Explanatory Memorandum to The Environmental Permitting (England and Wales) (Amendment) Regulations 2015

This Explanatory Memorandum has been prepared by The Department for Natural Resources and is laid before the National Assembly for Wales in conjunction with the above subordinate legislation and in accordance with Standing Order 27.1.

Minister's Declaration

In my view, this Explanatory Memorandum gives a fair and reasonable view of the expected impact of The Environmental Permitting (England and Wales) (Amendment) Regulations 2015. I am satisfied that the benefits outweigh any costs.

Carl Sargeant AM

Minister for Natural Resources

23 February 2015

Description

1. The Environmental Permitting (England and Wales) (Amendment) Regulations 2015 transpose Article 14(5)-(9) of Directive 2012/27/EU on energy efficiency ("the Energy Efficiency Directive" – "the EED"), which aims to promote efficiency in heating and cooling. Article 14(5)-(9) specifies that when certain large, new industrial installations are planned or existing such installations are substantially refurbished, a Cost-Benefit Assessment ("CBA") must be undertaken examining the viability of operation in co-generation (Combined Heat and Power – "CHP") mode. Where the CBA finds that co-generation is viable, the installation must operate in that mode.

Matters of special interest to the Constitutional and Legislative Affairs Committee

Use of a 'composite' statutory instrument

2. The purpose of Article 14(5)-(9) is to facilitate the recovery and use of waste heat from electricity power installations and other industrial installations which could otherwise cause pollution. Nearly all of the installations subject to Article 14(5) are already subject to the environmental permitting regime, which provides for an established process for regulating industrial installations across England and Wales. In light of this, and the commonality between the Article 14(5)-(9) provisions and the existing arrangements for considering energy efficiency under the environmental permitting regime, the UK and Welsh Governments are transposing these requirements through an amendment to that existing regime. Use of this existing system allows implementation of the requirements of Article 14(5)-(9) in a manner which limits the additional burdens on operators and regulators.

3. The environmental permitting regime is established by the Environmental Permitting (England and Wales) Regulations 2010 (S.I. 2010/675) ("the 2010 Regulations"), which are composite regulations. This statutory instrument transposes Article 14(5)-(9) by making amendments to the 2010 Regulations. The 2010 Regulations, their predecessors (the Environmental Permitting (England and Wales) Regulations 2007 (S.I. 2007/3538) – ("the 2007 Regulations"), which are the origin of the single regulatory permitting framework that we have today, and subsequent amendments have almost all been made on a composite basis. This composite approach remains appropriate for these Environmental Permitting (England and Wales) (Amendment) Regulations 2015 to ensure a consistent and expedient transposition of Article 14(5)-(9) across England and Wales.

4. This composite statutory instrument applies to England and Wales and is subject to approval by the National Assembly for Wales and by the UK Parliament. Accordingly, it is not possible for this Instrument to be laid or made bilingually.

Consultation

5. In accordance with section 2(4)[1] of the Act, the Welsh Ministers have consulted, amongst others, Natural Resources Wales (NRW).

Late transposition of an EU obligation

6. The deadline for all Member States to have legislation in place for transposing the Energy Efficiency Directive was 5 June 2014. Delays to finalising the regulations following consultation have resulted in this deadline being missed.

[1] as amended by article 4 of, and paragraphs 394 and 395 of Schedule 2 to, the Natural Resources Body for Wales (Functions) Order 2013 (S.I. 2013/755 (W.90).

Confirmation of making of the Pollution Prevention and Control (Designation of Directives) (England and Wales) Order 2015

5. These regulations are made pursuant to section 2 of, and Schedule 1 to, the Pollution Prevention and Control Act 1999 (c.24). Several paragraphs of Schedule 1 are engaged, including paragraph 20(1)(b). That paragraph may only be used in relation to a “relevant directive”. An order designating the Energy Efficiency Directive as a “relevant directive” under paragraph 20(2)(c) of Schedule 1 to the 1999 Act will be made and will come into force before the draft Regulations are made. This order will revoke and replace the current Pollution Prevention and Control (Designation of Directives (England and Wales) Order 2013 (SI 2013/123).

Parliamentary Procedure

6. The draft instrument was laid before Parliament on 17 December 2014.

7. The Joint Committee on Statutory Instruments (“JCSI”) considered this instrument at its meeting on 28 January 2015. In its Twentieth Report of the 2014/2015 session dated 30 January 2015, the Committee reported the draft instrument for elucidation. Department for Environment Food and Rural Affairs provided the required elucidation in a memorandum dated 16 January 2015; that memorandum is at appendix 4 to that report.

8. The draft instrument was debated, and was approved, by the Grand Committee of the House of Lords on 4 February 2015.

Known errors in the draft instrument as laid

9. A number of errors were discovered in the draft statutory instrument as laid before Parliament on 17 December 2014. A decision was made not to withdraw and re-lay the draft regulations. It was considered that there was a significant risk that, if the regulations were withdrawn and re-laid, the opportunity for debate to take place in both Houses of Parliament before prorogation would be lost, causing further delay to the transposition of Article 14(5)-(9) of the Energy Efficiency Directive. Instead, it is proposed that the errors will be corrected in the version of the instrument that is made.

10. The errors that it is proposed will be corrected prior to the making of the statutory instrument are as follows:

    a) In regulation 5(3), in the new sub-paragraph (1A) to be inserted in paragraph 1 of Schedule 8 to the principal Regulations (as defined in regulation 1(3) of the draft regulations), the reference to “paragraph 2 of Section 1.1” should be a reference to “paragraph 1A of Section 1.1”. This is clearly an error as there is no paragraph 2 of Section 1.1 of Part 2 of Schedule 1 to the principal Regulations. This paragraph should refer to the new paragraph 1A as inserted by regulation 4(2), as referenced by regulation 5(2) of the draft regulations.

    b) In regulation 6, which inserts the new Schedule 8A:

        i. The title to regulation 6 reads “Energy Efficiency Directive”, and the title to the new Schedule 8A reads “Energy Efficiency Directive: promotion of efficiency in heat and cooling”. They are clearly in error as they do not accord with the title given to Schedule 8A in the operative provision inserted (by regulation 3 of these regulations) into regulation 35 of the principal regulations. It is proposed to correct these provisions so that Schedule 8A is consistently titled.

ii. in paragraph 1(1), in paragraph (b) of the definition of "installation", reference to "small waste incineration operation" should refer to "small waste incineration plant". This is clearly an error as the defined term in the principal Regulations is "small waste incineration plant" – see regulation 2(1) of the principal Regulations.

iii. in paragraph 1(2)(c) in the reference to the interpretation of installation, the words "within the meaning of Part 1 of Schedule 1" should be removed. This is clearly an error as in the previous paragraph 1(1), there is a definition of "installation" which is not the same as the definition of "installation" within the meaning of Part 1 of Schedule 1 to the principal Regulations due to the inclusion in the former of all small waste incineration plants (the latter includes only small waste incineration plants that are also Part B activities in Section 5.1 of Part 2 of Schedule 1 to the principal Regulations). Paragraph 1(2)(d) also requires this wider definition of "installation".

iv. In the title to the table in paragraph 11, the reference to "Radios" should read "Radius". This is clearly a typographical error.

Legislative background

11. This legislation transposes the requirements of Article 14(5)-(9) of Council Directive 2012/27/EU on energy efficiency and amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC ("the Energy Efficiency Directive").

12. Prior to the coming into force of the 2010 Regulations on 6 April 2010, the environmental permitting regime was set out in the 2007 Regulations (S.I. 2007/3538). The 2007 Regulations created a single regulatory framework in England and Wales for waste management licensing and pollution, prevention and control activities. They transposed the provisions of 11 EU Directives which impose obligations required to be delivered through permits or capable of being delivered through permits. The 2007 Regulations were amended in 2009 to transpose the permitting and compliance requirements of the Mining Waste Directive (Directive 2006/21/EC) and the Batteries Directives (Directive 2006/66/EC) and to revise the provisions relating to exempt waste operations. The amending instruments were S.I. 2009/890, 2009/1799 and 2009/3381.

13. On 6 April 2010 the 2007 Regulations were revoked, subject to some savings and exceptions, and were re-made as the 2010 Regulations with the addition of permitting regimes covering water discharge consenting, groundwater authorisations and radioactive substances regulation. The Environmental Permitting (England and Wales) (Amendment) Regulations 2015 will amend the 2010 Regulations.

14. The power to make the Environmental Permitting (England and Wales) Regulations 2010 and subsequent amendments is contained in section 2 of the Pollution Prevention and Control Act 1999 ("the 1999 Act"). That power was, in relation to Wales, transferred to the National Assembly for Wales, except in relation to offshore oil and gas exploration and exploitation, by the National Assembly for Wales (Transfer of Functions) Order 2005 (S.I. 2005/1958). Those functions are now exercisable by the Welsh Ministers by virtue of section 162 of and paragraph 30 of Schedule 11 to the Government of Wales Act 2006. In accordance with section 2(8) and (9) of the 1999 Act, the Environmental Permitting (England and Wales) (Amendment) Regulations 2015 are subject to the draft affirmative procedure. As they are composite regulations (made by the Secretary of State in relation to England and by the Welsh Ministers in relation to Wales) they must be laid before, and approved by a

resolution of the National Assembly for Wales (and both Houses of Parliament). The reference in section 2(8) to approval by each House of Parliament has effect in relation to exercise of functions by the Welsh Ministers as if it were a reference to approval by the National Assembly for Wales by virtue of section 162 of, and paragraph 33 of Schedule 11 to, the Government of Wales Act 2006.

Purpose & intended effect of the legislation

15. The Environmental Permitting (England and Wales) (Amendment) Regulations 2015 transpose the Cost Benefit Assessment (CBA) and authorisation requirements of Article 14(5) and (7) of Directive 2012/27/EU (the Energy Efficiency Directive), together with the exemptions set out in Article 14(6) and (8), through amendments to the existing environmental permitting regime.

16. The provisions of Article 14(5) aim to promote the adoption of co-generation of heat and power (Combined Heat and Power – CHP) at industrial installations by specifying that a Cost Benefit Assessment (CBA) must be undertaken at the following industrial installations for the following purposes, where the total input is above 20MW thermal:

   a. new or substantially refurbished electricity generation installations, for the purpose of identifying cost-effective opportunities for co-generation of heat and power (Combined Heat and Power – CHP);
   b. new or substantially refurbished industrial installations generating usable waste heat, for the purpose of identifying cost-effective opportunities for co-generation or connection to a heat network; and
   c. new district heating or cooling networks, or new or substantially refurbished energy production installations within existing such networks, for the purpose of identifying cost-effective opportunities for utilising waste heat from nearby industrial installations.

17. Article 14(7) requires that the CBA must be taken into account when the installation is authorised.

18. Article 14(6) exempts peak load or back-up installations planning to operate less than 1,500 hours per year, nuclear power stations, and installations that need to be close to a geological storage site approved under Directive 2009/31/EC (a site for the purposes of geological storage of carbon dioxide). It also allows member states to set thresholds for exempting individual installations where any of a number of proximity and heat demand/supply thresholds are not met. Article 14(8) allows member states to exempt individual installations if there are imperative reasons of a law, ownership or finance for so doing.

19. The Environmental Permitting (England and Wales) (Amendment) Regulations 2015 transpose the Directive requirements principally by inserting a new schedule 8A into the Environmental Permitting (England and Wales) Regulations 2010. Necessary Amendments are also made to other parts of the 2010 Regulations.

Consultation

20. On 10 February 2014, Defra and the Welsh Government published a consultation document seeking views on the transposition of Article 14(5)-(9) of the Directive through amendments to the EPR. The consultation closed on 21 March 2014. In total 20 responses were received from a range of industry bodies, individual companies and regulators. All supported the use of the Environmental Permitting (England and Wales) regulations to transpose the requirements of articles 14 (5)-(9) of the Energy Efficiency Directive. There

were a number of concerns raised by respondents regarding the suitability and practicality of the thresholds applied in the instrument, particularly in reference to the maximum appropriate distance between the installations which would make up the network using waste heat. These concerns have been taken on board, and changes have been made to the regulations to reflect this.

Regulatory Impact Assessment (RIA)

Executive Summary

Introduction and problem under consideration

This is the final stage impact assessment (IA) for the transposition of Articles 14(5)-(9) of the Energy Efficiency Directive (2012/27/EU).

The European Union has introduced the EED as part of the strategy to meet the EU's 20% energy savings objective by 2020. It establishes 'a common framework of measures for the promotion of energy efficiency within Europe[2]'. Chapter 3 of the Directive deals with promoting efficiency in heating and cooling. Articles 14(5)-(9) require that after 5th June 2014 a cost benefit analysis (CBA) must be undertaken for the following installations where the total thermal input is above 20MW:

- new or substantially refurbished electricity generation installations;
- new or substantially refurbished industrial installations generating usable waste heat; and
- new district heating or cooling networks, or a new or substantially refurbished energy production installation within an existing network.

This CBA is intended to identify cost effective opportunities for cogeneration and waste heat recovery. Under the regulation the CBA is a financial analysis reflecting actual cash flow transactions from investing in and operating installations. Where cost effective and technically feasible opportunities are identified, then national authorities are required to authorise only installations developed as co-generation or using waste heat recovery. If an operator chooses not to take such actions, then they must not be granted a permit to operate, except in cases where imperative reasons of law, ownership or finance preclude this. Defra and the Welsh Government have elected to transpose Articles 14(5)-(9) through amendment of the Environmental Permitting (England and Wales) Regulations 2010.

A public consultation was held during February and March 2014. In total 20 responses were received from a range of industry bodies, individual companies and regulators. Additionally Defra met with representatives of industry organisations, environmental regulators, environmental NGOs and other Government departments to discuss the proposals and the IA. This IA has been updated in light of the responses received. The information and opinion received was qualitative in nature. No further evidence was identified to update the quantitative estimates as presented in the consultation stage IA.

The options that have been considered are:

- Option 0 (do nothing): For baseline purposes only as not transposing creates risk of infraction.
- Option 1 (preferred): Transpose and implement requirements with no gold plating. Operators are required to undertake CBAs when developing new installations or significantly refurbishing existing installations, to assess whether alternative cogeneration/waste recovery options are cost-effective. Where cost-effective options are identified, permits for operation will only be granted when these options are taken up except for in exceptional circumstances. Transposition is by amendment of the Environmental Permitting Regulations.

[2] http://ec.europa.eu/energy/efficiency/eed/eed_en.htm

Rationale for intervention and policy objective

The European Commission attributes the fact that the 2020 energy savings objective is unlikely to be met without the EED due to a combination of regulatory and market failures. Specifically for cogeneration and waste heat recovery, it identifies barriers to uptake including high transaction costs and a lack of liquidity in the heat market. Articles 14(5)-(8) should identify cost-effective potential for cogeneration and waste heat recovery, and ensure that such opportunities are not missed.

The policy objective is to transpose Articles 14(5)-(8) of the EED, which should increase the uptake of energy efficiency via cogeneration and waste heat recovery. This will deliver cost savings to those installations and reduce carbon emissions. Transposition is also required to avoid infraction.

Overview of analysis

To estimate the effects of transposition we have first estimated the number of new or significantly refurbished installations that will be affected between 2014 and 2024. This baseline is set out in Section 3. The costs include the cost of undertaking a CBA (which is assumed to be completed by consultants) and the administrative costs for operators and regulators. Benefits have not been monetised because of the lack of evidence to inform such estimates, and uncertainty around the extent to which the CBAs represent additional assessments which operators would not otherwise have done.

Costs

Section 4 of the report describes the assessment of costs that has been undertaken. This focussed on the costs associated with undertaking the CBAs themselves (operator time and independent consultant fees) and the time (and associated costs) for regulators to review them. Table 1 below provides a summary of costs by type of cost and group affected. The central values presented are the midpoint of the low and high ranges. The base year for the present value calculation is 2014 and a discount rate of 3.5% has been applied (following HM Treasury Green Book).

Table 1 Summary of total costs for the period 2014-2024 (PV, £m 2013 prices)

	Low	Central	High
Costs of CBAs – operators	6.2	11.8	17.3
Admin costs – operators	0.2	0.3	0.5
Admin costs – regulators	0.2	0.3	0.4
Total	6.6	12.4	18.2

Benefits

The transposition of Articles 14(5)-(9) of the EED will result in installations in scope making investment decisions on the basis of better information, where operators would not already make use of such information as a matter of course.

The extent of the benefits will also depend on the number of new and refurbished installations carrying out CBAs and the outcomes of these. Recommendations and the choice of options

stemming from the assessments will be site and installation specific, and a number of regulatory and economic drivers will influence any decisions that are subsequently taken.
Benefits have not been monetised because of uncertainty around the extent to which the CBAs represent additional assessments which operators would not otherwise have done and the extent to which additional assessments would lead to additional co-generation development. Where transposition does bring on additional cogeneration and waste heat options, these are likely to be for the more marginal cases where benefits are less substantial.

Competition assessment and direct impact on business

Section 6 describes the competition assessment undertaken for the study. Overall, the proposed requirement to develop a CBA for new and refurbished installations is unlikely to have any adverse impacts on competition. While this IA is out of scope for One-In Two-Out, as it is an EU transposition, we present the direct cost to business with an estimated EANCB of -£1.0m (2009 prices). Other non-quantified impacts are also considered.

Wider impacts

Section 7 describes the potential distributional effects focused primarily on small and micro-businesses, and Section 8 presents the social impact assessment.

No affected plants are expected to fall within the micro-business definition. Whilst some of the affected plants could fall within the small business definition it is considered highly unlikely. An assessment of potential financial implications has shown that possible impacts (if any plants are in the small business category) are likely to be minimal and could be offset by any savings if potential for cogeneration or waste heat recovery are identified and taken forward.

A high level social impact assessment was undertaken and is described in Section 8. The additional costs of compliance are not expected to have implications for employment). There could be impacts on the environment and human health (both positive and negative) as a result of any actions taken in response to the findings of the CBAs.

Uncertainties and limitations

As with any assessment of this nature, there are a number of uncertainties and limitations that should be kept in mind when considering the findings. We have assumed that operators affected are not considering cogeneration options already. The number of CBAs that will be required is considered more uncertain relative to the cost of undertaking them. This is discussed in Section 9 alongside a summary of the main uncertainties and assumptions, which were tested through the consultation.

Conclusions

The transposition of Articles 14(5)-(9) will lead to additional costs being incurred by the operators of industrial installations comprising or incorporating combustion units with a total thermal input exceeding 20 MW. The central estimate is a net cost of £12.4m (present value, for the period 2014-2024), of which £11.8m is the cost of undertaking the CBAs and the remainder are admin costs, split between regulators and operators. Costs to regulators may be recouped through environmental permitting fees and charges.

1. Introduction

1. This impact assessment concerns transposition of Articles 14(5)-(8) of the Energy Efficiency Directive (2012/27/EU) – “the EED” hereafter[3]. This report is structured as follows:

   - Further details of the Articles are covered in Section 2. This also includes an assessment of the need for legislation, its objectives and the stakeholders likely to be affected, and a summary of the consultation;
   - The baseline is defined in Section 3. This explores the number of existing and potential installations likely to be affected;
   - An assessment of costs and benefits associated with the proposals in the relevant articles are contained in Sections 4 and 5;
   - Sections 6, 7 and 8 contain a competition assessment, analysis of distributional and social effects; and
   - An overall summary is in Section 9.

2. Overview

2. This section provides further detail of the requirements of the relevant articles of the EED, including Annex IX as referred to in Article 14(5), which relate to the need to carry out a cost-benefit analysis (CBA) looking at the potential for CHP or use of waste heat when a new plant is constructed or an existing plant is substantially refurbished.

What is cogeneration?

3. Cogeneration integrates the production of electricity and useful heat into one single and energy efficient process. Cogeneration can result in up to a 30% reduction in primary fuel consumption, compared to the separate generation of heat and power. Delivering the same amount of electricity and heat, but more efficiently and using less fuel, lowers energy costs for the operator, reduces CO_2 emissions, and enhances security of energy supply.

What is district heating?

4. District heating supplies heat from a central source directly to homes and business through a network of hot water pipes. Currently it provides less than 2% of the UK’s heat demand. Modelling for DECC suggests that district heating could supply up to 14% of the UK’s heat demand, and be a cost-effective and viable alternative to individual renewable technologies whilst reducing the cost of energy for consumers.

Problem under consideration

5. The European Commission considers energy efficiency to be important in limiting greenhouse gas emissions, reducing dependence on energy imports and in supporting economic growth. The European Union has a headline target to achieve a 20% improvement in energy efficiency by 2020. The EED establishes ‘a common framework of measures for the promotion of energy efficiency within Europe[4]’. It aims to support and accelerate the delivery of the European Union’s target for a 20% reduction in anticipated energy consumption by 2020 and to support further energy efficiency improvements beyond that date. Reductions in energy consumption achieved to date currently fall short of the 2020 target.
6. The requirements in the EED aim to remove barriers and overcome specific market failures in the energy market which impede efficiency in the supply and use of energy. The Directive

[3] http://ec.europa.eu/energy/efficiency/eed/eed_en.htm
[4] http://ec.europa.eu/energy/efficiency/eed/eed_en.htm

sets out various provisions related to: energy efficiency in its buildings; energy obligation schemes, audits and management systems; the provision of consumer information, including on energy bills; and other incentives and penalties.

7. Article 14 of the EED deals with promoting efficiency in heating and cooling. The article stipulates that Member States: identify the potential for high-efficiency cogeneration and efficient district heating and cooling and analyse the costs and benefits of the opportunities that may exist, as well as enacting policies designed to increase uptake, including supporting or accommodating the development of viable projects. Complementary policies that are already in place or being developed are outlined in paragraphs 16 and 17. Specifically, Articles 14(5)-(8) require that after 5th June 2014 a CBA must be undertaken for the following installations where the total thermal input is above 20MW:
    - New or substantially refurbished[5] electricity generation installations;
    - New or substantially refurbished industrial installations generating usable waste heat; and
    - New district heating or cooling networks, or a new or substantially refurbished energy production installation within an existing network.
8. The required CBA is intended to identify cost effective opportunities for cogeneration and waste heat recovery – essentially, CHP and district heating or cooling. Under the regulation the CBA is a financial analysis of the operator's actual cash flow transactions from investing in and operating installations. Where cost effective and technically feasible opportunities are identified, national authorities are required to authorise only installations developed as co-generation or using waste heat recovery. If an operator chooses not to take such actions then they must not be granted a permit to operate, except for in exceptional circumstances where a strong case can be made to justify non-compliance.
9. Defra and the Welsh Government have elected to transpose Article 14(5)-(8) through amendment of the Environmental Permitting (England and Wales) Regulations 2010 – "the EPR" hereafter. This impact assessment examines the transposition of Articles 14(5)-(8) of the EED which is focussed on the 'promotion of efficiency in heating and cooling'.
10. A public consultation on the transposition of Articles 14(5)-(8) was held during February and March 2014. In total, 20 responses were received from respondents including industry bodies, energy companies and regulators. In addition Defra met with representatives of industry organisations, environmental regulators, environmental NGOs and other Government departments to discuss the proposals and the impact assessment. We requested further information to address the evidence formally through the consultation as well as from other departments and agencies. In particular the consultation asked for data to refine the estimates of plants affected and the likely costs incurred, however no additional evidence was identified. A number of useful points were made by respondents that have been built into the discussion in relevant parts of the IA.

Rationale for intervention

11. The European Union has a headline target to achieve a 20% improvement in energy efficiency by 2020, which is intended to address the multiple barriers to energy efficiency uptake. Market failures include high transaction costs, information failures and lack of technical or institutional capacity. These dilute price signals and thus demand for energy

[5] Article 2(44) of the EED defines substantial refurbishment as "*a refurbishment whose cost exceeds 50 % of the investment cost for a new comparable unit*". This is not to be confused with the term "substantial change" that is defined in Article 3(9) of the Industrial Emissions Directive.

savings[6]. The Energy Efficiency Directive was introduced to address the problem that the target would not otherwise be met, which was attributed to market and regulatory failures.

12. Article 14 aims to promote energy efficiency in heating and cooling. Regarding cogeneration, the Commission identify a number of barriers to uptake, including[7]:

    - High transaction costs because of lengthy administrative procedures
    - Additional complexity of cogeneration compared to single generation, as different output is sold to different markets.
    - The lack of liquidity in the heat market because of the limited customer base. This means if a customer is lost it can be hard to sell the heat elsewhere. This possibility of ending up with stranded assets could increase the investment risk and required rate of return.
    - For district heating, the historic prevalence of individual heating solutions is suggested to be a cultural barrier to uptake.

13. Transposition of Articles 14(5)-(8) is expected to promote energy efficiency to the extent that it will provide a consistent approach by which operators will assess different technology options. This could help operators deal with the added complexity of cogeneration, particularly as they will have a standardised template to follow. Where cultural barriers mean that options are not even considered then the requirement to conduct a CBA may also help address these.
14. The more fundamental barriers such as the high transaction costs are unlikely to be addressed by transposition of Articles 14(5)-(8). While the CBA process may help operators deal with the complexity of cogeneration options it will not remove this as a barrier. Limited evidence was identified during consultation to inform our understanding of the market failures. Consultation responses reflected the numerous challenges with cogeneration and waste heat options, but these did not tend to be market failures (for instance, site constraints such as not being near sources of heat demand).
15. The extent to which operators are already conducting CBAs or similar analyses is unclear. If they are already making assessments of different options then the costs associated with transposition will be lower than estimated in this IA. There will however be consistency in the approach that all operators take.

Policy objectives

16. The intention of the EED is to ensure that energy saving options are considered and opportunities are not missed, improving the ability of Member States to meet the energy savings target. Transposition of the EED is now required to avoid infraction. The policy will help us meet our carbon budgets and contributes to the Welsh Government's 2026 vision[8] that 'our distinctive Welsh environment [will be] thriving and contributing to the economic and social wellbeing and health of all the people of Wales'.
17. The overall objective of Articles 14(5)-(8) of the EED is to promote efficiency in heating and cooling, through identification of cost-effective potential for cogeneration and waste heat recovery. These options are, generally speaking, combined heat and power (CHP) and district heating or cooling.
18. There is large untapped potential for energy saving via cogeneration in the UK. DECC modelling estimates that this could be up to 18GWe in 2020 (Ricardo-AEA, 2013). Of this, 8.4GWe is projected to be built by 2020 under existing policy arrangements. There also

[6] IEA (2013) *Energy Efficiency market report 2013*, Executive Summary. Available at http://www.iea.org/Textbase/npsum/EEMR2013SUM.pdf

[7] Commission impact assessment available at: http://ec.europa.eu/energy/efficiency/eed/eed_en.htm, accessed November 2013

[8] At http://www.wales.com/en/content/cms/english/about_wales/wales_fact_file/sustainability/sustainability.aspx

might be considerable potential to recover surplus heat from industry. DECC estimates suggest that there may potentially be 7TWh/yr technically available with a positive business case, with the majority of this potential having a payback period of 2 years of less (DECC, 2014). Implementing regulations obliging plants of >20MW thermal input to consider opportunities to operate as cogeneration and/or supply their waste heat to third parties would mean that this untapped potential could be more quickly realised. Such requirements could also help increase co-ordination between parties in different sectors, who perhaps wouldn't usually be engaged in considering the development of shared heat and power installations.

What is being done to address the wider barriers to uptake of cogeneration?

19. A number of existing policy measures are already in place to help overcome financial barriers to CHP uptake. CHP schemes that are fully or partially certified as Good Quality CHP under the CHP Quality Assurance programme are exempt from the Climate Change Levy on their input fuel and on the qualifying power output generated and used on-site. Further to Budget 2014, CHP will be exempt from Carbon Price Support costs from 1st April 2015 in respect of electricity generated for on-site consumption. Fuel used to generate electricity for export will be liable still. Under the CRC Energy Efficiency Scheme, gas used in CHP installations is exempt from CRC allowance costs. CHP is only liable for CRC costs in respect of electricity produced and consumed on-site. Investment in new CHP capacity can also be eligible for Enhanced Capital Allowances allowing investment in plant and technology to be offset against tax liability on first-year profits. Good Quality CHP schemes are also eligible for preferential business rates. Under the Renewables Obligation, CHP schemes that use renewable fuels are eligible for Renewable Obligation Certificates ("ROCs") on electricity produced. Some types of renewable CHPs (including energy from Waste) are eligible for a higher level of support per MWh electrical output than power-only plant. Biomass CHP is also exempt from the cap on new build biomass power plant capacity. New renewable CHP plants may also opt to receive a Renewable Heat Incentive ("RHI") tariff on useful heat exported on top of ROCs for power-only plant instead of receiving a higher level of ROCs for being CHP.

20. DECC is also developing options for a bespoke policy to support new, good quality, natural gas CHP capacity. Modelling is on-going to show how natural gas CHP will interact with the electricity market to determine its impacts on generation displaced and on carbon emissions. In addition, qualitative research is being undertaken on Gas CHP investment decision making to inform policy development. While this bespoke policy is being developed, DECC are working with BIS to make affordable finance available from the European Structural and Investment Funds to support to new CHP and District Heating projects.

Who is affected?

21. The main stakeholders who will be affected are the operators of planned new plants and those due to be refurbished which fall into one of the relevant categories. They will be required to undertake CBAs in line with the obligations set out in the Directive. The European Commission has published guidance on the Directive as a whole[9] and on Article 14 specifically[10] which address CBAs. Furthermore, the regulatory authorities (SEPA, EA, NRW, NIEA and, for the smallest plants in England, Wales and NI, local authorities) will also be affected by the transposition as they will be required to review and assess the CBAs submitted by operators to ensure they meet the requirements of the legislation. The Environment Agency (EA) is producing guidance for operators on what is required from the

[9] At http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2013:0762:FIN:EN:PDF
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2013:0762:FIN:EN:PDF

[10] At http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2013:0449:FIN:EN:PDF

CBA, and this is being consulted on until 11 April 2014[11]. Potential exemptions are set out in Article 14(6) and include: peak load or backup installations planned to operate less than 1,500 hours/year; nuclear power stations; installations that need to be close to a geological storage site. Member States can also lay down thresholds to exempt individual installations from the provisions. Various thresholds were consulted on, including the maximum distance between a heat source and a heat load, the minimum amount of heat demand for a district heating network to have to be considered, and the minimum amount of heat considered worth recovering. If an installation found insufficient heat demand within the specified area, or could not generate enough useful heat, then it would be exempt from the CBA.

Scoping of Impacts

22. The key impacts associated with the transposition of Article 14(5)-(8) of the EED are likely to be the costs associated with undertaking a CBA (consultancy costs as well as the operator's own costs) and the regulator's costs for reviewing these assessments. The benefits that may be realised are entirely dependent upon the outcomes of the CBA and any decisions that result from it these. There are three potential outcomes to the CBA:

    - It may show cogeneration to have a positive return and the operator may go ahead with the option;
    - It may show cogeneration to have a negative return in which case the operator won't go ahead with the option; and,
    - It may be the case that the CBA shows a positive return but the operator decides not to go ahead with implementing cogeneration (due to other reasons).

    Outcomes will be site specific and linked to a number of other drivers including achieving compliance with other related legislation such as the European Emissions Trading Scheme (EU ETS).

23. To estimate the effects of transposition we have first estimated the number of new or significantly refurbished installations that will be affected between 2014 and 2024. These use DECC projections supplemented where necessary with estimates by AMEC based on the turnover of plants. The baseline number of plants is set out in Section 3. The costs include the cost of undertaking a CBA (which is assumed to be carried out by consultants, although some operators may choose to use their own staff) and the administrative costs for both operators and regulators. Benefits have not been monetised but are discussed qualitatively in Section 5.

Options considered

24. The following options have been considered for assessment:

    - Option 0: Do nothing (baseline). If the UK were not to transpose the requirements of Articles 14(5)-(9) then they would be at risk of infraction. The baseline is set out in Section 3.
    - Option 1 (preferred): Transpose and implement with no gold plating. Operators would be required to undertake CBAs in line with the requirements of the Directive.

25. No further options have been considered realistic. The reasons for transposing through the EPR are set out in Annex B.

[11] The draft guidance for operators alongside an excel template for carrying out the CBA is available at the EA consultation web page: https://consult.environment-agency.gov.uk/portal/ho/ep/h2energyefficiency/h2_energy_efficiency?pointId=2831815

3. Baseline definition

Overview

26. This section sets out the baseline that has been developed for the assessment. It focuses primarily on the number of plants likely to be affected by the transposition of Articles 14(5)-(9).
27. For the purpose of this assessment three rated thermal net input capacity ranges have been considered:
    - 20 – 50 MWth[12] input (equivalent to approximately 6 – 20 MWe or 16 – 45 MWth output);
    - 50 – 300 MWth input (equivalent to approximately 18 – 135 MWe or 40 – 270 MWth output); and
    - >300 MWth input (equivalent to approximately > 105 MWe or >240 MWth output).

Evidence Review

28. This section presents the data used in the IA. It comprises the numbers of plants in each category covered by Article 14(5) over a 10 year timeline (July 2014 to July 2024). Based on the data available, the assessment has been made for the whole UK. A number of data sources for the estimates of plant affected were only available at UK level and with no basis to scale to England and Wales it was considered more prudent to estimate impacts at the UK level. We have sought to identify the total number of installations affected, and have assumed that the operators affected would not be considering cogeneration or waste heat recovery options already. Consultation responses demonstrated that some respondents are already considering these options to some extent. There was an even split between those who felt they already consider cogeneration options fully, those that consider them to some extent, and those that did not give them particular consideration. Transposition is expected to lead to some additional work even for those that consider options fully, for instance liaison with the Environment Agency (EA). The number of installations affected and the costs they incur has not been adjusted for the possibility that some will already be undertaking the necessary action to some extent. As such this represents a conservative approach to the analysis, with costs more likely to be overestimates than underestimates. The assumptions used were tested at consultation and no responses provided additional information with which to refine our estimates. As such, the estimates are unchanged from the consultation stage IA.

New installations

29. Two sets of data were used for estimating the number of new installations:

DECC data

30. The first dataset was provided by DECC and included forecasts for electricity generation and district heating for the UK. No data were provided for installations of 20 – 50 MWth or for industrial thermal plants.
31. Many of the existing coal and oil fired electricity generation plants are close to the end of their operating life and therefore can be expected to shut down and be replaced during the assessment period. According to DECC forecasts, a total of 76 plants for electricity generation and 45 district heating combustion plants are expected to be commissioned

[12] MWth refers to thermal power produced which includes heat lost to the surroundings whilst MWe is solely electrical power produced.

between July 2014 and July 2024. DECC data for electricity plants included annual figures for each thermal input range. Data for district heating was in five-year intervals. It was assumed that plants were being commissioned evenly across the years covered by each interval. Numbers for the years 2014 and 2024 were halved in order to account only for the relevant time period (which starts in July 2014 and runs until July 2024).

32. Original data provided by DECC was based on DECC analysis and the Consultation on the draft Electricity Market Reform Delivery Plan (2013). An upper and lower range of plant numbers was provided for these projections, which has been used in the analysis to calculate the potential range of impacts. The figures include existing plants that close and then re-open using new technology (CCGT[13] upgrades to CCGT with CCS[14] and coal plant conversions to biomass). Installations fitting CCS would be exempt from conducting a CBA under Article 14(6)(c). As CCS on CCGT has yet to be demonstrated on a commercial scale plant, it is assumed that the likelihood of such installations being commissioned before 2014 is low and within the uncertainty range. Therefore no further adjustment to the plant numbers has been made to subtract these possible installations.

Gap filling

33. In order to fill the gap for industrial thermal plants and for installations of 20 – 50 MWth, a second set of data was developed by AMEC based on the total turnover of plants. This was calculated using the number of existing plants in 2014, average operating lifetime of plants and the expected annual growth for each type of fuel.

34. For industrial plants with a rated thermal input capacity above 50MWth the current number of 162 plants was extracted from the LCP Inventory (Defra 2009) and modelled by fuel type and capacity range category. The number of existing plants of 20-50 MWth is estimated to be 451 in an AMEC (2012) study for the European Commission on 1-50 MWth plant. That estimate was based largely on an earlier IA carried out by AMEC (then Entec) in 2009 during the early discussions on the proposed industrial emissions Directive when the Commission was proposing to lower the threshold for combustion installations in Annex I of the Directive to 20MWth (this was subsequently dropped during negotiations). These plants have been assumed to be gas fired for the growth modelling, as this is by far the most widely used fuel type in this size range, and divided evenly into each category (electricity, industry and district heating).

35. The table below shows the estimated number of plants for 2014. Since the DECC dataset only provided estimates for future projections, the following table also includes estimates for existing plant numbers for electricity generation and district heating plants with a capacity greater than 50 MWth (also taken from the Defra 2009 LCP Inventory).

[13] Combined Cycle Gas Turbines are a form of energy generation technology which combines a gas fired turbine with a steam turbine

[14] Carbon Capture and Storage

Table 2. Estimated number of plants in 2014

Plant type	Fuel	Plant numbers 2014[1]		
		20-50 MW[2]	50-300 MW	>300 MW
Thermal - electricity generation	Coal	0	1	18
	Gas	150	31	59
	Oil/diesel	0	11	6
	Biomass	0	2	0
	All	150	46	83
Thermal - industrial	Coal	0	2	0
	Gas	150	156	12
	Oil/diesel	0	3	1
	Biomass	0	1	0
	All	150	163	13
District heating/cooling	Coal	0	0	0
	Gas	150	11	2
	Oil/diesel	0	0	0
	Biomass	0	0	0
	All	150	12	2
Overall total		451	220	98

Notes

1. Values are rounded, hence difference between totals
2. As indicated above the estimate of plant numbers for the 20-50 MW category has been based on AMEC (2012) data. We have assumed an even distribution of installations between each of the categories (electricity generation, industry and district heating). For calculation purposes all plant have been assigned as gas fired, as this is the most common fuel, and because for the results, plant numbers are aggregated by category, without distinguishing fuel type.

Electricity generation plants >50MW

36. The number of new electricity generation plants in the table above could be overestimated. This is because new plants >50MW electrical capacity (approximately 100-150MWth depending on fuel) already have to consider the potential for waste heat recovery as part of the consenting regime. Consents can include conditions for plants to be built in a way so that it can supply heat in the future if a suitable recipient became available. Industrial or district heating/plants are not covered by equivalent requirements. This existing assessment means that transposition of Articles 14(5)-(8) may not result in additional costs for operators and regulators as they could already be covered by the existing regulatory regime.

37. Furthermore, >50MWth power stations currently have to undertake a BAT (Best Available Techniques) assessment as a requirement of the Industrial Emissions Directive. BAT for energy efficiency for combustion plants includes operating as a cogeneration/CHP plant. The assessment justifies the chosen techniques to minimise environmental impact, taking into account their cost and the location-specific characteristics of the installation. If an operator does not meet BAT, the Environment Agency can refuse the permit or may issue a permit which includes pre-operational or improvement conditions.

38. These BAT requirements will effectively be superseded by the combined requirements of Article 14(5) as considered in this IA and Article 14(3) (which is being transposed separately). The installation-level CBA under Article 14(5) requires a financial analysis to determine the financial viability of supplying heat. Article 14(3) considers the wider

economic, socio-economic and environmental benefits of potential cogeneration and district heating schemes.

39. The consultation asked whether existing BAT requirements mean some of the requirements of Articles 14(5)-(8) are already being undertaken. This was to understand better whether transposition is likely to result in additional activity and cost for operators. A number of responses were received. The majority of respondents felt that additional costs resulting from permit/consenting activities are unavoidable, although many seem to be doing some form of assessment already. The permit application process for combustion installations already includes the need to evaluate BAT through which cogeneration would be considered. The additional requirements of Option 1 are not significantly new. As the estimates here assume the CBA represents completely additional activity the cost estimates are considered an overestimate.

Plant lifetimes and annual growth estimates

40. The average operating lifetime of plants provided by DECC is presented in the following table. The DECC estimates are not fuel specific, therefore the lifetimes provided were compared against information derived from DUKES (DECC, 2013) which lists the age of currently operating installations in the electricity generation sector, by fuel type and capacity. The DECC lifetime estimates are considered to be too low for coal and oil fuelled plants, and biomass fired plants >300 MW, since the majority of existing installations are already much older than those estimates. Therefore in these cases an estimate of 50 years, based on the oldest existing plant in DUKES, have been used in the modelling for this assessment.

Table 3. Average operating lifetime

Capacity (MWth)	Lifetime		
	Low	High	Average
<20	20	28	-
20 – 50[1]	-	-	25.5
50 - 300	24	31	27.5
>300	22	25	23.5

Notes

1. No data estimate provided – therefore average calculated using <20 (low) and 50-300 (high)

41. The current average plant age was also taken into account when estimating the number of new build plant that would occur during the 2014-2024 assessment period. This average age of electricity generating 20-50 MWth plant was based on DUKES (DECC, 2013). For industrial and district heating facilities, the current average age was assumed to be half of the estimated lifetime, assuming there is an even distribution of plant of each age (e.g. if the lifetime is assumed to be 28 years the current average age is assumed to be 14 years).

42. The annual growth by fuel type was estimated from DECC Updated Energy Projections (DECC 2013b). For industrial plants, the “Iron and steel” and “Other industrial sectors” categories were used. For district heating, the categories “Domestic”, “Public administration” and “Commercial” were used. CHP plants were assumed to be evenly distributed between the three plant categories considered (electricity, industrial and district heating).

Table 4. Estimated annual growth

Plant type	Fuel	Annual growth %
Thermal - electricity generation	Coal	-17.0
	Gas	4.0
	Oil/diesel	0.0
	Biomass	8.6
Thermal - industrial	Coal	-0.8
	Gas	-1.1
	Oil/diesel	-1.1
	Biomass	11.7
District heating/cooling	Coal	-0.9
	Gas	-0.5
	Oil/diesel	-5.6
	Biomass	12.3

43. Table 5 in the summary section below presents the forecasted number of plants covered by Article 14(5) for the period 2014-2024 based on the DECC forecast and AMEC gap filling[15].

Installations envisaged for substantial refurbishment

44. To estimate the number of plants requiring substantial refurbishment during the period assessed the current number of plants and their average lifetime, presented in Section 3.2.1 above, were considered. Plant lifetime by category, thermal input range and fuel type, was estimated from DUKES (2013) and from information provided by DECC. It was assumed that plants are subject to one substantial refurbishment[16] during their lifetime with the exception of coal and oil plants, as well as large (<300MW) biomass plants, which are assumed to conduct two refurbishments due to the longer lifetime and higher overall capital value of plant.

Baseline summary

45. As detailed above, projections of new installations for electricity generation and district heating plants >50 MWth have been provided by DECC. Projections for new installations in the industrial sector and installations of 20 – 50 MWth in all three sectors have been developed by AMEC based on the current number of plants and the projected changes in fuel consumption. The number of plants requiring substantial refurbishment was calculated by AMEC from the average plant lifetime and making assumptions on the number of refurbishments per plant.

46. The period between July 2014 and July 2024 has been modelled (a ten-year appraisal period, but spanning 11 calendar years). The DECC projections of new installations are variable over the time period. District heating plant projections have been provided for five

[15] Tables 2, 3 and 4 combine to produce the estimate of plant numbers used to fill the gaps in the DECC forecasts (plant in the 20-50MW category and estimates of refurbishments). The calculation for new plant is: (1/(2*(max age plant – average age plant in 2014))) * (1 + annual growth) * (number of plant). For refurbishments it is: (number refurbishments in lifetime * (1/max age of plant) * (number of plant).

[16] Defined as a refurbishment whose cost exceeds 50% of the investment cost for a new comparable unit

year intervals and electricity plant projections per year. The AMEC based estimates have assumed a constant rate of turnover and refurbishment for this period.

47. Table 5 below summarises the forecast for the number of plants covered by Article 14(5). It combines the estimates based on the AMEC model and the DECC forecast. Numbers for 2014 and 2024 reflect the fact that only half the year is considered. Plant estimates are in general constant across the years, apart from new thermal electricity generation plant. The variation here comes from the DECC forecasts from the Electricity Market Reform analysis. Plant numbers based on AMEC's modelling produce constant plant numbers across years.

Table 5. Estimated number of new and refurbished plants by year for the period 2014-2024

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Thermal-Electricity Generation	New	6	13	15	15	17	11	8	12	15	14	10	139
	Refurbishment	6	11	11	11	11	11	11	11	11	11	6	111
Thermal-Industrial	New	6	12	12	12	12	12	12	12	12	12	6	122
	Refurbishment	6	12	12	12	12	12	12	12	12	12	6	124
District Heating	New	4	7	11	11	11	11	11	11	11	11	5	104
	Refurbishment	3	6	6	6	6	6	6	6	6	6	3	64

Notes

1. Numbers are rounded, so may not sum to the totals.

48. To reflect the uncertainty associated with developing any projections, a high and low range of plant number projections has been modelled. These are set out in Table 6 below. The associated uncertainty estimates are presented in the following table, based on AMEC's judgement, or DECC's reported range where indicated. A full statistical uncertainty analysis has not been performed for this assessment. Uncertainties are discussed in greater detail in Section 9.

Table 6 Total Plant Numbers in Central, low and high scenarios for the period 2014-2024

		Central	Low	High
Thermal-Electricity Generation	New	139	122	164
	Refurbishment	111	89	133
Thermal-Industrial	New	122	110	141
	Refurbishment	124	99	148
District Heating/Cooling	New	104	89	124
	Refurbishment	64	51	77

4. Costs

Overview

49. This section sets out the costs that are expected to be incurred as a result of transposition of Articles 14(5)-(8) of the EED. This assessment is focussed on the costs associated with undertaking the CBAs themselves (operator time and independent consultant fees) and the time (and associated costs) for regulators to review them. The cost assessment does not include the potential costs associated with any decisions and subsequent actions that result from the findings of the CBA as these will be site specific and influenced by a number of other drivers such as compliance with other legislation (e.g. EU Emissions Trading Scheme) and other economic factors. As discussed previously, if the CBA shows a positive return to cogeneration/heat recovery then an operator will only be granted a permit if they implement the findings, except for where a strong case can be made to prove why the cost effective option cannot be pursued.
50. The consultation asked whether the cost estimates were reasonable. No responses were received that provided additional evidence of the likely costs to operators or regulators of undertaking and assessing the CBAs. There was varying opinion on the extent to which transposition would lead to additional effort and cost over and above that already incurred by operators. This would affect the total cost estimates and is discussed in the next section.

Additional activity implied by transposition

51. The estimates of affected plant as set out in Section 3 are used to estimate the costs of Option 1. It is assumed that all plants that fall into scope must conduct a CBA and that this represents entirely additional activity. Both of these assumptions can be questioned.
52. Not all plants that fall into scope will have to conduct a CBA. The draft Environment Agency guidance for operators on conducting an Article 14 cost benefit assessment (CBA) involves a number of initial steps to decide whether or not a CBA is required, including identification of existing and potential heat loads in the area. Part of this process will consider whether or not it will be technically feasible for the installation to supply those heat loads. The main reason would be if the demand for or supply of heat was not appropriate, within the radius defined by the EA CBA guidance. The radii range from 2 to 15km depending on the type of installation, grade of heat and amount of heat required or available. Where operators can demonstrate insufficient demand for or supply of heat from within that area, they will be exempt from conducting a full CBA. The estimated number of plants do not take into account the operators that might be excluded as a result of this, because of a lack of data to inform how many might be affected, and because they would still incur a share of the costs determining the nature of the local heat market.

53. Articles 14(5)-(8) are based on the premise that operators are not considering cogeneration and heat recovery options as a matter of course, however where these offer potential cost savings it would be expected that some sort of assessment might be made. This was tested at consultation and whilst the majority of respondents felt transposition would result in additional costs, it was clear that many operators already consider the options to some extent.
54. These two assumptions therefore represent a conservative approach to the cost estimates, with costs more likely to be overestimates than underestimates.

Cost of Compliance

55. The cost of an independent consultant undertaking a cost-benefit analysis has been based on estimates provided by DECC for this study in their initial draft IA for the overall Directive (dated 17/05/12), and AMEC's judgement as a consultancy providing such services to industry. It has been assumed that the requirements, and therefore the cost, will be the same for a new build or a significant refurbishment. Furthermore, the cost is also assumed to be the same for each category (electricity generation, industry and district heating/cooling). However, the cost is assumed to be higher for larger installations due to the additional information that would need to be assessed. There is likely to be variation in cost for different complexity of installation and therefore a high and low cost estimate has been developed. We do not know the frequency with which operators consider the options covered by the CBA, so have assumed that they would not otherwise consider them. It is possible that this will overestimate the cost of compliance. If operators are already considering some of the options we would only count their additional costs, which would be lower than the total estimated here. The estimated costs are presented in the following table.

Table 7. Assumed cost of a CBA (£2013/installation)

Capacity (MW_{th})	Low	High
20-50	10,000	25,000
50-300	15,000	30,000
>300	20,000	40,000

56. The costs above were applied to the low and high range forecast number of new and refurbished installations per year, to calculate a low-low and high-high cost per year. The number of plants affected per year changes through the 2014-2024 period for new >50MWth plant in the electricity generation and district heating categories. For other categories the number of plants, and therefore the costs, are estimated to be constant across the period.

57. The present value of the projected annual costs of undertaking CBA for the period 2014-2024 by plant type are detailed in Table 8 below. The base year for the PV calculation is 2014 and a discount rate of 3.5% has been applied (HM Treasury Green Book). Table 12 shows the yearly profile of the costs to operators of undertaking CBAs.

Table 8. Total PV costs of conducting CBAs for the period 2014-2024

Installation type		£m, 2013 prices (low)			£m, 2013 prices (high)		
		20-50 MW	50-300 MW	>300 MW	20-50 MW	50-300 MW	>300 MW
Thermal - electricity generation	New	0.43	0.58	0.39	1.60	1.28	0.81
	Refurbishment	0.40	0.17	0.47	1.50	0.35	0.94
Thermal - industrial	New	0.39	0.74	0.08	1.48	1.63	0.23
	Refurbishment	0.40	0.60	0.07	1.50	1.20	0.15
District heating/cooling	New	0.40	0.26	0.35	1.49	0.57	1.01
	Refurbishment	0.40	0.04	0.01	1.50	0.09	0.02

Administrative Burden

58. There will be an administrative burden on the operator to prepare information for the CBA, to engage with the provider of the CBA, to submit the CBA to the regulator and to respond to any queries that arise from the application. There will also be time required by the regulator to review the CBA and follow up on any gaps and uncertainties with the regulator. In each case the cost of this administrative burden has been estimated using an assumed associated time requirement and wage rate. The time assumption is based on AMEC's judgement, informed by information from the EA indicating that to review the recent Tilbury Power Station CBA (refurbished biomass - 870MW output power) took the permitting officer 5 days. The wage rates have been taken from the ONS's Annual Survey of Hours and Earnings 2011, assuming the operator time is priced at £20.11 per hour for category 112 Production Manager and the regulator time is £14.51 per hour for category 3551 Conservation and Environmental Protection officers. Wage rates are median values in 2011 prices, inflated to 2013 prices using HMT's GDP deflator, and uplifted by 30% to account for non-wage costs. The resulting wage rate is hence assumed to be £20.88 per hour for operators and £15.06 per hour for regulators.
59. The assumed hours and the resulting costs are presented in the following table. A low-high range is presented to reflect the variation in complexity of different installations.

Table 9. Assumed administrative burden of a CBA (per installation)[17]

Capacity (MW_{th})	Operator time (hours)	Operator cost (£)	Regulator time (hours)	Regulator cost (£)
20-50	14-28	380-760	21-35	411-685
50-300	14-28	380-760	21-35	411-685
>300	21-35	570-950	28-45	548-881

60. The present value of the projected total administrative burden associated with the preparation and review of CBA for the period 2014-2024 is detailed in the table below for both operators and regulators. The base year for the PV calculation is 2014 and a discount rate of 3.5% has been applied (HM Treasury Green Book). Table 12 provides the discounted yearly profile of admin costs.

Table 10. Total present value of administrative burden for operators and regulators for the period 2014-2024 (2013 prices, £m)

		£m (low)			£m (high)		
		20-50 MW	50-300 MW	>300 MW	20-50 MW	50-300 MW	>300 MW
Operator	New	0.05	0.04	0.02	0.14	0.09	0.04
	Refurbishment	0.05	0.02	0.02	0.14	0.04	0.03
Regulator	New	0.05	0.04	0.02	0.13	0.08	0.04
	Refurbishment	0.05	0.02	0.02	0.12	0.04	0.02

Non-quantified costs to business

61. The majority of costs have been quantified, some respondents to the consultation raised concerns regarding what the CBA would include. The EA is separately consulting on

[17] The estimates are unchanged from the consultation stage IA, as no further evidence was identified to refine the estimates. However some errors in the table have now been corrected. These were presented correctly elsewhere in the previous version of the IA, so overall impacts remain the same.

guidance on the CBA to provide clarity on this for operators. Respondents suggested non-quantified costs including some that are expected to be addressed through the EA's guidance or through heat supply contracts, such as who is responsible for providing back-up heat.

62. The requirements could result in investment being deterred if the operators do not pursue the most cost-effective option identified by the CBA. This could occur where operators do not believe the outcome of the CBA. A specific issue highlighted from consultation concerned the issue of who bears infrastructure costs. In establishing a high efficiency cogeneration or district heating scheme, one of the most significant costs will be the infrastructure (pipe work) required to connect the heat source with the heat user. The default case for completing the CBA assumes that this cost will be met by the operator. However where an operator has agreed that the heat user will meet the infrastructure costs they will be required to indicate this and include these costs from the CBA. Another issue identified was regarding the cost of capital that would be used for the CBA. To address this issue the EA CBA guidance provides operators with flexibility to apply alternative assumptions, including for the cost of capital, provided that operators can demonstrate that the EA's prescribed cost of capital rate is inappropriate for their specific case. This flexibility should enable operators to accurately reflect the specific risks for their particular project. Since it is a financial analysis it is expected that monetisation of the relevant impacts will be possible in the CBA and therefore the risk that development is deterred is considered to be low.

63. If CBAs identify cost-effective options which operators are unwilling to pursue, it is possible that some development will be deterred. One possible reason for this would be where operators face capital constraints that mean they cannot afford the option shown to be more cost-effective. As cogeneration and waste heat recovery options are often more expensive than single-generation alternatives, the risk of deterred investment was identified as an important possibility to explore through the consultation. There is an exemption in Article 14 that enables the regulator to permit an option which is not the most cost-beneficial scheme on financial grounds. This means that where operators face capital constraints limiting their ability to go ahead with more expensive cogeneration options they could receive a permit for single generation if they can provide the Environment Agency with evidence of their capital constraints. It is possible a permit could still be refused if evidence was not considered sufficient. The EA are considering how to mitigate the possibility that capital constraints lead to deterred investment, and are exploring this through their consultation.

64. It is possible that development could be deterred for reasons other than capital constraints. The Environment Agency recognises that there will be some factors which are outside of the operator's control, for example if a potential heat recipient has no interest in being supplied with heat from the installation or refuses to provide information to allow the CBA to be properly completed. In this case it is likely to be appropriate to exclude the heat load in question from the assessment, although the Environment Agency will expect the operator to submit evidence to support this. Such situations will be dealt with on a case by case basis by the Environment Agency.

65. An issue that was flagged in consultation responses was whether the CBA process could increase the time taken to complete the permitting process. It is expected that businesses will develop appropriate timescales factoring these new processes in. The EA usually suggest a 13-week turnaround time for their assessments to be completed, although timescales can be raised with the EA in pre-application discussions. It was also noted that cogeneration options could take longer to design and plan than single-generation options. This means that investment could take longer under Option 1 than under the baseline, but these differing timescales can be accounted for in the CBA. As such Option 1 is not expected to delay investment significantly.

66. Additionally it is possible that operators might decide to develop smaller installations than they would otherwise have done, so as to keep below 20MW total thermal input and avoid the need to complete a CBA. This would result in potential benefits from cogeneration being missed and the adoption of sub-optimal sized single generation.

67. Having examined these possible sources of cost to business, it is concluded that unquantified costs to business are unlikely to be significant, as measures have been considered to mitigate potential costs. Further, it is noted that the quantified cost estimates are conservative as they assume no businesses conduct similar CBAs already, and no downward adjustments are made for operators that are not required to conduct a CBA (for instance, if no demand for waste heat is identified).

Wider Costs

68. Air quality impacts of CHP deployment will depend on the specific nature of the additional CHP capacity deployed, the heat and power generation capacity which does not operate as a result of CHP being deployed and the location of both CHP and displaced generation. Although it might be expected that, as a more energy efficient form of generation CHP will reduce air quality emissions this is not necessarily the case. For example reciprocating engine technology has inherently higher NOx emissions per unit of power generated than larger Combined Cycle Gas Turbine (CCGT) power plant and might therefore worsen air quality relative to larger remote power plant, especially if deployed in urban situations. Evidence of this potential air quality cost is provided by recent studies such as "Economic and Air Quality Assessment of CHP and DH[18]". Owing to the dependency of air quality impacts on CHP project-specific factors it is not possible to assess the likely impacts in this Impact Assessment. Other possible non-quantified costs could include technological 'lock-in' to cogeneration or waste heat recovery options. It is unclear how lock-in to these options might differ to lock-in to the technologies operators might have chosen in the baseline. The reliability of CHP compared to grid electricity and gas could also generate some non-quantified costs, although this could be reflected in the CBA.

Summary of costs

69. Table 11 below summarises the estimated costs of option 1. It shows the present value costs per year, in 2013 prices. Central values represent the midpoint of the high and low estimates. The base year for the PV calculation is 2014 and a 3.5% discount rate is used.

[18] December 2012 by Par Hill Research for the Royal Borough of Kensington & Chelsea Available at At: https://static.squarespace.com/static/5006f1cc84ae2a41e73b7aad/t/5152ed55e4b047ba3da65984/1364389205697/Economic%20&%20Air%20Quality%20Impacts%20Of%20CHP%20&%20DH.pdf

Table 11. Profile of discounted yearly costs (PV, £m, 2013 prices)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
CBA costs - operators	0.6	1.2	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1	0.6	11.7
Admin costs – operators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Admin costs - regulators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Total (central)	0.7	1.3	1.4	1.4	1.4	1.2	1.1	1.2	1.2	1.1	0.6	12.4
Low	*0.4*	*0.7*	*0.8*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.3*	*6.6*
High	*1.0*	*1.9*	*2.1*	*2.0*	*2.0*	*1.7*	*1.6*	*1.7*	*1.7*	*1.6*	*0.9*	*18.2*

Notes:

1. Numbers are rounded, so may not sum to the totals.

5. Benefits

70. Where installations would not have considered cogeneration options fully the transposition of Articles 14(5)-(8) of the EED will result in installations in scope making investment decisions on the basis of better information.

71. The extent of the benefits will depend on the number of new and refurbished installations carrying out CBAs, the outcomes of these and the difference they make to investment decisions. Recommendations and the choice of options stemming from the assessments will be site and installation specific. In order to estimate the net benefits to operators of any cogeneration/waste heat recovery options resulting from the regulation, evidence or assumptions for the following would be required:

- an estimate of the likely proportion of installations for which the CBA will identify cost-effective cogeneration or waste heat recovery options;
- an estimate of the number of operators already carrying out CBAs;
- evidence on the marginal cost of developing cogeneration rather than single generation, for installations within the range covered by the amended Regulations;
- further information on the savings that may result from the implementation of cost-beneficial schemes. This requires information on the annual saving to the operator from installing cogeneration rather than single generation (taking into account cost differences, following the previous point), and an understanding of possible variation between plants, sectors and sites; and,
- any evidence on the cost of capital for cogeneration.

72. Evidence to address these gaps was sought during consultation. In particular the consultation sought to understand the extent to which operators already consider cogeneration and waste heat options, and undertake CBAs. However as insufficient information was received benefits have not been estimated. A number of respondents felt that all options are already considered, at least to some degree. A respondent from the glass sector pointed out that the energy intensity of production and large amount of waste heat produced means that energy efficiency and reducing operating costs are top priorities for glass companies. Less information was received from operators where the options might be considered more marginal.

73. Where large cost savings can be achieved through cogeneration or waste heat recovery it is considered likely that operators will already assess such options when making investment decisions. This suggests that better informed investment decisions may result in the more marginal cases, and it will be here that sub-optimal investment decisions may be avoided as a result.

74. The benefits associated with any improvements in energy efficiency resulting from Option 1 include the economic benefits resulting from reduced costs and /or additional income from sale of waste heat. The savings of interest are the net savings, taking into account the associated costs of the technology installed. CHP has higher capital costs compared to single generation, and these higher costs would be included in the CBA. The draft EA guidelines include a recommended cost of capital but also make provision for alternative rates to be used where appropriate and supported by evidence.

75. The CBAs are intended to reflect the costs and benefits to businesses in making an investment, rather than wider impacts. As such it should be possible to estimate the relevant costs and benefits needed to carry out a CBA. This is being tested with stakeholders through the EA's consultation, which includes a draft CBA template alongside the draft guidance. To make an accurate assessment of different options the CBAs will need to use an appropriate cost of capital, to ensure that any cost savings identified are feasible and fully reflect the risk of a specific project. Where heat is sold to others this is important because the limited customer base means there is a risk of stranded capital if a customer is lost. This increases the investment and social risk linked to cogeneration. Using an appropriate cost of capital in the CBA will help reduce the possibility that cost-effective options are wrongly identified. The Environment Agency is producing guidance on the CBA assessments, which is currently out to consultation. The draft guidance proposes a nominal pre-tax cost of capital of 16.5%. There is discretion to adjust this in certain circumstances, provided the operator can robustly justify the use of another discount rate. Assuming that the final content of the EA's guidance does not differ substantively from that being consulted on this provision is considered to provide operators with sufficient flexibility to apply an appropriate cost of capital.

76. It is expected that where cogeneration options offer substantial cost savings operators should already be considering them when making investment decisions. Transposition of Articles 14(5)-(8) is therefore more likely to bring on smaller-scale options where the case is more marginal and for which cost savings are likely to be lower. Given the uncertainty around what additional capacity will result from transposition, the lack of required evidence as set out above, and the likelihood that cost savings will be relatively low, it is considered most appropriate not to quantify possible benefits.

77. Although it has not been possible to quantify benefits, evidence has been sought to provide an indication of the possible cost savings to operators (Box 1). The case studies described in Box 1 have been provided by DECC and are for installations compatible with those that would fall in scope of Articles 14(5)-(8). However as they are case studies they cannot be used to generalise and estimate the possible benefits of transposition. They do however serve to indicate the possible scale of energy cost savings that could occur at the operator level. The annual savings do not take account of the variations in capital and operating costs between single and cogeneration options, so Box 1 does not present net impacts.

Box 1: Case study examples of possible options and their illustrative benefits

This box provides some examples of the possible benefits for operators of developing CHP instead of a single-generation technology. This information has been provided by DECC based on information from their Quality Assurance certification scheme for CHP. These examples are intended to give an indication of the possible scale of benefits that could occur at the operator level. The size of the installations described above is consistent with those in scope of Articles 14(5)-(8). The following equations have been used to calculate the key figures:

$$Annual\ Savings = Energy\ Cost + Fiscal\ benefits$$

(based on predicted 2020 energy and policy prices and 2013 prices)

$$Simple\ Payback = \frac{Marginal\ Capital\ Cost\ (CHP - Alternative)}{Total\ Annual\ Savings}$$

$$CO2\ Saving = Avoided\ Emissions - Additional\ Emissions\ from\ new\ scheme$$

Case 1: <u>CHP installed where the alternative would have been an industrial boiler</u>

Key Assumptions

- CHP Capital and O&M costs are entirely additional
- Displaced Boiler Efficiency = 81% GCV
- The comparison is against a heat only boiler and importing all electricity from the grid.

1.

Case 1a) A 35 MWe gas-fired CCGT CHP providing heat and electricity to the site with surplus electricity exported to the grid.

- Annual savings: £7.44m/year
- Simple payback: 5.8 years
- CO2 Saving: 51,058 TCO2/year

Case 1a) delivers savings of over £7.44m per year. It is considered likely that where operators could make energy cost savings of this scale and with this rate of payback they would be aware of cogeneration options and their benefits already, so would assess them in the baseline.

Case *1b)* A 3.6MWe gas-fired OCGT[19] CHP providing heat and electricity to the site with surplus electricity exported to the grid.

- Annual savings: £1.61m/year
- Simple payback: 2.6 years
- CO2 Saving: 8,194 TCO2/year

Both of these options could enable operators to save money compared to if they had installed an industrial boiler.

[19] Open Cycle Gas Turbine is a form of energy generation technology which uses a gas turbine to generate electricity. It may also recover heat.

Case 2: CHP installed where the alternative would have been a District Heating Boiler

Key Assumptions

- CHP Capital and O&M costs are entirely additional
- Displaced Boiler Efficiency = 81% GCV
- The comparison is against a heat only boiler and importing all electricity from the grid.

2.

Case 2a) A CHP scheme comprising 2 x 2.4MWe gas engines providing heat to the DH scheme with electricity exported to the grid.

- Annual savings: £0.59m/year
- Simple payback: 6.5 years
- CO_2 Saving: 2580 TCO_2/year

3. **Case 2b)** A CHP scheme comprising 2 x 2.3MWe gas engines providing heat to the DH scheme with electricity exported to the grid

- Annual savings: £0.56M/year
- Simple payback: 6.8 years
- CO2 Saving: 2,547 TCO2/year

The operator of the both these installations would be expected to go ahead with the CHP option.

Case 3: CHP installed where the alternative would have been a power only plant

Key Assumptions

- CHP would have a capital cost 20% higher than the power only plant alternative
- The CHP and counterfactual plant would have the same condensing capacity, fuel consumption and O&M cost
- Displaced Boiler Efficiency = 81% GCV

4.

5. **Case 3a)** A 300 MWe gas fired CCGT CHP providing heat and electricity to the site with surplus electricity exported to the grid.

- Annual savings: £4.49M/year
- Simple payback: 8.8 years
- CO2 Saving: 16,632 TCO2/year

6. **Case 3b)** A 50 MWe gas fired CCGT CHP providing heat and electricity to the site with surplus electricity exported to the grid.

- Annual savings: £3.76M/year
- Simple payback: 2.4 years

• CO_2 Saving: 14,583 TCO_2/year

Wider benefits

78. The recovery and use of heat that would otherwise be 'wasted' should give additional benefits which have not been quantified in this assessment. These include:

- reduced carbon emissions, contributing to the achievement of set targets and low carbon economy and potentially improving air quality (see Section 8). This cannot currently be quantified due to uncertainty over the number of plants that will install cogeneration or waste heat recovery;
- possible air quality benefits, although this is likely to depend on the technologies that are installed, what they replace from the baseline, and their location; and
- improved security of energy supply through a reduction of fuel use and exposure to domestic and international energy market risks.

The level of these wider benefits depends on the outcomes of the CBAs and what technologies are installed as a result, as the carbon and air quality impacts will depend on the technology chosen and fuel saving achieved. As such the wider benefits have not been quantified.

6. Competition assessment and direct impact on business

79. The competition assessment guidelines[20] set out four questions to establish whether a proposed policy is likely to have an effect on competition. In particular, the assessment needs to establish whether the requirement to carry out a CBA across a range of new and refurbished combustion installations >20MWth would affect the market by:

- directly limiting the number or range of suppliers;
- indirectly limiting the number or range of suppliers;
- limiting the ability of suppliers to compete; or by
- reducing suppliers' incentives to compete vigorously.

80. A brief summary of the four questions and a response considering the proposed requirement is presented in Table 12 below.

Table 12. Competition Assessment Filter Questions

[20] OFT http://www.oft.gov.uk/shared_oft/reports/comp_policy/Quick-Guide1-4.pdf

Do the proposed requirement to carry out a CBA	Response	Comment
Q1. …directly limit the number or range of suppliers?	No	The proposed requirement to carry out a CBA does not seek to directly limit the number of suppliers
Q2. …indirectly limit the range of suppliers?	No	The proposed requirement to carry out a CBA is not likely to limit the range of suppliers. In particular, the proposed requirement does not prevent entry or exit from the market for any of the sectors affected, e.g. Electricity Supply Industry (ESI), refineries, iron and steel, chemical industry etc. Furthermore, the cost associated with developing a CBA accounts for less than 1% of Gross Operating Surplus available to plants even in the case of small enterprises and, therefore, are unlikely to create further barriers and limit the range of suppliers.
Q3. …limit the ability of suppliers to compete?	No	Carrying out the required CBA will provide new and refurbished installations with better information on relative costs and benefits of alternative heat supply and waste heat management options available to them and avoid investing in sub-optimal options. In the longer-term the proposed policy option should result in increased energy efficiency and, potentially in cost savings. Furthermore, taking into account the relatively low compliance costs, the proposed requirement is not likely to affect the ability of suppliers to compete.
Q4. …reduce suppliers' incentives to compete rigorously?	No	The proposed requirement does not seek to limit the incentives for suppliers to compete. In particular, implementing energy saving measures in line with CBA recommendations could result in reduction of (energy) cost or additional revenue and place the installation in an advantageous position.

81. Overall, the proposed requirement to develop a CBA for new and refurbished installations is unlikely to have any adverse impacts on competition. As the regulation is being transposed with no gold plating it is not expected that operators in the UK will be disadvantaged relative to their European counterparts.

Direct cost and benefit to business

82. As this impact assessment concerns the transposition of a European Directive, it is out of scope of “One-In, Two-Out” (OITO). The direct impact on business has nevertheless been calculated. The net present value of the cost to business for the period July 2014 to July 2024 is £12.05 million (£6.41 to £17.69 million).
83. The Equivalent Annual Net Cost to Business (EANCB) incorporates only the direct costs and benefits associated with the policy change that would be incurred by businesses. The EANCB is £1.03million (2009 prices)[21].

Non-quantified impacts on business

84. Some possible non-quantified costs have been identified that could affect businesses. These are discussed in greater detail in the unquantified costs part of Section 4. They largely relate to whether investment could be deterred as a result of transposition. As the EA has the discretion to permit less cost-effective options if capital constraints make the more cost-effective option unaffordable, this risk is considered to be low. Additionally operators have flexibility around the assumptions they apply in the CBA to reflect their particular circumstances. As such the results of the CBA should be robust.
85. The possibility that the requirement to complete a CBA could introduce delays to investment was also considered. Timescales for the EA to assess CBAs will be discussed with operators as part of their ongoing discussions, so that this can be planned for. The CBAs will be able to factor in appropriate timescales for cogeneration options to be designed and planned. The risk of unforeseen delay should therefore be low.

[21] For the purpose of OITO, net costs to business are to be presented in 2009 prices and discounted to 2010 using the GDP deflator, in order to enable all policies to be compared using consistent pricing and discounting.

86. Considering these possible sources of cost to business, it is concluded that unquantified costs to business are unlikely to be significant. Further, it is noted that the quantified cost estimates are conservative as they assume no businesses conduct similar CBAs already, and no downward adjustments are made for operators that are not required to conduct a CBA (for instance, if no sources of waste heat are identified).

87. No quantitative estimates of benefits have been produced in this impact assessment. The likely benefits to business are the cost savings that result from operators taking up cogeneration/waste heat recovery options. These benefits would not count towards the EANCB calculation as they are not direct.

7. Distributional effects

Definitions and the Small and Micro-business Assessment

88. Small and micro-businesses are affected disproportionately by the burden of regulation and all new regulatory proposals should be designed and implemented in a manner aiming to mitigate disproportionate burdens. The default assumption set in the Better Regulation Framework Manual (June 2013) is that there will be a legislative exemption for small and micro-businesses where a large part of the measure can be achieved without including such businesses in the scope of the policy proposal. There is no exemption for SMEs in the EED so this section considers the possible impacts on them.

89. The Better Regulation Framework Manual defines micro and small businesses according to a staff headcount. Micro-businesses are those employing up to 10 FTE staff members while small businesses employ between 11 and 49 FTE staff. The Manual provides guidance on Small and Micro-business Assessment including a range of potential mitigation measures if the proposed policy option does have an impact on small and micro-businesses.

Assessment of Businesses likely to be affected

90. Annex A sets out the consideration given to the businesses that are likely to be affected. Overall, the key sectors affected include Electricity Supply Industry (ESI sector), Iron and Steel, Petroleum Refineries and other industrial sectors, including non-ferrous metals, chemical, food and drink, pulp and paper production etc.

91. This analysis concludes that operators of combustion plants >50MWth are unlikely to fall within small and micro-business categories. Similarly operators of combustion plants between 20 and 50MWth in the electricity supply and refinery sectors are not expected to be small or micro-businesses. However in the industrial sector it is possible that some operators of combustion plants between 20 and 50MWth may fall within the small enterprise category. None are expected to be micro-businesses.

Measurement of the Impact on Micro and Small Enterprises

92. The impact of the proposed regulation on micro and small enterprises relates to whether the operators are able to meet the costs of compliance i.e. costs associated with carrying out CBA for planned or refurbished installations as well as the administrative costs associated with the regulation. These costs can then be assessed by comparing the compliance and administrative cost per plant against the level of financial resources available to the operator for investment, as indicated by the gross operating surplus (GOS). Annex A details the comparison conducted.

93. The assessment suggests that even in the case of small enterprises (10-49 FTE), the expected annual compliance and administrative cost per enterprise is negligible and corresponds to 0.03%-0.7% of the average GOS across the affected sectors. Furthermore,

any adverse impacts, may potentially be counteracted by the financial savings associated with increased energy efficiency and additional revenues if waste heat is used on site or sold to a third party.

8. Social Impact Assessment

94. The proposed policy option requires a cost benefit analysis (CBA) to be undertaken for a range of new and refurbished plants > 20MWth. The policy requirement per se would only affect the installations concerned and environmental and energy consultancy sector that is likely to be assisting in carrying out these CBAs.

95. As discussed above it is very unlikely the proposed legislation will impact SMEs significantly. In particular, the costs of developing CBAs are estimated to be below 1% of annual Gross Operating Surplus across the sectors affected even in the case of small enterprises. Although the legislation does not allow for derogations for SMEs, the impact on SMEs if they are affected is likely to be small.

96. Depending on the outcomes of the CBAs carried out on new and refurbished installations, a range of energy efficiency measures might need to be implemented resulting in further costs and potentially employment impacts. However, the results of these assessments will be site and installation specific and no predictions with regard to the associated costs can be made at this stage.

97. The reduction in total energy consumption has the potential to lead to environmental and health benefits of reducing air pollution, including NOX, SO2 and dust (PM) as well as other air pollutants. However, this cannot be determined without further information on the originally proposed schemes and the alternative approach taken as a result of a requirement to fit CHP. For example, installation of a diesel fired reciprocating engine CHP plant instead of meeting the same demand using a gas fired boiler and grid electricity can actually lead to an increase in air pollutant emissions.

9. Uncertainties and assumptions

98. As with any assessment of this nature, there are a number of uncertainties and limitations that should be kept in mind when considering the findings, these include:

- DECC provided data covering new electricity and district heating plants for two of the three considered thermal input categories. This was complemented with AMEC estimations based on plant turnover to fill the gaps. Although filled using the best available estimates, this adds a degree of uncertainty to the final results. In particular, no information on industrial plants was provided by DECC and therefore the forecast applied in the analysis is solely based on AMEC modelling. Similarly, no data was provided for plants between 20-50MW.
- There is uncertainty over how many of these plants may already be required to undertake a CBA as part of existing permitting requirements, and how many may be exempt from conducting a CBA (for instance, due to lack of identified heat demand in the surrounding area).
- Plant forecasts in the model also rely on a number of assumptions. For example, growth data is based on energy consumption projections by fuel type and sector. However, it is impossible to discern if the projected change in consumption is directly linked to a proportional change in the considered plant types or is the result of other factors. Assumptions regarding the number of refurbishments in current and future plants are also applied introducing uncertainty in the results of the model. Emerging technologies may increase the lifetime of the plant but may also trigger more frequent refurbishments. Future regulations may also alter the lifetime and the number of required refurbishments.

- Uncertainties with respect to the costs associated with undertaking and reviewing a CBA. This will depend largely on the complexity of the plant in question. We have applied ranges to try and reflect this variation.
- It is uncertain what benefits the CBAs might identify (and what benefits would result in practice).

99. There is greater uncertainty associated with the number of CBAs compared to the cost of the CBAs. The estimated number of plants affected was developed based on the best available information from DECC and AMEC, however the range remains uncertain. In view of the uncertainty we have taken a conservative approach, for instance by including all generators >50MW because the extent to which they are already covered by existing requirements is unclear.

100. Given the uncertainties outlined above, no benefits have been estimated. It is not clear what benefits might be expected from the policy. Just as the costs are considered conservative because they don’t take account of where operators already make similar assessments, this represents a conservative approach on the benefits side.

Assumptions

101. The key assumptions are listed in the table below, along with their source. These assumptions were tested at consultation but respondents did not provide any additional evidence that suggested these assumptions were inaccurate or information enabling us to improve them. In consequence the calculations and assumptions are the same as those presented in the consultation stage IA.

Table 13. Assumptions and sources

Assumption		Source
Wage costs: operator	£27.14/hour	ONS Annual Survey of Hours and Earnings (2011)[22]. 2011 prices inflated to 2013 (HMT GDP deflator) and uplifted by 30% for non-wage costs. Operators assumed to be Production Manager (112) and regulator assumed to be Conservation and Environmental Protection Officer (3551).
Wage costs: regulator	£19.58/hour	
Costs of CBA	£10,000-£40,000/CBA	From DECC's consultation stage impact assessment on the EED and supplemented by estimates from AMEC.
Time: operator Time: regulator	14-35 hours/CBA 21-45 hours/CBA	Larger installations assumed to require more time. AMEC expert judgement plus information from Environment Agency on the time taken to review the recent Tilbury Power Station CBA (870MW output power). Time for operator could be higher if they don't commission consultants to complete the CBA. Total costs of this are not expected to be greater than when consultants are commissioned.
Number of installations affected	See Table 3.4 for summary	DECC forecasts and data (included DUKES, 2013; Updated Energy Projections 2013); AMEC – previous analysis and expert judgement; Large Combustion Plant Inventory (Defra, 2009);
Price year	2013	Except for direct impact on business, when 2009 prices are used.
PV base year	2014	

Implementation

102. Implementation will be a matter for the regulators, in accordance with guidance from the European Commission[23] and, if necessary, from Government.

103. The preferred option will be delivered through amendment of the Environmental Permitting (England and Wales) Regulations 2010. As already amended[24], these Regulations as a whole have to be reviewed in relation to England and a report published by 6 April 2017. This review will therefore provide a means of **post-implementation review**.

104. Article 24(6) of the EED requires Member States to submit to the European Commission before 30 April each year statistics on:

- national electricity and heat production from high and low efficiency cogeneration
- cogeneration heat and electricity capacities and fuels for cogeneration, and
- district heating and cooling production and capacities, in relation to total heat and electricity production and capacities.

In that way, information relevant to the effectiveness of the measures covered by this impact assessment will be accumulated.

[22] ONS Annual Survey of Hours and Earnings was available. The hourly wage cost for a production manager changed from £20.11 in 2011 to £19.89 in 2012. The corresponding wage rate for an Environmental Protection Officer (EPA) was not available. A similar job title to EPA was checked. However its suitability as a substitute was questionable due to a large drop in employment of over 75% between 2011 and 2012. As the wage of a production manager fell between 2011 and 2012 our estimates (in which we use 2011 figures) are likely to be an overestimate and hence are conservative estimates.

[23] http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:52013SC0449

[24] Specifically, by regulation 11 of the Environmental Permitting (England and Wales) (Amendment) Regulations 2012 (SI 2012 No.630) which inserts a review requirement.

105. Defra has a long established arrangement through which representatives of industry organisation, environmental regulators, environmental NGOs, the devolved administrations and other Government Departments meet regularly to discuss issues arising from the EPR as they concern pollution control at industrial installations component Directives. This arrangement will continue to provide an effective means of reviewing the implementation of Articles 14(5)-(8) of the EED.

10. Conclusions

106. Overall the transposition of Articles 14(5)-(8) will lead to additional costs being incurred primarily by developers/operators as a result of needing to undertake CBAs of the potential for using waste heat. Regulators will also incur costs as a result of needing to review any CBAs provided to ensure they meet the requirements of the legislation and agree what further actions, if any, may need to be undertaken. In practice these costs for the regulators are likely to be passed onto operators.

107. As highlighted above, a CBA must be undertaken by developers of installations above 20MWth and if the result is positive, the appropriate authorisation criteria and/or permit will require operation as cogeneration or with waste heat recovery. A permit will not be granted for operation without cogeneration/heat recovery where the CBA is positive except for in exceptional circumstances.

108. Overall, the total additional cost for both regulators and developers/operators associated with the transposition of these articles is estimated to be £12 million in the central case, within a range of £6-18million, over the assessment period (2014-2024). This assumes that all new or refurbished plants in scope are required to undertake a detailed CBA. This cost assessment may be an overestimate as some of the plants already have to consider recovering waste heat as part of the existing consent regime or choose to conduct similar assessments anyway.

109. Benefits have not been quantified due to their site specific nature and uncertainty around the extent to which the CBAs will represent additional activity. Where benefits do arise for operators, they are likely to include improvements in energy efficiency. Wider benefits could include reductions in carbon emissions as well as potential economic benefits for the use of waste heat (either on site or elsewhere).

References

- Environmental Permitting (England and Wales) Regulations 2010: www.legislation.gov.uk/ukdsi/2010/9780111491423/contents
- Industrial Emissions Directive:

www.defra.gov.uk/industrial-emissions/eu-international/industrial-emissions-directive/

- Ricardo-AEA (2013), Projections of CHP capacity and use to 2030
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- AMEC (2012), Collection and analysis of data to support the Commission in reporting in line with Article 73(2)(a) of Directive 2010/75/EU on industrial emissions on the need to control emissions from the combustion of fuels in installations with a total rated thermal input below 50MW. *Final report for the European Commission, September 2012. Available from:* https://circabc.europa.eu/w/browse/7976d5b7-c037-43e6-9406-e898006396d0

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Annex A: impact on small and micro-businesses

Overview

110. The scope of Articles 14(5)-(8) of the Energy Efficiency Directive (2012/27/ EU)[25] includes the following installations:

- New or refurbished electricity generation installations;
- New or refurbished industrial installations generating usable waste heat; and
- New district heating or cooling networks, or a new or refurbished energy production installation within an existing network.

111. The requirement to undertake a CBA concerns only new or refurbished installations. The number and the size of new or refurbished installations, in particular across different industrial sectors, is highly uncertain. For the purpose of the assessment, it is assumed that the existing composition with regard to the sectors affected and typical size of the companies remains over the assessment period.

112. Overall, the key sectors affected include Electricity Supply Industry (ESI sector), Iron and Steel, Petroleum Refineries and other industrial sectors, including non-ferrous metals, chemical, food and drink, pulp and paper production etc.

Combustion plants >50 MWth

113. The assessment of the number and size of the businesses likely to be affected was based on the analysis of the UK LCP 2009 emissions inventory[26] that captures plants >50MWth and DUKES 2013 data.

Electricity Supply Sector

114. According to the inventory there were about 130 large combustion plants within the electricity supply sector split equally between 50-300MW and >300MW plants. In total, about 30 companies are operating these plants including E.ON, EDF Energy, Scottish and Southern Energy, Scottish Power, AES Corporation, Centrica, GDF Suez, RWE Npower, Drax Power Limited and others. Overall, the operators within the sector tend to be large multinational corporations (e.g. GDF Suez, AES Corporation etc.) employing up to tens of thousands of employees or large plant operators, e.g. Eggborough Power Ltd or Drax Power Ltd employing 800 staff members. It is, therefore, unlikely that companies operating LCPs within electricity supply sector fall within small and micro-businesses category.

Refineries

115. The LCP Inventory 2009 reports about 55 combustion plants within refinery sector with the capacity above 50MWth located on about twelve sites (although as of 2013 there are only seven operational sites), including,

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[25] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:315:0001:0056:EN:PDF

[26] Available from: http://cdr.eionet.europa.eu/gb/eu

for instance, Grangemouth, Fawley, Humber and other refineries. The analysis of their ownership and operation indicates that these refineries are owned and operated by large international corporations, including, for example, Valero Energy Corporation, Essar Energy, Philips66, Ineos, Murco, ExxonMobil, and Total. The majority of these plants have a capacity of 50-300MWth and there are no refineries with a capacity between 20 and 50MWth. No small and micro-businesses within refineries sector will be affected by the new requirements.

Iron and Steel Sector

116. The UK LCP 2009 inventory suggests that there are about 10 plants within the iron and steel sector >50MWth situated on four different industrial sites. All of these steelworks are owned and operated by two international corporations employing thousands of people on the affected industrial sites alone. All these plants except for one fall within 50-300 MWth capacity.

Other Industrial Sectors

117. A wide range of sectors also appear on the UK LCP Inventory including, in particular, chemical sector (organic and inorganic), pulp and paper production, food manufacturing, textiles production, manufacturing of cars as well as specialised utilities services companies and gas compressor stations.

118. The majority of these plants, i.e. about 95% are between 50-300 MWth. Like with the other sectors, large national and international companies that employ hundreds and thousands of staff dominate the list. For instance, food production is represented by companies such as British Sugar, British Salt, Tate & Lyle; while chemical sector combustion plants are owned by companies such as Shell, BP, Ineos, SABIC Petrochemicals, Ciba UK etc. No impact on small and micro-businesses is anticipated for plants > 50MWth.

Combustion plants 20-50 MWth

Electricity Supply Sector

119. The assessment of the data available (DUKES) suggests that it is unlikely that companies operating installations with a capacity between 20MWth and 50MWth within the electricity supply sector fall within small and micro-businesses category

120. According to DUKES 2013 data, as of May 2013 there were in total 18 plants with a capacity between 20-50MWth. All of these installations are owned and operated by the same large energy companies, including E.ON, Scottish and Southern, EDF Energy, GDF Suez and others.

Refineries

121. No small and micro-businesses within the refineries sector are likely to be affected by the new requirements as there are no further refineries with a capacity between 20 and 50MWth.

Industrial Sectors

122. No data is available on operators of the installations with a capacity below 50 MWth across a wide range of sectors.

123. For some of these sectors, Eurostat Structural Business Statistics (SBS) provides sectoral data on enterprise size categories, thus allowing for a preliminary assessment of SMBA-relevance to be made. The key sectors affected may include iron and steel, pulp and paper, chemical industry, textiles, food production, car manufacturing etc.

124. Eurostat data suggests that a significant proportion of the industrial sectors affected fall within micro enterprise group (0-9 employees). In practice, however, installations with a thermal input of 20-50MW are typically a part of a bigger complex requiring more than 9 employees to maintain and operate, and therefore it is highly unlikely that any micro-size enterprises would operate such installations.

125. A number of the plants within 20-50 MWth are directly associated to an IED regulated installation, which is extremely unlikely to be an SME and are assumed to be large-size enterprises. Furthermore, 20-50 MWth plants are captured under the EU ETS and unlikely to be micro or small enterprises.

Table A1. Enterprise Size Categories per Sector in 2007 for UK (numbers and %)

Sector	Micro (0-9)	Small (10-19)	Small (20-49)	Notes
Basic metals manufacturing	21,604	3,469	2,440	Basic metals and fabricated metal products
	75%	12%	8%	
Chemical production	2,369	368	381	
	64%	10%	10%	
Pulp and Paper	24,053	2,426	1,405	
	83%	8%	5%	
Food Industry	4,006	1,021	862	
	57%	14%	12%	
Textiles	6,585	817	573	
	79%	10%	7%	
Manufacture of vehicles	2,017	329	270	Manufacture of motor vehicles, trailers and semi-trailers
	66%	11%	9%	
Manufacture of coke, refined petroleum products	184	14	13	Manufacture of coke, refined petroleum products and nuclear fuel
	76%	6%	5%	

Note: Number of enterprises per size category, available in Eurostat Structural Business Statistics (SBS) for various sectors in 2007, used to estimate the proportions of different enterprise size categories for the sectors considered in this report.

126. Based on these arguments it can be assumed that no plant operators are micro-sized enterprises, although some of the installations could fall within the small enterprise category.

Non-industrial sectors

127. In addition to the sectors discussed above, 20-50MWth plants can also be found in non-industrial sectors such as public buildings (e.g. hospitals and universities) as the 20MWth threshold is aggregate.

128. In some cases they are owned and operated by specialist companies providing such services. As such, the size of the organisation(s) using the output of a combustion plant (e.g. a hospital) may not be the same as the size of the enterprise operating it. In addition, as demonstrated by the analysis of plants >50 MWth, in many cases an enterprise owns and operates more than one combustion plant.

129. It is unlikely that any of these plant operators are micro-sized enterprises although some could potentially fall within the small enterprise category.

Measurement of the impact on Micro and Small Enterprises

130. The impact of the proposed regulation on micro and small enterprises relates to whether the operators are able to meet the costs of compliance i.e. costs associated with carrying out CBA for planned or refurbished installations as well as the administrative costs associated with the regulation. These costs can then be assessed by comparing the compliance and administrative cost per plant against the level of financial resources available to the operator for investment.

131. In the case of 20-50 MW plants the costs of undertaking a CBA range between £10,000 (low estimate) and £25,000 (high estimate). Administrative costs range between approximately £360 up to £715 per plant. The lifetime of a new installation is around 26 years while that of refurbished installations is about 13 years. The equivalent annual compliance and administrative cost ranges between £620 and £1,020 per new/refurbished installation as a low cost estimate and £1,540 and £2,530 per new/refurbished plant as a high cost estimate.

132. Information available in Eurostat Structural Business Statistics includes gross operating surplus (GOS), which is the capital available to companies which allows them to repay their creditors, to pay taxes and eventually to finance all or part of their investment[27]. Considering that GOS can be used for financing investment, total cost per plant are compared against GOS per operator to assess the economic impacts of proposed regulation. For each enterprise size category and per sector, GOS was divided by the number of operators to estimate the level of capital available at the operator level on an annual basis and compared with the cost estimates. The table below provides an indication of the regulatory burden[28] in general and for small businesses in particular on a sectoral basis.

[27] http://epp.eurostat.ec.europa.eu/statistics_explained/index.php/Glossary:Gross_operating_surplus_(GOS)_-_NA

[28] By dividing total annualised cost per enterprise by the GOS for the relative size class to express the costs as a percentage of the GOS.

Table A2. Total Annual Compliance and Administrative Costs per Enterprise as a Proportion of GOS

20-50 MWth	GOS: small enterprises (10 to 49 employees)	Low cost estimate		High cost estimate	
		New, % of GOS	Refurbished, % of GOS	New, % of GOS	Refurbished, % of GOS
Basic metals manufacturing	372,212	0.17	0.27	0.41	0.68
Chemical production	706,008	0.09	0.14	0.22	0.36
Pulp and Paper	359,567	0.17	0.28	0.43	0.70
Food Industry	545,512	0.11	0.19	0.28	0.46
Textiles	416,906	0.15	0.24	0.37	0.61
Manufacture of vehicles	533,556	0.12	0.19	0.29	0.47
Manufacture of coke, refined petroleum products	1,962,963	0.03	0.05	0.08	0.13

Note: Total annual costs per enterprise consist of annualised compliance costs (i.e. annualised capital costs) and annual administrative costs. Administrative costs only include those for operators. The assessment is relevant to the installations with the thermal input 20-50 MW and concern small businesses only. No micro businesses (0-9) are assumed to operate installations of such size.

133. The assessment suggests that even in the case of small enterprises (10-49 FTE), the expected annual compliance and administrative cost per enterprise is negligible and corresponds to 0.03%-0.7% of the average GOS across the affected sectors. Furthermore, the adverse impacts, if any, are likely to be counteracted by the financial savings associated with increased energy efficiency and additional revenues if waste heat is used on site or sold to a third party.