-offs. Although adding to the adaptability of the regulatory regime, the introduction of the ad hoc Power to Direct

could reduce predictability and give rise to unintended consequences in the market depending on how it was applied.

87. Option 3 is the preferred option as this is expected to deliver best against the policy objective of reducing regulatory uncertainty for investors in the energy sector. This reduction in regulatory uncertainty has been assessed using the BIS principles for economic regulation. As the costs and benefits to reducing regulatory uncertainty cannot be quantified, the decision has to be based on some subjectivity. Based on the evidence considered the Strategy and Policy Statement is expected to be the best option. The IA estimates that the proposal entails no net costs to business.

3.9 Ofgem Consumer Redress

88. These clauses implement the powers to allow Ofgem to compel businesses to compensate consumers for losses suffered as a result of a breach in licence conditions and other regulatory requirements. The overall objective is to help ensure that consumer interests are better protected by the enforcement system through the use of pound for pound redress payments to domestic and business consumers that have suffered losses as a result of a breach.

89. The accompanying IA describes the rationale for intervention and explains how the policy is intended to improve equity: those who have suffered losses should receive redress (by contrast fines flow to the HMT Consolidated Fund and hence to the general taxpayer purse). The options considered and evaluated post consultation are as follows:

90. Option 1: Do nothing - Ofgem would continue to seek to negotiate redress when breaches lead to consumer losses, but would lack the powers to compel businesses to provide such redress. Ofgem would continue to have the power to fine an energy business up to 10% of its annual turnover if it breaches a requirement or licence condition.

91. Option 3A[16]: Introduce consumer redress powers covering licence-holding electricity and gas businesses and other market participants with a cap on the level of penalty and redress payments. Ofgem would receive powers to obtain redress for consumers who suffer losses as a result of a breach of a licence condition or energy regulation. The present cap of 10% turnover will continue to apply to fines and also cover consumer redress payments. Therefore the combined total of fine and consumer redress payments would not exceed 10%.

92. Option 3B: Introduce consumer redress powers covering licence-holding electricity and gas businesses and other market participants. Ofgem would receive powers to obtain redress for consumers who suffer losses as a result of a breach of a licence condition or energy regulation as specified in 3A. However, there would not be a cap on the level of redress payments. Ofgem would continue to have the power to fine an energy business up to 10% of its annual turnover if it breaches a requirement or licence condition.

93. The final proposal is to introduce consumer redress powers covering licence holding electricity and gas businesses and other market participants with a cap on the level of penalty and redress payments (Option 3A). This gives Ofgem the power to fine and require redress payments to be made up to the (combined) cap of 10% of the company’s annual turnover if an energy business breaches a regulatory requirement or licence condition which results in consumer harm.

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[16] Options 2 and 4 were ruled out following consultation, and option 3 was developed into 2 separate options.

94. Under this proposal there will be a transfer to those that suffer the harm of the breach from the general taxpayer[17] which is estimated to be some fraction of annual fines (£10m) and will depend on Ofgem's specific analysis of each individual case. Society may benefit from increased social welfare (a reduction in deadweight loss), if the policy helps drive a reduction in non-compliant practices and hence a small (effective) reduction in energy prices. We do not believe there will be any costs to compliant businesses.

95. Following the consultation it was decided that the cap that applies currently to the fines Ofgem can order should also apply to the combined total of fines and consumer redress payments required by Ofgem in future. Without the cap there could be higher costs from insuring against the risk, or a higher required rate of return for investors, due to the risk of being liable for uncapped compensation payments, which could then be passed through to consumers. Due to the evidence that no fine or voluntary redress payment made to date has neared the cap we believe the small potential benefit of increased compliance and efficiency due to the additional market signal of the uncapped nature of consumer redress payment does not outweigh the costs associated with it.

96. Introducing powers covering redress for consumers with a cap on the level of penalty and redress payments (Option 3A) provides the equitable solution required of necessary consumer redress, is a proportionate response to the problem and addresses concerns raised during our consultation responses.

[17] The fine flows into the HMT Consolidated Fund

3.10 Creation of the Statutory Office for Nuclear Regulation

97. The 2008 Stone Review made clear recommendations for improvements to the UK's nuclear regulator. At that time the HSE's Nuclear Directorate was responsible for nuclear regulation. From 1 April 2011, the non-statutory ONR was set up as an agency of the HSE pending legislation to create a statutory body. Under the current arrangements the HSE Board is accountable to Ministers for the ONR.

98. The legislation the Government is proposing would make the ONR a stand alone, statutory body with a Board that is fully and directly accountable to Ministers and to Parliament. It is proposed that legislation would set out a clear governance model for the statutory ONR; provide for the appointment of a statutory Board; and transfer the statutory regulatory functions for nuclear safety, security, safeguards, and the transport of radioactive material to the statutory ONR.

99. The evaluation of the policy options are assessed in the accompanying IA. In summary two broad options were considered:

1. Retain the interim ONR with no legislative intervention; or
2. Establish the statutory ONR using legislative means.

100. The option to simply retain the interim ONR (option 1) will not result in an ONR that is more transparent, accountable, properly resourced, independent or effective. This is because legislation is needed in order to remove the remaining barriers to achieving such a regulator.

101. It is therefore proposed that the current nuclear regulator, the interim Office for Nuclear Regulation (ONR), will be placed on a statutory footing by means of primary legislation. This legislation will set out a clear governance and accountability model for the new statutory ONR and transfer the relevant statutory regulatory functions.

102. The IA estimates that the one-off costs of establishing the statutory ONR will be around £960,000.[18] Annual running costs are estimated to increase by around £13m per year compared to those incurred by the interim ONR, reflecting the need for the statutory ONR to recruit additional staff, establish its own Board and provide for itself support functions currently provided by HSE. The additional running costs are expected to be offset by around £1.3m per year from reductions in accommodation costs and other operational expenses.

103. An adequately resourced statutory ONR is expected to lead to direct benefits for nuclear operators. The IA estimates that benefits of around £3.2m per year will result from a reduction in regulatory delays of two days per year in restarting reactors after

[18] For details of costs and benefits listed in section 3.10, see Creation of the Statutory Office for Nuclear Regulation (ONR) Impact Assessment

outages. In addition, it is estimated that there would be a benefit of around £78m by reducing regulatory delays to the new nuclear programme by one month in 2018.

104. Table 11 sets out the estimated Net Present Value of the policy over an appraisal period of ten years.

Table 11: Summary of Societal Costs and Benefits, NPV 2011-2020

Costs	£56.7m
Benefits	£82.3m
Net Benefit	£25.7m

3.11 Nuclear Sites: Decommissioning and Cost Recovery

105. The Energy Act 2008 requires prospective operators of new nuclear power stations in the UK to have a Funded Decommissioning Programme (FDP) approved by the Secretary of State before nuclear related activity can begin. The Act also allows the Secretary of State to enter into an agreement that sets out the manner in which he will exercise his powers to modify an approved FDP. This is known as a Section 46 (S46) Agreement. Alongside the FDP, the Secretary of State will expect to enter into a contract with the operator regarding the terms on which the Government will take title to and liability for the operator's spent fuel and intermediate level waste for disposal in a Geological Disposal Facility (GDF). This is known as a Waste Transfer Contract (WTC).

106. DECC will require advice during the development phase of a FDP, prior to its submission, in addition to the post-submission scrutiny phase. This is to facilitate and support meaningful engagement between DECC and prospective operators while they are defining their approach to the FDP.

107. The Energy Act 2008 currently allows DECC to charge a fee to a site operator in order to recover the costs of obtaining advice in relation to an operator's FDP, upon its submission to DECC. However, the Act does not allow the Government to recover: (1) the costs incurred by DECC for advice received in relation to agreeing a WTC or agreeing a S46 Agreement, and (2) the costs incurred by DECC in relation to advice received prior to the submission of the FDP.

108. The Government intends to amend the current legislation to ensure that costs can be recovered from industry for technical, financial and legal advice that DECC procures: (1) in relation to agreeing a WTC or agreeing a S46 Agreement, and (2) prior to the submission of a FDP.

109. The evaluation of the policy options are assessed in the accompanying IA. In summary, three options were considered:

a. retain the current legislation without amendments;
b. introduce non-regulatory approaches such as (i) voluntary agreements with prospective operators or (ii) prospective operators to pay advisers directly for advice provided to the Department, and;
c. amend the legislation.

110. The option of retaining the legislation in its current state was considered and ruled out given the quite substantial costs which are likely to be incurred by the Secretary of State in obtaining this advice. Non-regulatory approaches (as indicated above) were considered however there is no guarantee that operators would be willing to enter into these types of arrangements (they would be extremely unlikely to go beyond what the current legislation provides for). Further, given that the Secretary of State requires a power to charge for the advice in question doubts may be raised as to the legitimacy of such arrangements.

111. It is therefore proposed that current legislation be amended so that the costs of advice on the wider waste and decommissioning framework and work prior to submission of an operator's FDP are recoverable, thereby removing costs to taxpayers. The proposed amendments are therefore consistent with the overall policy objective of enabling new nuclear investment in the UK without public subsidy.

112. The IA estimates that the total costs to an operator of the preferred option in NPV terms would be around £0.8 million[19] over an appraisal period of two years. The creation of the cost recovery mechanisms mean that the estimated total costs to industry represent a benefit to Government of equal value, i.e. £0.8m in NPV terms. At societal level the policy is therefore estimated to have a zero net impact as the amendments will effectively enable a transfer of costs from Government to industry.

[19] See Amendments to Part 3, Chapter 1 of the Energy Act 2008 (as amended): Nuclear Sites: Decommissioning and Clean- Up Impact Assessment (published in April 2012) https://www.gov.uk/government/publications/energy-bill-impact-assessments

3.12 Government Pipe-line and Storage System (GPSS)

113. The GPSS is used to receive, store, transport and deliver aviation fuel for the MoD and US Visiting Forces, with spare capacity utilised by commercial customers to supply important civil airports such as Heathrow, Gatwick, Stansted and Manchester. Following a review of the GPSS, it was concluded that the GPSS did not need to remain in public ownership. Because the existing rights to access the private land on or under which the GPSS runs are generally personal to the Secretary of State, primary legislation is required, the main purpose of which is to create a transferable set of rights to maintain, use and access the GPSS.

114. The IA shows that sale of the GPSS will generate a capital receipt in order to pay down Government debt and should deliver value for money. It may also enable greater commercial exploitation of the GPSS to meet the current and future requirements of civilian airports.

115. The sale is not expected to lead to increased costs to customers, since the GPSS is already operating under the same health, safety and environmental regime as private pipelines, although a purchaser may seek to increase revenues and profitability, subject to market forces.

116. Once sold, the GPSS would be operated under a similar regime to civilian pipelines constructed under the Pipe-lines Act 1962, which will ensure that a privately owned GPSS pipeline is not at a commercial advantage to its competitors.

117. The benefits of selling the GPSS include generating a capital receipt for Government and enabling increased private sector investment in the pipeline in order to increase the resilience of the system and allow even greater commercial development. Sale of the pipeline will not impact on Defence outputs.

118. The legislation allows for the transfer of the GPSS, but does not force a sale. A final decision on the sale will not be made until the Bill has been approved and the Government can be sure that it will deliver value for money. The earliest date for sale is 2014 since the sale process can only begin once the legislative provisions have been passed by Parliament and received Royal Assent.

3.13 Offshore Transmission Systems

119. In 2010, the Government decided to enable offshore windfarm developers to build their own transmission infrastructure back to shore for the export of power (the 'generator build' model). Before developers start generating power, they need to test the conveyance of electricity over their transmission assets, before transferring them to an Offshore Transmission Owner (OFTO) upon completion.

120. This measure seeks to provide an exception to the prohibition of participating in the transmission of electricity during testing of offshore transmission connections, to avoid offshore generators constructing transmission assets falling foul of the law. This change to the Electricity Act 1989 is crucial to ensure that UK offshore grid constructors can build and test infrastructure to export power without committing a criminal offence.

121. The measure is a technical change to enable the generator build model to function as intended. Implementation of the generator build model is not expected to lead to any additional costs or benefits beyond those already identified for implementation of the offshore transmission regime (see December 2010 Impact Assessment).[20] The costs and benefits associated with the regime captured in the 2010 Impact Assessment are summarised below. Since this impact assessment was conducted, Ofgem/DECC have published analysis suggesting that additional benefits are available from the coordinated development of certain transmission assets.[21] Industry, Ofgem and Government are taking forward a number of measures to further enable these additional benefits to be realised.

Table 12: Summary of Societal Costs and Benefits, NPV 2010-2029

Costs	£302-309m
Benefits	£763-1699m
Net Benefit	£461-1390m

[20] http://www.decc.gov.uk/assets/decc/Consultations/offshoreElectricityTransmission/1032-ia-extension-offshore-transmission.pdf, and the March 2009 Impact Assessment, available at http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file50576.pdf
[21] Analysis published at http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Pages/OTCP.aspx

3.14 Decarbonisation

122. Part 1 of the Energy Bill enables a 2030 decarbonisation target range to be set for the electricity sector in 2016. A decision to exercise this power will be taken once the Committee on Climate Change has provided advice on the level of the 5th Carbon Budget and when the government has set this budget, which is due to take place in 2016. If a target range is set, then in line with the regulatory requirements a full Impact Assessment (including consultation) will be undertaken. This would consider the costs and benefits to businesses and consumers across a number of scenarios representing different decarbonisation levels in 2030. The results of this analysis and subsequent consultation would then inform the level of the target that is set in law.

3.15 Consumer Tariff Amendments: Main tariff provisions

123. The majority of gas and electricity consumers do not engage in the market, which leads to the market not operating as effectively as it could, potentially resulting in higher prices for consumers. Factors that deter people include: proliferation of tariffs with complex structures (making it difficult for consumers to compare tariffs across the market) and lack of awareness of the savings to be made. Government intervention is needed to help inactive consumers benefit from cheaper tariffs and to prompt them to engage more widely in the market.

124. In its Retail Market Review (RMR), Ofgem has published final proposals to make it easier for consumers to engage in the electricity and gas retail supply markets, secure a better deal and in doing so increase competitive pressure on energy suppliers. The Government intends to support Ofgem in legislation to ensure Ofgem can implement these final proposals, without any undue delay.

125. The IA assesses the option of taking powers to limit the number of core tariffs suppliers can provide, prescribe features of tariffs and mandate suppliers to move customers on poor value "dead" tariffs to better value "live" ones, require suppliers to provide personalised information on bills about the cheapest tariff and to use common tariff comparison metrics for each tariff.

126. There could potentially be costs to some players in the market if they believe that there is increased regulatory uncertainty due to the Government taking powers in this area. However, there is already uncertainty in the retail market partly due to the length of time Ofgem has been considering reform. By taking powers Government will provide a strong signal to suppliers that it intends to act should they seek to unnecessarily delay or impede Ofgem's implementation of its final proposals. This will increase certainty in the market that action will be taken and so may encourage early implementation by suppliers so consumers benefit more quickly. We believe this outweighs any concerns that taking powers increases uncertainty. It is not possible to quantify estimates of these costs and benefits.

127. If a power is not taken now and instead delayed, an appropriate primary legislative vehicle may not be readily available. This would significantly delay any government intervention to put proposals through, in the event that Ofgem is unduly delayed or impeded in implementing their final proposals. This would result in any potential benefits to consumers being delayed unnecessarily. Also, the Government is determined to ensure that at this time when household budgets are under substantial pressure consumers are not paying unnecessarily high prices for their gas and electricity.

128. The impact of any specific interventions, if powers were exercised, would be examined separately, alongside any consultation on secondary legislation, with a full impact assessment.

3.16 Consumer Tariff Amendments: Third-Party Intermediaries

129. Third party intermediaries (TPIs), such as switching sites, are now the main source of information for domestic consumers to compare tariffs across the market. It is important therefore that consumers are assured that the services TPIs provide are independent and the information they give is clear and accurate. Ofgem has received some complaints about TPIs in the non-domestic market, and there is some frustration that there isn't a clear process to resolve such issues. Therefore Ofgem is launching a review of the regulatory framework for TPIs, which will consider whether a separate regulatory regime covering TPIs' activities would benefit consumers.

130. There is currently some uncertainty over whether or not the power for the Secretary of State to make specified activities licensable at the request of Ofgem would cover the activities of TPI such as brokering energy supply, tariff comparison. The Government's objective is to provide certainty that the activities of TPI could be licensable, so that Ofgem is able to move quickly should its review conclude that there is a case to regulate their activities for the benefit of consumers.

131. The accompanying IA describes the rationale for intervention and explains how the policy is intended to enable Ofgem to move quickly should its review conclude that there is a case for further regulation, without the risk of appeal on the basis that it does not have the power to regulate TPIs. The intended effect is to ensure TPIs work effectively and are trusted by consumers, which should encourage engagement and improve competition in the retail energy market.

132. If the Government does not clarify existing powers there would be no certainty around Ofgem's ability to apply to the Secretary of State to make an order which introduces a licence regime which covers the activities of TPIs. Ofgem could still apply to the Secretary of State, but given the ambiguity surrounding the scope of the powers, an objection could be raised which could trigger a reference to the Competition Commission resulting in the regulation being delayed.

133. By clarifying existing powers to make specified activities licensable to make them expressly clear that they cover the activities of third party intermediaries, Ofgem would be able to move quickly should its review conclude that there is a case for them to regulate their activities, without the risk of an appeal on the grounds that current powers to not cover TPIs. Licensing TPIs would allow Ofgem to place binding conditions on TPIs to ensure that they treat consumers fairly and do not mislead them.

134. If clarifying the powers were delayed until the outcome of the forthcoming review, an appropriate primary legislative vehicle may not be readily available, which could lead to a delay in the licensing of TPIs. This would not allow problems that are identified by Ofgem in its review to be resolved in a timely manner. This would result in any potential harm on consumers continuing unnecessarily and risking further distrust in the sector.

135. The costs and benefits of clarifying these powers depend on whether or not the existing powers would be deemed by the Competition Commission to cover TPIs. For

example, if the existing powers do cover TPIs then there are no costs or benefits from this clarification, or if TPIs are not presently covered, and Ofgem finds that regulation is necessary, consumers would benefit from being protected sooner than otherwise, and TPIs would experience any costs resulting from the regulation sooner than otherwise. It is not possible to estimate these costs and benefits as they would depend on the regulation that Ofgem deems necessary. The IA includes a scenario analysis that presents the different possible outcomes of options based on the uncertainty present[22].Should Ofgem request that the Secretary of State make the activities of TPIs be made licensable then an IA will be developed on the basis of the request, setting out the costs and benefits to business and consumers.

[22] See scenario analysis in paragraphs 29-31

3.17 Consumer Tariff Amendments: Electronic Information

136. The majority of gas and electricity consumers do not engage in the market, which leads to the market not operating as effectively as it could, potentially resulting in higher prices for consumers. Factors that deter people from engaging include a perception that reviewing energy options is a time consuming and complicated process.

137. This Impact Assessment (IA) examines the arguments for and against Government taking primary powers to require suppliers to provide key information to customers in a form that allows smart phones to read and use it, most typically, but not restricted to, a Quick Response (QR) code[23]. QR codes are essentially a type of bar code that includes information that can be scanned by QR code readers on smart phones, tablet computers and similar devices. QR codes combined with the appropriate development of applications means that people will be able to check the best deals and switch supplier using their smart phones.

138. The Government objective in seeking to take powers is to provide certainty that appropriate action can be taken if necessary to ensure that consumers can take advantage of beneficial technological advances being applied to the energy supply sector. These changes, if applied, should aid quicker and easier switching, increase engagement and competitive pressure on suppliers, leading to lower prices for consumers.

139. Government intervention is needed because suppliers may not have sufficient incentives to work voluntarily to provide consumers with their data in a format that will enable 'frictionless' cross market comparisons from accredited switching sites.

140. BIS is leading on work in this area and is specifically progressing QR Codes with the energy sector on a voluntary basis. The cost of developing the QR codes is being investigated by the voluntary work BIS is taking forwards with energy suppliers. They are also considering further issues such as consumer data protection, to ensure that comparisons are quick and easy, whilst still protecting data. The cost of placing QR codes on energy bills is expected to be low, with potentially higher costs involved with the development of applications that make use of QR code data.

141. DECC is working closely with BIS to ensure policy is coherent and joined up. If sufficient progress is made with the voluntary approach these powers may not need to be used.

142. Taking powers may be seen by consumers and suppliers as insurance against the risk that the voluntary approach led by BIS is unsuccessful at delivering quick and easy cross market comparison and switching. Therefore any early planning and work on implementing such technology can be taken forward with certainty, potentially resulting in benefits to consumers being brought forward. It may also enhance the opportunity for

[23] There are other similar technologies which allow smart phones to read data and upload it – i.e. Google Goggle and Blippar.

the present voluntary action in advance of any regulatory action due to the knowledge that if effective action isn't taken forward by suppliers DECC would have the power to legislate changes.

143. If taking the powers were delayed until the outcome of the voluntary approach, an appropriate primary legislative vehicle may not be readily available. This could lead to a delay in utilising the technology to benefit consumers and suppliers.

144. The impacts of any specific interventions, if powers are exercised, would be examined separately, alongside any consultation on secondary legislation, with a full impact assessment.

145. In summary, taking these powers will create greater certainty that beneficial technological advances will be implemented, support the development of these applications, and increase the likelihood of a successful voluntary solution.

3.18 Energy Resilience

146. Government is committed to working with business and regulators to reduce the likelihood of disruptions to energy and fuel supplies, and to ensure that contingency arrangements are in place to respond to emergencies when they do occur.

147. In the event of a major disruption, Government could provide support for business in the form of services (for example personnel, supplies, equipment or assets). This could be a useful tool as part of an effective response to improve the resilience of essential services in event of a disruption. Provision of these types of services comes at an additional cost and so Government may only be in a position to provide such services to business if it can recover some or all of the cost it incurs in doing so.

148. This provision will enable DECC to charge fees for providing energy resilience services in the event of a disruption or threatened disruption to energy supplies. It will allow government to recoup some or all of the costs of support services provided to businesses, and to set appropriate fees for those services.

149. At present DECC does not have the relevant powers to charge fees for provision of such services to the energy sector, unless the services can clearly be defined as commercial services.

150. The charges and/or fees for these services will be set through secondary legislation or administratively, and relevant impact assessment and consultation carried out as appropriate at that time.

3.19 Electricity Demand Reduction (EDR)

151. 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". In November 2012 the Government launched a consultation on options to capture this further potential, which closed on 31 January 2013.

152. The presence of market failures (misaligned incentives, imperfect information, undervalued energy efficiency opportunities and embryonic markets) 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. This saving is made up of avoided generation costs (including operating, carbon and fuel costs), avoided capital costs (investment in new generation plant) and avoided transmission and distribution costs.

153. Analysis undertaken with McKinsey at the consultation stage suggested there is 92 TWh of potential across domestic, industrial and commercial sectors, most of which can be achieved at a negative cost to society. This analysis provided a high level estimate of the total potential, on the basis of a top down methodology. Following the consultation. DECC has focused on the sectors which are likely to deliver a significant majority of the demand reduction. Taking a conservative approach, sector specific UK data sources have been used where they were judged to be more accurate. Refined analysis suggests the available potential for EDR is closer to 32TWh.

154. The impact assessment briefly considers the following options:

- **Do nothing** - The majority of consultation responses supported action for EDR. Given the cost effectiveness of this potential, and potential savings for society there is a strong case for intervention and therefore this is not the preferred option.
- **Non-financial policies –** the government will consider these further and report on these in the 2013 update to the Energy Efficiency Strategy.
- **Narrow financial incentive** - 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.

155. The focus of the impact assessment is on an examination of three market wide financial incentives:

- **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.

156. The analysis shows that these three market wide mechanisms should lead to equivalent net monetised benefits if the same funding level was provided; therefore the choice of delivery mechanism is driven by non-monetised benefits.

157. The Capacity Market approach is the preferred option as it builds upon a framework and institutions already in development, and targets reductions at peak and so incentivises demand reduction at times when it is more valuable. Given the uncertainty involved and the need to develop a robust evidence base, we care considering testing the effectiveness of EDR participating in the Capacity Mechanism through a pilot.

158. A Supplier Obligation is not the preferred option as 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.

159. A Premium Payment is not the preferred option as does not provide the option for as direct a trade-off with the supply side as the Capacity Market option. There is also an inability to build on institutions and frameworks already in development.

Table 13: Summary of Societal Costs and Benefits, NPV[24]

Costs	£0.09bn-£1.02bn
Benefits	£0.29bn-£3.12bn
Net Benefit	£0.19bn-£2.10bn

[24] Analysis covers the period 2017-2034. Figures discounted to 2012.

Section 4: Other Impacts

4.1 Net costs to business (including One-In Two-Out)

160. As part of the Impact Assessment process we have also applied ‘One-In, Two-Out’ methodology (OITO) to identify any new net costs to business from regulatory measures included in the Bill. For the majority of policies the individual IAs show that these are out of scope of OITO, or have zero net cost. Only the EPS measure is likely to be an ‘in’ and a new IA will be submitted to accompany the secondary legislation for EPS. This IA will get validated at the appropriate time.

4.2 Equality, Human Rights, Privacy and Justice System

161. The policy measures in the accompanying IAs are not expected to impact on equality as set out in the Statutory Equality Duties Guidance. There are also no foreseen impacts of the options on human rights, privacy, and the justice system.

Glossary

Access Land	Land not owned by the landowner on or under whose land the GPSS runs, but over which he exercises a right to pass in order to access his own land on or under which the GPSS runs.
Auction	A price discrimination mechanism for the buying/selling of goods or services by offering them up for competitive bid, taking bids, and then selling the item to realise the greatest value.
Authority	The Authority refers to The Gas and Electricity Markets Authority (GEMA) who govern Ofgem.
Balancing Mechanism	Balancing Mechanism (BM) is a reserve service contracted on-the-day by the System Operator to ensure plant with a start up time of several hours is available in the Balancing Mechanism at peak.
Baseload generation	Baseload generation generally operates continuously to serve the minimum electricity demand over a given period of time ("baseload").
Bilateral markets/contracts	A direct contract between the power producer and user or broker outside of a centralised power pool.
Buy-out price	In the context of a balancing mechanism; the buy-out price sets the rate which suppliers need to pay for additional electricity required. In the context of the RO, it is the rate licensed electricity suppliers need to pay if they do not present sufficient numbers of ROCs to meet their obligations under the RO scheme.
CAA	Civil Aviation Authority
Capacity margin	The difference between peak demand and installed capacity on the system, adjusted for probable availability at peak.
Capacity Market	A type of Capacity Mechanism in which the total volume of capacity required is estimated, and providers willing to offer capacity (whether in the form of generation or non-generation technologies and approaches such as storage or demand side response) can sell that capacity. There are several forms of Capacity Market, depending on the nature of the 'capacity' and how it is bought and sold.
Capacity mechanism	Policy instrument designed to help ensure security of supply by providing a more secure capacity margin than that which would be determined by the market without intervention.
Capacity payments	A type of Capacity Mechanism where the price paid for capacity, rather than the volume required, is set centrally.
Carbon Capture and Storage (CCS)	CCS technology captures carbon dioxide from fossil fuel power stations. The CO_2 is then transported and stored safely, offshore, in deep underground structures such as depleted oil and gas reservoirs, and deep saline aquifers.

Carbon Price Floor (CPF)	A carbon price support mechanism to support investment in low carbon generation. The Government has achieved this by reforming the Climate Change Levy (CCL) and fuel duty, to enable fossil fuels used for power generation to be taxed on the basis of their carbon content.
Cash out	The process used to settle differences between financial contracts and physical metered volumes of electricity wholesale market participants
Cash-out reform	Ofgem project to increase the accuracy of cash out prices and improve security of supply by providing greater market confidence
CEO	Chief Executive Officer
CEPA	Cambridge Economic Policy Associates
Coalition Agreement	The Coalition's programme for government, setting out agreements between the parties on various issues. Released in May 2010.
Combined Cycle Gas Turbine (CCGT)	A gas turbine that generates electricity. Waste heat is used to make steam to generate additional electricity via a steam turbine, thereby increasing the efficiency of the plant.
CNC	Civil Nuclear Constabulary
CNI	Chief Nuclear Inspector
CNPA	Civil Nuclear Police Authority
Contracts for Difference (CfD)	Agreements that provide variable premium payments on top of an underlying wholesale electricity price that ensures the generator receives a stable price. In the event the wholesale price is higher than the capped level monies may be required to be repaid.
CO_2/kWh	Carbon Dioxide emitted per Kilowatt Hour
DCNS	Director of Civil Nuclear Security
Demand Side Management	The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand.
Demand side response	Demand side response (DSR) is active, short term, reduction in consumption whereby an energy user or aggregator guarantees to reduce demand at a particular time. It can be used to help balance supply and demand in a context of significant intermittent and inflexible generation. It enables this by shifting demand from periods where demand is greater than supply to periods where supply is more plentiful - by self-supplying using local backup generation, or by not using the electricity.
Emissions Performance Standard	A back-stop to limit how much carbon the most carbon intensive power stations - coal - can emit. An Emissions Performance Standard will reinforce the existing requirement that no new coal is built without demonstrating carbon capture and storage technology.

Energy Company Obligation(ECO)	Government proposal to create a new obligation on energy companies, as from the end of 2012, which draws on the strengths of the existing energy company obligations. The priorities for ECO are: • To ensure that households who are less able to take advantage of Green Deal finance can still be supported and can improve their homes; and • Vulnerable households on low incomes, as well as those in properties that are more difficult to treat, will be a key focus of the scheme.
Energy unserved	The amount of demand within each year that cannot be met due to insufficient supply.
(UK's) Renewable energy targets.	EU target requiring that at least 15 per cent of UK energy comes from renewable sources by 2020.
Feed-in Tariffs (FiTs)	A type of support scheme that provides revenues to certain generators, such as low-carbon generators,
gCO_2/kWh	Grams of carbon dioxide produced per kilowatt hour of energy generated.
GPSS	Government Pipeline and Storage System
Grandfathering	In the context of the EPS: the ability to allow some activities or former rights to continue even though they would not technically be allowed under current conditions. In the context of the RO; it is the policy intention that once accredited the level of support generators receive does not change for the period of time that they are eligible to receive the RO.
GW	A measure of power (usually electricity) equivalent to 1,000,000 kilowatts. e.g. 1,000,000,000 W 1,000,000 kW 1,000 MW 1 GW 0.001 TW
GWh	A measure of energy (usually electricity) equivalent to 1,000,000 kilowatts for a whole hour.
Hedge	'Hedging' refers to making some kind of investment, with the objective of reducing exposure to (short-term) price movements in an asset already held. Normally, a hedge consists of taking an offsetting position in a related asset. Hedges can be either financial or physical. For example, a generator might hedge the risk of electricity price movements: • financially, by selling electricity in the forward markets or entering into long-term contracts, or • physically, by integrating with an electricity supply business, such that any downward movement in prices resulting in a loss in revenues for the generation business is offset by an increase in revenues for the supply business.

HSE	Health and Safety Executive
HSWA	Health and Safety at Work Act 1974
IAEA	International Atomic Energy Agency
Imbalance Settlement or ‘cash out’	See ‘cash out’
Interim ONR	An agency of the HSE that exercises the bodies functions in relation to the nuclear industry
Intermittency or Intermittent generation	Any generation which is inherently variable and dependent on primary power sources outside the control of generators, e.g. wind, hydro, wave, and solar.
Kilowatt-hour (KWh)	A kilowatt-hour is a unit of energy equivalent to one kilowatt (1 kW) of power expended for one hour (1 h) of time.
Low Carbon generation	Power generated from sources that produce less greenhouse gases per unit of power than traditional means of power generation.
Low Carbon Technologies	Technologies that are used to produce energy with low-carbon emissions. These include, wind power, solar power, geothermal power and nuclear power, and also technologies that prevent carbon dioxide from being emitted into the atmosphere, such as carbon capture and storage.
Megawatt Hour (MWh)	A measure of energy equal to 1000 kWh.
National Policy Statements	The Government produces National Policy Statements (NPS) that establish the national case for infrastructure development and set policy framework for the decisions on major infrastructure projects.
NPT	Treaty on the Non-proliferation of Nuclear Weapons.
Ofgem	‘Office of the Gas and Electricity Markets’ is the independent regulator for the energy sector.
OFTO	Offshore Transmission Owner. Government has put in place a new regulatory regime for offshore electricity transmission. A key element of the regime is the competitive tender process run by Ofgem to appoint OFTOs to construct (where a generator chooses not to do so itself) and own and operate the offshore transmission assets.
ONR	Office for Nuclear Regulation created under the Energy Bill
Peak load, peak demand	These two terms are used interchangeably to denote the maximum power requirement of a system at a given time, or the amount of power required to supply customers at times when need is greatest. They can refer either to the load at a given moment (e.g. a specific time of day) or to averaged load over a given period of time (e.g. a specific day or hour of the day).
Peak-load generation / Peaking plant	Peak-load generation is used to satisfy short periods of maximum demand. Typical fast-start generation such as pumped storage and open cycle gas turbines.
Plant flexibility	The ability of generation plant to respond to demand at short notice.

Premium FiT (PFiT)	A payment which generators receive in addition to their revenues from selling electricity in the wholesale market.
Power Purchase Agreement (PPA)	Agreement to purchase some pre-specified quantity of electricity over a specified future time period. Usually includes associated products such as ROCs and LECs
Reliability market approach	A market wide capacity mechanism in which all providers willing to offer reliable capacity (whether in form of generation, storage or demand response) receive payment for doing so. In times of scarcity/high prices, they repay any revenues above a "strike price" to the counterparty to the contract – in effect exchanging high revenues in times of scarcity for a steady revenue stream.
Renewables	Energy resources, where energy is derived from natural processes that are replenished constantly. They include geothermal, solar, wind, tide, wave, hydropower, biomass and biofuels.
Renewable Obligation Certificate (ROC)	A Renewable Obligation Certificate (ROC) is a green certificate issued to an accredited generator for eligible renewable electricity generated within the UK .
Renewables Obligation (RO)	The UK's current scheme to incentivise large scale investment in renewable generation. An obligation on licensed electricity suppliers to provide a set number of Renewable Obligation Certificates (ROCs) per MWh of electricity supplied in the UK.
Reference Price	The underlying price used to assess Contracts for Difference payments, relative to the strike price.
Reserve Capacity	Capacity in excess of that required to carry peak load.
Security of supply	The certainty with which energy supplies (typically electricity, but also gas and oil) are available when demanded.
'Slippery Slope' (over-procurement)	If being in the capacity mechanism and receiving a capacity payment is more attractive than remaining wholly in the market, it could lead to lack of investment outside of the mechanism, meaning that the central body has to procure ever more generating capacity.
State Aid	Requirement of the EU Treaty to ensure that government interventions do not distort competition and trade inside the EU. In this respect, state aid is met where there is a transfer of state resources, which provides a selective advantage and has the potential to distort competition and trade.
Strategic reserve	Strategic Reserve is an amount of reliable capacity which is held outside the electricity market apart from under certain, exceptional conditions.
Strike price (CfD)	The CfD works by stabilising revenues for generators at a pre-agreed price level known as the 'strike price'. Generators will receive revenue from selling their electricity into the wholesale market as usual. However, when the market reference price is below the strike price they will also receive a top-up payment for the additional amount. Conversely if the reference price is above the strike

	price, the generator must pay back the difference.
System Operator (SO)	The System Operator (SO) is responsible for ensuring the electricity system remains balanced within each half hour period. Generators may generate more or less energy than they have sold; customers of suppliers may consume more or less energy than their supplier has purchased.
Targeted capacity mechanism	Under a targeted capacity mechanism, capacity payments are only made to those generators that provide the additional capacity needed to make up any anticipated shortfall in the capacity margin.
tCO_2	Tonne of carbon dioxide
Wholesale electricity price	The price of electricity sold directly from generators, generally sold at lower rate than retail prices.
2050 targets	The UK target to reduce our carbon emissions by 80 per cent below 1990 levels by 2050.