PARSONS BRINCKERHOFF

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Coal and Gas Assumptions

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CONTENTS

LIST OF ABBREVIATIONS

BAT	Best Available Technology
BREF	BAT Reference
°C	Degree Celsius
CCGT	Combined Cycle Gas Turbine
CEGB	Central Electricity Generating Board
DCO	Development Consent Order
DCS	Digital Control Systems
DECC	Department of Energy and Climate Change
EA	Environment Agency
ELV	Emission Limit Values
EOH	Equivalent Operating Hours
EPC	Engineer, Procure, Construct
EU	European Union
FD	Forced Draught
FGR	Flue Gas Recirculation
GE	General Electric
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
HP	High Pressure
HT	High Temperature
ID	Induced Draught
IP	Intermediate Pressure
IPP	Independent Power Producers
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant Directive
LHV	Lower Heating Value
mg/Nm^3	Milligram per normal metre cubed
MWh	Megawatt hour
NO_x	Nitrous Oxides
OCGT	Open Cycle Gas Turbine (also called Simple Cycle Gas Turbine, SCGT)
O&M	Operation and Maintenance
PA	Primary Air
pH	Measure of acidity
PSSR	Pressure System Safety Regulations

ROFA	Rotating Opposed Fire Air
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
TNUOS	Transmission Network Use of System
UK	United Kingdom
UoS	Use of System
£M	Million Pound Sterling

EXECUTIVE SUMMARY

Parsons Brinckerhoff was asked by the Department of Energy and Climate Change (DECC) to undertake work in relation to the future use of gas and coal power plant technology in the UK and the associated modelling assumptions. The areas considered were:

a Maximum feasible build rates for Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT) power stations

The maximum feasible build rate for CCGT has been found to be 6 GW per year and the maximum feasible build rate for OCGT has been found to be 4 GW per year. Before 2017 these values are lower as a plant would need to have begun construction to be commissioned in these years. In 2014 and 2015 the maximum build rate is zero and in 2016 it is 0.9 GW. Table 2 shows how the build rates may be combined if both CCGT and OCGT are built in the same year.

b The factors that could affect the variation in costs for CCGT and OCGT power stations

A wide range of factors was considered including location, type of plant, international market, commercial, technical and design factors, regulation and cost of equipment. Interactions between these factors were also considered. Tables 8 and 9 show the maximum and minimum values for individual inputs affected by these factors. Table 10 shows realistic low and high cost cases for 900 MW CCGT plant; Tables 11 and 12 show realistic low and high cost cases for Large Frame Standby Plant and Aeroderivative Peaking Plant.

c The technologies which could be applied to existing coal fired power plants in order to attain compliance with the forthcoming Industrial Emissions Directive (IED)

A number of technologies have been described that reduce NOx emissions for coal fired plant. Only two technologies can be retrofitted that will meet the criteria for the IED. These are Selective Catalytic Reduction (SCR) and Hybrid SCR/Selective Non-Catalytic Reduction (SNCR). Hybrid SCR/SNCR is technically feasible but to the authors' knowledge has not been implemented on any plant. SNCR has not yet been applied at full scale in coal plant. There are a number of uncertainties associated with the hybrid approach due to its first of a kind nature, however as both technologies are applied at different points in the cycle they are essentially independent, which reduces the likelihood of any problems with applying both in sequence. There may be technical issues to be dealt with however as both technologies have been successfully retrofitted to coal plant separately it is unlikely that any such problems would be serious enough to render the hybrid unworkable.

d The costs of retrofitting SCR, and Hybrid SCR/SNCR

A number of sources were used to produce estimates of SCR and Hybrid SCR/SNCR retrofit costs. Table 18 shows the range of each input assumption, covering both SCR and Hybrid SCR/SNCR (with Hybrid values highlighted to differentiate them), and Table 19 shows the central cost estimates for SCR and Hybrid.

e The Work required for Plant Life Extension of existing power stations

Work required to extend the life of existing coal, CCGT and OCGT plants has been described and cost estimates have been produced. Most costs would fall under the standard Operation and Maintenance (O&M) cost that is already included in the model, and only additional costs that would not typically occur during the lifetime of the plant have been considered. All of the life extension works could be undertaken during planned outages. Table 24 shows the costs for a 10-year life extension of coal plant, Table 26 shows the costs for a 10-year life extension of CCGT plant, For OCGT plant life extension should be covered by the O&M cost.

For CCGT a cost is presented for upgrade of plant to meet emissions limits; this applies to some operating plant in the UK but not to others. Apart from this value no costs have been included for upgrade work.

The decision to extend the life of a plant would take into account not just the costs of life extension, but also the cost of continuing O&M and the cost of upgrades required e.g. to meet new legislative limits. The value of keeping the plant operating would be heavily dependent on the number of operating hours expected per year. As plant ages it becomes more obsolete and will be lower on the merit order, so it will operate less.

If plant life is extended long term eventually it will become impossible to find spares and the cost of O&M would increase as bespoke spares need to be manufactured. No cost estimates have been produced for such long term life extension.

1 INTRODUCTION

Parsons Brinckerhoff was asked by the Department of Energy and Climate Change (DECC) to undertake work in relation to the future use of gas and coal power plant technology in the UK and the associated modelling assumptions. Parsons Brinckerhoff has produced estimates for the relevant modelling assumptions based on a range of sources and a number of methods of analysis.

1.1 Structure of report

Section 2 of this report describes the expected maximum feasible build rates for CCGT and OCGT power plants from 2014 to 2050.

Section 3 describes the factors that could affect the variation in costs for CCGT and OCGT power plants. This section presents expected maximum and minimum values for each modelling input as well as realistic low and high cost cases for these plants.

Section 4 specifically describes the technologies which could be applied to existing coal fired power plants in order to attain compliance with the forthcoming IED.

Section 5 describes the costs of retrofitting SCR, and Hybrid SCR/ SNCR to existing UK coal fired power plants.

Section 6 describes the work required for Plant Life Extension of existing UK power plants and cost estimates for this work.

1.2 Scope of work

Appendix C contains the redacted methodology from the initial proposal; however some changes were later made to the scope of the work as follows:

- Section 1.2.6 of the proposal was removed from the scope.
- Only a maximum technically feasible build rate was produced as described in Section 2 of this report, rather than distinct high and low cases.
- Section 1.3.2 of the proposal was removed from the scope.
- The scope of Section 3 was clarified to identify the factors that could affect variation in costs for CCGT and OCGT and to produce new values including a wider range of factors than previously considered; and
- Tables were produced showing which life extension works could be adopted for coal and gas plant, when these works would be required and how much they would cost.

1.3 Acknowledgements

Parsons Brinckerhoff would like to thank the team at DECC and the following organisations that contributed to the peer review:

- EdF Energy.
- Mott MacDonald.
- DONG Energy.
- A number of other organisations that did not wish to be named.

2 FEASIBLE BUILD RATES FOR CCGT AND OCGT

2.1 Introduction

Parsons Brinckerhoff has undertaken research to assess the maximum feasible build rates for OCGT and CCGT in the UK, using information on historical build rates, manufacturers' production capability and expected availability of existing power plant sites which could become available for replanting. This report also considers significant future constraints such as the planning process, electricity and gas grid connections. The period 2014 to 2050 was considered.

It should be noted that the maximum feasible build rate described in this report is independent of economic constraints and considers only technical and procedural constraints. Economic constraints which would limit the interest of investors include the relative price of coal and gas and the expected falling load factor for CCGT plant in the face of rising capacity of intermittent renewable generation. In addition, access to finance may become a serious constraint if larger numbers of plants proceed at the same time. Financing would be constrained by limited resources and increased due diligence requirements due to perceptions of increased risk in an overheated market.

It should be further noted that the maximum feasible build rate is independent for each year, and represents the maximum capacity that could become operational in a given year *ignoring activity in other years*. It is understood that this maximum build rate will be used within DECC's modelling as an upper practical limit on the number of CCGT or OCGT plant beginning operation in any given year, and will not be applied in each year.

2.2 Approach

The maximum feasible build rate applicable in the UK is considered to be the result of several different constraints on power plant development and delivery, including:

- The availability of suitable sites.
- The rate at which power plant projects can be given sanction to proceed.
- The rate at which design and contracting of plants can progress.
- The capacity of the international market to deliver gas turbines.
- The ability of contractors to construct and commission power plant.

The first two of these constraints only limit the rate of construction when there are fewer sites with consent available than power plant projects. Currently there is a large pool of suitable sanctioned sites which have not yet proceeded to construction and further plants that are awaiting sanction.

Site availability is reviewed in Appendix A and a summary of the findings are presented below. The remaining constraints relate to the implementation of plants once a consented site is available. The building of a power plant requires skilled design resources, internationally sourced equipment, and local construction contractor resources. These elements are separate, but can interact at a plant level since design and construction resources are generally common to, and may be in demand from, other industries. For example, an EPC contractor may not offer a contract to deliver a plant on a particular timescale if he is not confident of the availability of the gas turbine from the factory or an available construction contractor able to build at the site on that timescale.

A historical perspective on the performance of the relevant stakeholders is described and the estimated capability of each of the constrained processes is set out and their interactions discussed to estimate the realistic range of maximum feasible build rates.

2.3 Site Availability

The most significant factors affecting how much CCGT and/or OCGT will be constructed and become operational in any given year are economics and policy. However both of these factors are outside the scope of this study. This study is investigating only technical limitations on build rates, and by extension only technical limitations on site availability.

The maximum technically feasible build rate is to be considered in isolation for each year, ignoring previous years. Appendix A considers a situation in which power plant sites obtain consent as they become available. It should be noted that consent is provided at a particular site for a particular type of plant, but is generally referred to as the “site” obtaining consent rather than the “plant” or “project” obtaining consent. This is because a particular power plant project may consider a number of sites before deciding on one, but the name of the project/plant may not change. In any individual year it is then assumed that no new plant has begun operation since 2014, but that all sites that have become available and had time for construction of new plant before that year are assumed to complete construction and be commissioned as CCGT or OCGT plant in that year. Appendix A therefore shows, for each individual year, the maximum amount of gas plant that could begin operation in that year *if no new plant had begun operation since 2014*. This is based on the following assumptions for identified sites:

- CCGT/OCGT sites at which plant are currently under construction continue construction; 900 MW is expected to begin operation in 2016.
- CCGT/OCGT sites that already have consent for CCGT/OCGT are available to begin plant construction in 2014 and therefore become available to operate in 2017.
- CCGT/OCGT sites that have applied for consent are granted consent in 2016 and become available for operation in 2019. It is not known for all of these sites when they applied for consent so it has been assumed that they would all be granted consent in the same year, although in reality some may be granted consent in 2014 or 2015.
- Sites that have withdrawn their application for consent or sites for which consent has expired begin a new application in 2014, are granted consent in 2017 and become available for operation in 2020.
- Sites that are currently planned to be developed as clean coal i.e. coal with carbon capture cancel their coal plants and apply for consent for CCGT/OCGT in 2014, are granted consent in 2017 and become available for operation in 2020. Obtaining a gas pipeline is not considered in this constraint and is discussed below.
- Currently operational power plants that have passed the end of their design life cease operation, begin demolition and begin the consenting process in 2014, are granted consent in 2017 and become available for operation in 2020. The demolition process would be completed before the final consent application is submitted but this is not anticipated to impact on the estimate of three years for the consenting process.

- Currently operational power plants of all types that have a design life beyond 2014 cease operation when their design life ends i.e. they do not extend their life, begin demolition and apply for consent as soon as their design life ends, are granted consent 3 years later and become available for operation 3 years after that, i.e. they become available for operation 6 years after the end of their design life.

From 2017 onwards, there is just under 14 GW potential at available sites which could begin operation as CCGT/OCGT, rising to 93 GW of potential at available sites by 2050. Therefore, from 2017 onwards, site availability is not considered to limit the maximum technically feasible build rate in any individual year.

Development Consent Orders can be issued at a rate of 5,500 MW per annum without significant change to the consenting process. However as previously stated there are almost 15 GW of sites that have already obtained consent and a further 10 GW that have already begun the consenting process and are assumed to obtain consent by 2016. Assuming that each year after this 5,500 MW of new sites were consented for gas plant and 6,000 MW of new gas plant were constructed, it would be 2025 before the backlog of consented sites would be used up and by then over 54 GW of gas plant would have been constructed, an unlikely scenario. As the limits are considered in each individual year, it should also be considered that it would be technically feasible to build on sites with existing consent or to obtain consent significantly in advance of beginning construction, so the maximum consenting rate would not impact on the maximum technically feasible construction rate in any given year.

New gas connections may require reinforcement of the existing high pressure gas network. This could mean that the development and consent period for a new CCGT/OCGT plant could take up to seven years. This constraint is separate from site availability and has therefore not been considered in the table and graph in Appendix A. It has been assumed that all CCGT and OCGT plant that have been granted consent or have applied for consent have already considered this issue and either already have or will have a gas grid connection by the time the plant is commissioned. Sites are listed in Appendix A as becoming available for operation by 2024 or later could feasibly apply for consent in 2014 and obtain gas grid connection consent by 2021, i.e. they are unaffected. Therefore this limitation could only feasibly affect sites that do not currently have a gas connection and are listed in Appendix A as becoming available for operation before 2024. None of these sites are currently listed as becoming operational before 2017. As the number of sites available for operation is higher than the maximum technically feasible build rate by 2017, this constraint will therefore not affect the maximum technically feasible build rate.

2.4 Maximum rate for design and contracting

The maximum historical rate of plant development in the UK took place in the 1990's when just over three large generation plants of all types per year were designed and contracted. Greater engineering capacity was then available but was also working on a larger number of overseas plants. There have been a number of new entrants such as SKM and Rambold, which have recruited from the established players, effectively spreading the capacity more widely than before. This has also contributed to the building of links with resources in their home countries. The European resource of EdF, EoN, GdF Suez, Iberdrola and RWE is very substantial and as the major owners of power plant in the UK it seems very likely that in any circumstances of maximum build rate they would apply substantial resources to development and engineering of UK investment.

In consequence, the total capability of the main UK technical advisors has remained strong and is estimated to be about six plants contracted per year. The large teams employed by the European utilities should be capable of a similar capacity. If all of this European utility resource was applied to UK plants it would mean that up to 12 UK plants could be designed and contracted per year.

2.5 Maximum rate at which financial markets can fund CCGT or OCGT

It should be noted that finance availability is outside the scope of this report. This issue is mentioned for information only but is not included in the estimation of the maximum technically feasible build rates.

The rate at which plants can be funded has become a severe constraint on independent power plants internationally in the last five years. In 2008-9 virtually no plants were funded. More recently the markets have eased somewhat but delays in plants proceeding due to funding issues have been widely experienced. These delays relate more to commercial issues and the limited confidence of lenders in forecast plant viability.

Historically the funding market has been able to finance a wide range of private investments in the power sector and a return to such levels of confidence would permit perhaps up to ten plants per year to reach financial close. However, these conditions do not currently prevail and serious delays in funding recent power plants have been experienced, leading to doubts that more than two large plants a year could be currently digested by the funding markets.

2.6 Maximum build rates for CCGT and OCGT

Parsons Brinckerhoff has analyzed historical data for commissioned CCGT and OCGT in the UK, as well as coal fired plants since 1965 to the present day. Figure 1 shows the total capacity (in MW) commissioned in the UK for the period 1965-2013.

Two distinct periods can be identified; 1965-1975 which is dominated by coal fired plants built by the Central Electricity Generating Board (CEGB) and 1990-2000 after privatisation, dominated by CCGT plants developed by private companies. During the first period 1965-1975, an average of about 3 GW per year was connected to the grid, whereas during the second period 1990-2000 the rate was about 2.5 GW per year. The maximum capacity connected to the electricity grid in one year was in 1972, when around 6 GW was commissioned.

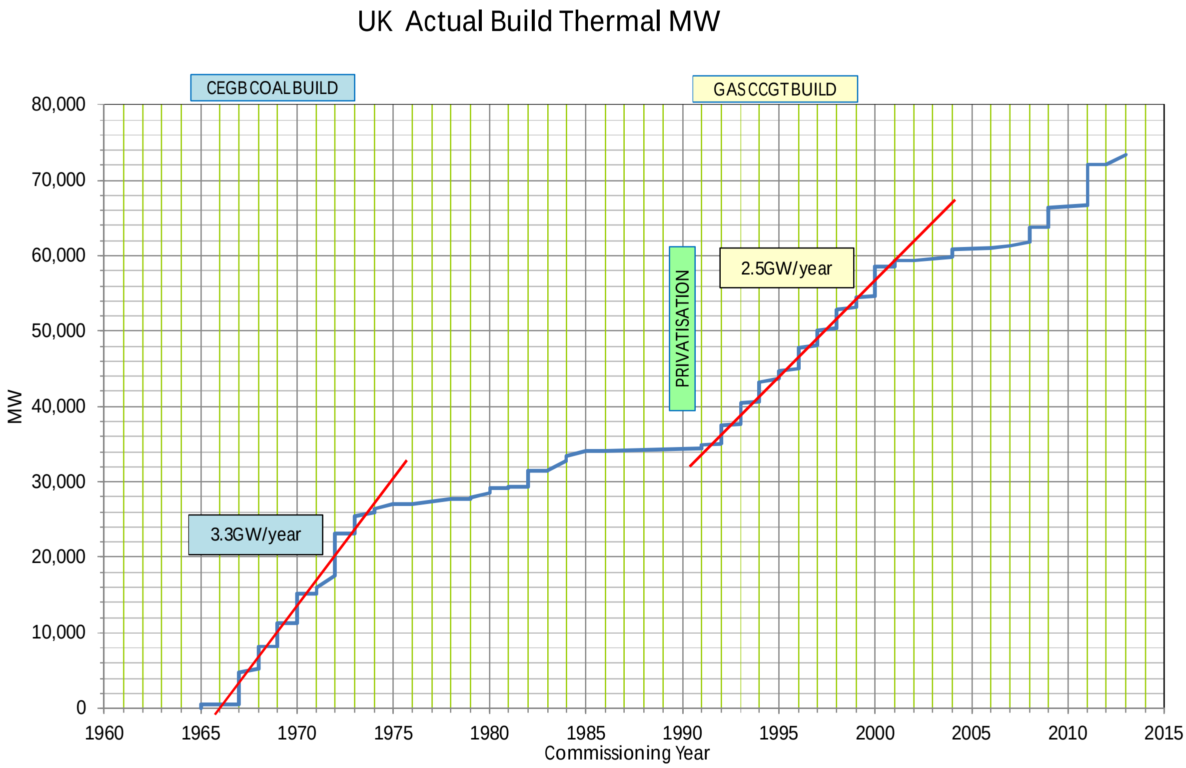

Figure 1 - Electrical Capacity Commissioned in the UK (DUKES, 2013)

As a measure of historic 'build capacity', Figure 2 shows the number of large grid connected generator units commissioned per year (although there are a number of configurations possible, a typical "unit" might be a single large coal-fired steam turbine or a single large gas turbine with or without an associated steam turbine; there would typically be more than one unit per project/plant/site). The CEGB coal build and period after privatisation can again be clearly distinguished. The average number of thermal generator units commissioned per year was 11 for both periods. The maximum number commissioned was in 1993 when 22 thermal generator units were commissioned at 6 different sites (i.e. 6 different power plants comprising 22 units total).

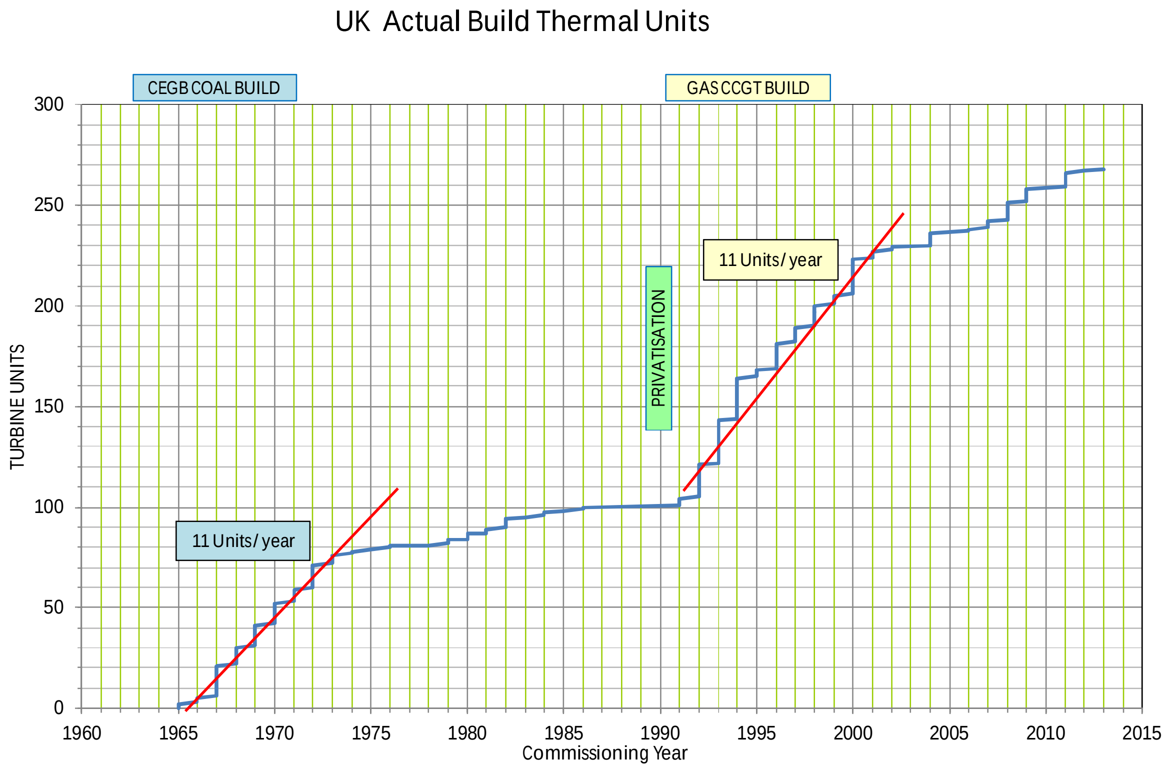

Figure 2 - Number of Units Commissioned in the UK (DUKES, 2013)

Figure 3 shows the number of large gas turbines delivered to the UK since 1960 (blue line), including both 'E' class and 'F' class turbines, and the total number of 50 Hz 'F' class machines delivered worldwide by manufacturers (red bars). Future plant are unlikely to be 'E' class and will be 'F' class or higher.

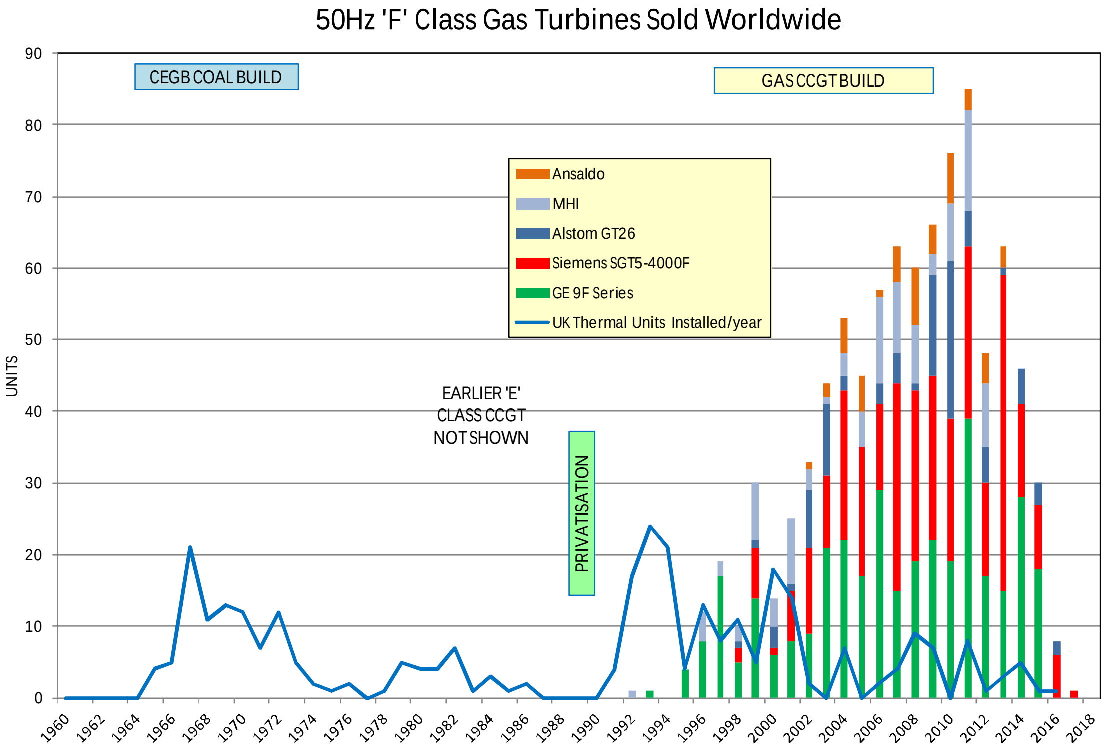

Figure 3 - 50Hz ‘F’ class Gas Turbines sold worldwide.

Over the last 10 years the majority of the thermal generator units commissioned in the UK have been ‘F’ class technology. The peak was 7 units in 2008.

Worldwide the manufacturing peak was 85 ‘F’ class gas turbines delivered in 2011. In recent years, the number of gas turbines delivered has reduced significantly as less 50 Hz plant has been purchased worldwide, especially in Europe.

It appears that the sustained capacity of the international gas turbine industry is around 60-65 50Hz ‘F’ class machines per year. Further capacity may be available from factories that manufacture 60 Hz machines, but the extent of such support will depend on international demand. Given their need to supply world markets, and their historical performance illustrated in Figure 2, it is considered unlikely that manufacturers would deliver more than about 20 per cent of this capacity into any single market, suggesting supply to the UK of around 12 gas turbines in any year.

2.7 Maximum rate for construction and commissioning

The number of UK power plant construction sites active at any time is likely to be a constraint, since the number of skilled construction personnel required can peak at around 600 for a 450 MW thermal generator unit. While under European Union (EU) legislation it is relatively simple to import European skilled labour to meet the demand, this has not proven straightforward where tensions with local resources has led to poor industrial relations severely delaying construction at several sites where it has been attempted in recent years.

Notwithstanding difficult industrial relations at some sites, recent experience has been that four CCGT plants at Pembroke, Staythorpe, Langage and West Burton (totalling 15 generator units, 6100 MW) have been able to be resourced largely simultaneously.

It has been estimated that a maximum 50 per cent increase in this level would be feasible if a greater proportion of UK construction resources were applied to the power sector. In that case up to six plants of 1500-2000 MW CCGT could be under construction at the same time. Given a typical plant construction period of around 30 months this would suggest that around three such plants could be completed per year within this constraint, offering between nine and twelve gas turbines in combined cycle.

There is no recent UK experience of construction of large OCGT plants. However, having a much higher proportion of factory assembly, OCGT plants require substantially less construction work with each generator unit completed after about 12 months site work with typically one third of the effort required for a CCGT. Hence potentially between two and three times the number of OCGT generator units can be completed per year than CCGT generator units.

2.8 Discussion of overall maximum feasible build rate

The various constraints on the maximum feasible build rate of CCGT/OCGT have been considered above and the findings are summarised in Table 1. A "Plant" is assumed to include 4 gas turbines with a net output of ~2,000 GW for CCGT and a single gas turbine rated ≤300 MW for OCGT.

Constraint Type	Limit Value Plants/year
current availability of suitable sites	16 consented sites available 14 GW available for operation from 2017 on: ~ 7 plants in this year, more in later years
rate of sanction to proceed	~3 plants/year in addition to existing suitable sites, also possible to obtain consent in advance of construction
rate of design and contracting	12 plants/year
manufacturing capacity	3-4 (assuming 4 gas turbines/ plant)
construction and commissioning rate	3 CCGT plants/year (3-4 gas turbines/ plant) 18 OCGT plants/year (1 gas turbine/ plant)

Table 1 - Constraints on Maximum Feasible Build Rates

With 15 GW of consented CCGT/OCGT sites, a further 10 GW that may be consented before 2016, and a consenting process that can consent 5.5. GW per annum, the availability of consented sites is not likely to become an issue unless 54 GW of plant has been constructed before 2025. As this is an extremely unrealistic scenario, site availability or consenting processes are not expected to limit the maximum feasible build rate in any individual year.

The capacity of the sector to design and contract plants is considerably less constraining than other constraints, although obtaining funding may be a serious limitation on the build rate. Funding limits have the potential to restrict the maximum feasible build rate if lenders are not satisfied with the robustness of the plant or the security on their funds.

International manufacturing capacity of appropriate large gas turbines is substantial and even if the UK is only able to command 20 per cent of the sustained capacity, between three and four plants of circa 2,000 MW could be delivered per year within this constraint.

While manufacturing has substantial capacity, construction and commissioning appears to be much more limited. Recent experience shows that even four plants under construction simultaneously has required significant imported skilled labour which has resulted in delays from industrial relations tensions. This suggests that up to six CCGT plants under construction simultaneously, in a two year period might be the limit for the sector, constraining completion of plants to three per year.

The smaller OCGT plants require much smaller construction effort so that many more plants could be completed per year within the construction and commissioning constraint, potentially delivering over 5,000 MW of capacity per year. However the logistics of moving the construction teams from site to site will mean that a reduced upper limit of around 4,000 MW per year is more realistic.

2.9 Combined build rates for CCGT and OCGT

Based on the analysis described above, it is estimated that up to 6,000 MW of CCGT can be built each year. There is a lot of variation available in size by selecting different GT manufacturers and different steam turbine configurations e.g. it is possible to link two GTs to a single ST, or one ST for each GT; these options would produce different size units of 450 - 600 MW. Individual plants of up to four generating units each would be expected, although more are possible if it is economically feasible. The 6,000 MW of CCGT could be three plants of 2,000 MW each, or 13 plants of 450 MW each, or 12 plants of 500 MW each.

For the purposes of combining the two maximum annual build rates for DECC's modelling, six CCGT blocks of 900 MW have been assumed, with a smaller plant of 500 MW also included to make up close to 6,000 MW, at 3 plant sites.

Alternatively, up to 4,000 MW of OCGT can be built each year as illustrated in Table 2. In reality this would likely be a mix of peaking aeroderivative plant and F-class standby plant as these offer lower costs of capacity than the older E-class technology. Aeroderivative plant is available in very small generating units, although, considering the planning, infrastructure and connection costs, the likely smallest economic size for a peaking plant would be two 50 MW turbines i.e. 100 MW. For large standby plant to provide capacity e.g. in case of a lack of wind power, F-class turbines are available in generating unit sizes of roughly 280 MW - 304 MW (smaller F-class turbines would be unlikely to be used for large standby plant). These are identical turbines to those used in CCGT plant. However without the bottoming cycle steam turbine, the power produced is less. These generating units could be combined into bigger plants, so the 4,000 MW could be 3 plants of 1,333 MW each or 13 plants of 299 MW each.

For the purposes of combining maximum build rates for DECC's modelling it is assumed the entire 4,000 MW of OCGT is composed of F-class turbines, and is divided into plants of 565 MW.

Assuming CCGT plants of 900 MW or 500 MW, and OCGT plants of 565 MW, the combined maximum build rate could be made up of any of the following combinations:

No of CCGT plants	CCGT MW	No of OCGT plants	OCGT MW	Combined total plants	Combined total of MW
7	5900	0	0	7	5900
6	5400	1	565	7	5965
5	4500	2	1130	7	5630
4	3600	3	1695	7	5295
3	2700	4	2260	7	4960
2	1800	5	2825	7	4625
1	900	6	3390	7	4290
0	0	7	3955	7	3955

Table 2 - Combined Maximum Technically Feasible Build Rates for CCGT and OCGT Plant

2.10 Conclusion

Site availability, planning, regulation, contracting, funding, historical manufacturing capability and construction rates have all been considered in relation to their impact on maximum technically feasible build rates. These constraints apply to any plant for which a final investment decision has not yet been made and will therefore typically not be in service before 2017. The following limitations have been identified applicable in order of significance:

- The likely maximum feasible build rate for new power plant in the UK appears to be limited by construction capability to about three CCGT / OCGT plants per year, typically 6,000 MW/yr if all three were CCGT or 4,000 MW/yr if all three were OCGT.
- If construction capability were significantly increased, as described, the next limitation would be the consenting process, which is expected to be able to consent roughly 5.5 GW per year. However this limitation would only apply in case of a sustained programme of new power plant construction which exceeded roughly 54 GW by 2025. In an individual year this would not be a technically insurmountable limit as it would be technically possible to consent plants in advance of beginning construction, and there are a large number of sites already available with consent. Consenting of individual CCGT plants will yield a larger GW result compared to consenting of OCGT plants due to the smaller net output of an OCGT..
- If both construction capability and consenting capacity were not limitations, the manufacturing capacity would be the limitation. As described it is unlikely the UK would be expected to obtain more than ~ 12 large frame turbines per year (4 GW - 6 GW), as this is a significant proportion of the worldwide market.
- Limitations in the financial markets have severely limited commercial funding in recent years and could limit the build rate to as little as two plants per year unless former levels of confidence can be restored allowing up to ten plants per year. However as this is not a technical limitation it is not included in the calculation of maximum technically feasible build rate.
- Capacity of the UK and European sector to engineer and contract for new CCGT or OCGT plants in the UK is estimated to be around 12 major plants (up to 24 GW) per year.

- The availability of sites is not currently a constraint as there are 16 consented sites suitable for CCGT or OCGT construction along with 76 existing sites which will become available on retirement of the existing plant. In case of an immediate surge of construction, sites for an average of 6 GW/year of new CCGT/OCGT capacity could become available each year from 2017 to 2026. Over 54 GW would have to be constructed before 2025 for either site availability or consenting process to become a limitation.

Some possible combinations of CCGT and OCGT to make up the combined maximum build rate have been presented.

3 SUPPLY CURVES FOR CCGT AND OCGT

Parsons Brinckerhoff previously produced cost and technical assumptions to be used as inputs to DECC's levelised cost of power generation model (Parsons Brinckerhoff, 2013). The assumptions for CCGT and OCGT are shown in Tables 3 and 4.

Gas - CCGT		Nth OF A KIND		
		Low	Med	High
Key Timings				
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	2.0	2.3	5.0
Construction Period	years	2.0	2.5	3.0
Plant Operating Period	years	20.0	25.0	35.0
Technical data				
Net Power Output	MW	900	900	900
Net LHV Efficiency	%	57.4%	58.8%	60.0%
Average Steam Output	MW (thermal)	0	0	0
Average Availability	%	91.9%	92.8%	93.7%
Average Load Factor	%	100.0%	100.0%	100.0%
CO2 Removal	%	0.0%	0.0%	0.0%
Capital costs				
Pre-licencing costs, Technical and design	£/kW	6.0	12.0	15.0
Regulatory + licencing + public enquiry	£/kW	0.36	0.42	4.00
EPC cost (excluding interest during construction) – variability only	£/kW	490	569	648
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	490	569	648
Infrastructure cost	£'000	7,000	17,500	36,000
Operating costs				
O&M fixed fee	£/MW/yr	18,026	21,954	25,882
O&M variable fee	£/MWh	0.00	0.08	0.15
Insurance	£/MW/yr	930	1,992	3,276
Connection and UoS charges	£/MW/yr	6,842	6,842	6,842
CO2 transport and storage costs	£/t	0.0	0.0	0.0

Table 3 - CCGT assumptions (Parsons Brinckerhoff, 2013)

OCGT		Nth OF A KIND		
		Low	Med	High
Key Timings				
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	1.5	1.8	4.5
Construction Period	years	1.5	1.8	2.0
Plant Operating Period	years	20.0	25.0	35.0
Technical data				
Net Power Output	MW	561	565	608
Net LHV Efficiency	%	37.3%	39.0%	39.1%
Average Steam Output	MW (thermal)	0	0	0
Average Availability	%	93.8%	94.7%	95.7%
Average Load Factor	%	5.0%	7.5%	10.0%
CO2 Removal	%	0.0%	0.0%	0.0%
Capital costs				
Pre-licencing costs, Technical and design	£/kW	16.3	18.9	24.6
Regulatory + licencing + public enquiry	£/kW	2.00	2.40	3.10
EPC cost (excluding interest during construction) – variability only	£/kW	218	274	330
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	218	274	330
Infrastructure cost	£'000	7,000	9,050	11,100
Operating costs				
O&M fixed fee	£/MW/yr	8,112	9,879	11,647
O&M variable fee	£/MWh	0.00	0.03	0.07
Insurance	£/MW/yr	414	959	1,667
Connection and UoS charges	£/MW/yr	3,440	3,440	3,440
CO2 transport and storage costs	£/MWh	0.0	0.0	0.0

Table 4 – OCGT Large Frame Standby Plant Assumptions (Parsons Brinckerhoff, 2013)

OCGT		1st OF A KIND		
		Low	Med	High
Key Timings				
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	1.5	2.1	4.5
Construction Period	years	1.7	1.9	2.5
Plant Operating Period	years	35.0	40.0	45.0
Technical data				
Net Power Output	MW	290	290	290
Net Efficiency	%	33.3%	35.0%	36.8%
Average Steam Output	MW (thermal)	0	0	0
Average Availability	%	93.8%	94.7%	95.7%
Average Load Factor	%	5.0%	20.0%	20.0%
CO_2 Removal	%	0.0%	0.0%	0.0%
Capital costs				
Pre-licensing costs, Technical and design	£/kW	16.3	18.9	24.6
Regulatory + licensing + public enquiry	£/kW	2.0	2.4	3.1
EPC cost (excluding interest during construction) –variability only	£/kW	417.3	472.5	567.0
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	417.3	472.5	567.0
Infrastructure cost	£'000	7,000	9,050	11,100
Operating costs				
O&M fixed fee	£/MW/yr	18,000	23,000	28,000
O&M variable fee	£/MWh	0	0	0
Insurance	£/MW/yr	1,252	1,890	2,835
Connection and UoS charges	£/MW/yr	1,884	1,884	1,884
CO_2 transport and storage costs	£/MWh	0	0	0

Table 5 - OCGT Aeroderivative Peaking Plant Assumptions (Parsons Brinckerhoff, 2012)

These assumptions are based on a single type of plant: large F-class CCGT and standby OCGT. Some other assumptions were also based on specific cases, for example infrastructure costs are based on specific distances from gas and electricity grid connections and Use of System (UoS) charges are based on the average charges in all zones in which it would be likely that such a plant would be built.

There are a number of different types of CCGT and OCGT plant, for example a CCGT plant could be significantly smaller, or a larger H or J-class plant could be built. OCGT plant could be standby plant (based on large frame gas turbines) or peaking plant (based on aero-derivative turbines). In addition there could be much more variation in other factors such as distance from the grid, access to cooling (which would impact on the efficiency) and UoS charges.

DECC commissioned Parsons Brinckerhoff to consider the likely variation in costs across potential future new build CCGT and OCGT plants in Great Britain. This required an adjustment of the low and high costs ranges above through a more in-depth assessment to produce a more realistic range, but re-assessment of the central case cost assumptions was out of the scope of this report.

Parsons Brinckerhoff has assessed the likely magnitude of variations in costs across plants. This considers the different types of CCGT and OCGT plant likely to be built in the context of the different conditions at the sites on which they will be built. A number of factors which could affect the cost and technical assumptions have been identified. By considering the breakdown of the levelised cost of power the factors most likely to affect the cost of power have been identified. The impact of these factors on the cost and technical parameters has been tabulated. Interactions between the factors are described qualitatively and a realistic high and low case has been produced.

3.1 Factors affecting assumptions

Table 6 lists factors which have been identified using technical expertise which could affect the cost and technical assumptions. The assumption(s) which would be affected have also been listed, and whether the factor would affect the low or high extent of the range.

Type of Factor	Factor	Assumption affected	Effect	Low or High
Location	Local objections	Pre-development period	Already assumed to be included in pre-development period	High
Location	Wildlife and landscape concerns	Pre-development period	Already assumed to be included in pre-development period	High
Location	Proximity to gas network	Pre-development period	For a new connection grid reinforcement may be needed	High
Location	Proximity to gas network	Infrastructure Cost (previously gas pipeline assumed to be 5, 10 and 20 km)	Low infrastructure cost changed to repowering at site with existing gas and power connections i.e. 0km pipe (previous low was 5km pipe): minimum value assumed for some infrastructure works High infrastructure cost increased to 50 km gas pipeline (previous high was 20km pipe; this is combined with 5 km grid connection)	Low and High
Location	Proximity to electricity grid	Infrastructure Cost (previously overhead line assumed to be 0, 5 and 10 km)	Low infrastructure cost changed to repowering at site with existing gas and power connections: minimum value assumed for some infrastructure works High cost unchanged for this factor as unlikely any developer would build more than 10 km from grid	Low
Location	Site and ground conditions for civil foundations	Construction period	Professional judgement that this could potentially cause longer delays than previously assumed for some plant	High
Location	Ground and site conditions (e.g. flood risk, accessibility and roads)	Engineer, Procure, Construct (EPC) cost	Professional judgement that this could potentially cause 10% increase in cost	High
Location	Proximity to Cooling / type of cooling	Net Lower Heating Value (LHV) efficiency	Efficiency for plant with air cooling adjusted slightly for CCGT (not applicable for OCGT)	Low
Location	Proximity to Cooling / type of cooling	EPC cost	Professional judgement that this could potentially cause 10% increase in cost	High

Type of Factor	Factor	Assumption affected	Effect	Low or High
Location	Transmission Network Use of System (TNUOS) Zone	Connection and UoS charges: includes TNUOS, TEC and local system charges, previously an average across all suitable TNUOS zones was used in modelling	For both CCGT and OCGT low changed to zone 24 (Essex and Kent) For CCGT high changed to zone 2 (Peterhead/East Aberdeenshire) For OCGT high changed to zone 14 (North Lancashire and The Lakes). It is unlikely under current TNUOS system that an OCGT plant would be built further north than Lancashire. TNUOS costs for peaking plant are significant because they must be paid even when the plant is not running, therefore unless TNUOS costs are changed significantly it would be unlikely that peaking plant would be built in Scotland for example. If renewable volatility necessitates peaking plant in Scotland this would be incentivised by reduced TNOUS so changing to higher TNUOS cost does not make sense in this case.	Low and High
International market	Lead times for equipment	Construction period	Professional judgement that this could potentially cause longer delays than previously assumed for some plant	High
Technical	Technical failures during testing	Construction period	Professional judgement that this could potentially cause longer delays than previously assumed for some plant	High
Commercial	Performance of contractors	Construction period	Professional judgement that this could potentially cause longer delays than previously assumed for some plant	High
Design	Design life	Plant operating period	Previous values considered to be reasonable	
National market	Operating strategy, affected by spark spread, policies favouring operation of renewable plant, merit order, etc	Plant operating period	Previous values considered to be reasonable	
National market	Operating strategy, affected by spark spread, policies favouring operation of renewable plant, merit order, etc	O&M variable fee	No change: impact on levelised cost is negligible	High
Technical	Operation and maintenance of equipment	Plant operating period	Previous values considered to be reasonable	

Type of Factor	Factor	Assumption affected	Effect	Low or High
Plant type	Type of plant: number and type of turbines	Net power output	Previously only a single size plant was considered for CCGT and a narrow range for OCGT based on lower cost E-class industrial turbines. This has been increased to include a wider range of plant sizes for both plant types, and for OCGT to include both aeroderivative and large frame plant. The consequence is that the new values for efficiency are not directly comparable with those for previous years.	Low and High
Plant type	Type of plant: number and type of turbines	Net LHV efficiency	Slight increase in high efficiency for CCGT based on peer review comments and professional judgement. OCGT efficiency range now separated into aero-derivative and large frame plant types. 2012 values included both types.	Low and High
Plant type	Size of Plant	Pre-licensing, Technical and design cost (per MW)	These costs are similar regardless of plant size so the per kW values have been adjusted to reflect the wider range of plant sizes	Low and High
Plant type	Size of Plant	Regulatory and Licensing cost (per MW)	No change: impact on levelised cost is negligible	Low and High
Plant type	Type of plant: complexity of design	Pre-licensing, Technical and design cost	No change: impact on levelised cost is negligible	
Plant type	Type of plant: number and type of turbines, complexity of design	EPC cost	Low value is for repowering at an existing site for a large plant with economies of scale. High value for CCGT adjusted in line with peer review comments. OCGT range now includes aeroderivative and large frame plant	Low and High
Plant type	Type of Plant: type of turbines e.g. newer technology	Pre-licensing, Technical and design cost	High design cost is possible for a new technology	High
Plant type	Type of plant: number and type of turbines	O&M fixed cost	OCGT range now includes aeroderivative and large frame plant	High
Construction expertise	Experience of contractors	EPC cost	Professional judgement that this could potentially cause 10% increase in cost	High
International market	Worldwide decrease in demand for Gas turbines or worldwide recession	EPC cost	Professional judgement that this could potentially cause 5% reduction in cost	Low
International market	Worldwide increase in demand for Gas turbines	EPC cost	Professional judgement that this could potentially cause 10% increase in cost	High
International market	Impact of other economic factors e.g. competition in contractor market	Pre-licensing, Technical and design cost	No change: impact on levelised cost is negligible	Low and High

Type of Factor	Factor	Assumption affected	Effect	Low or High
International market	Impact of other economic factors e.g. resource prices, competition in the contractor market	EPC cost	Professional judgement that this could potentially cause 5% reduction or increase in cost	Low and High
Cost of equipment	Minimum price below which cost cannot fall based on cost to manufacture and install	EPC cost	Value based on professional judgement and confirmed as suitable for repowering at existing site by peer review	Low
Regulatory	Regulatory uncertainty, change of regulatory requirements	Regulatory and Licensing Cost	No change: impact on levelised cost is negligible	High
Technology	Number of suppliers offering spare parts (e.g. common Gas Turbine (GT) classes will have more suppliers of spares and therefore competitive pricing)	Operation and Maintenance (O&M) fixed fee	Professional judgement that this could potentially cause 10% increase in cost	
Technology	Number of suppliers offering spare parts (e.g. common GT classes will have more suppliers of spares and therefore competitive pricing)	O&M variable fee	No change: impact on levelised cost is negligible	
Commercial	Size of utility (affects overheads and competitiveness of O&M)	O&M fixed fee	Professional judgement that this could potentially cause 10% increase or 5% reduction in cost	
Commercial	Type of O&M contract	O&M fixed and variable fee	Insufficient information to estimate cost impact	Low and High
International market	EPC cost, insurance market	Insurance	Professional judgement that this could potentially cause 10% reduction or increase in cost	Low and High
Change to Law	DCO Process	Pre-development Period	Pre-development period expected to take a minimum of three years	Low

Table 6 - Factors affecting assumptions

3.2 Impact of factors on levelised cost of power

DECC has provided values for levelised cost of electricity for CCGT and OCGT based on previous technical and cost assumptions provided by Parsons Brinckerhoff (PB, 2013) and fuel and carbon price estimates provided by DECC. These values are the outputs of the model; the CCGT and OCGT assumptions shown on previous pages were the inputs. For CCGT fuel and carbon cost combined account for 82 per cent of the overall cost. For OCGT, which has much lower load factors, the impact of fuel and carbon cost is only 16 per cent of the total, although this is still a significant amount. Factors affecting efficiency and net power output of the plant are therefore likely to have a significant impact on costs, extremely significant in the case of CCGT.

Table 7 shows the percentage breakdown of the levelised cost of power for CCGT and OCGT, both including and excluding cost of fuel and carbon.[1] These values are rounded to the nearest percentage point so the total does not add up to 100 per cent.

Cost Component	% of CCGT levelised cost[2]		% of OCGT levelised cost[3]	
	Total	Excluding fuel and carbon	Total	Excluding fuel and carbon
Pre-licensing costs, Technical and design	0%	2%	4%	5%
Regulatory, licensing and public enquiry	0%	0%	0%	1%
EPC Cost	11%	62%	49%	59%
Infrastructure Cost	0%	2%	3%	3%
Fixed O&M	4%	24%	19%	23%
Variable O&M	1%	1%	0%	0%
Insurance	0%	2%	2%	2%
Connection and UoS	1%	8%	7%	8%
Fuel	60%		12%	
Carbon	21%		4%	

Table 7 - Breakdown of Levelised Cost of Power, Excluding Fuel and Carbon

It is apparent that for regulatory, licensing and public enquiry and for variable O&M, the factors affecting cost will only have a significant impact if they more than double those costs.

Changes to the timing assumptions e.g. construction period can also significantly impact on the levelised cost of power, as this affects the net present value of the plant. For example, for CCGT, when all values other than timescales are set to "medium", using high timing assumptions from PB (2013) e.g. construction period of 3 years produces a cost estimate 7 per cent higher than low timing assumptions from PB (2013) e.g. construction period of 2 years. The difference between low and high operating periods causes a 15 per cent change in levelised cost.

[1] These levelised costs calculations use the input data from Parsons Brinckerhoff (2013), DECC fossil fuel prices and Oxera (2011) for the technology-specific hurdle rate. The load factors are based on DECC modelling for the EMR Draft Delivery Plan.
[2] 71% Load factor, 7.5% discount rate
[3] 1% load factor, 7.5% discount rate

3.3 Impact of factors on CCGT assumptions

Table 8 shows the factors most likely to impact on the levelised cost of power for CCGT and their impact on the input assumption range. The values are only shown where there is a change from the 2013 assumptions.

Type of Factor	Factor	Assumption affected	Previous Low value	Previous High value	New Low value	New high Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central
Change to Law	Development Consent Order process	Pre-development Period	2	5	3		130%[4]	
Location	Proximity to gas network	Pre-development period	2	5		7		304%
Location	Proximity to gas network	Infrastructure Cost	7000	36000	1000	53000	6%	303%
Location	Proximity to electricity grid	Infrastructure Cost	7000	36000	1000		6%	
Location	Site and ground conditions for civil foundations	Construction period	2	3		4		160%
Location	Ground and site conditions (e.g. earth type, accessibility and roads)	EPC cost	490	648		713		125%
Location	Proximity to Cooling / type of cooling	Net LHV efficiency	57.4%	60%	57%		97%	
Location	Proximity to Cooling / type of cooling	EPC cost	490	648		713		125%
Location	TNUOS Zone	Connection and UoS charges	6842	6842	1360	23964	20%	350%
International market	Lead times for equipment	Construction period	2	3		5		200%

[4] A new central value for the Pre-development period of 4 years is required to take account of experience of the DCO process.

Type of Factor	Factor	Assumption affected	Previous Low value	Previous High value	New Low value	New high Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central
Technical	Technical failures during testing	Construction period	2	3		4		160%
Commercial	Performance of contractors	Construction period	2	3		6		240%
Plant type	Type of plant: number and type of turbines	Net power output	900	900	450	2500	50%	278%
Plant type	Type of plant: number and type of turbines	Net LHV efficiency	57.4%	60%		60.5%		103%
Plant type	Size of Plant	Pre-licensing, Technical and design cost (per MW)	6	15	3.9	18.5	33%	154%
Plant type	Type of plant: number and type of turbines, complexity of design	EPC cost	490	648	380	710	67%	125%
Plant type	Type of Plant: type of turbines e.g. newer technology	Pre-licensing, Technical and design cost	6	15		25		208%
Construction expertise	Experience of contractors	EPC cost	490	648		713		125%
International market	Worldwide decrease in demand for Gas turbines or worldwide recession	EPC cost	490	648	466		82%	
International market	Worldwide increase in demand for Gas turbines	EPC cost	490	648		713		125%

Type of Factor	Factor	Assumption affected	Previous Low value	Previous High value	New Low value	New high Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central
International market	Impact of other economic factors e.g. resource prices, competition in the contractor market	EPC cost	490	648	466	681	82%	120%
Cost of equipment	Minimum price below which cost cannot fall based on cost to manufacture and install	EPC cost	490		380		67%	
Technology	Number of suppliers offering spare parts (e.g. common GT classes will have more suppliers of spares and therefore competitive pricing)	O&M fixed fee	18026	25882		28470		130%
Commercial	Size of utility (affects overheads and terms of fuel supply)	O&M fixed fee	18026	25882	17124	28470	78%	130%
International market	EPC cost, insurance market	Insurance	930	3276	837	3604	42%	181%

Table 8 - Impact of Factors on CCGT Assumptions

3.4 Impact of factors on OCGT assumptions

Table 9 shows the factors most likely to impact on the levelised cost of power for OCGT and their impact on the input assumption range. The values are only shown where there is a change from the 2013 assumptions.

Type of Factor	Factor	Assumption Affected	Previous Low Value	Previous High Value	New Low Value	New High Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central

Type of Factor	Factor	Assumption Affected	Previous Low Value	Previous High Value	New Low Value	New High Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central
Change to Law	DCO process	Pre-development Period	2	5	3		167%[5]	
Location	Proximity to gas network	Pre-development period	1.5	4.5		7		389%
Location	Proximity to gas network	Infrastructure Cost	7000	11100	1000	53000	11%	586%
Location	Proximity to electricity grid	Infrastructure Cost	7000	11100	1000		11%	
Location	Site and ground conditions for civil foundations	Construction period	1.5	2		3		167%
Location	Ground and site conditions (e.g. earth type, accessibility and roads)	EPC cost	218	330		363		132%
Location	TNUOS Zone	Connection and UoS charges	3440	3440	1191	8475	35%	246%
International market	Lead times for equipment	Construction period	1.5	2		4		222%
Technical	Technical failures during testing	Construction period	1.5	2		3		167%
Commercial	Performance of contractors	Construction period	1.5	2		4		222%
Plant type	Type of plant: number and type of turbines	Net power output	561	608	100	1350	18%	239%
Plant type	Type of plant: number and type of turbines	Net LHV efficiency	37.3%	39.1%	37.3%	43.2%	96%	111%

[5] A new central value for the Pre-development period of 4 years is required to take account of experience of the DCO process.

Type of Factor	Factor	Assumption Affected	Previous Low Value	Previous High Value	New Low Value	New High Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central
Plant type	Size of Plant	Pre-licensing, Technical and design cost (per MW)	16.3	24.6	12.5	42.8	66%	226%
Plant type	Type of plant: number and type of turbines	EPC cost	218	330		675		246%
Plant type	Type of plant: number and type of turbines	O&M fixed cost	8112	11647		28000		283%
Construction expertise	Experience of contractors	EPC cost	218	330		363		132%
International market	Worldwide decrease in demand for Gas turbines or worldwide recession	EPC cost	218	330	207		76%	
International market	Worldwide increase in demand for Gas turbines	EPC cost	218	330		363		132%
International market	Impact of other economic factors e.g. resource prices, competition in the contractor market	EPC cost	218	330	207	363	76%	132%
Cost of equipment	Minimum price below which cost cannot fall based on cost to manufacture and install	EPC cost	218	330	200		73%	
Technology	Number of suppliers offering spare parts (e.g. common GT classes will have more suppliers of spares and therefore competitive pricing)	O&M fixed fee	8112	11647		30800		312%

Type of Factor	Factor	Assumption Affected	Previous Low Value	Previous High Value	New Low Value	New High Value	New Low value as a %age of previous central value (PB, 2013), assuming all other values remain Central	New High Value as a %age of previous central value (PB, 2013), assuming all other values remain Central
Commercial	Size of utility (affects overheads and terms of fuel supply)	O&M fixed fee	8112	11647	7706	29400	78%	298%
Plant type	Type of plant: number and type of turbines	Insurance	414	1667		2835		296%
International market	EPC cost, insurance market	Insurance	414	1667	372	3119	39%	325%

Table 9 - Impact of Factors on OCGT Assumptions

3.5 Interactions between factors

- Delays in the planning process will run concurrently with any delay caused by the need for gas network reinforcement planning.
- Some sites will already have both gas and power connection capacity so will have a minimum cost of zero for infrastructure.
- Adverse site and ground conditions, poor contractor performance and problems discovered during commissioning would all cause delays and cost overruns. Bad planning in ordering equipment would cause delays but not cost overruns. It is possible that a number of problems could occur during construction, so the overall delays could substantially extend the length of the construction period, however it is unlikely that cost overruns would all be additive as some money could be clawed back from a poor contractor or from insurance.
- It is unlikely that any developer would select a site with both high UoS charges and high infrastructure costs.
- Costs for development and design and regulatory cost are largely independent of scale. Therefore small scale plant would have the highest per MW costs and large scale plant the lowest. Economies of scale would also play a part with the largest plant having a cheaper EPC cost per MW and the smallest more expensive.

3.6 Realistic high and low cases

Realistic Low and High Cases for CCGT plant are shown in Table 10. These cases each represent an internally consistent set of values for a mid-scale plant. The Low Case represents a plant that is expected to be at the low end of the range of levelised cost of power for potential plant that may come forward in any given future year, and the High Case represents a plant that is expected to be at the high end of this range. Values that are not shown have the same value as in the 2013 update assumptions.

The realistic low plant case does not include the low value for each assumption, nor does the high case include the high value, because this would not result in internally consistent cases. For example it is unlikely any developer would choose a site with high transmission charges, a need for air cooling and a large distance from the gas network so the "High" case includes high Transmission charges and lower efficiency but not high infrastructure cost.

To produce a realistic low and high case, a 900 MW plant has been considered and the extremes of small and very large plant have not been included. For a CCGT plant, the levelised cost of power is strongly related to efficiency, therefore the "Low" case includes a high efficiency value and vice versa. A lower efficiency turbine would cost less to purchase and vice versa so the low cost, high efficiency case includes a high EPC cost and vice versa.

Gas – CCGT: Realistic low and high cost cases for 900MW class CCGT plant				Previous Med Values[6]
		Low	High	Med
Key Timings				
Total Pre-development Period (including pre-licensing, licensing and public enquiry)	years	3.0	7.0	2.3[7]
Construction Period	years	2.0	7.0	2.5
Technical data				
Net Power Output	MW	1100	900	900
Net LHV Efficiency	%	60.5%	57%	58.8%
Capital costs				
Pre-licensing costs, Technical and design	£/kW	6.0	25.0	12.0
EPC cost (excluding interest during construction) - variability only	£/kW	745	490	569
EPC cost (excluding interest during construction) - variability and uncertainty	£/kW	745	490	569
Infrastructure cost	£'000	1,000	36,000	17,500
Operating costs				
O&M fixed fee	£/MW/yr	18,026	28,470	21,954
Insurance	£/MW/yr	930	3,604	1,992
Connection and UoS charges	£/MW/yr	1,360	23,964	6,842

Table 10 - Realistic Low and High Cost Cases for CCGT plant

Realistic Low and High Cases for Large Frame Standby OCGT plant are shown in Table 11. These cases each represent an internally consistent set of values for a mid-scale large frame plant. Similar assumptions have been used as those for CCGT in producing these cases. These values only include large frame plant and not aeroderivative plant.

The Low-cost case is a standby OCGT plant comprising two F-class turbines with a total output of 608 MW, and the High-cost case is a standby OCGT plant comprising two F-class turbines with a total output of 565 MW.

For OCGT plant the levelised cost of power is strongly related to EPC cost. Therefore, the "Low" case includes a low EPC cost and vice versa. A lower efficiency turbine would cost less to purchase and vice versa; so the low cost, low EPC case, includes a low efficiency and vice versa.

[6] Previous Med values from PB (2013)
[7] Revised central value is 4 years to take account of experience of the DCO process.

Gas - OCGT: Realistic Low and High Cost Cases for Large Frame Standby Plant				Previous Med Values[8]
		Low	High	Med
Key Timings				
Total Pre-development Period (including pre-licensing, licensing and public enquiry)	years	3	7.0	1.8[9]
Construction Period	years	2	4.0	1.8
Plant Operating Period	years	35	20	25
Technical data				
Net Power Output	MW	608	561	565
Net LHV Efficiency	%	37.3%	39.1%	39.0%
Average Availability	%	98%	97%	94.7%
Average Load Factor	%	10%	5%	7.5%
Capital costs				
Pre-licensing costs, Technical and design	£/kW	16.3	24.6	18.9
EPC cost (excluding interest during construction) – variability only	£/kW	218	380	274
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	218	380	274
Infrastructure cost	£'000	1,000	11,100	9,050
Operating costs				
O&M fixed fee	£/MW/yr	7,706	12,812	9,879
Insurance	£/MW/yr	414	1,834	959
Connection and UoS charges	£/MW/yr	1,191	8,475	3,440

Table 11 - Realistic Low and High Cases for Large Frame Standby OCGT plant

Realistic Low and High Cases for Aeroderivative Peaking OCGT plant are shown in Table 12. These cases each represent an internally consistent set of values for a mid-scale aeroderivative plant. Similar assumptions have been used as those for CCGT in producing these cases. These values only include aeroderivative plant and not large frame plant.

The Low-cost case is a peaking OCGT plant with a total output of 290 MW, and the High-cost case is a peaking OCGT plant comprising two 50 MW aeroderivative turbines with a total output of 100 MW.

For OCGT plant, the levelised cost of power is strongly related to EPC cost. Therefore, the "Low" case includes a low EPC cost and vice versa. A lower efficiency turbine would cost less to purchase and vice versa. So the low cost, low EPC case includes a low efficiency and vice versa.

[8] Previous Med values from PB (2013)
[9] Revised central value is 4 years to take account of experience of the DCO process.

Gas – OCGT: Realistic Low and High Cost Cases for Aeroderivative Peaking Plant				Previous Med Values[10]
		Low	High	Med
Key Timings				
Total Pre-development Period (including pre-licensing, licensing and public enquiry)	years	3	7.0	2.1[11]
Construction Period	years	2	4.0	1.9
Plant Operating Period	years	35	20	40
Technical data				
Net Power Output	MW	290	100	290
Net LHV Efficiency	%	38.5%	43.2%	35.0%[12]
Average Availability	%	98.5%	97.5%	94.7%
Average Load Factor	%	20%	5%	20%
Capital costs				
Pre-licensing costs, Technical and design	£/kW	16.3	24.6	18.9
EPC cost (excluding interest during construction) – variability only	£/kW	417	650	472.5
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	417	650	472.5
Infrastructure cost	£'000	1,000	11,100	9,050
Operating costs				
O&M fixed fee	£/MW/yr	18,000	30,800	23,000
Insurance	£/MW/yr	1,189	3,119	1,890
Connection and UoS charges	£/MW/yr	1,191	8,475	1,884

Table 12 - Realistic Low and High Cases for Aeroderivative Peaking OCGT plant

[10] Previous Med values from PB (2012)
[11] Revised central value is 4 years to take account of experience of the DCO process.
[12] Previous value is not on a common basis, being for smaller heavy frame gas turbines.

4 INDUSTRIAL EMISSIONS DIRECTIVE COMPLIANT TECHNOLOGIES

4.1 Background

The UK coal plant fleet is ageing and operators are now obliged to consider their approach to NO_x abatement which may require substantial investment and an extension to the projected plant life.

The existing Large Combustion Plant Directive (LCPD) emission limit values for NO_x will be replaced by those of the IED Emission Limit Values (ELV) which come into force with effect from January 2016. UK coal fired power plants are all over 300 MW (thermal) and for coal plants in this category the NO_x limits will be tightened from 500 mg/Nm^3 to 200 mg/Nm^3.

Plant which has selected to opt-out of the LCPD is committed to close by December 2015 and a number have already been retired from service by the operating companies. The remaining plants which opted-in to LCPD have now to decide whether they will opt-in to the subsequent IED. This will require them to meet the IED NO_x limits with an ELV of less than 200 mg/Nm^3.

Compliance of gas plant with IED is outside the scope of this report, however this is described briefly in Section 6 of this report, which states that newbuild gas plant are expected to be compliant, and some existing gas plant are already compliant. Section 6 also includes an estimate for the cost of upgrading non-compliant gas plant to meet IED limits, although this is a single estimate and has not been considered in the same detail as coal plant is in this section.

4.2 Industrial Emissions Directive

All existing UK plants operate currently at around 500 mg/Nm^3 NO_x and significant investment will be required in order to ensure a coal plant is compliant post 2016. Plant operators will now decide whether to opt out of or into of the IED framework.

4.2.1 Opt-out

Plants which opt-out of IED will be limited to 17,500 operating hours between 2016 and 2023 (average 2,187 hours or 25 per cent load factor per annum).

It would not be economic for all plant to run at these average levels and in reality operators will concentrate their usage of eligible hours into high price periods. Few plants are likely to be retained until 2023.

4.2.2 Opt-in

Plants which opt-in to IED will have the following options:

- Meet the new ELV of 200 mg/Nm^3 from January 2016.
- Utilise the flexibility afforded by a Transitional National Plan in the years to June 2020. The Transitional National Plan (TNP) will provide a cap on emissions for the 4½ year period to June 2020, starting at the current ELV of 500 mg/Nm^3 but reducing over time to the IED limit of 200 mg/Nm^3, with an allocation to each generator and a system of trading implemented to address imbalances as required.

- Keep emissions at the levels currently associated with mid-merit plant and restrict operation to peaking hours - 1500 pa rolling five year average.

4.3 Best Available Technology (BAT)

The IED requires Member States to utilise the BAT in line with the EU's reference document (BREF) (EU, 2013)(EU, June 2013). The UK Environment Agency (EA) has submitted two documents into the BREF process (EA, 2011) commenting separately for mid-merit (TWG6) and for baseload operation (TWG13). In these documents, baseload operation is taken to be in excess of 4000 hours pa. Whilst it has yet to be clarified, on the assumption that this is taken at stack (i.e. for the entire plant) rather than at generating unit level, then most of the UK coal fired plants would currently be categorised as "baseload" under this definition.

The outcome of the BREF will not be concluded until much closer to 2015.

In brief EA (2011) states:

- Mid merit plant (< 4000 hours pa.) – the EA believes that for these plants major investment such as SCR retrofit could not be justified economically for such an operating regime. Therefore the EA proposes that for mid-merit plant NO_x reduction is best achieved by cheaper incremental combustion techniques i.e. reducing the NO_x produced rather than removing the NO_x after combustion. However BAT in this case would not attain the IED limit of 200 mg/Nm^3 but be in the band 350 to 460 mg/Nm^3.
- Baseload plant (>4000 hours pa) – the EA believes that BAT is recognised to be SCR but subject to certain caveats, reflecting the difficulty of defining a generic best available technique for a wide range of pre-existing boiler designs. In addition it is not yet clear from the limited experience of SNCR or hybrid solutions with SCR or other combustion modifications whether any of these will be capable of achieving the limit or in fact being BAT.

4.4 NO_x control technologies

4.4.1 Background

There are many methods of reducing NO_x emissions. SCR is the most expensive method but currently SCR or a hybrid of SCR and SNCR is the only method by which a coal-burning plant can reach the 200 mg/Nm^3 ELV.

The formation of NO_x during combustion is dependent on a number of factors including the amount of nitrogen in the fuel but also the interaction of fuel, air and flame temperature. NO_x control technologies comprise:

- Primary control through combustion modifications.
- Secondary control post combustion techniques such as SCR or SNCR.

A range of primary controls are already in place across the UK coal fleet and Low NO_x burners and over-fired air have been deployed already to attain compliance with the LCPD giving emissions at around 500 mg/Nm^3.

While primary control techniques alone will not be able to achieve the IED emissions limit values for NO_x on coal fired plant, they can reduce the NO_x emissions to a level which subsequently allows the size and cost of the secondary control technology required to be reduced.

4.5 Primary control - combustion techniques

4.5.1 Combustion optimisation

Typically optimisation is the first method used for the control of NO_x formation. This includes the appropriate maintenance and operation of the combustion process. There is a focus on the burners but also the improved classification and flow of fuel and the distribution of the pulverised material in the boiler. It is possible to modify the operating conditions of the boiler to reduce the formation of NO_x at the burner. This involves the control of excess air, fine tuning of the boiler and the balancing of the fuel and air flow.

4.5.2 Low NO_x burners

Designed to control fuel and air mixture and create larger more branched flames, reducing the combustion temperature and staging combustion resulting in lower NO_x formation. Due to the improved flame structure less oxygen is required in the hottest part of the flame and thus less NO_x is produced. Plant experience shows that the combination of low NO_x burners combined with other primary methods have achieved a significant NO_x removal efficiency. Low NO_x burners are proven technology and are generally installed at UK coal-fired plants (IEA, 2013).

4.5.3 Air-staging/overfired air

Air staging/two stage combustion is normally described as the introduction of overfire air into the boiler or furnace. The introduction occurs in two, primary and secondary, sections to achieve complete burnout and encourage the formation of nitrogen instead of NO_x. During the first section primary air (70-90 per cent of the total) is mixed with the fuel to create a low temperature, oxygen deficient, fuel rich zone meaning that relatively small amounts of fuel NO_x are produced. During the secondary section the remaining 10 - 30 per cent of combustion air is injected through a special wind-box mounted above the burners into the combustion zone. Combustion is completed at this increased flame volume and as a result the relatively low-temperature secondary stage limits the production of NO_x.

Retrofitting of over-fired air has been possible and involves modifications to the waterwall tubes to create the ports for the secondary air nozzles, addition of ducts, dampers and the wind box.

Over-fired air is currently in use, both as a stand-alone measure and in conjunction with other primary NO_x control measures.

4.5.4 Re-burning (re-burn or staged fuel injection)

Re-burning reduces NO_x emissions through a combustion process of three stages.

1. In the first stage (main combustion zone) NO_x formation is controlled by reducing burner heat release rate and the amount of oxygen present. As a result a greater part of fuel (about 85 per cent) is burned, in little air excess.

2. In the second stage additional fuel is injected under reducing conditions (oxygen deficient) producing hydrocarbon radicals that react with the NO_x formed in the first stage producing nitrogen gas.
3. In the third stage additional air is injected in the lower temperature third stage, to reach the stated air excess and combustion is complete.

When combining re-burning with other reduction techniques such as low NOx burners with SNCR it is possible to achieve reductions in NO_x of 50-70 per cent, where the low NOx Burners provide 50% reduction and SNCR & re-burning provide 20% NOx reduction.

4.5.5 Flue Gas Recirculation (FGR)

FGR involves the recirculation of 20-30 per cent of the flue gas which is then mixed with the combustion air thus diluting the flame and decreasing the temperature and oxygen content. Reduced oxygen in the combustion mixture results in the reduced formation of NO_x. The retrofit of FGR involves extensive additional plant items in order to extract the flue gas from the boiler, remove fly ash and re-route it back into the combustion chamber. FGR alone is capable of achieving reductions in NO_x of less than 20 per cent.

4.6 Secondary controls - post combustion techniques

4.6.1 Selective Catalytic Reduction (SCR)

SCR controls emissions of nitrogen oxides within the waste gases of boilers through catalytic reduction reactions. Ammonia vapour is injected into the flue gas stream at the optimum temperature range for reaction, typically between 300 - 400 °C (normally the temperature at the economiser outlet). The gases are then passed over a catalyst promoting a reaction between the NO_x of the flue gas and the ammonia producing nitrogen and water vapour. The type of catalyst required is highly dependent on the exhaust conditions of the boiler and the constituents of the flue gas.

SCR options include "high dust" where the catalyst is positioned before the precipitators at higher gas temperatures and "tail end" where the installation takes flue gas after the dust has been removed but at lower temperatures. Investment and process costs differ significantly between the two positions.

Retrofitting SCR to existing UK plants is seen to be problematical and optimum extraction rates for this technology are unlikely to be attained. Each site is different but all are space restricted, limiting the size of catalyst structure and requiring ductwork to be extended outside the main building. In addition existing pressure and temperatures of gas flows and the ductwork arrangements on site will differ from those specified on an integrated "new build" site.

SCR remains unproven under flexible plant operation due to its requirement for a narrow catalyst operating temperature window and there is a reluctance to apply SCR to mid-merit or peaking plants. Although coal plants have seen a recent resurgence in production volumes, SCR is prone to greater uncertainty within the UK market where coal plants have generally been considered to be more marginal, operating mid-merit and at the peaks.

4.6.2 Selective Non-Catalytic Reduction (SNCR)

SNCR selectively reduces NO_x by injection of ammonia or urea as a reagent into the boiler. The product of this reaction is molecular nitrogen, carbon dioxide and water. The optimum temperature range for the reaction is quite specific, although broader than for SCR, being between 900 and 1100ºC. Above this temperature range the NO_x reduction efficiency is greatly reduced and below the minimum temperature excessive "ammonia slip" occurs.

The EA (2011) suggested that combustion optimisation coupled with SNCR appeared more attractive than an SCR retrofit on the basis of cost, although it is not clear whether such a solution would achieve adequate NOx reduction.

4.6.3 Rotating Over Fire Air (ROFA)

In a ROFA system 25 to 40 per cent of furnace air is injected into the upper furnace through asymmetrically placed air nozzles. This increases turbulence and mixing in the furnace improving temperature and species distribution and particle burnout in the upper furnace. As a result the formation of laminar flow is prevented. The furnace is used more effectively in the combustion process and the maximum temperature in the combustion zone can be reduced due to increased heat transfer. As the combustion air is mixed more effectively less excess air is needed and thus the amount of NOx produced is reduced (Coombs, 2004). ROFA can be used in conjunction with SNCR or SCR.

4.6.4 Rotamix

Rotamix is an SNCR and sorbent injection system and is used in conjunction with and downstream of ROFA. By injecting pre-ROFA the system takes advantage of the highly kinetic environment created by ROFA to mix the chemical reagents with the combustion products in the furnace. The Rotamix system adapts to changes in load and temperature in the furnace, ensuring that reducing chemicals are only introduced to the furnace when the temperature is favourable for pollution reduction. This reduces chemical consumption and slippage and increases the reaction efficiency (Coombs, 2004). Rotamix is used in conjunction with SNCR and ROFA.

4.6.5 Hybrid (SNCR and SCR)

Hybrid SNCR and SCR involves the processing of the exhaust gas through SNCR followed by SCR through the processes previously described. Hybrid has benefits over SCR in that the catalyst volumes can be decreased resulting in a lower capital cost investment and reduced space requirements.

Hybrid SCR/SNCR is technically feasible but to the authors' knowledge has not been implemented on any plant. There are a number of uncertainties associated with the hybrid approach due to its first of a kind nature, however as both technologies are applied at different points in the cycle they are essentially independent, which reduces the likelihood of any problems with applying both in sequence. There may be technical issues to be dealt with such as unexpected impacts on flexibility or possible issues with slippage of ammonia, however as both technologies have been successfully retrofitted to coal plant separately it is unlikely that any such problems would be serious enough to render the hybrid unworkable. SNCR has not yet been applied at full scale in coal plant. One possible problem is that contractors may be unwilling to implement a cheaper option when a more expensive option is available and is more proven, however this is a challenge that faces every new technology and can be overcome through e.g. competitive bidding processes.

In a Hybrid plant SNCR would be applied by injecting reagent into the boiler furnace, reducing the NOx concentration at the furnace outlet and SCR would be applied to the boiler flue gases by introducing a new bypass section of ductwork cantilevered outside the rear of the boiler, which contains the catalyst. This could be achieved by building an SCR reactor with only 2/3 of the catalyst required for a full-size SCR. This hybrid option would be cheaper in capital cost to a full SCR and would have minimal impact on plant operation. Alternatively the catalyst required could be installed in existing ductwork which would be cheaper than a full size SCR, making the hybrid option significantly cheaper in terms of capital cost.

4.7 Key parameters for operators' decisions

4.7.1 Summary

The decision to retrofit NO_x abatement will not be based simply on its cost but will take into account the remaining operating life and the potential requirement for additional investment to ensure the integrity of the whole power plant for an extended period i.e. life extension work. Parsons Brinckerhoff believes that all UK coal plant operators will have to consider specific life extensions works as part of the NO_x abatement investment decision.

The decision to install NO_x reduction technologies is complex and plant operators consider many parameters in parallel. The decision will be made based on financial viability and the technical implications on costs will need to be carefully considered. With substantial investment it would be possible to retrofit and upgrade any plant but the operator may believe it to be quicker, easier and more economic to build new modern generating capacity and close the existing facility. New build is unlikely to be coal. The key parameters for operators' consideration are discussed below.

4.7.2 Capital cost

Operators will consider whether the installation costs of NO_x reduction technologies are sufficiently offset by the benefits that accrue and companies cannot invest in plants that do not pay back within a timeframe commensurate with the risk. The logistics of working with old plant mean that the outturn costs of a major retrofit are difficult to predict and are plant specific since each plant has differing configurations, sizing, sites and locations, market conditions and existing technology designs.

This element should provide for the costs of the planning and development, the construction and commissioning, project management and also the cost of finance prior to commercial operation.

4.7.3 Operating cost

Operating costs should reflect routine operations and maintenance but also the need for additional auxiliary plant and the effect on the rated output and thermal efficiency of the plant. In SCR options the cost of the initial charge of catalyst and the subsequent cyclical costs of regeneration or replacement are likely to be significant. For SCR, SNCR or a hybrid of the two there is the added cost of the reagent (ammonia or urea) that is utilised in the process.

4.7.4 Carbon price

The impact of the cost of carbon will be greater on coal fired plant than other generating technologies. The extent to which this is reflected in the wholesale UK power price is not certain but it is probable that the dark spread will deteriorate, reducing the earnings and cash flow of the coal plant operators. Decisions to invest in NO_x abatement will take account of the future impact on earnings of the cost of EU carbon allowances and UK carbon price support.

4.7.5 Operating regime

The power plant's anticipated regime influences the operator's decision in two respects:

- The profile of generation within year may preclude certain technologies with two-shifting and peak lopping plant less likely to be able to deploy SCR effectively.
- Production volumes across the remaining plant life must be sufficient to allow the operator to recover the additional cost of the investment and operation.

4.7.6 Plant capability

The installation of an abatement process has the potential to reduce the plant output capacity as power will be drawn off for auxiliary equipment such as pumps, motors and heaters. In "tail end" SCR applications, this may reduce capacity by up to 2 per cent. In addition sub optimal gas flows are likely to impinge on the plant's thermal efficiency.

4.7.7 Fuel type

A number of operators have considered a move away from coal burn to biomass and the Drax part conversion is underway. It is not certain that burning biomass will avoid the need for NO_x abatement and generators will need to consider their site specific need for abatement measures to ensure they can meet the 200 mg/Nm^3 limit required by IED for biomass plants at this scale.

4.7.8 Remaining plant life

The remaining plant life impacts upon the economic viability of any upgrade decision. In calculating remaining plant life one must consider five limiting factors:-

a Life expiry of major components

UK power plants were traditionally designed with a 25 year life. As a result plants that would be considered for upgrades are already beyond their original design life and only Drax is within the 40 year lifespan. A major investment decision to manage NO_x emissions may require parallel works on site to ensure the integrity of other major critical components approaching the end of their operating life. Post investment, the operator has to provide reliable and economic generation from the plant in order that the company can recover the cost of the abatement.

Tables are provided later in this report which show the typical lifecycle of major power plant components together with associated failure mechanisms.

b Degradation of performance

During the life of a plant there will inevitably be a degradation of plant performance due to a series of factors resulting in an increase in the heat rate and a reduction in the maximum plant output. The plant is economically disadvantaged and there is a subsequent tendency towards a declining running load factor and a reduction in the annual operating hours as the plant moves from baseload to mid merit and then peaking plant.

c Decline in plant reliability

With increased age the plant becomes less reliable, losing income opportunities from flexibility and with potential down time of the plant should it fail. This will have an adverse effect on the availability and costs of maintenance will rise.

d Obsolescence of plant reliability

As the plant ages, procurement of spare parts (particularly electrical and electronic components) becomes more difficult with longer lead times and potential unavailability. In the event of the failure of a major component on a particular marginal plant, it could prove to be life limiting.

e Inability to comply with changing regulatory requirements

Regulatory requirements may change further imposing even stricter limits on plant operations. Despite upgrades to meet the known requirements for NO_x, the plant may not be compliant in other areas and the overall position (particularly with respect to emissions) should be considered.

4.7.9 Plant design

Power plant design differs across the UK installations and the type of boiler influences the production of NO_x and the subsequent optimum method of abatement. The majority of UK power plant boilers are front fired and lend themselves to primary methods of abatement. However others which employ tangential or corner fired arrangements have different combustion flows which limit the benefit which can be derived from over-fired air arrangements. One plant has "down-shot" burners which precludes the use of over-fired air.

Station	Boiler Firing	Start Up [6]
Uskmouth	Front	1959
Ferrybridge	Front	1966
Eggborough	Front	1967
Ratcliffe	Front	1968
West Burton	Tangential	1968
Cottam	Front	1969
Longannet	Front	1970
Aberthaw	Down-shot	1971
Fiddlers Ferry	Tangential	1971
Rugeley	Front	1972
Lynemouth	Tangential	1972
Drax	Front and Rear	1974 1986

Table 13 - Power Station Boiler Types

4.7.10 Performance impact

The installation of NO_x reduction technologies has a negative impact on the overall output and efficiency of the plant as a result of a more complex exhaust gas stream and the use of auxiliary energy during the process itself.

4.7.11 Down time

It is envisaged that much of the manufacturing and fabrication work could be completed off or on site while the plant is in operation with a carefully planned intervention concurrent with a planned overhaul/inspection. Whilst there is always risk of schedule slippage and overrun, this will limit the lost availability and reduction in earnings potential. Coal fired plant in the UK has adopted a four year major overhaul cycle with a minor at the two year stage. Typically these are of 10 and 3-4 week durations.

4.8 Conclusions

- There are only two technologies available that enable coal plant to meet the IED NO_x emissions limits. These are SCR and Hybrid SCR/SNCR.
- The decision whether to retrofit these technologies to a coal plant will not be taken in isolation but will also consider the other work required to extend the life of the coal plant.

5 COSTS TO RETROFIT SCR AND HYBRID SCR/SNCR

5.1 Decision to update cost and technical parameters for SCR retrofit

In 2012 Parsons Brinckerhoff completed a costing exercise for DECC in which the costs of retrofitting SCR to coal plant were evaluated. The findings can be seen in Table 14 - SCR and SNCR Assumptions 2012 (Parsons Brinckerhoff, 2012). The range of costs included both SCR and SNCR. For some values SCR is at the low end of the range, for others SNCR at the low end of the range.

Since Parsons Brinckerhoff completed this analysis further information has come into the public domain which would improve the overall understanding of the investment and operating costs of NO_x abatement. This information includes:

- Information included in the EA's submission to the BREF process.
- Costs from new build and retrofit SCR in the US.
- Updates to the database used in SteamPro modelling, which will enable Parsons Brinckerhoff to model the cost of new build SCR.

While the average of the new information falls within the range presented in 2012, the upper end of the range is significantly higher than the 2012 values. Initially it was unclear whether this new information was applicable to UK plant and further analysis was required to assess whether it is applicable.

DECC and Parsons Brinckerhoff agreed to undertake an additional piece of work to further investigate the information available and produce updated costs for retrofit of SCR to coal plant.

Parsons Brinckerhoff believes that hybrid SCR and SNCR is a technically viable alternative to SCR for meeting the IED ELV of 200mg/Nm^3. The updated costs produced by Parsons Brinckerhoff include both SCR and hybrid SCR/SNCR. For some values hybrid is at the low end of the range, for others it is at the high end. Central values for both SCR and hybrid SCR/SNCR are shown separately.

The possible alternative of further combustion improvements with SNCR identified by the EA is considered to be a highly plant specific solution with significant uncertainties in performance and cost. Due to these uncertainties, costs for this possibility have not been estimated.

It is worth repeating that operators must incorporate additional lifetime extension works into their investment decisions so SCR or hybrid SCR/SNCR would not be considered in isolation.

Many of the costs have been estimated per 500 MW generating unit. The final values are then calculated for a 1000 MW two-unit plant using scaling factors as necessary and are presented in Tables 17 and 18.

Coal – retrofit SCR or SNCR		1st OF A KIND			Nth OF A KIND		
		Low	Med	High	Low	Med	High
Key Timings							
Total Pre development Period (including pre-licensing and public enquiry)	years	1.0	2.0	3.0	1.0	2.0	3.0
Construction Period	years	0.5	0.8	1.0	0.5	0.8	1.0
Plant Operating Period	years	2.0	5.0	15.0	2.0	5.0	15.0
Technical Data							
Net Power Output	MW	988	988	988	988	988	988
Nett Efficiency	%	32.0	34.0	36.0	32.0	34.0	36.0
Average Steam Output	MW (thermal)	0	0	0	0	0	0
Average Availability	%	91.9	92.8	93.8	91.9	92.8	93.8
Average Load Factor	%	100.0	100.0	100.0	100.0	100.0	100.0
CO_2 Removal	%	0.0	0.0	0.0	0.0	0.0	0.0
Captial Costs							
Pre licensing costs, technical and design	£/kW	0.0	0.1	0.1	0.0	0.1	0.1
Regulatory + licensing + public enquiry	£/kW	0.0	0.0	0.0	0.0	0.0	0.0
EPC Costs (excluding interest during construction) - variability only	£/kW	22.2	56.5	143.6	22.2	56.5	143.6
EPC Costs (excluding interest during construction) - variability and uncertainty	£/kW	22.2	56.5	143.6	22.2	56.5	143.6
Infrastructure Cost	£,000	0	0	0	0	0	0
Operating Costs							
O&M fixed fee	£/MW/yr	120	240	360	120	240	360
O&M variable fee	£/MW/h	0	0	0	0	0	0
Insurance	£/MW/yr	0	0	0	0	0	0
Connection and UoS charges	£/MW/yr	0	0	0	0	0	0
CO_2 transport and storage costs	£/MW/h	0	0	0	0	0	0

Table 14 - SCR and SNCR Assumptions 2012

5.2 Sources of updated assumptions

It has been assumed that the unabated NOx concentration would be 450 mg/Nm³ (as NO_2 at 6 per cent vol O_2 dry reference conditions). The current limit under the IED is 200 mg/Nm³, but the June 2013 draft update to the Large Combustion Sector BREF (Best Available Techniques (BAT) Reference guide), issued for consultation, sets out more ambitious targets of 65-180 mg/ Nm³, which could potentially become mandatory limits under IED within the lifetime of existing plant with extended lifetimes. Moreover, the IED retains the Integrated Pollution Prevention and Control Directive principles that performance should exceed mandatory limits and achieve BAT. Reduction to the current IED limit of 200 mg/Nm³ requires a removal of 56 per cent, while reduction to 100 mg/Nm³ would require a removal of 78 per cent. SCR is capable of removing up to 95 per cent of NO_x, while SNCR removes typically 40 per cent. Estimates have therefore been made of the costs of SCR at 80 per cent and 90 per cent removal. SNCR alone would not remove sufficient NO_x, but a SCR/SNCR hybrid arrangement has been considered. Here SNCR would be installed to remove nominally 40 per cent NOx, with SCR downstream removing 80 per cent of the remainder. This would achieve an overall reduction of 88 per cent with a significantly smaller SCR component than with SCR alone. Removing 88 per cent of 450 mg/Nm³ NO_x would reduce the level to 54 mg/Nm³, which would meet even the most ambitious target currently under consultation.

Where the percentage NO_x removal required is significantly below 90 per cent, it is customary to provide an arrangement which treats a portion of the exhaust gas to a high degree of removal. In the case of the reductions discussed above, this is not considered appropriate. It is proposed that any SCR should be sized to handle the entire exhaust gas flow, with sufficient catalyst to achieve the reduction required, but with provision to add further catalyst if required.

5.2.1 Capital costs

Retrofitting SCR entails not only the SCR equipment itself but also support structures to locate the SCR at an appropriate elevation of the boiler. It is assumed that these costs were included in the previous estimates.

Estimates of SCR and SNCR capital costs from a number of sources are discussed below. Some sources are clearly for retrofitting, while others refer to new build only or are unclear.

5.2.1.1 SteamPro/PEACE

Capital and operating costs have been estimated using SteamPro and PEACE software for a number of options. This software is designed to simulate new build, so while the predicted impacts on operating parameters are reasonably representative of retrofitted plant, the additional costs associated with retrofitting are absent. These costs account for those directly associated with the SCR based abatement equipment itself, including nominal figures for some balance of plant (BOP) and erection. The base case represents normal operation of a 500 MW generating unit with flue gas desulphurisation (FGD) but without NOx abatement. Further cases included in Table 15 are SCR Case 1 (SCR with 80 per cent NOx removal), SCR Case 2 (SCR with 90 per cent removal) and SNCR with 40 per cent removal. In order to simulate the addition of SCR or SNCR to an existing plant, the further cases are run with the same steam flow rates as the base case. This results in a small reduction in net power output due to the additional auxiliary power consumed by the abatement plant, particularly with SCR.

Table 15 summarises the impacts of these SCR/SNCR modifications. SteamPro cannot model the Hybrid arrangement directly, so the values for the hybrid arrangement have been calculated from the SCR and SNCR results. A Hybrid plant would consist of a full size SNCR combined with an SCR solution only about 2/3 the size of a full SCR solution. This would be expected to be roughly 75 per cent of the cost of the full SCR, therefore the hybrid arrangement cost is estimated as SNCR plus 75 per cent of the cost of the Case 1 SCR unit (total 84 per cent of Case 1). Reagent consumption for the hybrid arrangement is taken as that for SNCR plus 60 per cent of that of the Case 1 SCR unit. Auxiliary power i.e. power lost is assumed to be that for the SNCR case plus 75 per cent of that for Case 1 SCR.

The presence of flue gas desulphurisation (FGD) does not significantly affect the impact of SCR or Hybrid on performance.

It should be noted these values are for newbuild plant only.

Case	Unit	Normal	SCR Case 1	SCR Case 2	SNCR	SCR/ SNCR hybrid
NO_x reduction	%		80	90	40	88
Gross power	MWe	531.6	531.6	531.6	531.6	531.6
Net power	MWe	499.8	498.049	497.79	499.7	498.4
Heat rate	kJ/kWh	8886	8918	8923	8888	Not considered
Total cost (as new build)	million GBP	795.88	822.32	825.90	798.61	Not considered
SCR/SNCR cost (as new build)	million GBP		20.99	23.98	1.91	17.66

Table 15 - Summary of SteamPro/PEACE capital costs for SCR/SNCR options

5.2.1.2 Retrofitting experience in North America

While it is recognised that market and regulation conditions in North America differ from those in the UK, some guidance may be taken from Parsons Brinckerhoff's experience there. Confidential information obtained from a plant supplier is that the median cost for a 500 MW plant SCR retrofit, excluding BOP and erection, is USD25 million (£15 million). BOP (including civil and electrical works) is very site dependent, but would be typically ~ £5 million. The estimated erection cost is USD30 million (£20 million). This would give a total installed cost of £40 million.

Confidential information from another supplier is that the overall installed cost for a 500 MW plant is considerably higher, ranging from USD110 to 140 million (£75 to 95 million). The wide range reflects the range in site specific conditions.

5.2.2 2013 BAT Reference Update

The draft BREF update issued in June 2013 includes information on SCR costs in a number of statements, of which three are of note. One of these specifically refers to new build, one specifically to retrofitting, while the other is unclear.

a Costs for new SCR, based on Austrian and German data, including erection and BOP but not catalysts, are estimated on the basis of flue gas flow. Making a number of technical assumptions consistent with the original SCR assumptions this information equates to a capital cost for a 500 MW unit of approximately £38 million.

An estimate of the cost for a 500 MW plant, making certain assumptions, is set out below.

Assumptions:

- 500 MW output;
- 33.88 per cent electrical efficiency;
- 350 Nm³ exhaust gas per GJ thermal (World Bank/IFC Guidelines);
- 400°C; and
- exhaust gas volume as actual m³ at temperature;

Calculations:

- thermal input = 500 x 100/33.88 MJ/s = 1,475.797MJ/s or 1.475797GJ/s
- exhaust flow = 350 x 1.475797 Nm³/s = 516.529 Nm³/s
- actual flow = 516.529 Nm³/s x (273.1 + 400)/273.1 = 1,273,071 m³/s = 1,273,071 x 3,600 m³/h = 4,583,055 m³/h
- cost = (4,583,055/1,000,000)0.7 x €15 million = €43.5 million, i.e. approximately £38 million.

b System capital costs for retrofit applications removing between 60 and 90 per cent NO_x, range between €50/kW and €100/kW, the lower end for higher capacity plant. Again it is not clear whether this includes BOP, erection or catalyst. For a 500 MW plant, this would correspond to £22 to £44 million.

c A 2001 Eurelectric reference indicates investment costs for a 500 MW plant with a high dust arrangement to be €25 to 40 million, which would escalate to £30 to £50 million today. It is not clear if "investment" includes BOP, erection or catalyst, or whether this is for new or retrofitted plant.

This document also notes that the cost of a SCR/SNCR hybrid plant would be about two thirds of the cost of an equivalent SCR plant i.e. £15 to 35 million, based on system capital costs in item b. above. This is slightly lower than the Parsons Brinckerhoff estimate of 84 per cent of SCR cost, which takes into account the impact of economies of scale.

5.2.3 UK submission to LCP BREF review

EA (2011) includes data on costs of providing SCR from three references. The report specifically addresses retrofitting SCR, but acknowledges that its own sources of cost information are limited.

A report by Barmoor Environmental Consultants in 2006 indicated "total installed capital cost" of SCR on a 500 MWe plant of £30 million for equipment reducing NOx to 200 mg/Nm³, but this rose to £40 million where NOx was reduced to 50 mg/Nm³. Escalating to 2012 prices raises these to £36 million and £48 million respectively.

A database of 19 retrofitted SCR installations round the world - intended to replace Barmoor's and earlier data - ranged from £27 to £225 per kW, averaging £136/kW.

Unit sizes were from 320 to 3400 MWe, with no trend of variation of cost per kW with unit size. Escalating to 2012 prices, the cost for a 500 MW plant corresponding to the average value would be £81 million.

The lowest cost, £27/kW, is significantly lower than all others, and another plant at the same site has a significantly higher cost. No explanation for the difference between co-located plants is given; this value is therefore discounted from this assessment. The next lowest cost is £76/kW; escalated to 2012 and converted to a 500 MW unit this is £53 million for a 500 MW plant. The highest value, £225/kW, escalated to 2012 and converted to a 500 MW unit gives a value of £169 million for a 500 MW unit. There are two other units in the list with costs almost as high. This value is for the Dan E Karn plant in Michigan. A technical report on this (B&W, 2006) showed that this was constructed using modular construction with transport of units to site; this may have affected the price but is not an unrealistic method of construction for the UK.

Discussions in 2008-2009 between the EA, Defra and the Joint Environmental Programme (JEP) concluded that a retrofitted SCR would cost £125 per kW. Escalating to 2012 pieces, the cost for a 500 MW plant would be £75 million.

5.2.4 Plant suppliers

Plant suppliers in Europe were approached and invited to provide information, but they declined. One European supplier agreed to peer review the assumptions after they were produced. Information from suppliers is presently limited to that obtained in North America as discussed above.

5.2.5 Catalyst suppliers

Approaches were made to catalyst suppliers. Only one supplier responded. They advised that the cost of catalyst was about 20 per cent of the capital cost of new plant. From their rules of thumb, a plant would require, per 100 MW, 80 m³ of catalyst, costing typically €5,500 (£5,000) per m³, so that the cost of catalyst for a 500 MWe unit would be £2 million. At 20 per cent of the cost of the whole plant, this gives an overall cost of £10 million. This is much lower than cost estimates from other sources. It is possible that this supplier may have disregarded or underestimated other investment costs including civil works and erection, however this was not confirmed.

5.2.6 Summary

The capex estimates obtained from these sources are summarised in Table 16.

Source	Process	NOx removal	New or retrofit	Comments	Cost for 500 MWe, £m
SteamPro/PEACE modelling (2013)					
SteamPro/ PEACE	SCR	80%	new	includes nominal BOP and erection	20.99
SteamPro/ PEACE	SCR	90%	new	includes nominal BOP and erection	23.98
SteamPro/ PEACE	SNCR	40%	new	includes nominal BOP and erection	1.91

Source	Process	NOx removal	New or retrofit	Comments	Cost for 500 MWe, £m
SteamPro/ PEACE	SNCR/ SCR hybrid	60% + 80% (88%)	new	includes nominal BOP and erection	17.66
Parsons Brinckerhoff North America (2013)					
SCR Supplier (US)	SCR		retrofit	includes BOP and erection	40
SCR Supplier (US)	SCR		retrofit	includes BOP and erection	75 – 95
2013 BREF update (2013)					
Austria and Germany	SCR		new	based on cost per m³/h exhaust; includes BOP and erection but not catalysts; certain assumptions	38
Austria and Germany	SCR	60 – 90%	retrofit	not clear if BOP or erection included	22 – 44
Eurelectric reference	SCR		unclear	not clear if BOP or erection included	30 – 50
Eurelectric reference	SNCR/ SCR hybrid			two thirds of equivalent SCR	15 – 35
UK submission to LCP BREF (2011)					
Barmoor	SCR	to 200 mg/Nm³	retrofit	not clear if BOP or erection included	36
Barmoor	SCR	to 50 mg/Nm³	retrofit	not clear if BOP or erection included	48
Worldwide database	SCR		retrofit	average £/kW; excludes civils and boiler modifications	53 low 81 average 169 high
JEP/EA/ Defra	SCR		retrofit		75
Catalyst supplier	SCR		unclear	Considered to be significantly underestimated	10

Table 16 - Summary of Capex Estimates

It is clear that the values for new build are not representative of retrofit values in general. Disregarding the value from the catalyst supplier, the lowest retrofit value for which BOP and erection are included is £40 million and the highest is £169 million for a 500 MW coal unit. Such a wide variation reflects the site conditions specific to individual plants or sites and the fact that there are a range of options for SCR.

A SCR/SNCR hybrid appears to be potentially viable at a cost of between 67 and 84 per cent of the corresponding SCR plus the cost of the SNCR.

The low SCR cost for 1000 MW plant is based on scaling the low cost for a 500 MW plant assuming economies of scale, giving a value of £65 million, and the high cost is based on the high cost, with an additional £5 million for civils and boiler modifications, again scaled to 1000 MW. Both costs were adjusted for the actual net power output for low and high cost plant. The final values are £65/kW and £284/kW. The central cost for SCR is assumed to be the average per kW of the low and high values. The low hybrid cost is assumed to be 2/3 of the low SCR cost and the central hybrid cost is assumed to be 75 per cent of the central SCR cost. The full range of values shown in Table 17 includes low hybrid, low SCR (mid) and high SCR.

Capital cost estimates were then peer reviewed, leading to a number of changes. The final values used in Tables 18 and 19 are:

- Low SCR £100/kW
- Med SCR £130/kW
- High SCR £200/kW
- Low Hybrid £86.7/kW
- Med Hybrid £97.5/kW

5.3 Operating costs

5.3.1 General

Retrofitting SCR entails more than the directly connected operating costs such as ammonia or urea consumption and auxiliary power. Small losses of output and efficiency will cause slight adverse changes in revenue and fuel consumption. In addition, there is likely to be significant expenditure associated with maintenance and refurbishment required to extend the operating life of the plant. The reductions in power output and efficiency have been calculated based on the SteamPro modelling results, applied to the before-retrofit values for subcritical coal that are already in DECC's model. The cost for life extension is discussed in Section 6 of this report. This section only considers direct operating costs for SCR/Hybrid.

Direct operating costs are considered for a baseload plant and include:

- Ammonia or urea consumption (most likely aqueous ammonia).
- Periodic replacement of catalyst.

Potentially there are other indirect costs e.g. additional maintenance and/or loss of sales of ash if it becomes too contaminated with surplus ammonia, however no information on these potential indirect costs has been found.

The O&M costs for SCR will include both reagent (most likely ammonia) and catalyst replacement.

5.3.2 Reagent cost

5.3.2.1 SteamPro/PEACE

Table 17 summarises relevant operating parameters and reagent costs for the options considered above. Reagent consumption is as 30 per cent ammonia solution. Annual reagent cost is estimated at £300 per tonne and assumes 8,000 hours operation per year.

Case	Unit	Normal	SCR	SCR	SNCR	SNCR/ SCR hybrid
NOx reduction	%		80	90	40	88
Gross power	MWe	531.6	531.6	531.6	531.6	531.6
Net power	MWe	499.8	498.049	497.79	499.7	498.4
Auxiliary power	MWe	31.8	33.551	33.81	31.9	33.2
Inferred SCR/SNCR power			1.751	2.01	0.1	1.4
Heat rate	kJ/kWh	8886	8918	8923	8888	
Reagent consumption	kg/s	-	0.2069	0.2326	0.3156	0.4397
Annual reagent cost	million GBP		1.76	2.01	2.73	3.8

Table 17 - Summary of SteamPro/PEACE operating parameters for SCR/SNCR options

SteamPro therefore calculates a range of £3.52 to £4.02 million annually for reagent for SCR for a 1000 MW plant. The hybrid costs are for SNCR plus two-thirds of the 80 per cent removal SCR case, hence, £7.6 million for hybrid SCR/SNCR for a 1000 MW plant.

5.3.2.2 Cost per tonne for ammonia (Reagent)

An alternative ammonia consumption rate and alternative cost per MWh can be estimated based on a cost of £300/tonne of 25 per cent by weight of ammonia. This produces an estimate of £0.48/MWh. For a baseload plant this is slightly higher than the PEACE estimate, so will be included in the "high" O&M cost for SCR.

Assumptions:

- reaction $6NO + 4NH_3 \rightarrow 5 N_2 + 6 H_2O$, with 20 per cent excess of ammonia;
- reduction of NOx from 450 mg/Nm³ to 90 mg/Nm³ (80 per cent removal);
- exhaust flow 500 Nm³/s (see above), all treated; and
- 25 per cent by weight ammonia at £300/tonne.

Calculations:

- NO_x removed per hour (as NO_2) = 516.529 Nm³/s x 3,600 s/h x (450 – 90) mg/Nm³ x 10-6 kg/mg = 669 kg/hour.
- 6 moles of NO_x (46 x 6 kg) require 4 moles of 100 per cent ammonia (4 x 17 kg) to react.
- 669 kg NO_x therefore requires 669 x (4 x 17)/(46 x 6) kg 100 per cent ammonia, i.e. 164.93 kg/hour.
- This corresponds to 164.93x 100/25 kg of 25 per cent ammonia, i.e. 659.7 kg/hour.

- Adding 20 per cent raises this to 791.7 kg/hour.
- Hourly cost is therefore 791.7 kg/h = 0.7917 t/h x £300/t = £237.50/h for a 500 MW unit = £475.00/h for a 1000 MW plant.
- Variable O&M cost (high) is therefore £475.00/ 996 = £0.48/MWh.

5.3.2.3 Peer review

One peer reviewer suggested a range of 0.2 - 0.5 £/MWh for reagent for SCR.

5.3.2.4 Summary of reagent costs

Assuming operation in the region of 8000 hours per annum the costs for SCR are as follows:

- STPro: £3.52 million to £4.02 million.
- Cost per tonne: £3.89 million.
- Peer review: £1.6 million to £4.05 million.

The other values fall within the peer review values, therefore the peer review values have been chosen as the low and high variable O&M cost for SCR.

For hybrid only one value is available, provided as an annual cost, so this will be considered part of the fixed O&M cost for hybrid, with a zero variable cost.

5.3.3 Catalyst replacement

The catalyst has a limited life and needs to be replaced at intervals. Replacement of batches will be staggered, typically to coincide with annual outages.

Catalyst lifetime typically varies between 3 and 5 years. Factors which shorten the life include the choice of auxiliary fuel used to start up the coal fired units, as metallic impurities carried into exhaust gas. Oil firing produces more contaminants than natural gas and contributes more to shortening the catalyst life than natural gas. Most coal fired plant in UK use oil, so a catalyst life of 3 years is assumed.

Both low and high O&M for SCR will include a catalyst cost of £1.34 million per annum for a 1000 MW plant. Hybrid O&M will include two thirds of this cost.

On the basis of rules of thumb offered above by the catalyst supplier, a 500 MW plant would use 400 m^3 of catalyst, so that each year on average 400/3 m^3 would be replaced, i.e. 133.3 m^3. At a typical cost of £5,000 per m^3, this represents an annual cost of £0.67 million for a 500 MW generating unit. Both low and high O&M for SCR will therefore include a cost of £0.67 x 2 = £1.34 million for a 1000 MW plant. Hybrid will include two thirds of this cost i.e. £0.89 million.

5.3.4 Summary

Low and high estimates for SCR O&M and an estimate for hybrid O&M have been produced for a 1000 MW plant:

- SCR fixed O&M cost: £1.34 million for a 1000 MW plant, dividing by actual net output this gives a value of £1345/MW/yr.

- SCR variable O&M cost: £0.2/MWh – £0.5/MWh.
- Hybrid O&M estimate: £8517/MW/yr.

Central hybrid = 3.8+0.67x2/3 = 4.27M for a 500 MW plant = 8.49M for a 1000 MW plant, divided by 997.2 = £8517/MW/yr.

It should be noted that the Hybrid cost would in reality consist of a fixed and variable amount, but this is estimated as fixed only.

It is not anticipated that there would be any additional O&M cost for maintenance, repair or overhaul, other than replacement of reagent and catalyst, during the expected lifetime of the retrofitted SCR or Hybrid plant.

The final O&M values used in Tables 18 and 19 are:

- Low SCR £1,345/MW/yr and £0.2/MWh
- Med SCR £1,345/MW/yr and £0.35/MWh
- High SCR £1,345/MW/yr and £0.5/MWh
- Low Hybrid £8,517/MW/yr
- Med Hybrid £8,517/ MW/yr

5.4 Other assumptions

Timings, availability and pre-licensing costs have been reviewed by experts within Parsons Brinckerhoff and by external peer reviewers. Very few changes have been made to these values from the 2012 values; changes are based on expert opinion.

The change to net power and efficiency after retrofit have been based on the SteamPro modelling undertaken, and also based on peer review comments.

No values could be found for reduction in availability or net power output due to potential issues with Hybrid described in Section 4.6.5. A nominal value of 5 per cent reduction in availability was proposed to one peer reviewer, who responded that that value “could be realistic”, however there is no real basis for this assumption. For worst case Hybrid, a 2 MW reduction in net power output below what was calculated from modelling has been assumed based on one peer reviewer’s comment that this could be “a couple of MW”. Again there is no reliable basis for this assumption. These assumptions have been included in Table 18 as a worst case but are not included in the central estimate for Hybrid in Table 19.

5.5 Peer review

Three companies responded to the peer review of the SCR values. Most of the values were considered to be reasonable by the peer reviewers; however a small number of values were changed as a result of peer review.

- The high outage period was increased slightly to allow for a situation with a complex tie-in requirement.
- One reviewer suggested the high operational life be increased to 30 years. While it is realistic that an SCR plant could operate for this long after it is built, it

is extremely unlikely that the coal plant would continue to operate for this period after retrofit of SCR, therefore this value was not changed.

- One peer reviewer suggested the loss of power should be greater and another that it should be less, however a third reviewer said the values were reasonable. SteamPro is considered accurate for these types of calculations and these values were not changed.
- The low pre-licensing, technical and design cost and the regulatory, licensing and public enquiry costs were increased as zero values are not thought to be realistic. However all reviewers stated that these costs were low.

5.6 Updated values

Table 18 shows the full extent of the range of each individual value, covering both retrofit of SCR to subcritical coal plant, and retrofit of Hybrid SCR/SNCR to a subcritical coal plant. The range for each value covers both SCR and SCR/SNCR hybrid, and values specifically relating to hybrid SCR/SNCR are highlighted in yellow. For each assumption that includes a highlighted Hybrid SCR/SNCR value, the other values represent the low and high end of the SCR range. Where the Hybrid SCR/SNCR value is in the low column, it represents the low end of the Hybrid SCR/SNCR range and where it is in the high column it represents the high end of the Hybrid SCR/SNCR range.

To enable a fair comparison, central values for both SCR and hybrid SCR/SNCR are shown in Table 19.

There is no reason to believe costs for retrofit would change significantly between now and 2020, therefore all costs are considered Nth Of A Kind.

SCR and SCR/SNCR hybrid retrofit		Nth OF A KIND		
		Low	Med	High
Key Timings				
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	0.8	1.4	2.0
Construction Period	years	0.8	1.0	2.0
Outage length for installation (can be installed as part of planned outage)	years	0.2	0.3	0.4
Plant Operating Period	years	10.0	15.0	20.0
Technical data				
Net Power Output before SCR retrofit	MW	1000	1000	1000
Net Power Output after SCR retrofit	MW	995.2	996.0	1000.0
Net LHV Efficiency before SCR retrofit	%	32.00%	34.00%	36.00%
Net LHV Efficiency after SCR retrofit	%	31.87%	33.88%	35.99%
Average Steam Output	MW (thermal)	0	0	0
Average Availability before SCR retrofit	%	91.9%	92.8%	93.8%
Average Availability after SCR retrofit	%	86.9%	91.9%	93.8%
Average Load Factor	%	100.0%	100.0%	100.0%
CO2 Removal	%	0.0%	0.0%	0.0%
Capital costs				
Pre-licensing costs, Technical and design	£/kW	0.025	1.00	2.00
Regulatory + licensing + public enquiry	£/kW	0.020	0.025	0.030
EPC cost (excluding interest during construction) – variability only	£/kW	86.7	100.0	200.0
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	86.7	100.0	200.0
Infrastructure cost	£'000	0	0	0
Operating costs				
O&M fixed fee	£/MW/yr	1,345	1,345	8,517
O&M variable fee	£/MWh	0.20	0.50	0.00
Insurance	£/MW/yr	0	0	0
Connection and UoS charges	£/MW/yr	0	0	0
CO2 transport and storage costs	£/t	0.0	0.0	0.0

Table 18 - Updated SCR and Hybrid SCR/SNCR Retrofit Assumptions (Ranges include SCR and Hybrid; Hybrid values are highlighted)

SCR and SCR/SNCR hybrid retrofit		Nth OF A KIND	
		SCR mid	hybrid mid
Key Timings			
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	1.4	1.4
Construction Period	years	1.0	1.0
Outage length for installation OR state if this can be installed as part of planned outage		0.3	0.3
Plant Operating Period	years	15.0	15.0
Technical data			
Net Power Output before SCR retrofit	MW	1000	1000
Net Power Output after SCR retrofit	MW	996.2	997.2
Net LHV Efficiency before SCR retrofit	%	34.00%	34.00%
Net LHV Efficiency after SCR retrofit	%	33.87%	33.99%
Average Steam Output	MW (thermal)	0	0
Average Availability before SCR retrofit	%	92.8%	92.8%
Average Availability after SCR retrofit	%	92.8%	92.8%
Average Load Factor	%	100.0%	100.0%
CO2 Removal	%	0.0%	0.0%
Capital costs			
Pre-licensing costs, Technical and design	£/kW	1.0	1.0
Regulatory + lisencing + public enquiry	£/kW	0.025	0.025
EPC cost (excluding interest during construction) – variability only	£/kW	130.0	97.5
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	130.0	97.5
Infrastructure cost	£'000	0	0
Operating costs			
O&M fixed fee	£/MW/yr	1,345	8,517
O&M variable fee	£/MWh	0.35	0
Insurance	£/MW/yr	0	0
Connection and UoS charges	£/MW/yr	0	0
CO2 transport and storage costs	£/t	0.0	0.0

Table 19 - Comparison of SCR and Hybrid Central Cases

6 PLANT LIFE EXTENSION

An integral part of the decision to retrofit NO_x reduction technologies or any other technology required to meet changes in legislation onto an existing coal fired power plant is the cost of extending the life of the power plant for sufficient years to achieve a commercial payback. The cost of life extension is not a single cost which can be applied to all power plants, but a number of individual costs which reflect where the power plant is in relation to the life cycle of its major components. A decision to invest in NO_x abatement can only be taken in the context of the whole plant and potential requirement to undertake wider investment to protect the whole asset.

While the EPC contract may specify an original design life intent of nominally 25 years, it is possible to extend economically the life of the power plant for a significantly longer period subject to continued plant inspection, sound operations and maintenance and timely replacement of life expired components.

6.1 Life limiting mechanisms

The age at which components are considered to be life expired can vary significantly, depending on the component design, operating conditions and regular maintenance/servicing. Within the context of a coal fired power plant, there are a number of life limiting mechanisms which apply to individual components. The most common mechanisms are creep, fatigue, corrosion, erosion, spallation and obsolescence, each of which are explained below. Engineering terminology used in the explanations include stress, defined as a force divided by the area over which the force is applied (similar to pressure but within a solid rather than a liquid), yield strength, which is the stress at which a material will deform or fail and pH, a measure of acidity of a substance.

6.1.1 Creep

Creep is the deformation of materials due to mechanical stresses usually occurring over long time-periods, due to stresses below the yield strength of the material. Power plant components most severely affected are those exposed to high temperatures (>320^{O}C) and high pressures, as the creep rate always increases with temperature. The deformation rate also depends on exposure time, structural load and material properties (such as melting point). Creep is also affected by changing conditions, such as loading and temperature changes.

6.1.2 Low cycle (thermo-mechanical) fatigue

In general, fatigue is material damage that occurs due to the stresses from cyclic loading, which can result in crack growth. Often the cyclic stresses are less than the yield limit of the material, so fatigue is typically built up progressively over time. Low cycle fatigue results from thermal stresses induced by repeated temperature changes. For example, firing stop/starts of boilers and turbines will induce heating and cooling, with associated expansion and contraction of the materials.

6.1.3 High cycle fatigue

High cycle fatigue occurs when materials are subjected to loading cycles of high frequency, often induced by vibrations in rotating equipment. The mechanical loading amplitudes will be lower than in the low cycle case, but the frequencies will be higher. Fatigue of this type will therefore be expected to progress over time in vulnerable components, and will be monitored accordingly during inspection cycles, especially for crack propagation.

6.1.4 Water corrosion

Water corrosion is caused by a chemical reaction between water/steam and exposed metals, in components such as piping, boiler circuits, and condenser tubes. It typically occurs when impurities, mainly dissolved oxygen are present, and/or if the water is acidic (low pH) in the boiler feed system. The corrosion process is essentially chemical oxidation of the container metals into their oxides, which can lead to roughening and pitting of the metal surfaces, also making them more prone to cracking. The typical control methods include selection of appropriate corrosion resistant materials and control of the water quality in the plant cycle (e.g. oxygen removal, pH control, blowdown system). High temperature conditions will exacerbate corrosion, for example within high temperature steam lines into the turbine, but lower temperature corrosion can also occur e.g. in cooling loops and feed water components.

6.1.5 Flue gas corrosion

The flue gas produced during combustion is rich in sulphur and chlorine, and can also contain moisture. The sulphur primarily, as well as the chlorine, can react with moisture to form acids that corrode components in the hot gas path (flue gas side in boilers and heat exchangers, outlets and stack, hot gas path in a gas turbine and Heat Recovery Steam Generator (HRSG)).

6.1.6 Civil corrosion

Atmospheric corrosion of structural steelwork occurs due to moisture in the air. High levels of sulphur and chlorine in the immediate surrounding environment from flue gas exhausts can also increase corrosion rates. Corrosion of steel and concrete can also occur below ground especially where aggressive soil conditions exist.

6.1.7 Particulate erosion

Erosion occurs when dust or particulates erode away component surfaces due to their constant impact over time, and can eventually lead to component failure. Water droplets, dust from coal and fly ash are typical particulate sources. Furnaces in coal fired boilers are particularly prone to dust erosion and last stage blades in steam turbines are affected by water droplets in moist exhaust steam.

6.1.8 Environmental erosion

Over time materials of construction, civil works and structural steelwork can be eroded due to wear and tear from weather conditions, and thermal expansion and contractions. For example, roofs of buildings and component housing will need to be resealed and maintained.

6.1.9 Concrete spallation

Concrete spallation has the potential to occur in any reinforced concrete if moisture is allowed to come into contact with the steel reinforcing bars which oxidise, pushing or "spalling off" a section of concrete. Typical areas of concern are main chimney, cooling towers and structural concrete.

6.1.10 Obsolescence

Digital Control Systems (DCS) of power plants can become outdated, due to the fast pace of advances in computer software and hardware. It is not uncommon for the complete DCS system to be replaced for compatibility with retrofit equipment, as original interfaces cannot be updated or reinstalled.

Table 20 gives an understanding of the typical failure mechanisms for major components in each plant area.

	Components	Creep	Low Cycle Fatigue	High Cycle Fatigue	Corrosion	Erosion	Concrete Spallation	Obsolescence
Boiler	HT components, headers, main steam pipework, steam chests HT bolts.	X HT Pressure parts	X Drums and Headers		X Internal tubing	X Parts in air/ gas path	X Support structures	
Steam Turbine	HP and IP rotors and cylinders, casings, valves, steam chests	X HT pressure parts	X	X	X Parts exposed to air/moisture/ heat	X LP blades		
Balance of Plant	Airheaters, ID Fans, FD Fans, PA fans, Milling Plant		X Fans, Mills, Airheaters		X ID Fans Mills, Airheaters	X	X Mill Foundations	
Cooling and Feedwater Systems	Condenser, air ejectors, pumps, motors, valves, cooling towers feedwater heaters.		X Pumps and Motors	X Pumps and Motors	X	X		
Electrical	Generators , transformers, switchyard , cabling breakers.		X	X	X			
Civils	Roofs, Walls, Steel Structures, Foundations				X	X	X	
Other	Instrumentation, Digital Control systems, auxiliary control systems							X

Table 20 - Typical Component Failure Mechanisms

6.2 Outage frequencies

On a coal fired power plant the main driver which dictates the requirement for a major overhaul is the Pressure System Safety Regulations (PSSR) 2000. Under the regulation the owner has to ensure that a suitable written scheme of examination is in place and examined in accordance with a specified intervals between examinations.

For a typical coal fired power plant the major overhaul frequency is shown in Table 21:

Plant Area	Type	Frequency (Years)	Duration (weeks)
Boiler	Major Overhaul	4	10 weeks
	Intermediate	2	4 weeks
Steam Turbine	Major Overhaul	12*	10 weeks
	Intermediate	4*	4 weeks

* The steam turbine work is aligned to the boiler outage cycle.

Table 21 - Major Overhaul Frequency for Coal Plant

Other plant items which are not unit specific may, if there is adequate redundancy, be maintained outside the outage period.

On a gas fired OCGT or CCGT power plant, the main driver which dictates the requirement for a major overhaul of the gas turbine is Equivalent Operating Hours (EOH). Each gas turbine manufacturer has a slightly different method of calculating EOH or factored fired hours, and both reflect the number and type of operating hours and starts. The frequency between major overhauls can therefore be dependent upon a fixed number of equivalent operating hour or starts, whichever occurs first.

The PSSR 2000 also applies to gas turbine plant, but the requirement to inspect the pressure systems of the combined cycle boiler is normally tailored to coincide with the major overhaul of the gas turbine.

For a typical CCGT power plant the major overhaul frequency is shown in Table 22. Frequency and duration of planned overhauls would not be expected to increase as plant ages.

Plant Area	Type	Frequency (Years)	Duration (weeks)
Gas Turbine	Major Overhaul	6	5 weeks
	Interim Inspection	3	3 weeks
HRSG	Major Overhaul	3*	5 weeks
	Intermediate	1.5*	3 weeks
Steam Turbine	Major Overhaul	12	5 weeks
	Intermediate	6	3 weeks

* The HRSG work is aligned to the gas turbine outage cycle.

Table 22 - Major Overhaul Frequency for Coal Plant

6.3 Coal fired life extension costs

Although most of the UK fleet of coal fired power plants are circa 45 years old, it is technically possible to extend the life for a further 10 years subject to continued investment to replace life expired components.

The cost of extended life can be sub divided into four main areas, namely:

1. Revenue - (routine repairs and maintenance only).
2. Capital - Major overhauls.
3. Capital - Life expired components.
4. Capital - cost of any upgrades required e.g. to meet new legislative requirements.

When an operator makes the decision whether to extend the life of the plant, all of these costs will be taken into account. The model that DECC uses to estimate levelised cost includes an O&M cost, which covers the first two areas; routine repairs and maintenance and major overhauls. Costs for the fourth area, upgrades, would include e.g. the cost to retrofit SCR described in Section 5 of this report. This section considers the cost of life expired components only.

6.3.1 Capital cost of life expired components

While the revenue and capital of overhaul costs are repeated, there will be the need for a "one off" replacement of life expired components.

The full cost of life extension is therefore not a single cost which can be applied to all power plants, but a number of costs which reflect where the individual power plant is in relation to the life cycle of its major components.

The main component life cycles for a coal plant are shown in Table 23. Assuming a 45 year standard life (as the DECC model currently assumes for coal plant), all replacement parts before 45 years should be covered by the O&M cost already included for coal plant. Continuing this O&M cost for a further 10 years should cover the majority of the ongoing replacement and refurbishment. Parsons Brinckerhoff has reviewed the O&M cost range currently included in the DECC levelised cost model and concluded that these costs are included within this assumption.

There is only one additional cost to extend the life of a coal plant for 10 years: replacement of main steam pipework. This could be undertaken during the major overhaul in year 40, so there should be no additional downtime. The costs shown are per generating unit. For a subcritical plant of the type currently in operation in the UK, a two-unit plant would typically produce about 1000 MW of net power. For a supercritical plant of the kind currently under construction worldwide, a two-unit plant typically produces about 1600 MW of net power. Table 24 shows the cost both total for a two-unit plant and in £/kW for currently operating subcritical plant and next generation supercritical plant.

Replacement or reblading of the turbine would be considered an upgrade rather than a maintenance or O&M cost so is not included in these costs.

				Cost £M															Year											
Area	Inspection	Activity	Frequency	Per Unit	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
Boiler	Major Overhaul		4	15			X				X				X				X				X				X			
	Inter Overhaul		2	1.5	X				X				X				X				X				X				X	
	HT Headers	Replace	28	1																										
	Main Steam Pipework	Replace	40	8											X															
Steam Turbine	Major Overhaul		12	8							X												X							
	Inter Overhaul		4	1			X								X				X								X			
	HP & IP Rotors	Refurb	16	8			X																X							
	LP Rotors	Refurb	28	6																										
	Steam Chests	Replace	28	2																										
	Generator	Refurb	16	2			X																X							
Feed Water System	Feed Heaters	Refurb	30	2	X																									
	Condenser Waterbox	Refurb	30	4	X																									
Electrical	Generator	Refurb	20	5											X															
	Transformers	Renew	30	3	X																									
	Motors	Refurb	10	2	X										X										X					
Control & Inst	DCS	Upgrade	10	2	X										X										X					
	Man Machine Interface	Upgrade	10	2	X										X										X					
Coal & Ash Plant	Coal Plant	Refurb	12	5							X												X							
	Ash Plant	Refurb	12	2							X												X							
	Precipitators	Refurb	12	3							X												X							
Civil	Exposed Steelwork	Repaint	25	2																					X					
	Roof & Cladding	Repairs	25	1																					X					

Table 23 - Main Component Life Cycles for Coal Plant

Life Extension Costs - Coal 1000MW subcritical	Year spent	value [£M]	£/kW subcritical
Main steam pipework replace	40	16	16
Life Extension Costs - Coal 1600MW supercritical	**Year spent**	**value [£M]**	**£/kW supercritical**
Main steam pipework replace	40	16	10

Table 24 - 10-year Life Extension Cost for Coal Plant

6.4 CCGT life extension costs

In common with coal fired plant, it is technically possible to extend the life of an OCGT or CCGT unit for a further 10 years subject to continued investment to replace life expired components. Within the UK fleet of "F" Class gas turbines, there is a mixture of age profiles and performance characteristics. From an environmental NO_x emissions point of view many of the earlier "E" Class gas turbines will require combustion system upgrades or the application of SNCR to be compliant with post 2016 emission limits. The latest generation of gas turbines are considered to be post 2016 compliant without modification.

As for a coal plant, when an operator decides to extend the life of a CCGT plant a number of costs will be considered: routine maintenance and outages, costs to upgrade such as ensuring compliance with 2016 emission limits, and costs for replacement of life expired components.

The main component life cycles for a CCGT plant are shown in Table 24. Assuming a 25 year standard life (as the DECC model currently assumes for CCGT plant), all replacement parts before 25 years should be covered by the O&M cost already included for CCGT plant. Continuing this O&M cost for a further 10 years should cover the majority of the ongoing replacement and refurbishment. Parsons Brinckerhoff has reviewed the O&M cost range currently included in the DECC levelised cost model and concluded that these costs are included within this assumption.

Although not strictly within the scope of the work, an indicative estimate has been included in Table 26 for life extension of gas turbine units. This is "Life Time Extension" cost at the bottom of the "Gas Turbine" row. There are a number of additional costs to extend the life of a CCGT plant for 10 years. All of these life extension works could be undertaken during the major or inter overhauls already planned for the years shown. The costs shown in Table 25 are per turbine. Table 26 shows the cost for a 900 MW CCGT plant, both total and in £/kW.

				Cost £M	Year																																		
Area	Inspection	Activity	Frequency	Per Unit	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Gas Turbine	Major Overhaul		6	12						X						X						X						X						X					
	Hot Gas Path Inspection		3	3			X						X						X						X						X					X			
	Life Time Extension		18	6																		X																	
HRSG	Major Overhaul		3	0.5				X				X				X				X				X				X				X				X			
	Inter Overhaul		1.5	0.1		X				X				X				X				X				X				X				X				X	
	HT Headers	Replace	28	0.25																												X							
	Main Steam Pipework	Inspect	6	0.5						x						X						X						X						X					
Steam Turbine	Major Overhaul		12	2												X												X											
	Inter Overhaul		6	1						X												X												X					
	HP & IP Rotors	Refurb	16	4																X																X			
	LP Rotors	Refurb	28	3																												X							
	Steam Chests	Replace	28	1																												X							
Electrical	Generator	Refurb	16	2																X																X			
	Transformers	Renew	30	2																														X					
	Motors	Refurb	10	1										X										X										X					
Control & Inst	DCS	Upgrade	10	1										X										X										X					
	Man Machine Interface	Upgrade	10	1										X										X										X					
Civil	Exposed Steelwork	Repaint	25	2																								X											
	Roof & Cladding	Repairs	25	1																								X											

Table 25 - Main Component Life Cycles for CCGT Plant

Life Extension Costs - 900 MW CCGT	Year spent	value [£M]	£/kW
Life time extension work	18	12	13.33
Exposed Steelwork repaint	25	2	2.22
Roof and cladding repairs	25	1	1.11
HT Headers replacement	28	0.25	0.27
LP rotors refurbishment	28	3	3.33
Steam chest replacement	28	1	1.11
Transformers renewal	30	6	6.67

Table 26 - 10 year Life Extension Cost for CCGT Plant

6.5 OCGT life extension costs

Both O&M and lifetime extension costs for OCGT tend to be determined based on the operating regime. Rather than an outage or a part replacement every number of years they would be determined by the number of starts the plant undergoes.

Gas turbines wear in different ways for different service duties. Thermal mechanical fatigue is the dominant limiter of life for turbines that operate intermittently, while creep, oxidation and corrosion are the dominant limiters of life for continuous duty (baseload) turbines. Interactions of these mechanisms are considered in the gas turbine design criteria, but to a great extent are second order effects. For these reasons, gas turbine maintenance is dependent upon either starts or fired hours; whichever criteria limit is first reached. Table 27 shows how the intervals between different maintenance activities vary for baseload and intermittent turbines. This example is for a General Electric (GE) 9FA gas turbine, although requirements would be specific to the turbine type.

Inspection	Frequency		Duration
	Hours	Starts	8 Hour Shifts
Combustion	8,000	450	10
Hot Gas Path	24,000	1,200	22
Major	48,000	2,400	46

Table 27 - Inspection Intervals for GE Gas Turbines

Normally at near base load (8,000 running hours per year) a major overhaul would be required every 48,000 hours i.e. about every six years. For a turbine that stops and starts daily except for weekends (i.e. about 260 starts per year) the requirement would be for a major overhaul every 2,400 starts i.e. about every nine years. As with any starts based maintenance cycle, the maintenance frequency will vary according to the actual number of starts. As for CCGT such inspections would be covered by the existing O&M cost assumptions for OCGT.

Parsons Brinckerhoff has considered the number of starts likely for aeroderivative peaking plants which typically is required for fast response at peak times, and large frame standby plant, which in a high-renewables future is likely to be required to switch on whenever there is a lack of wind power. The latter case was informed by consideration of Poyry, 2009. It seems likely that extending the life of an OCGT plant of either type up to 40 years could be achieved merely by extending the existing O&M cost assumptions up to 40 years.

Therefore the additional capital cost to extend an OCGT life to 40 years, other than O&M costs, is estimated to be £0/kW.

After about 40 years spares for the turbine will become obsolete and difficult to find, and reverse engineering such spares is expensive. The electrical and civil infrastructures surrounding the OCGT may also need some refurbishment. It is possible that it may be economically viable to continue running an OCGT beyond 40 years but no sources of cost estimates for this could be found. It is not recommended that DECC model OCGT life extension beyond 40 years.

6.6 Summary

It is technically feasible to extend coal, CCGT and OCGT plant beyond their design lives. Costs have been presented for extension of life of each type of plant for 10 years beyond design life for coal and CCGT and up to 40 years operation for OCGT.

The costs presented are for plant currently in operation in the UK. For plant built in the future the costs are expected to be similar in general, and specific values have been provided for supercritical coal plant. For CCGT plant, all plant built in the future, as well as some currently in operation, would not need the "Lifetime extension work" cost. Future OCGT plant is expected to have similar extension cost to currently operating plant.

The costs presented in this section do not include costs to upgrade plant e.g. to meet new emission limits (other than the "Lifetime extension work" for CCGT). As plant gets older and more obsolete, and emissions limits become more and more stringent, it is probable that more and more limits will be imposed, and the cost of meeting these limits would also be taken into account by operators in their lifetime extension decisions.

Obviously with unlimited money, new equipment and complete refurbishment and replacement of major parts of the plant, it may be possible to enable a plant to run indefinitely, just as some extremely old steam trains and antique cars are still operational. However in this case the plant would not be a typical power plant operating to produce a profit, just as old steam trains and antique cars are not expected to be used as common means of transport. Eventually finding spares for the turbine and other equipment will become impossible and it would be necessary to pay for design and manufacture of such bespoke spares. The decision to extend the life would be taken each time a new cost is required, and the economics must be favourable each time to continue with operation. In the meantime the plant would be becoming obsolete and uncompetitive with newer more efficient and cleaner plant, and the operating hours would be reducing accordingly. Eventually it would become economically unviable to continue to upgrade and refurbish the plant.

No sources of cost estimates for such long term life extension could be found. The costs estimated in this report relates to ten years extension for coal and CCGT as that was the scope of this task. For OCGT cost estimates are expected to be reasonable up to a 40 year life. It is not recommended that DECC model life extension for longer periods using the information in this report.

It may be expected that near to the original efficiency can be achieved after life extension but no improvement should be assumed.

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APPENDIX A: SITE AVAILABILITY

Sites for CCGT or OCGT generating plants are generally chosen for proximity to gas and electrical grid connections, suitable zoning of land, availability of cooling sink (for CCGT only) and proximity to load centres.

It is assumed that the same cohort of sites is available either for OCGT or CCGT since the core technology of gas turbines is the same. The main difference is the access to cooling required for steam cycle condensing at CCGT plants.

Parsons Brinckerhoff has categorized sites for generating plants into four groups. Sites in England, Scotland and Wales have been included. Northern Ireland has not been taken into account as it is part of a different grid.

Former CEGB sites, including CCGT, coal and oil.

Independent Power Producers (IPP) sites, mainly CCGT.

New sites which have already secured Section 36 Consent to Construct and Operate, mainly CCGT.

New sites which have applied for Development Consent Orders under the Planning Act 2008, mainly CCGT.

The total capacity that these sites represent is 92 GW. Therefore it is expected that these sites will be sufficient to meet the national requirements for new CCGT or OCGT plants to 2050. In addition, several of the existing or planned sites also have the possibility of adjacent extension, which is always a preferred choice to take advantage of existing operational infrastructure. Hence the maximum feasible build rate will not necessitate the location and approval of additional sites that are currently unidentified, although new sites will always be developed as well.

Further detail on these site categories is presented below:

FORMER CEGB SITES

Most former CEGB coal fired sites could be reused with many plants now nearing the end of their economic life or due for closure to meet emissions standards. Many of these sites were chosen by specialist planning teams working under the former nationalised industry structure with preferential purchase rights to secure the best sites for cooling and fuel supply.

This category includes coal and oil fired plants, CCGT and OCGT, biomass plants, as well as sites at which electrical grid connections can be used and the power train replaced by more efficient modern combined cycle gas turbines.

Closure dates are derived from a mix of publicly available information or an assumption that gas turbine plant has a nominal life of 25 years and coal fired plant has a life of 50 years.

Within this former CEGB group there are:

16 coal fired and biomass plants with a total installed capacity of 28.4 GW.

3 oil fired plants with a total installed capacity of 3 GW.

3 OCGT plants with a total installed capacity of about 370 MW.

1 gas fired steam plants with 400 MW capacity, later repowered to CCGT.

The total installed capacity within this group is about 32 GW.

IPP SITES

Many Independent Power Producers (IPP) plants developed since the privatisation of the Electricity Supply Industry after 1989 have plant which is now nearing the end of its economic life. It is assumed that these sites in general can be reused for new CCGT/OCGT construction.

CCGT and OCGT sites have been included in this category, as well as some coal and oil fired plants, whose electrical grid connections can be used and the power train replaced by the more efficient modern gas turbine technology.

Within this group there are:

46 CCGT plants with about 32 GW total installed capacity.

1 coal fired plant with an installed capacity of about 360 MW.

1 OCGT plant with a total installed capacity of 140 MW.

The total installed capacity within this group is 32.2 GW.

NEW SITES WITH SECTION 36 CONSENT TO CONSTRUCT AND OPERATE

Plant construction has begun at only one of the sites within this group while others are not yet sanctioned for investment due to adverse market factors.

At present there is one CCGT power plant in construction with expected commissioning date in 2016. The total installed capacity for this site is 910 MW.

14 CCGT sites with a total installed capacity of about 14 GW have consent granted. One additional site with capacity of about 470MW obtained consents for development but this has expired.

There is one clean coal fired plant with capacity of about 800MW within this group.

The total installed capacity within this group is about 15.4 GW. Several developers are waiting for improved market conditions to make investment decisions. As this study is concerned with the maximum feasible build rates ignoring economic constraints, it is assumed that investment decisions for these plants are taken and construction begins in 2014. Gas plant is assumed to be commissioned three years later (2017). The plant currently planned as clean coal is assumed to cancel the clean coal project, begin planning application for gas plant in 2014, and be commissioned by 2020. The site with application expired is assumed that would need to restart the process in 2014 and would be available for commission by 2020.

NEW SITES WITH DEVELOPMENT CONSENT ORDER APPLICATIONS UNDER THE PLANNING ACT 2008

At present there are 13 sites with ongoing IPC applications, including:

10 CCGT sites with a total capacity of 10 GW.

1 coal fired plant of 426 MW.

2 OCGT sites with a total capacity of 600 MW.

There are two CCGT sites with a total capacity of about 3 GW which started the process that have withdrawn the application.

The total capacity of this group is 14 GW.

For the purpose of this study it has been assumed that all these sites are at the beginning of the process and all sites take three years to complete the process i.e. all these sites become available for construction in 2016. Gas plant is therefore assumed to be commissioned in 2019, with coal plant commissioned in 2020. Withdrawn applications may be able to restart the application process and be available for 2020. The Development Consent Order DCO process and duration is explained in more detail later in this Appendix.

At present there are no CCGT and OCGT applications which have reached the end of the DCO process, which adds some uncertainty about the timing and future development of new power plants.

Appendix B summarizes in a table the information above for the gas and coal fired plants.

EVALUATION OF CAPACITY LIMITS OF AVAILABLE SITES

Many sites are available for CGGT and OCGT development in the UK. It would be technically feasible to repower the vast majority of existing sites as CCGT or OCGT plant, reusing grid connection, access to cooling and gas connections (if present).

For the purposes of identifying the maximum availability of sites for CCGT/OCGT a number of assumptions have been made:

- The capacity installed at each site is in compliance with the existing consent or currently operation plant. In reality most plants would permit 20-50 per cent larger CCGT or OCGT capacities to be installed within the site constraints.
- All sites in the categories above are suitable for either CCGT or OCGT. In reality the main difference from a site selection perspective is that CCGT plant needs additional space and provision of a cooling system. The vast majority of sites above could accommodate either plant, using air cooled condensers where necessary.
- All sites with currently operational power plant continue operating until the end of their operational life, which is assumed to be 25 years for gas turbines and 50 years for steam plant.
- All sites that have obtained consent but at which construction has not yet begun will begin construction in 2014 and achieve commissioning in 2017. These plants then operate for their design lives before replanting.
- All sites that have already applied for consent are successful, obtain consent in 2016 and achieve commissioning in 2019. These plants then operate for their design lives before replanting.
- No new sites are identified between now and 2050.

- When a plant reaches the end of its operational life it is repowered as CCGT or OCGT, with the same net power export capacity.
- Development and planning for CCGT and OCGT plant that are replacing end of life plant is undertaken in parallel with the plant ending its operational life, so that demolition of the old plant and construction of the new plant begins as soon as the original plant reaches the end of its operational life.
- Demolition of the existing plant and construction of the new CCGT or OCGT plant takes five years. Construction of CCGT or OCGT plant on a greenfield site takes three years.
- All currently operating sites that will reach the end of their operational life by 2017 or earlier will apply for consent in 2014. They will begin demolition and the consenting process in 2017 and achieve commissioning in 2022.

Figure 4 presents the available site capacity in GW which could become operational in each year in the period 2013-2050, based on the assumptions described above.

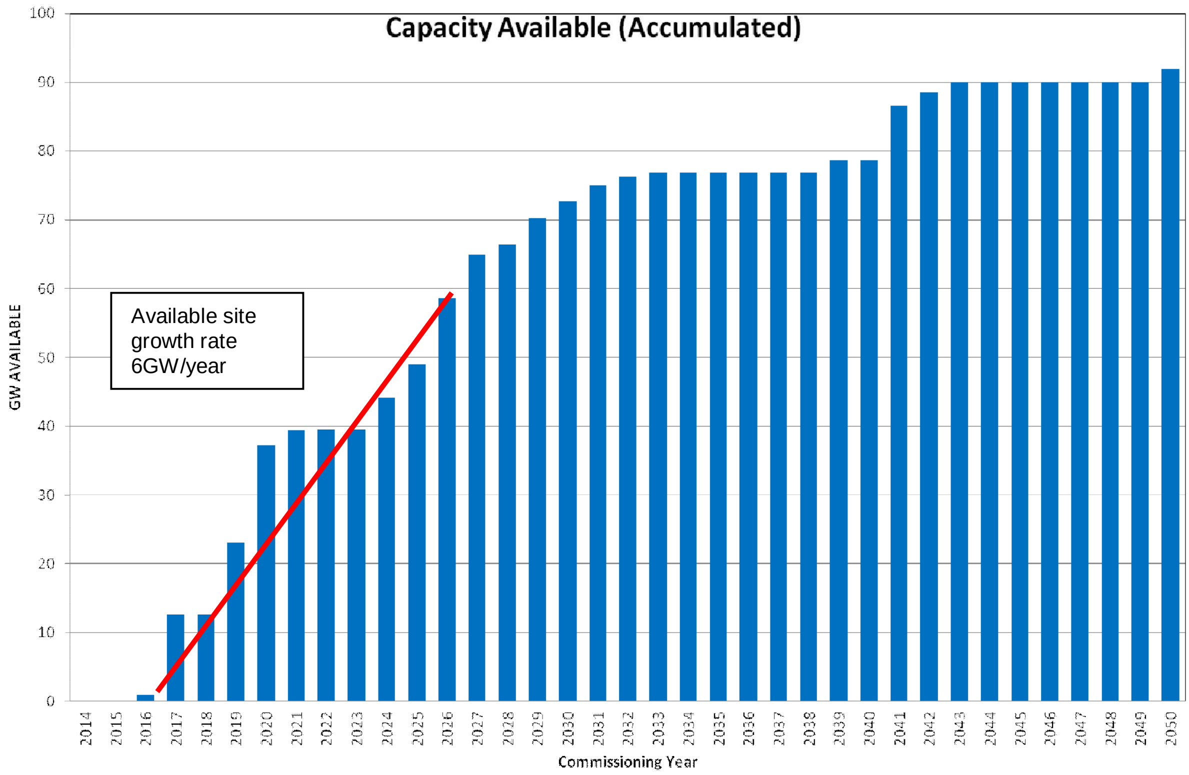


Figure 4 - Maximum capacity of sites available for CCGT/OCGT to 2050

This analysis indicates that available sites would permit a sustained build rate of 6 GW per year initiated in 2013 with first operation in 2017. A later start date would mean that unused sites would be available, permitting even higher rates of construction if feasible within other constraints.

The limit calculated in this report is not intended to be a sustained build rate, rather it is intended to be an annual limit, ignoring activity in other years. Therefore as the annual limit of 6GW per annum has been identified based on capacity of the power plant construction industry, the limit for commissioning of capacity yet to be contracted each individual year would be:

Year	Maximum Technically Feasible Build Rate - commissioning
2014	0 GW
2015	0 GW
2016	0.9 GW
2017 - 2050	6 GW

Table 28 - Annual Maximum Technically Feasible Build Rates - commissioning, limited by site availability

PLANNING AND REGULATORY CONSTRAINTS

Prior to 2008, the planning of power plants with output greater than 50 MW was managed under Section 36 of the Electricity Act 1989 by DECC, or its predecessors. Several future power plants already have Section 36 Consent, but have not yet had an investment decision due to unfavourable economic circumstances. The provisions of the Growth and Infrastructure Act 2013 also now allows some flexibility in the configuration of plants consented under Section 36 of the Electricity Act 1989 to benefit from latest technology developments.

The development of every plant can be broken down in three different phases:

a Development Phase.

a EPC contract Negotiation and award.

b Construction.

The Development Phase includes feasibility studies, assessment for gas and grid connection, CHP assessment and carbon capture readiness assessment. In this phase, the developer needs to meet with the Planning Inspectorate (PINS) to prepare all the required documentation to start the DCO application process. After the first meeting and submission of scoping of the plant the developer receives instructions about the work that has to be covered. The Environmental Impact Assessment is part of the Development Phase and covers all aspects related to the impact of the plant. Normally it includes site surveys, ecology and Noise surveys, landscape studies, Archaeology studies, Flood Risk analysis and Traffic planning.

Planning for a new CCGT and OCGT plant is constrained in time by the DCO process. EPC Contract negotiation and award phase can take different amounts of time depending on the process selected by the developer, but 12 months is reasonable for a typical plant in the UK. This phase can be done largely in parallel with the development phase, allowing the construction to begin on site a few months after DCO approval is granted.

For repowering of an existing site i.e. replacing an existing plant with a new plant at the same site, it would be technically feasible to undertake the Development, Planning and EPC negotiation activities while the existing plant is still operational, but it is more likely that the planning activities would require surveys after demolition of the plant, leading to a delay before new construction could start.

Estimating the timescale for the DCO process requires consideration of early plants that have completed the process as there is limited experience of their application to power plant. There are 8 projects for which a decision has been issued by National Infrastructure Planning, including:

- Hinkley Point C New Nuclear Power Station granted its development consent in March 2013 after a process of 17 months which started in October 2011. The submitted Scoping Opinion report is dated April 2010, which suggests 35 months since it was issued.
- Port Blyth New Biomass Plant was granted its development consent in July 2013 after a process of 16 months which started in March 2012. The Scoping report is dated August 2010, which suggests 35 months since it was first issued.
- Preesall Saltfield Underground Gas Storage started its application in November 2011 and the Secretary of State refused the project in April 2013, 17 months after the process started.

From these three examples, it can be seen that the overall planning process time from start to finish may be approximately 35 months (nearly 3 years) until the project is granted approval or refused. All the documentation before the DCO process must be submitted at the early stages, giving an overall development timescale of the order of four years.

The delay in obtaining approval for construction of a plant need not constrain site availability, as discussed above, but the rate at which sites are approved could do so in the extreme case of a sustained programme of new construction. As described earlier the maximum number of thermal generating units that received consent in a single year was 22, in 1993, and 11 units per year was the average during two periods in UK history. Although the maximum rate of plant approval occurred twenty years ago it is considered likely that the planning process should be able to sustain a rate of approval comparable to the maximum sustained historical rate, even if this required increasing the number of inspectors for power plants. This corresponds to an approval rate of around 5,500 MW per year. However as previously stated there are a number of plants that have already obtained consent or begun the consenting process. If it were necessary to bring more plant than this online in a particular year it would be technically feasible to build plants with existing consent or to obtain consent significantly in advance of beginning construction. If necessary additional planning inspectors could also be employed to increase the consenting rate.

Parsons Brinckerhoff also considered the possibility of regulatory constraints other than planning constraints. However none of the regulatory processes considered would impact on the build rate more than the planning process. All other regulations that apply prior to construction e.g. obtaining licenses etc will be obtained more quickly than obtaining consent. Regulations during construction are considered in the assumption for a 3 year construction duration (which is a high estimate), and no construction regulations would impact on the number of plants that could be built at a time. Regulations that apply after construction obviously would not affect build rates.

GAS AND ELECTRICITY GRID CONSTRAINTS

All currently operating plants have electricity grid connections. For the maximum technically feasible build rates it has been assumed that plant that have already applied for consent have or will have an electricity grid connection by the time they complete construction. In general this is realistic as the time required for obtaining consent and construction of the grid connection is typically less than the time required for obtaining consent and construction for the plant.

For repowering of existing sites it has been assumed that the new plant has the same capacity as the old plant, and therefore no increase or reduction in electrical capacity is required. In general this is technically realistic, however there may be some sites at which space constraints could limit the amount of CCGT plant built, however such detailed site-by-site analysis is outside the scope of this study.

Electricity grid constraints are therefore not considered to significantly impact on the maximum technically feasible build rates.

All existing gas fired CCGT and OCGT plants have gas connections. Some of the future CCGT plants already have a gas connection (National Grid, 2010). Plant that is currently operational using other fuel would require a new gas connection when repowering as CCGT or OCGT. Many of these sites are physically close to high pressure gas pipelines.

The time required to get gas connection is generally less than the time required for planning consent for the power plant. However, the new gas connections may require reinforcement of the existing high pressure gas network. This could mean that the development and consent period for a new CCGT/OCGT plant could take up to seven years.

It has been assumed that all CCGT and OCGT plant that have been granted consent or have applied for consent have already considered this issue and either already have or will have a gas grid connection by the time the plant is commissioned.

For sites with non-gas plant currently operational, that will come to end of life by 2021 or later, it would be technically feasible for those sites to begin the process in 2014, and therefore to have gas connection consent by 2021, so those sites are unaffected by this constraint.

CONCLUSION

This Appendix has demonstrated that:

- Sites suitable for 14 GW of CCGT and OCGT will be available from 2017 (assuming no new plants of any type have been built in previous years).
- Sites suitable for CCGT and OCGT will become available at a rate of about 6 GW per annum from 2017 to 2026.
- The planning process for new sites will permit maximum feasible CCGT or OCGT build rates of 5,500 MW per year respectively, with the possibility to increase this in any individual year by obtaining consent in advance of building or by deploying additional inspectors.
- The supply of gas or the export of electricity from a new power plant could constrain the maximum feasible build rate. However at a site by site level these issues are found not to restrict the rate of build.
- Neither gas nor electricity grid constraints are expected to significantly limit the maximum technically feasible build rates. For some sites grid constraints could result in significant delays in the planning process e.g. where a new gas connection requires reinforcement of the gas network. It should be noted that as stated in the main body of this report the maximum build rates are independent

for each year; a sustained programme of CCGT construction e.g. maintaining the maximum build rate for a number of years has not been considered.

APPENDIX B: SITES AVAILABLE FOR CONSTRUCTION AS CCGT/OCGT

Licensee	Plant Type	Power Plant	Owner		Capacity	Category
NGET	CCGT	Partington Power Station	Carrington Power Limited	2016	910	Under Construction
NGET	CCGT	Abernedd Power Station Stage 1	Abernedd Power Company Ltd	2017	500	Consents Granted
NGET	CCGT	Abernedd Power Station Stage 2	Abernedd Power Company Ltd	2017	414	Consents Granted
NGET	CCGT	Carrington II Power Station	Wainstones Energy Limited	2017	1,520	Consents Granted
NGET	CCGT	Damhead Creek II	ScottishPower(DCL) Limited	2017	1200	Consents Granted
NGET	CCGT	Drakelow D	E.ON UK plc	2017	1,320	Consents Granted
NGET	CCGT	Kings Lynn B	Centrica KL Ltd	2017	981	Consents Granted
NGET	CCGT	Thorpe Marsh	Thorpe Marsh Power Limited	2017	1,500	Consents Granted
NGET	CCGT	Brine Field (Teesside)	Thor Cogeneration Limited	2017	1,020	Consents Granted
	CCGT	Keadby 2	Keadby Generation Ltd	2017	710	Consents Granted
	CCGT	Coryton 2	Gateway Energy Centre Power Station	2017	1000	Consents Granted
	CCGT	Seal Sands Teesside	Norsea Pipelines Ltd	2017	800	Consents Granted
	CCGT	Spalding Expanion	Spalding Energy Company Ltd	2017	900	Consents Granted
NGET	CCGT	Seabank 3	Seabank Power Limited	2019	1,400	IPC Application
	CCGT	Knottingley Power Project	Knottingley Power Limited	2019	1500	IPC Application
	CCGT	Palm Paper 3 CCGT Power station Kings Lynn	Palm Paper Ltd	2019	162	IPC Application
	CCGT	Avon Power Station	Scottish Power	2019	950	IPC Application
	CCGT	Wrexham Energy Centre	Wrexham Power Limited	2019	1200	IPC Application
	CCGT	North Killingholme Power Station	C.GEN Killingholme Ltd	2019	470	IPC Application
	OCGT	Hirwaun Power Station	Hirwaun Power Limited	2019	299	IPC Application
	OCGT	Progress Power Station	Progress Power Limited	2019	299	IPC Application

Licensee	Plant Type	Power Plant	Owner		Capacity	Category
	CCGT	South Hook Combined Heat & Power Station	QPI Global Ventures Ltd	2019	500	IPC Application
NGET	CCGT	Tilbury Stage 2	RWE Npower plc	2019	2,400	IPC Application
	CCGT	Killingholme Energy Centre	Killingholme Energy Limited	2019	1200	IPC Application
	CCGT	Meaford Energy Centre	Meaford Energy Limited	2019	299	IPC Application
NGET	CCGT	Barking Power Station C	Barking Power Ltd	2020	470	Application Expired
NGET	CCGT	Wyre Power	Wyre Power Limited	2020	950	Application Withdrawn
	CCGT	Brigg North Lincolnshire Power Station	Centrica	2020	2000	Application Withdrawn
NGET	Large Unit Coal + AGT	Kingsnorth	E.ON UK plc	2020	1,966	CEGB
NGET	CCGT	Kings Lynn A	Centrica KL Ltd	2020	340	IPP
NGET	CCGT	Roosecote	Centrica RPS Ltd	2020	229	IPP
NGET	CCGT	Teesside	Teesside Power Ltd	2020	1,875	IPP
NGET	IGCC with CCS	Hatfield Power Station	Powerfuel Plc	2020	800	Clean Coal
SHETL	CCGT	Peterhead	SSE Generation Limited	2020	1,180	CEGB
SPTL	Medium Unit Coal	Cockenzie	Scottish Power Generation Ltd	2020	1,102	CEGB
NGET	Small Unit Coal	Uskmouth	Uskmouth Power Company	2020	363	IPP
	Clean Coal	White Rose CCS	Capture Power Limited	2020	426	IPC Application
	CCGT	Willington	RWE Npower plc	2020	2,400	Consents Granted
NGET	Large Unit Coal + AGT	Ironbridge	E.ON UK plc	2021	964	CEGB
NGET	Medium Unit Coal + AGT	Tilbury Stage 1	RWE Npower plc	2021	1,131	CEGB
NGET	OCGT	Didcot A GTs	RWE Npower plc	2022	100	CEGB
NGET	CCGT	Brigg	Centrica Brigg Limited	2024	260	IPP
NGET	CCGT	Corby	Corby Power Ltd	2024	401	IPP
NGET	CCGT	Killingholme	E.ON UK plc	2024	900	IPP
NGET	CCGT	Peterborough	Centrica PB Ltd	2024	405	IPP
NGET	CCGT	Rye House	Scottish Power Generation Ltd	2024	715	IPP

Licensee	Plant Type	Power Plant	Owner		Capacity	Category
NGET	Large Unit Coal + AGT	Ratcliffe on Soar	E.ON UK plc	2024	2,021	CEGB
NGET	CCGT	Barking	Barking Power Ltd	2025	1,000	IPP
NGET	CCGT	Deeside	Deeside Power Development Co Ltd	2025	515	IPP
NGET	CCGT	Keadby	Keadby Generation Ltd	2025	735	IPP
NGET	CCGT	Killingholme 2	Centrica Generation Ltd	2025	665	IPP
NGET	Large Unit Coal + AGT	Cottam	EDF Energy (Cottam Power) Ltd	2025	2,000	CEGB
NGET	CCGT	Little Barford	RWE Npower plc	2026	665	IPP
NGET	CCGT	Medway	Medway Power Ltd	2026	700	IPP
NGET	Large Unit Coal + AGT	Eggborough	Eggborough Power Limited	2026	1,940	CEGB
NGET	Large Unit Coal + AGT	Ferrybridge	Keadby Generation Limited	2026	1,986	CEGB
NGET	Large Unit Coal + AGT	West Burton	West Burton Ltd	2026	1,987	CEGB
SPTL	Large Unit Coal	Longannet	Scottish Power Generation Ltd	2026	2,284	CEGB
NGET	CCGT	Connahs Quay	E.ON UK plc	2027	1,380	IPP
NGET	CCGT	South Humberbank	Humber Power Ltd	2027	1,285	IPP
NGET	Large Unit Coal + AGT	Aberthaw	RWE Npower plc	2027	1,665	CEGB
NGET	Large Unit Coal + AGT	Fiddlers Ferry	Keadby Generation Ltd	2027	1,987	CEGB
NGET	Large Unit Coal + AGT	Rugeley	Rugeley Power Ltd	2028	1,018	CEGB
NGET	Small Unit Coal	Lynemouth	Alcan Aluminium UK Ltd	2028	420	CEGB
NGET	CCGT	Barry	Centrica Barry Ltd	2029	245	IPP
NGET	CCGT	Didcot B	RWE Npower plc	2029	1,550	IPP
NGET	CCGT	Rocksavage	Rocksavage Power Company Ltd	2029	810	IPP
NGET	CCGT	Seabank	Seabank Power Ltd	2029	1,234	IPP
	CCGT	Castleford	E.ON UK plc	2029	56	IPP
NGET	CCGT	CDCL	E.ON UK plc	2030	395	IPP
NGET	CCGT	Enfield	E.ON UK plc	2030	408	IPP
NGET	CCGT	Sutton Bridge	EDF Energy (Sutton Bridge Power)	2030	819	IPP
NGET	CCGT	Spalding	Spalding Energy Company Ltd	2030	880	IPP

Licensee	Plant Type	Power Plant	Owner		Capacity	Category
NGET	CCGT	Damhead Creek	Scottish Power (DCL) Ltd	2031	805	IPP
NGET	CCGT	Saltend	Saltend Cogeneration Company Ltd	2031	1,100	IPP
NGET	CCGT	Shoreham	Scottish Power (SCPL) Ltd	2031	420	IPP
NGET	CCGT	Coryton	Coryton Energy Company Ltd	2032	800	IPP
NGET	CCGT	Great Yarmouth	RWE Npower plc	2032	420	IPP
NGET	CCGT	Baglan Bay	Baglan Generating Ltd & Baglan Operations Ltd	2033	552	IPP
NGET	CCGT	Langage	Centrica Langage Ltd	2039	905	IPP
NGET	CCGT	Marchwood	Marchwood Power Ltd	2039	900	IPP
NGET	CCGT	Grain Stage 2	E.ON UK plc	2041	860	IPP
NGET	CCGT	Grain Stage 3	E.ON UK plc	2041	430	IPP
NGET	CCGT	Severn Power Stage 1	Severn Power Limited	2041	425	IPP
NGET	CCGT	Severn Power Stage 2	Severn Power Limited	2041	425	IPP
NGET	CCGT	Staythorpe C Stage 1	RWE Npower plc	2041	425	IPP
NGET	CCGT	Staythorpe C Stage 2	RWE Npower plc	2041	425	IPP
NGET	CCGT	Staythorpe C Stage 3	RWE Npower plc	2041	425	IPP
NGET	CCGT	Staythorpe C Stage 4	RWE Npower plc	2041	425	IPP
NGET	Large Unit Coal + AGT	Drax	Drax Power Ltd	2041	3,906	CEGB
NGET	CCGT	Wilton Stage 2	Sembcorps Utilities (UK) Limited	2041	99	IPP
NGET	CCGT	Pembroke Stage 1	RWE Npower plc	2042	840	IPP
NGET	CCGT	Pembroke Stage 2	RWE Npower plc	2042	510	IPP
NGET	CCGT	Pembroke Stage 3	RWE Npower plc	2042	750	IPP
NGET	CCGT	West Burton B	West Burton Limited	2043	1,370	IPP
NGET	Large Unit Coal	Didcot A	RWE Npower plc	2050	2,058	CEGB

APPENDIX C: PROPOSAL METHODOLOGY

Department of Energy and Climate Change (DECC)

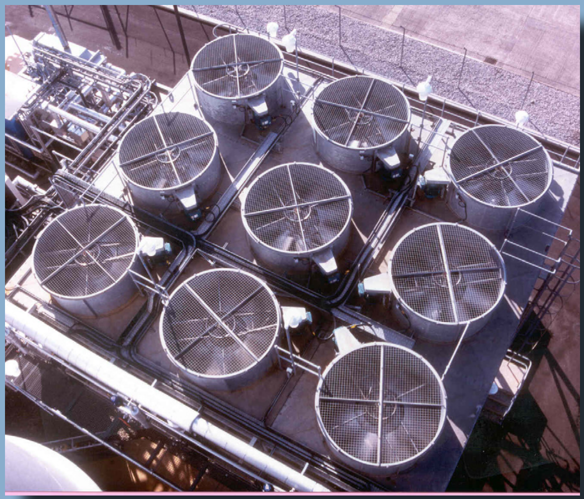
Proposal for Gas and Coal Technology Assumptions

Tender Reference Number: 671/09/2013

Submitted by

PARSONS BRINCKERHOFF

September 2013
2013 09741



Integrity Teamwork Excellence Respect

1. MEETING THE SPECIFICATION

1.1 BACKGROUND

DECC has an on-going need for robust and up to date evidence on electricity generation technologies, especially in the context of major policies such as Electricity Market Reform. In the light of this, DECC requires to gather up-to-date evidence in certain areas related to the generation of electricity from gas and coal. This includes:

1. Feasible build rates for Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT).

2. Supply curves for CCGT and OCGT.

3. Industrial Emissions Directive (IED) compliant technologies including economics and costs of Selective Catalytic Reduction (SCR) upgrades and cost and parameter information for relevant IED compliant technologies, (applied to coal plant only).

4. CCGT and coal plant life, including operational life of existing CCGT and coal plants and on the economics of potential life extensions.

Parsons Brinckerhoff proposes to investigate each of these drivers based on our experience of the UK and worldwide generation plant supply market and knowledge of technology status and trends. We will ensure that the evidence will be produced and presented in a manner consistent with assumptions produced for the annual electricity generation cost updates, which we have produced for DECC since 2011.

1.2 FEASIBLE BUILD RATES FOR CCGT AND OCGT

Parsons Brinckerhoff proposes to undertake forward looking research and assessment of the feasible build rates for CCGT and OCGT, building from information on historical build rates. This will consider whether there are any future significant constraints relating to site availability, planning, electricity and gas grid and any other regulatory constraints (except economic constraints).

1.2.1 Site Availability

The sites available for Combined Cycle Gas Turbine or Open Cycle Gas Turbine generating stations are determined by proximity to gas and electrical grid connections, suitable zoning of land, availability of cooling sink (for CCGT only) and proximity to load centres.

Sites for generating stations can be categorized into:

1. Existing Central Electricity Generating Board (CEGB) sites which could be reused with many plant now nearing the end of its economic life or due for closure to meet emissions standards. Many of these sites were chosen by specialist planning teams working under the former nationalised industry structure with preferential purchase rights to secure the best sites for cooling and fuel connection.

2. Existing Independent Power Producer (IPP) sites which could be reused. These sites were developed since the privatisation of the Electricity Supply Industry after 1989 with some having plant which is now nearing the end of its economic life.

3. New sites which already have secured Section 36 Consent to Construct and Operate.

4. New sites which have applied for Development Consent Orders under the Planning Act 2008.

5. New sites which have applied for grid connections, but have not yet applied for planning permission.

Parsons Brinckerhoff proposes to investigate and tabulate all known generating sites from these categories and assess their operating status, remaining or future life, owning party, fuel and grid connection status and location and rank their suitability or availability for use as future CCGT or OCGT stations.

Over the years Parsons Brinckerhoff have been retained to carry out site searches for many OCGT and CCGT power stations, with many sites being discarded for one or another reason. However, it is expected that the full complement of sites in the categories above will be sufficient to meet the national requirements for these stations to 2050. Several of the existing or planned sites also have the possibility of adjacent extension, which is always a preferred choice to take advantage of existing operational infrastructure. Known and planned sites in our list for CCGT and OCGT total 56 GW, therefore we anticipate that there will be no need to seek additional sites that are currently unknown for the purposes of identifying a maximum level of feasible build.

1.2.2 Planning Constraints

Prior to 2008, the planning of power stations with output greater than 50 MW net was managed under Section 36 of the Electricity Act 1989 by DECC, or its predecessors. Several future power stations already have Section 36 Consent, but have not yet benefited from an investment decision due to unfavourable economic circumstances. Parsons Brinckerhoff have developed many stations under the Section 36 regime and found that the process was effective. The provisions of the Growth and Infrastructure Act 2013 also now allow some flexibility in the configuration of projects consented under Section 36 the Electricity Act 1989 to benefit from latest technology developments.

The planning of future power stations with output greater than 50 MW net is covered by the Planning Act 2008 process which was introduced to streamline the decision-making process for nationally significant infrastructure projects, making it fairer and faster for communities and developers alike. Applications are managed by the Planning Inspectorate, the government agency responsible for examining planning applications for nationally significant infrastructure projects. The outcome is a Development Consent Order (DCO) under which a project may be constructed and operated.

Parsons Brinckerhoff proposes to collect evidence of OCGT and CCGT power stations which are currently engaged in the National Infrastructure Planning (NIP) process. This will include a summary of the required NIP process, its time scale, an assessment of the required studies and quantum of data required to be provided and analysed through the planning and consultation stages. It is recognised that very few projects have yet completed the NIP process with confirmation of a Development Consent Order, but it is expected that the analysis will inform a measure of the planning constraints which may be excepted for development of future OCGT and CCGT power stations.

1.2.3 Gas and Electricity Grid Constraints

1.2.3.1 Gas Grid Connections

It is expected that most new OCGT stations and all CCGT stations will be gas fuelled. If the expected operating hours of the station are very limited , there may be cases where distillate fuel operation is economic for stations which are not close to the gas network, but given the availability of suitable sites for gas fuelled projects, these will be few.

The UK gas National Transmission System (NTS) provides widespread supply of natural gas to both domestic and industrial demands, the latter including power stations, generally connected to the high pressure network. Every power station requiring gas supply needs to apply for connection to the NTS.

National Grid (Gas) indicate that it can take a long time to get a new connection designed and constructed - typically around 3 years. However it can take even longer to add additional capacity to the NTS in order to allow use of a new connection - anything up to 7 years - it is therefore important that NGC are contacted at the earliest stages of the project so that the connection can be provided in the timeframe required. New pipelines also require planning permission with associated complex data submissions and consultation process which also represents an additional constraint.

Against this general constraint it is recognised that several of the already consented power station sites already have gas connections which may be suitable for future or extended use.

Parsons Brinckerhoff proposes to collect evidence of the status of gas connections to the future national portfolio of OCGT and CCGT power stations and to identify the degree of constraint these represent. Long Term Exit Capacity can require lead times of 38 months. Enduring Capacity increases can only commence in the period 4 to 6 years ahead.

1.2.3.2 Electricity Grid Connections

New generators wishing to connect directly to the National Electricity Transmission System (NETS) are required to enter into a Bilateral Connection Agreement (BCA) with National Grid. The requires an application form, fee and appropriate technical data. NGET have 90 days within which to develop the agreement offer for the applicant. There is then a 90 day review period in which the offer would usually be signed by the applicant.

The actual connection then has to obtain planning permission, often under the same National Infrastructure Planning (NIP) process.

Parsons Brinckerhoff proposes to collect evidence of OCGT and CCGT power station connections which are currently engaged in the National

Infrastructure Planning (NIP) process or already have defined Bilateral Connection Agreements with NGET. This will allow an analysis of the projects which can be connected and the constraints implied by the electricity grid connection process.

1.2.4 Regulatory Constraints

Based on previous experience Parsons Brinckerhoff will identify constraints due to regulations such as Generation Licence, The Environmental Permitting (England and Wales) Regulations 2010 (EPR) and several EU Directives covering Environmental Impact Assessment, Public Participation, Industrial Emissions, Conservation of Natural Habitats and of Wild Fauna and Flora, Conservation of Wild Birds, Ambient Air Quality, Emissions Trading System, Carbon Capture and Storage as well as the influence of the Planning Act 2008, National Policy Statements, Land Use Planning, Regional Planning Policy and Local Planning Policy.

1.2.5 Maximum Build Rates For CCGT and OCGT

Parsons Brinckerhoff proposes to provide an analysis of the historical data for commissioned CCGT and OCGT in the UK, such as information about the capacity installed, expected commissioning and closures. This information will be, combined with other source information on the constraints discussed above to understand which sites may be re-planted or extended and when. The analysis will provide maximum build rates for CCGT and OCGT over the period 2013-2050. Where primary, robust information is not available, Parsons Brinckerhoff will apply and record assumptions based on experts' opinion within Parsons Brinckerhoff consistently across the data set. Analysis of the past build rates during even one or two "dash for gas" periods e.g. the roll-out of IPP plant from 1988 on should indicate what can be built per year as a reference for the future.

Relevant plant suppliers will be requested to provide information on their current and planned production capability for candidate plant, although it is recognised that they supply global markets of which the UK represents only a small fraction. New build is currently suppressed by economic conditions and this will be taken into account is assessing the past build profile.

1.2.6 Influence of High and Low Demand Assumptions

The methodology proposed in the previous section will derive the maximum feasible build rates. Although the maximum build rates are not influenced by demand, actual build rates may be. Parsons Brinckerhoff will therefore derive estimated build rates based on high, central and low demand assumptions, limited by the maximum feasible build rates identified. The choice of the high, medium and low cases (which will be discussed with DECC) will be justified, and sources stated. Please note that that one source will be demand assumptions which it is expected will be provided by DECC.

1.3 SUPPLY CURVES FOR CCGT AND OCGT

1.3.1 Assess Variation in Cost Parameters

Parsons Brinckerhoff will assess the likely magnitude of variations in costs across projects. We will consider the different types of CCGT and OCGT plant likely to be built (identified using internal expertise) in the context of the different conditions at the sites on which they will be built (based on information gathered in the previous section). This will enable us to identify which cost parameters will be likely to vary and whether they will be correlated. The existing low, medium and high assumptions which are based on one type of plant will then be considered in light of this more extensive analysis, and the ranges will be adjusted to take into account the different types of plants and sites. Parameters that may be adjusted include plant capacity, availability of a cooling medium, distance to utilities, connections etc.

1.3.2 Assess Feasibility of and Produce Supply Curve

A supply curve plots unit price against number of units purchased, to identify if the unit price varies according to the number of units purchased, or as a scale effect.

Parsons Brinckerhoff recognises that the gas turbine market is global, where each power plant is an individual project with an individual owner and specific financial parameters. CCGT and OCGT plants are not generally built in bulk and hence, cannot easily be represented with a supply curve approach. Nevertheless, Parsons Brinckerhoff will investigate whether it can be and will provide evidence of the importance of the UK gas turbine market as a percentage of the world demand.

It is apparent from historical prices trends, that the power equipment market responds to global demand as well as commodity price movements.

The main Original Equipment Manufacturers (OEMs) will be contacted to assess their supply capacity and evaluate the constraints that can result of an increase in the gas turbine demand. However, it should be recognised that the UK only represents a small fraction of global demand.

When more CCGT and OCGT projects are required globally, pressure on manufacturers may increase resulting in a rise of project price. Parsons Brinckerhoff will analyse different sources of information, which will be clearly identified, to assess these variations, such as the OEM annual reports and reference lists for past projects worldwide, in order to inform an analysis of the influence on the UK market.

It is recognised that DECC has cost ranges for these technologies provided by Parsons Brinckerhoff across a range of parameters[1], and we

[1] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections

propose to build on this to provide further evidence on the degree of overall cost variation across these technologies. Consideration will be given to the validity and feasibility of modelling the CCGT and OCGT supply side through supply curves rather than as single points. The proposed effect will be discussed with DECC to assess the extent to which this can be integrated into DECC's electricity dispatch model in an appropriate way.

Parsons Brinckerhoff will provide an analysis of the historical evolution of the CCGT and OCGT plant cost known to us, including in the UK, based on previous project information. This will allow assessment of overall costs and provide guidance for future trends in the UK over the coming decades.

The analysis will also be supported by examples of commodity price curves which influence the cost of power generation equipment. Parsons Brinckerhoff will provide a list of the parameters that affect the cost of a CCGT and OCGT plant, defining their impact and correlation. Most of the parameters that impact on the cost of the power station such as price of steel, copper, engineering or manufacturing are not correlated to each other, as will be demonstrated. Evidence of this will be presented in the report.

Please note:

It is not intended to propose new "central" estimates of CCGT and OCGT costs, but to propose and follow a methodology for describing the degree of variability around existing central cost estimates in the form of a supply curve.

1.4 IED Compliant Technologies

Our response to this section is predicated on the assumption that this work applies only to low NO_x technologies for coal plant. We can undertake similar work for low NO_x technology for gas plant and for technology that will address the differences between Large Combustion Plant Directive (LCPD) limits and IED limits for SO_x, CO and Particulate Matter (PM), however our understanding is that this aspect of the specification relates only to low NO_x technology for coal plant. Please do not hesitate to contact us if you wish us to provide additional estimates for similar work for gas plant and/or SO_x, CO and/or PM reducing technologies.

1.4.1 Part A: Initial Review

The initial review will first identify a list of parameters that would inform operators' SCR (or equivalent) upgrade decisions. These will include capital and operating cost of SCR retrofit, remaining life of plant, as well as impacts of SCR on plant operation. The project team will gather information on other parameters from Parsons Brinckerhoff experts in this area and where necessary through contacting power plant owners and operators.

The initial review will also assess the technical and cost aspects of upgrading power plant by retrofitting SCR as a means of reducing NO_x emissions to levels prescribed in the IED. These will include the constraints imposed on the retrospective fitting of SCR facilities on existing plants. We will undertake a literature review to identify any recent publicly available information relating to SCR cost estimates and technical parameters. The estimation of capital and operating costs and technical impacts will also be assisted by Parsons Brinckerhoff's experience and contacts with plant vendors and operators. While it is considered that emission reduction by primary methods (at the source of combustion) is preferable to secondary methods (by end-of-pipe means such as SCR), it is recognised that the application of primary methods as upgrades to existing plants is limited. Alternatives to be considered will include combustion modification where feasible and alternative secondary abatement methods, of which many have been proposed but with varying commercial success.

The review will consider not only compliance with the IED emission limit values, but also:

1. The Best Available Technology (BAT) principle within the Pollution Prevention and Control (PPC) Philosophy that regulators may expect operators' performance to reach beyond emission limits to values which are reasonably achievable; and

2. The revised Large Combustion Sector BAT reference guide (BREF), currently in draft form, which proposes emission levels some of which are somewhat ambitious but which may, within the terms of the IED, become mandatory limits.

We will undertake a literature review to identify alternatives to SCR for NOx reduction e.g. Non-Selective Catalytic Reduction. Our environment team will assess whether these alternatives are feasible, are considered BAT and/or will meet IED standards. Where the literature review does not make clear whether these alternatives are economically viable we will assess this by producing cost estimates and comparing to SCR.

1.4.2 Part B - Detailed Assessment (optional)

Central, high and low estimates will be produced for relevant assumptions for application of low NO_x technology to coal plant. Assumptions will include parameters that would affect the decision to retrofit plant as well as technical and economic assumptions required for the work described in this section of the proposal. We will draw upon our experience in producing similar estimates for the DECC electricity generation cost updates in 2011, 2012 and 2013. Sources of information will vary for each parameter but are expected to include:

- Literature search.
- Contact with experienced professionals both within Parsons Brinkerhoff and externally.

- Contact with suppliers.
- Thermodynamic modelling e.g. Thermoflow and/or chemical modelling e.g. Aspen, both of which include cost estimation as part of the software package.
- Techno-economic modelling or calculations e.g. bottom-up estimates, applying adjustment factors to similar estimates to take into account differences in size, duration, or passage of time, learning rates etc. This may include applying factors for variation and uncertainty in a similar way to the DECC electricity generation cost model.
- Peer review in the form of checks of estimates (to be completed in conjunction with peer review of other draft evidence).

For SCR retrofit we will show where the new estimates differ from our previous (2012) estimates and explain the differences.

We will review published information on learning rates and costs from similar technologies such as Flue Gas Desulphurisation and apply those rates to the most recent SCR costs, to anticipate future costs of this technology. This will require making assumptions about levels of global deployment of SCR. We have produced similar learning-rate based estimates for DECC in the past, for example for Carbon Capture and Storage plant in the UK electricity generation cost updates.

We will ensure all our assumptions are compatible with previous assumptions made during UK electricity generation cost updates, including assumptions on deployment rates. We will liaise with DECC throughout the process to ensure new assumptions are compatible with all relevant DECC work and will agree with DECC assumptions on inflation rate, exchange rate and commodity prices.

The learning rate assumptions will include both FOAK costs and NOAK costs, and an assumption about when technology will switch from being considered FOAK to NOAK. There may be an assumption relating to a FOAK premium however this will depend on assumptions relating to global versus UK deployment - for example if a plant is FOAK in the UK it may not be FOAK globally so a premium to cover novel design work may not apply, but it may still not be considered NOAK technology if there are relatively few such plants in existence.

We will review the cost updates we have previously produced for a base case coal plant to be agreed with DECC e.g. 2013 estimates for new build coal plant with 300 MW of CCS, or new-build coal plant with full CCS. We will identify where any of the assumptions would be impacted by IED compliant technology. It is not expected that these assumptions would need to change significantly as new-build plant in general would be expected to meet IED requirements. Nonetheless we will consider each value individually and in context of its impact on the whole plant, to ensure that any impacts are identified and where required an updated set of values will need to be produced for the base case coal plant incorporating the IED-compliant technology. This refers to pre-development cost, construction and operating cost and technical assumptions previously produced by Parsons Brinckerhoff as shown below, as well as other values identified in the ITT, many of which were also previously produced by Parsons Brinckerhoff but are not shown in the table below:

- Pre-licensing - cost and time period.
- Public enquiry and planning - cost and time period.
- Technical development (including design selection).
- Distribution of the costs over the pre-development period.
- Owner’s cost.
- Distribution of the costs over the construction period.

- Split of O&M costs into different categories.
- Short-run marginal cost - £/MWh.
- Auxiliary loads.
- Load factors prior to full operational.
- HHV efficiency.
- CO_2 emissions - tonnes CO_2e/MWh.

This review will take into account the sources of the original assumptions when assessing whether the values need to be adjusted.

2013 assumptions for new build coal plant with 300 MW of CCS[2]

Coal - ASC with FGD and 300MW post-comb capture		1st OF A KIND			Nth OF A KIND		
		Low	Med	High	Low	Med	High
Key Timings							
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	4.0	5.3	7.0	3.0	4.5	6.5
Construction Period	years	4.5	5.0	6.0	4.0	4.5	5.0
Plant Operating Period	years	20.0	25.0	30.0	20.0	30.0	35.0
Technical data							
Net Power Output	MW	1486	1506	1535	1530	1523	1554
Net LHV Efficiency	%	38.3%	41.4%	43.9%	39.5%	41.9%	44.7%
Average Steam Output	ЛW (therma	0	0	0	0	0	0
Average Availability	%	94.9%	95.8%	96.8%	94.9%	95.8%	96.8%
Average Load Factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 Removal	%	21.0%	21.9%	22.0%	20.6%	20.8%	21.2%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	15.6	20.2	33.3	18.8	24.2	30.9
Regulatory + licencing + public enquiry	£/kW	0.16	0.20	1.43	0.22	0.25	1.77
EPC cost (excluding interest during construction) – variability only	£/kW	1,788	1,932	2,139	1,751	1,877	2,079
EPC cost (excluding interest during construction) – variability and uncertainty	£/kW	1,736	1,932	2,179	1,688	1,877	2,115
Infrastructure cost	£'000	0	7,500	15,000	0	7,500	15,000
Operating costs							
O&M fixed fee	£/MW/yr	27,157	45,670	63,359	23,617	40,597	57,470
O&M variable fee	£/MWh	1.22	1.38	1.53	1.04	1.21	1.38
Insurance	£/MW/yr	1,788	2,899	7,485	1,751	2,815	7,277
Connection and UoS charges	£/MW/yr	9,022	9,022	9,022	9,022	9,022	9,022
CO2 transport and storage costs	£/t	8.2	19.6	32.2	8.2	19.6	32.2

Using the technical and cost assumptions previously gathered for SCR we will produce estimates for the length of outage required for upgrade of existing coal plant to SCR or similar technology to existing coal plant, the

[2] Parsons Brinckerhoff (2013), https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections.

energy penalty and impact on load factors of the upgrade and any other efficiency or economic penalties.

1.5 CCGT and Coal Plant Life

The case for continued operation or life extension of any generating plant is based on economic grounds. There is no general means of determining plant operating life from the technical standpoint that is not ultimately also an economic one. Furthermore, the economic considerations are dynamic, not only in terms of the changing costs relating to the particular plant in question but also with respect to its position relative to newer plant which may be more efficient, reliable and flexible than older units.

A number of coal fired plants in the UK have operated beyond their original nominal design life and the commissioning dates and retirement dates are generally publically known. Although emissions compliance is sometimes cited as a principal reason for the retirement of coal plant, the case is usually still an economic one where the cost of modifications has to be weighed against the benefit of continued operation. In some cases the modifications needed to meet new regulations are technically very challenging and therefore prohibitively costly.

For CCGT plant, commissioning and retirement dates are generally also publically known but in the main such plants have not yet reached the end of their intended design life. Nevertheless, some of these units have already been retired or put into long-term preservation for economic reasons.

The present-day costs of refurbishment, life extension or re-purposing (e.g. conversion to OCGT or biomass firing) are well understood from Parsons Brinckerhoff’s own studies and from public domain information. The economics of such actions are harder to predict reliably since they would take place against a background of future fuel costs, power prices and regulatory requirements as well as running patterns influenced by renewable generators. Nevertheless, given a set of agreed assumptions about such parameters an estimate of the cost of generation can be made and weighed against the cost of capital expenditure.

In summary, when considering the feasibility of life-extension projects, multiple factors need to be considered including capital expenditure, fuel cost and efficiency, flexibility, emission compliance, incentives and regulatory compliance. Whilst technical considerations will play an important part in any decision to proceed they will be used to inform the overall judgement on the economic value of continued operation.

1.6 Review and Reporting

Any modelling undertaken will be Quality Assured using Parsons Brinckerhoff's internal QA process, including review by someone not involved in producing the model. The evidence gathered will be presented within a draft report and provided to DECC for comment.

Draft evidence will be peer reviewed by inviting review from the same reviewers who peer reviewed the 2013 non-renewable generation cost input assumptions. This peer review will run concurrently with DECC comments on the report.

2. MANAGEMENT AND DELIVERY PLAN

2.1 Project Management

Parsons Brinckerhoff will approach the project management of the study in compliance with our approved internal business processes. These reflect best practice within project management and incorporate documentation control processes, risk management, environmental sustainability and health and safety. These processes cover design, design review, management consultancy, specification, programme management and the associated risk and quality management activities