Title: Periodic Review of FITs 2015	**Impact Assessment (IA)**
IA No: DECC0196	**Date:** 17/12/2015
Lead department or agency: Department for Energy and Climate Change	**Stage:** Final
	Source of intervention: Domestic
Other departments or agencies:	**Type of measure:** Secondary legislation
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Summary: Intervention and Options

RPC: N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB on 2009 prices)	**In scope of One-In, Three-Out?**	**Measure qualifies as**
£3,390m			No	NA

What is the problem under consideration? Why is government intervention necessary?

The European Commission's State aid approval for FITs places an obligation on the Government to review scheme performance every three years, to ensure that FIT generators are not being over-compensated, among other things. The last Review was 2012. The Review requires revising the level of support based on the latest evidence on costs and revenues. In addition, FITs has contributed significantly towards the increased spending under the Levy Control Framework, which caps expenditure of renewable subsidies levied from consumer bills. The expected spending under the Levy Control Framework in 2020/21 has increased significantly above the £7.6bn limit. In light of these financial pressures, the Government is proposing measures to reduce the impact of the scheme on consumer bills.

What are the policy objectives and the intended effects?

The primary policy objectives are to improve value for money and to control spending under the FITs scheme to limit the impact on consumer bills. The intention is that a maximum of £100m is spent on new-build deployment per year over this FITs review period (from early 2016 to the end of 2018/19). The scheme is also due for review under the terms of the State Aid agreement. Generation tariffs are set to secure value for money to consumers by targeting only well-sited installations at an acceptable rate of return. Caps limit the amount of deployment to ensure that spending does not go above £100m per year by 2018/19.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

Option 1 – do nothing. Under this option the FITs scheme continues as is. This assumes that pre-accreditation is in place.

Option 2 – make the policy changes as set out in the Government response and in this Impact Assessment. This includes; changing some tariffs bands; changing some degression bands; tariff changes; introduction of caps; changes to default and contingent degression; and re-introduction of pre-accreditation.

Will the policy be reviewed? It will not be reviewed **If applicable, set review date:** Month/Year

Does implementation go beyond minimum EU requirements?			N/A		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** Yes	**< 20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:**	**Non-traded:**	

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

Signed by the responsible Minister: ______________ Date: 16/12/2015

Summary: Analysis & Evidence

Policy Option 2

Description: Changing some tariffs bands; changing some degression bands; tariff changes; introduction of caps; changes to default and contingent degression; and reinstatement of pre-accreditation.

FULL ECONOMIC ASSESSMENT

Price Base Year 2016	PV Base Year 2015	Time Period Years 45	Net Benefit (Present Value (PV)) (£m)		
			Low: £3,360m	**High: £3,720m**	**Best Estimate: £3,390m**

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low				£740m
High				£810m
Best Estimate				£750m

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

New build renewable capacity falls in this scenario, as does renewables generation. The generation forgone is assumed to be replaced by the grid average, which has higher carbon emissions than renewables – therefore, carbon emissions increase in this scenario. In addition there is £200,000 admin cost to implement the changes, largely due to system changes in Ofgem's monitoring of the scheme.

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

There are likely to be some negative impacts on employment across the renewables sector as a result of these changes; potential impacts are discussed in the employment Annex. There may also be some air quality impacts as a result of greater consumption of fossil fuels.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low				£4,100m
High				£4,530m
Best Estimate				£4,140m

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

New build renewable capacity falls in this scenario, as does renewables generation. The generation forgone is assumed to be replaced by an "average" generation mix (based on the grid average), which has a lower resource cost than FITs generation. This results in a resource saving from lower FITs deployment and generation, relative to no intervention.

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

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

The analysis is based on a revised set of assumptions for small scale generation, set out in this document. This includes capital costs, operating costs, load factors and hurdle rates.

Sensitivities are included where necessary through the document.

The main risk is of further overspend under the FITs scheme, which is mitigated through lower tariffs and the introduction of caps. There is an additional risk that by reducing tariffs and introducing uncertainty through the caps, deployment is reduced by more than is currently anticipated.

There is an uncertainty about what replaces displaced FITs generation. In this document, it is assumed to be the Long Run Variable Cost of electricity; a sensitivity of gas generation is included in the body of the document.

BUSINESS ASSESSMENT (Option 2)

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

Contents

Background, and problem under consideration

1.1 The EU Renewable Energy Directive commits the UK to producing 15% of its energy from renewable sources by 2020. The UK is aiming to meet this through renewables generation in electricity, heat and transport. The ambition is for at least 30% of electricity to be generated by renewable sources.

1.2 Renewable electricity generation is at present funded through the Renewables Obligation (RO), which provides financial support to projects with a capacity above 5MW,[1] and Feed-in Tariffs (FITs), which supports projects up to and including 5MW. The Renewables Obligation is currently being closed to new capacity at the end of 2016/17, with some exceptions,[2] and will be replaced by Contracts for Difference (CfDs). The results of the first CfD allocation round were announced earlier this year.[3]

1.3 Support for renewable electricity generation is paid for by consumers of electricity. Generators pass on the costs to energy suppliers, who are assumed to pass them on fully to consumers. The support for renewable electricity sits within the Levy Control Framework (LCF). This intends to limit the amount of support that is levied onto consumer bills. A trajectory was set out to 2020/21, reaching £7.6bn in 2011/12 prices.

1.4 As published projections estimate[4], the expected spending under the LCF in 2020/21 has increased significantly above the £7.6bn. FITs has played a major part in this, with projected spending increasing from c£1,125m in 2020/21 at the time of the EMR Delivery Plan to £1,600m at the time of the consultation publication; projections have since increased to over £1700m as set out in the latest Office of Budgetary Responsibility projections[5]. It is important that Government gets control over these costs and brings spending down as it is not acceptable for demand-led schemes to impose unlimited costs on consumers. Government has already announced or is announcing policies to reduce spending and to limit the exposure of the LCF to further spending risks. These announcements include:

- The removal of grandfathering for biomass co-firing plants and biomass conversions, where they change their RO band, reducing risk of further spend emerging by around £500m per year;[6]
- Action on solar under the RO. This includes closure of the RO to solar PV up to and including 5MW from the end of 2015/16; the removal of grandfathering for projects that do not meet the grace period criteria; and a re-banding for projects that come forward in 2015/16 but do not meet the grace period criteria. This is assumed to reduce spending projections by c£80m per year in 2020/21 (with a range from £60m-£100m), further to early closure to projects larger than 5MW announced last year;[7] and
- The removal of pre-accreditation under the FITs scheme[8], announced on 9th September 2015 and applying from the end of September 2015. This has reduced certainty for projects looking to deploy after this date that did not pre-accredit, and so is likely to have reduced deployment and therefore spending.

LCF Impact

Solar spending increase in 2011 and 2012

1.5 FITs has contributed significantly towards the increased spending under the LCF. In 2011 and in 2012, there were comprehensive reviews of the FITs scheme as a result of significantly higher than predicted solar deployment, at tariffs of around 40p/kWh. This led to major reductions in the tariffs at the time of the last review.

[1] Some <5MW projects are also supported under the RO, but they are usually supported by FITs.
[2] The RO Closure Order 2014 extends this closure date in some circumstances where projects are eligible for grace periods aimed at facilitating the RO to CfD transition. The RO closed early to new large-scale (>5MW) solar PV on 1 April 2015 with grace periods. On 18 June 2015 Government announced its intention to introduce primary legislation to close the RO early across Great Britain to new onshore wind generating stations from 1 April 2016 with grace periods and on 22 July 2015 published a consultation proposing changes to financial support for solar PV up to and including 5MW, including early closure from 1 April 2016 with grace periods.
[3] More information is available at https://www.gov.uk/government/statistics/cfd-auction-allocation-round-one-a-breakdown-of-the-outcome-by-technology-year-and-clearing-price
[4] The latest OBR LCF projections were published alongside the Spending Review on 25 November and is available at http://cdn.budgetresponsibility.independent.gov.uk/EFO_November__2015.pdf
[5] See table 2.7: http://cdn.budgetresponsibility.independent.gov.uk/Fiscal__Supplementary__Tables_November__2015.xls
[6] https://www.gov.uk/government/consultations/changes-to-grandfathering-policy-with-respect-to-future-biomass-co-firing-and-conversion-projects-in-the-renewables-obligation
[7] https://www.gov.uk/government/consultations/changes-to-financial-support-for-solar-pv
[8] https://www.gov.uk/government/consultations/changes-to-feed-in-tariff-accreditation. Note that pre-accreditation windows vary by technology, depending on the anticipated speed of construction: solar PV has a pre-accreditation window of 6 months, wind and AD have 12 months and hydro has 24 months.

Introduction of pre-accreditation

1.6 As well as lower tariffs, the 2012 Review also introduced degression policy. This meant that if deployment reached a certain level, tariffs would automatically reduce. This was felt to increase spending controls within the scheme.

1.7 Responding to that consultation, industry set out that degression would reduce certainty of funding and mean that much deployment would not go ahead. In response to this concern, Government introduced pre-accreditation. Pre-accreditation allowed developers to apply for funding under the scheme before they start generating and generally prior to beginning construction, and resulted in generators being guaranteed a particular tariff provided they commission the project within a certain window.

1.8 While successful in its aim of tackling the risk of a deployment freeze, pre-accreditation has contributed to further increases in spending under the LCF above and beyond the levels expected when the policy was established. In December 2013, there were major spikes in applications for pre-accreditation in Anaerobic Digestion (AD), hydro and wind ahead of tariff reductions in April 2014. While this resulted in significant tariff reductions through the degression policy, there have been further spikes seen in September and December 2014, ahead of tariff reductions. There has then also been a further pre-accreditation spike in September 2015, associated with the announced removal of pre-accreditation from the end of September 2015 as well as the FITs Review consultation. In addition, there is likely to be a deployment spike at the end of 2015, particularly from <50kW installations who cannot pre-accredit but could still be aiming to deploy before the changes from this FIT review are enacted, which will put more upwards pressure on spending under the LCF.

1.9 The spikes in 2013 and 2014 have resulted in significant spending increases under the LCF. In addition the September 2015 spike is expected to a further £120m to spend projections, with a range from £30m-£150m[9]. The expected spike at the end of 2015 around solar <50kW has not been quantified at this stage.

Spending projections

1.10 At the time of the 2012 FITs Comprehensive Review, spending on FITs in 2020/21 was anticipated to be c£1,160m; in the 2013 EMR Delivery Plan, spending was anticipated to be c£1,125m[10]. The 2013 and 2014 pre-accreditation spikes increased spending projections to £1,600[11]m in the absence of intervention, as set out in the FIT Review consultation and accompanying IA[12] . Pre-accreditation in September 2015 and the revised information received as part of the consultation have increased projections to c£1740m in the absence of intervention. While the ranges show that there remains uncertainty about deployment and spending under the scheme, it is clear that spending projections have increased markedly.

1.11 Pre-accreditation spikes have remained high over time, suggesting that the tariff reductions are insufficient to manage deployment and spending, as was intended following the 2012 review.

State Aid agreement

1.12 The European Commission's State aid approval for FITs places an obligation on Government to review scheme performance every three years. As part of the review process, Government will reassess the costs of technologies, electricity price forecasts and other income streams and whether the target rate of return is still appropriate, and consider revision of tariff levels accordingly. In particular, tariff levels will take account of any decreases in the levelised costs of generation to ensure there is no overcompensation.[13]

Results of review of underlying costs information

1.13 Available evidence suggests that costs of developments have reduced significantly over time. For the FIT Review consultation, DECC commissioned an independent evidence update earlier this year from WSP Parsons Brinckerhoff to review the cost and technical assumptions of FIT-eligible technologies, and supplemented this with work from Ricardo Energy and Environment on hurdle rates.[14] In addition, evidence collected through the consultation suggests that installations under FITs are, in general, significantly less expensive than previous estimates, suggesting that deployment could come forward at lower tariffs.

1.14 This review therefore aims to reflect the updated evidence in setting revised tariffs across technologies. It also aims to introduce robust cost control measures, to ensure that further risks around increased spending are managed and do not come to pass.

[9] This range depends on the % of pre-accreditation that converts in to full deployment and starts generating and costing consumers.
[10] Ranges from £930m to £1,340m
[11] Ranges from £1,450m to £1,730m
[12] https://www.gov.uk/government/consultations/consultation-on-a-review-of-the-feed-in-tariff-scheme#history
[13] http://ec.europa.eu/competition/state_aid/cases/235526/235526_1104588_39_2.pdf, para. 39.
[14] The WSP Parsons Brinckerhoff report is available on the FITs consultation page - https://www.gov.uk/government/consultations/consultation-on-a-review-of-the-feed-in-tariff-scheme

1.15 Throughout this document, cost, benefit and savings figures are given in 2016 prices. The exception is figures for deployment under the LCF, which are given in 2011/12 prices as this is the price base in which the LCF caps are currently set. The Office of Budget Responsibility publish regular forecasts for spend under the RO, FITs and CfDs in nominal terms; the figures provided in 2011/12 prices here underpin those. All spending figures are rounded to the nearest £5m.

Rationale for intervention

2.1. As a result of the increased LCF spending and the evidence suggesting significant cost changes, Government intends to change the support levels for FITs, and to introduce robust cost controls. This is to help ensure that:

- deployment and spending are brought under control;
- generators are not making excessive returns on their investments; and
- tariffs reflect the most up-to-date evidence.

2.2. Table 1 below shows the deployment under the FITs scheme projected at the time of the last FITs Comprehensive review, compared to the latest deployment information available. This shows that for AD, hydro and wind in particular, there has been significantly more deployment than had previously been expected. This includes pre-accredited projects: indications so far are that the majority of projects that pre-accredited have gone on to full accreditation.[15]

Table 1: comparison of actual deployment to 2014/15 to projections from 2012 Comprehensive review

MW	Actual deployment and pre-accreditation to July 2015*	2020/21 projection	
		2012 FITs Review	without cost control (2015 FITs Review)
PV	3,830	3,500-21,100	11,220
Wind	620	290	1,330
Hydro	200	160	400
AD	220	220	340

* Source: Actual Deployment and Pre-accreditation to July 2015 has been estimated using Commissioned Installed Capacity to March 2012[16] and then capacity registered in the monthly degression statistics[17].

2.3. Table 2 demonstrate the success of the FITs scheme in bringing forward deployment, which is contributing to 2020 renewable energy targets and longer-term objectives around decarbonisation. However, this has come at a cost. The tables below show the projections for FITs from the time of the scheme's introduction; from the last Review \in 2012; from those provided to the Office of Budget Responsibility (OBR) in July, and those now.

Table 2: Changes in spending projections over time

£m, 11/12 prices	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
2010 (introduction)	-	-	-	-	-	490
2012 (Comprehensive Review)	-	-	-	-	-	1,160
2013 (Delivery Plan)	800	885	955	1,020	1,080	1,125
2015 (OBR – July)	925	1,095	1,255	1,375	1,490	1,600
2015 (OBR – November)	1,155	1,310	1,440	1,550	1,640	1,720
Current[18]	1,120	1,330	1,470	1,580	1,670	1,740

Note that the current figures include the pre-accreditation spike from September 2015, but do not include an assessment of a spike in domestic solar deployment in Q4 2015.

2.4. Table 2 above clearly shows that spending projections have been increasing over time. Within the context of a limited LCF budget, this is unsustainable, and puts increasing pressure on consumer bills. In conjunction with the increases in expectations of deployment and generation under the RO and CfDs (including Final Investment Decision enabling for Renewables – FIDeR) that have been seen, the LCF spending estimates have increased to c£9bn, as set out in the November estimates. This was prior to the cost controls being put in place, set out in paragraph Section 5.

[15] This applies to solar, wind and AD. The hydro pre-accreditation window is two years, so data will not be available on how much of the pre-accredited capacity from 2013 has gone ahead until early next year.
[16] https://www.gov.uk/government/statistics/monthly-small-scale-renewable-deployment
[17] https://www.gov.uk/government/statistical-data-sets/monthly-mcs-and-roofit-statistics
[18] Note that this does not include the expected <50kW spike at the end of this year as the size is too uncertain

2.5. Based on the updated underpinning assumptions, which are based on the WSP Parsons Brinckerhoff report and the information received during the consultation, the Government response sets out revised tariffs for all technologies covered at this stage. This is in line with the scheme's State aid agreement, which requires reviews every three years to ensure there is no overcompensation under the scheme. AD and micro-Combined Heat and Power (micro-CHP) are not included at this stage, and will be consulted upon early in 2016.

2.6. DECC is using the best available evidence to set tariffs over this FITs Review period, through to the end of 2018/19. However, it is possible that some of the information may prove to be imprecise. It is also likely that over the period covered by the FITs review, there will be changes in the underlying factors that are not currently predicted. Recognising these inherent uncertainties, DECC is introducing caps, to be introduced as soon as possible, to offer certainty that spending cannot go above a certain level. This is to mitigate the risk of higher than predicted deployment which would result in further overspends in the absence of caps.

2.7. The costs of the relatively small scale technologies under FITs tend to be higher than for larger scale technologies.[19] However, the FITs scheme can offer wider benefits, including potentially encouraging behavioural change of households, communities and businesses involved in the scheme, and supporting a significant number of jobs in the supply chain (including installations). It is not possible to quantify these potential benefits.

Policy objective

3.1. The aims of this FITs review are firstly to revise tariffs reflecting the updated information, and secondly to control costs effectively, in a way that is consistent with the UK's undertaking in its State Aid approval. The State Aid approval states that DECC will consider "*the costs of technologies, electricity price forecasts and whether the target rate of return is still appropriate, and consider revision of tariff levels and decrease rates accordingly*".

3.2. The approach to be implemented offers better value for money through introducing lower tariffs to reduce excessive returns; it also reflects the updated data available. Government is introducing deployment caps to offer control over FITs expenditure. Government has decided that it is feasible for the scheme to be kept open with these cost controls in place, after consulting on an option to close the scheme entirely.

3.3. Given the need to control the LCF budget, Government has decided to limit spending on new generation under the scheme after tariffs have been revised. This cap on spend resulting from new deployment is set at a maximum of £100m cumulatively of LCF expenditure by 2018/19. This is a significant reduction compared to the amount of incremental spend attributable to new deployment over the last few years, which has generally been around £150m-£250m additional per year.

3.4. Within the constraints of the LCF framework and the £100m cap, the intention is to design a revised FITs scheme that:

- is sustainable over the longer term;
- offers a stable investment framework;
- avoids boom / bust scenarios;
- provides value for money for the consumer; and
- helps to move technologies and bands within those technologies towards zero subsidy.[20]

This, combined with the State Aid agreement, has governed the decisions set out within the consultation document and within this Impact Assessment.

3.5. While it is clear that deployment under the FITs scheme will reduce as a result of these changes to the scheme, the proposals in this review aim to provide continuity of support and a stable investment framework over this FITs Review period, whilst recognising the need to act in the billpayers' overall interests. The intention is for there to minimise the risk of booms and busts, which in turn should help to reduce costs of new installations over time by encouraging further investment in the technologies covered and in the skills to install and operate these technologies.

[19] The electricity generation costs report provides levelised cost estimates for all technologies. Levelised costs are the average cost per MWh of generation over the lifetime of the project, and are used as a valid comparison between different technologies. The latest electricity generation costs report is available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf. Table 13 clearly shows that costs tend to be higher for the smallest installations for each technology.

[20] Zero subsidy in this context will be likely to mean socket parity – i.e. the level at which a domestic, commercial or industrial installer can viably go ahead with a project without needing support through the generation tariff to make it viable as an investment. Grid parity is the level at which an installation does not need any income in addition to the market price.

3.6. As set out above, the tariffs for AD and micro-CHP are not being altered at this stage but will be addressed in a separate consultation in early 2016. It should be noted that some changes for other technologies – most notably, the introduction of caps and the revised degression policy – will also apply to AD from the same point at which it applies to solar PV, wind and hydro.

Future of the scheme

3.7. DECC does not intend to implement a decision on the long-term future of the FIT scheme at this stage. At present, the generation tariff element of the FIT is expected to close for new applicants in 2018/19. Generation tariffs will be available until the caps have been committed; underspend of these caps may be recycled within the scheme or used to offset budgetary risks.

3.8. Once the caps end at the end of 2018/19, DECC is currently minded to retain an export tariff, which would apply to new build capacity under FITs from 2019/20 onwards. However, the formulation of the export tariff may change, following consultation, to limit the impact on energy bill payers and better reflect the costs and benefits of renewable generation.

Supporting evidence

4.1. FITs installations incur costs and benefits. The private costs include the upfront cost of the installation and the operating cost over time. The private benefits include bill savings (as some generation is used on site, and therefore installations have lower demand for electricity); export tariffs (as some generation is exported back to the grid); and the generation tariff (which is set out within the Government response and within this Impact Assessment). The social costs and benefits compare the changes in the social costs of energy supply and emissions consistent with Green Book supplementary guidance.[21]

4.2. There are also assumptions made about technical characteristics of individual installations. These too influence the returns for installations. Therefore, the list below sets out the assumptions used in the analysis

- reference installation size;
- hurdle rates;
- capital expenditure (capex);
- operating expenditure (opex);
- load factors;
- export fraction;
- the value of bill savings;
- plant operating life;
- technical potential; and
- inflation assumptions.

4.3. DECC appointed WSP Parsons Brinckerhoff, an external consulting firm, to update the data on small-scale renewable generation costs used to calculate generation tariffs for the consultation. The data collection exercise was conducted using questionnaires issued to industry contacts and Trade Associations, interviews with key stakeholders, and literature reviews. WSP Parsons Brinckerhoff produced a report, *Small Scale Generation Cost Update*[22], showing the findings of their research that was published alongside the Consultation Document.

4.4. These results were subject to a large degree of uncertainty due to the small sample of data, in some cases, gathered by WSP Parsons Brinckerhoff. Throughout the consultation period, DECC encouraged stakeholders to submit information to supplement WSP Parsons Brinckerhoff report and increase the evidence base of the technologies' costs and technical characteristics.

Consultation responses and review of existing evidence

4.5. Around 100 respondents to the consultation supplied usable and evidenced costs data through the consultation in the form of receipts, company invoices, or other official documents. The evidence submitted generated around 8,800 new data points to inform capital expenditure of solar PV, wind and hydro, which

[21] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[22] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF

were added to the data provided by WSP Parsons Brinckerhoff to increase the evidence base. Evidence on operational expenditure was limited, with the exception of hydro.

Box: Treatment of new evidence on capital and operating expenditure (capex and opex), and hurdle rates

A large part of the evidence received through consultation consisted of receipts, invoices, quotes and some contractual agreements. It was diverse in both its format and inclusion of cost components.

Adjustments were made to ensure consistency of the data collected and that costs used in the analysis aligned with WSP Parsons Brinckerhoff's definitions of capex and opex, as set out in their report.

For example, a10% uplift was applied to evidence on supply and installation costs, where such data were assumed to exclude pre-development costs. This involved a significant amount of judgement, as it was not always explicit what was included in the quote or invoice, and whether certain components contributed to the capital expenditure of the installer.

In addition, the following changes were made in order to accommodate this new evidence into the overarching dataset:

- inflation adjustment using RPI to re-base costs in 2016 prices development year adjustment to reflect changing costs as set out by the WSP Parsons Brinckerhoff report;
- VAT adjustments for both domestic and commercial installations; and
- the exclusion of installations commissioned before 2008 and after 2015, as they were deemed to be either too outdated, or based on expected rather than actual costs.

This adjusted evidence was then merged with WSP Parsons Brinckerhoff data, augmenting DECC's evidence base. PB's previous method – calculating the median in each tariff band, excluding outliers 75% below and above the median and then re-calculating a median from the restricted sample of observations – was used to identify central values within each tariff band.

This approach was used consistently with the exception of a handful of tariff bands, where insufficient data points were available. Full details are set out in Annex A on inputs for the tariff calculator.

Due to the commercially sensitive nature of hurdle rates, the feedback received on this topic through consultation responses was mostly qualitative. Some respondents did provide quantitative estimates supported by detailed argumentation or specific evidence such as project finance models. Wherever sufficient information was provided, these quantitative responses were converted into data points which were then merged with the dataset initially gathered and analysed by WSP Parsons Brinckerhoff and Ricardo Energy and Environment, thus leading to a revised set of assumptions (see Annex A on hurdle rate methodology for the updated hurdle rate ranges).

The analysis focused on ensuring that the estimates provided by respondents were expressed using the same definitions as those used in DECC's modelling, as there are many different ways to measure rates of return and hurdle rates. In both the consultation and Government response, DECC has used pre-tax, real hurdle rates, and returns have been considered at project level rather than equity level. As a result, when consultation responses were expressed in terms of maximum payback times, they were converted into hurdle rate equivalents – first to post-tax nominal estimates, then pre-tax real estimates. Similarly, post-tax nominal hurdle rates provided were converted to pre-tax real hurdle rates. Finally, equity hurdle rates were converted to project hurdle rates. Annex A provides further detail on each of these conversion steps, as well as on a number of points where consultation responses revealed a degree of confusion around the definition and methodology used by DECC.

4.6. For load factors and export fraction, little evidenced data was received through consultation responses, apart from for hydro. As a result, updated internal evidence and external published reports have been used to review the assumptions, in light of comments from stakeholders.

4.7. Regarding hurdle rates (i.e. the minimum rate of return an investor will accept before proceeding with an investment), although most of the responses received were of a qualitative nature, sufficient quantitative evidence was received to add 16 new data points to the existing 85-point dataset initially gathered and analysed by WSP Parsons Brinckerhoff and Ricardo Energy and Environment. The new evidence received suggested that minimum hurdle rates for domestic and commercial investors were generally higher than those proposed in the consultation, thus also leading to an increase in the target rates of return used for tariff setting.

4.8. Other assumptions, for example the electricity price projections, were also updated following the consultation reflecting updates of projections.

Summary of assumption changes following consultation

4.9. Following the consultation, this section summarises the main changes across each of the assumptions used to derive generation tariffs. A more detailed list is available in Annex A.

4.10. In the consultation, tariffs were based on the best available information and evidence across a range of factors. This was mainly drawn from the WSP Parsons Brinckerhoff report. Given the intention to only bring forward the most efficient sites, and given the financial constraints on the scheme, DECC proposed setting tariffs based on median costs, low hurdle rates and high load factors excluding outliers in the available evidence. As well as targeting the most efficient sites and investors, the intention of this was to offer a level of support that provided adequate compensation for the costs and risks developers face.

4.11. During the consultation, further information was received, which has led to revisions to the underpinning assumptions. The information received, and how it was used, is included in Annex A. The Annex begins with what was proposed in the consultation; what information was received during the consultation; how that information has been used; and what was the final assumption used for tariff setting and modelling in the Government response. The approach taken in the consultation – to targeting efficient sites, with high load factors and relatively low rates of return, has been maintained.

New tariff bands

5.1. The consultation proposed changes to some of the tariff bands. Table 3 below shows new bands versus old bands. The general approach to tariff and degression bands has been to merge bands to simplify the scheme, and to more accurately reflect genuine differences in the types of installations covered. There have been some amendments following information received in the consultation.

Table 3: Final tariff bands compared to current tariff bands

Tariff bands in Government Response	Tariff bands in consultation	Current Tariff bands
Solar PV		
0 -10kW	0 -10kW	<4kW
		4-50kW
10 - 50kW	10 - 50kW	
50 - 250kW	50 - 250kW	50-150kW
		150-250kW
250-1000kW	250-1000kW	250-5000kW
> 1000kW	> 1000kW	
Stand alone	Stand alone	Stand alone
Wind		
<50kW	<50kW	0-100kW
100–1500kW	50–1500kW	
50–1500kW		100–500kW
		500–1,500kW
>1500kW	>1500kW	>1500kW
Hydro		
<100kW	<100kW	<15kW
		15-100kW
100-500 kW	100-500 kW	100-500kW
500-2000kW	500-2000kW	500-2000kW
>2000kW	>2000kW	>2000kW

5.2. The tariff band changes are as set out above:

(i) The decision to create a new 0-10kW domestic solar band is retained. Other solar bands remain as per the consultation.

(ii) Following feedback during the consultation, the 50-1,500kW wind band is split into a band for 50-100kW projects and one for 100-1,500kW projects. This reflects information received setting out that this wind band uses different technology to the other wind installations within the 50-1,500kW band that was proposed in the consultation. Other bands remain the same.

(iii) The hydro bands are as set out in the consultation. No compelling evidence was received disagreeing with the creation of the 0-100kW hydro band.

5.3. Table 4 below sets out the assumptions that are used for each tariff band. A short description is set out of each factor following the table, with greater detail provided in Annex A.

Table 4: assumptions used in final tariff calculations[23]

Tariff band		Reference size of installation (kW)	Target rate of return (%)	Capex (incl. grid connection) (£/kW)	Opex (£/kW)	Load factor (%)	Export fraction (%)	Electricity price faced	Plant lifetime (years)
Solar PV	**0 -10kW**	3	4.8	1,630	20	10.8	55	Residential	30
	10 - 50kW	30		1,770	10		50	Services/ Industrial	
	50-250kW	140		1,550	10		50	Services/ Industrial	
	250-1000kW	455		1,480	10		50	Services/ Industrial	
	> 1000kW	2,840		1,310	10		50	Services/ Industrial	
	Stand alone	2,590		1,310	10		100	Wholesale	
Wind	**<50kW**	10	5.9	4,360	30	26.4	50	Services/ Industrial	20
	50-100kW	80		4,350	30	26.4	75	Services/ Industrial	
	100–1500kW	482		2,700	60	28.7	85	Services/ Industrial	
	>1500kW	3,408		1,680	20	32.4	100	Wholesale	
Hydro	**<100kW**	33	9.2	6,910	70	60	75	Services/ Industrial	35
	100-500 kW	346		4,640	40	50	88	Services/ Industrial	
	500-2000kW	1,046		3,780	20	40	99	Wholesale	
	>2000kW	2,253		3,730	19	40	99	Wholesale	

Reference size of Installation

5.4. The reference size of an installation is an average-sized project, based on the projects that have previously commissioned under the scheme.

Hurdle rates / target rates of return

5.5. The target rates of return proposed in the consultation were challenged for two main reasons. The first was the level of the assumed overall hurdle rate ranges, and the second was the proposal to target the low end of the intersection between the domestic and commercial hurdle rate ranges for tariff setting. Although mostly qualitative, the responses received during the consultation also included some new quantitative information, including project finance models from developers.

5.6. The quantitative feedback gathered on hurdle rates was adjusted to ensure that the values provided by respondents were on an equivalent basis to the values used in DECC modelling, as there are many different ways to measure rates of return and hurdle rates (see annex D for detail on the methodology). Wherever sufficient information was provided, new evidence was converted into data points which were then added to the dataset initially gathered and analysed by WSP Parsons Brinckerhoff and Ricardo Energy and Environment. This has led to revised assumptions, summarised in Annex A.

5.7. This is the only amendment DECC has made to the assumptions on hurdle rates. The methodology used to determine the target rates of return has not been changed – they are still set on the basis of the lowest

[23] All figures in this Table are rounded to the nearest £10,

intersection point of domestic and commercial investors, reflecting the desire to target only the most efficient installations. They are now, however, based on the new hurdle rate ranges including the information provided during the consultation.

5.8. DECC recognises that hurdle rates could increase as a result of the introduction of caps. As explained in paragraph 5.41 onwards, Government has mitigated against this risk, so hurdle rates have not been adjusted.

Capital costs (Capex)

5.9. Capex costs are expressed in £/kW per year and are in 2016 prices.[24] The capex values from WSP Parsons Brinckerhoff were adjusted according to the tariff bands set out in the consultation. The consultation tariff bands did not always correspond to the tariff bands for which WSP Parsons Brinckerhoff collected data, which reflected the tariff bands that were in place prior to the consultation. To do the conversion, the underlying project level data were used.

5.10. During the consultation, the majority of responses with usable data were about capex. This included receipts from individual installations and developers and reports compiled by organisations on behalf of Trade Associations and including data points. Annex A provides more detail on the information received and how it has been taken into account.

5.11. In general, solar data received was broadly in line with the information used for the consultation. Of the data points received, the vast majority came from the Renewable Energy Consumer Code (RECC) database. The evidence from this suggested a marginal reduction in the capex for domestic (up to 10kW) solar installations; for the 10-50kW band, information received suggested a slight increase.

5.12. For wind, the new data received suggested that capex was underestimated in the consultation, particularly for 50-100kW installations. As a result, the capex figure has been revised upwards, and a separate tariff band for projects of this size has been introduced.

5.13. The hydro data received in the consultation also suggested that the WSP Parsons Brinckerhoff capex data was an underestimate for plants up to 500kW. The British Hydro Association supplied a report, which gave data on more than 160 installations or projects. This covered costs and technical assumptions contained in the WSP Parsons Brinckerhoff report and used in tariff setting.

5.14. There were two further adjustments:

(i) For wind data <100kW, which incorporates the 0-50kW and 50-100kW bands, all capex observations up to 100kW were used to derive capex. This reflects firstly that few data points were received for <50kW installations; secondly, it reflects that there is not felt to be any significant difference in the type of installations to suggest that they would have significantly different capex costs. This means that with the exception of grid connection costs, all wind installations below 100kW are assumed to have the same capex per kW.

(ii) For hydro data >500kW, which incorporates the 500-2,000kW and >2,000kW bands, all capex observations >500kW were used. As above, this reflects that few observations were received for projects >2,000kW, and that the installations costs per kW were again felt to be similar.

For both of these, while the raw data suggests cost differences, there is not felt to be anything systematically different the bands that would justify differences in the underlying capex.

Operating costs (Opex)

5.15. Opex costs are expressed in £/kW per year and are in 2016 prices.[25] As in the consultation, the opex value used is the central value, and has been adjusted to reflect the change in tariff bands. New opex data was received during the consultation. This has been combined with the original data from WSP Parsons Brinckerhoff and included within the revised opex figures, set out in Table 4 and described in more detail in Annex A.

Load Factors

5.16. In the consultation, load factors were taken from the high end of the range of data from WSP Parsons Brinckerhoff. This reflects the intention of targeting well-sited installations, and represents the desire to target the most efficient sites. The exception to this was for hydro, where central load factors were used. This reflected the site-specific nature of hydro load factors, and so the central load factor was assumed to be more appropriate.

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[24] Capex figures have been converted into £2016 prices using RPI from those given in the WSP Parsons Brinckerhoff report.
[25] Opex figures have been converted into £2016 prices using RPI from those given in the WSP Parsons Brinckerhoff report.

5.17. The consultation responses did not challenge the load factor ranges for wind or for solar. What they did, however, challenge was the use of the high load factors for each technology. This was particularly the case for solar, where the proposed load factor of 11.3% used in generation tariff setting was based on the high realised load factor of the south west, which is the sunniest part of the country.

5.18. As a result of the responses, the solar load factor has been amended in three ways. Firstly, the data has been re-assessed. This involved removing the inapplicable data points (e.g. modelled data and data for sites larger that permitted on the FITs scheme). Secondly, tariffs are now set on the upper quartile of the available estimates for the load factor of installations located in the Midlands rather than the South West. This gives a raw load factor of 11.1%. DECC are still using the upper quartile load factor estimate, reflecting the intention to bring forward well-sited projects In addition, solar panel degradation – i.e. falling output over the lifetime of the project – has been taken into account for the first time for solar generation. Government has assumed that degradation results in a progressive linear fall of 0.5% per year in panel efficiency. This reduces the load factor assumed over the lifetime of the installation falling from 11.1% to 10.8% which has been taken into account in tariff setting.

5.19. The load factors used for wind have not changed.

5.20. For hydro, the report provided by the British Hydro Association included additional load factor information. Following analysis of this information, the load factor for the smallest hydro band (0-100kW) was revised upwards to 60% and for the 100-500kW it was revised upwards to 50%. While the WSP Parsons Brinckerhoff data on high load factors was initially rejected during the consultation, the information received from the British Hydro Association has corroborated that smaller sites tend to have higher load factors.

Export income and export fraction

5.21. An export tariff of 4.85p/KWh has been used to calculate export income. This is the current export tariff referred to in Ofgem "Tariff Tables" for Financial Year 2015/16.[26]

5.22. Export payments reflect current export arrangements for smaller installations as reported in Ofgem's Annual Report.[27] In the consultation, WSP Parsons Brinckerhoff data was used for the majority of installations to understand how much electricity was exported or consumed on site. The only exception to this was for <100kW hydro installations, where the export fraction is assumed as 75% rather than 20%. This 75% is the deemed export fraction set in the Secretary of State Determinations.

5.23. The majority of larger installations were assumed to sell their exported electricity outside of the scheme under Power Purchase Agreements, and therefore do not receive the export tariff. Due to the lack of information on the agreed price in Power Purchase Agreements, for the purposes of calculating the generation tariff the consultation assumed that the export tariff is applied to all size installations. This means the developer is assumed to receive the export tariff for any electricity exported to the grid. This assumption has been retained for the Government response.

5.24. The consultation did not provide significant additional information on the export fraction for hydro and wind. As a result, the export fraction for these technologies has been maintained at the level that was proposed in the consultation. For solar, additional information for the <10kW band was received. The consensus in the literature and evidence received is that between 25 and 45% of electricity generated is used on site, compared to the 47% that was assumed in the consultation (giving an export fraction of 53%). The scheme seeks to incentivise greater self-consumption to reduce the impact on distribution networks of exported energy and its associated costs so the assumption used for tariff calculation is that 45% is used on-site, giving an export fraction of 55%. For all other building mounted solar bands Government has simplified the approach and assumed an export fraction of 50% as per the annual determinations. For standalone PV installations Government had continued to assume that 100% of the electricity generated is exported.

5.25. While the solar export fraction for the <10kW band is assumed to be 55%, the deemed export fraction in the Secretary of State Determinations is only 50%. This is the value that has been used to in the calculation of solar tariffs i.e. Government assumes that a typical installation in the <10kW PV band gets bill savings from 45% of electricity generated but gets the export tariff for only 50% of the electricity generated.

Electricity Prices

5.26. The price of electricity is used to estimate the value of the electricity consumed on-site and the potential bills savings that FIT generators are making. FIT generators face different electricity prices depending on the sector to which they belong. It is assumed that this in turn relates to the size of their installation. Residential electricity prices tend to apply to the smallest solar PV tariff band for installations <10kW. Wholesale prices apply to the larger tariff bands – standalone Solar PV; installations >1,500kW for wind and installations >500kW for hydro. For all other installations facing either the service or industrial electricity price, an average

[26] https://www.ofgem.gov.uk/environmental-programmes/feed-tariff-fit-scheme/tariff-tables
[27] https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/feed-in_tariff_fit_annual_report_2013_2014.pdf

of the services and industrial electricity price is applied. This is due to the difficulty in defining whether installations in these bands belong to the services or industrial sector.

5.27. For the consultation, the electricity prices from the 2014 Energy Emissions and Projections (EEP) were used. Since the consultation was published, an updated EEP has been published.[28] In general, central electricity price projections are now lower than they were in 2014 (as are the high and low). This means that the benefit an installation gets from forgoing part of its electricity bill is correspondingly lower, and the generation tariff has been increased to compensate for the difference.

5.28. The tariffs set out in the Government response also make changes to how the reductions in electricity bills are calculated. As installations will remain connected to the grid, they will also tend to face standing charges, regardless of how much electricity is consumed. Therefore tariffs for the <10kW solar tariff band have been set using only the variable element of the electricity price, excluding the standing charge, as it is on this part of the electricity bill that savings can be made. It is assumed that 88% of the retail electricity price is variable, and 12% is a standing charge. This is because the average standing charge was 12% in 2014.[29] Tariffs for all other solar bands, and hydro and wind, have been set using the total electricity price. This is because there is insufficient information available on the variable percentage of the price for non-householders.

Plant lifetime

5.29. No compelling information was received to challenge the operating period of plants under the FITs scheme. Therefore, the technology lifetimes remain as they were in the consultation.

Resulting tariffs

5.30. The tariffs that result from the assumptions set out above are included in Table 5 below. Where the tariffs do not solely come from the underlying assumptions, and judgements have been made as to what the level of the tariffs should be, this is clearly set out.

Options considered

5.31. In the consultation, the options presented were:

(i) to do nothing;

(ii) to implement the changes set out in the consultation, and

(iii) to close the scheme as soon as was feasible.

Closure was included as an option reflecting that there was uncertainty as to whether spending control could be introduced through the measures proposed in the consultation. If it was not felt feasible to have a scheme that brought forward deployment, the scheme would have been closed.

5.32. The changes proposed in the consultation and the amendments set out in the Government Response should allow for a scheme that brings forward deployment, but that also offers Government cost control over the scheme. As a result, the only Option presented in this final IA is to alter the scheme as set out in the Government response. A summary of the policy decisions associated with this option is below.

- **Option 1 – do nothing**. Under this option the FITs scheme continues as is, prior to the consultation. This would also assume that pre-accreditation is not removed.
- **Option 2 – make the policy changes as set out in the Government response and in this Impact Assessment**. This includes:
  i. Changing tariff bands;
  ii. Changing tariffs;
  iii. Introducing caps;
  iv. Changing default degression;
  v. Changing contingent degression;
  vi. Changing degression bands; and
  vii. Re-introduction of pre-accreditation, following its removal at the end of September 2015.

[28] The 2015 EEP is available at https://www.gov.uk/government/collections/energy-and-emissions-projections
[29] This is based on a fixed consumption of 3,800kWh and data tables published at: https://www.gov.uk/government/statistical-data-sets/annual-domestic-energy-price-statistics

5.33. The rest of this section explains each of these changes in detail, including the rationale for the change, what options have been considered and why the preferred option has been chosen. The information on which these decisions have been based is set out in Section 4, above. More information is available in Annex A.

Option 1 – do nothing

5.34. By definition, the costs and benefits of doing nothing are zero. Deployment and spending projections would be as set out in Tables 11 and 17. In addition to spending significantly more money than was forecast at the time of the FITs Comprehensive review in 2012, there would remain a risk that there would be further deployment and spending increases beyond current forecasts. This would need to be paid for out of consumer bills, through the LCF.

Option 2 – make the policy changes as set out in the Government response

5.35. This option assesses the likely impact of the changes set out in the Government response, including the amendments to tariff and degression bands; reduction of tariffs; the introduction of caps; the changes to default and contingent degression; and the reintroduction of pre-accreditation. These decisions are dealt with individually below.

5.36. As was set out in the consultation document, if more time is considered necessary to introduce caps and ensure robust cost control, a temporary pause to new generators aiming to accredit under the scheme may be introduced. DECC is intending to pause the scheme from 15th January to 7th February inclusive, during which time plants will not be allowed to accredit.

5.37. FITs is a State Aid scheme, and was notified to the EU Commission in 2010. Any change beyond merely administrative change has to be notified to the Commission: changes that are based on changes in costs and return rates, aimed at maintaining the current rates of return, do not require notifying. However it is likely that anything which changed which technologies can benefit from the scheme would be a change which requires notifying. All of the changes set out within this option are therefore made with this in mind.

Tariff setting - combining the assumptions into tariffs

5.38. Table 3 above sets out the revised tariff bands following the consultation. Table 5 below sets out the tariffs that are based on the assumptions set out in section 4. The costs of an installation are calculated over the lifetime of the project, compared with the revenue streams, and the generation tariff is set to bring on well-sited installations with low hurdle rates. It does this by making up the residual – the amount of money over and above the income streams that a plant would need to hit its target rate of return. This is based on median capex and opex, high load factors (apart from for hydro) and targeting a low rate of return.

5.39. This method is used for the majority of tariff bands. There are a few exceptions:

(i) Ground-mounted solar: As for the consultation, the tariff for ground-mounted solar is capped at the level of the largest roof-mounted solar tariff band. As costs for roof- and ground mounted installations are approximately equal, but ground-mounted solar would have a higher tariff because all of its power is exported. Government would like to see continued deployment of commercial solar, and would like to prioritise projects that offer the best value for money – be they ground-mounted or building-mounted. In the absence of this, the ground-mounted solar tariff would have been 5.93p/kWh, rather than 0.87p/kWh.

(ii) Wind 50-100kW: Because the 0-50kW wind band is assumed to use 50% of electricity generated on site whereas a 50-100kW installation is assumed to use only 25% on site, the tariff required for a 50-100kW installation is greater than that for a 0-50kW installation. DECC has decided to cap the 50-100kW tariff band at the level of the 0-50kW band, at 8.54p/kWh. In the absence of this, the 50-100kW wind tariff would have been 10.52p/kWh.

(iii) Hydro 500-2,000kW: Because of lower assumed load factor between the 100-500kW band than in the 500-2,000kW band, the tariff required for a 500-2,000kW band to achieve the target rate of return is slightly higher (6.93p/kWh) than that for the 100-500kW band (6.14/kWh). It has been decided to cap the 500-2,000kW band at the same tariff as the 100-500kW band.

(iv) Hydro >2,000kW: The tariff for this band is currently 2.43p/kWh, and no deployment has occurred in this band. This could be due to the support rate being too low to bring plants forward, or because of the unavailability of suitable sites. The assumptions set out in Table 4 would suggest a tariff of 6.77p/kWh. However, this is above the equivalent level of support available under the Renewables Obligation, which has been sufficient to bring forward deployment. Therefore, the hydro tariff for >2,000kW installations has been set to reflect the support available under the RO, at 4.43p/kWh.[30]

Table 5: New tariffs, applying from implementation

Decided Generation Tariffs for Jan 2016 (p/kWh, Nominal prices)		Generation Tariffs consulted on for Jan 2016 (p/kWh, Nominal prices)		Ofgem Tariffs for installations with an eligibility date on or after 1 October 2015 (p/kWh, 2015/16 values)	
Solar PV					
0 -10kW	4.39	**0 -10kW**	1.63	**<4kW**	12.47
				4-50kW	11.30
10 - 50kW	4.59	**10 - 50kW**	3.69		
50 - 250kW	2.70	**50 - 250kW**	2.64	**50-150kW**	9.63
				150-250kW	9.21
250-1000kW	2.27	**250-1000kW**	2.28	**250-5000kW**	5.94
> 1000kW	0.87	**> 1000kW**	1.03		
Stand alone	0.87	**Stand alone**	1.03	**Stand alone**	4.28
Wind					
<50kW	8.54	**<50kW**	8.61	**0-100kW**	13.73
100–1500kW	8.54	**50–1500kW**	4.52		
50–1500kW	5.46			**100–500kW**	10.85
				500–1,500kW	5.89
>1500kW	0.86	**>1500kW**	0.00	**>1500kW**	2.49
Hydro					
<100kW	8.54	**<100kW**	10.66	**<15kW**	15.45
				15-100kW	14.43
100-500 kW	6.14	**100-500 kW**	9.78	**100-500kW**	11.40
500-2000kW	6.14	**500-2000kW**	6.56	**500-2000kW**	8.91
>2000kW	4.43	**>2000kW**	2.18	**>2000kW**	2.43

5.40. For solar PV, multi-installations will continue to receive either the middle or lower rate as set out in Ofgem's "Guidance for Renewable Installations (version 9)" published in June 2015. The middle rate is 90% of the proposed higher rate unless that is less than the lower rate, in which case it shall be equal to the lower rate. The lower rate is equal to the proposed generation tariff for the solar PV band >1,000kW.[31] The analysis in this document is based on the higher tariff rate (set out in Table 5) only.

Setting deployment caps

5.41. As set out above, one of the primary aims of the 2015 FITs review is to introduce control over spending under the FITs scheme. While the reduction of tariffs alone will help to reduce projected spending and improve value for money, it will not offer certainty about what total spending under the FITs scheme will be. Changes in underlying costs and revenue streams would still have the potential to result in significant increases in spending compared to forecasts in future.

5.42. In the consultation, the maximum budget for new deployment under FITs between when the changes are implemented in early 2016 and April 2019 was set at £100 million. The Government remains of the view that introducing deployment caps for FITs is necessary to keep spending within this budget, delivering the

[30] This is based on a ROC price in 2015/16 of £44.33, as set out on the Ofgem website. https://www.ofgem.gov.uk/environmental-programmes/renewables-obligation-ro/information-suppliers. The assumed ROC support level is set at 1 ROC, reflecting support in Scotland, rather than the 0.7 ROCs used in England and Wales. This reflects that the majority of hydro sites are in Scotland.
[31] https://www.ofgem.gov.uk/publications-and-updates/feed-tariff-fit-guidance-renewable-installations-version-9

overriding cost control objectives of the FITs review. Government has decided to keep the cap at the same level as proposed in the consultation, of £100m.[32]

5.43. The Government has decided to proceed with the proposal to set deployment caps on a quarterly basis. The Government has decided to continue to set caps based on degression bands. The Government has decided to adjust these bands in response to industry requests made through the consultation. The result is a single degression (and cap) band for AD; and an additional degression band for wind and hydro. New degression bands are set out in Table 6.

Table 6: New degression bands (and cap bands)

Degression/cap bands	Degression bands in Government Response	Degression bands in consultation	Current degression bands
PV	<10kW	<10kW	<10kW
	10-50kW	10-50kW	10-50kW
	50-5,000kW	50-5,000kW	50-5,000kW
	Standalone	Standalone	Standalone
Wind	<50kW	<50kW	<100kW
	50-100kW	50kW-5,000kW	
	100-1,500kW		100-5,000kW
	1,500kW-5,000kw		
Hydro	0-100kW	All	All
	100-5,000kW		
AD	All	<500kW	<500kW
		500-5,000kW	500-5,000kW

5.44. In the consultation, Government proposed distributing the £100 million budget between technologies based on the underlying FITs modelling. As the spending projection from the revised assumptions was in the region of £90m, the caps proposed in the consultation were above the unconstrained projected level of deployment from the proposed tariffs.

5.45. However, the additional evidence and revised assumptions now give a spending projection, in the absence of caps, which is greater than £100m. Because of this, decisions must be made about how to apportion the cap across technologies.

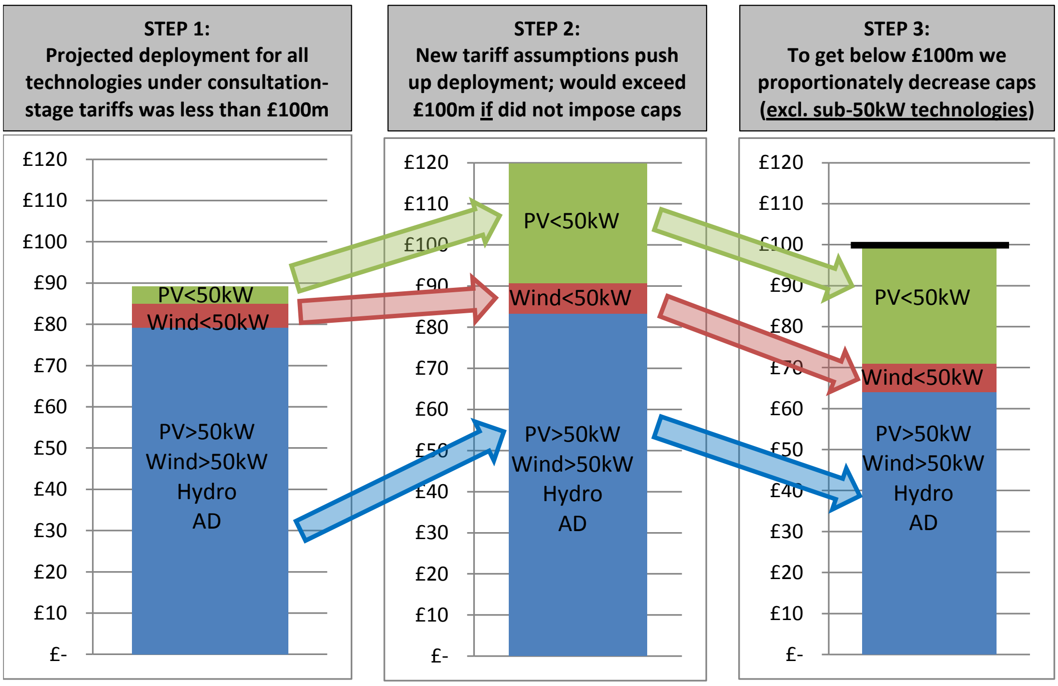
5.46. The implementation of deployment caps introduces allocation risk into the scheme, as projects are not certain when they begin developing that they will get support under the scheme. Government has decided to mitigate this allocation risk for all technologies. While this cannot be done in the same way for all technology bands, Government considers the mitigating actions are in line with the State Aid agreement for the FITs scheme. They are:

- For the projects and tariff bands that previously had pre-accreditation prior to its repeal in September 2015, they will once again have access to pre-accreditation. Projects can pre-accredit up to the cap in a particular quarter; once the cap is reached, based on both accredited and pre-accredited projects[33], the cap is closed until the next quarter and no further projects can either accredit or pre-accredit in that degression band. This will reduce the allocation risk to the developer to the costs incurred prior to being able to apply for pre-accreditation only.

- For projects that cannot pre-accredit (solar and wind projects <50kW), the cap is set at the level of the deployment projection. This should serve to reduce allocation risk for these projects – if the underlying assumptions and deployment projections are correct, then all projects that cannot pre-accredit but can come forward would be able to accredit. While this does not remove allocation risk for solar and wind projects <50kW, it does reduce it. This is illustrated in Chart 1.

[32] Note that this does not include deployment that pre-accredited in September 2015, or at any point prior to the changes being implemented.
[33] It will be based on pre-accreditation applications, rather than predicted or realised pre-accreditations.

Chart 1: How caps are implemented



5.47. The intention of both the re-introduction of pre-accreditation and the adjustment to the caps is to mitigate allocation risk for all projects, albeit in different ways depending on whether pre-accreditation is possible. This is considered preferable to the alternative, which would be to increase hurdle rates, and therefore tariffs, to compensate for the allocation risk. This would result in higher generation tariffs, and therefore less capacity and generation coming forward under the cap.

5.48. The result is caps for AD, hydro and >50kW solar and wind which are affordable, but are lower than the central deployment projected. This means that not all projects that are projected to deploy in the absence of caps will be able to. However, pre-accreditation will be available to these projects. This means they will be able to reserve a place within a cap before they are fully commissioned, reducing (although not removing) the risks associated with missing out on a cap. If the cap is reached then projects will not be able to pre-accredit into it. This means there will remain some residual risk for these projects – albeit much less so than if pre-accreditation were not re-introduced and developers needed to fully build the project before finding out whether they had a place within the cap.

5.49. Table 7 below shows how the budget has been divided between technologies on the basis of this approach.

Table 7 – Division of the budget between technologies and years

£m 2011/12 prices, full year spend	2016/17	2017/18	2018/19	Total
PV	10	10	10	35
Wind	5	5	5	20
Hydro	5	10	10	25
AD	10	10	10	25
Total	30	35	35	100

5.50. Table 8 below shows the deployment levels at which the caps have been set for each technology and which will apply from the 8th February 2016]. This represents the conversion from the spending cap, set out in Table 7, into deployment limits by quarter for each degression band. Some of these caps – for example, the stand alone solar cap and the 1,500-5,000kW wind cap – have been adjusted to 5MW; in the absence of this adjustment, the caps would be lower. This is done to ensure that all projects up to and including 5MW remain eligible to come forward under the FITs scheme.

Table 8 – Maximum Deployment caps (deployment per quarter)

Maximum Deployment (MW)		2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1
PV	<10kW	48.4	49.6	50.6	51.7	52.8	53.8	54.2	55.9	57.0	58.0	59.1	60.1	61.1
	10-50kW	16.5	17.0	17.4	17.8	18.2	18.6	18.7	19.4	19.8	20.3	20.7	21.1	21.5
	>50kW	14.1	14.5	14.9	15.4	15.8	16.2	16.4	17.1	17.6	18.0	18.5	19.0	19.4
	Standalone	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Wind	<50kW	5.6	5.6	5.5	5.5	5.6	5.5	5.5	5.4	5.5	5.4	5.4	5.3	5.4
	50-100kW	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	100-1500kW	6.8	6.7	6.6	6.5	6.4	6.3	6.2	6.1	6.1	5.9	5.8	5.7	5.7
	1500kW-5000kW	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Hydro	0-100kW	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4
	100-5000kW	6.1	6.2	6.3	6.3	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.3	6.3
AD	All	5.8	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

5.51. Table 9 provides an estimate of the number of installations that could come forward under each cap. These numbers are based on the average installation size within each band and are therefore only indicative. If larger than average installations come forward, then the number of installations that are included within the deployment cap will be lower.

Table 9 – Estimated number of installations at maximum deployment (deployment per quarter)

Estimated number of installations[34]		2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1
PV	<10kW	15,330	15,710	16,050	16,380	16,720	17,060	17,170	17,720	18,060	18,390	18,710	19,040	19,360
	10-50kW	500	510	520	530	550	560	560	580	600	610	620	630	650
	>50kW	70	70	70	70	80	80	80	80	80	90	90	90	90
	Stand-alone	2	2	2	2	2	2	2	2	2	2	2	2	2
Wind	<50kW	540	540	540	530	540	530	530	520	530	520	520	510	520
	50-100kW	4	4	4	3	4	3	3	3	3	3	3	3	3
	100-1500kW	20	20	20	20	20	20	20	20	20	20	10	10	10
	1500kW - 5000kw	2	2	2	2	2	2	2	2	2	2	2	2	2
Hydro	0-100kW	50	50	60	60	60	60	60	70	70	70	70	70	70
	100-5000kW	10	10	10	10	10	10	10	10	10	10	10	10	10
AD	All	10	10	10	10	10	10	10	20	20	20	20	20	20

5.52. The caps set out in Table 8 could increase in future. This is because the Government has decided to introduce a system for recycling underspend – i.e. where a cap for a particular degression band is not reached within a given quarter. Underspend will be recycled in two ways:

- In-year rollover process – any unused capacity for a particular technology and degression band from one quarter simply gets added on to the next quarter; and
- A budget reconciliation for FITs, which Government expect to be biannual but could be more or less frequent depending on deployment: this would bring together any underspend and, subject to addressing any budgetary pressures, redistribute it as deployment cap "top ups". In considering where Government redistribute these top-ups, Government will take into account its policy priorities. At present, Government expects this redistributed underspend could be towards solar PV to continue supporting a trajectory towards subsidy-free deployment as well as providing additional support to meet previous deployment projections.

[34] Note that this is based on the average installation size – the number of installations permitted under the cap could be higher or lower.

5.53. The caps set out in Table 8 may need to be adjusted in the event of any future tariff changes. A reduction in tariffs beyond the automatic reductions for a particular technology and/or degression band, could lead to an increase in the cap for that and other technologies. This is because lower tariffs mean more deployment can be afforded for the same cost. This will be relevant for the decisions following the AD consultation in early 2016.

5.54. Further detail on responses to the consultation questions on caps and the Government's final decision on how caps will be implemented is set out in Chapter 2 of the Government Response.

Degression

5.55. The current FITs scheme includes two forms of degression, the mechanism by which tariffs fall over time. The first of these is "default degression", which means that tariffs fall automatically over time. This is independent of deployment. The second is "contingent degression", which means that tariffs fall if certain criteria are fulfilled. In practice, contingent degression is linked to deployment thresholds being reached. While both have reduced tariffs over the current FITs review period, they have not proved adept at maintaining spending control over the scheme, as was previously envisaged.

5.56. The consultation proposed to maintain default and contingent degression, but to amend their values and how they operate. In particular, it was proposed that both forms of degression will operate within the context of a capped FITs scheme.

5.57. Government has decided that default degression occurs independently of other factors, such as deployment. The aim of default degression is to offer an investor the same rate of return over time. Therefore, it will take into account projected changes to the bill savings and to the costs of installations. The bill savings are based on the projected electricity bill savings of the installed project. The costs of installations are based on projected changes in capex and opex; more information is available in in the WSP Parsons Brinckerhoff report, and in Annex A. For the purposes of setting default degression, the tariff reductions are smoothed over time and averaged equally over the period Quarter 1 2016 to Quarter 1 2019.

5.58. Table 10 sets out the proposed generation tariffs over this FITs review period, taking into account default degression only. For the majority of tariff bands, particularly solar, it is clear that costs are anticipated to decline further over time, moving closer to socket parity. At the time of consultation, evidence suggested that some solar PV tariffs should fall to zero under default degression. The updated evidence that was received and has come to light since the consultation suggests that this is no longer the case.

Table 10: Tariffs over time, as a result of default degression only

Generation Tariffs p/kWh, Q1 2016 prices		2016				2017				2018				2019
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
PV	<10kW	4.39	4.32	4.25	4.18	4.11	4.04	3.97	3.90	3.83	3.76	3.69	3.62	3.55
	10 - 50kW	4.59	4.53	4.46	4.39	4.32	4.25	4.19	4.12	4.05	3.98	3.91	3.85	3.78
	50 - 250kW	2.70	2.64	2.58	2.51	2.45	2.39	2.33	2.27	2.20	2.14	2.08	2.02	1.96
	250-1000kW	2.27	2.21	2.15	2.09	2.03	1.97	1.91	1.85	1.78	1.72	1.66	1.60	1.54
	1000-5000kW	0.87	0.82	0.76	0.70	0.64	0.58	0.52	0.46	0.41	0.35	0.29	0.23	0.17
	Stand alone	0.87	0.82	0.76	0.70	0.64	0.58	0.52	0.46	0.41	0.35	0.29	0.23	0.17
Hydro	<100kW	8.54	8.53	8.51	8.50	8.48	8.46	8.45	8.43	8.42	8.40	8.39	8.37	8.35
	100-500 kW	6.14	6.14	6.13	6.12	6.11	6.11	6.10	6.09	6.09	6.08	6.07	6.06	6.06
	500-2000kW	6.14	6.14	6.13	6.12	6.11	6.11	6.10	6.09	6.09	6.08	6.07	6.06	6.06
	2000-5000kW	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
Wind	0-50kW	8.53	8.46	8.39	8.33	8.26	8.19	8.13	8.06	7.99	7.93	7.86	7.79	7.73
	50-100kW	8.53	8.46	8.39	8.33	8.26	8.19	8.13	8.06	7.99	7.93	7.86	7.79	7.73
	100-1500kW	5.46	5.43	5.40	5.37	5.34	5.32	5.29	5.26	5.23	5.20	5.17	5.14	5.12
	1500-5000kW	0.86	0.85	0.84	0.83	0.82	0.81	0.79	0.78	0.77	0.76	0.75	0.74	0.73

5.59. However, as has been seen over the last FITs review period, costs can change significantly and unexpectedly. Therefore, while tariffs are currently set based on the best information available, there is the possibility that actual costs and revenues could deviate from those projected over time. If this were to be the case, and for example costs were to fall more quickly than predicted, it would likely manifest through higher than projected deployment. Given the introduction of caps, this would not increase spend above £100m. However it would suggest that tariffs could be reduced to bring forward the levels of deployment set out in this document, which would improve the value for money of the scheme. Where the cap is set lower than the level of projection, while hitting the cap may mean that nothing has changed, it would also mean that deployment is likely to be able to come forward at a lower tariff than set out above.

5.60. Therefore, Government has decided that default degression will continue to be supplemented by contingent degression. This would mean that tariffs would fall under specific circumstances. Given the rationale set out above, it is decided to tie contingent degression to deployment, and specifically to the caps. The decision is that if the cap is hit in any quarter, there would be 10% degression in all future tariffs from the following quarter for that degression band. This means that tariffs, beyond default degression, are only reduced when significant deployment is happening in that degression band.

5.61. Contingent degression will operate in addition to default degression – so, for example, if a cap was reached in a particular quarter, the tariff in the following quarter (and all future quarters) would be 10% lower than is set out in Table 10 above. Furthermore, contingent degression will be cumulative – so if the cap was hit two quarters running, there would be two quarters worth of 10% degression in addition to the default degression corresponding to that technology.[35]

Policy decisions not considered in detail in this IA

5.62. There are various decisions set out in the Government Response document that are not formally assessed within this Impact Assessment. The proposals and the reasons for their exclusion are set out below.

5.63. Prevent extensions to existing installations from claiming FITs: Government has decided that the right to receive a generation tariff for extensions should be removed for all installations. Whilst encouraging the deployment of renewable installations, the scheme should provide the best value for money for the consumer. Extensions have in most cases provided generators an opportunity to receive a feed-in tariff that provides a higher rate of return on investment than our State aid approval provides for. Extensions have not been included in the modelling of Option 2, and therefore they are excluded from the analysis.

5.64. In the consultation, one thing considered was to change the tariffs from being linked to the Retail Price Index (RPI) to being linked to the Consumer Price Index (CPI). Responses raised objections to this proposal. The impact of moving to CPI would also be relatively marginal.[36] Therefore, the FITs scheme will remain linked to RPI.

5.65. Limit the size of renewable electricity purchased from overseas which can be offset against levelisation contributions: this policy change mitigates a distortion within the scheme.

5.66. Linking eligible technologies to specific MCS standards: this change removes a sub-delegation in the legislation. It will have no impact on how the scheme operates.

5.67. Use interest accrued in the Levelisation Fund for scheme administration: there is some funding in the Levelisation Fund which has accrued interest since the beginning of the FITs scheme. This is a relatively small amount of money (c£77,000), and will be used to part-fund the Levelisation Fund. Given its magnitude, this has not been assessed within this impact assessment.

5.68. Measures on smart meters: these are not proposed to be implemented immediately after the consultation, and will be further consulted on in due course.

5.69. Measures on energy efficiency: This is the requirement that the Energy Performance Certificate (EPC) showing the banding needed to obtain the higher tariff (currently band D) is obtained prior to the commissioning date of the solar PV installation. This is assumed to have no impact on deployment. Other energy efficiency proposals are not proposed to be implemented immediately after this consultation.

Monetised / non-monetised costs and benefits

6.1. This section assesses the likely impact of each Option. The assessment is based on the assumptions set out in sections 4 and 5 above.

Option 1 – do nothing

6.2. The costs and benefits of Option 1 are by definition zero used as a baseline against which all other options are assessed. The Tables in this section set out the expected deployment, generation and spending under this scenario.

[35] Note that contingent degression is compounded. This means that, for example, if the cap is reached in two successive quarters it would lead to tariffs 19% lower than in Table 10. This is because the first quarter would see contingent degression of 10%, so the tariff would be 90% of that in Table 10. The second quarter would see a further 10% contingent degression, but this reduction is applied to the 90%, meaning that the new tariff would be 81% of that set out in Table 10.
[36] Because the CPI tends to be lower than the RPI, the change would have had the effect of increasing initial target rates of return to maintain returns consistent with the hurdle rates, though the tariffs would have increased more slowly over time.

Option 2 – make the policy changes as set out in the Government Response

6.3. This Option assesses the impact of making the policy changes as set out in the Government Response, including revised tariffs, the introduction of cost control through caps and revised degression policy, against the baseline of not changing the FITs policy. Tables below include expected deployment, generation, spending, carbon emissions and Net Present Values (NPVs) including a comparison with Option 1.

6.4. As the proposal here – of reduced tariffs and caps on deployment, among other things – will reduce renewable electricity supply, electricity demand must be met in other ways. Given the scale of the reduction in generation under FITs, rather than assume that a particular type of generation comes forward, it is replaced by the grid average. An alternative would be to assume that the marginal plant – which is CCGT (gas) – increases its output to compensate for the displaced electricity generation. This is included as a sensitivity.

Modelling Method

6.5. DECC's FITs model forecasts deployment and therefore cost to consumers until 2020/21. The model performs the following steps to forecast unconstrained deployment each month:

a. Calculate the distribution of the levelised cost[37] for each technology by tariff band for installations installed in that month. The model assumes that levelised costs follow a normal distribution. The distribution of the levelised cost depends on the distributions of capex, opex, and hurdle rates.

b. Calculate the levelised revenue[38] for each technology by tariff band for installations in that month. The levelised revenue includes revenue from the generation tariff, export tariff and bill savings.

c. Calculate the percentage of the levelised cost distribution that is smaller than the levelised revenue. This becomes the percentage of total demand that is willing to install, as the cost is less than revenue.

d. Apply this percentage to the maximum possible deployment in that month. The maximum possible deployment in a certain time period is the technical potential constrained by one of the market barrier or the social barrier[39]. The parameters for these are set by comparing forecasts in previous time periods against the actual deployment figures. This is how the model is calibrated to actual deployment.

e. Finally, once the model has estimated the amount of deployment in that month, aggregates it to a quarter, and if applicable it applies the cap and the degression mechanism to estimate future tariffs and deployment. It then moves on to estimate deployment in the following quarter. More detail is set out in Annex D.

Deployment Projections

6.6. The following tables show forecast deployment under each Option. There are three deployment scenarios for each Option, reflecting uncertainty about deployment. This is modelled through adjustment to the hurdle rate, which is assumed to represent some of the uncertainty around costs and cost reductions, electricity prices, deployment potential, supply chain barriers and other factors.

6.7. The low deployment scenario uses the high distribution of hurdle rates. A higher hurdle rate increases the minimum rate of return required, so a smaller percentage of the market will be incentivised to install causing projected deployment to fall. The high deployment and spend scenarios give a worst case hypothetical scenario if deployment is marginally below the deployment cap, so no contingent degression is hit. All other variables are constant at central values across the range of deployment scenarios.

6.8. Table 11 also sets out the high and low projections under Option 1. The comparison of the deployment scenarios under Option 2 is against the central scenario of Option 1. More detail is provided in Tables B1 and B2 in Annex B.

[37] A 'levelised cost' is the average cost over the lifetime of the plant per MWh of electricity generated.
[38] Similar to the levelised cost, the 'levelised revenue' is the average revenue over the lifetime of the plant per MWh of electricity generated
[39] The social barrier represents people's willingness to invest in renewables; the market barrier represents the likelihood that as deployment of a technology increases, awareness of it grows and supply chains develop.

Table 11: Deployment projections under each option

		Cumulative Deployment at end of year from Solar PV, Wind, AD and Hydro installations (MW)						
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact by 2020/21, against Option 1 (central)
Option 1	Low	5,880	6,800	7,650	8,450	9,240	10,000	-
	Central	6,040	7,420	8,870	10,350	11,850	13,300	-
	High	6,180	7,950	9,930	12,070	14,260	16,400	-
Option 2	Low	6,130	6,440	6,750	7,060	7,060	7,060	-6,240
	Central	6,170	6,620	7,090	7,580	7,580	7,580	-5,720
	High	6,170	6,650	7,150	7,680	7,680	7,680	-5,620

Number of installations

6.9. Table 12 shows the forecast of the number of installations under each Option. These have been calculated by dividing the deployment forecasts above by the reference size of installation. More detail is provided in Tables B3 and B4 in Annex B.

Table 12: Number of installations from deployment projections under each option

		Cumulative number of Solar PV, Wind, AD and Hydro installations at end of year						
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact by 2020/21, against Option 1 (central)
Option 1	Low	745,000	888,000	1,026,000	1,156,000	1,284,000	1,412,000	-
	Central	763,000	955,000	1,159,000	1,367,000	1,575,000	1,777,000	-
	High	775,000	1,005,000	1,268,000	1,552,000	1,831,000	2,096,000	-
Option 2	Low	741,000	780,000	822,000	865,000	865,000	865,000	-912,000
	Central	748,000	813,000	883,000	959,000	959,000	959,000	-818,000
	High	748,000	818,000	894,000	975,000	975,000	975,000	-802,000

Generation

6.10. Table 13 shows the forecast of generation under each Option. The model uses the load factors in Table 13 to estimate generation from the deployment projections shown in table 11. More detail is provided in Tables B5 and B6 in the Annex.

Table 13: Generation projections under each option

		Full-year generation from Solar PV, Wind, AD and Hydro installations (GWh)						
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact by 2020/21, against Option 1 (central)
Option 1	Low	8,980	10,430	11,550	12,570	13,540	14,440	-
	Central	9,170	11,130	12,890	14,600	16,270	17,860	-
	High	9,330	11,750	14,100	16,500	18,870	21,160	-
Option 2	Low	9,160	10,060	10,600	11,130	11,130	11,130	-6,730
	Central	9,200	10,260	10,970	11,680	11,680	11,680	-6,180
	High	9,200	10,310	11,090	11,900	11,900	11,900	-5,960

Calculating the Net Present Value

6.11. The NPV is calculated as the discounted value of the benefits minus the discounted value of the costs. To estimate the NPV, Option 1 is used as the baseline scenario; the NPV of Option 2 is then compared to Option 1 central scenario.

6.12. The three components of NPV are:

- Net Resource cost savings;

- Reduced Carbon Savings; and
- Administrative costs of implementing changes (this figure is up to £200,000 in Option 2.

6.13. These are set out in Table 16 below, along with the range of NPVs (resulting from the range in deployment as set out in Table 11). This assumes that the displaced FITs generation is replaced by generation representing the grid average for that particular year.[40] If instead the displaced electricity were replaced by gas, the resource impact would be measured through the Short Run Marginal Cost (SRMC) of gas. This is included in the Tables below as a sensitivity.

Net resource change

6.14. The net resource change of Option 2 relative to Option 1 is calculated as the difference between the levelised costs of the FITs installations and the Long Run Variable Cost (LRVC) of electricity supply.[41] FITs installations are generally more expensive than the LRVC, so Option 2 represents a resource benefit relative to Option 1. The assumed LRVC uses the central values used in the supplementary guidance toolkit, weighted according to the share of electricity demand.[42]

6.15. The NPV has been calculated up to 2055/56. It is assumed that all installations installed in 2020/21 will have stopped generating by 2055/56, in accordance with the technology lifetimes set out in the report by WSP Parsons Brinckerhoff.

Table 14: resource cost changes under each scenario

	Low	Central	High
LRVC	£4,530m	£4,140m	£4,100m
SRMC sensitivity	£9,610m	£8,810m	£8,700m

6.16. This analysis uses the social discount rate of 3.5% in accordance with the Green Book.[43] The figures in Table 14 are reductions in resource cost over the lifetime of the projects. This is a benefit as the resource cost of the grid average electricity generation (or the gas generation used as a sensitivity) is lower than the levelised cost of the FITs technologies. It is higher in the low scenario as this is associated with less deployment under the FITs scheme. It is also higher under the gas sensitivity as the SRMC of gas generation is below the LRVC.

Net carbon emission change

6.17. Installations coming forward under FITs reduce the carbon emissions of the electricity sector. The volume of carbon savings as a result of generation being produced by installations supported by FITs are the main monetised benefit of the FITs policy. The carbon savings are calculated using the long run marginal generation based emissions factors (table 1 of supporting data tables to Green Book supplementary guidance)[44]. The central traded values of carbon are then used to place a value on those carbons changes, i.e. the value of changes in the amount of EU Emissions Trading System allowances the UK is required to purchase.[45]

6.18. Option 2 reduces the amount of forecast generation from FITs installations and increases generation from the overall electricity system, some of which will be supplied by fossil fuel generation. The result is an increase in UK traded-sector (EU ETS) emissions, resulting in an increased opportunity cost to the UK of using EU ETS allowances compared to Option 1. The volumes and values are shown in Table 15 below.

Table 15: Carbon savings under Option 2[46] and monetised costs

	Low	Central	High
LRVC – carbon emissions ($MtCO_2$)	24.9	22.8	22.4
LRVC – carbon costs	£810m	£750m	£740m
SRMC sensitivity – carbon emissions ($MtCO_2$)	75.6	69.9	68.9
SRMC sensitivity – carbon costs	£3,540m	£3,290m	£3,250m

[40] The grid average reflects increasing decarbonisation of the electricity sector over time. This means that the cost of the electricity increases, and the carbon emissions falls.
[41] Note that the LRVC is adjusted to remove transmission and distribution costs. This is to make it more comparable with the levelised cost of electricity.
[42] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[43] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf
[44] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[45] Table 3 of the Green Book supplementary guidance, available at https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[46] This is measured as million tonnes of carbon saved over 2015/16-2054/55

6.19. The figures in Table 15 are additional carbon emissions and costs associated with that, for Option 2 relative to Option 1. They are lower in the high deployment scenario as there is greater generation from renewables under FITs, meaning that there is less of an increase in carbon emissions as a result of the changes. The SRMC sensitivity means the renewable generation is replaced by gas generation, meaning that carbon emissions and therefore costs are higher in the SRMC counterfactual than when the FITs generation is replaced by the grid average.

Changes in admin costs

6.20. Ofgem estimate the cost of implementing new systems to implement the policy changes in Option 2 to be up to £200,000; DECC and Ofgem will work to implement the changes as cost-effectively as possible. This is additional to the administrative costs under Option 1.

6.21. The resource savings and carbon costs are then brought together to give the Net Present Value of Option 2 relative to Option 1. This is set out in Table 16.

Table 16: Net Present Value of each option

6.22. The NPV for Option 2 ranges between £3,360m and £3,720m, with a value of £3,390m in the central scenario (all in £2016 prices). Lower resource costs of energy supply more than offset reduced carbon savings and additional administrative costs.

Values over 2015/16-2054/55, £m 2016 values, discounted	Low	Central	High
Using LRVC			
Total net resource cost £m	4,530	4,140	4,100
Total carbon savings £m	810	750	740
NPV (£m)	3,720	3,390	3,360
Using SRMC			
Total net resource cost	9,610	8,810	8,700
Total carbon savings £m	3,540	3,290	3,250
NPV (£m)	6,070	5,510	5,450

LCF impacts

6.23. Generation tariff payments and deemed export payments are passed on to consumers and consumer bills (both households and other users) through the levelisation process.[47] This counts as spending under the LCF. Table 17 below shows the LCF impact of each option; Table 17 then shows the impact on consumer bills of each Option. In 2020/21, Option 2 results in an estimated reduction in the cost of tariff payments and deemed export payments of between £380m and £430m per annum, relative to Option 1.[48] More detail is provided in Tables B7 and B8 in the Annex.

Table 17: LCF impact of each option

		Annual costs to consumers from Solar PV, Wind, AD and Hydro installations (£m, 11/12 prices)						
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact by 2020/21, against Option 1 (central)
Option 1	**Low**	1,120	1,300	1,390	1,460	1,520	1,570	
	Central	1,120	1,330	1,470	1,580	1,670	1,740	
	High	1,120	1,360	1,530	1,670	1,780	1,850	
Option 2	**Low**	1,130	1,270	1,290	1,310	1,320	1,320	-430
	Central	1,130	1,270	1,300	1,320	1,330	1,330	-410
	High	1,130	1,270	1,310	1,340	1,360	1,360	-380

[47] https://www.ofgem.gov.uk/sites/default/files/docs/2015/06/feed-in_tariff_guidance_for_renewable_installations_v9_0.pdf
[48] No assumptions have been made about the value of deemed exports. This is a simplification which is expected to have at most a small impact.

Bill impacts on consumers

6.24. Results for each user are consistent with final estimated electricity demand per user after policies consistent within DECC's 2014 Prices and Bills report[49]. Note the bill impacts do not include the proposed exemption from the costs of FITs for eligible energy-intensive users announced in the 2015 Spending Review. The proposal will be consulted upon in due course. The figures presented in Table 18 below set out the impact on the average bill following the intervention. So, for example, in the medium scenario the average household electricity bill is expected to be £5 lower in 2020, or 0.9%.

Table 18: Impact on Electricity Bills of each option

Impact on Average Electricity Bills of Option 2 (central scenario)			
		Impact against option 1 (£, Real 2016)	Impact against option 1 (%)
Average household consumer	**2016**	-1	-0.1%
	2017	-2	-0.4%
	2018	-3	-0.6%
	2019	-4	-0.7%
	2020	-5	-0.9%
Small-sized business consumer	**2016**	-50	-0.2%
	2017	-150	-0.5%
	2018	-230	-0.8%
	2019	-310	-1.0%
	2020	-390	-1.2%
Medium-sized business consumer (in the CRC Energy Efficiency Scheme)	**2016**	-2,300	-0.2%
	2017	-6,200	-0.5%
	2018	-9,900	-0.8%
	2019	-13,200	-1.0%
	2020	-16,300	-1.2%
Large energy intensive industrial consumer	**2016**	-21,000	-0.2%
	2017	-57,000	-0.6%
	2018	-91,000	-1.0%
	2019	-122,000	-1.2%
	2020	-151,000	-1.5%

Non-monetised costs

Employment impacts

6.25. As a result of the lower FITs deployment set out in Table 11, it is likely that there will be fewer jobs supported by FITs. There is some information available on which a quantification has been based this is set out in Annex C. It should be noted that this information is both incomplete and tentative, and so quantified impacts should be treated with caution. It should also be noted that the impact is set out to the end of 2018/19 only, corresponding to this FITs Review period, reflecting that decisions have not yet been taken about the future of the scheme beyond this point.

Wider electricity system impacts

6.26. Decreased FITs deployment relative to Option 1 may also entail some wider system impacts – positive or negative – that are not reflected in the levelised cost estimates. These have not been quantified as their magnitude is uncertain. It is important to note that the benefits of reduced transmission and distribution costs associated with FITs deployment are reflected to some extent in the long-run variable cost estimates used for the electricity displaced.

[49] https://www.gov.uk/government/publications/estimated-impacts-of-energy-and-climate-change-policies-on-energy-prices-and-bills-2014

Risks and assumptions

7.1. The assumptions used within the FITs modelling are set out in section 4 above. While they are based on the best available information, there is still the possibility that the information is inaccurate, or that it is not adequately picking up changes over time.

Reduced rate of deployment

7.2. While the FITs modelling suggests that the proposed changes to tariffs, degression and the introduction of caps will continue to allow deployment to come forward, there is a risk that these changes may result in greater reductions than anticipated. However, industry has proven resilient to previous significant changes to FITs, and has been able to adapt to previous tariff reductions and the introduction of degression. The risk of an unexpectedly large reduction in deployment has to be seen in the context of this and of the need to have more robust controls on spend to enable the FITs scheme to continue. More broadly, it should be seen in the light of most of the technologies in the scheme having already deployed more now than had been expected by 2020.

Reduced rate of deployment

7.3. Many responses highlighted that potential VAT changes, exchange rate movement with the euro and US dollar and the European Commission rules on the Minimum Import Price (MIP) will all have an impact on capex costs in the future. Since the consultation closed, the EU Commission have announced an expiry review into the MIP which is expected to conclude in 2017. HMRC have also launched a consultation on removing VAT relief on solar panels. The outcome and implementation of these proposals are currently unclear and tariffs have therefore been set assuming no changes.

Impact on community developers

7.4. There is a risk that uncertainties created by a capped system may be more pronounced for community projects. This is because community installations typically take longer to develop and to build than commercial installations. This is partly as a result of the need for involvement of more people and partly due to the complications around agreeing financing. However, the re-introduction of pre-accreditation, and the longer pre-accreditation window for community projects, should reduce this risk.

7.5. There is an additional risk of projects claiming to be a community installation, that don't meet the definition in the FIT order. Government will keep this under review.

Load factors

7.6. The load factor remains a risk to spending under the scheme. The deployment caps have been set using central load factors as set out in section 4. If load factors are above these, this may result in spending increases beyond the £100m cap. This risk is mitigated in part by the annual cap redistribution – if load factors are consistently higher than expected the Government will not re-distribute all of the deployment caps that have not been reached. The only way of eliminating this load factor risk is to cap spend rather than deployment. The Government has not pursued this option as it would require an overhaul of the current administrative system, which would be costly and take a significant amount of time.

What replaces the displaced FITs generation

7.7. The main NPV calculations assume that the displaced FITs generation is replaced by the grid average electricity generation. This means a lower resource cost relative to FITs, and higher carbon emissions and therefore costs. This is monetised and figures are included in the summary sheet. There is also a sensitivity included where the displaced FITs generation is replaced by increased gas generation from the existing fleet. This is not included in the summary sheet.

Annex A – Costs and technical assumptions

A1. This Annex illustrates the cost and technical assumptions for solar PV, wind and hydro used in the Government Response, and shows how they have changed following the consultation responses. The whole range of values is presented in this Annex, as well as the value used for the reference installation when setting generation tariffs.

A2. All figures are expressed in 2016 prices and are adjusted from the underlying figures where required.

Capex, opex and grid connection costs

A3. During the consultation, the majority of the data received were about the capex values used. A large part of the evidence consisted of receipts, invoices, quotes and some contractual agreements. It was diverse in both its format and inclusion of cost components, so judgements were made to convert the information to a comparable format to the WSP Parsons Brinckerhoff (PB) *Small-scale generation cost up-date*[50]. This was done by replicating PB's method and by aligning with PB definitions of capex and opex, as set out in their report. For each data point, the following adjustments were made:

- **Inflation adjustment:** All capex prices received were adjusted for inflation using the RPI, published in the latest Office for Budget Responsibility forecasts.[51]
- **Year of commissioning:** Apply a weight based on year of commissioning to capture falling costs or higher tariffs sustaining more expensive projects, as set out in the PB report annex A[52].
- **Tax adjustment** – Adding or removing VAT following the distinction between domestic and non-domestic. This is done because non-domestic properties are able to reclaim VAT, unlike domestic generators. Therefore, domestic installations include a 5% VAT cost, while commercial and utility installations have VAT removed.
- **Cost considerations** – Adjustments were made to ensure that capex and opex received in the consultation responses reflect PB definition and cover elements such as pre-development costs (i.e. planning applications); labour installations costs; scaffolding for solar PV; the cost of the electrical infrastructure, and preparation of the grounds.

A4. This last adjustment involved a significant amount of judgement, as it was not always explicit what was included in the quote or invoice, and whether certain components contributed to the capital expenditure of the installer. This was done through a 10% uplift, which was applied to construction costs when evidence excluded pre-development costs. Installations commissioned before 2008 and after 2015 were excluded from the analysis, as they were deemed to be either too outdated, or based on expected, not actual, costs.

A5. This adjusted evidence was then merged with PB data, enlarging DECC's underlying dataset. This was particularly true for the mid-size band of wind (50-1,500kW), hydro, and domestic solar PV.

A6. PB's previous method – calculating the median in each tariff band, excluding outliers 75% below and above the median and then re-calculating a median from the restricted sample of observations – was used to identify central values within each tariff band. This method was applied consistently for each tariff band with the following exceptions:

- **Wind <100kW**: Both capex and opex were assumed to be equal across the <50kW and 50-100kW bands. The figures in these two bands are based on the same set of evidence combining all data points for installations of 100kW and below. This has been done to address the lack of data in the <50kW tariff band, where there was only information for eight wind plants.
- **Hydro > 500kW**: Capex and opex for the 500-2000kW are assumed to be equal to those for the >2000kW band. These figures are based on the same set of evidence combining all data points for installations greater than 500kW. This has been done to address the lack of data in the >2000kW tariff band, where there was only information for three hydro plants, and because there is assumed to be little difference in the underlying capex and opex costs per kW.

[50] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF
[51] http://budgetresponsibility.org.uk/pubs/Economy_Supplementary_Tables__November___2015.xls
[52] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF

Table A1: Capital expenditure, £/kW in 2016 prices

£/kW	Tariff band	Consultation	Consultation responses	Government response	% change from consultation to Government response
Solar PV	<10kW	£1,675	£1,607	£1,634	-2%
	10-50kW	£1,289	£1,510	£1,376	7%
	50-250kW	£1,159	£1,415	£1,159	0%
	250-1000kW	£1,105	-	£1,103	0%
	>1000kW	£1,029	-	£1,029	0%
	Standalone	£1,071	-	£1,013[53]	-5%
Wind	<50kW	£3,703	£5,583	£3,957[54]	7%
	50-100kW	£2,144	£3,893	£3,957[55]	47%
	100-1500kW		£2,425	£2,325	
	>1500kW	£1,137	-	£1,422[56]	25%
Hydro	<100kW	£4,858	£8,611	£6,518	34%
	100-500kW	£4,278	£4,260	£4,260	0%
	500-2000kW	£3,387	£3,309	£3,425[57]	1%
	>2000kW	£2,160	£3,817	£3,425[58]	59%

Table A2: Operational expenditure, £/kW in 2016 prices

£/kW	Tariff band	Consultation	Consultation responses	Government Response	% change from consultation to Government response
Solar PV	<10kW	£24	-	£24	0%
	10-50kW	£9	-	£9	0%
	50-250kW	£9	-	£9	0%
	250-1000kW	£10	-	£10	0%
	>1000kW	£10	-	£10	0%
	Standalone	£10	-	£10	0%
Wind	<50kW	£58	£132	£31[59]	-47%
	50-100kW	£59	£36	£31[60]	-48%
	100-1500kW		£34	£59	0%
	>1500kW	£28	-	£20[61]	-30%
Hydro	<100kW	£51	£92	£86	70%
	100-500kW	£53	£42	£43	-18%
	500-2000kW	£18	£22	£19[62]	7%
	>2000kW	£5	£13	£19[63]	264%

[53] This figure has been revised and is now based on the data provided by PB in the 2015 update. The previous figure published in the consultation and recommended by PB was based on the discounted data of the 2012 PB update.

[54] This figure is based on the same set of evidence combining all data points for installations of 100kW and below.

[55] This figure is based on the same set of evidence combining all data points for installations of 100kW and below.

[56] This figure has been revised and is now based on the data provided by PB in the 2015 update. The previous figure published in the consultation and recommended by PB was based on the discounted data of the 2012 PB update.

[57] This figure is based on the same set of evidence combining all data points for installations greater than 500kW.

[58] This figure is based on the same set of evidence combining all data points for installations greater than 500kW.

[59] This figure is based on the same set of evidence combining all data points for installations of 100kW and below.

[60] This figure is based on the same set of evidence combining all data points for installations of 100kW and below. The median for 50-100kW wind is £30. As there are more data points for this group than for the <50kW group, the effect of the 50-100kW group dominates when the datasets are merged.

[61] This figure has been revised and is now based on the data provided by PB in the 2015 update. The previous figure published in the consultation and recommended by PB was based on the discounted data of the 2012 PB update.

[62] This figure is based on the same set of evidence combining all data points for installations greater than 500kW.

[63] This figure is based on the same set of evidence combining all data points for installations greater than 500kW.

A7. No information was received to challenge the assumptions around grid connection costs. Therefore grid connection costs were left unaltered.

Table A3: Grid connection costs, £/kW in 2016 prices

£/kW	Tariff band	Consultation and Government response
Solar PV	<10kW	£0
	10-50kW	£397
	50-250kW	£392
	250-1000kW	£380
	>1000kW	£284
	Standalone	£294
Wind	<50kW	£397
	50-100kW	£395
	100-1500kW	£378
	>1500kW	£261
Hydro	<100kW	£396
	100-500kW	£384
	500-2000kW	£356
	>2000kW	£307

Load factors

A8. With the exception of hydro, little new load factor evidence was received through consultation responses. As a result, updated internal evidence has been used to review the assumptions in the consultation, in light of comments from stakeholders on how this data should be interpreted.

A9. The main changes relate to:

- **Solar PV**: this is now based on the upper quartile of the available estimates referring to installations located in the Midlands rather than the South West. This gives a raw load factor of 11.1%. The methodology used in DECC was broadly similar to that used by PB, but with the inapplicable data points removed (e.g. modelled data and data for sites larger that permitted on the FITs scheme).
- **Hydro:** higher load factors for <500kW based on evidence provided by the British Hydro Association.

A10. In addition, Solar PV's load factor now includes the impact of panel degradation. This aims to capture a progressive linear fall of 0.5% per year in panel efficiency. This reduces the load factor assumed over the lifetime of the installation from 11.1% to 10.8%.

A11. The change in wind load factor is due to the introduction of an additional band.

Table A4: Load factors

%	Tariff bands	Consultation			Government Response			Change
		Min	*Max*	*Load factor of reference installation*	*Min*	*Max*	*Load factor of reference installation*	*% for reference installation*
Solar PV	All bands	8.4%	11.3%	11.3%	8.3%	11.8%	10.8%	-4%
Wind	<50kW	14.0%	32.0%	26.4%	9.0%	32.0%	26.4%	0%
	50-100kW	14.0%	31.0%	28.7%	18.7%	31.1%	26.4%	-8%
	100-1500kW	13.0%	58.0%		13.2%	58.0%	28.7%	0%
	>1500kW	15.0%	44.0%	32.4%	14.7%	44.4%	32.4%	0%
Hydro	<100kW	27.0%	53.0%	40.0%	60.0%		60%	50%
	100-500kW	27.0%	53.0%	40.0%	50.0%		60%	25%
	500-2000kW	27.0%	53.0%	40.0%	40.0%		40%	0%
	>2000kW	27.0%	53.0%	40.0%	40.0%		40%	0%

Export fraction

A12. DECC received comments on solar PV export fraction and on-site use of electricity, although little usable evidence was received to provide alternative figures. DECC conducted an internal review of the available evidence covering the following studies and reports:

Table A5: Summary of information available on domestic solar export fraction

Response/Study	**Approach**	**Limitations**	**Self-consumption**
Consultation Response	Modelled on national generation and consumption profiles, for 3kW system using 11.3% load factor	Predicted self-consumption with no behaviour change	23-46% interquartile range, estimated value of 36%
Evaluating Low Carbon Communities project case studies[64]	Energy monitoring of real systems, typical size 2.5kW. Based on small sample (n=10)	Only June – August data provided	45%
DECC modelling	Household comparison of insolation and energy consumption profiles for 4kW system	One year of insolation data used only	25-35%
Parsons Brinckerhoff 2015	Survey respondents self-reporting	Based on only 4 data points	33-80%
Customer-led Network Revolution[65]	Monitoring of ~150 with PV compared with ~150 without, recruited via telemarketing	It is unclear whether the installations recruited are representative of the average	80%
Energy Trends (ET)[66] 2014 and National Energy Efficiency Database (NEED)[67]	ET and DECC NEED, savings of 450kWh against average PV generation (450kWh/2990kWh) 2990kWh is PVGIS defaults for 3.1kW in Solihull	Studies ignore in-direct and consumption rebound effects	15%

A13. Based on the above evidence, an estimate of 45% on-site consumption was adopted for solar PV. This represents the higher range of the evidence collected (assumed to be 25%-45%) and was chosen in order to encourage those installations that make most use of the renewable electricity generated.

Table A6: Export fraction and on-site use of electricity, % of electricity generated

£/kW	Tariff band	Export fraction				On-site use		
		Consultation	Government response	% change		Consultation	Government response	% change
Solar PV	<10kW	53%	50%	-6%		47%	45%	-4%
	10-50kW	53%	50%	-6%		47%	50%	6%
	50-250kW	53%	50%	-6%		47%	50%	6%
	250-1000kW	53%	50%	-6%		47%	50%	6%
	>1000kW	53%	50%	-6%		47%	50%	6%
	Standalone	100%	100%	0%		0%	0%	0%
Wind	<50kW	50%	50%	0%		50%	50%	0%
	50-100kW	85%	75%	-12%		15%	25%	67%
	100-1500kW		85%	0%		15%	15%	0%
	>1500kW	100%	100%	0%		0%	0%	0%
Hydro	<100kW	75%	75%	0%		25%	25%	0%
	100-500kW	88%	88%	0%		12%	12%	0%
	500-2000kW	99%	99%	0%		1%	1%	0%
	>2000kW	99%	99%	0%		1%	1%	0%

64 www.evaloc.org.uk

65 http://www.networkrevolution.co.uk/project-library/insight-report-domestic-solar-pv-customers/

66 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/404641/energy_usage_in_households_with_solar_pv.pdf

67 https://www.gov.uk/government/collections/national-energy-efficiency-data-need-framework

A14. The change in wind export fraction is due to the introduction of an additional band. Hydro's export fractions have been left unaltered.

Export rate

A15. An export tariff of 4.92 p/kWh (£2016 prices) was to calculate export income. This corresponds to the inflated export tariff of 4.77p/kWh referred to in the Ofgem Tariff Tables for the financial year 2014/15, uplifted by expected RPI.

A16. The majority of larger installations were assumed to sell their exported electricity outside of the scheme under Power Purchase Agreements, and therefore do not receive the export tariff. Due to the lack of information on the agreed price in Power Purchase Agreements, the consultation assumed that the export tariff is applied to all size installations for calculating the generation tariff and for modelling deployment. This means the developer is assumed to receive the export tariff for any electricity exported to the grid. This assumption has been retained for the Government response.

A17. The same reasoning applies to generator revenues after the lifetime of the FIT. Due to a lack of information on existing Power Purchase Agreements, DECC assumes that generators earn export revenues based on the 4.92p/kWh export tariff when the FIT support expires after 20 years.

Electricity prices

A18. FIT generators face different electricity prices depending on the sector to which they belong. It is assumed that this in turn relates to the size of their installation. Residential electricity prices apply to the smallest solar PV tariff band for installations <10kW. Wholesale prices apply to the larger tariff bands – standalone solar PV; wind installations >1,500kW and hydro installations >500kW. For all remaining installations facing either the service or industrial electricity price, an average of the services and industrial electricity price is applied. This is due to the difficulty in defining whether installations in these bands belong to the services or industrial sector.

Table A7: Electricity price projections (p/kWh in 2016 prices)

Consultation										
Sector	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
Residential	17.4	18.5	18.7	19.9	19.9	20.1	20.3	20.5	20.7	20.9
Services/industrial	10.9	10.9	11.0	12.4	12.5	12.6	12.7	12.8	13.0	13.1
Wholesale	5.8	5.5	5.2	5.2	5.6	5.7	5.7	5.8	5.8	5.9
Government Response										
Sector	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
Residential	13.5	14.4	15.0	15.4	15.8	15.9	16.3	16.2	16.6	17.3
Services/industrial	10.3	10.8	10.8	11.4	11.9	12.6	12.9	13.1	14.0	14.5
Wholesale	4.9	5.3	4.9	4.7	5.0	5.5	6.0	6.1	6.6	6.9
% change										
Sector	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
Residential	-23%	-22%	-19%	-22%	-20%	-21%	-20%	-21%	-20%	-17%
Services/industrial	-6%	-1%	-2%	-8%	-4%	0%	1%	2%	8%	11%
Wholesale	-15%	-5%	-7%	-9%	-12%	-2%	4%	6%	13%	16%

A19. Electricity prices in the Government Response have been up-dated with DECC's latest projections published in the 2015 Energy Emissions and Projections.[68] The new reference case prices are generally lower up to 2021, and then are higher than the previous projection.

A20. The second amendment relates to the amount of residential electricity price faced by domestic installations. As domestic installations remain connected to the grid, they face standing charges regardless of how much electricity is consumed. Therefore tariffs for the <10kW solar tariff band have been set using only the variable element of the electricity price, significantly reducing the value of bill savings assumed for domestic installations. It is assumed that 88% of the retail electricity price is variable, and 12% is a standing

[68] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/477625/Annex-m-price-growth-assumptions.xls

charge. This is based on the average standing charge in 2014.that was 12% of the total retail price.[69] Tariffs for all other solar bands, and hydro and wind, have been set using the total electricity price.

Other assumptions

A21. Installation sizes are based on the average installation size in each tariff band. The data on the number of installations and their capacity used to calculate average sizes are taken from DECC statistics on cumulative deployment as of June 2015.[70]

Table A8: Average installation size (kW)

kW	Tariff band	Consultation and Government Response
Solar PV	<10kW	3
	10-50kW	30
	50-250kW	140
	250-1000kW	455
	>1000kW	2,840
	Standalone	2,590
Wind	<50kW	10
	50-100kW	80
	100-1500kW	482
	>1500kW	3,408
Hydro	<100kW	33
	100-500kW	346
	500-2000kW	1,046
	>2000kW	2,253

A22. The technical potential for solar PV has been revised downwards from PB estimates in light of comments from the consultation, which pointed out the use of an incorrect assumption by PB when estimating the technical potential. All other assumptions remain unaltered.

Table A9: Technical potential, GWh

GWh	Consultation	Government Response	% change
Solar PV	709,907	220,289	-69%
Wind	23,932	23,932	0%
Hydro	9,905	9,905	0%

A23. No compelling information was received to challenge the operating period of plants under the FITs scheme. Therefore, the technology lifetimes remain as they were in the consultation.

Table A10: Lifetime of installations

Years	Consultation and Government Response
Solar PV	30
Wind	20
Hydro	35

Hurdle rates

A24. In the Impact Assessment accompanying the consultation, DECC used the hurdle rate ranges recommended by PB and Ricardo Energy & Environment. These were based on their analysis of survey responses and complemented by their in-house expertise, as well as a review of literature references. Due to the commercially sensitive nature of hurdle rates, the feedback received on this topic through consultation responses was mostly qualitative. However some respondents also provided quantitative

[69] This is based on a fixed consumption of 3,800kWh and data tables published at: https://www.gov.uk/government/statistical-data-sets/annual-domestic-energy-price-statistics

[70] https://www.gov.uk/government/statistics/monthly-small-scale-renewable-deployment

comments and evidence such as project finance models. The qualitative feedback is summarised in the Government Response. This annex focuses on the quantitative feedback received.

Clarification on terminology used by DECC – hurdle rate ranges and. target rates of return

A25. Several respondents felt that the DECC hurdle rate methodology was unclear. In particular there was uncertainty in the responses about the terms "hurdle rate", "rate of return", "internal rate of return" (IRR) and "target rate of return", with some responses using the terms interchangeably. The below paragraphs therefore provide further detail on DECC's approach to, and use of, hurdle rate assumptions.

- **Hurdle rate ranges**: DECC has used the results of the PB survey and the consultation responses to determine a representative range of hurdle rates across 3 main investor categories – domestic, commercial and utility[71]. Each range of hurdle rates aims to represent the distribution of potential investors in that category according to their relative appetite for investment in a particular technology.
- **Link between hurdle rate ranges and deployment projections**: the assumed hurdle rate ranges are then combined with assumption ranges for other parameters such as capex and opex in DECC's modelling to determine the proportion of the supply curve that would be willing to deploy at a certain level of generation tariff (see Annex D for more detail on the models used by DECC).
- **Target rates of return and link with tariff setting**: to set generation tariffs, DECC has selected a single target rate of return within the range of hurdle rates for each technology, following the same methodology as described in paragraph 5.14 of the Impact Assessment published alongside the Consultation. The tariff calculation for each tariff band then uses a single load factor assumption, a single capex assumption, a single opex assumption and a single export fraction assumption to determine the generation tariff which, when combined with revenues from the export tariff and bill savings, delivers this single target rate of return (see Annex D for more detail on the models used by DECC).

A26. In summary, when the DECC methodology mentions hurdle rates it refers to ranges of assumptions that are intended to describe the whole population of investors and their relative willingness to deploy at different rates of return. When the methodology mentions target rates of return it refers to the single technology-specific rates of return that are targeted when setting generation tariffs.

Aligning different ways to measure rates of return

A27. DECC uses pre-tax real hurdle rates in its modelling, and returns are considered at a project level rather than an equity level. This definition was explicitly stated in the PB questionnaire, and in paragraph 4.12 of the Impact Assessment accompanying the FIT Review consultation, though some of the quantitative responses received assumed different definitions – with post-tax nominal equity returns most commonly featured.

A28. Wherever sufficient information was provided, the quantitative comments received were converted into new data points using a combination of the below adjustment steps:

- **Pre-tax real hurdle rates vs. post-tax nominal hurdle rates**: Investors tend to use post-tax nominal hurdle rates; however DECC's methodology assumes pre-tax real hurdle rates. As a result, responses received through the PB survey and through the consultation were generally assumed to be expressed in post-tax nominal returns, except when respondents explicitly stated that they were using pre-tax real numbers or when they provided spreadsheets indicating that their calculations were in pre-tax real terms. Post-tax nominal hurdle rates were then converted into pre-tax real equivalents using the same methodology as the one that had been used by PB and Ricardo Energy & Environment, i.e.
    - Convert post-tax nominal returns into pre-tax nominal returns by using the relevant Effective Tax Rate (ETR) for the corresponding technology and type of investor[72]; and

[71] The "commercial" investor category refers to small and medium businesses that are not energy professionals (e.g. businesses which own offices or factories and which choose to develop renewable electricity installations on their sites), while the "utility" category refers to energy professionals and includes both utilities and independent renewable energy developers.

[72] The analysis used discounted ETR's from KPMG's report *Electricity Market Reform: Review of effective tax rates for renewable technologies* of July 2013, i.e. 12% for solar, wind and AD and 20% for hydro. An ETR of 0% was used for domestic projects to reflect the HMRC exemption for micro-generation (HMRC BIM40520 – Specific receipts: domestic micro-generation: Income Tax exemption for domestic micro-generation, see http://www.hmrc.gov.uk/manuals/bimmanual/BIM40520.htm).

  - Convert pre-tax nominal returns into pre-tax real returns, assuming an inflation rate of 3%, which is HMT's projection for RPI in the long-term[73].

- **Project hurdle rate vs. equity hurdle rate**: The DECC methodology assumes that returns are measured at project cash flow levels, thus reflecting the returns available to be distributed to all the funders of the project without distinction. In contrast, equity returns are the returns that are available to be distributed to the equity providers of the project, once the debt providers have been paid. Whenever responses were provided in equity terms, they were converted back into project hurdle rates using the gearing and interest rate information provided by respondents.
- **Maximum payback time vs. hurdle rate**: Many respondents quoted required payback times for their investments instead of hurdle rates. When this was the case the payback time was converted into an equivalent return by using a simple cash flow calculation and assuming that the initial investment would be recouped through constant annual repayments.

A29. The data points obtained through this analysis were then added to the dataset initially gathered and analysed by PB and Ricardo Energy & Environment, thus leading to a revised set of assumptions as shown in Table A11. This is the only amendment DECC has made to the assumptions on hurdle rates. The methodology used to determine the target rates of return has not been changed, but these are now based on the new hurdle rate ranges outlined above. As a result, target rates of return have increased respectively from 4% to 4.8% for solar; from 5% to 5.9% for wind and from 9% to 9.2% for hydro.

[73] The Government's Consumer Prices Index target is 2%. The evidence is that RPI tends to exceed CPI by around 1%, so that the projected RPI rate is 3%. Source: Office for Budget Responsibility, *Economic and Fiscal Outlook*, March 2015, p.62.

Table A11: Underlying hurdle rates information

		Consultation ranges	Number of data points	Revised ranges	Incl. additional data points
PV					
Domestic, small	Min	2.5%	6	3.8%	4
	Max	10.0%		12.4%	
	Avg	6.2%		5.7%	
Commercial developer, medium	Min	4.0%	0	4.8%	3
	Max	11.0%		11.0%	
	Avg	7.0%		6.2%	
Utility, large	Min	4.0%	0	4.8%	1
	Max	11.0%		11.0%	
	Avg	7.0%		5.6%	
Wind					
Domestic, small	Min	3.0%	0	3.0%	0
	Max	11.0%		11.0%	
	Avg	6.5%		6.5%	
Commercial developer, medium	Min	5.0%	4	5.9%	1
	Max	12.0%		12.5%	
	Avg	8.3%		8.7%	
Utility, large	Min	5.0%	43	4.6%	5
	Max	14.0%		13.6%	
	Avg	8.3%		7.3%	
Hydro					
Domestic, small	Min	3.0%	0	3.0%	0
	Max	11.0%		11.0%	
	Avg	6.5%		6.5%	
Commercial developer, medium	Min	9.0%	3	9.2%	0
	Max	15.0%		15.3%	
	Avg	11.0%		11.2%	
Utility, large	Min	7.0%	15	6.8%	2
	Max	15.0%		15.3%	
	Avg	8.5%		8.5%	
AD					
Domestic, small	Min	N/A	0	N/A	0
	Max	N/A		N/A	
	Avg	N/A		N/A	
Commercial developer, medium	Min	9.0%	4	9.0%	0
	Max	14.0%		14.0%	
	Avg	13.0%		13.0%	
Utility, large	Min	8.0%	10	8.0%	0
	Max	13.0%		13.0%	
	Avg	12.0%		12.0%	
Total number of data points			85		101

Notes:

- Solar PV hurdle rates: the initial recommendations from PB were primarily based on literature references; new ranges reflect the merged dataset except for utility-style investors, where only one data point was received and where the min and max of the range were assumed to be equal to those of the commercial investors.
- Domestic wind and hydro hurdle rates: the initial recommendations from PB were primarily based on literature references; no new information was received.
- Commercial and utility wind hurdle rates: the average recommendations from PB were based on literature references; the new ranges reflect the merged datasets.
- Commercial hydro hurdle rates: no new information was received but the ranges were adjusted to remove rounding for consistency with the rest of the updated analysis.
- AD hurdle rates: no new information was received; ranges remain as per the PB report. AD hurdle rates will be consulted on as part of the consultation on AD and micro-CHP in early 2016.

Annex B – Detailed Deployment, Number of Installations, Generation and Cost to Consumer Projections

Deployment Projections

B1. Table B1 shows the forecast of deployment under each Option. This provides further breakdowns of the scenarios presented in Table 11 of the IA.

Table B1 - Cumulative Deployment at end of year (MW)

Cumulative Deployment at end of year (MW)							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact on cumulative deployment by 2020/21 against Option 1 central estimate
Option 1 - Low							
PV	4,540	5,290	6,010	6,700	7,400	8,090	
Wind	830	950	1,040	1,100	1,160	1,200	
Hydro	200	240	280	320	350	380	
AD	300	310	320	320	330	330	
Total	5,880	6,800	7,650	8,450	9,240	10,000	
Option 1 - Central							
PV	4,670	5,840	7,120	8,480	9,860	11,220	
Wind	850	1,000	1,120	1,200	1,280	1,330	
Hydro	200	260	300	340	370	400	
AD	300	320	320	330	340	340	
Total	6,040	7,420	8,870	10,350	11,850	13,300	
Option 1 - High							
PV	4,790	6,290	8,070	10,040	12,080	14,120	
Wind	880	1,060	1,210	1,320	1,410	1,480	
Hydro	210	270	330	380	420	450	
AD	310	320	330	340	350	350	
Total	6,180	7,950	9,930	12,070	14,260	16,400	
Option 2 - Low							
PV	4,830	5,040	5,250	5,480	5,480	5,480	-5,740
Wind	790	840	890	940	940	940	-390
Hydro	180	210	240	270	270	270	-130
AD	330	340	360	370	370	370	30
Total	6,130	6,440	6,750	7,060	7,060	7,060	-6,240
Option 2 - Central							
PV	4,870	5,200	5,560	5,960	5,960	5,960	-5,260
Wind	800	870	930	980	980	980	-350
Hydro	180	210	240	270	270	270	-130
AD	330	340	360	370	370	370	30
Total	6,170	6,620	7,090	7,580	7,580	7,580	-5,710
Option 2 - High							
PV	4,870	5,220	5,610	6,020	6,020	6,020	-5,200
Wind	800	870	930	1,000	1,000	1,000	-330
Hydro	180	210	240	270	270	270	-130
AD	330	350	370	390	390	390	50
Total	6,170	6,650	7,150	7,680	7,680	7,680	-5,610

B2. Table B2 shows the detailed forecast of deployment under the central estimates of Options 1 and 2.

Table B2 - Cumulative Deployment at end of year (MW)

Cumulative Deployment at end of year (MW)													
	Option 1 - Central						Option 2 - central						Impact on cumulative deployment by 2020/21 against Option 1 central estimate
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
PV													
<4kW	1,590	2,000	2,450	2,940	3,430	3,910	1,560	1,720	1,910	2,100	2,100	2,100	-1,810
4-10kW	100	140	180	220	270	320	100	110	120	130	130	130	-190
10-50kW	560	850	1,180	1,570	1,980	2,370	570	640	720	800	800	800	-1,560
50-150kW	190	300	420	540	670	810	170	190	210	230	230	230	-580
150-250kW	190	270	370	470	570	680	180	210	230	250	250	250	-430
250-5000kW	220	290	350	420	500	570	230	230	230	230	230	230	-340
Standalone	1,250	1,310	1,370	1,440	1,500	1,550	1,470	1,490	1,500	1,510	1,510	1,510	-40
Agg<4	540	650	740	820	890	940	540	550	560	570	570	570	-370
Agg>4	30	40	50	50	60	60	30	40	40	40	40	40	-20
250-1000kW	-	-	-	-	-	-	-	10	20	30	30	30	30
1000-5000kW	-	-	-	-	-	-	-	20	30	50	50	50	50
Total	4,670	5,840	7,120	8,480	9,860	11,220	4,870	5,200	5,560	5,960	5,960	5,960	-5,260
Wind													
B-M<1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	50	70	100	110	130	140	30	50	60	70	70	70	-60
15–50kW	30	40	50	60	70	70	20	30	30	40	40	40	-30
50–100kW	100	110	110	110	110	110	100	100	100	110	110	110	-10
100–500kW	430	510	570	620	650	680	390	420	440	460	460	460	-220
500–1,500kW	100	100	100	100	100	110	100	100	110	110	110	110	-
1,500-5,000kW	150	170	190	200	210	230	150	170	180	200	200	200	-30
Total	850	1,000	1,120	1,200	1,280	1,330	800	870	930	980	980	980	-350
Hydro													
B-M<1.5kW	-	10	10	10	10	20	-	-	10	10	10	10	-10
1.5–15kW	10	20	20	30	30	30	10	10	20	20	20	20	-10
15–50kW	20	20	20	30	30	30	10	20	20	20	20	20	-10
50–100kW	60	80	100	110	120	130	50	60	70	80	80	80	-50
100–500kW	50	60	70	70	70	80	50	50	60	60	60	60	-20
500–1,500kW	50	60	70	80	90	90	50	50	60	70	70	70	-20
1,500-5,000kW	10	10	10	20	20	20	-	10	10	20	20	20	-
Total	200	260	300	340	370	400	180	210	240	270	270	270	-130
AD													
AD<250kW	30	30	40	40	50	50	30	30	40	40	40	40	-10
AD250-500kW	80	80	90	90	90	90	80	80	90	90	90	90	-
AD>500kW	190	200	200	200	200	200	220	230	230	240	240	240	40
Total	300	320	320	330	340	340	330	340	360	370	370	370	30

Number of installations

B3. Table B3 show the forecast of the number of installations under each Option. This provides further breakdowns of the scenarios presented in Table 12 of the IA.

Table B3 - Number of installations at end of year (cumulative)

Number of installations at end of year (cumulative)							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact on number of installations by 2020/21 against Option 1 central estimate
Option 1 - Low							
PV	735,000	874,000	1,009,000	1,136,000	1,263,000	1,389,000	
Wind	9,000	12,000	14,000	16,000	18,000	19,000	
Hydro	1,300	1,800	2,200	2,700	3,100	3,500	
AD	500	500	500	600	600	600	
Total	746,000	888,000	1,026,000	1,156,000	1,284,000	1,412,000	
Option 1 - Central							
PV	752,000	938,000	1,138,000	1,344,000	1,549,000	1,749,000	
Wind	10,000	14,000	18,000	20,000	23,000	24,000	
Hydro	1,300	1,900	2,500	3,000	3,500	3,900	
AD	500	500	600	600	600	600	
Total	763,000	955,000	1,159,000	1,367,000	1,575,000	1,777,000	
Option 1 - High							
PV	763,000	985,000	1,243,000	1,522,000	1,797,000	2,059,000	
Wind	11,000	17,000	22,000	26,000	29,000	32,000	
Hydro	1,400	2,100	2,800	3,500	4,100	4,600	
AD	500	600	600	600	700	700	
Total	775,000	1,005,000	1,268,000	1,552,000	1,831,000	2,096,000	
Option 2 - Low							
PV	732,000	770,000	809,000	851,000	851,000	851,000	-898,000
Wind	7,000	9,000	10,000	12,000	12,000	12,000	-12,000
Hydro	1,100	1,400	1,700	2,000	2,000	2,000	-2,000
AD	500	500	600	600	600	600	-
Total	741,000	780,000	822,000	865,000	865,000	865,000	-912,000
Option 2 - Central							
PV	739,000	802,000	869,000	942,000	942,000	942,000	-806,000
Wind	7,000	10,000	12,000	14,000	14,000	14,000	-10,000
Hydro	1,100	1,400	1,700	2,000	2,000	2,000	-2,000
AD	500	500	600	600	600	600	-
Total	748,000	813,000	883,000	959,000	959,000	959,000	-818,000
Option 2 - High							
PV	739,000	806,000	880,000	958,000	958,000	958,000	-790,000
Wind	7,000	10,000	12,000	14,000	14,000	14,000	-10,000
Hydro	1,100	1,400	1,700	2,000	2,000	2,000	-1,900
AD	500	600	600	700	700	700	-
Total	748,000	818,000	894,000	975,000	975,000	975,000	-802,000

B4. Table B4 shows the detailed forecast of number of installations under central estimates of Options 1 and 2.

Table B4 - Number of Installations at end of year (cumulative)

Number of Installations at end of year (cumulative)													
	Option 1						Option 2						Impact on number of installations by 2020/21 against Option 1 central estimate
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
<4kW	518480	653380	802200	959340	1119750	1279290	508690	563350	622670	686970	686970	686970	-592310
4-10kW	12720	16950	21840	27240	33060	39170	12280	13270	14340	15500	15500	15500	-23670
10-50kW	16850	25400	35610	47190	59530	71150	17240	19360	21660	24170	24170	24170	-46980
50-150kW	1860	2920	4110	5350	6630	7940	1700	1870	2070	2280	2280	2280	-5660
150-250kW	880	1290	1750	2230	2710	3220	870	970	1080	1200	1200	1200	-2010
250-5000kW	180	230	290	340	400	460	190	190	190	190	190	190	-280
Standalone	480	510	530	550	580	600	570	570	580	580	580	580	-10
Agg<4	194420	230890	264070	292700	316750	336740	191350	195990	200570	205130	205130	205130	-131610
Agg>4	5800	6880	7850	8680	9380	9970	5820	5950	6090	6220	6220	6220	-3750
250-1000kW	-	-	-	-	-	-	-	20	40	60	60	60	60
1000-5000kW	-	-	-	-	-	-	-	10	10	20	20	20	20
Total	751680	938450	1138240	1343630	1548800	1748550	738700	801540	869290	942340	942340	942340	-806210
B-M<1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	5970	9510	12280	14490	16310	17520	4170	5970	7730	9470	9470	9470	-8050
15–50kW	1070	1690	2180	2560	2880	3100	750	1100	1440	1780	1780	1780	-1320
50–100kW	1280	1330	1370	1390	1410	1430	1290	1300	1320	1330	1330	1330	-100
100–500kW	1130	1350	1510	1630	1720	1780	1030	1100	1160	1210	1210	1210	-570
500–1,500kW	110	110	110	110	110	110	110	110	110	110	110	110	-
1,500-5,000kW	50	60	60	70	70	80	50	60	60	70	70	70	-10
Total	9600	14060	17510	20250	22510	24010	7410	9640	11830	13970	13970	13970	-10040
B-M<1.5kW	420	770	1120	1460	1780	2100	300	460	640	850	850	850	-1250
1.5–15kW	430	560	670	760	850	920	370	430	480	530	530	530	-390
15–50kW	190	240	280	300	330	360	170	190	210	230	230	230	-130
50–100kW	180	240	290	320	360	380	150	180	200	230	230	230	-160
100–500kW	70	80	90	90	100	100	60	70	80	80	80	80	-20
500–1,500kW	30	40	50	50	60	60	30	40	40	40	40	40	-20
1,500-5,000kW	-	-	10	10	10	10	-	-	10	10	10	10	-
Total	1300	1900	2500	3000	3500	3900	1100	1400	1700	2000	2000	2000	-2000
AD<250kW	180	220	250	270	290	310	170	200	230	260	260	260	-50
AD250-500kW	170	180	180	180	180	190	170	180	180	190	190	190	-
AD>500kW	140	140	140	140	140	140	160	160	170	170	170	170	20
Total	490	540	570	600	620	640	500	540	580	620	620	620	-20

Generation

B5. Table B5 show the forecast generation under each Option. This gives further breakdowns of the scenarios presented in Table 13 of the Impact Assessment.

Table B5 – Annual generation (GWh)

Cumulative full year generation (GWh)							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact on cumulative full year generation by 2020/21 against Option 1 central estimate
Option 1 – central estimate							
PV	4,300	5,010	5,690	6,340	7,010	7,660	
Wind	2,020	2,320	2,550	2,710	2,840	2,940	
Hydro	660	1,030	1,210	1,370	1,500	1,630	
AD	2,000	2,060	2,110	2,150	2,180	2,210	
Total	8,980	10,430	11,550	12,570	13,540	14,440	
Option 1 – central estimate							
PV	4,410	5,520	6,730	8,020	9,330	10,620	
Wind	2,060	2,430	2,710	2,930	3,100	3,240	
Hydro	680	1,090	1,300	1,470	1,610	1,750	
AD	2,010	2,090	2,140	2,190	2,220	2,250	
Total	9,170	11,130	12,890	14,600	16,270	17,860	
Option 1 – central estimate							
PV	4,510	5,930	7,620	9,480	11,420	13,360	
Wind	2,100	2,550	2,890	3,160	3,370	3,530	
Hydro	690	1,150	1,400	1,610	1,790	1,950	
AD	2,030	2,130	2,190	2,240	2,290	2,320	
Total	9,330	11,750	14,100	16,500	18,870	21,160	
Option 2 - Low							
PV	4,580	4,780	4,980	5,200	5,200	5,200	-5,420
Wind	1,900	2,060	2,180	2,290	2,290	2,290	-950
Hydro	600	930	1,060	1,190	1,190	1,190	-560
AD	2,080	2,290	2,380	2,460	2,460	2,460	200
Total	9,160	10,060	10,600	11,130	11,130	11,130	-6,730
Option 2 - Central							
PV	4,610	4,930	5,280	5,650	5,650	5,650	-4,970
Wind	1,900	2,110	2,250	2,380	2,380	2,380	-860
Hydro	600	930	1,060	1,190	1,190	1,190	-560
AD	2,080	2,290	2,380	2,460	2,460	2,460	210
Total	9,200	10,260	10,970	11,680	11,680	11,680	-6,180
Option 2 - High							
PV	4,620	4,950	5,320	5,710	5,710	5,710	-4,910
Wind	1,900	2,110	2,260	2,410	2,410	2,410	-830
Hydro	600	930	1,060	1,200	1,200	1,200	-550
AD	2,080	2,320	2,450	2,580	2,580	2,580	320
Total	9,200	10,310	11,090	11,900	11,900	11,900	-5,960

B6. Table B6 shows the detailed forecast of generation under the central estimates of Options 1 and 2.

Table B6 - Full Year Generation (GWh)

Table 6 - Full Year Generation (GWh)													
	Option 1 - Central						Option 2 - central						Impact on full year generation by 2020/21 against Option 1 central estimate
PV													
<4kW	1500	1900	2330	2780	3250	3710	1480	1630	1810	1990	1990	1990	-1720
4 - 10kW	100	130	170	210	260	300	100	100	110	120	120	120	-180
10 - 50kW	530	800	1120	1490	1880	2240	540	610	680	760	760	760	-1480
50-150kW	180	280	390	510	630	760	160	180	200	220	220	220	-540
150-250kW	170	250	350	440	540	640	170	190	220	240	240	240	-400
250-5000kW	210	270	330	400	470	540	-	-	-	-	-	-	-540
Stand alone	1180	1240	1300	1360	1420	1470	1400	1410	1420	1440	1440	1440	-30
Agg <4	510	610	700	770	840	890	510	520	530	540	540	540	-350
Agg >4	30	40	40	50	50	60	30	30	30	40	40	40	-20
250-1000kW	-	-	-	-	-	-	70	80	90	100	100	100	100
1000-5000kW	-	-	-	-	-	-	150	160	180	200	200	200	200
Total	4410	5520	6730	8010	9340	10610	4610	4910	5270	5650	5650	5650	-4960
Wind													
B-M <1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	70	110	150	170	200	210	50	70	90	110	110	110	-100
15–50kW	40	60	80	90	100	110	20	40	50	60	60	60	-50
50–100kW	160	170	170	170	180	180	160	160	170	170	170	170	-10
100–500kW	1230	1480	1660	1790	1890	1970	1120	1220	1290	1350	1350	1350	-620
500–1500kW	190	190	200	200	200	200	190	200	200	200	200	200	-
1500-5000kW	380	420	460	500	530	570	370	420	460	490	490	490	-80
Total	2060	2430	2710	2930	3100	3240	1900	2110	2250	2380	2380	2380	-860
Hydro													
<15kW	10	30	40	50	60	80	10	20	20	30	30	30	-40
15-50kW	50	80	100	110	120	130	40	60	70	80	80	80	-60
50-100kW	60	90	100	110	120	130	50	70	80	90	90	90	-50
100-500kW	200	350	420	480	530	570	170	270	310	350	350	350	-230
500-1000kW	160	250	280	300	320	340	150	230	250	270	270	270	-70
1000-2000kW	170	270	310	340	370	400	150	240	270	300	300	300	-100
2000-5000kW	20	40	50	60	80	100	20	40	60	80	80	80	-20
Total	680	1090	1300	1470	1610	1750	600	930	1060	1190	1190	1190	-560
AD													
< 250kW	160	190	220	240	260	270	150	180	210	230	230	230	-40
250 - 500kW	500	520	530	530	540	550	500	520	530	550	550	550	-
> 500kW	1360	1380	1400	1410	1420	1430	1430	1590	1640	1680	1680	1680	250
Total	2010	2090	2140	2190	2220	2250	2080	2290	2380	2460	2460	2460	210

LCF impacts and cost to consumers

B7. Table B7 show the forecast of the LCF breakdown of each Option. This provides a more detailed breakdown of the figures presented in Table 17 of the IA.

Table b7 - Cost to consumers, £m 2011/12 prices

Cost to consumers, £m 2011/12 prices							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Impact on cost to consumer in 2020/21 against Option 1 central estimate
Option 1 – Low Deployment Scenario							
PV	670	760	810	860	900	940	
Wind	200	240	260	270	280	280	
Hydro	80	110	120	130	140	150	
AD	160	190	190	190	200	200	
Total	1,120	1,300	1,390	1,460	1,520	1,570	
Option 1 – Central Deployment Scenario							
PV	670	780	870	960	1,030	1,090	
Wind	200	250	270	290	300	300	
Hydro	80	110	130	140	150	150	
AD	160	190	190	200	200	200	
Total	1,120	1,330	1,470	1,580	1,670	1,740	
Option 1 – High Deployment Scenario							
PV	670	800	910	1,020	1,110	1,170	
Wind	200	260	280	300	310	320	
Hydro	80	110	130	150	160	160	
AD	160	190	200	200	200	200	
Total	1,120	1,360	1,530	1,670	1,780	1,850	
Option 2 – Low Deployment Scenario							
PV	680	740	750	750	760	760	-330
Wind	200	230	230	230	240	240	-70
Hydro	80	100	100	100	110	110	-50
AD	170	200	210	220	220	220	20
Total	1,130	1,270	1,290	1,310	1,320	1,320	-430
Option 2 – Central Deployment Scenario							
PV	680	740	750	760	770	770	-320
Wind	200	230	230	240	240	240	-60
Hydro	80	100	100	100	110	110	-50
AD	170	200	210	210	220	220	20
Total	1,130	1,270	1,300	1,320	1,330	1,330	-410
Option 2 – High Deployment Scenario							
PV	680	740	760	770	770	770	-320
Wind	200	230	230	240	240	240.00	10
Hydro	80	100	100	110	120	120	-40
AD	170	200	210	220	230	230	30
Total	1,130	1,270	1,310	1,340	1,360	1,360	-380

B8. Table A8 shows the detailed cost to consumers under the central estimates of Options 1 and 2.

Table B8 - Cost to Consumers (£m, 11/12 prices)

	Option 1 - Central						Option 2 - central						Impact on cost to consumers by 2020/21 against Option 1 (central)
Actual cost to consumers	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
PV													
<4kW	330	370	410	450	480	500	330	350	360	360	360	360	-140
4 - 10kW	20	20	20	30	30	30	20	20	20	20	20	20	-10
10 - 50kW	80	100	120	150	170	190	80	90	90	90	100	100	-90
50-150kW	20	20	30	30	30	40	20	20	20	20	20	20	-20
150-250kW	10	20	20	30	30	30	10	20	20	20	20	20	-10
250-5000kW	20	30	30	30	30	30	20	20	20	20	20	20	-10
Stand alone	60	80	80	80	80	80	70	90	90	90	90	90	-
Agg <4	110	120	130	140	140	140	110	120	120	120	120	120	-30
Agg >4	10	10	10	10	10	10	10	10	10	10	10	10	-
250-1000kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1000-5000kW	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin costs	10	20	20	20	30	30	10	10	20	20	20	20	-20
Total	670	780	870	960	1,030	1,090	660	730	740	750	750	750	-340
Wind													
B-M <1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	10	20	20	20	20	20	10	10	10	10	20	20	-10
15–50kW	10	10	10	10	10	10	-	10	10	10	10	10	-
50–100kW	30	30	30	30	30	30	30	30	30	30	30	30	-
100–500kW	130	170	180	190	200	200	130	150	150	160	160	160	-50
500–1,500kW	10	10	10	10	10	10	10	10	10	10	20	20	-
1,500-5,000kW	10	10	10	10	10	20	10	10	10	10	10	10	-
Admin costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	200	250	270	290	300	300	200	230	230	240	240	240	-60
Hydro													
<15kW	-	-	-	10	10	10	-	-	-	-	-	-	-
15-50kW	10	10	10	10	10	20	10	10	10	10	10	10	-10
50-100kW	10	10	10	20	20	20	10	10	10	10	10	10	-
100-500kW	30	40	40	50	50	50	30	30	30	30	30	30	-20
500-1,000kW	20	20	30	30	30	30	20	20	20	20	20	20	-10
1,000-2,000kW	20	20	30	30	30	30	20	20	20	20	20	20	-10
2,000-5,000kW	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	80	110	130	140	150	150	80	100	100	100	110	110	-50
AD													
AD < 250kW	10	20	20	20	20	20	10	20	20	20	20	20	-
AD 250 - 500kW	50	60	60	60	60	60	50	60	60	60	60	60	-
AD > 500kW	100	120	120	120	120	120	100	130	130	140	140	140	20
Admin costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	160	190	190	200	200	200	170	200	210	210	220	220	20

Annex C – Employment impacts

C1. In the consultation, a few companies returned information about job losses that had already been incurred or were anticipated. However, as these respondents constitute a very small sample of business within the industry (around 200 jobs in total) the data provided did not give sufficient information to offer an industry-wide estimate.

C2. As set out in the main document, it is expected that there will be lower deployment of solar as a result of the revised tariffs and the introduction of caps than if there was no intervention. Deployment of domestic rooftop solar, for example, is anticipated to be c50% of the current monthly average (around 10,000 installations per month]) over the next FITs Review period. The available information provides the following assessments of current jobs currently supported by solar and wind in particular, across all support mechanisms:

Table C1: estimates of jobs supported by technology sector

Number of jobs (in direct sector and supply chain)	**Solar PV**	**Wind**
BIS 2015 study[1] (jobs in 2013 - headcount)	34,400	19,000
REA figures[2] (jobs in 2013/14 – FTEs)	16,103	18,191

C3. The majority of FITs deployment is solar, and then wind. Given this, the analysis of the effects has been limited to solar PV and wind only.

C4. Employment figures on a headcount basis will be higher than on a Full Time Equivalent (FTE) basis, as it includes those who only spend a proportion of their time working in the sector. Direct jobs are those involved in, for example, installing solar panels whereas indirect jobs are those generated in the supply chain by activity in the direct sector.

BIS report

C5. This was a joint report between BIS, DECC and Defra. It was commissioned through consultants Trends Business Research Ltd (TBR), and was published in March 2015. Data is available for both direct and indirect jobs, and the employment figures from the BIS report in Table C1 above are headcount figures. The study used a combination of a survey of low carbon businesses and existing company data sets to quantify activity in the direct sector. Activity in the supply chain was estimated through use of multipliers.

Renewable Energy Association report

C6. These estimates were published as part of a review carried out by the Renewable Energy Association (REA) in May 2015, who appointed Innovas to provide information on employment in the renewable energy supply chain. According to the published document, estimates are based on existing sources and refer to direct full time equivalent (FTE) jobs covering all aspects of the supply chain.

Office for National Statistics estimates

C7. The Office for National Statistics (ONS) ran a new survey in 2015 on the low carbon and renewable energy economy. First estimates of results have been published for the UK sector and data is available for 2014. Revised estimates are due to be published in 2016 and will contain figures for employment in the direct solar PV sector and onshore wind sector on an FTE basis. However, this data is not available in time for this analysis. [3]

C8. While the figures are the best available, there is uncertainty around them, and it is not straightforward to translate them into employment impacts. These uncertainties include a lack of robust evidence on the following:

- The proportion of jobs associated with installing projects, those with maintaining existing installations and those involved in the supply chain;
- The composition of job types – for example, engineers, installers, managers, roofers, sales and marketing – and how they might be affected by the changes;

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/416240/bis-15-206-size-and-performance-of-uk-low-carbon-economy.pdf

[2] http://www.r-e-a.net/news/uk-renewable-energy-jobs-grow-over-7-times-faster-than-national-average-employment-growth

[3] http://www.ons.gov.uk/ons/rel/environmental/uk-environmental-accounts/low-carbon-and-renewable-energy-economy-survey--2014/index.html

- For the headcount figures, the proportion of people's time is spent working with the installations – for solar in particular, it is likely that roofers, builders or similar are installing solar panels as part of their work. Therefore, changes in the number of solar panels installed may have less of an impact on unemployment as people re-divert to their other trades;
- The breakdown of the figures above into estimates under FITs and under other support schemes; and
- How labour productivity would be anticipated to change in line with deployment.

Assessing the job impacts of the measures

C9. Given the lack of evidence, it is difficult to estimate accurately the impacts of the scheme changes upon jobs supported by FITs. To provide approximate estimates, various assumptions must be made:

- The changes to the FITs scheme are only assumed to affect jobs supported by new installations, and not those associated with maintaining existing ones;
- Jobs for new installations also includes those involved in the supply chain – it is assumed that each direct sector job accounts for an equal number of supply chain jobs;
- Both the BIS and REA estimates above remain static over time – so it is assumed that the same number of jobs are supported in 2018/19 as were in 2013;[4]
- The split of jobs across the support schemes is assumed to be proportional to the approximate LCF spend on that support scheme in 2013/14, as set out in Table C2 below; and
- The share of jobs that represent installers is based on evidence from UK Energy Research Centre (UKERC), set out in Table C3 below.

Table C2: approximate spend in 2013/14 by technology by scheme

£2013/14m	RO	FITs	Proportion FITs
Solar	85	535	94%
Onshore wind	755	85	10%

Table C3: implied proportion of jobs related to installations[5]

		Jobs/GWh (installations)	Jobs/GWh (O&M)	Implied share of installation jobs
Wind	Min	0.01	0.04	20%
	Median	0.02	0.08	20%
	Max	0.12	0.23	34%
Solar PV	Min	0.11	0.04	73%
	Median	0.20	0.11	65%
	Max	0.50	0.27	65%

Note that in this table, min and max refer to the number of jobs supported per GWh of generation, rather than min and max job effects as a result of the changes to the FITs scheme.

C10. As Table C3, which is an average across all OECD countries, sets out, solar jobs are significantly more focused on installations than operation and maintenance; the reverse is true for wind.

C11. To understand the scale of employment that may no longer be supported through the FITs scheme, as compared to levels supported now, it is assumed that the number of installation jobs is directly and linearly correlated with the total deployment that comes forward under the scheme in a given time period. In reality, the relationship may not be linear; this is a simplifying assumption.

[4] This is likely to be inaccurate. However, there are countermanding factors that may mean that this is not clear-cut. Firstly, more deployment – both existing and new build - is likely to mean more people employed. Secondly, more people being involved in deployment is likely to improve their efficiency and productivity, meaning that the same amount of capacity may correspond to fewer people employed. A static assumption is therefore used.

[5] This is based on Table 10 of the FITs evidence review, taken from the UKERC report. The calculation is the total number of jobs per annual GWh of generation in installations and in O&M, with only the people associated with installations assumed to be affected. So, for example, for the wind minimum, the calculation is 0.01/(0.01+0.04)=20%. The report, and the link to the UKERC report, is available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456181/FIT_Evidence_Review.pdf

C12. To calculate the number of jobs that may no longer be supported through the FITs scheme the following method is used:

- Jobs across support schemes are split proportionately to spend.[6] This means, for example, that 94% of solar jobs are assumed to be FITs-related, as 94% of support paid to solar is through the FITs scheme.
- Jobs are also split into installations (including the supply chain), which is assumed to be affected by the changes, and maintenance, which is assumed not to be.[7]
- The jobs associated with installations are assumed to correspond to new-build capacity coming forward in that year only. The reduction in installations and jobs has been presented here under option 2 compared to option 1. As set out in Table 11, the deployment reduction is in the region of 65% per year for solar.
- The high and low estimates comprise the high and low split between installation and maintenance from the UKERC report, and the high and low deployment figures set out in Table 11 of the Impact Assessment.

C13. So, for example, in the central case the impact on headcount in the solar sector would be:

Jobs impact = Total jobs * Proportion spend on solar through FITs * proportion of jobs in installations * new-build deployment reduction

C14. Table C4 sets out assumed jobs supported under the FITs scheme at present, and how this is broken down between installations (including the supply chain) and maintenance. Table C5 then sets out the potential reductions in job numbers that are supported by FITs, as a result of these changes, out to 2018/19. Given the different figures for solar from the BIS report (headcount) and the REA report (FTE), both figures are included below for solar. As the onshore wind figures are relatively similar, only one set of figures is included, which is based on the FTE figures provided by REA.

Table C4: Jobs supported by FITs, disaggregated

	Installations	Maintenance	Total
Solar (headcount)	21,000 - 23,700	8,600 - 11,300	32,300
Solar (FTE)	9,800 - 11,100	4,000 - 5,300	15,100
Wind (FTE)	400 - 600	1,200 - 1,500	1,800

Table C5: Jobs estimated to no longer be supported by FITs

	High job impacts	Low job impacts
Solar (headcount)	18,700	9,700
Solar (FTE)	8,700	4,500
Wind (headcount or FTE)	300	100

C15. There are therefore assumed to be between 9,700 and 18,700 (out of c32,300) fewer solar jobs supported on a headcount basis, and between 4,500 and 8,700 (out of c15,100) on an FTE basis by the end of 2018/19, as a result of these changes. There are also between 100 and 300 (out of c1,900) fewer wind jobs supported. Given the imprecise nature of these estimates and the assumptions made, figures are rounded to the nearest hundred. They must also be treated with caution, and are used to give an indication of the reduction in jobs supported only.

C16. At present, no assumptions have been made about FITs deployment after the end of 2018/19. While there is currently intended to be no generation tariff for new-build plants after the end of 2018/19, the scheme may continue, with one option being a scheme that offers an export tariff only. Based on available information, a small number of plants – particularly solar and wind – may already be able to deploy under such a scheme now, without the support of a generation tariff. The aim is for this number of installations that can go ahead without support to increase over time, both to build a renewables sector that does not require ongoing support and so that there continues to be employment in the sector. It is also important to note that jobs

[6] An alternative method would be to split by the number of installations. However, as larger installations will require more labour, it is likely that splitting this way would be unrepresentative.

[7] As existing installations will not be affected by the changes and will continue to require maintenance, there is not assumed to be any reduction in jobs supported in the maintenance sector as a result of fewer new installations being built.

associated with maintenance would continue to be supported under the FITs scheme as the existing installations would continue to require maintenance. Based on the above methodology, this would be c11,500 headcount in solar, c5,400 FTE in solar and c650-700 in wind.

C17. These figures are tentative. They are also subject to uncertainties as to precisely what they mean. For example, the reduction in solar headcount or FTE in particular could represent people transferring back to the professions they held prior to the introduction of the FITs scheme – roofing, building and related. Assuming the figures from the BIS and REA reports are accurate, it would imply that people working in the solar industry spend less than 50% of their time installing and maintaining solar plants. Assuming such people are full-time workers and only spending part of their time on FITs, this could in turn imply that fewer jobs supported under FITs may have a less harmful impact on the economy than for other technologies. This is because people spending less than half of their time working in an area may find it more straightforward to increase their time spent on other aspects of their job, such as roofing and building. If, alternatively, the people concerned are part-time workers, then this may not be the case, and the impact of the reduced jobs supported under the FITs scheme would be more detrimental. The information is not available on which to make this judgement with any degree of certainty.

Annex D: The Tariff Calculator and the FITs Model

D1. This Annex explains how tariffs are set and the method used to forecast deployment, generation and the resulting costs under the Levy Control Framework. DECC has used two models to do this - the Tariff Calculator and the FITs Model. The Tariff Calculator is used to set generation tariffs to target a particular rate of return for generators. The FITs Model is used to forecast deployment under the scheme, based on a set of initial generation tariffs. This is then used to calculate the amount of electricity generated from FITs installations throughout their lifetime and the associated spend under the Levy Control Framework. This model is also used as the basis for setting caps and estimating contingent degression.

The Tariff Calculator

Inputs

D2. Generation tariffs are based on a reference installation. This is an average-sized installation within each tariff band and across different technologies. For the reference installation, DECC makes assumptions on the following characteristics:

- installation size
- technology lifetime
- load factor
- the proportion of electricity that the generator exports to the grid or consumes on-site
- generating costs
    - capital expenditure (capex)
    - operating expenditure (opex)
- revenue streams
    - revenues from export payments or Power Purchase Agreements (PPAs)
    - savings on electricity bills

D3. These assumptions are outlined in Annex A.

Methodology

D4. This section explains how the Tariff Calculator calculates generation tariffs, illustrating step-by-step a simplified version of the formulae used.

D5. Generation tariffs are calculated by topping up the income streams for an average FITs installation to give the target rate of return over the lifetime of the project. Rates of return are based on discounted cash flows, which is the approach often used by investors to evaluate opportunities. Discounting cash flows allows assessment of the value of an investment made today, taking into account future costs and revenues. This captures the fact that investors are likely to place a higher value on today's payments compared to future payments.

D6. The rate at which cash flows are discounted is the target rate of return DECC believes will be needed to allow future deployment to come forward while avoiding overcompensation. The target rate of return is based on the assumptions on hurdle rates, as explained in Annex A.

Step 1: Calculate the present value of the costs of the reference installation

D7. The first step when setting the generation tariffs is to estimate the present value[8] of the generation costs for the reference installation. This includes capital expenditure (one-off installation costs) and operating expenditure (annual maintenance costs). To set tariffs, Government assumes that capex costs are incurred in the first year of the installation. The calculations used are set out below:

[8] Present Value: The current worth of a future sum of money or stream of cash flows given a specified discount rate.

$$CAPEX = (unit\ capex + unit\ grid\ connection) \times installation\ size$$
$$OPEX = unit\ opex \times installation\ size$$

D8. The tariff calculator calculates the present value of the generation costs using the assumptions outlined in Annex A. The present value (PV) is calculated by discounting future values of operational expenditure by the target rate of return. This approach allows the generator to recoup costs and achieve the target rate of return. The calculations used are set out below:

$$PV\ of\ generation\ costs = CAPEX + PV\ of OPEX$$
$$PV\ of\ OPEX = PV\ (rate\ of\ return, installation\ lifetime, OPEX)$$

Step 2 – Calculate the present value of the revenues of the reference installation

D9. The next step is to calculate the revenue streams for the reference installation (excluding the generation tariff). These are the bill savings from consuming the electricity generated and the export income from selling the electricity generated back to the grid.

D10. Revenue from export payment is calculated as:

$$export\ payments = export\ tariff \times exported\ generation$$
$$exported\ generation = total\ generation \times export\ fraction$$
$$total\ generation = capacity \times load\ factor \times hours\ in\ a\ year$$

D11. Bill savings are calculated as:

$$bill\ savings = electricity\ price \times generation\ consumed\ onsite$$
$$generation\ consumed\ onsite = total\ generation - exported\ generation$$
$$total\ generation = capacity \times load\ factor \times hours\ in\ a\ year$$

D12. There are exceptions to the formula above. Installations below 30kW may opt to have their exports deemed to be 50% of their generation, rather than install an export meter. This would imply 50% on-site consumption. DECC modelling assumes instead that for installations <10kW on-site consumption is 45%, and therefore acknowledges that 5% of the electricity generated does not receive the export tariff nor can be counted towards bill savings, though it is assumed to be exported to the grid.

D13. The present value of these income streams is then calculated in the same way as for costs.[9] This approach allows an internal rate of return for the generator equal to the target rate of return (ROR). The calculations are set out below:

$$PV\ of\ revenue\ streams = PV\ of\ export\ payment + PV\ bill\ savings$$
$$PV\ of\ export\ payment = PV\ (ROR, installation\ lifetime, export\ payment)$$
$$PV\ of\ bill\ savings = generation\ consumed\ onsite \times NPV\ (ROR, electricity\ price)$$

Step 3 – Setting the generation tariff

D14. Generation tariffs are set to make up for the difference between the present value of generation costs and revenues discounted by the target rate of return. This implies that when a generator takes generation tariffs revenues into consideration, the net present value of its cash flows are equal to zero, making the investment worthwhile.

D15. As a result, when the DECC methodology refers to a project that has a 5% rate of return, it does not mean that each year the project will generate an amount of cash equal to 5% of the initial investment. What it

[9] Note that for bill savings a Net Present Value (NPV) function is required as the bill savings vary over the years with electricity price changes.

means instead is that if all the project cash flows are discounted using a 5% rate, then its net present value will be equal to zero.

$$PV\ generation\ tariff\ revenue = PV\ of\ revenue\ streams - PV\ of\ generation\ costs$$

D16. Finally, the revenue from generation tariffs expressed in present value is converted into annual payments and then unit payments, into the familiar pence per kWh[10].

$$generation\ tariff = \frac{PMT(ROR, tariff\ lifetime, PV\ of\ generation\ tariff\ revenue)}{total\ generation}$$

The FITs Model

D17. Future deployment is forecast on the basis of the assumption that investors will join the FITs scheme if it makes financial sense to them. In other words people will invest if the total expected cash flows over the lifetime of the installation (i.e. setup and operating costs but also tariff revenues and bill savings) deliver a rate of return equal to or higher than their minimum acceptable rate of return (known as the 'hurdle rate'). The revenues and costs, together with the revenue from generation tariffs produced in the Tariff Calculator, are used as inputs in the FITs Model.

D18. Costs and revenues are calculated as above for the tariff calculator. The model also takes into account the revenue for the generation tariff which is calculated as:

$$generation\ tariff\ revenue = generation\ tariff \times total\ generation$$

$$total\ generation = installation\ size \times load\ factor$$

D19. The typical installation size in each tariff band is determined using the reference installations described above, using historical data on installations registered for the FITs scheme.

D20. Load factor means the rate at which an installation generates electricity, compared to its maximum capacity, and is typically expressed as a percentage. Assuming a load factor of 11%, for example, a 4kW solar installation would generate around 3,850 kWh of electricity over a year. The load factor of an installation depends on a number of factors, including geographical location and weather, for example sunshine hours (for solar panels) or wind speeds (for wind turbines).

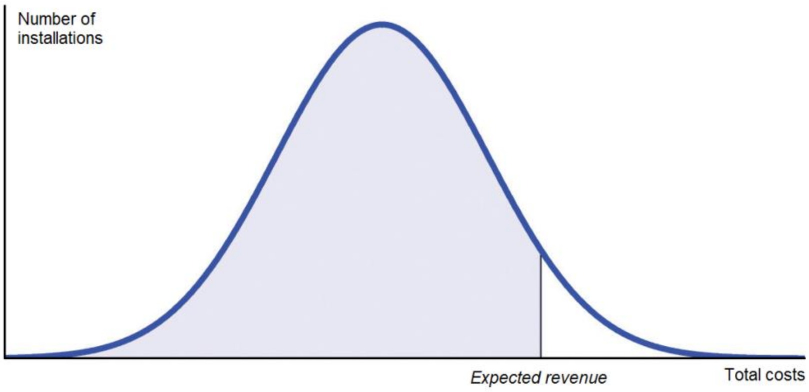
D21. Multiplying installation capacity with the load factor gives the estimated total generation over a year. This is then multiplied by the applicable generation tariff over the lifetime of the technology to calculate total revenue from generation tariffs.

Forecasting deployment

D22. The FITs model uses an algorithm to forecast future deployment. Figure 1 below illustrates the main principle.

[10] The calculation to convert present value into annual payments is done by using the "PMT" function in excel. The revenues in annual terms are then divided by the total generation in a year to be expressed in units.

Figure D1: Cost-benefit analysis performed by potential investors



D23. The horizontal axis shows total capital and operating expenditure, and the vertical axis shows the number of installations at each cost level. Investors in the shaded area can generate a profit because their expected revenue is higher than their total costs. The FITs model therefore assumes that they will potentially join the scheme. The distribution of levelised costs is calculated using a large body of evidence collected by DECC's contractors and submitted to DECC as part of the FITs Review. After excluding outliers (i.e. projects that are much cheaper or much more expensive than typical), costs are assumed to follow what is known as a "normal" distribution. The properties of this distribution are well described mathematically, so DECC can produce not just a central estimate of the typical levelised cost but also a low and a high estimate for testing various deployment scenarios. This process is described in more detail in WSP Parsons Brinckerhoff's *Small-scale Generation Costs* publication.

D24. In addition to the percentage of people that want to invest, future deployment is limited by:

- the available technical potential, i.e. how much micro-generation capacity can physically be installed in the country;
- the supply barrier, i.e. the rate at which installers can complete new projects;
- the social barrier, which represents people's willingness to invest in renewables; and
- the market barrier, which represents that as deployment of a technology increases as awareness of it grows and supply chains develop.

D25. The model is periodically recalibrated. This means that the assumptions about supply barrier, social barrier and market barrier are updated on the basis of actual deployment data so that predictions are aligned with historical trends.

D26. The FITs model also includes mechanisms that simulate trends in deployment due to investor behaviour. For example, at present, deployment typically surges in the month before a tariff degression and drops immediately afterwards, as investors rush to secure the higher tariff. To incorporate these changes in predictions, the model multiplies deployment forecasts by an uplift factor when a degression is anticipated, and reduces it afterwards. The value of these factors is based on historical information and data collected by DECC's contractors.

D27. Under the revised FITs scheme, deployment in a given quarter cannot exceed the cap for that tariff band, so if the result of the above calculations exceeds the applicable threshold, the deployment forecast is automatically set at the level of the cap. If a cap is reached, contingent degression is triggered and the appropriate reduction is applied to tariffs in the next deployment period. The new tariffs then feed into the estimation of investor revenues as the forecasting process starts again for the next quarter. Spend under the Levy Control Framework (LCF) is calculated at the total of generation forecasts based on estimates of future deployment times the applicable generation tariffs.