National Grid EMR Analytical Report

December 2013

Final report with results from work undertaken for DECC in order to support the development of Strike Prices under Feed in Tariffs with Contracts for Difference (CfD) for renewable technologies.

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[1] https://www.gov.uk/government/news/national-grid-and-decc-publication-memorandum-of-understanding-and-management-of-information-agreements

National Grid EMR Analytical Report

1. Executive Summary

This report summarises the modelling analysis undertaken by National Grid in its role as the designate Electricity Market Reform (EMR) Delivery Body and is published as an appendix to the Department of Energy & Climate Change's (DECC) December Delivery Plan document.

1.1 Electricity Market Reform

Due to plant closures and the need to replace and upgrade the UK's electricity infrastructure, over the next decade the UK electricity sector will require significant capital investment. The Government's EMR programme provides an ambitious package of measures to incentivise the investment needed to replace the UK's ageing electricity infrastructure with a more diverse and low-carbon energy mix. Up to £110bn of capital investment is needed from now until 2020.

The Government's objectives for EMR are to:

- Ensure a secure electricity supply
- Ensure sufficient investment in sustainable low-carbon technologies and
- Maximise benefits[2] and minimise costs to taxpayers and consumers.

The transitional arrangements from the Renewable Obligation (RO) to the Feed in Tariff with Contract for Difference (CfD) support mechanism aim to prevent a hiatus in renewable investment while the new arrangements are being put in place. Proposals for these arrangements were set out in the RO Transition Consultation published on 17 July 2013, to which Government expects to issue a response in January 2014.

1.2 Requirement for analysis

A key component of the Government's EMR package is the setting of the prices that will be paid to low carbon generation under the CfD. These Strike Prices are intended to incentivise sufficient investment to meet the Government's objectives (see section 2.2) whilst remaining affordable to consumers.

To inform the setting of Strike Prices the Government requires analysis of a number of policy option scenarios for the July draft Delivery Plan. The Government also asked for their policy choice scenario to be "stress tested" against a number of key uncertainties (e.g. technology costs, fossil fuel prices and electricity demand) to ensure that policy objectives can be achieved.

In addition to helping inform the setting of Strike Prices, analysis is also required to assess the likely requirement of capacity to maintain security of supply in each of the scenarios.

[2] Compared to other policies, such as the Renewables Obligation, which could allow the UK to meet our legal obligations under the Renewable Energy Directive and the Climate Change Act.

1.3 National Grid's Role

To inform the Government's decisions on Strike Prices and the Capacity Market, National Grid, in its role as the designate EMR Delivery Body, will provide evidence and analysis to the Government. National Grid's electricity market knowledge and expertise will help to ensure that the analysis and evidence that inform Government's decisions are robust. National Grid already has the technical expertise, modelling, commercial and financial capabilities; and has expanded its capacity in these areas to take on this task.

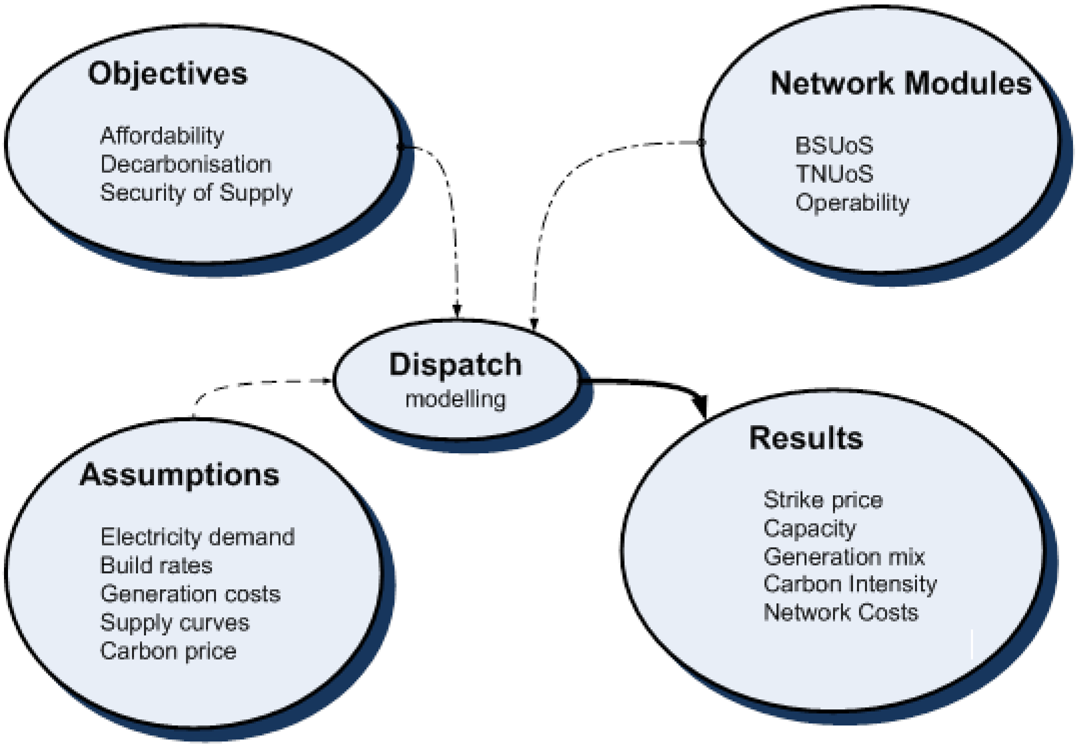
The CfD will apply to Northern Ireland as well as Great Britain and in order to carry out the analysis for the Single Electricity Market in Northern Ireland effectively, National Grid has worked with the System Operator Northern Ireland (SONI) and the Department of Enterprise Trade & Investment (DETI).

1.4 Modelling Process

A key aim of the analysis to date has been to help the Government understand how different scenarios (see section 5.2) would impact on its objectives and ambitions, so that it can take informed decisions. As such, the modelling brief[3] set out the Government's objectives for EMR, as well as describing the analysis to be carried out, including the data, assumptions, models and scenarios to be used or developed. The Government also provided guidance on the inputs and assumptions to National Grid during the course of the analytical process and worked closely on the development of a range of decarbonisation scenarios to model.

The following diagram illustrates the relevant inputs and outputs from the modelling. The objectives and assumptions have been provided by DECC with the analysis being undertaken by National Grid, including the development of supplementary models such as the network models. For network infrastructure costs, the modelling focuses on transmission-related costs as this is the main infrastructure needed to connect large scale generation. Therefore, the term "network costs" in this document refers only to TNUoS, BSUoS and inertia costs (not distribution network costs).

[3] See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65639/7081-electricity-market-reform-annex-e.pdf for the commission to the System Operator. See Annex A to the December Delivery Plan for details on the modelling process (https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan).



During the modelling phase the scenarios investigated offered a range of likely generation build outcomes which are intended to meet the required decarbonisation, security of supply and affordability levels as set out by Government policy.

The principal modelling tool National Grid has used is a fully integrated power market model, the Dynamic Dispatch Model (DDM). The model enables analysis of electricity dispatch from power generators and investment decisions in generating capacity to at least 2030. The model runs on sample days, including demand load curves for both business and non-business days. Investment decisions are based on projected revenue and cash flows allowing for policy impacts and changes in the generation mix and interconnection capacity. The full lifecycle of power generation plant is modelled through to decommissioning, and account taken of the risk and uncertainty involved in investment decisions.

In order to provide the most complete view of the implications of the alternative scenarios (see section 5.2), National Grid has also built models to analyse network development and operational costs and has advised on relevant System Operator issues.

In addition to the modelling process itself, extensive stakeholder engagement was undertaken before and during the analysis phase to inform the industry about the modelling process and how it will provide important evidence for the Government.

1.5 National Grid analysis delivery timeline 2013

The process and analysis followed a co-development path with both DECC and National Grid working closely together at a working group level to consider demand, generation and networks. This work was overseen by an Analytical Steering Group jointly chaired by DECC and National Grid.

The work was carried out between October 2013 and December 2013 and builds on the analysis that was undertaken for the July draft Delivery Plan[4] and consultation responses (see Electricity Market Reform Delivery Plan: Summary of Responses and Government Response to the July 2013 Consultation[5]), which were analysed by DECC and NERA (on the cost of capital)[6].

The following timeline illustrates the key milestones over the modelling phase of the work from the initial Call for Evidence to the December Delivery Plan.

- Call for Evidence report February
- NG July draft Delivery Plan analysis March to July
- NG July draft Delivery Plan report to DECC July
- July draft Delivery Plan consultation July to September
- NG December Delivery Plan analysis October to December
- NG December Delivery Plan report to DECC December

For a more detailed timeline please see chapter 3 section 3.1.

Throughout the analysis DECC's Panel of Technical Experts (PTE) have scrutinised the analysis to ensure the process is fit for purpose.

1.6 Summary of results and key conclusions

Below we summarise the key results to 2020 from our analysis:

- The percentage of renewable electricity in 2020 ranges between 30% and 36% across the scenarios.

- The Levy Control Framework (LCF) spend in 2020/21 ranges between £6.5 billion and £7.6 billion (2011/12 prices) across the scenarios.

- Three main technologies will contribute most to renewable electricity in 2020:
    - Offshore Wind - GB capacity between 8.1 and 15.0 GW.
    - Onshore Wind - GB capacity between 11.3 and 13.7 GW (of which Scottish Islands provide 0.4 to 0.7 GW).
    - Biomass Conversions – GB capacity between 1.7 and 3.4 GW.

- The modelling projects that later phases of offshore wind projects signing contracts up to 2020 add a further 5.3GW of offshore wind deployment shortly after 2020.

- GB network costs range from £3.9bn to £4.6bn in 2020, with the exception of the High Offshore Deployment scenario, which has higher costs of £4.9bn in 2020 due to the extra costs of connecting offshore wind and increased balancing costs. However, network cost figures include investment needed to replace ageing assets, which are independent of EMR and policies to promote low-carbon generation.

[4] https://www.gov.uk/government/consultations/consultation-on-the-draft-electricity-market-reform-delivery
[5] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan
[6]https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan

2. Introduction-Electricity Market Reform

2.1 Structure of Report

Chapter 2 gives an introduction to EMR and National Grid's involvement. Chapter 3 of the report aims to describe the modelling and the tools used. Chapter 4 gives details of the input assumptions to the modelling and the ambitions to achieve. Chapter 5 of the report describes the individual scenarios. Chapter 6 contains the results from the scenarios modelled along with conclusions.

2.2 EMR Objectives summary

The Government's current objectives for energy policy are:

- Energy security: to ensure that UK businesses and consumers have secure supplies of energy, for light and power, heat and transport;
- Climate change: to lead the UK Government's efforts to prevent dangerous climate change, both through international action and through cutting our own greenhouse gas emissions. The UK has legally binding targets to cut our emissions by at least 80% by 2050[7], and to source 15% of our energy from renewable sources by 2020;
- Affordability: deliver secure, low-carbon energy at least cost to consumers, taxpayers, and the economy as a whole;
- Support growth: deliver the EMR policies in a way that maximises the benefits to the economy in terms of jobs, growth and investment, including by making the most of the UK's existing oil and gas reserves and seizing the opportunities presented by the rise of the global green economy;
- Fairness: ensure that the costs and benefits of the EMR policies are distributed fairly, so that we protect the most vulnerable and fuel poor households are protected and to address any competitiveness problems faced by energy intensive industries; and
- Manage the UK's energy legacy safely, securely and cost effectively.

The Annual Energy Statement 2013[8] sets out the Government's energy policy framework.

Due to plant closures and the need to replace and upgrade the UK's electricity infrastructure, over the next decade the UK electricity sector will require significant capital investment. The Government's Electricity Market Reform (EMR) programme provides an ambitious package of measures to incentivise the investment needed to replace the UK's ageing electricity infrastructure with a more diverse and low-carbon energy mix.

[7] The Climate Change Act 2008 established a legally binding target to reduce the UK's greenhouse gas emissions to at least 80% below 1990 base levels by 2050, and to achieve a 50% reduction in emissions over the 2023-27 period.
[8]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/254250/FINAL_PDF_of_AES_2013_-_accessible_version.pdf

EMR will provide the tools to help meet these objectives by:

- 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 supply shortages.
- Encouraging sufficient investment in low-carbon technologies to put us on a path consistent with our EU 2020 renewables targets and our legally binding target to reduce carbon emissions by at least 80% of 1990 levels by 2050.
- 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.

The elements of EMR covered in National Grid's EMR work:

- A mechanism to support investment in low-carbon generation: the Feed-in Tariffs with Contracts for Difference (CfD).
- A mechanism to support security of supply in the form of a Capacity Market.
- The institutional arrangements to support these reforms for example the CM auctions.

2.3 National Grid (System Operator) Involvement

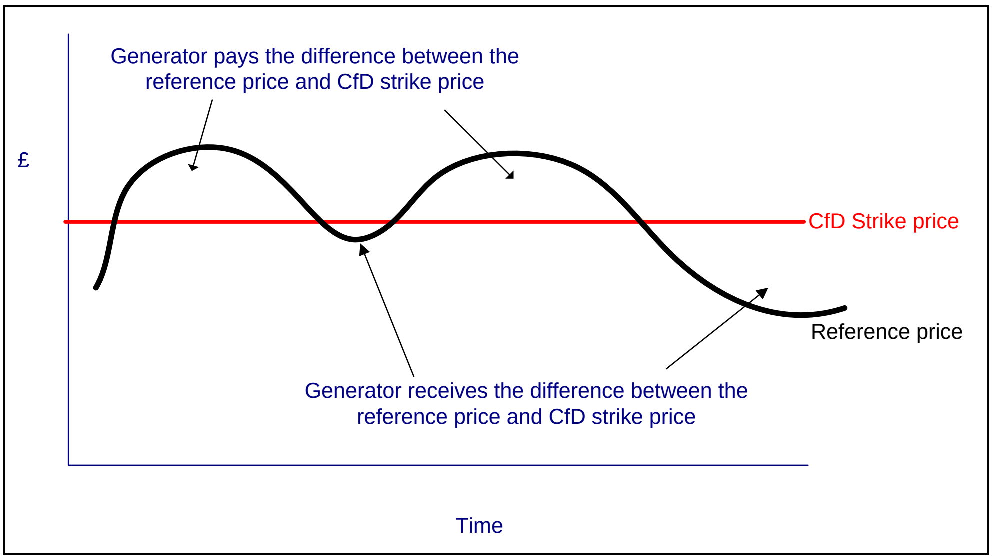
To inform the Government's decisions on CfDs and the Capacity Market, National Grid, as the System Operator, will provide evidence and analysis to the Government. National Grid's electricity market knowledge and expertise will help to ensure that the analysis and evidence that inform Government's decisions are robust. National Grid already has the technical expertise, modelling, commercial and financial capabilities and skills; and has expanded its capacity in these areas to take on this task.

In order to carry out the analysis for the Single Electricity Market in Northern Ireland effectively, National Grid has worked with SONI and DETI.

2.4 Contracts for Difference overview

Contracts for Difference are long-term contracts between the CfD counter-party and eligible generators. These are funded by contributions from licensed electricity suppliers to provide stable and predictable revenues for companies to invest in low-carbon electricity generation.

Illustration of how the CfD mechanism will operate:



The CfD works by stabilising revenues for generators at a fixed price level known as the Strike Price. Generators will receive revenue from selling their electricity into the market as usual. However, when the market reference price is below the Strike Price they will also receive a top-up payment, via the counter-party body, from suppliers for the additional amount. Conversely if the reference price is above the Strike Price, the generator must pay back the difference.

2.5 Stakeholder engagement

National Grid has engaged with stakeholders to explain its role in relation to EMR and participated in industry wide groups such as the CfD Expert Group. We have explained our modelling approach in a number of industry forums and by presentation at a number of conferences and seminars. Additional areas of National Grid's stakeholder engagement relating to the EMR modelling work are highlighted in the sub-sections below.

2.5.1 Call for Evidence (CfE)

In order to support the development of Strike Prices under the CfD for renewable technologies, National Grid launched a call for evidence (in late 2012) under EMR. The call for evidence was specifically to ensure that National Grid took into consideration the most recent and relevant technology costs, and economic assumptions for the setting of Strike Prices for CfDs.

National Grid therefore invited responses from all stakeholders to ensure the latest information was utilised and combined with DECC's generation data. The resulting generation cost data then fed through to the analysis thus ensuring the first phase of Strike Price setting under CfD[9] [10] was supported by robust economic assumptions and new data evidence.

[9] http://www.nationalgrid.com/NR/rdonlyres/F6CF8344-D00B-4335-A86F-871BB2E3D248/56915/NGEMRCallforEvidenceFinal91012.pdf
[10] http://www.nationalgrid.com/uk/Electricity/Electricity+Market+Reform/

2.5.2 Industry meetings on technology costs

National Grid attended a number of wider industry meetings, in order to achieve greater understanding on technology costs.

2.5.3 July Draft Delivery Plan consultation and workshops

The Government consulted on draft Strike Prices between 17th July and 25th September. As part of this process, the Government held a number of public stakeholder engagement workshops, which were used as a forum to take stakeholders through the strike price setting methodology and to seek feedback on the wider draft Delivery Plan. National Grid attended these events and provided clear guidance to stakeholders on how they had modelled Strike Prices.

The Government also received a number of written consultation responses as part of the process (over 120 in total). These were thoroughly analysed by the Government, who made recommendations on input and assumption changes to be used by the System Operator in setting final Strike Prices.

2.6 Devolved Administrations

National Grid has met with the Devolved Administrations to keep them abreast of progress with the modelling work and gain their feedback.

National Grid has also worked with the SONI and DETI as appropriate to ensure that the analysis properly covers the differences between the GB and Northern Ireland electricity markets. This will help inform Northern Ireland Ministers in their decision on giving consent to CfD Strike Prices in Northern Ireland.

2.7 Generation costs

The results of the National Grid Call for Evidence were combined with similar generation cost data collected by DECC to produce the aggregated cost information utilised in the modelling.

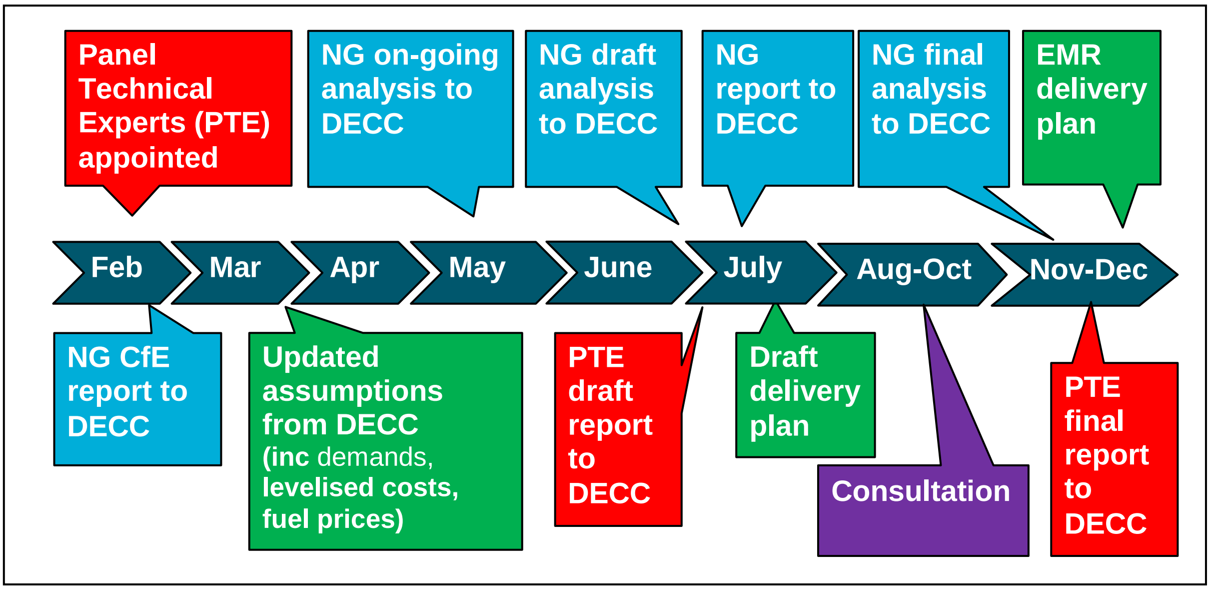
As part of the consultation process these costs were reviewed and incorporated the results of a study on technology investment hurdle rates carried out by NERA[11]. This resulted in a change to the generation technology costs which has been reflected in the December Delivery Plan analysis. For more detailed on these costs please see Chapter 4.

[11] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan

3. The Modelling Approach

3.1 National Grid analysis delivery 2013

The work for the December Delivery Plan was carried out between October 2013 and December 2013 and builds on the analysis from the July draft Delivery Plan[12] and consultation responses.



National Grid also gave advice and challenges on System Operator issues, this being an underlying benefit of National Grid's involvement. There has been a good relationship built between National Grid and DECC assisted by regular planned and ad-hoc meetings from senior stakeholder level to the analytical working groups. The areas involved in the analysis and research have drawn on expertise in many areas across National Grid.

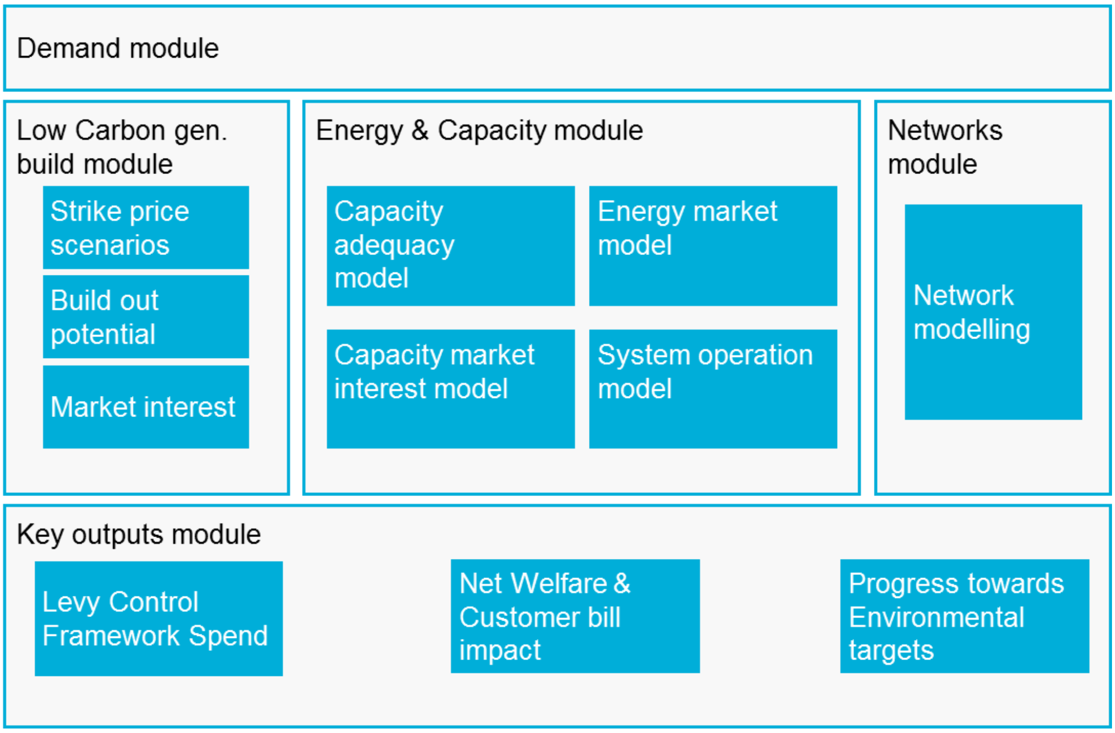
3.2 High level Process

The modelling approach is guided by the policy backdrop and in particular the objectives set by Government regarding the "trilemma" of decarbonisation, security of supply and affordability. Modelling aims to address a series of questions relating to:

- the cost, level of support required and build potential of new low carbon generation
- the level of capacity that will be required to meet security of supply and system operability
- network cost implications

[12] https://www.gov.uk/government/consultations/consultation-on-the-draft-electricity-market-reform-delivery

To answer these questions a suite of models has been developed including the DDM[13] provided by DECC, and in-house National Grid built models. The following concept diagram illustrates some of the areas considered when developing the models.



National Grid carried out analysis for DECC to explore the implications of a number of Strike Price scenarios for delivery of Government policy. These illustrate scenarios that the Government could use to guide Strike Price setting and sensitivity analysis that brings out the risks associated with the underlying assumptions. This final set of scenarios is described in chapter 5 with results in chapter 6.

The demand used in the modelling is based on DECC's latest Updated Energy Projections[14] (see section 3.3).

The low carbon generation build, energy and capacity and key outputs modules in the above diagram are covered by the DDM. The DDM uses aggregated cost information for each technology based on a combination of National Grid's Call for Evidence and DECC levelised cost consultations. The DDM calculates, given a set of inputs, the build rates for each generation technology including closures where plant is no longer profitable. The modelling assumes that a Capacity Market will be introduced for delivery year in 2018/19 in line with Government policy.

The networks module considers the network costs associated with each scenario and how it will change over time depending on the level of new build. We also model the balancing costs, including system inertia issues for each scenario.

[13] https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm
[14] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2013

3.3 Electricity Demand Projections

The UK energy demand projections up to 2030 come from the DECC Energy and Emissions Model. This projects demand for energy using a series of equations that relate energy demand to its key drivers such as projected energy prices, GDP growth and the estimated impacts of current policies. The DDM projects wholesale prices for a given electricity demand. These two models can then be used together to project electricity demand for an equilibrium where prices and demand balance.

The projections take into account the impact of all policies where funding has been agreed and where decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made. The policies that will be put in place to deliver the fourth carbon budget are still under development. Therefore the projection for the fourth carbon budget period represents a scenario in which there is no extension of existing policies or introduction of new policies after 2022 and will provide the baseline against which the Government will consider further opportunities to reduce emissions over the 2020s. It is important to note that policy development beyond the current set of firm and funded policies will affect demand patterns over the 2020s.

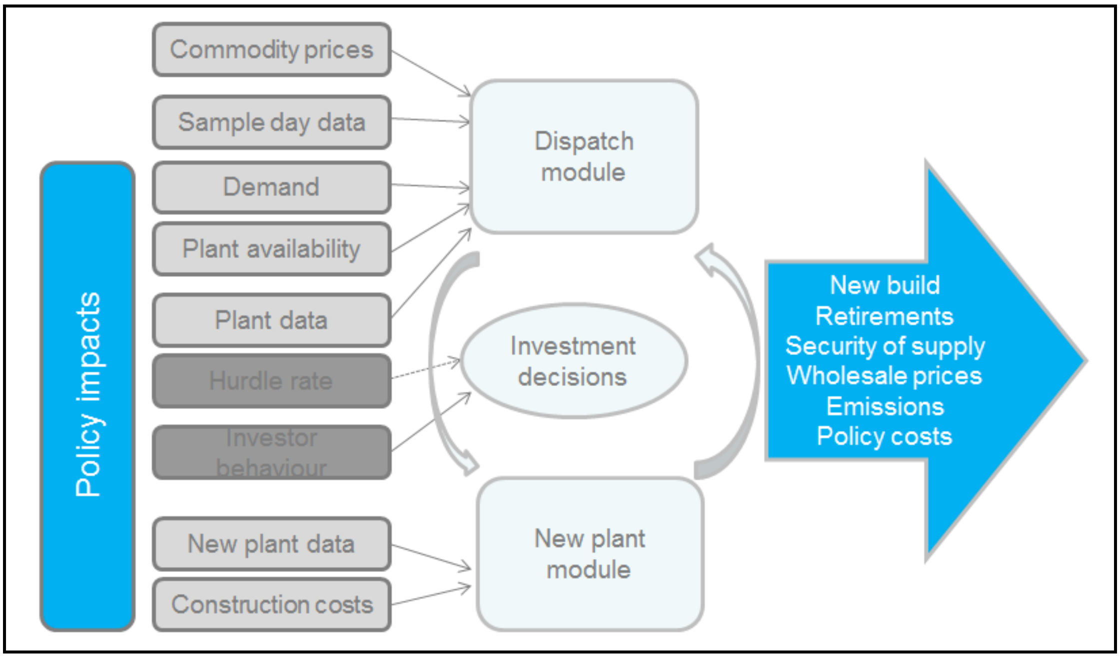
DECC publishes Updated Energy and Emissions Projections annually. The last full set of projections was published in September 2013[15]. The analysis in this report makes use of these updated projections. For more detail please see Annex section 2 (GB electricity demand).

[15] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2013

3.4 Electricity Supply Modelling

3.4.1 Overview

The DDM is an electricity supply model, which allows the impact of policies on the investment and dispatch decisions to be analysed. The diagram below illustrates the high level structure of the model.



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

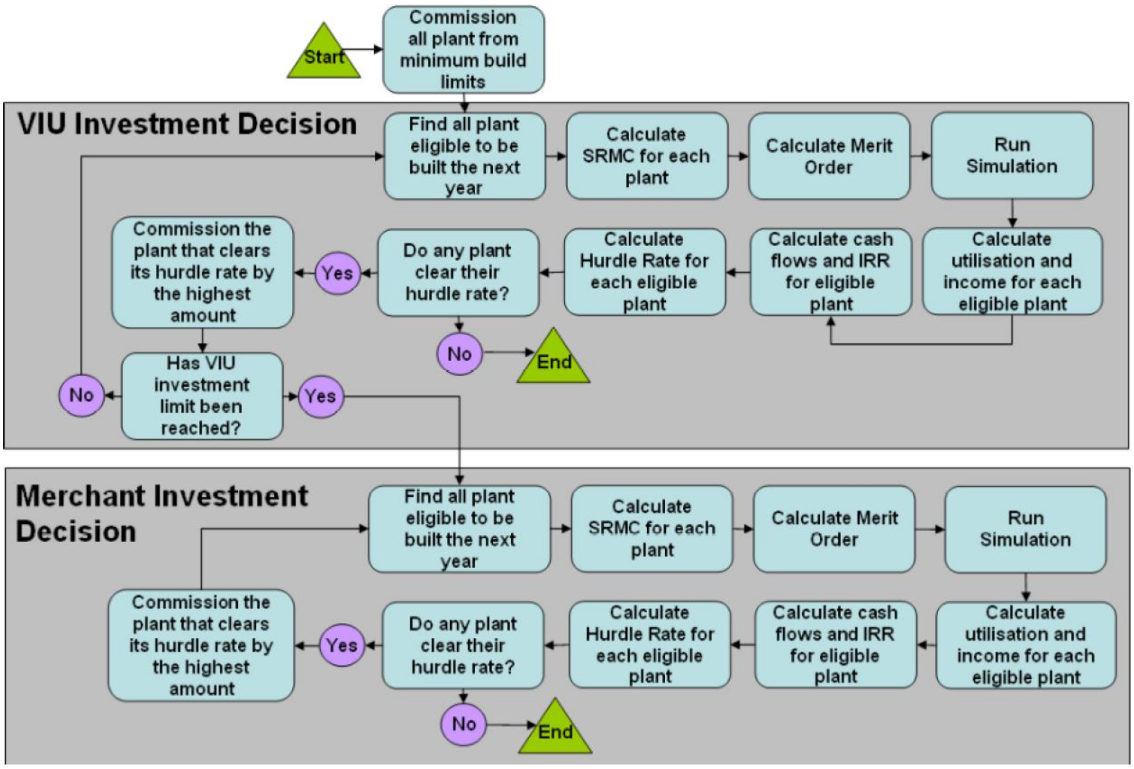
3.4.2 Dispatch Decisions

Economic, energy and climate policy, generation and demand assumptions are external inputs to the model. The model runs on sample days, including demand load curves for both business and non-business days. For more details see the Annex section 2 (GB electricity demand). The generation data includes plant availabilities (incorporating planned and unplanned outage rates), efficiencies and emissions. The modelling of energy unserved also considers the probabilities around demand, generation and loss of load expectations.

The Short Run Marginal Cost (SRMC) for each plant is calculated and determines a generation merit order taking into account support payments. Demand for each sample day is then calculated taking interconnector flows, pumped storage, autogeneration and wind generation into account. Once the level of demand and system reserve has been determined, the system SRMC is calculated by matching the demand and reserve against the generation merit order and taking the SRMC of the marginal plant which meets this. The wholesale price is equal to this marginal price plus a mark-up. The mark-up is derived from historic data and reflects the increase of system price above marginal costs at times of tight capacity margins. Plant income and utilisation are calculated and carbon emissions, unserved energy, and policy costs are reported.

3.5 Investment Decisions

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



3.5.1 Levelised Costs

Levelised Energy Cost, also known as Levelised Cost of Energy (LCOE), is the price at which electricity must be generated from a specific source to break even over the lifetime of the project. It is an economic assessment of the cost of the energy-generating system including all the costs over its lifetime i.e. initial investment, operations and maintenance, cost of fuel, cost of capital, and is essential in calculating the costs of generation from different sources.

Generation costs will vary across projects which the model takes into account (see section 4.1). Generation costs are also uncertain, especially further into the future and to take account of this we have run different technology cost scenarios (see chapter 5).

The underlying LCOE data from DECC's Electricity Generation Costs December 2013[16] report is used as input into the DDM.

3.5.2 Policy Tools

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

3.5.3 Outputs

The model outputs many metrics on the electricity market and individual plant that enables the policy impacts to be interpreted.

The DDM therefore enables analysis to be carried out on policy impacts in different future scenarios, allowing comparisons of the impacts of different potential policies on the electricity market.

3.6 Network modules (extra to the DDM model)

The DDM model does not contain all the System Operator elements. In order to cover these additional areas National Grid has used external software and in-house designed and built models. The models use DDM outputs on the capacity/generation mix as inputs and present results for each separate area of interest. These areas include Transmission Network Use of System (TNUoS) charges, System inertia costs and Balancing Services Use of System (BSUoS) charges (see sections below for explanations of these).

These models do not inform Strike Prices but give an idea of how these costs change with EMR policy. There will be a degree of overlap between these network models and the allowance for use of system charges already included as generator costs in the DDM.

[16] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections

National Grid has provided DECC with copies of all non-licensed models being used for this purpose.

3.6.1 Transmission Network Use of System model

TNUoS charges recover the costs of transmission network investment and maintenance costs incurred by all GB Transmission Owners[17]. The current charging methodology splits the recoverable amount between generation and suppliers in the ratio 27% to 73%

The purpose of TNUoS tariffs is twofold; firstly to reflect the impact that transmission users at different geographical locations have on transmission costs; and secondly to recover the total allowed revenue of the transmission licences. The specific charges for generators and suppliers vary locationally based upon the incremental cost of investment to facilitate additional generation or demand[18]. Some generator charging zones have a negative wider locational element of the TNUoS charge, this provides a signal of the impact of generation in this area of the network.

Generator TNUoS tariffs are currently made up of four components set out below although this may be subject to change as a result of Project TransmiT. The sum of these forms the total TNUoS tariff for a generator:

- Wider Locational - A locational zonal tariff that reflects the cost of providing incremental capacity on the onshore transmission network.

- Local Circuit - A locational nodal tariff that reflects the cost of the transmission circuits from the point of connection to the main interconnected transmission system.

- Local Substation - A locational nodal tariff that reflects the cost of the transmission substation where the generator is connected.

- Wider Residual - A non-locational tariff that ensures the correct revenue is recovered from generation users.

The DDM model is non-spatial and therefore does not take into account the variability of TNUoS charges by generator location. In order to address the spatial element, the TNUoS model was built in-house by National Grid as an addition to the DDM. The TNUoS model contains the Transmission Owner (TO) Allowed Revenues agreed with Ofgem in the final RIIO proposals[19] and a relevant cost associated with Offshore Transmission Owners (OFTOs) based on an average cost per kW for known projects. National Grid does not forecast the revenue past 2021 and in order to provide this detail for the model a projection has been used based on project TransmiT[20].

Differences in generation build rate assumptions require allowed revenues in the model to be revised. There is a ratio of fixed and variable revenue, meaning that only a proportion of the TO revenue can change depending on the generation build compared with National Grid's Gone Green scenario as used for the latest regulatory

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[17] NGET, SHET, SPETL, and SPT have a fixed and variable revenue split. OFTO revenue is 100% variable.
[18] http://www.ofgem.gov.uk/Sustainability/Environment/Policy/SmallrGens/CommArrg/ChgsandEmbdded/Pages/ChgsandEmbdded.aspx
[19] https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf
[20] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-impact-assessment-cmp213-options

RIIO proposals. For more details on Gone Green please refer to the RIIO proposals or National Grid's Future Energy Scenarios document[21]. OFTO revenue in the model is treated as completely variable as connections are assumed to be point to point. For example, a reduced generation build scenario that requires less transmission investment, will result in a decrease in the amount of variable transmission revenues to be recovered through TNUoS.

The TNUoS model uses the DDM output generation capacity mix, which it compares to the Gone Green generation capacity mix, and calculates a revised allowed revenue for the Transmission Owners. These revenue changes are reflected in the TNUoS charges and the model provides average charges for Scotland, England and Wales, and Offshore for the years 2012-2030. The output of the TNUoS model feeds into the total network costs.

In summary, the total transmission costs that TNUoS charges will need to recover in the future will be sensitive to changes in both generation and supply. For the EMR analysis, the TNUoS model demonstrates how this total cost varies with increasing generation on the network and different mixes of generation type.

3.6.2 Balancing Services Use of System model

BSUoS charges are paid by suppliers and generators based on their energy taken from or supplied to the National Grid in each half-hour Settlement Period. These charges are paid to cover the costs of keeping the system in electrical balance and maintaining the quality and security of supply. Currently the cost ratio is split 50:50 between generators and suppliers.

The BSUoS cost forecast model is contained within an add-on to the DDM. BSUoS cost forecast estimates within the add-on model are split into the component parts that the System Operator currently procures[22].

3.6.3 Operation of Transmission Congestion Model

A transmission constraint is a restriction on power flow across a part of the transmission system. A transmission constraint occurs when there is too much electrical power attempting to flow along a circuit than that circuit is rated to carry. A transmission constraint can also occur if the system operator determines that if a credible fault were to occur on a particular circuit, then other circuits would be overloaded by the resultant change in the power flow.

The System Operator must manage the power flows on the grid to avoid constraints occurring. The system operator aims to resolve a constraint in the most economic and efficient manner, and has various tools available to achieve this; a usual option is to restrict generation 'behind constrained boundaries', and replace that restricted generation by instructing generators to run on unconstrained parts of the network. The cost associated with this type of action can be executed through contracts/trades with generators, or at real-time in the balancing mechanism[23]

[21] http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/61591/UKFES2013FINAL3.pdf

[22] Frequency Response, Reactive Power, Fast Start, Black Start, BM Startup, Fast Reserve, Operating Reserve, STOR (short term operating reserve), Energy Imbalance, SO to SO trades, Operational inter-trips, Commercial inter-trips, Contracts, Balancing Mechanism (BM) constraints, Max. Gen service, Forward trades, downward regulation, and Inertia management.

[23] http://www.elexon.co.uk/knowledgebase/what-is-the-balancing-mechanism/

The cost components related to transmission constraints are calculated using the results from a software package Plexos[24] which simulates market dispatch and constraint resolution in the balancing mechanism. Three scenarios have been simulated using this software covering different generation mixes; for example, connected wind. The final constraint cost in any particular DDM scenario is then a derivation of the costs taken from the simulations, matching the results from the DDM scenario to the simulated scenarios.

3.6.4 Inertia Model

A certain level of inertia is required on a power system in order to limit the rate at which the frequency falls following a fault caused by a large loss of generation. Thus it avoids activating "Rate of Change of Frequency" protection that small generators commonly use to detect when the generator has been disconnected from the system. Sufficient inertia has historically been provided by stored mechanical energy in rotors of spinning synchronous generators and rotors of spinning motors on the demand side without the grid operator needing to intervene. Both of these provisions are reducing due to more non-synchronous generation becoming prevalent (for example, wind turbines which do not provide inertia), and less demand-side inertia (for example, due to traditional synchronous motors being replaced by electronically driven motors, and a fall in demand from manufacturing industry).

The System Operator can take actions to mitigate against low inertia, such as bidding down generation to reduce the level of the largest credible generation loss, or bidding off generation which contributes low inertia, and replacing it with generation which contributes high inertia. National Grid has developed a model that calculates, given a mix of generation, the level of curtailment required due to insufficient inertia on the system at any point in time, both in volume and cost.

3.6.5 Incorporation of network costs in EMR analysis

The network costs (TNUoS, BSUoS and Inertia) are included in the cost benefit analysis for the EMR impact assessment. They are included alongside the DDM's generation costs (i.e. generator capital, operating, fuel and financing costs). These network costs capture some costs and growth in costs that the DDM's generation costs (also included in the cost-benefit analysis) are unlikely to capture. These costs are:

- Network costs borne by suppliers (the DDM's generation costs are costs paid by generators only)
- BSUoS paid for by non-renewable generators
- Inertia costs[25]

National Grid's network costs are therefore an important enhancement to DECC's EMR cost benefit analysis. However, it is recognised that a small proportion of these network costs will overlap with the generation costs.

[24] http://www.energyexemplar.com/software/
[25] Inertia costs are included in the BSUoS costs (mentioned separately due to the modelling required)

3.7 Modelling Northern Ireland Generation

3.7.1 July Draft Delivery Plan Analysis

For the July draft Delivery Plan, SONI was tasked with modelling the likely build and dispatch of low carbon technologies in Northern Ireland in response to CfDs based on its view of capacity evolution. Generators in Northern Ireland (NI) over 10MW participate in the All Island Single Electricity Market (SEM), and dispatch differently from similar plant situated in GB. Through detailed market modelling of the SEM, SONI projected dispatch of NI generators under a number of scenarios as agreed with National Grid and DECC. In this section we summarise the methodology used.

A detailed market model representing the SEM was developed to project generation volumes and wholesale price, used to calculate the reference price. Capacity assumptions were developed using the most credible public sources available, and kept consistent with the scenarios modelled by National Grid. Strike Prices consistent with National Grid's modelling were then used exogenously to calculate the CfD support for low carbon generators from 2017/18 onwards.

SONI used Plexos for Power Systems[26] software to model generator dispatch at an hourly level in the SEM.

The SEM model contained an explicit representation of all generators, sources of demand, aggregated small scale generation, interconnection and current market rules for priority dispatch of renewable generation.

3.7.2 Key Assumptions Used in July Draft Delivery Plan Analysis

SONI used publicly available sources where possible, and was consistent with National Grid where applicable as detailed below. The following table describes the key input assumptions to the market model, sources, and any differences from the National Grid modelling.

Model Input	Data Source	Description	Differences to National Grid Modelling
Horizon	Na	2013-2030, modelled at hourly granularity	GB modelled half hourly for sample days and then scaled.
Capacity	EirGrid/SONI Generation Capacity Statement (GCS) 2013-2022 EirGrid Vision 3 (internal)	System Operators' view of capacity evolution, taking into account retirement announcements and plant in planning / connection queue. Thermal plant is retired and commissioned based on market economics and to ensure a consistent capacity margin	National Grid has used the DDM investment decision process to build UK capacity based on Strike Prices and assumptions on levelised costs by technology.
Renewable Load Factors	EirGrid/SONI GCS 2013-2022	Consistent with GCS, such that ROI and NI meet 40% RES-E target in 2020.	Similar approach with annual wind output being based on three different load factors for onshore

[26] http://www.energyexemplar.com/software/

			and offshore sites.
Demand	EirGrid/SONI GCS 2013-2022 EirGrid Vision 3 (internal)	Hourly demand modelled using historic hourly demand profile scaled to the median peak and annual energy projections given in GCS. Demand in the period 2023-2030 (peak and annual energy) is scaled to meet EirGrid's long term projections.	NG uses DECC's UK wide demand projections with an allowance for NI to give GB demands. This allowance is fixed at the current percentage of UK demand attributable to NI (2.7%).
Fuel Prices	DECC	As supplied by DECC	Consistent
Carbon Prices	DECC	As supplied by DECC. Generators in the SEM are not liable to pay Carbon Price Support on fuel, and so the DECC supplied "Appraisal value" has been used – this follows EUA projections to 9 £/t by 2020, rising to 75 £/t by 2030 following an assumed global agreement on carbon pricing	Consistent, though CPS omitted in NI modelling.
Interconnection	EirGrid/SONI internal	Two interconnectors (Moyle and East-West) from SEM to GB, 750 MW total capacity. Losses and wheeling charges used to calibrate flows.	NG modelling assumes full imports to NI from GB in all periods.
GB representation	National Grid DDM model	Hourly price file at GB end of interconnectors. SEM assumed price taker to GB market. Price file developed from National Grid DDM model, on monthly characteristic day basis	Prices consistent for scenarios.
Strike Prices	National Grid DDM modelling	Assume UK wide Strike Prices to calculate CfD spend as used in National Grid DDM modelling	Consistent
Reference prices	EirGrid/SONI internal following discussion with National Grid	Reference prices are assumed to be set using forecasted SEM market price. Intermittent generation assumed to receive day ahead price, baseload generation assumed to receive year ahead price.	NG assumes reference price set at time weighted annual price for baseload plant in GB and at half-hourly price for intermittent plant.
Capacity Payments	EirGrid/SONI internal	EirGrid/SONI internal projections from 2013-2020, kept constant thereafter. Capacity payments are an additional revenue stream to generators in the SEM based on availability and are added to the forecasted SMP to calculate the difference payments for NI generators	With DDM CM payments (if triggered) are calculated based on the auction clearing price.
Curtailment	EirGrid/SONI internal	Modelling of wind results in curtailment of 5% by 2020, consistent with the GCS and ensuring System Non-Synchronous Penetration rules of 75% in 2020 are met in all periods.	Wind is curtailed in the dispatch model if supply is greater than demand. Additional curtailment due to constraints or inertia is modelled separately to calculate levels and associated costs.
Market rules	EirGrid/SONI internal	We have assumed current market rules will remain. There is currently little visibility of changes that may occur as part of the adoption of the EU target model by end 2016.	Current market rules apply prior to the introduction of a capacity mechanism.

3.7.3 December Delivery Plan Analysis for Northern Ireland

Given that there were some differences in the input assumptions in the July draft Delivery Plan analysis and that the CfD Strike Prices from the GB modelling were not used directly to model investment decisions for renewable generation in Northern Ireland, a modified approach was used in the analysis for the December Delivery Plan as outlined below.

In the December Delivery Plan, for each scenario modelled the estimated renewable deployment and generation to 2015/16 under the RO in Northern Ireland and the associated RO spend to 2020/21 was taken from the SONI July draft Delivery Plan modelling from the nearest equivalent scenario. The estimated reference price to 2020/21 was taken from the SONI July draft Delivery Plan modelling where relevant; this was broadly similar for the scenarios modelled (apart from the high and low fossil fuel price cases). For the scenarios not modelled by SONI in the July draft Delivery Plan, an estimate was derived by taking the NI reference price from Scenario 1 and scaling by the ratio of the GB reference price in that scenario to the GB reference price in Scenario 1.

The renewable deployment in NI under the RO in 2016/17 and under CfDs from 2017/18 to 2020/21 was estimated using a separate NI calculator model developed by DECC in conjunction with National Grid, with input from DETI. The NI calculator considers all of the capital and operational costs over a plant's lifetime and also considers all revenues expected by plants for example ROCs/CfDs, LECs, heat revenues and wholesale revenue. It takes the RO support levels in 2016/17 and the Strike Prices for commissioning years 2017/18 to 2020/21 from the modelled GB scenario, along with NI specific maximum build limits for those years and uses the same load factors as the GB modelling except for NI specific values for onshore wind (33%) and large solar photo-voltaic (10.3%). It models investment decisions in a similar way to the DDM to derive the NI deployment and generation from 2016/17 to 2020/21 for each renewable technology. The resulting RO and CfD supported renewable deployment and generation was added to the RO supported figures from the SONI modelling to give an overall NI estimate for renewable deployment and generation to 2020/21.

Post 2020/21, we assumed that NI total renewable generation as a proportion of UK total renewable generation remained the same as in 2020/21 and assumed that the NI RO / CfD spend as a proportion of UK spend remained the same as in 2020/21.

The UK LCF spend in 2020/21 and UK renewable electricity percentage in 2020 as presented in Section 6.4 were derived by combining the estimates from the NI and GB modelling.

3.8 Quality Assurance

3.8.1 Models

A Quality Assurance (QA) process was followed across the full suite of models used.

The DDM model has been through previous QA within DECC. In parallel with this the models built specifically for the analysis of system costs have been internally reviewed and shared with DECC for QA purposes.

Existing models have followed a due diligence process. The DDM model has been peer reviewed and used for previous published analysis (including the DECC's Gas Generation Strategy and its Updated Energy and Emissions projections). It has also been reviewed by National Grid to test its suitability for the July draft Delivery Plan and December Delivery Plan analysis. Plexos is an agreed tool between National Grid and Ofgem for use in, for example, the Balancing Services Incentive Scheme (BSIS)[27].

Annex G to the December Delivery Plan on modelling quality assurance describes the systematic process for quality assuring the analysis[28].

3.8.2 Peer Review

An earlier version of the DDM model was peer reviewed by external independent academics to ensure the model is fit for the purpose of policy development. Professors David Newbery and Daniel Ralph of the University of Cambridge undertook a peer review to ensure the model met DECC's specification and delivered robust results. It was deemed an impressive model with attractive features and good transparency. For the Peer Review report, see 'Assessment of LCP's DDM for DECC'[29].

3.8.3 Results and Process and role of PTE

The Government has appointed a PTE[30] to scrutinise the System Operator's analysis. The Panel is made up of experts who have knowledge across various sectors of the electricity market and have analytical and technical modelling skills. The members are independent of particular viewpoints and thus provide impartial advice. The Panel's final report has been published alongside this report as an Annex to the main report.

[27] http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/BSIS/
[28] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan
[29] http://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65711/5427-ddm-peer-review.pdf
[30] https://www.gov.uk/government/policy-advisory-groups/141

4. Input Assumptions

4.1 Modelling assumptions

This section sets out the main modelling assumptions provided by DECC and where these have been updated since the Government Response to the RO Banding Review and the Consultation on the July draft Delivery Plan.

A generic description follows with more specific scenario detail in chapter 5.

4.1.1 Technology costs

The modelling has been updated to use generation costs from DECC's Electricity Generation Costs December 2013 report[31]. For that report, further updates as a result of evidence received through the Consultation on the July draft Delivery Plan and other evidence (for further detail see Annex H to the December Delivery Plan) have been considered in addition to the several datasets that were considered as part of a review on costs for use in the July draft Delivery Plan. The generation costs are provided by DECC within the data sources summarised below. Further detail on the assumptions used and modelling changes made for the December Delivery Plan and their sources are set out in DECC's Electricity Generation Costs December 2013 report[32]

Non – Renewable Technologies:
Underlying data on non-renewable technologies has been provided by Parsons Brinckerhoff. The underlying data and assumptions can be found in the Parsons Brinckerhoff (2013) report "Update of Non-Renewable Technologies"[33]. Since the July draft Delivery Plan, Parsons Brinckerhoff has further revised the low and high technology costs for CCGT and OCGT plants in its forthcoming report "Coal and Gas Technology Assumptions"[34].

Renewable Technologies:
The following data sources for various renewable technologies have been used and/or considered by DECC:

1. Government Response to the Banding Review (GRBR) - data and evidence underpinning the 'Government response to the consultation on proposals for the levels of banded support under the RO for the period 2013-17 and the Renewables Obligation Order 2012' for renewable technologies[35].
2. Large solar photo-voltaic data - data and evidence on the costs and performance of large solar photo-voltaic underpinning 'Government response to

[31]https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[32]https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[33]https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[34]https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[35] https://www.gov.uk/government/consultations/supporting-large-scale-renewable-electricity-generation (This is referred to as the 'Government Response to the RO' throughout this report. Please note that the data has been inflated from 2010 to 2012 prices and heat revenues have been updated to reflect DECC's 2013 fuel and carbon prices when compared to those published as part of the Government Response to Renewables Obligation).

further consultations on solar PV support, biomass affordability and retaining the minimum calorific value requirement in the RO[36].
3. FiTs data: Data and evidence from Parsons Brinckerhoff (PB) (2012) published as part of the Government response to Phase 2A and 2B comprehensive review of feed in tariffs[37] [38].
4. Onshore Wind Call for Evidence - Data received in response to DECC's Onshore Wind Call for Evidence and published in June 2013[39]
5. National Grid Call for Evidence - Data received as part of National Grid's Call for Evidence[40] (2013)
6. PB 2013 - a DECC commissioned report from Parsons Brinckerhoff (2013) on renewable technologies[41].
7. TNEI offshore wind costs assessment[42]
8. Crown Estate's Offshore Wind Cost Reduction Pathways Study[43]
9. Offshore Wind Cost Reduction Task Force[44]

To sign off the updated technology costs and other key assumptions for the December Delivery Plan, DECC set up a Levelised Cost Board (LCB) chaired by DECC's Chief Economist.

4.1.2 Electricity demand

GB electricity demand projections up to 2030 come from the DECC Energy and Emissions Model (as set out in section 3.3). These are described in more detail in Annex section 2 (GB electricity demand).

4.1.3 Daily load curves

The model scales annual demand to half hour demand for sample days using daily load curves. These are half hour demand profiles for a range of days for each quarter from a high demand day to a low demand day. Each day is split into domestic and non-domestic load bands. The values are demand in the half hour as a percentage of average half hour demand for the whole year. The profiles are based on demand from 2008/09 to 2011/12 (see Annex section 2 for further details).

4.1.4 Fossil fuel prices

The modelling uses the same set of fossil fuel price projections as the July draft Delivery Plan analysis, which were published alongside the Consultation on the July draft Delivery Plan earlier this year[45]. The publication covers low, medium and high long-term price scenarios for oil, gas and coal prices out to 2030. All scenarios

[36] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66516/7328-renewables-obligation-banding-review-for-the-perio.pdf
[37] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/43083/5381-solar-pv-cost-update.pdf
[38] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42912/5900-update-of-nonpv-data-for-feed-in-tariff-.pdf
[39] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/205423/onshore_wind_call_for_evidence_response.pdf
[40] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[41] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[42] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[43] ttp://www.thecrownestate.co.uk/media/305094/Offshore%20wind%20cost%20reduction%20pathways%20study.pdf
[44] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66776/5584-offshore-wind-cost-reduction-task-force-report.pdf
[45] https://www.gov.uk/government/publications/fossil-fuel-price-projections-2013

assume central DECC fossil fuel price assumptions except for the low and high fossil fuel price scenarios. The fossil fuel price projections are set out in Annex section 3.

4.1.5 Carbon prices

The modelling takes into account the Carbon Price Floor (CPF)[46] which came into effect in April 2013. The CPF trajectory reaches £30/tCO_2 (2009 prices) in 2020, further rising to £70/tCO_2 (2009 prices) in 2030. Post 2030 the modelling assumes that carbon prices follow the social appraisal values.[47] These assumptions are set out in more detail in Annex section 4.

4.1.6 Maximum build limits

In general the assumptions on maximum build limits are informed by maximum historic build rates or Government's and industries' assessment of future potential. However, the supply chains of some technologies either do not yet exist or are at a very early stage and therefore assumptions on maximum build limits are uncertain.

Since the July draft Delivery Plan analysis, maximum build limits for unabated gas plants have been updated in line with new evidence from a forthcoming Parsons Brinckerhoff report[48], which considered the potential constraints on new unabated gas build related to site availability, planning, regulation, contracting, funding, historical manufacturing capability and construction rates. The modelling takes account of the latest Transmission Entry Capacity (TEC) notifications.

The modelling assumes two Carbon Capture and Storage (CCS) early stage projects come forward. Commercial CCS plants first become operational from 2025. There is significant uncertainty around maximum build limits for CCS as the technology has yet to be demonstrated commercially. Maximum build limits are set to two CCS plants per year. The chapter in the EMR Delivery Plan "Forward Look to 2030" considers a scenario with higher deployment of CCS than Scenario 1.

The modelling assumes that the first new nuclear reactors become operational in 2023. The Nuclear Supply Chain Action Plan[49] estimates that by 2030 up to 16.5GW of new nuclear could be operational. The scenarios in this report assume a more constrained feasibility of nuclear over the 2020s reflecting uncertainty around potential deployment rates. Post 2030, nuclear maximum build limits are on average two plants every 3 years. The chapter in the EMR Delivery Plan "Forward Look to 2030" considers a scenario with higher deployment of nuclear than Scenario 1.

Maximum build limits for renewable technologies are broadly consistent with those used in the Renewables Obligation Banding Review Government Response (2012), which are based on Arup (2011) and information obtained during the Renewables Obligation Banding Review Consultation[50] [51]. Following the July draft Delivery Plan

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[46]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/190279/carbon_price_floor_consultation_govt_response.pdf
[47] https://www.gov.uk/government/collections/carbon-valuation--2
[48] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan
[49] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65658/7176-nuclear-supply-chain-action-plan.pdf
[50] https://www.gov.uk/government/consultations/supporting-large-scale-renewable-electricity-generation
[51] Build constraints for large solar photo-voltaic reflect assumptions underpinning analysis for the Renewables Obligation Banding Review for the period 1 April 2013 to 31 March 2017*:* Government Response to further consultations on solar PV support, biomass affordability and retaining the minimum calorific value requirement in the RO (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66615/7328-renewables-bligation-

analysis, there have been two updates to the renewables pipeline information and build limits. Firstly, information gathered as part of the Renewables Obligation for 2014/15 has been taken into account.[52] This includes more information about projected deployment before the Delivery Plan period; the starting point now more accurately reflects best estimates of deployment by the end of 2014/15. Secondly, updated pipeline information and build limits are included. This is based on commercial information and detailed information about the pipeline of potential projects[53]. This particularly applies to onshore wind, large solar photo-voltaic, biomass conversions and offshore wind.

The build limits for offshore wind used in the modelling for the December Delivery Plan have been updated since the July draft Delivery Plan to assume that projects will be phased over three years. All phases receive the same Strike Price and this price is determined by the target commission date of the first phase. The modelling assumes that 25% of a project comes forward in the first phase and 37.5% in both the second and third phase[54].

4.1.7 Variation in technology costs

The generation cost information includes low, medium and high capital cost estimates. To allow for the increase in costs when constructing multiple plants in a single year caused by factors such as less attractive sites, less advanced planning or greater costs for renewable technologies, the DDM takes account of difference in cost of potential new build in any year. The first plant available to build in any given year is assigned the cheapest new build cost, while the last plant available is assigned the most expensive new build cost. The construction costs of all other plant are defined by the linear interpolation of the low, medium and high cost points. This provides technology-specific new capacity supply curves for each year and each renewable technology.

The RO Banding Review Government Response analysis used five cost tranches (low, low/medium/, medium, medium/high, high), each with 20% of the available potential[55].

The December Delivery Plan analysis now also assumes increases in costs when constructing multiple plants in a single year for unabated gas plants, i.e. technology-specific new capacity supply curves for each year in line with the treatment of renewable technologies.

4.1.8 Technology costs over time

There is significant uncertainty about how the costs of technologies will evolve over time. In general, estimates of the cost of different electricity generating technologies in the future are driven by expectations and assumptions of technology specific

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banding-review-for-the-perio.pdf), and build constraints for tidal stream and wave technologies reflect DECC's current understanding.

[52] https://www.gov.uk/government/publications/renewables-obligation-level-calculations-2013-to-2014--2

[53] This is in the Renewable Energy Planning Database (REPD), available at https://restats.decc.gov.uk/app/reporting/decc/datasheet. This gives information both about projects currently operational, and those that have applied for planning approval. Note that not all projects in REPD will come forward.

[54] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263182/Final_Document_-_Investing_in_renewable_technologies_-_CfD_contract_terms_and_strike_prices.pdf

[55] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42847/5945-renewables-obligation-government-response-impact-a.pdf

learning rates and global and UK deployment. In general IEA[56] projections are the main source for global deployment for all technologies. Three notable exceptions are advanced conversion technologies (ACT), wave, tidal stream and estimates for renewables technologies under 5 MW. These are driven by scenarios of technical potential for UK deployment[57].

The approach to offshore wind technology costs over time is set out in Annex H to the December Delivery Plan. The assumed learning rate for offshore wind has been adjusted following the draft Delivery Plan consultation.

4.1.9 Maximum annual net load factors

The maximum annual net load factors for CfD supported renewable plant are based on the Government Response to the Banding Review, with the exception of:

- Onshore wind: Since the July draft Delivery Plan analysis, the maximum annual load factor has been updated to reflect a UK average load factor of 27.5% from 1998 to 2012[58] in line with calculating the Level of the RO for 2014/15[59].
- Scottish Islands onshore wind: The December Delivery Plan analysis takes into account a separate CfD Strike Price for Scottish Islands onshore wind. These projects are assumed to have load factors of 42% for Orkney, 44% for Shetland and 35% for the Western Isles. These are based on the Baringa/TNEI report[60]
- Large solar photo-voltaic: As per the July draft Delivery Plan analysis, the maximum annual load factor reflects assumptions underpinning analysis for the RO Banding Review for the period 1 April 2013 to 31 March 2017. Government Response to further consultations on solar PV support, biomass affordability and retaining the minimum calorific value requirement in the RO[61].
- Landfill and sewage gas: Since the July draft Delivery Plan analysis, the maximum annual load factors have been updated in line with Calculating the Level of the RO for 2014/15[62].
- Biomass CHP and hydro: The table in the Annex has been corrected for these technologies, as the maximum annual net load factors were quoted incorrectly in the load factor table in the July draft Delivery Plan report.
- Tidal Stream and Wave technologies: As per the July draft Delivery Plan analysis, the maximum annual load factors have been updated following the

[56] Estimates for renewable technologies are based on IEA Bluemap (see ARUP 2011 for details), and non-renewable technologies are IEA Energy Technology Perspectives (2012). Future deployment scenarios are not based on year-on-year data and therefore there is uncertainty about how costs will evolve overtime. This approach is intended to capture trends in cost reduction rather than precise year-on-year changes.
[57] See Arup 2011 and PB 2012 for FiTs for more details.
[58] A recent study by Staffell and Green (2013) finds that the load factor of wind turbines declines over time. The load factor used in December Delivery Plan analysis is derived from 15 years of Dukes data. This historic data should capture the decline in load factors of current wind farms over time.
[59] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/245488/calculatingro_2014_15.pdf
[60] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/199038/Scottish_Islands_Renewable_Project_Baringa_TNEI_FINAL_Report_Publication_version_14May2013__2_.pdf
[61] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66615/7328-renewables-obligation-banding-review-for-the-perio.pdf
[62] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/245488/calculatingro_2014_15.pdf

National Grid Call for Evidence - Data received as part of National Grid's Call for Evidence[63] (2013).

The maximum annual net load factors vary by scenario for dispatchable technologies and for intermittent technologies due to potential curtailment. The maximum annual net load factors are set out in Annex section 9.

4.1.10 Investor hurdle rates and hurdle rate reductions due to CfDs

As in the July draft Delivery Plan the starting point for the pre-tax real hurdle rates used in the December Delivery Plan analysis are the post-tax nominal hurdle rates underlying the RO Banding Review Government Response (2012). The post-tax nominal rates are based on evidence from Arup (2011)[64], Oxera (2011)[65], Redpoint (2010)[66] and NERA (2013)[67]. To convert post-tax nominal to pre-tax real hurdle rates, updated effective tax rate assumptions from work undertaken by KPMG (2013)[68] and a 2% inflation assumption consistent with the Government's inflation target have been applied. This is set out in DECC's Electricity Generation Costs December 2013[69] report.

Updated estimated hurdle rate reductions due to the introduction of CfDs are based on evidence received through the consultation responses, analyst reports and interviews with the finance community. This evidence was reviewed, analysed and summarised in a report by NERA (2013)[70]. Work undertaken by PwC (as part of the Crown Estates cost reduction pathways work[71]) has also been used to update hurdle rates of different types of offshore wind. More detail on the hurdle rate updates are set out in Annex H to the December EMR Delivery Plan. The resulting pre-tax real hurdle rates for technologies for which Strike Prices are being set are also shown in Annex section 6.

4.1.11 Plant closures and extensions

Information on plant closures for the period covering financial years 2013/14 and 2014/15 has been updated with National Grid's latest notified Transmission Entry Capacity (TEC) reductions. The updated retirement decisions have been verified by National Grid and have been signed off by the DECC Levelised Cost Board.

In order to project retirement decisions by plants due to the Large Combustion Plant Directive (LCPD), DECC uses the Environment Agency's public data on the running hours of LCPD opt out plant to estimate future retirement dates. Industrial Emission Directive (IED) decisions are based on Redpoint analysis and stakeholder engagement. The modelling assumes life extensions for existing nuclear plants based on plant announcements. This is seven years for all of EDF's AGR fleet except for Hartlepool and Heysham 1, which have previously been granted life extensions of

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[63] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[64] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42843/3237-cons-ro-banding-arup-report.pdf
[65] http://hmccc.s3.amazonaws.com/Renewables%20Review/Oxera%20low%20carbon%20discount%20rates%20180411.pdf
[66] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42638/1043-emr-analysis-policy-options.pdf
[67] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan
[68] https://www.gov.uk/government/publications/electricity-generation-costs
[69] https://www.gov.uk/government/publications/electricity-generation-costs
[70] https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan
[71] http://www.thecrownestate.co.uk/media/305102/PwC%20OWCRP%20project%20finance%20work%20stream.pdf

five years. For these two plants two further years extension are assumed. Wylfa power plant is assumed to have a one year life extension to reflect their application for a one year extension. Retirements due to plant economics are modelled in the DDM. When plants have made losses for two consecutive years, the model assesses the profitability of these plants over the next five years. If plants are projected to lose money over the next five years they decide to close.

Assumptions around retirements of distribution connected generation (including autogeneration) have been provided by DECC.

4.1.12 Capacity Mechanism

The reliability standard for all scenarios targets a Loss of Load Expectation (LOLE) of 3 hours on average per year before any mitigating actions are taken (for example emergency interconnector assistance or voltage reduction). In all scenarios the capacity mechanism is triggered in 2014 for 2018/19 in order to achieve the required reliability standard. The choice and rationale of the reliability standard is set out in the December Delivery Plan document.

4.1.13 Interconnections

The modelling accounts for various interconnections between GB, Northern Ireland and other European countries. Existing interconnections modelled are the England-France, Scotland-Northern Ireland, England-Netherlands and Wales-Ireland interconnectors. The modelling also assumes that three additional interconnectors become operational between the latter part of this decade and early part of the next decade, reflecting the strong project pipeline. In the draft Delivery Plan analysis only one additional interconnector was assumed which we consider to be conservative.

4.1.14 Renewables Obligation, small scale Feed-in-Tariffs and levy exemption certificates

All the scenarios model the Renewables Obligation for new build that commissions up to and including 2015 and CfDs from 2016 commissioning onwards (with the exception of one biomass conversion that is assumed to come forward under CfDs in 2015). While in reality RO transitional arrangements mean that the split between the RO and CfD will not be this straightforward, the modelling requires making a simplifying assumption.

Small scale Feed in Tariffs (FiTs) is not modelled within the DDM, but is an input assumption. Actual deployment under FiTs will depend on future costs and policy decisions.

The modelling also includes the provision of levy exemption certificates (LECs) to renewable generators.

4.1.15 Power Purchasing Agreements (PPAs)

It is not possible to assess with a high degree of certainty what level of discounts will be available in PPAs for CfD holding generators since, by definition, such PPAs are not currently available. We have therefore estimated potential discounts for renewable generators by reference to discounts available in the market for RO generators today, adjusted to reflect likely changes in the market following the move to CfDs.

The estimate for discounts for current RO plant is based on the evidence underpinning the RO banding review[72] together with evidence provided by market participants through a call for evidence over the summer of 2012[73]. These were then adjusted to reflect the likely changes in the market as a result of the move from the RO to CfDs reflecting the changing risk landscape, in particular:

- Removal of price risk through guaranteed top-up payment against reference price.
- Removal of exposure to ROC price volatility.
- Removal of risk of carrying ROCs.
- Application of discounts to wholesale price only, rather than the entire revenue stream.

These discounts assume efficient pricing of imbalance risk and route to market costs. DECC is actively considering interventions to promote competition in the PPA market.

For the December Delivery Plan analysis, the PPA wholesale price discount under CfDs for large solar photo-voltaic (and other non-wind intermittent generators) has been corrected to be in line with the PPA discount for onshore wind under CfDs.

A table of the PPA rates assumed under the RO and CfDs can be found in Annex section 7.

4.1.16 Renewable proportion of waste generation

Following the publication of the draft Delivery Plan in July, DECC has updated the figure for the renewable content of electricity generated from waste. This is now based on the latest DUKES (Digest of UK Energy Statistics) information, which estimates that 63.5% of electricity generation from municipal solid waste should be considered to be renewable. Therefore, CfD payments are modelled as only being made on 63.5% of their total loss-adjusted (see below) generation.

The December EMR Delivery Plan modelling assumes that emissions caused by the non-biodegradable content of waste are accounted for.

For all other technologies (i.e. non-waste technologies) we assume renewable fuel content of 100%.

4.1.17 Transmission Loss Assumption

The modelling assumes that CfD payments are made on the loss-adjusted output. The loss assumption is based on a generator share of 45% of transmission loss percentage estimated from National Grid's 2013 Future Energy Scenarios[74] but

[72] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42846/4081-poyry-revised-ro-bands-review.pdf
[73] https://www.gov.uk/government/consultations/barriers-to-long-term-contracts-for-independent-renewable-generation-investment
[74] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

adjusted for total demand. A table of the losses assumed in the modelling can be found in Annex section 10.

4.1.18 Levy Control Framework profile

The table below shows the upper limits to electricity policy levies agreed under the LCF. These caps are upper limits on the levies raised to fund electricity policies like the RO, FiTs and CfDs. Current arrangements allow for 20% headroom above the LCF cap, which represents the level of permissible variation in spend. For further details see Chapter 2 of the December Delivery Plan.

£m, 2011/12 prices	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
LCF cap	3,300	4,300	4,900	5,600	6,450	7,000	7,600

4.2 Network costs and system operability

National Grid's analysis incorporates the impacts of network costs associated with network development, network operation and system operability. These three elements of costs are modelled separately to give a breakdown by TNUoS, BSUoS and system inertia/operability.

5. Scenario Analysis

5.1 Overview

Since the July draft Delivery Plan publication further work has been carried out by National Grid, again in conjunction with DECC, that has refined the three core scenarios into Scenario 1 and alternative scenarios into a range of scenarios for the December Delivery Plan. Changes include updates due to updated DECC projections being available, due to market intelligence as well as evidence from the July draft Delivery Plan consultation. The scenarios have been developed to consider a wide range of plausible uncertainties over the scenario period.

All scenarios include a low-carbon instrument (the CfD) and a Capacity Market, combined with an Emissions Performance Standard (EPS). All scenarios aim to stay within the LCF profile up to 2020/21 (further detail on the profile used can be found in Annex Section 5). All scenarios generate at least 30% of UK electricity from renewable sources by 2020 and, apart from the Higher Biomass Conversions scenario, assume around 1.7 GW of biomass conversion capacity by 2020.

Strike Prices for renewable technologies are set at the levels in the December Delivery Plan.

The role of this modelling and analysis is to provide an evidence base to help advise Ministers on Strike Prices levels per technology, that best meet the Government's policy objectives.

In taking account of the evidence base that was required by Ministers to make the required decisions the following conditions had to be met by the analysis:

- Total costs must lie within the LCF profile (see Annex Section 5)
- Supporting technologies to ensure the UK is on track to meeting the 2020 Renewable energy target
- Support levels appropriately take account of generator costs and revenues, and will deliver a cost-effective mix of technologies
- Security of supply is maintained

5.2 Scenario descriptions

Descriptions of the scenarios are listed below. There are some similarities to the scenarios in the July draft Delivery Plan; however, the High and Low LOLE scenarios are no longer modelled, as they do not significantly alter either the level of renewable generation or spend under the LCF. In addition High Fossil Fuel Prices and Low Demand scenarios have been added to give a wider range to LCF spend and electricity demand.

All scenarios assume maximum Strike Prices for renewable technologies at the levels as set out in the December Delivery Plan. Technologies affected by constrained allocation would be likely to see their actual Strike Price set at a lower value than the maximum. This has been captured within the modelling.

5.2.1 Scenario 1

Scenario 1 spends around £7bn in 2020/21 and achieves around 33% renewable electricity in 2020.

5.2.2 High Technology Costs scenario

This scenario tests the impact on the generation mix and support costs should technology costs turn out to be higher than those assumed in Scenario 1. The scenario assumes that low, central and high capital costs are 10% higher across all technologies. This is to reflect an upward risk/uncertainty in capital costs. This scenario assumes a modest increase in Strike Prices from 2019 to reflect the higher technology costs.

5.2.3 Low Technology Costs scenario

This scenario tests the impact on the generation mix and support costs of lower technology costs as compared to those assumed in Scenario 1. The scenario assumes that low, central and high capital costs are 10% lower across all technologies. This is to reflect a downward risk/uncertainty in capital costs. This scenario assumes a modest reduction in Strike Prices from 2019 to reflect the lower technology costs.

5.2.4 High Fossil Fuel Prices scenario

This scenario tests the impact on the generation mix and support costs of fossil fuel prices being higher than anticipated in Scenario 1. It uses DECC's fossil fuel price projections and demand consistent with higher fossil fuel prices. Further detail is set out in Annex section 3.

5.2.5 Low Fossil Fuel Prices scenario

This scenario tests the impact on the generation mix and support costs of fossil fuel prices being lower than anticipated in Scenario 1. It uses DECC's fossil fuel price projections and demand consistent with lower fossil fuel prices Further detail is set out in Annex section 3.

5.2.6 High Demand scenario

This scenario tests the impact on the generation mix and support costs of demand being higher than anticipated in Scenario 1. It uses DECC's high demand projections Further detail is set out in Annex section 2.

5.2.7 Low Demand scenario

This scenario tests the impact on the generation mix and support costs of demand being lower than anticipated in Scenario 1. It uses DECC's low demand projections Further detail is set out in Annex section 2.

5.2.8 High Offshore Deployment scenario

This scenario tests how much more offshore wind can be deployed should average offshore wind levelised costs come down to the Offshore Wind Cost Reduction Task Force[75] estimate of £100/MWh[76] for projects achieving final investment decisions in 2020. Faster cost reductions are assumed to unlock more build potential. In this scenario around 15 GW of offshore wind can be incentivised by 2020 within the LCF budget. The modelling projects that later phases of projects signing contracts up to 2020 add a further 5.3GW of offshore wind deployment shortly after 2020.

5.2.9 Higher biomass conversion scenario

This scenario tests the impact of higher deployment of biomass conversions coming forward this decade (around 3.4 GW of capacity by 2020) compared to 1.7 GW in all other scenarios. It also assumes additional deployment of biomass CHP of 0.3 GW by 2020.

[75] www.gov.uk/government/policy-advisory-groups/offshore-wind-cost-reduction-task-force
[76] www.gov.uk/government/uploads/system/uploads/attachment_data/file/66776/5584-offshore-wind-cost-reduction-task-force-report.pdf

6. Results and Conclusions

6.1 Overview of results and metrics

In this chapter we consider the results from the modelling of the scenarios outlined in sections 4 and 5. First we consider key metrics from the modelling to 2020 across all the scenarios. Then we consider each scenario in turn and highlight the key results and conclusions which can be drawn.

Also included is an overview of NI results and more detailed conclusions and findings for the overall set of scenarios.

6.1.1 Strike Prices

For the purposes of this report Strike Prices have been considered for the following renewable technologies:

- Advanced Conversion Technologies (with or without CHP)
- Anaerobic Digestion (with or without CHP)
- Dedicated biomass (with CHP)
- Energy from Waste (with CHP)
- Geothermal (with or without CHP)
- Hydro
- Landfill gas
- Sewage gas
- Onshore Wind
- Scottish Islands Onshore Wind
- Offshore wind
- Biomass Conversion
- Tidal stream
- Wave
- Large Solar Photo-Voltaic

Each of these technologies is modelled with a specific Strike Price as set out in Investing in Renewable Technologies – CfD contract terms and Strike Prices (2013)[77]. Maximum Strike Prices have been assumed for the Delivery Plan period 2014/15 to 2018/19 (as shown in the following table). Technologies affected by constrained allocation would be likely to see their actual Strike Price set at a lower value than the maximum. This has been captured within the modelling.

While Strike Prices have been shown for 2014/15 in order to ensure comparability with the RO, the EMR consultation on proposals for implementation discussed a start date for CfD payments of April 2015.

The modelling assumes that new build commissioning before 2016 is supported by the RO while projects commissioning from 2016 are supported by the CfD, with the exception of biomass conversions which commission in 2015. While in reality RO

[77] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263937/Final_Document_-_Investing_in_renewable_technologies_-_CfD_contract_terms_and_strike_prices_UPDATED_6_DEC.pdf

transitional arrangements mean that the split between the RO and CfD will not be this straightforward, the modelling requires making a simplifying assumption.

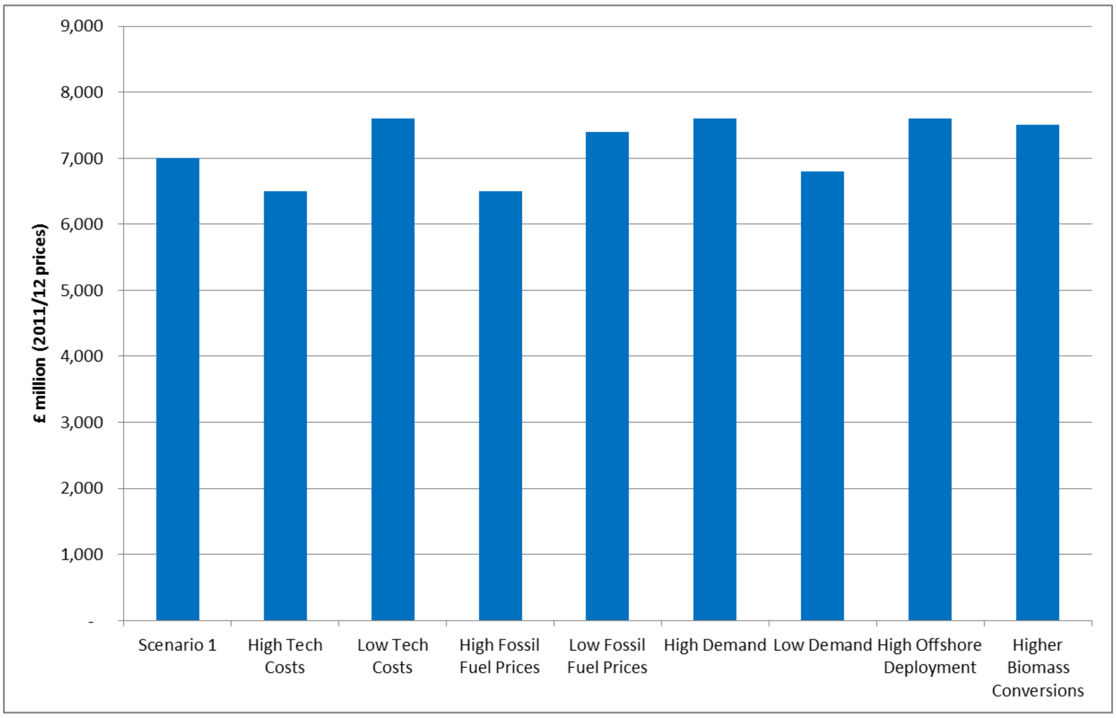
Strike Prices, 2014/15 to 2018/19 for the scenarios:

Renewable Technology	Strike Prices £/MWh (2012 prices)				
	2014/15	2015/16	2016/17	2017/18	2018/19
Advanced Conversion Technologies (with or without CHP)	155	155	150	140	140
Anaerobic Digestion (with or without CHP)	150	150	150	140	140
Dedicated biomass (with CHP)	125	125	125	125	125
Energy from Waste (with CHP)	80	80	80	80	80
Geothermal (with or without CHP)	145	145	145	140	140
Hydro	100	100	100	100	100
Landfill gas	55	55	55	55	55
Sewage gas	75	75	75	75	75
Onshore Wind	95	95	95	90	90
Scottish Islands Onshore	N/A	N/A	N/A	115	115
Offshore wind	155	155	150	140	140
Biomass Conversion	105	105	105	105	105
Tidal & Wave	305	305	305	305	305
Large Solar Photo-Voltaic	120	120	115	110	100

6.1.2 Levy Control Framework Spend in 2020/21

Total LCF spend in 2020/21, which consists of CfD, RO and FiT spend, ranges between £6.5 billion and £7.6 billion, within the 2020/21 cap. The figures in the following chart are shown in 2011/12 prices and are for the whole UK.

LCF Spend for all Scenarios in 2020/21:



6.1.3 2020 GB Capacity and New Build Capacity

The amount of generation capacity installed in GB is a result of the various policy and modelling assumptions described in chapters 3, 4 and 5. In 2020, the three largest renewable technologies (in terms of electricity generated) are onshore wind, offshore wind and biomass conversions. Apart from the High and Low Demand and High and Low Fossil Fuel Price scenarios, all other scenarios have the same underlying demand. We show total capacity in 2020 and new build capacity to 2020 in the following tables[78] [79].

The variation in installed capacity is relatively limited for most technologies. This is because the deployment is primarily driven by the Strike Prices which are the same for 2014/15-2018/19. Some small changes in the Strike Prices beyond this period are made which have a minor effect on deployment. The main factor which affects deployment at a given set of Strike Prices is technology costs, hence the scenarios showing higher and lower technology costs demonstrate different levels of deployment.

Small scale FIT technologies deployment does not vary in these scenarios because this is not what these scenarios are intended to model. Actual deployment under FITs will depend on future costs and policy decisions.

	2020 Total GB Capacity - GW								
Capacity - GW	Scenario 1	High Tech Costs	Low Tech Costs	High Fossil Fuel Prices	Low Fossil Fuel Prices	High Demand	Low Demand	High Offshore Deployment	Higher Biomass Conversions
Advanced Conversion Technologies	0.3	0.2	0.3	0.3	0.2	0.3	0.2	0.3	0.3
Anaerobic Digestion	0.3	0.3	0.4	0.3	0.3	0.4	0.3	0.4	0.3
Dedicated biomass with CHP	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6
Energy from Waste with CHP	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Geothermal	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Hydro	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Landfill gas	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9	0.9
Sewage gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Onshore wind	11.9	10.9	13.0	11.9	11.3	11.9	11.9	11.9	11.9
Scottish Islands onshore	0.4	0.4	0.7	0.4	0.4	0.4	0.4	0.4	0.4
Offshore wind	10.2	8.1	12.2	10.7	9.3	11.6	9.1	15.0	10.2
Biomass Conversion	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	3.4
Tidal & Wave	0.11	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Large Solar Photo Voltaic	2.7	2.4	4.0	2.7	2.7	2.7	2.7	2.7	2.7
Other renewables (incl small scale FITs)	10.3	10.3	10.4	10.4	10.3	10.3	10.3	10.3	10.3
Unabated gas	33.3	33.3	32.4	33.3	33.3	37.8	28.3	33.7	31.5
Unabated coal	11.3	11.3	11.3	11.3	11.3	11.3	9.8	11.3	10.9
CCS	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.6
Nuclear	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Other	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8

[78] Note in the tables "Other renewables" includes small scale FITs, Energy from Waste (without CHP), small and large dedicated biomass (without CHP), bioliquids and bioliquids CHP. "Other" includes interconnectors, auto-generation, pumped storage, Demand Side Response and oil-fired plants.
[79] Technology groupings reflect a presentational choice, and may be revised in future updates to analysis

	New Build 2013 - 2020 - GW								
Capacity - GW	Scenario 1	High Tech Costs	Low Tech Costs	High Fossil Fuel Prices	Low Fossil Fuel Prices	High Demand	Low Demand	High Offshore Deployment	Higher Biomass Conversions
Advanced Conversion Technologies	0.3	0.2	0.3	0.3	0.2	0.3	0.2	0.3	0.3
Anaerobic Digestion	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3
Dedicated biomass with CHP	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.5
Energy from Waste with CHP	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Geothermal	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Hydro	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Landfill gas	0.02	0.02	0.02	0.03	0.01	0.02	0.02	0.02	0.02
Sewage gas	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Onshore wind	6.9	5.9	8.0	6.9	6.3	6.9	6.9	6.9	6.9
Scottish Islands onshore	0.4	0.4	0.7	0.4	0.4	0.4	0.4	0.4	0.4
Offshore wind	7.6	5.4	9.6	8.1	6.7	9.0	6.5	12.3	7.6
Biomass Conversion	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	3.4
Tidal & Wave	0.10	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Large Solar Photo Voltaic	2.4	2.1	3.7	2.4	2.4	2.4	2.4	2.4	2.4
Other renewables (incl small scale FITs)	8.1	8.1	8.1	8.1	8.0	8.1	8.1	8.1	8.1
Unabated gas	8.0	8.0	7.1	8.0	8.0	12.5	5.3	8.0	6.2
Unabated coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCS	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.6
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1

6.1.4 GB generation in 2020

Electricity generation in GB is a result of the installed capacity, the assumed load factors of intermittent technologies and modelled dispatch decisions. As mentioned above, apart from the High and Low Demand and High and Low Fossil Fuel Price scenarios, all other scenarios have the same underlying demand. We show total GB generation in 2020 in the following table[80].

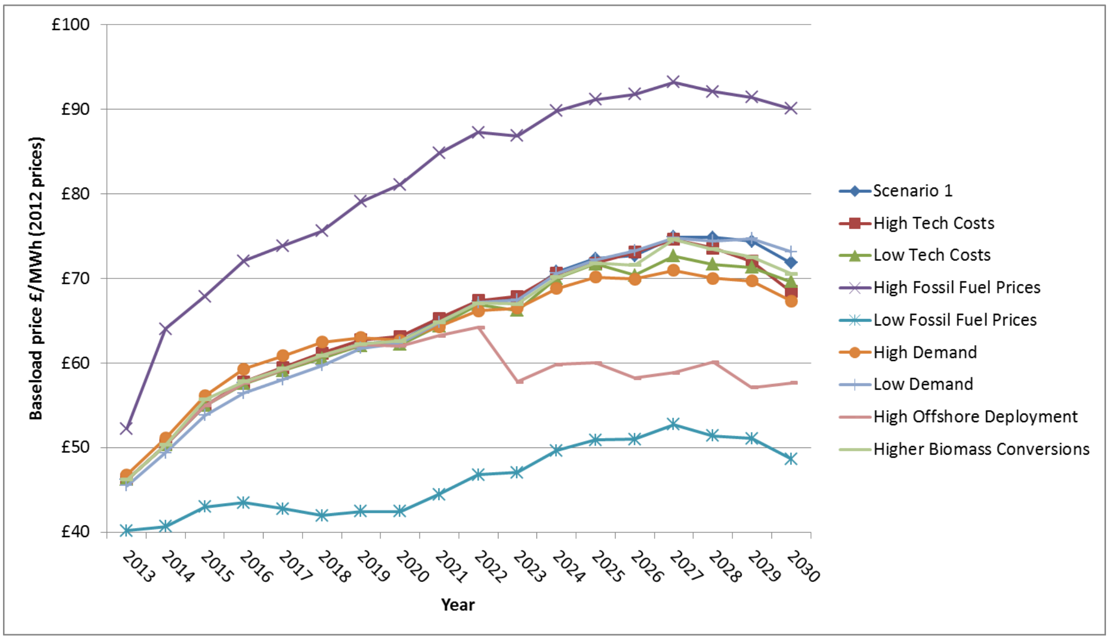
	2020 Total GB Generation - TWh								
Capacity - TWh	Scenario 1	High Tech Costs	Low Tech Costs	High Fossil Fuel Prices	Low Fossil Fuel Prices	High Demand	Low Demand	High Offshore Deployment	Higher Biomass Conversions
Advanced Conversion Technologies	1.2	1.2	1.2	1.3	1.2	1.2	1.2	1.2	1.2
Anaerobic Digestion	2.2	2.2	2.3	2.2	2.2	2.4	2.1	2.3	2.2
Dedicated biomass with CHP	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	4.2
Energy from Waste with CHP	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Geothermal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Hydro	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Landfill gas	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Sewage gas	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Onshore wind	28.7	26.0	31.2	28.7	27.3	28.6	28.7	28.7	28.7
Scottish Islands onshore	1.3	1.3	1.8	1.3	1.3	1.3	1.3	1.3	1.3
Offshore wind	29.0	22.0	34.9	30.4	25.9	31.9	26.7	39.7	29.0
Biomass Conversion	10.5	10.6	10.4	10.5	10.5	10.5	10.5	10.4	19.7
Tidal & Wave	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Large Solar Photo Voltaic	2.7	2.4	3.7	2.7	2.7	2.7	2.7	2.7	2.7
Other renewables (incl small scale FITs)	15.3	15.3	15.6	15.6	14.8	15.3	15.3	15.3	15.3
Unabated gas	107.3	116.6	97.7	93.2	136.9	131.4	85.3	101.9	97.0
Unabated coal	21.6	22.4	21.0	31.0	0.7	22.0	18.6	21.2	20.4
CCS	4.7	4.7	4.7	4.7	4.7	4.7	4.7	0.0	4.7
Nuclear	56.3	56.3	56.3	56.3	56.3	56.3	56.3	56.3	56.3
Other	28.9	28.9	28.9	29.0	28.9	28.9	28.9	28.9	28.9

[80] Note Other includes the non-renewable portion of the Energy from Waste and ACT plants

6.1.5 Wholesale Price

The wholesale power price (baseload) is broadly similar for all the scenarios, apart from the High and Low Fossil Fuel Prices scenarios, until 2020. The price increases to around £63/MWh in 2020, most of the increase is in the earlier years as the gas price increases and capacity margins tighten. For the High Fossil Fuel Prices scenario, prices are around £81/MWh in 2020, as the cost of gas generation is higher. For the Low Fossil Fuel Prices scenario, prices are around £42/MWh in 2020, as the cost of gas generation is lower. The following chart shows wholesale price for each scenario to 2030[81].

Wholesale Prices for all Scenarios 2013-2030:

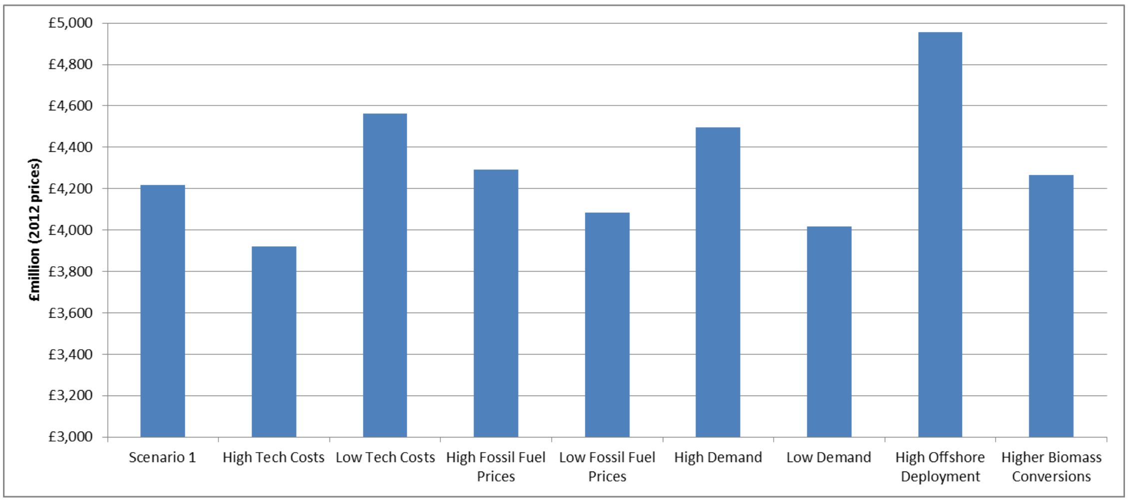


[81] In contrast to other results in this section, wholesale prices are presented to 2030 to enable comparison of revenues under the RO and under CfDs (see Annex B of the December Delivery Plan) (https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan)

6.1.6 Network Costs (TNUoS, BSUoS and Inertia costs)

All of the scenarios have slowly increasing network costs over the period with the more pronounced cost increase being for the higher wind scenarios[82]. In 2020, total costs range from £3.9bn to £4.6bn a year, with the exception of the High Offshore Deployment scenario which has costs around £4.9 billion. The following chart shows total annual transmission network costs in 2020 for each scenario.

Total Annual Network Costs for all Scenarios in 2020:



Transmission costs are paid by both generators and suppliers. For generator costs there is a degree of overlap between these network costs, derived from National Grid's network models, and the allowance for use of system charges already included the costs of low carbon support through the LCF although it is not large enough to materially change the analysis.

One of the main components of transmission balancing costs is constraint costs, which are a longstanding aspect of GB's electricity transmission system. However, in the future constraint costs will continue to represent less than half a percentage of consumer bills.

[82] For clarity this does not necessarily translate into a continued rise in network tariffs that energy consumers would pay over the period, network costs modelled here do not directly correlate with consumer tariffs.

6.2 Summary of results and conclusions

In this section we outline the key results for each of the scenarios and the conclusions can be drawn from these:

6.2.1 Scenario 1

Key results:

- The UK LCF spend is £7.0bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 33% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 10.2 GW offshore wind, 11.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions.

Conclusions:

This scenario has a broadly balanced range of technologies and meets all ambitions.

6.2.2 High Technology Costs scenario

Key results:

- The UK LCF spend is £6.5bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 30% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 8.1 GW offshore wind, 10.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions. In addition large solar photo-voltaic decreases to 2.4 GW from 2.7 GW in Scenario 1.

Conclusions:

This scenario represents unexpectedly higher capital costs for generation technologies which lead to lower LCF costs this decade, due to lower build rates. In order to achieve at least 30% of renewable generation in 2020 modest increases in Strike Prices in 2019/20 are required for some technologies.

6.2.3 Low Technology Costs scenario

Key results:

- The UK LCF spend is £7.6bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 36% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 12.2 GW offshore wind, 13.0 GW onshore wind (plus 0.7 GW on Scottish Islands) and 1.7 GW of biomass conversions. In addition large solar photo-voltaic increases to 4.0 GW from 2.7 GW in Scenario 1.

Conclusions:

This scenario represents unexpectedly lower capital costs for generation technologies which lead to greater LCF costs this decade, due to higher deployment. Since costs are lower the Strike Prices are potentially over-rewarding developers. In order to restrict the LCF spend in 2020/21 modest reductions in Strike Prices in 2019/20 are required for some technologies.

6.2.4 High Fossil Fuel Prices scenario

Key results:

- The UK LCF spend is £6.5bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 34% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 10.7 GW offshore wind, 11.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions.

Conclusions:

This scenario represents a potential outcome under high fossil fuel prices; in particular coal generation is favoured over gas generation. Strike Prices this decade are the same as Scenario 1 but renewable deployment is higher due to expectation of higher long term wholesale prices beyond the CfD contract period. Also higher wholesale prices reduce CfD top up payments. Thus, in spite of the lower LCF spend; the renewable generation percentage in 2020 is higher.

6.2.5 Low Fossil Fuel Prices scenario

Key results:

- The UK LCF spend is £7.4bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 31% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 9.3 GW offshore wind, 11.3 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions.

Conclusions:

This scenario represents a potential outcome under low fossil fuel prices; in particular gas generation is favoured over coal generation. This leads to a lower wholesale price, as gas is the marginal plant with lower running costs. This is in turn increases the top up payments required under the CfD. Thus, given the high LCF spend the renewable generation percentage in 2020 is lower. This potentially presents risks for the electricity portion of the 2020 renewable energy target.

6.2.6 High Demand scenario

Key results:

- The UK LCF spend is £7.6bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 31% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 11.6 GW offshore wind, 11.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions.

Conclusions:

This scenario represents a potential outcome with higher electricity demand. This requires more renewable generation to achieve at least 30% of renewable electricity in 2020. This scenario shows how potential demand uncertainty has been considered.

6.2.7 Low Demand scenario

Key results:

- The UK LCF spend is £6.8bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 35% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 9.1 GW offshore wind, 11.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions.

Conclusions:

This scenario represents a potential outcome with lower electricity demand. This requires less renewable generation to help meet the overall 2020 renewable energy target. This scenario shows how potential demand uncertainty has been considered.

6.2.8 High Offshore Deployment scenario

Key results:

- The UK LCF spend is £7.6bn in 2020/21, within the LCF cap.
- In 2020 the UK achieves 36% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 15.0 GW offshore wind, 11.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 1.7 GW of biomass conversions.
- The modelling projects that later phases of offshore wind projects signing contracts up to 2020 add a further 5.3GW of offshore wind deployment shortly after 2020.

Conclusions:

This scenario is dependent on significant offshore wind levelised cost reductions by 2020 and higher build potential as a result. There is a larger requirement for network spend than in other scenarios due to the extra costs of connecting offshore wind and increases balancing costs. Since spend is close to the LCF cap there is a greater risk of spend going above the cap in the case of, for example, low fossil fuel prices or higher wind speeds.

6.2.9 Higher Biomass Conversions scenario

Key results:

- The UK LCF spend is £7.5bn in 2020/21, within the LCF cap, but breaches the profile in 2016/17.
- In 2020 the UK achieves 36% of generation from renewable sources.
- The key technologies see deployment levels in 2020 of 10.2 GW offshore wind, 11.9 GW onshore wind (plus 0.4 GW on Scottish Islands) and 3.4 GW of biomass conversions. In addition biomass CHP deployment increases by 0.3 GW by 2020 compared to all other scenarios which have 0.3 GW.

Conclusions:

This scenario represents more coal plants converting to biomass and additional biomass CHP uptake as compared to other scenarios. Due to higher generation from biomass and other renewable generation similar to Scenario 1, overall renewable generation is higher and spend is close to the LCF cap. This scenario highlights the uncertainty around biomass conversion and biomass CHP uptake and the associated impact on spend.

6.3 Results for Northern Ireland

In this section we outline the key metrics for Northern Ireland to 2020 for the scenarios modelled, as in section 3.7.4.

6.3.1 Northern Ireland Generation Capacity in 2020

The following table shows the 2020 capacity (GW) (excluding interconnection) in Northern Ireland by technology for the scenarios.

	2020 Capacity - GW								
Capacity - GW	Scenario 1	High Tech Costs	Low Tech Costs	High Fossil Fuel Prices	Low Fossil Fuel Prices	High Demand	Low Demand	High Offshore Deployment	Higher Biomass Conversions
Onshore wind	1.11	1.09	1.19	1.13	1.01	1.11	1.11	1.11	1.11
Offshore wind	0.20	0.20	0.20	0.20	0.20	0.40	0.20	0.20	0.20
Tidal & Wave	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other renewables	0.11	0.10	0.14	0.15	0.10	0.11	0.11	0.11	0.11
Unabated gas	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Unabated coal	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Other (excluding interconnection)	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37

The following table shows the 2020 new build capacity (GW) (excluding interconnection) in Northern Ireland by technology for the scenarios.

	2013 to 2020 New Build - GW								
Capacity - GW	Scenario 1	High Tech Costs	Low Tech Costs	High Fossil Fuel Prices	Low Fossil Fuel Prices	High Demand	Low Demand	High Offshore Deployment	Higher Biomass Conversions
Onshore wind	0.64	0.62	0.72	0.66	0.54	0.64	0.64	0.64	0.64
Offshore wind	0.20	0.20	0.20	0.20	0.20	0.40	0.20	0.20	0.20
Tidal & Wave	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other renewables	0.08	0.07	0.11	0.12	0.07	0.08	0.08	0.08	0.08
Unabated gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unabated coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other (excluding interconnection)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Over the period to 2020, there is growth in renewable generation capacity in all scenarios, mainly onshore wind but also tidal stream and wave, offshore wind and other renewables.

6.3.2 Northern Ireland Generation in 2020

The following table shows the modelled generation (TWh) (excluding interconnection) in 2020 in Northern Ireland by technology for the scenarios.

	2020 Generation - TWh								
Generation - TWh	Scenario 1	High Tech Costs	Low Tech Costs	High Fossil Fuel Prices	Low Fossil Fuel Prices	High Demand	Low Demand	High Offshore Deployment	Higher Biomass Conversions
Onshore wind	2.76	2.70	2.96	2.82	2.50	2.76	2.76	2.76	2.76
Offshore wind	0.50	0.50	0.50	0.50	0.50	0.99	0.50	0.50	0.50
Tidal & Wave	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Other renewables	0.44	0.42	0.46	0.47	0.42	0.44	0.44	0.44	0.44
Unabated gas	2.48	2.55	2.25	2.38	3.91	2.22	1.90	2.48	2.48
Unabated coal	0.51	0.51	0.51	0.51	0.29	0.51	0.51	0.51	0.51
Other (excluding interconnection)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

6.3.3 Northern Ireland renewable electricity

NI renewable generation has been incorporated in to the UK total used to calculate the renewable share of electricity which for all scenarios achieves the ambition.

6.3.4 Northern Ireland contributions to UK LCF

Support will be received by NI generators under both the RO and Contracts for Difference frameworks. NI support payments have been included in the UK LCF spend figures shown in the next section (estimated as explained in section 3.7.3).

6.4 Summary of UK Results

The following table shows the LCF spend and UK renewable generation percentage across all scenarios to give a UK picture for some of the key metrics in 2020 as explained in section 3.7.3.

Scenario Summary	LCF Spend in 2020/21 £million 2011/12 prices	UK Renewable Electricity %
Scenario 1	£7,000	33%
High Technology Costs	£6,500	30%
Low Technology Costs	£7,600	36%
High Fossil Fuel Prices	£6,500	34%
Low Fossil Fuel Prices	£7,400	31%
High Demand	£7,600	31%
Low Demand	£6,800	35%
High Offshore Deployment	£7,600	36%
Higher Biomass Conversions	£7,500	36%

In our modelling, generation for new capacity in 2020 is assumed to reflect plants on average coming on half way through the year. This allows us to more accurately calculate the renewable percentage in 2020 and LCF spend in 2020/21.

6.5 Key Conclusions

The key conclusions of the analysis are:

- The percentage of renewable electricity in 2020 ranges between 30% and 36% across the scenarios which contributes to the overall 2020 renewable energy target. The greatest risks to this ambition come from high technology costs, low wholesale electricity prices and high demand.

- The LCF spend in 2020/21 ranges between £6.5 billion and £7.6 billion across the scenarios. The greatest risks to breaching the LCF cap come from low technology costs (if allocation/deployment is not constrained), low wholesale electricity prices and high demand.

- Three technologies contribute significantly to renewable electricity in 2020 in the scenarios. These are onshore wind, offshore wind and biomass conversions. Below we put the deployment of these technologies into context regarding build potential[83] and historic build rates:

  - Between 8 and 15 GW of GB offshore wind capacity is installed by 2020. There are sufficient projects within the planning process that have connection agreements by 2020 either with consent or awaiting consent, to achieve significantly more than 8 GW, whereas 15 GW requires additional projects currently at the scoping stage to be commissioned by 2020. Build rates for 8 GW are comparable with rates which have been seen historically in 2011 and 2012, but 15 GW requires, on average, 50% higher build rate than seen historically.
  - Between 11 and 13 GW of GB onshore wind capacity is installed by 2020. There are sufficient projects currently under development to deliver 13GW of installed capacity by 2020. However, future build rates will depend on a range of factors, and it is unlikely that all projects currently under development will come forward.
  - Between 1.7 and 3.4 GW of biomass conversion capacity is built by 2020 across the scenarios. There are sufficient projects currently being developed to achieve the range.

- Technology costs are highly uncertain and could have a significant impact on deployment levels. As such reliable sight of technology costs and any changes to them is critical when setting Strike Prices to avoid step changes. Such changes would make investment decisions more difficult and potentially disrupt supply chains.

- Low fossil fuel prices, in particular low gas prices, risks higher LCF spend, as wholesale prices are lower than in the other scenarios. This will require an increase in CfD top up payments. Conversely high fossil fuel prices will lead to lower CfD top up payments.

[83] http://www2.nationalgrid.com/UK/Services/Electricity%20connections/Industry%20products/transmission%20networks%20quarterly%20connections%20updates/

- GB Network costs range from £3.9bn to £4.6bn in 2020/21 across the scenarios, with the exception of the High Offshore Deployment scenario, which has costs of £4.9 billion in 2020/21 due to the extra costs of connecting offshore wind and increased balancing costs.

- Wholesale power prices are broadly similar across the scenarios at around £63/MWh in 2020, as the price is set by similar marginal plants. The exceptions are the Low Fossil Fuel Prices scenario which has significantly lower prices at around £42/MWh and the High Fossil Fuel Prices scenario which reaches £81/MWh.

7. Annex

1. Electricity generation costs

Cost and technical data for new plant is taken from DECC's Electricity Generation Costs December 2013[84] report for all renewable and non-renewable technologies.[85]

2. GB Electricity demand

The low, central and high GB electricity demand projections up to 2030 are consistent with the DECC Energy and Emissions Model and are set out below.

Low and high demand projections represent

- For the low demand projections the 2.5th percentile of the distribution around the Updated Energy Projection (UEP) annual demand.
- For the high demand projections the 97.5th percentile of the distribution around UEP annual demand.

National Grid used DECC's UK wide demand projections with a 2.7% allowance for NI to give GB demands. The SONI analysis for Northern Ireland for the July draft Delivery Plan used different demand assumptions.

Electricity demand post 2030 is based on assumptions consistent with the Carbon Plan[86].

[84]https://www.gov.uk/government/publications/electricity-generation-costs
[85] https://www.gov.uk/government/publications/electricity-generation-costs
[86]www.gov.uk/government/uploads/system/uploads/attachment_data/file/48073/2270-pathways-to-2050-detailed-analyses.pdf

Annual Demand TWh	Low	Central	Adjusted for low fossil fuel prices	Adjusted for high fossil fuel prices	High
2012	338	338	338	338	338
2013	330	340	340	339	347
2014	323	335	337	334	346
2015	315	331	333	328	344
2016	309	327	330	324	344
2017	304	325	328	322	345
2018	302	324	328	322	346
2019	298	324	327	321	348
2020	296	324	328	321	351
2021	299	328	332	325	359
2022	299	331	335	328	365
2023	302	336	339	333	372
2024	306	341	344	338	377
2025	308	345	349	342	386
2026	313	351	355	348	394
2027	319	358	361	355	402
2028	325	366	369	362	414
2029	330	373	377	370	422
2030	337	381	385	378	431

Daily load curves

The model scales annual demand to half hour demand for sample days using daily load curves. These are half hour demand profiles for a range of days for each quarter from a high demand day to a low demand day. Each day is split into domestic and non-domestic load bands.

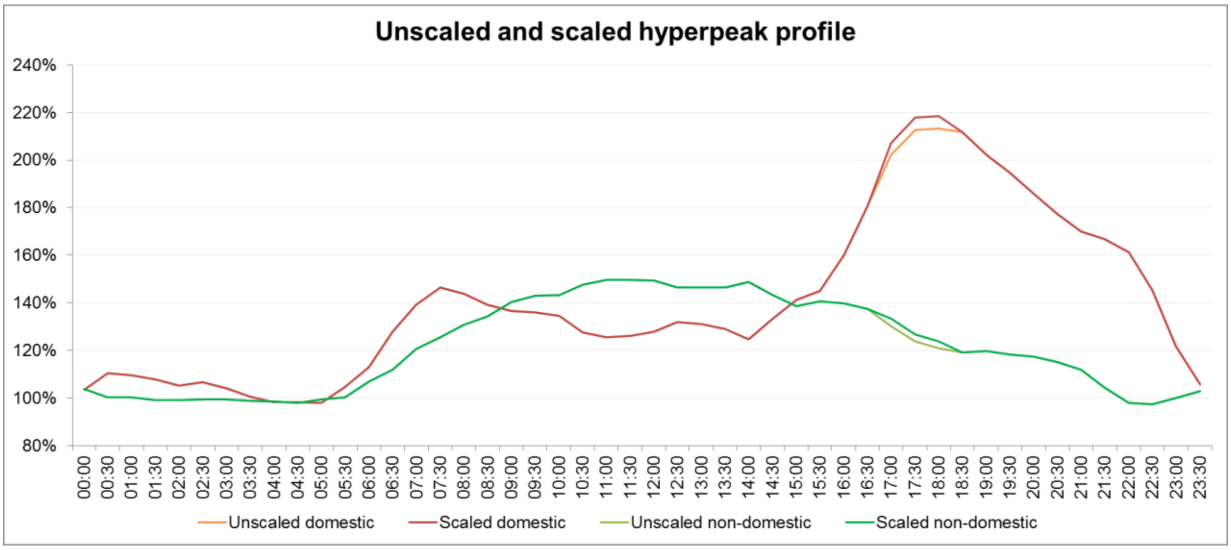
Domestic half hour demand is derived from the domestic profile classes from Elexon's sample of electricity customers scaled to annual demand. Non-domestic is calculated by subtracting the domestic demand from Initial National Demand Outturn (INDO)[87] demand and adding estimates of embedded wind, hydro, CHP and biomass. Embedded wind was given the profile of metered wind and embedded hydro the profile of metered hydro. CHP and biomass were both assumed to have the same values for every half hour of the year.

Half hour demands were calculated for the 4 years from April 2008 to March 2012. From this data half hour demand as a percentage of average half hour demand was calculated for a range of demand levels for each quarter.

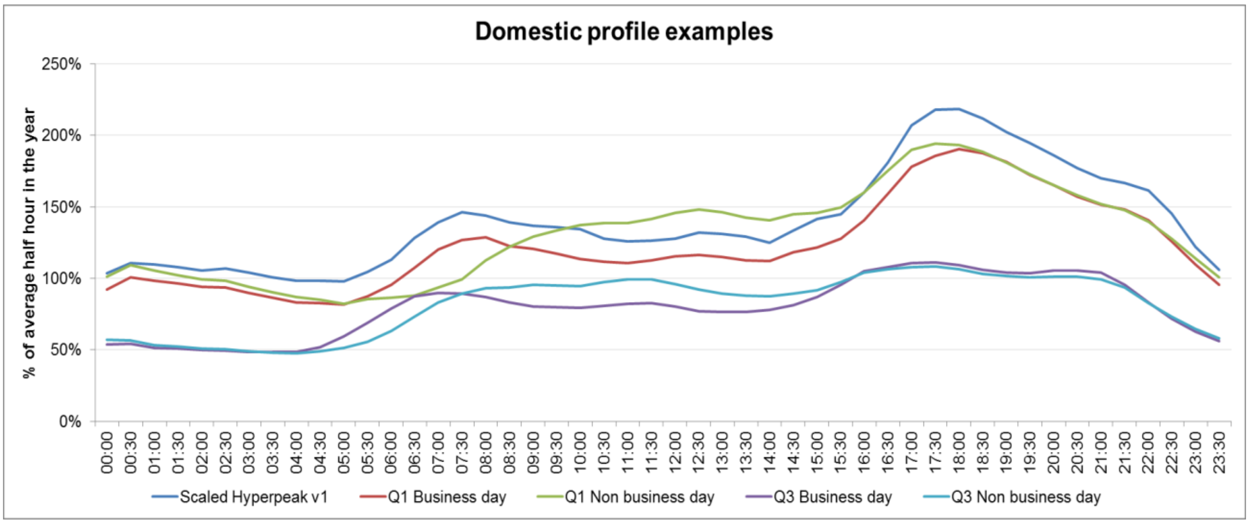
The highest demand day in the winter quarter was labelled hyper-peak. The evening peak values were scaled so that the resulting demands equalled the ACS peak in winter 2012/13.

[87] http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/

The chart below shows the hyper-peak profiles.



The chart below shows some example domestic profiles for winter (Q1) and summer (Q3).



3. Fossil fuel prices

DECC's fossil fuel price assumptions are used in the DDM as set out below to 2030.[88]

Oil Prices $/bbl			
	Low	Central	High
2012	111.6	111.6	111.6
2013	93.0	107.7	122.4
2014	91.8	109.0	125.7
2015	90.5	110.4	129.0
2016	89.2	111.7	132.4
2017	88.1	113.0	135.9
2018	86.8	114.4	139.6
2019	85.6	115.8	143.2
2020	84.4	117.2	147.0
2021	83.3	118.6	150.9
2022	82.1	120.1	154.9
2023	81.0	121.5	159.1
2024	79.8	123.0	163.3
2025	78.7	124.5	167.6
2026	77.7	126.0	172.0
2027	76.6	127.5	176.6
2028	75.5	129.1	181.3
2029	74.5	130.7	186.1
2030	73.5	132.2	191.0

Gas Prices p/therm			
	Low	Central	High
2012	60.1	60.1	60.1
2013	53.0	62.3	71.7
2014	50.6	65.3	86.4
2015	48.3	68.3	88.7
2016	45.9	69.1	91.1
2017	43.7	70.7	93.4
2018	41.3	72.3	95.9
2019	41.3	72.3	98.4
2020	41.3	72.3	101.1
2021	41.3	72.3	103.2
2022	41.3	72.3	103.2
2023	41.3	72.3	103.2
2024	41.3	72.3	103.2
2025	41.3	72.3	103.2
2026	41.3	72.3	103.2
2027	41.3	72.3	103.2
2028	41.3	72.3	103.2
2029	41.3	72.3	103.2
2030	41.3	72.3	103.2

Coal Prices $/tonne			
	Low	Central	High
2012	92.3	92.3	92.3
2013	85.0	89.5	94.0
2014	85.9	95.6	105.2
2015	86.7	101.8	110.4
2016	87.6	105.5	115.6
2017	88.3	109.2	120.8
2018	89.2	112.9	126.0
2019	90.0	116.7	131.1
2020	90.9	120.4	136.3
2021	90.9	120.4	141.6
2022	90.9	120.4	146.8
2023	90.9	120.4	152.0
2024	90.9	120.4	157.2
2025	90.9	120.4	162.4
2026	90.9	120.4	162.4
2027	90.9	120.4	162.4
2028	90.9	120.4	162.4
2029	90.9	120.4	162.4
2030	90.9	120.4	162.4

[88] https://www.gov.uk/government/publications/fossil-fuel-price-projections-2013 Note prices are deflated from 2013 prices in link to 2012 prices above

4. Carbon prices

The DDM uses DECC's published appraisal values of carbon.[89]

In addition, the Carbon Price Floor is included in the model following the trajectory set out in the Government's response to the Consultation on the Carbon Price Floor.[90] The trajectory between 2020 and 2030 is indicative.

Carbon Price Floor, 2012 £/tonne of CO_2e:

Year	Carbon Price
2013	7
2014	12
2015	19
2016	23
2017	25
2018	28
2019	30
2020	32
2021	36
2022	41
2023	45
2024	49
2025	53
2026	58
2027	62
2028	66
2029	70
2030	75

5. LCF profile

Spend in all scenarios has to be within the agreed LCF envelope as set out below.

£m, 2011/12 prices	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
LCF cap	3,300	4,300	4,900	5,600	6,450	7,000	7,600

[89] https://www.gov.uk/government/policies/using-evidence-and-analysis-to-inform-energy-and-climate-change-policies/supporting-pages/policy-appraisal
[90] http://webarchive.nationalarchives.gov.uk/20130129110402/http:/www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf

6. Pre-tax real hurdle rates by technology type

Technology name	RO hurdle rates used for December Delivery Plan*	Hurdle rate under CfDs during the Delivery Plan period
ACT advanced	11.2%	10.7%
ACT CHP	9.4%	9.5%
ACT standard	8.4%	7.9%
AD >5MW	12.0%	11.5%
AD CHP	13.0%	13.1%
Dedicated Biomass CHP	13.5%	13.6%
Biomass Conversion	11.6%	10.9%
EfW CHP	11.9%	10.8%
Geothermal	22.5%	22.0%
Geothermal CHP	23.5%	23.8%
Hydro	7.0%	5.8%
Landfill gas	8.4%	5.7%
Offshore Wind**	10.2%	9.7%
Offshore Wind R3**	10.4%	10.1%
Onshore Wind	8.3%	7.1%
Scottish Islands Onshore	8.3%	7.9%
Sewage gas	9.4%	7.5%
Large Solar Photo-Voltaic	6.2%	5.3%
Tidal stream (pre-commercial)	8.0%	8.3%
Wave (pre-commercial)	8.0%	8.3%

*As per the draft Delivery Plan analysis in July, these are adjusted for the Effective Tax Rate work which is explained in DECC's Electricity Generation Costs December 2013[91] report.
**Note that there is unlikely to be a clear distinction between all R2 and all R3 projects, as pre-tax real hurdle rates will vary on a project by project basis.

[91] https://www.gov.uk/government/publications/electricity-generation-costs

7. Power Purchasing Agreements

PPA discounts under the Renewables Obligation

	Wholesale price	ROC	LEC
Offshore wind	5%	5%	5%
Onshore wind	13%	10%	10%
Other intermittent renewables	13%	10%	10%
Non-intermittent renewables	7%	10%	10%

PPA discounts under CfDs

	Wholesale price	LEC
Offshore wind	5%	5%
Onshore wind	10%	10%
Other intermittent renewables	10%	10%
Non-intermittent renewables	7%	10%

8. Renewable maximum build limits

Maximum build limits are broadly consistent with those used in the RO Banding Review Government Response (2012), which are based on Arup (2011) and information obtained during the RO Banding Review Consultation[92 93]. Following the analysis, some of the build constraints have been revised based on information and commercial intelligence about the total capacity of projects that are coming forward. Projects already in the pipeline are consistent with DECC's latest view on what is in construction, based on planning consent databases and industry intelligence. For more detail see Annex H to the December EMR Delivery Plan.

GB Max build limits of renewable technologies eligible for CfD support in the modelling, by commissioning year.

Technology name	2016	2017	2018	2019	2020
ACT advanced	30	60	30	30	15
ACT CHP	0	15	0	15	0
ACT standard	90	105	75	105	45
AD	45	65	70	70	65
AD CHP	0	0	0	0	5
Dedicated Biomass CHP	25	100	60	200	100
EfW CHP	30	0	200	100	30
Geothermal	0	0	0	0	0
Geothermal CHP	0	0	5	5	5
Hydro	10	10	10	10	10
Landfill gas	5	5	5	5	5
Large Solar Photo-Voltaic	300	1000	1000	1000	1000
Offshore Wind	400	1300	2400	3000	2900
Onshore Wind	2100	2100	2100	2100	1100
Scottish Islands onshore	0	0	200	500	400
Sewage gas	5	5	5	5	5
Tidal range	0	0	0	0	0
Tidal stream	30	5	40	0	20
Wave	0	0	0	0	50

Notes:

- No assumed maximum build limits have been set in the modelling for biomass conversions. The deployment range is modelled based on projects potentially coming forward, as well as wider considerations about affordability under the LCF.

[92] https://www.gov.uk/government/consultations/supporting-large-scale-renewable-electricity-generation
[93] Build constraints for large solar photo-voltaic reflect assumptions underpinning analysis for the Renewables Obligation Banding Review for the period 1 April 2013 to 31 March 2017*:* Government Response to further consultations on solar PV support, biomass affordability and retaining the minimum calorific value requirement in the RO (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66615/7328-renewables-obligation-banding-review-for-the-perio.pdf), and build constraints for tidal stream and wave technologies reflect DECC's current understanding.

- There is limited information on maximum build limits for tidal range, but when details of potential projects emerge, impacts may be considered on a project-by-project basis.
- Build in earlier years for some technologies is given by pipeline plant rather than maximum build limits.
- Maximum build limits >100MW are rounded to the nearest 100MW; maximum build limits <100MW are rounded to the nearest 5MW.
- A build limit of 0MW means no build is assumed in that year.
- Compared to the draft Delivery Plan in July, tidal maximum build limits for GB have been revised to reflect potential location of build in Northern Ireland. Maximum build limits for the UK reflect draft Delivery Plan assumptions.
- Offshore wind maximum build limits from 2016 include the effect of phasing, so the figure for 2016 only represents the first phase of potential projects. 2017 represents phase 1 of potential projects in 2017 and phase 2 of potential projects from 2016 etc.

9. Maximum annual net load factors

The table below sets out the (rounded) maximum annual net load factors for CfD supported renewable plant.

Technology name	Maximum annual net load factors of CfD supported plant
ACT advanced	87%
ACT CHP	77%
ACT standard	89%
AD >5MW	84%
AD CHP	84%
Dedicated Biomass CHP	90%
EfW CHP	85%
Geothermal	91%
Geothermal CHP	91%
Hydro	34%
Landfill gas	58%
Offshore Wind	38%
Onshore Wind	28%
Orkney onshore wind	42%
Sewage Gas	51%
Shetland onshore wind	44%
Large Solar Photo-Voltaic	11%
Tidal stream (pre-commercial)	31%
Wave (pre-commercial)	31%
Western Isles onshore wind	35%

Notes:

- Biomass conversion plants are modelled on a plant by plant basis.
- The load factor for tidal stream refers to tidal stream shallow. Tidal stream deep is assumed to have a maximum annual net load factor of 39%.
- Maximum load factors for offshore wind refer to R2 sites. R3 sites are assumed to have an average maximum load factor of 39.5%. In practice there is unlikely to be a clear distinction between all R2 and all R3 projects, as load factors will vary on a project by project basis.
- Scottish Islands onshore wind load factors (Orkney, Shetland and Western Isles) are based on data that was published in the Baringa/TNEI report[94]

[94] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/199038/Scottish_Islands_Renewable_Project_Baringa_TNEI_FINAL_Report_Publication_version_14May2013__2_.pdf

10. Transmission Loss Assumption

The loss factors to 2035 assumed in the modelling are set out in the table below:

Year	Assumed losses
2010	0.68%
2011	0.83%
2012	0.83%
2013	0.83%
2014	0.84%
2015	0.85%
2016	0.85%
2017	0.87%
2018	0.88%
2019	0.89%
2020	0.89%
2021	0.90%
2022	0.90%
2023	0.90%
2024	0.90%
2025	0.90%
2026	0.91%
2027	0.91%
2028	0.91%
2029	0.91%
2030	0.92%
2031	0.92%
2032	0.92%
2033	0.93%
2034	0.93%
2035	0.93%

Notes:

- The loss factor is flat post 2035.
- Loss assumptions out to 2035 are presented as DECC envisages these being required to support the Contract for Difference.

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