Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes

A report for the Department of Business, Enterprise and Regulatory Reform, June 2008

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Study Objectives

This study was commissioned by the Department for Business, Enterprise and Regulatory Reform (BERR) to assess the suitability of different financial support schemes in delivering a major expansion of renewable electricity generation in the UK consistent with the overall EU renewable energy targets for 2020. In particular, the objective was to identify a shortlist of three schemes and to undertake a detailed comparative cost benefit analysis using dynamic modelling of the UK electricity market under the different schemes, whilst utilising input assumptions derived from BERR's own forecasts and from other studies commissioned by BERR in support of the Energy White Paper and Renewables Consultation.

Meeting the 2020 target

Meeting the EU 2020 renewables target will be extremely challenging, and will require the proportion of electricity generation from renewables sources to increase from around 5% currently to at least 32% by 2020, and possibly higher. The effort faced by the heat and transport sectors is similarly challenging.

Adopting an effective financial support scheme to stimulate the levels of investment required to reach the target generation within just a decade will form one component of the Government's strategy. However, at least as important will be policies that address current constraints in planning and the renewables supply chain, and that promote the efficient expansion of the grid to allow an additional 15 to 25 GW of generation capacity (renewable and non-renewable) to be simultaneously connected to the network by 2020 as a direct result of the increased renewables targets. The greater penetration of renewables may also necessitate changes to the current market arrangements (for example, to deal with congestion management), and the role of the System Operator between now and 2020. None of these additional policy considerations were within the scope of this study.

Putting these other considerations aside, a critical question facing policy makers is what type of financial support scheme is likely to be most effective and efficient in delivering against the 2020 targets.

Financial support schemes

A wide variety of support schemes are employed internationally. These fall into four broad groupings:

- obligation-based schemes, whereby suppliers or generators must meet a given proportion of total volume from renewable sources, usually through a market in tradeable certificates;
- feed-in tariff (FIT) schemes, whereby renewable generators obtain a long term guaranteed price for their output;
- tenders for specific volumes of different technologies, with guaranteed output prices for successful bidders; and,
- fiscal mechanisms including differential taxes or levies between renewable and non-renewable electricity, and grants for renewables projects.

The scheme currently in operation in the UK, the Renewables Obligation (RO), falls into the first category, with suppliers obliged to match a target percentage of sales with Renewables Obligation Certificates (ROCs). ROCs are issued to qualifying renewable generators for each unit of output. Proposals in the Energy Bill currently before Parliament would introduce 'banding', whereby different numbers of ROCs would be issued for each MWh output from different types of renewable technologies.

Policy makers face a complex set of decisions in the face of considerable uncertainty in commodity prices, the costs of renewables plant, and how the dynamics of investment and market operation might change under the new renewables strategy. We identified nine key criteria for evaluating different renewables financial support schemes. These were: minimising resource costs, avoiding excess economic rents, ensuring dispatch efficiency, robustness to uncertainty, avoiding unintended consequences, minimising the effect of the transition, promoting wider benefits, ensuring international consistency and compatibility with existing market arrangements.

The choice of preferred scheme may ultimately depend on the relative importance attached to each of these criteria. From our long list of fifteen potential schemes we identified three that scored relatively highly against these criteria, and which encompassed the spread of different approaches. These were:

- Extended RO - reflecting the RO as set out in the proposals currently included within the Energy Bill, with some further modifications required to meet a higher target level.
- Standard FIT - providing generators with a fixed price tariff for the output of the plant over its economic life.
- FIT/Tender hybrid – offering a feed-in tariff for more mature technologies (such as onshore wind), combined with tenders for less mature technologies with higher cost uncertainties, such as offshore wind, wave and tidal.

Quantitative assessment

The quantitative analysis of these three schemes suggests that each could be designed to meet the electricity targets modelled; 28%, 32% and 37%. The 37% target would be at the boundary of what was achievable according to the study of deployment constraints[1] conducted in parallel by Sinclair Knight Merz, and assumes a Severn Tidal Power project could deliver an additional 5% of renewable electricity, and that this would be eligible towards the 2020 target. Achievement of these targets would, however, be contingent on removal of significant constraints currently in planning and connection access, sufficient investment in the supply chain, and, to a greater or lesser extent, on the Government's ability to forecast accurately the costs of renewables generation relative to the alternatives. The sensitivity testing demonstrated that failings in any of these areas could jeopardise the achievement of the targets, and could have other consequences such as unnecessarily increasing costs to consumers. Another key risk to the achievement of the target, but not explicitly modelled in this study, would be a systematic failure of emerging renewables technologies to achieve the operational availability levels expected.

The higher renewables targets would reduce carbon dioxide emissions from the electricity sector by between 26% and 37% by 2020 from current levels. For each of the three electricity targets modelled, under base case assumptions the renewables policy led to a net prevent value welfare loss for the period

[1] SKM, *Quantification of constraints on the Growth of UK Renewable Generating Capacity,* June 2008

2008-2030 compared to a Status Quo scenario (which included the amendments to the RO introduced in the Energy Bill). These ranged across the three schemes between negative £20bn-£24bn under the 28% target, negative £30-£35bn under the 32% target, and negative £38bn-£42bn under the 37% target, representing between 6% and 14% of the total wholesale value of electricity. The additional resource costs (which include the costs of providing back-up generation, extra balancing services, and grid expansion as well as the investment costs in the renewables plant themselves) significantly outweighed the savings in terms of carbon dioxide emissions avoided (valued at the EU ETS allowance price). The impact was greater the higher the renewables target. (Had we attached additional value to renewables generation, such as avoidance of penalties for failing to meet the Directive targets, the net welfare loss would have been reduced.) The results were sensitive to the input assumptions used. For example, the net present value welfare loss across the schemes under a 37% target ranged from negative £19bn to negative £53bn, the lower figure associated with a world of high commodity prices ($153/barrel oil, $133/t coal, €60/t carbon), where renewables are relatively less expensive compared to the alternatives, the latter figure in a world of low fuel prices ($34/barrel oil, $49/t coal, €21/t carbon).

Whichever scheme is adopted, consumers will in most cases bear the majority of the additional costs of achieving the renewables target. Under the base case assumptions, the costs to consumers in meeting a 37% target ranged between £34bn and £40bn on a net present value basis across the three schemes, adding around £32-£56 (8%-15%) to the average annual domestic consumers' bill by 2020 relative to the Status Quo. However, when compared to a revised Status Quo of rapidly rising fuel prices coupled with continuing connection queues, and hence high producer rents, the deployment of high volumes of renewables through an effective financial support mechanism combined with a streamlined planning and connection process, appeared far less unfavourable to consumers (since they would already be facing high bills). Under one sensitivity, the highest commodity price case, the additional cost to consumers of a 37% target was close to zero under one of the schemes. In contrast, in our low fuel price case the additional net present value costs to consumers between 2008 and 2030 was as high as £44bn.

The analysis demonstrated the impact that a high penetration of intermittent renewables could have on electricity prices, depressing baseload prices and potentially leading to periods of zero or negative offpeak prices, but with higher, and increasingly volatile, peak prices (and with peak prices increasingly driven by low wind availability rather than peak demand). This may reduce investment in inflexible baseload plant, including some low-carbon options like nuclear and plant fitted with carbon capture and storage. Conversely, more flexible plant may be able to benefit from the increasing market volatility and increasing demand for system balancing services from the System Operator. These opportunities for flexible generation coupled with response from the demand side to emerging price signals suggest that security of supply need not be compromised by the higher renewables target, provided clear UK and EU government policy provides a robust framework that allows companies to anticipate the opportunities and to invest in a timely manner.

Of the three schemes modelled, the Extended RO shows the greatest net welfare loss, driven primarily by the higher cost of capital for renewables investment given the revenue uncertainty for generators under this scheme. The Extended RO is susceptible to high rents for renewables generators in the early years, particularly where commodity prices and hence electricity prices are high, or where build is constrained by external factors. While policy measures to reduce these rents could be taken over time (for example, by reducing planning and grid access bottlenecks and/or further refining the subsidy scheme), interventions to remove the rents directly could undermine investor confidence and hence be counterproductive.

The Standard FIT scheme has the lowest net welfare loss, is least expensive for consumers under the base case assumptions modelled and has the lowest risk of cost increases. Compared to the Extended RO, the additional consumer costs associated with the renewables target were between 16% and 19% lower (a difference of about 1% on the average domestic customer bill) under the Standard FIT depending on the target level. This is mainly due to the lower cost of capital for investors given the high degree of revenue certainty provided by guaranteed long term offtake agreements, relative to the uncertain subsidy level and increasing electricity price volatility to which ROC holders are exposed. However, the Standard FIT scheme is susceptible to errors in forecasting renewables costs and setting tariffs too low could jeopardise meeting the targets by 2020. This may encourage policy makers into offering higher tariffs to stimulate the levels of investment required over the short timeframes. Thus it cannot be assumed that economic rents could be eliminated using this approach. On the other hand, the Standard FIT has the advantage that subsidies for new plant can be adjusted in the light of experience of costs and opportunities without jeopardising the expectations of existing generators.

The FIT/Tender scheme appears most robust to external factors such as changing commodity prices. Using the tender component for off-shore technologies makes it also more robust to uncertainties about costs of earlier stage technologies and facilitates coordination with grid connection and planning. However, experience both internationally and in the UK has been of tenders under-delivering against targeted volumes. The inclusion of delivery obligations was designed to shift this risk to project developers, but led to the FIT/Tender scheme being more expensive than the Standard FIT in terms of resource costs, due mainly to the higher cost of capital for investors exposed to the greater delivery risk.

The Standard FIT and FIT/Tender approaches would both involve a transition from the existing arrangements, and would require some form of grandfathering arrangements for plant built under the RO, which would need to be sufficiently attractive to avoid any investment hiatus prior to the implementation of the new scheme. Both schemes assume that renewables generation is remunerated outside of the main market arrangements and careful consideration would be required as to how this output is aggregated and made available to suppliers.

Overall conclusions

The results from modelling a complex system should always be treated with caution. Many of the assumptions adopted in this study are highly uncertain and some potentially significant simplifications have been necessary, for example not modelling specific transmission upgrades and ignoring the possible impact of transmission constraints on the ability to meet the 2020 renewables electricity target. Nonetheless, the modelling captures the investment and price dynamics of the electricity market in an internally consistent manner and therefore provides a good vehicle for comparing the effects of different schemes.

The analysis demonstrates that there are potential pros and cons with each of the three schemes, and that there are a number of issues that require careful consideration in the detailed design of each. Overall, the results appear to bear out observations from international experience that the feed-in tariff approach could be the most effective in minimising resource costs and costs to consumers, particularly for technologies for which costs can be assessed with a reasonable degree of accuracy. However, given the tight timescales involved, there is a significant risk associated with transitioning away from a RO-based approach, leaving open the question of whether these risks exceed the potential benefits. The move to a potentially lower cost scheme (but untested in the UK context) could be self-defeating if it is poorly managed and results in a slow down in investment between now and the implementation of the new scheme, making the achievement of the 2020 target yet more challenging. On the other hand, a well communicated change that reflects the new renewable target level could signal a step-change that is part of a consistent policy framework, and could thus accelerate private sector investment decisions.

Either way, a swift resolution of the overall approach and the scheme details is essential to ensure that investors have the confidence to start the process of expanding their renewables project delivery capabilities which will be required to meet the 2020 target.

1 Introduction

1.1 Study objectives

This study was commissioned by the Department of Business Enterprise and Regulatory Reform (BERR) to assess the suitability of different financial support schemes in delivering a major expansion of renewable electricity generation in the UK consistent with the overall EU renewable energy targets for 2020. In particular, the objective was to identify a shortlist of three schemes and to undertake a detailed comparative cost benefit analysis using dynamic modelling of the UK electricity market under the different schemes, whilst utilising input assumptions derived from BERR's own forecasts and from other studies commissioned by BERR in support of the Energy White Paper and Renewables Consultation.

1.2 Contributing organisations

The study has been led by Redpoint Energy, working with Trilemma UK and the Electricity Policy Research Group (EPRG) of the University of Cambridge.

Redpoint Energy (www.redpointenergy.com) is a specialist energy consultancy, advising clients on investments, risk, strategy, policy and regulation across Europe's liberalised power and gas markets.

Trilemma UK (www.trilemma-uk.co.uk) provides clients with advice on regulatory, policy and strategic issues affecting UK and European energy markets.

The Electricity Policy Research Group (www.electricitypolicy.org.uk) is based at the Faculty of Economics and at the Judge Business School, University of Cambridge. The group offers rigorous independent research output that informs public and private sector decision making in the electricity and energy industry.

1.3 Structure of report

This report is structured as follows:

In **Section 2** we outline the policy objectives for financial support mechanisms. We summarise the requirements of the EU 2020 targets, provide the historic UK context, examine the requirements for meeting the UK obligation under the targets, and consider policy issues from the perspectives of investors, consumers and policy makers.

In **Section 3** we introduce the different types of support schemes that have been deployed internationally, highlighting observations from a survey of schemes in different countries.

In **Section 4** we describe our qualitative assessment of scheme types, and provide a short outline of each of the 'long list' of the scheme types we considered.

In **Section 5** we present and discuss the quantitative results from our modelling of the three shortlisted schemes. We outline our modelling framework and approach, describe the detailed features of each scheme, and present our 'Status Quo' scenario as the reference case (or counterfactual) in the absence of a change in policy. We illustrate the impact of a world of high renewables penetration using an example case that meets a 37% target. We then show the comparative results between the three schemes against this target. Finally we show how each scheme is impacted by a number of different sensitivities.

In **Section 6** we present the conclusions of the study.

The **Appendices** contain further details of the review of international experience, approach, assumptions and results:

- Appendix A summarises the results of our survey of international experience
- Appendix B describes our qualitative assessment process in more detail
- Appendix C documents our modelling input assumptions
- Appendix D describes our assumptions for modelling output from renewables
- Appendix E contains the detailed cost benefit results for all the cases modelled

2 Policy Objectives

2.1 Introduction

The UK has had policies providing explicit financial support for large scale renewable electricity generation since 1989. Without such support, the development of renewable capacity would not have been commercially viable. The broad objectives of such policies have been to increase directly the level of renewable generation for its environmental benefits, whilst also accelerating progress along the 'learning curve' with the long term aim of making renewables competitive with other forms of generation. Alongside the policies, the Government has set targets for renewables deployment. The 2002 Energy Review set a target share for renewables generation of 10% by 2010, and the 2006 Review added an aspirational target of 20% by 2020. As discussed below, the 'EU 2020' target proposed by the Commission's 2008 draft renewables Directive would represent a step change compared to current target levels.

At a high level, the objective of policies providing financial support for renewables is to establish a mechanism that leads to the deployment of sufficient renewable capacity to meet target generation levels as efficiently as possible. In practice, assessing the impact of a given potential policy, and determining its likely efficiency and effectiveness ex-ante, is challenging and complex. In this section, we review the EU 2020 targets, provide background on UK renewable electricity financial support mechanisms to date, and assess the perspectives of key stakeholders (investors, consumers and policy makers) that an assessment of policy must consider.

2.2 EU 2020 targets

At the 2007 Spring Council, the European Union Heads of State agreed on a target of meeting 20% of total energy consumption from renewable sources by the year 2020. This is one key component in meeting overall EU energy policy objectives of combating climate change, enhancing security of supply and increasing economic competitiveness.

On January 23, 2008, the European Commission proposed a draft Directive[2] to implement this target. The Directive is currently being debated in the European Parliament and changes are possible, but adoption is expected by the end of 2008 or in the first months of 2009.

To deliver an arrangement that allows for a fair allocation of the 20% renewable target, shares have been apportioned to Member States taking into account current renewable energy production, resource potential, and relative gross domestic products (GDPs). Under these proposals, the UK target is 15% in 2020, compared to 1.3% level achieved in 2005. (The Directive also presents interim trajectories although these are non-binding.)

[2] Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources, Brussels, 23.1.2008 COM(2008) 19 final 2008/0016(COD), at ec.europa.eu/energy/climate_actions/doc/2008_res_directive_en.pdf

Within the draft Directive there is a 10% target for the use of biofuels within the transport sector, subject to sustainability. Other than that it is up to Member States how to allocate their individual targets between their electricity, heat and transport sectors.

Details surrounding the possibility of trading renewables certificates, so-called Guarantees of Origin (GOOs), between Member States are still to be negotiated.

2.3 UK renewable electricity policy development to date

2.3.1 Non-Fossil Fuel Obligation

The 1989 UK Electricity Act introduced the restructuring and privatisation of the electricity sector, and the introduction of the England & Wales Pool. (Separate arrangements applied to Scotland and Northern Ireland.) At the same time, the Non-Fossil Fuel Obligation (NFFO) was introduced, and this remained the prime renewable support scheme until 2002. The NFFO was administered as a series of competitive tenders, for which renewable energy developers submitted bids specifying the price at which they would be prepared to develop a project. The Government determined the level of capacity for different technology bands, and offered contracts to the winning bids. The Public Electricity Supply companies were obliged to purchase all NFFO generation offered to them and to pay the contracted price for this generation. The difference between the contracted price and the wholesale price, which represented the subsidy to renewable generation, was reimbursed using funds from a Fossil Fuel Levy raised on customer bills.

2.3.2 Renewables Obligation

In April 2002, the NFFO was replaced by the Renewables Obligation (RO). Eligible renewable generation facilities receive Renewable Obligation Certificates (ROCs), corresponding to energy produced (1 ROC issued for each 1 MWh of generation). Electricity suppliers are obliged to buy ROCs corresponding to their share of total electricity sales. This obligation was set at 3% of sales in 2002/3, increasing to 15.4% by 2015/16. A supplier that does not obtain sufficient ROCs has to make 'buy-out' payments (£30/MWh in 2002/3, rising annually in line with inflation). These buy-out payments are recycled back to suppliers that have presented ROCs, hence increasing the value of producing renewable electricity in years where the obligation size is not achieved.

The UK is in fact covered by three RO schemes. The Renewables Obligation Order, covering England and Wales, and the Renewables Obligation Order (Scotland) were introduced simultaneously. The Renewables Obligation (Northern Ireland) Order came into effect later, in April 2005. The Orders mirror each other in implementation, such that certificates are mutually tradable between the different regions. England and Wales and Scotland have the same obligation levels (in percentage terms), whereas Northern Ireland has smaller relative obligation sizes. Ofgem administers the England and Wales and Scotland schemes, and provides the same service for Northern Ireland on behalf of the Northern Ireland Authority for Utility Regulation (NIAUR).

2.3.3 Energy Bill proposals

The current RO provides the same support level irrespective of technology, leading to strong investment in the lower cost technologies such as landfill gas, onshore wind and co-firing. In May 2007, the Government published a consultation document[3] on the introduction of 'banding', which would lead to the issue of different numbers of ROCs per MWh for different types of renewable generation. The Energy Bill currently before Parliament provides the necessary powers to introduce banding and, subject to Parliamentary approval, the changes would be likely to be implemented in 2009. Five bands are proposed, ranging from 0.25 to 2.0 ROCs/MWh, with technologies categorised by market maturity.

The proposals also include two new mechanisms designed to reduce the risk to investors of a ROC price crash in the event that the obligation is exceeded. Under the current RO, if more ROCs were to be issued for a given year than required for suppliers to meet their obligations, the price of certificates could theoretically fall close to zero as generators competed to sell in an oversupplied market. (This situation would be analogous to the collapse of the price of EU Allowances (EUAs) in Phase 1 of the EU Emissions Trading Scheme for carbon.) The 'headroom' mechanism will adjust the size of the obligation upwards if actual generation is forecast to exceed the target up to a level of 20% of total supply. (The headroom mechanism also avoids the risk of excessive recycling revenues by only increasing the size of the obligation as a function of the delivery capability of the market.) The 'ski-slope' mechanism would ensure that prices tapered down smoothly in the event of oversupply (should the 20% maximum target be reached) rather than collapse. The details of how these mechanisms are introduced are expected to be finalised over the next few months.

2.4 Meeting the 2020 target

2.4.1 Meeting the UK obligation

The draft Directive contained the proposed allocation of the overall EU renewable energy target amongst member states. As mentioned above, the UK target is 15% and, provided that the draft Directive passes into legislation, the UK Government will be required to present to the European Commission by March 2010 a 'National Action Plan' which explains how this target will be met.

In preparing the National Action Plan, the Government will need to take a view on two key issues:

1. To what extent does it intend to meet the targets through the domestic production of renewable energy and what assumption should it make about the ability to purchase credits from other countries; and,

2. How the national target should be split between the electricity, heat and transport sectors.

The Directive allows for two mechanisms for trading of obligations under the targets. Member States can either:

- trade their surplus or deficit of renewable generation at a Government level; *and/or*

[3] Reform of the Renewables Obligation, May 2007

- give market participants the flexibility to trade between themselves by issuing 'Guarantees of Origin' (GOOs) for units of renewable energy output, which can then be sold in other Member States, instead of contributing to the target in the originating location.

GOOs may only be transferred from Member States where the share of energy from renewables sources equals or exceeds the indicative trajectory set out in the draft Directive. At this stage it is not clear what choices Member States will make in this regard. Thus far, there seems to be limited enthusiasm for a full integration of renewable trading schemes through GOO trading. It was therefore felt that for the purposes of this study it should not be assumed that the UK can rely on meeting its target through importing credits from elsewhere, and hence the potential to integrate the UK support scheme with trading schemes in other European countries was not explored within the scope of this study. This does not imply that the Government cannot ultimately cooperate with other member states and agree on the transfer of GOOs for renewable energy in exchange for financial and technical support for their renewable deployment. Such agreements need not alter the type of support scheme in the UK, only the target level of renewable energy to be delivered in the UK.

The allocation of the national target between the various energy sectors will be critical since there may be limited opportunity for trading of burden across sectors. The Government will therefore need to take a view on the least cost route to deliver the overall target and derive sector targets accordingly. Policies will need to be implemented to deliver these targets most efficiently, taking into account interactions such as ensuring that limited resources (e.g. biomass) are used economically. In the UK, the electricity sector has a more easily accessible renewable potential than heat and transport, and is therefore likely to have a correspondingly higher target, and one that will be significantly higher than the previous aspirational target for 2020 of 20%.

This study is focused solely on policies for the electricity sector. In undertaking the modelling work, it was necessary to assume the proportion of the overall target to be delivered in this sector. This target was taken as an exogenous input, and since the burden share between different sectors is still to be finalised, we examined three different target levels from renewables electricity generation: 28%, 32% and 37%.

2.4.2 Measures required to meet electricity target

Delivering any of the assumed target levels represents a step change compared with expected renewable penetration arising from existing (or currently planned) policy measures. Meeting these new targets will involve a combination of policy initiatives including financial support, streamlined planning and connection policy.

The Government must consider whether an extension of the RO will form the most efficient financial support mechanism, compared to a transition to an alternative set of arrangements. This study is intended to provide input to this decision.

Outside the financial support mechanism, relieving the bottlenecks that impose hard physical constraints on renewables deployment is likely to be particularly important. It is expected that, as long as the financial incentives provided by any support scheme are both attractive and credible, the supply chain will respond to the expected market need and gear up production capacity of the necessary plant and equipment. However, there will be some aspects of the supply chain that will be difficult to expand over even a ten year time horizon, such as the number of installation barges needed to deliver a dramatic expansion of offshore wind capacity.

Other possible bottlenecks, in particular the planning system and grid connection, are the subject of ongoing policy reviews and legislative proposals.

In November 2007 the Government introduced a Planning Bill containing draft legislation that proposes changes to the planning system for nationally significant infrastructure projects across the water, waste, energy and transport sectors along with the establishment of an Infrastructure Planning Commission (IPC). The Bill will also enshrine new National Policy Statements (NPS) to set out Government policy for infrastructure development and BERR expects to produce a suite of NPSs for energy infrastructure.

In the 2007 Energy White Paper, the Government announced a review led by Ofgem and BERR of the framework for connecting renewable generation to the grid. The review examines the technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the grid to ensure that they remain fit for purpose as the proportion of renewable generation on the system grows. The Transmission Access Review project is expected to conclude shortly.

All of these physical build constraints are the subject of a separate study by consultants Sinclair Knight Merz (SKM) and their results have been used as an input to this work[1].

Finally, some argue that fundamental reform of the overall wholesale market arrangements will be necessary to ensure efficient plant dispatch and utilisation of the transmission network with such a large proportion of non-controllable renewables output, regardless of the support scheme. This is an important issue which requires further consideration, but is outside the scope of this study.

2.4.3 Contribution of large and small scale generation to the target

Renewable generation can be both large scale and directly connected to the transmission system, such as large wind farms, or small scale, perhaps providing power to a particular consumer and exporting small amounts onto the local grid network. Both ends of this spectrum have a role to play in meeting the renewable electricity targets. However, given the size of the challenge, it is likely that the vast majority of the electricity generated will arise from larger scale projects.

This study focuses solely on policies to support large scale schemes of capacity 50 kW or more. However, it is important to note that there remains an active policy debate over the most appropriate way to incentivise growth in renewable microgeneration. In particular, this debate has focused on the most appropriate way to reward electricity not required for local use and therefore sold back onto the grid system. There has been considerable debate over the need to introduce a feed-in tariff system to support this spill generation although it should be noted that different issues arise for small and large scale generation and one might not necessarily adopt the same support system for both. This would however require that both schemes offer similar levels of support, otherwise investors might alter the capacity of projects closer to the marginal size so as to be covered by their preferred scheme and potentially forgo cost savings from economies of scale.

The targets modelled in this study (28%, 32%, 37%) exclude the additional potential contribution from microgeneration.

2.4.4 Severn Barrage

During the time of the CEGB, there were a series of studies focusing on examining the possibility of harnessing the huge tidal range found in the Severn Estuary (~14m) to generate electricity. These studies concluded in 1989 in Energy Paper 57 and found that an ebb generation scheme between Lavernock Point and Brean Down (the scheme now known as Cardiff-Weston) was (having been identified as the preferred scheme by earlier studies) technically feasible and would have an annual output of approximately 17 TWh. However, Government decided that a Severn Barrage was not a cost-effective option for generating electricity at that time.

With renewed focus on renewable generation there have been various calls to look again at the desirability of a Severn tidal power scheme and the Government published the terms of reference for a feasibility study on 22 January 2008[4]. The study is expected to last up to two years and will look at a number of potential locations and different tidal range (rather than tidal stream) technologies, such as barrages and lagoons, as this is where the energy potential in the Severn Estuary is greatest.

While this feasibility study is still ongoing, it is difficult to make modelling assumptions as to whether a tidal power project in the Severn Estuary will be delivered or the location and timing of any electricity output generated by a potential project. However, given the potential size of such a project and its likely impact on the rest of the market, it is sensible to model a Severn Tidal Power project as a sensitivity.

Given that there is a greater amount of currently available information for the Cardiff-Weston barrage, and that this scheme is the largest in generation terms and so is likely to have a greater impact on the electricity market than any smaller scheme, our analysis has only looked at sensitivities with and without a Cardiff-Weston barrage.

It is not expected that a Cardiff-Weston Barrage could be built by 2020, although it is possible that it may be completed shortly after this date. There is provision in the draft Directive for special consideration to be given to very large renewables developments, with a production capacity of 5 GW or greater. Where construction has started by 2016, and the plant can be operational by 2022, then an adjustment to the 2020 share may be made to reflect the future contribution of the plant. The rules for such an adjustment must be formulated by the end of 2012.

The size of a Cardiff-Weston Barrage (hereon referred to as a Severn Barrage for simplicity) makes it very different from any other renewable project currently contemplated. As such it represents a ‘special case’, and we have assumed that it would be supported under separate specific arrangements whatever the main renewables financial support scheme in place. The analysis in this study has been carried out for a number of scenarios with and without a Severn Barrage.

2.4.5 Northern Ireland

On 1 November 2007, the Single Electricity Market (SEM) went live, under which a single set of wholesale trading arrangements is in effect for both the Republic of Ireland and Northern Ireland. The SEM consists of a mandatory Pool, with centralised dispatch based on day-ahead commercial and technical offers from generators, combined with a Capacity Payment Mechanism, whereby an annually set ‘pot’ is paid to

[4] http://www.berr.gov.uk/energy/sources/renewables/explained/severntidalpower/page41473.html

generators based on availability. As a result, the investment framework for new generation is very different to Great Britain.

The renewable support mechanisms in the Republic and the North are still, however, those set by the respective Governments, with the Northern Ireland RO in the North and a feed-in tariff scheme in the Republic.

The main focus of this study has been the Great Britain (GB) electricity market. However, careful consideration is required whether the same scheme adopted in GB can be successfully applied in Northern Ireland given the different underlying market arrangements. It will also be necessary to determine the contribution of renewables plant in Northern Ireland to the UK target. For the purposes of this study we have implicitly assumed that Northern Ireland will contribute the same proportion of renewables generation as a percentage of consumption as the rest of the UK. However, modelling of the Northern Ireland market was not included in the quantitative assessment in this study.

2.5 Stakeholder perspectives

To help identify the key challenges associated with formulating renewables support schemes, we consider the perspectives of three key stakeholder groups:

- investors;
- customers; *and*
- policy makers.

2.5.1 Investors

As it is the market participants that will actually deliver new renewables capacity, it is clearly important to understand the perspective of investors when analysing policy options. A wide range of different players are involved. At one end of the spectrum are the large portfolio investors, operating across the full range of power generation technologies, other parts of the value chain and often many geographical regions. At the other extreme are entrepreneurs looking to take advantage of specific opportunities. There will be a similar spectrum of financing structures, with varying debt/equity ratios. Even apparently similar companies may behave differently due to particular circumstances or the personalities involved. However, most key players will already have significant experience of investing in renewable energy, and will have derived lessons from their previous UK involvement. The following list is typical of the comments often expressed by UK renewables investors:

- The UK has considerable renewable energy resource, much of which is, as yet, unexploited.
- Political commitment to supporting the growth in renewables appears robust, the market share for renewables will grow, and this is therefore a critical part of the overall power market for established players and new entrants alike.
- Planning and consenting processes can be fraught, so the policy designed to provide financial support and meet renewables targets has to be robust to delays and a significant proportion of failed projects.

- Many of the technologies, particularly those deployed offshore, remain immature and there is still some way to go before there is adequate technical learning to ensure good operational performance.
- There is a concern that manufacturers have the potential to increase prices to take rents arising from subsidy mechanisms and/or that policy makers will 'change the rules' if profits are deemed to be too high.
- Those markets elsewhere in Europe that have achieved significant penetration of renewable energy have placed greater demands (and costs) on grid owners and operators, whereas the lower deployment of renewables in the UK has mainly been achieved thus far through the existing market and transmission arrangements.

Impact of the Renewable Energy Directive on investors

The significance of the proposed Directive is already apparent and companies will already be considering how it affects strategy going forward. It is likely that the following key questions are being addressed.

Are the targets credible? Most renewables developers will be acutely aware of the various obstacles that have constrained the rate of renewable deployment hitherto and may therefore be cynical about the ability of policy makers to trigger the step change necessary to hit the new targets. They may therefore see a future political 'watering down' of the targets as a plausible scenario, and may see any change from current investment plans as a major risk until there is strong evidence that the obstacles are being addressed.

What is the impact on existing portfolios? Existing investments in renewables and other assets will have been justified on the basis of a view of the future and will be enshrined in business plans and financial targets. Meeting these targets will be of paramount importance to companies, and the key individuals involved. Any policy change following from the Directive that adversely affects their ability to do so will be damaging, and increase the policy risk attributed to investment decisions. Satisfactory resolution of this issue is therefore key to avoiding an investment hiatus and/or higher hurdles for future projects.

How much and when should we invest? The increased growth potential for renewables in light of the Directive will be an attraction for all investors. However, the challenging nature of the targets means that the UK Government will need to make at least some revisions to the policy framework. Experience shows that market interventions risk unsettling investor confidence and reducing, albeit perhaps temporarily, the flow of investment. Companies are now familiar with making investment appraisals on the basis of the RO and are currently absorbing the impact of the introduction of banding, and they will inevitably need to assess the risks and opportunities arising from any future changes. During this time some investors may place current projects on hold, and it is unlikely that any decision will be taken to increase investment until the future of the support mechanism has been clarified and the commercial implications are fully absorbed. In practice, confidence in the new market arrangements will develop progressively as evidence of political commitment to delivering the 2020 targets emerges at national and European levels, a holistic package of measures is introduced covering both the renewables sector and its impact on the residual market and, finally, as practical experience of the new measures is obtained. The willingness of financiers to lend on the basis of the new arrangements will be a critical test of their credibility. As confidence grows it is likely to be accompanied by companies setting increasingly ambitious internal renewable capacity targets and stepping up deployment of the necessary resources. The decisions as to how to allocate those resources will be influenced by the relative risks and opportunities companies see across different markets.

Policy preferences

Different organisations are likely to express different preferences about the detailed design of the ongoing renewable support mechanism. Large diversified energy companies will tend to prefer ongoing subsidy mechanisms that contain a degree of market risk which their scope and scale will help them manage, whilst niche developers may prefer advantage to lie with those best able to seek out and develop project opportunities with the market risk managed on their behalf through long term guaranteed offtake agreements. However, all investors would undoubtedly see the need for clarity and certainty as more important than any of these detailed design features.

If fundamental changes are made to the renewables support mechanism, it is possible that investors will begin to view this as a step on a policy journey and therefore expect further changes to be made in the future. If this is the case, investors will be cautious when future revenue streams rely on future policy stability and they will place particular focus on the cost and management of this risk. On the other hand, a well communicated change that reflects the new renewable target level could signal a step-change that is in part of a consistent policy framework, and would thus accelerate private sector investment decisions.

Summary of investors attitudes

In summary, investors will be balancing the opportunities for profitable growth with the inevitable concern that the future profit potential results largely from a Government created subsidy mechanism rather than a fundamental market need. The extent to which investors will be attracted to exploit fully the growth potential depends on their beliefs about Government commitment to deliver future targets and implement the necessary enabling changes (planning, transmission), and the extent to which they will honour through grandfathering arrangements the reasonable expectations of investors for returns in the event that the subsidy mechanism is revised. They will be comparing opportunities across European countries (and indeed elsewhere), and resource allocation decisions will take into account the relative risks and opportunities between markets.

2.5.2 Consumers

As a stakeholder group, electricity customers will be affected most directly by the impact that renewables support mechanisms have on energy prices and the level of policy ambition is such that this impact will be significant. Therefore, although perhaps less interested in the technical aspects of policy design, customers will be acutely interested in the outcomes they create. Although this interest will be largely focused on energy costs, there is a growing interest in some customer groups in the way energy is produced and, therefore, support for policies that promote renewable energies.

Industrial and commercial customers

The primary concern of industrial and commercial customers will be on the impact that renewables support mechanisms have on energy prices and, critically, the extent to which these costs can be passed through to customers. This is of concern for electricity intensive consumers who are competing with firms located outside of Europe and possibly not subject to similarly ambitious renewable policies. Even those customers whose markets and competitors lie within Europe or even within the UK will still have concerns about cost increases. Their customers will choose not to buy their product if prices increase above affordability thresholds and this can have a significant impact on some businesses.

On the other hand, an increasing number of industrial and commercial consumers are finding that their customers demand accurately calculated and low carbon footprints for the products they supply. An increase in the proportion of renewable energy sources will make it easier for companies to meet these expectations on their products.

Domestic customers

The extent to which energy costs increase over the next decade relative to overall household budget is an important political issue. There are, of course, those customers for whom energy costs are low relative to income levels, and who may care little about increased prices. However, an increasing number of customers will be hurt as prices rise and for some vulnerable customers this effect can be serious. It is expected that these social aspects of energy policy will remain on the political agenda over the next decade, and will require the adverse consequences for vulnerable customers to be addressed.

On the other hand, there are those customers who place increasing importance on the way energy is produced and who are prepared to pay more to support the development of renewable sources of energy. At the moment, this represents a relatively small proportion of the customer base (hence the need for substantial subsidy) but a developing understanding of the impact of climate change could well see this proportion of customers increase significantly over coming years. These customers will require good quality information and likely seek guarantees that their energy is being sourced from renewable sources.

2.5.3 Policy makers

Policy makers face a complex and difficult set of challenges to attract the investment needed, and to provide the regulatory framework, to deliver the EU 2020 targets. As an integral part of Europe's long-term climate policy trajectory, their success will be used by international observers to measure the credibility of the European commitment to climate policy. As such, policies may not only deliver direct emission reductions, technology development and long-term options for the UK, but can play an important role in encouraging other countries and regions in pursing ambitious climate policy. We discuss a number of the key challenges below.

Competing policy objectives

Setting energy policy involves identifying and resolving the conflicts between a number of competing objectives. In particular, measures to achieve environmental goals can have negative impacts on energy costs and security of supply. The challenge of policy makers, therefore, is to develop renewables support mechanisms in ways that minimise adverse conflicts and leverage synergies where they exist. This is an extremely complex process with no easy answers, and difficult decisions will inevitably need to be faced.

Policy interaction

The financial support mechanism for renewable electricity is just one of an interconnected network of policies being considered to support the overall UK target. The Government is assessing transmission network issues, planning issues, and other non-financial barriers, as well as determining the policy frameworks that will be required for the heat and transport sectors. Energy efficiency measures will be needed to meet the targets emerging from this component of the overall EU Climate Change Package, which in itself could reduce the burden to meet the renewables target by reducing consumption against which the target is set. There will also be interaction with other existing environmental policies (such as the future of the EU ETS, and the Climate Change Levy). As well as the need to ensure an integrated approach to achieve efficient deployment, factors such as planning delays or transmission access queues can also have an impact in terms of inflating economic rents for successful projects (depending on the financial support scheme in place) due to constraints on new build.

Uncertainty

Policy makers face a high degree of uncertainty with regard to future commodity prices, costs of new renewable and conventional generation capacity, costs of capital, the evolution of emerging technologies, overall resource potential, the impact of non-financial barriers, and the limits around maximum build each year. All these factors play a major role in determining the potential costs and impacts of policy options. For example, the need for a subsidy to incentivise renewable generation decreases significantly at times of high fuel prices and a subsidy mechanism that does not adjust to these circumstances with reduced remuneration levels could create high rents. Conversely, if fossil fuel prices collapse then the subsidy would need to be greatly increased to continue to attract new investment. Similarly, any scheme with support levels fixed based on forecasts of plant costs is particularly exposed to large changes in capital costs with the result that too little or too much new capacity could be built.

Attracting investment

Meeting the 2020 target requires a significant scaling up of investment compared to that previously envisaged. Companies must be satisfied that the value in existing and planned renewable assets is preserved (or possibly enhanced) even as policy evolves to that needed to attract a higher level of investment going forward. The treatment of ‘grandfathering’ of historic investments is therefore critical. Time pressures are such that policy solutions need to be practical and easy to implement. For example, changes involving the need for primary legislation will inevitably be more fraught and time consuming than those which can be introduced via secondary legislative routes. This must go hand-in-hand with clarity as to how non-financial barriers currently constraining growth will be reduced or removed. Government must also consider how the UK compares relative to other countries as international companies make choices as to where to invest.

Allocating risks

In setting the policy framework, the Government is effectively allocating risks between investors and customers. If investors are exposed to higher risk their cost of capital will be high, increasing the level of support required for renewables to be built. Reducing the risk for investors by providing revenue and policy certainty can reduce the cost of capital and level of support needed, but shifts the risk of any non-economic investments to consumers. Finding the optimal allocation of risk between investors and consumers is a key challenge in scheme design.

Technology differentiation

As noted above, there is large uncertainty in the accessible potential, economic viability and public acceptance of different technologies. Government must weigh the costs of explicit support for a portfolio of technologies against the possible longer term benefits that may result from a diverse mix of capacity, accelerated learning curves, and earlier development of less economic resources in meeting the challenging target timeframe. Support mechanisms which involve little differentiation in reward between different projects will tend to lead to those projects with lowest resource costs being exploited first, whilst those mechanisms which provide differentially greater support to more expensive projects are more likely to attract investment in both higher and lower resource cost projects at the same time. Equally, the level of technology differentiation will also have an allocation impact between consumers and producers. Support mechanisms which do not differentiate will tend to lead to higher rents for producers, since the price which will be earned by all asset owners will need to be sufficient to attract the highest cost project required to meet the target. On the other hand, support mechanisms which differentiate can be designed with the aim of attempting to minimise rents.

System impact

Irrespective of the financial support mechanism, a large proportion of output from intermittent generation will clearly have a major physical impact on the network, and consideration must be given to issues such as grid expansion, congestion management and balancing arrangements. The security of supply implications of different policies, resulting from the changing investment dynamics for both renewable and conventional plant, will be critical, pointing to the need to understand the impact of policies on all players in the market.

Market interaction

The choice of subsidy scheme will also have a direct impact on the way in which power from renewables is integrated with the overall wholesale market. Under the existing RO, which is a premium based subsidy, renewables participate in the market like all other generators, responsible for selling forward their output and balancing their position. For schemes that subsidise renewables outside of the main market arrangements, such as feed-in tariffs, there is the consideration of how the output would be sold into the market. As the proportion of renewables increases there is the risk that the market bifurcates into two separate markets, one for renewables and one for non-renewables.

Furthermore, as the volume of intermittent renewables on the system grows, there is an increasing probability of periods when the output from low marginal cost plant exceeds demand. This includes all renewables other than biomass, but also nuclear stations. The design of the policy can influence dispatch decisions in these circumstances. For example, under an RO-style scheme, a generator would theoretically be prepared to sell power at minus the ROC price to stay generating and, indeed, a multiple of this for higher banded technologies. This could result in negative market prices and lead to other inflexible baseload plant, such as nuclear (which is also low carbon) reducing output. Conversely, under a FIT-style scheme, the dispatch outcome could be different depending on how renewables output is prioritised.

The details of the scheme require careful consideration in this respect to ensure that the marginal value of renewables generation is accurately reflected in the market price where supply exceeds demand. This will ensure efficient dispatch outcomes whilst allowing the demand side to respond.

3 Types of renewables support schemes

3.1 Introduction

A wide range of different support schemes have been employed internationally. Although none are exactly alike, they can usefully be categorised into a number of different types for consideration, which we introduce in this section. These categories are:

- obligation-based schemes, usually involving tradable certificates, similar in concept to the UK RO;
- feed-in tariff (FIT) schemes, whereby renewable generators obtain a guaranteed long term price for their output;
- tenders for specific volumes of different technologies, similar in concept to the UK NFFO; *and*
- fiscal mechanisms including differential taxes or levies between renewable and non-renewable electricity, and capital grants for renewables projects.

For each category, we provide a brief description of the motivation behind the scheme type. To supplement the theoretical considerations, and to inform the evaluation of different policy options, we conducted a short review of the renewables support mechanisms in a number of European countries, and two American states. A summary of the schemes in each of these countries is presented in Appendix A. From this we drew out a number of observations, helpful for evaluating options in the UK, which we outline for each of the categories below.

3.2 Obligation-based schemes

The main motivation behind obligation-based schemes is to utilise a market-based approach under which participants are free to make investment and trading decisions within a target framework set by Government. The obligation is normally defined as a percentage of total electricity supplied, and usually (though not necessarily) this can be met through the purchase of certificates issued to renewables generators (as opposed to physical contracted volumes). It will typically be up to suppliers to recover the additional cost of meeting the obligation from their customers.

Because the target will (at least in the first years of such schemes) be higher than actual renewable output, it is necessary to establish a penalty, or 'buy-out', price that obligated parties will pay for each MWh not covered by certificates. The buy-out price is thus the key driver of certificate prices. Some versions of the scheme also put cap and floor prices in place.

Under obligation-based schemes, therefore, renewables generators sell power in the market in the same manner as conventional generators, but receive an additional revenue stream by selling their issued certificates. From an investment perspective, they face corresponding market risks around the future prices of power and of the certificates.

Observations from the international survey include the following:

- Obligation-based schemes are often measured as more expensive than FIT schemes, although the profile of certificate prices over the lifetime of the scheme (which is likely to be higher in the earlier years as capacity is below target) is rarely accounted for. This does not necessarily lead to lower welfare for society as a whole as producers benefit from higher profits.
- Schemes typically provide transparency about short-term certificate prices, often through exchange trading or formal price reporting.
- Uncertainty about scheme continuity and future price levels has led to higher financing costs. A number of arrangements have been used to reduce this investor risk:
  - The risk around price collapse in over-supplied markets will be addressed in the UK through the headroom and 'ski-slope' pricing mechanisms as described in Section 2.3.3 and in Italy through a buy-back guarantee, priced off the previous year's average certificate price.
  - Italy derives its buy-out price from a target 'all-in' revenue level (including wholesale electricity and subsidy), such that wholesale price risk is partially hedged through the exposure to certificate prices.
  - In Wallonia (Belgium), the government has implemented a supplementary scheme to allow generators the option to sell certificates to the government at a fixed price for up to 10 years.
- Without a cap, the political impact of high certificate prices can force regulatory changes, for example through expanding the definition of renewable generation to allow hydro-generated imports in Connecticut.
- In countries that already have a high renewables base, an obligation scheme has not necessarily resulted in significant new build. For example, in Sweden, existing capacity has switched to widely available biomass fuels, and similarly no limit on co-firing in Wallonia has reduced incentives for other technologies.

3.3 FIT schemes

FIT schemes typically have different motivations compared to obligation-based schemes. First, by providing a guaranteed price for all, or a significant part, of the economic lifetime of a new asset, the risk for investors is reduced, thus lowering financing costs. Second, schemes are designed to incentivise a range of different types of generation by offering technology-specific tariff levels (although 'banding' for obligation-based schemes is designed to achieve a similar goal). Third, tariffs are normally set close to anticipated long run marginal costs, with the aim of minimising economic rents for generators.

Under FIT schemes, governments make a much more detailed set of decisions with regard to price setting (usually facing considerable uncertainty with regard to current and future cost levels), and implicitly with regard to desirable volumes of each technology type, as tariff levels will normally be adjusted over time (for new plant) partly in response to levels of deployment. They, on behalf of consumers or tax payers[5], also face the risks associated with making a long term fixed price commitment to offtake power.

Renewables generators under FIT schemes typically receive a single revenue stream for their power, and do not participate in the wholesale market in the same way as conventional generators. Unlike obligation-based schemes, alternative mechanisms are therefore needed to integrate their generation into the market. In some cases "premium" FIT schemes have been used, whereby generators are guaranteed a fixed additional payment for each MWh generated, but where they still sell their power in the same manner as conventional generators.

Observations from the international survey include the following:

- FIT schemes are often measured as achieving subsidy levels relatively close to LRMCs of renewables technologies, indicating that Governments have been successful in limiting rents to producers through the tariff level set (although it may be that those undertaking studies drew conclusions based on similar, uncertain, data to that used in Government decision-making).
- The lack of subsidies for technologies not 'recognised' by the scheme can be argued to dampen incentives for innovation. When Ireland launched its REFIT scheme in 2006 there was no offshore wind specific tariff, despite the significant potential for the technology in that country. There have been no significant offshore proposals as a result. On the other hand, governments have flexibility to introduce new technology categories without undermining investment certainty for other technologies (and in Ireland a new tariff for offshore wind has been introduced for 2008).
- Schemes can be defined such that tariff levels are calibrated according to wind speeds (above a given minimum). For example, in Germany, wind subsidies are adjusted based on the average of a plant's first five years' load factor (relative to a baseline), but are lost if the yield of a new facility drops below 60% of the reference yield.
- Premium schemes without caps and floors can lead to large generator profits when wholesale prices rise. This situation triggered the introduction of a price cap and floor in Spain, whilst in the Netherlands the high rewards resulted in excessive build and scrapping of a scheme that was considered to have become too expensive.
- Too much optionality in schemes can lead to potential 'adverse selection' against the government. In Spain, generators can elect to receive either a fixed feed-in tariff or a feed-in premium. They are able to revise this decision once each year. The investor may therefore capture upside associated with increased wholesale electricity prices, without the associated downside risk.

3.4 Tenders

Tenders can be used to provide a mechanism for price discovery in the market, whilst maintaining long term guarantees for generators. Governments will typically determine the volume of different technology types for each tender round, and applicants will submit bids, usually based on their required unit offtake price. Those with the best priced bids will be awarded contracts for offtake, with a price set either as bid, or at the clearing price. In principle, tenders can also be used where a greater degree of central co-

[5] In practice the actual purchasing entity will usually be an independent body or the system operator.

ordination is an objective (such as with planning or grid connection arrangements, for example), as they can easily be made location-specific. Once the tender has taken place, arrangements are similar to those for FIT schemes.

A key issue for tenders is the level of financial commitment required from participants. If this is low, the Government is subject to the risk that successful parties may subsequently withdraw, due to unforeseen issues or higher costs. On the other hand, if this is set too high, it may pose too high a risk for investors who will be deterred from developing and bidding in projects.

Observations from the international survey include the following:

- In both Ireland and the UK, tender schemes resulted in situations where applicants bid aggressively to succeed in the auction, but subsequently determined that the corresponding price was insufficient to make the project commercially viable, and hence the capacity was never delivered. In the UK under NFFO, 2.4 GW of projects that won contracts in the auction were subsequently not built. (The total contracted build was 3.6 GW.) Under the final two phases of the Irish Alternative Energy Requirement (AER V and VI), only 277 MW of a total contracted capacity of 724 MW was built.
- Under the AER in Ireland there was no requirement for a bid to have obtained approval for grid access or planning permission.
- Both AER and NFFO had a discrete set of tender ‘rounds’ leading to investor uncertainty regarding the ‘ad-hoc’ timing of support availability.
- The winner of a recent offshore wind generation tender in Denmark pulled out of the project on the grounds of increasing costs. Re-tendering may increase costs and cause delays.

3.5 Fiscal mechanisms

A wide variety of other incentive schemes have been used internationally. These have either been aimed at encouraging consumer ‘pull’ through different sales taxes for renewable and non-renewable electricity, or by lowering the effective investment cost for generators through tax breaks or capital grants.

One of the issues with fiscal mechanisms is that they tend to be perceived as subject to a high degree of political risk, as usually they are subject to change or withdrawal through Governments’ annual budget cycles.

Observations from the international survey include the following:

- The Netherlands had fiscal support in place prior to setting up its FIT. This took the form of an energy consumption tax from which consumers of ‘green’ or renewable energy were exempt. The result was that a significant proportion of consumers signed up to green tariffs, but most of this energy was sourced from existing renewable capacity outside the Netherlands. Very little new capacity was built.
- A range of fiscal mechanisms can lead to complexity and lack of alignment. Whilst clearly a potential issue with any scheme, fiscal mechanisms appear to be particularly prone to this problem, with grants and tax incentives more subject to short term political pressures.

4 Qualitative assessment of different schemes

4.1 Introduction

The objective of the qualitative assessment phase of the study was to start with a 'broad net' to capture a wide range of possible types of schemes, and then to apply a systematic evaluation method. Whilst qualitative, the method was designed to enable a 'ranking' of different schemes. Of these, three were then selected for more detailed definition in the quantitative assessment phase.

In this section, we outline the evaluation method we used, list the key criteria against which different schemes were evaluated, and then provide a short description of each of the schemes we considered, highlighting pros and cons emerging from the process. The full results of the evaluation are included in Appendix B.

4.2 Evaluation method

The first step in the policy evaluation approach involved the identification of a wide range of potential schemes, drawn both from international experience and from approaches developed within this study. In parallel we drew up a list of criteria based on the stakeholder perspectives outlined in Section 2.5 above. We then scored each potential scheme against each criterion using a simple scale. This provided us with a 'scoring matrix' against which we could rank scheme types based on different criteria weightings. Given the complexity of issues and the diversity of potential views, we felt it was important to test the ranking against a number of different sets of weightings (for example, placing more or less importance on market compatibility, the level of producer rents, and so forth). This allowed us to show how different economic and political viewpoints would lead to different conclusions with regard to which schemes were preferable.

4.3 Key criteria for support scheme evaluation

Minimising resource costs

A key measure of economic efficiency of any support scheme is the extent to which resource costs can be minimised. The costs of developing renewable generation capacity include both the costs of physical investments and the financing costs. Physical costs vary depending on the mix of technologies that the subsidy promotes, and financing costs are impacted by the level of risk faced by investors. The costs involved in deploying renewables are not just the costs of the plant themselves but also the additional costs associated with grid expansion, back-up generation to manage the variability of renewables output, and system balancing to manage the unpredictability of renewables output. For a given renewables target, these costs may be largely independent of the financial support scheme, but not entirely. Different policies may promote a more or less geographically diverse renewables base which could impact on the levels of transmission investment and system balancing required. It is also worth noting that the extent to which these additional costs are targeted at renewables generators will directly impact on the level of financial support they require through the subsidy mechanism.

Minimising excess economic rents

The rents, or excess profits over and above their required rate of risk-adjusted return, captured by asset owners can also vary greatly depending on the subsidy mechanism adopted. Whilst these rents do not directly impact resource costs, they do increase the overall level of the cost borne by consumers. Although not necessarily economically inefficient, the distributional effect between producers and consumers is a key political consideration.

Ensuring dispatch efficiency

It is important that the market framework allows for the least cost dispatch of generation plant consistent with meeting a number of constraints (e.g. target renewable output). Under different support schemes, the incentives for participants (whether individual generators or a central purchasing entity) will vary, with different outcomes for patterns of dispatch as the penetration of intermittent renewables reaches high levels.

Robustness to uncertainty

It is important that the preferred support mechanism is robust towards key uncertainties such as commodity prices, capital costs and speed of planning and connection access. Any scheme design should seek to minimise the efficiency losses potentially arising from such inevitable uncertainty. With the potential for changes to overall wholesale market arrangements during the lifetime of the mechanism (for example, to deal with congestion management), the possible impact of these is also a consideration.

Avoiding unintended consequences

Renewable generators will have to operate alongside conventional generation plant for the foreseeable future and it is therefore important to ensure that a benefit in one part of the market is not undermined by corresponding problems elsewhere. For example, the renewables target operates across sectors and it is important that scarce renewables resources are not used inefficiently. This issue is particularly great in the case of biomass, where the potential resource is constrained and yet it could be effectively employed in both heat and electricity sectors (as well as transport with second generation biofuels).

Minimising the negative effects of transition

Given that the development timescales for renewables projects can be long (up to 5 years), investor attitudes during a transition period, when uncertainty remains over the enduring rules, will be critical in delivering 2020 targets. In particular, investors will not only need to push forward with projects already in the development pipeline, but be incentivised to step up the overall level of resource devoted to prospecting for new project opportunities.

Promoting wider benefits

Different schemes may deliver different wider benefits. For example, given the uncertainty in future technology costs, the development of a range of technologies in the period up to 2020 provides a greater range of options thereafter, as well as tending to reduce delivery and operational risks in the period up to 2020. Other potential wider benefits include the promotion of a domestic manufacturing base for renewable technologies or the promotion of the take-up of renewable generation internationally.

Ensuring international consistency

The renewable investment market is global and the UK is competing for funds with other countries, each with their own range of support schemes. The simplicity and transparency of the support mechanism (along with the consenting, planning and grid connection processes) relative to experiences in other markets is an important consideration in scheme design. Furthermore, maintaining options for trading renewable credits between countries (which may require the existence of compatible schemes) is a benefit in maximising flexibility to meet the target.

Compatibility with existing market arrangements

Since the long term objective should be for renewables to operate in the market without support, the compatibility of the support scheme with current or anticipated future market arrangements requires consideration.

4.4 Schemes considered

As described in Section 3.1, most policies seen internationally fall into one of four broad categories: obligation-based schemes (such as the RO), feed-in tariffs, tenders, or fiscal mechanisms (including levies and grants). All of these were considered in the qualitative evaluation, as well as a cap-and-trade mechanism for non-renewable energy use, and a range of hybrids and variants. It is clear that, in practice, financial support mechanisms are often a mixture of approaches, either through the application of different mechanisms to different technologies, or through variations that draw on characteristics from different types of schemes. We recognised this by identifying a range of 'pure' schemes, and then selecting a representative sample of potential 'hybrids' that mixed elements of the former.

In this first stage, schemes were characterised to a sufficient level of definition such that the scoring could be unambiguously applied, but not to the level of detail subsequently developed for the quantitative assessment phase. In some cases we used specific examples as representative of a generic type (such as the current UK RO as an obligation-based scheme). We clearly made choices as to how to define different types of schemes for the purpose of the evaluation, but in doing so aimed to use 'standard' definitions as far as possible.

The 'pure' schemes we considered were:

- A renewables obligation (based on the current non-banded RO)
- A standard FIT (based on the German implementation)
- A tender-based scheme
- Contracts for difference (CfDs)
- A non-renewable levy
- Grants
- Non-renewable allowances

The variants and hybrids we considered were:

- A banded obligation scheme (based on the proposed UK Banded RO)
- A hybrid of an RO scheme combined with a FIT
- A 'GOO-compatible' RO
- A premium FIT
- An availability-linked FIT
- A FIT/Tender hydrid
- A hybrid of a non-renewables allowances scheme with a FIT
- A scheme offering a choice of a banded RO or a premium FIT

Each of these is described briefly below, together with highlighted benefits and issues emerging from the evaluation.

4.4.1 Non-banded Renewables Obligation

This scheme would be a continuation of the current non-banded RO. It would place an obligation on suppliers to cover a target percentage of their electricity supplied with tradable Renewable Obligation Certificates (ROCs), or pay a buy-out price. Buy-out revenues are paid proportionately to certificate holders (such that in an undersupplied market the price of certificates may rise above the buy-out price in anticipation of these additional revenues). ROCs are issued to renewable generators for each MWh of output.

Whilst such a scheme would have the benefit of matching the current arrangements, and in this sense would represent a minimum change, the fact that it would be a reversal of the Banding proposals currently before Parliament could in practice undermine, rather than strengthen, the credibility of the policy framework. Clearly, there have been good reasons to reform the RO, so going back to what was generally considered a sub-optimal mechanism would be unlikely to bring benefits.

The scheme would have the merit of simplicity, and would leave specific investment decisions to the market (although relying on other mechanisms to send appropriate locational signals). Rents to producers would rise significantly if deployment were constrained by factors such as planning or connection access (as the fixed RO 'pot' would be shared by those able to overcome these barriers). Similarly, the ROC prices that would be required to stimulate higher cost technologies would provide lower cost generators with further significant rents.

4.4.2 Standard Feed-in Tariff

This scheme would provide generators with a fixed price offtake commitment for the economic life of the asset. A central body would purchase the power and recover (or return) the difference between the tariff price and wholesale power prices through levies on suppliers based on market share. Tariff levels would be set based on technology type and resource potential (wind speeds), and would be 'vintaged' such that the price paid for a particular project depends on the year it is commissioned, even if the price offered for new projects later changes.

The certainty in revenues under a FIT may lower the cost of capital for investors (and hence overall resource costs), and reduces the barrier for new entrants. The ability to set different tariff levels means that a range of technologies can be promoted, and lower potential resources (e.g. lower wind speeds) can be stimulated in parallel, without increasing producer rents for lower cost technologies or higher resource potential sites.

The change to a FIT would have a material implementation time and could lead to a hiatus in development during any transition. As renewable output would be sold to a single buyer, an appropriate mechanism for selling the output (such as day-ahead auctions) would be needed to make this compatible with existing trading arrangements. Consumers would be exposed to the risk associated with taking on a long term fixed price obligation, and Government would face significant uncertainty in setting appropriate tariff levels. The technology-specific tariffs, combined with a goal of minimising rents, could have the effect of dampening innovation.

4.4.3 Tenders

A central body would hold annual auctions, with developers invited to tender for the delivery of a given volume of capacity for an offered fixed price for output. Separate auctions would be held for each technology type. As for the Standard FIT, net costs (or revenues) would be recovered (or returned) through a levy on suppliers. An upfront deposit, payable by successful applicants, would be required as a delivery obligation.

Technology-specific, long term fixed price commitments for generators, the 'single-buyer' issue, and the required transition period, are features shared with the Standard FIT. Tenders should provide more precise control over the total volume of build, and could facilitate coordination of grid expansion with siting of renewables projects. They also provide a price discovery process, avoiding the need for Government to 'set prices', and potentially reducing rents through increased competition.

Investment decisions are however constrained by the timing of tender rounds, and the right balance of financial commitment required from successful applicants against the increased risk this imposes (with, in turn, higher financing costs), would be difficult to strike.

4.4.4 Contracts for Difference

Under this scheme, a fixed price commitment for generators would be achieved through financial contracts rather than physical offtake agreements. A long term 'Contract for Difference' (CfD) (a swap) would be provided to generators between a wholesale electricity price index and a technology-based strike price[6]. Strike prices could be fixed in advance or set via auctions designed to allocate pre-determined volumes of CfDs with investors competing through their price offers. Difference payments (or receipts) would be levied on suppliers based on their market share.

The CfDs could be 'one-way' or 'two-way'. Under a two-way CfD, payments would be made to the generator where the electricity price was lower than the strike price, but in the event that the electricity price rose above strike, generators would pay back the difference. Effectively, therefore, the generator would receive a fixed price for its output at all times, and in this respect the CfD approach closely resembles a FIT or tender approach. One major difference, however, is that the generator is exposed to price and balancing risk between when the CfD is settled (which might be against a day-ahead index, for example) and the physical delivery of electricity. Under a FIT or tender, the generator would typically not be exposed to this risk. Under a one-way arrangement, generators would still receive the difference payments when electricity price was below strike, but would keep the full electricity price should it rise above. (Hence the generator would receive the electricity price but with the strike price acting as a floor.)

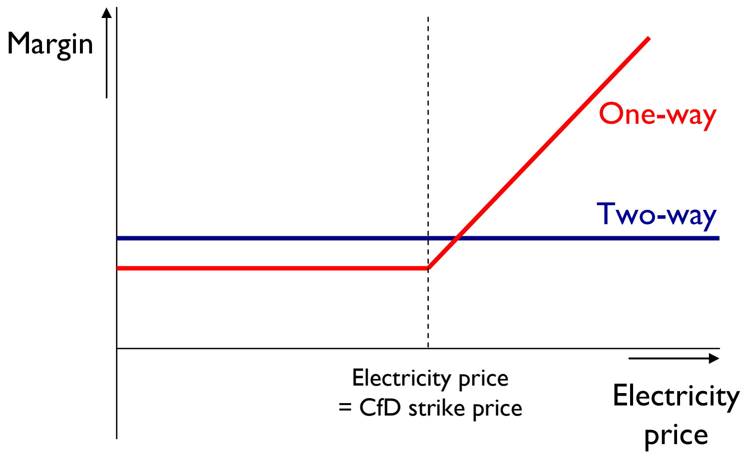
Under two-way CfDs the generator is free to sell its physical power forward in the market at any point, but in practice, if it is to minimise price risk, it will aim to do this in such a way as to match the selected index against which the CfD is settled. For example, if the CfD is based on a day-ahead index, the generator will be likely to aim to sell its power physically day-ahead to match this.

Under one-way CfDs, the situation changes in a scenario where the electricity price rises above the contract strike price. Renewables then effectively compete directly in the market without subsidy. For the generator, the one-way CfD is more valuable than the two-way CfD since it is able to retain the upside of higher wholesale electricity prices but there is a floor on its downside risk. Hence, strike prices should be expected to be lower than under two-way CfDs reflecting the value of this optionality. Estimating this value would be difficult for policy makers setting fixed strike prices for CfDs. Under a fixed volume auction approach, it would be investors that would be valuing this optionality.

The pay-offs for renewables generators under one-way and two-way CfDs are shown schematically in Figure 1. Under a two-way CfD the margin is invariant with changes in electricity prices. Under a one-way CfD the margins are fixed where electricity prices are below the CfD strike price, but increase where electricity prices are higher than the strike price. Since the strike of the one-way CfD should be expected to be lower than the two-way CfD, the margins should be lower under a one-way CfD whilst the electricity price remains below the strike price.

[6] The use of CfDs as a renewable support mechanism was proposed by Ofgem in its January 2007 response to the Government's 2006 consultation on the reform of the Renewables Obligation.

Figure 1 Pay-off diagrams for CfDs



A major benefit of the one-way CfD approach is that it is more robust than a premium based scheme such as the RO to very high electricity prices since the subsidy automatically falls away if renewables no longer require financial support. Hence, the rents should be lower under these circumstances. They would, however, be higher than for a two-way CFD or FIT where margins (and hence rents are fixed). The trade-off is that rents should be lower under one-way CfDs than two-way CfDs when electricity prices are below the costs of renewables generation due to the lower strike prices as explained above.

4.4.5 Non-renewable levy

Under this mechanism, a fixed charge per unit would be levied on all non-renewable generation supplied. The result would be a market premium on generation from renewables. The levy would be periodically reset depending on deployment compared to target levels. The revenues generated from the levy could be recycled to customers.

In principle such a scheme could be relatively easy to implement (and could potentially be consolidated with the Climate Change Levy), and would lead to investment based on market signals. Setting the levy at an appropriate level to deliver volumes against target would be difficult. It would need to reflect the difference between wholesale prices and the long run marginal cost of renewables.

A theoretical benefit of this approach is that it would elicit greater reduction in usage (assuming some degree of elasticity of demand) by exposing consumers to the marginal cost of renewables. This would eliminate the 'deadweight' inefficiency associated with mechanisms that only pass through the average costs of renewables (whereby the producer cost of the marginal unit of supply exceeds the consumer benefit, resulting in a net loss of welfare). However, if deployment was constrained, or higher cost technologies were needed, the levy, and correspondingly consumer costs, could be very high.

4.4.6 Grants

A fixed capital grant (based on an amount per unit of capacity) would be paid to developers, dependent on technology and location. The grant would be payable following plant commissioning over the economic life of the project. The costs of grants would be recovered through levies on suppliers.

This would provide close control over the total volume (by location) of renewable build, and (as for other schemes with technology-specific support) enable promotion of different generation types and locations without increasing rents.

Investors would face the risk of uncertain electricity prices, increasing cost of capital, and there is no additional incentive through the subsidy to maintain full plant availability. Moreover, in gearing up and scaling their renewables prospecting and development activity, investors might be concerned about the continuity of the grant scheme into the future. Finding a transparent mechanism to set the level of grants offered would be difficult.

4.4.7 Non-renewable allowances

This mechanism would operate as a cap-and-trade scheme for generation from non-renewable sources. Generators would be required to present a tradable Non-Renewable Allowance (NRA) for every non-renewable unit of output generated. NRAs would be auctioned by the Government to a level consistent with the overall renewable target, starting ten years prior to the target year. Full (forward) banking would be allowed (such that an NRA from one year can be held and presented against non-renewable generation in a future year), with borrowing (from future years to current) restricted to 10% within a 5-year phase. Revenues generated from the auctions could be recycled to consumers, though finding an appropriate mechanism for this would be a challenge.

Such a scheme would be consistent with the approach deployed for carbon emissions under the EU ETS (and the two could perhaps converge at a future point). Just as for carbon, the broader the scheme coverage (across heat and transport sectors, and across other countries) the more effective it would be in allowing efficient market decisions. Similarly to the non-renewable levy, the marginal cost of renewables could be expected to be reflected in electricity prices, creating an efficient demand side response but increasing consumer costs.

As a pure market-based approach, there would be no differentiation between technologies, investors would face price risks, and lower cost renewable generators would benefit from higher rents. Managing price risks through long term contracts may be easier if longer term market signals are supported through an early auctioning process.

Although consistent with international emissions mechanisms, such an approach would be a radical departure from renewables support policies deployed internationally thus far, with a corresponding risk with regard to implementation complexity, transition time, and investor confidence.

4.4.8 Extended RO

This mechanism would reflect the RO as set out in the proposals currently included within the Energy Bill, with some further modifications required to meet a higher target level.

Assuming the Banded RO is implemented in 2009, this effectively represents the ‘status quo’ approach, and hence has the major benefit of continuity (at least compared to expectations) for market participants. It allows Government more directly to incentivise a range of technologies, whilst avoiding large increases in rents for lower cost generation. However, the introduction of banding creates an element of policy risk, and breaks the relationship between the number of ROCs issued and renewable output, making it more difficult to achieve a precise target.

4.4.9 Premium FIT

Under a premium FIT, renewable plant sell their power in the wholesale market under normal trading arrangements, but receive in addition a fixed price premium per unit output. Compared to the Standard FIT, this avoids the need for a ‘single buyer’ for renewable offtake. However, because the revenue for generators is heavily dependent on wholesale power prices, such an approach is prone to excess rents or under-build depending on the evolution of fuel, and hence electricity, prices. This risk could be addressed by including caps or floors on the premium dependent on level of underlying wholesale price.

4.4.10 RO/FIT Hybrid

Under this approach, a (non-banded) RO would be combined with a ‘top-up’ premium FIT for emerging technologies. This would be an alternative means for Government to target a range of different generation types, whilst avoiding increased rents of an unbanded RO (as the ROC price no longer needs to rise to the point where more expensive technologies become commercially viable). It would retain the link between the number of ROCs and renewables generation, making it arguably more transparent to investors than the Banded RO. The scheme would be more complex to administer than the Banded RO, and would be subject to a similar level of policy risk around FIT levels (although the premium for existing projects would be grandfathered).

4.4.11 Non-renewables allowances/FIT hybrid

This would be a similar concept to the RO/FIT Hybrid described above, but applied to a Non-renewable allowances base scheme. A premium FIT would be paid just to selected emerging renewables technologies, to promote their development, with associated costs recovered through levies on consumers. This would allow the stimulation of a greater diversity of generation without increasing rents to such an extent for lower cost renewables, as well as reducing the exposure of consumers to marginal costs.

4.4.12 GOO-compatible RO

Under the current RO, cashflows associated with suppliers paying the 'buy-out' price in place of presenting ROCs are recycled to certificate holders. This means that the value of certificates can rise above the buy-out price where there is an expectation of a shortfall. Whilst this provides a useful price signal (giving a greater incentive for new build where renewables generation is below target), it is not a typical feature of green certificate schemes internationally. This potential incompatibility may make it harder to integrate with a broader European market in GOOs traded at the installation level, as the value of certificates would not be equivalent in different countries. If international trading were a priority, then a simpler RO scheme, with a penalty price (without recycling) may be required.

4.4.13 Availability-linked FIT

This scheme would function in the same way as a Standard FIT, but the payments to generators would be split between availability and output rather than on output alone. The objective of such a variation would be to address the potential inefficiency that stems from either guaranteeing priority dispatch to renewables, or having to compensate them at the full tariff price if 'constrained off'. Output payments could be set based on the marginal value[7] of renewables output and would be the same for all technologies, since there is no economic rationale for prioritising higher cost renewables over lower cost ones when making dispatch decisions. The remainder of the tariff would be made up with availability payments which would vary by technology and resource potential.

4.4.14 FIT/Tender hydrid

This scheme is aimed at capturing the benefits of a Standard FIT, whilst using auctions to reduce the risk for Government around cost uncertainties for less mature technologies, specifically offshore wind, wave and tidal. For these projects, tenders would be held annually for fixed volumes by technology and location. Planning and connection issues would be resolved prior to the auctions. For all other renewables, a Standard FIT would apply.

This would create a process of price discovery for technologies with higher cost uncertainty, whilst not tying investment in smaller schemes to auction cycles. There would also be a greater degree of control over the total volume of renewables developed. The practical issues associated with tenders would need to be dealt with, including the need for a delivery commitment, and administration would be required for two separate schemes.

4.4.15 Banded RO/Premium FIT choice

Under this model, investors would have the choice, when commissioning a project, to elect to receive either a Premium FIT or ROCs. Projects electing for the former would transfer the ROCs they would

[7] This marginal value should reflect the value of the loss of each MWh of renewables generation against the 2020 target. Further consideration would be required on how this would be defined.

have received to a central body. This central body pays the premium to the generator and sells the received ROCs in the shorter term markets. Any revenue surplus/shortfall would be handled through levies on suppliers.

Such a scheme could offer an option for investors to reduce policy and subsidy risk through electing for a long term contract for a premium, without having to replace the overall RO scheme. However, setting the premium at the appropriate level would be difficult, and with investors able to pick the best option available (with a more current view of fuel price movements compared to the point at which they were set), the Government would be subject to a problem of 'adverse selection'. The uncertainty as to changing FIT price levels would also make the prediction of expected future ROC prices more difficult.

4.5 Schemes selected for quantitative assessment

Of the schemes outlined above, three were selected for the full quantitative assessment. The objectives in making the selection were to provide a representative spread of different types, as well as to pick robust schemes based on the ranking from the qualitative analysis (shown in full in Appendix B).

As noted above, our evaluation process involved scoring each scheme against the key criteria we identified, and tested rankings based on different weightings, reflecting different perspectives on the importance of each of the key considerations. We used four different weighting sets, broadly reflecting priorities of: minimising change; facilitating central co-ordination; seeking market- and trading-based solutions; and minimising investor risk. As may be imagined, very different rankings resulted under these different sets.

When weightings were set to reflect 'minimising change' as the highest priority, the Extended RO (unsurprisingly) ranked first, with the RO/FIT Hybrid in second place.

Of the seven 'pure' schemes, the Standard FIT and Tender options ranked highest when emphasis was placed on minimising investor risk, or in facilitating centrally co-ordinated approaches, with Contracts for Difference third. When 'variants' were included, the FIT/Tender hybrid topped the list, with the Availability-linked FIT second.

With weightings geared to stressing market- and trading-based solutions, the Non-banded RO, Non-renewable allowances and the Non-renewable levy ranked highest amongst 'pure' schemes, with the GOO-compatible RO first when all schemes were considered.

It was clearly essential to include an Extended RO approach as one of the three modelled schemes, reflecting an extension of the current proposals, appropriately modified to meet the higher target levels for renewable generation. Of the 'pure' schemes, the Standard FIT ranked in the top two for two out of the four weighting sets, and, combined with the perceived success of a FIT-based approach in a growing number of markets internationally, this was included in the final three. Tenders ranked similarly to the Standard FIT, but where their practicality for mature generation types was an issue in 'pure' form, this was avoided when combined with a FIT, shown by the FIT/Tender hybrid rankings for 'minimising investor risk' and 'central co-ordination'.

Each of these three shortlisted schemes (Extended RO, Standard FIT and FIT/Tender) was developed in much more detail for the quantitative assessment phase, as we describe in Section 5.2 below.

5 Quantitative assessment

5.1 Approach

5.1.1 Overview

The objective of the quantitative assessment phase was to analyse in further detail the potential impact of the three selected renewables support schemes (Extended RO, Standard FIT and FIT/Tender) on the GB electricity market. In particular, we were attempting to assess the effectiveness of each scheme in delivering different target levels of renewables generation, and their impacts in terms of resource costs, costs to consumers and overall net welfare relative to a 'Status Quo' counterfactual. We were also looking to understand the impact of high penetration of renewables on security of supply, carbon dioxide emissions, wholesale electricity prices and volatility, and the costs of system balancing.

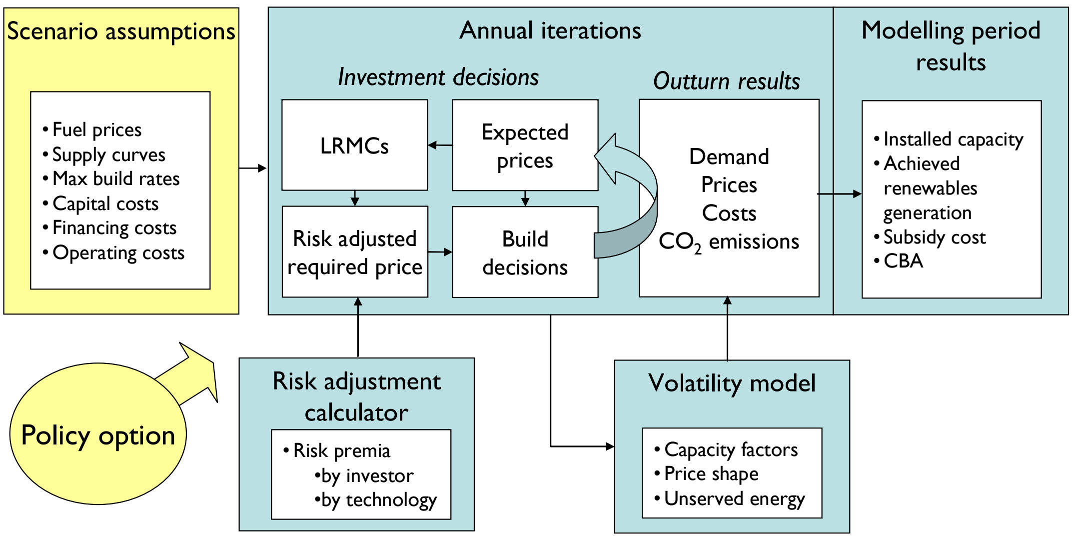
Sensitivities were modelled to assess the robustness of each scheme to external factors such as uncertain commodity prices and renewables plant capital costs, and physical constraints on building new renewable capacity.

The quantitative assessment required complex simulation of investments, retirements and market operation between 2008 and 2030.

5.1.2 Modelling framework

An overview of the modelling framework used for the study is shown schematically in Figure 2.

Figure 2 Modelling framework



At the heart of the framework lies an ***investment decisions*** simulator. This computes the risk-adjusted long run marginal costs (LRMCs) of all generation technologies by player type. Where these are less than expected revenues (given assumed load factors and future price expectations), players move new plant first to a planning stage, and subsequently, if still economic, to a committed development phase. On an annual basis, ***outturn results*** for demand, prices, generation output and carbon emissions are computed. These in turn feed back to expected prices for the following year's iteration.

The LRMCs used in the build decision algorithm are risk-adjusted in the ***risk adjustment calculator*** by computing a distribution of gross margins for each investment under the full range of uncertainties in revenues and project costs. The ***volatility model*** analyses the market at an hourly level for each year by simulating demand, spot fuel prices, forced outages and renewables output. It produces annual price duration curves and estimates of price volatility and volumes of short term demand side response and expected energy unserved. It is used to calibrate the expected price and renewables 'capacity credit' functions within the investment decisions simulator as explained in 5.4.4 below.

5.1.3 Cases considered

Status Quo counterfactual

The Status Quo is used as the counterfactual for assessing the impact of the different renewables support schemes on the market. It represents the 'business as usual' case where renewables policy follows the Energy Bill proposals with the introduction of the banding in the RO and an upper limit on the obligation size of 20% by 2020. The Status Quo case adopts BERR's central views of commodity prices and demand.

Different target levels

Three different target levels for electricity generation from renewables by 2020 were analysed, reflecting a range of possible outcomes in the allocation of the UK target between electricity, heat and transport. These were 28%, 32% and 37%.

The 37% case represents deployment close to the maximum potential from SKM's assessment of renewables build constraints and includes the Severn Barrage[1].

Input assumption sensitivities

Uncertainty in commodity prices, renewables plant capital costs and maximum renewables build rates were identified as likely to be the most material factors that could influence the costs and deployment rate of renewables. Three different sensitivities were run to the Central fuel and carbon prices; these were Low, High and High High. Two sensitivities were run to the Central renewables capital cost assumptions; these were Higher than Expected and Lower Than Expected[8]. We used SKM's High maximum build rates for the

[8] For the purposes of comparison in the cost benefit analysis the Status Quo was also run under the fuel price and capital cost sensitivities.

base case policy runs since the higher target levels could only be achieved with these assumptions. We tested the impact of lower maximum build rates using their Central maximum build rate as a sensitivity[9].

Severn Barrage sensitivities

We tested the 28% and 32% target cases with and without the Severn Barrage. In the cases with the Severn Barrage, we assumed that it became fully operational by 2022 and that 100% of its generation would be eligible towards the 2020 target[10]. The 37% target case was only modelled with the Severn Barrage since with the assumed annual build constraints it would not be possible to reach this level of renewables generation without it.

Summary of cases

Table 1 summarises the cases that were modelled. Base case assumptions for each scheme/target level run are highlighted in bold. Sensitivities are highlighted in italics.

Table 1 Cases modelled

SQ/Scheme	Target level	Severn Barrage	Fuel/carbon assumptions	Renewables capital cost assumptions	Maximum build rate assumptions
Status Quo (counterfactuals)	n/a	**Excluded**	**Central** *Low* *High* *High High*	**Central** *Higher than Expected* *Lower then Expected*	**Low**
Support schemes - Extended RO - Standard FIT - FIT/Tender	28%	**Excluded**	**Central**	**Central**	**High**
	32%	**Excluded** *Included*	**Central**	**Central**	**High**
	37%	**Included**	**Central** *Low* *High* *High High*	**Central** *Higher than Expected* *Lower then Expected*	**High** *Central*

We adopt the following notation when describing the results form these runs: [Scheme] [Target Level] [Sensitivity]. For example, the Extended RO under the 37% target is referred to as Extended RO37; the Standard FIT under the 32% target including the Severn Barrage is called Standard FIT32 SB.

[9] Under SKM's Low maximum build rate, a continuation of existing constraints, the maximum renewables generation by 2020 would be 20.6% including the contribution of the Severn Barrage, or 15.9% without the Barrage. This case was not modelled.

[10] Given that the feasibility study is still ongoing, there is a risk that a Severn Barrage is not considered feasible. Even if Government did support such a scheme, there is still a significant risk that some or all of the output will not be delivered in a timeframe that is compatible with eligibility towards meeting the target. Hence any policy that was designed on the assumption that the Severn Barrage could be fully eligible is at risk of missing the target.

5.1.4 Key assumptions

Below we summarise the sources for the key assumptions used in the quantitative assessment. Full details can be found in Appendix C.

- **Demand**. Based on the latest *Updated Energy Projections*, published by BERR[11]. This includes the effect of Energy White Paper energy efficiency measures.
- **Fuel and carbon prices.** Fossil fuel price assumptions are based on the latest *Updated Fossil Fuel Price Assumptions*[12] published by BERR. Carbon price assumptions were provided by BERR for the study.
- **Renewables resource potential.** Based on the Green-X study[13], which reviewed RES-E potential across Europe. The resource potential for onshore wind has been doubled to reflect a higher availability of low wind speed sites than assumed in that study.
- **Maximum build rates.** Based on scenarios developed by SKM in its study[1] of constraints to renewables deployment.
- **Renewable plant costs.** Based on Pöyry's study of the compliance costs of meeting the 20% renewables target[14]. The reductions in renewables costs between 2010 and 2020 assumed in the Pöyry study have been halved in recognition that the strong demand for renewables technologies resulting from the EU2020 targets is likely to offset, at least partially, the learning curve effects.
- **Other assumptions.** All other assumptions are made by Redpoint based on research of publicly available sources, and using its own interpretation.

5.1.5 Technologies modelled

The renewables technologies modelled in the quantitative assessment are shown in Table 2 together with the assumptions used for annual availability or capacity factors[15].

[11]BERR, *Updated Energy Projections*, May 2007. http://www.berr.gov.uk/files/file39580.pdf

[12]BERR, *Updated Fossil Fuel Price Assumptions*, May 2008. http://www.berr.gov.uk/files/file46071.pdf

[13] Green-X, *Deriving optimal Promotion strategies for Increasing the Share of RES-E in a Dynamic European Electricity Market. Dynamic cost-resource curves Work Package 1*. 2003

[14] Pöyry, Compliance costs for meeting the 20% renewable energy target in 2020, 2008. http://www.berr.gov.uk/files/file45238.pdf

[15] The capacity factors take into account annual maintenance as well as resource availability.

Table 2 Renewable technologies modelled

	Annual availability
Onshore wind (High)	29%
Onshore wind (Medium)	27%
Onshore wind (Low)	21%
Offshore wind (High)	39%
Offshore wind (Low)	35%
Biomass regular	80%
Biomass energy crop	80%
Biomass CHP	80%
Wave	30%
Tidal Stream	35%
Tidal Range (< 1 GW)	29%
Biowaste	73%
Biogas	61%

We have divided onshore wind into three categories, and offshore wind into two categories, based on different wind speeds. This is to demonstrate differences between the support schemes. Under the Extended RO, support for wind projects (per MWh) would not be differentiated by wind speed, whereas under the Standard FIT we assume that higher tariffs are paid to locations with lower wind speeds. Under the FIT/Tender, participants bid at a lower price for offshore wind locations with higher wind speeds.

Biomass schemes are divided into regular, energy crop, and combined heat and power (CHP) since the cost structures of these technologies are different and they receive different levels of support under the financial support schemes modelled.

Tidal generation technologies are classified into two types, tidal stream and tidal range. Tidal range (also known as tidal impoundment), creates a height difference (head) by impounding water behind a barrage or in a lagoon. Generation occurs by using the head to force water through turbines, in a similar manner to conventional hydro. (Due to its potential size, 8 GW, the Severn Barrage has been treated as a special case of tidal range project.) Tidal stream devices typically work in an analogous way to a wind turbine, generating power from fast moving tidal water.

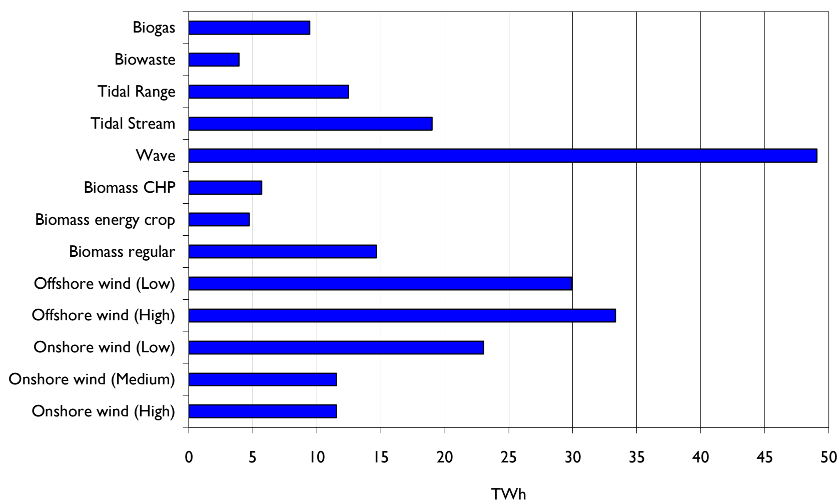
The biogas technology represents schemes that use sources such as farm slurries and agricultural residues. Biowaste is generation from the biodegradable fraction of waste.

Landfill gas, sewage gas and hydro are not modelled explicitly within the investment decision framework, because these opportunities have largely been exploited and are opportunity constrained. We make explicit assumptions regarding output from these technologies, and hold these constant across all schemes and sensitivities:

- Landfill gas: 4.7 TWh/annum in 2008, rising to 4.9 TWh/annum in 2010 and declining to 3.66 TWh/annum in 2020 as existing sites become depleted[16]
- Sewage gas: rising to 0.7 TWh/annum in 2010 and held constant for the rest of the modelling period[17]
- Hydro: 1.3 TWh/annum of new small and medium hydro generation by 2020[13,14]

Figure 3 shows the total resource potential for the major technologies in 2020 as derived by Redpoint from the Green-X[13] and Pöyry[14] studies. These total potentials take no account of build rate constraints which will restrict the speed at which these resources can be exploited.

Figure 3 Total available resource in 2020



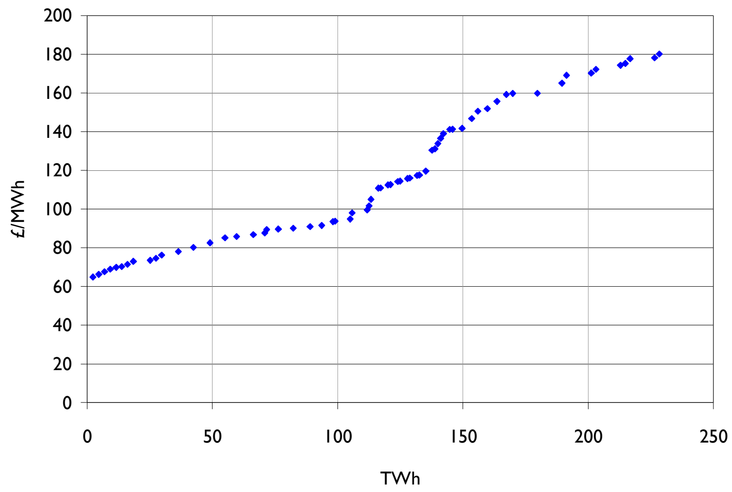
The total 2020 resource potential is ranked by approximate Long Run Marginal Costs (LRMCs) in Figure 4[18]. The differentiation in costs shows the different costs of different technologies, but also supply curves within each technology relating to the spread between the cheapest (and most accessible) projects and the most expensive ones.

[16] Ernst & Young, *Impact of banding the Renewables Obligation - Costs of Electricity Production*, 2007, prepared for the Department of Trade and Industry.

[17] Assumption supplied by BERR.

[18] These LRMCs have been calculated using the input assumptions for the Extended RO37 case.

Figure 4 Long run marginal costs for renewable technologies, 2020



5.1.6 Approach to cost benefit analysis

The costs and benefits of each of the renewables support schemes are measured against the Status Quo counterfactual. They are calculated annually and as a net present value (NPV) for the period 2008-2030 using the Green Book discount rate of 3.5%. It is important to note that the NPV measure extends ten years beyond 2020 and hence the results are influenced not just by what happens between now and 2020, but also by the impact of the different support schemes beyond 2020.

The primary measures within the cost benefit analysis are as follows:

- **Cost of carbon dioxide emissions.** The change in value of carbon dioxide emissions as measured against the cost of EU Allowances (EUAs). A positive number represents a decrease in carbon dioxide emissions (i.e., a saving in EU ETS allowance costs to the GB power sector).
- **Resource costs.** The change in the costs of generating electricity, including changes in investment costs, fuel costs, variable and fixed operating costs and system balancing costs. It excludes changes in the costs of carbon which are captured above. A negative number represents an increase in resource costs.
- **Consumer surplus**. The change in welfare to consumers which is a combination of the change in wholesale electricity prices, change in the net subsidy to renewables, the change in system balancing costs and the change in scheme administration costs[19]. A negative number represents a reduction in consumer surplus or an increase in the costs to consumers.

[19] We assume that the costs of administering the financial support schemes increase with the growing proportion of renewables as there would be more sites to verify. We also assume that the costs of administering the Standard FIT and FIT/Tender schemes would be greater than the Extended RO. There would be additional administrative costs in setting tariffs, organising tenders and auctioning the output from renewables plant. Further details of the assumptions used for scheme administration costs are provided in Appendix C.

- **Producer surplus.** The change in the profits made by electricity producers measured as the change in the difference between revenues (wholesale prices and net subsidies) and generation costs. This is broken down by profits (rents) made in renewable and non-renewable generation portfolios. A positive number represents an increase in the producer surplus.
- **Treasury receipts.** The change in tax receipts to the Treasury which is the combination of changes in revenues under the Climate Change Levy and the change in VAT on domestic consumer bills. A negative number represents a loss of revenue to the Treasury.
- **Net welfare.** The change in economic welfare which is the sum of the change in carbon dioxide emissions less the change in resource costs. It can also be calculated by summing the changes in consumer surplus, producer surplus and treasury receipts. A negative number represents a loss in net welfare to the economy.

A number of ancillary measures are captured within the cost benefit analysis but are not quantified financially. These are as follows:

- **Impact on security of supply.** The change in expected energy unserved[20]. Expected energy unserved is a probabilistic assessment of the electricity demand that cannot be met in each year due to situations where demand exceeds supply. If, for example, we expect on average there will be 2 hours where demand will exceed supply by 500 MW, expected energy unserved for that year would be 1 GWh. Expected energy unserved is close to zero in situations where the de-rated peak capacity margin exceeds 10% (as has been the case historically), but increases significantly where de-rated peak capacity margins fall below this level.
- **Fuel usage.** The change in consumption of gas, coal and oil in electricity generation measured in millions of tonnes of oil equivalent.
- **Carbon abatement cost.** The average cost of abating each tonne of carbon dioxide saved relative to the Status Quo[21].

In order to facilitate the comparison of the support schemes, the Status Quo counterfactual has been re-calculated for the purposes of the cost benefit analysis using the lower demand assumed in the support schemes cases to remove differences in the cost benefit analysis associated with differences in demand. For the same reason, we have assumed no long term elasticity of demand[22].

All costs and prices shown in the quantitative assessment are in 2008 real terms.

[20] The measure of security of supply used in this study has been expected energy unserved, rather than loss-of-load probability (LOLP), which only looks at the frequency, but not size, of interruptions. Expected energy unserved is a more meaningful summary measure of the risks and consequences of involuntary interruptions on any energy system. A simple explanation of this concept, along with a case example, can be found on the BERR Energy Markets Outlook website at: http://www.berr.gov.uk/files/file41822.pdf.

[21] This is the absolute cost not the incremental cost above the EUA cost.

[22] Short demand side response from large industrial consumers is however considered under all cases.

5.1.7 Limitations of the modelling

The modelling approach provides a comprehensive framework for the quantitative assessment of different support schemes and the impact of sensitivities. However, it is not intended to provide predictions of the future.

Key points to note include:

- The modelling requires multiple input assumptions including variables that are very uncertain such as commodity prices, future capital costs of plant and maximum build rates. Note that we have adopted BERR's Updated Fossil Fuel Price Assumptions, May 2008, which are significantly lower than current prevailing market levels.
- Sensitivities have been used to test these uncertainties, but only a small handful of possible sensitivities has been analysed. One area that we have not tested is the risk of a systematic failure of emerging renewables technologies to achieve the operational availability levels expected.
- The modelling approach is dynamic and evolves prices and investment/retirements decisions through time in each run. This results in year on year variability as would be expected in reality. However, care should be used when comparing the results in individual years.
- The model estimates different hurdle rates for different technologies by simulating gross margin risk for investors over the project lifetime. This significantly simplifies the complex interaction of factors that determine the cost of capital for different investors in different technologies under different support schemes.
- The modelling does not explicitly model specific transmission upgrade projects and assumes an unconstrained transmission network. In reality, transmission constraints could reduce the output from renewables plant and impact on the achievement of the renewables target.
- The model captures the evolution of market prices over time, and the impact on investment and retirements, in an internally consistent manner. However, there is huge uncertainty surrounding the market dynamics in a world of significantly higher renewables output. The competitive dynamics will determine the extent to which consumers and producers pay for the additional costs associated with renewables.
- The model captures short demand side response in determining expected energy unserved and peak prices. However, it does not include longer term demand side elasticity or changing shape in demand in response to evolving price signals.
- It has been necessary to divide the total biomass resources into volumes available separately to the electricity and heat sectors. The model does not consider how interactions between support schemes affect the demand for biomass in each sector.
- The model only covers the GB electricity market, and excludes Northern Ireland.

5.2 Modelled policies: details

5.2.1 Introduction

In this section we describe the detailed design adopted for the three schemes included in the quantitative assessment. It should be recognised that there are a number of different possible variations to these schemes (some of which we discuss), and a further level of detail that would need to be defined prior to the implementation of any of these schemes.

5.2.2 Extended RO

Design objectives

The central design objective for the Extended RO is to adapt the proposed Banded RO mechanism sufficiently to meet the increased 2020 targets.

Annual RO levels

The Banded RO proposals[3] have the concept of 'headroom' under which the RO is increased in the event that the predicted number of ROCs to be issued in the coming year could exceed the target for that year. The proposed headroom is 8% above target, selected to cover the variability in ROC volumes associated with uncertain wind output. The objective of the mechanism is to avoid the possibility of prices falling below the buy-out price if there were to be an over-supply of ROCs, and hence increase certainty for investors[23]. This should address one of the perceived weaknesses of the current scheme. This is set to operate up to a cap of 20% (compared to the initial RO for 2015/16 of 15.4%), above which the RO would not be increased.

The 'minimum change' option would therefore be simply to remove the 20% cap, with a commitment to maintain headroom at least until the new EU2020 target was met. This, combined with the option to 'band up' certain technologies to make them competitive, and assuming that planning and connection access constraints were significantly alleviated, could be sufficient to meet the 2020 electricity target. This approach has the significant benefit of policy continuity, and would be likely to avoid any potential hiatus in build associated with transitioning to a new scheme.

However, it was felt that this would have three major shortcomings:

- a lack of a clear and transparent signal to investors of a step change in Government policy to achieve the new EU target;
- no explicit linkage to the actual targets; *and*
- no market price signal when deployment was falling below the new build trajectory required to meet the 2020 target, as the market price for ROCs would be unlikely to rise significantly above the buy-out price, regardless of the level of build.

[23] The 'ski-slope' pricing mechanism is an additional proposed measure to prevent prices collapsing which is a risk under the current mechanism.

To address these, the Extended RO was considered, under which the size of the RO is more directly related to the 2020 electricity target. We assume a linear increase in the target from the starting year to the required 2020 level (although alternative trajectories could be considered, for example, linked to the draft Directive proposals). Since the banding proposals will break the link between the number of ROCs and MWhs of renewables generation we need to account for the average 'net banding' as different technologies come on-line[24]. To achieve this, the size of the obligation would be calculated according to the following formula:

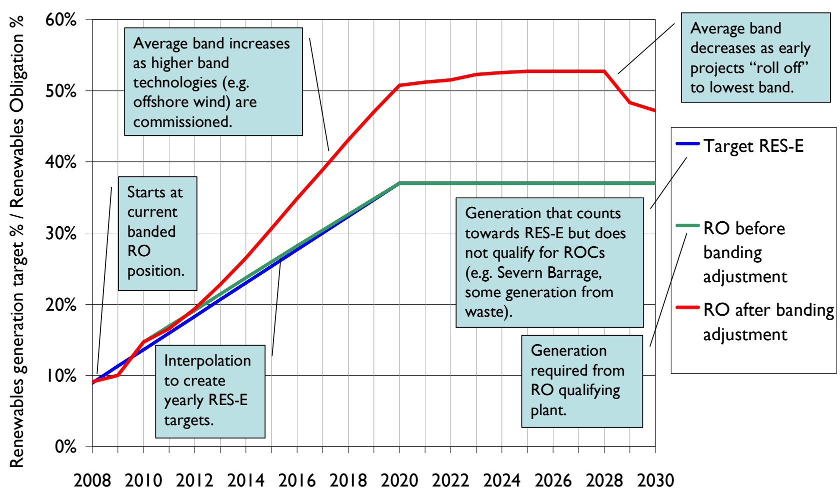
- Size of obligation = annual renewables generation target (less non-RO renewables) * average net banding calculated in previous year

In other words, if the RO for a given year was met in full (given the expected generation capacity within each band), then the renewables target for that year would be achieved. The new 2020 electricity target is thus embedded more transparently in the policy framework, and (with the potential for ROC prices to rise above buy-out in the early years) there is the potential for a clearer market signal and corresponding upside for investors. Arguably such an upside may be required to ensure the rapid step up in prospecting and investment needed if the 2020 target is to be met.

The more algebraic and predictable the formula is for setting the obligation size, the easier it would be for companies to model using their own assessments of likely future renewables deployment, and should improve investor confidence.

The way in which this would evolve over time is illustrated in Figure 5 below.

Figure 5 Extended RO evolution



[24] The Banded RO aims to set bands with a principle of net banding neutrality, but recognises that in practice maintaining strict net neutrality would be too difficult and artificially constraining.

The blue line shows the 2020 renewable electricity target, linearly extrapolated back to the current position[25]. This is then adjusted (the green line) for expected non-qualifying renewables generation. This would represent the RO size with no banding. The red line then shows how this is 'corrected' via the formula to account for the fact that the total number of ROCs issued may diverge from the MWh target under banding. (In the diagram we illustrate a situation where the average net banding in the early years is less than 1, due to co-firing, but increases above 1 as increasing amounts of higher band technologies such as offshore wind are commissioned.) The decrease after 2022 occurs as plant operating for more than twenty years are moved to the lowest band.

There are two key differences between this Extended RO approach and the 'minimum change' option.

First, the impact of re-banding is different. Under the Extended RO any re-banding, up or down, directly affects the size of the overall subsidy, whereas under the 'minimum change' option, and in the absence of any accompanying change in headroom, re-banding simply results in re-distribution of the subsidy between existing and new plant. Thus the Extended RO may provide additional confidence to investors since plant revenues are impacted less by future decisions on banding and headroom, and arguably it is more transparent and predictable.

Second, the success of the Extended RO approach is critically dependent on resolution of planning and connection access issues. Were these issues still constraining new build, the steadily increasing obligation size could lead to very high ROC prices and rents for renewables generators. The 'minimum change' option is less susceptible to this risk since the size of the obligation would only increase in response to the level of renewables that have been built to that point. As a consequence of this risk the linear interpolation of the target from the start year to 2020 under the Extended RO may require further consideration.

Remaining design features

The Extended RO as modelled is assumed to start in 2010 and to run to 2037/38. Other features are assumed to be consistent with the current Banded RO proposals, as described below:

- Bands would be reviewed, with potential resetting, in 2013 and 2018, with 2 years advance warning.
- Bands would be adjusted depending on cost evolution of the various technologies.
- Banding granularity may be adjusted where further subdivisions of bands are required (compared to the initial groupings) to ensure that targets are met without incurring significant rents.
- Existing plant would continue to receive 1 ROC/MWh. Bands for future plant would be grandfathered and not subject to change following band reviews.
- After 20 years of operation, but not before 2027/28, plant would drop to the lowest band.

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[25] The EU draft directive suggests that renewable energy proportions will be calculated on a final energy demand basis, which includes, amongst other things, transmission and distribution losses, energy industry own use and demand met by embedded generation. This differs significantly from the definition used in the current RO (and the Extended RO as modelled here). The Obligation is calculated based on metered consumption, which excludes losses and demand met by embedded generation. The RO definition leads to a number smaller by about 50 TWh per annum than the likely EU definition. Hence meeting a particular target renewables generation percentage under the EU definition is more onerous than an equivalent RO target.

- There would be a 10% limit on suppliers meeting their obligation with co-firing, and co-firing bands would not be subject to grandfathering.
- Schemes in the planning phase during a band review receive the best of current bands or proposed bands.
- The buy-out price would remain indexed to RPI.
- Ski-slope pricing would be implemented as currently proposed[3].

There are a number of potential variants to this design. One option that was considered, but not modelled, was to relate the indexation of the buy-out price to the wholesale price for electricity, rising in periods of low electricity prices and falling in periods of high electricity prices. This could potentially stabilise revenue streams for renewables generators whilst reducing the risk of very high rents in worlds of high electricity prices. Such an approach would however need to be carefully considered in the context of banding since the relativity of support levels for different technologies would be affected by changing wholesale electricity prices when this may not be intended.

It is assumed that very large scale projects, such as the Severn Barrage, would not be subsidised via the Extended RO. Instead, we assume that this project is delivered through a separate mechanism. For simplicity we assume that this mechanism is a simple tender and that successful tenderers (which may be a consortium) bid at their levelised costs, thus earning their required rate of return but without the potential upside afforded by the obligation-based scheme.

5.2.3 Standard FIT

Design Objectives

The objective for the design of the Standard FIT was to create a simple structure which would capture the benefits of insulating investors from future policy and market risk, and provide the flexibility for policy makers to adjust tariffs to attract new investment in light of evolving plant costs whilst avoiding significant rents.

Setting tariff levels

We assume that the Standard FIT scheme offers all-in tariffs, rather than a premium to the wholesale electricity price, and, as is the case in most countries where feed-in tariffs have been implemented, these tariffs are differentiated by technology type. We have further differentiated tariffs for onshore (three categories) and offshore wind (two categories) depending on wind speeds. (This contrasts with the Extended RO where all sites of the same technology receive the same ROC band.) The purpose of this differentiation is to reduce investor risk from output uncertainty, thus increasing the exploitation of all available resources. The downside with this approach is that it weakens the incentive to develop the highest resource potential sites first. There may be other good reasons for wishing to promote lower wind speed sites which were not reflected in the modelling or cost benefit analysis, for example, to increase geographic diversity of intermittent renewables, thus improving security of supply and reducing the risk of transmission constraints.

Another consideration in the siting of (transmission network connected) generation projects are Transmission Network Use of System (TNUoS) charges which vary across the country depending on the relative cost to National Grid of providing capacity in different parts of the network. We assume that tariffs will be further differentiated to reflect these different costs, and retain a locational signal for investors, but that the generator is not exposed directly to these costs which can change year-on-year. Similarly we assume that renewables generators connected to distribution networks would not be exposed to changes in Distribution Network Use of System Charges (DNUoS) for embedded generators[26]. We also assume that FIT generators are not exposed to Balancing Services Use of System (BSUoS) charges. We have assumed for the quantitative assessment that these Use of System (UoS) charges are passed through since it removes an element of cost risk that would otherwise need to be reflected in higher tariffs. However, different approaches are possible and these issues warrant careful consideration in the detailed design of a FIT scheme.

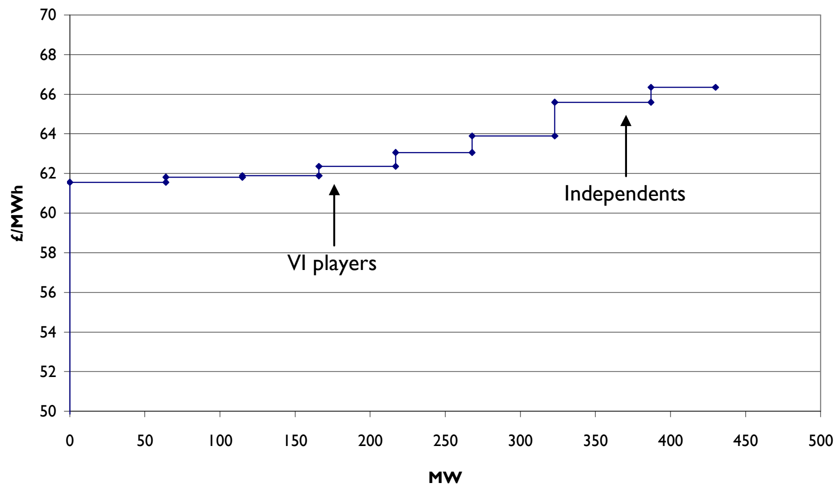
The challenge for the 'FIT Agency', assumed to be appointed to set and administer FITs, in setting the tariffs is to estimate accurately the costs of deployment of different technologies. Set them too low and insufficient investment will be attracted, whilst if they are set too high renewables generators may enjoy excessive rents at the expense of consumers. We have assumed that under the Standard FIT scheme the tariffs could be reset every three years, providing some flexibility to correct for any errors. However, because we also assume vintaging of tariffs, each plant will receive a fixed tariff for its economic lifetime (20 years), and it will not be possible to recoup any rents for tariffs set previously too high. Likewise, it may not be possible, given the tight timescales involved to 2020, to catch up fully on lost ground following a period when tariffs were set too low and build was limited. (These risks are explored in the sensitivity analysis presented below.)

Recent evidence suggests that future capital costs for renewables technologies are very uncertain. The recent rapid increase in the cost of offshore wind is evidence of this. Traditionally, renewables support schemes have worked on the assumption that the costs of renewables should decrease with increasing deployment. At this stage it is not clear the extent that the significant increase in demand for renewables in the EU and elsewhere, combined with increased commodity costs, will offset or even override the learning curve effects, at least in the short term. This may lead policy makers to err on the side of setting tariffs above central forecasts of plant costs, particularly for emerging technologies.

A further consideration when setting a tariff is to estimate the cost of capital of investors under a FIT scheme. To an extent international experience could be helpful here. However, it must also be recognised that the costs of capital may vary by type of investor and that a wide range of investors may be needed in order to meet the 2020 target. Figure 6 shows an example from the modelling of the levelised costs of Onshore Wind (High) for different investor types reflecting a lower assumed cost of capital for vertically integrated (VI) players relative to independent developers.

[26] New charging methodologies were introduced from 2005 by the Distribution Network Operators (DNOs) to move from a 'deep' connection policy whereby embedded generators do not pay DNUoS charges, to one of lower connection charges but payment of DNUoS charges.

Figure 6 Levelised costs for Onshore Wind (High) for different investor types, 2018



The combination of uncertainty in capital costs and the likely spread in cost of capital of different players will require policy makers to set feed-in tariffs at a premium to the central view of levelised costs for a vertically integrated player. The higher the target, the greater the premium will need to be. Thus it is unrealistic to assume that a FIT policy could be rent free, particularly if very high penetrations of renewables are being targeted by 2020. Table 3 shows the premia assumed above central levelised costs in the modelling for FITs under the different target cases (28%, 32%, 37%). The FIT approach will, however, be less susceptible to excessive rents than the obligation-based approach of the Extended RO when electricity prices are high, or deployment is constrained by planning or connection access.

Table 3 Premia above central view of levelised costs assumed for FITs under different targets

Technology	Standard FIT37	Standard FIT32 SB	Standard FIT32 no SB	Standard FIT 28
Onshore wind (High)	12%	10%	12%	10%
Onshore wind (Medium)	12%	10%	12%	10%
Onshore wind (Low)	12%	10%	12%	10%
Offshore wind (High)	20%	10%	18%	10%
Offshore wind (Low)	20%	10%	18%	10%
Biomass regular	20%	10%	18%	10%
Biomass energy crop	20%	10%	18%	10%
Biomass CHP	25%	10%	20%	10%
Wave	25%	10%	20%	10%
Tidal Stream	25%	10%	20%	10%
Tidal Range	25%	10%	20%	10%
Biowaste	25%	10%	20%	10%
Biogas	25%	10%	20%	10%

The FIT for co-firing is calculated on a different basis since its purpose is to compensate for the additional fuel costs associated with burning biomass in existing plant rather than to support significant upfront capital investments. First, we assume that it is a premium-based tariff rather than an all-in tariff. We assume that the tariff is set based on an estimate of the difference in short run marginal cost of burning biomass compared to coal (plus carbon), plus an additional £5/MWh to cover uncertainty in the biomass price, with a minimum tariff of £5/MWh. Two different tariffs apply, one for regular biomass and one for energy crops. The co-firing tariffs are reset annually rather than every three years. This approach is assumed to be the same under all 2020 target cases.

Trading of renewable output

A key issue with regard to a FIT scheme is how the power from renewables generators under the scheme is sold into the market. Unlike the Extended RO scheme, where generators are responsible for selling their own power output in the market, under the Standard FIT scheme the power would be purchased from the generators in the first instance by an independent 'Renewables Purchasing Agency'. This entity may or may not be the same as the FIT Agency responsible for setting tariffs.

There are many ways in which renewable output could be allocated. The power could be auctioned by the Renewables Purchasing Agency to market participants[27]. A spectrum of different time periods can be envisaged, with, at one extreme, a virtually 'back-to-back' process with power purchase agreements for the life of the project auctioned contemporaneously with FITs being signed with generators[28], and at the other extreme, day-ahead auctions of the aggregate forecast output. Alternatively, renewables volumes could be 'deemed' to suppliers ex-post, based on a pro-rata allocation determined by market share, and thus effectively handled outside of the market.

It was felt that a day-ahead auction represented a practical approach that could be consistent with the existing design of the wholesale market, and that could gradually be expanded to auctions for longer-term products. Under this approach, the Renewables Purchasing Agency would pay the renewable generator the FIT price for its output. It would also pay the UoS charges on behalf of the generator. It would hold day-ahead auctions for firm volumes, at half-hourly granularity, based on the forecast output from FIT eligible plant. These forecasts would be based on information received from the plant and would use the Agency's own forecasting capability. It would then be responsible for balancing the renewables portfolio from the day-ahead stage to real-time and would be incentivised to reduce these balancing costs on behalf of the industry.

The Renewables Purchasing Agency would levy a charge ex-post to suppliers based on their customers' share of final consumption. This charge (the 'net FIT levy') would be the sum of the FIT payments, generator UoS charges and Agency balancing costs (adjusted for any incentive payment) and administration costs, less the revenues the Renewables Purchasing Agency receives from auctioning renewables output at the day-ahead stage[29].

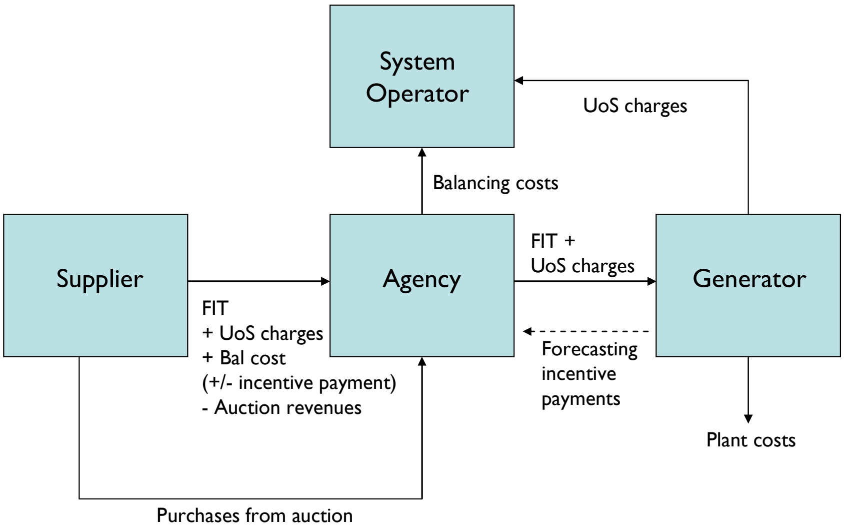
[27] This would be similar to the auctions held by the Non-Fossil Purchasing Agency in selling power from generators originally awarded contracts under the Non-Fossil Fuel Orders.

[28] In this case the buyer of the power purchase agreement would be exposed to the volume risk associated with the uncertain renewables output.

[29] Note that the FIT levy would cover losses between generator output and final end-user consumption. Further consideration would be required regarding how the embedded benefits from distribution connected renewables were treated via the Renewables Purchasing Agency model.

A hypothetical model of how cashflows could operate under the Standard FIT scheme is illustrated schematically in Figure 7 below.

Figure 7 FIT cashflows



The exact details for selling output from FIT eligible generators would need to be carefully considered, not least because a large proportion of overall generation would find its way to market through this mechanism. This may have implications for the dynamics of the existing wholesale market.

Remaining design features

The Standard FIT scheme would start in 2012, the assumed earliest possible date should primary legislation be required to implement it. In order to remove the risk that investment slows as 2020 approaches because investors are worried that they may miss out on a FIT because of project overruns, we assume that FITs are available to generators until 2022.

Other features of the scheme are as follows:

- Larger schemes would be incentivised to provide accurate output forecasts.
- Generators would transfer Levy Exemption Certificates to the Renewables Purchasing Agency who would sell them on their behalf via auction[30]
- Tariffs (other than for co-firing) would be for a fixed price indexed to RPI.
- Plant would be paid even if 'constrained off' (with the exception of co-firing).

The grandfathering arrangements for plant build under the RO prior to 2012 are discussed below.

[30] Revenues from the sale of LECs would be in addition to the feed-in tariff received.

As is the case with the Extended RO, we assume that the Severn Barrage would operate outside of the Standard FIT, and be developed via a tender.

5.2.4 FIT/Tender

Design objectives

The intention of the FIT/Tender scheme is to combine FITs for on-shore technologies with tenders for offshore technologies – offshore wind, wave, tidal and barrages. The rationale for using tenders rather than FITs for the offshore technologies is twofold. First, it would introduce a more market-based approach to reveal the cost of developing these emerging technologies, thus avoiding the risk of setting bands or feed-in tariffs incorrectly. Second, it could facilitate a more coordinated approach between planning, grid expansion, connections and the siting of new renewables projects, which arguably may be needed to ensure the rapid expansion of offshore renewables within the tight timeframes.

Below we describe the features of the tenders for offshore technologies that were modelled. The implementation of the FITs for on-shore technologies is assumed to be the same as described for the Standard FIT.

Tender approach

The first stage for the 'Tendering Agency' in designing the tender will be to establish what proportion of the 2020 target will be delivered from offshore technologies via the tenders and what proportion should be delivered via the FIT mechanism onshore. We have determined this split according to the assumed maximum build rates achievable for different technology types.

We assume annual tenders by technology type between 2012 and 2019. We also assume that these tenders are site specific and that these sites have planning approved and connection agreements in place[31]. We assume that the costs incurred in securing these agreements are recovered from the successful tenderers (and hence would be included in their bids). The benefit of this approach, should it be feasible, would be to reduce the risk, seen in other tenders schemes such as the NFFO, of successful tenderers subsequently being unable to secure planning or connection agreements and thus not delivering the required renewables generation.

Delivery incentives

Another potential concern with tenders is the possibility of failure of the successful parties to complete delivery of the projects, as has been seen recently in Denmark. To reduce the risk of this occurring, it would be possible to introduce a (non-returnable) deposit. Any such approach will need to balance the increased delivery certainty with an increased risk, and hence higher cost of capital, for the investor. For the modelling, we have simply assumed that successful bidders must post a deposit equivalent to one year's worth of subsidy as determined by their bid price. This deposit is returned in full if the project is

[31] On 4 June 2008, the Crown Estate, in announcing Round 3 of licensing for offshore wind development, proposed that it will co-invest 50% of the costs of obtaining planning consents and enabling works. This will facilitate the role of the Tendering Agency in this respect.

operational on time but is reduced pro-rata for each day of late delivery, with the deposit lost if the project is more than one year late.

For the modelling, we have assumed for simplicity that the combination of pre-arranged planning and connection and delivery incentives leads to 100% delivery performance. In reality some consideration of the proportion of projects that will not be delivered may need to be factored into the decision of the volumes of capacity to be tendered.

Remaining design features

Other key design features of the Tender are as follows:

- Tenders are pay as bid[32].
- Contracts awarded through the tenders would be of twenty year duration.
- Schemes would be incentivised to provide accurate output forecasts.
- Output from the tendered plant would be auctioned by the Renewables Purchasing Agency in the same way as under the Standard FIT.
- As for the Standard FIT, we assume that UoS charges would be passed through to the Renewables Purchasing Agency (and hence not included in the tender bids).
- We assume that the cost of the subsidy to tendered plant (contract price less wholesale revenues received) would be levied to suppliers in the same was as the Standard FIT.

A simplifying assumption that we have made for the modelling is that tenderers bid at their own levelised costs using a cost of capital (hurdle rate) commensurate with their perceived risk of the project. Hence, unlike the Extended RO and Standard FIT, there is no opportunity to earn additional rents. Whilst this is a potential benefit of the Tender approach, in reality bidders may attempt to 'bid up' to where they believe the tender might clear and secure additional rents. The extent to which they are able to do this will depend on the competitiveness of the tenders, information about other tenderers' likely behaviour, and detailed auction design, among other things.

5.2.5 Modelling transitions to new schemes

Impact of transition

Any move from the RO to a Standard FIT or FIT/Tender approach would involve significant transition issues, whereas the transition to an Extended RO could be relatively seamless.

It is recognised that a significant change in the renewables support scheme could in itself reduce the rate of deployment and increase costs, contrary to the objectives of moving to a new scheme. It might lead to a hiatus in investment during the period of policy transition, slower build up in project prospecting as

[32] This was a design choice in order to minimise the total subsidy required. An alternative would be to pay at the marginal clearing price of the tender.

companies adjust to the new scheme, and the transition itself will create some additional administrative costs.

An assessment of these factors can be critical in deciding whether a change in support mechanism is desirable or not and therefore we have attempted to include these effects within the quantitative assessment.

Timescales

It is assumed in all cases that the Banded RO is implemented as proposed in 2009. The Extended RO could be implemented as early as 2010, whereas we assume that the Standard FIT and FIT/Tender schemes would require primary legislation, and could only be implemented in 2012 at the earliest.

Grandfathering

It is vital that any change is not seen to reduce the value of existing and currently planned investments and therefore it is assumed that existing subsidies implicit within the RO mechanism will be grandfathered. The transition to the Extended RO would require no additional specific grandfathering arrangements since it is essentially a continuation of an existing scheme which already has provisions to safeguard investors' returns in the case of future reviews. If the Standard FIT or FIT/Tender schemes were to be introduced in 2012 we assume that all plant built under the RO prior to 2012 would continue to receive a premium subsidy comparable to the existing RO, rather than the alternative approach of converting them to a FIT. This would lead to renewables plant operating under two different schemes. RO plant would be participating directly in the market, whereas plant receiving a FIT or tender contract price would be operating outside the wholesale market. The implications of this would require careful consideration. We have assumed that the premium received by RO plant in each year would be the buy-out price + 8% (the proposed headroom value) multiplied by the relevant band for the technology.

Alternatively, plant existing under the RO could be offered a FIT equivalent to the subsidy they could have expected under the RO, based on prevailing electricity prices at the time. This might simplify market design if, as a result, all renewables were treated in the same way through a Renewables Purchasing Agency. Such design questions would require further refinement before implementation.

Depending on how wholesale electricity prices outturn this level of support may appear high relative to subsequent FITs. While the exact level of grandfathering will have to be separately assessed, it will probably be necessary to offer generous grandfathering arrangements to avert a reduction in investment in the period running up to the new scheme being introduced. Any such reduction would, however, need to be balanced against concerns about the cost of the scheme as a whole.

We have assumed that the grandfathering arrangements do not apply for co-firing and that co-fired plant would receive the relevant annual co-firing premium FIT.

Investor behaviour during the transition

There are a variety of potential investor responses to a change in support mechanism, and associated possible means of incorporating these within the modelling. We have outlined three potential behaviours in Table 4 below.

Table 4 Modelling investor behaviour through scheme transition

No	Potential investor behaviour	Possible modelling approach
1	Hiatus or slow down in investment in new projects during period of policy uncertainty[33].	Reduce build rates during period of transition prior to new scheme.
2	Investment rush as companies seek to capitalise on favourable grandfathered RO before new scheme comes into place.	Increase build rates during period of transition.
3	Companies slow to ramp up project prospecting capability until experience of new regime is gained.	Reduce build rates for first few years of new scheme.

All three of these behaviours are plausible. For the modelling we have examined only Behaviour 3, on the assumption that the proposed grandfathering arrangements are sufficiently attractive to maintain investment in the run up to the new scheme, and yet an investment rush is unlikely given other constraints in planning and connection access.

The following assumptions were adopted to model Behaviour 3[34]:

- No impact on project deployment prior to 2011.
- Maximum build rates for plant receiving FITs reduced by 50% in Year 1 (2012) of new scheme, and by 25% in Year 2 (2013) relative to Extended RO. Thereafter as under Extended RO.
- No impact on offshore technologies built under the Tender.

[33] We assume that the details of any new scheme other than the extension of the RO are finalised in 2010.

[34] For modelling simplicity we have constrained the annual maximum build rates to represent the slow down in investment during the transition. In reality the constraint is not a physical one, but the result of investor behaviours.

5.3 Status Quo counterfactual

5.3.1 Overview

The Status Quo case is used as the counterfactual against which to assess the impact of the different renewables support schemes designed to promote higher levels of renewables penetration. The cost benefit analysis is reported as the change from the Status Quo case.

The Status Quo case represents business as usual renewables policy, assuming implementation of the Energy Bill proposals in 2009, and BERR's central views on demand, fossil fuel and carbon prices.

In the Status Quo we have assumed that the Banded RO is implemented from 2009 as per the proposals in the Energy Bill. The banding assumptions are shown in Table 5. We assume that in the Status Quo there is no rebanding in future years. The size of the obligation increases linearly to 15.4% by 2015/16, and thereafter a headroom of at least 8% is maintained.

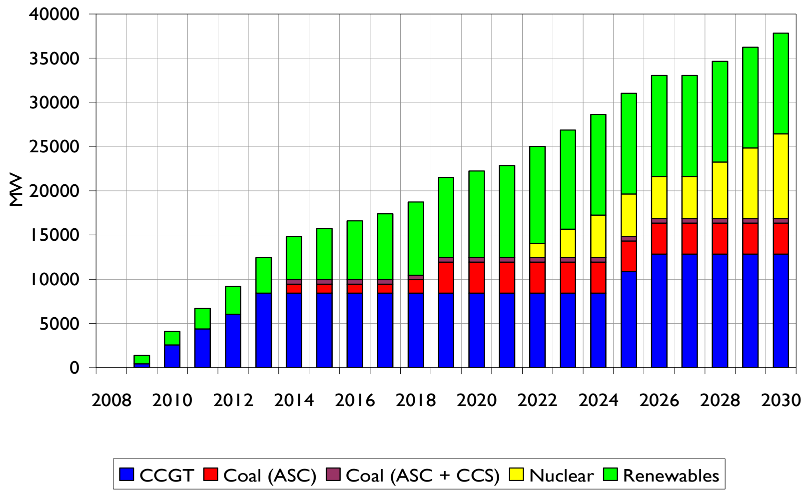
Table 5 Banding assumptions, Status Quo

Band	Example technologies	Support in ROCs/MWh
Established 1	Landfill gas	0.25
Established 2	Sewage gas, co-firing of non-energy crop biomass	0.5
Reference	Onshore wind, hydroelectric, energy from waste with CHP, co-firing of energy crops	1.0
Post-demonstration	Offshore wind, regular biomass	1.5
Emerging technologies	Wave, tidal-stream, solar, geothermal, tidal barrages (< 1 GW)	2.0

5.3.2 Generation mix

Figure 8 below shows new plant build under the Status Quo scenario from 2009 broken down by technology type.

Figure 8 New plant build, Status Quo



There is a steady growth in renewables, which deliver 14% of output by 2020. Growth slows after that point, as the end of the Renewables Obligation (in 2027/28, as currently proposed) approaches. New investment in the early years is dominated by combined cycle gas turbines (CCGTs[35]), some of which are already under construction (such as the Langage and Marchwood projects). Some new advanced super-critical (ASC) coal plant is constructed from 2014 to replace plant closing under the Large Combustion Plant Directive (LCPD). We also assume that a 500 MW demonstration carbon capture and storage (CCS) plant becomes operational in 2014, through the Government organised competition, but no further CCS plant gets built thereafter on economic grounds. The first new nuclear plant becomes operational in 2022 and by 2030 there is 9.6 GW of new nuclear plant on the system. In total, 26 GW of new capacity is built between the end of 2008 and 2020, and a further 15 GW by 2030. This excludes the repowering of existing plant.

Figure 9 shows the breakdown of new renewables build by type[36]. This is dominated by onshore and offshore wind. Investment is focused on the higher wind speed sites as would be expected given a single level of support for each technology. Very small quantities of other renewable types are built.

[35] We have included gas-fired combined heat and power (CHP) plant within the CCGT category.

[36] Note that this graph excludes landfill gas which is assumed to expand in the near term before declining.

Figure 9 Renewables plant build, Status Quo

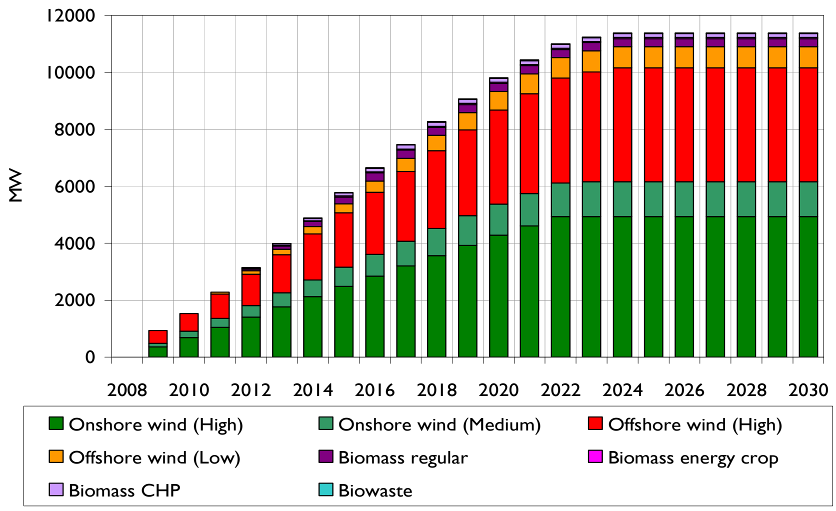
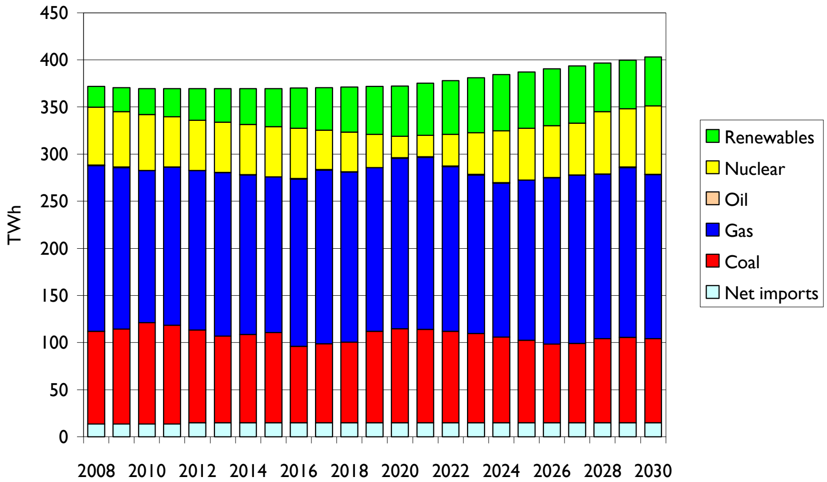


Figure 10 shows output by fuel type[37]. Renewables output (including co-firing) grows steadily as the amount of capacity grows. Output from nuclear plant contracts until 2021 due to closures within the existing fleet, before increasing as the new nuclear plant come on line. Coal output remains relatively constant[38], with load factors for existing coal plant that remain open which assume that the necessary investments are made to comply with future environmental legislation. Output from gas plant also remains relatively constant, despite an increase in the capacity mix, as the older generation (less efficient) plant operate at increasingly lower load factors.

[37] The sum of the output shown in the figure is total generation from transmission and distribution connected plant in GB (i.e. excluding Northern Ireland), excluding station own use, plus net imports.

[38] The relatively high carbon price and low gas price under the Updated Fossil Fuel Price Assumptions central case leads to output from coal in 2008 lower than levels currently observed.

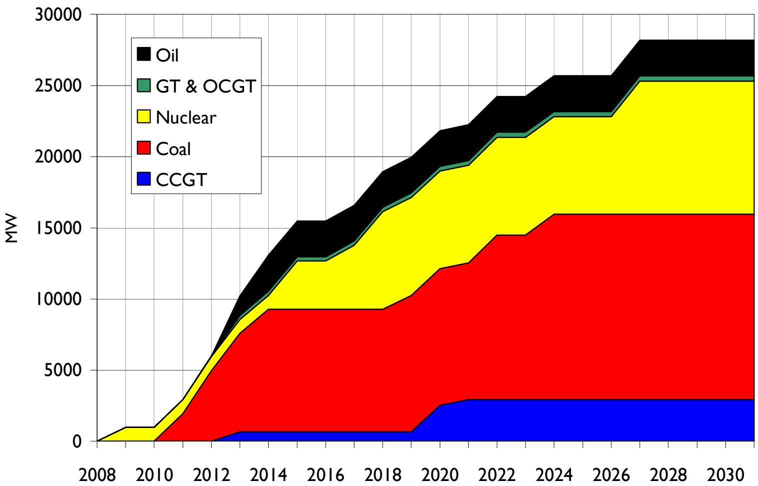
Figure 10 Plant output by type, Status Quo



5.3.3 Plant retirements

Figure 11 shows cumulative plant retirements from 2008 to 2030. The 10.8 GW of currently available plant that is opted-out of the LCPD must close by the end of 2015. Some accelerate the use of their 20,000 running hours and close earlier. Further closures of coal plant occur between 2018 and 2025 on economic grounds. There are also some closures of the earlier generation CCGTs. Most of the existing plant on the system will require further investment in re-powering and, in some cases, retro-fitting environmental protection equipment before 2030 in order to remain operational. All of the existing nuclear plant closes by 2028 with the exception of Sizewell B.

Figure 11 Cumulative plant retirements, Status Quo

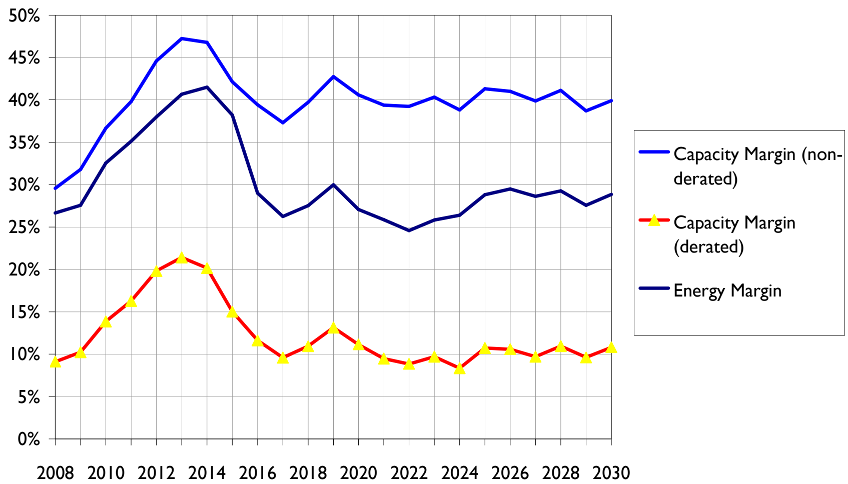


5.3.4 Plant margins

Figure 12 shows three different measures of supply margin for the Status Quo scenario. The light blue line indicates the peak capacity margin, which is the percentage by which total nameplate capacity on the system exceeds the peak demand. The red line shows the de-rated peak capacity margin, which scales back nameplate capacity by the expected availability of each plant at peak demand, taking into account probability of forced outages[39], and expected output from intermittent renewables plant. For wind plant, the average de-rated capacity under the Status Quo case ranges from 24% to 28% of its nameplate capacity. This figure is a function of how much other intermittent capacity there is on the system, as well as how it is distributed, as we describe in more detail in Section 5.4.4 below. The de-rated peak capacity margin is therefore a better indicator of security of supply than the peak capacity margin, although it does not capture factors such as the possibility of correlated forced outages (for example, nuclear type failures requiring several stations to be taken offline) or fuel supply risks.

The dark blue line shows the energy margin, which is the difference between theoretical maximum generation and annual demand, expressed as a percentage.

Figure 12 Supply margins, Status Quo

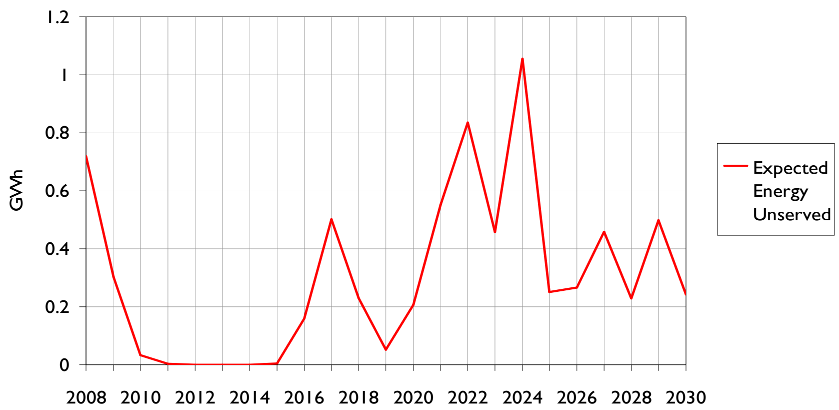


The de-rated peak capacity margin increases over the next few years due to commissioning of new CCGTs and assumed falling demand. However, it should be noted that due to constrained running for opted-out plant under the LCPD, the supply-demand balance may be tighter away from the peak than historically since the availability of opted-out plant may be reduced at times of lower demand in order to preserve running hours. There is a steep decline in the de-rated peak capacity margin from 2013 to 2017 as the LCPD opt-out plant begin to close, coincident with closures of some Advanced Gas Reactor (AGR) nuclear plant. It falls back to 10% by 2017 and then remains in this region, close to current levels.

Figure 13 shows another measure of security of supply, the annual expected energy unserved.

[39] For example, if there is a 10% probability of forced outage for a plant, its de-rated capacity will be 90% of its nameplate capacity.

Figure 13 Expected energy unserved, Status Quo



For 2008 the model suggests annual expected energy unserved of around 700 MWh[40] at the current de-rated peak capacity margin of 9.1%. This is material, but low relative to transmission/distribution failures, which we estimate account for in the region of 10 GWh of lost load annually[41]. The risks fall in the next few years as demand falls and new plant is commissioned. However, the risks increase again following the decline in the de-rated peak capacity margin after 2013. Although annual expected energy unserved returns to levels comparable to today the nature of potential shortfalls could be different due to the changing plant mix and increasing renewables.

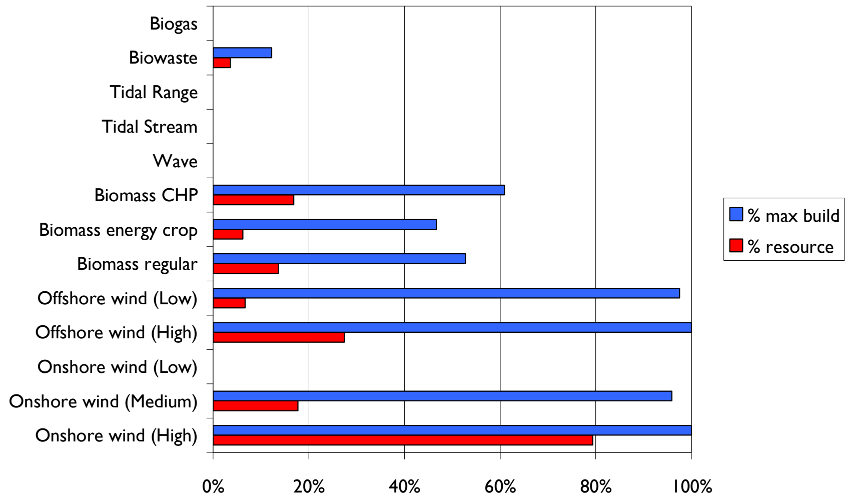
5.3.5 Renewables resource usage

Figure 14 shows the exploitation of renewables resources between 2008 and 2020 as a percentage of the available resource potential (red bars) and as a percentage of the cumulative maximum build rates (blue bars).

[40] The GB market experienced power shortages on 27 May 2008 following the sudden loss of Sizewell B and Longannet power stations. The amount of energy unserved during this event may be comparable with this figure.

[41] Transmission-related outages have varied from 100 to 900 MWh/annum since 1991/92. In 2004/05 the average customer minutes lost in GB from outages on distribution networks as reported by Ofgem was 94.29. Assuming an average load of 0.4 kW for 20 million customers, this would equate to approximately 12.5 GWh/annum of distribution-related outages.

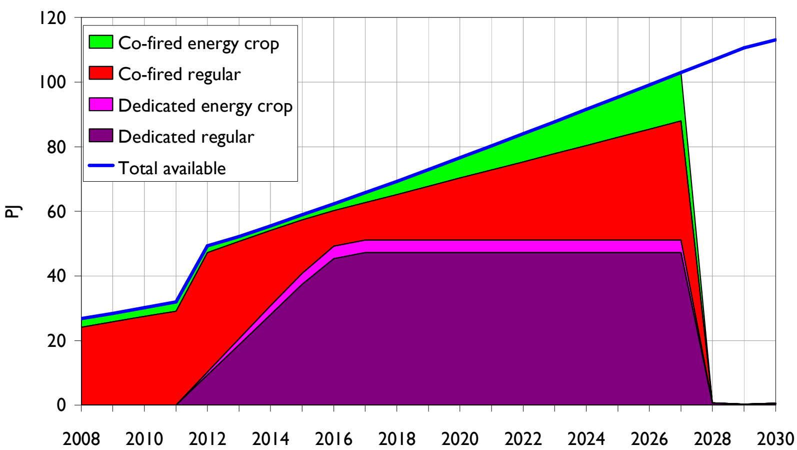
Figure 14 Renewable resource usage by 2020, Status Quo



Overall there is plenty of resource potential remaining by 2020, although nearly 80% of the available onshore high wind speed sites are exploited. Maximum build rates (the SKM Low case) are constraining the development of onshore and offshore wind. The banding up of wave and tidal projects (2 ROCs per MWh) is, according to the costs assumptions used, insufficient to promote investment in these technologies, although separately supported demonstration projects may be in operation by 2020.

Figure 15 shows the usage of biomass deemed available to the electricity sector under the Status Quo scenario. The blue line shows the total available and it can be seen that all of this resource is utilised until the RO ends in 2027/28. Biomass (regular and energy crops) is burned through a combination of dedicated biomass plant and co-firing in coal stations.

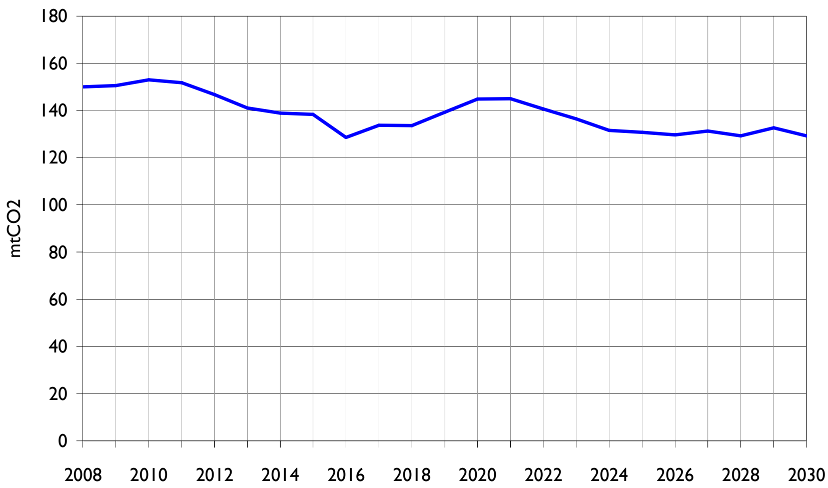
Figure 15 Biomass usage, Status Quo



5.3.6 Carbon dioxide emissions

Figure 16 shows the annual carbon dioxide emissions from the generation sector between 2008 and 2030 under the Status Quo[42]. These show a modest decline over the period. There are benefits from improving average efficiency of thermal plant and increasing penetration of renewables, but these are to an extent offset by nuclear closures, until new nuclear plant become operational from 2022, by which time demand is rising again.

Figure 16 Annual carbon dioxide emissions, Status Quo



5.3.7 Prices

Figure 17 shows the evolution of ROC prices under the Status Quo scenario. There is a steady decline in price as the number of ROCs issued increases faster than the growth in the size of the obligation. In order to maintain headroom of at least 8% the obligation size is increased to 20% by 2020. By 2020 the net 'banding' is 1.16 ROCs per MWh mainly as a result of offshore wind receiving 1.5 ROCs per MWh of generation. Hence the percentage of renewables generation in 2020, 14%, is still significantly below the obligation size of 20%. The kink down in prices after 2020 reflects the fact that the obligation size is fixed at that point although the number of ROCs issued increases for a few years further.

[42] Carbon dioxide emissions for 2008 are low relative to current levels due to the relatively high carbon price and low gas price assumed in the Updated Fossil Fuel Price Assumptions central case. Coal to gas switching can lead to a swing in carbon dioxide emissions of up to 30 $mtCO_2$ annually depending on the relativity of coal, gas and carbon prices.

Figure 17 ROC prices, Status Quo

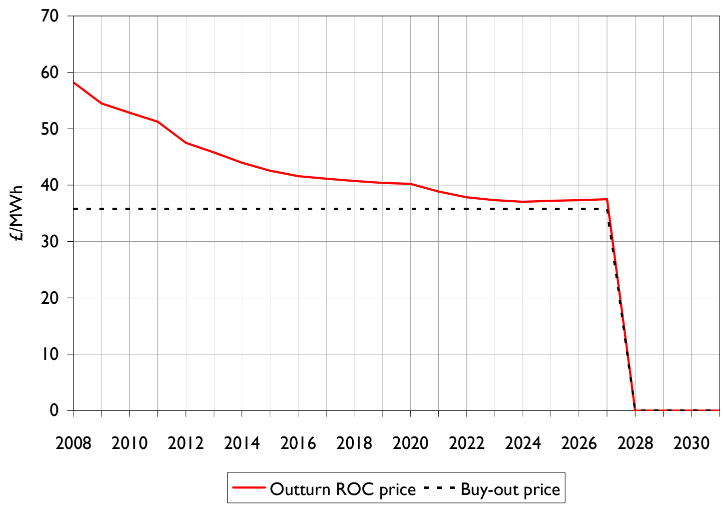
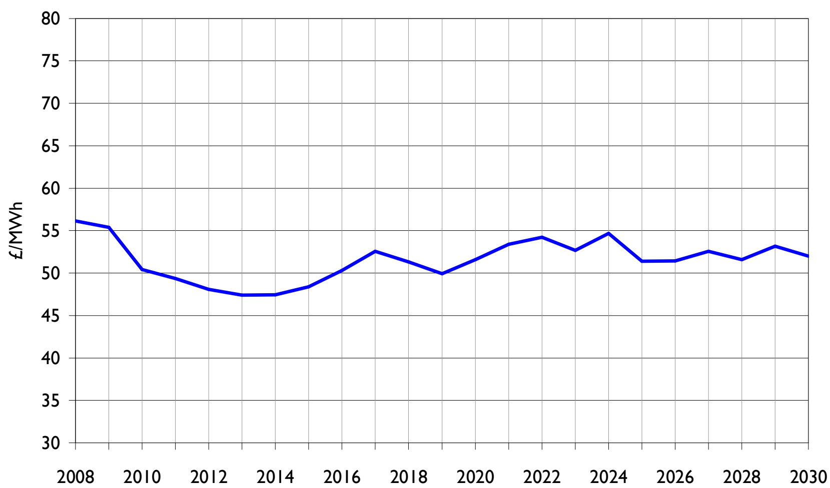


Figure 18 shows annual baseload wholesale electricity prices under the Status Quo. Note that the Status Quo uses the Updated Fossil Fuel Price Assumptions (May 2008) central case as inputs and hence prices in the near term are significantly lower than those currently observed in the market.

Figure 18 Wholesale baseload electricity prices, Status Quo



Prices decline in the earlier years in response to falling demand and commissioning of new CCGTs. Thereafter as the capacity margin contracts again prices increase.

5.3.8 Plant profitability

Figure 19 shows the estimated economic rent in £/MWh for different types of renewables plant between 2012 and 2020 under the Status Quo. It is calculated as the difference between expected revenues (ROC, LEC and wholesale electricity) and long run marginal costs for a typical integrated player for new plant in each year. Overall (except for biowaste and co-firing of energy crops, which represent relatively small volumes of output) the rents are very high (30% above LRMC for an onshore wind plant, for example) which in part is the result of constraints in planning and connection access for new plant leading to high ROC prices. (For investors with higher costs of capital the rents would be lower.) For most technologies, rents decline until 2015 due to falling ROC prices and wholesale electricity prices, although this effect is offset by falling capital costs for new plant. Thereafter rents fluctuate as a function of electricity prices.

The exception to this is for plant burning regular biomass, since we assume a steep increase in the cost of regular biomass in our input assumptions. Rents for these plant thus fall across the period. We have assumed no banding up in response to the cost increases since this could disadvantage biomass plant built under a previous lower ROC band who would be competing for the same resources.

Figure 19 Economic rent for renewables plant, Status Quo

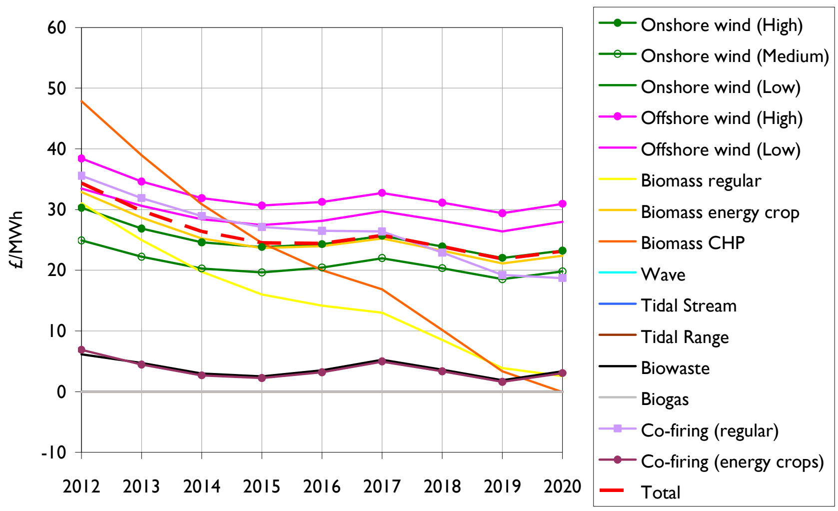
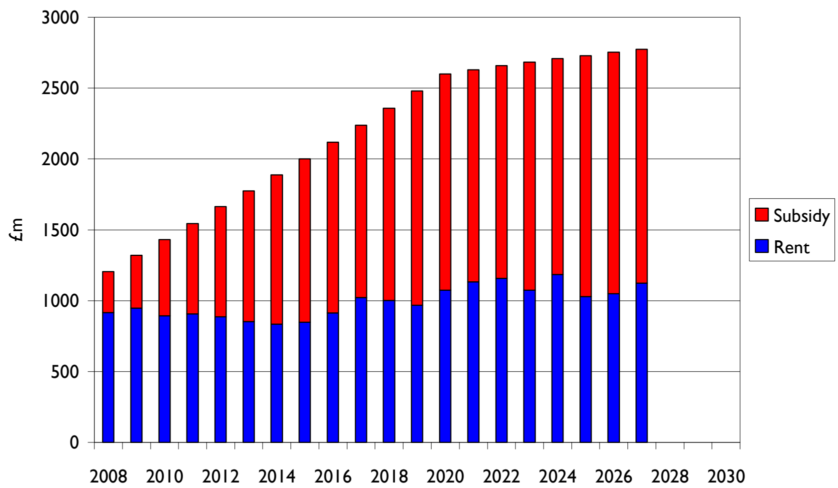


Figure 20 shows the total subsidy received by RO eligible plant between 2008 and 2027, when the RO finishes under the Status Quo. The estimated proportion of this that is economic rent is shown in blue. This is only an approximate measure since it uses simplified assumptions of the levelised costs of existing renewables plant. Economic rents remain roughly constant in absolute terms, but decrease as a proportion of the overall subsidy as ROC prices decline over time.

Figure 20 Net subsidy breakdown, Status Quo



5.4 Impact of high renewables target

5.4.1 Example case: Extended RO, 37% target including Severn Barrage

To explore the impact of high penetrations of renewables on the electricity market we look at the 37% target case under the Extended RO. Whilst the exact generation mix and capacity margins under the Standard FIT and the FIT/Tender schemes are different, many of the messages are the same. (One major difference, explored in Section 5.2.3, is the way that renewables output interacts with the wider wholesale market.)

To achieve 37% of generation from renewables sources by 2020 requires renewables deployment close to the High maximum build rates produced by SKM. To achieve these build rates would require removal of planning and connection access constraints and significant expansion of the supply chain. (Note that the Status Quo used as the counterfactual assumes the SKM Low maximum build rates, which approximately represents business as usual in terms of planning and connection access.) In addition, the Severn Barrage would need to be in operation by 2022, and its full output eligible to count towards the 2020 target under the terms of the draft Directive.

We have maintained the same banding assumptions as in the current Banded RO proposals, with the exception of wave, tidal stream and biogas which are banded up to 3 ROCs per MWh from 2 ROCs per MWh in 2013. Without this re-banding these technologies would not be commercially viable under the base case assumptions.

We have assumed that electricity demand is some 12 TWh lower by 2020 than the Status Quo under the Extended RO and other schemes on the assumption that some electrical heating load is displaced by heating from renewables sources as a result of financial incentives in the heat market. This is facilitating the achievement of the 37% electricity target[43].

As the analysis below illustrates, there is an increasing likelihood with higher penetrations of renewables of some 'spill' when the supply from inflexible plant exceeds demand. This may require plant, including renewables, to be 'constrained off'. (This situation may also occur even where overall supply does not exceed demand as a result of transmission constraints that are not modelled in this analysis.)

For the purposes of modelling simplicity we have assumed that renewables are unconstrained, and that all renewables built are able to achieve their expected capacity factor. This would represent the most optimistic outcome, and it is likely that a certain proportion of potential renewables output will be spilled or constrained off. More detailed modelling, including transmission constraints, regional distribution of intermittent output, the impact of new interconnectors and response on the demand side, would be required to quantify this effect. To the extent that it becomes material, higher amounts of capacity will be required to meet a given target, requiring a greater level of subsidy.

In this section we describe the impact of a high renewables target on generation mix, plant margins, renewables resource usage, carbon dioxide emissions, prices, system balancing costs, plant profitability and consumer costs.

5.4.2 Generation mix

Figure 21 compares new plant build between the Status Quo and Extended RO37 cases. Overall new capacity build is much greater under the Extended RO37 case, the difference reaching nearly 30 GW by 2030, due to the large investment in renewables. Less nuclear plant is built since the economics look less attractive as baseload electricity prices are suppressed. The impact on CCGT investment is minimal since their flexibility allows them to operate at lower load factors, benefiting from higher peak prices, whilst shutting down and avoiding very low (or even negative) offpeak prices. The impact of high penetrations of renewables on prices is described in more detail below.

[43] Note that for the purposes of the cost benefit analysis we have recalculated the Status Quo using this lower demand assumption.

Figure 21 Comparison of new plant build between SQ and Extended RO37

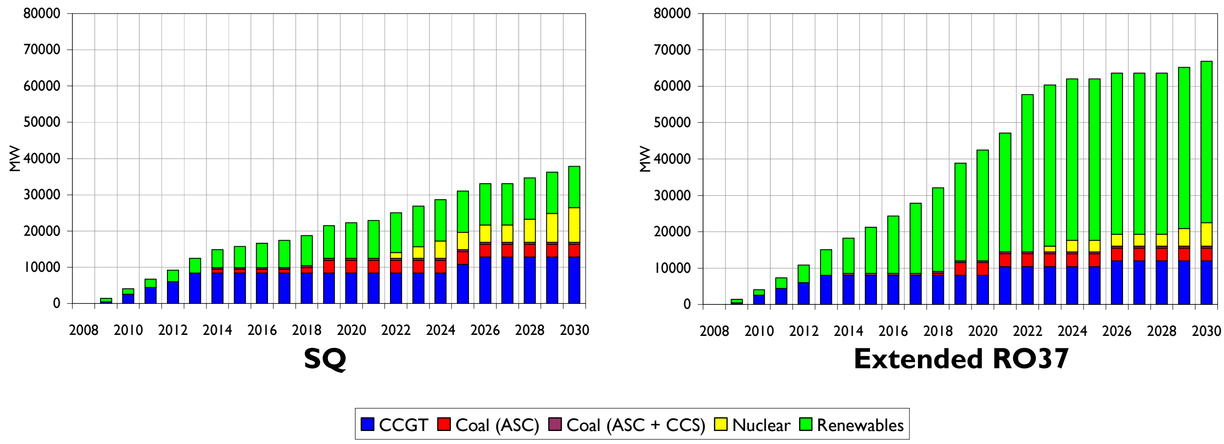


Figure 22 breaks down the renewables build by technology for the two cases. Clearly overall levels of build are much higher under the Extended RO37 case. The exploitation of lower wind speed sites for onshore and offshore wind is required to meet the target. In addition, some wave and tidal projects are built after these technologies are banded up to 3 ROCs per MWh from 2013. The Severn Barrage becomes fully operational in 2022 under the Extended RO37 case.

Figure 22 Comparison of renewables build between SQ and Extended RO37

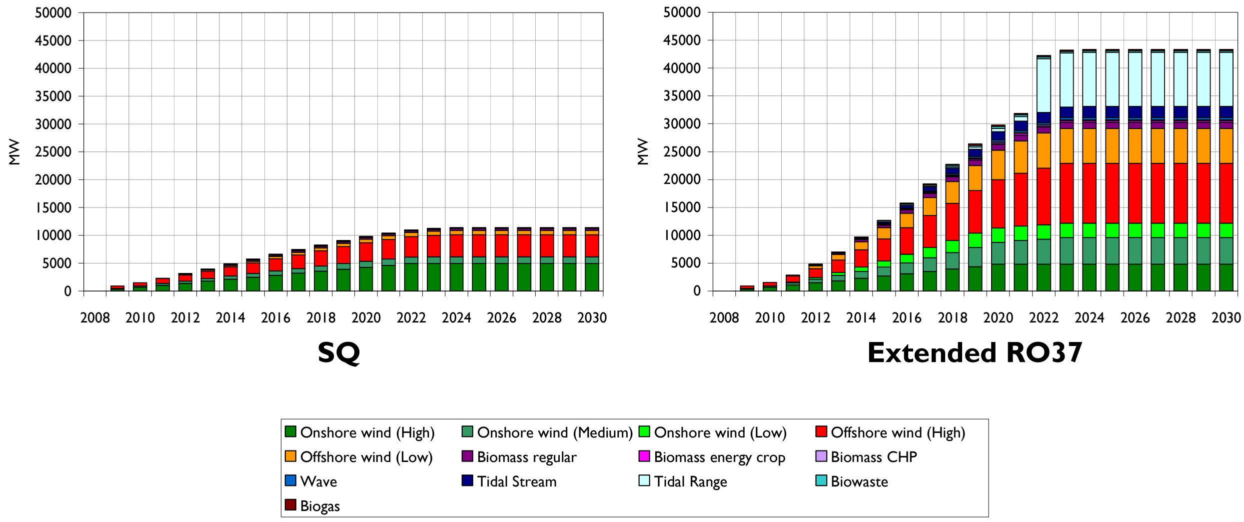
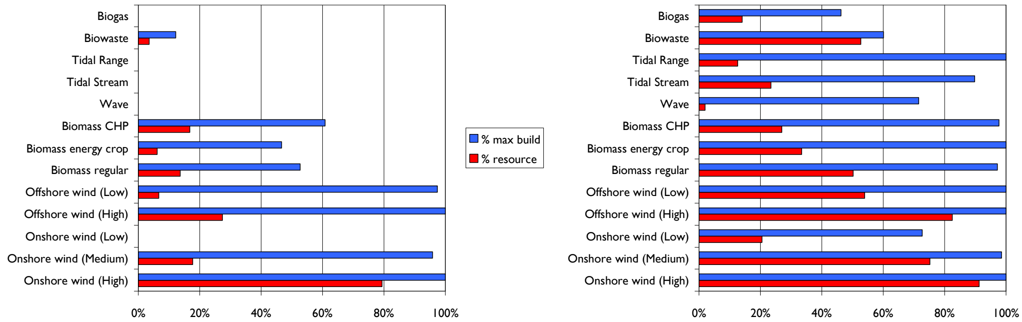


Figure 23 compares the exploitation of renewables resources between 2008 and 2020 between the two cases. A much greater proportion of the overall resource potential is exploited under the Extended RO37 case, as would be expected. Deployment is mostly constrained by the maximum build rates, as shown by the blue bars. Note that the Extended RO37 case assumes the High maximum build rate constraints, whereas the Status Quo case assumes the Low (business as usual) maximum build rate constraints.

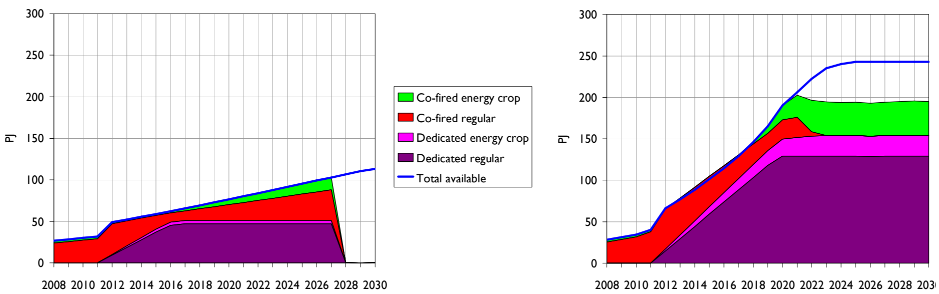
Figure 23 Comparison of renewables resource usage between SQ and Extended RO37



SQ **Extended RO37**

Figure 24 compares the biomass usage under the two cases, again assuming a much higher availability of resource under the Extended RO37 cases. All biomass available to the electricity sector is used until 2021, before levels of co-firing on regular biomass drop off in response to rising costs. Since the lifetime of the RO is extended until 2037/38 under the Extended RO case, biomass usage does not end abruptly in 2027/28, when all support is removed under the Status Quo.

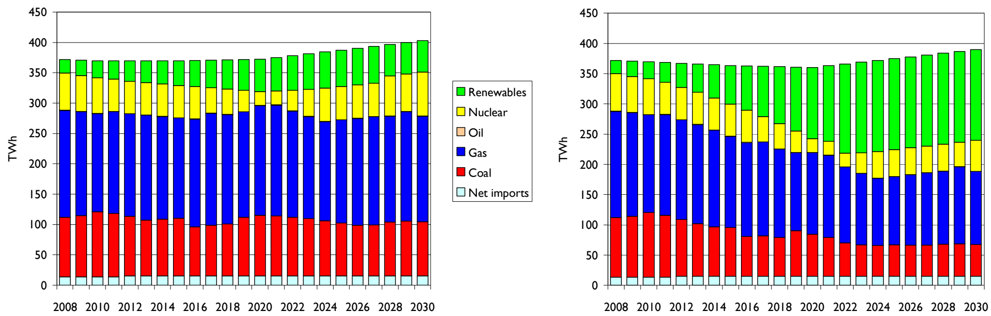
Figure 24 Comparison of biomass resource usage between SQ and Extended RO37



SQ **Extended RO37**

Figure 25 compares the output by fuel type between the Status Quo and Extended RO37 cases. Under the assumptions used, the 37% renewables target is met, if we assume that the Severn Barrage output is fully eligible. Renewables output reaches 36.8% of the total by 2020, compared to just 14.0% under the Status Quo. The growth of renewables output under the Extended RO37 case is at the expense of nuclear, coal and gas.

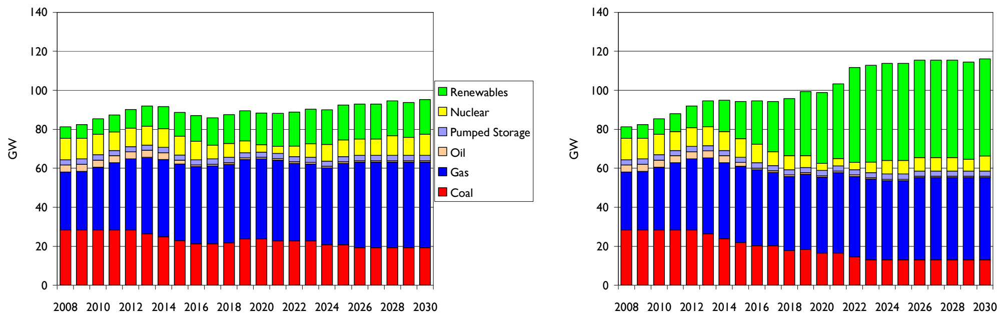
Figure 25 Comparison of output by fuel type between SQ and Extended RO37



SQ **Extended RO37**

Figure 26 compares the total capacity mix between the two cases. By 2022 there is 112 GW of generation capacity on the system under Extended RO37 compared to 89 GW under the Status Quo. Despite the additional renewables capacity, the amount of non-renewables capacity on the system is not much lower under the Extended RO37. This is because of the conventional capacity that the model calculates can profit from providing back-up (in response to higher and more volatile peak prices), and the balancing services required to accommodate the amount of renewables on the system. As described below, the amount of 'back-up' capacity calculated by the model is critically dependent on the 'capacity credit' for intermittent renewables.

Figure 26 Comparison of total capacity mix in 2022 between SQ and Extended RO37

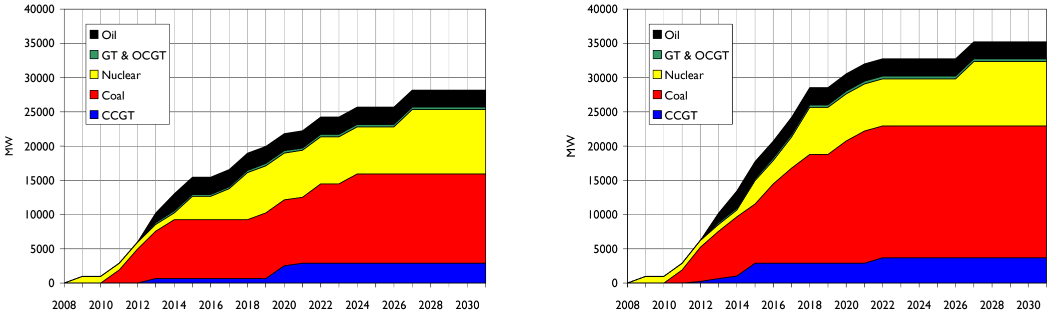


SQ **Extended RO37**

5.4.3 Plant retirements

Figure 27 compares the cumulative plant retirements under the Status Quo and Extended RO37 case. Although overall retirements are greater under the Extended RO37 case, the additional capacity retired does not mirror the additional capacity added. There are likely to be opportunities for fully written down plant to remain operational to benefit from higher peak prices and to meet the greater need for balancing services by the System Operator.

Figure 27 Comparison of plant retirements between SQ and Extended RO37



SQ **Extended RO37**

Coal and oil plant that are opted out of the LCPD currently play an important role in meeting peak demand and providing balancing service to System Operator. Furthermore, the requirement for flexible supply and balancing services will increase with the increasing penetration of intermittent renewables. Whether this requirement can be fully met by existing plant or require further investment in new peaking plant is uncertain.

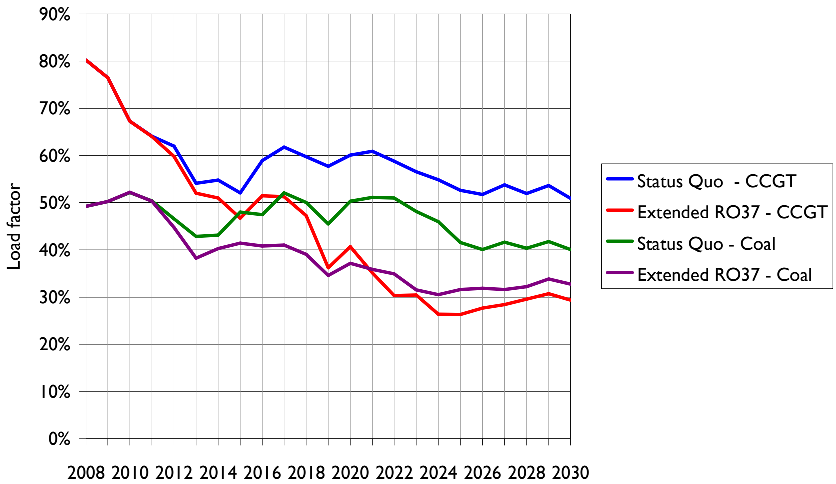
By 2016, under the Extended RO37 case there would still be approximately 20 GW of coal plant on the system. Under existing Integrated Pollution Prevention and Control (IPPC) legislation these plant would need to retrofit selective catalytic reduction (SCR) equipment to reduce emission of nitrogen oxides or have their running hours constrained. However new proposals published in December 2007[44] will tighten the regulations further, which could lead to further closures if the economics of retrofitting SCR look unfavourable for certain plant.

By 2016 there would be approximately 39 GW of CCGT on the system, some of which will be forced into running at lower load factor by the increasing proportion of renewables[45], as shown in Figure 28. Building of new peaking open-cycle gas turbines (OCGTs) may not be necessary if existing older generation CCGTs can operate profitably in a peaking mode. Further investment in these plant may be required to offer the balancing services required by the System Operator.

[44] Directive of the European Parliament and of the Council on industrial emissions (integrated pollution prevention and control)

[45] The impact on the gas transmission system of CCGTs operating in more of a peaking mode needs to be considered.

Figure 28 Comparison of thermal plant load factors between SQ and Extended RO37[46]



Finally, the demand side can play an important role in this area and this could be facilitated by technological developments such as smart metering.

5.4.4 Plant margins

The contribution that intermittent generation makes to supply at times of peak demand is the subject of much debate. Some have even argued that wind power can not be relied upon at all, and therefore "back-up capacity" is required to the order of 100% of the installed wind capacity[47]. This argument is based on the observation that there are times when there is essentially no wind across the UK and hence no output from wind plant. However, the chance of this occurring, as we discuss further below, is close to zero. (Indeed, theoretically, there is a very small probability that all plant of any technology, intermittent or otherwise, may be off-line at the same time through coinciding forced outages.) Comparing the reliability of wind, or other intermittent renewables, with conventional capacity must therefore be based on assessment of the probabilities of different output levels (for renewables and conventional plant) and their co-incidence with peak demand.

According to the British Wind Energy Association, individual wind turbines in the UK only generate electricity around 70-85% of the time[48]. However, the probability of there being no wind generation anywhere in the entire country at any given time, and therefore requiring 100% back-up capacity, is close to zero. In his 2007 paper summarising hourly wind speed data from 66 onshore sites in the UK between

[46] The load factors shown are for a CCGT at 50% efficiency (HHV) and a coal plant at 36.5% efficiency

[47] Laughton, M.G. (2002). Renewables and UK grid infrastructure. *Platts Power in Europe* **383**, 9–11.

[48] BWEA (http://www.bwea.com/energy/rely.html)

1970–2003[49], Graham Sinden found that the occurrence rate of low wind speed events (i.e. events in which the wind speed is too low to generate electricity) affecting more than 90% of the UK is about one hour per year. In fact, across the whole time period he analysed, there were no hours in which low wind speeds would have prevented generation across the entire country. The occurrence rate of events during which the wind speed was too great to generate electricity was much lower still.

One measure traditionally used to determine the contribution to system reliability of intermittent renewable generation, such as wind power, is the capacity credit. A plant's capacity factor measures its average output at any given time period relative to its installed capacity, whereas the capacity credit measures the percentage of maximum potential output that will be statistically available during times of peak load. The capacity credit is often expressed as the amount of conventional thermal generation (taking into account its availability probability) that intermittent generation could effectively "replace" during times of peak load, without any increase in the loss-of-load probability (LOLP). It is therefore meant to be a like for like comparison of the contribution to peak demand of different types of generation with different output patterns and availability.

Capacity credit functions may be calculated either analytically, or probabilistically using simulation models. The capacity credit functions used in this study have been calculated using the latter approach[50]. The functions calculated have then been benchmarked against other studies[51] to ensure consistency with other sources. For the capacity credit of some emerging technologies, such as the Severn Barrage or tidal stream, no other studies exist, to our knowledge.

The capacity credit for total installed intermittent capacity will generally be lower than the sum of individual plant capacity factors, and is also a function of the mix of plant on the system. In particular, the capacity credit for a given technology will be affected by:

- the total existing installed capacity of that technology on the system;
- penetration levels of other types of intermittent technology; *and*
- the geographical distribution of different plant, and the split between different technologies.

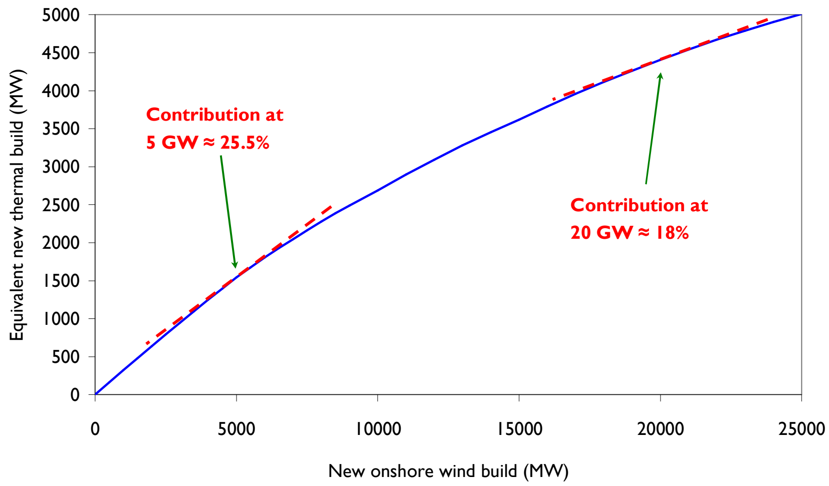
The first of these is due to the fact that the output of individual units of intermittent capacity of any single technology (such as wind) is generally correlated. As a result the credit declines as the installed capacity of that technology increases. Each extra unit of installed capacity yields a diminishing marginal contribution to security of supply, because of the high likelihood that its output profile (and especially its zero-output hours) will be correlated with those of the remainder of the installed capacity. An example of the declining marginal capacity credit is shown in Figure 29 below, illustrating the capacity credit function calculated for onshore wind with a capacity factor of 27%.

[49] Sinden, G. (2007). Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. *Energy Policy* **35**(1), 112-127.

[50] The capacity credit functions of various intermittent renewable technologies have been calculated by adding increasing levels of the technology to the supply-side, and then determining the amount of additional conventional thermal capacity that would have resulted in the equivalent benefit in terms of security of supply.

[51] The main source of published capacity credit data points used was published by the UK Energy Research Centre in 2006: Gross, R., Heptonstall, P., Anderson, D., Green, T., Leach, M. and Skea, J. (2006). The Costs and Impacts of Intermittency. UK Energy Research Centre, London.

Figure 29 Modelled capacity credit function for diverse onshore wind resource with 27% capacity factor



Quoted de-rated peak capacity margins in this study take into account the diminishing capacity credit of increased renewables penetration. This ensures that the measured level of security of supply is consistent between different capacity mixes with similar quoted peak de-rated capacity margins.

Second, if a system already has a high penetration of intermittent renewable technology, regardless of whether or not the output profiles of the different technologies are correlated, the benefit to security of supply of adding more intermittent capacity (instead of conventional thermal capacity) is relatively lower. For example, in a system with a significant penetration of wind power, the marginal contribution that extra wave or tidal power generating units can make to security of supply diminishes much more quickly relative to systems that have a lower level of wind penetration. This is a feature of the way in which more intermittent capacity changes the probability distribution of supply, making it wider and flatter. To reduce the frequency of events at the "tails", when the distribution is already flat, requires a larger shift in the average MW availability (and hence capacity) of intermittent plant that is added to that mix.

Third, the geographic (and technology) diversity of the renewables resource is strongly influential in the determination of capacity credit[52]. The capacity credit function shown in Figure 29 assumes a relatively diversified geographic resource, and hence is toward the higher end of the range seen in other studies, although lower than the numbers suggested by National Grid in its latest Seven Year Statement, published in May 2008[53]. A less diversified renewables resource base would lead to lower peak capacity margins and higher and more volatile peak prices, signalling the requirement for investment in additional capacity.

In addition, it should be noted that the average output of wind plant in the UK is generally higher during the day and in winter, when peak load occurs currently, which has a positive impact on its capacity credit.

[52] As a very simplified example, the total generation of a single hundred-turbine wind farm in an area of one square kilometre will be a great deal more variable than the total generation of a hundred turbines spread across the entire country. The output profile of the single wind farm will be not dissimilar from that of a single generator, with the aggregate output greater than zero for only 70-85% of the time. Adding an extra turbine to that wind farm will do very little for security of supply. However, analogous to Sinden's analysis, the probability of none of the hundred well-dispersed turbines generating at any given time is practically zero.

[53] National Grid is suggesting a 20% capacity credit for 25 GW of wind plant.

Tidal stream power, the output of which is dependent on the moon and not the sun, does not have the benefit of this correlation. Further details of our assumptions for modelling the output of renewables can be found in Appendix D.

Figure 30 compares the de-rated peak capacity margin under the Extended RO37 case with the Status Quo, taking into account the diminishing capacity credit at the higher penetration of intermittent renewables. Prior to 2018 the de-rated peak capacity margin is higher under the Extended RO37 case mainly as a result of the lower demand assumption. Thereafter the de-rated peak capacity margin is somewhat lower than the Status Quo representing a lower level of supply security.

Figure 30 Comparison of de-rated peak capacity margins between SQ and Extended RO37

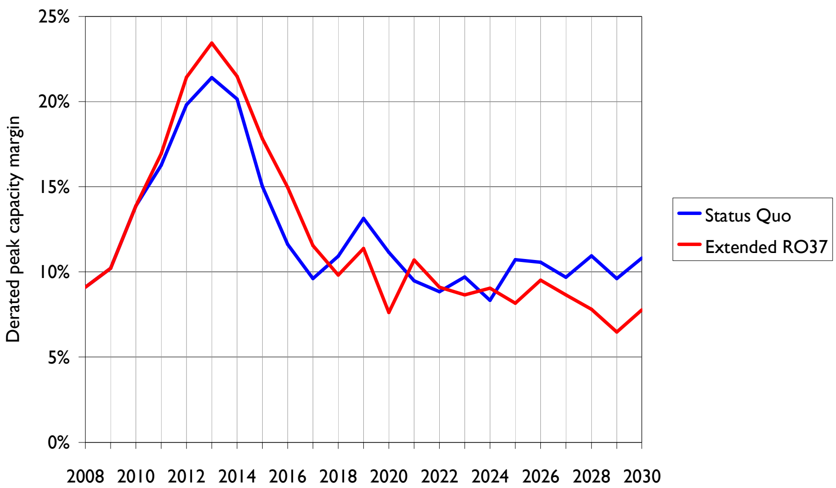
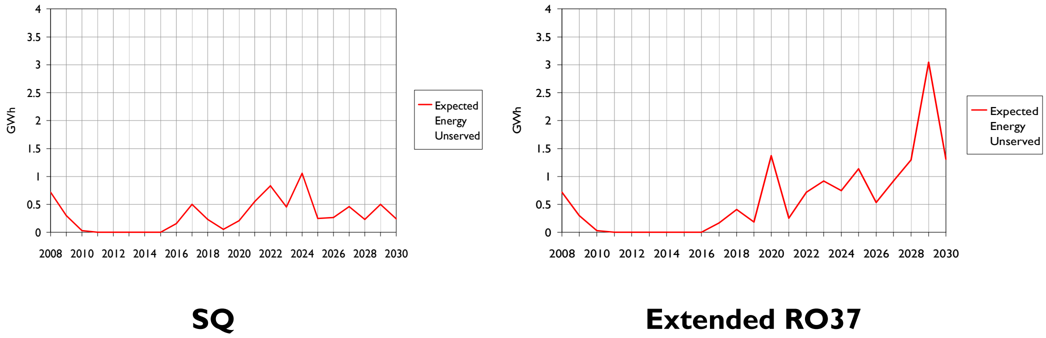


Figure 31 shows the impact on annual expected energy unserved, which is higher in the later years under the Extended RO37 case, but still relatively low compared to demand lost annually through network outages. However, this result is critically dependent on the geographic diversity of intermittent renewables, the volumes of demand side response available and the amounts of reserve contracted by the System Operator. For most periods the average level of supply could be higher due to the higher volumes of renewables capacity, but there is a greater chance of high impact events, for example a period of low wind output coinciding with plant outages and high demand.

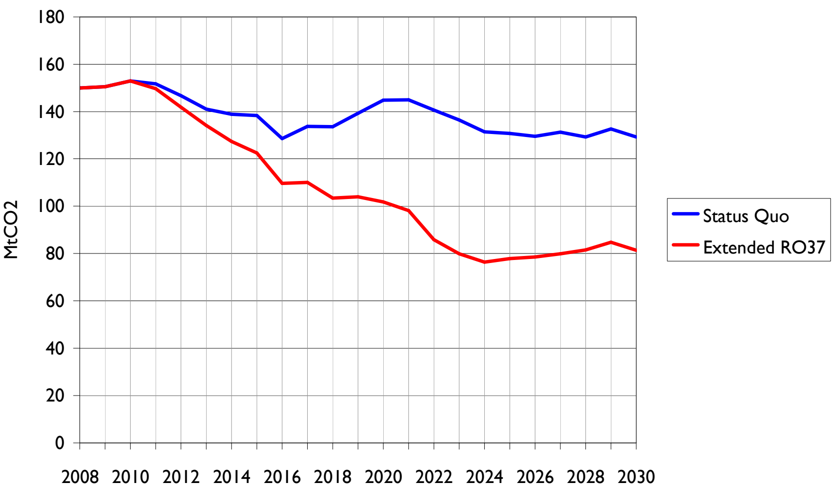
Figure 31 Comparison of annual expected energy unserved between SQ and Extended RO37



5.4.5 Carbon dioxide emissions

Figure 32 compares the annual carbon dioxide emissions from the GB generation sector under the Status Quo and Extended RO37 cases. Unsurprisingly the amount of carbon dioxide emissions are significantly lower under the Extended RO37 (a 37% reduction by 2030). However, these savings are not as great as they may otherwise have been since renewables are in part displacing nuclear (and hence low-carbon) output.

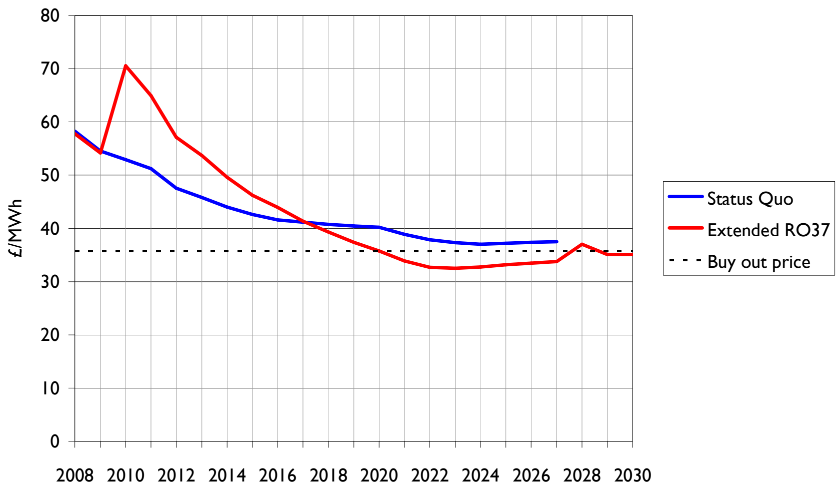
Figure 32 Comparison of carbon dioxide emissions between SQ and Extended RO37



5.4.6 Prices

Figure 33 compares the price of ROCs under the Status Quo and Extended RO37 case. Prices are initially higher under Extended RO37 as the target steps up. (In reality a slightly more gradual increase in the target might be implemented to avoid any sudden jump in the ROC price.) Due to the High maximum build rates assumed under Extended RO37, the ROC price falls more rapidly than under the Status Quo, and from 2017 onwards is lower. There is no headroom concept under the Extended RO since the way that the obligation size is formulated means that if RO target is hit the renewables target is hit. Hence there is no need to increase size of obligation and ROC prices can fall below buy-out price.

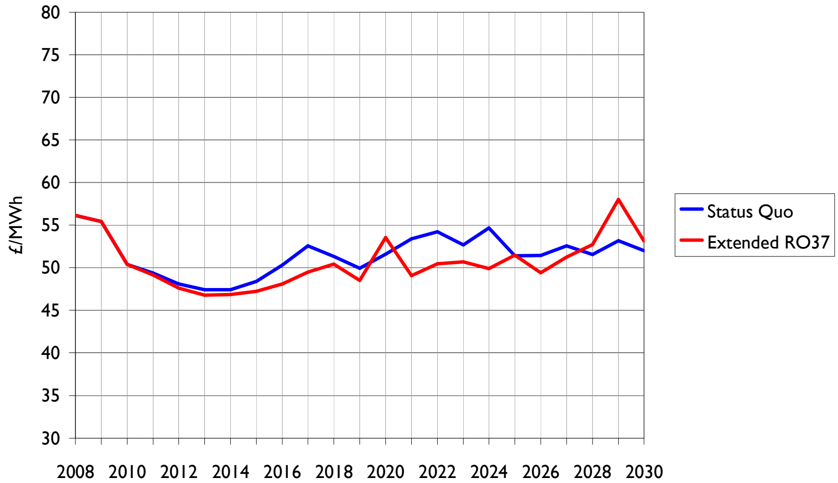
Figure 34 Comparison of ROC prices between SQ and Extended RO37



It should be noted that if new build was constrained below the High maximum build rates assumed, and the size of the obligation was increasing faster than new plant could be built, ROC prices could be significantly higher under the Extended RO37 case, as explored in the sensitivity analysis below. In these circumstances, further intervention might be required to prevent large economic rents accruing, such as reducing the buy-out price or banding down certain technologies (although the latter would not reduce rents for existing plant since bands are assumed to be grandfathered). Any significant intervention would need to be weighed against the impact on investor confidence.

Figure 35 compares the annual average baseload electricity price under the Status Quo and Extended RO37 cases. In general the greater amount of renewables under the Extended RO37 case depresses prices since the average short run generation cost is lowered. However, in certain years, such as 2021 and 2029 in this example, prices may outturn higher due to periods of tighter capacity margins.

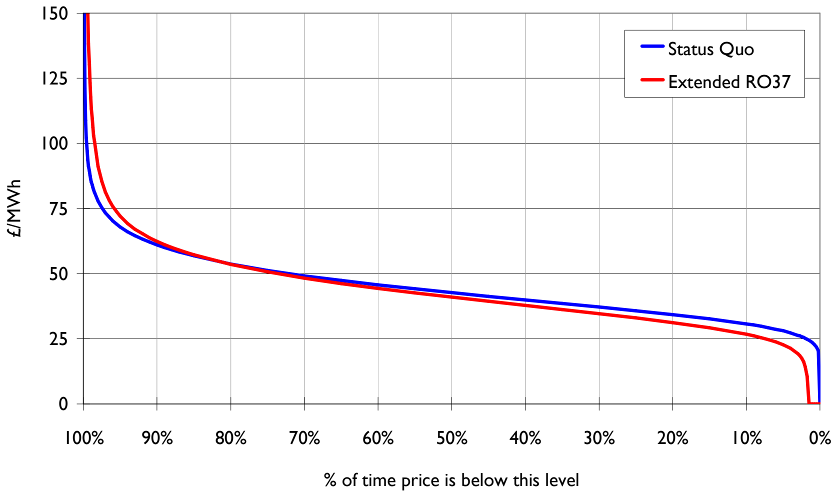
Figure 35 Comparison of wholesale electricity prices between SQ and Extended RO37



Despite the lower baseload prices, investment in new plant continues (but to a lesser extent in the case of inflexible plant such as nuclear). In the case of renewables this is because they receive separate financial support through the Extended RO scheme. Opportunities exist for flexible thermal plant to enter the market on the back of lower load factor expectations because of the anticipated impact of high renewables penetrations on the 'shape' of prices, as we discuss below.

Figure 36 shows simulated price duration curves (PDCs) in 2022 for both the Status Quo and the Extended RO37 cases. For the majority of hours in the year, prices are lower with the higher penetration of renewables. This is due to the fact that low short run marginal cost renewables are displacing higher cost thermal plant. In some hours (approximately 2% of the time), total supply from low marginal cost renewables and inflexible generation such as nuclear exceeds demand, causing prices to approach zero or even go negative as discussed in Section 4.3.

Figure 36 Comparison of price duration curves for 2022, SQ and Extended RO37



There is also a large differential between the PDCs for the highest 10% of prices. There will be periods in the world of high renewables deployment when low wind-speed events coincide with periods of high demand or a number of thermal plant outages. It is on these occasions that the most expensive peaking generation will need to be dispatched more frequently, and prices will be significantly higher than in the Status Quo. Furthermore, in the majority of hours in the year away from the tighter supply margin, thermal generators are capturing less infra-marginal rents than under the Status Quo. Hence they may attempt to push up prices well above SRMC at times of tightness in order to recover annual fixed costs and earn a return on capital invested. The occurrence of high price periods relating to tight supply margins will be as much a function of renewables supply as consumer demand, and hence peak prices are likely to become more random and not necessarily coincide with current patterns observed.

Such changes in price shape may illicit changes in the way that maintenance is scheduled on conventional plant and importantly on consumption patterns. These may reduce the extremes of high and low prices. For example, greater load shifting may occur and new technologies, such as smart metering, may facilitate greater consumer participation in such behaviours. The economics of electricity storage becomes more attractive with greater spreads in peak and offpeak prices, and technological advances in this area could yield some significant benefits. Furthermore, very low offpeak prices could attract additional sources of demand such as charging of electric cars or greater use of electricity for hot water and heating.

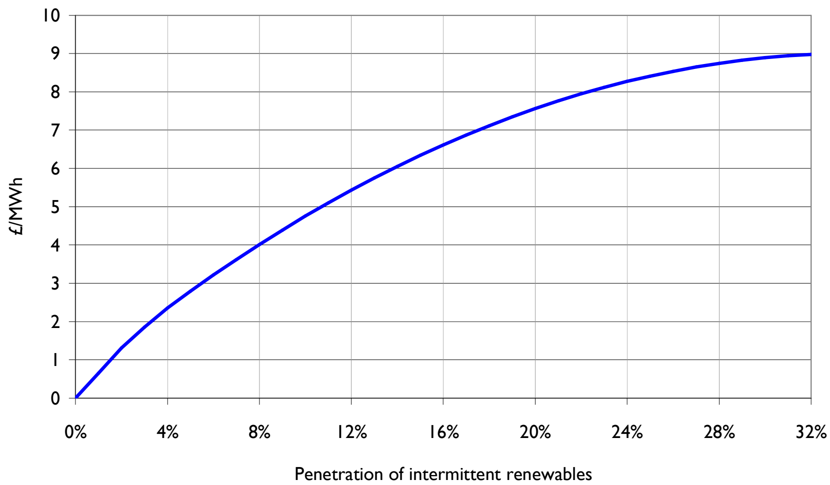
5.4.7 System balancing costs

If parties are anticipating and reacting to the impact of intermittent renewables on prices and volatility, the market should be able to deliver the back-up generation necessary to account for the variability in renewables output and maintain the de-rated peak capacity margins at acceptable levels. This may come from new generation investments, extension of the lifetimes of existing plant, new interconnectors, or demand side response.

However, as well as being variable, intermittent renewables output is also highly unpredictable. The mean forecast error for wind output four hours prior to delivery is approximately 10%. The result is that the System Operator will have a greater requirement for deploying reserve and frequency response to deal with sudden fluctuations in output from intermittent renewables. In its submission to the 2008/09 System Operator Incentives review[54], National Grid estimated that the 3 GW of wind capacity it anticipated on the system in 2008/09 would add an additional £27m of cost to an annual total of around £700m. It was also forecasting these costs to increase significantly with increasing wind connection in the coming years.

The total costs of extra system balancing due to intermittent renewable generation have been calculated using a function, parameterised from the results of various published studies, including those reported by the European Commission (2005)[55], Anderson (2006)[56], and Verhaegen, Meeus and Belmans (2006)[57], and calibrated to current system balancing costs. The function is concave, as shown in Figure 37, which suggests that the additional cost of system balancing increases per MWh of intermittent renewables on the system, but that the rate of increase slows.

Figure 37 Function for estimating additional system balancing costs per MWh of renewables output at different penetrations of renewables output



Although the marginal cost on system balancing of a single intermittent plant is high, at low levels of renewables deployment, its output unpredictability is 'lost in the noise' of uncertainty of demand and larger plant outages. Hence the additional system balancing cost is relatively low. Based on this function the average additional system balancing cost for intermittent renewables is around £2/MWh at current levels of

[54] National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2008: Final Proposals Consultation, Ofgem.

[55] European Commission (2005). The support of electricity from renewable energy sources. Communication COM(2005) 627, December 2005.

[56] Anderson, D. (2006). Power System Reserves and Costs with Intermittent Generation. UK Energy Research Centre Working Paper.

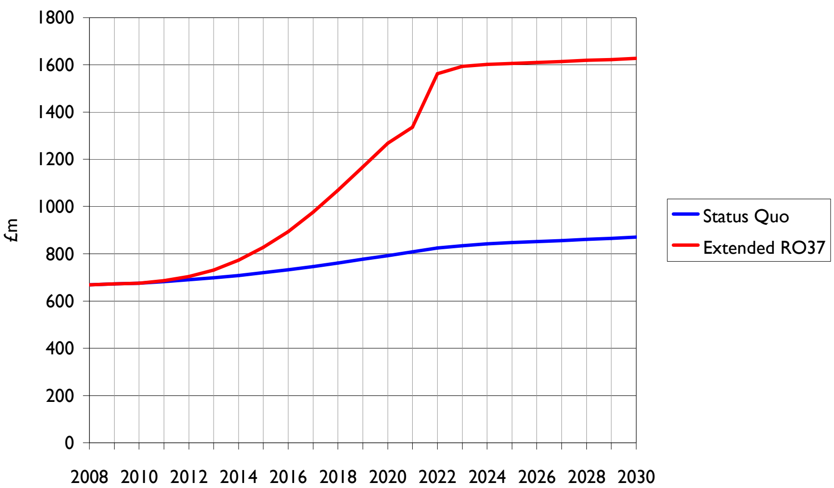
[57] Verhaegen, K., Meeus, L., and Belmans, R. (2006). Development of balancing in the internal electricity market in Europe. *European Wind Energy Conference*, Athens, Greece, February 27 – March 2, 2006

intermittent renewables penetration of around 2%[58]. As penetration grows, renewables intermittency becomes a more important driver of the requirement for reserve and frequency response and hence the cost to the system operator of intermittent renewables increases. With increasing diversification of renewables plant, the marginal cost of system balancing each plant reduces, which explains why the rate of increase in system balancing costs slows as penetration increases.

It should be noted that determining exactly which plant will provide these extra services was outside of the scope of this study; the balancing costs reported should be seen as approximate only.

Figure 38 compares the annual system balancing costs under the Status Quo and Extended RO37 cases. This suggests that system balancing costs could almost double by 2022 due to the additional volumes of reserve and frequency response required to manage unpredictability of intermittent renewable output, and the additional costs associated with managing transmission constraints. It should be noted that there is considerable uncertainty surrounding the additional system balancing costs associated with high penetrations of renewables and further analysis will be required in the next few years. This is particularly the case if the System Operator's current annually based incentive scheme is to be replaced with a set of longer term incentives which will arguably be required to ensure that sufficient forward looking investment is made to manage the higher levels of intermittent generation.

Figure 38 Comparison of system balancing costs between SQ and Extended RO37



Currently the direct costs of system balancing are recovered through BSUoS charges which are levied on every MWh of electricity produced and consumed. Parties are also exposed to Imbalance Charges, or cash-out, to the extent that their metered production or consumption does not match their contracted position. Excess monies recovered by the System Operator through Imbalance Charges are recycled to parties through the Residual Cashflow Reallocation Cashflow (RCRC) mechanism, again on every MWh of electricity produced and consumed. For parties able to balance accurately this RCRC can offset to an

[58] In the Seven Year Statement, May 2008, National Grid estimated the system balancing costs of wind in 2008/09 to be in the range £5.00/MWh to £7.50/MWh. However, we believe this figure to represent the marginal cost of balancing an individual plant rather than the impact on total system balancing costs of each MWh of wind generation.

extent its BSUoS charges, thus reducing the amount that they are in effect paying the System Operator for system balancing. Parties with poor balancing performance, which typically includes independent renewables generators, will pay more in Imbalance Charges than they receive in RCRC, hence making a greater contribution towards the costs of system balancing.

Under the Balancing and Settlement Code (BSC) rules there is an attempt to channel the System Operator costs of reserve into the Imbalance Charges. There is currently debate within the industry surrounding how successful this process is and indeed whether the costs of reserve should be targeted at out-of-balance parties or paid equally by all parties as a form of system insurance. As the costs of reserve increase with increasing penetration of intermittent renewables it is likely that this debate will be revisited and changes to the BSC may be proposed.

For modelling simplicity we have assumed that all of the additional costs of system balancing associated with intermittent renewables are targeted at these generators (acknowledging that this would represent a change from the current arrangements). This would have a material impact on the operating costs of intermittent plant, increasing their 'balancing cost'[59] from our estimate of around £2/MWh currently to around £9/MWh by 2020 under a 37% renewables target. It is worth noting that the impact of this would be different for renewables generators under the different schemes being considered. Under the Extended RO, the generator would be fully exposed to this cost, thus reducing its expected margin, and this would impact on investment decisions. (Other things being equal the subsidy would need to rise to maintain the same level of renewables investment.) Under the Standard FIT and FIT/Tender schemes as defined in this study, the generator is not exposed to these costs, instead passing them through to the Renewables Purchasing Agency to be levied on suppliers.

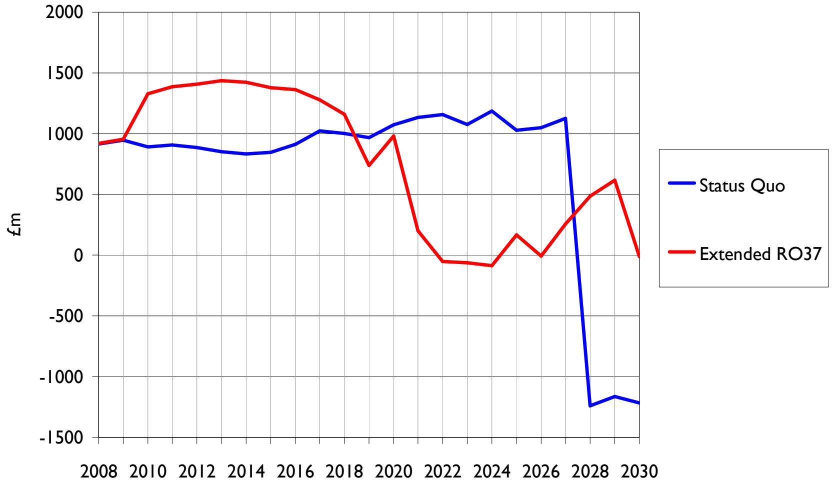
This illustrates an important interaction between the market rules (BSC) and the renewables support scheme. The level of support offered to intermittent generators needs to take into account the extent to which they will be exposed to the costs of increasing system balancing costs associated with their increasing penetration. In theory, it should make sense to leave the risk of unpredictable output levels with the party with the best ability to reduce or manage this unpredictability, for example by improving their capability to predict wind output or through diversification of the output risk. In this respect, the three support schemes modelled differ. For the Extended RO, renewables generators will have an incentive to minimise their balancing costs, whereas under the Standard FIT or FIT/Tender schemes this incentive will lie with the Renewables Purchasing Agency.

5.4.8 Plant profitability

Figure 39 compares the annual total economic rent for renewables plant under the Status Quo and Extended RO37 cases. Under the Status Quo case rents remain relatively constant in absolute terms prior to the RO ending in 2027/28. In the Extended RO37 case, rents are higher prior to 2018 and then fall rapidly thereafter.

[59] Balancing costs include costs associated with managing the volume risk associated with varying wind output plus Imbalance Charges (which results from unpredictability of wind output) plus BSUoS less RCRC.

Figure 39 Comparison of total annual rents for renewables between SQ and Extended RO37



There are four factors that explain this decline. First, ROC prices fall as the penetration of renewables increases substantially (assuming the high maximum build rates). Second, average wholesale electricity prices also fall with the higher proportion of low marginal cost plant on the system.

The third factor is the relationship between renewable output and the wholesale price they receive as the amount of intermittent generation on the system increases. At current penetration levels there is little relationship between wind output and spot prices, and a plant may expect to achieve an average price close to a baseload average, notwithstanding the discount often applied to power purchase agreements from wind plant to account for their output variability. However, as the proportion of intermittent generation grows, a negative correlation between wind output and spot prices is likely to emerge. As discussed above, in extreme cases prices could become negative during periods of high wind output.

The final factor is the increase in balancing costs associated with the growing level of intermittency, which we have assumed in the Extended RO37 case the intermittent generators are fully exposed to.

This relationship between the amount of renewables plant built and the margins for renewables generators is a key risk associated with the Extended RO policy where high levels of renewables generation are targeted. Investors' expectations of this effect will affect their build decisions. In the Extended RO37 case, investment slows rapidly after 2020. If this happened any earlier, the achievement of the target could be jeopardised. This may require levels of support for renewables to be increased even for the same level of baseload wholesale price in order for investment to continue. As we discuss below, renewables generators are insulated from these effects under the Standard FIT and FIT/Tender schemes.

The growth of renewables will be likely to have a significant impact on the profitability of non-renewable plant, but the effect may be complex. The results shown in Section 5.4.6 above suggest baseload prices might be expected to fall due to the impact of renewables on the system short run marginal cost. However, the price duration curves demonstrate that flexible plant should be able to achieve a better average price for their output due to the increase in peak prices. Hence, provided companies build the expectation of these higher peak prices into their investment decisions, overall security of supply need not necessarily reduce as a result of lower baseload prices. Furthermore, portfolio players may be able to offset lower margins on their conventional generation portfolios with greater margins on their renewables portfolio, and earn additional margins on providing additional balancing services to the System Operator.

The overall generation sector profitability will depend on the complex interplay of market dynamics that drive wholesale electricity prices (and balancing services), and the level of subsidises offered under the renewable electricity support scheme. In the long run, generators will need to earn their required rate of return in order to continue to invest, but the level of rents over and above these returns, for either conventional or renewables generators, is uncertain.

5.4.9 Consumer costs

The EU2020 renewables target will almost certainly lead to an increase in the cost of electricity to consumers. At the simplest level we might assume that the additional costs incurred by generators will ultimately be passed on to consumers, and the size of this increase will be a function of the difference between costs of renewables generation and the alternatives.

In reality the additional costs that consumers actually pay will depend on the profitability of the entire generation sector, as mentioned above. Should this decrease, consumers will pay less than the additional generation costs associated with renewables, but there is a risk they could end up paying more, for example if rents for renewables generators are sustained at high levels. There is significant uncertainty since it is difficult to predict the exact impact of a fundamental shift in the generation mix on prices, or the competitive dynamics several years out. Given the importance of the behaviour of portfolio generators, who builds the renewables plant could have a significant bearing on the impact on market prices. However, the modelling approach attempts to simulate the complex dynamics between renewables and non-renewables investment and the impact on wholesale prices in an internally consistent manner.

Figure 40 compares the additional generation costs with the additional estimated consumer costs in £/MWh under the Extended RO37 case relative to the Status Quo. In the earlier years, the higher rents earned by renewables generators mean that consumers pay more than the increase in generation costs, whereas as wholesale and ROC prices decrease the reverse is true. The volatility in the additional consumer costs reflects the year-on-year variation in wholesale electricity prices in the modelling runs. On average, between 2008 and 2030 consumers are paying close to the additional generation costs, which suggests the profitability of the generation sector is on average largely unchanged. There are cases that we describe below where this is not necessarily the case.

Figure 40 **Comparison of additional generation costs and additional estimated consumer costs under Extended RO37 relative to SQ**

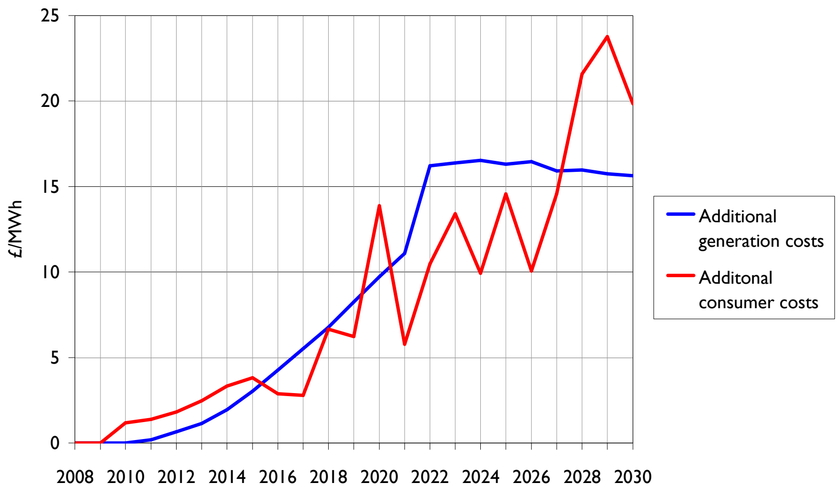
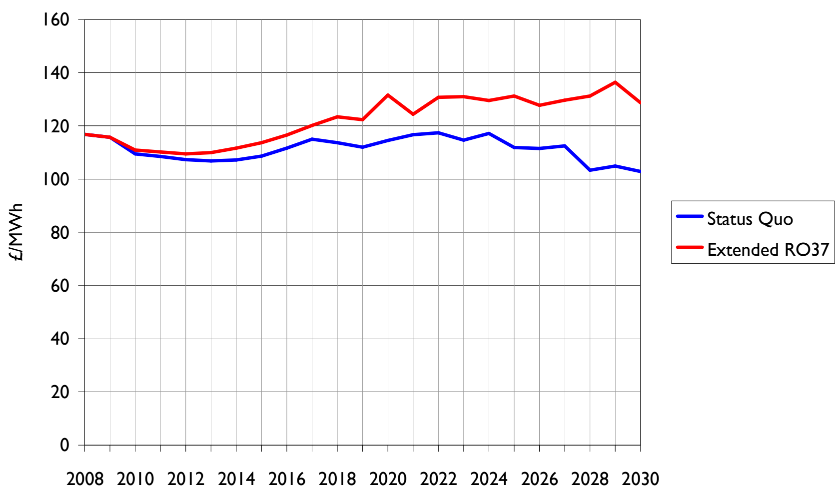


Figure 41 shows the impact of the Extended RO37 case on the average cost of electricity for domestic consumers, which includes the cost of the subsidy, wholesale electricity costs, transmission and distribution costs and the supplier costs and margins. This would suggest bills would be around 10% higher by 2020 relative to the Status Quo, reflecting the higher levels of subsidy but with some savings from the reduction in wholesale electricity prices. The incremental cost of renewables to consumers is a function of the cost of the alternative electricity sources and we test the sensitivity of these results to higher and lower fuel and carbon prices below.

Figure 41 **Comparison of domestic consumer prices between SQ and Extended RO37**



5.4.10 Cost benefit analysis

Table 6 shows the results of the cost benefit analysis (as explained in Section 5.1.6) for the Extended RO37 case relative to the Status Quo.

Table 6 Cost benefit analysis of Extended RO37 relative to SQ, NPV 2008-2030

Change in annual welfare		NPV, £m (real 2008)
Net Welfare	Carbon saved	9,829
	Less increase in resource costs	-51,348
	Change in Net Welfare	**-41,519**
Distributional analysis		**NPV, £m (real 2008)**
Consumer Surplus	Change in wholesale price	3,887
	Change in balancing costs	-5,346
	Change in net subsidy	-40,656
	Change in administration costs	-16
	Change in CCL	2,800
	Change in VAT	-652
	Change in Consumer Surplus	**-39,983**
Producer Surplus	Change in wholesale price	-3,887
	Change in balancing revenues	5,346
	Change in net subsidy	40,656
	Change in generation costs	-41,503
	Change in Producer Surplus	**612**
	Change in renewables rent	*1,623*
	Change in non-renewables rent	*-1,010*
Treasury Receipts	Change in CCL	-2,800
	Change in VAT	652
	Change in Treasury Receipts	**-2,148**
Ancillary metrics		**2020**
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38
	Cost per tonne CO_2 avoided (£/tCO2)	132
Fuel use	Annual change in use of gas (mtoe)	-5.47
	Annual change in use of coal (mtoe)	-7.14
	Annual change in use of oil (mtoe)	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-11.9

Overall the results suggest a net welfare loss of around £42bn associated with this policy. The value of carbon saved is significantly less that the additional resource costs[60]. The cost per tonne of carbon saved is

[60] Resource costs exclude the costs of carbon (EUAs).

£124/t relative to an average EUA price of around £26/t in this scenario. No additional value has been attached to renewables beyond the carbon savings, although arguably there is an additional benefit in terms of diversity of fuel supply and avoiding the consequences of missing the EU 2020 target. We have not attempted to quantity these effects.

The increase in cost to consumers (£40bn) is approximately equal to the increase in generation costs[61]. This is broken out by change in wholesale electricity price, change in balancing costs, change in net subsidy, change in administration costs (which increase with more renewables plant) and changes in taxation (avoided Climate Change Levy and additional VAT resulting from higher domestic electricity bills).

Producer surplus is largely unchanged. There is a small increase in renewables rent of around £1.5bn but this is largely offset by a corresponding reduction in profitability of non-renewable plant of around £1bn. It should be noted, however, that for simplicity we have assumed no margin for producers on the provision of balancing services, although these services can be very profitable for generators. An increasing demand for balancing services under higher renewables deployment could lead to a corresponding increase in profitability for flexible generators.

Revenues to Treasury fall as receipts from the Climate Change Levy (CCL) decrease as a result of more Levy Exemption Certificates (LECs) available in the market associated with the greater renewables output. The increase in VAT on domestic customer bills is relatively small in comparison.

5.5 Scheme comparison: 37% target

5.5.1 Basis of comparison

In this section we compare the results of the modelling of the three schemes, Extended RO, Standard FIT and FIT/Tender against the 37% target case using the base case assumptions on commodity prices and capital costs. In particular, we focus on the impact of the different schemes on resource costs, generation mix, how renewables plant are remunerated, costs to consumers and overall net welfare.

Under all three schemes we use SKM's High maximum build rate constraints and assume that the development and operation of the Severn Barrage is delivered through a separate mechanism to the main support scheme. We assume that under the Standard FIT and FIT/Tender schemes the RO (as modified under the Energy Bill proposals) is operational until 2011, and that plant built under the RO will continue to receive a premium subsidy under grandfathering arrangements described in Section 5.2.3 above. Hence, under these cases, two, and in the case of the FIT/Tender, three different support schemes would be operating in parallel from 2012[62].

The modelling approach illustrates a number of key differences between the schemes. However, it should be noted that since the model dynamically simulates possible evolutions of the market by stepping through time, variations between runs for individual years can emerge associated with the exact timing of investment and retirement decisions and their impact on supply margins and prices.

[61] Since we ignore demand elasticity for simplicity, the change in generation costs is simply the negative of the change in net welfare.

[62] Some of the NFFO contracts that were awarded in the 1990s to support renewables only expire in 2013. They are handled by the Non-Fossil Fuel Purchasing Agency Limited (http://www.nfpa.co.uk) and provide an example of parallel operation of two schemes (with the RO).

5.5.2 Resource costs

The potential impact of different support schemes on the cost of deploying renewables to meet the 2020 targets is twofold. First, the different schemes may promote a different technology mix by offering different levels of support for the same technology. For example, under our Standard FIT scheme design we assume that greater levels of support are offered to wind plant in sites with lower wind speeds. At face value this is sub-economic but it may yield benefits in terms of greater geographic diversity of plant with benefits for security of supply and efficient use of the transmission network (although this potential benefit is not captured in the modelling). Under our FIT/Tender scheme we see greater deployment of emerging technologies, such as wave, which may lead to increased costs in the near term but could yield benefits in the longer term (beyond on the modelling timeframe) if it accelerates learning and reduces technology costs in the future. Overall there is not a great difference in the generation mix between the schemes that we have modelled, mainly because all available renewable resources are needed to meet the 2020 targets, and the schemes have been designed accordingly.

The second difference in resource costs between the schemes is the cost of capital, arising because of different levels of risk for investors, and this has a potentially greater effect. Advocates of feed-in tariff approaches point to the lower cost of capital associated with these schemes due to the higher degree of revenue certainty, with much of the market risk being transferred from the investor to the consumer. There is evidence to suggest that banks are more willing to lend to schemes covered by feed-in tariffs, with their guaranteed power purchase agreement covering the economic lifetime of the project.

It is difficult to determine how the relative risk of different support schemes impacts on the cost of capital, with market participants claiming that the cost of capital premium for obligation-based schemes over feed-in tariffs is anywhere between 0% and 4%. The high end of this range can be derived by comparing discount rates for renewables projects in Germany and the UK (although factors outside of the financial support scheme may also be having a material impact). The low end would suggest that generators are able to secure long term power purchase agreements (equivalent to FITs) commercially that banks are willing to lend against, or that the market risks can be internalised, as is the case for vertically integrated companies.

For the purposes of the quantitative assessment we have attempted to derive analytically cost of capital (hurdle rate) assumptions for the different support schemes by analysing the gross margin risk for renewables projects over their economic lifetimes.

The first stage of the analysis is to determine which risks are managed on behalf of the generator through the different support schemes. Our assumptions are shown in Table 7 below.

Table 7 Risk management afforded by different support schemes

Risk factor	Explanation	Extended RO	Standard FIT	FIT/Tender
Policy risk	The risk that revenues for existing projects are affected by future changes in renewables policy.	x	✓	✓
Subsidy risk	The risk that the value of the subsidy changes over time.	x	✓	✓
Electricity price risk	The risk from uncertainty in future levels of wholesale electricity price.	x	✓	✓
Forecasting/balancing risk	The risk associated with the costs of managing the variability and unpredictability of output.	x	✓[63]	✓[63]
Locational/transmission charging risk	The risk that use of system charges and costs associated with congestion management will change over time.	x	✓	✓
Project risk	The risks from cost overruns, late delivery, breakdowns or poor availability.	x	x	X
Non-delivery penalty risk	The specific risk under the FIT/Tender scheme of losing the delivery obligation deposit due to late delivery.	n/a	n/a	x (for offshore technologies)

We assume that generators under the Standard FIT and FIT/Tender are not exposed to future policy risk since the tariff or tender agreement is a contractual relationship between the generator and Renewable Purchasing Agency. (Ultimately policy risk cannot be completed eliminated even under these schemes.) Under the Extended RO there is greater policy risk associated with future changes in target levels, banding decisions, any change to the buy-out price and even the possibility that the scheme is abandoned at some point in the future if it is deemed to have become too expensive. Generators under the Extended RO are also exposed to subsidy risk (changes in the value of ROCs) and electricity price risk, which is not the case under the Standard FIT and FIT/Tender. Furthermore, in our design we have assumed that generators are not exposed to balancing risks under the Standard FIT and FIT/Tender (since these are managed on their behalf by the Renewables Purchasing Agency) or changes in UoS charges (which are passed through).

[63] Tariffs for larger schemes may include incentives on the generator with respect to output forecasting. Hence, generators may be exposed to an element of forecasting risk in certain cases.

Generators are exposed to project risks under all three schemes. Project risks include changes in project costs, construction delays, technology risks and plant availability. Generators under the FIT/Tender are exposed to the additional risk associated with the non-delivery penalty risk.

With the exception of policy risk (which we do not attempt to quantify), each of the risk factors is simulated for each technology over their economic lifetimes to measure the gross margin at risk.

The gross margin at risk is then used as a proxy for investment risk to determine the proportion of the project that could be financed with 'safe' capital and the proportion of the project that will be financed with 'risky' capital. For example, if the gross margin at risk over the project lifetime is £20/MWh against an expected average revenue of £50/MWh, the proportion of risky capital in the project is deemed to be 40% (20/50 £/MWh) and the remaining 60% is safe capital.

The gross margin at risk will be a function of revenue and cost risks. Under the Standard FIT and FIT/Tender schemes the distribution of revenue risk is typically narrower than under the Extended RO, yielding lower gross margin at risk and hence a lower proportion of risky capital required in the project.

Whilst the actual cost of financing will not necessarily be project specific, since most vertically integrated players will create an 'investment pot' from a combination of retained earnings and debt raised against the company as a whole, this approach recognises a higher 'opportunity' cost from risky investments since if all projects were risky the cost of capital for the company would increase.

For simplicity we assume that safe capital is priced at the company cost of debt (risk free rate + debt premium[64]), whereas risky capital is priced at a higher level[65]. We assume that the cost of this risky capital is related to the costs of equity for each company, whether the actual financing comes from higher priced debt or is financed with equity[66]. This is calculated as the risk free rate + equity premium * equity beta * investment beta. The equity premium and equity beta are derived from analysis of financial reports of individual companies. The investment beta (2.5) has been set to calibrate hurdle rates produced by the model for mature technologies against benchmarks from recent known investments, for example around 10% (post tax nominal) for CCGTs. This leads to a cost of risky capital between 12% and 19% depending on the player type.

Further details of the methodology used for deriving cost of capital assumptions are included in Appendix C.

Table 8 compares the range of hurdle rates produced by the model for different investor types for each technology under each of the three support schemes.

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[64] Debt premium varies by company type from 2% to 4.5%.

[65] We recognise that in reality projects are financed in a multitude of different ways with different types of debt at different costs.

[66] On the assumption that companies would use equity rather than debt to finance projects where the cost of debt for a risky project exceeds the cost of equity.

Table 8 Example calculated hurdle rates (post-tax nominal) for different technologies, 2010

Technology	Extended RO	Standard FIT	FIT/Tender
Onshore wind (High)	9.1% - 11.5%	8.1% - 9.7%	8.1% - 9.7%
Onshore wind (Medium)	9.4% - 11.9%	8.3% - 10.1%	8.3% - 10.1%
Onshore wind (Low)	9.1% - 11.3%	8.3% - 9.9%	8.3% - 9.9%
Offshore wind (High)	10.2% - 13.2%	8.5% - 10.5%	9.4% - 12.2%
Offshore wind (Low)	10.0% - 12.8%	8.7% - 10.9%	9.6% - 12.8%
Biomass regular	10.0% - 13.4%	7.7% - 9.6%	7.7% - 9.6%
Biomass energy crop	10.1% - 13.7%	8.1% - 10.2%	8.1% - 10.2%
Biomass CHP	11.5% - 15.7%	9.7% - 12.6%	9.7% - 12.6%
Wave	10.2% - 13.2%	9.7% - 12.5%	10.5% - 14.0%
Tidal Stream	10.7% - 14.1%	10.0% - 13.1%	10.9% - 14.6%
Tidal Range	9.7% - 12.3%	9.2% - 11.6%	9.7% - 12.5%
Biowaste	10.9% - 14.1%	9.9% - 12.9%	9.9% - 12.9%
Biogas	10.2% - 12.9%	8.9% - 10.9%	8.9% - 10.9%

For the wind technologies the hurdle rates are typically in the range of 1-2% lower under the Standard FIT than the Extended RO. This translates to an additional £5/MWh to £9/MWh for onshore wind on a levelised cost basis, and between £9/MWh and £16/MWh for offshore wind. The difference tends to be greater for biomass plant (2-4%) as a result of the greater load factor risk that a biomass plant may experience operating in the wholesale market under the Extended RO. (This assumes that biomass plant are able under feed-in tariffs to secure long term fixed price agreements for fuel supply.) The differences in hurdle rates between the Extended RO and Standard FIT tend to be lower for the emerging offshore technologies (around 0.5% - 1.0%) which reflects the fact that project risks of these newer technologies tend to dominate the revenue risks. It should be noted that for these high capital cost technologies, such as tidal stream, a difference of between 0.5% and 1.0% in hurdle rates can add between £9/MWh and £13/MWh (between 6% and 9%) to the levelised cost.

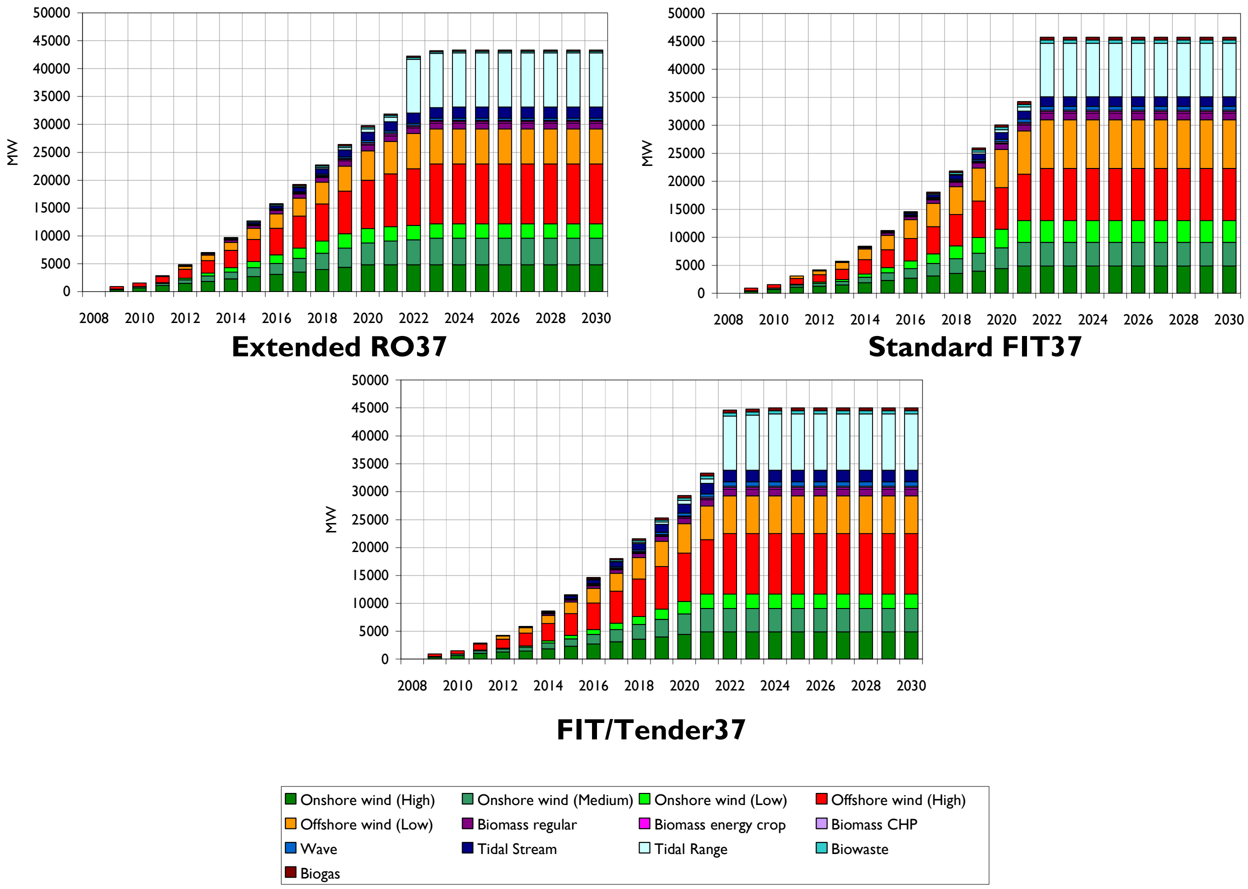
The hurdle rates for onshore technologies are the same under the FIT/Tender and Standard FIT schemes since these receive the same feed-in tariffs under both schemes. Under the FIT/Tender, the hurdle rates for offshore technologies are higher reflecting the risk from the non-delivery penalty. These are comparable or slightly higher than for the corresponding technologies under the Extended RO.

The example hurdle rates shown in Table 8 are for investment decisions made in 2010 for plant that would become operational in 2012 at the earliest. We assume that the project risks for emerging technologies reduce over time due to learning curve effects.

5.5.3 Generation mix

Figure 42 compares the renewables build by technology between the three schemes under the 37% target case. There are relatively minor differences between them. The overall build profile is slightly more concave under the Standard FIT and FIT/Tender relative to the Extended RO, which reflects the slower rates of build associated with the transition to the new scheme. There is more low resource onshore and offshore wind built under the Standard FIT than the Extended RO since these sites receive higher levels of support, whereas under the Extended RO all plant of the same technology are in the same band.

Figure 42 Comparison of renewables build under the three schemes, 37% target



Under all three schemes, the 2020 target of 37% is met using the base case assumptions. Slightly more renewables capacity gets built post-2020 under the Standard FIT and FIT/Tender than under the Extended RO given the way that we have designed these schemes. Under the Standard FIT, for example, we have assumed that tariffs are available until 2022 in order to remove the risk that investment slows as 2020 approaches because investors are worried that they may miss out on a FIT because of project overruns. The result is that there is an overshoot in the target after 2020. Under the Extended RO, however, the overshoot is lower since investment in renewables is already starting to slow by 2020 in response to falling profit margins for new plant.

There is a choice for policy makers in designing the final support scheme with respect to whether the sole objective is to meet the 2020 target and minimise any further expenditure on renewables, or whether meeting the 2020 target is a point on a path to yet higher deployment of renewables in the future. The answer to this question may have a bearing on the details of the renewables support scheme.

5.5.4 Plant revenues

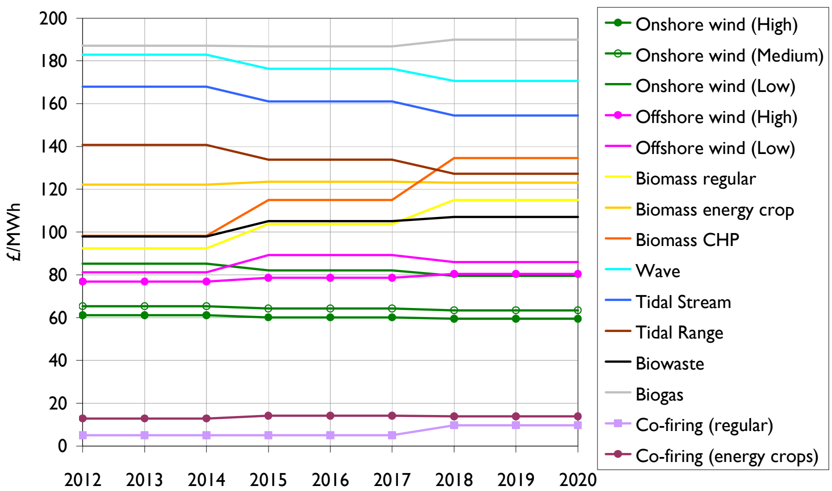
The key difference between the Extended RO and the other two schemes is that it is a premium subsidy, with plant exposed to the wholesale market and the impact that renewables are having on prices. Under the Standard FIT and FIT/Tender, plant receive an all-in price for their output and are therefore not exposed to these risks.

Figure 43 shows the FITs for different technologies between 2012 and 2020 under the Standard FIT37 case. As described in Section 5.2.3 above, tariffs are reset every three years to reflect changes in the estimated LRMC of different technologies. For certain technologies, such as tidal stream, tariffs decrease as international learning curve effects bring costs down. However, for other technologies such as offshore wind, their rapid expansion leads to increases in costs; the learning curve effect is more than offset by the fact that the more accessible sites are exhausted combined with increasing costs associated with the required grid expansion. Where tariffs are rising, there is a risk of investment lulls as companies wait for a better tariff.

The significant increase in the biomass tariffs reflects increasing fuel costs. It may be necessary to change the vintaging arrangements for existing plant to remove the disadvantage they would face from having to compete for the same fuel resources with newer plant receiving tariffs.

The higher tariffs received for lower resource onshore and offshore wind sites can be seen.

Figure 43 Feed-in tariffs, Standard FIT37

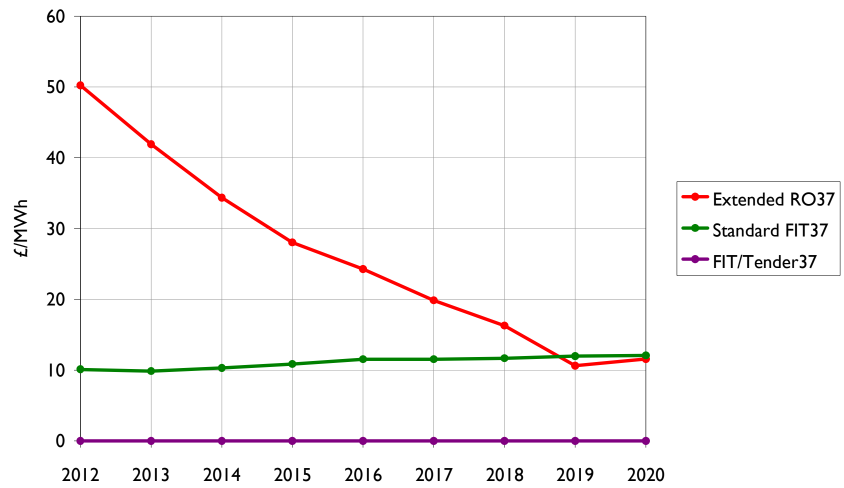


The tender contract prices for offshore technologies under the FIT/Tender scheme also track the evolution of the LRMCs of these technologies. Tender prices are generally higher than the equivalent FIT under the

Standard FIT reflecting the higher cost of capital for investors who are faced with the risk of delivery obligations. However, we assume for simplicity that investors bid at an LRMC reflecting their own cost of capital rather than increase their bid to their expectation of the price of the marginal bidder. Since we are assuming that the tenders are pay-as-bid, this means that no economic rent accrues for offshore technologies under the FIT/Tender scheme.

This can be seen in Figure 44 which compares the economic rents for offshore wind plant between 2012 and 2020 under all three schemes.

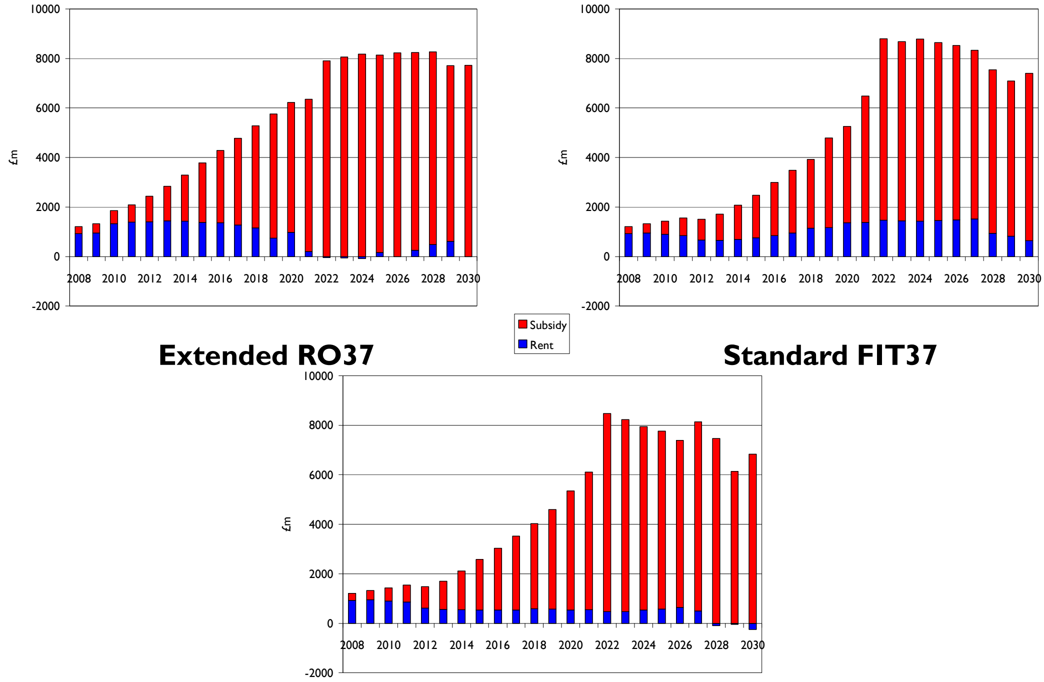
Figure 44 Comparison of rents for new offshore wind plant between the three schemes, 2012-2020



Over this period, rents are significantly higher (but falling) under the Extended RO than the Standard FIT (and FIT/Tender where they are zero). However, if we look at total rents out to 2030 the picture is somewhat different. Figure 45 shows how much of the total net subsidy[67] is attributed to economic rents under the three schemes between 2008 and 2030. Total rents are indeed initially lower under Standard FIT and FIT/Tender than Extended RO but the situation reverses after 2020 as renewables are exposed to lower ROC prices, lower wholesale prices (that they help create) and an increasing anti-correlation between their output and price they receive, and increasing balancing costs. Rents, although initially smaller under FITs, are locked in for the economic lifetime of the project. Also significant rents are accruing under the Standard FIT (and FIT/Tender) through the grandfathering arrangements for existing RO-eligible plant. Annual rents for renewables plant are lower under FIT/Tender than Standard FIT due to the assumption that successful tenderers bid at their long run marginal costs and extract no additional economic rent.

[67] Under the Extended RO the net subsidy is simply the sum of ROC and LEC revenues. For the Standard FIT and FIT/Tender the net subsidy is calculated as the difference between the tariff and LEC revenues and the wholesale electricity revenues 'forsaken'. This is equivalent to the net cashflow for the Renewables Purchasing Agency resulting from paying tariffs and tender contract prices and receiving revenues from auctioning output from renewables plant. It is equivalent to the levy charged to suppliers under these schemes.

Figure 45 Comparison of total net subsidy between three schemes, 2008-2030

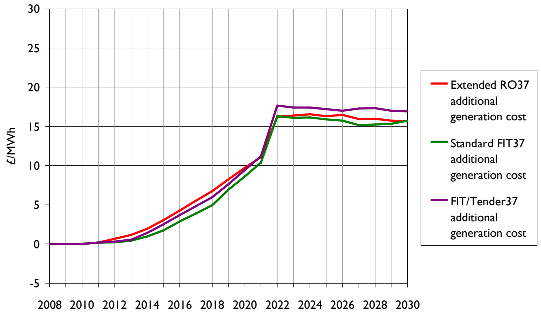


FIT/Tender37

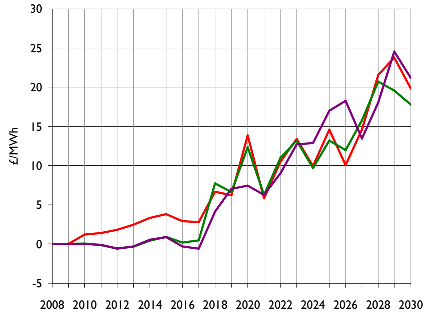
5.5.5 Costs to consumers

Figure 46 shows the additional generation costs and additional costs to consumers on a per MWh basis under the three schemes relative to the Status Quo. Generation costs rise steadily with the increasing deployment of renewables until 2022, with a step up when the Severn Barrage is commissioned. (These results obviously reflect policies designed to meet the 2020 target and do not consider how they may be extended to achieve higher deployment of renewables further into the future.) The additional generation costs are lower throughout under the Standard FIT due to the lower cost of capital. Additional generation costs are highest under the FIT/Tender after 2022 since more renewables are built under this scheme post-2020.

Figure 46 Comparison of additional generation costs and consumer costs between the three schemes, 37% target



Additional generation costs

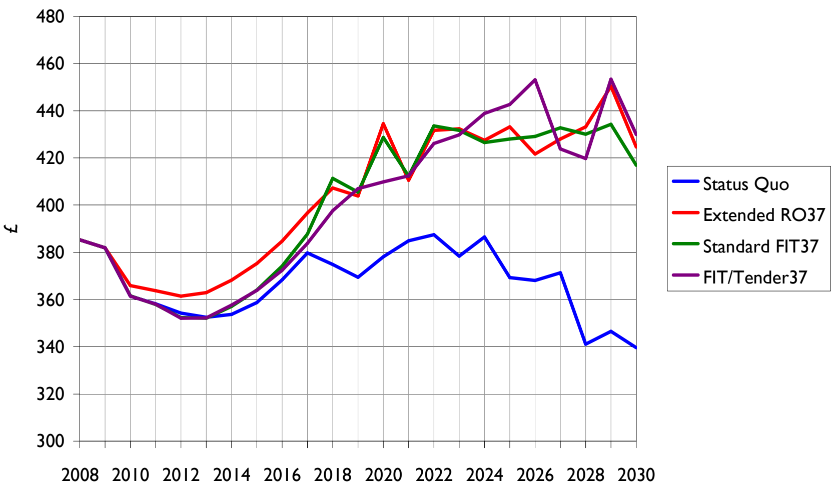


Additional consumer costs

There is a much greater variation in growth of consumer costs reflecting year-on-year variation in wholesale prices. Tightening capacity margins beyond 2020 mean that costs to consumers continue to rise after the additional generation costs have levelled off. Prior to 2016 there is very little increase in costs to consumers under the Standard FIT and FIT/Tender which reflects the high economic rents for renewables generators under the RO in the Status Quo counterfactual. Thereafter, costs to consumers are broadly similar on average between the three schemes.

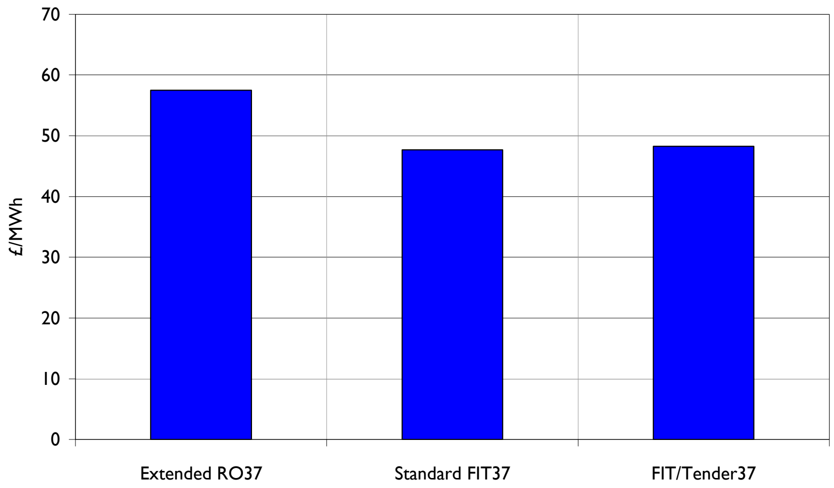
To put these increases in consumer costs into context, Figure 47 shows the average domestic consumer bill under the three schemes relative to the Status Quo.

Figure 47 Average domestic consumer electricity bill under the three schemes compared to the Status Quo



Finally, Figure 48 shows the average additional cost to consumers per MWh of additional renewables generation over the period 2008-2030[68]. This measure reflects not only the additional investment and connection costs associated with renewables but also the requirement for 'back-up' generation and additional balancing services. The costs are very similar between the Standard FIT and FIT/Tender, but higher for the Extended RO.

Figure 48 Average additional consumer cost per MWh of additional renewables generation between the three schemes



5.5.6 Cost benefit analysis

Table 9 presents a summary cost benefit analysis (NPV, 2008-2030) for the three schemes under the base case assumptions relative to the Status Quo.

[68] This is calculated as the net present value of the additional consumer costs over the period 2008-2030 at a 3.5% discount rate, divided by the "net present value" of the additional renewables generation at the same discount rate

Table 9 **Comparison of cost benefit analysis (NPV, 2008-2030) under three schemes, 37% target, base case assumptions**

NPV 2008-2030, £m (real 2008)	Extended RO37	Standard FIT37	FIT/Tender37
Carbon saved	9,829	10,050	8,942
Less increase in resource costs	-51,348	-47,935	-51,108
Change in Net Welfare	**-41,519**	**-37,885**	**-42,167**
Change in Consumer Surplus	**-39,983**	**-33,733**	**-34,144**
Change in Producer Surplus	**612**	**-1,742**	**-5,646**
Change in renewables rent	*1,623*	*4,425*	*-2,688*
Change in non-renewables rent	*-1,010*	*-6,166*	*-2,958*
Change in Treasury Receipts	**-2,148**	**-2,411**	**-2,377**
Qualifying renewables generation in 2020	36.8%	36.9%	37.0%

The 37% target is approximately met under all three schemes, noting again that this result is dependent on assuming the High maximum build rates. The Standard FIT appears to have the lowest overall net disbenefit mainly as a result of the lower resource costs. However, rents for renewables plant are actually higher under Standard FIT than Extended RO. This is a function of generous grandfathering arrangements for RO plant and the fact the plant receiving FITs are not exposed to falling subsidy and wholesale revenues and increasing balancing costs as the penetration of renewables increases, which is the case under the Extended RO. Overall, producers are slightly worse off, and consumers correspondingly better off, under the Standard FIT due to somewhat lower wholesale electricity prices resulting from a higher level of renewables output after 2020.

The net welfare disbenefit of the FIT/Tender is slightly worse than the Extended RO despite similar additional resource costs. This is the result of lower avoided carbon dioxide emissions caused by greater displacement of nuclear investment under this scheme, which is itself a function of slightly higher levels of renewables deployment after 2020 in the way that this scheme has been designed.

The producer surplus is the lowest under the FIT/Tender scheme which reflects the assumption that successful tenderers bid at their own LRMCs and do not capture additional rents by bidding up to the level of the marginal successful bid. Were the latter to happen the relative benefits to consumers of the FIT/Tender scheme would be less than those stated.

5.6 Sensitivities

5.6.1 Renewables target

Renewables target sensitivities

Three different target levels of renewables from the generation sector were modelled. The 37% case as described above, and 28% and 32% targets. In the 28% and 32% cases, we assume that the Severn Barrage is not built, although we test the sensitivity of this assumption on the 32% case in Section 5.6.2 below.

In order to model these different target levels we adjust the subsidy levels in the model. For the Extended RO, we change the target obligation size and the size of the subsidy scales back accordingly. The banding assumptions for Extended RO32 are the same as for Extended RO37. The banding assumptions for Extended RO28 are also the same except that onshore wind is banded down to 0.5 ROCs/MWh in 2013.

Under the Standard FIT we reduce the tariffs by reducing the premia above expected LRMC of each technology. For the FIT/Tender, in addition to reducing the tariffs for plants that receive FITs, we also reduce the volumes of offshore capacity that gets tendered in each auction round. In doing this, we have needed to make a judgement on the amount of the overall target that will be aimed to be delivered through offshore technologies versus onshore technologies.

Below we present the results of the different target level sensitivities on the summary CBA results (NPV, 2008-2030) under each scheme. Full cost benefit analysis tables for these sensitivities are included in Appendix E.

Extended RO

Table 10 shows the summary CBA results (NPV, 2008-2030) for the Extended RO scheme under the three different target level sensitivities.

Table 10 Comparison of CBA (NPV, 2008-2030) for Extended RO under 28%, 32% and 37% target, base case assumptions

NPV 2008-2030, £m (real 2008)	**Extended RO37**	**Extended RO32**	**Extended RO28**
Carbon saved	9,829	9,301	6,331
Less increase in resource costs	-51,348	-43,108	-28,695
Change in Net Welfare	**-41,519**	**-33,807**	**-22,364**
Change in Consumer Surplus	**-39,983**	**-33,662**	**-19,600**
Change in Producer Surplus	**612**	**2,025**	**-875**
Change in renewables rent	*1,623*	*2,624*	*290*
Change in non-renewables rent	*-1,010*	*-599*	*-1,165*
Change in Treasury Receipts	**-2,148**	**-2,170**	**-1,889**
Qualifying renewables generation in 2020	36.8%	31.8%	28.3%

The net welfare loss reduces the lower the target as a result of the lower additional resource costs. The value of avoided carbon dioxide emissions also reduces with the lower targets, although the difference between the 32% and 37% is not that great since the additional 5% of renewables in the latter is mainly at the expense of new nuclear build. The net welfare losses are broadly borne by consumers in each case, with relatively small variations in producer surplus between cases.

Standard FIT

Table 11 shows the summary CBA results (NPV, 2008-2030) for the Standard FIT scheme under the three different target level sensitivities.

Table 11 Comparison of CBA (NPV, 2008-2030) for Standard FIT under 28%, 32% and 37% target, base case assumptions

NPV 2008-2030, £m (real 2008)	Standard FIT37	Standard FIT32	Standard FIT28
Carbon saved	10,050	9,774	5,103
Less increase in resource costs	-47,935	-39,360	-25,159
Change in Net Welfare	**-37,885**	**-29,586**	**-20,056**
Change in Consumer Surplus	**-33,733**	**-28,130**	**-15,804**
Change in Producer Surplus	**-1,742**	**998**	**-2,278**
Change in renewables rent	*4,425*	*3,354*	*-755*
Change in non-renewables rent	*-6,166*	*-2,356*	*-1,523*
Change in Treasury Receipts	**-2,411**	**-2,454**	**-1,975**
Qualifying renewables generation in 2020	36.9%	32.0%	27.6%

As for the Extended RO scheme, the net welfare loss reduces the lower the target. In each case the net welfare loss is lower than the corresponding Extended RO case due to lower resource costs. The levels of economic rents earned by renewables generators decrease with reducing target level since the premia over LRMCs set in tariffs are lower when lower levels of renewables generation are being targeted.

FIT/Tender

Table 12 shows the summary CBA results (NPV, 2008-2030) for the FIT/Tender scheme under the three different target level sensitivities.

Table 12 Comparison of CBA (NPV, 2008-2030) for FIT/Tender under 28%, 32% and 37% target, base case assumptions

NPV 2008-2030, £m (real 2008)	FIT/Tender37	FIT/Tender32	FIT/Tender28
Carbon saved	8,942	8,035	5,727
Less increase in resource costs	-51,108	-43,014	-29,326
Change in Net Welfare	**-42,167**	**-34,979**	**-23,599**
Change in Consumer Surplus	**-34,144**	**-23,528**	**-15,179**
Change in Producer Surplus	**-5,646**	**-8,929**	**-6,456**
Change in renewables rent	*-2,688*	*-2,709*	*-3,130*
Change in non-renewables rent	*-2,958*	*-6,220*	*-3,326*
Change in Treasury Receipts	**-2,377**	**-2,521**	**-1,964**
Qualifying renewables generation in 2020	37.0%	32.1%	28.0%

As in the other two schemes net welfare loss reduces with lower targets.

5.6.2 Severn Barrage

Severn Barrage sensitivities

In order to test the sensitivity of the results to whether the Severn Barrage is built we have run the 32% case with and without the Severn Barrage. In the case with the Severn Barrage we assume that it would be operational by 2022 and that 100% of its output could contribute to the target. Given the risk of late delivery of a project of this nature, any policy that requires the Severn Barrage to meet the target would involve some risk.

To re-iterate, we assume that the Severn Barrage is built outside of the main renewables support scheme through a tender mechanism, and that it receives a level of support equivalent to its LRMC with no additional economic rent.

The banding assumptions are the same in the Extended RO32 SB case as for the Extended RO32 case with the exception that onshore wind is banded down to 0.75 ROCs/MWh in 2013, since the target can be met without exploiting the lower wind speed locations.

Table 13 shows the summary CBA results (NPV, 2008-2030) for the Extended RO scheme 32% case with and without the Severn Barrage.

Table 13 Comparison of CBA (NPV, 2008-2030) for Extended RO32 with and without Severn Barrage

NPV 2008-2030, £m (real 2008)	Extended RO32	Extended RO32 SB
Carbon saved	9,301	8,373
Less increase in resource costs	-43,108	-40,631
Change in Net Welfare	**-33,807**	**-32,258**
Change in Consumer Surplus	**-33,662**	**-29,733**
Change in Producer Surplus	**2,025**	**-969**
Change in renewables rent	*2,624*	*687*
Change in non-renewables rent	*-599*	*-1,656*
Change in Treasury Receipts	**-2,170**	**-1,556**
Qualifying renewables generation in 2020	31.8%	31.8%

The analysis suggests a reduction in the net welfare loss if the Severn Barrage is included in meeting the target. However, this result is critically dependent both on assumptions on capital costs for the project which are very uncertain[69], and the costs of the alternative renewables generation which are also uncertain, particularly since many of the lower cost opportunities may have already been exploited by this point. Another factor is the relative impact on usage of the transmission network and the requirements for reserve of having a very large (and hence high impact outage risk) but predictable output profile from a tidal range project versus a more geographically diverse but less predictable set of intermittent plant.

The rents for renewables generators appear to be lower if the Severn Barrage is included in the target. This is because we assume that the Barrage is developed based on a competitive tender with the successful tenderers bidding close to their LRMC for operating the plant. This removes the requirement for the equivalent of 8 GW of plant which may have been earning economic rents under the RO.

The results of the Severn Barrage sensitivities on the other two schemes are similar to the Extended RO case. Full cost benefit analysis tables for these sensitivities are included in Appendix E.

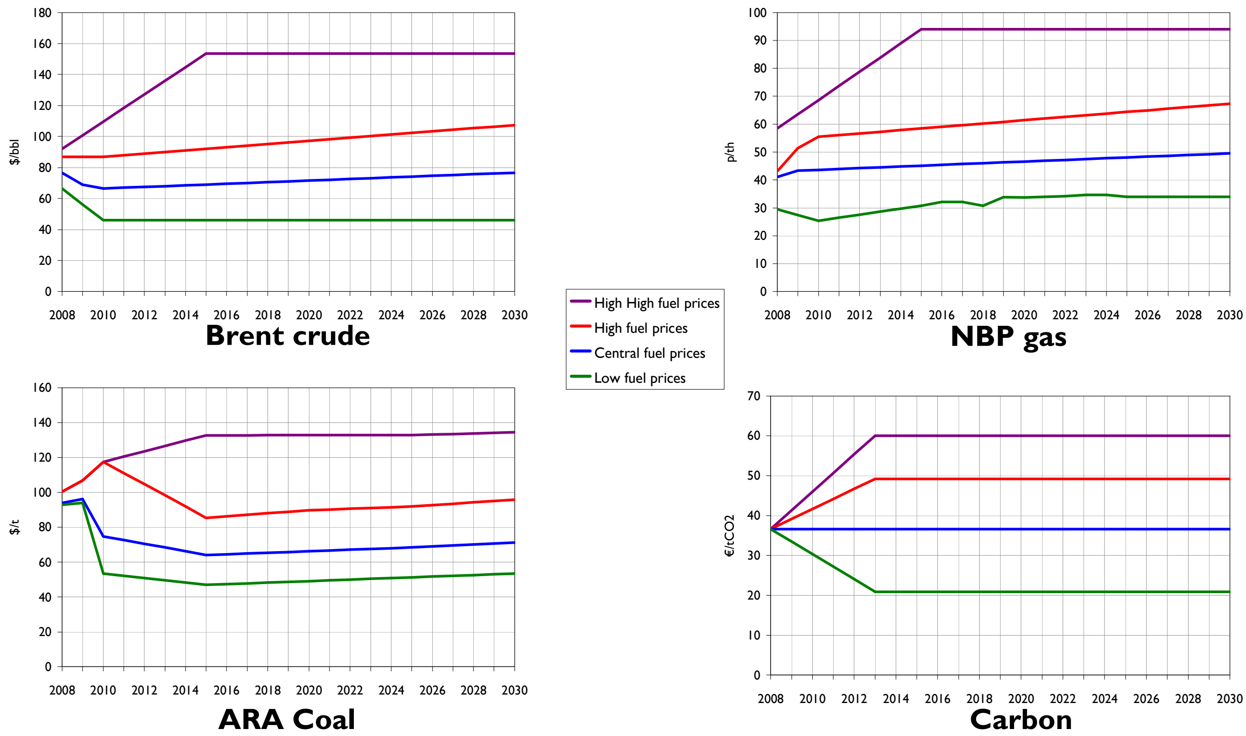
5.6.3 Fuel and carbon prices

Fuel and carbon price sensitivities

We have analysed three different fuel and carbon price sensitivities in addition to the Central case. These are Low, High and High High. Figure 49 shows the assumptions used in each sensitivity.

[69] We have assumed capital costs of £16bn in 2008 real terms based on the cost indicated in Energy Paper 57 and including additional environmental reparation costs of £1bn. However, recent work by Harlow suggests costs of up to £23bn based on increasing the contingency element of the project

Figure 49 Fuel and carbon price sensitivities



Below we present the impact of the different fuel and carbon price sensitivities on the three different schemes. It should be noted that within the CBA analysis the Status Quo counterfactual in each case assumes the same fuel and carbon prices sensitivities to facilitate comparison. Full cost benefit analysis tables for these sensitivities are included in Appendix E.

Extended RO

Under the Extended RO, the revenues received by renewables generators are very sensitive to fuel and carbon price assumptions. Figure 50 compares the rents earned by onshore (high) and offshore (high) wind plant under the High High fuel and carbon sensitivity relative to Central fuel and carbon assumptions for the Extended RO37 case. We have assumed the same banding in the High High case as in the Status Quo to facilitate comparison, although banding down might follow a sustained period of high fuel prices in an attempt to reduce rents for renewables generators.

Figure 50 Comparison of rents for onshore and offshore wind plant between Extended RO37 High High and Extended RO37, 2012-2020

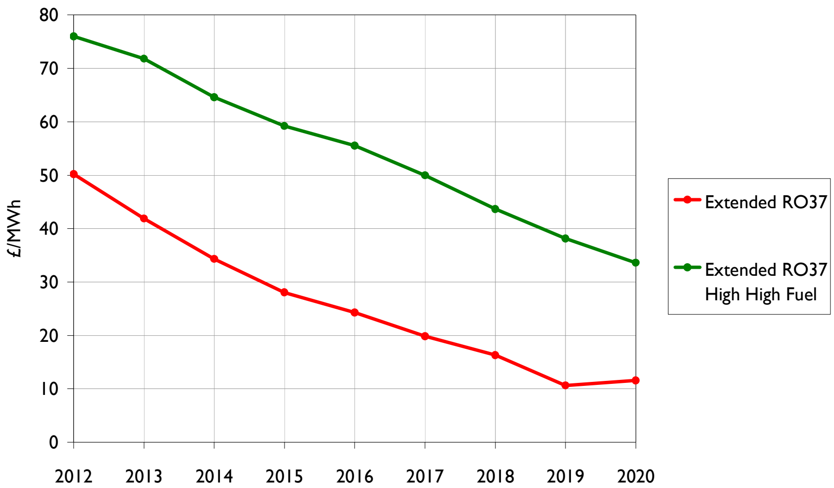


Figure 51 shows the impact of the High High fuel and carbon price sensitivity on the economic rent for renewables generators relative to the Central fuel and carbon assumptions for the Extended RO37 case. Rents are significantly higher until the greater amount of renewables built results in large falls in the ROC price and wholesale electricity revenues received by renewables.

Figure 51 Comparison of total rents for renewables between Extended RO37 High High and Extended RO37

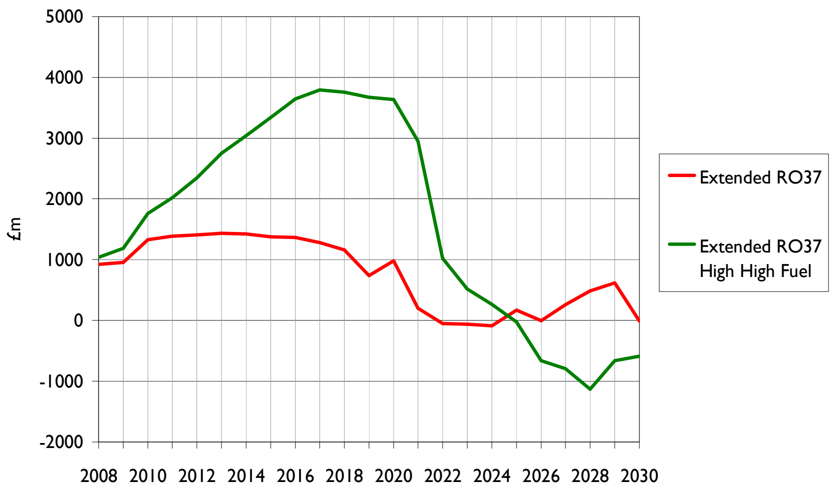


Table 14 presents the summary CBA results (NPV, 2008-2030) for the Extended RO37 cases under the different fuel and carbon price sensitivities. Note that the Status Quo counterfactual assumes the same fuel and carbon prices in each sensitivity.

Table 14 Comparison of CBA (NPV, 2008-2030) for Extended RO37 under different fuel price sensitivities

NPV 2008-2030, £m (real 2008)	Extended RO37	Extended RO37 Low Fuel	Extended RO37 High Fuel	Extended RO37 High High Fuel
Carbon saved	9,829	5,288	11,042	13,836
Less increase in resource costs	-51,348	-51,452	-44,632	-42,975
Change in Net Welfare	**-41,519**	**-46,165**	**-33,590**	**-29,138**
Change in Consumer Surplus	**-39,983**	**-38,036**	**-21,007**	**-14,588**
Change in Producer Surplus	**612**	**-6,264**	**-10,034**	**-11,792**
Change in renewables rent	*1,623*	*-556*	*1,796*	*2,582*
Change in non-renewables rent	*-1,010*	*-5,707*	*-11,829*	*-14,373*
Change in Treasury Receipts	**-2,148**	**-1,865**	**-2,550**	**-2,758**
Qualifying renewables generation in 2020	36.8%	34.0%	37.5%	38.1%

The results demonstrate that the renewables deployment and achievement of the 2020 target under Extended RO37 is sensitive to fuel and carbon prices since these directly impact wholesale electricity prices and the revenues that renewables plant receive. In high fuel and carbon price worlds, renewables look more attractive and more get built and the opposite is the case in low price worlds. Renewables output in 2020 ranges from 34.0% under the Low fuel and carbon prices to 38.1% under the High High fuel and carbon prices. The amount of renewables output under the High High sensitivity is constrained by the maximum build rates to 2020, but the resulting high electricity prices sustain renewables beyond this point. By 2025 renewables output is 45% under the High High sensitivity compared to 39% under the Central fuel and carbon prices.

The net welfare disbenefit is less under the High, and significantly less under the High High sensitivity, since the incremental resource costs are less when conventional generation is more expensive. The opposite is the case under the Low fuel and carbon sensitivity, although this effect is mitigated by the fact that less renewables are built, with a saving in resource costs.

There is a large drop in producer surplus under the High sensitivity and a further fall under the High High sensitivity. The impact of renewables on the wholesale electricity price is greater where fuel and carbon prices are high. This reduces the profitability of non-renewables generators, and although the resulting fall in new investment might ultimately lead to higher prices and recovering margins, there is a significant lag effect; the renewables policy is serving to erode 'bubbles' of high infra-marginal rents that may appear in the market following steep increases in commodity prices. This result suggests that producers with mainly conventional or nuclear plant portfolios would be better off if they collectively did not invest in renewables. However, provided the market is sufficiently competitive and there is the ability for independent renewables developers to enter, this potential threat to the achievement of the 2020 renewables target is small.

The change in rents for renewables is not significantly different under the High and High High sensitivities when compared to the Central case. This is because these cases are being compared to counterfactuals which also have high rents. In absolute terms the rents for renewables are very high as shown in Figure 50.

Consumers are relatively better off under the High and High High sensitivities due to the overall falls in producer surplus. For example, consumers are paying only 50% of the additional generator costs under the High High sensitivity compared to 96% under the Central fuel and carbon price assumptions.

Standard FIT

Table 15 presents the summary CBA results (NPV, 2008-2030) for the Standard FIT37 cases under the different fuel and carbon price sensitivities.

Table 15 Comparison of CBA (NPV, 2008-2030) for Standard FIT37 under different fuel price sensitivities

NPV 2008-2030, £m (real 2008)	Standard FIT37	Standard FIT37 Low Fuel	Standard FIT37 High Fuel	Standard FIT37 High High Fuel
Carbon saved	10,050	5,916	10,271	12,714
Less increase in resource costs	-47,935	-54,906	-35,466	-31,907
Change in Net Welfare	**-37,885**	**-48,990**	**-25,195**	**-19,193**
Change in Consumer Surplus	**-33,733**	**-44,586**	**-15,653**	**-1,204**
Change in Producer Surplus	**-1,742**	**-1,937**	**-6,873**	**-15,119**
Change in renewables rent	*4,425*	*4,220*	*2,136*	*-366*
Change in non-renewables rent	*-6,166*	*-6,157*	*-9,009*	*-14,753*
Change in Treasury Receipts	**-2,411**	**-2,468**	**-2,668**	**-2,870**
Qualifying renewables generation in 2020	36.9%	37.0%	37.2%	37.2%

The key difference from the Extended RO is that the 2020 renewables output is largely unaffected by changing fuel and carbon prices. This is because the FITs provide a hedge for renewables generators from changes in wholesale electricity prices.

As under the Extended RO scheme, the net welfare loss reduces with increasing fuel and carbon prices and increases with decreasing fuel and carbon prices. The combination of a relatively small increase in resource costs and large fall in producer surplus leads to costs to consumers only increasing by around £1bn for the High High sensitivity under the Standard FIT scheme.

With the Low fuel and carbon sensitivity, rents for renewables under the Standard FIT scheme are higher by about £4bn when compared to the corresponding Status Quo. This leads to an increase in consumer costs of around £45bn and this is the only case within the analysis where consumers pay more under the Standard FIT than the Extended RO (although the target is not met in the latter). An alternative interpretation of this result is that the Standard FIT provides a better hedge than the RO under the Status Quo for consumers; rents are higher when fuel prices are low and lower when fuel prices are high but the costs to consumers are relatively stable.

FIT/Tender

The effect of the fuel and carbon sensitivities on the FIT/Tender scheme is similar to the Standard FIT. Achievement of the target is largely unaffected by the change in commodity prices. Table 16 presents the summary CBA results (NPV, 2008-2030) for the FIT/Tender cases under the different fuel and carbon price sensitivities. Under the High High sensitivity consumers may actually be paying less under the FIT/Tender37 case than the Status Quo.

Table 16 Comparison of CBA (NPV, 2008-2030) for FIT/Tender under different fuel price sensitivities

NPV 2008-2030, £m (real 2008)	FIT/Tender37	FIT/Tender37 Low Fuel	FIT/Tender37 High Fuel	FIT/Tender37 High High Fuel
Carbon saved	8,942	6,103	10,929	12,786
Less increase in resource costs	-51,108	-59,488	-40,667	-36,279
Change in Net Welfare	**-42,167**	**-53,385**	**-29,737**	**-23,493**
Change in Consumer Surplus	**-34,144**	**-42,225**	**-13,154**	**362**
Change in Producer Surplus	**-5,646**	**-8,686**	**-13,928**	**-20,961**
Change in renewables rent	*-2,688*	*-2,974*	*-5,240*	*-5,514*
Change in non-renewables rent	*-2,958*	*-5,712*	*-8,688*	*-15,447*
Change in Treasury Receipts	**-2,377**	**-2,473**	**-2,656**	**-2,895**
Qualifying renewables generation in 2020	37.0%	36.6%	36.9%	37.0%

5.6.4 Capital cost uncertainty

Capital cost uncertainty sensitivities

In order to capture the effect of changing renewables capital costs and in particular the risk of over- or under-estimating capital costs when setting policy, we have analysed two different capital costs sensitivities, Higher than Expected and Lower than Expected. Our assumptions for these sensitivities are presented in Table 17 below. We have assumed that the risk of under-estimating the costs of emerging technologies is greater than for more established technologies.

Table 17 Assumptions for capital cost sensitivities, percentage increase or decrease on capital costs

Technology	Higher than Expected	Lower than Expected
Onshore wind (High)	+5%	-10%
Onshore wind (Medium)	+5%	-10%
Onshore wind (Low)	+5%	-10%
Offshore wind (High)	+20%	-10%
Offshore wind (Low)	+20%	-10%
Biomass regular	+20%	-10%
Biomass energy crop	+10%	-10%
Biomass CHP	+10%	-10%
Wave	+10%	-10%
Tidal Stream	+25%	-10%
Tidal Range	+25%	-10%
Biowaste	+15%	-10%
Biogas	+15%	-10%

Under the Extended RO, we have simply re-run the analysis with these higher and lower capital costs. We have assumed the same banding as under the Central capital cost assumptions, since the relativity of the errors in forecast costs between technologies is relatively low compared to the size of bands. For the Standard FIT, we have assumed that the tariffs have been set in 2012 (incorrectly) based on the Central capital cost assumptions, and that they are revised in 2015 but only corrected for 50% of the over- or under-estimation. Finally, in 2018 they are set at the 'correct' level based on the higher/lower capital costs. These assumptions assume a systematic over- or under-estimation of costs to illustrate the risks involved in setting tariffs. Equally, scenarios could be imagined where there is an over-compensation effect. For example, if initial tariffs were set too low in 2012 and insufficient renewables were built, tariffs could be reset in 2015 at much higher levels in order to catch up. Making significant changes in tariffs could however be politically difficult. First, there is a risk that investors may defer investment if they have an expectation of a significant increase in tariffs. Second, existing biomass plant operators who will be competing for the same resources as new biomass plant could be at a disadvantage if later plant receive higher subsidies[70].

For the FIT/Tender scheme, we make the same assumptions on the setting of tariffs as the Standard FIT. For the tendered plant, we assume that participants bid at the 'correct' costs and hence the volumes built are unaffected by the higher or lower capital costs. Such price discovery is one of the advantages of the tender approach.

[70] This potential issue has already been raised in the context of re-banding biomass under the RO.

Below we present the results of the different capital cost sensitivities. It should be noted that the Status Quo counterfactual in each case assumes the same capital cost sensitivities to facilitate comparison. Further details of the results from these sensitivities are included in Appendix E.

Extended RO

Table 18 presents the summary CBA results (NPV, 2008-2030) for the Extended RO under the Higher and Lower than Expected capital cost cases.

Table 18 Comparison of CBA (NPV, 2008-2030) for Extended RO37 under different renewables capital costs sensitivities

NPV 2008-2030, £m (real 2008)	Extended RO37	Extended RO37 Higher Cap Costs	Extended RO37 Lower Cap Costs
Carbon saved	9,829	9,324	10,540
Less increase in resource costs	-51,348	-49,764	-51,623
Change in Net Welfare	**-41,519**	**-40,440**	**-41,084**
Change in Consumer Surplus	**-39,983**	**-40,851**	**-41,534**
Change in Producer Surplus	**612**	**2,186**	**2,707**
Change in renewables rent	*1,623*	*1,976*	*4,171*
Change in non-renewables rent	*-1,010*	*211*	*-1,464*
Change in Treasury Receipts	**-2,148**	**-1,776**	**-2,257**
Qualifying renewables generation in 2020	36.8%	34.6%	37.6%

As would be expected the amount of renewables deployment is affected by the capital costs of renewables plant. Where capital costs are higher than expected deployment falls (34.6% to 2020) whereas where costs are lower than expected deployment rises (37.6% to 2020), although this is constrained by maximum build rates. Because of this constraint, rents for renewables are greater where capital costs are lower, but are not lower where capital costs are higher since less plant is built and the value of ROCs increases, compensating for the higher plant costs.

Standard FIT

The impact of inaccurate forecasting of renewables capital costs is perhaps greater for the Standard FIT scheme. Deployment is as low as 26.4% by 2020 under the Higher than Expected capital cost sensitivity, as shown in Table 19, because tariffs have been set too low. As would be expected under a FIT scheme, rents for renewables would be higher if capital costs outturn Lower than Expected, and lower if the reverse was true.

Table 19 Comparison of CBA (NPV, 2008-2030) for Standard FIT37 under different renewables capital costs sensitivities

NPV 2008-2030, £m (real 2008)	Standard FIT37	Standard FIT37 Higher Cap Costs	Standard FIT37 Lower Cap Costs
Carbon saved	10,050	5,501	9,639
Less increase in resource costs	-47,935	-28,268	-44,789
Change in Net Welfare	**-37,885**	**-22,768**	**-35,150**
Change in Consumer Surplus	**-33,733**	**-25,114**	**-30,818**
Change in Producer Surplus	**-1,742**	**3,395**	**-1,881**
Change in renewables rent	*4,425*	*2,098*	*5,600*
Change in non-renewables rent	*-6,166*	*1,296*	*-7,482*
Change in Treasury Receipts	**-2,411**	**-1,048**	**-2,450**
Qualifying renewables generation in 2020	36.9%	26.4%	37.2%

FIT/Tender

The impact of inaccurate forecasting of capital costs is less under the FIT/Tender scheme since offshore technologies are tendered and there is no requirement for policy makers to attempt to forecast these costs in advance. Deployment falls to 33.5% by 2020 for the Higher than Expected capital cost sensitivity compared to 26.4% under the Standard FIT.

Table 20 Comparison of CBA (NPV, 2008-2030) for FIT/Tender37 under different renewables capital costs sensitivities

NPV 2008-2030, £m (real 2008)	FIT/Tender37	FIT/Tender37 Higher Cap Costs	FIT/Tender37 Lower Cap Costs
Carbon saved	8,942	9,598	8,981
Less increase in resource costs	-51,108	-55,630	-47,546
Change in Net Welfare	**-42,167**	**-46,032**	**-38,566**
Change in Consumer Surplus	**-34,144**	**-36,616**	**-28,369**
Change in Producer Surplus	**-5,646**	**-7,408**	**-7,716**
Change in renewables rent	*-2,688*	*-2,725*	*-2,682*
Change in non-renewables rent	*-2,958*	*-4,683*	*-5,034*
Change in Treasury Receipts	**-2,377**	**-2,009**	**-2,481**
Qualifying renewables generation in 2020	37.0%	33.5%	37.4%

5.6.5 Build constraints

Build constraint sensitivities

We have used the SKM High maximum build rates as the base case for all of our scheme cases. (The Low maximum build rates have been used in the Status Quo.) In order to test the sensitivity of the results to this assumption we ran sensitivities using SKM's Central maximum build rates to represent the case where measures to make significant improvements to planning and connection access were not fully successful, or where there were ongoing constraints in the supply chain. (We did not model the Low maximum build rates as a further sensitivity since it did not seem credible that a financial support scheme designed to promote significant deployment of renewables would be implemented if build constraints remained at current levels.)

Below we present the results of the maximum build rate sensitivity. It should be noted that the Status Quo counterfactual in each case assumes the Low maximum build rates as these are a component of the definition of Status Quo[71]. Further details of the results from these sensitivities are included in Appendix E.

Extended RO

Where maximum build rates are constrained there is a big impact on deployment of renewables. Renewables output only reaches 26.6% by 2020 with the Central maximum build rate sensitivity, ten percentage points short of the target. The main further consequence of this under the Extended RO is a dramatic increase in the rent for renewables by over £13bn, pushing up the cost to consumers well above the additional generation costs, as shown in Table 21. To avoid this, further intervention may be required, for example banding down, although this would only reduce rents for new plant, or alternatively a reduction in the buy-out price which would affect all plant. However, such interventions may undermine future investor confidence.

[71] This contrasts with the other sensitivities where the Status Quo counterfactual was re-run with the same change in input assumptions as the scheme cases.

Table 21 Comparison of CBA (NPV, 2008-2030) for Extended RO37 under build rates sensitivities

NPV 2008-2030, £m (real 2008)	Extended RO37	Extended RO37 Central Build
Carbon saved	9,829	5,843
Less increase in resource costs	-51,348	-34,074
Change in Net Welfare	**-41,519**	**-28,231**
Change in Consumer Surplus	**-39,983**	**-34,502**
Change in Producer Surplus	**612**	**7,347**
Change in renewables rent	*1,623*	*13,429*
Change in non-renewables rent	*-1,010*	*-6,082*
Change in Treasury Receipts	**-2,148**	**-1,076**
Qualifying renewables generation in 2020	36.8%	26.6%

The overall net welfare loss reduces since less renewables are built.

Standard FIT

The risk of increasing rents for renewables under constrained build sensitivities does not exist for the Standard FIT scheme since revenues for individual plant are independent of most external factors. As shown in Table 22 rents actually decrease under the Central maximum build rate sensitivity since less renewables plant is built and fewer tariffs are paid.

Table 22 Comparison of CBA (NPV, 2008-2030) for Standard FIT under build rates sensitivities

NPV 2008-2030, £m (real 2008)	Standard FIT37	Standard FIT37 Central Build
Carbon saved	10,050	3,962
Less increase in resource costs	-47,935	-21,505
Change in Net Welfare	**-37,885**	**-17,542**
Change in Consumer Surplus	**-33,733**	**-19,619**
Change in Producer Surplus	**-1,742**	**3,098**
Change in renewables rent	*4,425*	*2,481*
Change in non-renewables rent	*-6,166*	*617*
Change in Treasury Receipts	**-2,411**	**-1,021**
Qualifying renewables generation in 2020	36.9%	27.4%

FIT/Tender

The FIT/Tender scheme would be similarly robust in terms of avoiding excessive rents under build constraints, as shown in Table 23.

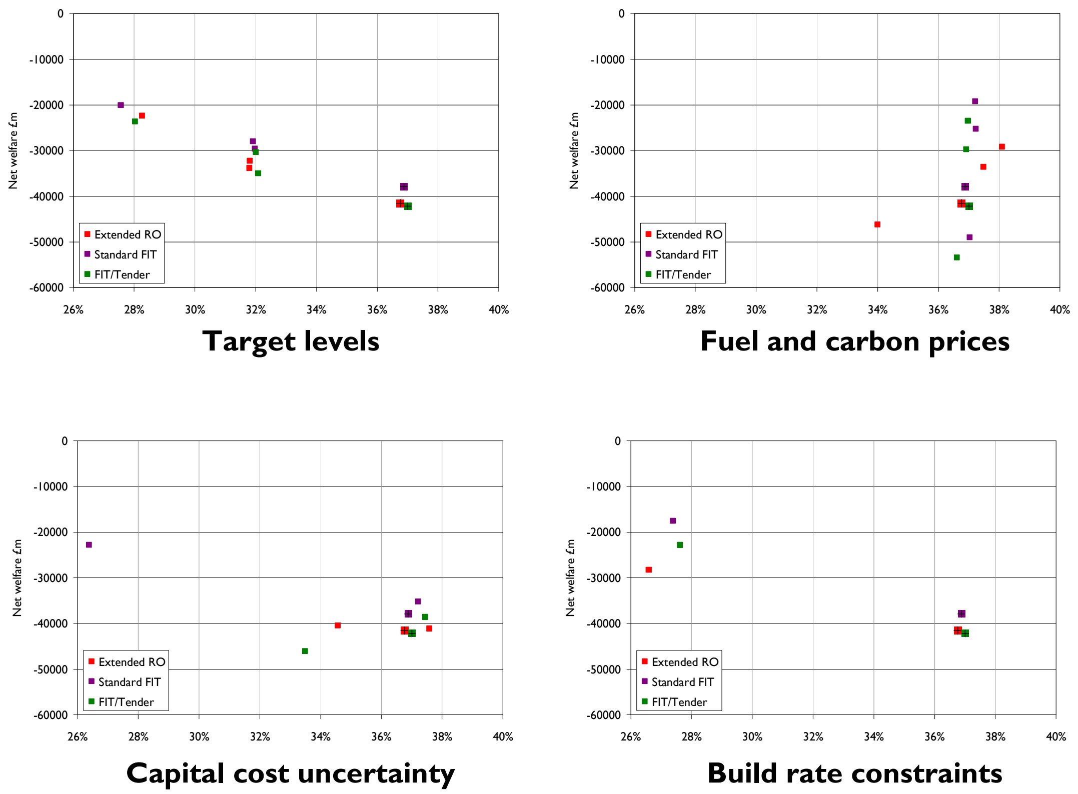
Table 23 Comparison of CBA (NPV, 2008-2030) for FIT/Tender under build rates sensitivities

NPV 2008-2030, £m (real 2008)	FIT/Tender37	FIT/Tender37 Central Build
Carbon saved	8,942	5,063
Less increase in resource costs	-51,108	-27,867
Change in Net Welfare	**-42,167**	**-22,804**
Change in Consumer Surplus	**-34,144**	**-15,913**
Change in Producer Surplus	**-5,646**	**-5,771**
Change in renewables rent	*-2,688*	*-2,360*
Change in non-renewables rent	*-2,958*	*-3,410*
Change in Treasury Receipts	**-2,377**	**-1,120**
Qualifying renewables generation in 2020	37.0%	27.6%

5.7 Results summary

Figure 52 summarises the results of the quantitative assessment of the three schemes. The graphs plot the amount of renewables output in 2020 against the net welfare loss (NPV, 2008-2030) for the Central cases (highlighted with a cross) and each of the four sets of sensitivities.

Figure 52 Summary of quantitative analysis



The key messages emerging from these results are:

- **Target levels.** The net welfare loss is similar for all three schemes, but is lower for the Standard FIT than the other two schemes for all three target levels under Central assumptions.
- **Fuel and carbon prices.** The Extended RO is least robust to changing commodity prices in terms of meeting the 2020 target (and controlling rents for renewables generators). The net welfare loss is less sensitive to changing commodity prices than the other two schemes, as the deployment of renewables adjusts to market price signals. Under the Standard FIT and FIT/Tender, the outcomes with highest net welfare loss (relative to the equivalent Status Quo) are associated with low fuel prices and vice versa. Hence, the absolute resource costs and costs to consumers are more stable.
- **Capital cost uncertainty.** The Standard FIT is least robust to uncertainty in capital costs in terms of meeting the 2020 target. The Extended RO is more robust in this respect since ROC prices will rise in response to lower than expected deployment. The net welfare loss under the

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Extended RO is largely unaffected by renewables capital cost since the total size of the subsidy is fixed; where capital costs are higher than expected the subsidy funds less MWs of investment, and vice versa.

- **Build rate constraints.** Constraints in planning, connection access or the supply chain could significantly reduce the ability of the market to meet high renewables target levels. The Extended RO appears least robust in this respect with the greatest net welfare loss (and importantly the highest impact on consumer costs) where build is constrained.

6 Conclusions

Meeting the 2020 target

Meeting the EU 2020 renewables target will be extremely challenging, and will require the proportion of electricity generation from renewables sources to increase from around 5% currently to at least 32% by 2020, and possibly higher. The effort faced by the heat and transport sectors is similarly challenging.

Adopting an effective financial support scheme to stimulate the levels of investment required to reach the target generation within just a decade will form one component of the Government's strategy. However, at least as important will be policies that address current constraints in planning and the renewables supply chain, and that promote the efficient expansion of the grid to allow an additional 15 to 25 GW of generation capacity (renewable and non-renewable) to be simultaneously connected to the network by 2020 as a direct result of the increased renewables targets. The greater penetration of renewables may also necessitate changes to the current market arrangements (for example, to deal with congestion management), and the role of the System Operator between now and 2020. None of these additional policy considerations were within the scope of this study.

Putting these other considerations aside, a critical question facing policy makers is what type of financial support scheme is likely to be most effective and efficient in delivering against the 2020 targets. Other European countries face similar challenges in adapting their current support schemes to deliver higher target levels of renewables generation. There is a wide range of schemes adopted internationally, but the suitability of any particular scheme depends critically on the circumstances. However, markets with feed-in tariffs, such as Germany and Spain, have delivered the highest investment in renewables recently. Even within the feed-in tariff approach there are wide variations in the details of each scheme, as evidenced by the differences in the German and Spanish schemes.

Investors' perspective

The most important factor for investors at this stage will be a credible commitment from the UK Government to the EU 2020 targets. In terms of the financial support scheme itself, large diversified energy companies will tend to prefer ongoing subsidy mechanisms that contain a degree of market risk which their scope and scale will help them manage, whilst niche developers may prefer advantage to lie with those best able to seek out and develop project opportunities with the market risk managed on their behalf through long term guaranteed offtake agreements. However, all investors would undoubtedly see the need for clarity and certainty as more important than any of these detailed design features.

Impact on consumers

Whichever approach is adopted, consumers will in most cases bear the majority of the additional costs of achieving the renewables target. Under the base case assumptions, the costs to consumers in meeting a 37% target ranges between £34bn and £40bn on a net present value basis across the three schemes, adding around £32-£56 (8%-15%) to the average annual domestic consumers' bill by 2020 relative to the Status Quo. However, when compared with a revised Status Quo of rapidly rising fuel prices coupled with continuing connection queues, and hence high producer rents, the deployment of high volumes of renewables through an effective financial support mechanism combined with a streamlined planning and connection process, appears far more favourable to consumers. Under the High High fuel and carbon sensitivity the additional cost to consumers of a 37% target is close to zero under the FIT/Tender scheme. In contrast, in the Low fuel price case the additional net present value costs to consumers between 2008 and 2030 is as high as £44bn under the Standard FIT scheme.

Impact of renewables target

The quantitative analysis of these three schemes suggests that each could be designed to meet the electricity targets modelled; 28%, 32% and 37%. The 37% target would be at the boundary of what was achievable according to the study of deployment constraints conducted in parallel by Sinclair Knight Merz, and assumes a Severn Tidal Power project could deliver an additional 5% of renewable electricity, and that this would be eligible towards the 2020 target. Achievement of these targets would, however, be contingent on removal of significant constraints currently in planning and connection access, sufficient investment in the supply chain, and, to a greater or lesser extent, on the Government's ability to forecast accurately the costs of renewables generation relative to the alternatives. The sensitivity testing demonstrated that failings in any of these areas could jeopardise the achievement of the targets, and could have other consequences such as unnecessarily increasing costs to consumers. Another key risk to the achievement of the target, but not explicitly modelled in this study, would be a systematic failure of emerging renewables technologies to achieve the operational availability levels expected.

The higher renewables targets would reduce carbon dioxide emissions from the electricity sector by between 26% and 37% by 2020 from current levels. However, for each of the three electricity targets modelled, under base case assumptions the renewables policy leads to a net prevent value welfare loss for the period 2008-2030 compared to a Status Quo scenario (which includes the amendments to the RO introduced in the Energy Bill). These range across the three schemes between negative £20bn-£24bn under the 28% target, negative £30-£35bn under the 32% target, and negative £38bn-£42bn under the 37% target, representing between 6% and 14% of the total wholesale value of electricity. The additional resource costs (which include the costs of providing back-up generation, extra balancing services, and grid expansion as well as the investment costs in the renewables plant themselves) significantly outweigh the savings in terms of carbon dioxide emissions avoided (valued at the EU ETS allowance price), with the impact greater the higher the target. (Had we attached additional value to renewables generation, such as avoidance of penalties for failing to meet the Directive targets, the net welfare loss would have been reduced.) The results are sensitive to the input assumptions used. For example, the net present value welfare loss across the schemes under a 37% target ranges from negative £19bn to negative £53bn, the lower figure associated with the High High fuel and carbon sensitivity where renewables are relatively less expensive compared to the alternatives, the latter figure with the Low fuel and carbon sensitivity.

The analysis demonstrated the impact that a high penetration of intermittent renewables could have on electricity prices, depressing baseload prices and potentially leading to periods of zero or negative offpeak prices, but with higher, and increasingly volatile, peak prices (and with peak prices increasingly driven by low wind availability rather than peak demand). This may reduce investment in inflexible baseload plant, including some low-carbon options like nuclear and plant fitted with carbon capture and storage. Conversely, more flexible plant may be able to benefit from the increasing market volatility and increasing demand for system balancing services from the System Operator. These opportunities for flexible generation coupled with response from the demand side to emerging price signals suggest that security of supply need not be compromised by the higher renewables target, provided clear UK and EU government policy provides a robust framework that allows companies to anticipate the opportunities and to invest in a timely manner.

The risk of 'spill', periods in which supply from inflexible plant such as intermittent renewables and nuclear exceeds demand, will increase with higher renewables deployment. At this point, the support scheme for renewables may have a distorting impact on price and lead to inefficient dispatch outcomes, and this requires careful consideration. At the same time it is important that the demand side has the ability to respond through load shifting or new uses for electricity at times of high renewables output. The other very important factor, not modelled in this study, is the impact of renewables on transmission constraints. If the transmission network is unable to expand fast enough, the achievement of the electricity target could be jeopardised, even where there is sufficient renewables capacity connected, as a result of renewables generation being 'constrained off'.

Scheme comparison

The Extended RO shows the greatest net welfare loss of the three schemes. This result is driven by the higher cost of capital for renewables investment given the revenue uncertainty for generators under this scheme. The Extended RO is susceptible to high rents for renewables generators particularly where commodity prices and hence electricity prices are high, or where build is constrained by external factors. In these circumstances, amendments to the scheme might be required to prevent large economic rents accruing, such as reviewing the buy-out price indexation or banding down certain technologies (although the latter would not reduce rents for existing plant since bands are assumed to be grandfathered). The amount of intervention would need to be weighed up against the potential impact on future investor confidence. Hence, there would be benefits in including measures to mitigate against these risks in a transparent manner in the up-front design, for example by linking the buy-out price indexation to the inverse of wholesale electricity prices.

However, the analysis suggests that, other things being equal and provided constraints in planning, connection and the supply chain are resolved, rents are likely to fall over time as a direct result of the increasing deployment of renewables, through a combination of falling ROC prices, downward pressure on wholesale electricity prices, increasing anti-correlation between intermittent renewables output and the price they receive and increasing system balancing costs (depending on how these are targeted under the market arrangements). This 'feedback' loop is very weak at the current low levels of renewables penetration but will become increasingly significant if higher levels of renewables generation are targeted. These effects will need to be recognised in the detailed design of the scheme if the electricity target is to be reached.

Another factor to consider in extending the RO to deliver higher renewables targets is the impact of the nature of the subsidisation on the market dispatch. At times of potential spill, renewables generators may be prepared to offer down to minus their ROC revenues (and banding thereof) in order to remain generating. This could lead to sub-economic market dispatch.

The Standard FIT scheme has the lowest net welfare loss and is least expensive for consumers under the base case assumptions modelled. This is mainly due to the lower cost of capital for investors given the high degree of revenue certainty provided by guaranteed long term offtake agreements, relative to the uncertain subsidy level and increasing electricity price volatility to which ROC holders are exposed. However, this approach is particularly susceptible to errors in forecasting renewables costs, and the modelling suggests that tariffs would need to be set relatively high to stimulate the levels of investment required over the short timeframes to ensure the target is met. Any scheme other than an extension of the RO would be likely only to be in place by 2012, leaving just eight years to meet the target. In addition, it may be necessary to offer generous grandfathering under the RO transitioning arrangements to ensure that there is no slow down in investment in the run up to the implementation of the new policy.

Due to these factors, the analysis suggests that whilst the excess economic rents which are currently a feature of RO could most effectively be reduced in the near team by transitioning to a feed-in tariff approach, over the lifetime of the scheme a certain level of rent is inevitable if the scheme is to be successful in delivering against the target. The feed-in tariff approach protects the renewables generators from the impact of increasing renewables deployment on the value of their output and increasing system balancing costs. These costs would be borne and passed onto consumers by the central body responsible for selling the output from feed-in tariff eligible generators at the day-ahead stage. Whether the associated risks are best managed centrally or by individual generators is a key factor in determining the benefits of the Standard FIT versus the Extended RO. A possible variant, which would leave the short term market and balancing risk with the generator, would be using Contracts for Difference. Such an approach would arguably be more compatible with the current market arrangements, addressing one of the downsides of the Standard FIT scheme.

The FIT/Tender scheme appears most robust to external factors and could deliver the kind of co-ordination in developing offshore technologies that might be required to deliver the electricity target. However, experience both internationally and in the UK of delivering renewables through tenders is not particularly positive. Although some of the historic pitfalls, like no delivery obligations and inability to secure planning/connection access after winning the tender, could be addressed, this approach would still be the least proven of the three schemes considered in detail.

The analysis suggests that the FIT/Tender scheme would be more expensive than the Standard FIT in terms of resource costs, due mainly to the higher cost of capital for investors exposed to delivery obligations under the terms of the tenders. However, it could be cheaper for consumers, depending on how competitive the tenders are, since it avoids the risk of having to cover renewables cost uncertainty by setting higher feed-in tariffs.

The issues of compatibility with the wider wholesale market are similar to those under the Standard FIT scheme.

Overall conclusions

The results from modelling a complex system should always be treated with caution. Many of the assumptions adopted in this study are highly uncertain and some potentially significant simplifications have been necessary, for example not modelling specific transmission upgrades and ignoring the possible impact of transmission constraints on the ability to meet the 2020 renewables electricity target. Nonetheless, the modelling captures the investment and price dynamics of the electricity market in an internally consistent manner and therefore provides a good vehicle for comparing the effects of different schemes.

The analysis demonstrates that there are potential pros and cons with each of the three schemes, and that there are a number of issues that require careful consideration in the detailed design of each. Overall, the results appear to bear out observations from international experience that the feed-in tariff approach could be the most effective in minimising resource costs and costs to consumers, particularly for technologies for which costs can be assessed with a reasonable degree of accuracy. However, given the tight timescales involved, there is a significant risk associated with transitioning away from a RO-based approach, leaving open the question of whether these risks exceed the potential benefits. The move to a potentially lower cost scheme (but untested in the UK context) could be self-defeating if it is poorly managed and results in a slow down in investment between now and the implementation of the new scheme, making the achievement of the 2020 target yet more challenging. On the other hand, a well communicated change that reflects the new renewable target level could signal a step-change that is part of a consistent policy framework, and could thus accelerate private sector investment decisions.

Either way, a swift resolution of the overall approach and the scheme details is essential to ensure that investors have the confidence to start the process of expanding their renewables project delivery capabilities which will be required to meet the 2020 target.

A Summary of international experience

A.1 Introduction

This appendix presents a representative summary of international financial support mechanisms for renewable electricity generation.

The countries were selected both to cover major European markets as well as to present a wide range of different approaches, including certificate-based markets, feed-In tariffs (FITs) and others. Two US states have also been included, and for two countries (the UK and the Republic of Ireland), we include previous as well as current regimes.

A.2 Summary table

In Table 24 below, we list the countries included in this appendix, and the nature of the main support scheme in place. (Where schemes have recently changed, this is indicated with an arrow.) For context, we also show here the proportion of total energy generated from renewables (% RES) and the proportion of total electricity generated from renewables (% RES-E) for each country in 2005.

Table 24 Country summary

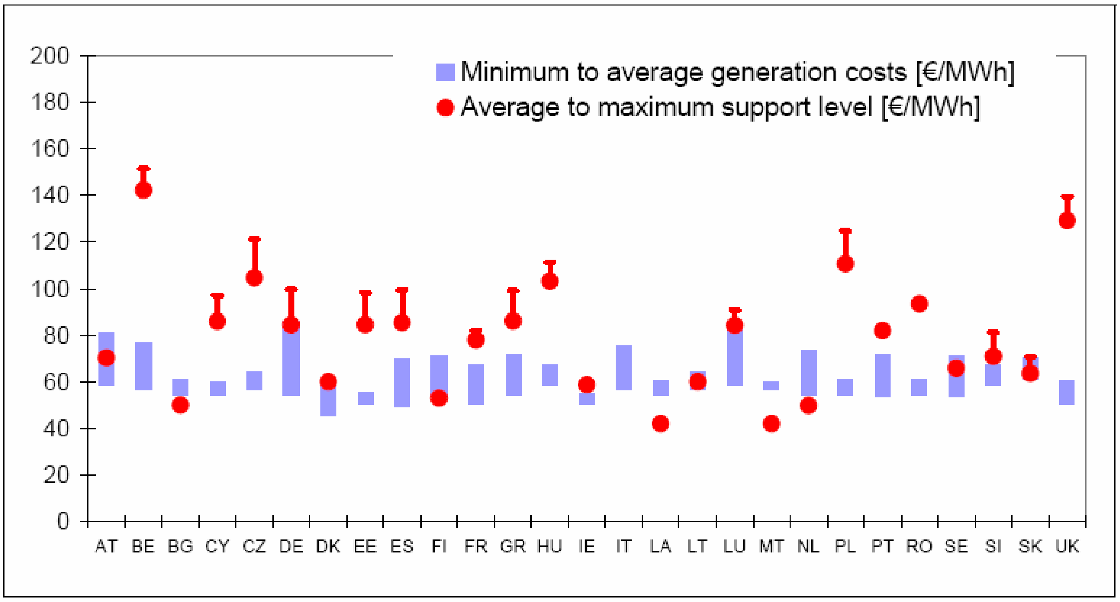
Country reviewed	Nature of support scheme	% RES (2005)	% RES-E (2005)
Austria	Feed-in tariff	23.3	59.7
Belgium	Supplier obligation (different parameters in Wallonia and Flanders)	2.2	3.0
Denmark	Feed-in tariff => Feed-in premium	17.0	29.3
Finland	Fiscal support	28.5	33.4
France	Feed-in tariff	10.3	10.1
Germany	Feed-in tariff	5.8	10.4
Ireland	Tender => Feed-in tariff	3.1	7.4
Italy	Generator obligation	5.2	16.4
Netherlands	Fiscal support => Feed-in premium (now withdrawn)	2.4	8.9
Poland	Supplier obligation	7.2	2.7
Spain	Feed-in premium	8.7	14.9
Sweden	Supplier obligation	39.8	51.8
UK	Tender => Supplier obligation	1.3	4.4
USA – California	Supplier obligation and fiscal support	11.5 (2006)	31.7
USA - Connecticut	Supplier obligation and fiscal support	-	3.6

For our effectiveness and efficiency data we have drawn heavily on a European Commission Staff Working Document, 'The support of electricity from renewable sources', produced in support of the proposal for the renewables Directive[72]. This document compares support levels in EU countries to generation costs for a number of different technologies. We have extracted the results for onshore wind and forestry biomass as indicative. The summary results from the report are shown in Figure 53 and Figure 54 below. Where not otherwise referenced, efficiency and effectiveness statements in the country sections are from this report.

[72] Commission Staff Working Document, The support of electricity from renewable sources, Brussels, 23/1/2008, http://ec.europa.eu/energy/climate_actions/doc/2008_res_working_document_en.pdf

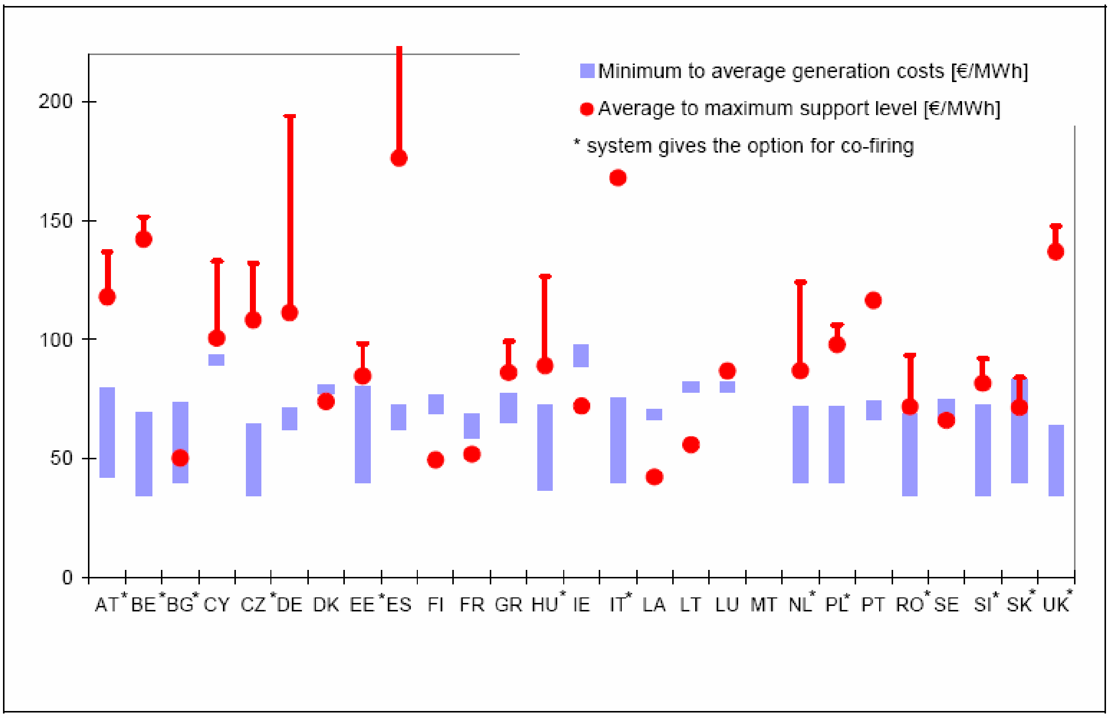
We note that in most cases, the schemes considered in the report have only been in operation for a few years. This needs to be taken into account when considering the data. In the case of FIT schemes, potential issues associated with changing costs over time, compared to the tariffs set, will not necessarily be picked up at this stage. For obligation schemes, in most cases certificate prices may be expected to be significantly higher in the earlier part of a scheme (as early targets may well be significantly above currently installed capacity), with the potential for prices to fall in the later years. Thus efficiency measures drawing on current certificate prices in early years may not be reflective of the expectations over the lifetime of the scheme. As a further caveat, the impact of non-financial barriers to deployment (such as planning and grid connections), or other incentives (such as grants or tax breaks), are not separated out in the effectiveness assessments and hence, again, care should be taken in conclusions drawn.

Figure 53 Onshore wind (Commission Staff Working Document))



Source: OPTRES, 2007

Figure 54 Forestry biomass (Commission Staff Working Document)



Source: OPTRES, 2007

A.3 Key learning points

In this section, we first summarise general observations drawn from all countries reviewed, grouped by type of scheme. We then focus more specifically on five countries that have gone through significant policy changes (Denmark, Germany, Ireland, the Netherlands and the UK) to draw lessons from the reasons behind the changes.

A.3.1 Obligation-based schemes

- As market-based mechanisms, these schemes have arguably allowed an efficient allocation of resources (for example the co-firing of biomass in UK thermal plant), and are more easily compatible with bilaterally traded wholesale markets.
- Obligation-based schemes are typically measured as more expensive to the consumer, at least in the early years, when subsidy levels are compared to long run marginal costs (LRMCs) of renewables technologies.
- Schemes typically provide price transparency, at least in the short term, often through exchange trading or formal price reporting.
- Uncertainty about continuity and future prices has led to higher financing costs. A number of arrangements have been used to reduce this investor risk:

- The risk around price collapse in over-supplied markets will be addressed in the UK through the proposals for a 'ski-slope' mechanism, and in Italy through a buy-back guarantee, priced off the previous year's average certificate price.
- Italy derives its buy-out price from a target 'all-in' revenue level (including wholesale electricity and subsidy), such that wholesale price risk is partially hedged through the exposure to certificate prices.
- In Wallonia, the government has implemented a supplementary scheme to allow generators the option to sell certificates to the government at a fixed price for up to ten years.

- Without a price cap, the political impact of high prices can force regulatory changes, such as expanding the definition of renewable energy, for example through allowing hydro-generated imports in Connecticut.
- In countries that already have a high renewables base, an obligation scheme has not necessarily resulted in significant new build. For example, in Sweden, existing capacity has switched to widely available biomass fuels, and similarly no constraint on co-firing in Wallonia has reduced incentives for other technologies.

A.3.2 FIT schemes

- FIT schemes are typically measured as achieving subsidy levels relatively close to LRMCs of renewables technologies, indicating that governments have aimed to limit rents to producers through the tariff level set.
- Similarly, the security of revenue streams can facilitate debt financing which in turn may allow project developers to focus on local support and planning process at crucial early stages of the project.
- The lack of subsidies for technologies not 'recognised' by the scheme can be argued to dampen incentives for innovation. When Ireland launched its REFIT scheme in 2006 there was no offshore wind specific tariff, despite the significant potential for the technology in that country. There have been no significant offshore proposals as a result. On the other hand, governments have flexibility to introduce new technology categories without undermining investment certainty for other technologies (and in Ireland a new tariff for offshore wind has been introduced for 2008).
- Schemes can be defined such that tariff levels are calibrated according to resource availability (above a given minimum). For example, in Germany, subsidies are adjusted based on the average of the plant's first five years' load factor (relative to a baseline), but are lost if the yield of a new facility drops below 60% of the reference yield.
- Premium schemes have been used as a way to maintain investor confidence whilst facilitating integration with competitive wholesale markets.
- However, premium schemes without caps and floors can lead to large generator profits when wholesale prices rise. This situation triggered the introduction of a price cap and floor in Spain, and the high rewards resulted in excessive build and scrapping of a scheme in the Netherlands that was considered to have become too expensive.

- Too much optionality in schemes can lead to potential 'adverse selection' against the government. In Spain, generators can elect to receive either a fixed feed-in tariff or a feed-in premium. They are able to revise this decision once each year. The investor can therefore capture upside associated with increased wholesale electricity prices, without the associated downside risk.

A.3.3 Tenders

- Significant decreases in bid prices for new wind capacity were seen over the period in which the Non-Fossil Fuel Obligation (NFFO) was in place in the UK.
- In both Ireland and the UK, tender schemes have resulted in situations where applicants have bid aggressively to succeed in the auction, but subsequently determined that the corresponding price is insufficient to make the project commercially viable, and hence the capacity is never delivered. In the UK under NFFO, 2.4 GW of projects that won contracts in the auction were subsequently not built. (The total contracted build was 3.6 GW). Under the final two phases of the Irish Alternative Energy Requirement (AER V and VI), only 277 MW of a total contracted capacity of 724 MW was built.
- Under the AER in Ireland there was no requirement for a bid to have obtained approval for grid access or planning permission.
- Both AER and NFFO had a discrete set of tender 'rounds' leading to investor uncertainty regarding the 'ad-hoc' timing of support availability.
- The winner of a recent offshore wind generation tender in Denmark pulled out of the project on the grounds of increasing costs. Re-tendering may increase costs and cause delays.

A.3.4 Fiscal mechanisms

- The Netherlands had fiscal support in place prior to setting up its feed-in tariff. This took the form of an energy consumption tax from which consumers of 'green' or renewable energy were exempt. The result was that a significant proportion of consumers signed up to green tariffs but most of this energy was sourced from existing capacity from outside the Netherlands. Very little new capacity was built.
- A range of fiscal mechanisms can lead to a complexity and lack of alignment. Whilst clearly a potential issue with any scheme, fiscal mechanisms appear to be particularly prone to this problem, with grants and tax incentives more subject to short term political pressures. Withdrawals of successful applicants in an Irish tender were in part due to the subsequent removal of a tax incentive. Finland has a carbon tax (in addition to being party to EU-ETS) and Energy Aid is available, covering up to 40% of the capital costs associated with building new renewables capacity.

A.3.5 Reasons for major scheme changes

We highlight five markets where renewables support schemes have gone through significant changes, with the aim of identifying the underlying reasons.

Denmark

Denmark moved from an 'all-in' FIT-based scheme to a premium-based scheme (combined with tenders for offshore wind) in 2003.

Denmark had operated a range of incentives for renewables generation dating back to 1979, but the FIT scheme was introduced through legislation in 1992. Approximately 2 GW of wind capacity was subsequently developed, until, in 1998, the rising costs, exacerbated by a period of low wholesale prices, led to increasing government concern about the scheme's long term viability. A long period of significant policy uncertainty followed. A traded certificate scheme was proposed in 1999, and introduced in law, but implementation was delayed and the scheme was abandoned in 2001. Transitional arrangements were extended and amended, until a premium scheme for onshore wind was introduced in 2003 (with grandfathering arrangements for existing plant), together with plans for tenders for offshore wind.

Learning points:

- Realistic long term subsidy costing and budgeting is important.
- There is potential for political pressure on FIT schemes in a world of falling wholesale prices.

Germany

Germany moved from scheme with indexation to retail electricity prices to a FIT in 2000.

In Germany, a policy introduced in 1991 – the Stromeinspeisungsgesetz (StreG) - required public energy supply companies to buy hydropower, landfill gas, sewage gas and biomass from producers for at least 80% of the retail consumer price as charged in the previous year. Wind and solar producers, meanwhile, were given a 90% price guarantee. A decline in electricity prices in the late 1990s, and thus in payments for renewable generation, prompted the introduction of new legislation in 1998 introducing feed-in tariffs, effective from 2000 onwards – the Erneuerbare-Energien-Gesetz (EEG). The objectives of the change were to both fix rates for economic lifetimes, and to accelerate the development of higher cost generation through greatly increasing tariff differentiation by technology, and introducing differentiation by resource potential for wind. This allowed developers more easily to secure credit for inland wind sites that were previously difficult to finance, and made market entry possible for other renewables such as solar photovoltaics and dedicated biomass. It also replaced a number of ad-hoc schemes (such as the '1000 roofs' PV programme) that failed to provide longer term incentives for the supply chain.

Learning points:

- Tariffs indexed to electricity prices create uncertainty for investors and can fall to levels that discourage new build.
- Significant tariff differentiation is required if higher cost technologies are to make a material contribution.
- Differentiation by resource potential, especially for wind, can be used to develop less attractive sites at an early stage.
- A straightforward long term policy, compared to 'one-off' ad-hoc schemes, gives the right incentives for investment in the supply chain.

Netherlands

The Netherlands moved from a tax based scheme (whereby renewables generation was exempt) to a premium-based scheme in 2003, which was in itself then abandoned in 2006.

Under the original scheme, an energy tax was levied on electricity, from which renewables-sourced power was exempt. The tax was sufficient to simulate a rapid growth in 'green' tariffs. Under the scheme, suppliers were able to utilise certificates of origin from other countries, but in the absence of regional demand through equivalent obligations in neighbouring markets, these were priced significantly below indigenous new entry cost. Most of the power was therefore sourced through imports from existing renewables sources (including large hydro) and there was correspondingly little new build. The scheme was replaced with fixed premium payments for renewables output (with power sold in the wholesale market). Whilst this was effective in stimulating new capacity, its introduction coincided with a period of rising wholesale prices, leading to increasingly higher returns, and a higher than anticipated uptake. The corresponding mounting costs led to the scheme initially being capped, and then abolished.

Learning points:

- Tax-based mechanisms can be effective in incentivising consumer choice.
- Certificate of origin trading between countries requires similar underlying obligations to create appropriate price signals.
- Volumes delivered by premium schemes are sensitive to movements in the underlying commodity price.

Republic of Ireland

Ireland moved from a tender-based scheme (the AER) to a FIT scheme[73] (REFIT) in 2006.

The AER scheme was introduced in 1993, and six auction 'rounds' had taken place by 2003. The form of the auctions was adapted during this period. Under AER I, applicants bid based on the capital grant sought to supplement a fixed price power purchase agreement (PPA). This switched in AER III, with a fixed grant available and applicants bidding based on required energy price[74]. By AER V, planning permission became a pre-requisite for bidders, and there was an option for applicants to increase their bid price for the first half of the PPA and reduce it for the second half to accelerate upfront payments.

Other than AER I (which had a target of only 30 MW), the actual delivery of capacity against the tender targets has been low (around 40% on average). A number of reasons have been cited for this[75]. First was a lack of co-ordination between PPA awards, planning permission and grid connections. Prior to AER V, contracts could be awarded to schemes without planning permission, which could subsequently not be

[73] There are some significant differences between the REFIT and FIT schemes elsewhere in Europe, described in the country section below.

[74] AER II was specifically for a single biomass plant, and AER IV was for CHP plant.

[75] See, for example, Ó Gallachóir, Bazilian and McKeogh, *Moving from Competitive Tender to Feed in Tariff – Wind Energy Policy in Ireland*, Proceedings, European Wind Energy Conference 2006.

granted. Although this was resolved in the final two rounds, grid connection was still not required for applicants, and projects faced a long backlog for a connection agreement, in some cases extending beyond the term of the planning permission. This problem was exacerbated by delays in finalising planning guidelines for wind farms, and in addressing technical network issues around renewable grid connections. Second, a financing assumption for a number of AER V projects was a tax incentive for capital allowances, but this was removed in the budget after winning applicants had been announced. Third, there were often significant delays in announcing results as State Aid approval was obtained.

The feed-in based REFIT scheme, introduced in 2006, is intended to provide increased certainty that target levels of renewables will be met. It removes the uncertain deployment associated with infrequent auction rounds. Projects must already have received planning permission and a grid connection before becoming eligible, reducing the chance that successful applicants will subsequently fail to deliver (although this could also have been achieved through a change to the tender process). For developers, it also takes away the uncertainty of success in the bidding process (although PPAs are still negotiated rather than being automatically granted).

Learning points:

- Non-financial barriers such as planning and grid connection, and the co-ordination between these and the financial support scheme, are critical.
- Agreements for both planning and connection should be prerequisites in auction processes to increase certainty of delivery.
- There is a high policy risk around fiscal incentives, and unforeseen interactions between different financial support schemes can create problems.

UK

The UK moved from a tender-based scheme (the NFFO) during the 1990s to an obligation-based scheme from 2002.

The NFFO was considered to have had significant drawbacks, most materially associated with the ad-hoc timing of the auction processes, and the lack of any delivery commitment on auction participants. The latter issue materialised in a very large ‘under-build’ of capacity compared to awarded contracts, as participants competed on price to levels which, in many cases, proved not to be commercially attractive subsequent to the auction. As there was no penalty for non-delivery, a contract awarded in the auction represented a free option. This was compounded as there was no requirement for planning to have been pre-approved, and two thirds was never built.

The Renewables Obligation (RO) was introduced to provide a longer term structure against which investment decisions could be made without the timing uncertainty of auctions, whilst preserving a market-based mechanism.

Learning points:

- Auctions need to be regular and sufficiently frequent.
- Agreements for both planning and connection should be prerequisites in auction processes to increase certainty of delivery.

- Careful consideration needs to be given to delivery obligations for auction participants, and associated penalties.

A.3.6 Conclusions

The following are examples of key considerations in scheme design, across all types, taking account of successful and unsuccessful examples drawn from the schemes we have reviewed.

- There is a complex interplay between the main financial support scheme, secondary support schemes, planning and connection access. Successful support schemes will enable as high a level of co-ordination as possible, and tenders in particular should ensure alignment.
- Consideration must be given as to the uncertainty associated with commodity prices and capital costs, and where the associated risks lie. Without this, governments may be forced to abandon schemes over time (such as the premium-based scheme in the Netherlands, or feed-in tariffs in Denmark).
- Schemes that rely on governments, rather than markets, making allocation decisions and setting prices are prone to ongoing political pressures, and legislation may need to be more detailed and prescriptive to counter this (as is the case in Germany).
- Schemes should be robust over time, and where necessary be adaptable as circumstances change. Where governments set tariffs, they should be able to differentiate between new and existing projects (as in Germany), or such changes will be much harder to implement (as in Spain).
- Consideration should be given in scheme design to facilitating new entry, especially if renewables build may be perceived to be against the strategic interests of the incumbents.
- Incentives for longer term investment in the supply chain should be considered. These are helped by longer term rather than ad-hoc schemes (such as solar in Germany), and by minimising the prospect of political decision-making over the scheme life.
- It is important to understand the impact of balancing costs and their allocation over the lifetime of the scheme, and associated incentives on the parties involved (such as forecast penalties in Spain).
- Recognising the trade-off between lowest cost build and diversity in technologies is important. Obligation-based schemes (such as the RO in the UK) tend to lead to the former, whereas FIT-based schemes (such as Germany) can be used to stimulate the latter. (It is too early to observe the impact of banding proposals on obligation schemes, for example in the UK and Italy.)

A.4 Individual country profiles

A.4.1 Austria

Scheme type:	Feed-in Tariff	A FIT scheme is in place, with tariffs adjusted annually by law. Contracts are available on a first-come first-served basis, against a pre-allocated budget (30% biomass, 30% biogas, 30% wind, 10% PV). Tariffs persist for 12 years. Tariffs for new plant are subject to an annual degressive re-configuration, under the assumption of (and in order to encourage) efficiency gains[76].
Start date:	2003 (amended 2006)	
Duration:	12 years	

Notable features There is a pre-specified RES-E subsidy budget, which was increased in November 2007 to €21m for new build up to 2011, with a fixed pre-allocation to different technologies. Any unused budget is carried forward to the following year and reallocated according to the proportions designated for each technology. After the 12 years of the contract have expired, the plant operator effectively has priority dispatch at the market-clearing price, less plant-specific balancing costs, for a further 12 years.

The subsidies for RES are financed by two mechanisms. The Green Electricity Clearing Agency sells the green electricity to all suppliers, who must purchase it in proportion to their sales volumes at a premium settlement price set by the Energie Control Kommission on a yearly basis. In addition, customers pay an annual fixed fee based on the grid level of the connection point, tending to shift the burden of the subsidy to smaller customers.

Other support mechanisms A heat tariff is also in operation, and there are separate subsidies for medium-scale hydro and CHP.

Effectiveness Installed wind capacity has grown from 139 MW in 2002 to 982 MW in 2007. There has been relatively high growth in biogas, but funds have not been fully utilised for other technologies.

Efficiency For onshore wind, average support appears to have been equal to the average LRMC, however biomass has been over-subsidised.

Strengths The focus on small and medium hydro encourages use of plentiful resource. **Weaknesses** The 12 year compensation period is low compared to other regimes, with the uncertainty about future feed-in levels after 12 years potentially increasing the financing risk.

Local considerations Austria has plentiful hydro resources, and significant hydro capacity already. Its target for RES-E in 2010 is 78.1%. The 2008 targets include 9% of electricity from small hydro and 4% from other green power.

[76] Korab, S., Austria, *International Energy Law & Taxation Review*, 2007, http://www.energylawgroup.eu/downloads/File/Pages%20from%20IELTR07_10_171-227-2.pdf

A.4.2 Belgium

Scheme type:	Obligation	Every supplier has an obligation to buy a certain proportion of green certificates from renewable electricity generators. Targets and fines vary by region. Generators earn green certificates for each MWh produced. All green certificates are exchangeable and are valid for five years. The Federal State is obliged to purchase green certificates from those generators that choose for a fixed price which varies by technology.[77,78]
Start date:	2002	
Duration:	No specified scheme termination date	

Notable features Fines are paid into a Renewable Energy Fund and recycled to subsidise (among other things) new renewable projects. There is no constraint on co-firing of biomass. In November 2003, the Government introduced a supplementary scheme whereby generators can opt for the Government to buy their green certificates at a fixed rate for an agreed period of not more than 10 years, financed by the Energy Fund[79].

In Flanders, the proportion is 6% for 2010, and the fine for each missing certificates was €75 in 2003, €100 in 2004 and €125 in 2005. In Wallonia, the target is 12% by 2012 with a €100 fine.

Other support mechanisms Tax subsidies are available for construction of new plant, and other subsidies for PV.

Effectiveness Installed wind capacity in the whole of Belgium in 2002 was 44 MW. This had grown to 287 MW by 2007.

Efficiency Average support appears to have been greater than the average LRMC, for onshore wind, biomass and biogas.

Strengths The support has been relatively effective for biomass (for which there is no constraint on co-firing). **Weaknesses** The penalty price in the first few years of the scheme was arguably too low[80], resulting in low sales of the certificates. Trading volumes are small and there is little liquidity.

Local considerations In 1997, Belgium had the lowest rate of RES-E generation in the EU-15, at 1%. Biomass has traditionally been strong in Belgium, with hydro power accounting for the second-largest proportion of RES-E.

[77] The fixed prices are €107/MWh for offshore wind (from the first 216 MW of capacity), €90/MWh for offshore wind (from capacity greater than the first 216 MW), €50/MWh for onshore wind, €50/MWh for hydraulic energy, €150/MWh for solar energy, and €20/MWh for other sources. Deltour, B. and Wijnants, C., Belgium, *International Energy Law & Taxation Review*, 2007, http://www.energylawgroup.eu/downloads/File/Pages%20from%20IELTR07_9_127-170-2.pdf

[78] IEA World Energy Outlook, http://www.iea.org/Textbase/pm/?mode=weo&id=986&action=detail

[79] IEA World Energy Outlook, http://www.iea.org/Textbase/pm/?mode=weo&action=detail&id=1256

[80] http://ec.europa.eu/energy/climate_actions/doc/factsheets/2008_res_sheet_belgium_en.pdf

A.4.3 Denmark

Scheme type:	FIT/Tender hybrid	Fixed feed-in tariffs for wind were abolished in 2000/1 and replaced with premiums in 2003. Renewable plant other than wind are still eligible for a full tariff for 20 years. An offshore wind tender was conducted in 2005 for 2×200 MW farms based on a FIT framework (bids based on tariff required).
Start date:	1992	
Duration:	20 years	

Notable features Originally, high tariffs were available up to a certain "full load hour" allowance, then the plant would receive a lower tariff for the rest of the 20 years. These tariffs have been grandfathered.

Other support mechanisms A 1993 Biomass Agreement forced central power stations to burn biomass. Other subsidy schemes and tax incentives have been in operation since the early 1980s. A re-powering scheme has been introduced for onshore wind turbines.

Effectiveness 3.1 GW of wind had been installed by the end of 2007, but only very minor increases have been seen (<1 GW) since 2002. A similar pattern is true of biomass. Effectiveness has decreased considerably since the abolishment of high tariffs.

Efficiency Average support for offshore wind appears to have been equal to the average LRMC, though biomass appears to have been slightly under-subsidised.

Strengths The hybrid set of schemes allows design to be tailored to technology. **Weaknesses** In the past, technology was arguably over-subsidised in general, due to decreasing production costs and high tariffs. Potential issues with auction commitment are indicated, as the initial winners of the Rødsand II offshore wind tender for the farm do not want to build the plant under the current tender conditions.

Local considerations Denmark has access to strong offshore wind resources, and has traditionally had one of the highest proportions of RES-E in Europe.

A.4.4 Finland

Scheme type:	Grants	Energy Aid is available, equivalent to 40% of the investment cost in renewable technologies such as wind and solar.
Start date:	1999	
Duration:	Ongoing	

Notable features Support is aimed towards the capital costs of investment in renewables capacity rather than operational costs.

Other support mechanisms A carbon tax was introduced in 1990, and this is currently 18.05 €/tCO2. Additionally, there is an electricity tax of €0.006/kWh for domestic users and €0.0025/kWh for industry. Peat is exempt from this tax and some renewable technologies receive a rebate (wind receives €69/MWh). Policy is currently under review but a FIT is in place for peat and a tariff for biogas installations <20 MW is to be introduced in 2008.

Effectiveness Renewables (largely hydro) accounted for 28.2% of generation in 2004 compared to 24.7% in 1997. The main source of steady growth is in solid biomass (10.2 TWh in 2004).

Efficiency €30.2m was spent in 2007 (note that this includes expenditure on subsidising Energy Aid as a whole and does not only include renewable energy).

Strengths There is a low subsidy risk for investors. **Weaknesses** The combination of grants and tax rebates, varying by technology, results in a complex set of arrangements.

Local considerations Peat is deemed a renewable technology in Finland.

A.4.5 France

Scheme type:	FIT/Tender	FITs have been the most significant part of the subsidy regime. Tariffs last for varying lengths of time and are set at varying levels, depending on technology. Rates are fixed for first 5-10 years and then reassessed depending on (for example) performance. Tendering has recently been introduced for larger installations, including wind, biomass and biogas facilities.
Start date:	2001	
Duration:	15-20 years	

Notable features Previously, all sites receiving FITs had to have a total capacity of less than 12 MW, but this constraint was recently dropped for wind generators. The FIT for wind is only in place in special wind energy development zones. There is an obligation on suppliers, notably EdF, to buy electricity contracted under these tariffs.

Other support mechanisms There are flexible depreciation structures for renewable technology.

Effectiveness Installed wind capacity has increased from 145 MW in 2002 to 2,454 MW in 2007.

Efficiency For onshore wind, average support appears to have been slightly greater than the average LRMC, but support levels have been below average LRMC for biomass.

Strengths Significant wind generation capacity has been added since the introduction of the tariff.
Weaknesses There is a range of uncertainty around the medium- to longer-term remuneration for generators.

Local considerations France has large hydro resources and a significant proportion of hydro generation. France also has vast resources of wind, geothermal energy and biomass.

A.4.6 Germany

Scheme type:	FIT	Guaranteed 20-year tariffs are available for most types of renewable technology, with the price varying by technology, location and (for wind plant) resource conditions. Tariffs for new projects may be adjusted over time.
Start date:	2000	
Duration:	15-20 years	

Notable features The compensation available to generators is inversely proportional to wind resources, avoiding rents. The resource level is established over the first five years of operation, with the tariff then established based on the average achieved capacity factor. Wind plant that cannot achieve 60% of the reference yield at the planned location will lose their tariff, encouraging repowering. The legal framework drafted by Parliament is very detailed, to counter possible influence from dominant players and provide greater certainty as to future government decisions.

Other support mechanisms Soft loans had been previously available for wind developers.

Effectiveness Total installed wind capacity has grown from 4 GW in 1998 to 17 GW in 2004 and 22 GW in 2007. Germany is also the EU leader in PV solar development, despite poor resources.

Efficiency Average support appears to have been equal to the average LRMC for onshore wind, although support levels appear to have been high for biomass. By promoting emerging technologies, such as PV, the overall costs of delivering renewables is increased (at least in the near term).

Strengths The scheme has benefited from high investment security and low administrative and regulatory barriers. RES-E generators also benefit from priority grid access. New entry has been encouraged through access to long term guarantees independent of incumbents. Because of the high degree of differentiation in the tariffs, there is also low potential for rents. The ability to adjust tariffs for new projects whilst leaving existing projects unaffected makes it easier to adapt to changing circumstances. (A current review is likely to reduce PV support following decreased costs and high deployment.)

Weaknesses The scheme is prescriptive in determining a price for each eligible technology. It is sometimes argued that this may dampen incentives for longer term innovation. Priority grid access complicates system operation; changes to allow the system operator to spill wind and compensate plants are being discussed.

Local considerations Wind has reached a level in Northern Germany at which grid capacity is a development constraint[81]. Grid expansion studies have demonstrated the need to spill some wind to provide the most cost effective overall solution. Given the weaker resource base, wind achieves a relatively low average load factor compared to other countries such as Ireland, hence increasing the overall cost of renewables in the near term.

[81] Ragwitz, M., Held, A., Resch, G., Faber, T., Huber, C. and Haas, R. Monitoring and evaluation of policy instruments to support renewable electricity in EU Member States, 2006.

A.4.7 Republic of Ireland (AER)

Scheme type:	Tender	The Alternative Energy Requirement (AER) scheme invited competitive bids for installing renewable generation capacity. The target for each 'round' was split down by technology type and PPA support. It was then available for up to 15 years for successful bidders. A price cap was also set for each technology category.
Start date:	1996	
Duration:	2005	

Notable features The AER programme was funded through a 'Public Service Obligation' (PSO) levy on electricity bills.

Other support mechanisms A tax incentive for capital allowances was available until 2002. As the retail market was opened up, access to smaller customers was initially restricted to 'green' suppliers, creating a route to market for wind developers on a non-subsidised basis. Of capacity installed in 2004, 61% was as a result of this mechanism.

Effectiveness New renewables build did take place as a result of each round of bids. However, many successful bids have not subsequently been built. For example, in the final two rounds, AER V and AER VI, a total of 724 MW was successful but only 277 MW has been built or is under construction from these rounds.

Efficiency In 2004 PSO payments for renewables totalled €16m, equating to about €10/MWh.

Strengths Competitive bidding resulted in lower costs. **Weaknesses** Connection agreements were not a pre-condition and so many projects that were approved have not been built. There was very little inclusion of biomass, despite high potential in Ireland.

Local considerations There is significant potential for wind and biomass in Ireland. However, the small size of the market may reduce the extent to which intermittent generation is able to displace conventional generators.

A.4.8 Republic of Ireland (REFIT)

Scheme type:	Feed-in Tariff	Reference prices are set by technology and these set the REFIT compensation that is paid to electricity suppliers. The aim of this is to incentivise suppliers to sign beneficial PPAs with renewable generators.
Start date:	2006	
Duration:	Ongoing	

Notable features Unlike most FIT schemes, PPAs are not directly awarded to generators. Instead, direct support is granted to suppliers by guaranteeing a subsidy payment for each unit of output purchased from renewables generators above a base price level. Generators must still negotiate their own PPAs with suppliers.

Other support mechanisms Capital grants totalling €65m are available over the period 2006-10 to technologies including biofuels and CHP, but these are mostly aimed at the heat sector. A subsidy is also available for the use of agricultural land for energy crops.

Effectiveness Support awarded to >600 MW of new capacity since launch of new scheme.

Efficiency No significant reimbursement under REFIT to date. However, for most large scale onshore wind developments suppliers would expect to receive €8.55/MWh.

Strengths Applicants must show evidence of full planning permission, a firm connection offer, and evidence of access to a fuel supply where relevant. **Weaknesses** There was initially no rate for offshore wind, but a price of €140/MWh was announced in 2008.

A.4.9 Italy

Scheme type:	Obligation	An obligation on generators and importers of electricity, which increases by 0.75% p.a. (3.8% in 2008), with a cap and floor for the certificate price. Commitment increased from 12 years to 15 years from 2008. Banding has also been introduced from 2008[82].
Start date:	1999	
Duration:	15 years	

Notable features The buy-out price is determined annually as the difference between a fixed all-in price (€180/MWh) and the prior year's average wholesale price. Green Certificate prices averaged 116 €/MWh in 2007 and €144/MWh in 2006[83]. In a year of oversupply, the excess certificates would be guaranteed by GSE (Gestore Servizi Elettrici, the certificate issuing body and independent system operator) at a price equal to the prior year's average price on GME (Gestore Mercato Elettrico, the market operator).

Other support mechanisms The obligation does not include PV, which is subject to a separate FIT scheme (c. 40/45 €ct/kWh, guaranteed for 20 years, with the price for new entrants reduced by 2% p.a. in real terms). Prior to the obligation being enacted, the CIP6 regime granted generators with an offtake price that was funded through a levy on retail electricity prices.

Effectiveness RES-E capacity (excluding large hydro) increased by 1874 MW in 5 years, from 4226 MW in 2001 to 6100 MW in 2006 (736 MW of new wind, 560 MW of biomass, biogas and waste, and 367 MW of small hydro[84]). Generation by renewable technologies (excluding hydro) in 2005 accounted for 4.6% of total supply against an obligation in that year of 2.7% (note that the obligation is a % of conventional energy produced or imported).

Efficiency The support level available for wind generation is significantly above the average level of LRMC.

Strengths The nature of the buy-out price calculation arguably reduces investor risk by offsetting electricity and certificate price exposure; in years when the electricity price is high, the buy-out price will be lower, and vice versa. **Weaknesses** The number of changes since the scheme replaced the previous FIT regime in 1999 has led to a high level of policy uncertainty.

Local considerations Authorisation procedures are complex, and grid connection costs are high.

[82] "Green Certificates regime as amended by Budget Law 2008"; Watson, Farley, and Williams, January 2008

[83] Source: GME website

[84] Hydro less than 10 MW.

A.4.10 Netherlands 1 - Fiscal

Scheme type:	Fiscal	The Netherlands introduced an energy consumption tax (>8 €ct/kWh in 2002) for small- and medium-sized energy users. Electricity for renewable sources was exempted.
Start date:	1996	
Duration:	Phased out 2002-2005	

Notable features The Netherlands was unusual in stimulating the green electricity market through incentives on customers.

Other support mechanisms Later replaced by a premium FIT: see below.

Effectiveness 'Green' electricity consumers increased to about 40%. However, new renewables capacity in the Netherlands was limited.

Efficiency The scheme failed to generate material new investment in installed capacity.

Strengths The scheme increased demand for electricity from renewable sources greatly by increasing the incentive to end users, and stimulated new entry in green energy supply. **Weaknesses** Most of the demand was met by cross border transfers (resulting in cross-border congestion), and very little additional renewable capacity was built as a result.

Local considerations The country is heavily populated and heavily built up, meaning that offshore wind may be key in meeting RES-E targets.[85]

[85] IEA Wind Energy 2006 Annual Report, http://www.ieawind.org/annual_reports.html

A.4.11 Netherlands II - FIT

Scheme type:	Feed-in Tariff	Fixed premium paid on top of market price; premium calculated annually.
Start date:	2003	
Duration:	Stopped in 2006	

Notable features The tariff was calculated each year based on calculations of the financial viability of typical wind projects.

Other support mechanisms Other fiscal incentives also exist in the Netherlands, including: a preferential rate of lending to generators through "Green Funds"; tax exemptions on dividends from investments in renewable generators up to c. €52k, and 100% first year capital allowances.

Effectiveness Growth of wind and biomass largely drove an increase in share of renewable electricity from 3.3% in 2003 to 6% in 2005. Wind, hydro, solar PV, and wood waste generation totalled 1,127 MW in 2003, increasing to 1,655 MW in 2005.

Efficiency Average support appears to have been below the average LRMC for wind.

Strengths Succeeded in attracting new investors to renewable generation. **Weaknesses** Only considers the supply side of the equation, with no cap on costs. Initially, a large deficit in funding the support mechanism resulted from higher than expected levels of uptake. However, expenditure was later capped at €700m p.a.

A.4.12 Poland

Scheme type:	Obligation	Tradable Green Certificates are issued to generators for new renewable capacity for each MWh of output. The obligation reaches 10.4% by 2010 with a substitution fee of PLN242/MWh in 2007.
Start date:	2005	
Duration:	Ongoing	

Notable features The scheme has both a 'substitution' fee and a fine, set at 130% of the certificate value, which is imposed if distributors neither purchase certificates nor pay the substitution fee.

Other support mechanisms Soft loans are available from the Environmental Fund (largely funded by substitution fee proceeds).

Effectiveness Increasing volumes of wind capacity are being planned although actual generation from wind in 2005 was only 135 GWh.

Efficiency The average support received by generators is above the average LRMC for wind generation.

Strengths Market based mechanism with transparent trading on PolPX, the Polish Power Exchange.
Weaknesses Use of substitution fee is not transparent. Obligation level does not increase beyond 2010.

Local considerations Much of the potential for wind generation in Poland is in the north of the country where the transmission network will need significant investment.

A.4.13 Spain

Scheme type:	FIT	Generators can choose between a fixed tariff or a market price premium. These tariffs are uniform by technology type and are not vintaged.
Start date:	2004	
Duration:	Open-ended	

Notable features The market premium option is now subject to a cap and floor. Market participants must choose which option they will take for no less than one year at a time. The original 1997 law guaranteed earnings for a decade, while the 2007 law guarantees the tariff received for the operating lifetime of the plant. Wind generators are incentivised to provide accurate forecasts through a fixed penalty for deviations from their announced schedule.

Other support mechanisms Soft loans, tax incentives and regional investment incentives are available.

Effectiveness There has been strong growth in wind capacity. Installed wind capacity has grown from around 1 GW in 1997 to 7.5 GW in 2004 and 15 GW in 2007. There has also been strong growth in small hydro, but relatively less growth for other technologies.

Efficiency Average support appears to have been approximately 50% above the average LRMC for onshore wind generation, and significantly higher than the LRMC for biomass.

Strengths The subsidy now lasts for the entire lifetime of plant, reducing risk, however this has the potential to lead to dramatic over-subsidisation. The forecasting incentive has led to investment in sophisticated forecasting tools. **Weaknesses** Wind generators have reaped large profits on the premium scheme due to large increases in the wholesale prices. A price cap has since reduced the scope for this to be repeated. The option to choose enables generators to take advantage of high wholesale prices whilst avoiding the downside risk, opening the government to a problem of adverse selection. The lack of vintaging exposes investors to some subsidy risk, thus constraining policy makers from making significant adjustments to the support levels.

Local considerations Spain benefits from good wind resources and relatively low investment costs relative to the rest of Europe. There are administrative barriers to new hydro[86]. The planning process provides flexibility for new wind. Spain's significant existing hydro resources are beneficial in maintaining system stability and security as wind capacity grows.

[86] Spanish Renewable Energy Association (Co-ordinator: Manuel Bustos), The New Payment Mechanism Of Res-E In Spain: Introductory Report, 2004, http://www.wind-works.org/FeedLaws/Spain/Report%20on%20the%20new%20Spanish%20RES-E%20payment%20mechanism.pdf

A.4.14 Sweden

Scheme type:	Obligation	Electricity suppliers (and some large users) must supply a target proportion of their power from renewable sources, and are required to pay a penalty price where this is not met.
Start date:	May 2003	
Duration:	Until 2030	

Notable features The penalty price is calculated as 150% of the volume-weighted certificate price from the previous year, but cannot exceed SEK200/MWh up to 2008. The Swedish Energy Agency (SEA) can redeem generators' unsold certificates for a guaranteed price, starting from SEK60/MWh in 2003, although this floor price will decrease to zero over subsequent years. Market prices for certificates have been much higher than these guaranteed prices, however, resulting in very little or no requirement for the SEA to have purchased unsold certificates.

Other support mechanisms An environmental premium for wind power, granted to electricity generators through tax subsidies, has been in operation but will be phased out from 2009. Municipalities and other entities may apply to the Climate Investment Programme for subsidies for (among other technologies) CHP, biogas and energy efficiency measures.

Effectiveness Output from renewables in the scheme increased from 2 TWh in 2002 to 5.7 TWh in 2006, with installed wind capacity growing from 322 MW in 2002 to 788 MW in 2007.

Efficiency Average support appears to have been equal to the average LRMC for onshore wind, but slightly lower than the average LRMC for biomass.

Strengths Transparent long term targets (to 2030) have been set by legislation. **Weaknesses** There were low expected profits for investors in the early years, with most suppliers opting to pay the (capped) penalty price. There is no technology differentiation; the cheapest option for deployment of renewable energy has so far been to switch to biomass, instead of developing new plant.

Local considerations The resource base in Sweden for both wind and biomass is extremely good, facilitating investment. Renewables currently cover approximately 50% of the Swedish total electricity consumption, mainly from hydro (which is not included in the obligation scheme).

A.4.15 United Kingdom I - NFFO

Scheme type:	Tender	The Non-Fossil Fuel Obligation (NFFO) was a competitive tender process for renewable capacity, with Public Electricity Suppliers obliged to buy the resulting electricity. Costs above the wholesale price were recovered from customers through the Fossil Fuel Levy.
Start date:	1990	
Duration:	Until 1999	

Notable features Auction rounds had prescribed capacity levels by technology.

Effectiveness The five NFFO rounds resulted in about 1.2 GW of renewables build in the course of a decade.

Efficiency The NFFO scheme resulted in a cost of approximately £714m[87] over the decade. The cost associated with NFFO (based upon output from winning bids) was funded through the Fossil Fuel Levy, a tax on electricity supplies through the use of non-renewable technologies. With total output at 23,760 GWh over this time period, the average subsidy was £30.05/MWh.

Strengths Competitive bidding costs led to lower costs with bid prices reducing between subsequent rounds of NFFO. **Weaknesses** Tenders were held infrequently, and on an ad-hoc basis, making planning for developers difficult. No delivery obligations for those entering the auctions encouraged bidders to bid too low; this is reflected by 2.4 GW of capacity that was contracted, but never built.

[87] Source: Evaluation of DTI Support for New and Renewable Energy under NFFO and the Supporting Programme, December 2001

A.4.16 United Kingdom II - Current RO

Scheme type:	Obligation	Electricity suppliers are obliged to supply a specific proportion of RES-E which rises annually. Renewable Obligation Certificates (ROCs) are issued for each MWh of qualifying RES-E generated. Suppliers must buy ROCs to meet their obligation or pay a buy-out price.
Start date:	1 April 2002	
Duration:	Until 2027	

Notable features The buy-out fund is recycled to the holders of the ROCs so that prices rise if there is a shortfall of renewables generation relative to the target.

Effectiveness Renewables generation has increased significantly, with 1195 MW (of which 842 MW is on-shore wind) added in the last 2 years[88]. The renewables generation under the obligation in the 2006-7 RO year totalled 14,613 GWh compared to an obligation of 21,630 GWh. Installed capacity in the UK totalled 6.3 GW[89] by the end of 2006, with 3.7 GW[90] being covered by the RO by April of the following year. There is over 11 GW of capacity in the planning pipeline.

Efficiency (from EU report) Average support appears to have been approximately twice the average LRMC for onshore wind, and has resulted in significant rents for landfill gas.

Strengths The RO provides a market-based mechanism which runs alongside existing wholesale market. This has been effective at promoting lower cost renewables such as biomass co-firing (which involves little investment cost), landfill gas and onshore wind. **Weaknesses** The cost to consumers has been high for the amount of renewables delivered. The size of the subsidy is the same despite planning and connection access issues constraining the amount of renewables built.

Local considerations The planning process and connection access have been a significant constraint on new build. Developers have difficulties in signing long term power agreements for power and ROCs.

[88] Source: Ofgem ROC reports for 2005-6 and 2006-7

[89] Source: DUKES 2007, includes hydroelectric capacity of 4.2 GW

[90] Source: Ofgem ROC report for 2006-7, includes co-fired capacity of 0.8 GW

A.4.17 United States: California

Scheme type:	Obligation (non-tradable)	California has a Renewables Portfolio Standard: a legislative mandate to increase the percentage of renewable retail sales by at least 1% per year to reach at least 20% by end of 2010, with a goal of 33% by end of 2020. This is achieved through a surcharge on retail electricity bills to support tenders for existing, new and emerging renewables projects.
Start date:	1998 & 2002	
Duration:	2010 (to be extended)	

Notable features Some flexibility in carrying forward supplier deficits (up to 3 years) but no trading. If obligation is not met there is a 5 ct/kWh penalty.

Other support mechanisms A variety of fiscal incentives is also available.

Effectiveness While amount of renewables has increased since the start of the RPS, so has demand, leaving the proportion of renewables at c.11% (plus 19% large-scale hydro). 2010 targets are likely to be missed but a new policy framework is required to meet 2020 targets.

Efficiency Between 2002 and 2006 the Public Benefits Fund raised $135m per year through the surcharge. (This only relates to the element of the fund spent on renewables - the fund also has elements relating to energy efficiency and R&D.) This is expected to increase to $150 m per year from 2007 to 2011.

Strengths There has been strong political commitment, and the schemes have proved successful in bringing forward a number of renewable technologies (e.g. solar and wind). **Weaknesses** Cumbersome and opaque contracting processes have led to calls for introduction of a FIT (which, as of February 2008, has been introduced for generators up to 1.5 MW), whilst lack of market signals to meet RPS efficiently have lead to calls for introduction of tradable renewable energy certificates.

Local considerations Lack of transmission capacity between areas rich in renewable resource and load centres remains a major constraint on renewable growth. Projects also face permitting obstacles. There are abundant solar and wind resources.

A.4.18 United States: Connecticut

Scheme type:	Obligation	Connecticut's Renewables Portfolio Standard (RPS) statutes require that a specific percentage of the generation provided to Connecticut consumers be produced from renewable sources, with a target increasing to 2020. Obligations may be met through purchases of certificates, or cashing out at $55/MWh.
Start date:	1998 (amended since)	
Duration:	2020	

Notable features Credits are tradable with New York, Pennsylvania, New Jersey, Maryland, and Delaware. For 2007, the RPS is 7.5%, increasing to 14% by 2010, 19.5% by 2015 and 27% by 2020. The contribution that can be made by biomass, other than that defined as "new sustainable biomass", is limited to 3% of the 27% target.

Other support mechanisms Legislation passed in 2003 requires two major utilities to enter into long-term power purchase agreements with developers to purchase a minimum of 100 MW of local renewable energy.

Effectiveness To date, the requirement has largely been met by existing hydro, and biomass.

Efficiency The state Clean Energy Fund (the equivalent of California's Public Benefits Fund) raises c. $20m each year through a surcharge to customers of $0.001/kWh and the 'buyout' of $0.055/kWh associated with the RPS.

Strengths Year-by-year targets set out a clear path to 2020. **Weaknesses** It is difficult for renewable developers to obtain long term contracts. Attempts to favour projects with 'in-state-benefits' (e.g. reducing congestion) create 'free-rider' problems and reduce liquidity of the certificate market. Since trading with other states has been introduced, much of the RPS has been met through imports. The extent to which existing biomass generators are eligible under the RPS has changed, creating significant REC price fluctuations, including a drop from $35 to $5 in summer 2005.

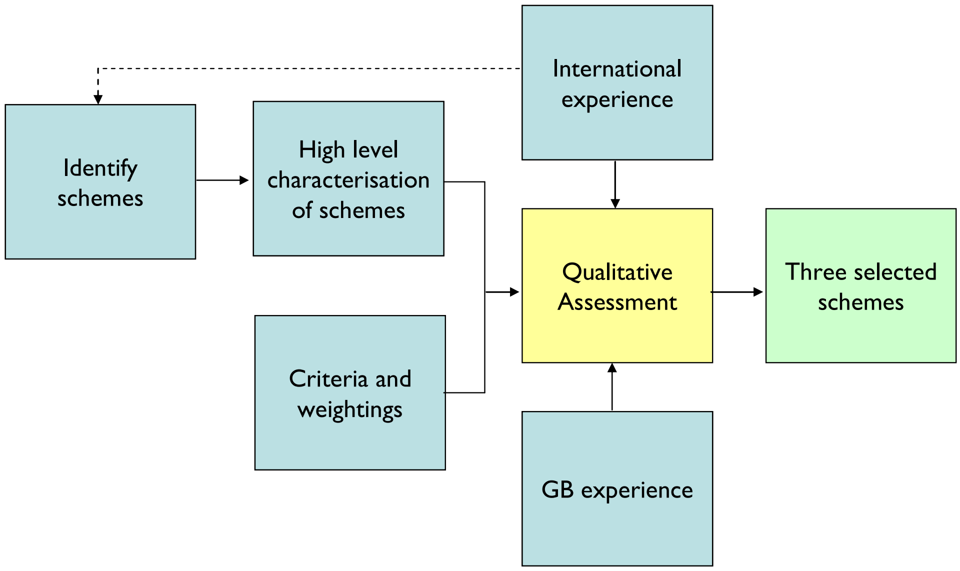
Local considerations Neighbouring states have better renewable resources and it is easier to permit projects (and get long term contracts), leading to suggestions that money should be spent on transmission to import clean energy from, for example, Canada.

B Qualitative assessment

B.1 Approach

A more detailed view of the approach used for the qualitative assessment of different schemes is shown in Figure 55.

Figure 55 Approach to qualitative assessment



A 'long list' of fifteen potential schemes was identified by drawing both on renewables policy experience internationally, and other analogous policy mechanisms for tackling externalities. For each one, the main characteristics of the scheme were specified. These schemes were separated into 'pure' schemes and variants and hybrids.

To perform a systematic qualitative assessment, a range of criteria were agreed with BERR against which each would be scored. A weighting system was then used to create an overall ranking. We recognised that the weightings to be applied could in themselves reflect different views or assumptions about the market, and we explicitly recognised this by defining different weighting sets and reviewing the ranking against each. Rankings were produced separately for the seven pure schemes and for the complete set of fifteen including hybrids and variants.

From this process, three schemes were selected for detailed design and quantitative assessment.

B.2 Scoring criteria

The schemes were evaluated against a range of key criteria, described at a high level in Section 4.2. For the evaluation, a more granular list of criteria was used, from which ten groups were identified. The sub-criteria within each group were weighted to reflect their relative importance within the group. Weightings are shown in Table 25.

Table 25 Scoring criteria

Criteria group	Scoring criterion	Weighting within group
Minimising resource costs (financing costs)	Policy risk (changing framework)	1
	Subsidy risk	1
	Wholesale electricity price risk	1
	Complexity risk	0.25
Minimising resouce costs (asset costs)	Policy uncertainty and credibility for supply chain	0.5
	Cost for technology portfolio	1
	Deadweight cost (lack of marginal renewable price)	0.5
Minimising excess economic rents	Risk of parameters misspecified	0.5
	Infra-marginal rents	1
Ensuring dispatch efficiency	Operational risk	0.5
	Efficient dispatch	1
Robustness to uncertainty	Precision of meeting target	0.5
	Cost of responding if target missed	1
	Resillience for investors to outside changes (eg GDP, fuel , investment costs)	1
	Resillience for investors to market arrangements changes (eg balancing markets)	1
	Alignment with (non-market) grid/planning decisions	2
	Responsiveness to uncertainty of Severn Barrage	0.25
Avoiding unintended consequences	Risk of unintended consequences (e.g. impact on renewables in the heat sector)	1.5
	Impact on other low carbon technologies (eg nuclear, CCS)	1.5
	Impact on ability to optimise market design for large shares of renewables	1
	Interaction with Ireland	0.25
Minimising the negative effects of transition	Risk of leading to hiatus in renewables investment prior to its implementation	1.5
	Lead time for implementation	1.5
	Compatibility with the current RO scheme	1
	Compatibility with existing Government energy markets policy and instruments	1
	Impact on competition in the wholesale market	1
Promoting wider benefits	Promoting new technologies (and incentivising R&D)	1
	Opening options post 2020	1
Ensuring international consistency	Consistency with international best practice/transparency for international investors	1
	Ability/need to coordinate with other countries	1
	Likely level of infrastructure investment in UK versus overseas	1
Compatibility with existing market arrangements	Enables investor response to market signals	1
	Compatibility with renewable heat mechanism(s)	1
	Interaction with demand efficiency measures	1
	Compatibility with installation based guarantee of origin trading	1

B.3 Scoring results

Each of the schemes listed in Section 4.4 was then scored against the full criteria list using a simple 0/1/2 scheme (with 0 indicating a poor score and 2 a good one). The scores we used are shown in Table 26.

Table 26 Scheme scores

Criteria group	Scoring criterion	Non-banded RO	Standard FIT	Tenders	Contracts for Difference	Non-renewable levy	Grants	Non-renewable allowances	Extended RO	RO/FIT hybrid	GOO-compatible RO	Premium FIT	Availability linked FIT	FIT/Tender hybrid	NRA/FIT hybrid	RO/FIT premium choice
Minimising resource costs (financing costs)	Policy risk (changing framework)	0	2	2	2	1	1	0	1	0	1	2	2	2	0	1
	Subsidy risk	1	2	2	2	1	2	0	0	1	0	2	2	2	0	2
	Wholesale electricity price risk	0	2	2	2	0	0	0	0	0	0	0	2	2	0	0
	Complexity risk	2	2	1	1	2	1	2	1	1	1	1	1	1	1	1
Minimising resouce costs (asset costs)	Policy uncertainty and credibility for supply chain	1	1	1	1	0	1	0	1	1	1	1	1	1	0	1
	Cost for technology portfolio	2	0	0	0	2	0	2	0	0	2	0	0	0	0	0
	Deadweight cost (lack of marginal renewable price)	0	0	0	0	2	0	2	0	0	0	0	0	0	0	0
Minimising excess economic rents	Risk of parameters misspecified	1	1	1	1	0	1	2	0	1	1	1	1	1	1	0
	Infra-marginal rents	0	2	2	2	0	1	0	1	1	0	1	2	2	1	1
Ensuring dispatch efficiency	Operational risk	2	2	2	2	2	1	2	2	2	2	2	2	2	2	2
	Efficient dispatch	0	0	0	0	0	2	0	0	1	0	0	2	2	1	0
Robustness to uncertainty	Precision of meeting target	2	2	2	2	0	1	1	1	2	2	1	2	2	2	1
	Cost of responding if target missed	0	2	2	2	0	1	0	0	1	0	2	2	2	0	0
	Resillience for investors to outside changes (eg GDP, fuel , investment costs)	1	2	2	2	0	0	1	1	1	1	1	2	2	0	1
	Resillience for investors to market arrangements changes (eg balancing markets)	0	1	1	0	0	0	0	0	1	0	0	2	2	0	0
	Alignment with (non-market) grid/planning decisions	0	1	2	1	0	0	0	0	0	0	1	1	2	0	0
	Responsiveness to uncertainty of Severn Barrage	0	2	2	2	0	1	1	0	1	0	1	2	2	0	0
Avoiding unintended consequences	Risk of unintended consequences (e.g. impact on renewables in the heat sector)	1	1	1	1	1	1	1	0	1	1	0	2	1	1	0
	Impact on other low carbon technologies (eg nuclear, CCS)	0	0	0	0	0	1	0	0	1	0	0	1	2	0	0
	Impact on ability to optimise market design for large shares of renewables	0	1	2	0	1	1	1	0	1	0	0	1	2	1	0
	Interaction with Ireland	0	2	1	1	1	1	0	0	1	0	1	1	1	0	0
Minimising the negative effects of transition	Risk of leading to hiatus in renewables investment prior to its implementation	1	0	0	0	0	0	0	2	1	1	0	0	0	0	2
	Lead time for implementation	2	0	0	0	0	1	1	2	1	2	0	0	0	0	1
	Compatibility with the current RO scheme	2	0	0	0	0	0	1	2	2	2	0	0	0	0	2
	Compatibility with existing Government energy markets policy and instruments	2	0	1	1	0	0	2	2	2	2	1	1	1	0	1
	Impact on competition in the wholesale market	2	0	0	1	2	2	2	2	2	2	1	1	1	2	2
Promoting wider benefits	Promoting new technologies (and incentivising R&D)	0	2	2	2	0	2	0	1	2	0	2	2	2	2	1
	Opening options post 2020	0	2	2	2	0	2	0	1	1	0	2	2	2	2	1
Ensuring international consistency	Consistency with international best practice/transparency for international investors	1	2	1	0	0	0	0	0	1	1	1	1	1	0	0
	Ability/need to coordinate with other countries	0	1	1	0	0	0	0	0	1	2	1	1	1	0	0
	Likely level of infrastructure investment in UK versus overseas	2	1	1	1	1	1	1	2	1	2	1	1	1	1	2
Compatibility with existing market arrangements	Enables investor response to market signals	2	0	1	1	2	1	2	1	1	2	1	0	0	1	1
	Compatibility with renewable heat mechanism(s)	1	1	0	1	1	0	1	1	1	1	1	1	1	1	1
	Interaction with demand efficiency measures	1	0	0	0	1	0	2	0	0	1	0	0	0	1	0
	Compatibility with installation based guarantee of origin trading	1	0	0	0	2	0	2	1	0	2	0	0	0	0	0

B.4 Capturing different perspectives

It is clear that different political and economic perspectives will influence views on the qualitative assessment of schemes against criteria. To illustrate the impact on scheme ranking, we created four different weighting 'sets' designed broadly to reflect a range of different standpoints. These were characterised as:

- **Minimising investor risk**: Overall subsidy level can be minimised through targeting subsidies by technology and offering investors price certainty thus reducing their cost of capital.
- **Co-ordination**: Scale of change needed is such that a centrally co-ordinated approach to planning, grid expansion and technology build is required.

- **Trading philosophy**: Market signals used as broadly as possible, with a focus on country and sector trading, and energy efficiency measures, to meet overall renewable energy target.
- **Minimising change**: Retaining consistency with current Banded RO proposals is the highest priority.

These were translated into weighting sets at the criteria group level as shown in Table 27.

Table 27 Weighting sets

Weighting set	Minimising investor risk	Co-ordination	Trading philosophy	Minimising change
Minimising resource costs (financing costs)	4.00	4.00	0.25	0.50
Minimising resource costs (asset costs)	0.50	0.50	2.00	0.50
Minimising excess economic rents	4.00	6.00	0.17	1.00
Ensuring dispatch efficiency	2.00	2.00	2.00	0.50
Robustness to uncertainty	1.00	4.00	0.25	0.25
Avoiding unintended consequences	1.00	1.00	1.00	1.00
Minimising the negative effects of transition	0.50	0.17	2.00	6.00
Promoting wider benefits	2.00	2.00	0.50	2.00
Ensuring international consistency	1.00	1.00	1.00	1.00
Compatibility with existing market arrangements	0.50	0.50	4.00	2.00

B.5 Ranking

Based on the scores and the weighting sets, the schemes were then ranked. Table 28 shows the top three ranked 'pure' schemes and the top three from all schemes for each of the weighting sets.

Table 28 Scheme rankings

Belief Set	Rank	Pure Schemes	All schemes
Minimising investor risk	1	Standard FIT	FIT/Tender hybrid
	2	Tender	Availability linked FIT
	3	Contracts for Differences	Standard FIT
Co-ordination	1	Tender	FIT/Tender hybrid
	2	Standard FIT	Availability linked FIT
	3	Contracts for Differences	Tender
Trading philosophy	1	Non-renewable allowances	GOO-compatible RO
	2	Current RO	Non-renewable allowances
	3	Non-renewable levy	Current RO
Minimising change	1	Current RO	Extended RO
	2	Non-renewable allowances	RO/FIT hybrid
	3	Grants	GOO-compatible RO

C Input assumptions

C.1 Demand

Figure 56 GB annual demand[91]

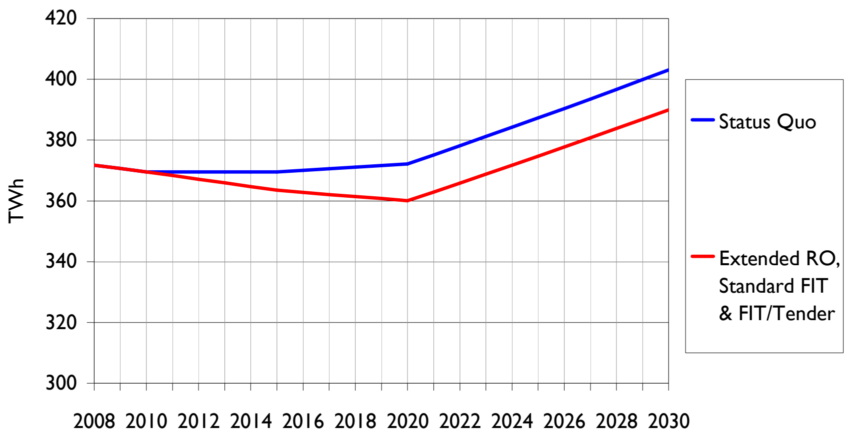
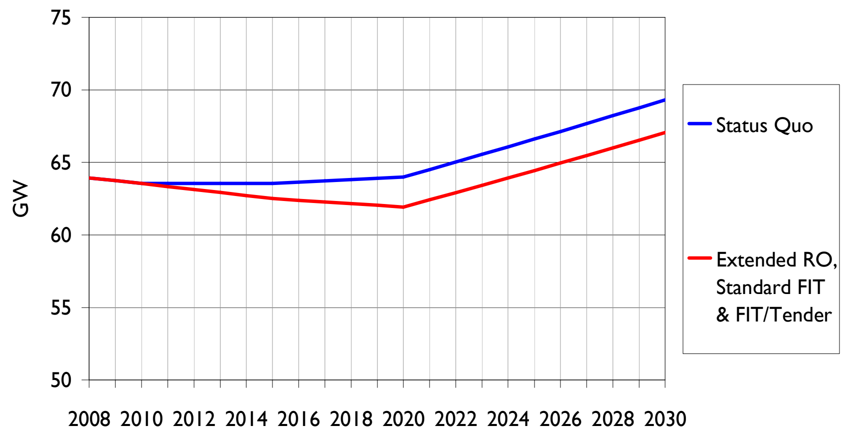


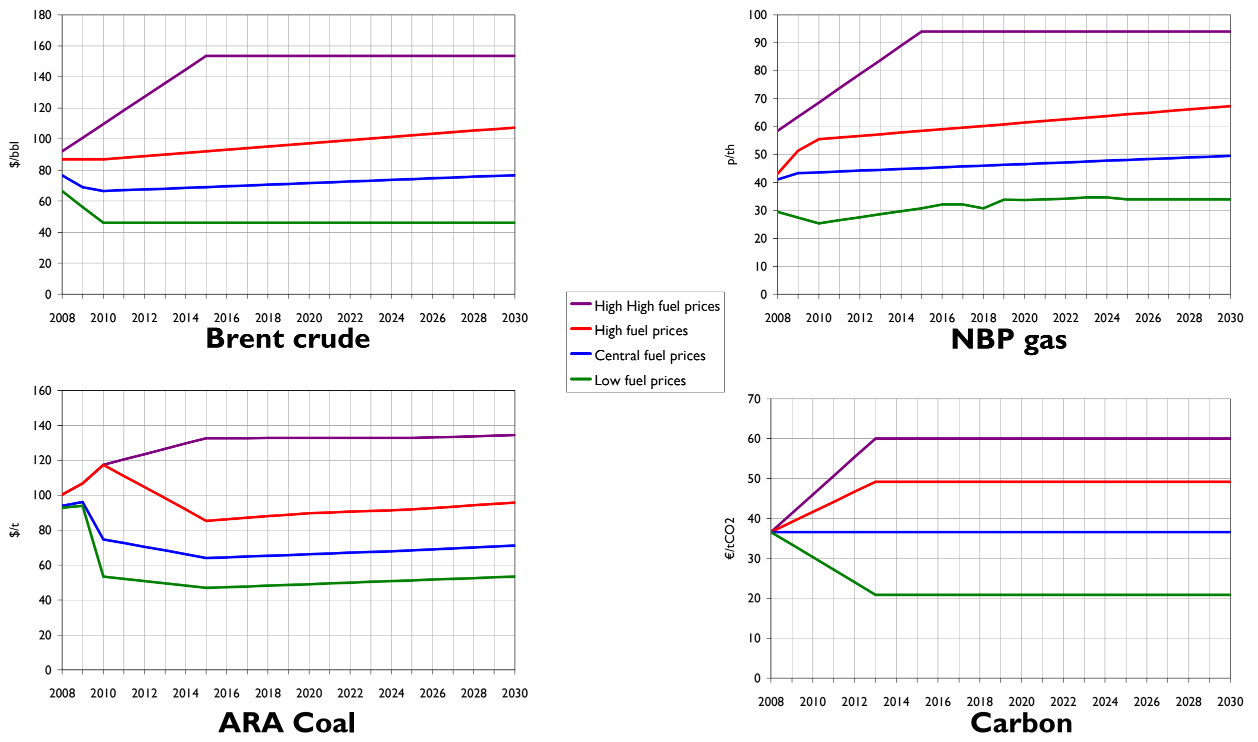
Figure 57 GB peak demand



[91] Source: BERR

C.2 Fuel and carbon prices

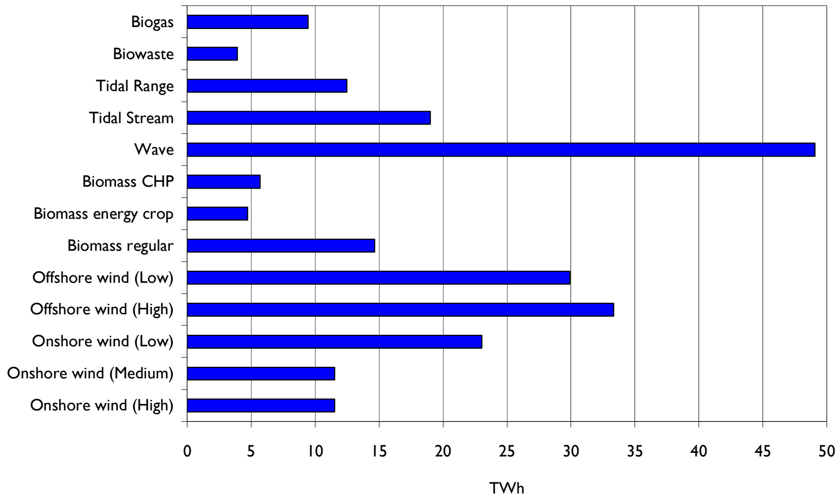
Figure 58 Fuel[12] and carbon prices[92]



[92] Source: BERR

C.3 Renewables resource availability

Figure 59 Renewables resource availability in 2020[93]



C.4 Renewables plant capital costs

Renewables plant capital costs are derived within the model as a function of the following three factors:

- Baseline capital cost in 2008.
- A technology-specific global learning effect leading to reductions in the baseline capital costs over time; the scope of the learning curve effect is greater for emerging technologies.
- A supply curve function which reflects the likely range in capital costs between 2008 and 2020; the most accessible (and cheapest) sites would be exploited first, with the costs progressively increasing to reflect higher project costs and the costs of additional grid reinforcements.

The combination of these factors means that in cases with low renewables penetration, such as the Status Quo, the capital costs of renewables projects tend to fall over time. Conversely, in the high target cases the cost for certain technologies rise.

The baseline capital costs for renewables plant are shown in Table 29. These costs include:

- Technical – the cost of the plant e.g. turbine
- Civils – site and construction costs
- Connection – costs to connect the project to the grid
- Planning costs.

[93] Derived by Redpoint from the Green-X[13] and Pöyry[14] studies

The figures for 2010 are based on Pöyry's study of the compliance costs of meeting the 20% renewables target[94]. The reductions in renewables costs between 2010 and 2020, assumed in the Pöyry study, have been halved in recognition that the strong demand for renewables technologies resulting from the EU2020 targets is likely to offset, at least partially, the learning curve effects.

Table 29 Renewables plant baseline capital costs

£/kW (real 2008)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind (High)	1111	1111	1111	1096	1081	1065	1050	1034	1019	1004	988	973	957
Onshore wind (Medium)	1111	1111	1111	1096	1081	1065	1050	1034	1019	1004	988	973	957
Onshore wind (Low)	1111	1111	1111	1096	1081	1065	1050	1034	1019	1004	988	973	957
Offshore wind (High)	1574	1574	1574	1553	1531	1510	1488	1467	1445	1424	1403	1381	1360
Offshore wind (Low)	1574	1574	1574	1553	1531	1510	1488	1467	1445	1424	1403	1381	1360
Biomass regular	1837	1837	1837	1831	1826	1820	1814	1809	1803	1797	1792	1786	1780
Biomass energy crop	1837	1837	1837	1831	1826	1820	1814	1809	1803	1797	1792	1786	1780
Biomass CHP	2552	2552	2552	2544	2536	2528	2520	2512	2504	2496	2488	2481	2473
Wave	2807	2807	2807	2793	2779	2764	2750	2735	2721	2706	2692	2678	2663
Tidal Stream	3062	3062	3062	3045	3027	3010	2993	2976	2958	2941	2924	2907	2889
Tidal Range	2480	2480	2480	2466	2452	2438	2424	2410	2396	2382	2368	2354	2340
Biowaste	3829	3829	3829	3825	3822	3818	3814	3810	3806	3802	3798	3794	3790
Biogas	6741	6741	6741	6735	6729	6722	6716	6710	6704	6698	6691	6685	6679

The supply curves are represented by five equal sized tranches of capacity. Table 30 shows how the baseline capital costs are scaled in each year dependent on the capacity of each technology built (or under construction) to that point.

[94] Pöyry, Compliance costs for meeting the 20% renewable energy target in 2020, 2008. http://www.berr.gov.uk/files/file45238.pdf

Table 30 Supply curve scaling factors

	1	2	3	4	5
Onshore wind (High)	0.97	1.00	1.03	1.07	1.10
Onshore wind (Medium)	0.97	1.00	1.03	1.07	1.10
Onshore wind (Low)	0.97	1.00	1.03	1.07	1.10
Offshore wind (High)	0.91	1.00	1.09	1.18	1.28
Offshore wind (Low)	0.91	1.00	1.09	1.18	1.28
Biomass regular	0.94	1.00	1.06	1.11	1.17
Biomass energy crop	0.94	1.00	1.06	1.11	1.17
Biomass CHP	0.94	1.00	1.06	1.11	1.17
Wave	0.96	1.00	1.04	1.08	1.13
Tidal Stream	0.96	1.00	1.04	1.08	1.13
Tidal Range	0.90	1.00	1.10	1.20	1.30
Biowaste	0.94	1.00	1.06	1.11	1.17
Biogas	0.98	1.00	1.02	1.04	1.06

C.5 Conventional plant capital costs

The capital costs for conventional plant are shown in Table 31. The CCGT capital cost was taken from the Pöyry study to ensure consistency with the renewable plant capital cost assumptions. Other technologies are Redpoint assumptions. We assume that the costs for new coal and nuclear plant decrease over time, based on a global learning effect for these technologies.

Table 31 Conventional plant capital costs

£/kW (real 2008)	2008	2020
CCGT	523	523
Coal (ASC)	1070	1049
Coal (IGCC)	1248	1186
Coal (ASC + CCS)	1658	1575
Nuclear	1500	1425
OCGT	324	324

C.6 Other plant assumptions

Table 32 Plant characteristics[95]

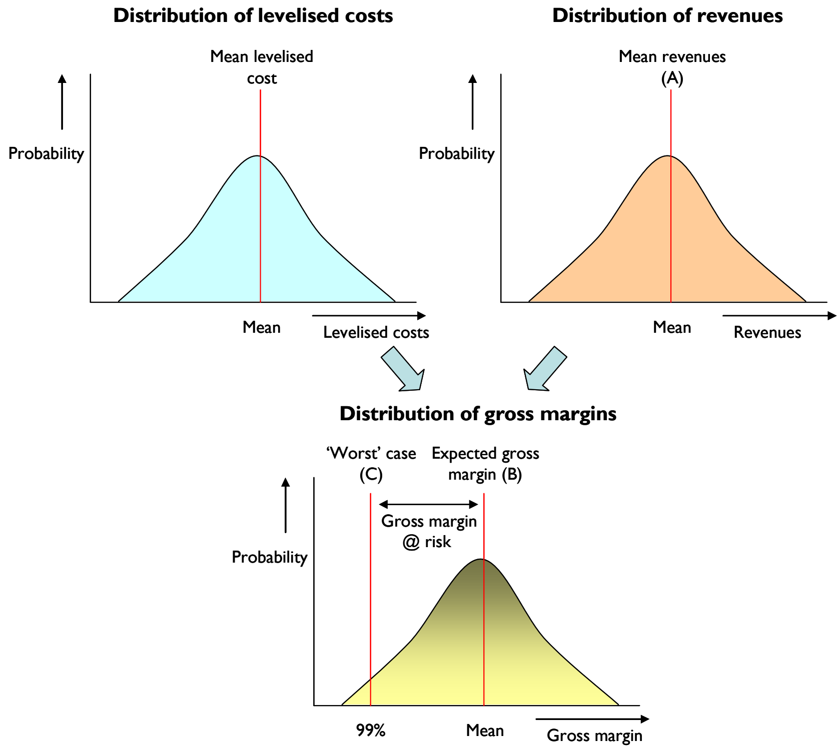
	Annual fixed costs, £/kW/yr	Variable operating costs, £/MWh	Economic lifetime	Efficiency of plant comissioned in 2008	Efficiency of plant comissioned in 2020	Annual availability
CCGT	25.0	0.4	20	52.7%	54.4%	81%
Coal (ASC)	24.2	1.6	25	44.9%	47.8%	81%
Coal (IGCC)	34.5	1.6	25	46.4%	51.6%	81%
Coal (ASC + CCS)	26.0	8.7	25	32.9%	39.4%	81%
Nuclear	56.6	2.0	30	36.0%	36.0%	77%
Onshore wind (High)	41.0	-	20	100.0%	100.0%	29%
Onshore wind (Medium)	41.0	-	20	100.0%	100.0%	27%
Onshore wind (Low)	41.0	-	20	100.0%	100.0%	21%
Offshore wind (High)	68.0	-	20	100.0%	100.0%	39%
Offshore wind (Low)	68.0	-	20	100.0%	100.0%	35%
Biomass regular	62.0	1.1	20	28.0%	28.0%	80%
Biomass energy crop	62.0	1.1	20	28.0%	28.0%	80%
Biomass CHP	83.0	1.1	20	16.0%	16.0%	80%
Wave	82.0	-	20	100.0%	100.0%	30%
Tidal Stream	75.0	-	20	100.0%	100.0%	35%
Tidal Range (< 1 GW)	54.0	-	30	100.0%	100.0%	29%
Biowaste	97.0	-	20	100.0%	100.0%	73%
Biogas	90.0	-	20	100.0%	100.0%	61%
OCGT	18.0	1.5	20	36.8%	39.8%	90%

C.7 Hurdle rate calculations

The hurdle rate (or cost of capital) for each investment is calculated on a risk adjusted basis for each type of investor (vertically integrated companies, independent developers, consortia). This is estimated by simulating the gross margin for the asset over its lifetime taking into account risk factors on both the revenue and cost sides. The revenue risk across the three schemes is quite different, which drives the different hurdle rates across the schemes.

[95] CCGT efficiency is stated in Higher Heating Value (HHV) terms

Figure 60 Simulation of gross margin at risk



The gross margin at risk for each investment is calculated as the difference between the mean gross margin and the gross margin at the 99% percentile ('worst case'), given by B-C (Figure 60). The gross margin at risk simulation is used to determine the proportion of 'risky' capital given by (B-C)/A, and proportion of 'safe' capital given by (1-(B-C)/A).

For simplicity we assume that safe capital is priced at the company cost of debt (risk free rate + debt premium[96]), whereas risky capital is priced at a higher level[97]. We assume that the cost of this risky capital is related to the costs of equity for each company, whether the actual financing comes from higher priced debt or is financed with equity[98]. This is calculated as the risk free rate + equity premium * equity beta * investment beta. The equity premium and equity beta are derived from analysis of financial reports of individual companies. The investment beta (2.5) has been set to calibrate hurdle rates produced by the model for mature technologies against benchmarks from recent known investments, for example around 10% (post tax nominal) for CCGTs. This leads to a cost of risky capital between 12% and 19% depending on the player type.

The tables below outline the assumptions used in the gross margin simulations.

[96] Debt premium varies by company type from 2% to 4.5%. Risk free rate is assumed to be 5.25%.

[97] We recognise that in reality projects are financed in a multitude of different ways with different types of debt at different costs.

[98] On the assumption that companies would use equity rather than debt to finance projects where the cost of debt for a risky project exceeds the cost of equity.

Table 33 Plant variable distributions

Variable	Capital costs				Construction times				Annual availability		Variable costs	Balancing costs	Fixed costs
Years	2008		2030		2008		2030		All		All	All	All
Distribution type	Triangular		Triangular		Triangular		Triangular		Triangular		Normal	Lognormal	Normal
Years	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	SD	SD	SD
CCGT	-10%	+10%	-10%	+10%	-10%	+10%	-10%	+10%	-5%	+5%	10%	10%	10%
Coal (ASC)	-10%	+20%	-10%	+10%	-10%	+20%	-10%	+20%	-5%	+5%	10%	10%	10%
Coal (IGCC)	-10%	+30%	-10%	+20%	-10%	+20%	-10%	+20%	-5%	+5%	10%	10%	10%
Coal (ASC + CCS)	-10%	+50%	-10%	+25%	-10%	+50%	-10%	+30%	-5%	+5%	15%	10%	15%
Nuclear	-10%	+60%	-10%	+25%	-10%	+60%	-10%	+60%	-20%	+5%	20%	10%	20%
Onshore wind (High)	-10%	+20%	-10%	+10%	-10%	+20%	-10%	+20%	-5%	+5%	0%	100%	10%
Onshore wind (Medium)	-10%	+20%	-10%	+10%	-10%	+20%	-10%	+20%	-10%	+5%	0%	100%	10%
Onshore wind (Low)	-10%	+20%	-10%	+10%	-10%	+20%	-10%	+20%	-15%	+5%	0%	100%	10%
Offshore wind (High)	-10%	+30%	-10%	+10%	-10%	+40%	-10%	+20%	-5%	+5%	0%	100%	10%
Offshore wind (Low)	-10%	+30%	-10%	+10%	-10%	+40%	-10%	+20%	-10%	+5%	0%	100%	10%
Biomass regular	-10%	+30%	-10%	+10%	-10%	+20%	-10%	+10%	-5%	+5%	10%	10%	10%
Biomass energy crop	-10%	+30%	-10%	+10%	-10%	+20%	-10%	+10%	-5%	+5%	10%	10%	10%
Biomass CHP	-10%	+30%	-10%	+10%	-10%	+20%	-10%	+10%	-5%	+5%	0%	10%	10%
Wave	-10%	+50%	-10%	+20%	-10%	+40%	-10%	+20%	-10%	+5%	0%	50%	10%
Tidal Stream	-10%	+50%	-10%	+20%	-10%	+40%	-10%	+20%	-5%	+5%	0%	50%	10%
Tidal Range	-10%	+50%	-10%	+20%	-10%	+40%	-10%	+20%	-5%	+5%	0%	50%	10%
Biowaste	-10%	+50%	-10%	+20%	-10%	+20%	-10%	+10%	-5%	+5%	0%	50%	10%
Biogas	-10%	+20%	-10%	+20%	-10%	+20%	-10%	+20%	-5%	+5%	10%	10%	10%
OCGT	-10%	+10%	-10%	+10%	-10%	+10%	-10%	+10%	-5%	+5%	5%	10%	5%

Table 34 Price variable distributions

Variable	Gas	Coal	Biomass reg	Biomass ec	Gas oil	Fuel oil	Uraninum	Carbon	ROCs
Years	All	All	All	All	All	All	All	All	All
Distribution type	Lognormal	Lognormal	Lognormal	Lognormal	Lognormal	Lognormal	Lognormal	Normal	Lognormal
Standard deviation	25%	20%	20%	20%	20%	20%	30%	30%	15%

Note: there is no subsidy risk under the Standard FIT and FIT/Tender schemes.

Table 35 Other assumptions

Variable	Description
Nuclear decommissioing costs	Triangular distribution: Min -10%, Max +100%
Probability of EU ETS post-2012	100%
Gas:coal correlation	50%

C.8 Maximum build rate constraints

The annual maximum build rate scenarios for onshore wind, offshore wind, wave tidal stream and tidal range are taken from the constraints study undertaken by SKM[1]. The maximum build rates for biomass technologies, biogas and biowaste are Redpoint assumptions.

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Table 36 Maximum build constraints, High

Max build, MW/annum	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind	450	500	600	700	800	900	1000	1100	1200	1300	1400	1500	1500
Offshore wind	350	350	350	660	870	1090	1310	1400	1400	1600	1600	1600	1800
Biomass regular	120	120	120	120	120	120	120	120	120	120	120	120	120
Biomass energy crop	25	25	25	25	25	25	25	25	25	25	25	25	25
Biomass CHP	25	25	25	25	25	25	25	25	25	25	25	25	25
Wave	0	0	0	0	25	35	45	55	65	75	85	95	100
Tidal Stream	0	0	0	0	60	120	180	240	240	240	240	180	0
Tidal Range	0	0	0	0	0	0	0	0	35	75	120	200	200
Biowaste	60	60	60	60	60	60	60	60	60	60	60	60	60
Biogas	60	60	60	60	60	60	60	60	60	60	60	60	60

Table 37 Maximum build constraints, Central

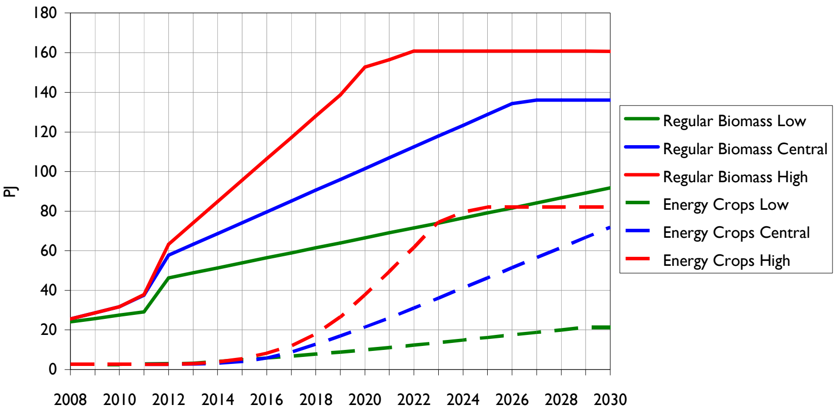
Max build, MW/annum	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind	450	475	500	600	600	600	700	700	700	800	800	800	900
Offshore wind	350	350	350	600	600	600	700	700	700	800	800	800	900
Biomass regular	70	70	70	70	70	70	70	70	70	70	70	70	70
Biomass energy crop	20	20	20	20	20	20	20	20	20	20	20	20	20
Biomass CHP	30	30	30	30	30	30	30	30	30	30	30	30	30
Wave	0	0	0	0	0	0	0	0	25	35	45	55	65
Tidal Stream	0	0	0	0	60	120	120	120	120	120	120	120	120
Tidal Range	0	0	0	0	0	0	0	0	0	0	0	0	35
Biowaste	40	40	40	40	40	40	40	40	40	40	40	40	40
Biogas	40	40	40	40	40	40	40	40	40	40	40	40	40

Table 38 Maximum build constraints, Low

Max build, MW/annum	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Onshore wind	450	450	450	450	450	450	450	450	450	450	450	450	450
Offshore wind	250	250	250	300	300	300	350	350	350	350	350	350	350
Biomass regular	70	70	70	70	70	70	70	70	70	70	70	70	70
Biomass energy crop	10	10	10	10	10	10	10	10	10	10	10	10	10
Biomass CHP	40	40	40	40	40	40	40	40	40	40	40	40	40
Wave	0	0	0	0	0	0	0	0	0	0	0	0	25
Tidal Stream	0	0	0	0	60	60	60	60	60	60	60	60	60
Tidal Range	0	0	0	0	0	0	0	0	0	0	0	0	0
Biowaste	20	20	20	20	20	20	20	20	20	20	20	20	20
Biogas	20	20	20	20	20	20	20	20	20	20	20	20	20

Associated with each maximum build rate scenario is a maximum availability of biomass. These are shown in Figure 61 below.

Figure 61 Maximum biomass available in different build rate sensitivities



C.9 Plant retirements

Table 39 Nuclear retirements

Plant	Capacity (MW)	Year
DUNGENESS B	1110	2018
HARTLEPOOL	1210	2019
HEYSHAM 1	1150	2019
HEYSHAM 2	1250	2028
HINKLEY POINT	1220	2016
OLDBURY	434	2008
SIZEWELL B	1190	2045
WYLFA	980	2010
HUNTERSTON	1190	2016
TORNESS	1250	2028

Table 40 Large Combustion Plant Directive opt-out plant retirements

Plant	Capacity (MW)	Year
DIDCOT A	1984	2014
FAWLEY	518	2015
GRAIN	650	2015
LITTLEBROOK	1475	2014
FERRYBRIDGE (2 of 4 units)	980	2012
IRONBRIDGE	964	2012
KINGSNORTH	2000	2013
TILBURY	1075	2013
COCKENZIE	1200	2015

C.10 Scheme administration costs

The costs of administering the different schemes are shown in Table 41. These are split between a fixed element and a variable element relating to the volume of renewables administered under the scheme. It is assumed that the costs (both fixed and variable) of administering the Standard FIT and FIT/Tender are higher than the Extended RO due to the requirement to administer contracts and set tariff levels, and to organise auctions in the case of the FIT/Tender scheme. Note that these administration costs do not include the costs incurred by the Renewables Purchasing Agency in forecasting and balancing renewables output. These costs are included in the net subsidy figures shown in the cost benefit analysis tables. Note also that the Severn Barrage is assumed to be funded under a separate scheme which is not included in these administration costs.

Table 41 Scheme administration cost assumptions 2020

£ (2008 real)	Extended RO	Standard FIT FIT/Tender
Annual fixed cost	500,000	2,000,000
Variable cost per 1% or renewables	100,000	200,000

Based on these assumptions the costs of administering the RO in 2008/09 would be approximately £1m. (Ofgem reported the costs of administering the RO in 2006/07 was £900,000).

D Renewables output modelling

D.1 Overview

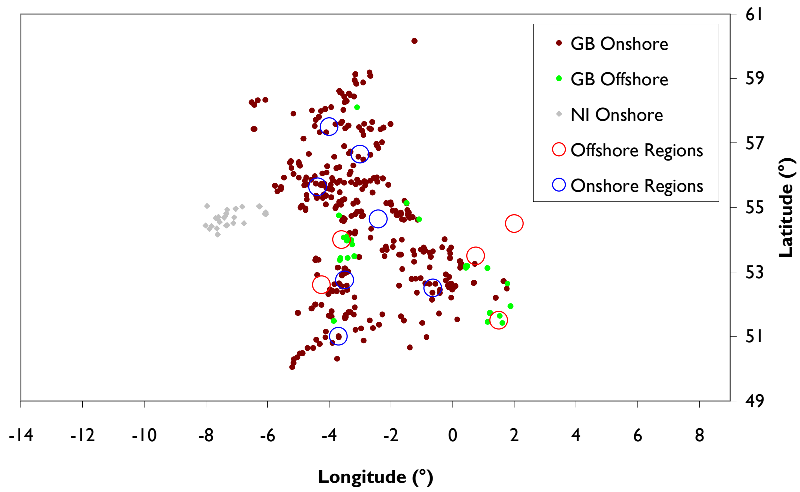
In this appendix we provide more details of how the variability of output from intermittent renewables sources is modelled within the Volatility Model. The assumptions used impact the analysis of expected energy unserved and price duration curves, and the capacity credits used in the calculation of the de-rated peak capacity margins.

D.2 Wind

Volatility in wind output is simulated taking into account the different locations of wind plant, as well as the various seasonal patterns in output.

Correlation of wind output across the country is handled by allocating each wind farm notionally to different onshore and offshore "regions". The midpoints of these regions have been determined using the locations of operational and planned wind farms listed on the British Wind Energy Association website, with each of these existing wind plant then allocated to the region closest to its location. The total MW allocated to a given region then determines the proportion of new plant that will be added to that region within the simulation framework[99].

Figure 62 Regions used for modelling output of wind plant[100]



[99] The location of the offshore wind regions was modified using data provided by BERR relating to the potential for development in different parts of the UK. The proportions of new plant allocated to these regions were adjusted accordingly.

[100] Source: British Wind Energy Association (http://www.bwea.com/), Redpoint analysis

Output for each region, each day, is simulated using a Weibull distribution, as per Gross *et al* (2006). The output in different regions is correlated through a function based on the approximate distance between the regions, parameterised using data published by Sinden (2007).

The output is simulated around average levels which vary by month, according to the profile of historic UK capacity factors published by Sinden. The output within individual days also change rapidly from hour to hour, consistent with the rates of change in actual hourly wind output data, but as the number of days simulated increases the average output for each hour of the day tend towards the seasonally-varying hourly profiles in Sinden's paper.

The aggregation of wind plant to regions rather than simulating output from individual wind farms will tend to err on the side of conservatism and underestimate the diversity benefit and capacity credit of wind. This method was employed as correlating wind output across hundreds of individual wind farms, as well as simulating the rest of the GB market, would have increased the processing time within a Monte Carlo simulation framework to an impractical level.

D.3 Wave

The hourly output of wave power plant is simulated following a similar logic to wind power. Individual wave plant are allocated to five different regions, spaced around the GB coastline, with equal region sizes. The output of the wave plant is correlated using the same function as the wind plant, for lack of more accurate information, however due to the distances between the regions the correlations are fairly low[101]. Average output levels for each month are profiled according to a report on the variability of marine resources in the UK published by the Enviromental Change Institute (2005)[102], and the outputs for each region are also sampled from a Weibull distribution.

D.4 Tidal stream

Unlike wave and wind, the output from tidal power plant can be predicted in advance. While tidal power output from any single plant varies dramatically during the day, the timing and scale of tides is very different across the country providing a diversity benefit. However, due to the likely prevalence of development in one particular region (the Pentland Region in northern Scotland)[103], the hourly patterns in output are likely to be dominated by the tides in this region.

With a cycle repeating approximately each month, tidal plant experience two peak output periods (mean capacity factor approximately 65%) and two trough output periods (approximately 15%). This is referred

[101] Such assumptions are unlikely to have a material impact on the results of this study, due to the relatively small amount of wave power that can be deployed by 2020.

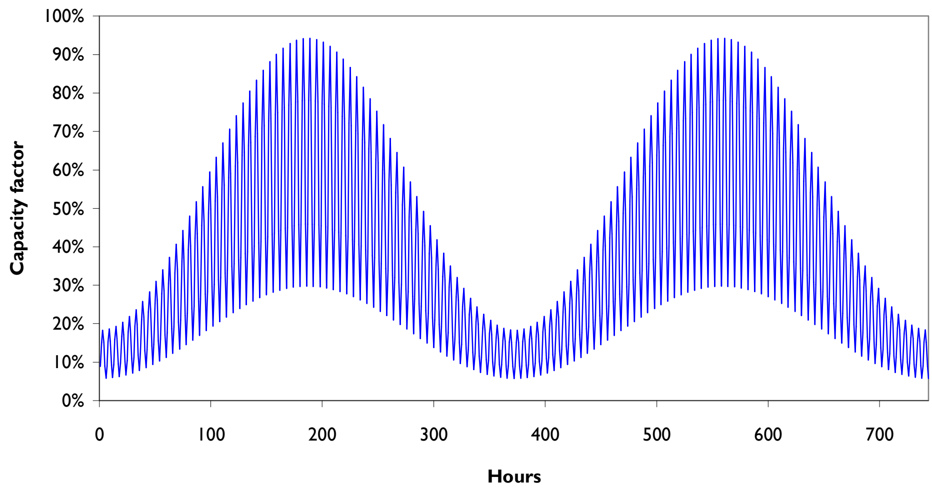
[102] Environmental Change Institute (2005). Variability of UK Marine Resources. Report commissioned by the Carbon Trust,

[103] This information comes from the Environmental Change Institute report.

to as the Spring-Neap tidal cycle[104]. The high-low tidal cycle also repeats approximately every 12.25 hours. Within each day therefore, output is maximised approximately four times; there are two low and two high tides, and output is maximised in between the low and high tides.

These cycles combine to give an output profile stylised from the Environmental Change Institute report, shown below in Figure 63.

Figure 63 Tidal stream aggregate capacity factors across a month



Within its Monte Carlo simulation framework, the Volatility Model simulates the aggregate output from all installed tidal stream plant for single days. Because the highest Spring tides fall within approximately the same two-hour window in each Spring-Neap cycle, approximately the same output cycle repeats itself every fifteen days. Therefore, for each of the individual days simulated, one of the fifteen daily output profiles is selected. The same point in the Spring-Neap cycle is selected for both stream and range capacity. The profiles simulated also maintain the correct timing relationship between the hourly profiles across the stream and range capacity.

D.5 Tidal range (excluding Severn Barrage)

Tidal range plant in GB may be spread across a number of locations, and use a range of different technologies and configurations. For this reason, we assume that the output from tidal range projects is well diversified and hence for simplicity have assumed that it is constant across the day simulated.

[104] The half-yearly cycle that gives rise to the largest Spring tides, approximately at the time of the March and September equinoxes, has not been modelled.

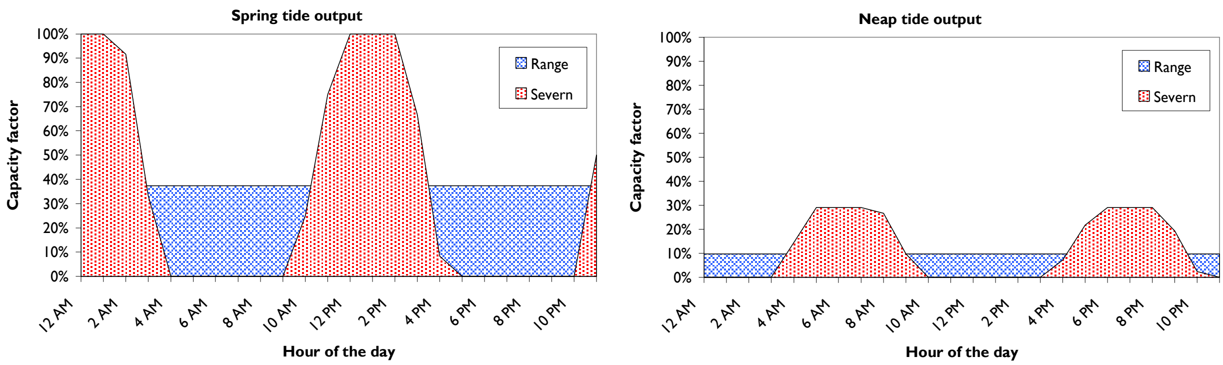
D.6 Severn Barrage

For the purpose of this modelling, we have not only had to make an assumption on the location and size of a potential tidal power project but we have also had to make an assumption on how it operates.

According to the Severn Tidal Power Group (2006)[105], there are three options for the configuration of the Severn Barrage: ebb generation, flood generation and two-way generation.

Ebb generation has previously been "preferred for most schemes", and is currently the type of generation most likely to be used for the Severn Barrage as it will provide the greatest possible annual power output. However, as the Sustainable Development Commission (SDC)[106] note, the Barrage may well be operated differently in a competitive environment in which profit-maximising, rather than output-maximising, is the main goal. For this analysis, an ebb generation configuration has been assumed, with the output profiles adapted from those in the Severn Tidal Power Group presentation. The output profiles of tidal range and the Severn Barrage assumed in the Volatility Model are shown in Figure 64 below. For simplicity, in the 7.5 days between Spring and Neap tides, the capacity factor profiles are shifted through time and scaled downwards in a linear fashion.

Figure 64 Assumed output profiles for tidal range and the Severn Barrage, Spring and Neap tides



Capacity credit of Tidal Range

It is important to note that by the time the Severn Barrage may be built (the assumed commissioning date in the modelling is 2022) the GB system is likely to have a very large penetration of renewable plant. Our empirical analysis suggests that the marginal benefit to security of supply of an extra unit of intermittent generation is much lower when renewable penetration levels are high, regardless of the type of intermittent generation built. Further, the risk of outage is not necessarily greatest at times of peak demand; recent events in the GB market have shown that plant margins can become low even with moderate demand as a result of a combination of plant outages, both planned and unplanned. Therefore a simulation framework is ideal for calculating the contribution of a large generating plant, such as the Severn Barrage, to security of supply. The capacity credit of tidal range and the Severn Barrage have been calculated in the same way as those of the other intermittent renewable plant.

[105] Severn Tidal Power Group (2006). The Severn Barrage. Presentation to the Gloucestershire County Council, 1 November 2006.

[106] Sustainable Development Commission (2007). Turning the Tide: Tidal Power in the UK. London.

Due to the assumptions used, the capacity credit calculated for the Severn Barrage is different to that of the other tidal range plant. The assumption that tidal range output is constant across the day (and varies only with the Spring-Neap cycle) results in its capacity credit being approximately equal to its annual capacity factor.

The Severn Barrage is assumed to follow an ebb generation profile, generating for up to just twelve hours a day with Spring tides. Maximum output levels also vary quite dramatically, depending on the Spring-Neap cycle. As a result, the capacity credit for the Barrage was calculated at 10.5%[107], compared to an annual capacity factor of 23%.

This result is important, as it implies that although its maximum output is 8640 MW, its contribution to the peak capacity margin is equal to the equivalent of approximately 1100 MW of conventional thermal plant. However, if, as suggested by the SDC, the output profile of the Barrage is operated in a profit-maximising mode with reduced annual output but a smoother output profile, rather than in simple ebb generation configuration, the capacity credit may be increased.

[107] Note that this capacity credit is much lower than the "capacity value" of around 20-23% calculated by the Sustainable Development Commission in their 2007 report. Their calculation was based on a static comparison for a single year of the net load duration curve with and without the Barrage. They concluded that the Barrage would be able to replace around 2 GW of conventional plant at peak load. However, their analysis does not take into account random fluctuations in both the demand- and supply-side.

E Supplementary results

E.1 37% target

Table 42 Detailed comparison of CBA (NPV, 2008-2030) under three schemes, 37% target, base case assumptions

Change in annual welfare, NPV £m (real 2008)		Extended RO37	Standard FIT37	FIT/Tender37
Net Welfare	Carbon saved	9,829	10,050	8,942
	Less increase in resource costs	-51,348	-47,935	-51,108
	Change in Net Welfare	**-41,519**	**-37,885**	**-42,167**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	3,887	9,104	3,943
	Change in balancing costs	-5,346	-5,399	-5,391
	Change in net subsidy	-40,656	-39,783	-35,007
	Change in administration costs	-16	-66	-66
	Change in CCL	2,800	2,852	2,852
	Change in VAT	-652	-441	-475
	Change in Consumer Surplus	**-39,983**	**-33,733**	**-34,144**
Producer Surplus	Change in wholesale price	-3,887	-9,104	-3,943
	Change in balancing revenues	5,346	5,399	5,391
	Change in net subsidy	40,656	39,783	35,007
	Change in generation costs	-41,503	-37,819	-42,100
	Change in Producer Surplus	**612**	**-1,742**	**-5,646**
	Change in renewables rent	*1,623*	*4,425*	*-2,688*
	Change in non-renewables rent	*-1,010*	*-6,166*	*-2,958*
Treasury Receipts	Change in CCL	-2,800	-2,852	-2,852
	Change in VAT	652	441	475
	Change in Treasury Receipts	**-2,148**	**-2,411**	**-2,377**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-45	-38
	Cost per tonne CO_2 avoided ($£/tCO_2$)	132	106	128
Fuel use	Annual change in use of gas (mtoe)	-5.47	-2.62	-5.56
	Annual change in use of coal (mtoe)	-7.14	-10.46	-7.35
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-12	-10	-1
Renewables	Qualifying renewables generation in 2020	36.8%	36.9%	37.0%

E.2 32% target

Table 43 Detailed comparison of CBA (NPV, 2008-2030) under three schemes, 32% target, base case assumptions

Change in annual welfare, NPV £m (real 2008)		Extended RO32	Standard FIT32	FIT/Tender32
Net Welfare	Carbon saved	9,301	9,774	8,035
	Less increase in resource costs	-43,108	-39,360	-43,014
	Change in Net Welfare	**-33,807**	**-29,586**	**-34,979**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	2,174	4,091	7,778
	Change in balancing costs	-4,448	-4,540	-4,552
	Change in net subsidy	-33,541	-30,069	-29,210
	Change in administration costs	-16	-66	-66
	Change in CCL	2,718	2,807	2,824
	Change in VAT	-548	-353	-303
	Change in Consumer Surplus	**-33,662**	**-28,130**	**-23,528**
Producer Surplus	Change in wholesale price	-2,174	-4,091	-7,778
	Change in balancing revenues	4,448	4,540	4,552
	Change in net subsidy	33,541	30,069	29,210
	Change in generation costs	-33,791	-29,520	-34,912
	Change in Producer Surplus	**2,025**	**998**	**-8,929**
	Change in renewables rent	*2,624*	*3,354*	*-2,709*
	Change in non-renewables rent	*-599*	*-2,356*	*-6,220*
Treasury Receipts	Change in CCL	-2,718	-2,807	-2,824
	Change in VAT	548	353	303
	Change in Treasury Receipts	**-2,170**	**-2,454**	**-2,521**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-42	-42	-38
	Cost per tonne CO_2 avoided ($£/tCO_2$)	123	108	128
Fuel use	Annual change in use of gas (mtoe)	-3.54	-3.54	-5.32
	Annual change in use of coal (mtoe)	-9.17	-9.31	-7.51
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-7	-9	0
Renewables	Qualifying renewables generation in 2020	31.8%	32.0%	32.1%

E.3 32% target Severn Barrage

Table 44 Detailed comparison of CBA (NPV, 2008-2030) under three schemes, 32% target with Severn Barrage, base case assumptions

Change in annual welfare, NPV £m (real 2008)		Extended RO32 SB	Standard FIT32 SB	FIT/Tender32 SB
Net Welfare	Carbon saved	8,373	6,947	7,146
	Less increase in resource costs	-40,631	-34,902	-37,472
	Change in Net Welfare	**-32,258**	**-27,955**	**-30,325**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	1,639	685	1,125
	Change in balancing costs	-3,894	-3,959	-3,863
	Change in net subsidy	-29,022	-21,826	-22,203
	Change in administration costs	-12	-57	-57
	Change in CCL	2,040	2,043	2,039
	Change in VAT	-485	-300	-314
	Change in Consumer Surplus	**-29,733**	**-23,415**	**-23,272**
Producer Surplus	Change in wholesale price	-1,639	-685	-1,125
	Change in balancing revenues	3,894	3,959	3,863
	Change in net subsidy	29,022	21,826	22,203
	Change in generation costs	-32,246	-27,898	-30,268
	Change in Producer Surplus	**-969**	**-2,798**	**-5,328**
	Change in renewables rent	*687*	*-1,180*	*-3,568*
	Change in non-renewables rent	*-1,656*	*-1,618*	*-1,760*
Treasury Receipts	Change in CCL	-2,040	-2,043	-2,039
	Change in VAT	485	300	314
	Change in Treasury Receipts	**-1,556**	**-1,743**	**-1,725**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-34	-29	-30
	Cost per tonne CO_2 avoided (£/tCO_2)	107	102	110
Fuel use	Annual change in use of gas (mtoe)	-1.24	-2.89	-2.93
	Annual change in use of coal (mtoe)	-8.38	-6.77	-6.80
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-32	-6	-2
Renewables	Qualifying renewables generation in 2020	31.8%	31.9%	32.0%

E.4 28% Target

Table 45 Detailed comparison of CBA (NPV, 2008-2030) under three schemes, 28% target, base case assumptions

Change in annual welfare, NPV £m (real 2008)		Extended RO28	Standard FIT28	FIT/Tender28
Net Welfare	Carbon saved	6,331	5,103	5,727
	Less increase in resource costs	-28,695	-25,159	-29,326
	Change in Net Welfare	**-22,364**	**-20,056**	**-23,599**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	5,214	2,608	4,292
	Change in balancing costs	-3,327	-3,311	-3,142
	Change in net subsidy	-23,363	-17,017	-18,235
	Change in administration costs	-13	-58	-58
	Change in CCL	2,208	2,138	2,145
	Change in VAT	-319	-163	-181
	Change in Consumer Surplus	**-19,600**	**-15,804**	**-15,179**
Producer Surplus	Change in wholesale price	-5,214	-2,608	-4,292
	Change in balancing revenues	3,327	3,311	3,142
	Change in net subsidy	23,363	17,017	18,235
	Change in generation costs	-22,351	-19,998	-23,541
	Change in Producer Surplus	**-875**	**-2,278**	**-6,456**
	Change in renewables rent	*290*	*-755*	*-3,130*
	Change in non-renewables rent	*-1,165*	*-1,523*	*-3,326*
Treasury Receipts	Change in CCL	-2,208	-2,138	-2,145
	Change in VAT	319	163	181
	Change in Treasury Receipts	**-1,889**	**-1,975**	**-1,964**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-28	-27	-29
	Cost per tonne CO_2 avoided ($£/tCO_2$)	126	112	117
Fuel use	Annual change in use of gas (mtoe)	-3.28	-2.87	-2.29
	Annual change in use of coal (mtoe)	-6.07	-6.04	-7.00
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	0	-1	-1
Renewables	Qualifying renewables generation in 2020	28.3%	27.6%	28.0%

E.5 Fuel and carbon prices

Table 46 Detailed comparison of CBA (NPV, 2008-2030) for Extended RO37 under different fuel price sensitivities

Change in annual welfare, NPV £m (real 2008)		Extended RO37	Extended RO37 Low Fuel	Extended RO37 High Fuel	Extended RO37 High High Fuel
Net Welfare	Carbon saved	9,829	5,288	11,042	13,836
	Less increase in resource costs	-51,348	-51,452	-44,632	-42,975
	Change in Net Welfare	**-41,519**	**-46,165**	**-33,590**	**-29,138**
Distributional analysis, NPV £m (real 2008)					
Consumer Surplus	Change in wholesale price	3,887	7,278	22,702	29,083
	Change in balancing costs	-5,346	-4,671	-5,535	-5,822
	Change in net subsidy	-40,656	-42,494	-40,707	-40,590
	Change in administration costs	-16	-14	-17	-18
	Change in CCL	2,800	2,485	2,892	2,996
	Change in VAT	-652	-620	-342	-237
	Change in Consumer Surplus	**-39,983**	**-38,036**	**-21,007**	**-14,588**
Producer Surplus	Change in wholesale price	-3,887	-7,278	-22,702	-29,083
	Change in balancing revenues	5,346	4,671	5,535	5,822
	Change in net subsidy	40,656	42,494	40,707	40,590
	Change in generation costs	-41,503	-46,150	-33,573	-29,120
	Change in Producer Surplus	**612**	**-6,264**	**-10,034**	**-11,792**
	Change in renewables rent	*1,623*	*-556*	*1,796*	*2,582*
	Change in non-renewables rent	*-1,010*	*-5,707*	*-11,829*	*-14,373*
Treasury Receipts	Change in CCL	-2,800	-2,485	-2,892	-2,996
	Change in VAT	652	620	342	237
	Change in Treasury Receipts	**-2,148**	**-1,865**	**-2,550**	**-2,758**
Ancillary metrics, 2020					
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-36	-33	-20
	Cost per tonne CO_2 avoided ($£/tCO_2$)	132	143	141	179
Fuel use	Annual change in use of gas (mtoe)	-5.47	-6.42	-7.51	-0.90
	Annual change in use of coal (mtoe)	-7.14	-5.22	-4.88	-11.05
	Annual change in use of oil (mtoe)	0.00	-0.02	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-12	-11	11	-2
Renewables	Qualifying renewables generation in 2020	36.8%	34.0%	37.5%	38.1%

Table 47 Detailed comparison of CBA (NPV, 2008-2030) for Standard FIT37 under different fuel price sensitivities

Change in annual welfare, NPV £m (real 2008)		Standard FIT37	Standard FIT37 Low Fuel	Standard FIT37 High Fuel	Standard FIT37 High High Fuel
Net Welfare	Carbon saved	10,050	5,916	10,271	12,714
	Less increase in resource costs	-47,935	-54,906	-35,466	-31,907
	Change in Net Welfare	**-37,885**	**-48,990**	**-25,195**	**-19,193**
Distributional analysis, NPV £m (real 2008)					
Consumer Surplus	Change in wholesale price	9,104	8,319	18,432	26,163
	Change in balancing costs	-5,399	-5,772	-5,286	-5,252
	Change in net subsidy	-39,783	-49,533	-31,402	-24,918
	Change in administration costs	-66	-67	-67	-67
	Change in CCL	2,852	3,080	2,819	2,787
	Change in VAT	-441	-613	-151	83
	Change in Consumer Surplus	**-33,733**	**-44,586**	**-15,653**	**-1,204**
Producer Surplus	Change in wholesale price	-9,104	-8,319	-18,432	-26,163
	Change in balancing revenues	5,399	5,772	5,286	5,252
	Change in net subsidy	39,783	49,533	31,402	24,918
	Change in generation costs	-37,819	-48,923	-25,129	-19,127
	Change in Producer Surplus	**-1,742**	**-1,937**	**-6,873**	**-15,119**
	Change in renewables rent	*4,425*	*4,220*	*2,136*	*-366*
	Change in non-renewables rent	*-6,166*	*-6,157*	*-9,009*	*-14,753*
Treasury Receipts	Change in CCL	-2,852	-3,080	-2,819	-2,787
	Change in VAT	441	613	151	-83
	Change in Treasury Receipts	**-2,411**	**-2,468**	**-2,668**	**-2,870**
Ancillary metrics, 2020					
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-45	-34	-31	-18
	Cost per tonne CO_2 avoided ($£/tCO_2$)	106	145	117	145
Fuel use	Annual change in use of gas (mtoe)	-2.62	-9.18	-7.38	-0.44
	Annual change in use of coal (mtoe)	-10.46	-3.85	-4.88	-11.00
	Annual change in use of oil (mtoe)	0.00	-0.03	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-10	-18	9	-3
Renewables	Qualifying renewables generation in 2020	36.9%	37.0%	37.2%	37.2%

Table 48 Detailed comparison of CBA (NPV, 2008-2030) for FIT/Tender37 under different fuel price sensitivities

Change in annual welfare, NPV £m (real 2008)		FIT/Tender37	FIT/Tender37 Low Fuel	FIT/Tender37 High Fuel	FIT/Tender37 High High Fuel
Net Welfare	Carbon saved	8,942	6,103	10,929	12,786
	Less increase in resource costs	-51,108	-59,488	-40,667	-36,279
	Change in Net Welfare	**-42,167**	**-53,385**	**-29,737**	**-23,493**
Distributional analysis, NPV £m (real 2008)					
Consumer Surplus	Change in wholesale price	3,943	7,226	16,628	26,816
	Change in balancing costs	-5,391	-5,765	-5,258	-5,301
	Change in net subsidy	-35,007	-46,092	-27,114	-23,980
	Change in administration costs	-66	-67	-66	-67
	Change in CCL	2,852	3,074	2,794	2,812
	Change in VAT	-475	-601	-138	82
	Change in Consumer Surplus	**-34,144**	**-42,225**	**-13,154**	**362**
Producer Surplus	Change in wholesale price	-3,943	-7,226	-16,628	-26,816
	Change in balancing revenues	5,391	5,765	5,258	5,301
	Change in net subsidy	35,007	46,092	27,114	23,980
	Change in generation costs	-42,100	-53,318	-29,671	-23,426
	Change in Producer Surplus	**-5,646**	**-8,686**	**-13,928**	**-20,961**
	Change in renewables rent	*-2,688*	*-2,974*	*-5,240*	*-5,514*
	Change in non-renewables rent	*-2,958*	*-5,712*	*-8,688*	*-15,447*
Treasury Receipts	Change in CCL	-2,852	-3,074	-2,794	-2,812
	Change in VAT	475	601	138	-82
	Change in Treasury Receipts	**-2,377**	**-2,473**	**-2,656**	**-2,895**
Ancillary metrics, 2020					
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-39	-31	-17
	Cost per tonne CO_2 avoided (£/tCO_2)	128	141	131	172
Fuel use	Annual change in use of gas (mtoe)	-5.56	-7.48	-7.08	-0.32
	Annual change in use of coal (mtoe)	-7.35	-5.94	-5.03	-10.96
	Annual change in use of oil (mtoe)	0.00	-0.03	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-1	-26	10	-3
Renewables	Qualifying renewables generation in 2020	37.0%	36.6%	36.9%	37.0%

E.6 Capital cost uncertainty

Table 49 Detailed comparison of CBA (NPV, 2008-2030) for Extended RO37 under different renewables capital costs sensitivities

Change in annual welfare, NPV £m (real 2008)		Extended RO37	Extended RO37 Higher Cap Costs	Extended RO37 Lower Cap Costs
Net Welfare	Carbon saved	9,829	9,324	10,540
	Less increase in resource costs	-51,348	-49,764	-51,623
	Change in Net Welfare	**-41,519**	**-40,440**	**-41,084**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	3,887	748	3,351
	Change in balancing costs	-5,346	-4,704	-5,552
	Change in net subsidy	-40,656	-38,656	-41,573
	Change in administration costs	-16	-14	-17
	Change in CCL	2,800	2,441	2,934
	Change in VAT	-652	-666	-677
	Change in Consumer Surplus	**-39,983**	**-40,851**	**-41,534**
Producer Surplus	Change in wholesale price	-3,887	-748	-3,351
	Change in balancing revenues	5,346	4,704	5,552
	Change in net subsidy	40,656	38,656	41,573
	Change in generation costs	-41,503	-40,426	-41,067
	Change in Producer Surplus	**612**	**2,186**	**2,707**
	Change in renewables rent	*1,623*	*1,976*	*4,171*
	Change in non-renewables rent	*-1,010*	*211*	*-1,464*
Treasury Receipts	Change in CCL	-2,800	-2,441	-2,934
	Change in VAT	652	666	677
	Change in Treasury Receipts	**-2,148**	**-1,776**	**-2,257**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-39	-43
	Cost per tonne CO_2 avoided ($£/tCO_2$)	132	129	118
Fuel use	Annual change in use of gas (mtoe)	-5.47	-3.29	-4.15
	Annual change in use of coal (mtoe)	-7.14	-8.58	-9.15
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-12	-11	-10
Renewables	Qualifying renewables generation in 2020	36.8%	34.6%	37.6%

Table 50 Detailed comparison of CBA (NPV, 2008-2030) for Standard FIT37 under different renewables capital costs sensitivities

Change in annual welfare, NPV £m (real 2008)		Standard FIT37	Standard FIT37 Higher Cap Costs	Standard FIT37 Lower Cap Costs
Net Welfare	Carbon saved	10,050	5,501	9,639
	Less increase in resource costs	-47,935	-28,268	-44,789
	Change in Net Welfare	**-37,885**	**-22,768**	**-35,150**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	9,104	-2,843	9,621
	Change in balancing costs	-5,399	-2,686	-5,394
	Change in net subsidy	-39,783	-20,585	-37,430
	Change in administration costs	-66	-48	-66
	Change in CCL	2,852	1,404	2,845
	Change in VAT	-441	-356	-395
	Change in Consumer Surplus	**-33,733**	**-25,114**	**-30,818**
Producer Surplus	Change in wholesale price	-9,104	2,843	-9,621
	Change in balancing revenues	5,399	2,686	5,394
	Change in net subsidy	39,783	20,585	37,430
	Change in generation costs	-37,819	-22,719	-35,083
	Change in Producer Surplus	**-1,742**	**3,395**	**-1,881**
	Change in renewables rent	*4,425*	*2,098*	*5,600*
	Change in non-renewables rent	*-6,166*	*1,296*	*-7,482*
Treasury Receipts	Change in CCL	-2,852	-1,404	-2,845
	Change in VAT	441	356	395
	Change in Treasury Receipts	**-2,411**	**-1,048**	**-2,450**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-45	-15	-45
	Cost per tonne CO_2 avoided ($£/tCO_2$)	106	116	99
Fuel use	Annual change in use of gas (mtoe)	-2.62	-1.38	-2.68
	Annual change in use of coal (mtoe)	-10.46	-3.87	-10.60
	Annual change in use of oil (mtoe)	0.00	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-10	0	-10
Renewables	Qualifying renewables generation in 2020	36.9%	26.4%	37.2%

Table 51 Detailed comparison of CBA (NPV, 2008-2030) for FIT/Tender37 under different renewables capital costs sensitivities

Change in annual welfare, NPV £m (real 2008)		FIT/Tender37	FIT/Tender37 Higher Cap Costs	FIT/Tender37 Lower Cap Costs
Net Welfare	Carbon saved	8,942	9,598	8,981
	Less increase in resource costs	-51,108	-55,630	-47,546
	Change in Net Welfare	**-42,167**	**-46,032**	**-38,566**
Distributional analysis, NPV £m (real 2008)				
Consumer Surplus	Change in wholesale price	3,943	5,104	6,114
	Change in balancing costs	-5,391	-5,121	-5,411
	Change in net subsidy	-35,007	-38,546	-31,487
	Change in administration costs	-66	-62	-67
	Change in CCL	2,852	2,531	2,860
	Change in VAT	-475	-522	-379
	Change in Consumer Surplus	**-34,144**	**-36,616**	**-28,369**
Producer Surplus	Change in wholesale price	-3,943	-5,104	-6,114
	Change in balancing revenues	5,391	5,121	5,411
	Change in net subsidy	35,007	38,546	31,487
	Change in generation costs	-42,100	-45,970	-38,499
	Change in Producer Surplus	**-5,646**	**-7,408**	**-7,716**
	Change in renewables rent	*-2,688*	*-2,725*	*-2,682*
	Change in non-renewables rent	*-2,958*	*-4,683*	*-5,034*
Treasury Receipts	Change in CCL	-2,852	-2,531	-2,860
	Change in VAT	475	522	379
	Change in Treasury Receipts	**-2,377**	**-2,009**	**-2,481**
Ancillary metrics, 2020				
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-40	-38
	Cost per tonne CO_2 avoided (£/tCO_2)	128	135	118
Fuel use	Annual change in use of gas (mtoe)	-5.56	-2.12	-5.78
	Annual change in use of coal (mtoe)	-7.35	-9.34	-7.33
	Annual change in use of oil (mtoe)	0.00	0.02	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-1	-1	-3
Renewables	Qualifying renewables generation in 2020	37.0%	33.5%	37.4%

E.7 Build constraints

Table 52 Detailed comparison of CBA (NPV, 2008-2030) for Extended RO37 under build rates sensitivities

Change in annual welfare, NPV £m (real 2008)		Extended RO37	Extended RO37 Central Build
Net Welfare	Carbon saved	9,829	5,843
	Less increase in resource costs	-51,348	-34,074
	Change in Net Welfare	**-41,519**	**-28,231**
Distributional analysis, NPV £m (real 2008)			
Consumer Surplus	Change in wholesale price	3,887	6,696
	Change in balancing costs	-5,346	-3,181
	Change in net subsidy	-40,656	-39,084
	Change in administration costs	-16	-10
	Change in CCL	2,800	1,638
	Change in VAT	-652	-562
	Change in Consumer Surplus	**-39,983**	**-34,502**
Producer Surplus	Change in wholesale price	-3,887	-6,696
	Change in balancing revenues	5,346	3,181
	Change in net subsidy	40,656	39,084
	Change in generation costs	-41,503	-28,221
	Change in Producer Surplus	**612**	**7,347**
	Change in renewables rent	*1,623*	*13,429*
	Change in non-renewables rent	*-1,010*	*-6,082*
Treasury Receipts	Change in CCL	-2,800	-1,638
	Change in VAT	652	562
	Change in Treasury Receipts	**-2,148**	**-1,076**
Ancillary metrics, 2020			
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-18
	Cost per tonne CO_2 avoided ($£/tCO_2$)	132	134
Fuel use	Annual change in use of gas (mtoe)	-5.47	-1.55
	Annual change in use of coal (mtoe)	-7.14	-3.13
	Annual change in use of oil (mtoe)	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-12	2
Renewables	Qualifying renewables generation in 2020	36.8%	26.6%

Table 53 Detailed comparison of CBA (NPV, 2008-2030) for Standard FIT37 under build rates sensitivities

Change in annual welfare, NPV £m (real 2008)		Standard FIT37	Standard FIT37 Central Build
Net Welfare	Carbon saved	10,050	3,962
	Less increase in resource costs	-47,935	-21,505
	Change in Net Welfare	**-37,885**	**-17,542**
Distributional analysis, NPV £m (real 2008)			
Consumer Surplus	Change in wholesale price	9,104	-2,431
	Change in balancing costs	-5,399	-2,414
	Change in net subsidy	-39,783	-15,747
	Change in administration costs	-66	-48
	Change in CCL	2,852	1,287
	Change in VAT	-441	-266
	Change in Consumer Surplus	**-33,733**	**-19,619**
Producer Surplus	Change in wholesale price	-9,104	2,431
	Change in balancing revenues	5,399	2,414
	Change in net subsidy	39,783	15,747
	Change in generation costs	-37,819	-17,494
	Change in Producer Surplus	**-1,742**	**3,098**
	Change in renewables rent	*4,425*	*2,481*
	Change in non-renewables rent	*-6,166*	*617*
Treasury Receipts	Change in CCL	-2,852	-1,287
	Change in VAT	441	266
	Change in Treasury Receipts	**-2,411**	**-1,021**
Ancillary metrics, 2020			
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-45	-18
	Cost per tonne CO_2 avoided ($£/tCO_2$)	106	90
Fuel use	Annual change in use of gas (mtoe)	-2.62	-0.32
	Annual change in use of coal (mtoe)	-10.46	-5.22
	Annual change in use of oil (mtoe)	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-10	1
Renewables	Qualifying renewables generation in 2020	36.9%	27.4%

Table 54 Detailed comparison of CBA (NPV, 2008-2030) for FIT/Tender37 under build rates sensitivities

Change in annual welfare, NPV £m (real 2008)		FIT/Tender37	FIT/Tender37 Central Build
Net Welfare	Carbon saved	8,942	5,063
	Less increase in resource costs	-51,108	-27,867
	Change in Net Welfare	**-42,167**	**-22,804**
Distributional analysis, NPV £m (real 2008)			
Consumer Surplus	Change in wholesale price	3,943	2,074
	Change in balancing costs	-5,391	-2,539
	Change in net subsidy	-35,007	-16,520
	Change in administration costs	-66	-49
	Change in CCL	2,852	1,335
	Change in VAT	-475	-215
	Change in Consumer Surplus	**-34,144**	**-15,913**
Producer Surplus	Change in wholesale price	-3,943	-2,074
	Change in balancing revenues	5,391	2,539
	Change in net subsidy	35,007	16,520
	Change in generation costs	-42,100	-22,755
	Change in Producer Surplus	**-5,646**	**-5,771**
	Change in renewables rent	*-2,688*	*-2,360*
	Change in non-renewables rent	*-2,958*	*-3,410*
Treasury Receipts	Change in CCL	-2,852	-1,335
	Change in VAT	475	215
	Change in Treasury Receipts	**-2,377**	**-1,120**
Ancillary metrics, 2020			
Carbon	Annual change in carbon dioxide ($MtCO_2$)	-38	-16
	Cost per tonne CO_2 avoided ($£/tCO_2$)	128	123
Fuel use	Annual change in use of gas (mtoe)	-5.56	-1.27
	Annual change in use of coal (mtoe)	-7.35	-4.37
	Annual change in use of oil (mtoe)	0.00	0.00
Energy unserved	Annual change in expected energy unserved (GWh)	-1	1
Renewables	Qualifying renewables generation in 2020	37.0%	27.6%