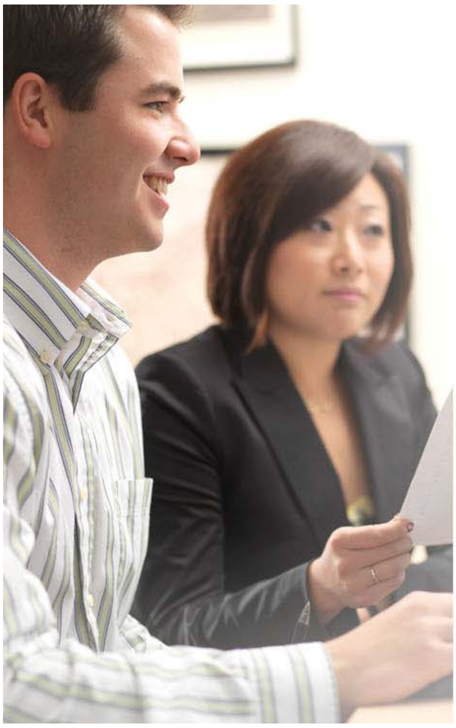
Defra

Updated Impact Assessment of the Industrial Emissions Directive (IED): Large Combustion Plants

Final Supporting Report



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UK Limited

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Contents

1. Introduction

1.1 Introduction

This Impact Assessment (IA) supporting report provides an updated assessment of the potential impacts on Large Combustion Plants (LCPs) in the UK of Directive 2010/75/EU, the Industrial Emissions (Integrated Pollution Prevention and Control) Directive (Recast) (henceforth cited as IED or the Directive), which was published in the Official Journal of the European Union in December 2010[1].

AMEC Environment & Infrastructure UK Ltd ("AMEC")[2] has been supporting Defra in understanding what the likely impacts could be from the implementation of the IED and has previously developed draft IA's for the LCP, intensive agriculture, waste treatments and recovery, water treatment and food processing sectors amongst others. These IA's were used as the basis for initial consultation with stakeholders, following which AMEC developed further scenarios for Defra to provide support in the ongoing IED proposal negotiations. Following the agreement by Council and Parliament in July 2010 and the finalisation of the Directive in November 2010, the IA work has been updated accordingly.

The work has been undertaken under the framework contract between Defra and AMEC on preparation of evidence to inform consideration of policy and legislative proposals in air quality, pollution control and industrial emissions (RMP 5161).

1.2 Background to the Industrial Emissions Directive (IED)

The Commission published its proposal and an impact assessment for a Directive on industrial emissions on 21 December 2007[3], which consolidated seven existing Directives related to industrial emissions into a single clear and coherent legislative instrument. The now repealed Directives included the titanium dioxide industry related directives (78/176/EEC, 82/883/EEC, 92/112/EEC), the IPPC Directive (2008/1/EC), the Solvent Emission Directive (1999/13/EC), the Waste Incineration Directive (2000/76/EC) and the LCP Directive (2001/80/EC). The Commission's IA[4] identified a number of problems related "(1) to shortcomings in the current legislation that lead to unsatisfactory implementation and difficulties in Community enforcement actions and, thereby, to loss of health

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1 http://eur-lex.europa.eu/JOHtml.do?uri=OJ:L:2010:334:SOM:EN:HTML

2 Previously known as Entec UK Ltd.

3 "Proposal for a Directive of the European Parliament and of the Council on industrial emissions (integrated pollution prevention and control) (recast)". European Commission, Brussels, 21st December 2007. Available from: http://ec.europa.eu/environment/ippc/proposal.htm

4 "Commission Staff Working Document: Accompanying document to the Proposal for a Directive of the European Parliament and of the Council on industrial emissions (integrated pollution prevention and control) (recast). Impact Assessment." European Commission, Brussels, 21st December 2007. Available from: http://ec.europa.eu/environment/ippc/proposal.htm

and environmental benefits and (2) to the complexity and lack of coherence of parts of the current legal framework." The IED was therefore intended to harmonise the various strands of industrial regulation.

Political agreement on the text was reached at the European Council on 25 June 2009 and a common position outlined by the Commission in November 2009[5]. Following agreement between Council and Parliament on 7 July 2010, the Directive (2010/75/EU) was formally adopted on 24 November 2010 and published in the Official Journal on 17 December 2010; coming into force on 6 January 2011. The timetable for implementation of the new directive is set out in Table 1.1 below:

Table 1.1 Key Dates for Implementation of the IED

Date	Description
January 2013	Member States shall bring into force the laws, regulations and administrative provisions necessary to comply with many of the IED articles (not 'other activities') (See Article 80); those measures shall apply from the same date.
January 2014	Directives 78/176/EEC, 82/883/EEC, 92/112/EEC, 1999/13/EC, 2000/76/EC and 2008/1/EC, as amended by the acts listed in Annex IX, Part A are repealed.
July 2015	The newly prescribed activities such as certain waste recovery activities and wood preservation activities must meet the requirements of the new Directive.
January 2016	Member States shall establish an annual inventory of the sulphur dioxide, nitrogen oxides and dust emissions and energy input of combustion plant.
January 2016	Directive 2001/80/EC as amended by the acts listed in Annex IX, Part A is repealed and the IED provisions in respect of existing large combustion plants come into effect
January 2016	The Commission shall submit to the European Parliament and to the Council a report reviewing the implementation of the Directive; this process is to be repeated every three years.

1.3 Aims and Objectives

The aim of this work was to reappraise the costs and benefits estimated in previous IAs in light of the final Directive text published in December 2010. Given the amendments and textual changes included in the final document, the focus of this work was to update the existing IAs and scenario analysis undertaken to date in relation to LCPs.

AMEC has already developed an IA of the likely impacts of the IED proposal on the combustion sector (LCPs and small combustion plants i.e. <50MWth). The Directive no longer includes the provision to include small combustion plants under the proposed IED. Previous analysis of the LCP sector has looked at a number of policy options and different scenarios (a total of twenty scenarios). These are described in the table below.

5 Common Position adopted by the Council with a view to the adoption of a Directive of the European Parliament and of the Council on industrial emissions (integrated pollution prevention and control) (Recast), Interinstitutional File: 2007/0286 (COD), 11962/09.

Table 1.2 Scenarios Developed To Date (November 2011)

Scenario Number	Description
1	**Baseline - No change** – i.e. plants continue to be regulated under current IPPC (which takes precedence) and LCPD. Assume current participants in NERP continue to do so after 2016 and 2018;
2	**As set in the Commission's proposal** - i.e. all plants subject to the proposed IED from 1 January 2016 with ELVs no less stringent than those set out in Parts 1 and 2 of Annex V of the proposal and the NERP being discontinued from that date. Part 1 of Annex V of the proposal applies to plants that will be operational (or with a granted permit or submitted a complete application) before 1st January 2016 whereas Part 2 of Annex V applies to plants that are built and operational after 1st January 2016
3	**As proposed + current trading** – i.e. all plants subject to the proposed IED from 1 January 2016 with ELVs no less stringent than those set out in Parts 1 and 2 of Annex V of the proposal, but with the continuation of the current NERP (assumed to be applying Annex V ELVs)
4	**As proposed + modified trading (1)** - all plants subject to the proposed IED from 1 January 2016 with ELVs no less stringent than those set out in Parts 1 and 2 of Annex V of the proposal but with current NERP participants in a revised NERP in which individual plant allocations would be based on the emissions which would have resulted over the calendar years 2004 – 2006 as presented in the UK 2004-2006 LCP emissions inventory[6] if the Annex V minimum ELVs were applied.
5	**As proposed + limited life derogation (1)** - 20,000 hour derogation from 1st January 2016 to 31st December 2023 (i.e. 8 years)
6	**As proposed + limited life derogation (2)** - 20,000 hour derogation from 1st January 2016 to 31st December 2019 (i.e. only 4 years to fit in with 2020 NECs)
7	**As proposed + limited life derogation (3)** - Pro-rata the 20,000 hour derogation (i.e. 10,000 hours) from 1st January 2016 to 31st December 2019 (i.e. only 4 years to fit in with 2020 NECs)
8	**As proposed + limited life derogation (4)** - Pro-rata the 20,000 hour derogation and divide by 2 (i.e. 5,000 hours) from 1st January 2016 to 31st December 2019 (i.e. only 4 years to fit in with 2020 NECs)
9	**As proposed + modified trading (2) -** all plants subject to the proposed IED from 1 January 2016 with ELVs no less stringent than those set out in Parts 1 and 2 of Annex V of the proposal but with current NERP participants in a revised NERP in which individual plant allocations would be based on the emissions which would have resulted over the calendar years 2009 – 2013 if the Annex V minimum ELVs were applied.
10	NERP expiring on 1 January 2020 with Annex V ELVs and a five-year reference period from 2006 to 2010
11	NERP expiring on 1 January 2021 with Annex V ELVs and a five-year reference period from 2006 to 2010
12	NERP expiring on 1 January 2024 with Annex V ELVs and a five-year reference period from 2006 to 2010
13	"limited life" of 15,000 hours expiring on 1 January 2020
14	"limited life" of 15,000 hours expiring on 1 January 2021
15	"limited life" of 15,000 hours expiring on 1 January 2024
16	NERP expiring 1 January 2020 with Annex V ELVs and 10 year reference period of 2001-2010 inclusive (this is the same as Scenario 10 except with a 10 year reference period instead of 5 year one)
17	Transitional National Plan (TNP, as referred in the paper from the Czech presidency) expiring on 1st January 2020 and having a 10 year reference period of 2001-2010 inclusive
18	Transitional National Plan (TNP, as referred in the paper from the Czech presidency) expiring on 1st January 2020 and having a 5 year reference period of 2004 – 2008 inclusive

[6] The 2004-2006 UK LCP emissions inventory has been submitted to the Commission as part of the LCPD reporting requirements of Member States before the 31st December 2007.

Scenario Number	Description
19	**As set in the Council's politically-agreed text without using flexibilities** - i.e. all plants subject to the proposed IED from 1 January 2016 with ELVs no less stringent than those set out in Parts 1 and 2 of Annex V of the proposal and the NERP being discontinued from that date. Part 1 of Annex V of the proposal applies to plants that will be operational (or with a granted permit or submitted a complete application) before 1st January 2016 whereas Part 2 of Annex V applies to plants that are built and operational after 1st January 2016
20	**As set in the Council's politically-agreed text using its flexibilities** i.e. Transitional National Plan expiring on 1st January 2021 and having a 10 year reference period of 2001-2010 inclusive and Limited Life of 20,000 hours expiring on 1 January 2024

This report examines two additional scenarios for the LCP sector: "IED upper cost" scenario (allowing for a Limited Life Derogation (LLD) and Emission Limit Values (ELV)) and "IED lower cost" scenario which also allows for a Transitional National Plan (TNP). This builds on upon the previous report examining scenarios 19-20 (Entec, 2010) so as to incorporate the final changes made to the agreed text. In particular the modelling of the following scenarios has been undertaken:

Table 1.3 New Scenarios Considered

Scenario	Description
(Upper)	**As set in the Directive without using a TNP** - i.e. all plants subject to the IED from 1 January 2016 with ELVs no less stringent than those set out in Parts 1 and 2 of Annex V of the Directive with the flexibility of opting for a Limited Life of 17,500 hours expiring on 31 December 2023. Part 1 of Annex V of the proposal applies to plants that will be operational (or with a granted permit or submitted a complete application) before 7 January 2013 whereas Part 2 of Annex V applies to plants that are built and operational after that date.
(Lower)	**As set in the Directive using a TNP** i.e. as for the "upper" scenario with the additional flexibility of a Transitional National Plan expiring on 31st June 2020 and having a 10 year fuel use reference period of 2001-2010 inclusive.

The TNP provides the option for a transition period during which all installations opting for the TNP are subject to an overall annual emissions cap ("bubble") – similar to the current National Emission Reduction Plan (NERP) applied in the UK – instead of concentration based ELVs. This emissions cap reduces over time (between 2016 and 2020) providing time for the installations to transition between the LCPD ELVs and the more stringent IED ELVs, thereby delaying the investment cost of installing abatement. This is further explained in Section 2.1.2.

The LLD provides an option for an operator to limit the operating life to less than 17,500 operating hours, starting from 1 January 2016 and ending no later than 31 December 2023. Under this derogation the ELVs under the LCPD will be maintained for the remaining operating life of the LCP. This is further explained in Section 2.1.3.

The modelling for this assessment has been performed on a plant by plant basis for all existing UK LCPs. However, there is significant uncertainty over the expected reaction of any individual LCP due to the limited availability of plant by plant information and the large number of factors that may influence each plant's decision(s) in addition to the IED. Therefore, the plant by plant modelling has been based on readily available information and informed judgement selecting representative plant. The results are orientated towards providing an indication of sector level impacts (electricity supply industry, iron and steel, refineries and other) due to the high uncertainties at a plant level.

2. Policy Options

The Directive covers combustion plants with a total rated thermal input equal to or greater than 50 MW, irrespective of the type of fuel used. If waste gases of two or more separate combustion plants are discharged through a common stack the capacities should be added, but only if total rated thermal capacity of these individual combustion plants is greater than 15 MW.

Each of the new scenarios has been compared to an updated business as usual (BAU) scenario (equivalent to Scenario 1 in previous modelling) which takes into account the latest fuel price scenarios (DECC, 2010b) and list of LCPs (2009 inventory).

2.1 Scenarios

Flexibilities included in the Directive have been considered in the scenarios analysed in this updated IA, namely the provisions set out in Articles 32 and 33 of the adopted IED text that refer to the TNP and LLD. This has been done under the following two scenarios to reflect a potential lower and upper impact range of the adopted text.

- Scenario "upper" ELV + LLD; and
- Scenario "lower" ELV + TNP + LLD.

2.1.1 Emission Limit Values

LCPs not opting or qualified for either the LLD or TNP shall comply with ELVs as per Article 30, i.e. complying with Parts 1 and 2 of Annex V:

- Existing LCPs shall comply with the ELVs set in Part 1 of Annex V. LCPs that were granted a permit (or submitted a complete application) before 7 January 2013 (provided it's operational no more than one year after that date) are considered to be existing plants; and
- New LCPs shall comply with the ELVs set in Part 2 of Annex V, i.e. LCPs that will be granted permits after 2012. LCPs that were granted an exemption as referred to in Article 4(4) of Directive 2001/80/EC and which will be in operation after 1 January 2016 shall also comply with the ELVs set in Part 2.

All LCPs considered in the current modelling are existing plants, thus the Part 1 ELVs of Annex V have been applied where appropriate. Special conditions for LCPs firing high sulphur indigenous solid fuel, as well as small isolated systems and district heating plants, are assumed to not be relevant in the UK.

The ELVs considered and applied in the modelling are summarised in Appendix B.

For the purpose of the modelling it was assumed that eligible LCPs would have to comply with the ELVs or the requirements under the TNP from 1 January 2016, including LCPs currently in the NERP.

2.1.2 Transitional National Plan (Article 32)

The TNP option is available between 1 January 2016 and 31 June 2020 and can cover one or more of the following pollutants: nitrogen oxides, sulphur dioxide and dust. According to Article 32, the ELVs for sulphur dioxide, nitrogen oxides and dust laid down in the permit for the combustion plant applicable on 31 December 2015, pursuant in particular to the requirements of Directives 2001/80/EC (LCPs) and 2008/1/EC (IPPC), shall at least be maintained.

All LCPs that were granted the first permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, can be included in the TNP, with the exception of LCPs in the refineries sector, district heating plants which meet the conditions in Art.35 of the IED and LCPs opting for the LLD. For gas turbines, only nitrogen oxides emissions shall be covered by the TNP. LCPs with a total rated thermal input of more than 500 MW firing solid fuels, which were granted the first permit after 1 July 1987, shall comply with the emission limit values for nitrogen oxides set out in Part 1 of Annex V; these are thus excluded from the TNP for nitrogen oxides.

For each of the pollutants it covers, the TNP will set a ceiling defining the maximum total annual emissions for all of the plants covered by the TNP on the basis of each plant's total actual rated thermal input on 31 December 2010, its actual annual operating hours and its fuel use, averaged over the last ten years of operation up to and including 2010. Thus the reference period for TNP is 2001 to 2010. The approach is as follows:

- The ceiling for the year 2016 is calculated on the basis of the relevant ELVs set out in Annexes III to VII of Directive 2001/80/EC. In the case of gas turbines, the ELVs for nitrogen oxides set out for such plants in Part B of Annex VI of Directive 2001/80/EC are used;
- The ceiling for the years 2019 and 2020 are calculated on the basis of the relevant ELVs set out in Part 1 of Annex V; and
- The ceilings for the years 2017 and 2018 are set providing a linear decrease of the ceilings between 2016 and 2019.

2.1.3 Limited Life Derogation (Article 33)

All LCPs which were granted a permit (or submitted a complete application for a permit) before 7 January 2013 (“existing plants”) may be exempted from compliance with the ELVs (Annex V Part 1) or TNP if:

- The operator of the LCP makes a commitment not to operate the plant for more than 17,500 operating hours, starting from 1 January 2016 and ending no later than 31 December 2023;
- The ELVs for sulphur dioxides, nitrogen oxides and dust laid down in the permit for the LCP applicable on 31 December 2015, pursuant in particular to the requirements of Directives 2001/80/EC and 2008/1/EC, shall at least be maintained during the remaining operational life of the LCP; and
- The LCP has not been granted an exemption as referred to in Article 4(4) of Directive 2001/80/EC.

However, LCPs with a total rated thermal input of more than 500 MW firing solid fuels, which were granted the first permit after 1 July 1987, shall comply with the emission limit values for nitrogen oxides set out in Part 1 of Annex V.

3. Who Is Affected?

The following sectors and public bodies will be affected by the provisions for LCPs:

- Operators, categorised into:
  - Electricity supply industry (ESI);
  - Petroleum refineries;
  - Iron and steel;
  - Other large industrial sites e.g. non-ferrous metals, chemical, food and drink, paper etc.
- Competent authorities and government e.g. EA, SEPA, DoE Northern Ireland, Defra, DECC;
- Others, e.g. abatement technology manufacturers and suppliers, fuel suppliers etc.

The detailed modelling of the two additional scenarios considered in this report has required a re-consideration of the individual plant closure assumptions made under scenarios considered in the previous IA. For this study, the following electricity supply industry (ESI) plants are assumed to close down before 2016 under the Limited Life Derogation ("opted out") of the Large Combustion Plant Directive (2001/80/EC) (Defra, 2010).

- Ironbridge
- Tilbury
- Cockenzie
- Kingsnorth
- Didcot A
- Ferrybridge C
- Grain
- Fawley
- Littlebrook
- Ballylumford (coal)

It is recognised that certain installations are considering closing and then re-opening as biomass fired plant as a means of extending the life of LCPD "opt-out" plant. This is not considered to be a direct impact of the IED as such and is therefore not addressed in this assessment which focuses only on existing plant. LCPD "opt-out" plant are not included in the analysis as they will close under LCPD not IED. New (or re-opened following significant change e.g. switch to biomass) plant are not included in the analysis as they are assumed to meet regulatory requirements at time of commissioning.

The decommissioning dates of ESI plants are assumed not to be affected by the possibility of delay in the introduction of new plant. This is because experience in the industry indicates that new generating capacity, once decided upon, can be installed relatively quickly.

All other LCPs listed in the UK's 2009 inventory are assumed to be affected by the IED. Certain gas turbines have been excluded from this analysis as there is no change in ELVs for "new-new" gas turbines, whilst others are exempt from meeting ELVs under low load (<500 operating hours per year) derogations (Annex V, Part 1(5) and (6)). The modelling for this IA has been performed for the period 2016 to 2030, with certain closures assumed during that period as explained in the Limited Life Derogation section below. The number of LCPs by sector is summarised in Table 3.1.

Table 3.1 Number of LCPs Modelled

Sector	Number of plants operating in 2016	Number of plants operating in 2030
ESI	97	69
Petroleum Refineries	48	48
Iron & Steel	10	10
Other	67	67
Total	222	194

Note: In comparison to the previous scenarios the number of LCPs has increased in this assessment. The reason for this is that in the 2009 LCP inventory a number of installations previously listed as one entry are now listed as having multiple LCPs. Additionally a small number of LCPs have been re-categorised as ESI instead of Other.

3.1 Flexibilities

The Directive allows for flexibility in terms of a TNP and LLD. The approach used to model the likely choice between LLD, TNP and ELVs is described below.

3.1.1 Limited Life Derogation

LLD choice was modelled first by identifying the plants in the ESI sector that are likely to opt for this option. As in previous scenarios, Petroleum Refineries Iron and Steel and Other industrial LCPs were assumed not to consider the LLD option. This is because these LCPs perform a specific purpose within a wider installation and their closure would prevent further operation of that installation. According to Article 33, all existing LCPs are eligible for the LLD, thus all LCPs in the ESI sector (coal fired plants plus existing gas turbines (GT)) were considered.

There are two potential approaches for identification of the plant of similar age and type which would choose the LLD option. The first is to assume that all such plant would choose the same option as any impact will affect them equally. The second is to assume that operators might explicitly choose different options for some plant as this would allow them some flexibility in managing potential risks. With the second approach, risk preferences will depend on owners and hence the approach to selected plant for LLD included consideration of the incentives of operators. This second approach allows the resolution of differences between these similar plants.

A number of factors are initially considered for each plant when selecting those opting for the LLD for the purpose of this analysis. These factors include the fuel type, age of plant, ownership (it is unlikely that all plants owned by a single operator will opt for LLD), and similarity to other plants in terms of capacity and fuel type (if there are two similar plants it makes little difference for the sector level analysis which is chosen to opt for LLD).

After the initial selection of plants, the ESI sector optimisation modelling indicated that a number of additional plants cease operating in either 2016 or in 2022. These plants are therefore also assumed to choose the LLD option.

Thus, seven coal fired plants and six gas fired plants are assumed to be opting for the LLD under IED. Whilst these installations have been identified for the reasons given above, the selection is intended mainly to provide a representation of the probable impact on the ESI sector as a whole. The final results are therefore presented at sector level rather than for individual plants for which there is far higher uncertainty.

3.1.2 Transitional National Plan

ESI Sector

Through the application of information on fuel consumption for different fuel types in the reference period from 2001 to 2010 (actual and estimated) and tightening emission targets throughout the TNP period, TNP bubbles were calculated for each year of the Plan, i.e. 2016, 2017, 2018 and 2019. As the TNP runs to the middle of 2020 it has been assumed that abatement to comply with ELVs would be installed for 2020. TNP bubbles were compared to the updated baseline emissions and necessary reductions were calculated per year for SO_2, NO_x and dust. The required reductions were then compared with the reductions required under the ELVs and the operators' choice modelled based on the least abatement required for SO_2, NO_x and dust. It was assumed that all eligible LCPs are allowed to join the TNP irrespective of whether these are currently in the NERP.

Based on these considerations, ESI plants were allocated to the TNP or ELV options in the following way:

Table 3.2 LCPs in ESI Sector Choosing the TNP

LCPs	SO_2	NO_x[1]	Dust
Coal-fired	4		6
GTs		47	
Other	7	6	7

Note 1: Solid fuelled LCPs >300 MW_{th} are required to meet an ELV of 200 mg/Nm^3 and so for these there is no transition period.

The remaining LCPs are assumed to choose the ELV option.

Petroleum Refineries

In accordance with the Directive, refineries firing the distillation and conversion residues from the refining of crude oil for their own consumption alone or with other fuels are excluded from the TNP. In the current modelling it has been assumed that all LCPs within refineries are either already firing distillation and conversion residues from the refining of crude oil or are likely to do so in 2016; thus they are not included in the TNP and are assumed to be required to comply with the relevant ELVs.

Iron and Steel and Other

LCPs within iron and steel and other sectors are all assumed to join the TNP to allow maximum flexibility.

3.1.3 Summary

The number of LCPs choosing the LLD, TNP or ELV option under each scenario, is summarised in the table below.

Table 3.3 Number of LCPs Choosing Different Options under each Scenario

	Option	SO_2		NOx		Dust	
Scenario		**Upper**	**Lower**	**Upper**	**Lower**	**Upper**	**Lower**
ESI	LLD	23	23	23	23	23	23
	TNP	0	11	0	53	0	13
	ELV	74	63	74	21	74	61
	Sub total	**97**	**97**	**97**	**97**	**97**	**97**
Petroleum Refineries	ELV	48	48	48	48	48	48

	Option	SO_2		NOx		Dust	
Iron & Steel	TNP		10		10		10
	ELV	10		10		10	
Other	TNP		67		67		67
	ELV	67		67		67	
Total		**222**	**222**	**222**	**222**	**222**	**222**

It should be noted that the assumptions above are subject to considerable uncertainty in that company/plant decisions to opt for the LLD, TNP or ELVs will be based on multiple factors not least changes in fuel prices and future demand.

3.1.4 Alternative flexibilities

Certain combustion plants which do not operate more than 1,500 operating hours per year as a rolling average over a period of five years are subject to less stringent ELVs, and gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the emission limit values (see Appendix B).

These alternative flexibilities have been considered to some extent within this assessment. The limitation in this assessment is that the modelling undertaken is not iterative. The load factors for existing LCPs have been modelled as described below. In instances where these load factors result in gas turbines or engines operating for less than 500 hours per year these plant have not been subject to ELVs. The output from the load factor model does not indicate that any plant can opt for the 1,500 hour derogation under the forecast load factor. In practise it is possible that an installation initially forecast to operate for more than 1,500 hours could chose to reduce running hours in order to be eligible for the less stringent ELVs rather than install abatement measures to meet the stated ELVs. If that was to occur then other installations would be required to operate at a higher load factor in order to fill the gap left to achieve the overall electricity demand.

To address such an eventuality in this assessment it would have been necessary to repeat the load factor modelling iteratively until the situation is optimised. This has not been undertaken as the purpose of this assessment is to estimate the overall impact of the IED on UK LCPs as a whole rather than perform a detailed assessment to forecast the exact decision that each installation is expected to take. Such prescriptive modelling introduces a false sense of accuracy to the forecast, as such plant by plant decisions would also be influenced by other factors in addition to IED.

4. Baseline Definition

This section describes the approach for developing the baseline scenario, including the number of plants that will be affected, future fuel consumption and associated emission levels, BAU policies and abatement techniques. The baseline reference year is 1st January 2016 when the provisions of the IED are assumed to apply.

The key assumptions for the modelling, set out below, were agreed with Defra before the modelling was undertaken (December 2010).

4.1 Establishing the Baseline

4.1.1 Overview

This study has focused on developing a baseline scenario for existing plants that are in operation now and already need to comply with current LCPD requirements – this includes "existing", "new" and "new new" as termed under the LCPD[7], i.e. plants that are currently operational. Any existing plants (i.e. operational before 1st July 1987) that have "opted out" of the LCPD requirements by adopting Article 4(a) of the Directive[8] have not been considered in the baseline as these will have shut down by 2016.

This study has incorporated pre-2002 gas engines and gas turbines into the baseline based on their requirements under the existing IPPC Directive (although they are not included in LCPD). It as assumed that 'new new' gas turbines will not be impacted by the IED because of no change in applicable ELVs. In-house expertise and discussion with suppliers has identified that the impact on gas engines will be minimal because gas engines greater than 50MWth are not common in the UK.

For determining the number of plants that will be impacted by the IED, the UK LCP 2009 emissions inventory[9] was used to categorise the plants into the different sectors i.e. ESI, Petroleum Refineries, Iron & Steel and Other. This inventory has been compiled by the UK as part of its reporting requirements under the LCPD and presents all LCPs operating during 2009 along with their associated annual energy input (related to net calorific value) and annual emissions of SO_2, NO_x and dust.

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7 "Existing" – granted an operating license before 1st July 1987; "New" – granted an operating license between 1st July 1987 and 27th November 2002; "New New"- granted an operating license after 27th November 2002

8 This is the limited life derogation of 20,000 hours where plants are required to close down no later than 31st December 2015

9 Available from: http://cdr.eionet.europa.eu/gb/eu

Although not required by the LCPD, the UK LCP inventory includes pre-2002 gas turbines as well as post-2002 gas turbines, and this has been used to compile the list of gas turbines in use in the ESI and Other sectors. DUKES has been used to provide CCGT ages and to consolidate this list of gas turbines in the ESI sector[10].

In addition the UK National Emission Reduction Plan (NERP) document and tables (Entec, 2007) have been used to cross check with the emissions inventory and to gather data about the LCPs. Gas turbines used as backup in large power stations have been excluded from the analysis on the basis of the derogation for gas turbines operating fewer than 500 hours per year i.e. they do not need to meet the ELVs set out in the IED.

4.1.2 LCP survey

For the previous scenarios assessed for Defra, AMEC has undertaken a survey of a selection of LCP operators in order to gather information on the current and future performance of the sector in terms of BAU abatement measures and emissions levels (current and expected in the future). This survey was sent to operators in the industrial sector (Petroleum Refinery, Iron & Steel and Other sectors) under the NERP as these LCPs represent the majority of industrial LCPs covered by the LCPD. It was then followed up with telephone contacts[11]. Almost all of the operators of Petroleum refineries operators and Iron & Steel plants provided AMEC with completed forms and supporting data, whilst the "Other" sector provided about 10 responses.

The ESI sector was not included in the survey because sufficient data was supplied from the competent authorities (EA and SEPA) and from additional assumptions confirmed with BERR/DECC and Defra. This included information on opted in power stations (both under the NERP and ELV approach) such as future fuel consumption, % S content of coal and crude oil, BAU measures and emissions performance etc. Additional information was also provided by the Association of Electricity Producers (AEP). Discussions with in-house specialists, gas turbine manufacturers and BERR/DECC provided sufficient detail on the BAU assumptions for gas turbines.

4.1.3 Future fuel activity for LCP sector

For the previous scenarios, AMEC has been in contact with BERR/DECC and the Environment Agency to gather data on future fuel consumption and further assumptions for the LCP sector. Key issues that were discussed included fuel type and consumption projections, any BAU policies included in the projections, closure dates of existing power stations and current and future fuel sulphur levels in coal-fired power stations and refineries.

A flat fuel growth (i.e. constant fuel consumption) has been assumed for petroleum refineries and the Iron & Steel and "Other" installations. This is because load factors are already generally high in the industrial sector and do not fluctuate much in comparison to the ESI sector. In cases where the fuel consumption data presented in the UK emissions inventory appeared inconsistent, data from the UK NERP tables (Entec, 2007) were used.

10 Digest of United Kingdom energy statistics 2007, available at http://stats.berr.gov.uk/energystats/dukes07.pdf

11 In the "Other" sector telephone contact was prioritised to the largest emitters of SO_2, NOx and dust

4.1.4 Current and future emissions and abatement measures

Power sector

A Regulatory Framework has been prepared by the Environment Agency to provide guidance on Best Available Techniques (BAT) for existing large coal- and oil-fired power plants in England and Wales (2007)[12] for the control of SO_2, NO_x and particulates from 17 power stations. Discussions with SEPA have revealed that the general principles of the framework will also apply to Scottish power stations as well. The regulatory framework sets out an outline of the abatement measures that are considered BAT and their associated emission levels for SO_2, NO_x and dust emissions for the period 1st January 2008 to 31st December 2015.

The power stations are broadly separated into the following categories:

- LCPs meeting Article 4(3a) of the LCPD i.e. the ELV option;
- LCPs that meet the requirements of Article 4(3b) of the LCPD i.e. the NERP option; and
- LCPs that "Opted out" under Article 4(4a) of the LCPD i.e. the 20,000 hour limited life derogation starting from 1st January 2008 and ending no later than 31st December 2015.

As discussed previously, for the purposes of this impact assessment the "Opted out" LCPs have been excluded from the analysis as they will be closing down before the requirements of the IED come into force on 1st January 2016.

Key data sources that were used to determine the 2016 emissions and BAU abatement measures for SO_2, NO_x and dust for the power sector are:

- 2004-2009 UK LCP emission inventories;
- Environment Agency data on the type of fuels burnt in coal fired power stations in England & Wales (including the % sulphur content in coal used at each power station);
- Environment Agency emissions concentration data (monthly and total emissions) for January 2008 for coal fired power stations that are under the ELV approach;
- Direct consultation with SEPA regarding Scottish LCPs;
- Environment Agency Regulatory framework for coal and oil fired power stations; and
- IPPC permits provided from the Environment Agency for some plants.

Key assumptions that have been included in the analysis are:

[12] Environment Agency (May 2007) "A Framework for the Regulation of existing large coal- and oil-fired combustion plant as power stations in England & Wales: 2008-2015"

- All coal fired LCPs (except 1 unit at 1 plant) are fitted with FGD by 2016 – this is already effectively required under the current LCPD from 2008 onwards under the ELV approach. The abatement efficiency of FGD is assumed to be 90% (required to project historic emissions to 2016). In practice, discussions with operating companies indicates that annual average abatement efficiencies are likely to be lower than this, although this is not a sensitive factor, since FGD is largely a BAU commitment; and

- Selective catalytic reduction (SCR) is fitted by 2016 onwards on coal fired power stations to meet the more stringent NOx ELVs of 200 mg/Nm^3 under the current LCPD requirements. Because this is the baseline, this does not assume additional SCR costs for early installation/compliance.

Petroleum Refineries, Iron & Steel and Other sectors (excluding gas turbines)

As described previously, a survey was undertaken for operators that are under the NERP (for Petroleum refineries, Iron & Steel and Other only) (see Appendix B) in order to better understand the current and future performance in terms of their emissions concentrations and BAU abatement measures under the current IPPC and LCPD requirements. Competent authorities (Environment Agency and SEPA) were contacted to get further information regarding abatement measures, emissions levels and IPPC permit conditions for these sectors.

Plant specific data provided directly by operators were taken into consideration for the analysis to determine the 2016 BAU emission concentration levels and annual emissions. For LCPs that did not provide any plant specific information via the survey or were not included in the survey sample, the 2004-2009 emissions inventories were used to calculate the emission concentration levels (see Box 1 for methodology) for the individual plants.

Box 1	**Methodology to calculate emission concentration levels from the UK LCP emission inventory**
The UK 2004-2009 LCP inventories provides annual emissions and fuel energy input (biomass, other solid fuels, liquid fuels, natural gas, other gases) for each individual plant. For “other solid fuels” it was assumed to be coal and “other gases” assumed to refer mainly to coke oven gas and blast furnace gases that are primarily used in the Iron & Steel industry, except for refineries for which it is assumed to be refinery gas. Default specific volumes (Nm^3/GJ) were applied to the different fuels to calculate the total waste gas flow rates for the plants: 370 Nm^3/GJ for coal, 380 for biomass, 300 for oil, 283 for gas, 443 for Blast furnace gas, 280 for coke oven gas, 740 for natural gas-fired gas turbines (15% oxygen content) and 813 for oil-fired gas turbines (15% oxygen content) (taken from UK NERP tables, 2007). These specific volumes were multiplied by the relevant fuel energy input for each plant to give the total waste gas flow rates in Nm^3. Emissions concentrations for each plant were calculated by dividing the SO_2, NOx and dust mass emissions by the total waste gas flow rate to give average emission concentrations for the year 2006.	

BAU abatement measures that operators and competent authorities have reported included:

- For SO_2 emissions: FGD (for large power stations), low sulphur coal and low sulphur heavy fuel oil; fuel switching to natural gas;

- For NOx emissions: low NOx burners, ultra-low NOx burners, overfire air (OFA), SCR; and

- For dust emissions: electrostatic precipitators (ESP), bag filters, fuel additives, low sulphur fuels, fuel switching to natural gas.

Gas turbines (ESI and Other)

Due to the tight timescale of the original gas turbine analysis, no survey was sent out to individual gas turbine operators. Instead, discussions with in-house specialists, gas turbine manufacturers and with BERR/DECC provided the underpinnings of the baseline assumptions. 2006 emission concentrations for each gas turbine were also derived from energy input data from the LCP inventory using the methodology outlined in Box 1. Discussions with in-house specialists and gas turbine suppliers indicated that emission performance of gas turbines using BAT by 2016 for IPPC permits will likely necessitate either dry low NO_x combustors or water/steam injection to be retrofitted to all gas turbines by 2016. This has been modelled using a 50% reduction in emission concentrations in 2016 compared to 2006[13].

4.2 ESI load Factor Forecasting

4.2.1 Approach

For the ESI sector, load factors[14] for each plant have been forecast for each year between 2016 and 2030. The load factors in the electricity sector have been derived through a complex UK Electricity System optimisation model, which runs as a short run marginal cost of generation minimisation exercise for four-hourly periods of the year matching demand. This takes into account only variable costs of production, accepts capacity inclusions and removals as exogenous variables and ignores fixed costs of generation. The maximum marginal abatement cost of generation is taken as the "electricity price" for that time period and the difference between the "electricity price" and the variable cost of generation is used to calculate "operator margin" for that period. The assumptions with regards to maximum electricity demand, fuel and carbon prices, plant availability and operating costs, existing plant retirements and new plant built are based on the Redpoint et al (2008) work. A number of specific revisions have been made with respect to this basic plan to account for changes to the installations opting out under the LCPD and to align with DECC's July 2009 forecast generation mix. In summary, existing coal plant have been assumed to remain in operation longer which delays the introduction of new coal plant, including that fitted with CCS. The current age of the existing coal plants was considered when choosing closure years of the remaining plant.

The baseline for this assessment has been developed to reflect forecasts from a time before the IED started to significantly influence operators' decisions. Operators' decisions are influenced by many interacting policy (and other) drivers and so decisions made after this time, even if primarily responding to other policy drivers may in part be due to the IED. A more up to date baseline has not been used as it would be likely to already incorporate effects of the IED. There is however a possibility that certain decisions driven primarily by the potentially significant changes resulting from Carbon Price Support and the Electricity Market Reform may mean that the impact of the

13 Abatement efficiency suggested by the LCP BREF.

14 In the context of electricity generation the term "load factor" is commonly used to denote the proportion of maximum theoretical generation for a given capacity and time period. The "load factor" thus encompasses both the percentage loading of the installed capacity and the numbers of hours operated.

IED is reduced. There is therefore potential for this analysis to be re-assessed once those changes become more apparent in future energy projections.

Baseline emissions of SO_2, NO_x and dust have been updated on the basis of the load factors resulting from the running of the optimisation model. The abatement measures assumed in the BAU scenario have been applied as for previous AMEC modelling, with some changes for SCR uptake, and the same emission rates were applied to each plant; the actual measures taken up by the operators do not change with changes in load factors under the baseline scenarios.

Existing and BAU uptake of abatement measures is based on consultation with DECC, Defra and industry under previous work packages of the IED Impact Assessment (Entec, 2010, Entec 2009a, Entec, 2008) and the Multi-Pollutant Measures Database (Entec, 2009b).

The modelling of LCPs in the ESI sector is based on a merit order dispatch model with the following main inputs and outputs:

1. **Supply:** The model includes UK plants listed in the DUKES database and used a closure plan originally based on Redpoint and Trillema (2008). In this work a change has been made so that existing coal plant remains longer in operation and thus delaying the introduction of new coal plant. The model also includes interconnector capacity of 3000 MW (the existing 2000 MW interconnector with France and the planned 2010 Netherlands interconnector with a capacity of 1000 MW) with a supply cost equivalent to that of UK nuclear stations. Northern Ireland plant are included and the model dispatches a notional combined UK system. This will give the least cost dispatch on the combined system and is to be expected as long as the Northern Ireland interconnector does not have capacity constraints and these have not been seen to date. Assumptions with regards to plant availability and operating costs are based on Redpoint (2008). Appendix C has further information on the capacity plan.

2. **Fuel prices** are as in DECC Energy Price Update, 2010.

3. **Average efficiency rates** by plant type are based on Redpoint et al 2008. Individual efficiency rates have not been disclosed to AMEC. To facilitate the modelling, the efficiency of each individual plant is based on the average efficiency adjusted by plant age, with each year's deviation from the plant group average incurring a 0.05% loss or gain in efficiency[15], e.g. the average age of coal fired stations is 36 years and an average efficiency of 36%. A power station built in 2000 is allocated by the model an efficiency of 37.5%.

4. **Demand:** The forecast of demand uses an NGC forecast for the system peak. The peak is "Average Cold Spell (ACS) peak excluding station load and exports" from Chapter 2 of the 2010 NGC Seven Year Statement with growth of 0.2% after the end of the seven year period as also specified in the same source. An additional 1500MW is included to account for demand in Northern Ireland, consistent with the modelling of a notional UK system. The shape of the demand curve (the load duration curve) is taken from that specified in the GB Annual Load Duration Curve for 2009/10 and is scaled to match the ACS peak

[15] The differentiated efficiency by individual plant is required for the successful running of the linear programming model.

demand in each year. The load duration curve is divided into 36 periods each with a representative level of demand and the model runs to match demand and supply for each period independently. The model runs the combined UK system as one and implements an overall least cost solution.

5. **Model outputs:** the model produces plant by plant annual load factor information, average electricity generation costs as well as the marginal cost of generating electricity at each of the 36 time periods considered. It is assumed that revenues reflect instantaneous (short run)[16] marginal cost of generation. The profits of each plant are calculated on basis of the product of the MWh generated by the plant at each time period and the marginal system cost of supply minus the costs of generation.

The model operates by scheduling plant for each of 36 time periods, beginning with ‘must run’ plant (such as nuclear) and then choosing plant according to a short run cost calculated as the efficiency multiplied by the fuel price. Whilst the benefit is that this is a transparent and simple process which reflects expected overall market prices, real world outcomes may depend on additional factors, some of which are commercially confidential. Application of judgement in this area risks generating arbitrary solutions and has not been adopted for this analysis. These additional factors include:

- **Fuel contracting strategies -** Most fuel contracts include a minimum take whereby the buyer must take the fuel or pay for it anyway. In practice, it is often better for plant to run ‘out of merit’ and earn the current price (even if this price is low) than to reduce running hours and earn nothing, while still paying for the fuel. Companies will negotiate fuel contracts, including minimum takes, in line with an expected running pattern. Even though fuel prices diverge from expectation, the minimum takes can mean that a particular running pattern will prevail, even though it is notionally no longer the cheapest for the system based on fuel prices in current markets. Recent high oil prices imply high gas prices which would be expected to reduce load factors on gas plant and increase them on coal plant, however as coal was expected to be relatively more expensive (with higher carbon prices), gas plant may still be running to its minimum takes, with lower load factors on coal plant as a result.

- **Price indexation in fuel contracts -** Fuel prices in contracts for power generation are usually indexed to a basket of other prices. The price of natural gas has traditionally been linked to oil prices, but indexation baskets are usually much more complex and can include, for example, the downstream electricity price as well as wider economic variables such as RPI. The effect is that generators may have different prices from one another, especially in the short term, and will benefit from fuel price movements in different ways. These impacts may also affect their operations at other plant.

- **Portfolio operations -** the major generating companies operate more than one type of plant. To mitigate effects of minimum takes and for other reasons they may adopt a particular running strategy. For example, they may be able to share a minimum take across two plant, or reschedule delivery to a different point in time.

The modelling also uses a simple approach to account for maintenance periods: the capacity of the plant is assumed to be reduced by the percentage of time that maintenance is expected in a year (i.e. availability, see Table 4.1). This provides a simple model in the sense that if the plant is expected to be unavailable for 10% of the time, and its short run costs are lower than a plant with the competing fuel it will be modelled as running for 90% of the time.

16 Short run marginal costs only include variable costs of production and do not account for plant investment costs.

The following tables set out the assumptions used in the scenario modelling.

- Table 4.1 re-iterates the key assumptions used in the model which have not changed from the previous model runs.
- Table 4.2 shows the fuel price assumptions (which have changed from the previous model runs).

Table 4.1 Constant Assumptions used in the Merit Order Dispatch Model for all Years

	Efficiency	Variable O&M	Average Availability	Availability at Peak[17]	Carbon Intensity
	%	£/MWh(e)	%	%	tC/MWh(e)
Nuclear	36%	2.00	77%	85%	0
Coal	35%	1.60	81%	90%	0.92
gas turbines	35%	1.50	90%	95%	0.53
Oil	35%	1.50	90%	95%	0.77
CCGT	47%	0.40	81%	95%	0.40
OCGT	30%	1.50	90%	95%	0.62
Diesel	30%	1.50	90%	95%	0.83
Hydro	100%	1.50	40%	40%	0
pumped storage	75%	1.50	99%	99%	0
wind on	100%	1.50	28%	28%	0
wind off	100%	1.50	37%	37%	0
Tidal	100%	1.50	35%	35%	0
biomass	35%	1.10	80%	90%	0
Interconnectors	98%	1.00	99%	98%	0
Waste	50%	1.60	81%	95%	0
CHP	60%	1.60	81%	95%	0.31

Table 4.2 Fuel Price Assumptions

Year	Oil price	Gas price	Coal price
	$/bbl	p/therm	£/tonne
2009	62.6	31.0	45.0
2010	71.6	59.6	70.3

17 The availability at peak is applied between 1:00 pm and 8:00 pm during winter week days, as it is assumed that the operators make efforts to have higher availability at peak hours; average availability includes planned outages.

Year	Oil price $/bbl	Gas price p/therm	Coal price £/tonne
2011	72.6	61.8	66.5
2012	73.6	62.5	62.6
2013	74.6	63.3	58.8
2014	75.7	64.0	55.0
2015	76.7	64.8	51.1
2016	77.7	65.5	51.1
2017	78.7	66.3	51.1
2018	79.8	67.0	51.1
2019	80.8	67.8	51.1
2020	81.8	68.5	51.1
2021	82.8	69.3	51.1
2022	83.9	70.0	51.1
2023	84.9	70.8	51.1
2024	85.9	71.6	51.1
2025	86.9	72.3	51.1
2026	87.9	73.1	51.1
2027	89.0	73.8	51.1
2028	90.0	74.6	51.1
2029	91.0	75.3	51.1
2030	92.0	76.1	51.1

Source: DECC Energy Price Update, 2010. As published in “69-annex-f--fossil-fuel-and-retail-price-assumptions.xls”

Table 4.3 presents the peak demand assumptions used in the scenario modelling, and Figure 4.1 shows available generating capacity derived from the modelling.

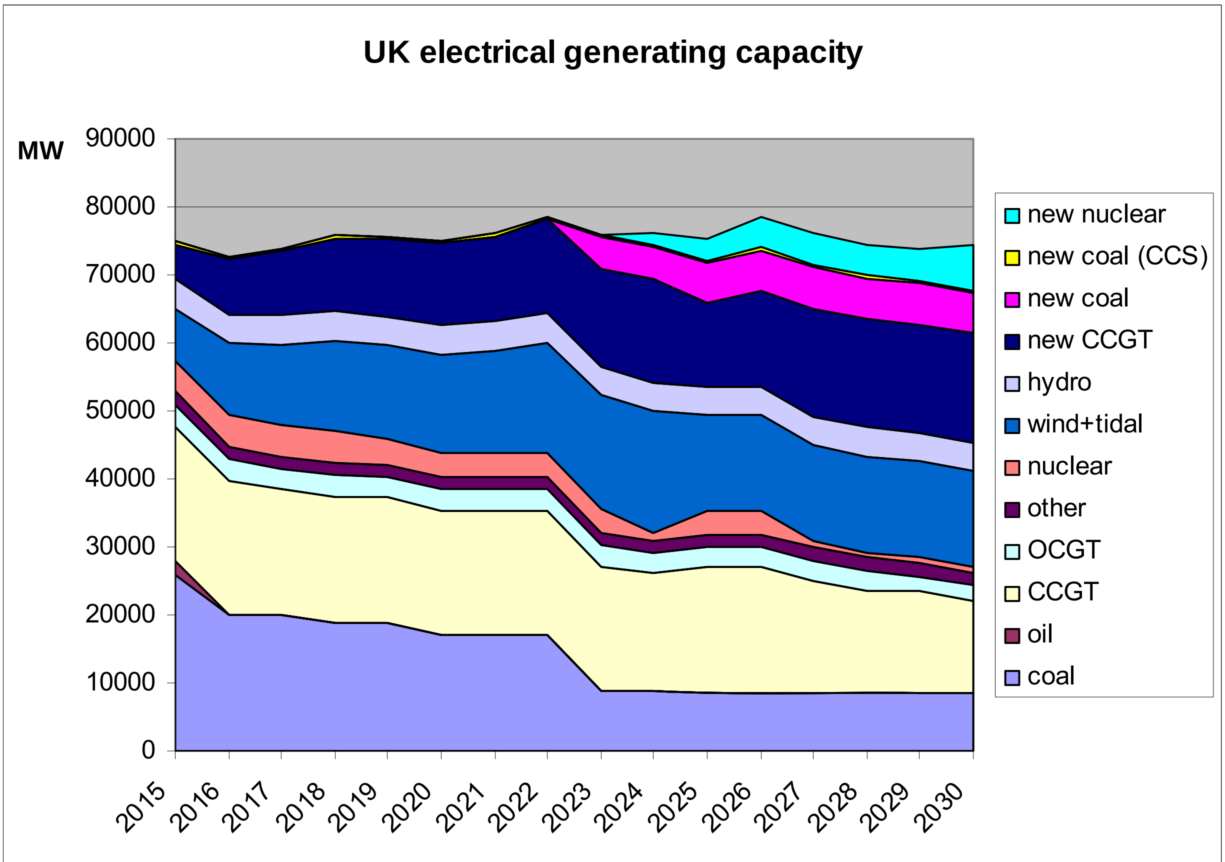
Table 4.3 Peak Demand Forecast

Year	GW
2009/10	57.5
2010/11	57.5887
2011/12	57.4830
2012/13	57.5535
2013/14	57.6168
2014/15	57.8740
2015/16	57.9867

Year	GW
2016/17	57.8542

Source: National Grid 7 Year Statement, 2010, Table 2.1 ACS Peak excl Station Demand and Exports to External Systems (for ranking order & SQSS studies, where exports to External Systems are treated as negative generation).

Figure 4.1 Generation Capacity, MWe



The above generating mix has been used for the baseline for this assessment. As explained above, this represents a “pre-IED” projection. It should be noted that the new coal shown above (pink) is taken to be “CCS ready” when built and then retro-fitted with CCS in 2025 onwards.

4.2.2 Results

Between 2016 and 2020, the modelling shows coal fired generation operating at an average load factor of 85% and CCGT at around 34%. This compares to only 34% for coal fired generation in 2016 in previous modelling on the basis of BERR data and similar gas fired generation load factors. As a reference, the average load factor for coal in 2006 was 69% and for 2007 – 62%[18]. Given the likely large capacity retirement just before 2016 due to the existing opt-out provisions of plants, the high load factors of the remaining coal and CCGT plants remain within a credible range.

Changes in the relative load factor (coal versus gas fired generation) leads to differences in emissions projections between the previous and current scenario modelling which are, as a result, sensitive to the relative price difference between coal and gas due to the fact that the model will in general choose all of one type of plant before all of another.

In general, the fuel price forecasts used here result in coal plant being cheaper to run than gas. This results in high load factors for coal plant and lower for gas. An increase in oil price (assuming simple indexation effects) would be expected in the first instance to result in even higher gas prices. As coal plant is already preferred to gas, the higher oil price would not substantially alter running patterns. The main change to running patterns would come from an inversion in the order of coal/gas preference and this would require lower oil prices or higher coal prices.

Changes in costs, due to upcoming policies such as Carbon Price Support, will affect the merit order of plant, but some of these changes will have been expected and may already be built into fuel contracts (e.g. as conditional clauses), and the overall combination of impacts will determine the extent of changes in observed running patterns.

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18 BERR – DUKES 2008.

5. Costs

5.1 Compliance Assessment

5.1.1 Overview

A compliance assessment was performed in order to identify the operating behaviour and required abatement measures, and associated costs, for installations to comply with the Directive. Modelling of the necessary emission reductions to ensure compliance under each scenario was undertaken on an emission concentration or total annual emissions basis.

Table 5.1 Compliance Assessment

Scenario	Description	Compliance Assessment
Upper	Eligible LCPs have a choice between LLD and ELV.	ELV and LLD: emission concentrations – BAU emissions concentrations assessed against scenario fuel weighted ELVs for LCPs (IED for ELV, LCPD for LLD)
Lower	Eligible LCPs have a choice between LLD, TNP and ELV.	TNP: total annual emissions – BAU annual emissions assessed against scenario target emissions for plants opting for the TNP approach ELV and LLD: emission concentrations – BAU emissions concentrations assessed against scenario fuel weighted ELVs for LCPs (IED for ELV, LCPD for LLD)

The following approach was utilised to identify the abatement required for each sector:

- ESI: this is the most complex sector to model under this scenario as three options are potentially available (depending on the scenario), including TNP, LLD or ELV. The assumed choice for each LCP between these options is described in Section 3, whilst the approach to estimating costs is discussed further below. It has been assumed that the LLD represents a potentially attractive choice for the older ESI sector plants;

- Petroleum Refineries: the sector is not eligible for TNP (due to firing distillation and conversion residues from refining of crude oil for their own consumption). Therefore plants are assumed to be subject to ELVs, with the same costs under each scenario;

- Iron and Steel: the sector is eligible for the TNP and ELVs. It is assumed that the LCPs in this sector would opt for the flexibility offered by the TNP if available (i.e. in the lower scenario); and

- Other industrial sectors: the sector is eligible for the TNP and ELVs. It is assumed that the LCPs in this sector would opt for the flexibility offered by the TNP if available (i.e. in the lower scenario).

The number of LCPs that will opt for early closure or will be required to install abatement measures, and the years in which such changes will be implemented, have been estimated, as presented in Table 5.2.

Table 5.2 Number of LCPs affected per year (not cumulative)

	Early closure (LLD)	Installation of abatement (high scenario)				Installation of abatement (low scenario)			
	ESI	ESI	PR	I&S	Other	ESI	PR	I&S	Other
2016	2	13	19	6	44	-	-	-	-
2017	4	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
2020	1	-	-	-	-	13	19	6	44
2021	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-
2023	7	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-

Note: Some installations have more than 1 LCP

5.1.2 Cost of compliance with Emission Limit Values

Following completion of the compliance assessment for the different pollutants (SO_2, NO_x and dust) for each individual LCP, the necessary emission reductions to ensure compliance were estimated and the most relevant abatement measure applied. An extensive list of abatement measures (see Box 1) and related details is presented in Appendix E and the same data (applicability, abatement efficiency, costs and lifetime) has been applied as for the previous scenarios. The only change made to the abatement costs from previous scenarios is for SCR for the ESI sector. Comments from the Environment Agency suggested a more up-to-date range of sources for SCR capital cost, with an increase of 60% compared to those used previously[19]. Furthermore, the assumed operating lifetime of the measure, across which the capital investment is annualised, has been reduced from 15 to 10 years. This change has a significant effect on the overall results of the cost-benefit assessment.

19 "*Figures from* (UK operators) *give a capex per unit of £71 to 73m (2010 prices) hence £140-146/kWe. AEP review of US and French SCR gave £136/kWe (2007 prices) and ENDs picked £125/kWe from somewhere unspecified in October 2010.*" Personal communication, email via Richard Vincent, Defra, 22/12/2010. Therefore a mid range value of £140/kWe (2008 price) has been applied for coal fired plant, and £150/kWe (2008 price) for CCGT applying an equivalent uplift from the previous JEP capital cost used in previous scenarios.

Box 2	Abatement Measures

Abatement measures considered for the different sectors, split by pollutant include:

- For SO_2:
  - ESI: Wet flue gas desulphurisation (FGD-wet) and low sulphur (0.5%) coal
  - Petroleum refineries: fuel switching to natural gas, amine treating units (scrubbers), low sulphur oil
  - Iron and Steel: coke oven gas (COG) desulphurisation
  - Other: FGD-wet and low sulphur (0.5%) oil;
- For NOx[20]:
  - ESI: selective catalytic reduction (SCR), combustion modification (CM) and additionally for gas turbines, closure and reopen new combined cycle gas turbine (CCGT)
  - Petroleum refineries: low NOx burners, selective non-catalytic reduction (SNCR) and SCR
  - Iron and Steel: SCR
  - Other: combustion modification, SNCR, SCR; and
- For dust:
  - ESI: (dust abatement included in FGD-wet)
  - Petroleum refineries: (dust abatement included in fuel switching to natural gas)
  - Iron and Steel: High efficiency deduster
  - Other: (dust abatement included in FGD-wet).

For the abatement costs, a range of costs have been estimated by applying a +/-30% margin of uncertainty, in a similar manner as used in the previous modelling. This uncertainty margin is based on our judgement of the uncertainty associated with the data available for this study. This includes consideration of the variation between generic costs and the actual costs influenced by site specific factors, as well general uncertainty associated with identifying costs from literature reviews and stakeholder consultation.

5.1.3 Costs of Transitional National Plan

The interaction between load factors and the TNP is complex; once a plant has decided to join the TNP, it is assumed that it stays in the TNP and load factors are not affected further. The emission ceilings (TNP bubble) have

[20] It has been commented that a number of operators are considering increased uptake of biomass to meet ELVs. This measure has not been considered as Entec (2009b) indicates that co-firing up to 20% biomass has no impact on NO_x and that co-firing biomass with coal above that level is not technically feasible. Conversion of a coal fired LCP to a wholly biomass fired LCP is considered as a closure and reopening as a new plant as discussed in Section 3.1.1.

been calculated based on the average of actual 2001 to 2008 and projected 2009 and 2010 fuel consumption data and the required emission reduction estimated for each year between 2016 and 2020 (see Table 5.3).

Table 5.3 Required Emission Reductions under TNP 2016-2020 (tonnes)

Year	SO_2	NO_x[1]	Dust	Abatement
2016	-47,191	-67,980	-8,618	Not required
2017	-32,556	-39,342	-6,573	Not required
2018	-17,923	-21,099	-4,528	Not required
2019	-3,285	-2,650	-2,483	Not required

Note 1: Solid fuelled LCPs >300 MW_{th} are required to meet an ELV of 200 mg/Nm^3 and so for these there is no transition period.

The difference in the required emission reductions is caused by a reduction in the TNP bubble due to fuel weighted ELVs becoming more stringent each year and changes in the load factors affecting projected baseline emissions for each particular year. The assessment assumes that under a perfect trading scheme, the least cost abatement measures would be undertaken by the operators to meet the total emission allowance targets. The assessment shows that LCPs in the TNP are not required to abate emissions, providing trading occurs between those which exceed their bubble contribution and those whose emissions are lower than their bubble. The surplus of emissions in the system means that trading costs will be low, making trading a lower cost option than installing abatement. It should be noted that actual cost impacts will depend on the relative surplus / deficit of plants against their allowance levels. If trading does not occur (as is allowed under the current UK NERP), then some of the installations in the TNP may be required to install abatement before 2020 in order to comply with their emission bubbles. The costs and benefits of such a situation would fall in between the "upper" and "lower" scenarios modelled in this assessment.

5.1.4 Costs of Limited Life Derogation

The assessment of costs associated with LLD was performed using the following approach:

- New load factors for the plants assumed to choose LLD were estimated in accordance with the 17,500 operating hours limit (see table below);
- The recast load factors and electricity prices are used to derive the profit losses or gains from switching from unconstrained to load factor / lifetime constrained operation (which was used to model plants' decision on whether to opt out for LLD); and
- The difference between profit/loss under baseline load factors and profit/loss under recast load factors was calculated to assess costs (or gains).

It should be noted that in the electricity sector, the choice of operators between the LLD and other options will depend to a large extent on the information flows among operators: if all operators select the LLD scenario, the capacity level will be constrained and this will lead to increased electricity prices and operator profits. Despite the gains related to the high electricity prices, as many plants retire, new capacity is required in order to meet electricity demand. The current approach to modelling does not include the cost of new capacity. This is due to the assumption that the cost of replacing closed capacity would have occurred anyway, albeit at a later date once the plant opting for early closure reached the natural end of its operating life, and because this assessment only considers the costs for existing installations. The knock-on effect that the early closure has on the load factors of other existing plants in the ESI sector has been used to calculate the resulting change in profit.

Table 5.4 LLD Costs

	2016	2017	2018	2019	2020	2021	2022	2023
Total costs (£m)	6.4	-1.4	-2.8	27.0	42.3	47.3	50.5	0.0

Costs are presented in 2008 prices.

For certain plants in some years the costs are negative, i.e. there is a financial gain resulting from the LLD option. This can be explained by increasing electricity price due to restricted capacity.

5.2 Administrative Costs

In terms of administrative costs, the costs developed in the previous IAs have been applied since all key assumptions and underlying data for administrative costs are the same for these two scenarios. Key assumptions for administrative costs include:

- The costs for a simple variation of a site's IPPC permit were considered in the analysis - this is currently £2,124 based on discussions with the EA (if a substantial change were to take place at the plant then a different cost would apply). This cost covers the competent authorities' time and effort for processing such a variation;
- Application fees were not considered since the LCP operators would already have in their possession an IPPC permit;
- Based on discussions with an operator it was indicated that a simple variation of their IPPC permit would probably take about 5 days (37.5 working hours) of their time; and
- The UK standard cost model was used to identify an appropriate hourly wage for an operator. The most relevant description of an environmental/energy manager at LCP sites was considered to be a "production manager" with hourly pay at £20.61 (2004 prices – this was updated to 2008 prices).

Based on these assumptions the annual administrative/permitting costs for the competent authorities and operators were estimated to be approximately £3k per plant.

5.3 Scenario “upper”

The total costs of this scenario have been calculated by aggregating the costs of LLD and ELV per plant depending on the choice each LCP is likely to make.

The estimated transitional (“one off”) costs that will be incurred due to the installation of abatement measures and permit variations, and the year in which they will occur, are presented in Table 5.5. The annual recurring costs associated with operation and maintenance of abatement measures and the loss in profit due to the LLD are presented in Table 5.6.

Table 5.5 Transitional Costs Under Scenario “upper” (£m) (2008 prices)

	Installation of abatement				Permit variation	Total
	ESI	PR	I&S	Other	All	
2016	753	120	57	354	1	1,285
2017-2030	0	0	0	0	0	0

Table 5.6 Annual Costs Under Scenario “upper” (£m) (2008 prices)

	Early closure (LLD)	Operating cost of abatement				Total
	ESI	ESI	PR	I&S	Other	
2016	6	41	21	6	20	94
2017	-1	41	21	6	20	86
2018	-3	41	21	6	20	84
2019	27	41	21	6	20	114
2020	42	41	21	6	20	130
2021	47	41	21	6	20	135
2022	50	41	21	6	20	138
2023	0	41	21	6	20	87
2024	0	41	21	6	20	87
2025	0	41	21	6	20	87
2026	0	41	21	6	20	87
2027	0	41	21	6	20	87
2028	0	41	21	6	20	87
2029	0	41	21	6	20	87
2030	0	41	21	6	20	87

The aggregated, annualised costs under this scenario are presented in Table 5.7. The costs in this table below include the following:

- Net present value (NPV) of the annualised capital expenditure and annual operating cost of abatement equipment required by installations to meet the respective ELVs for 2016-2030 for SO_2, NO_x and dust under scenario “upper”;
- costs of installations opting for early closure under the LLD (i.e. loss of profit); and
- administrative costs, annualised over the lifetime of a permit (assumed to be 20 years) using a discount rate of 3.5%.

Table 5.7 Total Annualised Costs Under Scenario “upper” (£m) (2008 prices)

Year	Low	Central	High	Range
2016	126	180	234	180 (126 - 234)
2017	121	172	224	172 (121 - 224)
2018	120	171	222	171 (120 - 222)
2019	140	199	259	199 (140 - 259)
2020	131	186	242	186 (131 - 242)
2021	134	192	249	192 (134 - 249)
2022	135	193	251	193 (135 - 251)
2023	101	144	188	144 (101 - 188)
2024	101	144	188	144 (101 - 188)
2025	101	144	188	144 (101 - 188)
2026	100	143	186	143 (100 - 186)
2027	101	144	188	144 (101 - 188)
2028	101	144	188	144 (101 - 188)
2029	101	144	188	144 (101 - 188)
2030	101	144	188	144 (101 - 188)
NPV_{2008} @ 3.5%	**£1,335m**	**£1,907m**	**£2,479m**	

5.4 Scenario “lower”

The total costs of this scenario have been calculated by aggregating the costs of TNP, LLD and ELV per plant depending on the choice each LCP is likely to make. The abatement costs for the LCPs that are not opting (or are not eligible) for the TNP are equal to the abatement costs under scenario “upper”.

The estimated transitional (“one off”) costs that will be incurred due to the installation of abatement measures and permit variations, and the year in which they will occur, are presented in Table 5.8. The annual recurring costs associated with operation and maintenance of abatement measures and the loss in profit due to the LLD are presented in Table 5.9.

Table 5.8 Transitional Costs Under Scenario "lower" (£m) (2008 prices)

	Installation of abatement				Permit variation	Total
	ESI	PR	I&S	Other	All	
2016	0	0	0	0	1	1
2017-2019	0	0	0	0	0	0
2020	754	120	57	354	0	1,286
2021-2030	0	0	0	0	0	0

Table 5.9 Annual Costs Under Scenario "lower" (£m) (2008 prices)

	Early closure (LLD)	Operating cost of abatement				Total
	ESI	ESI	PR	I&S	Other	
2016	6	0	0	0	0	6
2017	-1	0	0	0	0	-1
2018	-3	0	0	0	0	-3
2019	27	0	0	0	0	27
2020	42	41	21	6	20	130
2021	47	41	21	6	20	135
2022	50	41	21	6	20	138
2023	0	41	21	6	20	87
2024	0	41	21	6	20	87
2025	0	41	21	6	20	87
2026	0	41	21	6	20	87
2027	0	41	21	6	20	87
2028	0	41	21	6	20	87
2029	0	41	21	6	20	87
2030	0	41	21	6	20	87

The aggregated, annualised costs under this scenario are presented in Table 5.10. The costs in this table below include the following:

- NPV of the annualised capital expenditure and operating cost of abatement equipment required by installations to meet the respective ELVs for 2016-2030 for SO_2, NO_x and dust;
- cost of installations opting for early closure under the LLD; and
- administrative costs, annualised over the lifetime of a permit (assumed to be 20 years) using a discount rate of 3.5%.

There is no cost associated with the TNP, rather a postponement of the installation, and associated costs, of abatement equipment. This can be seen in the lower cost for the first four years of this scenario compared to the upper scenario.

Table 5.10 Total Annualised Costs Under Scenario "lower" (£million) (2008 prices)

Year	Low	Central	High	Range
2016	73	105	136	105 (73 - 136)
2017	68	97	126	97 (68 - 126)
2018	67	96	124	96 (67 - 124)
2019	88	125	163	125 (88 - 163)
2020	131	186	242	186 (131 - 242)
2021	134	192	249	192 (134 - 249)
2022	135	193	251	193 (135 - 251)
2023	101	144	188	144 (101 - 188)
2024	101	144	188	144 (101 - 188)
2025	101	144	188	144 (101 - 188)
2026	100	143	186	143 (100 - 186)
2027	101	144	188	144 (101 - 188)
2028	101	144	188	144 (101 - 188)
2029	101	144	188	144 (101 - 188)
2030	101	144	188	144 (101 - 188)
NPV_{2008} @ 3.5%	**£1,142**	**£1,631**	**£2,121**	

6. Benefits

6.1 Overview

For the estimation of benefits the IGCB and CAFE damage cost functions for SO_2, NO_x ,dust (PM) and CO_2 were used as in the previous IAs (see Box 2). These are summarised below.

Box 3 Damage Cost Functions

The potential benefits (damage costs avoided) that may be realised if the calculated SO_2, NO_x, dust and CO_2emission reductions are achieved have been estimated through the application of the damage cost functions developed by Defra IGCB[21,22]. For comparison with the European Commission's EU-wide impact assessment, potential benefits have also been estimated using the cost-benefit analysis developed under the CAFE programme[23]. A range of values have been calculated under the CAFE programme to take account of variation in the methodologies used to value mortality; this reflects the use of the median and mean estimates for the value of a life year (VOLY) and statistical life (VSL).

The IGCB and CAFE damage cost functions vary quite significantly for many pollutants. The main differences relate to:

- The use of different pollution metrics (IGCB use PM2.5 and CAFE PM10).
- 6.5% higher UK population estimate for CAFE than IGCB.
- IGCB only uses YOLL (years of life lost) whereas CAFE uses YLL (years life lost) and VSL (value of a statistical life).
- The impact matrix used.
- CAFE places much higher values of health endpoints, with the high CAFE value 2.75 times higher than the IGCB value.
- The IGCB figures discount (@3.5% p.a) and uplift (@2%p.a.) values in accordance with the Green book whereas CAFE does not.
- CAFE includes a much wider range of morbidity effects equating to approx 10% of total impact value.
- CAFE does not include a cost for CO_2. The IGCB cost of carbon[24] has been applied only to the IGCB benefits presented below.

The table below summarises the damage cost functions applied in the analysis for each pollutant.

21 AEAT (2006): Damage costs for air pollution. Final report to Defra, March 2006. Available from: http://www.defra.gov.uk/environment/airquality/publications/stratreview-analysis/damagecosts.pdf

22 IGCB (2007): Economic analysis to inform the Air Quality Strategy. Final report, July 2007. Available from: http://www.defra.gov.uk/environment/airquality/publications/stratreview-analysis/index.htm

23 Available from: http://www.cafe-cba.org/assets/marginal_damage_03-05.pdf

24 DECC and HM Treasury (2010) Valuation of energy use and greenhouse gas emissions for appraisal and evaluation

Table 6.1 Damage Cost Functions for SO_2, NOx and PM

	£/tonne per annum		
CAFE[1]	**Low**	**Central**	**High**
SO_2	5,001	9,699	14,396
NOx	2,955	5,266	7,577
PM	28,035	55,692	83,348
IGCB[2]	**Low**	**Best**[3]	**High**
SO_2	1,320	1,633	1,855
NOx	744	955	1,085
PM ESI	1,899	2,425	2,756
PM Industry	19,746	25,220	28,660

Note 1: Assuming a 2008 exchange rate of £1 = €1.32.
Note 2: Figures from IGCB Damage Cost Calculator (January 2008)
Note 3: Referred to as Monte Carlo Best estimate

It is noted that the IGCB has developed a number of damage cost functions for particulate matter (PM) depending on the emission source. For LCPs the PM ESI damage cost has been used for power stations and the PM industry value has been applied to Iron & Steel, other industry and petroleum refineries[25]. IGCB damage costs have been updated from those used under previous scenarios.

It is important when applying and interpreting damage cost functions to note that a number of impacts are not taken into account in the quantification; this includes impacts on ecosystems and cultural heritage. Therefore, the benefits estimated through the application of damage cost functions may be underestimated.

Using the damage cost functions developed by the IGCB and CAFE programme presented above, the estimated benefits of the "lower" and "upper" scenarios are further discussed.

25 Based on discussions with Defra economists, 25th March 2008.

6.2 Scenario "upper"

The forecast BAU (i.e. no-IED) emissions and the estimated reductions resulting from the IED "upper" scenario, are presented below in Table 6.2.

Table 6.2 BAU Emissions and "Upper" Scenario Emission Reductions

	BAU emissions (kt)			Upper scenario emission reduction (kt)			Percentage reduction (%)		
Year	SO_2	NOx	Dust	SO_2	NOx	Dust	SO_2	NOx	Dust
2016	149.0	214.4	9.1	35.4	80.0	6.6	24%	37%	72%
2017	148.0	214.7	9.1	33.5	77.0	6.5	23%	36%	71%
2018	142.9	195.1	8.0	30.0	57.9	5.5	21%	30%	68%
2019	144.4	197.9	8.1	32.2	60.6	5.6	22%	31%	69%
2020	132.5	145.8	7.9	16.7	1.7	5.3	13%	1%	67%
2021	132.4	145.5	7.9	16.4	1.4	5.3	12%	1%	67%
2022	131.8	144.6	7.9	15.6	0.7	5.3	12%	0%	67%
2023	95.6	111.7	4.1	36.8	39.0	2.0	39%	35%	49%
2024	95.8	111.3	4.1	36.7	37.5	2.0	38%	34%	50%
2025	93.0	98.1	4.0	36.7	38.6	2.0	39%	39%	50%
2026	91.9	96.1	4.0	36.7	38.4	2.0	40%	40%	51%
2027	94.2	92.8	4.1	36.7	38.7	2.0	39%	42%	50%
2028	94.2	91.4	4.1	36.7	38.8	2.0	39%	42%	50%
2029	94.3	91.5	4.1	36.7	38.8	2.0	39%	42%	50%
2030	92.5	89.0	4.0	36.7	38.8	2.0	40%	44%	51%

The estimated benefits, using the IGCB damage cost functions, are presented in the table below. These are calculated by multiplying the emission reduction achieved as a result of the IED by the damage cost functions, to estimate the damage cost avoided (i.e. the benefit).

Table 6.3 Estimated Benefits (IGCB Damage Cost Functions) (£m) (2008 prices)

Year	SO_2	NOx	Dust	AQ Total	CO_2	Total	Range
2016	171	148	42	361	421	781	781 (510 - 943)
2017	168	145	42	355	435	790	790 (499 - 947)
2018	163	129	39	331	452	782	782 (488 - 940)
2019	166	131	39	337	468	804	804 (501 - 967)

Year	SO_2	NOx	Dust	AQ Total	CO_2	Total	Range
2020	143	80	39	261	418	679	679 (417 - 845)
2021	142	79	39	261	572	832	832 (493 - 1050)
2022	141	79	39	259	691	950	950 (564 - 1266)
2023	55	34	26	115	24	139	139 (103 - 165)
2024	55	33	26	113	29	142	142 (104 - 169)
2025	55	34	26	114	33	147	147 (107 - 177)
2026	55	34	26	114	37	151	151 (109 - 183)
2027	55	34	26	114	41	155	155 (111 - 190)
2028	55	34	26	114	45	159	159 (113 - 196)
2029	55	34	26	114	49	164	164 (115 - 203)
2030	55	34	26	114	53	167	167 (117 - 209)
Net NPV, net benefits from emissions reductions						**£5,718m**	

The table below presents the estimated benefits using the CAFE damage cost functions.

Table 6.4 Estimated Benefits (CAFE Damage Cost Functions) (£m) (2008 prices)

Year	SO_2	NOx	Dust	Total	Range
2016	1164	937	547	2648	2,648 (1401 - 3,894)
2017	1144	921	541	2606	2,606 (1379 - 3,832)
2018	1108	815	481	2404	2,404 (1271 - 3,538)
2019	1132	830	487	2449	2,449 (1294 - 3,603)
2020	973	504	474	1950	1,950 (1023 - 2,878)
2021	970	502	473	1945	1,945 (1020 - 2,870)
2022	962	498	470	1930	1,930 (1012 - 2,848)
2023	376	216	119	711	711 (375 - 1,047)
2024	375	208	119	701	701 (370 - 1,033)
2025	375	213	119	707	707 (373 - 1,041)
2026	374	213	119	706	706 (372 - 1,040)
2027	374	214	119	708	708 (373 - 1,043)
2028	375	215	119	709	709 (374 - 1,044)
2029	375	215	119	709	709 (374 - 1,044)
2030	375	215	119	708	708 (374 - 1,043)
Net NPV, net benefits from emissions reductions				**£17,857m**	

6.3 Scenario “lower”

The forecast BAU (i.e. no-IED) emissions and the estimated reductions resulting from the IED “lower” scenario, are presented in Table 6.5.

Table 6.5 BAU Emissions and “Lower” Scenario Emission Reductions

	BAU emissions			Lower scenario emission reduction			Percentage reduction		
Year	SO_2	NOx	Dust	SO_2	NOx	Dust	SO_2	NOx	Dust
2016	163.1	215.8	5.9	36.8	76.1	2.9	23%	35%	49%
2017	163.1	215.8	5.9	35.9	72.6	2.8	22%	34%	48%
2018	163.1	215.8	5.9	37.5	73.1	2.9	23%	34%	49%
2019	163.1	215.8	5.9	38.3	73.0	2.9	23%	34%	50%
2020	132.5	145.8	7.9	16.7	1.7	5.3	13%	1%	67%
2021	132.4	145.5	7.9	16.4	1.4	5.3	12%	1%	67%
2022	131.8	144.6	7.9	15.6	0.7	5.3	12%	0%	67%
2023	95.6	111.7	4.1	36.8	39.0	2.0	39%	35%	49%
2024	95.8	111.3	4.1	36.7	37.5	2.0	38%	34%	50%
2025	93.0	98.1	4.0	36.7	38.6	2.0	39%	39%	50%
2026	91.9	96.1	4.0	36.7	38.4	2.0	40%	40%	51%
2027	94.2	92.8	4.1	36.7	38.7	2.0	39%	42%	50%
2028	94.2	91.4	4.1	36.7	38.8	2.0	39%	42%	50%
2029	94.3	91.5	4.1	36.7	38.8	2.0	39%	42%	50%
2030	92.5	89.0	4.0	36.7	38.8	2.0	40%	44%	51%

The estimated benefits using the IGCB damage cost functions are presented in the table below.

Table 6.6 Estimated Benefits (IGCB Damage Cost Functions) (£m)

	SO_2	NOx	Dust	AQ Total	CO_2	Total	Range
2016	55	67	18	140	427	566	566 (338 - 699)
2017	54	64	18	135	442	577	577 (328 - 705)
2018	56	64	18	138	458	596	596 (338 - 729)
2019	57	64	18	139	474	613	613 (347 - 750)
2020	143	80	39	261	418	679	679 (417 - 845)
2021	142	79	39	261	572	832	832 (493 - 1050)
2022	141	79	39	259	691	950	950 (564 - 1266)

	SO_2	NOx	Dust	AQ Total	CO_2	Total	Range
2023	55	34	26	115	24	139	139 (103 - 165)
2024	55	33	26	113	29	142	142 (104 - 169)
2025	55	34	26	114	33	147	147 (107 - 177)
2026	55	34	26	114	37	151	151 (109 - 183)
2027	55	34	26	114	41	155	155 (111 - 190)
2028	55	34	26	114	45	159	159 (113 - 196)
2029	55	34	26	114	49	164	164 (115 - 203)
2030	55	34	26	114	53	167	167 (117 - 209)
NPV, benefits from emissions reductions						**£4,975m**	

The table below presents the estimated benefits using the CAFE damage cost functions.

Table 6.7 Estimated Benefits (CAFE Damage cost Functions) (£m)

Year	SO_2	NOx	Dust	Total	Range
2016	357	401	162	920	920 (491 - 1,349)
2017	348	383	159	889	889 (474 - 1,304)
2018	363	385	161	910	910 (485 - 1,335)
2019	371	384	163	918	918 (489 - 1,348)
2020	973	504	474	1950	1,950 (1023 - 2,878)
2021	970	502	473	1945	1,945 (1020 - 2,870)
2022	962	498	470	1930	1,930 (1012 - 2,848)
2023	376	216	119	711	711 (375 - 1,047)
2024	375	208	119	701	701 (370 - 1,033)
2025	375	213	119	707	707 (373 - 1,041)
2026	374	213	119	706	706 (372 - 1,040)
2027	374	214	119	708	708 (373 - 1,043)
2028	375	215	119	709	709 (374 - 1,044)
2029	375	215	119	709	709 (374 - 1,044)
2030	375	215	119	708	708 (374 - 1,043)
NPV, benefits from emissions reductions				**£11,903m**	

7. Competition Assessment

In May 2008, a competition assessment was carried out for Defra assessing policy options (scenarios 1-4) prior to negotiations with stakeholders and the Council. Since then there has been numerous proposals which have been assessed (scenarios 5-20). The final text of the Directive was agreed and subsequently published in the OJEU in December 2010. This section focuses on the possible impacts on competition under the "lower" and "upper" scenarios which have been assessed in this report based on the final text of the Directive.

The competition guidelines (August 2007)[26] set out four main questions, which requires asking whether the scenarios considered for implementation of the IED for LCPs would affect the market by:

1. Directly limiting the number or range of suppliers?
2. Indirectly limiting the number or range of suppliers?
3. Limiting the ability of suppliers to compete?
4. Reducing suppliers' incentives to compete vigorously?

A brief summary of the four questions are presented below in Table 7.1 and for those where the answer to one of the questions is "Yes", then an explanation is provided within this section.

The results should be included in the "Evidence Base" within the Impact Assessment template.

Table 7.1 Summary of the Competition Test

Question	LCP sector
Q1. Directly limit the number or range of suppliers?	Yes*
Q2. Indirectly limit the range of suppliers?	Yes
Q3. Limit the ability of suppliers to compete?	No
Q4. Reduce suppliers' incentives to compete vigorously?	Yes*

* For ESIs only

Many ESI plants will not be required to abate beyond their BAU level and are therefore largely unaffected by the IED. However under the "upper" scenario for those plants currently under the NERP, there could be significant abatement requirements as the flexibilities of the NERP would be removed. This could involve significant investment in SO_2 and NOx abatement although the option of opting for the LLD is still available. Because the other ESI plants will not need to face this significant additional cost, it can not be assumed that these plants can

26 http://www.oft.gov.uk/shared_oft/reports/comp_policy/oft876.pdf

necessarily pass on the full costs to their customers[27]. If these plants decide closure is a better alterative (financially) this may have implications on energy supply and indirectly result in limiting the number of suppliers.

Under the "lower" scenario, there is more flexibility in complying with the requirements, and in particular there is the option of the TNP in addition to the LLD. Based on the modelling undertaken, it is estimated that some installations will opt for the LLD or the TNP rather than comply with the proposed ELVs. It is also possible for installations to opt under the TNP for only one or more pollutants. The cost advantage of the TNP is that it allows installations more time to meet the ELV requirements (with gradual reductions in overall emissions and not subject to the tighter ELVs). There is also the added flexibility from being able to trade for allowances assuming that the UK implements the TNP in this way (i.e. similar to the current NERP). This allows installations more flexibility in aligning investment in abatement technology with the natural lifetime of existing equipment. It is assumed that the Iron & Steel sector and the "Other" sector will also opt for the TNP for similar reasons.

If a large proportion of ESIs opt for the LLD (which would mean that these firms would have limited operational hours and subject to current ELVs) then in the absence of any new significant supply, this would directly reduce electricity production supply and overall capacity. This could drive prices up and operator's profits. If there is a reduction in supply (and demand remains relatively constant) there could potentially be fewer incentives for suppliers to compete given their market power and limited supply.

The majority of petroleum refineries currently under the NERP will be required to make SO_2 and NOx reductions whilst only some of those plants currently subject to ELVs will need to reduce SO_2 and NOx emissions given the final content of the Directive. It is important to note that some of the affected plants (ESI and PR) may be able to pass on the costs of abatement (and the administrative burdens) to their customers due to the nature of the electricity and petroleum markets where these plants might have the power to dictate prices (especially as the whole of the EU will be impacted) rather than absorb the costs of abatement (e.g. limited suppliers and high investment costs leading to oligopoly powers). The high annual cost will be an additional barrier to entry for new entrants – however it is already very difficult to enter the industry due to very high investment costs (e.g. infrastructure, network distribution, and advertising costs) and the industry is therefore dominated by larger multinational companies.

Unlike ESI and PR plants, I&S plants have less power to pass on the costs of abatement due to import penetration (imports from other countries). This is less of an issue against EU competitors as they will also be subject to the new Directive, but those plants not subject to IED and possibly a carbon trading scheme (e.g. like the EU ETS) may gain a competitive advantage.

Plants in the Other industrial sectors will be required to make reductions under both scenarios, although the distribution of impacts is very uneven, with a small number of plants expected to contribute the majority of emissions reductions and costs. Given the wide spectrum of industries covered it is difficult to do a competition assessment. Some larger plants that have some form of monopoly/oligopoly power should be able to pass on the costs of abatement to their customers and therefore be somewhat unaffected by the IED (e.g. some chemicals

[27] However, these plants already have installed abatement and have incurred the additional costs already – if anything the NERP plants have had a competitive advantage for some time now

plants) whilst those who are price takers (e.g. those trading in international commodity products) may be adversely affected.

8. Distributional Effects on Different Size Firms

LCPs considered under the “lower” and “upper” scenarios are plants that have aggregate combustion units greater than 50MWth (taking into account the relevant aggregation rules). LCPs that have to comply with ELVs under one (or both) of the Scenarios considered in the analysis will not be subjected to the same cost, as some plants may not require further reductions (although they will still be subject to approximately £3k in additional administrative burdens).

Overall costs over the time period of the analysis (2016-2030) are expected to be lower under the ”lower” scenario (compared to the ”upper” scenario) as under a TNP many plants will initially have allowances greater than their BAU emissions so will not have to install abatement until a later date (although some would choose to abate to sell excess allowances to those who need to abate, and these plants may choose to purchase allowances if it is cheaper then the cost of abatement).

The table below shows the number of plants affected and an indicative cost for some sectors.

Table 8.1 Average Compliance Costs per Affected Plant (2008 prices)

<table>
<tr><th>LCP Sectors</th><th>Scenario “lower”</th><th>Scenario “higher”</th></tr>
<tr><td>ESI</td><td></td><td></td></tr>
<tr><td>No of plants affected on average 2016-2030</td><td colspan="2">11</td></tr>
<tr><td>% of plants affected on average 2016-2030</td><td colspan="2">11%</td></tr>
<tr><td>Average cost per affected plant (£m) per year between 2016-2030</td><td>5.65</td><td>6.54</td></tr>
<tr><td>PR</td><td></td><td></td></tr>
<tr><td>No of plants affected on average 2016-2030</td><td colspan="2">19</td></tr>
<tr><td>% of plants affected on average 2016-2030</td><td colspan="2">40%</td></tr>
<tr><td>Average cost per affected plant (£m) per year between 2016-2030</td><td>1.25</td><td>1.25</td></tr>
<tr><td>I&S</td><td></td><td></td></tr>
<tr><td>No of plants affected on average 2016-2030</td><td colspan="2">6</td></tr>
<tr><td>% of plants affected on average 2016-2030</td><td colspan="2">60%</td></tr>
<tr><td>Average cost per affected plant (£m) per year between 2016-2030</td><td>0.56</td><td>0.83</td></tr>
</table>

LCP Sectors	Scenario “lower”	Scenario “higher”
Other		
No of plants affected on average 2016-2030	40	
% of plants affected on average 2016-2030	60%	
Average cost per affected plant (£m) per year between 2016-2030	0.28	0.42

Note: Costs in the table above are presented based on NPV with a discount rate of 3.5%.

9. Social Impact Assessments

9.1.1 Statutory Equality Duties Impact Test guidance

The impact of the IED on the people of different ages, disability, gender reassignment, pregnancy and maternity, race, religion or belief, sex and sexual orientation have been considered and it is not expected that it will have any impact.

9.1.2 Health and well-being

The impact of the IED on education, housing, crime, transport and people's lifestyle choices have been considered and it is not expected that it will have any impact. The impacts on health of the IED are discussed in the benefits section and estimated using IGCB damage cost functions. The impact on employment is discussed in the competition assessment section.

9.1.3 Human rights

The impact of the IED on human rights has been considered and it is not expected that it will have any significant impact.

9.1.4 Justice

The impact of the IED on the courts, tribunals, prisons, probation, the legal aid budget, the prosecuting bodies and the judiciary have been considered and it is not expected that it will have any significant impact.

9.1.1 Rural proofing

The impact of the IED on rural communities has been considered and it is not expected that it will have any impact.

9.1.2 Sustainable Development

There is no increase in the scope of the IED for LCPs however there is a tightening of the ELVs for certain categories of LCP (categorised by fuel, capacity and sector). It is not expected that the IED will have any impact on the installations' waste production or water efficiency. There could theoretically be incentive to improve energy efficiency for installations covered by the LLD and TNP to optimise useful energy output achievable within the hours or absolute emissions cap. However, this effect has not been quantified within this study under the assumption that improvements in energy efficiency will be minimal as there is already existing incentive to maximise efficiency under other legislation such as the European Emissions Trading System (EU ETS).

10. Summary

This assessment show that the IED will result in a significant reduction of emissions of SO_2, NO_x and dust from LCPs, as presented in Table 10.1.

Table 10.1 Emission Reductions Resulting from IED

	Upper scenario emission reduction (kt)			Lower scenario emission reduction (kt)		
Year	**SO_2**	**NOx**	**Dust**	**SO_2**	**NOx**	**Dust**
2016	35.4	80.0	6.6	36.8	76.1	2.9
	24%	37%	72%	23%	35%	49%
2017	33.5	77.0	6.5	35.9	72.6	2.8
	23%	36%	71%	22%	34%	48%
2018	30.0	57.9	5.5	37.5	73.1	2.9
	21%	30%	68%	23%	34%	49%
2019	32.2	60.6	5.6	38.3	73.0	2.9
	22%	31%	69%	23%	34%	50%
2020	16.7	1.7	5.3	16.7	1.7	5.3
	13%	1%	67%	13%	1%	67%
2016-2030 total	**473.8**	**588.1**	**56.3**	**491.1**	**607.4**	**43.8**
	27%	**29%**	**62%**	**27%**	**29%**	**55%**

Overall both scenarios considered have positive Benefit/Costs ratios. The table below presents the aggregated results for the two Scenarios based on net present values of the costs and benefits between 2016 and 2030.

Table 10.2 Total NPV Costs and Benefits (£m) for 2016-2030

Scenarios	Total Costs (£m)	Total Benefits (£m)	Ratio (Benefits/Costs)
Scenario "upper"	1,907 (1,335 – 2,479)	IGCB: 5,718 (3,623 – 7,049) CAFE: 17,857 (9,417 – 26,296)	IGCB: 3.0 (1.5 – 5.3) CAFE: 9.4 (3.8. – 19.7)
Scenario "lower"	1,631 (1,142 – 2,121)	IGCB: 4,975 (3,027 – 6,209) CAFE: 11,903 (6,282 – 17,525)	IGCB: 3.0 (1.4 – 5.4) CAFE: 7.3 (3.0 – 15.3)

Of the two scenarios, the results suggest that the "lower" scenario entails lower compliance costs than the "upper" scenario. However, the ratio of costs and benefits is the same for the two scenarios. This is due to lower benefits anticipated under the "lower" scenario (i.e. less emission reduction under TNP).

Appendix A
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Table A.1 List of Organisations Contacted during Baseline Development

Type of organisation	Name
Competent authorities	Environment Agency SEPA
ESI	AEP
Petroleum Refineries	ConocoPhillips Ltd Exxon Mobil Total Lindsey Oil Refinery Ltd Petroplus Refining Teesside Ltd ConocoPhillips Shell (UK) Ltd Innovene Manufacturing Scotland Ltd Milford Haven Refinery
Iron & Steel	Corus UK Ltd
Other	Survey was emailed to all “Other” plants under the NERP and telephone calls were prioritised to plants with the largest emissions. SembCorp Utilities, Alcan Smelting & Power UK, Sabic UK Petrochemicals Holdings Ltd, Invista Textiles (UK) Ltd, UPM-Kymmene (Caledonian Paper Mill), BASF plc, UPM-Kymmene (Shotton Paper Mill), Ford Motor Co Ltd, Humber Energy, Polimeri Europa, Ineos Chlor Ltd
Gas turbine manufacturers	Siemens Rolls Royce GE

Appendix B
IED Emission Limit Values

Table B.1 ELVs set in Part 1 of Annex V

Pollutant	**Fuel type**	**ELVs (figures in mg/Nm3)** (Note 1)			
		50 to 100 MWth	**100 to 300 MWth**	**>300 MWth**	**Notes**
SO2	Coal & lignite	400	250	200	1,2
	Biomass	200	200	200	
	Liquid fuels	350	250	200	
	Peat	300	300	200	
	Gaseous	In general		35	3
		Liquefied gas		5	
		Low calorific gases from coke oven		400	
		Low calorific gases from blast furnace gas		200	
NOx	Coal & lignite and other solid fuels	300	200	200	4,5
		450	in case of pulverised lignite combustion for 50-100 MWth only		
	Biomass & peat	300	250	200	
	Liquid fuels	450	200	150	6,7,8,9
	<u>Gaseous</u>				14, 15
	LCPs firing natural gas with the exception of gas turbines and engines	100			
	Gas turbines (including CCGT), using natural gas (Note) as fuel	50			10
	Gas turbines (including CCGT), using natural gas as fuel (Note)	*75*			*11, 12*
	Gas turbines (including CCGT), using other gases as fuel (Note)	120			13
	Gas engines	100			
	LCPs firing blast furnace gas, coke oven gas or low calorific gases from gasification of refinery residues, with the exception of gas turbines and gas engines	200	17	20	
	LCPs firing other gases, with the exception of gas turbines and gas	200	200	200	

Pollutant	Fuel type	ELVs (figures in mg/Nm3) (Note 1)			
		50 to 100 MWth	**100 to 300 MWth**	**>300 MWth**	**Notes**
	engines				
	Liquid fuels	30	25	20	16
	Gaseous	In general		5	
		Blast furnace gas		10	
		Gases produced by steel industry which can be used elsewhere		30	
CO	<u>Gaseous</u> LCPs firing natural gas with the exception of gas turbines and engines	100			Note that for CO emissions only gaseous fuels have ELVs
	Gas turbines (including CCGT), using natural gas (Note) as fuel	100			
	Gas turbines (including combined cycle gas turbines (CCGT)) using light and middle distilates as liquid fuels	100			Gas turbines for emergency use that operate less than 500 operating hours per year are not covered by the ELVs set out in this point.
	Gas engines	100			

Notes:		**all**	**<300**	**>300**
1	SO2: LCPs, using solid fuels which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years (SO2). A part of a LCP discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to these ELVs in relation to the total rated thermal input of the entire LCP	800		
2	SO2: LCPs using liquid fuels, which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years. A part of a LCP discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to these ELVs in relation to the total rated thermal input of the entire LCP.		850	400
3	SO2: LCPs, firing low calorific gases from gasification of refinery residues, which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003. A part of a LCP discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to these ELVs in relation to the total rated thermal input of the entire LCP.	800		

Notes:		all	<300	>300
4	NOx: LCPs using solid or liquid fuels with a total rated thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 (or submitted application, provided that the plant was put into operation no later than 27 November 2003), and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years, shall be subject to an ELV for NO_x of 450 mg/Nm^3. A part of a combustion plant discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to the emission limit values set out in the preceding three paragraphs in relation to the total rated thermal input of the entire combustion plant.	450		
5	NOx: LCPs using solid fuels with a total rated thermal input greater than 500 MW, which were granted a permit before 1 July 1987 and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years, shall be subject to an ELV for NO_x of 450. A part of a combustion plant discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to the emission limit values set out in the preceding three paragraphs in relation to the total rated thermal input of the entire combustion plant.	450		
6	NOx: For the firing of distillation and conversion residues from the refining of crude oil for own consumption in LCPs with a total rated thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003 - the ELV is 450 mg/Nm3	450		
7	NOx: LCPs in chemical installations using liquid production residues as non commercial fuel for own consumption with a total rated thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, shall be subject to an ELV for NO_x of 450 mg/Nm^3.	450		
8	NOx: LCPs using solid or liquid fuels with a total rated thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years, shall be subject to an ELV for NO_x of 450 mg/Nm^3. A part of a combustion plant discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to the emission limit values set out in the preceding three paragraphs in relation to the total rated thermal input of the entire combustion plant.	450		
9	NOx: LCPs using liquid fuels, with a total rated thermal input greater than 500 MW which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years, shall be subject to an ELV for NOx of 400 mg/Nm^3. A part of a combustion plant discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to the emission limit values set out in the preceding three paragraphs in relation to the total rated thermal input of the entire combustion plant.	400		
10	Natural gas is naturally occurring methane with not more than 20 % (by volume) of inerts and other constituents. For gas turbines (including CCGT), the NOx and CO ELVs set out in the table contained in this point apply only above 70 % load. Gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the emission limit values set out in this point. For single cycle gas turbines not falling into any of the above categories mentioned under note 3, but having an efficiency greater than 35 % - determined at ISO base load conditions - the emission limit value for NOx shall be $50x*\eta/35$ where η is the gas turbine efficiency at ISO base load conditions expressed as a percentage.			

Notes:		all	<300	>300
11	75 mg/Nm3 in the following cases, where the efficiency of the gas turbine is determined at ISO base load conditions: (i) gas turbines, used in combined heat and power systems having an overall efficiency greater than 75 %; (ii) gas turbines used in combined cycle plants having an annual average overall electrical efficiency greater than 55 %; (iii) gas turbines for mechanical drives. Natural gas is naturally occurring methane with not more than 20 % (by volume) of inerts and other constituents. For gas turbines (including CCGT), the NOx and CO ELVs set out in the table contained in this point apply only above 70 % load. Gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the emission limit values set out in this point.	75		
12	For gas turbines (including CCGT) firing natural gas which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years. A part of a LCP discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to the ELVs set out in the preceding paragraph in relation to the total rated thermal input of the entire LCP	150		
13	NOx: 300 mg/Nm³ for such LCPs with a total rated thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 (or submitted application, provided that the plant was put into operation no later than 27 November 2003). For gas turbines (including CCGT), the NOx and CO ELVs set out in the table contained in this point apply only above 70 % load. Gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the emission limit values set out in this point.	300		
14	NOx: For gas turbines (including CCGT) firing other gases (or liquid fuels) which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1 500 operating hours per year as a rolling average over a period of five years; ELV for NOx is 200 mg/Nm³ A part of a LCP discharging its waste gases through one or more separate flues within a common stack, and which does not operate more than 1 500 operating hours per year as a rolling average over a period of five years, may be subject to the ELVs set out in the preceding paragraph in relation to the total rated thermal input of the entire LCP	200		
15	NOx: Gas turbines (including combined cycle gas turbines (CCGT)) using light and middle distillates as liquid fuels shall be subject to an ELV for NOx of 90 mg/Nm3. Gas turbines for emergency use that operate less than 500 operating hours per year are not covered by the ELVs set out in this point.	90		
16	Dust: for the firing of distillation and conversion residues from the refining of crude oil for own consumption in combustion plants which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003; ELV is 50 mg/Nm3	50		
17	NOx: 300 mg/Nm³ for such LCPs with a total rated thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 (or submitted application, provided that the plant was put into operation no later than 27 November 2003).	300		
18	SO2: Average emission limit values (mg/Nm3) for SO2 for multi fuel firing combustion plants within a refinery, with the exception of gas turbines and gas engines, which use the distillation and conversion residues from the refining of crude oil for own consumption, alone or with other fuels: for combustion plants which were granted a permit before 27 November 2002 or the operator of which had submitted a complete application for a permit before that date, provided that the plant was put into operation no later than 27 November 2003 For other combustion plant	1000 600		

Appendix C
Derivation of Capacity Expansion Plan

Aim

The expansion plan has been derived following an aim of a developing a conservative central estimate. As such, the approach aims to ignore more extreme alternative judgements that could be taken on plant retirement and other supply side issues. The most important of these, the ratio between CCGT and nuclear plant is maintained throughout the period. In addition the ratio to renewable resources is maintained. At the end of the period there is slightly less coal capacity, though new coal is developed.

Method

The plant in the capacity plan uses the list of plant identified in the DUKES table 5.11 “Power Stations in the United Kingdom (operational at the end of May 2008)” and checked against the updated version for 2010. This provides a list of existing plant together with in-service dates and capacity.

Looking forward, a number of retirement plans and new build scenarios are possible with degrees of interdependency. The original basis of the plan was the scenario identified as “Extended RO32” in the Redpoint report “GB Electricity Generation Investment: Potential impact of policy options on security of supply, prices and CO2 emissions, [draft results 18 September 2008]”. A number of specific revisions have been made with respect to this basic plan and are reflected in the main report. In overall terms, existing coal plant has been assumed to remain longer in operation which delays the introduction of new coal plant, including that fitted with CCS.

As this plan is intended to reflect opinion prevailing in 2008, tidal capacity (Severn barrage) is retained. However the total of wind plus tidal capacity is what could be considered a central estimate nowadays and hence provides an appropriate basis for the investigations of this study.

The original Redpoint forecasts categorised retired plant in the following groups:

- CCGT;
- Coal;
- Nuclear;
- GT&OCGT;
- Oil.

It is therefore possible, without use of any other data sources, to match the retiral of existing plant at this level of aggregation.

In addition, Redpoint provide the details of specific plant which is retired before 2015 in Redpoint et al 2008, table 40. As well as defining dates for these specific plants, this also constrains choices made in the expansion plan for the remaining plant within the aggregated totals.

The methodology for remaining plant was to retire older plant first and, where there was a subsequent choice, to retire plant first that was less essential to maintaining regional security of supply.

New build is also specified at an aggregated level and is categorised as.

- CCGT;
- Coal(ASC);
- Coal(ASC+CCS);
- Nuclear;
- Renewables.

The expansion plan does not attempt to do other than assign a block of capacity under each of these headings.

Methodological Simplifications

Site by Site Retirals

With a few exceptions plant has been retired on a site by site basis, i.e. all generating sets at a site retire on the same date. The exceptions include only plant that is specifically identified as having been partially retired in the data sources identified above. The analysis using the capacity plan is expected to be concerned with aggregate results and so this simplification is appropriate to conclusions by plant type. Conclusions which considered more detailed set by set, or site by site impacts would need a plan which better reflected system stability and other local concerns.

Annual Data

Retiral data in these plans is expressed annually. For tight demand/supply balances this can be over-crude in not capturing impacts of summer/winter differences, the understanding being that plant would retire after the winter peak, which would reduce available summer capacity in the same nominal year.

Appendix D
Derivation of Emissions from Fossil Fuel Fired Plants

In order to convert the LCPD ELVs and LCP BREF BAT-AELs into fuel specific emission factors for comparison with actual performance the methodology adopted in EEA (2008) has been employed and the fuel-specific flue gas volumes presented in Table D.1 have been assumed. These values have been calculated in-house on a dry basis at the reference oxygen content and using the gross calorific values for each fuel.

Table D.1 Fuel-Specific Flue Gas Volumes

Fuel	Excess air (% O_2)	Specific Flue Gas Volume (m^3/GJ) (Note 1)
Biomass	6	331 (Note 2)
Hard coal	6	374
Brown coal	6	366
Liquid fuels	3	279
Natural gas	3	251
Natural gas (gas turbines)	15	760

Note 1: Entec calculated figures (on a dry basis at the reference oxygen content and using gross calorific values for each fuel).
Note 2: For biomass there is a wide range of variability in terms of types of fuels and their associated combustion properties. Therefore an average has been calculated and applied in this study based on analysis of a range of common biomass fuels.

New CCGT Emission Factors

For gas turbines there should not be in general any SO2 or dust emissions, hence we should only be concerned about NOx emissions. Unfortunately the BREF LCP document does **not** give an upper (or lower) range for NOx BREF BAT AELs for gas turbines. Therefore we applied the NOx ELVs that is applicable in the LCP directive for gas turbines. This is 50 mg NOx /Nm3 set in the LCPD for gas turbines (specific volume is 760 Nm3/GJ from table above), hence the emission factor is: 38 g / GJ for gas turbines.

New Coal Advanced Supercritical

The table below presents the emission factors for hard coal fired stations for upper and lower range BREF BAT AELs. Note that the emission factors are capacity dependent; most UK coal fired plants are > 300 MWth.

Table D.2 Emission Factors (g/GJ) for BREF BAT AELs (upper and lower range)

			Fuel					
Pollutant	**BREF Range**	**Capacity (MWth)**	**Biomass**	**Hard Coal**	**Brown Coal**	**Fuel Oil**	**Other Oil**	**Gas**
SO2	SO2 Upper	10000	66	74	74	56	56	3
		1000	66	74	74	56	56	3
		301	66	74	74	56	56	3
		300	99	93	93	70	70	3
		101	99	93	93	70	70	3
		100	99	148	148	98	98	3
		50	99	148	148	98	98	3
	SO2 Lower	10000	17	7	7	14	14	3
		1000	17	7	7	14	14	3
		301	17	7	7	14	14	3
		300	50	37	37	28	28	3
		101	50	37	37	28	28	3
		100	66	56	56	42	28	3
		50	66	56	56	42	28	3
NOx	NOx Upper	10000	66	74	74	42	42	25
		1000	66	74	74	42	42	25
		301	66	74	74	42	42	25
		300	83	74	74	56	56	25
		101	83	74	74	56	56	25
		100	99	111	167	126	126	25
		50	99	111	167	126	126	25
	NOx Lower	10000	17	19	19	14	14	5
		1000	17	19	19	14	14	5
		301	17	19	19	14	14	5
		300	50	33	33	14	14	5
		101	50	33	33	14	14	5
		100	50	33	74	42	42	5
		50	50	33	74	42	42	5
Dust	Dust Upper	10000	7	7	7	6	6	1
		1000	7	7	7	6	6	1

			Fuel					
Pollutant	**BREF Range**	**Capacity (MWth)**	**Biomass**	**Hard Coal**	**Brown Coal**	**Fuel Oil**	**Other Oil**	**Gas**
		301	7	7	7	6	6	1
		300	7	9	9	7	7	1
		101	7	9	9	7	7	1
		100	10	11	11	8	8	1
		50	10	11	11	8	8	1
	Dust Lower	10000	2	2	2	1	1	1
		1000	2	2	2	1	1	1
		301	2	2	2	1	1	1
		300	2	2	2	1	1	1
		101	2	2	2	1	1	1
		100	2	2	2	1	1	1
		50	2	2	2	1	1	1

Below are the emission factors for Coal ASC that were applied in the modelling:

In g/GJ	**SO2**	**NOx**	**Dust**
Coal ASC	74	74	7

Appendix E
Abatement Measures

Compliance measures and abatement costs have been taken from a range of sources, including GAINS, BREF documents, other published reports and consultation with specialists and operators. The following abatement measures have been considered as available options for this assessment. Inclusion in the list does not necessarily mean that the measure has been implemented in the modelling.

Table E.1 SO_2 Abatement Measures and their Costs used for LCPs (all costs presented in 2008 prices)

Sector	Measure	Abatement efficiency (%)	Lifetime of measure (years)	Capital cost (£m)	Operating cost (£/year)	Total annualised cost (£/year)	Cost (£/tonne abated)	Source
ESI (coal)	Flue Gas Desulphurisation (FGD) (wet)	90%	15	£130/GWe	£10m/GWe	£21.3m/GWe	(Plant specific)	Operator
ESI (coal)	Low sulphur coal (0.5%)	depends on BAU	-	-	-	-	£330	GAINS
ESI (oil)	FGD (wet)	90%	20	-	-	-	£3,740	GAINS
ESI (biomass)	FGD (wet)	95%	20	-	-	-	£3,380	GAINS
Pet Ref (gas)	Amine treating unit	99.5%	15	£3.0	£80,000	£342,000	£7,021 (Note 1)	Operator
Pet Ref (oil)	Low sulphur oil (0.5%)	depends on BAU	-	-	-	-	£445	GAINS
Pet Ref	Fuel switching to natural gas	100%	-	0	(Natural gas price: £5.67/GJ)	-	£10,567	Own estimates
Iron and Steel	Coke oven gas (COG) desulphurisation	95%	15	£4.33 (per 1000g/Nm3 COG)	£3.82 per 1000mg/Nm^3 COG	(Plant specific)	(Plant specific)	BREF
Other industry (oil)	FGD (wet)	85%	20	-	-	-	£780	GAINS
Other industry (coal)	FGD (wet)	85%	20	-	-	-	£1,170	GAINS
Other (oil)	Low sulphur oil (0.5%)	depends on BAU	-	-	-	-	£438	GAINS

Note 1: This is calculated based on the LCP to which it applies.

Table E.2 NOx Abatement Measures and their Costs used for LCPs (all costs presented in 2008 prices)

Sector	Measure	Abatement efficiency (%)	Lifetime of measure (years)	Capital cost (£)	Fixed operating cost (£/year)	Variable operating cost (£/MWhr)	Total annualised cost (£/year)	Cost (£/tonne abated)	Source
ESI (coal)	Selective Catalytic Reduction (SCR)	80%	10	£140/kWe	£3.2/kWe	£0.74	(Plant specific)	(Plant specific)	JEP
ESI (CCGT)	SCR	80%	10	£150/kWe	£2.4/kWe	£0.05	(Plant specific)	(Plant specific)	JEP
ESI (oil/gas)	Combustion Modification (CM)	65%	20	-	-	-	-	£234	GAINS
ESI (OCGT/CCGT)	closure and reopen new CCGT	Depends on plant	20	CCGT: £460,000/Mwe OCGT: £280,000/MWe	(Plant specific)	(Plant specific)	(Plant specific)	(Plant specific)	Own estimates
Pet Ref	Low NOx burners	30%	15	£615,000	£8,200	-	£61,600	(Plant specific)	BREF
Pet Ref	Selective Non-Catalytic Reduction (SNCR)	70%	15	£3.28m	£492,000	-	£777,000	(Plant specific)	BREF
Pet Ref	SCR	85%	15	£14.3m	£1.64m	-	£2.89m	(Plant specific)	BREF
Iron and Steel	SCR	80%	20	£ 73/MW_{th}	-	-	-	£3,810	BREF
Other industry (coal)	CM	50%	20	-	-	-	-	£298	GAINS
Other industry (gas)	CM	50%	20	-	-	-	-	£621	GAINS
Other industry (oil)	SNCR	70%	20	-	-	-	-	£1,041	GAINS
Other industry (gas)	SNCR	70%	20	-	-	-	-	£1,479	GAINS
Other industry (coal)	SCR	80%	20	-	-	-	-	£1,602	GAINS
Other industry (gas)	SCR	80%	20	-	-	-	-	£2,798	GAINS

Table E.3 Dust Abatement Measures and their Costs used for LCPs (all costs presented in 2008 prices)

Sector	Measure	Abatement efficiency (%)	Lifetime of measure (years)	Capital cost (£)	Fixed operating cost (£/year)	Variable operating cost (£/MWhr)	Total annualised cost (£/year)	Cost (£/tonne abated)	Source
ESI	(FGD)	50%	(15)	(Assume FGD abates dust emissions; costs are given under the SO_2 abatement)					
Petroleum refineries	Fuel switching to natural gas	100%	(15)	(Assume switching to natural gas abates dust emissions; costs are given under the SO_2 abatement)					
Iron and Steel	High efficiency deduster	99%	20	-	-	-	-	£10,720	GAINS
Other industry	(FGD)	50%	(15)	(Assume FGD abates dust emissions; costs are given under the SO_2 abatement)					