Title: **Review of Feed-In-Tariff for AD and micro-CHP 2016** **IA No: DECC0213** **Lead department or agency:** Department of Energy and Climate Change **Other departments or agencies:**	# Impact Assessment (IA) **Date: 26/05/2016** **Stage: Consultation** **Source of intervention: Domestic** **Type of measure: Secondary legislation** **Contact for enquiries**: ADmCHPreview@decc.gsi.gov.uk

Summary: Intervention and Options

RPC: Not applicable

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**
£261m	£0m	£0	No	

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

The European Commission's State Aid approval for the FIT places an obligation on the Government to review the scheme every three years. The previous review that took place in 2015 did not cover Anaerobic Digestion (AD) and micro-Combined Heat and Power (micro-CHP), which are addressed in this consultation. The purpose of the review is to ensure that level of support is still at appropriate levels. In addition, this stage of the review proposes a way to remove the expenditure risk associated with micro-CHP and ensures spending for this technology is managed within the £100m budget assigned for FIT under the Levy Control Framework.

What are the policy objectives and the intended effects?

The policy objectives for AD are to: improve value for money; to control spending under the FIT scheme, in order to limit its direct impact on consumer bills; and to improve sustainability and greenhouse gas emissions savings. For micro-CHP the objective is also to remove the risk of high spending levels, and therefore of a high direct impact on consumer electricity bills.

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

Option 1 – Do nothing

Option 2 – Revise AD generation tariffs across all bands based on the latest data and implement default degression. Introduce sustainability criteria and feedstock restrictions for new AD plants. Implement deployment caps and contingent degression for micro-CHP.

Option 3 - Revise AD generation tariffs based on the latest data for the largest tariff band applying to plants greater than 500 kW. Maintain current tariff trajectory for the two smaller AD tariff bands applying to plants equal to or lower than 500 kW, based on the number of applications under the cap. Implement default degression. Introduce sustainability criteria and feedstock restrictions for new AD plants. Implement deployment caps and contingent degression for micro-CHP.

Will the policy be reviewed? It **will** be reviewed. **If applicable, set review date: July 2016**

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: 26 May 2016

Summary: Analysis & Evidence Policy Option 2

Description: Re-basing generation tariffs for AD plants from January 2017.

FULL ECONOMIC ASSESSMENT

Price Base Year : 2015/16	PV Base Year 2016	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate: 244

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate			5	**73**

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

Smaller new build AD (<500kWe) increases under this option, and the increased resource costs from this outweigh reduced resource costs associated with a decrease in larger new build AD (>500kW), leading to a monetised cost.
There is a small net reduction in AD electricity generation. Since this is a relatively small amount, in the central case it is assumed to be replaced by the marginal electricity technology of gas. There is monetised resource cost increase associated with this gas (incorporating the carbon costs associated with this gas generation).
There is also a small net reduction in AD heat generation, which is assumed to be replaced by heat from a mixture of gas, gasoil and biomass-fired boilers. The extra carbon costs associated with this alternative heat generation are a monetised cost.

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

Administrative costs related to sustainability criteria and feedstock restrictions are likely to increase, although these have not been quantified. Air quality is also likely to deteriorate due to increased fossil-fuel energy generation because of the decreased deployment of large-scale installations. There are also likely to be some

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate			22	**317**

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

The net increase in AD heat generation is made up of an increase in heat from smaller AD offset by a decrease in heat from larger AD. The resource cost reductions associated with having less heat from alternative sources due to having more smaller-scale AD, are greater than the resource cost increases associated with having more heat from alternative sources due to having less larger-scale AD. This leads to a net monetised benefit of lower alternative heat resource costs.
The policy of feedstock restrictions and sustainability criteria is estimated to lead to a monetised benefit through lower greenhouse gas emissions.

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

There are macroeconomic benefits related to lower electricity bills which are non-monetised. There are also likely to be some wider system benefits which are not considered in the NPV.

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

The analysis is based on a revised set of assumptions for <5MW AD plants. This includes capital and operating expenditure, feedstock price and usage, technical assumptions such as load factors and heat-to-power ratio, fossil fuel price projections to estimate bill savings and investors hurdle rates. There is a large degree of uncertainty in a number of our assumptions, in particular for gate fees, bankability of heat, CHP costs, and digestate disposal costs. There is a risk that at the proposed tariffs, there will be limited deployment due to non-financial factors placing barriers to deployment, such as restricted access to heat-demand and RHI payments, and limited food-waste supply.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs:	Benefits:	Net:	Yes/No	IN/OUT/Zero net cost

Summary: Analysis & Evidence Policy Option 3

Description: Re-basing generation tariffs for AD plants from January 2017.

FULL ECONOMIC ASSESSMENT

Price Base Year : 2015/16	PV Base Year 2016	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: 249	High:	Best Estimate: 261

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High			5	**70**
Best Estimate			4	**52**

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

The net AD electricity generation foregone is a relatively small amount, and so in the central case it is assumed to be replaced by the marginal electricity technology of gas. There is monetised resource cost increase associated with this gas (incorporating the carbon costs associated with this gas generation).
The net AD heat generation foregone is assumed to be replaced by heat from a mixture of gas, gasoil and biomass-fired boilers. The extra resource costs and carbon costs associated with this alternative heat generation are also monetised costs.

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

Administrative costs related to sustainability criteria and feedstock restrictions are likely to increase, although these have not been quantified. Air quality is also likely to deteriorate due to increased fossil-fuel energy generation because of the decreased deployment of large-scale installations. There are also likely to be some

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High			22	**318**
Best Estimate			21	**314**

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

New build AD capacity decreases under this option, along with AD generation. This leads to a monetised reduction in AD resource costs.
The policy of feedstock restrictions and sustainability criteria is estimated to lead to a monetised benefit through lower greenhouse gas emissions, even netting off the estimated increase in greenhouse gas emissions due to lower deployment of AD.

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

There are macroeconomic benefits related to lower electricity bills which are non-monetised. There are also likely to be some wider system benefits which are not considered in the NPV.

Key assumptions/sensitivities/risks | **Discount rate (%)** | **Key assum**

The analysis is based on a revised set of assumptions for <5MW AD plants. This includes capital and operating expenditure, feedstock price and usage, technical assumptions such as load factors and heat-to-power ratio, fossil fuel price projections to estimate bill savings and investors hurdle rates. There is a large degree of uncertainty in a number of our assumptions, in particular for gate fees, bankability of heat, CHP costs, and digestate disposal costs. There is a risk that at the proposed tariffs, there will be limited deployment due to non-financial factors placing barriers to deployment, such as restricted access to heat-demand and RHI payments, and limited food-waste supply.

BUSINESS ASSESSMENT (Option 3)

Direct impact on business (Equivalent Annual) £m:	In scope of OIOO?	Measure qualifies as

Costs:	Benefits:	Net: Assumed 0	Yes/No	IN/OUT/Zero net cost

Contents

1. Overview

1.1. The UK is committed to producing 15% of its energy from renewable sources by 2020, in line with the EU Renewable Energy Directive (RED). As part of this commitment, the ambition is to generate at least 30% of electricity from renewable sources. The Feed-in Tariffs (FITs) scheme, which supports renewable electricity generation projects up to and including 5 MW electrical output, is one of the policies introduced by the Government in order to achieve this ambition.

1.2. As per the terms of the European Commission's State aid approval for FITs, the Government must review the performance of the scheme every three years. The latest review took place in 2015 and reviewed support levels for hydro, solar PV and wind. The review did not cover tariff levels for anaerobic digestion (AD) and micro-combined heat and power (micro-CHP), and the Government committed to review these technologies shortly after the conclusion of the 2015 review.

1.3. Subsidies for low-carbon electricity generation are paid for through additions to consumer bills. This includes payments made through FITs, the Renewables Obligation (RO), Contracts for Difference (CfDs) and Final Investment Decision Enabling for Renewables (FIDeR). In order to limit the impact on consumer bills, the Government set a limit on the annual low-carbon energy subsidy expenditure which could be collected from consumers, known as the Levy Control Framework (LCF).

1.4. At the outset, it was envisaged that the LCF would reach £7.6bn[1] by 2020/21; however, projections in July 2015 were considerably higher at £9.1bn[2]. As part of the 2015 FITs review, measures were put in place to control future spend under the scheme and limit the impact on consumer bills. A deployment cap of £100m between February 2016 and March 2019 was introduced for solar PV, wind, hydro and AD technologies. Micro-CHP already had an eligibility limit of 30,000 installations. On reaching this 30,000 unit limit, the technology was to become ineligible for FITs. However, spending on micro-CHP was not set within the £100m budget.

1.5. The 2015 review also revised the tariff degression mechanism, which now provides for quarterly default degression in addition to a 10% degression that is contingent on deployment reaching quarterly caps. Details of these changes and the process through which they were designed are outlined in the Impact

[1] 2011/12 prices
[2] 2011/12 prices

Assessment published in December 2015[3], and the related Government Response document[4].

1.6. Throughout this document, cost, benefit and bill saving figures are given in 2016 prices[5], unless otherwise specified. Figures pertaining to the LCF are given in 2011/12 prices as this is the price base on which the LCF is set. Fossil fuel price projections are interim Government estimates made in the first quarter of 2016, following the fall in oil and natural gas market prices.[6]

2. Rationale for intervention

2.1. The changes proposed in this consultation are driven by the European Commission's State aid requirement to reassess the costs of technologies, electricity price forecasts and whether the target rate of return is still appropriate to facilitate deployment while preventing over-compensation.[7]

2.2. Although neither AD nor micro-CHP tariffs were revised at the time of the 2015 Review, the Government declared its intention to consult on both of these in early 2016. Tariffs for AD were not included in the 2015 Review because of the complexities associated with this technology that do not apply to the others, most notably the overlap with the Renewable Heat Incentive (RHI).

2.3. In addition, this consultation aims to ensure:

- Deployment and spending of micro-CHP and AD remain under control and in line with the LCF projections, building on the 2015 Review;
- FIT support for AD is aligned with the RHI to ensure compensation levels are adjusted and requirements under both schemes are in line with each other;
- AD plants comply with sustainability criteria and make use of a sustainable feedstock that complies with the proposed feedstock restrictions.

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3 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/486084/IA_-_FITs_consultation_response_with_Annexes_-_FINAL_SIGNED.pdf

4 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/487300/FITs_Review_Govt__response_Final.pdf

5 Figures were inflated or deflated as necessary using the retail price index (RPI.

6 These were published in Annex B of the Impact Assessment for the Government Response to the March 2016 Consultation on capacity markets: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf

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

Anaerobic digestion (AD)

2.4. The FITs scheme has been successful in encouraging deployment of AD installations. As of the end of March 2016, 250 installations had been accredited on FITs (including preaccreditations), representing 177 MW of installed capacity. Including FITs-scale sites awaiting full accreditation, the number of sites commissioned by the same date was 270, with an installed capacity of 184 MW. This figure is close to the level projected for 2020/21 in the 2012 comprehensive review of the scheme (220 MW).

2.5. The Government proposes in this consultation to reassess AD tariffs and implement a two-tiered degression mechanism for this technology covering default and contingent degression.

Micro-combined heat and power (micro-CHP)

2.6. This consultation also seeks comments on changes proposed to micro-CHP, which was not included in the 2015 Review. This low-carbon technology was included in the FITs scheme as a pilot, and has seen very low deployment. Since the 2012 FITs Review, deployment of micro-CHP has remained low with only 501 installations supported under the scheme by the end of 2015, with a further 158 commissioned, and awaiting accreditation. Annual deployment rates have continued to fall since 2011 with only 18 installations deployed in 2015.[8]

2.7. Given the very low level of deployment to date, micro-CHP has never moved beyond its pilot phase. Following the changes introduced after the core FITs Review consultation in 2015, the FITs scheme as a whole is now operating under a limited budget of £100m for new spend. The Government must ensure that the available funds are used in a way that offers best value for money for bill payers whilst achieving the scheme's objectives. In light of these factors, the FITs scheme is only able to continue to offer support for early adopters and it is not considered the appropriate vehicle to support the mass roll-out of this low-carbon technology.

3. Policy objectives

3.1. As set out in the 2015 Review, it is the Government's declared intention to ensure that FITs remains open and viable and continues to support new low-carbon generation up to 2018/19. The overall spending cap of £100m for the FITs under the LCF has been set and is not subject to review at this stage.

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

3.2. Expenditure on micro-CHP also needs to be included within the £100m cap to limit the risk of an unexpected surge in LCF spending. This consultation therefore seeks to ensure support for micro-CHP is captured in deployment caps and generators are suitably compensated via their tariffs, while also limiting the risk of an unexpected surge in micro-CHP deployment as this may have an unacceptable adverse impact on the budget.

3.3. In compliance with State aid requirements, the support level for AD has been reassessed to ensure that only the well-sited installations come forward, thus creating a level playing field with the other technologies and ensuring value for money to consumers. The same method has been used as in the 2015 Review, where generation tariffs for the other FITs technologies were calculated based on reference plants defined as installations with high load factors, average deployment costs, and aimed at delivering rates of return in line with the lower end of investors' hurdle rates.

3.4. AD support levels are revisited to ensure that generation tariffs take into account the income and cost streams derived from the generation of heat, and the receipt of RHI payments. Market intelligence and anecdotal evidence indicate an increasing number of AD plants claiming the RHI in addition to FITs as a combined heat and power unit (AD CHP). Utilising the heat as well as the electricity generated by an AD CHP plant is considered to be beneficial as it maximises its overall energy output.[9] This is consistent with the FITs objective of encouraging efficient installations.

3.5. As well as collecting data from industry over the past year, the Government has closely monitored the number of applications coming forward under the cap. There continues to exist in the market a strong appetite to deploy AD. As of the end of March 2016, a total of 21 MW of applications for AD had been submitted to Ofgem since the introduction of deployment caps[10]. This corresponds to over four quarters' worth of deployment caps, indicating that the current tariff levels are attractive to investors. The Government therefore considers this as indication that the current tariff trajectory provides an adequate incentive to deploy.

3.6. To inform proposed changes to the RHI for biogas and biomethane production, the Government conducted an assessment of the impact of using different types of feedstock on the carbon cost effectiveness[11] of AD plants.

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[9] See also the UK Bioenergy Strategy: https://www.gov.uk/government/publications/uk-bioenergy-strategy

[10] https://www.ofgem.gov.uk/environmental-programmes/feed-tariff-fit-scheme/feed-tariff-fit-reports-and-statistics/feed-tariff-deployment-caps-reports

[11] Carbon cost effectiveness measures the net resource costs incurred to save a tonne of carbon (£ per tonne of CO2 saved). It is calculated as the difference in levelised costs between the low-carbon technology and its counterfactual, over the difference in the carbon emissions of the low-carbon technology and its counterfactual.

According to the assessment, using waste as a feedstock achieves higher carbon cost savings in comparison to using crops, in particular in the case of food waste.

3.7. In addition to the above objectives required by State aid, this consultation proposes to introduce sustainability criteria for AD plants, and a restriction to limit the use of crops in line with the proposed changes in the RHI scheme.[12]

3.8. These proposals would reduce the risks of generating energy from material which does not achieve a substantial greenhouse gas saving, or has a detrimental impact on land with a high ecological value. They would also provide a consistent application of sustainability across incentive schemes, to further encourage the use of waste and avoid the risk that AD operators gravitate to the FITs if their feedstock is not likely to meet sustainability criteria in the RO or the RHI.

4. Options considered – AD

4.1. This IA discusses three options for AD:

- Option 1: Do nothing. Under this option, AD generation tariffs continue on the current trajectory.
- Option 2: Revise generation tariffs for AD based on the most recent cost evidence, introduce default degression and introduce sustainability standards and feedstock restrictions.
- Option 3 (preferred option): As Option 2, but also consider the current application pipeline when revising tariffs. This, in effect, means keeping the lower of the tariffs proposed under Option 1 or Option 2 in each band.

Table 1 below shows the generation tariffs proposed under each of the above options. The tariffs shown in Table 2 also take into account contingent degressions that would be triggered under projected deployment in each tariff band.

[12] https://www.gov.uk/government/consultations/the-renewable-heat-incentive-a-reformed-and-refocused-scheme

Table 1. Proposed generation tariffs for AD

between January 2017 and March 2019 (2016/17 prices, p/kWh)

		2017				2018				2019
	Tariff band	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**
Option 1	0 – 250 kW	5.98	5.98	5.98	5.98	5.98	5.98	5.98	5.98	5.98
	250 – 500 kW	5.52	5.52	5.52	5.52	5.52	5.52	5.52	5.52	5.52
	500 kW – 5 MW	5.69	5.69	5.69	5.69	5.69	5.69	5.69	5.69	5.69
Option 2	0 – 250 kW	8.52	8.48	8.43	8.38	8.34	8.29	8.24	8.19	8.15
	250 – 500 kW	9.83	9.78	9.74	9.69	9.64	9.60	9.55	9.50	9.47
	500 kW – 5 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Option 3 (preferred)	0 – 250 kW	5.98	5.95	5.92	5.89	5.85	5.82	5.79	5.75	5.72
	250 – 500 kW	5.52	5.50	5.47	5.45	5.42	5.39	5.37	5.34	5.32
	500 kW – 5 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 2. Modelled generation tariffs for AD including contingent degression,

between January 2017 and March 2019 (2016/17 prices, p/kWh)

		2017				2018				2019
	Tariff band	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**
Option 1	0 – 250 kW	5.98	5.38	4.84	4.36	3.92	3.53	3.53	3.53	3.53
	250 – 500 kW	5.52	4.97	4.47	4.02	3.62	3.26	3.26	3.26	3.26
	500 kW – 5 MW	5.69	5.12	4.61	4.15	3.73	3.36	3.36	3.36	3.36
Option 2	0 – 250 kW	8.52	7.67	6.90	6.21	6.21	6.21	6.21	6.21	6.21
	250 – 500 kW	9.83	8.85	7.96	7.17	7.17	7.17	7.17	7.17	7.17
	500 kW – 5 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Option 3 (preferred)	0 – 250 kW	5.98	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38
	250 – 500 kW	5.52	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97
	500 kW – 5 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

The next section discusses the three options, including the rationale for selecting the preferred option.

Option 1 – Do nothing

4.2. Under this option, AD would continue to be supported at the current tariff levels, subject to the quarterly deployment caps and contingent degression mechanism introduced in the 2015 Review.

4.3. For the purposes of quantifying the impact of this option, it was assumed that deployment caps are hit and contingent degressions are triggered in each quarter of 2016. This is considered to be the most likely scenario, as deployment caps for the first two quarters of 2016 have already been hit, and the queued capacity is sufficient to fill caps for quarters 3 and 4, as well.

4.4. The Government considers this option as suboptimal for the following reasons:

- The terms of the State aid approval for FITs require the Government to periodically revise generation tariffs to ensure that they offer an appropriate rate of return to investors. This requires updating generation tariffs to reflect the latest evidence and implementing a two-tiered degression mechanism. This has already been done for other technologies supported under FITs, but not for AD.

- Current tariffs do not reflect the full body of evidence available on the cost of deployment, which must be considered in order to ensure that the projects supported are those that offer the best value for money.

Option 2 – Revise generation tariffs to reflect the latest cost evidence and introduce default degression

4.5. In this option, tariffs were calculated using the same method as for other technologies in the 2015 Review: targeting the lower-cost installations by using central values for capital expenditure, high values for load factors and the lower end of the range of hurdle rates. The assumptions underpinning the tariff-setting process were updated using the latest available cost evidence as detailed in Annex B: Supporting evidence.

4.6. In addition, assumptions about the technical parameters of our reference AD installations were also updated. The analysis took into account compliance with the proposed sustainability criteria and the proposed feedstock restrictions as detailed in Annex B: Supporting evidence.

4.7. The tariffs calculated are shown in Table 1 above. For the 0-250 kW and 250-500 kW tariff bands, these tariffs are substantially higher than Option 1, but in the 500 kW-5 MW tariff band they are zero.

4.8. The analysis showed that AD generators larger than 500 kW, receiving RHI payments, relying on 100% food waste as their feedstock and receiving a gate fee of £20 per tonne are able to make sufficient revenues to make the deployment of the plant viable and achieve a 9.1% rate of return without support from the generation tariff.

4.9. The calculated generation tariff levels for the 500 kW-5 MW tariff band are very sensitive to the gate fee value assumed for food waste, affecting the amount of revenues food waste AD generators are able to make. A sensitivity analysis is presented in Annex A, which shows the impact of different gate fees values on the generation tariff. The Government notes the large degree of uncertainty of current and future gate fees, and the impact it has in determining support levels. More detail on gate fees is provided in Annex A.

<u>Default and contingent degression</u>

4.10. In accordance with the Government's declared intention to align the treatment of AD with that of other technologies under FITs, this option also includes introducing a default degression mechanism to capture the evolution of costs and revenue streams over the next three years.

4.11. The proposed default degression trajectories are set out in Table 3 below.

Table 3. Proposed default degression rates for AD between April 2017 and March 2019

	2017			2018				2019
	Q2	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**
0-250 kW	-0.5%	-0.6%	-0.6%	-0.6%	-0.6%	-0.6%	-0.6%	-0.6%
250 -500 kW	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.3%
>500 kW	Not applicable (zero generation tariff)							

4.12. The Government does not propose to amend the contingent degression mechanism which was introduced in the 2015 Review. This means that contingent degression of 10% will apply in addition to default degression if a quarterly cap is hit. Contingent degression will affect all future tariffs.

4.13. The Government considers this option as suboptimal for the following reason:

- The analysis does not reflect the latest evidence available from the application pipeline, which suggests that current tariff levels are sufficient to incentivise deployment. Offering higher tariffs in the 0-250 kW and 250-500 kW tariff bands would therefore be in contravention of the Government's State aid obligation and commitment to offer sufficient incentive but not excessive returns.

4.14. The Government notes the large degree of uncertainty around many of the assumptions feeding into the calculation of tariffs according to this methodology, such as gate fees as discussed in Annex A. It would therefore welcome evidence on each of these assumptions through this consultation.

4.15. The strength of the application pipeline suggests that the tariffs calculated under this option are higher than necessary to secure deployment up to the caps for <500kWe installations, and therefore Option 3 considers lower tariffs for these installations.

Option 3 (preferred option) – Revise generation tariffs to reflect the latest evidence and the application pipeline, and introduce default degression

4.16. As set out in the 2015 Review, it is the Government's intention that FITs should remain open and continue to support new low-carbon generation up to 2018/19. However, this must be balanced against the impact on consumer bills and value-for-money considerations.

4.17. Under this option, therefore, the Government proposes to revise generation tariffs so that the current trajectory is maintained for the 0-250 kW and 250-

500 kW tariff bands, and the tariff calculated using the most recent evidence is implemented for the 500 kW-5 MW band.

4.18. The proposed tariff is set at the current tariff trajectory for the 0-250 kW and 250-500 kW tariff bands because there continues to exist in the market a strong appetite to deploy AD. As of 13 May 2016, the deployment caps for the first two quarterly tariff periods of 2016 had been met and the queued applications were sufficient to fill deployment caps in the next two tariff periods as well, with the queue extending into the first quarter of 2017[13]. This would seem to indicate that tariff levels currently available are attractive to investors, and the Government therefore believes that the current tariff trajectory provides an adequate incentive to deploy.

4.19. In the 500 kW-5 MW tariff band, the Government proposes a zero generation tariff for the reasons outlined in Section 4.8 above.

Default and contingent degression

4.20. Under this option, the Government proposes the same two-tiered degression mechanism (i.e. both default and contingent degression) as was described for Option 2 above.

Deployment caps

4.21. Under each of the above options, the Government intends to leave quarterly AD deployment caps unchanged, as set out in Table 4 below. Reducing the cap below 5 MW would prevent the largest plants from accrediting, restricting eligibility for plants of 5 MW capacity. The Government therefore proposes that AD caps remain at 5 MW in each quarter until March 2019, and other technologies' caps also remain unaltered. These deployment caps were used when quantifying the impact of each option.

[13] Source: https://www.ofgem.gov.uk/publications-and-updates/fit-deployment-caps-have-been-reached-tariff-period-2.

Table 4. Quarterly deployment caps for AD

	2017				2018				2019
Deployment Caps (MW)	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**
AD (all tariff bands)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

5. Options considered – Micro-CHP

5.1. In terms of micro-CHP, this IA discusses two policy options:

- Option 1: Do nothing. Under this option, both the generation tariff and the overall deployment cap for micro-CHP would remain unchanged.

- Option 2: Implement the changes outlined in the Consultation Document and this Impact Assessment. The proposed changes are:

  - introduce annual deployment caps; and

  - introduce contingent degression to bring micro-CHP in line with other technologies supported by FITs, but do not reduce generation tariffs at this point.

Option 2 is currently the Government's preferred option.

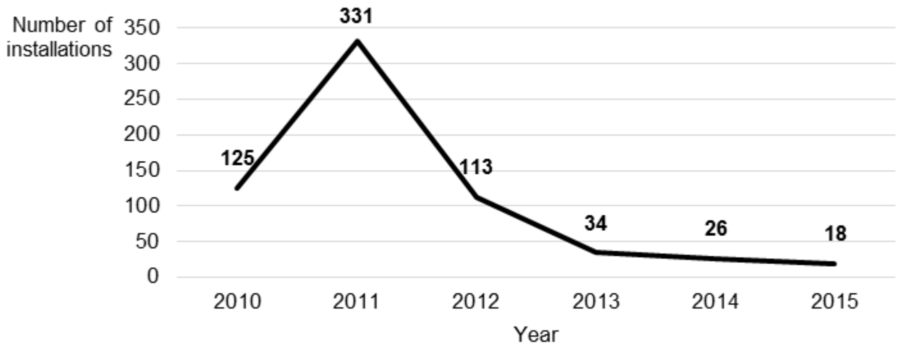
The rest of this section discusses the above two options, including the rationale for selecting the preferred option.

Option 1 – Do nothing

5.2. Under this option, the generation tariff would remain unchanged and, unlike other technologies supported under FITs, micro-CHP would not be subject to periodic deployment caps.

5.3. Although deployment of micro-CHP has been slow (see Figure 1 below), and slowing further after the 2012 FITs Review, there is a risk associated with an surge in micro-CHP deployment.

Figure 1. Number of micro-CHP installations per year



5.4. Such a surge would result in a marked increase in LCF spending on micro-CHP which, in turn, would necessitate revising the deployment caps for other technologies. In an extreme case, reaching the current eligibility limit of 30,000 units would translate into an additional annual spend of £14.5m (in 2011/12 prices). As micro-CHP is not a renewable technology and was included in FITs as a pilot, this would be disproportionate and adversely affect the budget available for other technologies under the FITs scheme.

Option 2 – Introduce annual deployment caps and contingent degression for micro-CHP

5.5. To manage the risk of a surge in deployment, the Government is proposing to complement the overall eligibility limit of 30,000 units by introducing deployment caps similar to those already used for the other technologies supported under the FITs scheme. In the light of historically low deployment figures, current projections indicate that this change will not curb deployment of micro-CHP that would otherwise be coming forward.

5.6. As the capacity of micro-CHP units varies, setting the deployment caps in terms of number of units installed (i.e. the current practice) causes uncertainty in the anticipated spending. Therefore the Government proposes to set the new caps expressed in capacity installed instead. This would also ensure that micro-CHP is treated similarly to the other technologies supported under the FITs.

5.7. Historical deployment figures and the available market intelligence suggest that micro-CHP installations are typically around 1 kW in capacity. If the deployment cap were to be expressed in number of installations instead of capacity, an assumption of 2 kW per unit would need to be used as this is the maximum allowed under the FITs. By setting the cap in terms of capacity, the Government allows a potentially much higher number of units to come forward.

5.8. In order to further align micro-CHP with the other technologies, the Government proposes to cap deployment on a periodic basis. It is the Government's view, however, that quarterly caps are not appropriate for micro-CHP because of the low level and seasonality of deployment. Therefore annual, rather than quarterly, caps are proposed at this stage.

5.9. The Government considers that a budget of £1m until the end of 2018/19 would provide an adequate level of incentive for micro-CHP deployment without putting undue pressure on the deployment caps of the other technologies supported under the FITs. The Government proposes to fund spending on micro-CHP from underspend on other technologies. Contingent degressions have already been triggered in several tariff bands in solar PV, AD and wind, which will reduce the LCF cost of deployment in these technologies in future quarters. This underspend will be sufficient to fund deployment of micro-CHP up to the caps proposed in this Consultation, without the need to adjust deployment caps for the other technologies.

5.10. This £1m spending translates into an overall deployment cap of 3.6 MW over the lifetime of the generation tariffs. It is estimated that this is equivalent to approximately 3,510 units. The breakdown of this overall cap into annual deployment caps is set out in Table 5 below.

Table 5. Annual deployment caps for micro-CHP

Period	**Deployment cap (kW)**	**Number of units (approximately)**
January to December 2017	1,600	1,560
January to December 2018	1,600	1,560
January to March 2019	400	390
Total	3,600	3,510

5.11. The new annual cap would allow a substantial increase in deployment, as it is set at over 90% of the total number of units installed in the past five years of the FITs scheme. This is in line with the Government's intention to keep the FITs scheme open and viable.

5.12. Note that because of historically low deployment, there continues to be a considerable degree of uncertainty around the costs and performance characteristics of micro-CHP and, therefore, on the rate of return achievable at current tariff levels. Market intelligence available to the Government is conflicting as to whether the current tariffs levels are sufficient to incentivise deployment of micro-CHP. Therefore, the Government proposes not to change generation tariffs for micro-CHP at this point. The Government will continue to monitor the market and invites respondents to submit evidence on the relevant aspects of micro-CHP technology in the course of this Consultation.

5.13. The available evidence is not sufficient to suggest that deployment costs are falling, therefore the Government proposes not to introduce default degression for micro-CHP at this time. In order to align with the other technologies, however, each time an annual deployment cap is met, all future generation tariffs will be subject to a 10% contingent degression, in line with the other technologies supported under the FITs.

6. Policy decisions not considered in detail in this IA

6.1. The Impact Assessment only partially assesses the impact of introducing sustainability criteria and feedstock restrictions on the market. The effect on carbon emissions is considered in the cost and benefit analysis but the impact on businesses is not quantified because of the scarcity of available evidence at this stage. The Government expects that the proposed changes would disincentivise the deployment of AD plants which are dependent on a high use of crops. This will result in a greater share of the market to utilise wastes and residues.

6.2. For large agricultural waste plants, this may lead to a reduction in future deployment. This would be the case if the local availability of waste and residues is insufficient to ensure an adequate feedstock supply. If waste and residues are available, it may lead to a feedstock switch. In some cases, it may lead to downscaling plants to better fit with feedstock availability.

6.3. For plants relying on food waste as their primary feedstock, the impact of the proposed policies will depend on the local availability and supply of food waste, and the gate fee at which the food waste is exchanged. Given the limited change in deployment projections since the 2015 Review, the Government does not expect new plants coming forward under the FIT to be able to heavily influence gate fees, although the extent of the impact is unclear at this stage.

7. Monetised costs and benefits for AD

7.1. This section assesses the likely impact of each option for AD. The assessment is based on the assumptions set out in sections 4 and 5 above.

Option 1 – Do nothing

7.2. The costs and benefits of the 'do nothing' option are by definition zero, and this is used as the baseline against which the other options are assessed.

7.3. The tables in this section set out the expected deployment, generation and spending under Option 1. For the purposes of the analysis, it was assumed that deployment caps are hit and contingent degressions are triggered in each quarter of 2016. This is in accordance with the latest evidence on deployment that has come forward since the implementation of the changes set out in the 2015 Government Response.[14]

Option 2 – Revise generation tariffs to reflect the latest cost evidence and introduce default degression

7.4. This option assesses the impact of revising generation tariffs to reflect the latest cost evidence, and introducing default degression for AD, compared against the counterfactual 'do nothing' option.

7.5. Tables below include expected deployment, generation, social welfare analysis, LCF spending and consumer bills, including comparisons with the 'do nothing' option.

Option 3 (preferred option) – Revise generation tariffs to reflect the latest evidence and the application pipeline, and introduce default degression

7.6. This option assesses the impact of revising generation tariffs to reflect the latest cost evidence the current application pipeline, and introducing default degression for AD, compared against the baseline of the 'do nothing' option.

7.7. Tables below include the same information as for Option 2.

Modelling method

7.8. DECC's FITs model forecasts deployment and therefore cost to consumers until 2020/21. As generation tariffs will be phased out at the end of 2018/19, deployment, generation and spend figures are expected to remain unchanged between 2018/19 and 2020/21. For clarity, therefore, the tables below do not cover the period after 2018/19.

7.9. The DECC FITs model performs the following steps to forecast deployment, generation and spend each month:

- Calculate the distribution of the levelised cost[15] 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. Feedstock costs (or revenues), heat bill savings and any RHI tariff payments are considered as part of opex.

[14] Source: https://www.ofgem.gov.uk/environmental-programmes/feed-tariff-fit-scheme/feed-tariff-fit-reports-and-statistics/feed-tariff-deployment-caps-reports

[15] A 'levelised cost' is the average cost over the lifetime of the plant per MWh of electricity generated.

- Calculate the levelised revenue[16] for each technology by tariff band for installations in that month. The levelised revenue includes revenue from the generation tariff, export tariff and electricity bill savings.

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

- 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 the lower of the market barrier and the social barrier[17]. 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.

- Monthly deployment is aggregated into a quarterly figure and, if necessary, constrained to the applicable deployment cap. Future tariffs are recalculated using the default and contingent degression mechanisms.

- The number of installations is estimated as the deployment capacity forecast divided by the capacity of the reference installation in each tariff band.

- Generation is estimated by multiplying the deployment capacity forecast by the applicable load factors.

- Spend is estimated by multiplying the generation forecast by the applicable generation tariffs and adding suppliers' administrative costs. The modelling process is set out in more detail in Annex D of the 2015 FITs Review.[18]

Deployment projections

7.10. The following tables show forecast deployment under each option. There are three deployment scenarios for Options 2 and 3, reflecting uncertainty about deployment. This is modelled through adjustment to hurdle rates, which are assumed to represent some of the uncertainty around costs and cost

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

[17] The social barrier represents people's willingness to invest in renewables; the market barrier represents the likelihood that as deployment of a technology increases, awareness of it grows and supply chains develop.

[18] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/486084/IA_-_FITs_consultation_response_with_Annexes_-_FINAL_SIGNED.pdf

reductions, electricity prices, deployment potential, supply chain barriers and other factors.

7.11. The low deployment scenario uses the high distribution of hurdle rates. A higher hurdle rate increases the minimum rate of return required, so a smaller percentage of the market will be incentivised to install, causing projected deployment to fall. The high deployment scenario uses the low distribution of hurdle rates. All other variables are held constant at central values across the deployment scenarios.

7.12. Table 6 below sets out the deployment projections (in MW) for all three options.

Table 6. Projected annual deployment of AD installations (MW)

Option	Deployment scenario	2016/17	2017/18	2018/19	Impact by 2018/19 against Option 1
Option 1	low	20	19	9	
	central	20	20	13	
	high	20	20	17	
Option 2	low	18	13	13	-4
	central	20	19	14	0
	high	20	20	17	0
Option 3	low	17	8	8	-15
	central	20	17	11	-5
	high	20	20	17	0

7.13. Overall deployment figures mask the complexity in the pattern of deployment changes across the tariff bands in the different Options. In Options 2 and 3, the 500 kW-5 MW tariff band receives zero generation tariff, therefore deployment in this band is substantially lower than in the baseline option. In Option 2, however, the 0-250 kW and 250-500 kW bands receive a higher tariff than in Option 1, prompting more deployment in these bands and making up for some of the shortfall in the 500 kW-5 MW tariff band.

7.14. In the high deployment scenario, developers are assumed to accept a rate of return 2 percentage points below the central estimate (i.e. 7.1% instead of 9.1%). This appears to be sufficient to drive the same level of deployment in Options 2 and 3 as in the baseline, despite the lower tariffs.

Number of installations

7.15. Table 7 below sets out the deployment projections (number of installations) for all three options.

Table 7. Projected annual number of AD installations

Option	Deployment scenario	2016/17	2017/18	2018/19	Impact by 2018/19 against Option 1
Option 1	low	33	31	28	
	central	42	39	39	
	high	52	48	50	
Option 2	low	38	53	55	+55
	central	47	52	48	+27
	high	52	48	49	-2
Option 3	low	31	25	26	-10
	central	42	37	36	-5
	high	48	36	34	-33

7.16. There is an apparent discrepancy between Table 6 and Table 7 above, namely that in some scenarios the projection for deployed capacity is lower than in the baseline scenario but the projected number of installations is higher. This difference is due to the fact that in Options 2 and 3 the 500 kW-5 MW tariff band receives zero generation tariff. As a result, the distribution of installations across the various tariff bands within each quarterly cap changes, with more installations coming forward in the lower capacity bands and fewer installations in the largest one. This results in a lower capacity figure but a higher number of installations.

Generation

7.17. Table 8 below shows the forecast of generation under each Option. The model uses the load factor described in Annex B: Supporting evidence to estimate generation from the deployment projections.

Table 8. Projected new generation from AD installations (GWh)

Option	Deployment scenario	2016/17	2017/18	2018/19	Impact by 2018/19 against Option 1
Option 1	low	159	155	76	
	central	158	158	105	
	high	158	158	135	
Option 2	low	146	106	102	-31
	central	158	150	111	1
	high	158	158	133	0
Option 3	low	136	68	64	-118
	central	158	132	89	-40
	high	158	159	98	-35

7.18. Generation is calculated from deployment projections, so these figures follow a similar pattern: very little difference from the baseline in Option 2 and a slightly larger decrease in Option 3 because of the lower number of large-scale installations.

Calculating the net present value

7.19. The net present value (NPV) is calculated by comparing the combined discounted costs and benefits of intervention (Options 2 and 3), against the combined discounted costs and benefits of no intervention (Option 1).

7.20. The two components of the NPV in each option are:

- Resource costs: These cover the change in the cost to society of generating heat and electricity as a result changes in AD CHP deployment resulting from the policy proposal.

- Carbon emissions: These cover the change in carbon emissions in both the electricity and heat sectors as a result of changes in AD CHP deployment resulting from the policy proposal.

7.21. Although the analysis included in this Impact Assessment is based on the best evidence available to the Government, there is a substantial degree of uncertainty around the net present value estimates, which should therefore be considered only as indications of the most likely impact of the proposed policy changes. One example of this uncertainty is the range of deployment projections, which vary widely across the low to high deployment scenarios under each option. This is not reflected in the CBA, which is based on the central deployment scenarios.

Modelling the impact of intervention

<u>Changes in AD CHP deployment as a result of policy changes</u>

7.22. The Government's modelling suggests that intervention (Options 2 and 3) may impact on the amount of AD CHP deployment under FITs, and therefore AD CHP generation.

7.23. This analysis assumes that any heat or electricity demand that would have otherwise been served by AD CHP output lost as a result of the proposed policy will be met by alternative heat and electricity generation. Similarly, where AD CHP generation is projected to increase, we have assumed a reduction in output from other generators on the heat and electricity networks.

7.24. We have monetised the change in electricity output from other generators on the network in our central scenario using the short-run marginal cost (SRMC) of electricity generation, which is assumed to be a gas plant. This is because the changes in electricity generation are relatively small. Our analysis also includes a scenario where changes in AD CHP electricity output as a result of intervention is monetised using the long-run variable cost (LRVC) of electricity generation[19], which represents an average rather than marginal cost of electricity.

7.25. We have monetised the heat generation that is substituted for or by other sources as a result of intervention. For our analysis, we have assumed that heat output from AD CHP plants greater than 500 kWe is replaced by natural gas. For AD CHP plants equal or smaller than 500 kWe we have assumed a mix of fuel; some would be replaced by natural gas, some by gas oil and some by wood pellets.

7.26. We have also monetised the resource costs of AD CHP generation. These costs include feedstock costs or revenues, digestate disposal costs, capital expenditure inclusive of grid connection, and financing costs[20]. These are all set out in Annex B: Supporting evidence. Financing costs associated with the total capital expenditure are spread over the lifetime of the installation, and are based on a pre-tax real target rate of return for AD CHP of 9.1%.

Introduction of feedstock restrictions

7.27. We have monetised the impact of introducing feedstock rules for CHP generators. Changes in feedstock rules increases the amount of carbon emissions savings as burning methane that would otherwise have been released into the atmosphere as a result of waste decay can reduce greenhouse gas emissions.

7.28. Our analysis assumes that AD CHP plants equal or below 500 kW in size are farm waste fed, using either manure or slurry, while AD CHP plants larger than 500 kW are assumed to be food waste fed.

Option 2

Resource costs

7.29. The figures in **Error! Reference source not found.** show an increase in resource cost over the lifetime of the projects when moving from Option 1 to Option 2. One of the main factors affecting resource costs is the increase in resource costs associated with AD CHP deployment. The increase occurs despite a fall in AD CHP deployment and generation. More small scale plants (equal and below 500 kWe) come forward compared to Option 1 and fewer large-scale plants, and the smaller plants have higher resource costs compared to the large waste-fed plants (greater than 500 kW), which benefit from gate fee revenues. As a result, the composition of AD CHP deployment

[19] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[20] More detail on these costs can be found in section 4 of this impact assessment.

supported under Option 3 turns out to be more costly than Option 1, pushing up resource costs associated with deployment by £71.2m.

Table 9. Resource cost of Option 2 (£m, 2016 prices, Present Value, rounded to 1 d.p.)

Increase in resource costs	**LRVC £69.2**	**SRMC £69.0**
AD CHP deployment	£71.2	£71.2
Electricity grid replacement	£1.1	£0.5
Alternative heat fuel	-£2.7	-£2.7
Transmission and distribution costs	-£0.4	n/a

7.30. In addition, the reduction in amount of AD CHP generation under Option 2 is replaced by electricity generation from the grid at a total cost of £0.8 (net of transmission and distribution costs) when valued at the LRVC; or at cost of £0.5m when valued at the SRMC of the electricity supply.

7.31. Despite the overall fall in AD CHP deployment, more small-scale plants come forward compared to Option 1. This means that less expensive generation needs to be replaced by the alternative fuel mix, which therefore results in a resource savings.

7.32. Resource costs savings from heat that do not need to be replaced are not sufficient to match the large increase in resource costs from AD CHP deployment, which has much higher resource costs. Overall, resource costs under Option 2 increase by £69m.

Greenhouse gas emissions

7.33. Figures in Table 10 show an increase in greenhouse gas savings in Option 2, as a result of the reduction in carbon emissions compared with Option 1. As for Option 3, the main factor affecting emission levels is the introduction of feedstock restrictions, which only allow deployment of plants with waste feedstock. This has a positive impact on the emission levels of Option 2, which are much higher than Option 1, where there are no feedstock rules in place. As a result, Option 2 has much higher greenhouse gas emissions savings associated with AD deployment and amounting to £620.8m.

Table 10. Carbon savings of Option 2 (£, 2016 prices, present value)[21]

Net carbon emissions savings	**£313.4**
Carbon emissions savings under Option 3	
AD CHP deployment with feedstock restrictions	£620.8
Alternative heat fuel	-£0.9
Carbon emissions savings under Option 1	
AD CHP deployment WITHOUT feedstock restrictions	£306.5

[21] Rounded to one decimal place.

7.34. Under Option 2, the decrease in AD CHP generation means that less heat is required from other sources on the heat network. This has a negative impact, decreasing savings by £0.9m. The monetised benefits from a reduction in carbon emissions from other parts of the electricity network is already captured in the cost of electricity contained in the resource costs analysis above, within the values of the LRVC and SMRC.

7.35. Overall, the greenhouse gas emissions savings of Option 2 are much greater than Option 1, resulting in a net carbon savings of £313.4m.

Option 3

7.36. Option 3 is the Government's preferred option.

Resource costs

7.37. Our modelling shows that the impact of pursuing Option 3 would be to reduce the amount of AD CHP deployment and generation compared with the counterfactual. We have therefore monetised the cost savings from a reduction in AD CHP generation, as well as the costs of replacing this generation with other sources on the heat and electricity networks.

7.38. The figures in Table 11 show resource costs from Option 3. The overall impact on resource costs depends on what electricity grid counterfactual is being used. The electricity replacement costs associated with gas costs are valued at £30m under the SRMC scenario. This compares to £43m under the LRVC (net of transmission and distribution costs). When electricity is replaced by the SRMC, there is an overall reduction in resource costs. When electricity is replaced by the long-run grid average, LRVC, the overall result is instead an increase in resource costs. This is because the resource costs associated with gas are expected to be cheaper compared to the long-run grid average.

Table 11. Option 3 resource costs (£m, 2016 prices, present value)[22]

Resource costs	LRVC £8.0	SRMC -£4.4
AD CHP deployment	-£48.6	-£48.6
Electricity grid replacement	£47.2	£30.1
Alternative heat fuel	£14.1	£14.1
Transmission & Distribution costs	-£4.7	n/a

7.39. In addition to the replacement costs associated with electricity generation, heat generation from alternative heat fuels further increases resource costs by £14.1m. This increases resource costs under both scenarios.

[22] Rounded to one decimal place.

7.40. The other main factor affecting resource costs are the costs of deploying AD CHP. Under Option 3, as AD CHP deployment falls, so do the associated resource costs. The reduction in AD CHP also reduces grid variable transmission and distribution costs, as less generation is exported to the grid. Transmission and distribution costs are not applied to the SRMC scenario, simply because while the definition of LRVC includes these costs, the definition of SRMC does not.

7.41. Despite the fall in resource costs associated with less AD CHP deployment coming forward, the resource saving is in part offset by an increase in costs from replacement generation. As mentioned above, the overall impact depends on whether the generation is replaced by the cheaper SRMC or the more expensive LRVC. The impact ranges between a resource savings of £-4.4m under the SRMC, or a resource increase of £8m under the LRVC.

Greenhouse gas emissions

7.42. AD CHP plants have different level of emissions depending on the type of feedstock used. The level of emissions associated with feedstock types are based on the net emissions published in Table C15 of the Renewable Heat Incentive 2016 Impact Assessment.[23] This takes into account direct emissions, methane leakage and saved up-stream emissions for food-waste, crops and manure/slurry. Food-waste and manure/slurry reduce emissions by a factor of 0.604 and 0.458 of kgCO2e per unit of biogas, while crop increase emissions by a factor of 0.145 of kgCO2e per unit of biogas. The emissions levels are then valued at the non-traded carbon price, set out in the Green Book supplementary guidance.[24]

7.43. Emissions associated with electricity from the grid are calculated using generation-based emissions factors. Emissions associated with heat generation from alternative fuels, are based on specific-fuel emission factors. Both of these are found in the Green Book supplementary guidance. The traded carbon prices are then used to value carbons emissions of grid electricity generation, while non-traded carbon prices are used to value alternative heat fuel emissions. Carbon prices are also found in the Green Book supplementary guidance.

7.44. Figures in Table 12 show an increase in greenhouse gas savings in Option 3, as a result of a reduction in carbon emissions compared to Option 1. The main factor affecting emission levels is the introduction of feedstock restrictions under Option 3, which only allows deployment of plants with waste

[23] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505132/Consultation_Stage_Impact_Assessment_-_The_RHI_-_a_reformed_and_refocussed_scheme.pdf

[24] Data tables 1-20: supporting the toolkit and the guidance

feedstock. Contrary to the use of crops, food waste and agricultural waste (either manure or slurry) help in reducing emission levels from AD CHP generation.

7.45. This has a positive impact on the emission levels of Option 3, which are much higher than Option 1 as there are no feedstock rules in place. As a result, greenhouse gas emissions savings under Option 3 amount to £571.6m, compared to £306.5 in Option 1.

Table 12. Carbon savings of Option 3 (£m, 2016 prices, present value)[25]

Monetised value of net carbon emissions savings	**£256.7**
Carbon emissions savings under Option 3	
AD CHP deployment with feedstock rules	£571.6
Alternative heat fuel	-£8.3
Carbon emissions savings under Option 1	
AD CHP deployment WITHOUT feedstock rules	£306.5

7.46. Under Option 3, lost AD CHP generation is replaced by electricity from the grid and a mix of alternative heat fuels. This increases emissions from heat generation by £8.3 as alternative heat fuels must be burnt to generate heat that would have otherwise been generated by ACT CHP in the absence of Government intervention. The monetised impact of additional carbon emissions from electricity is already captured in the cost of electricity contained in the resource costs analysis above, within the values of the LRVC and SMRC. Their impact is nonetheless very small, and greatly outweighed by the carbon savings associated with feedstock restrictions.

7.47. Overall, the greenhouse gas emissions savings of Option 3 are much greater than Option 1, resulting in a net carbon savings of £319m.

Total net present value of Options 2 and 3

7.48. The net present value is calculated for each option by combining the net carbon emission savings with changes in resource costs. The carbon emissions savings represent the benefit of Option 3 and 2 over Option 1, whilst the resource costs represent the additional costs of Option 3 or 2 over Option 1.

7.49. The table below shows that the net carbon emissions savings of Option 3 outweigh the associated resource costs, resulting in a positive net value. The net value ranges between £249m and £261m depending on the value of grid electricity replacing the fall in AD CHP deployment.

[25] Rounded to one decimal place.

Table 13. Net present value of Option 3 (£m, 2016 prices, present value)

Net present value		LRVC	SRMC
(+)	Net carbon emissions savings	£257	
(-)	Resource costs	£8	£-4
	Total	**£249**	**£261**

7.50. Most of the benefits come from the introduction of feedstock rules, which increase the carbon savings of Option 3. There are small resource costs associated with this option, as the resource savings from less AD CHP generation are in part off-set by the costs associated with electricity and heat replacement.

7.51. The table below shows that the net carbon emissions savings of Option 2 out-weigh the associated resource costs, resulting in a positive net value. The net value is £244m in either cases.

Table 14. Net present value of Option 2 (£m, 2016 prices, present value)

Net present value		LRVC	SRMC
(+)	Net carbon emissions savings	£313	
(-)	Resource costs	£69	£69
	Total	**£244**	**£244**

7.52. As in option above, there are large benefits due to the introduction of feedstock rules. Despite the reduction in AD CHP deployment, the composition of AD CHP deployment shifts towards more expensive smaller plants and away from the cheaper large-scale plants, maintaining high resource costs.

7.53. The policies considered in this impact assessment have been appraised over a 23-year period, as both policies impact on AD CHP deployment over three delivery years (2016/17, 2017/18 and 2018/19) and AD CHP plants are have an assumed lifetime consistent with cost data produced for the Government by WSP Parsons Brinckerhoff[26].

7.54. The NPV was calculated using a discount rate of 3.5% in accordance with the Green Book.[27]

[26] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF

[27] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf

Distributional impacts

Direct costs to consumers through the Levy Control Framework spending

7.55. Generation tariff payments and deemed export payments are passed on to consumers and consumer bills (both households and other users) through the levelisation process.[28] This counts as spending under the LCF. Table 15 below shows the LCF impact of each option.[29]

Table 15. Full-year spend from deployment at end of year (£m, 2011/12 prices)

Option	Deployment Scenario	2016/17	2017/18	2018/19	Impact by 2018/19 against Option 1
Option 1	low	206	212	214	
	central	206	212	215	
	high	206	212	216	
Option 2	Low	204	208	211	-8
	Central	204	207	209	-12
	High	204	206	208	-15
Option 3	Low	204	205	206	-18
	Central	204	205	206	-17
	High	204	205	205	-19

7.56. For comparison, the FITs budget for new spend across all technologies in £100m, within an overall LCF envelope of £7.6bn in 2020/21.

7.57. Savings against the "do nothing" counterfactual Option 1 are realised even when deployment is higher because in Options 2 and 3 the 500 kW-5 MW tariff band receives zero generation tariff (as opposed to positive in Option 1) and in Option 2 the 0-250 kW and 250-500 kW tariff bands also receive lower tariffs than in Option 1.

Direct bill impact on consumers

7.58. Table 16 below shows the direct impact of the proposed changes under Options 2 and 3 on bills across households on average and on illustrative business user types, relative to the same scenario under Option 1. These figures do not include any indirect impacts of FITs deployment on the wholesale electricity market, so-called merit order effects, which also affect final consumer bills.

[28] https://www.ofgem.gov.uk/sites/default/files/docs/2015/06/feed-in_tariff_guidance_for_renewable_installations_v9_0.pdf

[29] No assumptions have been made about the value of deemed exports. This is a simplification which is expected to have a small impact.

Table 16. Bill impacts on consumers (£ and % difference from Option 1 in 2018/19, in 2011/12 prices)[30]

Option	Deployment Scenario	Household		Small business		Medium business		EII with compensation		EII without compensation	
		£/yr	%	£/yr	%	£/yr	%	£/yr	%	£/yr	%
Option 2	Low	0	-1	-3	-1	-110	-1	-150	-1	-1,000	-1
	Central	0	-3	-5	-3	-210	-3	-300	-3	-2,000	-3
	High	0	-4	-6	-4	-270	-4	-380	-4	-2,500	-4
Option 3	Low	0	-4	-7	-4	-300	-4	-420	-4	-2,800	-4
	Central	0	-4	-7	-4	-310	-4	-430	-4	-2,900	-4
	High	0	-5	-9	-5	360	-5	-500	-5	-3,300	-5

7.59. The direct bill impact of the changes proposed in the central deployment scenario of Option 3 (the preferred option) is 3% lower than the bill impact of the same scenario in Option 1 (the ‘do nothing’ option).

8. Non-monetised costs and benefits

Air quality impacts

8.1 Options 2 and 3 involve a reduction in generation from AD, more fossil fuel-fired heat and electricity generation would be expected to increase emissions such as sulphur and nitrogen oxides. This would be an unmonetised social cost. The reduction is only small, however, and the impact would therefore be expected to be marginal.

Macroeconomic impacts

8.2 Option 2 and 3 are expected to lead to lower electricity bills, meaning lower business costs. This would be expected to increase UK competitiveness and increasing consumer real disposable income, representing an unmonetised social benefit.

8.3 There would also be an impact on the AD-related supply chains and those of alternative generation sources, but the net impact is unclear and expected to be negligible.

Wider electricity system impacts

8.4 Changes in FITs deployment relative to Option 1 are generally low across the scenarios but may entail wider system impacts (positive or negative) that are not reflected in the analysis here. These have not been quantified as their magnitude is uncertain.

[30] Figures in this table are rounded to the nearest £ for households and small businesses, to the nearest £10 for medium businesses and EIIs with compensation, and to the nearest £100 for EIIs without compensation.

9. Risks and evidence gaps

9.1 The capital and operational expenditure assumptions used in the analysis are based on limited data, and there remain large uncertainties in the Government's assessment of the costs of AD CHP.

9.2 Due to the limited deployment of micro-CHP, there are still major evidence gaps in the costs and performance characteristics of micro-CHP.

9.3 Limited evidence was used to inform the fuel price counterfactual of heat, and there is a risk that this leads to an over- or underestimating of the true value of heat bill savings.

9.4 Two income streams are likely to change significantly in the future: food waste gate fees, and the marketed value of digestate. Market intelligence and evidence provided in the consultation will help inform analysis of the current and future markets of these commodities and the impact on the deployment of AD plants. Gate fees also remain an area in which the Government has significant evidence gaps. More detail is provided in Annex A.

9.5 There is a risk of overcompensation if on-farm usage is higher than the assumed value, e.g. in the case of intensive pig production. The same risk exists for large installations situated in industrial areas, where all of the electricity generated is used on-site, for industrial processes. Both cases would result in generators achieving higher bill savings, and therefore being overcompensated by the generation tariff.

9.6 There is a risk associated with the assumed value of heat generation accruing to the AD developers' bottom line. The analysis currently assumes that 80% of the theoretical total heat value thus accrues. If this value were lower, the generation tariff would increase to compensate for lower heat revenues, and vice versa.

9.7 The Government is currently assessing the supply of food waste available and how this compares with the expected deployment levels of AD plants relying on food waste for their feedstock. There is in fact a risk that there will not be sufficient food waste in the market to support the expected future deployment of food-based AD plants.

9.8 The change from annual to quarterly contingent degression represents a risk insofar as the quick degression of generation tariffs (and therefore revenues) may stunt future deployment.

9.9 There is a significant risk around attrition. Developers are not required to notify Ofgem if they choose not to deploy an installation that they have received preaccreditation for. As a result, installations that will never deploy may nonetheless remain queued and trigger contingent degressions. This will not become evident until the applicable preaccreditation windows are elapsed. The Government therefore encourages developers to provide early evidence of attrition whenever possible. If Ofgem is notified and a queued application is withdrawn, the Government will have a more accurate reflection of the length of the queue, and this will help offer a fair tariff to other projects awaiting accreditation.

ANNEX A: Gate fees

A.1 A gate fee is the price at which food waste is exchanged between food-waste suppliers, such as local authorities and commercial food distributors, and AD generators. Gate fees are used to estimate the revenues AD operators make from their feedstock use. The gate fee available is highly variable and depends on factors such as geography and demand for food waste for AD.

Gate fee evidence

A.2 We have three main sources of information for the appropriate gate fee for tariff setting: the Biomethane Tariff Review[31], gate fee assumptions based on our current evidence, and Market Intelligence from stakeholders. The evidence is summarised below.

Biomethane tariff review

A.3 Information collected through the 2014 DECC Biomethane Review[32] caused the Government to decrease its gate fee assumption to £15 per tonne for unpackaged food waste.

A.4 Feedback from that consultation revealed a broad consensus that the gate fees presented in the Biomethane Review consultation document were too high (£25 per tonne plus), that contracts offering that level of income are no longer available, and there is limited opportunity to secure the long-term contracts for food waste which have been available in the past. The tariffs modelled in that review were based on gate fees of £15 per tonne for unpackaged food waste sourced from evidence received during the consultation.

A.5 This assumption has been used for the 2016 RHI consultation[33].

Arup study

A.6 In 2015, DECC commissioned Arup to carry out a review of the generation costs and technical assumptions of renewable technologies. This Arup study will be published in due course. As part of their work, Arup assessed the available evidence on gate fees and concluded that WRAP provided the most representative view of current gate fees in the UK. WRAP monitors the gate fee

[31] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384203/Biomethane_Tariff_Review_-_Impact_Assessment_-_Annex_G.pdf

[32] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384203/Biomethane_Tariff_Review_-_Impact_Assessment_-_Annex_G.pdf

[33] https://www.gov.uk/government/consultations/the-renewable-heat-incentive-a-reformed-and-refocused-scheme

and publishes reports indicating the gate fees available from a sample of local authorities and AD operators.[34]

A.7 The values used by Arup rely on a survey conducted among AD operators, reporting a median gate fee of £25 per tonne. This is based on information from eight commercial AD operators that receive food waste from local authorities. To inform the future value of gate fees, Arup based its recommendation on data collected from stakeholders, which expected gate fees to fall to £15/tonne by 2020, the lowest value in Arup's data sample. Arup had no evidence that gate fees will continue to fall beyond 2020 and they are therefore assumed constant after that date.

Market intelligence

A.8 The REA also provided some comments on gate fees as part of the wider FIT Review: "*Some members of the REA have reported that in some cases average gate fees have fallen over the previous years from £18 per tonne, to £12 per tonne, with the expectation that the current year's average will be around £6 per tonne. In addition, it has been reported that for some quality feedstocks, associated gate fees are now moving into negative territory."*

A.9 Stakeholders have also been pointing to increasingly tight feedstock markets and, accordingly, to the downward pressure on gate fees. It has been pointed out that gate fees at the higher end of the reported range of prices often stem from legacy contracts, of which price levels and duration are not achievable anymore in today's market environment.

Analytical impact of gate fee

A.10 DECC realises that gate-fees achievable in today's market fall within a range of prices depending on various determinants, including, but not limited to, the regional demand and supply match, quality of the feedstock required, the source of feedstock, contract duration and transport conditions.

A.11 DECC considers that a reasonable assumption for gate fees would be between £15/t and £20/t, based on the evidence provided at the Biomethane Review and our current evidence.

A.12 For this consultation DECC has used gate fees from the latest information available. Generation tariffs are set on a gate fee of £20 per tonne over the life time of the installation. This is based on the mid-point of the assumption that the current gate fee is £25 per tonne falling to £15 in 2020.

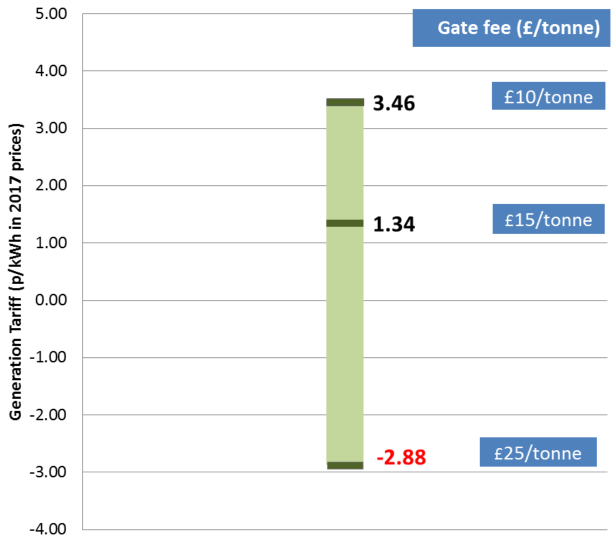
[34] http://www.wrap.org.uk/content/wrap-gate-fees-report-2015-download-summary-report

A.13 The Government is aware of the limitations in the evidence underpinning our gate fees assumption. There are a wide range of gate fees available in the market, and values reported are affected by the local availability of food waste and therefore may not be representative of the whole of the UK. In addition, as the market for food waste has changed over time, gate fees reported in older contracts may not be a good reflection of today's market and of the gate fees that future AD operators are likely to face. Lack of evidence on the date at which contracts are being negotiated does not allow distinguishing the latest contracts from older ones.

A.14 It is the Government's intentions to gather more detailed evidence on the latest gate fees available in the market to ensure generation tariffs are set taking into account the potential revenues of AD plants coming online. We therefore welcome stakeholder views as to the appropriate gate fee for setting the FITs tariff, backed-up with detailed evidence on today's available contracts for food waste.

A.15 The figure below shows the impact of different gate fee levels on the FIT generation tariff. Gate fees of £25, £15 and £10 per tonne are reported as sensitivity.

Figure A1. Sensitivity of generation tariffs (p/kWh) to gate fees (£/tonne)



A.16 The analysis shows that AD generators receiving RHI payments, relying on 100% food waste as their feedstock and receiving a gate fee of £20 per tonne are able to make sufficient revenues to make the deployment of the plant viable and achieve a 9.1% rate of return without support from the generation tariff. Table 17below illustrates the estimated costs and revenues streams for a 2 MW reference plant, based on the assumptions set out in the Impact Assessment. The figure shows the annual expenditure for each cost and revenue stream, with the exception of capital expenditure, which is a one-off payment.

Table 17. Estimated costs and revenues streams for a 2MW AD CHP plant commissioning in 2017 (£ in 2016 prices)

Costs (£/year, except for Capex, £)	
Capex	10,094,397
Opex	1,517,399

Revenues (£/year)	
Gate Fees	1,318,459
RHI payments	285,974
Heat bill savings	402,177
Electricity exports	744,140
Electricity bill savings	0

ANNEX B: Supporting evidence

B.1 FITs generators face both costs and benefits when deploying an AD installation. The costs include:

- upfront costs of the installation;
- on-going costs related to its operation.

The revenues to FITs generators include:

- bill savings for electricity and heat: as some of the electricity and heat generated may be used on site, generators do not need to buy electricity from the grid or other fuels to generate heat;
- revenues for any heat sold as hot water or steam;
- export revenues: when electricity generation is exported back to the grid, generators receive an income from their exports;
- potential gate fees for the use of food waste; and
- the generation tariff.

B.2 There are a set of assumptions made about technical characteristics of individual installations, and the related cost and income streams FITs AD generators face. These are used in the analysis to set generation tariffs and project deployment levels:

- type of installation and related feedstock;
- reference installation size;
- target rate of return;
- capital expenditure (capex);
- fixed and variable operating expenditure (opex), as well as digestate disposal costs, where relevant;
- load factors;
- export fraction;
- revenues or costs associated with feedstock;
- the value of electricity bill savings;
- heat generation and use;
- the value of heat bill savings/ heat sales;
- RHI payments;
- plant operating life;
- technical potential; and
- inflation assumptions.

B.3 DECC appointed WSP Parsons Brinckerhoff, an external and independent engineering consulting firm, to update the data on small-scale renewable generation costs used to calculate generation tariffs, looking at costs and technical assumptions associated with AD technology. The data collection exercise was conducted using questionnaires issued to industry contacts and trade associations, interviews with key stakeholders, and a literature review. WSP Parsons Brinckerhoff produced a report, Small Scale Generation Cost Update[35], showing the findings of their research. It was published alongside the consultation document for the first stage of the FITs Review in August 2015.[36]

B.4 Due to some evidence gaps in the data provided by WSP Parsons Brinckerhoff, the Government investigated and used alternative data sources to fill these gaps and gain more information. Government used alternative data sources on feedstock, digestate disposal, load factors and the specific costs associated with food waste plants and AD CHP.

B.5 To inform assumptions on digestate disposal, the costs of food waste plants and of AD CHP, evidence from the Biomethane Review[37] was used. The Biomethane Review was conducted in 2014 for the purposes of the Renewable Heat Incentive scheme and summarised evidence from over sixty consultation responses, including some AD cost models, and published sources on AD costs, mainly for biomethane plants between 1-6 MW thermal capacities. Information on gate fees from the Biomethane Review was used in combination with the Government's latest evidence. More details on gate fees are found in Annex A.

B.6 The Government currently holds little evidence on mCHP and most of it is anecdotal. Limited information was provided by WSP Parsons Brinckerhoff while several respondents to the core FITs Review consultation provided views and some supporting evidence concerning mCHP. Some additional evidence and information has also subsequently been provided by companies active or potentially interested in the mCHP sector in anticipation of this consultation. However, the information provided represents a very small data sample. The Government therefore invites stakeholders to submit evidence on the costs and technological parameters of this technology to inform our tariff setting and deployment projections.

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35 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF

36 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF

37 https://www.gov.uk/government/consultations/rhi-biomethane-injection-to-grid-tariff-review

Tariff bands

B.7 For AD, the Government does not propose any changes to the existing tariff bands: below or equal to 250 kW; greater than 250 kW and below or equal to 500 kW; greater than 500 kW. Degression bands and cap bands are also left unaltered. Industry has not raised strong views against the current bands, and the sparse available cost evidence does not provide sufficient grounds to reassess the existing bands.

B.8 For micro-CHP, the Government proposes to keep the current single tariff band. The preferred option involves introducing a single-tiered degression mechanism. Unlike other technologies, micro-CHP tariffs would not be subject to quarterly default degression but contingent tariff degression would be triggered each time a deployment cap is hit.

Reference size and type of installation

B.9 In order to set generation tariffs in the FITs Scheme, a reference plant for each technology in each tariff band is defined. The characteristics of the AD reference plants are described below. The characteristics of AD plant will vary across the pipeline of potential new plants. The reference plants represent one point at the lower cost end of that distribution. The distribution of overall AD plant costs is proxied in the Government's FITs deployment model, by assuming variation in capital costs, operating costs and hurdle rates. Only those plant which are economic at the generation tariff (i.e. with lower costs and hurdle rates) are assumed to deploy in each tariff band.

B.10 The Government wishes to encourage the deployment of AD plants with a combined heat and power unit (AD CHP). These plants should make use of the heat generated in a way that complies with the RHI proposed heat uses as set out in the RHI Consultation[38]. The heat generated is intended to satisfy an existing source of heat demand and is therefore referred to as "useful" heat throughout the analysis.

B.11 In order to align with the proposed feedstock restrictions, the AD plant is also expected to rely on waste (either agricultural waste or food waste) as its primary feedstock, and to limit the use of energy crops. The analysis underpinning the generation tariffs is therefore based on 100% waste feedstock, in order to allow deployment of plants that rely entirely on waste to come forward.

B.12 Taking into account the two criteria mentioned above, the analysis assumes that installations with a capacity equal to or lower than 500 kW are farm-based

[38] https://www.gov.uk/government/consultations/the-renewable-heat-incentive-a-reformed-and-refocused-scheme

AD CHP plants using 100% agricultural waste as their feedstock, whilst installations with a capacity greater than 500 kW are AD CHP plants situated in an urban or industrial area that use 100% food waste as their feedstock. These assumptions are reflective of the types of plant the Government wishes to encourage, and are in line with the types of feedstock that are likely to be employed across different plant scales.

Reference plant characteristics

Technology	Tariff band	Reference plant		
		Type	Feedstock	Size
AD CHP	0-250 kWe	farm-based	100% agricultural waste	125 kWe
	250-500 kWe	farm-based	100% agricultural waste	375 kWe
	500-5000 kWe	urban / industrial area	100% food waste	2000 kWe

B.13 The reference plants at different sizes are reflective of the type of feedstock that can be sourced locally. According to evidence gathered in the 2014 Biomethane Review[39], plants operating on food waste generally face additional regulatory costs related to the recycling of food, making feedstock processing more costly than for plants relying solely on crops. Bigger plants with economies of scale are better able to absorb the higher costs of using food waste, and are therefore more likely to use food waste than plants at the small scale. Plants smaller than 500 kWe tend instead to be located in rural areas to make use of the agricultural waste and residues related to their farming activities.

B.14 Although there may be exceptions to these cases, the Government understands that there are very few large AD plants greater than 500 kWe that are able to rely 100% on agricultural waste. Similarly, although the use of food waste is technically possible at the small scale, the Government understands that it may not be economic to deploy.

B.15 The Government is aware that larger plants within the 250-500 kWe tariff band may find it difficult to locally source large amounts of agricultural waste to achieve a 100% waste feedstock. This would require a lot of animals to generate sufficient manure or slurry in the vicinity of the plant. Therefore the reference size assumed for this tariff band, at 375 kWe, is lower than the average plant currently deploying at this scale. Within this scale, an increasing number of 499 kWe plants are coming forward, increasing the reliance on

[39] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384203/Biomethane_Tariff_Review_-_Impact_Assessment_-_Annex_G.pdf

crops in their feedstock mix, which is not in line with the Government's sustainability objectives. The Government is therefore proposing tariffs based on a smaller plant to ensure greater use of agricultural waste.

Hurdle rates / target rates of return

B.16 The target rate of return is set at 9.1% for the reference AD plants, which corresponds to the low end of the hurdle rate range for commercial investors.[40] This is based on the same approach as that used for other technologies, insofar as their target rates of return were based on the lowest intersection point between the hurdle rate ranges for domestic and commercial investors.[41] For AD, since there is no evidence of domestic investors (and there are unlikely to be any such investors), the intersection is simply reduced to the low end of the commercial range.

Capital costs (capex) and operating costs (opex)

B.17 Evidence on capital and operational expenditure is based on two main sources: WSP Parsons Brinckerhoff; and the Biomethane Review. The use of alternative sources is intended to fill evidence gaps on AD, and increase the accuracy of the data.

B.18 For food waste installations in the largest tariff band (greater than 500 kW), the analysis uses the Biomethane Review evidence to reflect specific characteristics of the plant being modelled. These characteristics are:

- Firstly, the type of feedstock used in the generation process. It includes costs components that are specific to the use of food waste, such as pre-treatment of waste, waste digester and landfill tax.
- Secondly, it is a CHP unit; therefore the costs include the heat element.

B.19 For the two smaller bands (i.e. for capacities below or equal to 250 kWe, or greater than 250 kWe and below or equal to 500 kWe), the analysis has relied mainly on data provided by WSP Parsons Brinckerhoff. The Government acknowledges that this data is not differentiated according to the feedstock used, although it is largely based on plants which are farm-based and use a mixture of agricultural wastes and crops. When using data from WSP Parsons

[40] Note that in the Impact Assessment accompanying the December 2015 Government Response, the low end of the commercial hurdle rate range was 9%. The 9.1% value used in this consultation is based on the same dataset, but the methodology used to analyse it has been slightly amended to reflect the data more closely. This brings AD in alignment with the treatment of other technologies in the December Government Response.

[41] Please see paragraphs 5.14 and 5.15 of the Impact Assessment published alongside the FITs Review consultation in August 2015 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/458662/IA_for_FITs_consultation_August_2015_-_FINAL_docx__e-signature_included__v2.pdf); and Annex A of the Impact Assessment published alongside the Government Response in December 2015 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/486084/IA_-_FITs_consultation_response_with_Annexes_-_FINAL_SIGNED.pdf) for more detail on the methodology used to determine hurdle rate ranges and target rates of return.

Brinckerhoff, the Government used the recommended values set out in the consultants' report and updated the costs to account for the additional costs of having a heat unit. WSP Parsons Brinckerhoff data on capex and opex has been uplifted by 14%, based on the difference in costs between and AD and AD CHP plants estimated in the Biomethane Review.

Table 18. Capital expenditure for AD CHP reference plants (£/kW in 2016 prices)

Size	Capex (£/kW)	Grid connection (£/kW)	Total capex (£/kW)
125 kW	7,050	390	7,450
375 kW	7,050	380	7,440
2,000 kW	4,770	380	5,140

Table 19. Operating expenditure for AD CHP reference plants (£/kW/year in 2016 prices)

Size	Opex (£/kW)	Digestate disposal (£/kW)	Total opex (£/kW)
125 kW	840	£0	840
375 kW	660	£0	660
2,000 kW	460	290	750

B.20 Government deviated from the consultants' recommendation when setting the assumption for capital expenditure of plants in the <250 kW and 250-500 kW bands. For these bands, individual observations provided by the consultants were merged into a single dataset combining evidence on all plants below 500 kW capacity. This reflects the Government's understanding that these plants employ similar technologies and face similar unit capital costs. The capex assumption is then based on the median of the merged dataset excluding outliers (outliers being defined as data points at least 75% away from the median)[42]. The median is then uplifted by 14% to capture CHP unit costs.

Additional costs: Grid connection and digestate disposal costs

B.21 Grid connections costs for plants >500 kW are based on our latest evidence from an external consultancy study[43], while for the smaller bands the costs are estimated based on the reference size of the installation, following the WSP Parsons Brinckerhoff method and in line with other FIT technologies.

B.22 The cost of digestate disposal for on-farms plants in the two smaller bands is assumed to be nil, as these plants make use of the digestate as fertilizer for

[42] The method for identifying the central capex values has been suggested by WSP Parsons Brinkerhoff and was used for other technologies. as part of the consultation and Government response for hydro, solar PV and wind.
[43] The study is not yet public, and will be published in due course along with the Generation Costs update.

their land. For plants larger than 500 kW, the analysis assumes plants face a cost for disposing of the digestate. The cost is valued at £10 per tonne, as set out in the Biomethane Review. The value reflects the disposal costs faced by urban plants to transport the digestate elsewhere.

Feedstock

B.23 The Government assumes that agricultural waste is free, as farm-based plants do not pay explicitly for their waste feedstock and it comes from the farm free of charge.

B.24 The analysis assumes that plants larger than 500 kW are being paid for collecting food waste and receive a gate fee for their feedstock. DECC has considered the evidence provided at the 2014 Biomethane Review and gate fee assumptions based on our current evidence. DECC realises that gate fees achievable in today's market fall within a range of prices depending on various determinants, including, but not limited to, the regional demand and supply match, quality of the feedstock required, the source of feedstock, contract duration and transport conditions.

B.25 For this consultation DECC has based its gate fee assumptions on the latest information available. Generation tariffs are set on a gate fee of £20 per tonne over the lifetime of the installation. This is based on the mid-point of the assumption that the current gate fee is £25 per tonne falling to £15 in 2020.This is explored further in Annex A.

B.26 The price and quantity of feedstock required to produce biogas, as well as the electrical efficiency assumptions are set out in the table below.

Table 20. Feedstock prices and technical assumptions

Feedstock	Price (£/t)	Feedstock required per unit of biogas (t/kWh of fuel CV)	Gross electrical efficiency (kWh electric /kWh of fuel CV[44]
Agricultural waste	0	0.28	38% to 42%
Food waste	-20	0.17	38% to 42%

B.27 The feedstock required in the table above is the amount of feedstock required to generate a unit of biogas in the AD process. The higher the gas generation potential of the feedstock, the lower the quantity of feedstock required to generate a given volume of biogas. For example, an AD plant which uses food

[44] The range of electrical efficiency from 38% to 42% reflects the increase in electrical efficiency with plant size. A single value is used for each reference plant: 38% for 125 kW plant, 40% for 375 kW plants and 42% of 2 MW plant.

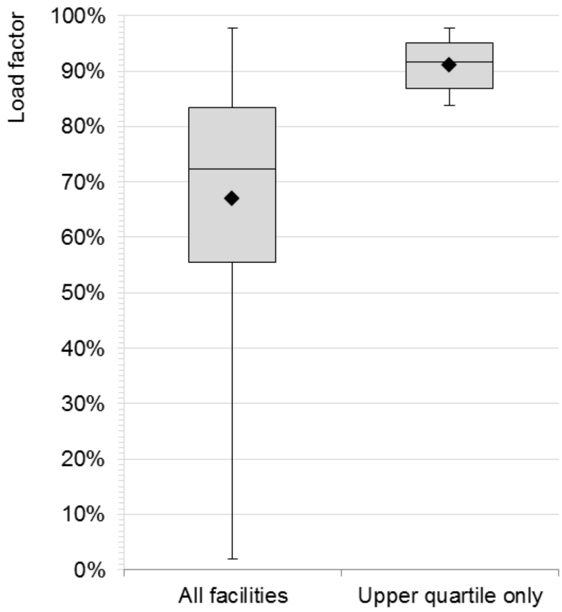
waste as its feedstock requires less feedstock to generate a given amount of biogas compared to agricultural waste.

B.28 Electrical efficiency expresses the conversion efficiency of the electricity generation process as the ratio of the gross electrical output to the energy content of the biogas supplied.

Load factors

B.29 Load factor assumptions are taken from the Green Investment Bank's (GIB)[45] latest report and are set at 91% to reflect the installations with the highest availability. The report demonstrated the continued improvements in the operational performance of AD plants since 2012, and recognised that the gap between the performance of agricultural and food waste facilities had been bridged. The 91% figure is the average of upper quartile annual load factors for agricultural and food waste AD facilities reported over 2014/15. The GIB indicated that the upper quartile sample represents the "best-in-class" operators and that their load factors are in line with those used by industry's financial models.

Figure 2. Load factors reported by GIB



B.30 The load factor reported by the GIB is also in line with the latest statistics produced by DECC and based on observed generations levels.[46]

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[45] http://www.greeninvestmentbank.com/media/44758/gib-anaerobic-digestion-report-march-2015-final.pdf

[46] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/487858/Feed-in_Tariff_load_factor_analysis.pdf

Export fraction, export income and on-site electricity consumption

B.31 Export fraction reflects the Government's assumptions related to the share of electricity generated that is exported to the grid and is used to estimate export revenues. On-site electricity fraction reflects the share of electricity generated that is consumed on-site on the farm to satisfy existing sources of electricity demand. It is used to estimate electricity bill savings.

B.32 Farm-based plants are assumed to make some use of the electricity on-site, whilst large food waste plants are assumed to export almost all of their electricity. To estimate the potential consumption of electricity of on-farm plants, the Government relied on Defra's publication looking at energy uses in the agricultural sector, which provides values for non-electric fuel consumption in a range of farm systems[47]. The values chosen were from the extensive dairy sector.

Table 21. Use of electricity generated (% of electricity generated)

Size	Export	On-site	AD process	Total
125 kW	85%	5%	10%	100%
375 kW	90%	3%	7%	100%
2,000 kW	95%	0%	5%	100%

B.33 The Government acknowledges that some of the electricity generated in the AD process is used within the AD plant for pumps, stirrers and other functions for parasitic use, and is therefore neither exported nor used on-site. This has been factored in to proposed generation tariffs.

B.34 The table below estimates the revenues that the reference plant would be making when producing electricity, based on the values of electricity reported below.

Table 22. Estimated revenues from electricity for AD CHP reference plant commissioning in 2017 (£/year in 2016 prices)

Plant size	Export payments (£/year)	Electricity bill savings (£/year)	Total electricity revenues (£/year)
125 kW	40,401	5,888	46,289
375 kW	128,333	10,599	138,932
2000 kW	722,466	0	722,466

[47] http://sciencesearch.defra.gov.uk/Default.aspx?Menu=Menu&Module=More&Location=None&Completed=0&ProjectID=14497

B.35 An export tariff of 4.91p/kWh has been used to calculate export income. This is the current export tariff referred to in Ofgem “Tariff Tables” for Financial Year 2016/17.[48] The Government is aware that installations can also opt to sell their exported electricity outside of the FITs scheme under Power Purchase Agreements (PPAs), in which case they do not receive the export tariff. Due to the lack of information on the agreed price in PPAs, however, for the purposes of calculating the proposed generation tariff, it is assumed that the export tariff is applied to all installations.

B.36 The following table shows how the reference plant in each of the tariff bands are split across the consumer sectors. The average of the electricity prices for services and for the industrial sector is applied to the 125 kWe and 375 kWe reference installations, whilst the retail industrial price is applied to the 2 MWe reference installation.

Table 23. Consumer sector

Size	Consumer's sector
125 kWe	Services/Industrial
375 kWe	Services/Industrial
2,000 kWe	Industrial

Heat to power ratio, useful heat and heat income

B.37 The AD process produces a biogas that can be combusted directly for heat or converted to biomethane for injection into the gas grid. When the biogas is burned to generate electricity, the heat produced from the engine or from cooling the flue gas can be captured so an AD plant can generate heat as well as electricity. The heat generated can be expressed as a proportion of the electricity generated, known as the heat-to-power ratio. The analysis assumes, across all installations, that for each unit of electricity generated, 1.1 units of heat are produced alongside. The heat-to-power ratio assumption is based on a range of industry data[49].

B.38 The Government acknowledges the limited bankability of heat revenues and seasonal variations in heat demand may reduce the value of heat generation. The analysis therefore assumes, across all installations, that 80% of the theoretical total heat value accrues to the AD investors’ bottom line.

B.39 The heat-to-power ratio and this 80% assumption determine the income streams that FIT generators of an AD CHP plant make on the heat generated.

[48] https://www.ofgem.gov.uk/environmental-programmes/feed-tariff-fit-scheme/tariff-tables

[49] https://www.chpqa.com/guidance_notes/CHPQA_UNIT_LIST.pdf

The analysis assumes that FIT generators have two income streams related to heat generation:

- Heat bill savings/ heat sales: avoided cost of using an alternative fuel to generate heat

- RHI payments: payments coming from the RHI scheme and based on heat uses as proposed in the 2016 RHI consultation[50].

B.40 The table below estimates the revenues that the reference plant would be making when producing heat, based on the assumptions of heat use and values of heat reported below.

Table 24. Estimated revenues from heat for AD CHP reference plant commissioning in 2017 (£/year in 2016 prices)

Plant size	RHI payments (£/year)	Heat Bill Savings (£/year)	Total Heat Revenues (£/year)
125 kW	46,359	30,278	76,637
375 kW	52,058	90,835	142,893
2,000 kW	277,644	390,463	668,107

Heat prices and RHI income

B.41 To determine the value of the heat bill savings, the analysis assumes that the FIT generator would have used an alternative fuel to generate the heat instead of recovering the heat generated in the AD process, known as "counterfactual" fuel. The price of fuel that would have been used in the counterfactual determines the value of the bills savings. In the alternative that the heat is sold, the price is also assumed to be the same as the avoided costs of heat generation.

B.42 Market intelligence available to the Government suggests that plants greater than 500 kW tend to be situated in an urban and industrial area to be closer to their source of feedstock, They have access to the gas grid and therefore Government assumes these plants use natural gas as their counterfactual fuel purchased at the retail industrial price.

B.43 For plants equal or smaller than 500 kW, the analysis assumes that the counterfactual fuel is a mix of the following fuels: natural gas valued at the retail price for industries and services, gas oil and wood pellets. The mix reflects the Government's current understanding of the counterfactual fuels

[50] https://www.gov.uk/government/consultations/the-renewable-heat-incentive-a-reformed-and-refocused-scheme

being used by biogas plants as reported in RHI application process, which includes plants located in remote areas that do not have access to the gas grid.

B.44 A weighted average of the price projections is taken, based on RHI's reported counterfactual fuel uses. A table with assumed price and proportion of fuel making up the mix for farm-based band is set out below.

Table 25. Weight of various fuels for farm-based plants

Size	Fuel	Weight
125 kW-375 kW	Natural gas (industrial/services)	60%
	Gas Oil	22%
	Biomass (wood pellets)	18%

B.45 The price of wood pellets is based on DECC's internal assessment of the biomass market using evidence from the Sutherland Tables.[51]

B.46 In calculating the quantity of fuel substituted, a value of 81% is used as the gross thermal efficiency of the counterfactual boiler, in transforming a unit of the counterfactual fuel into a unit of thermal output. The value is based on the European Commission latest efficiency assessment[52,] and is converted from net to gross using the fuel calorific value tables published by the Government[53].

B.47 To determine the value of the RHI payments, the latest RHI biogas tariff has been applied to the relevant FIT band on the basis of the reference plant size. The RHI tariffs are consistent with current tariff levels that are in place after April 2016.[54]

Plant lifetime

B.48 The analysis assumes a plant life of 20 years, as suggested in the WSP Parsons Brinckerhoff report.

Technical Potential

B.49 The technical potential, indicating the theoretical supply curve of AD plants, is provided in WSP Parsons Brinckerhoff report and illustrated below.

[51] http://www.energysavingtrust.org.uk/domestic/corporate/our-calculations

[52] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:343:0091:0096:EN:PDF

[53] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/447648/DUKES_2015_Annex_A.pdf

[54] https://www.ofgem.gov.uk/environmental-programmes/non-domestic-renewable-heat-incentive-rhi/tariffs-apply-non-domestic-rhi-great-britain

Table 26. Technical potential (GWh)

	Generator's type		
Plant size	**Commercial**	**Developer**	**Total**
125 kW	433	433	867
375 kW	172	689	862
2000 kW	0	1,600	1,600