Title: Periodic Review of FITs 2015	**Impact Assessment (IA)**
IA No: DECC0196	**Date:** 27/08/2015
Lead department or agency: Department for Energy and Climate Change	**Stage:** Consultation
	Source of intervention: Domestic
	Type of measure: Secondary legislation
Other departments or agencies:	**Contact for enquiries**: FITreview@decc.gsi.gov.uk

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, One-Out?**	**Measure qualifies as**
£1,510 - £2,250m	£m	£m	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 in 2015 to ensure that FIT generators are not being over-compensated. This 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 objective is to control spending under the FITs scheme, with the intention being that a maximum of £100m is spent on new-build deployment over this FITs review period. Generation tariffs are set to secure value for money to consumers by targeting only well-sited installations. Caps limit the amount of deployment to ensure that spending does not go above £100m. Reducing this cap or ending generation tariffs are proposed as alternative means of controlling expenditure.

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 would also assume that pre-accreditation is not removed.

Option 2 – make the policy changes as set out in the consultation document 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 removal of pre-accreditation (it is assumed for the purpose of this analysis that the decision is taken to remove it).

Option 3 – full closure of the scheme.

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: 27.08.2015

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 removal of pre-accreditation (it is assumed for the purpose of this analysis that the decision is taken to remove it).

FULL ECONOMIC ASSESSMENT

Price Base Year 2016	PV Base Year 2010	Time Period Years 45	Net Benefit (Present Value (PV)) (£m)		
			Low: £1,510m	**High:** £2,250m	**Best Estimate:** £1,810m

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				£560m
High				£700m
Best Estimate				£610m

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

Renewable capacity falls in this scenario, as does renewables generation. The generation 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 £250,000 admin cost to implement the changes.

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; this is not quantified and any evidence is welcome as part of this review.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				£2,070m
High				£2,950m
Best Estimate				£2,420m

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

Renewable capacity falls in this scenario, as does renewables generation. The generation is assumed to be replaced by the grid average, which has a lower resource cost than FITs generation. This results in a saving from lower FITs deployment and generation.

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 overspends under the FITs scheme, which is mitigated through lower tariffs and the introduction of caps. There is an additional risk that by reducing tariffs so significantly deployment is reduced by more than is currently anticipated.

BUSINESS ASSESSMENT (Option 1)

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

Summary: Analysis & Evidence — Policy Option 3

Description: Full closure of the Feed-in Tariffs scheme

FULL ECONOMIC ASSESSMENT

Price Base	PV Base	Time Period	Net Benefit (Present Value (PV)) (£m)		
Year 2016	**Year** 2010	**Years** 45	**Low:** £1,480m	**High:** £2,830m	**Best Estimate:** £2,660m

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low				£810m
High				£860m
Best Estimate				£830m

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

Renewable capacity falls in this scenario, as does renewables generation. The generation is assumed to be replaced by the grid average, which has higher carbon emissions than renewables – therefore, carbon emissions increase in this scenario. Capacity and generation is likely to fall by more than in Option 2.

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; this is not quantified and any evidence is welcome as part of this review.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low				£2,290m
High				£3,690m
Best Estimate				£3,490m

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

Renewable capacity falls in this scenario, as does renewables generation. The generation is assumed to be replaced by the grid average, which has a lower resource cost than FITs generation. This results in a saving from lower FITs deployment and generation. Savings are likely to be higher than in Option 2.

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

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

The main assumption in this Option is when the scheme can be closed. The working assumption is that this would happen in January 2016. The risk around this would be that there is significantly higher than predicted deployment ahead of the scheme's closure.

BUSINESS ASSESSMENT (Option 2)

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

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1. Problem under consideration

1.1 The EU Renewable Energy Directive commits the UK to producing 15% of its energy from renewable sources by 2020. Broadly, this is set across electricity, heat and transport. The ambition is for at least 30% of electricity to be generated by renewable sources. The 15% commitment is within the wider intention for 80% decarbonisation by 2050, relative to 1990 levels.

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 announced earlier this year[4], the expected spending under the LCF in 2020/21 has increased significantly above the £7.6bn. While the projected spending of £9.1bn remains within the LCF headroom (which is 20% above the £7.6bn), it is important that Government gets a grip on 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 policies to reduce spending and to limit the exposure of the LCF to further spending risks. This includes:

- 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;[5]
- A proposal to close the RO to solar PV up to and including 5MW from the end of 2015/16, reducing spending projections by c£60m per year up to 2020/21 (with a range from £40m-£100m), further to early closure to projects larger than 5MW announced last year;[6] and
- A consultation on the removal of pre-accreditation under the FITs scheme[7], which, if implemented, is expected to reduce spending by only allowing projects to access a tariff when they begin generating rather than securing it through pre-accreditation (which is in general prior to beginning construction). This is likely to reduce the certainty for an individual project, and therefore to both reduce deployment and to mean that the deployment that does go ahead receives a lower generation tariff.

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, as well as the introduction of degression policy. 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 the Government introduced pre-accreditation. Pre-accreditation allows developers to apply for funding under the scheme before they start generating and generally prior to construction, and results in generators being guaranteed a particular tariff.

1.6 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. 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. This has resulted in significant spending increases under the LCF, from c£1,160m at the time of the 2012 Comprehensive review to c£1,600m in 2020/21 (range £1,070m to £1,600m) now, in

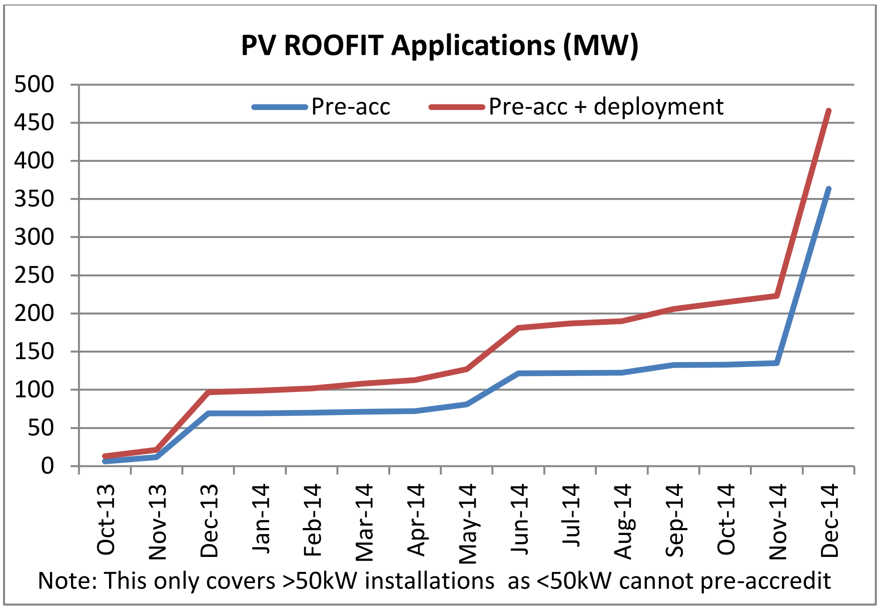
[1] Some <5MW projects are also supported under the RO, but they are usually supported by FITs.
[2] The RO Closure Order 2014 extends this closure date in some circumstances where projects are eligible for grace periods aimed at facilitating the RO to CfD transition. The RO closed early to new large-scale (>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 OBR report is available at http://cdn.budgetresponsibility.independent.gov.uk/July-2015-EFO-234224.pdf
[5] https://www.gov.uk/government/consultations/changes-to-grandfathering-policy-with-respect-to-future-biomass-co-firing-and-conversion-projects-in-the-renewables-obligation
[6] https://www.gov.uk/government/consultations/changes-to-financial-support-for-solar-pv
[7] https://www.gov.uk/government/consultations/changes-to-feed-in-tariff-accreditation

the absence of intervention.[8] While the range shows that there remains uncertainty about deployment and spending under the scheme, spending projections have increased markedly.

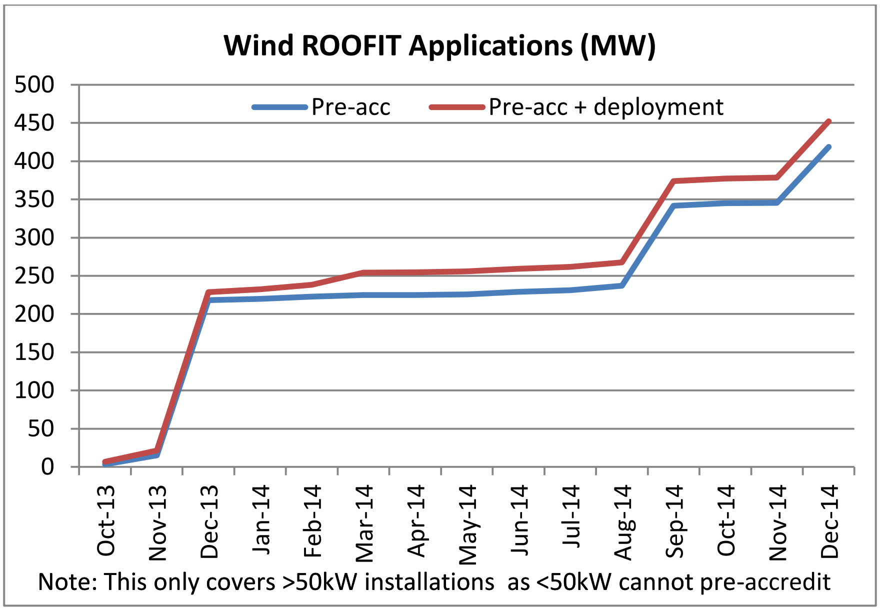
1.7 Given that pre-accreditation spikes have remained high over time, particularly for hydro, it suggests that the tariff reductions are insufficient to manage deployment and spending, as was intended within the 2012 review. The charts below illustrate this – on average 87% of applications eligible for pre-accreditation or accreditation were for pre-accreditation.

<u>Chart 1: proportion of applications for pre-accreditation relative to total, split by technology</u>

Solar PV (>50kW)

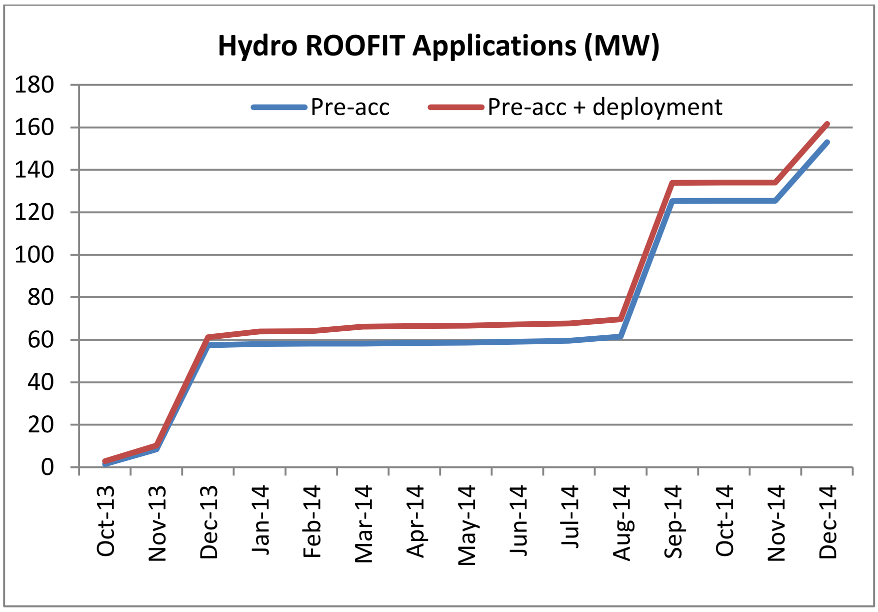


Wind (>50kW)

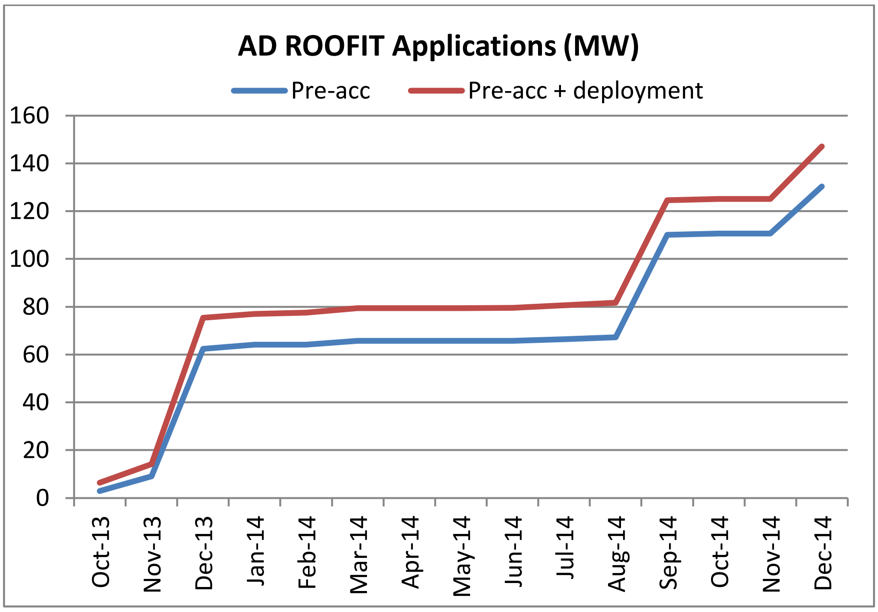


[8] These figures are in £2011/12 prices, for comparability with the LCF.

Hydro (all)



AD (all)



1.8 Alongside the LCF context, there is also evidence to suggest that costs of developments have changed significantly over time. DECC commissioned an independent evidence update earlier this year from Parsons Brinckerhoff (PB) to review the cost and technical assumptions of FIT-eligible technologies, and supplemented this with work from Ricardo-AEA on hurdle rates.[9] This evidence suggests that installations under FITs in general are now significantly less expensive than previous estimates, suggesting that there is scope for deployment to come forward at lower tariffs.

1.9 This review therefore aims to reflect the updated evidence in setting revised tariffs across technologies. It also intends to address the over-spending that has occurred under the scheme, compared to previous forecasts, and to introduce robust cost control measures to ensure that future overspends are avoided.

1.10 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 whether the target rate of return is still appropriate, and consider revision of tariff levels and change accordingly. In particular, tariff levels will take account of any decreases in the levelised costs of generation to ensure there is no overcompensation.[10]

1.11 Throughout this document, cost, benefit and savings figures are given in 2016 prices. The exception is figures pertaining to the LCF, which are given in £2011/12 prices as this is the price base in which the LCF is set. All spending figures are rounded to the nearest £10m.

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[9] The PB report is available on the FITs consultation page - https://www.gov.uk/government/consultations/consultation-on-a-review-of-the-feed-in-tariff-scheme

[10] http://ec.europa.eu/competition/state_aid/cases/235526/235526_1104588_39_2.pdf, para. 39.

2. 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. This is to help ensure that deployment and spending are brought under control, and that generators are not making excessive returns on their investments.

2.2. The tables below show the deployment under the FITs scheme which was predicted at the time of the last FITs Comprehensive review. This is then 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. In addition, much of the deployment is pre-accrediting prior to full accreditation, suggesting that the introduction of pre-accreditation in the last review has been successful at offering developers certainty and mitigating or removing the degression risk. Combined with Chart 1 above, this shows that actual deployment has outstripped projections. Note that the figures in Table 1 are based on registered accreditations rather than applications for registration, which are included in Chart 1, so the figures do not correspond exactly. Indications so far are that the majority of projects that pre-accredited have gone on to full accreditation.[11]

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)	2020/21 projection without cost control (2015 FIT Review)
Hydro	170	160	420
AD	220	220	310
Wind	690	290	1440
PV	3460	3,500-21,100	9370

* Source: Actual Deployment and Pre-accreditation to July 2015 has been estimated using Commission Installed Capacity to March 2012[12] and then capacity registered in the monthly degression statistics[13].

Table 2: proportion of capacity that has registered that has pre-accredited

Total Capacity registered (April 2012 to July 2015, MW)*			% of capacity that pre-accredited
PV	Deployment	2,200	
	- *of which pre-accredited*	160	7%
Wind	Deployment	600	
	- *of which pre-accredited*	410	68%
Hydro	Deployment	150	
	- *of which pre-accredited*	110	74%
AD	Deployment	200	
	- *of which pre-accredited*	120	58%
Total	**Deployment**	**3,150**	
	- ***of which pre-accredited***	**790**	**25%**

** Note that this does not match the charts as this is for all installations, whereas Chart 1 is for >50kW*

2.3. The tables above demonstrate the success of the FITs scheme in bringing forward deployment, which is contributing to 2020 renewable energy targets and longer-term objectives. 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), and those now.

Table 3: 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
2015 (OBR)*	925	1,095	1,255	1,375	1,490	1,600
Current	1,040	1,190	1,320	1,430	1,520	1,600

[11] 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.
[12] https://www.gov.uk/government/statistics/monthly-small-scale-renewable-deployment
[13] https://www.gov.uk/government/statistical-data-sets/monthly-mcs-and-roofit-statistics

** Current spend projections have been slightly updated since those that contributed to the OBR update in July 2015. This is because there is more realised deployment data included in the updated forecast and therefore the model has been recalibrated.*

2.4. Table 3 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 increasing expectations of deployment and / or generation under the RO and under CfDs (including Final Investment Decision enabling for Renewables – FIDeR), the LCF spending estimates have increased from £7.6bn in 2020/21 to £9.1bn.

2.5. The costs of technologies under FITs tend to be higher than for other technologies.[14] FITs does offer wider benefits, including offering households, communities and businesses the opportunity to reduce their electricity bills, and potentially to encourage behavioural change of people involved in the scheme, and the FITs scheme is likely to support a significant number of jobs. However, this is unlikely to fully compensate for the discrepancy in the relative costs and value for money of the scheme.

2.6. Therefore, the FITs consultation proposes to reduce tariffs for all technologies covered at this stage.[15] This is the first way of introducing more control over deployment and spending on the scheme; it is also in line with our State aid requirement to use our three-year reviews to ensure there is no overcompensation under the scheme. It is important to note that, while DECC is using the best available evidence at this stage, it is possible that some of the information may prove to be inaccurate. It is likely that over the period covered by the FITs review, there will be changes to underlying assumptions that are not currently predicted. Recognising that our information is not perfect, DECC is also proposing to introduce caps to offer absolute 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.

3. Policy objective

3.1. The primary objective of this review of the FITs scheme is to control costs effectively in a way that is consistent with the UK's undertaking in its State Aid approval to 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*". The proposed approach is that better value for money is achieved by introducing tariff reductions to avoid excessive returns, and deployment caps are introduced control the overall expenditure of the scheme. Within the constraints of controlling costs, Government currently intends to keep the scheme open and viable. However, and as set out in the consultation document, if the consultation indicates that caps cannot be implemented to control costs effectively, the Government may decide that it is appropriate to end generation tariffs for new applicants earlier.

3.2. As such, this consultation seeks views on the impacts of scheme closure, whether implemented in the immediate term (i.e. as soon as the legislative process allows) or as a phased closure over several years. It also seeks views on constraining the scheme to particular technologies or particular groups, for example householders (subject to State aid approval).

3.3. Given LCF budget constraint, the Government proposes that spending on new generation under the scheme after we have revised tariffs should be capped and phased out. It considers that this cap should not exceed £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. This is set out in Table 4 below; the underpinning assumptions and basis for these projections are set out in sections 4, 5 and 6.

Table 4: Central spending estimates for each Option

	Cost to consumers, £m 11/12 prices										
	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Option 1	20	150	490	650	850	1,040	1,190	1,320	1,430	1,520	1,600
Option 2						1,020	1,080	1,110	1,140	1,150	1,150
Option 3						1,030	1,070	1,070	1,070	1,070	1,070

3.4. Within the constraints of the LCF framework, the intention is to design a revised FITs scheme that is sustainable over the longer term; that offers a stable investment framework; that avoids boom / bust scenarios; that provides value for money for the consumer; and that helps to move technologies and bands

[14] 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.

[15] AD is not included at this stage, as there are complexities for AD that do not exist for other technologies, which are still being considered. Therefore, the review of AD will be published later this year. Micro CHP has also not been covered at this stage.

within those technologies towards zero subsidy.[16] This has governed the decisions set out within the consultation document and within this Impact Assessment.

3.5. Industry and Trade Associations have previously told the Department that stability is a necessity to ensure that investment happens. This is linked to the other objectives set out above: a stable investment framework means there are no booms and busts, which in turn helps to reduce costs of new installations over time by investing in new technologies and in the skills to install and operate these technologies.

3.6. While the forecast deployment levels by technology based on the proposed tariffs are significantly lower than previous forecasts, they are the maximum currently considered affordable within the LCF. The tariffs proposed within the consultation are based on the available evidence, and on targeting efficient sites. Any increases in maximum allowed deployment and spending within one particular technology or band would need to be accompanied by a reduction in that for other technologies or bands.

3.7. Therefore, the policy set out in the consultation document has been designed to treat all technologies covered in this stage of the consultation equally. It is based, as far as is possible, on the available evidence, unless stated otherwise.

3.8. The exception for this is – at this stage –tariffs for AD, which we are not proposing to change as part of this consultation. There are complexities associated with AD that do not apply to the other technologies covered by FITs, most importantly around the overlap with the Renewable Heat Incentive (RHI). The Department intends to consult on AD tariffs later this year.

3.9. Other policy set out within the consultation and within this Impact Assessment is intended, subject to consultation, to apply to AD as it would apply to the other technologies.

4. Supporting evidence

4.1. FITs installations face both 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 consultation document 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[17].

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:

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

4.3. The majority of these assumptions have been updated by external contractors Parsons Brinckerhoff (PB). The following sections outline the assumptions, how they have changed since 2012 and the source, when they differ from the PB report.

4.4. Some tariff bands have been altered from existing bands since PB conducted their research. Where tariff bands have changed, the underpinning assumptions are broken down by installation size and have then been re-calculated from the raw data gathered by PB. For example, information gathered on a 7kW solar installation would previously have informed the 4-50kW tariff; now it informs the 0-10kW tariff. More information about where tariff bands have been altered is set out in section 5.

Load factors

[16] 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 profitable.
[17] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

4.5. The load factor is the proportion of time for which an installation is expecting to generate electricity. The 2015 PB analysis shows that average load factors have increased for solar PV, Hydro, Wind and AD, compared to assumptions from the 2012 Review.[18] It is assumed that the load factors are constant over time.

Table 5 – Load factors used in the FITs modelling

	2015			**2012**
	Low	*Central*	*High*	*Central*
PV				
Scotland	8.4%	8.9%	9.5%	9.0%
Midlands	9.7%	10.3%	10.9%	9.5%
South East	9.9%	10.5%	11.1%	9.7%
South West	10.1%	10.7%	11.3%	10.0%
Wind				
<1.5kW	0	0	0	0
1.5–15kW	14% - 29%	14% - 29%	22% - 29%	14% - 29%
15–50kW	12% - 28%	13% - 29%	22% - 32%	13% - 29%
50–100kW	14% - 29%	16% - 30%	17% - 31%	16% - 30%
100–500kW	19% - 35%	30% - 43%	32% - 58%	16% - 35%
500–1,500kW	13% - 31%	18% - 38%	20% - 40%	18% - 38%
1,500-5,000kW	15% - 33%	21% - 41%	23% - 44%	21% - 41%
AD				
< 250kW	63%	65%	67%	60%
250 - 500kW	68%	70%	72%	65%
500-5,000kW	77%	80%	83%	80%
Hydro				
All	27%	40%	53%	35%

4.6. The wind load factors vary by average wind speed. The whole range of load factors from 5.5m/s to 8.0m/s is shown above. Load factors are broken down in more detail in the PB report.

4.7. Wind load factors have increased significantly in the 100-500kW band. This is due to the practice of de-rating. De-rating is the tendency for installers and manufacturers of equipment to increase the generating capability of the equipment at lower wind speeds by using larger turbine blades than would be normal for a given generator capacity. This enables more of the wind energy to be captured than normally would be expected for a given installation size.

Capex

4.8. The findings of the Parsons Brinckerhoff review showed that, in general, capex has reduced across all technologies. As part of the survey, installation and grid connection costs were presented separately to provide greater insight into the breakdown of costs. The installation and grid connection costs are shown in table 6. For PV installation of <10kW, it is assumed that significant costs are not associated with the grid connection.

4.9. All the analysis in this IA uses the central value of capex. Capex is also assumed to fall over time for PV and wind. More information about this is available in the PB report, and in Table 6.

4.10. AD is not included within this Table, and will be covered within the AD part of the FITs review later this year.

[18] The two stages of the review are available at https://www.gov.uk/government/consultations/feed-in-tariffs-first-phase-of-a-comprehensive-review for PV and https://www.gov.uk/government/consultations/tariffs-for-non-pv-technologies-comprehensive-review-phase-2b for non-PV.

Table 6 – Capex used in modelling, including grid connection where applicable

£/kW, 2016 prices	Capex			Grid Connection*	Capex and grid connection		
	Mar-2015				*Mar-2015*	*Mar-2012*	*% change*
Solar PV							
<4kW	1,314	1,732	2,146	0	1,732	2,683	-35%
4 - 10kW	1,124	1,480	1,832	0	1,480	2,356	-20%
10 - 50kW	971	1,283	1,587	395	1,678	2,101	-20%
50-150kW	912	1,205	1,497	392	1,597	1,948	-18%
150-250kW	834	1,100	1,368	388	1,488	1,772	-16%
250-5000kW	793	1,049	1,296	347	1,396	1,384	1%
Stand alone	812	1,067	1,325	358	1,425	1,384	3%
Hydro							
<15kW	1,923	3,699	5,474	396	4,095	8,633	-53%
15–50kW	2,977	5,726	8,474	395	6,120	6,385	-4%
50–100kW	2,754	5,296	7,838	393	5,689	6,043	-6%
100–500kW	2,216	4,261	6,306	382	4,643	4,978	-7%
500–1,000kW	1,739	3,345	4,950	366	3,711	3,817	-3%
1,000–2,000kW	1,367	2,628	3,890	335	2,964	2,999	-1%
2,000–5,000kW	1,118	2,150	3,183	306	2,456	2,454	0%
Wind							
<1.5kW	0	0	0	0	0	0	N/A
1.5–15kW	2,139	4,097	6,056	396	4,494	4,771	-6%
15–50kW	1,711	3,278	4,845	395	3,673	3,817	-4%
50–100kW	555	1,064	1,572	393	1,457	4,090	-64%
100–500kW	1,222	2,342	3,461	381	2,723	2,704	1%
500–1,500kW	650	1,245	1,840	359	1,604	1,969	-19%
1,500-5,000kW	591	1,132	1,673	280	1,412	1,780	-21%

** This analysis uses grid connection costs based on the raw data collected by PB. For more detail on this see Section 3.2 of the PB report. This analysis uses the same method to estimate the grid connection costs, but splits them by tariff band.*

Hurdle Rates

4.11. A hurdle rate is the minimum expected rate of return at which a potential investor would consider investing. For example, if a commercial investor – e.g. a small business which owns a warehouse – has a hurdle rate of 5% for solar PV, it means that they will only consider installing solar panels on the roof of their warehouse if the expected internal rate of return (IRR) of the project is 5% or more.

4.12. Pre-tax, real hurdle rates are used, and returns are considered at a project level i.e. before taking any financing structure into account. While some industry players often prefer to refer to post-tax, nominal returns, and may also be more familiar with equity returns rather than returns at project level, these factors were taken into account by Ricardo AEA when analysing the survey results. Finally, it is likely that some domestic investors are less inclined to make their investment decisions in terms of hurdle rates, and are more likely to consider other parameters such as payback time or sustainability motivations; this is why Parsons Brinckerhoff designed a separate questionnaire for domestic stakeholders.

4.13. Hurdle rate assumptions were previously based on theoretical analysis rather than on evidence. The hurdle rates recommended by Parsons Brinckerhoff and Ricardo AEA in the context of this review are primarily based on their analysis of survey responses and complemented by their in-house expertise and a review of key literature references. As a result hurdle rate assumptions have broadly decreased for solar PV (which possibly reflects the fact that investors are becoming more and more comfortable with any risks associated with this technology), whereas they have broadly increased for AD and hydro, reflecting the higher levels of risk perceived by investors for these technologies (e.g. feedstock risk and operational risk for AD, or the high variability of site conditions for hydro).

Table 7: hurdle rates by technology and investor type

		PV		Wind		AD		Hydro	
		2015	2012	2015	2012	2015	2012	2015	2012
Domestic	Min	2.5%	3.5%	3.0%	1.0%	N/A	1.0%	3.0%	1.0%
	Max	10.0%	12.5%	11.0%	12.0%	N/A	12.0%	11.0%	12.0%
	Avg	6.2%	8.0%	6.5%	6.5%	N/A	6.5%	6.5%	6.5%
Commercial developer	Min	4.0%	5.0%	5.0%	5.0%	9.0%	5.0%	9.0%	5.0%
	Max	11.0%	12.0%	12.0%	8.0%	14.0%	8.0%	15.0%	8.0%
	Avg	7.0%	8.5%	8.3%	6.5%	13.0%	6.5%	11.0%	6.5%
Utility	Min	5.0%	6.5%	5.0%	5.0%	8.0%	5.0%	7.0%	5.0%
	Max	11.0%	11.5%	14.0%	8.0%	13.0%	8.0%	15.0%	8.0%
	Avg	7.0%	9.0%	8.3%	6.5%	12.0%	6.5%	8.5%	6.5%

4.14. It is assumed hurdle rates remain constant over time.

4.15. In this context "Commercial developer" 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.

Technical Potential

4.16. The technical potential is the theoretical maximum amount of generation possible in Great Britain from each of the different technologies supported by FITs. We do not expect ever to reach the technical potential, but it is used to model spend and deployment projections (more detail in section 5).

4.17. Table 8 below shows how technical potential has changed. The large increase in PV technical potential is due to a change in method, explained in the PB report on page 21.

Table 8: Technical potential by technology

Assumption	**Technology**	**New assumption (PB, 2015)**	**Approximate equivalent capacity (MW)**	**GWh change from 2012 to 2015**
Technical Potential (GWh)	PV	344,300	370,000	470%
	AD	1,700	300	-50%
	Hydro	4,100	1,200	-40%
	Wind	8,100	4,100	-20%

Opex

4.18. Table 9 sets out the assumptions on opex and how they have been calculated from the PB data. AD is not included within this Table, and will be covered within the AD part of the FITs review later this year.

Table 9: Opex by technology

£/kW, 2016 prices	Mar-2015			Mar-2012	% change
	Low	*Central*	*High*	*Central*	*Central*
Solar PV					
<4kW	27	34	40	23	46%
4 - 10kW	12	15	18	21	-27%
10 - 50kW	7	9	11	21	-55%
50-150kW	7	9	11	21	-57%
150-250kW	7	9	10	20	-58%
250-5000kW	8	10	12	20	-52%
Stand alone	8	10	12	12	-16%
Hydro					
<15kW	3	43	84	100	-57%
15–50kW	4	69	133	158	-57%
50–100kW	6	96	185	157	-39%
100–500kW	3	52	102	120	-57%
500–1,000kW	1	22	43	89	-75%
1,000–2,000kW	1	12	24	73	-83%
2,000–5,000kW	0	5	10	31	-83%
Wind					
<1.5kW	-	-	-	-	-
1.5–15kW	43	68	93	67	2%
15–50kW	29	46	64	45	2%
50–100kW	26	42	57	41	2%
100–500kW	37	59	80	55	7%
500–1,500kW	18	28	38	27	2%
1,500-5,000kW	18	28	38	27	2%

Reference installation size

4.19. Table 10 shows the average installation size. The reference installation size reflects the typical size of existing installations deploying under the scheme in each size band. These are drawn from DECC FIT deployment statistics.[19] These are felt to be a more robust and representative data source than PB research.

[19] Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/455084/July_2015_FIT_Deployment_Statistics.xlsx

Table 10: average installation size by band

	Size (kW)
Solar PV	
<10kW	3
10 - 50kW	30
50 - 250kW	140
250-1000kW	455
> 1000kW	2,840
Stand alone	2,590
Hydro	
<100kW	30
100-500 kW	345
500-2000kW	1,150
>2000kW	2,250
Wind	
<50kW	10
50-1500kW	263
>1500kW	2910
AD	
< 250kW	155
250 - 500kW	480
500-5,000kW	1415

Plant operating life

4.20. Different plants have different operating periods. This is important as beyond the 20-year support period under FITs, they will continue to benefit through export revenues and potentially through bill savings. The estimated operating lives of different plants are set out below.

Table 11: Average technology lifetime

	Technology lifetime (years)
PV	30
Wind	20
Hydro	35
AD	20

Export fraction

4.21. The export fraction determines the percentage of electricity generated that installations export back to the grid, rather than what is used on site. Assumptions for the export fraction are based on the PB report. The exceptions are for small hydro and small wind, for which PB's research suggested that installations export 20% and 0% of their electricity generated respectively. In accordance with the Secretary of States FITs determinations[20], hydro generators will be paid the export tariff for at least 75% of their electricity and wind generators at least 50%. Therefore, this is set as the export fraction minimum for hydro and wind installations.

[20] The FITs Order allows DECC to set annually "determinations". These refer to factors that could not be set in advance at the start of the scheme or be updated automatically. These are the deemed export fraction, the export tariff, qualifying FITs costs and a range for mutualisation. More information is available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/407522/FITs_Determinations.pdf

Table 12: assumed export fraction by tariff band

Export fraction (%)	*2015*	*2012*	*% change*
PV			
All building mounted	53%	50%	6%
Stand alone	100%	100%	0%
Wind			
<1.5kW	0%*	0%	0%
1.5–15kW	0%*	50%	-100%
15–50kW	75%	75%	0%
50–100kW	80%	80%	0%
100–500kW	85%	90%	-6%
500–1,500kW	95%	90%	6%
1,500-5,000kW	100%	90%	11%
Hydro			
<15kW	20%*	75%	-73%
15–50kW	75%	95%	-21%
50–100kW	75%	99%	-24%
100–500kW	88%	99%	-11%
500–1,000kW	99%	99%	0%
1,000–2,000kW	99%	99%	0%
2,000–5,000kW	99%	99%	0%
AD			
< 250kW	75%	80%	-6%
250 - 500kW	90%	85%	6%
500 - 5,000kW	95%	87%	9%

**Values for which the PB update is not used, as set out in paragraph 4.21.*

Value of exports

4.22. All new installations are assumed to receive the export tariff of 4.85p/kWh (in 2015/16 prices), in the absence of any information about rates agreed under Power Purchase Agreements.

Value of Bill Savings

4.23. Bill savings are valued using the central retail electricity prices in the Green Book supplementary guidance.[21] These are set out in table 13 below. We have taken an average of the services and industrial prices for the relevant bands in the absence of information about the sector of the installations in those bands. More information about which installation group faces which electricity price is set out in paragraph 5.28 below.

4.24. The medium electricity prices have been used within this analysis. These are due to be revised and republished by DECC during the period of the consultation. This will be taken into account in the analysis for the Government response to the consultation. Since the publication of DECC's retail prices, declines in fossil fuel price have led to falls in the electricity wholesale price. Other things being equal, this would result in a decrease in the bill savings for a FITs installation and therefore an increase in the generation tariff to reach a particular point on the supply curve for FITs installations. While in the short term electricity prices may be lower, this may not be true over the longer term. Given that FITs installations may continue to generate for up to 35 years, DECC has decided to continue using central electricity price projections for this analysis.

Table 13: Electricity price projections

p/kWh, 2016 prices							
Sector	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Wholesale	4.8	5.5	5.7	5.4	5.2	5.3	5.7
Residential	16.6	16.3	17.4	18.4	18.6	19.8	19.8
Service/Industrial	9.1	10.1	10.9	10.9	11.0	12.3	12.4

[21] Available at https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal. Note that this link provides only the source for the retail prices – wholesale electricity prices are available at https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2014.

4.25. Figures have been converted into 2016 prices, and a simple average has been taken of the service and industrial electricity prices.

Carbon emission assumptions

4.26. The long run marginal, generation based emissions factors are used to estimate the changes in the amount of UK territorial carbon from the policy options (table 1 of supporting data tables to Green Book supplementary guidance). 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 (table 3 of supporting data tables to supplementary guidance[22]).

Inflation assumptions

4.27. This analysis uses the RPI projections from the OBR's Economic and Fiscal outlook in July 2015[23] to inflate values related to generation tariffs. It uses the GDP deflators for all other assumptions. It is proposed that new projects coming forward under the FITs scheme have their tariffs uplifted by the CPI rather than the RPI. Since investment decisions are often taken based on expected nominal rather than real returns, this is likely to have an impact on deployment and therefore on spending; however this impact is expected to be less significant than the impact of other proposed changes in this consultation. The change has not been included in the analysis at this stage.

5. Options considered.

5.1. Within the FITs policy and support scheme, the undertakings associated with its State aid approval and the budget constraints associated with the LCF, the options considered result in significantly reduced spending projections under the scheme. As there are a large number of variables, the policy options are split down into three, one of which encapsulates a significant number of individual proposals. These are set out as individual proposals that are then aggregated into the second option.

5.2. Therefore, this Impact Assessment sets out three options:

- Option 1 – do nothing. Under this option the FITs scheme continues as is. This would also assume that pre-accreditation is not removed.
- Option 2 – make the policy changes as set out in the consultation document and in this Impact Assessment. This includes:
    i. Merging tariff bands (as set out in paragraphs 5.7-5.13);
    ii. Merging degression bands (as set out in paragraphs 5.7-5.13);
    iii. The proposed tariff changes;
    iv. The proposed introduction of caps;
    v. The proposed changes to default degression;
    vi. The proposed changes to contingent degression; and
    vii. Removal of pre-accreditation (it is assumed for the purpose of this analysis that the decision is taken to remove it).
- Option 3 – full closure of the scheme.

5.3. The rest of this section goes through 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.

<u>Option 1 – do nothing</u>

5.4. By definition, the costs and benefits of doing nothing are zero. Deployment and spending projections would be as set out in Tables 3 and 27. In addition to spending likely to be significantly higher than was forecast at the time of the FITs Comprehensive review in 2012, there would remain risks that there would be further deployment and spending increases beyond our current forecasts, which would need to be paid for out of consumer bills.

[22] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/360323/20141001_Supporting_Tables_for_DECC-HMT_Supplementary_Appraisal_Guidance.xlsx
[23] http://budgetresponsibility.org.uk/economic-fiscal-outlook-july-2015/

Option 2 – make the policy changes as set out in the consultation document

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

5.6. As 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.

New Tariff and Degression bands

5.7. The consultation proposes some changes to the tariff bands. Table 14 below shows new bands versus old bands. The general approach to tariff and degression bands has been to merge bands to simplify the scheme.

5.8. The <4kW PV tariff band has been enlarged to include installations of <10kW. This is because installations up to 10kW share similar installation costs, and are expected not to face significant grid connection costs. A generation capacity of <10kW is expected to be domestic households. Therefore they are also expected to benefit from residential bill savings. Both of these factors impact on generation tariffs required to meet the target rate of return.

5.9. Revising the generation tariffs at current tariff bands (4-50kW) would have resulted in overcompensation of installations sized 4-10kW. This is because the analysis would have under-estimated the bill savings - installations 10-50kW are assumed to receive services/manufacturing bill savings which are lower. In addition the analysis would have to compensate for a higher capex cost which would include grid connection costs, as it is assumed that some installations 10-50kW band have to pay grid connection costs.

5.10. The mid-scale wind tariff bands have been merged to reduce the incentive to de-rate wind turbines. There is some evidence that wind installations that would be sized in the 500-2,000kW band are de-rating their turbines to benefit from the higher tariff in the 100-500kW band. Giving all mid-scale turbines (50-1500kW) the same generation tariff reduces the incentives to de-rate.

5.11. Small wind turbines still benefit from a higher tariff under proposed tariff bands, although this consultation proposes moving the upper boundary from 100kW to 50kW. This is because it appears from the PB analysis that capex falls significantly for the 50-100kW band.

5.12. The two small hydro tariff bands have been merged to create a <100kW band. If generation tariffs were revised at current tariff bands the smallest band (<15kW) would receive a significantly lower tariff than the band above (15-100kW). The main driver behind this is the lower capex for the <15kW installations. It is assumed that at current tariff bands no hydro installations would accredit as <15kw, generators would artificially increase the capacity of their installation to benefit from the higher tariff being offered to the 15-100kW band. Additionally, it is assumed that hydro installations below 15kW and with a capacity from 15-100kW are similar. To avoid the potential distortion, the two bands have been merged.

Table 14: Proposed tariff bands compared to current tariff bands

<table>
<tr><th>Proposed tariff bands</th><th>Current tariff band</th></tr>
<tr><td colspan="2">PV</td></tr>
<tr><td rowspan="2">0 -10kW</td><td><4kW</td></tr>
<tr><td rowspan="2">4-50kW</td></tr>
<tr><td>10 - 50kW</td></tr>
<tr><td rowspan="2">50 - 250kW</td><td>50-150kW</td></tr>
<tr><td>150-250kW</td></tr>
<tr><td>250-1000kW</td><td rowspan="2">250-5000kW</td></tr>
<tr><td>> 1000kW</td></tr>
<tr><td>Stand alone</td><td>Stand alone</td></tr>
<tr><td colspan="2">Wind</td></tr>
<tr><td><50kW</td><td rowspan="2">0-100kW</td></tr>
<tr><td rowspan="3">50–1500kW</td></tr>
<tr><td>100–500kW</td></tr>
<tr><td>500–1,500kW</td></tr>
<tr><td>>1500kW</td><td>>1500kW</td></tr>
<tr><td colspan="2">Hydro</td></tr>
<tr><td rowspan="2"><100kW</td><td><15kW</td></tr>
<tr><td>15-100kW</td></tr>
<tr><td>100-500 kW</td><td>100-500kW</td></tr>
<tr><td>500-2000kW</td><td>500-2000kW</td></tr>
<tr><td>>2000kW</td><td>>2000kW</td></tr>
</table>

5.13. The only change to degression bands is to change the two wind degression bands to match with new tariff bands.

Table 15: Proposed changes to degression bands

Current degression bands for wind	Proposed new degression bands for wind
<100kW	<50kW
>100kW	>50kW

Tariff setting

5.14. The proposed generation tariffs for PV, wind and hydro installations have been set to aim for the rates of return in the following table. As set out above, DECC intends to consult on revision to support for AD under FITs later this year. The target rates of return have been set as the maximum of the low end of hurdle rate ranges for domestic and commercial investors (please refer to table 7 in section 4 for a reminder of the full range of hurdle rates). For example the low end of the hurdle rate ranges for domestic and commercial investors in PV are respectively 2.5% and 4%. The maximum of these two values (4%) is therefore identified as the target rate of return for solar PV. The focus on domestic and commercial hurdle rates reflects the scheme's objective to support primarily non-energy professionals (as per our State aid approval); and the choice of level corresponds to targeting a level that is high enough to allow deployment to come forward, but low enough to avoid overcompensation.

Table 16: target rates of return by technology

Technology	Target rate of return
PV	4.0%
Wind	5.0%
Hydro	9.0%

5.15. For investments in different technologies to be equally financially attractive, investors require rates of return that reflect the relative levels of perceived risk in each of the technologies. Assuming a constant cost of capital, investors might still require a higher rate of return on technologies which are perceived to be riskier. As an illustration, the same investor, with the same source of funds, might require a higher rate of return to invest in AD than in solar PV if they consider that having to secure a feedstock supply, or having to operate a plant where chemical processes take place, is riskier than to invest in a solar PV project. In other words, by targeting different rates of return for different technologies, the aim is to ensure that the risk / return balance is at the same level for all technologies.

5.16. The following cash flows are taken into account when setting generation tariffs to target a certain rate of return:

- Capital expenditure including grid connection (capex)
- Operational expenditure (opex)
- Export income derived from the export tariff and based on the amount of electricity exported or deemed to be exported to the grid; or alternatively from Power Purchase Agreements (PPAs).
- Bill savings reflecting the costs saved by the generator from not importing electricity from the grid.

5.17. The level of support offered through the generation tariffs makes up for the difference between the generating costs and revenues of the FIT generator, and is set to deliver a specific rate of return to the FIT generator.

5.18. These factors are in turn influenced by other assumptions. For example, the export income will be influenced by the export tariff that is set, and the bill savings will be dependent on assumptions made about the wholesale and retail electricity prices. Moreover, both will then also be dependent upon assumptions about export fractions, load factors and the length of time for which a plant is assumed to be operational.

5.19. Given the budgetary pressure on the scheme's spending and in line with the original intentions of the scheme, DECC is proposing to revise generation tariffs with the intention of incentivising only the best sited installations – those with high load factors – and allowing for sufficient returns on investment to encourage deployment among domestic and commercial investors. The exception for this is for hydro installations, for reasons set out in the load factors section below. For all technologies the central capex and opex cost estimates have been used. The rationale for setting tariffs in this way is to support the most cost-effective generators in order to improve cost control in the FITs scheme in a way that provides better value for money to the bill payer.

5.20. The following sections of the IA outline in detail the assumptions on which the proposed tariffs were set.

Reference size of Installation

5.21. Revenue streams and costs are defined based on a "reference installation", which is what is viewed as a "typical" project with specific characteristics. These define the size of the installation, its technology life, generating costs (capex and opex), load factors and proportion of electricity that the generator exports to the grid. The assumptions used in tariff setting are set out in Table 11.

Load Factors

5.22. Load factors are taken from the higher range of PB data. This reflects the intention of targeting well-sited installations. For PV, the 11.3% estimate is representative of installations located in the South West with high load factors. The exception is hydro, where central load factors (40%) are used. This reflects the highly site-specific nature of hydro load factors, and so the central load factor is assumed to be more appropriate.

5.23. For wind, the load factor differs depending on the size of the installation, and is based on the best sited rural installation where an average wind speed of 6.5 m/s applies. The wind speed reflects the typical wind speed faced by well-sited installations. The load factors for new bands are representative of the load factors for the largest band in the group of bands that were merged.

Table 17: Load factors used for wind

Wind Installations	**Load Factor**
<50kW	26%
50–1500kW	29%
>1500kW	32%

Capital and operating costs

5.24. Capex and opex are expressed in £/kW per year and are in 2016 prices.[24] Capex and Opex are taken from the central figure of PB data, and have been adjusted to reflect the change in bands. Capex also include estimated grid connection costs where applicable.

Table 18: capex and opex costs for each band

£2016 prices	**Opex (£/kW/year)**	**Capex (£/kW)**
	Solar PV	
<10kW	20	1,700
10 - 50kW	10	1,700
50 - 250kW	10	1,500
250-1000kW	10	1,500
> 1000kW	10	1,300
Stand alone	10	1,400
	Hydro	
(£/kW)		
<100kW	50	5,200
100-500 kW	50	4,600
500-2000kW	20	3,700
>2000kW	10	2,500
	Wind	
<50kW	60	4,100
50-1500kW	60	2,500
>1500kW	30	1,300

Export payments

5.25. 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.[25]

5.26. Export payments reflect current export arrangements for smaller installations as reported in Ofgem's Annual Report.[26] For the majority of installations, Parsons Brinckerhoff data was used to understand how much electricity was exported or consumed on-site. The only exception to this is 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.

5.27. The majority of larger installations sell their export 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, we have assumed that the export tariff is applied to all size installations.

[24] Capex and opex have been converted into £2016 prices from those in the PB report.
[25] https://www.ofgem.gov.uk/environmental-programmes/feed-tariff-fit-scheme/tariff-tables
[26] https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/feed-in_tariff_fit_annual_report_2013_2014.pdf

Table 19: assumed export fractions

	Export Fraction
Solar PV	
<10kW	53%
10 - 50kW	53%
50 - 250kW	53%
250-1000kW	53%
> 1000kW	53%
Stand alone	100%
Hydro	
<100kW	75%
100-500 kW	88%
500-2000kW	99%
>2000kW	99%
Wind	
<50kW	50%
50-1500kW	85%
>1500kW	100%

Electricity Prices

5.28. FIT generators face different electricity prices depending on the sector they belong to. 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 for Solar PV; installations >1,500kW for wind and >500kW for hydro. For all other installations, 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.

5.29. 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. Table 13 sets out the electricity price assumptions used.

Combining the assumptions into tariffs

5.30. Table 20 below sets out the tariffs that are based on the above assumptions. 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. This is based on central capex and opex, high load factors (with the exception of hydro) and targeting a low rate of return.

5.31. This method is used for the majority of tariff bands. The exception is for ground-mounted solar: here, using the central capex and the high load factor assumptions, the tariff for standalone solar PV would be 4.97p/kWh, which would be higher than the tariff proposed for building mounted installations larger than 1,000kW (i.e. 1.03p/kWh). This in part is the reflection of slightly higher grid connections costs for standalone projects, but is mainly the consequence of the fact that bill savings are estimated to be zero for these projects (which are assumed to export 100% of the electricity they generate).

5.32. The proposed tariff for standalone solar PV however, has been made equal to the proposed tariff for building mounted installations larger than 1,000kW. Indeed 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.

Table 20 – Proposed tariffs under Option 2

Proposed Generation Tariffs 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	1.63	<4kW	12.47
		4-50kW	11.30
10 - 50kW	3.69		
50 - 250kW	2.64	50-150kW	9.63
		150-250kW	9.21
250-1000kW	2.28	250-5000kW	5.94
> 1000kW	1.03		
Stand alone	1.03	Stand alone	4.28
Wind			
<50kW	8.61	0-100kW	13.73
50–1500kW	4.52		
		100–500kW	10.85
		500–1,500kW	5.89
>1500kW	0.00	>1500kW	2.49
Hydro			
<100kW	10.66	<15kW	15.45
		15-100kW	14.43
100-500 kW	9.78	100-500kW	11.40
500-2000kW	6.56	500-2000kW	8.91
>2000kW	2.18	>2000kW	2.43

5.33. 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.[27] The analysis in this document is based on the higher tariff rate only.

5.34. The costs and income streams resulting from the assumptions set out above are illustrated in Table 21. Three example tariff bands have been used.

Table 21 - Cost and revenue streams over the lifetime of a reference installation

£2016, Discounted to 2016 values	**Solar PV <10kW**	**Solar PV 10 - 50kW**	**Wind >1500kW**
Costs	**6,210**	**54,800**	**4,750,000**
Capex	4,950	49,900	3,750,000
Opex	1,260	4,900	1,000,000
Revenues	**5,550**	**39,700**	**5,040,000**
Bills savings	4,210	26,400	0
Export income	1,340	13,400	5,040,000
Generation tariff			
Income over 20 years from Generation tariff required to give target RoR (£)	660	15,000	0*
Equivalent annual figure (A) (£)	50	1,100	0
Annual Generation (B) (kWh)	2,980	29,800	8,250,000
Generation tariff (A/B) (p/kWh)	1.63	3.69	0.00

[27] https://www.ofgem.gov.uk/publications-and-updates/feed-tariff-fit-guidance-renewable-installations-version-9

**Note that this figure is actually negative as costs are less than revenues for this band without a generation tariff. The tariff has been set at zero.*

Setting caps

5.35. As set out above and within the consultation document, maintaining control over spending under the FITs scheme is the overriding aim of this review. While the reduction of tariffs will help to reduce and control projected spending and ensure value for money, it will not offer certainty about what total spending under the FITs scheme will be, and changes in underlying costs and revenue streams would still have the potential to result in significant increases in spending compared to forecasts in future.

5.36. Therefore, Government proposes to introduce caps to offer control over spending under the scheme. This is felt to be the best way to ensure that there are no further overspends; without this guarantee, it is not considered viable to keep the scheme open.

5.37. There are different ways to set caps. They could be set based on deployment, on generation or on spending. These approaches will all amount to the same thing before the event; deployment is multiplied by the load factor to get to generation, and then multiplied by the generation tariff to give spending. The generation tariff is certain, whereas the load factor is assumed before the event and only after the event does it become observable.

5.38. Therefore, a direct cap on spending would be the purest way to achieve cost control. However, this would be difficult to put into operation, and add further complexity for new generators. Therefore, it is proposed that the cap is set based on deployment. While this would mean that there remains some residual load factor risk – in that if the load factors are higher within a particular year, spend may be higher than predicted – it is felt to be a more straightforward way of putting a cap into practice.

5.39. To mitigate against the residual load factor risk and as an alternative to simply setting the overall cap below the £100m budget from the outset, we have built in some headroom by having the caps as an integral part of the degression mechanism – i.e. by tying contingent degression to the caps. In this way, high deployment (which by itself would push expenditure to the top end of the £100m budget, increasing the risk of overspend from the load factor risk) would in practice trigger contingent degression, reducing the cost of further deployment compared to projections. We consider that this should provide a built-in buffer against the remaining load factor risk.

5.40. The deployment cap could also be applied in different ways. There are various degression bands and technologies within the FITs scheme; options would include setting caps by technology; by degression band; or across the scheme as a whole. Given that one of the aims of the revised scheme is to continue to offer technologies under FITs a route to market, splitting caps according to degression bands is felt to be a more sensible approach. An alternative would be to set caps on a technology basis, or to have a single cap across the entire scheme; both would run the risk that one band within one technology could potentially take the entire budget.

5.41. It is also proposed to set caps on a quarterly basis. While this would mean that caps are lower and so fewer new installations can be supported under the scheme each quarter, the alternatives – for example an annual cap – run the risk that the cap is reached very early on in the year, leading to an immediate closure of the scheme for that degression band. This is contrary to the intention to maintain a steady investment pipeline, and so quarterly caps are felt to be preferable. Here, if the cap is reached immediately it would mean that no deployment goes forward under that band for the quarter only rather than for the entire year. This is intended to offer industry greater opportunity for deployment and stability, within the constraints of a £100m cap, while offering Government certainty about the spending on the scheme.

5.42. Therefore, the proposed approach is to set caps by degression band by technology by quarter, as set out in Table 22 below. Views are invited as per consultation question 13 as to whether responders agree with this approach.

5.43. The caps have been set based on the underlying modelling. Given the assumptions set out above, the model predicts how much deployment will come forward in particular periods. This is then converted into spend estimates. Based on the tariffs, hurdle rates, load factors and other assumptions set out above, the projections for the period January 2016 – March 2019 correspond to approximately £90m worth of new building spending.

5.44. To turn these projections into caps, and to cap at £100m, the deployment projections are each inflated by a factor representing the proportional difference between the £90m spending projection and the £100m cap – so each projection for each degression band in each quarter is inflated by approximately 10% to give the level of the cap. Table 22 below shows the levels at which the caps are set for each technology. This is shown in both MW of capacity and the number of installations, which is based on the average installation size within each band. The installation numbers are therefore indicative only – if larger than average installations come forward, then the number of installations that are included within the deployment cap will be lower.

Table 22 – Maximum Deployment caps

Maximum Deployment (MW)		Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Q1 2019
PV	<10kW	17.8	18.4	18.8	19.2	19.7	19.9	19.7	19.5	19.2	19.2	19.8	20.5	21.1
	10 - 50kW	10.3	10.4	10.3	10.2	10.1	10.0	9.9	9.9	9.8	9.9	10.4	11.0	11.5
	>50kW	8.8	9.0	8.9	8.9	8.8	8.7	8.6	8.6	8.5	8.7	9.3	9.9	10.6
	Stand alone	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	4.4	4.6	4.7	4.8	5.0	5.1	5.2	5.2	5.3	5.5	5.7	6.0	6.2
	>50kW	14.6	14.8	15.0	15.1	15.3	15.5	15.7	15.8	16.0	16.2	16.5	16.7	16.9
Hydro	All	13.4	13.8	14.0	14.3	14.6	14.8	15.0	15.2	15.3	15.4	15.5	15.6	15.6
AD	AD<500kW	2.7	2.8	2.7	2.7	2.6	2.7	2.7	2.6	2.5	2.7	2.6	2.6	2.5
	AD>500kW	4.4	3.8	3.6	3.3	3.1	3.1	2.9	2.7	2.5	2.5	2.3	2.1	2.0

Table 23 – Estimated number of installations at maximum deployment

Estimated number of installations[28]		Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Q1 2019
PV	<10kW	5466	5626	5762	5903	6049	6122	6044	5965	5884	5888	6067	6254	6447
	10 - 50kW	308	314	311	307	304	301	299	296	294	298	313	330	347
	>50kW	34	34	34	33	33	32	32	32	31	32	34	36	38
	Stand alone	2	2	2	2	2	2	2	2	2	2	2	2	2
Wind	<50kW	463	479	494	508	524	537	547	557	567	583	611	640	669
	>50kW	18	18	19	19	19	19	19	19	19	19	20	20	20
Hydro	All	192	205	217	230	241	252	262	271	279	286	292	296	299
AD	AD<500kW	13	13	13	13	13	13	13	13	12	13	13	13	12
	AD>500kW	3	3	3	3	3	3	3	3	3	3	3	3	3

5.45. For ground-mounted solar, the cap has been set at 5MW per quarter; based on the above methodology, the cap would only be c1MW per quarter. Given that the average installation of ground-mounted solar is c2.6MW, as set out in Table 10, a cap of c1MW would not allow an average-sized ground-mounted solar installation to deploy. The cap has therefore been increased to 5MW, which allows for at least one installation of ground-mounted solar to come forward per quarter. While the indicative number of installations that would come forward under the cap, set out in Table 23, is two, this is because the average capacity of projects in this band is c2.6MW. Setting the cap at 5MW allows for one project at the maximum capacity of the band to come forward in each quarter. It should be noted that if the tariff for ground-mounted solar was increased, available spend for other tariff bands would need to decrease accordingly.

5.46. Further detail on the proposed approach to implementing caps is set out in section 3 of the consultation document.

Degression

5.47. 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 largely 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.

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

5.49. It is proposed that default degression occurs independently of other factors, such as deployment. The aim of default degression under Option 2 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 electricity price projections set out in Table 13. The costs of installations are based on projected changes in capex and opex; more information is available in in the PB report. While the changes in installation costs and electricity prices are not smooth over time, they have been smoothed for the purposes

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

of setting default degression – so the tariff reductions are averaged over the period January 2016 to January 2019.

5.50. Table 24 sets out the proposed generation tariffs over this FITs review period, taking into account default degression only. As can be seen, for some installations – for example, domestic solar PV <10kW, it is anticipated that by the start of 2019/20 installations will be able to operate with a zero generation tariff. That is to say, the bill saving and income from the export tariff adequately compensate for the predicted upfront and ongoing costs of the installation, based on it having average costs and being well-sited (so having a higher than average load factor).

Table 24: Tariffs over time, as a result of default degression

Generation Tariffs p/kWh, Q1 2016 prices		Jan-2016	Apr-2016	Jul-2016	Oct-2016	Jan-2017	Apr-2017	Jul-2017	Oct-2017	Jan-2018	Apr-2018	Jul-2018	Oct-2018	Jan-2019
PV	<10kW	1.63	1.50	1.36	1.22	1.09	0.95	0.82	0.68	0.54	0.41	0.27	0.14	0.00
	10 - 50kW	3.69	3.59	3.48	3.38	3.27	3.17	3.06	2.96	2.86	2.75	2.65	2.54	2.44
	50 - 250kW	2.64	2.54	2.44	2.34	2.24	2.13	2.03	1.93	1.83	1.73	1.63	1.53	1.43
	250-1000kW	2.28	2.18	2.08	1.98	1.88	1.78	1.68	1.58	1.48	1.38	1.29	1.19	1.09
	> 1000kW	1.03	0.94	0.86	0.77	0.69	0.60	0.51	0.43	0.34	0.26	0.17	0.09	0.00
	Stand alone	1.03	0.94	0.86	0.77	0.69	0.60	0.51	0.43	0.34	0.26	0.17	0.09	0.00
Wind	<50kW	8.61	8.52	8.42	8.32	8.22	8.13	8.03	7.93	7.83	7.74	7.64	7.54	7.45
	50–1500kW	4.52	4.48	4.44	4.40	4.36	4.32	4.28	4.24	4.20	4.16	4.12	4.08	4.04
	>1500kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	<100kW	10.66	10.63	10.60	10.56	10.53	10.50	10.46	10.43	10.40	10.36	10.33	10.30	10.27
	100-500 kW	9.78	9.77	9.75	9.74	9.72	9.71	9.69	9.68	9.67	9.65	9.64	9.62	9.61
	500-2000kW	6.56	6.56	6.56	6.56	6.56	6.56	6.56	6.56	6.56	6.56	6.56	6.56	6.56
	>2000kW	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18

5.51. As has been seen over the last FITs review period, costs have changed significantly. This is shown in the PB data and by the comparison in Table 6 above. Therefore, while tariffs are currently set based on the best information available, there is the possibility that actual values of costs – capex and opex – deviate from projected costs 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 risk is managed, but it would indicate individual installations receiving a higher rate of return than set out in Table 16 above.

5.52. Therefore, it is proposed that default degression is supplemented by contingent degression. This would mean that tariffs would fall under specific circumstances. Given the rationale set out above, it is proposed to tie contingent degression to deployment, and specifically to the projections and to the caps. The proposal is that:

- If the projection is exceeded in any quarter, there is then a 5% tariff reduction in the following quarter; and
- If the cap is reached in any quarter, there is then a 10% tariff reduction in the following quarter.

5.53. Contingent degression would operate in addition to default degression – so, for example, if a cap was reached in a particular quarter, the tariff in the following quarter would be 10% lower than is set out in Table 24 above. Furthermore, contingent degression would 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.

Table 25 –Thresholds for 5% contingent degression (Note caps resulting in 10% degression are in Table 21)

5% contingent degression thresholds (MW)		Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Q1 2019
PV	<10kW	16.0	16.5	16.9	17.3	17.7	17.9	17.7	17.5	17.3	17.3	17.9	18.4	19.0
	10 - 50kW	9.2	9.4	9.3	9.2	9.1	9.0	8.9	8.9	8.8	8.9	9.4	9.9	10.4
	>50kW	7.9	8.1	8.0	8.0	7.9	7.8	7.8	7.7	7.7	7.8	8.3	8.9	9.5
	Stand alone	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Wind	<50kW	4.0	4.1	4.2	4.3	4.5	4.6	4.6	4.7	4.8	4.9	5.1	5.4	5.6
	>50kW	13.2	13.3	13.5	13.6	13.8	13.9	14.1	14.2	14.4	14.6	14.8	15.0	15.2
Hydro	All	12.1	12.4	12.6	12.9	13.1	13.3	13.5	13.7	13.8	13.9	14.0	14.0	14.1
AD	AD<500kW	2.4	2.5	2.5	2.4	2.4	2.5	2.4	2.3	2.3	2.4	2.4	2.3	2.3
	AD>500kW	4.0	3.5	3.2	3.0	2.8	2.8	2.6	2.4	2.2	2.2	2.1	1.9	1.8

Removal of Pre-accreditation

5.54. As set out in the consultation document proposing the removal of pre-accreditation under the FITs scheme, if it is decided to remove pre-accreditation, it is anticipated that hurdle rates could increase as a result of the change. This is because the removal of pre-accreditation is expected to reduce certainty for an individual developer under the scheme.

5.55. The estimated impact on hurdle rates is set out in Table 26 below. It is expected to differ by technology, reflecting the relative change in risks faced. For solar developers, for example, the construction period is relatively quick, and the pre-accreditation window is 6 months. The removal of pre-accreditation is therefore assumed to have a lower impact on solar than it would on hydro developers, where the construction period is longer and the pre-accreditation window is 24 months. This reflects that there are likely to be greater changes in tariffs over 24 months than over 6 months. The pre-accreditation window for AD and for wind is 12 months, so the impact on the hurdle rate is estimated to be somewhere between the impacts on hurdle rates for solar and for hydro. These figures are added on to the hurdle rates set out in Table 7.

5.56. For those installations that never had access to pre-accreditation, which is solar and wind projects under 50kW, no impact is assumed on the hurdle rate from the removal of pre-accreditation.

Table 26: assumed impact of the removal of pre-accreditation on hurdle rates

Technology	Percentage point increase in hurdle rates
PV >50kW	0.25
Wind >50kW	0.5
AD	0.5
Hydro	1

5.57. At this stage, and with the information available, the assessment of change in the hurdle rates as a result of the removal of pre-accreditation can only be an assumption. However, the principle – of an increase in the required return and of a differential impact on technologies with different construction periods – is felt to be robust. Based on the levels of deployment seen in 2012 between the introduction of degression and that of pre-accreditation, where solar continued to deploy, it is also felt that the impact of removing pre-accreditation would be minimal for solar PV deployment and that a premium of 0.25% for solar PV is therefore an appropriate assumption.

5.58. These impacts have been included in the modelling for the purpose of forecasting deployment and spend under Option 2, though they have not been included within tariff setting; more background on this decision is presented in Section 7.

5.59. It is likely that introducing caps would add another layer of risk to investment decisions, on top of the risk that would be introduced should the decision be made to remove pre-accreditation from the scheme. This has not been assumed to impact hurdle rates further, because if caps were introduced, the decision of whether to proceed with an individual project would be a commercial decision for each participant of the scheme, rather than a decision purely based on hurdle rates. Therefore, while the introduction of caps may mean that some potential generators choose not to proceed, those that remain are assumed to have the same hurdle rates as they would under an uncapped scheme.

Option 3 – full closure of the scheme

5.60. Under this option, the scheme would be closed to new entrants (i.e. the generation tariff would no longer be available to new entrants). The export tariff may still be available. Closure would occur at the first available opportunity, which is likely to be early to mid-January 2016. This would mean that as of that date, no more capacity would be able to receive a generation tariff under the FITs scheme. Projects accredited before the cut-off date this date would continue to be supported and would receive FITs generation tariffs for the 20 years under the current grandfathering policy.

5.61. The likely impact of this on deployment and generation is set out in Table 27-29.

6. 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 the do nothing option 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.

Option 2 – make the policy changes as set out in the consultation document

6.3. This Option assesses the impact of making the policy changes as set out in the consultation document, 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 and spending, including a comparison with the do nothing Option, as well as Net Present Values (NPVs) and carbon emissions relative to the do nothing.

Option 3 – full closure of the scheme

6.4. If the proposals set out in Option 2 are not considered to be viable during the consultation, and if proposed cost control caps are deemed unable to place costs of the scheme on an affordable and sustainable trajectory, the scheme may be closed (i.e. the generation tariff would be no longer available). Tables below again include expected deployment, generation and spending, with a comparison to the do nothing Option, as well as Net Present Values (NPVs) and carbon emissions relative to the do nothing.

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 deployment each month:

a. Calculate the distribution of the levelised cost[29] 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[30] for each technology by tariff band for installations in that month (e.g. March). It 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. 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, it applies the degression mechanism to estimate future tariffs, and moves on to estimate deployment in the next month.

6.6. Cash flows included in the rate of return calculation are:

- Capex
- Opex
- Export income
- Bill savings
- Generation tariff

Deployment Projections

6.7. The following tables show forecast deployment under each Option. There are 3 deployment scenarios for Option 2, reflecting uncertainty about deployment. This is modelled through adjustment to the hurdle rate, which is assumed to represent some of the uncertainty around things like costs and cost reductions, deployment potential, supply chain barriers others

6.8. 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. Similarly the high scenario uses low hurdle rates. All other variables are constant at central values across the range of deployment scenarios.

[29] A 'levelised cost' is the average cost over the lifetime of the plant per MWh of electricity generated.
[30] Similar to the levelised cost, the 'levelised revenue' is the average revenue over the lifetime of the plant per MWh of electricity generated.

6.9. The Table also sets out the high and low projections under the do nothing Option. The comparison from Option 2 to the do nothing is done on the basis of the high, central and low scenarios from Option 2 to the central scenario only for Option 1. Similarly, the high, central and low scenarios for Option 3 are compared only to the central scenario from Option 1. More detail is provided in Tables A1 and A2 in the Annex.

Table 27: 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 on cumulative deployment by 2020/21 against Option 1 central estimate
Option 1 - Low	4,550	5,340	6,200	7,060	7,920	8,690	
Option 1 - Central	4,910	6,150	7,440	8,800	10,190	11,540	
Option 1 - High	5,230	6,910	8,760	10,750	12,790	14,750	
Option 2 - Low	4,330	4,500	4,670	4,840	4,840	4,840	-6,700
Option 2 - Central	4,550	4,830	5,120	5,420	5,420	5,420	-6,120
Option 2 - High	4,740	5,070	5,410	5,760	5,760	5,760	-5,780
Option 3 - Low	4,290	4,290	4,290	4,290	4,290	4,290	-7,250
Option 3 - Central	4,480	4,480	4,480	4,490	4,490	4,490	-7,050
Option 3 - High	4,660	4,660	4,660	4,660	4,660	4,660	-6,880

Number of installations

6.10. Table 28 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 A3 and A4 in the Annex.

Table 28: 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 on cumulative deployment by 2020/21 against Option 1 central estimate
Option 1 - Low	702,000	820,000	956,000	1,090,000	1,222,000	1,342,000	
Option 1 - Central	743,000	911,000	1,090,000	1,280,000	1,477,000	1,670,000	
Option 1 - High	774,000	984,000	1,224,000	1,490,000	1,764,000	2,025,000	
Option 2 - Low	675,000	687,000	699,000	711,000	711,000	711,000	-958,000
Option 2 - Central	703,000	728,000	754,000	781,000	781,000	781,000	-889,000
Option 2 - High	723,000	751,000	780,000	810,000	810,000	810,000	-860,000
Option 3 - Low	672,000	672,000	672,000	672,000	672,000	672,000	-997,000
Option 3 - Central	697,000	697,000	697,000	698,000	698,000	698,000	-972,000
Option 3 - High	716,400	716,400	716,400	716,400	716,400	716,400	-953,300

Generation

6.11. Table 29 shows the forecast of generation under each Option. The model uses the load factors in Table 5 to estimate generation from the deployment projections shown in table 27. More detail is provided in Tables A5 and A6 in the Annex.

Table 29: 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 on cumulative deployment by 2020/21 against Option 1 central estimate
Option 1 - Low	7,020	8,170	9,320	10,440	11,520	12,480	
Option 1 - Central	7,430	9,100	10,720	12,350	13,960	15,480	
Option 1 - High	7,820	9,980	12,190	14,470	16,740	18,870	
Option 2 - Low	6,730	7,160	7,590	8,030	8,030	8,030	-7,460
Option 2 - Central	7,010	7,640	8,250	8,880	8,880	8,880	-6,610
Option 2 - High	7,300	7,990	8,690	9,390	9,390	9,390	-6,090
Option 3 - Low	6,650	6,650	6,650	6,650	6,650	6,650	-8,840
Option 3 - Central	6,890	6,890	6,890	6,910	6,910	6,910	-8,580
Option 3 - High	7,130	7,130	7,130	7,130	7,130	7,130	-8,360

Carbon Savings

6.12. The volume of carbon savings as a result of generation being produced by installations supported by FITs are the main 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). 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 (table 3 of supporting data tables to supplementary guidance). Option 2 reduces the amount of forecast generation from FITs installations and increases generation from the electricity grid, 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 cost to the UK of purchasing EU ETS allowances compared to Option 1. The volumes and values are shown in table 30 below.

Table 30: Carbon savings under each Option

Volumes and Values of Carbon Saved under Options							
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	
Volumes of carbon saved (MT CO2)							
Option 1							
PV	0.95	1.18	1.43	1.67	1.91	2.12	
Wind	0.51	0.62	0.71	0.78	0.82	0.86	
Hydro	0.18	0.23	0.28	0.32	0.35	0.37	
AD	0.82	0.90	0.94	0.97	0.99	1.00	
Total	2.46	2.94	3.36	3.74	4.07	4.35	
Option 2 (central)							Impact on volumes in 2020/21
PV	0.93	0.96	0.97	0.98	0.96	0.92	- 1.21
Wind	0.49	0.54	0.57	0.60	0.59	0.57	- 0.29
Hydro	0.18	0.23	0.27	0.32	0.33	0.31	- 0.06
AD	0.81	0.88	0.94	0.98	0.98	0.96	- 0.04
Total	2.41	2.61	2.75	2.87	2.85	2.75	- 1.59
Option 3 (central)							Impact on volumes in 2020/21
PV	0.92	0.93	0.90	0.87	0.84	0.81	- 1.32
Wind	0.49	0.50	0.48	0.47	0.45	0.44	- 0.42
Hydro	0.17	0.18	0.17	0.17	0.16	0.16	- 0.21
AD	0.81	0.81	0.80	0.78	0.77	0.75	- 0.25
Total	2.39	2.42	2.35	2.29	2.22	2.15	- 2.20
Values of carbon saved (£m 11/12 prices, discounted)							
Option 1							
PV	3.44	4.22	5.05	5.93	6.81	8.42	
Wind	1.84	2.23	2.51	2.76	2.94	3.39	
Hydro	0.64	0.83	0.99	1.13	1.24	1.46	
AD	2.95	3.20	3.34	3.46	3.53	3.94	
Total	8.87	10.47	11.89	13.27	14.51	17.21	
Option 2 (central)							Impact on values in 2020/21
PV	3.34	3.44	3.44	3.47	3.40	3.62	- 4.80
Wind	1.78	1.91	2.01	2.12	2.11	2.24	- 1.15
Hydro	0.64	0.81	0.97	1.13	1.17	1.24	- 0.22
AD	2.93	3.15	3.31	3.47	3.48	3.77	- 0.17
Total	8.69	9.31	9.72	10.18	10.16	10.87	- 6.34
Option 3 (central)							Impact on values in 2020/21
PV	3.33	3.32	3.19	3.10	2.99	3.18	- 5.24
Wind	1.77	1.77	1.70	1.65	1.62	1.72	- 1.67
Hydro	0.63	0.64	0.62	0.60	0.58	0.62	- 0.85
AD	2.91	2.90	2.82	2.78	2.73	2.96	- 0.98
Total	8.63	8.63	8.33	8.13	7.92	8.47	- 8.74

Admin costs

6.13. Ofgem estimate the cost of implementing new systems to implement the policy changes in Option 2 to be up to £250,000; DECC and Ofgem will work to implement the changes as cost-effectively as possible.

Net Present Value (NPV)

6.14. 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, and estimated the NPV of Options 2 and 3 are therefore compared to Option 1. The three components of NPV are:

- Net Resource cost savings
- Reduced Carbon Savings
- Administrative costs of implementing changes (this figure is up to £250,000 in Option 2l this is rounded to zero in the table as all figures are rounded to the nearest £10m)
- These are set out in Table 31 below, along with the range of NPVs (resulting from the range in deployment as explained in section 6).

6.15. The net resource costs are calculated as the levelised costs of the FITs installations minus the Long Run Variable Cost (LRVC) of electricity supply. In this way, the net resource costs are the additional (non-carbon) costs to society of producing the electricity through a FIT installation, rather than producing the electricity from additional supply from the national grid (including transmission and distribution costs). This analysis uses the central values of the LRVC in the supplementary guidance toolkit.[31] Option 2 reduces the amount of FITs deployment relative to Option 1 but increases the amount of electricity supplied from the grid. Overall this reduces the resource costs of energy supply for society.

6.16. 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 Parsons Brinckerhoff.

6.17. This analysis uses the social discount rate of 3.5% in accordance with the Green Book.[32] The NPV for Option 2 ranges between +£1,510m and +£2,250m, with a value of +£1,810m in the medium scenario (all in real 2011/12 prices). Lower resource costs of energy supply more than offset reduced carbon savings and additional administrative costs.

Table 31: Net Present Value of each option

Values over the FITs lifetime from 2010/11 to 2055/56							
£m 2016 prices, discounted	Option 1	Option 2			Option 3		
	Central	Low Deployment	Medium Deployment	High Deployment	Low Deployment	Medium Deployment	High Deployment
Carbon savings	1,510	810	900	950	650	680	700
Net resource costs	12,930	9,980	10,510	10,860	9,240	9,440	10,640
Admin costs for OFGEM	-	-	-	-		-	
Impact of Options 2 and 3 against Option 1 central estimate							
		Option 2			Option 3		
		Low Deployment	Medium Deployment	High Deployment	Low Deployment	Medium Deployment	High Deployment
Reduced Carbon Savings		- 700	- 610	- 560	- 860	- 830	- 810
Net resource cost savings		2,950	2,420	2,070	3,690	3,490	2,290
NPV		2,250	1,810	1,510	2,830	2,660	1,480

LCF impacts and cost to consumers

6.18. Generation tariff payments and deemed export payments are passed on to consumers and consumer bills (both households and other users) through the levelisation process.[33] This is part of the spending under the LCF. Table 32 below shows the LCF impact of each option; Table 33 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

[31] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[32] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf
[33] https://www.ofgem.gov.uk/sites/default/files/docs/2015/06/feed-in_tariff_guidance_for_renewable_installations_v9_0.pdf

deemed export payments of between £440m and £480m per annum, relative to Option 1.[34] More detail is provided in Tables A7 and A8 in the Annex.

Table 32: LCF impact of each option

Annual Cost 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 on cumulative deployment by 2020/21 against Option 1 central estimate
Option 1 - Low	1,020	1,130	1,230	1,310	1,390	1,450	
Option 1 - Central	1,040	1,190	1,320	1,430	1,520	1,600	
Option 1 - High	1,050	1,240	1,410	1,540	1,660	1,730	
Option 2 - Low	1,010	1,060	1,080	1,110	1,120	1,120	-480
Option 2 – Central	1,020	1,080	1,110	1,140	1,150	1,150	-450
Option 2 - High	1,040	1,110	1,130	1,150	1,160	1,160	-440
Option 3 - Low	1,010	1,040	1,040	1,040	1,040	1,040	-560
Option 3 - Central	1,030	1,070	1,070	1,070	1,070	1,070	-530
Option 3 - High	1,040	1,090	1,090	1,090	1,090	1,090	-510

6.19. Results for each user are consistent with final estimated electricity demand per user after policies consistent with DECC's 2014 Prices and Bills report[35]. Results for the large energy intensive industrial consumer assume no compensation from the cost of FITs. Eligible energy intensive industries will be compensated for up to 85% of the cost of FITs on electricity bills from 2016/17 to 2019/20 (subject to State aid approval).

Table 33: Impact on Electricity Bills of each option

Impact on Average Electricity Bills							
		Impact against option 1			Impact against option 1 (%)		
£2016 prices		Option 2 - Low Deployment Scenario	Option 2 - Medium Deployment Scenario	Option 2 - High Deployment Scenario	Option 2 - Low Deployment Scenario	Option 2 - Medium Deployment Scenario	Option 2 - High Deployment Scenario
Average household consumer	2016	- 1	- 1	- 1	-0.2%	-0.2%	-0.1%
	2017	- 3	- 2	- 2	-0.4%	-0.4%	-0.3%
	2018	- 4	- 4	- 3	-0.6%	-0.6%	-0.5%
	2019	- 5	- 5	- 4	-0.8%	-0.7%	-0.7%
	2020	- 6	- 6	- 5	-1.0%	-0.9%	-0.9%
Small-sized business consumer	2016	- 90	- 80	- 50	-0.3%	-0.3%	-0.2%
	2017	- 190	- 170	- 140	-0.6%	-0.5%	-0.5%
	2018	- 280	- 250	- 230	-0.9%	-0.8%	-0.7%
	2019	- 360	- 320	- 310	-1.0%	-0.9%	-0.9%
	2020	- 440	- 400	- 390	-1.2%	-1.1%	-1.1%
Medium-sized business consumer (in the CRC Energy Efficiency Scheme)	2016	- 4,000	- 3,500	- 2,200	-0.3%	-0.3%	-0.2%
	2017	- 8,100	- 7,200	- 6,100	-0.6%	-0.6%	-0.5%
	2018	- 11,700	- 10,500	- 9,900	-0.9%	-0.8%	-0.8%
	2019	- 15,200	- 13,600	- 13,200	-1.1%	-1.0%	-0.9%
	2020	- 18,600	- 16,700	- 16,500	-1.3%	-1.2%	-1.2%
Large energy intensive industrial consumer	2016	- 36,500	- 31,700	- 20,600	-0.4%	-0.3%	-0.2%
	2017	- 74,200	- 66,100	- 56,100	-0.8%	-0.7%	-0.6%
	2018	- 107,400	- 96,900	- 90,700	-1.1%	-1.0%	-0.9%
	2019	- 139,900	- 124,700	- 121,800	-1.3%	-1.1%	-1.1%
	2020	- 170,900	- 154,200	- 152,000	-1.5%	-1.4%	-1.4%

[34] 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.
[35] https://www.gov.uk/government/publications/estimated-impacts-of-energy-and-climate-change-policies-on-energy-prices-and-bills-2014

Non-monetised costs

Employment

6.20. Although figures aren't available on the number of jobs currently supported by FITs, given the success of the scheme to date it can be assumed that FITs has contributed at least in part to the green growth seen in the UK since 2010 (please refer to section 7 of Dr Colin Nolden's Review of Evidence[36] which was published alongside this consultation). The scheme has certainly seen a significant amount of jobs transfer from other parts of the economy to support renewables installation. The proposed changes will see the current high rate of deployment decrease, likely leading to a rebalancing of jobs in this sector. There is therefore likely to be a negative impact on existing jobs in the renewable electricity generation sector, though DECC has not been able to quantify it. It is also likely that the impact of the changes proposed in option 2 will be negative on new jobs created by the scheme, although this – as well as wider impacts on jobs across the economy – has not been quantified. We are seeking evidence on this through the consultation.

Wider electricity system impacts

6.21. Decreased FITs deployment relative to the 'do nothing' option 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.

7. 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 incorrect, or that it is not adequately picking up changes over time.

Operation of caps

7.2. As seen over the last few years, industry has adapted to the changing FITs policy to continue deploying at high rates and at rates not expected. While this remains a risk under the proposed revisions to the FITs scheme, the proposed deployment caps are intended to stop spending going above a certain level. Therefore, while there may still be cost changes over time that increase returns to developers and result in more projects looking to deploy than currently expected, the introduction of caps should ensure that this does not result in overspends under the FITs scheme as it has done in the past.

7.3. However, there are practical challenges to the introduction of caps. For example, there are practical challenges with tracking deployment in a timely fashion to know if and when a cap has been hit, and then ensuring that this information is correctly reflected in the system of determining which installations are eligible for which tariffs.

7.4. More information about caps and their operation is included in the consultation document. It is important to note that if the risks of implementing a capped scheme prove to be insurmountable, the government propose to close the scheme altogether as the LCF risks posed by an uncapped scheme are too high.

Reduced rate of deployment

7.5. While the FITs modelling suggests that the proposed changes to tariffs, degression and the introduction of caps, will result in continued deployment, there is a risk that these changes – combined with the separate consultation proposals to remove pre-accreditation – may result in significantly reduced rates of deployment relative to the 'do nothing'. 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 reduced 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.

The impact on community developers

7.6. Community installations typically take longer to agree financing 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 and related. This may mean that the uncertainties associated with a capped FITs system may be more pronounced for community projects, particularly if there are any changes to the rules on pre-accreditation as proposed in the consultation of 22nd July 2015. However, community projects will often have lower hurdle rates than commercial installations (if, for example, they are driven primarily by altruistic, energy saving objective) which could counter balance this risk.

[36] The evidence review is available on the FITs consultation page: https://www.gov.uk/government/consultations/consultation-on-a-review-of-the-feed-in-tariff-scheme

Load factors

7.7. The load factor remains a risk to spending under the scheme. The tariffs and the caps have been set based on the information available, but if the load factor is higher than thought, or indeed the load factor in a particular year is higher, this may result in spending increases beyond the £100m cap. While this is felt to be unlikely, as set out above, the tying of contingent degression to the projections and to the caps should provide a built-in buffer against the load factor risk.

Export Fraction

7.8. There is uncertainty about the share of electricity that <10kW PV installations export. PB's research gave an export fraction of 53% for all building mounted PV installations. However, it may be that domestic PV installations export more than 53%, given the electricity is generated in the day which is not when the majority of electricity is consumed. We are seeking further evidence on this through the consultation.

Target Rate of Return for generation tariffs

7.9. As discussed in section 5, it may be that hurdle rates increase under option 2 as a result of the removal of pre-accreditation, and this is reflected in our estimates of how much deployment might come forward at our proposed tariff levels. However, the target rates of return on which tariffs are set have not been increased because:

- The modelling shows that deployment would still come forward at these tariff rates. This is because even if hurdle rates do increase for a certain proportion of the investor population, a) some investors will continue to assess projects in the same way as before (in particular for projects which would not have used pre-accreditation in the first place); and b) there will still be well-sited projects that remain attractive, for example if their costs are towards the low end of the range.
- Amending the hurdle rate would result in higher tariffs, and lead to worse value for money under the scheme. Furthermore, should tariffs be calculated to offer higher rates of return, this would lead to lower deployment caps in order to remain within the limit of the overall cap on spend. Tables 34 and 35 respectively show tariffs calculated assuming the higher hurdle rates used to model the impact of removing pre-accreditation on deployment, and the associated deployment caps.

7.10. Separately from the impact of pre-accreditation, section 5 also explained why the introduction of caps was assumed not to have any additional impact on hurdle rates. However, should evidence be brought forward to suggest the contrary, a similar decision would have to be made regarding target rates of return. In other words, any increase to target rates of return would lead to higher generation tariffs but also to lower deployment caps.

7.11. Although the consultation does not explicitly include a question seeking views on whether the impact of removing pre-accreditation should be taken into account into target rates of return for the purpose of tariff setting, or on the impact of introducing caps on hurdle rates, DECC would welcome any such views within the broader context of Consultation questions 1, 2 or 8.

Table 34 – tariffs aiming at higher Rates of Return to account for removal of pre-accreditation

Q1 2016 prices, p/kWh		Jan-2016	Apr-2016	Jul-2016	Oct-2016	Jan-2017	Apr-2017	Jul-2017	Oct-2017	Jan-2018	Apr-2018	Jul-2018	Oct-2018	Jan-2019
PV	<10kW	1.99	1.82	1.66	1.49	1.32	1.16	0.99	0.83	0.66	0.50	0.33	0.17	0.00
	10 - 50kW	4.03	3.93	3.82	3.72	3.61	3.51	3.41	3.30	3.20	3.09	2.99	2.88	2.78
	50 - 250kW	2.96	2.86	2.76	2.66	2.56	2.46	2.35	2.25	2.15	2.05	1.95	1.85	1.75
	250-1000kW	2.59	2.49	2.39	2.29	2.19	2.09	1.99	1.89	1.79	1.69	1.59	1.49	1.39
	> 1000kW	1.31	1.20	1.09	0.98	0.87	0.76	0.65	0.55	0.44	0.33	0.22	0.11	0.00
	Stand alone	1.31	1.20	1.09	0.98	0.87	0.76	0.65	0.55	0.44	0.33	0.22	0.11	0.00
Wind	<50kW	9.13	9.03	8.93	8.83	8.73	8.63	8.53	8.43	8.33	8.23	8.13	8.03	7.94
	50–1500kW	4.82	4.78	4.74	4.70	4.65	4.61	4.57	4.53	4.49	4.45	4.41	4.36	4.32
	>1500kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	<100kW	11.86	11.82	11.79	11.75	11.72	11.69	11.65	11.62	11.58	11.55	11.52	11.48	11.45
	100-500 kW	10.83	10.82	10.80	10.79	10.77	10.75	10.74	10.72	10.70	10.69	10.67	10.65	10.64
	500-2000kW	7.44	7.44	7.44	7.44	7.44	7.44	7.44	7.44	7.44	7.44	7.44	7.44	7.44
	>2000kW	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83

Table 35 – caps at higher tariffs to account for removal of pre-accreditation

Maximum Deployment (MW)		Jan-2016	Apr-2016	Jul-2016	Oct-2016	Jan-2017	Apr-2017	Jul-2017	Oct-2017	Jan-2018	Apr-2018	Jul-2018	Oct-2018	Jan-2019
PV	<10kW	16.91	17.27	17.54	17.82	18.11	18.18	17.84	17.48	17.13	17.01	17.40	17.80	18.21
	10 - 50kW	9.76	9.93	9.86	9.78	9.69	9.61	9.56	9.51	9.46	9.58	10.08	10.61	11.17
	>50kW	8.41	8.60	8.54	8.46	8.38	8.31	8.25	8.19	8.12	8.24	8.77	9.33	9.93
	Stand alone	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Wind	<50kW	4.08	4.21	4.32	4.43	4.55	4.65	4.73	4.81	4.90	5.02	5.24	5.46	5.70
	>50kW	13.20	13.35	13.48	13.62	13.76	13.90	14.05	14.21	14.37	14.54	14.73	14.94	15.14
Hydro	All	12.91	13.24	13.55	13.84	14.10	14.32	14.52	14.69	14.83	14.94	15.03	15.08	15.11
AD	AD<500 kW	2.31	2.40	2.35	2.30	2.25	2.35	2.29	2.23	2.18	2.28	2.24	2.20	2.16
	AD>500 kW	3.80	3.29	3.06	2.85	2.65	2.64	2.45	2.27	2.11	2.11	1.96	1.82	1.70

8. Rationale and evidence that justify the level of analysis in the IA.

8.1. There are various proposals in the consultation document that are not formally assessed within this impact assessment. The proposals and the reasons for their exclusion are set out below.

8.2. Prevent extensions to existing installations from claiming FITs: preventing installations already accredited under FITs from extending, it removes a complication from estimating FITs generation support costs. This is because extensions are more difficult to predict than new-build generation. Extensions have not been included in the modelling of Option 2, and therefore they are implicitly excluded from the analysis.

8.3. Moving from tariffs linked to the Retail Price Index (RPI) to the Consumer Price Index (CPI): RPI tends to be around 1% higher per annum than CPI. Therefore, the proposed change, for new installations under FITs, would reduce income streams over time. The move to CPI has not been assessed as it is a relatively minor change.

8.4. 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.

8.5. 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.

8.6. 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£60,000), and will be used to part-fund the Levelisation Fund. Given its magnitude, this has not been assessed within this impact assessment.

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

8.8. 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.

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

Deployment Projections

1. Table A1 shows the forecast of deployment under each Option. This provides further breakdowns of the scenarios presented in Table 27 of the IA.

Table A1 - Cumulative Deployment at end of year (MW)

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	3,400	3,990	4,660	5,370	6,090	6,740	
Wind	740	880	1,000	1,100	1,200	1,280	
Hydro	180	220	260	300	340	380	
AD	240	250	270	280	290	300	
Total	4,550	5,340	6,200	7,060	7,920	8,690	
Option 1 - Central							
PV	3,700	4,690	5,770	6,940	8,160	9,370	
Wind	780	950	1,100	1,230	1,340	1,440	
Hydro	190	240	290	340	380	420	
AD	240	270	280	290	300	310	
Total	4,910	6,150	7,440	8,800	10,190	11,540	
Option 1 - High							
PV	3,970	5,350	6,930	8,700	10,530	12,310	
Wind	810	1,020	1,200	1,360	1,510	1,620	
Hydro	200	270	330	390	440	490	
AD	250	280	300	310	320	330	
Total	5,230	6,910	8,760	10,750	12,790	14,750	
Option 2 - Low							
PV	3,240	3,300	3,360	3,420	3,420	3,420	-5,950
Wind	680	730	790	850	850	850	-590
Hydro	170	210	250	300	300	300	-130
AD	230	250	270	280	280	280	-30
Total	4,330	4,500	4,670	4,840	4,840	4,840	-6,700
Option 2 - Central							
PV	3,420	3,560	3,700	3,850	3,850	3,850	-5,520
Wind	710	780	850	930	930	930	-510
Hydro	180	230	290	340	340	340	-80
AD	240	260	280	300	300	300	-10
Total	4,550	4,830	5,120	5,420	5,420	5,420	-6,120
Option 2 - High							
PV	3,570	3,740	3,910	4,100	4,100	4,100	-5,270
Wind	730	810	890	980	980	980	-460
Hydro	190	250	310	370	370	370	-50
AD	250	270	290	310	310	310	-
Total	4,740	5,070	5,410	5,760	5,760	5,760	-5,780
Option 3 - Low							
PV	3,230	3,230	3,230	3,230	3,230	3,230	-6,130
Wind	670	670	670	670	670	670	-770
Hydro	160	160	160	160	160	160	-260
AD	230	230	230	230	230	230	-90
Total	4,290	4,290	4,290	4,290	4,290	4,290	-7,250
Option 3 - Central							
PV	3,380	3,380	3,380	3,380	3,380	3,380	-5,980
Wind	690	690	690	700	700	700	-740
Hydro	170	170	170	170	170	170	-250
AD	230	230	230	230	230	230	-80
Total	4,480	4,480	4,480	4,490	4,490	4,490	-7,050
Option 3 - High							
PV	3,530	3,530	3,530	3,530	3,530	3,530	-5,840
Wind	710	710	710	710	710	710	-730
Hydro	180	180	180	180	180	180	-240
AD	240	240	240	240	240	240	-70
Total	4,660	4,660	4,660	4,660	4,660	4,660	-6,880

2. Table A2 shows the detailed forecast of deployment under the central estimates of Options 1 and 2.

Table A2 - Cumulative Deployment at end of year (MW)

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	2,010	2,460	2,930	3,420	3,900	1,510	1,570	1,630	1,690	1,690	1,690	-2,210
4 - 10kW	110	160	220	300	400	510	100	110	110	120	120	120	-390
10 - 50kW	670	1,000	1,350	1,750	2,140	2,520	550	590	620	660	660	660	-1,860
50-150kW	140	210	280	370	460	560	120	130	130	140	140	140	-420
150-250kW	130	190	250	310	380	440	120	120	130	140	140	140	-300
250-5000kW	130	150	180	200	230	260	120	120	120	120	120	120	-140
Stand alone	410	440	460	480	500	510	410	410	410	420	420	420	-100
Agg <4	470	490	510	530	540	550	460	460	460	460	460	460	-80
Agg >4	40	50	70	80	100	110	30	30	40	40	40	40	-80
250-1000kW								10	20	20	20	20	20
1000-5000kW								10	30	40	40	40	40
Total	3,700	4,690	5,770	6,940	8,160	9,370	3,420	3,560	3,700	3,850	3,850	3,850	-5,520
Wind													
B-M <1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	50	80	100	130	150	170	40	60	70	90	90	90	-80
15–50kW	30	40	40	50	60	60	20	30	30	40	40	40	-20
50–100kW	120	140	160	170	180	190	100	110	110	120	120	120	-70
100–500kW	360	420	470	510	550	570	320	340	360	380	380	380	-200
500–1,500kW	90	90	100	110	120	120	90	90	100	110	110	110	-10
1,500-5,000kW	140	180	220	250	290	330	140	160	180	200	200	200	-120
Total	780	950	1,100	1,230	1,340	1,440	710	780	850	930	930	930	-510
Hydro													
<15kW	10	10	20	20	30	40	10	10	20	20	20	20	-10
15-50kW	10	20	20	20	20	30	10	20	20	20	20	20	-10
50-100kW	20	20	20	20	30	30	10	20	20	20	20	20	-
100-500kW	50	70	80	90	100	110	50	60	80	90	90	90	-10
500-1,000kW	40	50	60	60	70	70	40	50	60	60	60	60	-10
1,000-2,000kW	50	60	80	90	100	100	50	60	80	90	90	90	-20
2,000-5,000kW	10	10	20	30	40	40	10	10	20	30	30	30	-10
Total	190	240	290	340	380	420	180	230	290	340	340	340	-80
AD													
AD < 250kW	20	30	30	40	40	40	20	30	40	40	40	40	-
AD 250 - 500kW	70	70	80	80	80	80	70	80	80	80	80	80	-
AD > 500kW	150	160	170	180	190	190	140	160	170	170	170	170	-20
Total	240	270	280	290	300	310	240	260	280	300	300	300	-10

Number of installations

3. Table A3 show the forecast of the number of installations under each Option. This provides further breakdowns of the scenarios presented in Table 28 of the IA.

Table A3 - 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	690,000	805,000	938,000	1,068,000	1,196,000	1,313,000	
Wind	10,000	13,000	15,000	18,000	20,000	22,000	
Hydro	1,400	2,200	3,100	4,000	5,000	5,800	
AD	400	400	500	500	500	500	
Total	702,000	820,000	956,000	1,090,000	1,222,000	1,342,000	
Option 1 - Central							
PV	730,000	893,000	1,068,000	1,253,000	1,445,000	1,635,000	
Wind	11,000	15,000	18,000	22,000	26,000	28,000	
Hydro	1,500	2,300	3,300	4,200	5,200	6,100	
AD	400	500	500	500	600	600	
Total	743,000	911,000	1,090,000	1,280,000	1,477,000	1,670,000	
Option 1 - High							
PV	760,000	964,000	1,197,000	1,458,000	1,725,000	1,982,000	
Wind	12,000	18,000	23,000	27,000	32,000	36,000	
Hydro	1,600	2,500	3,500	4,600	5,600	6,500	
AD	400	500	500	600	600	600	
Total	774,000	984,000	1,224,000	1,490,000	1,764,000	2,025,000	
Option 2 - Low							
PV	665,000	675,000	684,000	694,000	694,000	694,000	-941,000
Wind	8,000	9,000	11,000	13,000	13,000	13,000	-16,000
Hydro	1,400	2,200	3,000	4,000	4,000	4,000	-2,100
AD	400	400	500	500	500	500	-100
Total	675,000	687,000	699,000	711,000	711,000	711,000	-958,000
Option 2 - Central							
PV	693,000	715,000	738,000	761,000	761,000	761,000	-874,000
Wind	9,000	11,000	13,000	15,000	15,000	15,000	-13,000
Hydro	1,500	2,300	3,300	4,300	4,300	4,300	-1,800
AD	400	500	500	600	600	600	-
Total	703,000	728,000	754,000	781,000	781,000	781,000	-889,000
Option 2 - High							
PV	711,000	736,000	761,000	788,000	788,000	788,000	-847,000
Wind	10,000	12,000	14,000	17,000	17,000	17,000	-12,000
Hydro	1,600	2,500	3,500	4,700	4,700	4,700	-1,400
AD	400	500	500	600	600	600	-
Total	723,000	751,000	780,000	810,000	810,000	810,000	-860,000
Option 3 - Low							
PV	663,000	663,000	663,000	663,000	663,000	663,000	-972,000
Wind	8,000	8,000	8,000	8,000	8,000	8,000	-21,000
Hydro	1,300	1,300	1,300	1,300	1,300	1,300	-4,800
AD	400	400	400	400	400	400	-200
Total	672,000	672,000	672,000	672,000	672,000	672,000	-997,000
Option 3 - Central							
PV	687,000	687,000	687,000	687,000	687,000	687,000	-948,000
Wind	8,000	8,000	8,000	9,000	9,000	9,000	-20,000
Hydro	1,300	1,300	1,300	1,300	1,300	1,300	-4,800
AD	400	400	400	400	400	400	-200
Total	697,000	697,000	697,000	698,000	698,000	698,000	-972,000
Option 3 - High							
PV	710	710	710	710	710	710	-930
Wind	9,000	9,000	9,000	9,000	9,000	9,000	-19,000
Hydro	1,000	1,000	1,000	1,000	1,000	1,000	-5,000
AD	400	400	400	400	400	400	-200
Total	716,400	716,400	716,400	716,400	716,400	716,400	-953,300

4. Table A4 shows the detailed forecast of number of installations under central estimates of Options 1 and 2.

Table A4 - Number of Installations at end of year (cumulative)

Table 4 - Number of Installations at end of year (cumulative)													
	Option 1 - Central						Option 2 - central						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
PV													
<4kW	520,560	655,770	802,480	957,370	1,118,030	1,275,470	491,910	511,830	532,360	553,420	553,420	553,420	-722,050
4 - 10kW	13,730	19,650	27,080	36,460	48,250	62,360	12,360	13,140	13,950	14,840	14,840	14,840	-47,530
10 - 50kW	20,220	29,910	40,550	52,470	64,370	75,660	16,500	17,610	18,680	19,840	19,840	19,840	-55,820
50-150kW	1,380	2,040	2,770	3,610	4,550	5,520	1,190	1,260	1,320	1,390	1,390	1,390	-4,120
150-250kW	630	890	1,160	1,460	1,780	2,090	560	590	620	650	650	650	-1,440
250-5000kW	100	120	140	160	190	210	100	100	100	100	100	100	-120
Stand alone	160	170	180	180	190	200	160	160	160	160	160	160	-40
Agg <4	167,210	176,240	182,970	188,020	191,920	194,840	164,010	164,230	164,430	164,600	164,600	164,600	-30,240
Agg >4	6,340	8,550	10,940	13,440	16,000	18,460	5,730	5,810	5,890	5,950	5,950	5,950	-12,500
250-1000kW	-	-	-	-	-	-	-	20	30	50	50	50	50
1000-5000kW	-	-	-	-	-	-	-	-	10	10	10	10	10
Total	730,340	893,340	1,068,290	1,253,180	1,445,280	1,634,800	692,520	714,750	737,550	761,020	761,020	761,020	- 873,790
Wind													
B-M <1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	6,980	10,150	13,110	16,100	19,140	21,470	5,530	7,140	8,920	10,950	10,950	10,950	-10,520
15–50kW	1,170	1,580	1,910	2,200	2,450	2,640	960	1,160	1,360	1,580	1,580	1,580	-1,060
50–100kW	1,460	1,740	1,970	2,160	2,300	2,400	1,290	1,370	1,440	1,520	1,520	1,520	-880
100–500kW	940	1,110	1,240	1,350	1,440	1,510	830	890	940	990	990	990	-510
500–1,500kW	90	100	110	120	120	130	90	100	110	120	120	120	-10
1,500-5,000kW	50	60	70	90	100	110	50	50	60	70	70	70	-40
Total	10,680	14,740	18,420	22,020	25,570	28,260	8,760	10,710	12,840	15,240	15,240	15,240	-13,020
Hydro													
<15kW	690	1,300	2,040	2,850	3,680	4,440	700	1,330	2,110	2,980	2,980	2,980	-1,460
15-50kW	400	510	600	680	750	810	380	460	550	640	640	640	-170
50-100kW	180	220	260	280	310	330	180	210	240	270	270	270	-60
100-500kW	150	190	230	260	290	310	150	190	230	270	270	270	-40
500-1,000kW	60	70	80	90	90	100	60	70	80	90	90	90	-10
1,000-2,000kW	30	40	50	60	60	70	30	40	50	60	60	60	-10
2,000-5,000kW	-	10	10	10	20	20	-	10	10	10	10	10	-10
Total	1,500	2,300	3,300	4,200	5,200	6,100	1,500	2,300	3,300	4,300	4,300	4,300	-1,800
AD													
< 250kW	160	190	210	230	250	270	150	190	230	270	270	270	-
250-500kW	150	160	160	160	170	170	150	160	160	170	170	170	-
> 500kW	100	110	120	130	130	130	100	110	120	120	120	120	-10
Total	410	460	490	530	550	570	400	460	510	560	560	560	-10

Generation

5. Table A5 show the forecast generation under each Option. This gives further breakdowns of the scenarios presented in Table 29 of the Impact Assessment.

<u>Table A5 – Annual generation (GWh)</u>

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	3,120	3,660	4,290	4,930	5,600	6,200	
Wind	1,760	2,090	2,370	2,610	2,830	3,020	
Hydro	590	750	900	1,040	1,180	1,300	
AD	1,550	1,670	1,770	1,850	1,910	1,960	
Total	7,020	8,170	9,320	10,440	11,520	12,480	
Option 1 - central estimate							
PV	3,390	4,310	5,300	6,370	7,490	8,600	
Wind	1,830	2,230	2,570	2,870	3,140	3,370	
Hydro	620	820	1,000	1,160	1,310	1,450	
AD	1,590	1,740	1,850	1,940	2,010	2,060	
Total	7,430	9,100	10,720	12,350	13,960	15,480	
Option 1 - central estimate							
PV	3,630	4,910	6,360	7,980	9,670	11,300	
Wind	1,890	2,360	2,780	3,140	3,470	3,730	
Hydro	650	890	1,120	1,330	1,520	1,680	
AD	1,640	1,820	1,940	2,030	2,090	2,150	
Total	7,820	9,980	12,190	14,470	16,740	18,870	
Option 2 - Low							
PV	3,000	3,050	3,100	3,150	3,150	3,150	-5,450
Wind	1,620	1,750	1,880	2,020	2,020	2,020	-1,350
Hydro	580	720	860	1,010	1,010	1,010	-440
AD	1,520	1,640	1,750	1,840	1,840	1,840	-220
Total	6,730	7,160	7,590	8,030	8,030	8,030	-7,460
Option 2 - Central							
PV	3,160	3,290	3,410	3,550	3,550	3,550	-5,050
Wind	1,680	1,850	2,020	2,200	2,200	2,200	-1,170
Hydro	610	790	980	1,180	1,180	1,180	-280
AD	1,560	1,710	1,840	1,950	1,950	1,950	-110
Total	7,010	7,640	8,250	8,880	8,880	8,880	-6,610
Option 2 - High							
PV	3,260	3,420	3,580	3,750	3,750	3,750	-4,860
Wind	1,740	1,910	2,100	2,290	2,290	2,290	-1,070
Hydro	680	870	1,090	1,300	1,300	1,300	-150
AD	1,630	1,790	1,930	2,050	2,050	2,050	-10
Total	7,300	7,990	8,690	9,390	9,390	9,390	-6,090
Option 3 - low							
PV	2,960	2,960	2,960	2,960	2,960	2,960	-5,640
Wind	1,610	1,610	1,610	1,610	1,610	1,610	-1,760
Hydro	570	570	570	570	570	570	-880
AD	1,500	1,500	1,500	1,500	1,500	1,500	-560
Total	6,650	6,650	6,650	6,650	6,650	6,650	-8,840
Option 3 - central							
PV	3,100	3,100	3,100	3,100	3,100	3,100	-5,510
Wind	1,650	1,650	1,650	1,670	1,670	1,670	-1,690
Hydro	600	600	600	600	600	600	-850
AD	1,540	1,540	1,540	1,540	1,540	1,540	-520
Total	6,890	6,890	6,890	6,910	6,910	6,910	-8,580
Option 3 - high							
PV	3,220	3,220	3,220	3,220	3,220	3,220	-5,380
Wind	1,700	1,700	1,700	1,700	1,700	1,700	-1,670
Hydro	630	630	630	630	630	630	-830
AD	1,580	1,580	1,580	1,580	1,580	1,580	-480
Total	7,130	7,130	7,130	7,130	7,130	7,130	-8,360

6. Table A6 shows the detailed forecast of generation under the central estimates of Options 1 and 2.

<u>Table A6 - Full Year Generation (GWh)</u>

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	1,470	1,850	2,260	2,690	3,150	3,590	1,380	1,440	1,500	1,560	1,560	1,560	-2,030
4 - 10kW	100	150	200	280	360	470	90	100	110	110	110	110	-360
10 - 50kW	620	920	1,240	1,610	1,970	2,320	500	540	570	610	610	610	-1,710
50-150kW	130	190	260	330	420	510	110	120	120	130	130	130	-380
150-250kW	120	170	220	280	340	400	110	110	120	130	130	130	-280
250-5000kW	110	140	160	180	210	240	-	-	-	-	-	-	-240
Stand alone	380	400	420	440	460	470	370	380	380	380	380	380	-90
Agg <4	430	450	470	480	490	500	420	420	420	420	420	420	-80
Agg >4	30	50	60	70	90	100	30	30	30	30	30	30	-70
250-1000kW	-	-	-	-	-	-	40	50	50	60	60	60	60
1000-5000kW	-	-	-	-	-	-	80	100	110	120	120	120	120
Total	3,390	4,320	5,290	6,360	7,490	8,600	3,130	3,290	3,410	3,550	3,550	3,550	-5,050
Wind													
B-M <1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	80	120	160	190	230	260	60	80	110	130	130	130	-130
15–50kW	40	50	70	80	90	90	30	40	50	60	60	60	-40
50–100kW	180	210	240	270	280	300	160	170	180	190	190	190	-110
100–500kW	1,020	1,210	1,370	1,490	1,590	1,670	920	980	1,040	1,100	1,100	1,100	-570
500–1,500kW	160	180	200	210	220	230	160	180	200	210	210	210	-20
1,500-5,000kW	340	440	540	630	730	820	330	390	450	510	510	510	-310
Total	1,830	2,230	2,570	2,870	3,140	3,370	1,680	1,850	2,020	2,200	2,200	2,200	-1,170
Hydro													
<15kW	20	40	60	80	100	130	20	40	60	80	80	80	-40
15-50kW	40	60	70	80	90	90	40	50	60	70	70	70	-20
50-100kW	50	60	80	80	90	100	50	60	70	80	80	80	-20
100-500kW	170	230	270	310	340	370	170	220	270	320	320	320	-50
500-1,000kW	150	180	200	220	240	260	140	170	200	220	220	220	-40
1,000-2,000kW	160	210	260	300	330	360	160	210	260	300	300	300	-60
2,000-5,000kW	30	50	70	90	120	150	30	50	70	100	100	100	-50
Total	620	820	1,000	1,160	1,310	1,450	610	790	980	1,180	1,180	1,180	-280
AD													
< 250kW	130	160	190	210	220	240	130	170	200	230	230	230	-
250 - 500kW	440	450	470	480	490	500	440	460	480	500	500	500	-
> 500kW	1,020	1,120	1,200	1,250	1,290	1,330	1,000	1,090	1,160	1,220	1,220	1,220	-110
Total	1,590	1,740	1,850	1,940	2,010	2,060	1,560	1,710	1,840	1,950	1,950	1,950	-110

LCF impacts and cost to consumers

7. Table A7 show the forecast of the LCF breakdown of each Option. This provides a more detailed breakdown of the figures presented in Table 32 of the IA.

Table A7 - 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	620	680	740	790	850	890	
Wind	190	220	240	250	260	270	
Hydro	60	80	90	100	110	110	
AD	140	150	160	170	170	180	
Total	1,020	1,130	1,230	1,310	1,390	1,450	
Option 1 - Central Deployment Scenario							
PV	630	720	800	880	950	1,010	
Wind	200	230	250	270	280	290	
Hydro	60	80	100	110	110	120	
AD	140	160	170	170	180	180	
Total	1,040	1,190	1,320	1,430	1,520	1,600	
Option 1 - High Deployment Scenario							
PV	640	750	860	970	1,050	1,110	
Wind	200	240	260	280	290	300	
Hydro	70	90	100	110	120	130	
AD	150	160	170	180	190	190	
Total	1,050	1,240	1,410	1,540	1,660	1,730	
Option 2 - Low Deployment Scenario							
PV	620	630	630	630	630	630	-380
Wind	190	200	200	210	210	210	-80
Hydro	60	70	80	100	100	100	-20
AD	140	150	160	170	170	170	-10
Total	1,010	1,060	1,080	1,110	1,120	1,120	-480
Option 2 - Central Deployment Scenario							
PV	610	640	640	640	640	640	-370
Wind	190	200	210	220	220	220	-70
Hydro	70	80	90	110	110	110	-10
AD	140	160	170	170	180	180	-
Total	1,020	1,080	1,110	1,140	1,150	1,150	-450
Option 2 - High Deployment Scenario							
PV	640	660	660	670	670	670	-350
Wind	190	210	210	210	210	210	-
Hydro	70	80	90	100	100	100	-20
AD	140	160	170	170	180	180	-10
Total	1,040	1,110	1,130	1,150	1,160	1,160	-440
Option 3 - Low Deployment Scenario							
PV	620	630	630	630	630	630	-380
Wind	190	200	200	200	200	200	-440
Hydro	60	70	70	70	70	70	-50
AD	140	140	140	140	140	140	-40
Total	1,010	1,040	1,040	1,040	1,040	1,040	-560
Option 3 - Central Deployment Scenario							
PV	630	650	650	650	650	650	-370
Wind	190	200	200	200	200	200	-460
Hydro	60	70	70	70	70	70	-50
AD	140	150	150	150	150	150	-40
Total	1,030	1,070	1,070	1,070	1,070	1,070	-530
Option 3 - High Deployment Scenario							
PV	630	660	660	660	660	660	-350
Wind	190	200	200	200	200	200	-430
Hydro	70	70	70	70	70	70	-50
AD	140	150	150	150	150	150	-30
Total	1,040	1,090	1,090	1,090	1,090	1,090	-510

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

Table A8 - 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	320	360	400	440	470	500	320	330	340	340	340	340	-160
4 - 10kW	20	20	30	30	40	40	20	20	20	20	20	20	-20
10 - 50kW	80	110	130	150	180	190	80	80	80	80	90	90	-110
50-150kW	10	20	20	30	30	40	10	10	10	10	10	10	-20
150-250kW	10	10	20	20	20	30	10	10	10	10	10	10	-20
250-5000kW	20	20	20	20	20	20	20	20	20	20	20	20	-
Stand alone	40	50	50	50	50	50	40	40	40	40	40	40	-
Agg <4	100	110	110	110	110	110	100	110	110	110	110	110	-10
Agg >4	10	10	10	10	10	10	10	10	10	10	10	10	-
250-1000kW	-	-	-	-	-	-	-	-	-	-	-	-	-30
1000-5000kW	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin costs	10	20	20	20	30	30	10	10	10	10	10	10	-20
Total	630	720	800	880	950	1,010	610	640	640	640	640	640	-370
Wind													
B-M <1.5kW	-	-	-	-	-	-	-	-	-	-	-	-	-
1.5–15kW	10	20	20	20	20	30	10	10	20	20	20	20	-10
15–50kW	10	10	10	10	10	10	10	10	10	10	10	10	-
50–100kW	30	30	40	40	40	40	30	30	30	30	30	30	-10
100–500kW	130	150	160	170	170	180	120	130	130	130	130	130	-40
500–1,500kW	10	10	10	10	10	10	10	10	10	10	10	10	-
1,500-5,000kW	10	10	10	20	20	20	10	10	10	10	10	10	-10
Admin costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	200	230	250	270	280	290	190	200	210	220	220	220	-70
Hydro													
<15kW	-	-	10	10	10	10	-	-	10	10	10	10	-
15-50kW	10	10	10	10	10	10	10	10	10	10	10	10	-
50-100kW	10	10	10	10	10	10	10	10	10	10	10	10	-
100-500kW	20	20	30	30	30	30	20	20	30	30	40	40	-
500-1,000kW	10	20	20	20	20	20	10	20	20	20	20	20	-
1,000-2,000kW	10	20	20	20	20	30	10	20	20	20	20	20	-
2,000-5,000kW	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	60	80	100	110	110	120	70	80	90	110	110	110	-10
AD													
AD < 250kW	10	20	20	20	20	20	10	20	20	20	20	20	-
AD 250 - 500kW	50	50	50	50	50	50	50	50	50	50	50	50	-
AD > 500kW	80	90	100	100	110	110	80	90	100	100	100	100	-10
Admin costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	140	160	170	170	180	180	140	160	170	170	180	180	-