Upgrading of NO_x Reduction Equipment Fitted to Large Fossil Fuel Power Station Boilers

R&D Technical Report P244

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Research Contractor:
Mitsui Babcock Energy Limited
Technology Centre

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Publishing Organisation:
Enviromnent Agency
Rio House
Waterside Drive
Aztec West
Almondsbury
Bristol BS32 4UD

Tel: 01454 624400 Fax: 01454 624409

ISBN : 1 857 05117 3

Dissemination status

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Statement of Use

This Technical Report is intended as a source of information to be used by the Environment Agency to assist it in forming a view as to what technologies might be considered to be BATNEEC, and thereby determine the future requirement for the emissions of NO_x from each Power Station

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GLOSSARY

Ammonia slip : Some of the ammonia reagent used in the post-combustion NO_x control technologies passes through the system unreacted and can impact on the surrounding environment through the releases from the stack and also via absorption by the flyash.

Anhydrous ammonia : Ammonia is the reducing agent in post-combustion NO_x control technologies and is commonly used in the anhydrous form - 100% ammonia, pressurised, and stored as a liquid.

Burnout zone : The final area of the combustion zone which dictates the carbon-in-ash level.

Capacity factor : The total energy output over a period of time in hours, divided by the product of the period hours multiplied by the unit capacity. The capacity can be computed on either a net or gross basis. Unless otherwise stated, all capacity factor data in this technical report, are stated as net.

Capital carrying charges : The revenue needed to support an investment. Equal to the sum of return on debt, return on equity, income taxes, book depreciation, property tax and insurance.

Costs and credits : The charges and financial benefits associated with the installation and operation of each NO_x control technology is calculated from operational details for individual power stations.

Difficulty factor : Sensitivity of capital cost to the relative degree of complexity of installation, estimated for each NO_x control technology.

Discount cash flow analysis : An analysis of an investment proposal that takes into account the time value of money.

Discount rate : The interest rate used to calculate the present value of a cash flow.

Downshot fired boilers : The burners in this type of boiler are located near the top of the boiler and the combustion process is directed downwards, which is beneficial for burning low volatile coals.

Economic outcome : The sum of the individual components making up the capital and O&M and £/te costs/credits for each NO_x control technology. In this technical report the economic outcome is quoted in p/KWh and £/te NO_x removed.

Escalation rate : The annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements in design or manufacturing (negative rate). The apparent escalation rate includes the effects of inflation, whereas, the real escalation rate does not.

Expenses : A general component of revenue requirements, used by EPRI, for goods and services that are usually utilised in one year or less e.g. fuel, operation, and maintenance.

Expert systems: Advanced control systems that are based on the on-line optimisation of power plant.

Front wall fired boilers : The burners on this type of boiler are located on one wall of the boiler.

Hybrid : The combination of post-combustion NO_x control technologies.

Inflation rate : The rise in price levels caused by an increase in available goods and services of equal quality. Inflation does not include real escalation.

Interest rate : see discount rate.

Levelisation factor : A constant annual capacity factor for a generating unit such that the total present worth of the energy produced during the analysis period using the constant annual capacity factors is the same as the present worth of the energy produced by the individual annual capacity factors.

Load cycling : A service provided to the grid by power stations who adjust their output or hours of running to meet the the variations in electricity demand within each day.
Load factor : The proportion of time for which a power station operates.
Net present value : The present value of a projects future cash flows less the cost of the initial investment.
Opposed wall fired boilers : The burners on this type of boiler are located on two walls opposite each other.
Outage : The period of time when the boiler is offline and routine maintenance is carried out.
Plant efficiency : The efficiency with which heat energy contained in the fuel is converted into electrical energy. It is calculated for fossil fuels burning stations by expressing electricity supplied as a percentage of the total energy content of the fuel consumed (based on average gross calorific values).
Primary combustion zone : The area of the boiler producing the maximum temperature of combustion.
Reburn zone : The area immediately above the primary combustion zone in which the secondary (reburn) fuel is combusted - relevent only to reburn NO_x control technologies.
Revenue requirement : The amount of revenue that a utility must collect from customers to cover all the costs associated with implementing an alternative decision involving money i.e. installation of NO_x control technologies.
Tangentially fired boilers : The burners are located near the corners, in the lower boiler area, directed towards the centre.
Unit heat rate : The amount of energy expressed in Btu required to produce a KWh of electric energy for fossil fuel burning technologies.

NOTATION

£/te	pounds (Sterling) per tonne
µm	micrometre (= 10^{-6} m)
aLNBs	Advanced Low NO_x Burners
BATNEEC	Best Available Techniques Not Entailing Excessive Costs
CAT-AH	Catalysed Air Heater
CCOFA	Close Coupled Overfire Air
CIA	Carbon In Ash
DoE	Department of the Environment
EA	Environment Agency
EPRI	Electric Power Research Institute
ESI	Electricity Supply Industry
ESP	Electrostatic Precipitator
FGR	Flue Gas Recycle
FWEC	Foster Wheeler Energy Corporation
ICL	International Combustion Limited
JTL	John Thomson Limited
K	Kelvin
kg/s	kilogramme per second
km	kilometre
kte	kilotonne
LNBs	Low NO_x Burners
LNCFS	Low NO_x Concentric Firing System
LTS	Local Transmission System
m	metre
MBEL	Mitsui Babcock Energy Limited
mg/Nm^3	milligramme per normal metre cubed
MW_e	megawatts (electrical)
NO_x	Nitrogen Oxides
NTS	National Transmission System
OEM	Original Equipment Manufacturer
OFA	Overfire Air
p/kWh	pence (Sterling) per kilowatt hour
PS	power station
SCR	Selective Catalytic Reduction
SNCR	Selective Non-catalytic Reduction
SOFA	Separated Overfire Air
TAG	Technical Assessment Guide
te	tonne
TJ	Terrajoule (= 10^9 Joule)
TSC	Two Stage Combustion

EXECUTIVE SUMMARY

The Environment Agency has responsibility in England and Wales for the authorisation of large combustion plant under the Integrated Pollution Control regime which requires the operators of such plant to prevent, and if that is not possible, to minimise and render harmless the emissions of substances which may cause harm, following the principle of using the "Best Available Techniques Not Entailing Excessive Cost" (BATNEEC). With regard to the Electricity Supply Industry (ESI), the Environment Agency called for station specific proposals to reduce NO_x emissions from all fossil fuel fired plant as part of an ongoing programme to improve ambient air quality. These proposals were requested in 1996, and by late 1998 most of these submissions had been prepared.

Mitsui Babcock Energy Limited (MBEL) were commissioned by the Environment Agency to undertake the study "Upgrading of NO_x Reduction Equipment Fitted to Large Fossil Fuel Power Station Boilers" with the objective of providing authoritative independent advice to the Environment Agency, identifying options which might be appropriate "Best Available Techniques". The results of the study are to be used by the Environment Agency to assist it in forming a view as to what technologies might be considered to be BATNEEC, and thereby determine the future requirement for the emissions of NO_x from each Power station.
From this overall aim the key activities were identified as follows:

- Determine the current status of each of the power stations, with particular attention given to the NO_x reduction equipment installed.

- Identify the potential NO_x reduction options available.

- Define cost algorithms to allow an economic assessment of each potential technology for each power station.

- Review each of the NO_x reduction options for each power station to establish the technical feasibility, anticipated NO_x reduction, and economic impact associated with their implementation.

The study considered all of the fossil fuel fired power stations in England and Wales that were in commercial operation at the time that it was commissioned.

These were:

Aberthaw	Fawley	Littlebrook
Blythe	Ferrybridge	Ratcliffe
Cottam	Fiddlers Ferry	Rugeley
Didcot	Grain	Tilbury
Drakelow	High Marnham	West Burton
Drax	Ironbridge	Willington
Eggborough	Kingsnorth	

The potential NO_x reduction technologies were reviewed. At the outset of the study it was decided to limit the scope of the review to processes which were aimed specifically at NO_x

reduction, and so modifications such as repowering, full gas conversion, etc. were not considered even though they would bring about a reduction in NO_x emission. Furthermore the review was based upon techniques that are currently commercially available or are at an advanced stage of plant demonstration. The technologies selected for the detailed assessment were based upon the two approaches to NO_x reduction – viz the control of NO_x through the modification of the combustion process, and the downstream removal of NO_x from the flue gas. The following processes were considered.

- Low NO_x Burners
- Advanced Low NO_x Burners
- Furnace Air Staging
- Reburn - Coal, Gas, Oil
- Selective Catalytic Reduction (SCR)
- Selective Non Catalytic Reduction (SNCR)
- SNCR/SCR Hybrid
- In Duct SCR / Catalysed Air Heater

Additionally the use of flue gas recycle was considered for the oil fired stations – this technology addresses thermal NO_x predominantly and so is not significantly effective for NO_x reduction in coal fired furnaces.

For each of the processes listed above a spreadsheet was prepared to allow the technical and economic assessment of each power station to be undertaken. The technical and financial data required were obtained from published sources – this included items such as the attainable NO_x reduction, the capital cost of the technology (in £/kWe), the cost of fuel (gas, oil, and coal) and other feedstocks (e.g. anhydrous ammonia), the price of saleable ash or its cost for disposal, the cost of auxiliary power, etc.

In order to undertake the station specific assessment, information was also obtained for each of the power stations listed. As far as possible this was taken from documents available from the public register, though some technical information (e.g. furnace dimensions) was obtained directly from the operators, or MBEL's own records as an original equipment manufacturer (OEM). Data on the proximity of each power station to the local and national gas transmission system was supplied by Transco.

As noted above, published or publicly available information was used where ever possible in the study. However it has to be recognised that in some instances the data has commercial sensitivity or may be variable. Among the more significant are fuel prices. Coal prices, and perhaps more significantly, gas prices are strongly dependent upon specific contract conditions. A value of £1.25/GJ for coal and £1.90/GJ for gas was agreed. Oil prices are mainly dependent upon the quality of the oil - a figure of £2.30/GJ was agreed. Similarly the cost of installing a natural gas pipeline for gas reburn is very site specific – the presence of natural obstacles (rivers etc), man-made obstacles (roads, railways), and the requirement to maintain the integrity of the transmission system (perhaps requiring the installation of additional compressor stations) means that specific site costs may vary considerably from the cost of £800,000/km, agreed for use in the study.

There are other site specific factors associated with most retrofit NO_x reduction technologies. It has, for example, been assumed that an SCR plant can be installed at each site whereas limited space availability may prevent this. Similarly it has been assumed that flyash can be disposed of to landfill as a non-hazardous waste at a cost of £8.70/te if it cannot be sold. In some areas there may be limited disposal options leading to a higher disposal cost.

Because of these issues it is important to recognise that detailed site specific assessments will always be required after this study and in advance of any decision to install a particular NO_x reduction process at any one power station. For similar reasons it is not the intention of this study to make any recommendations with regard to specific technologies for any site – such decisions must lie with the operators who, whilst maintaining their competitive edge in an aggressive market, need to consider how best to meet the requirements of the Environment Agency.

The technical assessment of each technology was based on simple criteria – could it be applied to a particular power station, and if so what was the expected NO_x reduction that could be achieved. Generally it was found that most technologies could be applied to most sites, with a few exceptions. The most significant of these was Aberthaw Power Station which fires low volatile coal in a downshot type furnace. Here the technologies of low NO_x burners are inappropriate, air staging is already practised as a means of aiding combustion stability, and coal reburn for this type of fuel is far from demonstration. Gas over coal reburn was considered, but it is recognised that significant development of the process would be required prior to it being installed at this site. Flue gas recycling for any coal fired power station was not considered appropriate.

A number of different approaches can be used to undertake the economic assessment of each process. For this study it was decided to use the "Revenue Requirement Method" as reported by the Electric Power Research Institute (EPRI) in their Technical Assessment Guide (TAG). The method is fully defined in published reports. The revenue requirement method provides a consistent economic technique for assessing the relative cost to the customers of a power generator of the potential financial impact of an alternative approach (i.e. an alternative NO_x control strategy). Its definition is summarised as:

"The amount of revenue that a utility must collect from customers to cover all the costs associated with implementing an alternative decision involving money".

The revenue requirements comprise of two components – the capital or fixed charges, and the operating costs. The method requires the assessment of all the applicable annual capital carrying charges and expenses for each year of the life of the plant. Central to the method is the use of levelised revenue requirements. Levelised values provide more meaningful comparisons in two ways – the economic outcome is presented in terms of a cost per unit product (i.e. p/kWh or £/te NO_x removed), and costs are averaged over the required period using present value arithmetic. The calculations are readily undertaken if certain simplifying assumptions are made with respect to the overall economy – such as a constant average rate of inflation over the evaluation period.

The levelisation factors were calculated by equations defined by EPRI and which include the influence of present worth, evaluation period (years), apparent annual escalation rate, real annual escalation rate, annual inflation rate and annual interest rate, when applied to operating costs, but exclude 'escalation', when applied to capital costs.

By taking a view on the anticipated rates of escalation, inflation, interest etc. the levelisation factor was used to assess the financial impact of each NO_x reduction technology over the short (5 year), medium (10 year) and long (15 year) term. Also of key importance in the economic analysis is the plant load factor and, as this cannot be forecast with any certainty, the sensitivity to this parameter was investigated by considering values of 10%, 40% and 75% for each site (regardless of the load factor that might actually be achieved over the analysis period). Clearly the analysis will favour low capital cost technologies for low load factor sites operated for short time periods, and this was indeed found to be the case. However for the most part the comparison of the technologies was less clear cut, and the analysis method used allowed a consistent and unbiased approach to be taken to provide the basis upon which expert advice could be given to the Environment Agency with regard to NO_x reduction technologies. Again it must be emphasised that it is not the intention of the study to recommend specific technologies, but to provide an informed opinion as to which technologies are worthy of further consideration, at which point a detailed, site specific assessment is called for.

The results of the economic assessment demonstrated that clear trends exist between the differing NO_x control technologies. Burner conversion is the least expensive option for any coal fired station using wall or corner firing technologies, and there is a staged increase in costs when moving from combustion to post-combustion processes, which is demonstrated for all stations in this study.

Reburning costs vary considerably depending upon which fuel is used as the reburn fuel. Coal reburn will be an attractive NO_x control option provided the demonstration at Vado Ligure matches rig trials and it becomes commercially available (at the earliest, in the year 2000). However, the influence of additional mill utilisation on total plant availability under sustained operation has to be determined. Gas reburn has been demonstrated at Longannet and if natural gas is available on site, a significant contribution to the capital costs is removed i.e. pipeline costs. There is also a potential reduction in operating costs should the price of gas drop.

SCR, which is the only proven post-combustion technology for controlling NO_x in large coal-fired stations becomes more economically competitive at higher load factors and longer operating periods.

Flue gas recycling is a very attractive technology for the reduction of NO_x in oil-fired stations and is shown to be on a par with burner conversion for the three stations reviewed.

KEYWORDS

Combustion, Economic Assessments, Fossil Fuel, Integrated Pollution Control, Load Factor, NO_x Control Technologies, Post-Combustion, Revenue Requirement, Sensitivity Studies, Site Specific Factors.

1. INTRODUCTION

The subjects of nitrogen oxide formation and the quality of our ambient air are unequivocally linked, with their presence in the atmosphere increasingly affecting the air we breathe and the environment in which we live. NO_x is an acidification precursor and is thought to affect respiratory capacity in vulnerable groups, such as the young, old and asthmatics. For many years, anthropogenic sources have been regarded as major contributors to atmospheric nitrogen oxide emissions and, more specifically, combustion processes have been classified as one of the primary sources of NO_x emissions. In the early nineties, estimates for the UK (DoE 1992, Longhurst *et al.* 1993) suggest that over three quarters of the total NO_x emissions during the last decade are attributable to the combustion of fossil fuels, with stationary sources (power stations) representing around 28% of the overall environmental loading of NO_x and mobile sources (road transport) representing 51%. More recent estimates indicate that power stations are the second largest source of nitrogen oxides (NOx) in the UK, at 22% of the total emitted (in 1995), compared with 46% from road transport. When stationary combustion sources alone are considered, however, the pattern of NO_x emissions changes significantly, with power stations contributing up to 67% to the total combustion-derived inventory (DoE, 1991), the balance of emissions being chiefly due to refineries, service and other industries.

The adverse effects on terrestrial ecosystems of increasing background nitrogen oxide concentrations are well known and therefore are not covered here. The threat of a continuing deterioration in ambient air quality as a result of further NO_x emissions, however, leads to two distinct conclusions : firstly, that there is a need for a major and concerted effort by the stationary combustion industries to reduce the amount of fossil fuels burnt by the promotion of energy efficiency through the introduction of good combustion practices to optimise their conversion efficiency; and secondly, that combustion processes need to be adequately controlled, or alternative methods need to be adopted, which minimise the overall emissions of pollutants per unit of fuel burnt. With this in mind, the enactment of increasingly stringent emission legislation in recognition of the problems associated with atmospheric pollutants has provided a stimulus for research into developing new and existing pollution control technologies. Current, available techniques to abate emissions of NO_x principally make use of two approaches :

(i) the control of NO_x formation through combustion modifications;
(ii) the downstream removal of NO_x from the flue gas by utilising flue gas treatment technologies.

Against this background relating to emissions of nitrogen oxides to the atmosphere from stationary combustion processes, the Environment Agency is required to use its powers to contribute to achieving sustainable development. The Agency authorises large combustion plant in England and Wales under the Integrated Pollution Control regime, requiring them to use Best Available Techniques Not Entailing Excessive Cost (BATNEEC) to prevent, and if that is not possible, then to minimise and render harmless the emissions of substances which may cause harm.

In 1996, the Agency required all fossil-fuelled stations to submit station specific proposals for techniques to reduce NOx emissions, as part of their ongoing improvement programmes. Late in 1998 most of those proposals had been received and Mitsui Babcock Energy Limited (MBEL) were commissioned to undertake this study entitled 'Upgrading of NOx Reduction

Equipment Fitted to Large Fossil Fuel Power Station Boilers'. It installs both its own and other manufacturers equipment on both new and existing fossil fuel plant worldwide. The study was undertaken by MBEL Technology Centre, Renfrew, Scotland and the objective of the study was, by using both the proposals submitted by power station operators and MBEL's experience, to provide authoritative independent advice to the Agency, identifying options which may be appropriate Best Available Techniques. The Agency will use the results of the study to assist it in forming a view on what constitutes BATNEEC and thereby determine the future requirement for the reduction of NOx at each power station.

The specific methodology used to approach the general study objective is described in Section 2 of this report, together with the scope of the study. The existing status of each of the power stations operated by the ESI in England and Wales is described in detail in Section 3 and the NO_x control technologies considered for application to the power stations are reviewed in Section 4. The economic aspects of the study are detailed in Section 5 of the report, where any assumptions used in undertaking economic assessments are stated explicitly. Results of the technical and economic assessments for each of the respective power stations are described in detail in Section 6 (where the economics associated with the NO_x control technologies are evaluated in terms of both p/kWh generated and £/te NO_x removed) and, based on these results, conclusions and observations arising from the investigation are presented in Section 7.

2. METHODOLOGY

The overall objective of this study was to prepare authoritative advice to allow the Environment Agency to formulate their requirements for further NO_x reduction measures on each of the coal and oil fired power stations operated by the ESI in England and Wales. From this general objective, 20 different coal and oil fired power stations, each operated by one of the three main power generators (Eastern Generation, National Power and PowerGen), were identified as the focus of the study. Due to the extensive nature of the study, therefore, and coupled with its relatively short timescale, it was vital that a specific and clearly defined methodology was adopted in order to satisfy the general objective. Hence, the approach used by MBEL to attain this objective was broadly four-fold:

(i) determine the existing status of the power stations concerned, with particular attention given to the currently installed NOx reduction equipment (brief details of each station are shown in Table 1);
(ii) define the potential NO_x reduction options available;
(iii) review each of the available NO_x reduction options against the respective power station concerned to establish both site specific anticipated NO_x reductions and the capital costs associated with their implementation;
(iv) define cost algorithms for each available NO_x reduction technique to calculate the capital and operating and maintenance costs associated with installing the technology on a given power station.

In addition to examining these technologies on an individual basis, combinations of 'combustion modification' technologies (i.e. LNBs with TSC) have been considered, as have combinations of 'combustion modification' and 'post combustion' control technologies. Repowering of a power station with a gas turbine has not been considered as this is not predominantly a NO_x reduction technology and is therefore beyond the scope of the present study. For the same reason, the conversion of a power station to gas firing has also not been considered.

These items are discussed further in subsequent sections. It is important to note that, in the course of preparing advice for the Environment Agency and where a degree of commercial sensitivity existed, only public domain information was used. Due to variations in information obtained from the public domain, however, MBEL were given the task of critically assessing data so as to ensure that it was both consistent and free from commercial bias. It is also important to note that while advice was provided by MBEL to the Environment Agency with respect to 'inappropriate' or 'appropriate' NO_x control technologies for the various power stations under consideration, it was not a duty of MBEL to recommend explicitly technologies to the Environment Agency and nor was it a duty to undertake detailed assessments of technologies at the stations considered. Due to site specific factors, a detailed assessment is a clear pre-requisite to the recommendation of a NO_x reduction system on any given power station site.

3. POWER STATION REVIEW

Prior to examining the applicability of NO_x reduction options on each of the power stations concerned in the study, it was clearly necessary to determine their existing status and, hence, a process of data acquisition was initiated. In addition to defining the existing level of NO_x conversion (e.g. Low NO_x Burners) on the stations, this process also provided important details for use in the study. Attention will be drawn to these when appropriate.

MBEL was the original equipment manufacturer (OEM) of the boiler and ancillary plant at several of the stations, and has also supplied NO_x reduction equipment and other plant or services to many of the sites. Original contract information on some stations was therefore able to be reviewed, as it had been openly available; as indicated earlier, public domain data was used where information could be considered as being of a sensitive nature (e.g. data relating to costs). For non-controversial information (e.g. furnace dimensions) data was obtained from MBEL's own records or from the plant operator. Public register documents were also reviewed with a view to both supplementing and confirming information derived internally and from other sources. Where information was found to be incomplete or inadequate, direct contact was made to the power station.

A summary spreadsheet detailing the information derived from the various sources was compiled, and certain of the key information is presented in Table 1, as follows :

- Station name
- Generator
- Year of commissioning
- Boiler type and manufacturer
- Fuel type
- Total Capacity (MW_e)
- Number of units - capacity of each (MW_e)
- Burner conversion details
- Equivalent NOx emission levels (mg/Nm^3)

Important details on the proximity of natural gas supplies were provided by Transco and are shown in Table 2.

Each of the individual power stations considered in this study are discussed in more detail below.

3.1 Aberthaw B Power Station

Aberthaw B Power Station, which is operated by National Power, is situated near Cardiff in South Wales. This downshot coal fired power station was constructed in 1977 by Foster Wheeler. Aberthaw B Power Station comprises of 3x500 MW_e units each containing 36 Foster Wheeler downshot fire 'burners' (6 out of service). These 'burners' are supplied with pulverised low volatile coal from 6 mills with static classifiers (5 required for full load). The 1998 and 1999 NOx emission limits are 36kte. With the coal that is currently fired at Aberthaw B Power Station 354kte of ash is produced annually with 53kte (15%) being sold.

CIA is currently 10%-20%. Aberthaw had dual flue gas conditioning equipment (SO_3/NH_3) added in 1996/1997.

3.2 Blythe A and B Power Stations

Blythe A and B Power Stations are situated on the East Coast of England near to Newcastle upon Tyne and they are both operated by National Power. Commissioned in 1958/66 both stations are coal fired. Blythe A Power Station has 4 units which are front wall fired boilers manufactured by MBEL. All of the units at Blythe A are 120 MW_e. Units 1-4 have 20 MBEL circular register burners (4 out of service). The burners are fed pulverised fuel from 5 mills with static classifiers (1 out of service). Blythe B Power Station has units 7 and 8 which are tangentially fired boilers manufactured by Clarke Chapman. Units 7 and 8 are 330 MW_e and contain 40 ICL Tilting burners (8 out of service). These are fed pulverised fuel from 5 mills with static classifiers (1 out of service). The 1998 NOx emission limit was 32 kte and the 1999 NOx emission limit drops to 28.4 kte. Blythe A and B Power Stations currently produce 46 kte of Ash and sell 19kte (41%).

3.3 Cottam Power Station

Cottam Power Station is located close to West Burton PS near Retford, Nottinghamshire, and is operated by PowerGen plc. The station dates back to circa 1969-70. Its boiler units (two units at 504 MW_e each and two units at 505 MW_e), originally supplied by John Thomson Limited (JTL), are fired on coal and have 32 burners (eight burners out of service at full load) arranged in a front wall fired configuration. Four pulverised fuel mills (one mill out of service) are associated with each boiler unit and these mills feature static classifiers. All units at Cottam PS were converted to LNBs (ICL) in 1990-94. The 1998 NO_x emission limit for Cottam PS was 54 kte and the 1999 limit is 33.6 kte. Levels of CIA are around 3.5%. In the last financial year ash production from the station on the current coals was 438 kte, of which 196 kte (45%) of ash was sold. At the time of writing, it is understood that Cottam PS was being converted to gas (prior to the government moratorium).

3.4 Didcot Power Station

Didcot Power Station is operated by National Power. This front wall pulverised coal fired power station, manufactured by MBEL, was commissioned in 1973. Didcot Power Station has 4x500MW_e units each with 48 burners (12 out of service). Each unit is fed pulverised fuel by 8 mills with static classifiers (2 out of service). A station conversion took place 1993-1997 when MBEL MkIII LNBs were introduced. At Didcot Power Station there is a gas supply to three out of the four units. These three units have had gas spuds installed into the burners, and can raise 100% load on gas firing. The 1998 NOx emission limit for Didcot was 49.8kte and the 1999 NOx emission limit is 39.7kte. On the coals currently being fired at Didcot Power Station 145kte of ash is produced of which 76kte (52%) is sold.

3.5 Drakelow C Power Station

Drakelow 'C' Power Station, situated near Burton-on-Trent, is operated by Eastern Generation Limited and is comprised of three coal-fired boilers (Units 9, 10 and 12). Units 9 and 10 (2x350 MW_e front wall-fired) were built by John Thomson Limited (JTL) and commissioned in 1966. There are 24 burners located in each of Units 9 and 10 and these are supplied with pulverised coal by four units (with static classifiers) per unit. The station installed MBEL MK III LNBs in Units 9 and 10 between 1996 and 1997.

Unit 12, which is a supercritical tangentially-fired boiler (325 MWe), was constructed by International Combustion Limited (ICL) and commissioned in 1962. Five mills with static classifiers feed pulverised coal to the 48 burners in Unit 12. It is anticipated that Unit 12 will be converted from the ICL LNCFS in 1999. Drakelow 'C' is fuelled by UK coal, coming mainly from Denby, Nadins and Welbeck. The current NOx emission limit for the Drakelow site is 22kte and this limit is to be retained for 1999. With current coals, the total ash production averages 6 tonnes/TJ of coal burnt and the CIA levels are approximately 5-7% on Units 9 and 10, and 2-3% for Unit 12. Recent ash sales for Drakelow indicate a market for 50% of the total ash produced at the site. Installation of flue gas conditioning equipment (SO_3 and NH_3) is proceeding at present.

3.6 Drax Power Station

Drax Power Station, which is located in Yorkshire near Selby, is operated by National Power. This station comprises of 6x660 MW_e opposed wall pulverised coal-fired units supplied by MBEL, the first of which was constructed in 1974. Each unit has 60 burners (18 out of service) which are supplied with pulverised fuel from 10 mills (2 or 3 out of service). The mills all have static classifiers. Between 1989 and 1993 units 4-6 at Drax Power Station were converted to MBEL MkIII LNBs; as were the top two burner rows of units 1-3. The lower three burner rows of units 1-3 have standard 55MW burners. The 1998 NOx emission limit for Drax Power Station was 99.2kte with the limit for 1999 being the same. With the coals that are currently fired at Drax 1495 kte of Ash is produced with 908 kte (60%) being sold. All of the bottom ash and 50% fly ash produced is sold. All units at Drax Power Station have been fitted with FGD.

3.7 Eggborough Power Station

Eggborough Power Station is operated by National Power and is situated near Selby, Yorkshire. Built in 1968 by Foster Wheeler, Eggborough Power Station comprises of 4 units. Units 1,3 and 4 are 505 MW_e while unit 2 is 480 MW_e. The front wall fired units all contain 24 burners which are fed pulverised fuel by 6 mills with static classifiers. Between 1986 and 1991 Eggborough Power Station underwent a conversion in which FW LNBs were installed. The 1998 NOx emission limit was 44.4kte with the 1999 NOx emission limit dropping to 39.9kte. With the coal that Eggborough Power Station currently burns 589 kte of ash is produced annually, with 239kte (40%) being sold.

3.8 Fawley Power Station

Fawley Power Station is situated on the South Coast of England on Southampton Water and it is operated by National Power. Constructed in 1969 by Foster Wheeler Energy Corporation (FWEC), it is comprised of 1x483 MW_e oil fired unit and a 34 MW_e Gas Turbine. The unit has 32 Hamworthy Pressure Jet burners. The 1998 and the 1999 NOx emission limit is 5.7kte.

3.9 Ferrybridge C Power Station

Ferrybridge C Power Station is sited in Yorkshire near Knottingley and is operated by PowerGen. Constructed in 1968 by MBEL, this front wall coal fired power station contains 4x500 MW_e units. Each unit contains 48 burners (12 out of service) which are fed pulverised fuel from 8 mills with static classifiers (2 out of service). Between 1994 and 1996 the burners were converted to MBEL MkIII LNBs. The 1998 NOx emission limit was 67kte while that for 1999 drops to 34.5kte. In the year 1997/98 Ferrybridge C Power Station produced 447kte of ash and sold 204kte (46%). Current CIA is around 8%.

3.10 Fiddler's Ferry Power Station

Fiddler's Ferry Power Station was constructed in 1971 by ICL and is operated by PowerGen. This tangentially fired station is comprised of 4x500 MW_e units. Each unit has 40 burners which are fed pulverised fuel by 6 mills with static classifiers. Five mills are required for full load. Between 1985 and 1990 the burners were converted to ICL LNCFS. CCOFA is in operation at Fiddler's Ferry Power Station. The 1998 and the 1999 NOx emission limit for Fiddler's Ferry is 27kte. During the year 1997/98 297kte of ash were produced with 147kte (49%) being sold. On the coals that are currently fired at Fiddler's Ferry Power Station CIA is typically 8%.

3.11 Grain Power Station

Grain Power Station, which is situated in the South East of England on the Thames estuary, is operated by PowerGen. This oil fired station was constructed in 1979 by MBEL and consists of 3x660 MW_e oil fired units. Each unit has 24 MBEL venturi oil fired burners. Grain Power Station is the only power station in this study which has flue gas recycle (FGR) for steam temperature control. The 1998 and the 1999 NOx emission limit for Grain Power Station is 12kte.

3.12 High Marnham Power Station

High Marnham Power Station is located near Newark in Nottinghamshire and is again part of the Eastern Generation Limited portfolio of power stations. It is the oldest power station considered in this study, having been constructed circa 1959-62. The station is coal fired and comprises five 200MW_e boiler units, all of which are of a tangentially-fired arrangement, supplied by ICL. Twenty-four burners (eight out of service) are located in each boiler and these are supplied with pulverised coal from six mills (four required for full load) with static classifiers. As with West Burton PS, each unit at High Marnham has been converted to the ICL LNCFS (1990-95) and features offset secondary air. Close-coupled overfire air is not installed on these units. The oil burners at the station can provide support up to 10% load. High Marnham PS currently uses UK coal but, as it has both road and rail access, it expects that future coal sources will vary (UK or overseas). The 1998 NO_x emission limit for the station was 21 kte and is due to fall to 10.8 kte in 1999. CIA levels are variable but average at around 5%. Ash production averages around 120 te/kte of coal fired and all of the bottom ash is sold. The flyash is landfilled.

3.13 Ironbridge Power Station

Located near Telford, Shropshire, Ironbridge Power Station is operated by Eastern Generation Limited. This coal fired station was constructed circa 1970 and comprises two 500 MW_e, front wall fired boiler units supplied by Foster Wheeler Energy Corporation (FWEC). Each unit is fitted with 24 burners (four burners out of service), fed by six pulverised fuel mills (with static classifiers); five mills are required for full load. Unit 1 at Ironbridge PS was converted to Senior Thermal Low NO_x burners (LNBs) between 1993 and 1995, and conversion of Unit 2 to ABB LNBs is anticipated in 1999. The oil burners on each boiler unit are capable of sustaining 10% load. The 1998 NO_x emission limit for Ironbridge PS was 32.5 kte and the 1999 limit is 31.5 kte. The corresponding levels of carbon in ash (CIA) are 5% and 3% respectively. On the current coals fired, ash production is of the order of 120 te/kte coal burnt, and all of the bottom ash and most of the fly ash is sold by this station. Flue gas conditioning equipment (SO_3 injection) was installed at Ironbridge in 1991 and the installation of ammonia injection equipment was planned for installation in 1998.

3.14 Kingsnorth Power Station

Kingsnorth Power Station is owned by PowerGen and it is situated in close proximity to Grain Power Station. Kingsnorth Power Station, which was commissioned in 1970, is coal fired, with an 80% load capability on oil firing. It is comprised of 4x500 MW_e tangentially fired units manufactured by International Combustion Limited (ICL). Each unit has 40 burners which are supplied with pulverised fuel from 5 mills having static classifiers. Kingsnorth Power Station underwent conversion between 1990 and 1992 such that all the burners are now ICL LNCFS. OFA Ports are in operation at this power station. The 1998 and 1999 NOx emission limit is 32 kte. Kingsnorth Power Station predominantly fires on coal with CIA lying between 5% and 8%. Total Ash production is around 317 kte with around 206 kte (65%) being sold.

3.15 Littlebrook Power Station

Littlebrook Power Station is operated by National Power and is situated to the South East of London. Constructed in 1982 this oil fired station consists of a 3x685 MW_e front wall fired units and 105 MW_e Gas Turbine capacity. The unit has 32 MBEL Parallel Flow burners. The 1998 and the 1999 NOx emission limit for Littlebrook Power Station is 11.2kte.

3.16 Ratcliffe Power Station

Ratcliffe Power Station is operated by PowerGen and is located close to Nottingham. This front wall coal fired power station was built by MBEL and commissioned in 1968. The station has 4x502 MW_e units, Each unit at Ratcliffe Power Station has 48 burners (36 required for full load) and 8 mills with static classifiers (6 required for full load). The burners at Ratcliffe Power Station were converted to MBEL MkIII LNBs between 1991 and 1997. The 1998 NOx emission limit for Ratcliffe Power Station was 64kte dropping to 40kte in 1999. During 1997/98 389 kte of ash were produced with 83% of this (323kte) being sold. All units at Ratcliffe Power Station have FGD installed.

3.17 Rugeley B Power Station

Rugeley 'B' Power Station is located near the town of Rugeley in Staffordshire. The station was commissioned in 1970 and is operated by Eastern Generation Limited. It is comprised of two front-wall fired 500MW_e Foster Wheeler boilers (Units 6 and 7). There are 28 burners mounted in each unit (4-8 burners out of service) and these are supplied with pulverised coal by seven mills (one out of service) with static classifiers. Units 6 and 7 were converted to Baumeister Wain Energy LNBs in 1996 and 1997 respectively. Each coal burner contains a centrally mounted oil burner, capable of carrying 20% of full load. The 1998 NO_x emission limit for Rugeley 'B' was 33.1 kte and is due to fall to 19.8 kte in 1999. All the ash produced by the station (bottom ash and flyash) is either sold or stockpiled for future sales, averaging 5.49 tonnes/TJ of coal burnt. The station is in the process of adding flue gas conditioning equipment (SO_3 and NH_3) to broaden the range of coal used in the future.

3.18 Tilbury Power Station

Tilbury Power Station which is situated on the Thames estuary to the east of London is operated by National Power. Built in 1968 by Foster Wheeler, this front wall fired station is comprised of 4x350 MW_e units. Each unit still operates the original 20 Foster Wheeler Intervane burners (4 out of service) and 5 mills with static classifiers (1 out of service). For Tilbury Power Station, the 1998 and the 1999 NOx emission limit is 29.3kte with the actual NOx emission being 11.6kte. With the coal that is currently being fired at Tilbury CIA is typically 10%. In year 1997/98 146kte of ash were produced with 55kte (38%) being sold.

3.19 West Burton Power Station

Like Ironbridge Power Station, West Burton Power Station is operated by Eastern Generation Limited. The station is located near Retford in Nottinghamshire. It was constructed circa 1967-69 and comprises four coal-fired 500MW_e boiler units. Each of the units at West Burton was constructed by International Combustion Limited (ICL) and is tangentially fired. The individual units have 48 burners (eight out of service), fed by six pulverised fuel mills (five mills required for full load) with rotary classifiers. Conversion to an ICL Low NO_x Concentric Firing System (LNCFS) was undertaken between 1989 and 1993; offset secondary air and close-coupled overfire air (CCOFA) is utilised. The oil burners on each unit are able to support 20% load. The 1998 limit for NO_x for West Burton PS was 45.2 kte and is 34.6 kte.for 1999. The corresponding level of CIA is around 5% to 7%. Total ash production on current coals is 6.94 te/TJ coal burnt and all of the bottom ash is sold. The proportion of fly ash currently sold is 40%.

3.20 Willington B Power Station

Willington B Power Station is operated by National Power and is situated to the South of Derby. This coal power station which is front wall fired was constructed in 1962 by MBEL. Willington B Power Station consists of 2x200 MW_e units. Each unit still operates on the original 32 circular register burners which are fed pulverised fuel from 8 mills with static classifiers. The 1998 NOx emission limit was 13.2kte which drops to 12.8kte in 1999. In the year 1997/98, 15kte of ash was produced, all of it being sold. Only one unit at Willington B Power Station is currently operational and the plant has a life expectancy of only a few years.

4. NO_X REDUCTION TECHNOLOGY REVIEW

The second of the four key activities involved in this study was to define the potential NO_x reduction options available to the power generator and these have been reviewed. The review has been based on published information.

As indicated in Section 1, current practices to reduce NO_x emissions on stationary combustion plant make use of two approaches:

i. the control of NO_x formation through combustion modifications;
ii. the downstream removal of NO_x from the flue gas by flue gas treatment technologies.

In accordance with these categories, the 'combustion modification' options examined in the course of this work were as follows: Low NO_x Burners (LNBs), Advanced LNBs (aLNBs), Furnace Air-staging or Two-stage Combustion (TSC) and Reburning (Gas, Oil and Coal). Selective Catalytic Reduction (SCR) and Selective Non-catalytic Reduction (SNCR) have been reviewed as 'post combustion' control technologies.

It is also noted that there are a number of ways in which the operators of fossil fuel furnaces can minimise emissions of NO_x from existing plant without recourse to dedicated NO_x reduction technologies At their simplest these could include investment in the coal milling plant so as to give a finer pf product - it then becomes possible to reduce excess air level (and hence NO_x) whilst maintaining acceptable carbon burnout, better maintenance of plant to ensure that it operates to its full potential, fuel purchasing strategy (awaiting low volatile high nitrogen coals) etc. In addition, a number of advanced control systems are becoming commercially available. These are based on the on-line optimisation of the plant by means of "expert systems" and typically would be set up to minimise NO_x whilst achieving a specified carbon in ash target. Available systems include "Ultramax", "Generic NO_x Control Intelligent System (GNOCIS)", "NO_x Adviser", " NO_x Emissions Advisor and Automation System (NO_xEA)", and "NO_xSMART". The NO_x reductions that these more advanced control systems can achieve are heavily dependent upon the maintained state of the existing plant and the nature and vintage of its existing control system. Whilst in general the technologies outlined above can be considered as "low cost" options, their applicability, cost, and NO_x reduction performance will be highly site specific - it is not possible to undertake a realistic assessment of these methods, to an acceptable standard, within a general study such as this, and so this has not been attempted.

A review of each of the available NO_x control options considered in this study is provided in the following sub-sections. Since the operating principles of these technologies are well known, this background information has not been presented here; further details on the various NO_x reduction techniques can be found elsewhere. The review outlines the commercial status of each technology (i.e. development/demonstration/well proven) and provides indicative costs associated with the implementation of the technology on large scale combustion plant. Technical requirements for the implementation of the NO_x control options are highlighted and, as a result of this, technical barriers are made apparent. The impact of the technologies on the production of other process streams or pollutants is discussed, as is the effect of the technologies on the process plant as a whole (i.e. impact on plant efficiency). Achievable NO_x reductions using the techniques are highlighted. In summary, this review presents the information salient to the undertaking of an assessment of a NO_x reduction technique on large scale power plant. It is important to note that any comments made on the various NO_x reduction strategies examined are from the perspective of an international equipment designer supplier/installer.

4.1 Combustion Modification NOx Control Technologies

4.1.1 Low NO_x Burners (LNBs)

Low NO_x burners are a well proven technology for NO_x control in both wall fired and tangentially fired furnaces, and there has been a significant uptake of this technology in the UK (see Table 1). For wall fired plant the normal retrofit path is to simply replace the existing burners, whilst for tangentially fired plant modifications would be made to the coal injector and air nozzles. The technology is relatively easy to retrofit into existing furnaces - generally no pressure part modifications are required, although the pf distribution is normally considered.

The performance of low NO_x burners is dependent upon the furnace arrangement (furnaces with high thermal rating produce a greater proportion of thermal NO_x), the fuel quality, and the operating conditions of the plant. Typically NO_x reductions of 40 to 50% compared to pre-conversion levels can be expected, with an increase in the carbon in ash level by a factor of 1.5 to 2.0 (Allen and King 1996).

All low NO_x burners operate on an air staging principle. It is therefore found that they achieve significantly lower NO_x emissions as volatile matter is increased. Whilst typical NO_x emissions are around 650 mg/Nm^3 @ 6% O_2, for high volatile coals emissions of below 400 mg/Nm^3 have been achieved in large highly rated furnaces. Conversely, lower volatile coals have a tendency to produce higher levels of NO_x. In addition to the volatile matter, the fuel nitrogen content is also important - higher fuel nitrogen levels lead to increased NO_x emission for both coal and oil combustion (Allen and King 1996, EC 1998, Kitto *et al.* 1998, Pershing *et al.* 1978, Turner *et al.* 1972).

The main concern with low NO_x burners is the potential for increased carbon in ash. As noted above this can be significant, and in retrofit situations it is normal for additional measures to be undertaken to reduce this negative impact - these will generally involve activities such as optimising the pf distribution to the burners and ensuring that the milling plant is operating to specification. It may also be necessary to consider improving the pf fineness in order to restore the carbon in ash levels to pre-conversion levels. The actual impact of a low NO_x burner retrofit on carbon in ash is strongly dependent upon the age and condition of the existing plant, the furnace arrangement, and the coal properties, and would be assessed on a site specific basis.

Other concerns associated with low NO_x burner retrofits relate to the possibility of a slight increase in flame length, burner pressure drop and slagging/corrosion. However the recent experience would indicate that there are generally no major problems which arise from well designed low NO_x burners, and the installation of low NO_x burners has generally had no significant detrimental impact on plant operation, reliability or availability. Indeed in some instances plant performance has been improved as a result of the optimisation undertaken during the retrofit prior to undertaking the performance guarantee tests.

The costs of low NO_x burner retrofits are clearly site specific, but are typically of the order of £6/kWe.

4.1.2 Advanced Low NO_x Burners (aLNBs)

Latest generation advanced Low NO_x burners are now becoming available as a result of constant development by equipment suppliers in a fiercely competitive world market. Typically these burners can achieve a further 20% reduction in NO_x compared to standard LNBs, and they tend to have less of an impact on burnout. Costs for aLNBs are similar to those for standard LNBs (around £7/kWe). Although there has, as yet, been no significant uptake of advanced low NO_x burner technology in the UK, they are being offered to utility customers with full commercial guarantees, and must therefore be considered as a fully available technology.

The issues associated with aLNBs are largely as discussed previously for standard LNBs. The main design aims of these burners (Allen and King 1996) are that:-

The burner should perform in such a way that the overall combustion efficiency is not altered significantly.

Flame stability and turndown limits should not be impaired.

The flame itself should have an oxidising envelope to minimise corrosion at the furnace walls.

Flame length should be compatible with furnace dimensions.

4.1.3 Furnace Air-staging or Two Stage Combustion (TSC)

Furnace air staging or two stage combustion (TSC) is a well proven commercially available technology for both wall fired and tangentially fired furnaces. In wall fired plant separate overfire air (OFA) injectors are located above the main burners, whilst in tangential fired plant it can be installed as close coupled overfire air (CCOFA) or separated overfire air (SOFA). NO_x reductions of up to 50% compared to LNBs alone can be achieved by this technology with a deeply staged primary zone.

Historically, furnace air staging was first developed and installed in conjunction with standard burners. More recently, with the development of LNBs using air staging principles, the tendency has been to apply TSC as an additional measure to further reduce the NO_x emissions arising when standard LNBs are installed.

In order to achieve the best possible NO_x reductions from this technology without significantly worsening the carbon burnout it is usual to operate the primary combustion zone fuel rich (typical stoichiometries being between 0.8 and 0.9) with the furnace design being such that there is ample residence time available to complete the combustion after the addition of the OFA. However this approach is usually only possible for new plant, and there are significant compromises required in order to retrofit the technology.

For pulverised coal firing, and in particular for UK coals which have high chlorine contents, the risk of water wall corrosion with substoichiometric combustion conditions in the primary zone is a major concern. Experience of TSC in the USA has shown evidence of greatly increased high temperature corrosion rates - for example the life of water wall panels can be below 4 years when previously they used to last as long as 12 to 15 years (Jones 1997). Even if TSC were to be applied to wall fired plant in the UK it is generally accepted that the primary zone would need to be operated fuel lean rather than fuel rich (i.e. a primary zone stoichiometry of 1.0 is the lowest practicable level for retrofit) and this would greatly reduce the performance of the process (NO_x reductions of only around 20% instead of 50% would be achievable). Under these circumstances the NO_x reduction performance of TSC is similar to that of advanced low NO_x burners.

The other significant compromise to the process in retrofit situations is the available residence time in the furnace. By operating the main combustion region at reduced stoichiometry there is less effective residence time available for burnout, and carbon in ash levels inevitably increase unless other measures are taken (e.g. mill enhancements to improve pf fineness).

The requirement to install overfire air injectors generally involves modifications to the pressure parts. Although OFA injectors are of simpler design than LNBs the cost of a retrofit installation reflects this increased difficulty. For wall fired plant a capital cost of between £3 and £7/kWe is typical. Tangential firing retrofits are more expensive at between £7 and £15/kWe depending upon the options involved.

The introduction of TSC can impact on the boiler thermal performance. By reducing the stoichiometry at the burners and supplying a fraction of the combustion air as OFA, there is greater heat release in the upper region of the furnace chamber, and this can lead to significantly higher gas temperatures at the arch level. Depending upon the boiler configuration there can be increased tube metal temperatures, and this has a negative impact on the life of these components.

Once installed the process is considered to be a low maintenance technology, with the significant proviso that the corrosion has not been worsened by the retrofit.

Whilst TSC can, in principle, be operated in load following or two shifted plant, it is found that this regime will exacerbate any corrosion problems as a result of changing flue gas composition (Jones 1997). Most UK coal fired plant is currently operated in a load cycling mode.

4.1.4 Reburning

Reburning is a relatively new in-furnace NO_x reduction technology based on the principle of furnace fuel staging. The process has been commercially demonstrated at up to 660 MWe for gas and oil over oil reburning (Antifora *et al.* 1998, De Michelle *et al.* 1995), and gas over coal reburn has been demonstrated in the UK at the 600 MWe Longannet Power Station (Golland *et al.* 1998). Coal over coal reburn is being demonstrated at the 320 MWe Vado Ligure Power Station in Italy (PEI 1998). UK companies (MBEL, Powergen, Scottish Power, and James Howden and Sons) have been involved in the development of the reburn process and its application to large plant (Hesselmann and Chakraborty 1998). The process is equally applicable to wall and tangentially fired plant, and in principle any hydrocarbon fuel might be considered as the reburn fuel (e.g. biomass pyrolysis gases, orimulsion, wastes etc), but before any of these fuels can be utilised as a reburn fuel a detailed study would have to be carried out.

Further NO_x reductions of up to 60% (compared with levels from LNBs alone) have been demonstrated at Longannet, with only a small increase in carbon in ash (by a factor of 1.0 to 1.25 or less, depending upon operating conditions), and similar levels of NO_x reduction are anticipated for coal over coal reburn based upon pilot scale combustion test facilities (Hesselmann and Chakraborty 1998) As with all staging technologies there are concerns with regard to water wall corrosion. However, with reburning, the main combustion zone operates fuel lean (stoichiometry $\cong$1.12) with only the relatively small reburn zone fuel rich (stoichiometry = 0.9). To date there has been no increase in wall corrosion or furnace slagging reported at Longannet after more than one years commercial operation of the plant.

Whilst a proportion of the fuel is injected above the main combustion zone, leading to a higher centre of heat input, practical experience has shown that the effects of this can be controlled by a modest increase in attemporator spray flowrate. Indeed the increase in spray flow is less than that required to account for the natural variability arising from changing furnace deposition prior to the retrofit of gas reburn at Longannet.

The retrofitting of reburn technology to existing plant requires careful consideration. Firstly it is important to achieve certain minimum residence times in the primary, reburn, and burnout zones to ensure optimal performance. These times can be reduced, but at the expense of either NO_x reduction or burnout. Secondly access to the upper furnace for reburn and OFA injection can be restricted - at Longannet it was not possible to introduce OFA to the rear wall, and at Vado Ligure the OFA injection is via the side walls rather than the front and rear walls due to access constraints.

Mixing is a key aspect to achieving good performance - in order to adequately mix the reburn fuel it may be necessary to introduce recycled flue gas to provide sufficient momentum, and this inevitably adds to the capital cost. For coal reburn it is likely that a finer pf size distribution will be required to maintain acceptable burnout, and mill upgrades or rotary classifier retrofits must be considered. For gas reburn the provision of a pipeline from the main gas supply network can add considerably to the cost of the project. In summary, the retrofitting of the reburn process to existing large plant is a relatively complex issue, with many site specific details needing to be taken into account. This is reflected in the capital costs associated with the retrofit - £10 to £13/kW_e for gas, oil or coal over coal reburn, excluding the cost of any gas pipeline.

Whilst reburning in oil firing applications, and gas over coal reburning, can be considered to be commercially available technologies, coal over coal reburning can only be considered to be at the demonstration stage until results are forthcoming from the Vado Ligure project.

4.1.5 Flue Gas Recirculation

Flue gas recirculation (FGR) is an established practice for the control of reheat steam temperature in large utility boiler plant. In this situation it is usual for the recycled flue gas to be supplied through the furnace hopper. By increasing the total mass of flue gas by the addition of a largely inert diluent, whilst maintaining the total heat input, the bulk furnace radiating temperature is reduced leading to lower furnace heat absorption (i.e. lower heat supplied to evaporation). The increased mass flux through the convective passes results in greater heat pick-up in the superheaters, reheater and economiser.

By acting to reduce gas temperature, FGR is effective in reducing the thermal NO_x produced. However, the location at which the recycled flue gas is introduced is also important. It is seen that FGR to the furnace hopper is largely ineffective as a means of reducing NO_x emissions. FGR to the whole burner air supply gives the best NO_x reduction. Investigations (Hesselmann 1995, Tager and Kalmaru 1977) have indicated that it is necessary to intimately mix the recirculated flue gas with the main combustion air so as to depress the peak flame temperatures in the near burner region in order to achieve good reductions in NO_x emission. FGR will reduce the thermal NO_x, but will not influence the fuel NO_x to any significant extent.

A major consideration for FGR is its impact on the boiler's thermal performance. As noted above, FGR to the furnace hopper is used for reheat steam temperature control, with typically 11 - 12% FGR being required for oil firing. Almost doubling this to 20% FGR for NO_x control will inevitably have a major effect on the boiler performance.

4.2 Flue Gas Treatment NOx Control Technologies

NO_x emission reductions for the 'post combustion' NO_x control technologies of SCR and SNCR have been identified and current prices obtained for anhydrous ammonia and SCR catalyst. This latter information is used in the formulation of costs for these technologies. Health & Safety issues associated with the transportation and storage of anhydrous ammonia are also considered, as well as the environmental impact of disposing of spent SCR catalyst. NO_x reductions achievable through the use of SCR and SNCR (and combinations/variations of these processes) have been extracted from published sources (Cochran *et al.* 1995, Eskinazi 1993, Hinton *et al.* 1997, Holliday *et al.* 1993, Huttenhofer *et al.* 1993, IEA 1996, Panesar 1998, Sigling *et al.* 1995, Staudt 1993, Tekeshita 1995, Veerkamp *et al.* 1993) and a list of the different post combustion processes available to the power generator has been tabulated.

4.2.1 Selective Catalytic Reduction (SCR)

SCR in power plant is described by various workers (Cochran *et al.* 1995, Eskinazi 1993, Hinton *et al.* 1997, IEA 1996, Sigling *et al.* 1995, Tekeshita 1995, TGSC 1997, Veerkamp *et al.* 1993). Full scale SCR plants are generally considered for new power plants and are designed based on 3 to 5 levels of installed catalyst material. The SCR reactor is most commonly installed upstream of the particulates removal system ('High Dust'). However, the reactor can also be installed after the particulates removal system ('Low Dust'). While this avoids the problem of catalyst degradation by flyash, this approach requires a costly hot-side ESP or reheating system to maintain the optimum operating temperature for SCR (300 – 400?C). Finally, the SCR reactor may be installed downstream of an FGD plant ('Tail-End') with the advantage of longer catalyst life but with the disadvantage of significant reheating costs.

In retrofit situations space restrictions may be problem, in which case more compact SCR plant is required. The reactor of a Compact SCR plant is characterised by an increased gas velocity. To limit the pressure drop on the flue gas side the number of catalyst levels must be reduced to 2 or 3. When space restrictions are a serious problem then catalyst elements can be located in the existing flue gas duct, upstream of the air preheater but the catalyst volume is limited to 1 or 2 levels to ensure that the pressure drop is not excessive. As a result of reducing the total volume of catalyst utilised, and for a given flue gas temperature there will be a corresponding deterioration in NOx removal efficiency, typically from 80% (full scale SCR) to 50% (In-duct SCR).

The major plant impacts, environmental considerations and Health & Safety issues related to SCR are as follows :

Reduced Catalyst Life Attributable To Trace Metals

Trace metals, particularly alkali and heavy metals such as arsenic can poison the catalyst - this is especially a concern with medium and high-sulphur coals, if as anticipated, catalyst lifetime is shorter than for low-sulphur fuels (see section on spent catalyst below).

Increased Corrosion

High SO_3 and sulphuric acid mists follow retrofit SCR (SO_2 is converted to SO_3 by the catalyst), producing an increased potential for low temperature corrosion in downstream equipment. Increased Air Heater temperatures minimise this effect but degrade the unit heat rate.

Air Heater Plugging

Deposition of ammonium sulphate or ammonium bisulphate takes place as the flue gas cools. Forced outages may therefore result if the deposition takes place in the airheater.

Injector Nozzle Pluggage and Ash Deposits

Medium- and high-sulphur coals can cause NH_3 injector nozzle plugging and hardened ash deposits in the reactor by the reaction products of NH_3 and SO_3.

FGD Waste Management

There is a potential for ammonia 'slip' or associated compounds to accumulate downstream in FGD scrubber liquor, and products such as gypsum will no longer be sold but will have to be disposed of as a solid waste.

Increased System Pressure Drop

Pressure drop associated with SCR catalysts is an issue for units with limited fan capacity. Existing fans may have to be modified or new fans added.

Spent Catalyst

A potentially hazardous waste material produced by SCR is spent catalyst which is generally disposed of at the end of its useful lifetime. As described under earlier, the catalyst is poisoned by 'heavy metals' such as arsenic and is therefore likely to be treated as 'special' waste in the UK, when spent.

Ash Contamination

A substantial amount of 'slip' ammonia will be absorbed by the flyash which is likely to affect flyash quality, making it unsuitable for subsequent use and therefore resulting in increased disposal costs.

Flyash, previously considered as 'inert' waste is likely to be considered as hazardous waste.

Potentially Hazardous Reagent

Potential Hazards of the Reagents are described by Cochran *et al.* (1995).

Ammonia is used as a reducing agent in SCR and it can be transported to site in the form of aqueous ammonia or anhydrous ammonia - generally, the anhydrous form of ammonia (100% NH_3) is chosen because it requires the least storage space and is the most cost effective.

Anhydrous ammonia requires a pressurised storage vessel and therefore potential problems are greater should a leak or an accident occur during transport/storage.

4.2.2 Selective Non-catalytic Reduction (SNCR)

Selective non-catalytic reduction is described by various workers (Eskinazi 1993, IEA 1996, Staudt 1993, Tekeshita 1995). It reduces NO_x emissions by reagent injection at the appropriate temperature window (850 - 1100 C). This temperature window is located in the highly congested convective bank pass of large coal-fired boilers. SNCR systems rely on good reagent/gas mixing and adequate reaction time, rather than a catalyst to achieve NOx reductions. The reagents most frequently used in these systems are ammonia or urea. Although these processes have been commercially demonstrated in gas-, oil-, and coal-fired boilers, the majority of coal fuelled experience is on circulating fluidised bed steam generators that have optimum residence times at an acceptable reagent injection temperature. The reported history of SNCR indicates that it is extremely difficult to install banks of long lances for the injection of reagent into the convective region of boilers due to space restrictions. To date SNCR has only been successfully installed in oil- and coal-fired boilers of < 200MWe. Substantial uncertainties still remain therefore, regarding the use of SNCR on large pulverised coal utility power plants, in particular multiple-injection points and careful design of the mixing zones are of increased importance in relation to two-shift operation and variable load situations.

The major plant impacts, environmental considerations and Health & Safety issues related to SNCR are as follows :

Air Heater Pluggage

Deposition of ammonium sulphate or ammonium bisulphate is likely to take place in the airheater as the flue gas temperature cools.

Due to higher levels of 'slip' ammonia, compared to that found in SCR, there is a greater risk of airheater pluggage and therefore forced outages may be longer and more frequent.

Unit Heat Rate

Unit heat rate can increase due to the power requirements of the compressors for reagent injection.

There are minimal impacts on unit heat rate due to latent heat losses associated with the volatilisation of the injected reagent.

Ash Contamination

High levels of 'slip' ammonia will be absorbed by the flyash, which will reduce flyash sales and result in increased disposal costs.

Flyash, previously considered as 'inert' waste, or even a saleable product would then be treated as hazardous, and require to be disposed of at a significantly increased cost.

Gaseous Emissions

Variable conditions, as a result of the boiler operating regime, can lead to emissions of gaseous ammonia to the atmosphere due to excessive 'slip'.

Injection of reagent into areas of the boiler, which are below the optimum operating temperature range of SNCR (850-1100 C), will not stimulate complete reduction of NOx and can potentially produce significant quantities of N_2O.

Potentially Hazardous Reagents

- Cyanuric acid, urea and ammonia are all utilised as reducing agents for SNCR
- Anhydrous ammonia is generally recognised as the most cost effective reducing agent, with or without the use of a catalyst, but potentially it is the most hazardous
- Transport and storage of anhydrous ammonia requires pressurised containers and strict safety procedures must be implemented

4.2.3 SNCR/SCR Hybrid

The main concerns with SNCR and SCR, as individual NOx abatement technologies, centre around by-product emissions and catalyst poisoning, respectively. Currently, investigations are taking place into the development of combined SNCR/SCR systems (IEA 1996, Staudt 1993, Tekeshita 1995) with a view to minimising levels of 'slip' ammonia and reducing the size of the SCR reactor. These objectives are potentially achievable because in the 'hybrid' system NOx is initially reduced by the SNCR process followed by additional NOx reduction in the SCR reactor downstream. Due to the significant NOx reductions by the upstream SNCR, downsizing of the SCR for only supplemental NOx reduction becomes possible. The smaller catalyst reactor and elimination of reheat requirements may result in considerable cost savings through minimising equipment modification costs and catalyst costs. Other benefits would include a reduced potential for oxidation of SO_2 to SO_3 and thus a subsequent reduction in the formation of catalyst-plugging ammonium salts. Ammonia 'slip' problems would also be minimised because the SCR catalyst in the 'hybrid' system utilises the unconverted ammonia 'slip' as the SCR reactor feed.

At present, it would appear that the SNCR/SCR Hybrid is restricted to pilot scale demonstrations. Further long-term tests are necessary to refine the operating conditions before it will become a commercially proven technology.

The major plant impacts, environmental considerations and Health & Safety issues related to the SNCR/SCR Hybrid are as follows :

Reduced Catalyst Life Attributable To Trace Metals

Trace metals, particularly alkali and 'heavy metals' such as arsenics can poison the catalyst - this is a problem with SCR on its own but it is still a concern with the hybrid system, especially with medium- and high-sulphur coals.

Increased System Pressure Drop

Although the size of the 'hybrid' SCR reactor is much smaller than a 'stand-alone' SCR reactor, the pressure drop associated with the catalyst is still significant for boiler units with limited fan capacity.

Modification of existing fans may be necessary, or new fans added.

Unit Heat Rate

An increase in the unit heat rate can be expected due to the power requirements of the compressors for the reagent injection in the SNCR section of the hybrid. However, there will be minimal impact on the unit heat rate from the SCR section of the hybrid because injection of additional reagent is limited.

Spent Catalyst

Although the catalyst volume for the 'hybrid' SCR reactor is much less than for a 'stand-alone' SCR reactor, there are still significant quantities of spent catalyst to be disposed of.

Spent catalyst is likely to be treated as 'special' waste in the UK.

Ash Contamination

The possibility remains that a significant quantity of 'slip' ammonia could be absorbed by the flyash if the 'hybrid' operating conditions are not sufficiently refined to react quickly to changes in boiler loads.

Flyash quality is likely to be affected and it is probable that the flyash would have to be treated as hazardous waste.

Potentially Hazardous Reagent

Although urea or ammonia can be used in SNCR, and both produce 'slip' ammonia, ammonia is likely to be considered as the primary reagent for application in this hybrid technology.

As for the individual NOx control technologies, strict safety procedures must be followed for transport and storage of anhydrous ammonia.

4.2.4 In Duct SCR/Catalysed Air Heater (CAT-AH)

Although, generally not accepted as a 'stand-alone' NOx abatement technology, a catalysed airheater (CAT-AH), where catalytically active heat transfer elements are used, is increasingly being considered as a component in an integrated approach to reducing NOx in flue gas (Holliday *et al.* 1993, Huttenhofer *et al.* 1993, Sigling *et al.* 1995). The most promising integrated option would appear to be the application of CAT-AH with In-duct SCR. In this approach the CAT-AH is utilised to reduce levels of 'slip' ammonia from the upstream SCR reactor, which improves flexibility of operation and enables the achievement of higher NOx removal rates. The smaller catalyst reactor associated with In-duct SCR should result in a significant reduction in catalyst costs compared to a full scale SCR reactor, whilst still providing 60-70% NOx removal efficiency.

Currently, the In-duct SCR/CAT-AH Hybrid, as is the case for the SNCR/SCR Hybrid, is restricted to demonstration plant and is generally not recognised as a commercially proven technology. However, the potential benefit of In-duct SCR/CAT-AH is that it could serve a reasonable niche function for retrofit situations where there is limited space available for certain power plant stations.

The major plant impacts, environmental considerations and Health & Safety issues related to the In-duct SCR/CAT-AH Hybrid are the same as those described above for SCR but the following points should be noted.

Increased System Pressure Drop

Although the catalyst volume will be less for In-duct SCR, the associated pressure drop will still be significant for power plant with limited fan capacity - modifications of existing fans may still be necessary, or new fans added.

Increased Corrosion

Increased CAT-AH temperatures minimise the potential for low temperature corrosion in downstream equipment but at the expense of the unit heat rate.

Ash Contamination

Although a potential benefit of In-duct SCR/CAT-AH is low ammonia 'slip', variable power plant operating conditions are likely to cause short periods of higher than normal levels of 'slip' ammonia.

Flyash sales would therefore be affected as a result of absorbing significant quantities of ammonia on an intermittent basis - the resulting flyash would need to be disposed of at a significant cost.

5. BASIS OF ANALYSIS

Reaching a decision on the most applicable and cost effective technique for controlling emissions of nitrogen oxides on stationary combustion plant is a complex task and involves many conflicting factors. Factors influencing the choice of a technology include, for example, its status with respect to its level of demonstration, the availability of on-site fuels, fuel price differentials, capital and operating costs, site specific retrofit limitations and plant operating characteristics. Against these issues, therefore, there clearly exists a need to be able to compare the various NO_x reduction technologies that can be applied to a given power station site directly. The economic impacts associated with the NO_x reduction technologies concerned in this study are detailed below. Comparison of the economic aspects relating to the various NO_x control technologies on each of the 20 power station of interest is made and discussed.

5.1 Background to Economic Analysis

As indicated above, the need exists to be able to compare NO_x reduction options on a specific power station arrangement directly. To assist in this end, the method used in the present study is based on the Technical Assessment Guide (TAG) used by the Electric Power Research Institute (EPRI 1987). For electrical supply technologies, the method which has been adapted by EPRI and widely used by the electrical utilities for economic analyses is the revenue requirement method. This method provides a consistent economic technique for assessing the relative cost to the customers of a power generator of the potential financial impact of an alternative approach (i.e. an alternative NO_x control strategy). More specifically, the revenue requirement definition can be summarised as 'the amount of revenue that a utility must collect from customers to cover all the costs associated with implementing an alternative decision involving money'.

In the case of NO_x reduction technologies, the 'alternative decision' may be a decision to install an emission control system on a power plant that is currently uncontrolled. The revenue requirement of an alternative is, therefore, the sum of the discrete charges associated with that alternative and is used to compare the alternative with other alternatives (e.g. LNBs with gas reburning).

The revenue requirements of a utility essentially comprise two components. These are (i) capital carrying charges, or fixed charges; and (ii) expenses. Capital carrying charges are related to capital investment and constitute the obligation inherent to an investment decision. Expenses are included in the analysis to cover the costs associated with the operating and maintenance practices of a plant; expenses are often referred to as operating costs. The revenue requirement technique requires the assessment of all of the applicable annual carrying charges and expenses for each year of the life of the plant.

The return on the capital expenditure that the utility must pay to investors for the use of their money is also a component of the revenue requirement and is an integral part of the obligation associated with an investment.

Traditional economic evaluations, as outlined above, involve the comparison of the present value revenue requirement of alternative technologies. For simplicity and ease of understanding, however, it often useful to compare levelised revenue requirements of alternative technologies. Levelised values provide more meaningful results in two ways: (i) the economic outcome is presented as a cost per unit of product or raw material (e.g. p/kWh or £/te NO_x removed); and (ii) costs are averaged over the required period using present value arithmetic. Levelised cost calculations are readily undertaken if certain simplifying assumptions are made, such as the constant or average value of inflation over the evaluation period; economic assumptions made as part of the current study are detailed in Section 5.2.1. Levelisation factors are given by the following equation:

$$L_n^e, L_n = \frac{k(1-k^n)}{a_n(1-k)}$$

$$a_n = \frac{(1-i)^n - 1}{i(1+i)^n}$$

$$k = \frac{1+e_a}{1+i}$$

$$e_a = (1+e_r)(1+e_i) - 1$$

where

L_n^e	=	levelisation factor applied to operating costs; A constant annual capacity factor for a generating unit such that the total present worth of the energy produced during the analysis period using the constant annual capacity factors is the same as the present worth of the energy produced by the individual annual capacity factors.
L_n	=	levelisation factor applied to capital costs (excluding escalation), e_r is set to zero and $e_a = e_i$.
a_n	=	present worth factor : a cumulative factor to compute the present value of a series equal annual amounts occurring over a period of n years.
n	=	number of years; (operating years)
e_a	=	apparent annual escalation rate; The total annual rate of increase in cost. The apparent escalation rate includes the effects of inflation and real escalation.
e_r	=	real annual escalation rate; The annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements in design or manufacturing (negative rate). The real escalation rate does not include inflation.
e_i	=	annual inflation rate; The rise in price levels caused by an increase in available currency and credit without a proportionate increase in available goods and services of equal quality. Inflation does not include real escalation.
i	=	annual interest rate - the discount rate, or the time value of money per time period.

The levelised revenue requirement method is the approach used in the current study and as in any analysis involving economic value, there are two variables, money and time. Due to the time value of money, monetary amounts cannot be added or compared directly unless they occur at the same point in time. It is necessary therefore to consider the effect of both the real escalation rate and the inflation rate, as defined above, in dealing with operating costs that will occur at a future time. If the operating costs are uniform over time, except for a constant apparent escalation, the levelised value of these costs can be calculated by multiplying the initial monetary amount by the levelisation factor, L_n^e. However, the levelisation factor applied to capital costs (L_n) does not include escalation, as the capital investment will be made in year 0 or 1 and therefore is not subject to escalation.

It is noted that a different approach is taken by Eastern Generation Limited, National Power and Powergen, when they assess the various NO_x control technologies, in their submissions to the Environment Agency (EGL 1998, NP 1998, PG 1998). The Generators base their economic assessments on a 'discounted cash flow analysis' which utilises the 'net present value' of an investment, discounted over the operating life of the plant. Whereas, the EPRI TAG approach considers the value of the investment over a fixed period of time, on the basis that the money is available for investment elsewhere i.e. following a normal economic progression. It is therefore not possible to directly compare costs obtained using these different methodologies. The difference between the two approaches means that the economic assessment carried out by the Generators result in costs, in the order of 2 - 3 times less than those calculated using the TAG methodology, although the trends remain the same.

Using the levelised revenue requirement methodology as a basis, to determine and compare the net economic value (costs or credits) of the various NO_x reduction options under consideration, the combined effects of each of them on the combustion plant of interest must be analysed and evaluated. To provide the consistency needed to permit direct comparisons of technologies, a series of primary financial assumptions and technical premises are required so that the credit or cost of a given NO_x control technique can be calculated; these are discussed below. Due to the fact that these assumption must be made, however, it is important to note that such evaluations relating to the available NO_x reduction options being considered may only provide relative indications of the costs incurred for their implementation. Whilst this approach may be adequate in providing advice to agencies such as the Environment Agency, for example, the need still remains for detailed, site-specific assessments before any NO_x reduction technology can be recommended for a given power station

5.2 Analysis Assumptions

The various assumptions used in the current study to undertake economic evaluations relating to the installation of NO_x control options on the various power stations under consideration are given below.

5.2.1 Economic Assumptions

Costs assumed for the economic assessments are taken from the public domain and fuel prices especially, are subject to wide variations depending on the individual contract details. Sources of data for the financial assumptions listed in Table 3 are as follows:

- Electricity costs - Generator Sales Price (Powerline 1999)
- Coal Cost - Government White paper (DTI 1998)
- Fuel oil cost - Eastern Generation Limited (EGL 1998)

- Gas Fuel Cost - Government White Paper - (DTI 1998)
- Gas Pipeline Cost - Penspen Ltd (Private Communication 1998)
- Cost of landfill ash - Powergen (Private Communication 1998)
- Price of saleable ash - Powergen (Private Communications 1998)
- Capital cost of technology - Lentjes Bischoff (Private Communication 1998) and published literature (Cochran *et al.* 1995, EPRI 1987, Eskinazi 1993, Hinton *et al.* 1997, Holliday *et al.* 1993, IEA 1996, Staudt 1993, Tekeshita 1995, TGSC 1997, Veerkamp *et al.* 1993).
- Catalyst Cost - Lentjes Bischoff (Private Communication 1998) and published literature (Eskinazi 1993, IEA 1996, Veerkamp *et al.* 1993).
- Cost of anhydrous ammonia - Terra Nitrogen UK (Private Communication 1998) and Hydrochemicals (Private Communication 1998).

5.2.2 Other Assumptions

Other parameters utilised in the economic assessment spreadsheets include:

- Timescales for evaluation - 5, 10 and 15 years, as specified by the Environment Agency.
- Load factors - 10%, 40% and 75%, as agreed with the Environment Agency.
- Unit heat rate - 10.55 MJ/kWh, presented by EPRI as being a typical value (EPRI 1986).
- NO_x emissions - With standard low NO_x burners fitted. 650 mg/Nm^3 (coal-fired) and 450 mg/Nm^3 (oil-fired), when not otherwise specified.
- PF fineness - 70% through 75 microns, unless otherwise specified.

- Fuel specifications.
  - Typical UK coal, oil and gas compositions are given in Tables 4 - 6, respectively
  - A typical low volatile coal composition for Aberthaw contains 11.20% Volatile Matter, 18.67% Ash, 1.20% Sulphur and a gross calorific value of 26267 kJ/kg fired.
- Residence times and typical NO_x reduction efficiencies are taken from published literature (Cochran *et al.* 1995, Eskinazi 1993, Hesselmann 1995, Hinton *et al.* 1997, Holliday *et al.* 1993, IEA 1996, Kitto *et al.* 1998, Sigling *et al.* 1995, Staudt 1993, Tager and Kalmaru 1977, Tekeshita 1995) and listed in Tables 7 and 8, respectively.

5.3 Definition of Cost Algorithms

Excel spreadsheets are used as the framework to link power plant information with the key operating parameters/details of the NO_x control technology being assessed. Within the spreadsheets, algorithms are incorporated to calculate operational details from data entered for each station, which is then used to calculate Credits and Costs associated with the installation and operation of the NO_x control technology. The economic outcome is summarised at the end of each spreadsheet, in tabular form, and the total economic cost produced in p/kWh and £/te NO_x removed, on a per Unit basis. Examples of spreadsheets for each NO_x control technology are given in the appendices.

5.3.1 Cost for Reduced NO_x Emissions

All NO_x control technologies require an initial capital outlay for construction and commissioning. The typical capital costs of each technology, shown in Table 3, are taken as an average of figures widely reported in literature (Cochran *et al.* 1995, Eskinazi 1993, Hinton *et al.* 1997, Holliday *et al.* 1993, Huttenhofer *et al.* 1993, IEA 1996, Staudt 1993, Tekeshita 1995, TGSC 1997, Veerkamp *et al.* 1993) and are assumed to include the capital carrying charges related to the capital investment. Combustion technology costs are generally much lower than the capital costs reported for the post-combustion technologies, due mainly to the extensive material and reagent costs associated with these latter technologies.

For each technology, the spreadsheet calculates, for specific timeframes, the total mass of NO_x reduced (in tonnes) based on the entered NO_x emissions at MCR (see Section 5.2.2) and the typical NO_x reduction achieved. These figures, in conjunction with the Difficulty Factor, which is used to take into account the degree of installation complexity and resulting sensitivity of capital cost, and the Levelisation Factor, provide the cost for reduced emissions in £/te NO_x removed. A similar calculation is carried out to provide the cost for reduced emissions in p/kWh based on the total power (in kWh) determined from the unit capacity and operating period.

Where stations have no natural gas supply on site there will be an additional capital cost for gas piping, which is calculated, based on the proximity of the station to the National Transmission System - £800,000/km (Penspen Ltd, Private Communication 1998). This cost is a one-off capital cost of gas pipeline and will be divided by the number of boiler units on site.

5.3.2 Cost for Lost Saleable Ash

Ash sales can potentially be affected by the deterioration in quality due to either increased levels of CIA, as a result of installing 'combustion' NO_x control technologies (LNB, aLNB, OFA, Reburning) or, contamination with 'slip' ammonia, as a result of installing 'post-combustion' NO_x control technologies (SNCR, SCR, SNCR-SCR Hybrid, In-duct SCR/CAT-AH).

From MBEL's experience in burner design and operation, it is assumed that there is no increase in CIA that would affect the saleability of the ash, from converting existing burners to LNBs or aLNBs, although coal type and plant operating conditions affect the accuracy of this assumption. 1 and 2% (absolute) increases in CIA are assumed for Reburning and OFA, respectively, with 100% loss of ash sales coming into effect when the CIA exceeds 7%. Information from literature (Cochran *et al.* 1995) indicates that all flyash sales are lost when the ammonia slip >10ppm, 50% of flyash sales are lost when the ammonia slip is between 5-10 ppm, and 25% of flyash sales are lost when the ammonia slip is between 2-5 ppm.

The spreadsheets calculate the amount of ash lost to landfill, as a result of deterioration in quality. Cost for lost saleable ash is calculated using the price of saleable ash quoted in Table 3, i.e. £3.00/te. The final cost is given in p/kWh and £/te NO_x removed.

5.3.3 Cost for Increased Ash Disposal to Landfill

In addition to the cost of 'lost saleable ash' there will be a cost attributed to 'increased ash disposal to landfill, which is calculated in the same manner using the disposal costs of ash, by landfill, quoted in Table 3, i.e. £8.70/te, if CIA >7% and £26/te, if the ash is contaminated with ammonia, causing it to be classed as hazardous waste. There is clearly a greater potential for increased disposal costs should the ash become contaminated with ammonia, compared to increased CIA levels.

5.3.4 Minimising CIA

It is generally accepted that there is an inverse correlation between PF fineness achieved by the mills and CIA. This section of the spreadsheet incorporates messages which indicate whether mill modifications are required, or not, based on an acceptable mill performance, i.e. if the PF fineness is 70% or greater through 75 microns and/or the CIA <7%. Two of the NO_x control technologies, OFA and Reburn are assumed to increase the CIA levels by 2% and 1% respectively, which in some cases may push the CIA level beyond the 7% limit.

Should mill modifications be recommended, then a cost of £250,000/mill is used to calculate the total cost of refurbishing all mills utilised to feed pulverised fuel to each boiler unit, otherwise the cost is shown as zero in both p/kWh and £/te NO_x removed.

5.3.5 Cost of Increased Auxiliary Power

Apart from burner conversions (LNBs and aLNBs), the NO_x control technologies considered in this review, require either additional fans for recirculation of flue gas or overfired air, or upgraded fans with increased power, to compensate for the increased pressure drop associated with the installation of a catalyst reactor. Information on the power requirement for fans, is taken from literature (Cochran *et al.* 1995, Hinton *et al.* 1997, Holliday *et al.* 1993, IEA 1996, Sigling *et al.* 1995, Tekeshita 1995, Veerkamp *et al.* 1993).

Power is also required for the injection and volatilisation of ammonia in the post combustion processes, SCR, SNCR, SNCR-SCR Hybrid and In-duct SCR/CAT-AH. For these processes an energy penalty due to the NH_3 injection system is taken from the Eastern Generation's submission to the Environment Agency (EGL 1998), in the form of kWh/te of ammonia injected.

The auxiliary power requirement for each technology is calculated by the spreadsheet, from the factors described above, and plant details specific to individual stations.

5.3.6 Cost of Ammonia and Replacement Catalyst in Post Combustion Processes

Ammonia is the primary reagent used in the post combustion processes and although it is available in aqueous solution only the more concentrated anhydrous form is considered in this study. The mass of ammonia required to react with NO_x in the flue gas is dependent on the stoichiometric ratio (NH_3:NO_x) adopted for each technology (Cochran *et al.* 1995, Eskinazi 1993, IEA 1996, Sigling *et al.* 1995, Veerkamp *et al.* 1993) and is generally less than 1.0 for SCR and of the order of 2.0 for SNCR - the hybrid technologies fall somewhere in between.

Volume of catalyst required for NO_x reduction is calculated based on typical residence times quoted in literature and the volume flow of flue gas through the SCR reactor. A check is made against a minimum residence time of 0.5 second to ensure that a realistic catalyst volume is used to determine catalyst costs for the 'High Dust' location, i.e. between the economiser and the ESP. It is assumed all the catalyst will be replaced within five years

(Cochran *et al.* 1995, IEA 1996, Sigling *et al.* 1995, Tekeshita 1995, TGSC 1997) and that only two thirds of the catalyst volume, calculated for the full scale plant ("High Dust'), will be used for the two hybrid options, and a quarter of the volume used for the 'Tail-End' option, i.e. after FGD.

5.3.7 Cost of Alternative Reburn Fuels

Three options are considered for the Secondary fuel in reburning, which are - coal, gas and oil. When the reburn fuel is the same as the primary fuel then no extra cost is recorded. However, when the reburn fuel is different, then costs are calculated based on the percentage of primary fuel replaced by the reburn fuel. Gas is the most proven reburn fuel for coal-fired stations, although there is a great deal of uncertainty on the level of gas prices in the future. Sensitivity studies are therefore carried out to investigate the effect of gas prices on Reburn Costs. Oil is also assessed as a reburn fuel but to a lesser degree.

5.3.8 Cost of Increased Flue Gas Moisture (Gas Reburn Only)

Combustion of natural gas as the reburn fuel results in the production of significant quantities of moisture in the flue gas, which affects plant efficiency. For gas reburn, therefore, the cost of this loss in efficiency is calculated based on the increase in heat rate necessary to maintain the original output of the plant. The percentage increase in heat rate is taken from MBEL's experience at Longannet PS (1.30%).

5.3.9 Cost of O & M Fixed Labour

Installation of NO_x control technologies increases the level of operation and maintenance required for each power station to varying degrees. It has been estimated that burner conversions/OFA will increase the normal plant O & M fixed labour costs by 1% (Allen and King 1996) and that the increase due to Reburn is 5% (Allen and King 1996, Golland *et al.* 1998).

Information taken from literature (Holliday *et al.* 1993, Staudt 1993, Tekeshita 1995) indicates that the cost of O&M fixed labour per annum for the post-combustion processes can be estimated as a proportion of the capital cost - 5% per annum and 1% per annum, for SNCR and SCR, respectively, 2% per annum and 1% per annum are assumed for the SNCR-SCR Hybrid and In-duct SCR/CAT-AH Hybrid, respectively, on the basis that the former is likely to be close to an average for the technologies taken separately and that the CAT-AH component of the latter is unlikely to add significant O&M costs to SCR on its own.

5.3.10 Cost of Forced Outages for Maintenance

Additional outages, as a result of installing post combustion NO_x control measures, are estimated in literature for SNCR and SCR, as a percentage of lost operating time i.e. 5% and 1.25% respectively (Tekeshita 1995) Since the increased forced outage rate is due to ammonia slip forming ammonium sulphate/bisulphate deposits downstream, outage factors are assumed for the SNCR-SCR Hybrid (2%) and the In-duct SCR/CAT-AH Hybrid (2%), based on typical levels of slip ammonia for these processes, compared to SNCR and SCR. The costs are calculated from the lost revenue from the sale of electricity.

5.3.11 Credits for Reduced Ash, Reduced SO_2 and Reduced Coal Mill Maintenance (Gas and Oil Reburn only)

Since gas and oil produce little or no ash, the use of these fuels as reburn fuels reduces the level of ash produced in the combustion process and therefore there is an associated reduction in disposal costs - calculated by the spreadsheet from the degree of reduction and the landfill cost of ash disposal.

There is also a reduction in operating costs due to reduced coal mill maintenance, which is calculated on the basis that mill costs equate to 10% of the total O&M costs and gas or oil reburn reduces the number of mills in service by one.

Due to the low levels of SO_2 in natural gas, gas reburn reduces the SO_2 load for an FGD plant. Therefore, if any station has FGD installed there is an associated credit for operating gas reburn, which is calculated from the typical cost for SO_2 removal by FGD of £125/te of SO_2 removed (Powergen Private Communication). No financial credit is taken for the reduced quantity of particulates in the flue gas where wet FGD plant is installed and operational.

6. RESULTS AND DISCUSSION

The relative costs of implementing the various NO_x control options at each power station considered in this review are listed in Tables 9 - 32 and discussed in the following sections.

Preliminary Techno-Economic Assessments

Most of the coal-fired power stations included in this study have been converted to low NO_x burners.. The exception to this trend is Aberthaw, which has downshot-fired boilers firing low volatile coals, but which achieves good combustion with some level of NO_x control through the use of thermal bias on overfire air staging. There is no additional NOx control technology currently installed at Aberthaw, nor at the three oil-fired stations, which operate with their original oil burners.

For the following stations : High Marnham, Drakelow 'C', Littlebrook, Grain and Fawley, the preliminary economic assessments indicate that residence times in the boiler are not long enough for optimum retrofit of OFA and/or Reburn. Major boiler modifications may therefore be required before OFA and/or Reburning can be installed in High Marnham and Drakelow 'C' to achieve efficient reduction of NOx. However, since oil-fired stations, generally require shorter residence times to optimise burnout compared to coal-fired stations, Littlebrook, Grain and Fawley are unlikely to require major boiler modifications to achieve reasonable NOx reduction. Similar problems associated with residence times are indicated for Blythe A and B, but only for Reburn.

Coal-, gas- and oil-reburn are assessed for most of the coal-fired stations, but gas is currently the most demonstrated reburn fuel for these stations. However, in the case of Aberthaw only gas-reburn is considered, due to their being no reburn demonstrations yet on downshot-fired boilers, and the particular economic assessment can only be taken as a very rough guide to the potential costs involved. Oil-reburn has recently been demonstrated at the 600MW oil-fired station at Monfalcone in Italy (Antifora *et al.* 1998) and is the most likely reburn option for oil-fired stations. Hence it is the only reburn option considered for Littlebrook, Grain and Fawley.

Since flue gas recirculation (FGR) to the whole burner air supply results in a significant reduction in thermal NO_x levels, this technology is most effectively applied to oil-fired stations. They have a greater potential for reduction in total NO_x, compared to coal-fired stations, due to the relatively higher contribution of thermal NO_x to their total NO_x emission levels. Therefore only the three oil-fired stations are assessed for FGR. Although Littlebrook and Grain already utilise FGR for reheat steam temperature control, the recycled flue gas is introduced via the furnace hopper in these stations, which is largely ineffective as a means of reducing NO_x emissions. Economic assessments are therefore carried out, based on recirculation of flue gas to the oil burners at Fawley, Grain and Littlebrook.

Sensitivity Studies

Sensitivity studies are carried out on important economic and process parameters. On all NO_x control technologies that are considered feasible for application on individual stations, economic assessments are carried out for permutations of load factor (10, 40 and 75%) and timeframe (5, 10 and 15 years), as agreed between MBEL and the Environment Agency. To gauge the effect of the economic parameters on the outcome of the economic assessments, a sensitivity study is also carried out on the 'annual inflation rate' (e_i), 'annual interest rate' (i) and 'annual real price escalation' (e_r), as applied to West Burton for all NO_x control technologies examined :

	5 Years	10 Years	15 Years
e_i	2.0%	3.0%	2.5%
e_r	4.00%	4.0%	4.0%
i	3.50%	4.5%	3.75%

The sensitivity of the economic parameters is indicated when comparing the costs listed in Table 33 with those listed in Table 31. In Table 31 the costs are calculated for 5, 10 and 15 years , using the relevant economic parameters shown above. However, in Table 33, the costs are calculated using the 5 year economic parameters (most favourable), for all three time periods considered. Generally, this sensitivity study indicates that the economic parameters shown for 5, 10 and 15 years do not have a major effect on the economic assessment of the different NO_x control options.

Finally, with regard to sensitivity of key parameters, two parameters in particular are identified as significant. The parameters in question are (a) the price of natural gas, which is examined because of the uncertainty of future gas prices, and (b) the proximity of gas mains to the station, which is examined because some stations are considering, or may consider in the future, installing natural gas on site, as an alternative fuel to coal. In both cases, these parameters only affect the cost of gas reburn. To gauge the effect of a change in value, the gas price is set to the same price as for coal, which effectively reduces the additional cost of the reburn fuel to zero, i.e. £1.90/GJ → £1.25/GJ (see Table 34). The proximity of the gas mains is set to zero to gauge the effect when natural gas is already available on site and there is no additional capital cost of gas piping (see Table 35).

The sensitivity of the price of gas is indicated by comparing the costs listed in Table 34 with those listed in Table 31 for gas-over coal reburn. This comparison demonstrates that the gas price has a significant effect on the economic outcome by reducing operating costs. Comparing Table 35 with Table 31 demonstrates that there is also a significant reduction in capital costs if no gas pipeline is required to connect the station to the National Transmission System.

Analysis Assumptions

In this study, only anhydrous ammonia is considered as the reducing agent for the post combustion processes, although aqueous ammonia may also be used, and urea or cyanuric acid are alternative options for SNCR. Ammonia is chosen because it is the most effective reducing agent and the price for the anhydrous form is used in the cost assessments because it is the most concentrated form of ammonia and is generally selected by operators of SCR in Europe, Japan and USA.

SCR catalyst is available in the form of plate or honeycomb monoliths, with the former generally utilised for 'high dust' locations. No assumption is made on catalyst type in this study but SCR reactors are assumed to be of the 'high dust' variety (i.e. located between the economiser and ESP) because it is reported in literature that most installations still are of this type. The cost of £5000/m^3 for catalyst used in the economic assessments is derived from current costs quoted by Lentjes Bischoff (supplier of SCR) and cost data reported in literature. It is now recognised that catalyst performance is improving and at the same time, because of competition between suppliers of catalyst, the price is dropping. These trends are expected to continue for at least the next few years, according to the manufacturers of catalyst.

Only seven stations, including the three oil-fired stations do not have burner conversions. Tables 10, 11, 19, 22, 27, 30 and 32, demonstrate the relatively lower costs of burner conversions, compared to the other NO_x control technologies, with the noticeable exception of FGR in oil-fired stations (see Tables 19, 22 and 27), where the costs are particularly low.

The application of OFA and Reburn to the various power stations under investigation is based on plug flow residence time considerations, which are the first assessed. In some instances, (e.g. High Marnham) the residence time was insufficient and cost data were not derived. This does not mean that these technologies can not be applied to particular stations, only that further examination of site specific details are required.

Due to a lack of site specific information relating to space availability and process temperatures, the post-combustion NO_x control options are considered for all 20 stations concerned. However, the final costs shown in the Tables 9 - 32 for these particular technologies must therefore be treated with care, and can only be taken as a comparative guide. Space availability will strongly influence the capital cost of SCR and its Hybrids, which is a major factor in the economic outcome for all stations. For SNCR, the major cost is associated with the much higher consumption of ammonia, which is more noticeable for stations with high NO_x emissions e.g. Grain (794 mg/Nm^3). The temperature range within boilers is critical to the feasibility of SNCR. Detailed plant modelling is required, on an individual station basis, to confirm the most suitable location for the SCR reactor and the SNCR injection lances.

Cost Data and Trends

Summary details of NO_x reduction costs in p/kWh and £/te NO_x removed for each technology and each power station reviewed in this study are given in Tables 9 - 32.

Typical plots displaying cost trends of NO_x reduction technologies are shown for a plant in Figures 1-12. The following graphs are displayed:

(1) Cost (p/kWh) vs Operating Period (years) for 10%, 40% and 75% load factor.
(2) Cost (£/te NO_x removed) vs Operating Period (years) for 10%, 40% and 75% load factor.
(3) Cost (p/kWh) vs Unit Load (%) for 5, 10 and 15 years.
(4) Cost (£/te NO_x removed) vs Unit Load (%) for 5, 10 and 15 years.

It must be emphasised that while the data given in the above mentioned tables and figures provide a preliminary economic assessment of the 20 power stations included in this study, detailed assessments are required to fully evaluate the potential application of each technology to a specific power station site. Although the data produced by the spreadsheets provide a preliminary assessment of the total costs (economic outcome), site specific factors may significantly affect the accuracy of these data.

A number of trends can be seen on examination of the data produced by the economic assessment spreadsheets, based on the variation of unit load and timeframe.

The combustion NO_x control technologies appear the more attractive options and their costs, either in p/kWh or £/te NO_x removed, remain fairly constant through variation in the unit load factor and operating time. This is to be expected because the combustion technologies have a relatively low capital outlay and O&M costs should be relatively constant.

However, generally the post-combustion NO_x control technologies have a significant capital outlay (except for SNCR) and there is a noticeable drop in costs as operating time passes, particularly for low load factors. SNCR reverses the trend somewhat because the initial capital outlay is much less compared to SCR but like SCR there is a significant operating cost associated with the consumption of ammonia. Both these factors result in a slight increase in costs at a constant load factor, as time passes, probably due to inflation.

For costs correlated against unit load, SNCR is similar to the combustion NO_x control technologies, in that the costs in p/kWh and £/te NO_x removed, remain reasonably constant across the range of load factors, albeit the SNCR costs are higher.

7. CONCLUSIONS

The overall objective of this study is to prepare authoritative advice to assist the Environment Agency to formulate requirements for further NO_x reduction measures on each of the coal- and oil-fire power stations operated by National Power, PowerGen and Eastern Electricity in England and Wales. This primary objective has been met. From the summarised details of the NO_x reduction costs given in Tables 9 - 32, the sensitivity studies shown in Tables 33 - 35, the assumption that the plant is already set up to minimise NO_x emissions from its existing equipment, and the typical plots of cost trends, shown for a notional station in Figures 1 - 12, the following conclusions are made:

- The least expensive NO_x control technologies are the LNB and aLNB burner conversions.
- The post-combustion NO_x control technologies become more economically competitive at higher load factors and longer operating periods.
- The variation in 'annual inflation rate', 'annual interest rate' and 'annual real price escalation' for 5, 10 and 15 year operating periods, has little effect on the economic outcome (in p/kWh and £/te NO_x removed) for the assessment of aLNB, OFA, Reburn, SNCR, SCR, SNCR/SCR Hybrid and In-duct SCR/CAT-AH.
- Coal reburn will be an attractive NO_x control option provided the demonstration at Vado Ligure matches rig trials and it becomes commercially available, at the earliest, in the year 2000.
- Capital costs for gas over coal reburn are significantly reduced when natural gas is already available on site (no pipeline costs) and there is a further potential reduction in operating costs should the price of gas drop.
- Due to its low NO_x reduction efficiency, OFA is best considered in conjunction with other NO_x control technologies, such as LNBs and Reburn.
- FGR is a very attractive technology for the reduction of NO_x in oil-fired stations and the recycling control process, directly through the burner, is fully demonstrated as a NO_x control technology, particularly in the USA.
- Gas over coal reburn and SCR are the most feasible NO_x control technologies for the downshot-fired boilers at Aberthaw.
- Further detailed assessments are required to fully evaluate the potential application of each technology or a combination of technologies to a specific power station site.

8. RECOMMENDATIONS

It is recommended that the results of this study are reviewed by the Environment Agency with each of the relevant Electricity Generators as follows :

1. The Environment Agency ensures that the power stations are set up to minimise NO_x formation with existing equipment and that up to date control systems are in use.

2. The Environment Agency reviews with the generators the likely life and load profile of each station, given the significant effect of these factors on costs.

3. In view of 2 above, the Environment Agency considers the possibility of coal over coal reburn becoming commercially available (at the earliest, in the year 2000) before reaching a conclusion for all stations.

4. The Environment Agency reviews further the site specific costs associated with the installation of NO_x control technologies, particularly for the post-combustion processes.

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Table 1 – Status of Power Stations

STATION	Generator	Year	Boiler Type (and Manufacturer)	Fuel	Capacity (MW_e)	Units (No. x MW_e)	Date Converted	Burner Types	Equivalent NO_x (mg/Nm^3)
Aberthaw B	National Power	1977	Downshot-fired (Foster Wheeler Energy Corp.)	Coal	1500	3x500	-	Foster Wheeler Downfire Burners	1000 (assumed)
Blythe A	National	1958/66	U1-4 Front-wall Fired (MBEL)	Coal	480	4x120	-	MBEL Circular Register	1000 (assumed)
Blythe B	Power		U7,8 T-fired (Clarke Chapman)	Coal	660	2x330	-	ICL Tilting	
Cottam	PowerGen	1969/70	Front-wall Fired (John Thomson Ltd)	Coal Gas	2018	2x504 (1290MWt) U2,3x505	1990-94	ICL LNB	666
Didcot	National Power	1973	Front-wall Fired (Mitsui Babcock Energy Ltd)	Coal (Gas)	2000	4x500	1993-97	MBEL MkIII LNB (also gas spuds)	650 (assumed)
Drakelow C	Eastern Generation	1962/66	U9,10 F.W. Fired / U12 T-Fired (John Thomson Ltd and ICL)	Coal	1025	U9,10x350 U12x325	1996-97	MBEL MkIII LNB (U9,10) ICL LNCFS (U12)	650 (U9,10) 750 (U12)
Drax	National Power	1974	Opposed-wall Fired (Mitsui Babcock Energy Ltd)	Coal	3960	6x660	1989-93	MBEL MKIII LNB (U4-6) + U1-3 (top 2 rows)	650 (assumed)
Eggborough	National Power	1968	Front-wall Fired (Foster Wheeler Energy Corp.)	Coal	1995	U2x480 U1,3,4x505	1986-91	FW LNB Intervane	650 (assumed)
Fawley	National Power	1969	Oil-fired (Foster Wheeler Energy Corp.)	Oil	517	1x483 +34GT	-	Hamworthy Pressure Jets	871
Ferrybridge	PowerGen	1968	Front-wall Fired (Mitsui Babcock Energy Ltd)	Coal	2000	4x500 (1260MWt)	1994-96	MBEL MkIII LNB (U1 - 3)	650
Fiddler's Ferry	PowerGen	1971	T-fired (International Combustion Ltd)	Coal	2000	4x500 (1259MWt)	1985-90	ICL LNCFS	512
Grain	PowerGen	1979	Venturi Oil-fired (Mitsui Babcock Energy Ltd)	Oil	1980	3x660	-	MBEL Venturi Oil-fired	794
High Marnham	Eastern Generation	1959/62	T-fired (International Combustion Ltd)	Coal	1000	5x200	1990-95	ICL LNCFS (with Offset SA)	650 (assumed)
Ironbridge	Eastern Generation	1970	Front-wall Fired (Foster Wheeler Energy Corp.)	Coal	1000	2x500	U1 1993-95 U2 (currently) U2 1999	Senior-Thermal Burners FW Intervane ABB ROBTAS Burners	650 (U1) 1400 (U2)
Kingsnorth	PowerGen	1970	T-fired (International Combustion Ltd)	Coal Oil	2000	4x500 (1276MWt)	1990-92	ICL LNCFS	666 563-640
Littlebrook	National Power	1982	Front-wall Fired (NEI - Clark Chapman Ltd))	Oil	790	1x685 +105GT	-	MBEL Parallel-flow	683
Ratcliffe	PowerGen	1968	Front-wall Fired (Mitsui Babcock Energy Ltd)	Coal	2008	4x502	1991-97	MBEL MkIII LNB	650 (assumed)
Rugeley B	Eastern Generation	1970	Front-wall Fired (Foster Wheeler Energy Corp.)	Coal	1000	2x500	1996-97	Baum. Wain Energy LNB	658
Tilbury	National Power	1968	Front-wall Fired (Foster Wheeler Energy Corp.)	Coal	1400	4x350	-	Foster Wheeler Intervane	1000 (assumed)
West Burton	Eastern Generation	1967/69	T-fired (International Combustion Ltd)	Coal	2000	4x500	1989-93	ICL LNCFS (with Offset SA)	580
Willington B	National Power	1962	Front-wall Fired (Mitsui Babcock Energy Ltd)	Coal	200	1x200	-	MBEL Circular Register	1000 (assumed)

Table 2 – Proximity of Stations to Natural Gas Supply

Power Station	Nearest NTS[1] AGI	NTS[1] Distance (km)	LTS[2] Distance (km)
Blythe A/B	Pidgon	15.7	6
Fiddlers Ferry	Helsby	12.7	1
Didcot	East Ilsley	10.8	22
Fawley	Braishfield	25.0	6
Tilbury	Tilbury Thames North	2.9	5
Littlebrook	Farningham	9.6	3
Grain	Isle of Grain	6.4	3
Kingsnorth	Isle of Grain	6.4	3
Eggborough	Rawcliffe	11.7	2
Ferrybridge C	Cawood	16.1	3
Drax	Rawcliffe	2.4	7
West Burton	Susworth Trent West	16.9	16
Cottam	Susworth Trent West	25.5	12
High Marnham	Blyborough	25.9	8
Drakelow C	Clifton Campville	8.8	6
Ratcliffe	Twycross	29.5	2
Willington B	Clifton Campville	18.1	3
Aberthaw	Rhigos	39.6	15
Ironbridge	Aspley	33.7	15
Rugeley	Alrewas	9.5	5

Notes: [1]NTS - National Transmission System
[2]LTS - Local Transmission System

TABLE 3 - Primary Financial Assumptions

Cost of Electricity	-	5p/KWh
Coal Cost	-	£1.25/GJ
Oil Cost	-	£2.30/GJ
Gas Cost	-	£1.90/GJ
Reagent Cost (Anhydrous Ammonia)	-	£150/te
Catalyst Cost	-	£5000/m^3
Cost of Landfill Ash	-	£8.70/te (£26/te)*
Price of Saleable Ash	-	£3.00/te
Gas Pipeline Cost		£800,000/km
Capital Cost (LNB)	-	£6/KW
Capital Cost (aLNB)	-	£7/KW
Capital Cost (OFA)	-	£7/KW
Capital Cost (Reburn)	-	£10/KW
Capital Cost (SNCR)	-	£8.5/KW
Capital Cost (SCR)	-	£65/KW
Capital Cost (SNCR/SCR Hybrid)	-	£30/KW
Capital Cost (In-duct SCR/CAT-AH)	-	£37.5/KW

Notes: * Cost of Landfill Ash when contaminated
All capital costs, including gas pipeline costs, are assumed to include the capital carrying charges related to the capital investment.

Table 4 - Typical UK Coal Composition

Proximate Analysis	% As Rec'd
Moisture	13.0
Volatile Matter	27.18
Fixed Carbon	44.22
Ash	15.60

Ultimate Analysis	% As Rec'd
Moisture	13.00
C	58.90
H	3.62
S	1.61
Cl	0.30
N	1.43
O	5.54
Ash	15.60

Table 5 - Heavy Fuel Oil Composition

Ultimate Analysis	% As Rec'd
Moisture	0.00
C	85.40
H	11.40
S	2.80
Cl	0.00
N	0.30
O	0.10
Ash	0.00

Table 6 - Typical Composition of Natural Gas

Ultimate Analysis	% As Rec'd
Moisture	0.00
C	73.00
H	23.60
S	0.00
Cl	0.00
N	3.30
O	0.00
Ash	0.00

Table 7 - Minimum Residence Times for NO_x Control Technologies

NO_x Control Technology	Location	Minimum Residence time(s)
OFA	Primary Furnace Zone	0.5
	Burnout Zone	0.7
Reburn	Primary Furnace Zone	0.4
	Reburn Zone	0.2 (gas)
		0.4 (oil)
		0.5 (coal)
	Burnout Zone	0.7
SNCR	Convective Banks	0.3
SCR	Catalyst Reactor	0.5

Table 8 - Typical NO_x Reduction Efficiencies for Combustion and Post-Combustion Technologies

	% NO_x Reduction
LNB from uncontrolled	40
aLNB from uncontrolled	52
aLNB from LNB	20
OFA from LNB	20
Reburn from LNB	50
FGR (oil-fired only) from uncontrolled	40
SNCR from LNB	40
SCR from LNB	80
SNCR/SCR Hybrid from LNB	50
In-duct SCR/CAT-AH from LNB	50

Table 9 - Details of NOx reduction costs per technology at Aberthaw Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOX Removed
Reburn - Gas	10	5	0.956	6311.49
"	10	10	0.629	4154.13
"	10	15	0.517	3418.11
"	40	5	0.354	2340.11
"	40	10	0.298	1966.14
"	40	15	0.290	1913.77
"	75	5	0.261	1722.34
"	75	10	0.246	1625.78
"	75	15	0.254	1679.76
SNCR	10	5	0.565	4676.92
"	10	10	0.537	4443.52
"	10	15	0.556	4604.99
"	40	5	0.395	3271.48
"	40	10	0.443	3669.21
"	40	15	0.492	4072.61
"	75	5	0.369	3052.86
"	75	10	0.429	3548.76
"	75	15	0.482	3989.80
SCR	10	5	2.169	8980.90
"	10	10	1.278	5289.73
"	10	15	0.947	3920.69
"	40	5	0.635	2630.12
"	40	10	0.433	1790.83
"	40	15	0.366	1515.04
"	75	5	0.397	1642.22
"	75	10	0.301	1246.56
"	75	15	0.276	1140.83
SNCR-SCR Hybrid	10	5	1.098	7275.68
"	10	10	0.755	5004.04
"	10	15	0.643	4258.24
"	40	5	0.445	2946.64
"	40	10	0.395	2614.99
"	40	15	0.395	2618.41
"	75	5	0.343	2273.23
"	75	10	0.339	2243.99
"	75	15	0.357	2363.33
In-duct SCR/Cat- AH	10	5	1.381	9146.91
"	10	10	0.934	6184.84
"	10	15	0.782	5178.03
"	40	5	0.462	3057.53
"	40	10	0.374	2479.62
"	40	15	0.356	2357.35
"	75	5	0.319	2110.29
"	75	10	0.287	1903.25
"	75	15	0.290	1918.58

Table 10 - Details of NOx reduction costs per technology at Blythe A Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.175	1395.68
"	10	10	0.097	773.58
"	10	15	0.067	535.73
"	40	5	0.044	354.15
"	40	10	0.025	199.76
"	40	15	0.018	141.20
"	75	5	0.024	192.13
"	75	10	0.014	110.50
"	75	15	0.01	79.83
Adv.Low Nox Burners	10	5	0.187	1147.79
"	10	10	0.104	635.93
"	10	15	0.072	440.20
"	40	5	0.047	290.97
"	40	10	0.027	163.88
"	40	15	0.019	115.64
"	75	5	0.026	157.69
"	75	10	0.015	90.45
"	75	15	0.011	65.15
Overfire Air	10	5	0.511	12249.42
"	10	10	0.327	7827.15
"	10	15	0.262	6276.87
"	40	5	0.179	4276.81
"	40	10	0.143	3434.71
"	40	15	0.136	3256.87
"	75	5	0.127	3036.63
"	75	10	0.115	2751.45
"	75	15	0.116	2787.09
Reburn - Coal	10	5	0.404	3447.10
SNCR	10	5	0.589	7215.25
"	10	10	0.566	6932.76
"	10	15	0.589	7222.03
"	40	5	0.419	5134.40
"	40	10	0.472	5786.34
"	40	15	0.525	6433.82
"	75	5	0.392	4810.72
"	75	10	0.457	5608.00
"	75	15	0.515	6311.21
SCR	10	5	2.181	13365.78
"	10	10	1.291	7915.73
"	10	15	0.963	5900.70
"	40	5	0.647	3963.04
"	40	10	0.446	2735.39
"	40	15	0.382	2338.97
"	75	5	0.408	2500.40
"	75	10	0.315	1929.55
"	75	15	0.291	1784.92
SNCR-SCR Hybrid	10	5	1.108	10861.95
"	10	10	0.766	7512.21
"	10	15	0.656	6429.44
"	40	5	0.454	4452.52
"	40	10	0.406	3980.99
"	40	15	0.408	4001.56
"	75	5	0.352	3455.49
"	75	10	0.350	3431.69
"	75	15	0.370	3623.90
In-duct SCR/Cat- AH	10	5	1.262	12381.33
"	10	10	0.810	7943.76
"	10	15	0.652	6391.00
"	40	5	0.446	4369.53
"	40	10	0.360	3529.74
"	40	15	0.342	3356.16
"	75	5	0.318	3123.25
"	75	10	0.290	2843.12
"	75	15	0.294	2884.07

Table 11 - Details of NOx reduction cost per technology at Blythe B Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.175	1533.04
"	10	10	0.097	849.71
"	10	15	0.067	588.45
"	40	5	0.044	389.00
"	40	10	0.025	219.42
"	40	15	0.018	155.09
"	75	5	0.024	211.04
"	75	10	0.014	121.37
"	75	15	0.01	87.68
Adv.Low Nox Burners	10	5	0.187	1260.74
"	10	10	0.104	698.52
"	10	15	0.072	483.52
"	40	5	0.047	319.60
"	40	10	0.027	180.01
"	40	15	0.019	127.02
"	75	5	0.026	173.20
"	75	10	0.015	99.35
"	75	15	0.011	71.56
Overfire Air	10	5	0.279	7347.24
"	10	10	0.172	4539.41
"	10	15	0.134	3529.13
"	40	5	0.091	2390.32
"	40	10	0.069	1808.45
"	40	15	0.063	1651.47
"	75	5	0.062	1619.25
"	75	10	0.053	1383.63
"	75	15	0.052	1359.38
Reburn - Coal	10	5	0.338	3407.42
SNCR	10	5	0.583	7855.12
"	10	10	0.559	7529.60
"	10	15	0.582	7835.22
"	40	5	0.414	5569.49
"	40	10	0.466	6270.35
"	40	15	0.518	6969.43
"	75	5	0.387	5213.95
"	75	10	0.451	6074.47
"	75	15	0.508	6834.75
SCR	10	5	2.176	14649.78
"	10	10	1.286	8656.56
"	10	15	0.956	6437.79
"	40	5	0.642	4321.68
"	40	10	0.441	2966.39
"	40	15	0.375	2525.54
"	75	5	0.403	2715.08
"	75	10	0.309	2081.25
"	75	15	0.285	1916.96
SNCR-SCR Hybrid	10	5	1.103	11882.16
"	10	10	0.760	8192.17
"	10	15	0.649	6994.42
"	40	5	0.449	4841.94
"	40	10	0.400	4313.43
"	40	15	0.402	4327.61
"	75	5	0.348	3746.80
"	75	10	0.344	3710.07
"	75	15	0.363	3912.77
In-duct SCR/Cat- AH	10	5	1.254	13511.01
"	10	10	0.800	8617.44
"	10	15	0.640	6896.52
"	40	5	0.437	4710.73
"	40	10	0.350	3769.02
"	40	15	0.331	3563.00
"	75	5	0.310	3341.80
"	75	10	0.280	3014.82
"	75	15	0.283	3044.46

Table 12 - Details of NOx reduction costs per technology at Cottam Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4511.47
"	10	10	0.104	2499.59
"	10	15	0.072	1730.24
"	40	5	0.047	1143.68
"	40	10	0.027	644.14
"	40	15	0.019	454.53
"	75	5	0.026	619.80
"	75	10	0.015	355.51
"	75	15	0.011	256.08
Overfire Air	10	5	0.233	5490.80
"	10	10	0.142	3342.04
"	10	15	0.109	2560.94
"	40	5	0.073	1729.61
"	40	10	0.054	1269.85
"	40	15	0.048	1136.21
"	75	5	0.049	1144.54
"	75	10	0.040	947.51
"	75	15	0.039	914.59
Reburn - Coal	10	5	0.325	2992.71
"	10	10	0.202	1858.17
"	10	15	0.157	1451.40
"	40	5	0.107	983.95
"	40	10	0.081	751.46
"	40	15	0.075	690.48
"	75	5	0.073	671.47
"	75	10	0.063	579.30
"	75	15	0.062	572.12
Reburn - Gas	10	5	0.679	6561.42
"	10	10	0.468	4520.51
"	10	15	0.398	3847.98
"	40	5	0.278	2685.23
"	40	10	0.247	2384.96
"	40	15	0.246	2379.69
"	75	5	0.216	2082.27
"	75	10	0.212	2052.76
"	75	15	0.223	2151.29
Reburn - Oil	40	10	0.365	3504.85
SNCR	10	5	0.593	7140.25
"	10	10	0.571	6873.56
"	10	15	0.595	7166.49
"	40	5	0.423	5059.52
"	40	10	0.477	5747.04
"	40	15	0.531	6391.96
"	75	5	0.397	4777.45
"	75	10	0.463	5571.80
"	75	15	0.521	6271.47
SCR	10	5	2.183	13146.04
"	10	10	1.294	7793.22
"	10	15	0.965	5815.27
"	40	5	0.649	3906.48
"	40	10	0.449	2702.78
"	40	15	0.384	2315.35
"	75	5	0.410	2469.22
"	75	10	0.317	1910.93
"	75	15	0.294	1770.92
SNCR-SCR Hybrid	10	5	1.109	10953.50
"	10	10	0.768	7584.62
"	10	15	0.658	6497.44
"	40	5	0.456	4500.26
"	40	10	0.408	4029.27
"	40	15	0.410	4052.97
"	75	5	0.354	3496.42
"	75	10	0.352	3476.21
"	75	15	0.372	3672.72
In-duct SCR/Cat- AH	10	5	1.259	12134.83
"	10	10	0.806	7767.42
"	10	15	0.647	6236.13
"	40	5	0.442	4262.07
"	40	10	0.356	3429.99
"	40	15	0.338	3253.96
"	75	5	0.315	3037.42
"	75	10	0.286	2755.28
"	75	15	0.290	2790.06

Note: Low NO_X burners already fitted at Cottam Power Station

Table 13 - Details of NOx reduction costs per technology at Didcot Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4945.35
"	10	10	0.104	2739.98
"	10	15	0.072	1896.64
"	40	5	0.047	1253.67
"	40	10	0.027	706.08
"	40	15	0.019	498.24
"	75	5	0.026	679.41
"	75	10	0.015	389.70
"	75	15	0.011	280.71
Overfire Air	10	5	0.271	7001.69
"	10	10	0.172	4430.95
"	10	15	0:136	3522.56
"	40	5	0.093	2396.18
"	40	10	0.073	1893.59
"	40	15	0.069	1778.00
"	75	5	0.065	1679.77
"	75	10	0.058	1498.89
"	75	15	0.058	1506.63
Reburn - Coal	10	5	0.435	4375.84
"	10	10	0.271	2728.27
"	10	15	0.212	2139.35
"	40	5	0.144	1451.43
"	40	10	0.111	1117.09
"	40	15	0.102	1031.59
"	75	5	0.099	996.52
"	75	10	0.086	866.46
"	75	15	0.085	859.27
Reburn - Gas	10	5	0.650	6877.91
"	10	10	0.464	4905.45
"	10	15	0.406	4299.35
"	40	5	0.281	2976.37
"	40	10	0.261	2755.93
"	40	15	0.267	2821.46
"	75	5	0.224	2369.46
"	75	10	0.229	2421.56
"	75	15	0.245	2591.57
Reburn - Oil	40	10	0.389	4086.87
SNCR	10	5	0.629	8300.71
"	10	10	0.614	8111.14
"	10	15	0.645	8514.06
"	40	5	0.459	6059.33
"	40	10	0.521	6876.28
"	40	15	0.580	7665.03
"	75	5	0.432	5710.67
"	75	10	0.506	6684.19
"	75	15	0.570	7532.96
SCR	10	5	2.199	14519.70
"	10	10	1.314	8675.81
"	10	15	0.988	6526.51
"	40	5	0.665	4391.54
"	40	10	0.469	3095.79
"	40	15	0.407	2689.99
"	75	5	0.427	2816.05
"	75	10	0.337	2227.79
"	75	15	0.317	2093.20
SNCR-SCR Hybrid	10	5	1.126	11896.89
"	10	10	0.789	8331.43
"	10	15	0.682	7201.99
"	40	5	0.473	4992.96
"	40	10	0.429	4527.77
"	40	15	0.434	4586.22
"	75	5	0.371	3919.01
"	75	10	0.373	3936.09
"	75	15	0.396	4179.33
In-duct SCR/Cat- AH	10	5	1.276	13483.72
"	10	10	0.827	8735.71
"	10	15	0.671	7088.56
"	40	5	0.459	4853.80
"	40	10	0.377	3981.15
"	40	15	0.362	3819.58
"	75	5	0.332	3511.37
"	75	10	0.307	3241.55
"	75	15	0.313	3311.07

Note: Low NO_X burners already fitted at Didcot Power Station

Table 14 - Details of NOx reduction costs per technology at Drakelow C Power Station - U 9&1

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4374.38
"	10	10	0.104	2423.63
"	10	15	0.072	1677.66
"	40	5	0.047	1108.92
"	40	10	0.027	624.56
"	40	15	0.019	440.72
"	75	5	0.026	600.96
"	75	10	0.015	344.71
"	75	15	0.011	248.30
Overfire Air	10	5	0.180	4110.96
Reburn - Coal	10	5	0.336	2963.12
SNCR	10	5	0.602	7033.89
"	10	10	0.582	6799.29
"	10	15	0.608	7102.42
"	40	5	0.432	5051.29
"	40	10	0.489	5707.00
"	40	15	0.544	6351.42
"	75	5	0.406	4742.88
"	75	10	0.474	5537.09
"	75	15	0.534	6234.60
SCR	10	5	2.189	12781.86
"	10	10	1.301	7599.35
"	10	15	0.974	5687.59
"	40	5	0.655	3823.06
"	40	10	0.456	2663.59
"	40	15	0.393	2294.03
"	75	5	0.416	2429.47
"	75	10	0.325	1895.81
"	75	15	0.302	1766.14
SNCR-SCR Hybrid	10	5	1.115	10423.54
"	10	10	0.776	7248.09
"	10	15	0.667	6229.29
"	40	5	0.462	4316.71
"	40	10	0.416	3883.59
"	40	15	0.419	3916.05
"	75	5	0.360	3366.76
"	75	10	0.360	3360.23
"	75	15	0.381	3556.21
In-duct SCR/Cat- AH	10	5	1.265	11825.17
"	10	10	0.814	7603.29
"	10	15	0.656	6128.74
"	40	5	0.449	4191.64
"	40	10	0.364	3397.67
"	40	15	0.346	3237.18
"	75	5	0.322	3004.21
"	75	10	0.294	2743.46
"	75	15	0.298	2787.39

Note: Low NO_X burners already fitted at Drakelow C - Units 9 and 10

Table 15 - Details of NOx reduction costs per technology at Drakelow C Power Station - U12

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4291.62
"	10	10	0.104	2377.78
"	10	15	0.072	1645.92
"	40	5	0.047	1087.94
"	40	10	0.027	612.75
"	40	15	0.019	432.38
"	75	5	0.026	589.59
"	75	10	0.015	338.19
"	75	15	0.011	243.60
Overfire Air	10	5	0.170	3796.19
Reburn - Coal	10	5	0.338	2917.36
SNCR	10	5	0.599	6862.51
"	10	10	0.578	6624.05
"	10	15	0.603	6914.83
"	40	5	0.429	4917.42
"	40	10	0.485	5552.42
"	40	15	0.539	6178.03
"	75	5	0.403	4614.85
"	75	10	0.470	5385.72
"	75	15	0.529	6063.42
SCR	10	5	2.186	12527.20
"	10	10	1.298	7439.96
"	10	15	0.971	5526.15
"	40	5	0.652	3737.89
"	40	10	0.453	2597.57
"	40	15	0.390	2232.79
"	75	5	0.414	2370.67
"	75	10	0.322	1844.31
"	75	15	0.299	1714.89
SNCR-SCR Hybrid	10	5	1.114	10208.08
"	10	10	0.773	7088.74
"	10	15	0.664	6086.07
"	40	5	0.460	4216.79
"	40	10	0.413	3787.90
"	40	15	0.416	3816.59
"	75	5	0.358	3284.81
"	75	10	0.357	3274.44
"	75	15	0.378	3463.56
In-duct SCR/Cat- AH	10	5	1.264	11583.46
"	10	10	0.811	7437.54
"	10	15	0.653	5987.78
"	40	5	0.447	4094.34
"	40	10	0.361	3311.48
"	40	15	0.344	3150.93
"	75	5	0.320	2929.37
"	75	10	0.291	2669.65
"	75	15	0.296	2709.64

Note: Low NO_X burners already fitted at Drakelow C - Unit 12

Table 16 - Details of NOx reduction costs per technology at Drax Power Station -U1,2&3

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4329.41
"	10	10	0.104	2398.72
"	10	15	0.072	1660.41
"	40	5	0.047	1097.52
"	40	10	0.027	618.14
"	40	15	0.019	436.19
"	75	5	0.026	594.79
"	75	10	0.015	341.16
"	75	15	0.011	245.75
Overfire Air	10	5	0.158	3566.60
"	10	10	0.098	2216.96
"	10	15	0.077	1733.46
"	40	5	0.052	1175.41
"	40	10	0.040	899.56
"	40	15	0.037	827.68
"	75	5	0.036	803.44
"	75	10	0.031	694.63
"	75	15	0.030	686.78
Reburn - Coal	10	5	0.319	2834.07
"	10	10	0.194	1728.80
"	10	15	0.149	1327.60
"	40	5	0.101	897.02
"	40	10	0.074	661.59
"	40	15	0.067	593.85
"	75	5	0.067	595.70
"	75	10	0.056	495.59
"	75	15	0.054	479.71
Reburn - Gas	10	5	0.473	4382.87
"	10	10	0.373	3454.20
"	10	15	0.349	3230.24
"	40	5	0.246	2282.59
"	40	10	0.248	2297.08
"	40	15	0.263	2434.66
"	75	5	0.211	1955.88
"	75	10	0.228	2117.08
"	75	15	0.249	2310.90
Reburn - Oil	40	10	0.339	3120.74
SNCR	10	5	0.605	6995.91
"	10	10	0.586	6771.17
"	10	15	0.612	7077.11
"	40	5	0.435	5033.69
"	40	10	0.492	5690.11
"	40	15	0.548	6333.83
"	75	5	0.409	4728.45
"	75	10	0.478	5521.94
"	75	15	0.538	6218.21
SCR	10	5	2.188	12646.68
"	10	10	1.300	7516.62
"	10	15	0.973	5623.86
"	40	5	0.654	3779.98
"	40	10	0.455	2631.60
"	40	15	0.392	2265.19
"	75	5	0.415	2400.71
"	75	10	0.324	1871.71
"	75	15	0.302	1742.73
SNCR-SCR Hybrid	10	5	1.115	10316.16
"	10	10	0.776	7173.30
"	10	15	0.667	6164.94
"	40	5	0.462	4272.11
"	40	10	0.416	3843.39
"	40	15	0.419	3875.48
"	75	5	0.360	3331.93
"	75	10	0.360	3325.41
"	75	15	0.381	3519.34
In-duct SCR/Cat- AH	10	5	1.264	11692.32
"	10	10	0.812	7511.38
"	10	15	0.654	6050.04
"	40	5	0.447	4137.26
"	40	10	0.362	3348.99
"	40	15	0.345	3188.20
"	75	5	0.320	2962.03
"	75	10	0.292	2701.51
"	75	15	0.297	2743.03

Note: Low NO_X burners already fitted at Drax Power Station - Units 1, 2 and 3

Table 17 - Details of NOx reduction costs per technology at Drax Power Station - U4, 5&6

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4329.41
"	10	10	0.104	2398.72
"	10	15	0.072	1660.41
"	40	5	0.047	1097.52
"	40	10	0.027	618.14
"	40	15	0.019	436.19
"	75	5	0.026	594.79
"	75	10	0.015	341.16
"	75	15	0.011	245.75
Overfire Air	10	5	0.158	3566.60
"	10	10	0.098	2216.96
"	10	15	0.077	1733.46
"	40	5	0.052	1175.41
"	40	10	0.040	899.56
"	40	15	0.037	827.68
"	75	5	0.036	803.44
"	75	10	0.031	694.63
"	75	15	0.030	686.78
Reburn - Coal	10	5	0.319	2834.07
"	10	10	0.194	1728.80
"	10	15	0.149	1327.60
"	40	5	0.101	897.02
"	40	10	0.074	661.59
"	40	15	0.067	593.85
"	75	5	0.067	595.70
"	75	10	0.056	495.59
"	75	15	0.054	479.71
Reburn - Gas	10	5	0.473	4382.87
"	10	10	0.373	3454.20
"	10	15	0.349	3230.24
"	40	5	0.246	2282.59
"	40	10	0.248	2297.08
"	40	15	0.263	2434.66
"	75	5	0.211	1955.88
"	75	10	0.228	2117.08
"	75	15	0.249	2310.90
Reburn - Oil	40	10	0.339	3120.74
SNCR	10	5	0.605	6995.91
"	10	10	0.586	6771.17
"	10	15	0.612	7077.11
"	40	5	0.435	5033.69
"	40	10	0.492	5690.11
"	40	15	0.548	6333.83
"	75	5	0.409	4728.45
"	75	10	0.478	5521.94
"	75	15	0.538	6218.21
SCR	10	5	2.188	12646.68
"	10	10	1.300	7516.62
"	10	15	0.973	5623.86
"	40	5	0.654	3779.98
"	40	10	0.455	2631.60
"	40	15	0.392	2265.19
"	75	5	0.415	2400.71
"	75	10	0.324	1871.71
"	75	15	0.302	1742.73
SNCR-SCR Hybrid	10	5	1.115	10316.16
"	10	10	0.776	7173.30
"	10	15	0.667	6164.94
"	40	5	0.462	4272.11
"	40	10	0.416	3843.39
"	40	15	0.419	3875.48
"	75	5	0.360	3331.93
"	75	10	0.360	3325.41
"	75	15	0.381	3519.34
In-duct SCR/Cat- AH	10	5	1.264	11692.32
"	10	10	0.812	7511.38
"	10	15	0.654	6050.04
"	40	5	0.447	4137.26
"	40	10	0.362	3348.99
"	40	15	0.345	3188.20
"	75	5	0.320	2962.03
"	75	10	0.292	2701.51
"	75	15	0.297	2743.03

Note: Low NO_X burners already fitted at Drax Power Station - Units 4, 5 and 6

Table 18 - Details of NOx reduction costs per technology at Eggborough Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4588.72
"	10	10	0.104	2542.39
"	10	15	0.072	1759.86
"	40	5	0.047	1163.26
"	40	10	0.027	655.17
"	40	15	0.019	462.31
"	75	5	0.026	630.41
"	75	10	0.015	361.60
"	75	15	0.011	260.47
Overfire Air	10	5	0.247	4736.46
"	10	10	0.159	3046.18
"	10	15	0.128	2456.92
"	40	5	0.087	1675.86
"	40	10	0.071	1359.97
"	40	15	0.068	1297.58
"	75	5	0.063	1199.77
"	75	10	0.057	1097.67
"	75	15	0.058	1117.24
Reburn - Coal	10	5	0.406	3804.11
"	10	10	0.253	2368.66
"	10	15	0.198	1855.06
"	40	5	0.134	1258.25
"	40	10	0.103	966.04
"	40	15	0.095	890.70
"	75	5	0.092	862.23
"	75	10	0.080	747.86
"	75	15	0.079	740.68
Reburn - Gas	10	5	0.638	6263.92
"	10	10	0.461	4521.38
"	10	15	0.407	3997.27
"	40	5	0.282	2771.31
"	40	10	0.265	2597.16
"	40	15	0.273	2674.28
"	75	5	0.227	2228.01
"	75	10	0.234	2297.84
"	75	15	0.252	2468.49
Reburn - Oil	40	10	0.404	3937.79
SNCR	10	5	0.610	7477.58
"	10	10	0.592	7252.98
"	10	15	0.619	7588.07
"	40	5	0.441	5397.84
"	40	10	0.498	6107.17
"	40	15	0.555	6800.27
"	75	5	0.414	5074.32
"	75	10	0.484	5928.93
"	75	15	0.545	6677.72
SCR	10	5	2.192	13426.28
"	10	10	1.305	7993.77
"	10	15	0.978	5991.47
"	40	5	0.658	4028.51
"	40	10	0.460	2816.16
"	40	15	0.397	2431.62
"	75	5	0.419	2566.64
"	75	10	0.328	2010.76
"	75	15	0.307	1877.87
SNCR-SCR Hybrid	10	5	1.119	10963.90
"	10	10	0.779	7639.28
"	10	15	0.671	6575.68
"	40	5	0.465	4557.85
"	40	10	0.419	4109.93
"	40	15	0.423	4149.09
"	75	5	0.363	3561.35
"	75	10	0.363	3560.92
"	75	15	0.385	3771.62
In-duct SCR/Cat- AH	10	5	1.268	12430.74
"	10	10	0.817	8007.66
"	10	15	0.660	6465.37
"	40	5	0.451	4423.17
"	40	10	0.367	3595.96
"	40	15	0.350	3432.13
"	75	5	0.324	3177.55
"	75	10	0.297	2909.70
"	75	15	0.302	2960.29

Note: Low NO_X burners already fitted at Eggborough Power Station

Table 19 - Details of NOx reduction costs per technology at Fawley Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.175	1488.42
"	10	10	0.097	824.98
"	10	15	0.067	571.32
"	40	5	0.044	377.68
"	40	10	0.025	213.03
"	40	15	0.018	150.58
"	75	5	0.024	204.90
"	75	10	0.014	117.84
"	75	15	0.01	85.13
Adv.Low Nox Burners	10	5	0.187	1224.08
"	10	10	0.104	678.20
"	10	15	0.072	469.46
"	40	5	0.047	310.31
"	40	10	0.027	174.77
"	40	15	0.019	123.33
"	75	5	0.026	168.17
"	75	10	0.015	96.46
"	75	15	0.011	69.48
Overfire Air	10	5	0.236	6527.20
Reburn - Oil	10	5	0.321	3609.85
Flue Gas Recycle	10	5	0.040	283.13
"	10	10	0.029	207.56
"	10	15	0.026	185.53
"	40	5	0.018	128.86
"	40	10	0.017	122.57
"	40	15	0.018	127.09
"	75	5	0.015	104.86
"	75	10	0.015	109.35
"	75	15	0.017	118.00
SNCR	10	5	0.541	7655.35
"	10	10	0.508	7182.98
"	10	15	0.523	7400.50
"	40	5	0.371	5253.16
"	40	10	0.414	5859.51
"	40	15	0.459	6490.56
"	75	5	0.345	4879.48
"	75	10	0.399	5653.64
"	75	15	0.449	6349.01
SCR	10	5	2.157	15264.59
"	10	10	1.263	8937.01
"	10	15	0.930	6582.24
"	40	5	0.623	4409.76
"	40	10	0.418	2956.64
"	40	15	0.349	2470.46
"	75	5	0.385	2721.23
"	75	10	0.286	2026.36
"	75	15	0.259	1830.85
SNCR-SCR Hybrid	10	5	1.083	12266.39
"	10	10	0.737	8340.10
"	10	15	0.622	7042.97
"	40	5	0.430	4867.12
"	40	10	0.377	4263.54
"	40	15	0.375	4240.15
"	75	5	0.328	3716.12
"	75	10	0.321	3629.41
"	75	15	0.336	3804.15
In-duct SCR/Cat- AH	10	5	1.234	13973.09
"	10	10	0.776	8780.72
"	10	15	0.612	6932.83
"	40	5	0.417	4724.00
"	40	10	0.325	3685.02
"	40	15	0.303	3429.31
"	75	5	0.290	3285.25
"	75	10	0.255	2892.36
"	75	15	0.255	2884.31

Table 20 - Details of NOx reduction costs per technology at Ferrybridge C Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.294	7784.90
"	10	10	0.169	4480.19
"	10	15	0.122	3239.06
"	40	5	0.082	2161.51
"	40	10	0.052	1382.04
"	40	15	0.042	1108.94
"	75	5	0.049	1286.76
"	75	10	0.034	900.11
"	75	15	0.029	777.58
Overfire Air	10	5	0.268	6940.69
"	10	10	0.168	4346.50
"	10	15	0.132	3422.29
"	40	5	0.090	2323.68
"	40	10	0.070	1802.80
"	40	15	0.065	1673.38
"	75	5	0.062	1605.47
"	75	10	0.054	1407.12
"	75	15	0.054	1401.32
Reburn - Coal	10	5	0.432	4354.06
"	10	10	0.267	2696.52
"	10	15	0.208	2101.13
"	40	5	0.141	1423.75
"	40	10	0.107	1082.10
"	40	15	0.098	991.14
"	75	5	0.096	967.93
"	75	10	0.082	830.97
"	75	15	0.081	818.48
Reburn - Gas	10	5	0.751	7954.86
"	10	10	0.517	5479.72
"	10	15	0.441	4678.37
"	40	5	0.304	3224.15
"	40	10	0.271	2873.38
"	40	15	0.272	2886.39
"	75	5	0.235	2488.26
"	75	10	0.233	2467.95
"	75	15	0.246	2607.64
Reburn - Oil	40	10	0.385	4056.55
SNCR	10	5	0.590	7808.01
"	10	10	0.567	7506.61
"	10	15	0.591	7821.88
"	40	5	0.420	5561.06
"	40	10	0.474	6268.67
"	40	15	0.527	6970.74
"	75	5	0.394	5211.53
"	75	10	0.459	6076.11
"	75	15	0.517	6838.34
SCR	10	5	2.180	14427.36
"	10	10	1.290	8541.08
"	10	15	0.962	6364.26
"	40	5	0.646	4274.03
"	40	10	0.445	2947.20
"	40	15	0.380	2518.21
"	75	5	0.407	2694.62
"	75	10	0.314	2077.04
"	75	15	0.290	1919.94
SNCR-SCR Hybrid	10	5	1.107	11720.90
"	10	10	0.765	8101.99
"	10	15	0.655	6931.38
"	40	5	0.453	4799.81
"	40	10	0.405	4288.88
"	40	15	0.407	4309.69
"	75	5	0.352	3723.20
"	75	10	0.349	3695.73
"	75	15	0.368	3901.87
In-duct SCR/Cat- AH	10	5	1.257	13311.86
"	10	10	0.803	8507.50
"	10	15	0.644	6820.79
"	40	5	0.440	4660.50
"	40	10	0.353	3741.12
"	40	15	0.335	3543.68
"	75	5	0.313	3314.73
"	75	10	0.283	2999.68
"	75	15	0.286	3033.91

Note: Low NO_X burners already fitted at Ferrybridge C Power Station

Table 21 - Details of NOx reduction costs per technology at Fiddler's Ferry Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.195	7570.14
"	10	10	0.113	4387.42
"	10	15	0.082	3196.48
"	40	5	0.055	2136.59
"	40	10	0.036	1393.86
"	40	15	0.029	1138.27
"	75	5	0.033	1291.37
"	75	10	0.024	928.19
"	75	15	0.021	818.10
Overfire Air	10	5	0.169	6418.58
"	10	10	0.112	4241.02
"	10	15	0.092	3501.00
"	40	5	0.063	2398.29
"	40	10	0.053	2026.08
"	40	15	0.052	1978.13
"	75	5	0.047	1772.91
"	75	10	0.044	1681.53
"	75	15	0.046	1741.24
Reburn - Coal	10	5	0.328	4831.38
"	10	10	0.206	3029.39
"	10	15	0.162	2388.02
"	40	5	0.110	1621.79
"	40	10	0.086	1261.10
"	40	15	0.080	1172.24
"	75	5	0.076	1122.52
"	75	10	0.067	986.03
"	75	15	0.067	983.12
Reburn - Gas	10	5	0.548	8521.92
"	10	10	0.391	6086.27
"	10	15	0.343	5339.59
"	40	5	0.238	3697.13
"	40	10	0.220	3428.10
"	40	15	0.226	3511.97
"	75	5	0.189	2946.61
"	75	10	0.194	3014.60
"	75	15	0.207	3227.68
Reburn - Oil	40	10	0.325	5027.51
SNCR	10	5	0.574	11161.54
"	10	10	0.548	10653.50
"	10	15	0.569	11064.20
"	40	5	0.405	7862.60
"	40	10	0.455	8835.98
"	40	15	0.505	9814.58
"	75	5	0.378	7349.43
"	75	10	0.440	8553.25
"	75	15	0.495	9620.19
SCR	10	5	2.168	21066.45
"	10	10	1.276	12399.22
"	10	15	0.945	9183.28
"	40	5	0.634	6159.47
"	40	10	0.431	4186.36
"	40	15	0.364	3536.56
"	75	5	0.395	3840.60
"	75	10	0.299	2908.80
"	75	15	0.274	2658.18
SNCR-SCR Hybrid	10	5	1.095	17019.29
"	10	10	0.750	11665.01
"	10	15	0.638	9913.68
"	40	5	0.441	6857.85
"	40	10	0.390	6066.66
"	40	15	0.390	6064.55
"	75	5	0.339	5277.18
"	75	10	0.334	5195.81
"	75	15	0.352	5465.80
In-duct SCR/Cat- AH	10	5	1.247	19390.10
"	10	10	0.791	12302.96
"	10	15	0.630	9799.94
"	40	5	0.430	6688.30
"	40	10	0.341	5305.03
"	40	15	0.321	4988.53
"	75	5	0.303	4712.46
"	75	10	0.271	4216.46
"	75	15	0.273	4240.09

Note: Low NO_X burners already fitted at Fiddler's Ferry Power Station

Table 22 - Details of NOx reduction costs per technology at Grain Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.175	1870.31
"	10	10	0.097	1036.65
"	10	15	0.067	717.91
"	40	5	0.044	474.58
"	40	10	0.025	267.69
"	40	15	0.018	189.21
"	75	5	0.024	257.47
"	75	10	0.014	148.07
"	75	15	0.01	106.97
Adv.Low Nox Burners	10	5	0.187	1538.14
"	10	10	0.104	852.21
"	10	15	0.072	589.91
"	40	5	0.047	389.93
"	40	10	0.027	219.61
"	40	15	0.019	154.97
"	75	5	0.026	211.31
"	75	10	0.015	121.21
"	75	15	0.011	87.31
Overfire Air	10	5	0.212	7369.55
Reburn - Oil	10	5	0.314	4444.80
Flue Gas Recycle	10	5	0.037	330.72
"	10	10	0.026	230.33
"	10	15	0.022	198.31
"	40	5	0.015	136.87
"	40	10	0.014	123.53
"	40	15	0.014	124.88
"	75	5	0.012	106.72
"	75	10	0.012	106.92
"	75	15	0.013	113.46
SNCR	10	5	0.539	9596.29
"	10	10	0.505	8993.38
"	10	15	0.520	9260.48
"	40	5	0.369	6572.91
"	40	10	0.411	7327.68
"	40	15	0.456	8115.24
"	75	5	0.343	6102.61
"	75	10	0.397	7068.57
"	75	15	0.446	7937.09
SCR	10	5	2.153	19172.23
"	10	10	1.258	11199.81
"	10	15	0.924	8229.28
"	40	5	0.619	5510.46
"	40	10	0.412	3672.99
"	40	15	0.343	3054.25
"	75	5	0.380	3385.29
"	75	10	0.281	2502.15
"	75	15	0.253	2249.24
SNCR-SCR Hybrid	10	5	1.079	15376.02
"	10	10	0.731	10420.91
"	10	15	0.616	8777.59
"	40	5	0.426	6063.38
"	40	10	0.371	5290.20
"	40	15	0.368	5250.00
"	75	5	0.324	4614.74
"	75	10	0.315	4492.09
"	75	15	0.330	4701.26
In-duct SCR/Cat- AH	10	5	1.231	17536.81
"	10	10	0.771	10991.00
"	10	15	0.608	8656.71
"	40	5	0.414	5896.01
"	40	10	0.321	4577.61
"	40	15	0.298	4247.21
"	75	5	0.287	4085.22
"	75	10	0.251	3579.97
"	75	15	0.250	3561.29

Table 23 - Details of NOx reduction costs per technology at High Marnham Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4507.24
"	10	10	0.104	2497.25
"	10	15	0.072	1728.62
"	40	5	0.047	1142.60
"	40	10	0.027	643.53
"	40	15	0.019	454.10
"	75	5	0.026	619.22
"	75	10	0.015	355.18
"	75	15	0.011	255.84
Overfire Air	10	5	0.184	4324.28
"	10	10	0.130	3051.80
"	10	15	0.113	2653.99
"	40	5	0.078	1834.87
"	40	10	0.071	1680.29
"	40	15	0.073	1711.01
"	75	5	0.062	1447.63
"	75	10	0.062	1466.94
"	75	15	0.067	1564.32
Reburn - Coal	10	5	0.362	3190.44
SNCR	10	5	0.566	6807.56
"	10	10	0.538	6470.39
"	10	15	0.557	6706.74
"	40	5	0.396	4764.74
"	40	10	0.444	5344.92
"	40	15	0.493	5932.93
"	75	5	0.369	4446.97
"	75	10	0.430	5169.84
"	75	15	0.483	5812.56
SCR	10	5	2.170	13058.24
"	10	10	1.279	7694.07
"	10	15	0.948	5704.93
"	40	5	0.636	3827.34
"	40	10	0.433	2608.39
"	40	15	0.367	2208.29
"	75	5	0.397	2391.42
"	75	10	0.302	1817.28
"	75	15	0.277	1664.37
SNCR-SCR Hybrid	10	5	1.097	10560.59
"	10	10	0.753	7249.74
"	10	15	0.641	6169.00
"	40	5	0.443	4268.28
"	40	10	0.393	3783.05
"	40	15	0.393	3785.49
"	75	5	0.342	3289.48
"	75	10	0.337	3243.79
"	75	15	0.355	3414.72
In-duct SCR/Cat- AH	10	5	1.249	12024.20
"	10	10	0.793	7639.33
"	10	15	0.633	6092.34
"	40	5	0.432	4158.81
"	40	10	0.343	3305.97
"	40	15	0.323	3112.96
"	75	5	0.305	2935.31
"	75	10	0.273	2631.89
"	75	15	0.275	2649.50

Note: Low NO_X burners already fitted at High Marnham Power Station

Table 24 - Details of NOx reduction costs per technology at Ironbridge Power Station - U1

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4215.24
"	10	10	0.104	2335.46
"	10	15	0.072	1616.63
"	40	5	0.047	1068.58
"	40	10	0.027	601.84
"	40	15	0.019	424.68
"	75	5	0.026	579.10
"	75	10	0.015	332.17
"	75	15	0.011	239.27
Overfire Air	10	5	0.161	3552.07
"	10	10	0.103	2255.27
"	10	15	0.082	1798.26
"	40	5	0.056	1223.93
"	40	10	0.044	972.61
"	40	15	0.042	916.37
"	75	5	0.039	861.78
"	75	10	0.035	773.09
"	75	15	0.035	779.18
Reburn - Coal	10	5	0.325	2803.61
"	10	10	0.202	1742.03
"	10	15	0.158	1361.62
"	40	5	0.107	923.21
"	40	10	0.082	706.05
"	40	15	0.075	649.33
"	75	5	0.073	630.70
"	75	10	0.063	544.89
"	75	15	0.062	538.53
Reburn - Gas	10	5	1.100	9924.65
"	10	10	0.709	6394.50
"	10	15	0.572	5156.91
"	40	5	0.393	3543.41
"	40	10	0.319	2878.82
"	40	15	0.304	2739.72
"	75	5	0.283	2550.77
"	75	10	0.258	2331.93
"	75	15	0.262	2363.71
Reburn - Oil	40	10	0.398	3565.90
SNCR	10	5	0.617	6944.27
"	10	10	0.600	6754.28
"	10	15	0.629	7075.10
"	40	5	0.447	5033.80
"	40	10	0.507	5701.72
"	40	15	0.564	6351.42
"	75	5	0.421	4736.61
"	75	10	0.492	5537.99
"	75	15	0.554	6238.84
SCR	10	5	2.197	12363.79
"	10	10	1.311	7380.00
"	10	15	0.985	5545.90
"	40	5	0.663	3730.91
"	40	10	0.466	2623.80
"	40	15	0.404	2275.79
"	75	5	0.424	2388.02
"	75	10	0.335	1883.95
"	75	15	0.314	1767.11
SNCR-SCR Hybrid	10	5	1.124	10118.78
"	10	10	0.786	7075.00
"	10	15	0.678	6106.12
"	40	5	0.470	4234.12
"	40	10	0.426	3832.90
"	40	15	0.431	3877.03
"	75	5	0.369	3318.73
"	75	10	0.370	3328.58
"	75	15	0.392	3530.29
In-duct SCR/Cat- AH	10	5	1.273	11460.30
"	10	10	0.823	7406.17
"	10	15	0.666	5996.55
"	40	5	0.456	4104.47
"	40	10	0.372	3353.55
"	40	15	0.357	3210.18
"	75	5	0.329	2960.23
"	75	10	0.302	2723.14
"	75	15	0.308	2776.75

Note: Low NO_X burners already fitted at Ironbridge Power Station - Unit 1

Table 25 - Details of NOx reduction costs per technology at Ironbridge Power Station - U2

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.146	759.64
"	10	10	0.081	421.54
"	10	15	0.056	292.35
"	40	5	0.037	193.32
"	40	10	0.021	109.54
"	40	15	0.015	77.83
"	75	5	0.02	105.23
"	75	10	0.012	61.00
"	75	15	0.009	44.46
Adv.Low Nox Burners	10	5	0.187	748.91
"	10	10	0.104	414.93
"	10	15	0.072	287.22
"	40	5	0.047	189.85
"	40	10	0.027	106.93
"	40	15	0.019	75.45
"	75	5	0.026	102.89
"	75	10	0.015	59.01
"	75	15	0.011	42.51
Overfire Air	10	5	0.234	5123.21
"	10	10	0.143	3119.36
"	10	15	0.109	2391.09
"	40	5	0.074	1615.01
"	40	10	0.054	1186.55
"	40	15	0.049	1062.20
"	75	5	0.049	1069.29
"	75	10	0.040	885.89
"	75	15	0.039	855.48
Reburn - Coal	10	5	0.325	2792.02
"	10	10	0.202	1734.83
"	10	15	0.158	1355.99
"	40	5	0.107	919.39
"	40	10	0.082	703.13
"	40	15	0.075	646.65
"	75	5	0.073	628.10
"	75	10	0.063	542.64
"	75	15	0.062	536.31
Reburn - Gas	10	5	1.100	9881.91
"	10	10	0.709	6366.96
"	10	15	0.572	5134.71
"	40	5	0.393	3528.15
"	40	10	0.319	2866.42
"	40	15	0.304	2727.92
"	75	5	0.283	2539.79
"	75	10	0.258	2321.89
"	75	15	0.262	2353.53
Reburn - Oil	40	10	0.398	3550.64
SNCR	10	5	0.617	6909.83
"	10	10	0.600	6720.97
"	10	15	0.629	7040.29
"	40	5	0.447	5009.05
"	40	10	0.507	5673.75
"	40	15	0.564	6320.28
"	75	5	0.421	4713.37
"	75	10	0.492	5510.85
"	75	15	0.554	6208.28
SCR	10	5	2.197	12301.51
"	10	10	1.311	7343.07
"	10	15	0.986	5518.32
"	40	5	0.663	3712.38
"	40	10	0.466	2610.97
"	40	15	0.404	2264.79
"	75	5	0.424	2376.30
"	75	10	0.335	1874.86
"	75	15	0.314	1758.68
SNCR-SCR Hybrid	10	5	1.124	10068.26
"	10	10	0.786	7040.07
"	10	15	0.678	6076.23
"	40	5	0.470	4213.42
"	40	10	0.426	3814.40
"	40	15	0.431	3858.44
"	75	5	0.369	3302.67
"	75	10	0.370	3312.63
"	75	15	0.392	3513.45
In-duct SCR/Cat- AH	10	5	1.273	11460.30
"	10	10	0.823	7406.17
"	10	15	0.666	5996.55
"	40	5	0.456	4104.47
"	40	10	0.372	3353.55
"	40	15	0.357	3210.18
"	75	5	0.329	2960.23
"	75	10	0.302	2723.14
"	75	15	0.308	2776.75

Table 26 - Details of NOx reduction costs per technology at Kingsnorth Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	5402.92
"	10	10	0.104	2993.50
"	10	15	0.072	2072.13
"	40	5	0.047	1369.66
"	40	10	0.027	771.42
"	40	15	0.019	544.34
"	75	5	0.026	742.27
"	75	10	0.015	425.76
"	75	15	0.011	306.69
Overfire Air	10	5	0.240	6777.71
"	10	10	0.158	4461.78
"	10	15	0.130	3671.81
"	40	5	0.089	2513.87
"	40	10	0.075	2112.66
"	40	15	0.073	2056.68
"	75	5	0.066	1850.61
"	75	10	0.062	1747.24
"	75	15	0.064	1805.43
Reburn - Coal	10	5	0.404	4422.82
"	10	10	0.258	2821.44
"	10	15	0.206	2259.28
"	40	5	0.140	1538.96
"	40	10	0.113	1232.60
"	40	15	0.107	1166.88
"	75	5	0.100	1090.36
"	75	10	0.090	985.45
"	75	15	0.091	996.95
Reburn - Gas	10	5	0.566	6538.23
"	10	10	0.414	4778.77
"	10	15	0.369	4262.46
"	40	5	0.256	2959.55
"	40	10	0.243	2807.13
"	40	15	0.252	2906.87
"	75	5	0.208	2402.86
"	75	10	0.216	2500.43
"	75	15	0.233	2696.00
Reburn - Oil	40	10	0.360	4140.26
SNCR	10	5	0.630	9083.09
"	10	10	0.615	8879.10
"	10	15	0.646	9321.78
"	40	5	0.460	6634.33
"	40	10	0.522	7529.98
"	40	15	0.582	8394.19
"	75	5	0.433	6253.41
"	75	10	0.507	7320.12
"	75	15	0.572	8249.90
SCR	10	5	2.197	15851.30
"	10	10	1.312	9464.13
"	10	15	0.986	7113.92
"	40	5	0.663	4786.02
"	40	10	0.467	3367.82
"	40	15	0.405	2922.42
"	75	5	0.425	3064.76
"	75	10	0.335	2419.50
"	75	15	0.315	2270.41
SNCR-SCR Hybrid	10	5	1.125	12981.13
"	10	10	0.787	9082.18
"	10	15	0.679	7842.27
"	40	5	0.471	5438.41
"	40	10	0.427	4926.59
"	40	15	0.432	4985.11
"	75	5	0.370	4265.09
"	75	10	0.371	4280.17
"	75	15	0.393	4540.66
In-duct SCR/Cat- AH	10	5	1.276	14721.69
"	10	10	0.826	9532.29
"	10	15	0.670	7731.08
"	40	5	0.459	5293.29
"	40	10	0.376	4337.80
"	40	15	0.360	4159.63
"	75	5	0.332	3826.65
"	75	10	0.306	3529.77
"	75	15	0.312	3604.07

Note: Low NO_X burners already fitted at Kingsnorth Power Station

Table 27 - Details of NOx reduction costs per technology at Littlebrook Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.175	2052.31
"	10	10	0.097	1137.53
"	10	15	0.067	787.77
"	40	5	0.044	520.77
"	40	10	0.025	293.74
"	40	15	0.018	207.63
"	75	5	0.024	282.53
"	75	10	0.014	162.48
"	75	15	0.01	117.38
Adv.Low Nox Burners	10	5	0.187	1687.82
"	10	10	0.104	935.14
"	10	15	0.072	647.31
"	40	5	0.047	427.87
"	40	10	0.027	240.98
"	40	15	0.019	170.05
"	75	5	0.026	231.88
"	75	10	0.015	133.00
"	75	15	0.011	95.81
Overfire Air	10	5	0.209	7983.68
Reburn - Oil	10	5	0.313	4860.11
Flue Gas Recycle	10	5	0.037	360.17
"	10	10	0.026	249.41
"	10	15	0.022	213.81
"	40	5	0.015	147.45
"	40	10	0.014	132.22
"	40	15	0.014	133.23
"	75	5	0.012	114.36
"	75	10	0.012	113.99
"	75	15	0.012	120.70
SNCR	10	5	0.538	10501.81
"	10	10	0.504	9838.00
"	10	15	0.519	10128.24
"	40	5	0.368	7188.63
"	40	10	0.410	8012.64
"	40	15	0.455	8873.22
"	75	5	0.342	6673.25
"	75	10	0.396	7728.69
"	75	15	0.445	8677.99
SCR	10	5	2.153	21011.46
"	10	10	1.258	12275.16
"	10	15	0.924	9020.15
"	40	5	0.619	6040.14
"	40	10	0.413	4026.86
"	40	15	0.343	3349.06
"	75	5	0.380	3711.27
"	75	10	0.281	2743.79
"	75	15	0.253	2466.89
SNCR-SCR Hybrid	10	5	1.079	16845.63
"	10	10	0.731	11414.64
"	10	15	0.616	9613.06
"	40	5	0.425	6640.33
"	40	10	0.371	5792.12
"	40	15	0.368	5747.33
"	75	5	0.324	5052.84
"	75	10	0.315	4917.51
"	75	15	0.330	5145.99
In-duct SCR/Cat- AH	10	5	1.231	19220.00
"	10	10	0.771	12047.21
"	10	15	0.608	9489.55
"	40	5	0.414	6463.37
"	40	10	0.321	5019.07
"	40	15	0.298	4657.38
"	75	5	0.287	4479.00
"	75	10	0.251	3925.80
"	75	15	0.250	3905.71

Table 28 - Details of NOx reduction costs per technology at Ratcliffe Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	4965.13
"	10	10	0.104	2750.94
"	10	15	0.072	1904.23
"	40	5	0.047	1258.68
"	40	10	0.027	708.91
"	40	15	0.019	500.23
"	75	5	0.026	682.12
"	75	10	0.015	391.26
"	75	15	0.011	281.84
Overfire Air	10	5	0.348	9019.51
"	10	10	0.217	5628.68
"	10	15	0.170	4417.48
"	40	5	0.116	2997.52
"	40	10	0.089	2310.92
"	40	15	0.082	2136.37
"	75	5	0.080	2060.76
"	75	10	0.069	1794.83
"	75	15	0.069	1781.53
Reburn - Coal	10	5	0.439	4438.09
"	10	10	0.277	2796.23
"	10	15	0.219	2214.03
"	40	5	0.149	1504.91
"	40	10	0.117	1180.22
"	40	15	0.109	1102.95
"	75	5	0.104	1048.63
"	75	10	0.092	928.84
"	75	15	0.092	930.11
Reburn - Gas	10	5	0.871	9252.96
"	10	10	0.613	6512.21
"	10	15	0.532	5651.70
"	40	5	0.368	3906.00
"	40	10	0.336	3566.36
"	40	15	0.341	3626.29
"	75	5	0.290	3074.26
"	75	10	0.293	3108.12
"	75	15	0.312	3311.22
Reburn - Oil	40	10	0.393	4152.40
SNCR	10	5	0.628	8328.72
"	10	10	0.614	8137.27
"	10	15	0.644	8540.90
"	40	5	0.458	6078.38
"	40	10	0.520	6897.47
"	40	15	0.580	7688.48
"	75	5	0.432	5728.32
"	75	10	0.506	6704.61
"	75	15	0.570	7555.88
SCR	10	5	2.199	14575.92
"	10	10	1.314	8708.25
"	10	15	0.988	6550.03
"	40	5	0.665	4407.24
"	40	10	0.469	3105.91
"	40	15	0.407	2698.17
"	75	5	0.426	2825.45
"	75	10	0.337	2234.44
"	75	15	0.317	2098.99
SNCR-SCR Hybrid	10	5	1.126	11941.56
"	10	10	0.788	8361.21
"	10	15	0.681	7223.88
"	40	5	0.472	5010.02
"	40	10	0.428	4542.34
"	40	15	0.434	4598.23
"	75	5	0.371	3931.77
"	75	10	0.372	3948.29
"	75	15	0.395	4189.80
In-duct SCR/Cat- AH	10	5	1.276	13534.96
"	10	10	0.827	8767.39
"	10	15	0.671	7113.18
"	40	5	0.459	4870.53
"	40	10	0.377	3993.80
"	40	15	0.361	3831.12
"	75	5	0.332	3522.73
"	75	10	0.307	3251.24
"	75	15	0.313	3320.58

Note: Low NO_X burners already fitted at Ratcliffe Power Station

Table 29 - Details of NOx reduction costs per technology at Rugeley B Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	5211.20
"	10	10	0.104	2887.28
"	10	15	0.072	1998.60
"	40	5	0.047	1321.06
"	40	10	0.027	744.04
"	40	15	0.019	525.03
"	75	5	0.026	715.93
"	75	10	0.015	410.65
"	75	15	0.011	295.80
Overfire Air	10	5	0.161	4391.34
"	10	10	0.103	2788.14
"	10	15	0.082	2223.14
"	40	5	0.056	1513.12
"	40	10	0.044	1202.42
"	40	15	0.042	1132.88
"	75	5	0.039	1065.40
"	75	10	0.035	955.75
"	75	15	0.035	963.29
Reburn - Coal	10	5	0.325	3441.04
"	10	10	0.202	2138.10
"	10	15	0.158	1671.20
"	40	5	0.107	1133.11
"	40	10	0.082	866.57
"	40	15	0.075	796.96
"	75	5	0.073	774.10
"	75	10	0.063	668.78
"	75	15	0.062	660.97
Reburn - Gas	10	5	0.613	6833.87
"	10	10	0.430	4792.13
"	10	15	0.372	4147.51
"	40	5	0.257	2865.08
"	40	10	0.234	2605.57
"	40	15	0.237	2644.15
"	75	5	0.202	2247.71
"	75	10	0.203	2265.43
"	75	15	0.216	2410.29
Reburn - Oil	40	10	0.340	3774.03
SNCR	10	5	0.639	8888.22
"	10	10	0.627	8719.12
"	10	15	0.659	9168.09
"	40	5	0.469	6526.35
"	40	10	0.533	7417.87
"	40	15	0.595	8273.42
"	75	5	0.443	6158.95
"	75	10	0.519	7215.45
"	75	15	0.585	8134.25
SCR	10	5	2.203	15326.62
"	10	10	1.319	9174.30
"	10	15	0.994	6914.01
"	40	5	0.669	4654.00
"	40	10	0.473	3294.32
"	40	15	0.413	2871.26
"	75	5	0.430	2993.81
"	75	10	0.342	2379.66
"	75	15	0.322	2242.39
SNCR-SCR Hybrid	10	5	1.130	12580.04
"	10	10	0.793	8832.37
"	10	15	0.687	7646.74
"	40	5	0.477	5304.97
"	40	10	0.433	4824.24
"	40	15	0.439	4890.96
"	75	5	0.375	4173.30
"	75	10	0.377	4200.76
"	75	15	0.401	4462.29
In-duct SCR/Cat- AH	10	5	1.281	14256.19
"	10	10	0.832	9263.28
"	10	15	0.677	7535.80
"	40	5	0.464	5162.35
"	40	10	0.382	4253.12
"	40	15	0.368	4091.09
"	75	5	0.337	3747.76
"	75	10	0.312	3473.76
"	75	15	0.319	3555.25

Note: Low NO_X burners already fitted at Rugeley B Power Station

Table 30 - Details of NOx reduction per technology at Tilbury Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.287	2477.15
"	10	10	0.164	1417.26
"	10	15	0.118	1018.01
"	40	5	0.079	678.40
"	40	10	0.049	426.26
"	40	15	0.039	336.65
"	75	5	0.046	398.60
"	75	10	0.032	272.10
"	75	15	0.027	230.67
Adv.Low Nox Burners	10	5	0.299	1985.81
"	10	10	0.171	1134.44
"	10	15	0.123	813.51
"	40	5	0.082	541.93
"	40	10	0.051	338.95
"	40	15	0.040	266.57
"	75	5	0.048	317.32
"	75	10	0.032	215.21
"	75	15	0.027	181.49
Overfire Air	10	5	0.384	9950.60
"	10	10	0.235	6087.10
"	10	15	0.181	4687.37
"	40	5	0.122	3168.85
"	40	10	0.091	2350.76
"	40	15	0.082	2118.47
"	75	5	0.081	2113.92
"	75	10	0.068	1769.55
"	75	15	0.066	1718.86
Reburn - Coal	10	5	0.443	4413.83
"	10	10	0.277	2756.56
"	10	15	0.217	2164.91
"	40	5	0.148	1469.22
"	40	10	0.114	1134.25
"	40	15	0.105	1049.50
"	75	5	0.102	1011.17
"	75	10	0.089	881.89
"	75	15	0.088	875.99
Reburn - Gas	10	5	0.591	6271.47
"	10	10	0.430	4561.21
"	10	15	0.382	4054.26
"	40	5	0.265	2813.35
"	40	10	0.250	2655.99
"	40	15	0.258	2744.34
"	75	5	0.214	2275.42
"	75	10	0.222	2359.62
"	75	15	0.239	2540.57
Reburn - Oil	40	10	0.393	4148.15
SNCR	10	5	0.582	7718.34
"	10	10	0.557	7392.36
"	10	15	0.579	7689.48
"	40	5	0.412	5465.61
"	40	10	0.463	6151.23
"	40	15	0.515	6836.15
"	75	5	0.385	5115.18
"	75	10	0.449	5958.17
"	75	15	0.505	6703.41
SCR	10	5	2.176	14437.27
"	10	10	1.285	8529.93
"	10	15	0.956	6342.81
"	40	5	0.642	4257.80
"	40	10	0.440	2921.66
"	40	15	0.375	2486.86
"	75	5	0.403	2674.33
"	75	10	0.309	2049.26
"	75	15	0.284	1887.05
SNCR-SCR Hybrid	10	5	1.103	11707.30
"	10	10	0.760	8069.57
"	10	15	0.649	6888.40
"	40	5	0.449	4768.40
"	40	10	0.400	4246.65
"	40	15	0.401	4259.96
"	75	5	0.347	3689.01
"	75	10	0.344	3651.98
"	75	15	0.363	3851.09
In-duct SCR/Cat- AH	10	5	1.259	13372.53
"	10	10	0.806	8561.54
"	10	15	0.648	6875.05
"	40	5	0.443	4698.91
"	40	10	0.356	3782.89
"	40	15	0.338	3589.51
"	75	5	0.315	3349.68
"	75	10	0.286	3039.55
"	75	15	0.290	3078.43

Table 31 - Details of NOx reduction costs per technology at West Burton Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	5621.15
"	10	10	0.104	3114.41
"	10	15	0.072	2155.82
"	40	5	0.047	1424.98
"	40	10	0.027	802.57
"	40	15	0.019	566.33
"	75	5	0.026	772.25
"	75	10	0.015	442.95
"	75	15	0.011	319.07
Overfire Air	10	5	0.245	7179.48
"	10	10	0.155	4561.39
"	10	15	0.124	3639.21
"	40	5	0.084	2477.21
"	40	10	0.067	1970.72
"	40	15	0.063	1858.01
"	75	5	0.060	1745.75
"	75	10	0.053	1567.72
"	75	15	0.054	1580.93
Reburn - Coal	10	5	0.325	3716.79
"	10	10	0.202	2309.44
"	10	15	0.158	1805.12
"	40	5	0.107	1223.91
"	40	10	0.082	936.01
"	40	15	0.075	860.83
"	75	5	0.073	836.13
"	75	10	0.063	722.37
"	75	15	0.062	713.94
Reburn - Gas	10	5	0.591	7104.37
"	10	10	0.416	5002.14
"	10	15	0.358	4304.09
"	40	5	0.250	3008.47
"	40	10	0.228	2740.26
"	40	15	0.229	2752.57
"	75	5	0.197	2371.33
"	75	10	0.199	2388.42
"	75	15	0.209	2511.23
Reburn - Oil	40	10	0.344	4116.26
SNCR	10	5	0.592	8882.74
"	10	10	0.569	8547.46
"	10	15	0.594	8910.06
"	40	5	0.422	6335.07
"	40	10	0.476	7143.84
"	40	15	0.529	7945.01
"	75	5	0.396	5938.77
"	75	10	0.461	6925.50
"	75	15	0.519	7794.89
SCR	10	5	2.180	16358.19
"	10	10	1.290	9684.11
"	10	15	0.962	7215.94
"	40	5	0.646	4845.98
"	40	10	0.445	3341.57
"	40	15	0.380	2855.16
"	75	5	0.407	3055.20
"	75	10	0.314	2354.95
"	75	15	0.290	2176.81
SNCR-SCR Hybrid	10	5	1.107	13286.56
"	10	10	0.765	9182.65
"	10	15	0.654	7854.86
"	40	5	0.453	5439.19
"	40	10	0.405	4859.22
"	40	15	0.407	4882.30
"	75	5	0.351	4218.48
"	75	10	0.349	4186.68
"	75	15	0.368	4419.90
In-duct SCR/Cat- AH	10	5	1.258	15100.44
"	10	10	0.804	9654.61
"	10	15	0.645	7743.37
"	40	5	0.441	5291.23
"	40	10	0.354	4250.32
"	40	15	0.335	4027.67
"	75	5	0.314	3765.35
"	75	10	0.284	3409.65
"	75	15	0.287	3449.67

Note: Low NO_X burners already fitted at West Burton Power Station

Table 32 - Details of NOx reduction costs per technology at Willington B Power Station

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Low Nox Burners	10	5	0.175	1412.19
"	10	10	0.097	782.73
"	10	15	0.067	542.06
"	40	5	0.044	358.34
"	40	10	0.025	202.12
"	40	15	0.018	142.87
"	75	5	0.024	194.41
"	75	10	0.014	111.80
"	75	15	0.01	80.77
Adv.Low Nox Burners	10	5	0.187	1161.36
"	10	10	0.104	643.45
"	10	15	0.072	445.40
"	40	5	0.047	294.41
"	40	10	0.027	165.82
"	40	15	0.019	117.01
"	75	5	0.026	159.55
"	75	10	0.015	91.52
"	75	15	0.011	65.92
Overfire Air	10	5	0.365	8857.80
"	10	10	0.230	5570.02
"	10	15	0.182	4402.42
"	40	5	0.123	2991.37
"	40	10	0.096	2337.97
"	40	15	0.090	2180.23
"	75	5	0.086	2078.81
"	75	10	0.076	1835.21
"	75	15	0.076	1834.56
Reburn - Coal	10	5	0.358	3241.25
SNCR	10	5	0.653	8103.74
"	10	10	0.644	7992.15
"	10	15	0.679	8423.54
"	40	5	0.484	5998.29
"	40	10	0.551	6832.17
"	40	15	0.615	7626.01
"	75	5	0.457	5670.77
"	75	10	0.536	6651.73
"	75	15	0.605	7501.94
SCR	10	5	2.213	13724.20
"	10	10	1.331	8253.16
"	10	15	1.008	6248.89
"	40	5	0.679	4210.26
"	40	10	0.486	3011.55
"	40	15	0.426	2645.04
"	75	5	0.440	2730.32
"	75	10	0.354	2196.19
"	75	15	0.336	2084.44
SNCR-SCR Hybrid	10	5	1.140	11310.62
"	10	10	0.805	7990.72
"	10	15	0.700	6950.44
"	40	5	0.486	4825.38
"	40	10	0.445	4417.74
"	40	15	0.453	4493.85
"	75	5	0.385	3816.56
"	75	10	0.389	3861.94
"	75	15	0.414	4111.72
In-duct SCR/Cat- AH	10	5	1.292	12821.39
"	10	10	0.846	8395.04
"	10	15	0.693	6874.62
"	40	5	0.475	4714.84
"	40	10	0.396	3928.82
"	40	15	0.383	3803.88
"	75	5	0.348	3453.82
"	75	10	0.326	3234.07
"	75	15	0.335	3326.21

Table 33 - Sensitivity Study - Economic Parameters (5, 10 and 15 years) at West Burton

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Adv.Low Nox Burners	10	5	0.187	5621.15
"	10	10	0.099	2960.92
"	10	15	0.069	2077.64
"	40	5	0.047	1424.98
"	40	10	0.025	763.02
"	40	15	0.018	545.74
"	75	5	0.026	772.25
"	75	10	0.014	421.12
"	75	15	0.010	307.45
Overfire Air	10	5	0.245	7179.48
"	10	10	0.148	4336.54
"	10	15	0.119	3505.15
"	40	5	0.084	2477.21
"	40	10	0.064	1873.54
"	40	15	0.061	1788.48
"	75	5	0.060	1745.75
"	75	10	0.051	1490.41
"	75	15	0.052	1521.44
Reburn - Coal	10	5	0.325	3716.79
"	10	10	0.192	2195.60
"	10	15	0.152	1738.76
"	40	5	0.107	1223.91
"	40	10	0.078	889.86
"	40	15	0.072	828.69
"	75	5	0.073	836.13
"	75	10	0.060	686.75
"	75	15	0.060	687.12
Reburn - Gas	10	5	0.591	7104.37
"	10	10	0.395	4745.42
"	10	15	0.345	4150.49
"	40	5	0.250	3008.47
"	40	10	0.216	2600.04
"	40	15	0.221	2655.19
"	75	5	0.197	2371.33
"	75	10	0.188	2266.31
"	75	15	0.201	2422.59
Reburn - Oil	40	10	0.328	3919.36
SNCR	10	5	0.592	8882.74
"	10	10	0.541	8125.92
"	10	15	0.571	8573.93
"	40	5	0.422	6335.07
"	40	10	0.452	6791.48
"	40	15	0.509	7643.84
"	75	5	0.396	5938.77
"	75	10	0.439	6583.90
"	75	15	0.500	7499.16
SCR	10	5	2.180	16358.19
"	10	10	1.227	9206.78
"	10	15	0.926	6952.04
"	40	5	0.646	4845.98
"	40	10	0.423	3176.83
"	40	15	0.366	2749.26
"	75	5	0.407	3055.20
"	75	10	0.298	2238.84
"	75	15	0.279	2095.50
SNCR-SCR Hybrid	10	5	1.107	13286.56
"	10	10	0.727	8734.00
"	10	15	0.630	7566.58
"	40	5	0.453	5439.19
"	40	10	0.385	4623.64
"	40	15	0.392	4701.73
"	75	5	0.351	4218.48
"	75	10	0.332	3984.26
"	75	15	0.354	4256.09
In-duct SCR/Cat- AH	10	5	1.258	15100.44
"	10	10	0.765	9181.22
"	10	15	0.621	7459.89
"	40	5	0.441	5291.23
"	40	10	0.337	4043.27
"	40	15	0.323	3878.82
"	75	5	0.314	3765.35
"	75	10	0.270	3244.04
"	75	15	0.277	3321.77

Table 34 - Sensitivity Study on Gas Price - Gas-over-Coal Reburn at West Burton

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Reburn - Gas	10	5	0.445	5354.16
"	10	10	0.237	2855.12
"	10	15	0.156	1871.93
"	40	5	0.105	1258.25
"	40	10	0.050	598.52
"	40	15	0.027	320.41
"	75	5	0.052	621.11
"	75	10	0.021	247.50
"	75	15	0.007	79.07

Table 35 - Sensitivity Study on Capital Cost of Gas Pipeline (Reburn) at West Burton

Technology	Unit Load Factor %	Time/Years	p/KWh	£/te NOx Removed
Reburn - Gas	10	5	0.427	5136.47
"	10	10	0.324	3900.84
"	10	15	0.296	3558.65
"	40	5	0.209	2516.49
"	40	10	0.204	2457.39
"	40	15	0.213	2566.21
"	75	5	0.175	2108.94
"	75	10	0.186	2232.85
"	75	15	0.201	2411.83

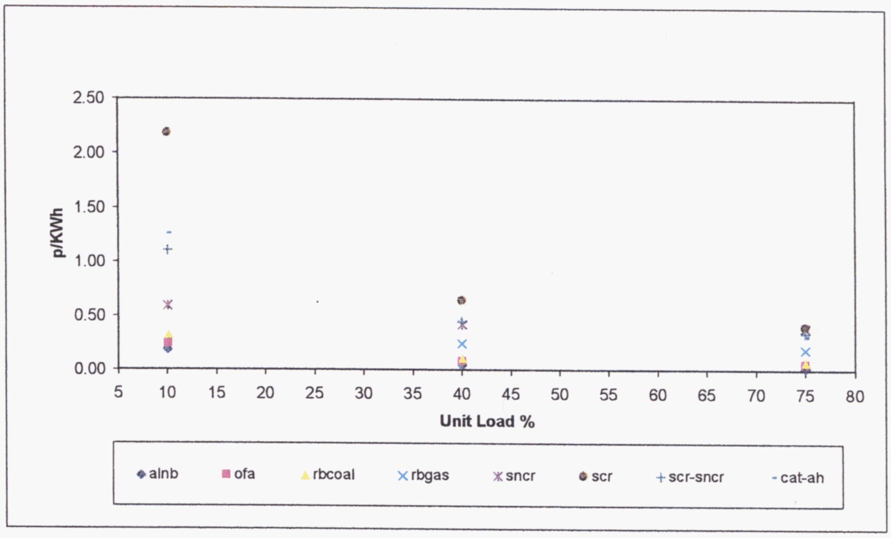


Figure 1 : Station A Cost Trends (p/kWh) - Timescale 5 years

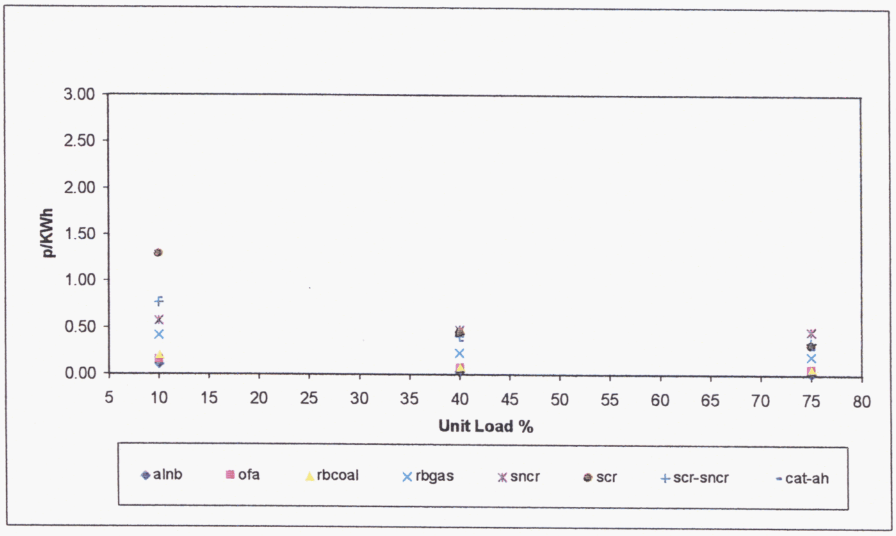


Figure 2 : Station A Cost Trends (p/kWh) - Timescale 10 years

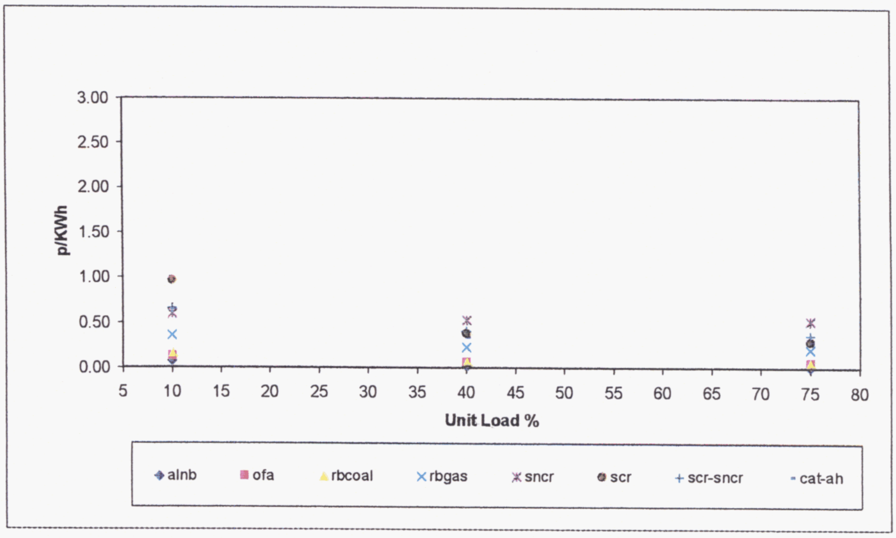


Figure 3 : Station A Cost Trends (p/kWh) - Timescale 15 years

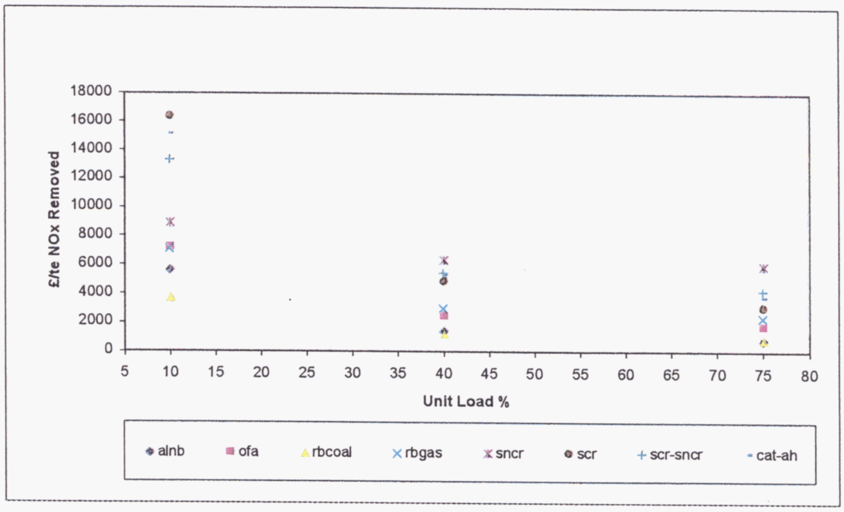


Figure 4 : Station A Cost Trends (£/te NO_X removed) - Timescale 5 years

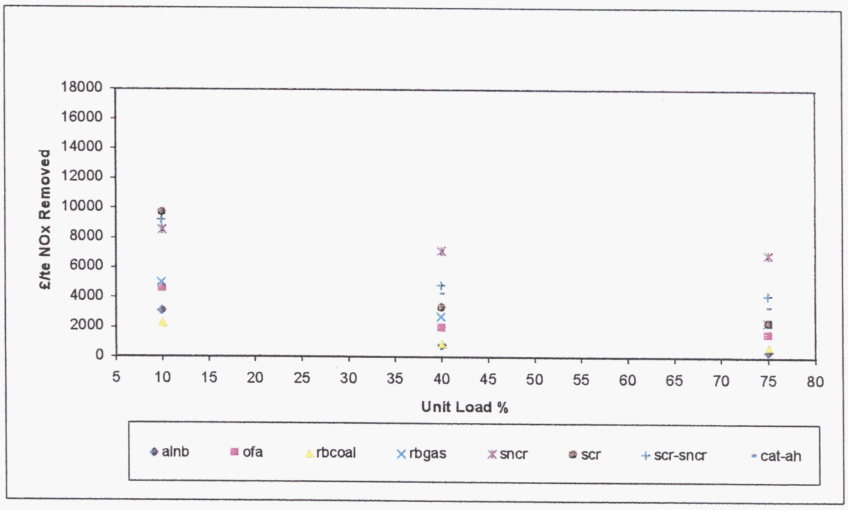


Figure 5 : Station A Cost Trends (£/te NO_X removed) - Timescale 10 years

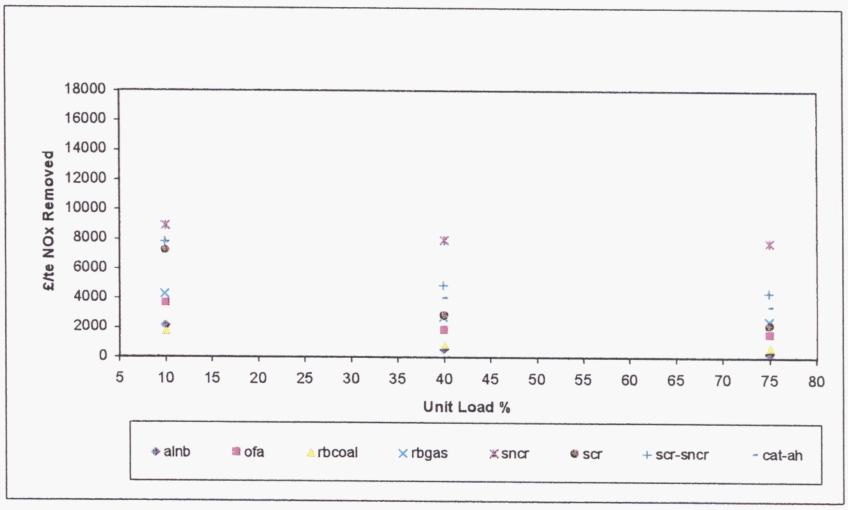


Figure 6 : Station A Cost Trends (£/te NO_X removed) - Timescale 15 years

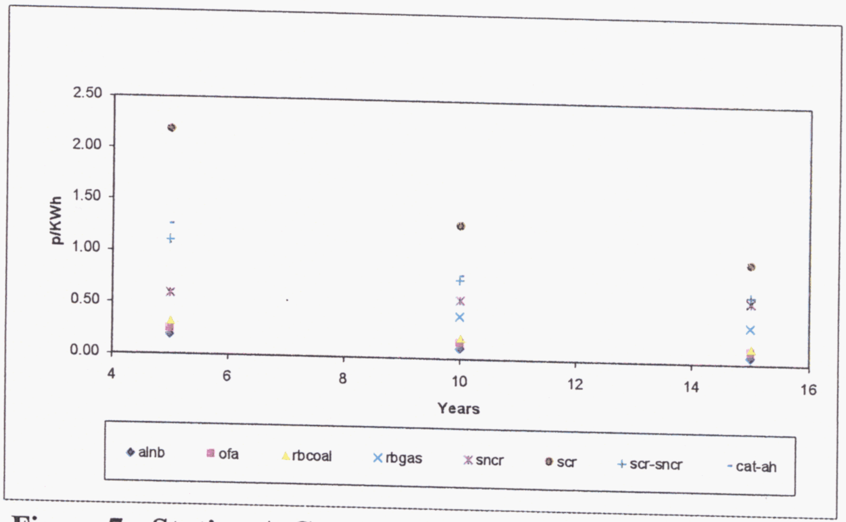


Figure 7 : Station A Cost Trends (p/kWh) - Unit Load 10%

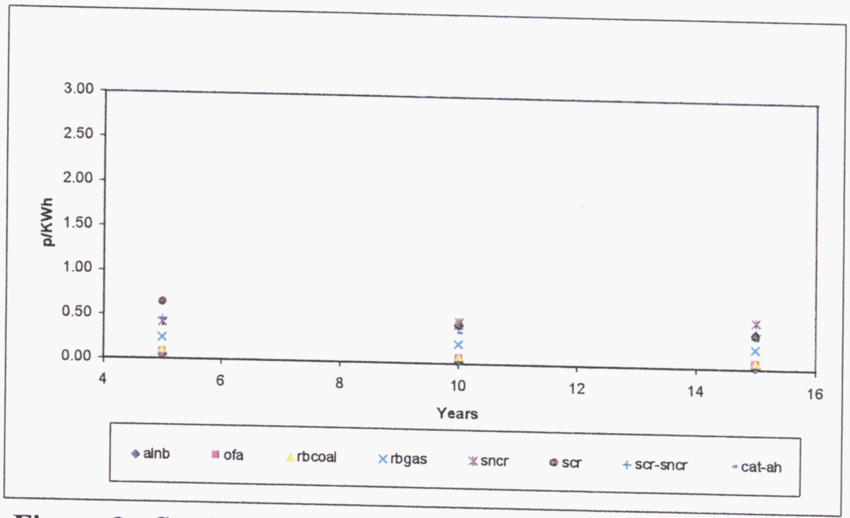


Figure 8 : Station A Cost Trends (p/kWh) - Unit Load 40%

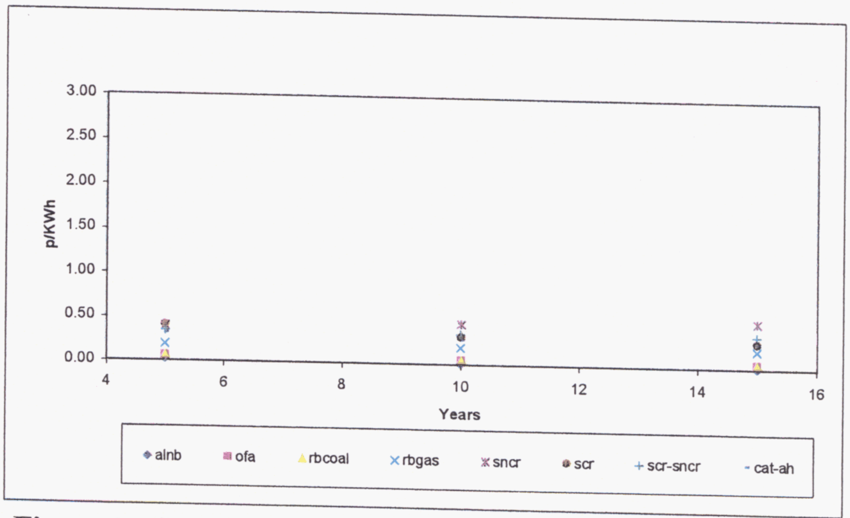


Figure 9 : Station A Cost Trends (p/kWh) - Unit Load 75%

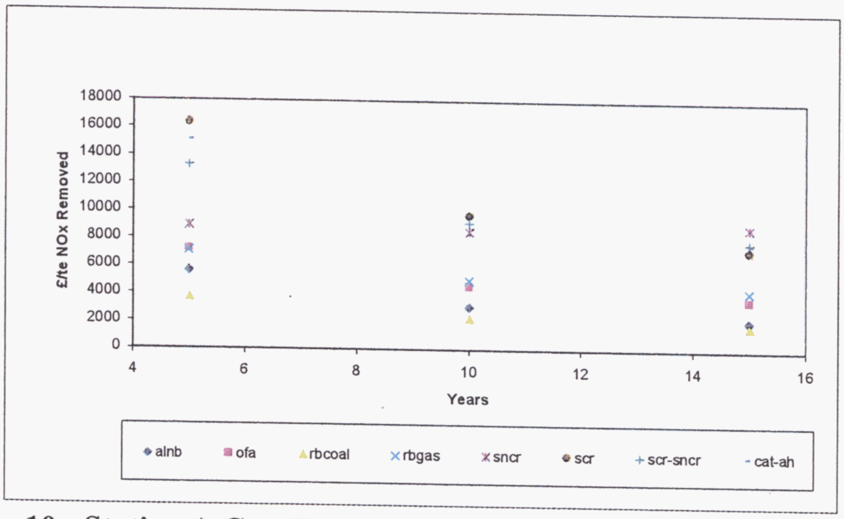


Figure 10 : Station A Cost Trends (£/te NO_X removed) - Unit Load 10%

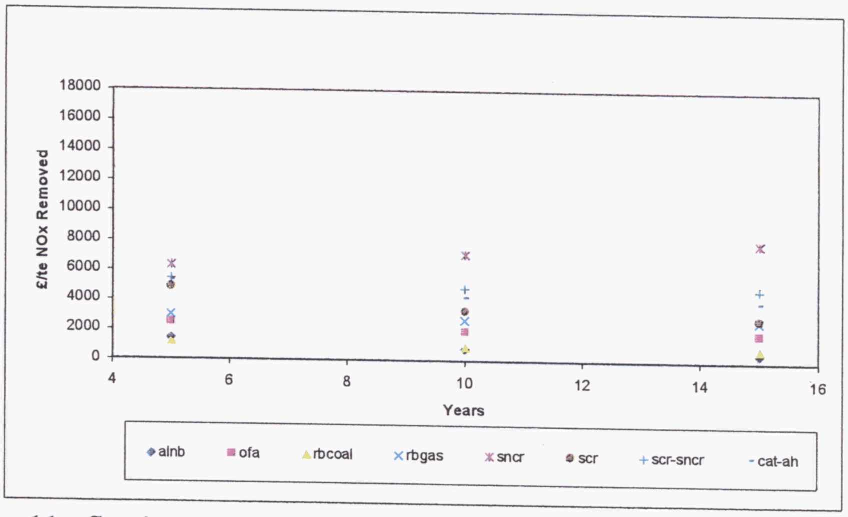


Figure 11 : Station A Cost Trends (£/te NO_X removed) - Unit Load 40%

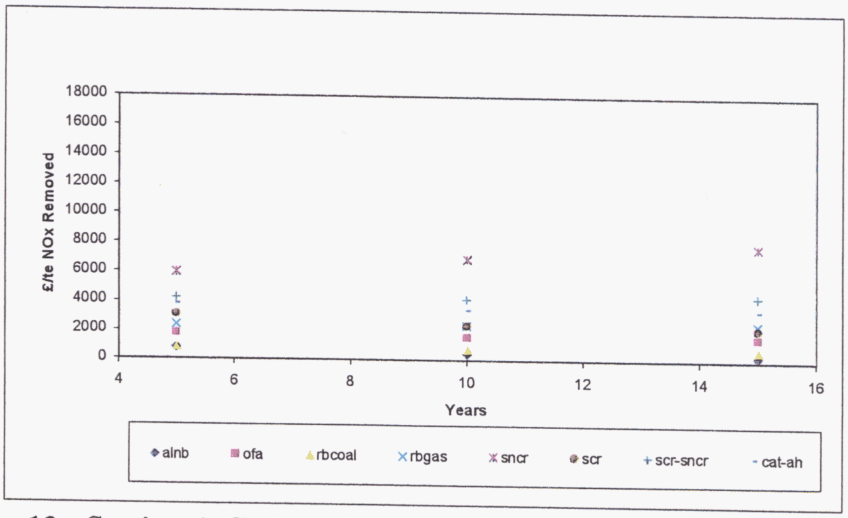


Figure 12 : Station A Cost Trends (£/te NO_X removed) - Unit Load 75%

Mitsui Babcock Energy Limited
Technology Centre

UPGRADE: *Low NO_x Burners*

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years

Annual Apparent Escalation Rate (e_a)	7.12 %	
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	↔ For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	↔ For Use in Costing

2. *Plant Information*

Station Name

Station A

2.1 Boiler Details

Boiler Type	Front Wall-fired	
Number of Units	1	
Unit Capacity at MCR	500	MW_e

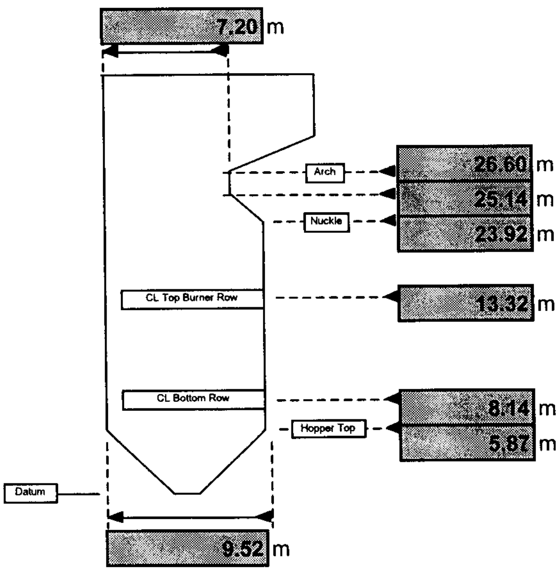
↔ Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'

Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	o
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Foster Wheeler Intervane	Enter Manufacturer & Model
Fuel Type	Coal	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners
Number of Burners for Full Load/Unit	20	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	2.59	m
Lateral Burner Spacing	2.54	m
Number of Burners Out of Service/Unit	4	Burners OOS
Burners/Column	3	Burners
Burners/Column for Full Load	2.5	Burners
Height to C_L of 2nd Top Burner Row	10.73	m
Number of Mills/Unit	6	Mills ⟷ Enter number of mills (incl. OOS mills)
Low Nox Burners Installed?	NO	Enter 'YES' or 'NO'
New/Old Burners Equally Rated?	NO	Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63	
Calorific Value of Fuel	24267	kJ/kg as rec'd
Basis of Calorific Value	GCV	⟷ Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired
NCV	23159	kJ/kg fired

Check of GCV for Main Fuel

GCV Based on Ultimate Analysis	*23907 kJ/kg fired*	***OK***
Δ GCV (Input/Calculated)	*1.5 %*	

Inlet Fuel Flow to Unit at MCR	62.90 kg/s
Operating Excess Air Level	17.0 % ⟷ Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature	75 °C ⟷ Enter value if known or use Mill Product Temp.
Windbox Air Temperature	250 °C
Absolute Humidity of Combustion Air	8.0 $g/kg_{dry\ air}$
Inlet Combustion Air Density	0.74 kg/m^3 (assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2

Calculated Exit O_2 Based on Ultimate Analysis *3.07 %*

Stoichiometric Dry Air Requirement	7.85 kg/kg_{fuel}
Dry Inlet Air Flow to Unit at MCR	577.78 kg/s (based on Unit Thermal Capacity and GCV)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature	1500 °C	⟷ Input estimate given fuel type (Suggest 1500 °C)
Measured Carbon in Ash (CIA)	5.0 %	
Unburnt Loss (UBL)	1.14 $\%_{GCV}$	
Unburnt Carbon (UBC)	0.0082 kg/kg_{fuel}	
Mass of Theoretical Dry Air Required	7.76 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Air Required	9.08 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Air Required	9.15 kg/kg_{fuel}	(corrected for humidity)
Mass of Flue-gas	9.98 kg/kg_{fuel}	
Total Mass Flow of Flue-gas at MCR	627.96 kg/s	

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements			
Stoichiometric Air Requirement	*7.84*	kg_{air}/kg_{fuel}	
Actual Air Requirement	*9.17*	kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2*	*%*	***OK***

Volume Flow of Flue-gas in Comb. Zone 3082.32 m^3/s at 1500 ^oC

Combustion Zone Stoichiometry 1.18

Residence Time - Top Burner Row to Arch 0.96 s

4.0 Calculation of Credits and Costs Associated with Low NO_x Burners

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500	MW_e	
Unit Heat Rate	10.55	MJ/kWh	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh	Enter price in p/kWh (typ. price is 5p/kWh)
Coal Cost	1.25	£/GJ	Enter price in £/GJ (1998 price is £1.25/GJ)
Cost of Landfill Ash	8.70	£/te	Enter price in £/te (1998 price is £8.70/te)
Price of Saleable Ash	3.00	£/te	Enter price in £/te (1998 prices is £1-15/te)
Proportion of Total Ash Sold Before LNB	60	%	Enter proportion sold as a percentage
Capital Cost	6	£/kW_e	Enter price in £/kW_e (1998 price is £6/kW_e)
Reduction Achieved	40	%	Enter reduction in % (typical reduction is 40%)

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	1083	mg/Nm^3	Enter emission (limit = 650mg/Nm^3)
Mass Flow of Flue Gas	627.96	kg/s	
Volume Flow of Flue Gas	474.60	m^3/s	
Density of Flue Gas	1.32	kg/m^3	
Total NO_x Produced at MCR	64838	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Capital Cost of Technology	3000000.00	£	
Do You Also Want to Install OFA with the LNBs?	no		Enter Yes or No

Difficulty Factor	1	◄──► Relates to Difficulty of Installation Range 1-1.4
Total Capital Cost of Technology	3000000.00	£
Levelised Capital Cost of Technology	3504573.00	£
NO_x Reduction Achieved	40	%
Capital Cost/te NO_x Removed	135.13	£/te NO_x Removed
Capital Cost/kWh Generated	0.020	p/kWh

4.1.2 Cost for Minimising Carbon In Ash

PF Fineness Achieved By Mills	70	% through 75µm ◄──► Enter existing value

***** Mill Modifications Not Required - CIA Acceptable*****

Cost of Mill Modification	250000.00	£/mill ◄──► Enter value (typical cost is £0.25million)
Capital Cost for Work on Mills	1500000.00	£
Levelised Capital Cost for Work on Mills	1752286.50	£
Capital Cost for Mills/te NO_x Removed	0.00	£/te NO_x Removed
Capital Cost for Mills/kWh Generated	0.000	p/kWh

4.2 Operating and Maintenance Costs

4.2.1 Cost of Ash Disposal due to Increase in CIA

Ash Content of Main Fuel	15.60	%
Main Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR Before LNBs	1237775.39	te
Total kWh Generated at MCR	1.752E+10	kWh
Amount of Ash Disposed Before LNBs	495110	te
Amount of Ash Disposed After LNBs	495110	te
Disposable Cost/te NO_x Removed	0.00	£/te NO_x Removed
Disposable Cost/kWh Generated	0.000	p/kWh

4.2.2 Cost of Increased Carbon in Ash (CIA) by LNBs

Measured CIA Before LNBs	5.0	%	
Measured CIA After LNBs	5.0	%	
Decrease in Boiler Efficiency	0.1	%/% point reduction in CIA	Ref: EPRI
Red'n in kWh Gen'd by CIA Increase	0	kWh	
Cost of CIA Increase/te NO_x Removed	0.00	£/te NO_x Removed	
Cost of CIA Increase/kWh Gen'd	0.000	p/kWh	

not applicable

4.2.3 Cost for Lost Saleable Ash due to Increased CIA

Ash Content of Main Fuel	15.60	%
Main Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR Before LNBs	1237775	te
Amount of Ash Sold Before LNBs	742665.2314	te
Amount of Ash Lost to Landfill by LNBs	0	te
Cost of Lost Ash Sales/te NO_x Removed	0.00	£/te NO_x Removed
Cost of Lost Sales/kWh Generated	0.000	p/kWh

4.2.4 Cost for O & M Fixed Labour

Est. O & M Costs for Coal-fired Plant	0.07	p/kWh	Ref: EPRI
Total O & M Costs Before LNBs	18653326	£	
Increase in O & M Costs Due to LNBs	1	%	
Increase in Total O & M Costs Due to LNBs	186533	£	
Fixed Labour Costs/te NO_x Removed	7.19	£/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.001	p/kWh	

4.3 Summary of Economic Analysis of LNBs

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for LNBs	0.000	0.00
TOTAL CREDIT OF LNBs	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.020	135.13
Minimising CIA	0.000	0.00
Operation and Maintenance Costs		
Increased CIA	0.000	0.00
Lost Saleable Ash	0.000	0.00
Fixed O & M Labour	0.001	7.19
TOTAL COST OF LNBs	**0.021**	**142.32**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF LNBs	**0.021**	**142.32**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (n)	10.0 Years
Unit Load Factor	40 %

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UPGRADE: *Advanced Low NO_x Burners*

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years
Annual Apparent Escalation Rate (e_a)	7.12	%
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	For Use in Costing

2. *Plant Information*

Station Name Station A

2.1 Boiler Details

Boiler Type	Front Wall-fired	
Number of Units	1	
Unit Capacity at MCR	500	MW_e

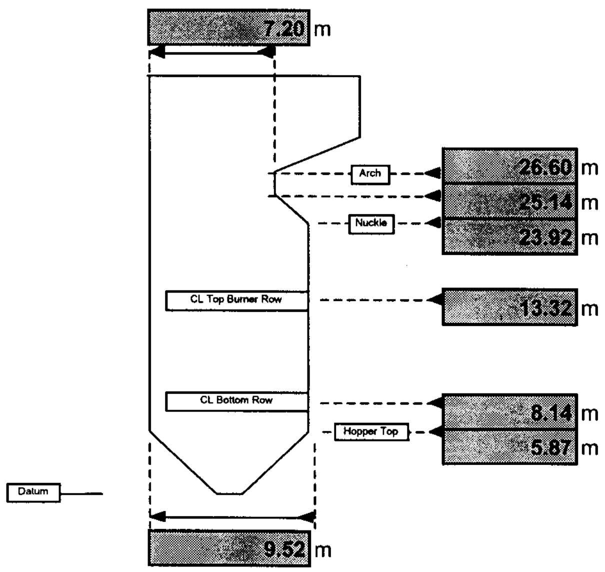
Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'

Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	°
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners	Enter Manufacturer & Model
Fuel Type	Coal	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners
Number of Burners for Full Load/Unit	20	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	2.59	m
Lateral Burner Spacing	2.54	m
Number of Burners Out of Service/Unit	4	Burners OOS
Burners/Column	3	Burners
Burners/Column for Full Load	2.5	Burners
Height to C_L of 2^{nd} Top Burner Row	10.73	m
Number of Mills/Unit	6	Mills ↔ Enter number of mills (incl. OOS mills)
Low Nox Burners Installed?	yes	
New/Old Burners Equally Rated?	yes	Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63	
Calorific Value of Fuel	24267	kJ/kg as rec'd
Basis of Calorific Value	GCV	↔ Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired
NCV	23159	kJ/kg fired

Check of GCV for Main Fuel
GCV Based on Ultimate Analysis *23907 kJ/kg fired* **OK**
Δ GCV (Input/Calculated) *1.5 %*

Inlet Fuel Flow to Unit at MCR 62.90 kg/s

Operating Excess Air Level 17.0 % ◄──► Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature 75 °C ◄──► Enter value if known or use Mill Product Temp.
Windbox Air Temperature 250 °C
Absolute Humidity of Combustion Air 8.0 $g/kg_{dry\ air}$
Inlet Combustion Air Density 0.74 kg/m^3 (assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2
Calculated Exit O_2 Based on Ultimate Analysis *3.07 %*

Stoichiometric Dry Air Requirement 7.85 kg/kg_{fuel}
Dry Inlet Air Flow to Unit at MCR 577.78 kg/s (based on Unit Thermal Capacity and GCV)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature 1500 °C ◄──► Input estimate given fuel type (Suggest 1500 °C)

Measured Carbon in Ash (CIA) 5.0 %
Unburnt Loss (UBL) 1.14 $\%_{GCV}$
Unburnt Carbon (UBC) 0.0082 kg/kg_{fuel}

Mass of Theoretical Dry Air Required 7.76 kg/kg_{fuel} (corrected for UBC)
Mass of Actual Dry Air Required 9.08 kg/kg_{fuel} (corrected for UBC)
Mass of Actual Moist Air Required 9.15 kg/kg_{fuel} (corrected for humidity)

Mass of Flue-gas 9.98 kg/kg_{fuel}
Total Mass Flow of Flue-gas at MCR 627.96 kg/s

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements			
Stoichiometric Air Requirement	*7.84*	*kg_{air}/kg_{fuel}*	
Actual Air Requirement	*9.17*	*kg_{air}/kg_{fuel}*	
Δ Stoich Air (calc/mass balance)	*0.2*	*%*	***OK***

Volume Flow of Flue-gas in Comb. Zone 3082.32 m^3/s at 1500 °C

Combustion Zone Stoichiometry 1.18

Residence Time - Top Burner Row to Arch 0.96 s

4.0 Calculation of Credits and Costs Associated with Advanced Low NO_x Burners

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500	MW_e	
Unit Heat Rate	10.55	MJ/kWh	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh	Enter price in p/kWh (typ. price is 5p/kWh)
Coal Cost	1.25	£/GJ	Enter price in £/GJ (1998 price is £1.25/GJ)
Cost of Landfill Ash	8.70	£/te	Enter price in £/te (1998 price is £8.70/te)
Price of Saleable Ash	3.00	£/te	Enter price in £/te (1998 prices is £1-15/te)
Proportion of Total Ash Sold Before aLNB	60	%	Enter proportion as a percentage
Capital Cost	7	£/kW_e	Enter price in £/kW_e (1998 price is £7/kW_e)
Reduction Achieved	20	%	Enter reduction in % (typical reduction is 50%)

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3	Enter emission (limit = $650mg/Nm^3$)
Mass Flow of Flue Gas	627.96	kg/s	
Volume Flow of Flue Gas	474.60	m^3/s	
Density of Flue Gas	1.32	kg/m^3	
Total NO_x Produced at MCR	38915	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Capital Cost of Technology	3500000.00	£	
Do You Also Want to Install OFA?	no		Enter Yes or No

Difficulty Factor	1.1	◄──►	Relates to Difficulty of Installation Range 1-1.4
Total Capital Cost of Technology	3850000.00	£	
Levelised Capital Cost of Technology	4497535.34	£	
NO_x Reduction Achieved	20	%	
Capital Cost/te NO_x Removed	577.87	£/te NO_x Removed	
Capital Cost/kWh Generated	0.026	p/kWh	

4.1.2 Cost for Minimising Carbon In Ash

PF Fineness Achieved By Mills	70	% through 75μm ◄──►	Enter existing value

***** Mill Modifications Not Required - CIA Acceptable *****

Cost of Mill Upgrade	250000.00	£/mill ◄──►	Enter value (typical cost is £0.25million)
Capital Cost for Work on Mills	1500000.00	£	
Levelised Capital Cost for Work on Mills	1752286.50	£	
Capital Cost for Mills/te NO_x Removed	0.00	£/te NO_x Removed	
Capital Cost for Mills/kWh Generated	0.000	p/kWh	

4.2 Operating and Maintenance Costs

4.2.1 Cost of Ash Disposal due to Increase in CIA

Ash Content of Main Fuel	15.60	%
Main Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR Before Adv. LNBs	1237775.39	te
Total kWh Generated at MCR	1.752E+10	kWh
Amount of Ash Disposed Before Adv. LNBs	495110	te
Amount of Ash Disposed After Adv. LNBs	495110	te
Disposable Cost/te NO_x Removed	0.00	£/te NO_x Removed
Disposable Cost/kWh Generated	0.000	p/kWh

4.2.2 Cost of Increased Carbon in Ash (CIA) by LNBs

Measured CIA Before Adv. LNBs	5.0	%	
Measured CIA After Adv. LNBs	5.0	%	
Decrease in Boiler Efficiency	0.1	%/% point reduction in CIA	Ref: EPRI
Red'n in kWh Gen'd by CIA Increase	0	kWh	
Cost of CIA Increase/te NO_x Removed	0.00	£/te NO_x Removed	
Cost of CIA Increase/kWh Gen'd	0.000	p/kWh	

not applicable

4.2.3 *Cost for Lost Saleable Ash due to Increased CIA*

Ash Content of Main Fuel	15.60 %
Main Fuel Flow Rate	62.90 kg/s
Total Ash Produced at MCR Before Adv. LNBs	1237775 te
Amount of Ash Sold Before Adv. LNBs	742665 te
Amount of Ash Lost to Landfill by Adv. LNBs	0 te
Cost of Lost Ash Sales/te NO_x Removed	0.00 £/te NO_x Removed
Cost of Lost Sales/kWh Generated	0.000 p/kWh

4.2.4 *Cost for O & M Fixed Labour*

Est. O & M Costs for Coal-fired Plant	0.07 p/kWh	Ref: EPRI
Total O & M Costs Before Adv. LNBs	18653326 £	
Increase in O & M Costs Due to Adv. LNBs	1 %	
Increase in Total O & M Costs Due to Adv. LNBs	186533 £	
Fixed Labour Costs/te NO_x Removed	23.97 £/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.001 p/kWh	

4.3 *Summary of Economic Analysis of Advanced LNBs*

4.3.1 *Credits*

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for Adv. LNBs	0.000	0.00
TOTAL CREDIT OF Adv. LNBs	**0.000**	**0.00**

4.3.2 *Costs*

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.026	577.87
Minimising CIA	0.000	0.00
Operation and Maintenance Costs		
Increased CIA	0.000	0.00
Lost Saleable Ash	0.000	0.00
Fixed O & M Labour	0.001	23.97
TOTAL COST OF Adv. LNBs	**0.027**	**601.84**

4.3.3 *Economic Outcome*

TOTAL ECONOMIC COST OF Adv. LNBs	**0.027**	**601.84**

4.4 *Summary of Economic Assumptions*

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 years
Unit Load Factor	40 %

Mitsui Babcock Energy Limited
Technology Centre

UPGRADE: ***Overfire Air (OFA)***

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years

Annual Apparent Escalation Rate (e_a)	7.12	
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	For Use in Costing

2. *Plant Information*

Station Name Station A

2.1 Boiler Details

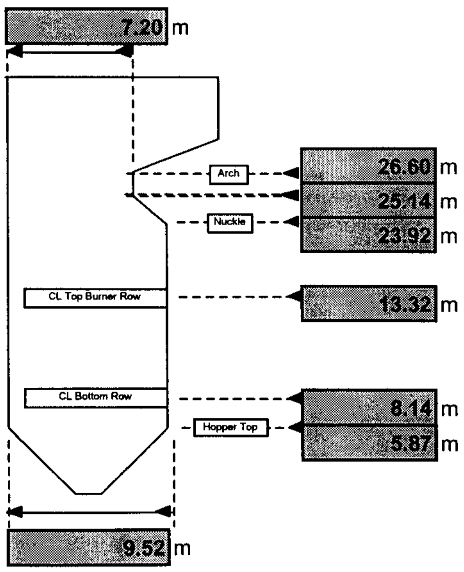
Boiler Type	Front Wall-fired	Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'
Number of Units	1	
Unit Capacity at MCR	500	MW_e

Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	°
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners	Enter Manufacturer & Model
Fuel Type	Coal	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners
Number of Burners for Full Load/Unit	20	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	2.59	m
Lateral Burner Spacing	2.54	m
Number of Burners Out of Service/Unit	4	Burners OOS
Burners/Column	3	Burners
Burners/Column for Full Load	2.5	Burners
Height to C_L of 2nd Top Burner Row	10.73	m
Number of Mills/Unit	6	Mills ⟷ Enter number of mills (incl. OOS mills)
Low Nox Burners Installed?	YES	Enter 'YES' or 'NO'
New/Old Burners Equally Rated?	YES	Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63	
Calorific Value of Fuel	24267	kJ/kg as rec'd
Basis of Calorific Value	GCV	⟷ Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired
NCV	23159	kJ/kg fired

Check of GCV for Main Fuel
GCV Based on Ultimate Analysis — *23907 kJ/kg fired* — ***GCV - OK***
Δ GCV (Input/Calculated) — *1.5 %*

Inlet Fuel Flow to Unit at MCR — 62.90 kg/s

Operating Excess Air Level — 17.0 % ⟷ Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature — 75 °C ⟷ Enter value if known or use Mill Product Temp.
Windbox Air Temperature — 250 °C
Absolute Humidity of Combustion Air — 8.0 $g/kg_{dry\ air}$
Combustion Air Density — 0.74 kg/m^3 (assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2
Calculated Exit O_2 Based on Ultimate Analysis — *3.07 %*

Stoichiometric Dry Air Requirement — 7.85 kg/kg_{fuel}
Dry Inlet Air Flow to Unit at MCR — 577.78 kg/s

2.4 Combustion-related Details

Estimated Combustion Zone Temperature — 1500 °C ⟷ Input estimate given fuel type (Suggest 1500 °C)

Measured Carbon in Ash (CIA) — 5.0 %
Unburnt Loss (UBL) — 1.14 $\%_{GCV}$
Unburnt Carbon (UBC) — 0.0082 kg/kg_{fuel}

Mass of Theoretical Dry Air Required — 7.76 kg/kg_{fuel} (corrected for UBC)
Mass of Actual Dry Air Required — 9.08 kg/kg_{fuel} (corrected for UBC)
Mass of Actual Moist Air Required — 9.15 kg/kg_{fuel} (corrected for humidity)

Mass of Flue-gas — 9.98 kg/kg_{fuel}
Total Mass Flow of Flue-gas at MCR — 627.96 kg/s

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements

Stoichiometric Air Requirement 7.84 kg_{air}/kg_{fuel}

Actual Air Requirement 9.17 kg_{air}/kg_{fuel}

Δ Stoich Air (calc/mass balance) 0.2 % ***OK***

Volume Flow of Flue-gas in Comb. Zone 3082.32 m^3/s at 1500 °C

Combustion Zone Stoichiometry 1.18

Residence Time - Top Burner Row to Arch 0.96 s

3. OFA Parameters

3.1 Operational Details

OFA Level 15.0 % of Total Air Input

Actual Moist Air Flow to 1^y Zone at MCR 489.08 kg/s

Actual Moist Air Flow to 2^y Zone at MCR 86.31 kg/s

Check of Total Air Inputs Before and After OFA

Total Air Input Before OFA 575.39 kg/s

Total Air Input After OFA 575.39 kg/s ***OK***

Overall Operating Excess Air Level	17.0	% ↔	Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature to Primary Zone	75	°C ↔	Enter value if known or use Mill Product Temp.
Windbox Air Temperature to Primary Zone	250	°C ↔	Enter estimated value.
Absolute Humidity of Combustion Air	8.0	$g/kg_{dry\ air}$ ↔	Enter value if known.
Inlet Combustion Air Density	0.74	kg/m^3	(assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2

Calculated Exit O_2 Based on Ultimate Analysis 3.07 %

Theor. Primary Zone Stoich. Dry Air Reqt 7.85 kg/kg_{1yfuel}

Theor. Dry Inlet Air Flow to Primary Zone 577.78 kg/s (based on Unit Thermal Capacity and GCV)

3.2 Combustion-related Details

Estimated Primary Combustion Zone Temp. 1500 °C ↔ Input estimate given fuel type (Suggest 1550 °C)

Measured Carbon in Ash (CIA)	7.0 %	
Unburnt Loss (UBL)	1.64 $\%_{GCV}$	
Unburnt Carbon (UBC)	0.0117 kg/kg_{fuel}	
Stoichiometry of 1^y Zone	1.00	
Resultant Excess Air in Primary Zone	0.2 %	
Mass of Theor. Dry Primary Zone Air Reqd	7.72 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Primary Zone Air Reqd	7.73 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Primary Zone Air Reqd	7.80 kg/kg_{fuel}	(corrected for humidity)
Actual Inlet Air Flow to Primary Zone at MCR	490.41 kg/s	(for total fuel flow at reqd 1^y zone stoichiometry)
Actual Inlet Air Flow to Burnout Zone	84.98 kg/s	
Mass of Primary Zone Flue-gas	8.63 kg/kg_{fuel}	
Total Mass Flow of Primary Zone Flue-gas	542.76 kg/s	

Mass Balance for Primary Zone Flue-gas Composition (100kg fuel basis, including UBC)

	Flowrate	O_2		Combustion Products		
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90					0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	3.9			3.89		
O_2	112.8	112.81				
N_2	373.7					373.71
		-1.49	135.74	32.42	2.02	374.61

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	26.57	24.98
O_2	-1.49	-0.29	-0.27
N_2	374.61	73.32	68.95
SO_2	2.02	0.40	0.37
Total (dry)	510.89	100.00	-
H_2O	32.42	-	5.97
Total (wet)	543.31	-	100.00

Check of Primary Air Requirements and Stoichiometry			
Stoichiometric Air Requirement	*7.84*	kg_{air}/kg_{fuel}	
Actual Air Requirement	*7.86*	kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2*	*%*	***OK***
Primary Zone Stoichiometry	1.01		
Δ Stoichiometry (calc/mass bal.)	*-0.8*		***OK***
Volume Flow of Flue-gas in Comb. Zone	2650.48	m^3/s at 1500 °C	
Primary Zone Residence Time Required	0.5	s ←→	Enter value
Elevation of OFA Injectors	18.08	m	***OK***
Total Vol. of Flue-Gas at OFA Injectors	3065.31	m^3/s	
Residence Time in Burnout Zone	0.73	s	***OK***

***** OFA CAN BE APPLIED TO THE CURRENT UNIT *****

***** BUT A DETAILED STUDY IS REQUIRED *****

4.0 Calculation of Credits and Costs Associated with Overfire Air

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500	MW_e	
Unit Heat Rate	10.55	MJ/kWh ←→	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh ←→	Enter price in p/kWh (typ. price is 5p/kWh)
Coal Cost	1.25	£/GJ ←→	Enter price in £/GJ (1998 price is £1.25/GJ)
Cost of Landfill Ash	8.70	£/te ←→	Enter price in £/te (1998 price is £8.70/te)
Price of Saleable Ash	3.00	£/te ←→	Enter price in £/te (1998 prices is £1-15/te)
Proportion of Total Ash Sold Before OFA	60	% ←→	Enter proportion as a percentage
Capital Cost	5.3	$£/kW_e$ ←→	Enter price in $£/kW_e$ (1998 price is $£5.3/kW_e$)
Reduction Achieved	20	% ←→	Enter reduction in % (typical reduction is 25%)

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3 ←→	Enter emission (limit = $650mg/Nm^3$)
Mass Flow of Flue Gas	629.07	kg/s	
Volume Flow of Flue Gas	473.08	m^3/s	
Density of Flue Gas	1.33	kg/m^3	
Total NO_x Produced at MCR	38790	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Capital Cost of Technology	2650000.00	£	
Do You Want to Install Low NOx Burners?	no	←→	Enter Yes or No
Difficulty Factor	1.1	←→	Relates to Difficulty of Installation Range 1-1.4

Total Capital Cost of Technology	2915000.00	£
Levelised Capital Cost of Technology	3405276.76	£
NO_x Reduction Achieved	20	%
Capital Cost/te NO_x Removed	438.94	£/te NO_x Removed
Capital Cost/kWh Generated	0.019	p/kWh

4.1.2 Cost for Minimising Carbon In Ash

PF Fineness Achieved By Mills	70	% through 75μm ◀▶	Enter existing value

***** Mill Modifications Not Required - CIA Acceptable *****

Cost of Mill Modification	250000.00	£/mill ◀▶	Enter value (typical cost is £0.25million)
Capital Cost for Work on Mills	1500000.00	£	
Levelised Capital Cost for Work on Mills	1752286.50	£	
Capital Cost for Mills/te NO_x Removed	0.00	£/te NO_x Removed	
Capital Cost for Mills/kWh Generated	0.000	p/kWh	

4.2 Operating and Maintenance Costs

4.2.1 Cost of Ash Disposal due to Increase in CIA

Ash Content of Main Fuel	15.60	%
Main Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR Before OFA	1237775.39	te
Total kWh Generated at MCR	1.752E+10	kWh
Amount of Ash Disposed Before OFA	495110	te
Amount of Ash Disposed After OFA	495110	te
Disposable Cost/te NO_x Removed	0.00	£/te NO_x Removed
Disposable Cost/kWh Generated	0.000	p/kWh

4.2.2 Cost of Increased Carbon in Ash (CIA) by OFA

Measured CIA Before OFA	5.0	%	
Measured CIA After OFA	7.0	%	
Decrease in Boiler Efficiency	0.1	%/% point reduction in CIA	Ref: EPRI
Red'n in kWh Gen'd by CIA Increase	35040000	kWh	
Cost of CIA Increase/te NO_x Removed	29.51	£/te NO_x Removed	
Cost of CIA Increase/kWh Gen'd	0.001	p/kWh	

4.2.3 Cost for Lost Saleable Ash due to Increased C/A

Ash Content of Main Fuel	15.60	%	
Main Fuel Flow Rate Before OFA	62.90	kg/s	
Total Ash Produced at MCR Before OFA	1237775	te	
Amount of Ash Sold Before OFA	742665	te	
Amount of Ash Lost to Landfill by OFA	0	te	
Cost of Lost Ash Sales/te NO_x Removed	0.00	£/te NO_x Removed	
Cost of Lost Sales/kWh Generated	0.000	p/kWh	

4.2.4 Cost of Increased Steam Attemperation

Cost of Attemperation	0	kJ/kWh	
Increase in Attemperation	15	%	Ref: Longannet
Incr.Steam Attemp.Cost/te Nox Removed	0.00	£/te NO_x Removed	
Incr.Steam Attemp.Cost/kWh Generated	0.0000	p/kWh	

4.2.5 Cost for Increased Auxiliary Power

Additional OFA Fan Power Reqt for OFA	1250	kW ◄──►	Enter estimated value
Total Additional Power Requirement	43800000	kWh	
Added Power Reqt Cost/te NO_x Removed	409.84	£/te NO_x Removed	
Added Power Reqt Cost/kWh Generated	0.018	p/kWh	

4.2.6 Cost for O & M Fixed Labour

Est. O & M Costs for Coal-fired Plant	0.07	p/kWh	Ref: EPRI
Total O & M Costs Before OFA	18653326	£	
Increase in O & M Costs Due to OFA	5	%	
Increase in Total O & M Costs Due to OFA	932666	£	
Fixed Labour Costs/te NO_x Removed	120.22	£/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.005	p/kWh	

4.3 Summary of Economic Analysis of OFA

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for OFA	0.000	0.00
TOTAL CREDIT OF OFA	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.019	438.94
Minimising CIA	0.000	0.00
Operation and Maintenance Costs		
Increased CIA	0.001	29.51
Lost Saleable Ash	0.000	0.00
Increased Steam Attemperation	0.000	0.00
Increased Auxiliary Power	0.018	409.84
Fixed O & M Labour	0.005	120.22
TOTAL COST OF OFA	**0.044**	**998.51**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF OFA	**0.044**	**998.51**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 years
Unit Load Factor	40 %

Mitsui Babcock Energy Limited
Technology Centre

UPGRADE: ***Reburning***

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years

Annual Apparent Escalation Rate (e_a)	7.12	%	
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	◄──►	For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	◄──►	For Use in Costing

2. *Plant Information*

Station Name Station A

2.1 Boiler Details

Boiler Type	Front Wall-fired	
Number of Units	1	
Unit Capacity at MCR	500	MW_e

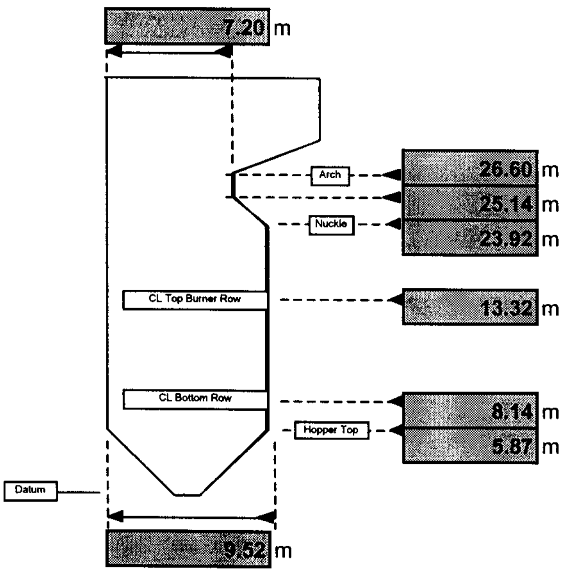
◄► Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'

Unit Load Factor 40 %

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	°
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners		Enter Manufacturer & Model
Fuel Type	Coal		Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners	
Number of Burners for Full Load/Unit	20	Burners	
Number of Burner Columns/Unit	8	Columns	
Vertical Burner Pitch	2.59	m	
Lateral Burner Spacing	2.54	m	
Number of Burners Out of Service/Unit	4	Burners OOS	
Burners/Column	3	Burners	
Burners/Column for Full Load	2.5	Burners	
Height to C_L of 2^{nd} Top Burner Row	10.73	m	
Number of Mills/Unit	6	Mills	Enter number of mills (incl. OOS mills)
Low Nox Burners Installed?	YES		Enter 'YES' or 'NO'
New/Old Burners Equally Rated?	YES		Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63		
Calorific Value of Fuel	24267	kJ/kg as rec'd	
Basis of Calorific Value	GCV		Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired	
NCV	23159	kJ/kg fired	

Check of GCV for Main Fuel

GCV Based on Ultimate Analysis	*23907*	*kJ/kg fired*	***OK***
Δ GCV (Input/Calculated)	*1.5*	*%*	
Inlet Fuel Flow to Unit at MCR	62.90	kg/s	

Operating Excess Air Level	17.0	%	Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature	75	°C	Enter value if known or use Mill Product Temp.
Windbox Air Temperature	250	°C	
Absolute Humidity of Combustion Air	8.0	$g/kg_{dry\ air}$	
Inlet Combustion Air Density	0.74	kg/m^3	(assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2

Calculated Exit O_2 Based on Ultimate Analysis *3.07 %*

Stoichiometric Dry Air Requirement	7.85	kg/kg_{fuel}	
Dry Inlet Air Flow to Unit at MCR	577.78	kg/s	(based on Unit Thermal Capacity and GCV)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature	1500	°C	Input estimate given fuel type (Suggest 1500 °C)
Measured Carbon in Ash (CIA)	5.0	%	
Unburnt Loss (UBL)	1.14	$\%_{GCV}$	
Unburnt Carbon (UBC)	0.0082	kg/kg_{fuel}	
Mass of Theoretical Dry Air Required	7.76	kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Air Required	9.08	kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Air Required	9.15	kg/kg_{fuel}	(corrected for humidity)
Mass of Flue-gas	9.98	kg/kg_{fuel}	
Total Mass Flow of Flue-gas at MCR	627.96	kg/s	

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements

Stoichiometric Air Requirement	*7.84* kg_{air}/kg_{fuel}	
Actual Air Requirement	*9.17* kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2* %	***OK***

Volume Flow of Flue-gas in Comb. Zone 3082.32 m^3/s at 1500 °C

Combustion Zone Stoichiometry 1.18

Residence Time - Top Burner Row to Arch 0.96 s

3. Reburning Parameters

3.1 Operational Details

Reburn Fuel Type **Coal** Enter 'Coal', 'Heavy Fuel Oil' or 'Gas'

Reburn Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Reburn Fuel Ratio	1.63		
Calorific Value of Reburn Fuel	24267	kJ/kg as rec'd	
Basis of Calorific Value	GCV	◄──►	Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired	
NCV	23159	kJ/kg fired	
Check of GCV for Reburn Fuel - Applies to Coal and Oil Only			
GCV Based on Ultimate Analysis	*23907*	*kJ/kg fired*	***OK***
Δ GCV (Input/Calculated)	*1.5*	*%*	
Reburn Level	20	% of Total Thermal Input	
Heat Input to Primary Zone at MCR	1221	MW_t	
Heat Input to Reburn Zone at MCR	305	MW_t	
Check of Thermal Heat Inputs at MCR for Baseline and Reburn Arrangements			
Heat Input for Baseline Arrangement	*1526*	MW_t	
Heat Input for Reburn Arrangement	*1526*	MW_t	***OK***
Inlet Fuel Flow to Primary Zone at MCR	50.32	kg/s (based on Primary Zone Heat Input and Primary Fuel GCV)	
Inlet Fuel Flow to Reburn Zone at MCR	12.58	kg/s (based on Reburn Zone Heat Input and Reburn Fuel GCV)	
Overall Operating Excess Air Level	17.0	% ◄──►	Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature to Primary Zone	75	°C ◄──►	Enter value if known or use Mill Product Temp.
Windbox Air Temperature to Primary Zone	250	°C ◄──►	Enter estimated value.
Absolute Humidity of Combustion Air	8.0	$g/kg_{dry\ air}$	Enter value if known.
Inlet Combustion Air Density	0.74	kg/m^3 (assuming PA represents 20% of total air)	
Check of Excess Air Against Exit O_2			
Calculated Exit O_2 Based on Ultimate Analysis		*3.07 %*	
Theor. Primary Zone Stoich. Dry Air Reqt	7.85	kg/kg_{1yfuel}	
Theor. Dry Inlet Air Flow to Primary Zone	462.22	kg/s (based on Unit Thermal Capacity and GCV)	

3.2 Combustion-related Details

Estimated Primary Combustion Zone Temp.	1500	°C ◄──►	Input estimate given fuel type (Suggest 1500 °C)
Carbon in Ash (CIA)	6.0	%	
Unburnt Loss (UBL)	1.39	$\%_{GCV}$	
Unburnt Carbon (UBC)	0.0100	kg/kg_{fuel}	
Reburn Zone Stoichiometry Required	0.9	◄──►	Note optimum stoichiometry range = 0.8 - 0.9 to ensure reburn zone is fuel-rich, primary zone fuel-lean (excludes O_2 in reburn coal transport air)
Resultant Primary Zone Stoichiometry	1.13		
Resultant Excess Air in Primary Zone	12.5	%	
Mass of Theor. Dry Primary Zone Air Reqd	7.74	$kg/kg_{1y\ fuel}$	(corrected for UBC)
Mass of Actual Dry Primary Zone Air Reqd	8.70	$kg/kg_{1y\ fuel}$	(corrected for UBC)
Mass of Actual Moist Primary Zone Air Reqd	8.77	$kg/kg_{1y\ fuel}$	(corrected for humidity)
Actual Inlet Air Flow to Primary Zone at MCR	441.46	kg/s	(for total fuel flow and required RBZ Stoichiometry)

Theor. Reburn Zone Stoich. Dry Air Reqt	7.85 kg/$kg_{reburn\ fuel}$	
Actual Reburn Zone Stoich. Dry Air Reqt	9.19 kg/$kg_{reburn\ fuel}$	
Actual Reburn Zone Stoich. Moist Air Reqt	9.26 kg/$kg_{reburn\ fuel}$	(corrected for humidity)

Actual Total Air Flow (Pri. + Reburn Fuels)	557.94 kg/s
Actual Inlet Air Flow to Burnout Zone	116.48 kg/s
Mass of Primary Zone Flue-gas	9.61 kg/$kg_{1y\ fuel}$
Total Mass Flow of Primary Zone Flue-gas	483.43 kg/s

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2		Combustion Products		
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	6.54	-		6.5		
C	29.64	-78.96	108.60			
H	1.82	-14.46		16.28		
S	0.81	-0.81			1.62	
Cl	0.15	-				
N	0.72	-				0.72
O	2.79	2.79				
Ash	7.85	-				
	50.3	-91.44	108.60	22.82	1.62	0.72
From Air	3.5			3.50		
H_2O	101.5	101.55				
O_2	336.4					336.41
N_2		10.11	108.60	26.32	1.62	337.13

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	108.60	23.74	22.45
O_2	10.11	2.21	2.09
N_2	337.13	73.70	69.69
SO_2	1.62	0.35	0.33
Total (dry)	457.45	100.00	-
H_2O	26.32	-	5.44
Total (wet)	483.78	-	100.00

Check of Primary Air Requirements and Stoichiometry

Stoichiometric Air Requirement	*7.84* kg_{air}/kg_{fuel}	
Actual Air Requirement	*8.82* kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2 %*	***OK***
Primary Zone Stoichiometry	1.13	
Δ Stoichiometry (calc/mass bal.)	*-0.8*	***OK***

Volume Flow of Flue-gas in Comb. Zone 2369.87 m^3/s at 1500 °C

Primary Zone Residence Time Required **0.40** s ⟷ Enter value
(Note minimum recommended = 0.4s)

Elevation of Reburn Injectors 14.13 m ***OK***

Reburn Fuel Transport Mass Flow	20	kg/s	For coal, enter value if known (zero for NG and Oil)
Recirculate Flue-Gas Vol. with Reburn Fuel	37.68	kg/s	
Total Flow Entering Reburn Injectors	70.26	kg/s	(including reburn fuel flow)
Density at Reburn Injectors	0.22	kg/m^3	
Volumetric Flow from the Reburn Injectors	326.37	m^3/s	
Total Vol. of Flue-Gas at Reburn Injectors	2696.24	m^3/s	
Reburn Zone Residence Time Required	0.5	s	Enter value (Note min. = 0.5s (coal), 0.4s (oil), 0.2s (gas))
Elevation of OFA Injectors	18.97	m	***OK***
Total Volume of Flue-gas at OFA Injectors	3215.34	m^3/s	
Residence Time in Burnout Zone	0.62	s	***OK***

***** REBURNING CAN BE APPLIED TO THE CURRENT UNIT *****
***** BUT A DETAILED STUDY IS REQUIRED *****

4.0 Calculation of Credits and Costs Associated with Reburning

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500	MW_e	
Unit Heat Rate	10.55	MJ/kWh	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh	Enter price in p/kWh (typical price is 5p/kWh)
Coal Cost	1.25	£/GJ	Enter price in £/GJ (1998 price is £1.25/GJ)
Fuel Oil Cost	2.30	£/GJ	Enter price in £/GJ (1998 price is £2.3/GJ)
Gas Cost	1.90	£/GJ	Enter price in £/GJ (1998 price is £1.9/GJ)
Cost of Landfill Ash	8.70	£/te	Enter price in £/te (1998 price is £8.70/te)
Price of Saleable Ash	3.00	£/te	Enter price in £/te (1998 prices is £1-15/te)
Proportion of Total Ash Sold Before Reburn	60	%	Enter proportion as a percentage
Capital Cost	10	£/kW_e	Enter price in £/kW_e (1998 price is £10/kW_e)
Reduction Achieved	50	%	Enter reduction in % (typical reduction is 50%)

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3	Enter emission (limit = $650mg/Nm^3$)
Mass Flow of Flue Gas	627.96	kg/s	
Volume Flow of Flue Gas	474.60	m^3/s	
Density of Flue Gas	1.32	kg/m^3	
Total NO_x Produced at MCR	38915	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Capital Cost of Technology	5000000.00	£	
Difficulty Factor	1.2		Relates to Difficulty of Installation
Total Capital Cost of Technology	6000000.00	£	Range 1-1.4

Additional Capital Cost for <u>Gas</u> Reburn Only - Gas Piping to Site

Distance of Gas Pipeline to Grid	33.7	km	
One-off Capital Cost of Gas Pipeline	26960000.00	£ ◄──►	Cost est.at £0.8million/km - Ref. Penspen)

Total Capital Cost of Technology	6000000.00	£
Levelised Capital Cost of Technology	7009145.99	£
NO_x Reduction Achieved	50	%
Capital Cost/te NO_x Removed	360.23	£/te NO_x Removed
Capital Cost/kWh Generated	0.040	p/kWh

4.1.2 Cost for Minimising Carbon In Ash

PF Fineness Achieved By Mills	70	% through 75µm ◄──►	Enter existing value
Acceptable CIA Level	7	% ◄──►	Typical value 7%

*****Mill Modifications Not Required - CIA Acceptable*****

Cost of Mill Modification	250000.00	£/mill ◄──►	Enter value (typical cost is £0.25million)
Capital Cost for Work on Mills	1500000.00	£	
Levelised Capital Cost for Work on Mills	1752286.50	£	
Capital Cost for Mills/te NO_x Removed	0.00	£/te NO_x Removed	
Capital Cost for Mills/kWh Generated	0.000	p/kWh	

4.2 Operating and Maintenance Costs

4.2.1 Credit for Reduced Ash Disposal due to Reburn Fuel (Gas and Oil Reburn Only)

Reburn Fuel Type	Coal		
Ash Content of Main Fuel	15.60	%	
Main Fuel Flow Rate Before Reburn	62.90	kg/s	
Main Fuel Flow Rate After Reburn	50.32	kg/s	
Total Ash Produced at MCR Before Reburn	1237775	te	
Total Ash Produced at MCR After Reburn	990220	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Amount of Ash Disposed Before Reburn	495110	te	
Amount of Ash Disposed After Reburn	396088	te	
Reduced Amount of Ash Disposed	99022	te	
Total Disposal Credit	1250754	£	
Disposable Credit/te NO_x Removed	0.00	£/te NO_x Removed	
Disposable Credit/kWh Generated	0.000	p/kWh	*** Not Applicable ***

4.2.2 Credit for Reduced SO_2 Emissions (Gas Reburn Only)

Sulphur Content of Main Fuel	1.61	%
Molecular Mass	64	kg/kmol
Mass Flow of S Produced Before Reburn	3.65	te/h
Mass Flow of SO_2 Produced (100% conv.)	7.29	te/h
Total SO_2 Produced Before Reburn	255490	te

Cost of SO_2 Removal	125.00 £/te	Enter estimated cost for SO_2 Removal (Ref: EPRI) (est.costs: FGD = £125/te)
Total SO_2 Produced After Reburn	204392 te	
SO_2 Emission Ceiling	no	Enter 'yes' if the station operates an SO_2 ceiling, if not, enter 'no'
Total Reduced SO_2 Production Credit	9273290.58 £	
Reduced SO_2 Credit/te NO_x Removed	0.00 £/te NO_x Removed	*** Not Applicable ***
Reduced SO_2 Credit/kWh Generated	0.000 p/kWh	

4.2.3 Credit for Reduced Coal Mill Maintenance (Gas and Oil Reburn Only)

Total O & M Costs Before Reburn	18653325.66 £	
O & M Cost Associated with Mills	1865332.57 £	(assumes Mill costs = 10% of Total O & M Costs)
Number of Mills in Service Before Reburn	6 Mills	
Number of Mills in Service After Reburn	5 Mills	
Reduced Mill O & M Credit/te NO_x Removed	0.00 £/te NO_x Removed	
Reduced Mill O & M Credit/kWh Generated	0.000 p/kWh	***Not Applicable***

4.2.4 Cost for Increased Flue Gas Moisture (Gas Reburn Only)

Coal Cost	1.25 /GJ	
Gas Cost	1.9 /GJ	
Average Fuel Cost	1.38 /GJ	
New Heat Rate	10.55 MJ/kWh	
Percentage Increase in Heat Rate	0.00 %	
Cost of Efficiency Loss/te NOx Removed	0.00 £/te NO_x Removed	
Cost of Efficiency Loss/kWh Generated	0.000 p/kWh	***Not Applicable***

4.2.5 Cost of Increased Carbon in Ash (CIA) by Reburn

Measured CIA Before Reburn	5.0 %	
Measured CIA After Reburn	6.0 %	
Decrease in Boiler Efficiency	0.1 %/% point increase in CIA	Ref: EPRI
Red'n in kWh Gen'd by CIA Increase	17520000 kWh	
Cost of CIA Increase/te NO_x Removed	5.88 £/te NO_x Removed	
Cost of CIA Increase/kWh Gen'd	0.0007 p/kWh	

4.2.6 Cost for Lost Saleable Ash due to Increased CIA

Amount of Ash Sold Before Reburn	742665.2314 te
Amount of Ash Lost to Landfill by Reburning	0 te
Cost of Lost Ash Sales/te NO_x Removed	0.00 £/te NO_x Removed
Cost of Lost Sales/kWh Generated	0.000 p/kWh

4.2.7 Cost of Increased Steam Attemperation

Cost of Attemperation	0	kJ/kWh	
Increase in Attemperation	15	%	Ref: Longannet
Incr.Steam Attemp.Cost/te Nox Removed	0.00	£/te NO_x Removed	
Incr.Steam Attemp.Cost/kWh Generated	0.000	p/kWh	

4.2.8 Cost of Use of Aternative Reburn Fuel (Gas and Oil Reburn Only)

Coal Cost	1.25	£/GJ	
Gas Cost	1.90	£/GJ	
Heavy Fuel Oil Cost	2.30	£/GJ	
Total Cost of Fuel Before Reburn	349433140.53	£	
Total Cost of Fuel After Reburn (for Gas)	349433140.53	£	
Total Cost of Fuel After Reburn (for Oil)	349433140.53	£	
Increase in Fuel Costs Due to Reburn	0.00	£	
Cost of Fuel Switching/te NO_x Removed	0.00	£/te NO_x Removed	
Cost of Fuel Switching/kWh Generated	0.000	p/kWh	***Not Applicable***

4.2.9 Cost for Increased Auxiliary Power

Additional OFA Fan Power Reqt for Reburn	1250	kW ←→	Enter estimated value
Additional FGR Fan Power Reqt for Reburn	850	kW ←→	Enter estimated value
Total Additional Power Requirement	73584000	kWh	
Added Power Reqt Cost/te NO_x Removed	274.53	£/te NO_x Removed	
Added Power Reqt Cost/kWh Generated	0.030	p/kWh	

4.2.10 Credit for Reduced Auxiliary Power (Gas Reburn Only)

Power Saving/Mill for Gas Reburn	360	kW ←→	Enter estimated value
Power Saving/Coal feeder for Gas Reburn	3	kW	
Power Saved	30099360	kWh	
Power Saved/te Nox Removed	0.00	£/te NO_x Removed	
Power Saved/kWh Generated	0.000	p/kWh	***Not Applicable***

4.2.11 Cost for O & M Fixed Labour

Est. O & M Costs for Coal-fired Plant	0.07	p/kWh	Ref: EPRI
Total O & M Costs Before Reburn	18653326	£	
Increase in O & M Costs Due to Reburn	10	%	
Increase in Total O & M Costs Due to Reburn	1865333	£	
Fixed Labour Costs/te NO_x Removed	95.87	£/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.011	p/kWh	

4.3 Summary of Economic Analysis of Reburn

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
Reduced Ash Disposal	0.000	0.00
Reduced SO_2 Emissions	0.000	0.00
Reduced Mill Maintenance	0.000	0.00
Reduced Auxiliary Power	0.000	0.00
TOTAL CREDIT OF REBURN	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.040	360.23
Minimising CIA	0.000	0.00
Operation and Maintenance Costs		
Increased Flue Gas Moisture	0.000	0.00
Increased CIA	0.0007	5.88
Lost Saleable Ash	0.000	0.00
Increased Steam Attemperation	0.000	0.00
Alternative Reburn Fuel (Oil/Gas)	0.000	0.00
Increased Auxiliary Power	0.030	274.53
Fixed O & M Labour	0.011	95.87
TOTAL COST OF REBURN	**0.082**	**736.52**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF REBURN	**0.082**	**736.52**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 years
Unit Load Factor	40 %
Reburn Fuel Type	Coal

Mitsui Babcock Energy Limited
Technology Centre

UPGRADE: ***Selective Non-Catalytic Reduction (SNCR)***

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years

Annual Apparent Escalation Rate (e_a)	7.12 %	
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	◄──► For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	◄──► For Use in Costing

2. *Plant Information*

Station Name Station A

2.1 Boiler Details

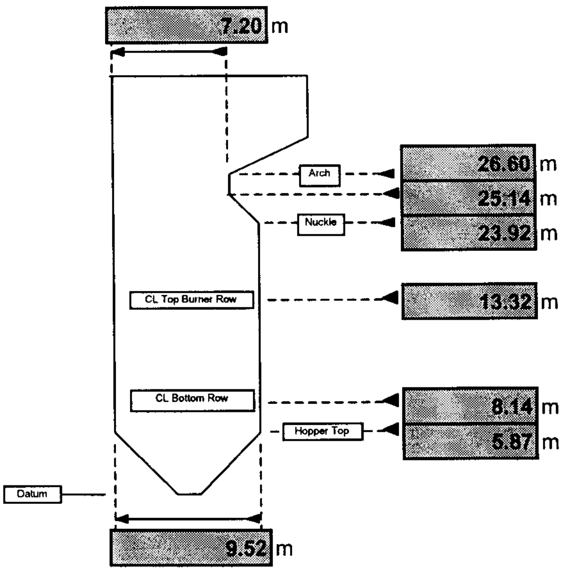
Boiler Type	Front Wall-fired	◄► Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'
Number of Units	1	
Unit Capacity at MCR	500	MW_e

Unit Load Factor 40 %

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	°
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners	Enter Manufacturer & Model
Fuel Type	Coal	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners
Number of Burners for Full Load/Unit	20	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	2.59	m
Lateral Burner Spacing	2.54	m
Number of Burners Out of Service/Unit	4	Burners OOS
Burners/Column	3	Burners
Burners/Column for Full Load	2.5	Burners
Height to C_L of 2^{nd} Top Burner Row	10.73	m
Low NOx Burners Installed?	YES	
New/Old Burners Equally Rated?	YES	← → Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63	
Calorific Value of Fuel	24267	kJ/kg as rec'd
Basis of Calorific Value	GCV	← → Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired
NCV	23159	kJ/kg fired

Check of GCV for Main Fuel

GCV Based on Ultimate Analysis	*23907 kJ/kg fired*	***GCV - OK***
Δ GCV (Input/Calculated)	*1.5 %*	

Inlet Fuel Flow to Unit at MCR	62.90 kg/s	
Operating Excess Air Level	17.0 %	Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature	75 °C	Enter value if known or use Mill Product Temp.
Windbox Air Temperature	250 °C	
Absolute Humidity of Combustion Air	8.0 $g/kg_{dry\ air}$	
Combustion Air Density	0.74 kg/m^3	(assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2

Calculated Exit O_2 Based on Ultimate Analysis — *3.07 %*

Stoichiometric Dry Air Requirement	7.85 kg/kg_{fuel}	
Dry Inlet Air Flow to Unit at MCR	577.78 kg/s	(based on Inlet Fuel Flow Rate)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature	1500 °C	Input estimate given fuel type (Suggest 1500 °C)
Measured Carbon in Ash (CIA)	5.0 %	
Unburnt Loss (UBL)	1.14 $\%_{GCV}$	
Unburnt Carbon (UBC)	0.0082 kg/kg_{fuel}	
Mass of Theoretical Dry Air Required	7.76 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Air Required	9.08 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Air Required	9.15 kg/kg_{fuel}	(corrected for humidity)
Mass of Flue-gas	9.98 kg/kg_{fuel}	
Total Mass Flow of Flue-gas at MCR	627.96 kg/s	

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^{w}/_{w}$)	% wet ($^{w}/_{w}$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements

Stoichiometric Air Requirement	*7.84* kg_{air}/kg_{fuel}	
Actual Air Requirement	*9.17* kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2 %*	***OK***

Volume Flow of Flue-gas in Comb. Zone 3082.32 m^3/s at 1500 ^oC

Combustion Zone Stoichiometry 1.18

Residence Time - Top Burner Row to Nuckle 0.96 s

3. SNCR Parameters (Assumes Boiler Volume Available at Required Temperature)

3.1 Operational Details

Reagent Used for NO_x Reduction	**Anhyd. Ammonia**	Enter 'Anhyd. Ammonia', 'Aq. Ammonia' or 'Urea'
Measured Ammonia Slip to Stack/Fly Ash	**10** ppmv	***ASH IS SALEABLE***
NO_x Reduction Achievable	**40** %	
Uncontrolled NO_x Produced from Unit at MCR	**650** mg/Nm^3	Enter emission (limit = 650mg/Nm^3)
NO_x Produced from Unit at MCR with SCR	390 mg/Nm^3	
Volume Flow of Flue-gas in Comb. Zone	3082.32 m^3/s at 1500 ^oC	
Vol. Flow of Flue-gas at Convective Banks	7967094.88 m^3/h at 1000 ^oC	
Vol. of NH_3 Injection Region for Reduction	**670.00** m^3/unit	Input value to give residence time > 0.3s
Flue-gas Res. Time in Convective Banks	0.30 s	***OK***
Amount of NH_3 Required for Reduction	328.34 kg/h (Anhydrous)	
Pressure Drop Across Reactor	0.0 mbar	

4. Calculation of Credits and Costs Associated with SNCR

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500 MW_e	
Unit Heat Rate	**10.55** MJ/kWh	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)

Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh	Enter price in p/kWh (typ. price is 5p/kWh)
Coal Cost	1.25	£/GJ	Enter price in £/GJ (1998 price is £1.25/GJ)
Oil Cost	2.30	£/GJ	Enter price in £/GJ (1998 price is £2.3/GJ)
Gas Cost	1.90	£/GJ	Enter price in £/GJ (1998 price is £1.9/GJ)
Reagent Cost	150.00	£/te	Enter price in £/te (1998 price is £150/te)
Capital Cost of SNCR	8500.00	£/MW_e	Enter price in £ (1998 price is £8500/MW_e)
Cost of Landfill Ash	26.00	£/te	Enter price in £/ton (1998 price is £26/ton)
Price of Saleable Ash	3.00	£/te	Enter price in £/ton (1998 price is £1-15/ton)
Proportion of Total Ash Sold Before SNCR	60	%	Enter proportion as a percentage

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3	
Mass Flow of Flue Gas	627.96	kg/s	
Volume Flow of Flue Gas	474.60	m^3/s	
Density of Flue Gas	1.32	kg/m^3	
Total NO_x Produced at MCR	38914.52	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Capital Cost of Technology	4250000.00	£	
Difficulty Factor	1.1		Relates to difficulty of installation (Range 1.0 - 1.4)
Total Capital Cost of Technology	4675000.00	£	
Levelised Capital Cost of Technology	5461292.92	£	
NO_x Reduction Achieved	40	%	
Capital Cost/te NO_x Removed	350.85	£/te NO_x Removed	
Capital Cost/kWh Generated	0.031	p/kWh	

4.2 Operating and Maintenance Costs

4.2.1 Cost for Increased Ash Disposal to Landfill due to NH_3 Slip

Fuel Type	Coal	
Ash Content of Fuel	15.60	%
Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR	1237775	te
Total kWh Generated at MCR	1.752E+10	kWh
Amount of Ash Disposed Before SNCR	495110	te
Extra Ash Disposed Due to SNCR	371333	te
Total Disposal Cost	14017068.30	£
Disposal Cost/te NO_x Removed	900.50	£/te NO_x Removed
Disposal Cost/kWh Generated	0.080	p/kWh

4.2.2 Cost for Lost Saleable Ash due to NH_3 Slip

Amount of Ash Sold Before SNCR	742665	te
Amount of Ash Lost to Landfill due to SNCR	371333	te
Cost of Lost Ash Sales/te NO_x Removed	103.90	£/te NO_x Removed
Cost of Lost Ash Sales/kWh Generated	0.009	p/kWh

4.2.3 Cost for Increased Power Consumption due to ΔP Across SNCR Injection Zone

Added Power Reqt/mbar ΔP	50	kW/mbarΔP	Ref.
Total Additional Power Requirement	0	kWh	
Added Power Reqt Cost/te NO_x Removed	0.00	£/te NO_x Removed	
Added Power Reqt Cost/kWh Generated	0.000	p/kWh	

4.2.4 Cost of Increased Power for NH_3 Injection

Energy Penalty due to NH_3 Injection System	390	kWh/te of NH_3 Injected	Ref.
Total Mass of NH_3 Injected for Reduction	11505	te	
Total Additional Power Requirement	4487013	kWh	
Added Power Reqt Cost/te NO_x Removed	20.93	£/te NO_x Removed	
Added Power Reqt Cost/kWh Generated	0.002	p/kWh	

4.2.5 Cost of Reagent Consumption

Cost of Anhydrous NH_3	150	£/te
Cost of Reagent/te NO_x Removed	160.97	£/te NO_x Removed
Cost of Reagent/kWh Generated	0.014	p/kWh

4.2.6 Cost of Forced Outages for Maintenance (Assumes Not Included in Normal Outages)

Operating Time Lost for Outages	5	%	Ref: IEA
Total Operating Time Lost for Outages	876000000	kWh	
Cost of Forced Outagest/te NO_x Removed	4085.29	£/te NO_x Removed	
Cost of Forced Outages/kWh Generated	0.363	p/kWh	

4.2.7 Cost for O & M Fixed Labour

Est. Proportion of Cap. Cost for Labour	5	%pa	Ref: EPRI
Total Cost for O & M Fixed Labour	850000	£	
Fixed Labour Costs/te NO_x Removed	79.28	£/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.007	p/kWh	

4.3 Summary of Economic Analysis of SNCR

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for SNCR	0.000	0.00
TOTAL CREDIT OF SNCR	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.031	350.85
Operation and Maintenance Costs		
Increased Ash Disposal	0.080	900.50
Lost Saleable Ash	0.009	103.90
Increased Power for Convective Bank ΔP	0.000	0.00
Increased Power For NH_3 Injection	0.002	20.93
Reagent Consumption	0.014	160.97
Forced Outages for Maintenance	0.363	4085.29
Fixed O & M Labour	0.007	79.28
TOTAL COST OF SNCR	**0.507**	**5701.72**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF SNCR	**0.507**	**5701.72**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 years
Unit Load Factor	40 %

Mitsui Babcock Energy Limited
Technology Centre

UPGRADE: ***Selective Catalytic Reduction (SCR)***

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years

INPUT VALUES IN SHADED CELLS

Annual Apparent Escalation Rate (e_a)	7.12 %	
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	For Use in Costing

2. *Plant Information*

Station Name Station A

2.1 Boiler Details

Boiler Type	Front Wall-fired	
Number of Units	1	
Unit Capacity at MCR	500	MW_e

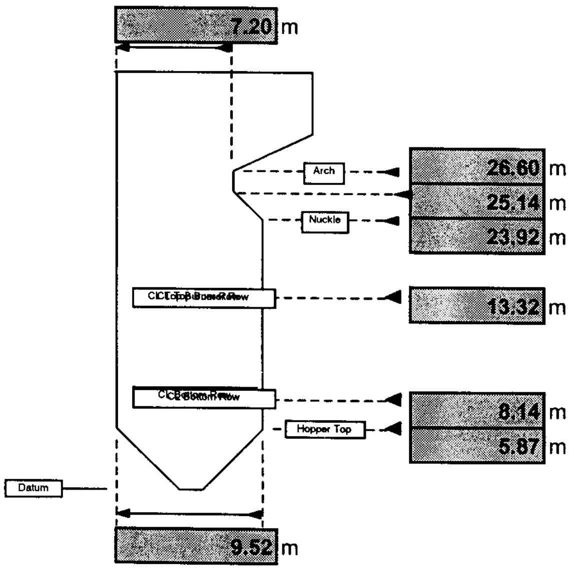
Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'

Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	°
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners		Enter Manufacturer & Model
Fuel Type	Coal		Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners	
Number of Burners for Full Load/Unit	20	Burners	
Number of Burner Columns/Unit	8	Columns	
Vertical Burner Pitch	2.59	m	
Lateral Burner Spacing	2.54	m	
Number of Burners Out of Service/Unit	4	Burners OOS	
Burners/Column	3	Burners	
Burners/Column for Full Load	2.5	Burners	
Height to C_L of 2nd Top Burner Row	10.73	m	
Low NOx Burners Installed?	YES		Enter 'YES' or 'NO'
New/Old Burners Equally Rated?	YES		Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63		
Calorific Value of Fuel	24267	kJ/kg as rec'd	
Basis of Calorific Value	GCV		Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired	
NCV	23159	kJ/kg fired	

Check of GCV for Main Fuel
GCV Based on Ultimate Analysis — *23907 kJ/kg fired* — ***GCV - OK***
Δ GCV (Input/Calculated) — *1.5 %*

Inlet Fuel Flow to Unit at MCR — 62.90 kg/s

Operating Excess Air Level — 17.0 % ⟷ Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature — 75 °C ⟷ Enter value if known or use Mill Product Temp.
Windbox Air Temperature — 250 °C
Absolute Humidity of Combustion Air — 8.0 $g/kg_{dry\ air}$
Combustion Air Density — 0.74 kg/m^3 (assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2
Calculated Exit O_2 Based on Ultimate Analysis — *3.07 %*

Stoichiometric Dry Air Requirement — 7.85 kg/kg_{fuel}
Dry Inlet Air Flow to Unit at MCR — 577.78 kg/s (based on Inlet Fuel Flow Rate)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature — 1500 °C ⟷ Input estimate given fuel type (Suggest 1500 °C)

Measured Carbon in Ash (CIA) — 5.0 %
Unburnt Loss (UBL) — 1.14 $\%_{GCV}$
Unburnt Carbon (UBC) — 0.0082 kg/kg_{fuel}

Mass of Theoretical Dry Air Required — 7.76 kg/kg_{fuel} (corrected for UBC)
Mass of Actual Dry Air Required — 9.08 kg/kg_{fuel} (corrected for UBC)
Mass of Actual Moist Air Required — 9.15 kg/kg_{fuel} (corrected for humidity)

Mass of Flue-gas — 9.98 kg/kg_{fuel}
Total Mass Flow of Flue-gas at MCR — 627.96 kg/s

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements		
Stoichiometric Air Requirement	*7.84 kg_{air}/kg_{fuel}*	
Actual Air Requirement	*9.17 kg_{air}/kg_{fuel}*	
Δ Stoich Air (calc/mass balance)	*0.2 %*	***OK***

Volume Flow of Flue-gas in Comb. Zone	3082.32 m^3/s	at	1500 °C
Combustion Zone Stoichiometry	1.18		
Residence Time - Top Burner Row to Nuckle	0.96 s		

3. SCR Parameters (Assumes Space Available on Site)

3.1 Operational Details

Conditions at Position of SCR Reactor	High Dust	Enter High Dust, Low Dust or Tail End
Measured Ammonia Slip to Stack/Fly Ash	3 ppmv	***ASH IS SALEABLE***
NO_x Reduction Achievable with Catalyst	80 % ◄──►	Enter '90' if Slip < 1ppmv, '80' if Slip >1 but <3 or '70' if Slip > 3
Uncontrolled NO_x Produced from Unit at MCR	650 mg/Nm^3 ◄►	Enter emission (limit = 650mg/Nm^3)
NO_x Produced from Unit at MCR with SCR	130 mg/Nm^3	

Volume Flow of Flue-gas in Comb. Zone	3082.32 m^3/s	at	1500 °C
Volume Flow of Flue-gas at Economiser	3899057.43 m^3/h	at	350 °C

Volume of Catalyst Required for Reduction	550.00 m^3/unit ◄►	Input value to give residence time > 0.5s
Flue-gas Residence Time in Catalyst	0.51 s	***OK***
Amount of NH_3 Required for Reduction	328.34 kg/h (Anhydrous)	
SO_3 Produced from SO_2 by Catalyst	0.003 %	
Pressure Drop Across Reactor	5.5 mbar	

4. Calculation of Credits and Costs Associated with SCR

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR 500 MW_e

Unit Heat Rate	10.55	MJ/kWh	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh	Enter price in p/kWh (typ. price is 5p/kWh)
Coal Cost	1.25	£/GJ	Enter price in £/GJ (1998 price is £1.25/GJ)
Oil Cost	2.30	£/GJ	Enter price in £/GJ (1998 price is £2.30/GJ)
Gas Cost	1.90	£/GJ	Enter price in £/GJ (1998 price is £1.9/GJ)
Anhydrous NH_3 Cost	150.00	£/te	Enter price in £/te (1998 price is £150/te)
Catalyst Cost	5000.00	£/m^3	Enter price in £/m^3 (1998 price is £5000/m^3)
Capital Cost of SCR	65000.00	£/MW$_e$	Enter price in £ (1998 price is £65000/MW$_e$)
Cost of Landfill Ash	26.00	£/te	Enter price in £/te (1998 price is £26/ton)
Price of Saleable Ash	3.00	£/te	Enter price in £/te (1998 prices are £1-15/ton)
Proportion of Total Ash Sold Before SCR	60	%	Enter proportion as a percentage

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3
Mass Flow of Flue Gas	627.96	kg/s
Volume Flow of Flue Gas	474.60	m^3/s
Density of Flue Gas	1.32	kg/m^3
Total NO_x Produced at MCR	38914.52	te
Total kWh Generated at MCR	1.752E+10	kWh
Capital Cost of Technology	32500000.00	£
Difficulty Factor	1.3	Relates to difficulty of installation (Range 1.0 - 1.4)
Total Capital Cost of Technology	42250000.00	£
Levelised Capital Cost of Technology	49356069.69	£
NO_x Reduction Achieved	80	%
Capital Cost/te NO_x Removed	1585.40	£/te NO_x Removed
Capital Cost/kWh Generated	0.282	p/kWh

4.2 Operating and Maintenance Costs

4.2.1 Cost for Increased Ash Disposal to Landfill due to NH_3 Slip

Fuel Type	Coal	
Ash Content of Fuel	15.60	%
Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR	1237775	te
Total kWh Generated at MCR	1.752E+10	kWh
Amount of Ash Disposed Before SCR	495110	te
Extra Ash Disposed Due to SCR	185666	te
Total Disposal Cost	7008534.15	£
Disposal Cost/te NO_x Removed	225.13	£/te NO_x Removed
Disposal Cost/kWh Generated	0.040	p/kWh

4.2.2 Cost for Lost Saleable Ash due to NH_3 Slip

Amount of Ash Sold Before SCR	742665	te
Amount of Ash Lost to Landfill due to SCR	185666	te
Cost of Lost Ash Sales/te NO_x Removed	25.98	£/te NO_x Removed
Cost of Lost Ash Sales/kWh Generated	0.005	p/kWh

4.2.3 Cost for Increased Power Consumption due to ΔP Across SCR Reactor

Added Power Reqt/mbar ΔP	50	kW/mbarΔP	Ref.
Total Additional Power Requirement	9636000	kWh	
Added Power Reqt Cost/te NO_x Removed	22.47	£/te NO_x Removed	
Added Power Reqt Cost/kWh Generated	0.004	p/kWh	

4.2.4 Cost of Increased Power for NH_3 Injection

Energy Penalty due to NH_3 Injection System	390	kWh/te of NH_3 Injected
Total Mass of NH_3 Injected for Reduction	11505	te
Total Additional Power Requirement	4487013	kWh
Added Power Reqt Cost/te NO_x Removed	10.46	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.002	p/kWh

4.2.5 Cost of Reagent Consumption

Cost of Anhydrous NH_3	150	£/te
Cost of Reagent/te NO_x Removed	80.48	£/te NO_x Removed
Cost of Reagent/kWh Generated	0.014	p/kWh

4.2.6 Cost of Forced Outages for Maintenance (Assumes Not Included in Normal Outages)

Operating Time Lost for Outages	1.25	%	Ref: IEA
Total Operating Time Lost for Outages	219000000	kWh	
Cost of Forced Outagest/te NO_x Removed	510.66	£/te NO_x Removed	
Cost of Forced Outages/kWh Generated	0.091	p/kWh	

4.2.7 Cost for Replacement Catalysts

Cost of Initial Catalyst on Installation	2750000	£
Number of Catalyst Replacements/Period	0.8	Catalysts
Cost of Replacement Catalysts	2200000	£
Replacement Cat. Costs/te NO_x Removed	102.60	£/te NO_x Removed
Replacement Cat. Costs/kWh Generated	0.018	p/kWh

4.2.8 Cost for O & M Fixed Labour

Est. Proportion of Cap. Cost for Labour	1	%pa	Ref: EPRI
Total Cost for O & M Fixed Labour	1300000	£	
Fixed Labour Costs/te NO_x Removed	60.63	£/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.011	p/kWh	

4.2.9 Cost for Reheating of Flue-Gases (Tail-End SCR Only)

Not Applicable

Cost for Reheating Flue-Gases	18	% of Final Levelised Costs of High Dust SCR	Ref: IEA

4.2.10 Credit for Eliminating Reheat After FGD (Tail-End SCR Only)

Not Applicable

Reheating of Flue-Gas After FGD Applied? no ⟷ Enter YES or NO

Typ.Credit for Eliminating Reheat/kWh Gen'd 0.000 p/kWh Ref: IEA

Typ.Credit for Elim. Reheat/te NO_x Rem'd 0.000 £/te NO_x Removed

4.3 Summary of Economic Analysis of SCR

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for SCR	0.000	0.00
TOTAL CREDIT OF SCR	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.282	1585.40
Operation and Maintenance Costs		
Increased Ash Disposal	0.040	225.13
Lost Saleable Ash	0.005	25.98
Increased Power for Reactor ΔP	0.004	22.47
Increased Power For NH_3 Injection	0.002	10.46
Reagent Consumption	0.014	80.48
Forced Outages for Maintenance	0.091	510.66
Replacement Catalysts	0.018	102.60
Fixed O & M Labour	0.011	60.63
Reheat of Flue-Gases	0.000	0.00
TOTAL COST OF SCR	**0.466**	**2623.80**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF SCR	**0.466**	**2623.80**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 years
Unit Load Factor	40 %

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Technology Centre

UPGRADE: ***SNCR-SCR Hybrid***

1. *Economic Assumptions* (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.60	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years
Annual Apparent Escalation Rate (e_a)	7.12	%
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	↔ For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	↔ For Use in Costing

2. *Plant Information*

Station Name Station A

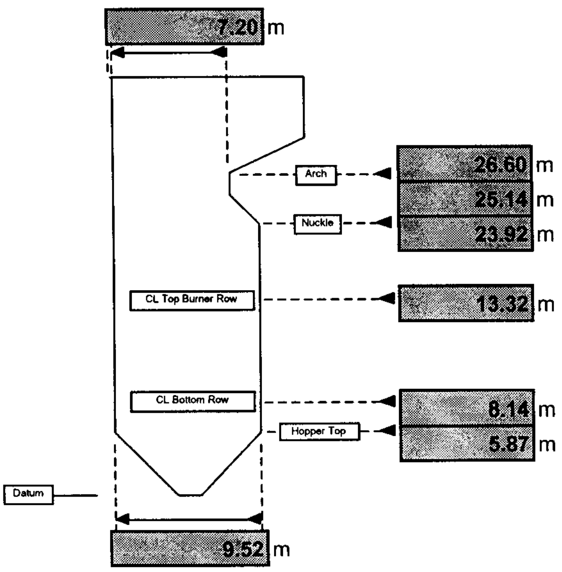
2.1 *Boiler Details*

Boiler Type	Front Wall-fired	↔ Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'
Number of Units	1	
Unit Capacity at MCR	500	MW_e
Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	^{o}
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners	Enter Manufacturer & Model
Fuel Type	Coal	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners
Number of Burners for Full Load/Unit	20	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	2.59	m
Lateral Burner Spacing	2.54	m
Number of Burners Out of Service/Unit	4	Burners OOS
Burners/Column	3	Burners
Burners/Column for Full Load	2.5	Burners
Height to C_L of 2^{nd} Top Burner Row	10.73	m
Low NOx Burners Installed?	YES	
New/Old Burners Equally Rated?	YES	← → Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63	
Calorific Value of Fuel	24267	kJ/kg as rec'd
Basis of Calorific Value	GCV	← → Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired
NCV	23159	kJ/kg fired

Check of GCV for Main Fuel
GCV Based on Ultimate Analysis — *23907 kJ/kg fired* — ***GCV - OK***
Δ GCV (Input/Calculated) — *1.5 %*

Inlet Fuel Flow to Unit at MCR	62.90 kg/s	
Operating Excess Air Level	17.0 %	Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature	75 °C	Enter value if known or use Mill Product Temp.
Windbox Air Temperature	250 °C	
Absolute Humidity of Combustion Air	8.0 $g/kg_{dry\ air}$	
Combustion Air Density	0.74 kg/m^3	(assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2
Calculated Exit O_2 Based on Ultimate Analysis — *3.07 %*

Stoichiometric Dry Air Requirement	7.85 kg/kg_{fuel}	
Dry Inlet Air Flow to Unit at MCR	577.78 kg/s	(based on Inlet Fuel Flow Rate)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature	1500 °C	Input estimate given fuel type (Suggest 1500 °C)
Measured Carbon in Ash (CIA)	5.0 %	
Unburnt Loss (UBL)	1.14 $\%_{GCV}$	
Unburnt Carbon (UBC)	0.0082 kg/kg_{fuel}	
Mass of Theoretical Dry Air Required	7.76 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Air Required	9.08 kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Air Required	9.15 kg/kg_{fuel}	(corrected for humidity)
Mass of Flue-gas	9.98 kg/kg_{fuel}	
Total Mass Flow of Flue-gas at MCR	627.96 kg/s	

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements			
Stoichiometric Air Requirement	*7.84*	kg_{air}/kg_{fuel}	
Actual Air Requirement	*9.17*	kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2*	*%*	***OK***

Volume Flow of Flue-gas in Comb. Zone	3082.32	m^3/s	at	1500	°C
Combustion Zone Stoichiometry	1.18				
Residence Time - Top Burner Row to Nuckle	0.96	s			

3. *SNCR-SCR Parameters (Assumes Boiler Volume Available at Required Temperature)*

3.1 Operational Details

Reagent Used for NO_x Reduction	**Anhyd. Ammonia**	◀──▶	Enter 'Anhyd. Ammonia', 'Aq. Ammonia' or 'Urea'
SCR Arrangement	**Compact**	◀──▶	Enter 'Compact' (High Dust) or 'In-duct' (High Dust)
Measured Ammonia Slip to Stack/Fly Ash	**2** ppmv		***ASH IS SALEABLE***
NO_x Reduction Achievable	**50** %		
Uncontrolled NO_x Produced from Unit at MCR	**650** mg/Nm^3		
NO_x Produced from Unit with SNCR-SCR	325 mg/Nm^3		

Volume Flow of Flue-gas in Comb. Zone	3082.32	m^3/s	at	1500	°C
Vol. Flow of Flue-gas at Convective Banks	7967094.88	m^3/h	at	1000	°C
Vol. Flow of Flue-gas through SCR Reactor	3899057.43	m^3/h	at	350	°C

Vol. of NH_3 Injection Region for SNCR	**670.00** m^3/unit	◀▶	Input value to give residence time > 0.3s
Flue-gas Res. Time in Convective Banks	0.30 s		***OK***
Volume of Catalyst Required for Reduction	**550.00** m^3/unit	◀▶	Input value to give residence time > 0.5s

Flue-gas Residence Time in Catalyst	0.51 s	*OK*
Amount of NH_3 Required for Reduction	410.43 kg/h(Anhyd)	It is assumed that ammonia slip from SNCR will act as the reducing agent for SCR
SO_3 Produced from SO_2 by Catalyst	0.003 %	

Pressure Drop Across SNCR Inj.Bank	0.0 mbar
Pressure Drop Across SCR Reactor	5.5 mbar

4. Calculation of Credits and Costs Associated with SNCR/SCR Hybrid

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500	MW_e	
Unit Heat Rate	10.55	MJ/kWh	
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Electricity Cost	5.00	p/kWh ⟷	Enter price in p/kWh (1998 price is 5p/kWh)
Coal Cost	1.25	£/GJ ⟷	Enter price in £/GJ (1998 price is £1.25/GJ)
Oil Cost	2.30	£/GJ ⟷	Enter price in £/GJ (1998 price is £2.30/GJ)
Gas Cost	1.90	£/GJ ⟷	Enter price in £/GJ (1998 price is £1.90/GJ)
Reagent Cost	150.00	£/te ⟷	Enter price in £/te (1998 price is £150/te)
Catalyst Cost	5000.00	£/m^3 ⟷	Enter price in £/m^3 (1998 price is £5000/m^3)
Capital Cost of SNCR/SCR Hybrid	30000.00	£/MW_e ⟷	Enter price in £ (1998 price is £30000/MW_e)
Cost of Landfill Ash	26.00	£/te ⟷	Enter price in £/ton (1998 price is £26/ton)
Price of Saleable Ash	3.00	£/te ⟷	Enter price in £/ton (1998 price is £1-15/ton)
Proportion of Ash Sold Before SNCR/SCR	60	% ⟷	Enter proportion of ash normally sold

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3
Mass Flow of Flue Gas	627.96	kg/s
Volume Flow of Flue Gas	474.60	m^3/s
Density of Flue Gas	1.32	kg/m^3
Total NO_x Produced at MCR	38914.52	te
Total kWh Generated at MCR	1.752E+10	kWh
Capital Cost of Technology	15000000.00	£
Difficulty Factor	1.2	⟷ Relates to difficulty of installation (Range 1.0 - 1.4)
Total Capital Cost of Technology	18000000.00	£
Levelised Capital Cost of Technology	21027437.98	£
NO_x Reduction Achieved	50	%
Capital Cost/te NO_x Removed	1080.70	£/te NO_x Removed
Capital Cost/kWh Generated	0.120	p/kWh

4.2 Operating and Maintenance Costs

4.2.1 Cost for Increased Ash Disposal to Landfill due to NH_3 Slip

Fuel Type	Coal	May also need to consider 2nd fuel ash content
Ash Content of Fuel	15.60	%
Fuel Flow Rate	62.90	kg/s
Total Ash Produced at MCR	1237775	te
Total kWh Generated at MCR	1.752E+10	kWh
Ash Disposed Before SNCR/SCR	495110	te
Extra Ash Disposed Due to SNCR/SCR	185666	te
Total Disposal Cost	7008534.15	£
Disposal Cost/te NO_x Removed	360.20	£/te NO_x Removed
Disposal Cost/kWh Generated	0.040	p/kWh

4.2.2 Cost for Lost Saleable Ash due to NH_3 Slip

Amount of Ash Sold Before SNCR/SCR	742665	te
Ash Lost to Landfill due to SNCR/SCR	185666	te
Cost of Lost Ash Sales/te NO_x Removed	41.56	£/te NO_x Removed
Cost of Lost Ash Sales/kWh Generated	0.005	p/kWh

4.2.3 Cost for Increased Power Consumption due to ΔP Across SNCR Injection Zone

Added Power Reqt/mbar ΔP	50	kW/mbarΔP
Total Additional Power Requirement	0	kWh
Added Power Reqt Cost/te NO_x Removed	0.00	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.000	p/kWh

4.2.4 Cost for Increased Power Consumption due to ΔP Across SCR Reactor

Added Power Reqt/mbar ΔP	50	kW/mbarΔP
Total Additional Power Requirement	9636000	kWh
Added Power Reqt Cost/te NO_x Removed	35.95	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.004	p/kWh

4.2.5 Cost of Increased Power for NH_3 Injection

Energy Penalty due to NH_3 Injection System	390	kWh/te of NH_3 Injected
Total Mass of NH_3 Injected for Reduction	14381	te
Total Additional Power Requirement	5608767	kWh
Added Power Reqt Cost/te NO_x Removed	20.93	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.002	p/kWh

4.2.6 Cost of Reagent Consumption

Cost of Anhydrous NH_3	150	£/te
Cost of Reagent/te NO_x Removed	160.97	£/te NO_x Removed

Cost of Reagent/kWh Generated	0.018	p/kWh	

4.2.7 Cost for Replacement Catalysts

Cost of Initial Catalyst on Installation	1842500	£	
Number of Catalyst Replacements/Period	0.8	Catalysts	
Cost of Replacement Catalysts	1474000	£	
Replacement Cat. Costs/te NO_x Removed	109.99	£/te NO_x Removed	
Replacement Cat. Costs/kWh Generated	0.012	p/kWh	

4.2.8 Cost of Forced Outages for Maintenance (Assumes Not Included in Normal Outages)

Operating Time Lost for Outages	3	%	Ref: IEA
Total Operating Time Lost for Outages	525600000	kWh	
Cost of Forced Outagest/te NO_x Removed	1960.94	£/te NO_x Removed	
Cost of Forced Outages/kWh Generated	0.218	p/kWh	

4.2.9 Cost for O & M Fixed Labour

Est. Proportion of Cap. Cost for Labour	2	%pa	Ref: EPRI
Total Cost for O & M Fixed Labour	1200000	£	
Fixed Labour Costs/te NO_x Removed	89.54	£/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.010	p/kWh	

4.3 Summary of Economic Analysis of SNCR/SCR Hybrid

4.3.1 Credits

	p/kWh	£/te NOx Removed
Operation and Maintenance Credits		
No Direct Credits Identified for SNCR-SCR	0.000	0.00
TOTAL CREDIT OF SNCR/SCR	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NOx Removed
Capital Costs		
Reduced NO_x Emissions	0.120	1080.70
Operation and Maintenance Costs		
Increased Ash Disposal	0.040	360.20
Lost Saleable Ash	0.005	41.56
Increased Power for Convective Bank ΔP	0.000	0.00
Increased Power for SCR Reactor ΔP	0.004	35.95
Increased Power For NH_3 Injection	0.002	20.93
Reagent Consumption	0.018	160.97
Replacement Catalysts	0.012	109.99
Forced Outages for Maintenance	0.218	1960.94
Fixed O & M Labour	0.010	89.54
TOTAL COST OF SNCR/SCR	**0.429**	**3860.77**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF SNCR/SCR	**0.429**	**3860.77**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 years
Unit Load Factor	40 %

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Technology Centre

UPGRADE: ***In-duct SCR / CAT-AH***

1. Economic Assumptions (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years
Annual Apparent Escalation Rate (e_a)	7.12	%
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	◄► For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	◄► For Use in Costing

2. Plant Information

Station Name Station A

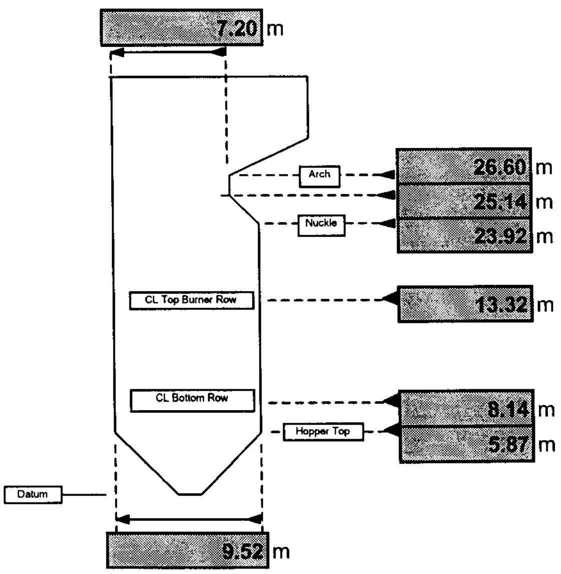
2.1 Boiler Details

Boiler Type	Front Wall-fired	◄► Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'
Number of Units	1	
Unit Capacity at MCR	500	MW_e
Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	29.27	m
Arch Angle	28.0	°
Lateral Burner Spacing	2.54	m

Other Relevant Dimensions:



Area at Arch	210.74	m^2
Area Below Arch	278.65	m^2
Area at Burner Belt	278.65	m^2
Vol. of Burner Belt	1443.41	m^3
Vol. from Burner Belt to Arch	3559.91	m^3

2.2 Burner and Associated Details

Burner Types	Senior Thermal Burners	Enter Manufacturer & Model
Fuel Type	Coal	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	24	Burners
Number of Burners for Full Load/Unit	20	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	2.59	m
Lateral Burner Spacing	2.54	m
Number of Burners Out of Service/Unit	4	Burners OOS
Burners/Column	3	Burners
Burners/Column for Full Load	2.5	Burners
Height to C_L of 2^{nd} Top Burner Row	10.73	m
Low NOx Burners Installed?	YES	Enter 'YES' or 'NO'
New/Old Burners Equally Rated?	YES	

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
Volatile Matter	27.18	31.24	38.07
Fixed Carbon	44.22	50.83	61.93
Ash	15.60	17.93	-
	100.00	100.00	100.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	13.00	-	-
C	58.90	67.70	82.49
H	3.62	4.16	5.07
S	1.61	1.85	2.25
Cl	0.30	0.34	0.42
N	1.43	1.64	2.00
O	5.54	6.37	7.76
Ash	15.60	17.93	-
	100.00	100.00	100.00

Fuel Ratio	1.63	
Calorific Value of Fuel	24267	kJ/kg as rec'd
Basis of Calorific Value	GCV	Enter 'NCV' or 'GCV'
GCV	24267	kJ/kg fired
NCV	23159	kJ/kg fired

Check of GCV for Main Fuel			
GCV Based on Ultimate Analysis	*23907*	*kJ/kg fired*	***GCV - OK***
Δ GCV (Input/Calculated)	*1.5*	*%*	

Inlet Fuel Flow to Unit at MCR	62.90	kg/s	
Operating Excess Air Level	17.0	%	Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature	75	°C	Enter value if known or use Mill Product Temp.
Windbox Air Temperature	250	°C	
Absolute Humidity of Combustion Air	8.0	$g/kg_{dry\ air}$	
Combustion Air Density	0.74	kg/m^3	(assuming PA represents 20% of total air)

Check of Excess Air Against Exit O_2		
Calculated Exit O_2 Based on Ultimate Analysis	*3.07*	*%*

Stoichiometric Dry Air Requirement	7.85	kg/kg_{fuel}
Dry Inlet Air Flow to Unit at MCR	577.78	kg/s (based on Inlet Fuel Flow Rate)

2.4 Combustion-related Details

Estimated Combustion Zone Temperature	1500	°C	Input estimate given fuel type (Suggest 1500 °C)
Measured Carbon in Ash (CIA)	5.0	%	
Unburnt Loss (UBL)	1.14	$\%_{GCV}$	
Unburnt Carbon (UBC)	0.0082	kg/kg_{fuel}	
Mass of Theoretical Dry Air Required	7.76	kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Air Required	9.08	kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Air Required	9.15	kg/kg_{fuel}	(corrected for humidity)
Mass of Flue-gas	9.98	kg/kg_{fuel}	
Total Mass Flow of Flue-gas at MCR	627.96	kg/s	

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	8.18	-		8.2		
C	37.05	-98.70	135.74			
H	2.28	-18.07		20.35		
S	1.01	-1.01			2.02	
Cl	0.19	-				
N	0.90	-				0.90
O	3.48	3.48				
Ash	9.81	-				
	62.9	-114.29	135.74	28.53	2.02	0.90
From Air						
H_2O	4.6			4.57		
O_2	132.4	132.36				
N_2	438.5					438.47
		18.06	135.74	33.09	2.02	439.37

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	135.74	22.81	21.61
O_2	18.06	3.03	2.87
N_2	439.37	73.82	69.93
SO_2	2.02	0.34	0.32
Total (dry)	595.20	100.00	-
H_2O	33.09	-	5.27
Total (wet)	628.29	-	100.00

Check of Air Requirements

Stoichiometric Air Requirement	*7.84*	*kg_{air}/kg_{fuel}*	
	9.17	*kg_{air}/kg_{fuel}*	
Δ Stoich Air (calc/mass balance)	*0.2*	*%*	***OK***

Volume Flow of Flue-gas in Comb. Zone	3082.32	m^3/s	at	1500 °C
Combustion Zone Stoichiometry	1.18			
Residence Time - Top Burner Row to Nuckle	0.96	s		

3. *In-duct SCR / CAT-AH Parameters (Assumes Space Available on Site)*

3.1 Operational Details

SCR Arrangement	In-duct		Enter 'In-duct' (High Dust)
Additional Catalyst System	CAT-AH		Enter 'CAT-AH' (Catalysed Air Heater)
Measured Ammonia Slip to Stack/Fly Ash	2	ppmv	***ASH IS SALEABLE***
NO_x Reduction Achievable with Catalyst	50	%	
Uncontrolled NO_x Produced from Unit at MCR	650	mg/Nm^3	
NO_x Produced from Unit with SCR/CatAH	325	mg/Nm^3	

Volume Flow of Flue-gas in Comb. Zone	3082.32	m^3/s	at	1500 °C
Volume Flow of Flue-gas at Economiser	3899057.43	m^3/h	at	350 °C
Vol. Flow of Flue-gas thro' CAT-AH	3460961.09	m^3/h	at	280 °C

Volume of Catalyst in SCR Reactor	550.00	m^3/unit	Input value to give residence time > 0.5s
Flue-gas Residence Time in SCR Reactor	0.51	s	***OK***
Typical Volume of Catalyst in CAT-AH	50	m^3/unit	
Amount of NH_3 Required for Reduction	205.21	kg/h (Anhydrous)	

SO_3 Produced from SO_2 by Catalyst	0.003	%
Pressure Drop Across Reactor	5.5	mbar
ΔP Due to Catalyst Elements in CAT-AH	0.5	mbar

4. Calculation of Credits and Costs Associated with In-duct SCR / CAT-AH

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	500	MW_e	
Unit Heat Rate	10.55	MJ/kWh	
Unit Load Factor	40	%	
Total Annual Power Available	4380000000	kWh	
Number of Years Operating	10.0	years	
Electricity Cost	5.00	p/kWh ↔	Enter price in p/kWh (1998 price is 5p/kWh)
Coal Cost	1.25	£/GJ ↔	Enter price in £/GJ (1998 price is £1.25/GJ)
Oil Cost	2.30	£/GJ ↔	Enter price in £/GJ (1998 price is £2.30/GJ)
Gas Cost	1.90	£/GJ ↔	Enter price in £/GJ (1998 price is £1.9/GJ)
Anhydrous NH_3 Cost	150.00	£/te ↔	Enter price in £/te (1998 price is £150/te)
Catalyst Cost	5000.00	£/m^3 ↔	Enter price in £/m^3 (1998 price is £5000/m^3)
Capital Cost of In-duct SCR / CAT-AH	37500.00	£/MW_e ↔	Enter price in £ (1998 price is £37500/MW_e)
Cost of Landfill Ash	26.00	£/te ↔	Enter price in £/te (1998 price is £26/ton)
Price of Saleable Ash	3.00	£/te ↔	Enter price in £/te (1998 prices are £1-15/ton)
Ash Sold Before In-duct SCR / CAT-AH	60	% ↔	Enter proportion of ash normally sold

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	650	mg/Nm^3	
Mass Flow of Flue Gas	627.96	kg/s	
Volume Flow of Flue Gas	474.60	m^3/s	
Density of Flue Gas	1.32	kg/m^3	
Total NO_x Produced at MCR	38914.52	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Capital Cost of Technology	18750000.00	£	
Difficulty Factor	1.2	↔	Relates to difficulty of installation (Range 1.0 - 1.4)
Total Capital Cost of Technology	22500000.00	£	
Levelised Capital Cost of Technology	26284297.47	£	
NO_x Reduction Achieved	50	%	
Capital Cost/te NO_x Removed	1350.87	£/te NO_x Removed	
Capital Cost/kWh Generated	0.150	p/kWh	

4.2 Operating and Maintenance Costs

4.2.1 Cost for Increased Ash Disposal to Landfill due to NH_3 Slip

Fuel Type	Coal		May also need to consider 2nd fuel ash content
Ash Content of Fuel	15.60	%	
Fuel Flow Rate	62.90	kg/s	
Total Ash Produced at MCR	1237775	te	
Total kWh Generated at MCR	1.752E+10	kWh	
Ash Disposed Before In-duct SCR / CAT-AH	495110	te	
Extra Ash Disposed Due to In-duct SCR / CAT-AH	185666	te	
Total Disposal Cost	7008534.15	£	
Disposal Cost/te NO_x Removed	360.20	£/te NO_x Removed	
Disposal Cost/kWh Generated	0.040	p/kWh	

4.2.2 Cost for Lost Saleable Ash due to NH_3 Slip

Ash Sold Before In-duct SCR / CAT-AH	742665	te
Ash Lost to Landfill due to In-duct SCR / CAT-AH	185666	te
Cost of Lost Ash Sales/te NO_x Removed	41.56	£/te NO_x Removed
Cost of Lost Ash Sales/kWh Generated	0.005	p/kWh

4.2.3 Cost for Increased Power Consumption due to ΔP Across SCR Reactor

Added Power Reqt/mbar ΔP	50	kW/mbarΔP
Total Additional Power Requirement	9636000	kWh
Added Power Reqt Cost/te NO_x Removed	35.95	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.004	p/kWh

4.2.4 Cost for Increased Power Consumption due to Increased ΔP Across CAT-AH

Added Power Reqt/mbar ΔP	50	kW/mbarΔP
Total Additional Power Requirement	876000	kWh
Added Power Reqt Cost/te NO_x Removed	3.27	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.0004	p/kWh

4.2.5 Cost of Increased Power for NH_3 Injection

Energy Penalty due to NH_3 Injection System	390	kWh/te of NH_3 Injected
Total Mass of NH_3 Injected for Reduction	7191	te
Total Additional Power Requirement	2804383	kWh
Added Power Reqt Cost/te NO_x Removed	10.46	£/te NO_x Removed
Added Power Reqt Cost/kWh Generated	0.001	p/kWh

4.2.6 Cost of Reagent Consumption

Cost of Anhydrous NH_3	150 £/te
Cost of Reagent/te NO_x Removed	80.48 £/te NO_x Removed
Cost of Reagent/kWh Generated	0.009 p/kWh

4.2.7 Cost for Replacement Catalysts

Cost of Initial Catalyst on Installation	2092500 £
Number of Catalyst Replacements/Period	0.8 Catalysts
Cost of Replacement Catalysts	1674000 £
Replacement Cat. Costs/te NO_x Removed	124.91 £/te NO_x Removed
Replacement Cat. Costs/kWh Generated	0.014 p/kWh

4.2.8 Cost of Forced Outages for Maintenance (Assumes Not Included in Normal Outages)

Operating Time Lost for Outages	2 %	Ref: IEA
Total Operating Time Lost for Outages	350400000 kWh	
Cost of Forced Outagest/te NO_x Removed	1307.29 £/te NO_x Removed	
Cost of Forced Outages/kWh Generated	0.145 p/kWh	

4.2.9 Cost for O & M Fixed Labour

Est. Proportion of Cap. Cost for Labour	1 %pa	Ref: EPRI
Total Cost for O & M Fixed Labour	750000 £	
Fixed Labour Costs/te NO_x Removed	55.96 £/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.006 p/kWh	

4.3 Summary of Economic Analysis of SCR

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for SCR/CatAH	0.000	0.00
TOTAL CREDIT OF In-duct SCR/CAT-AH	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.150	1350.87
Operation and Maintenance Costs		
Increased Ash Disposal	0.040	360.20
Lost Saleable Ash	0.005	41.56
Increased Power for Reactor ΔP	0.004	35.95
Increased Power for CAT-AH	0.0004	3.27
Increased Power For NH_3 Injection	0.001	10.46
Reagent Consumption	0.009	80.48
Replacement Catalysts	0.014	124.91
Forced Outages for Maintenance	0.145	1307.29
Fixed O & M Labour	0.006	55.96
TOTAL COST OF In-duct SCR/CAT-AH	**0.374**	**3370.97**

4.3.3 Economic Outcome

TOTAL ECON. COST OF SCR/CAT-AH	**0.374**	**3370.97**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (n)	10.0 years
Unit Load Factor	40 %

Mitsui Babcock Energy Limited
Technology Centre

UPGRADE: ***Flue Gas Recycle***

1. Economic Assumptions (Revenue Requirement Method, Current £sterling Basis)

INPUT VALUES IN SHADED CELLS

Annual Inflation Rate (e_i)	3.00	%
Annual Interest Rate (i)	4.50	%
Annual Real Price Escalation (e_r)	4.00	%
Timeframe for Evaluation (n)	10.0	Years
Annual Apparent Escalation Rate (e_a)	7.12	%
Levelisation Factor (L_n^e) - O&M Costs	**1.4518**	◄──► For Use in Costing
Levelisation Factor (L_n) - Capital Costs	**1.1682**	◄──► For Use in Costing

2. Plant Information

Station Name Station A

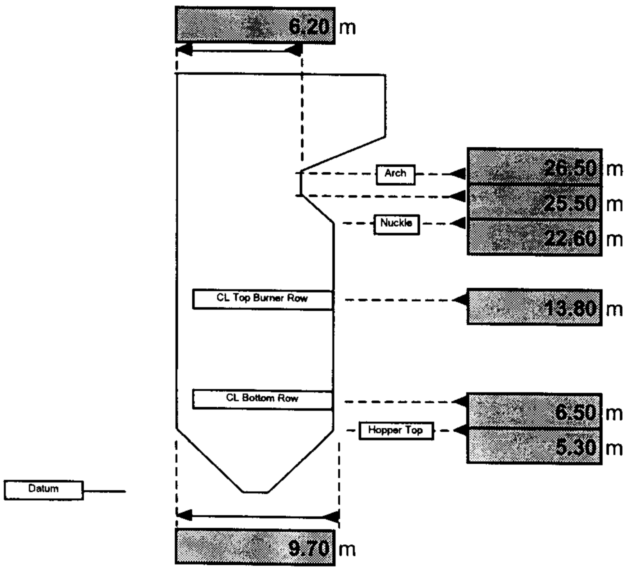
2.1 Boiler Details

Boiler Type	Front Wall-fired	◄► Enter 'Front Wall-fired', 'Opposed-Wall Fired', 'Downshot-fired' or 'Tangential-fired'
Number of Units	1	
Unit Capacity at MCR	483	MW_e
Unit Load Factor	40	%

Boiler Dimensions (ground level datum)

Total Width (including any division wall)	18.30	m
Arch Angle	44.0	°
Lateral Burner Spacing		m

Other Relevant Dimensions:



Area at Arch	113.46	m^2
Area Below Arch	177.51	m^2
Area at Burner Belt	177.51	m^2
Vol. of Burner Belt	1295.82	m^3
Vol. from Burner Belt to Arch	2097.45	m^3

2.2 Burner and Associated Details

Burner Types	Hamworthy Pressure Jets	Enter Manufacturer & Model
Fuel Type	Heavy Fuel Oil	Enter 'Coal', 'Heavy Fuel Oil' or 'Natural Gas'
Number of Burners/Unit	32	Burners
Number of Burners for Full Load/Unit	32	Burners
Number of Burner Columns/Unit	8	Columns
Vertical Burner Pitch	1.20	m
Lateral Burner Spacing		m

Number of Burners Out of Service/Unit	0	Burners OOS
Burners/Column	4	Burners
Burners/Column for Full Load	4	Burners
Height to C_L of 2nd Top Burner Row	12.6	m

Low Nox Burners Installed?	NO	
New/Old Burners Equally Rated?	NO	Enter 'YES' or 'NO'

2.3 Operational Details

Fuel Analyses

Proximate Analysis	% As Rec'd	% Dry	% DAF
Moisture	0.00	-	-
Volatile Matter	0.00	0.00	0.00
Fixed Carbon	0.00	0.00	0.00
Ash	0.00	0.00	-
	0.00	0.00	0.00

Ultimate Analysis	% As Rec'd	% Dry	% DAF
Moisture	0.00	-	-
C	85.40	85.40	85.40
H	11.40	11.40	11.40
S	2.80	2.80	2.80
Cl	0.00	0.00	0.00
N	0.30	0.30	0.30
O	0.10	0.10	0.10
Ash	0.00	0.00	-
	100.00	100.00	100.00

Calorific Value of Fuel	43000	kJ/kg as rec'd
Basis of Calorific Value	GCV	Enter 'NCV' or 'GCV'

GCV	43000	kJ/kg fired
NCV	40512	kJ/kg fired

Check of GCV for Main Fuel
GCV Based on Ultimate Analysis *43826 kJ/kg fired* ***OK***
Δ GCV (Input/Calculated) *-1.9 %*

Inlet Fuel Flow to Unit at MCR	33.85	kg/s
Operating Excess Air Level	17.0	% ⟷ Adjust to get required Exit O_2 (see Check below)
Primary Air Temperature		°C ⟷ Enter value if known or use Mill Product Temp.
Windbox Air Temperature	315	°C
Absolute Humidity of Combustion Air	8.0	$g/kg_{dry\ air}$

Check of Excess Air Against Exit O_2
Calculated Exit O_2 Based on Ultimate Analysis *3.11 %*

Stoichiometric Dry Air Requirement	13.85	kg/kg_{fuel}
Dry Inlet Air Flow to Unit at MCR	548.72	kg/s

2.4 Combustion-related Details

Estimated Combustion Zone Temperature	1500	°C	⟷ Input estimate given fuel type (Suggest 1500 °C)
Measured Carbon in Ash (CIA)	0.0	%	
Unburnt Loss (UBL)	0.00	$\%_{GCV}$	
Unburnt Carbon (UBC)	0.0000	kg/kg_{fuel}	
Mass of Theoretical Dry Air Required	13.85	kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Dry Air Required	16.21	kg/kg_{fuel}	(corrected for UBC)
Mass of Actual Moist Air Required	16.34	kg/kg_{fuel}	(corrected for humidity)
Mass of Flue-gas	17.34	kg/kg_{fuel}	
Total Mass Flow of Flue-gas at MCR	586.96	kg/s	

Mass Balance for Flue-gas Composition (including UBC)

	Flowrate	O_2	Combustion Products			
	kg/s	required	CO_2	H_2O	SO_2	N_2
Moisture	0.00	-		0.0		
C	28.91	-77.01	105.92			
H	3.86	-30.63		34.49		
S	0.95	-0.95			1.89	
Cl	0.00	-				
N	0.10	-				0.10
O	0.03	0.03				
Ash	0.00	-				
	33.85	-108.55	105.92	34.49	1.89	0.10
From Air						
H_2O	4.4			4.39		
O_2	127.2	127.23				
N_2	421.5					421.49
		18.68	105.92	38.88	1.89	421.59

Flue-gas Composition

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	105.92	19.33	18.05
O_2	18.68	3.41	3.18
N_2	421.59	76.92	71.83
SO_2	1.89	0.35	0.32
Total (dry)	548.08	100.00	-
H_2O	38.88	-	6.62
Total (wet)	586.96	-	100.00

Check of Air Requirements

Stoichiometric Air Requirement	*13.83*	kg_{air}/kg_{fuel}	
Actual Air Requirement	*16.18*	kg_{air}/kg_{fuel}	
Δ Stoich Air (calc/mass balance)	*0.2*	*%*	***OK***

Percentage Flue Gas Recycle 20 % ⟷ Enter value (suggest 20%)

Total FGR 117.39 kg/s

Mass Balance for Flue-gas Composition (FGR)

	kg/s	% dry ($^w/_w$)	% wet ($^w/_w$)
CO_2	21.18	19.33	18.05
O_2	3.74	3.41	3.18
N_2	84.32	76.92	71.83
SO_2	0.38	0.35	0.32
Total (dry)	109.62	100.00	-
H_2O	7.78	-	6.62
Total (wet)	117.39	-	100.00

Furnace Exit Composition with FGR

	without FGR kg/s	FGR kg/s	with FRG kg/s	% wet (w/w)
CO_2	105.92	21.18	127.10	18.05
O_2	18.68	3.74	22.42	3.18
N_2	421.59	84.32	505.91	71.83
SO_2	1.89	0.38	2.27	0.32
H_2O	38.88	7.78	46.65	6.62
Total	586.96	117.39	704.35	100.00

Volume Flow of Flue-gas in Comb. Zone 3531.67 m^3/s at 1500 ^oC

Combustion Zone Stoichiometry 1.20

Residence Time - Top Burner Row to Arch 0.44 s

4.0 Calculation of Credits and Costs Associated with Flue Gas Recycle

4.0.1 Details Required for Economic Analysis

Unit Capacity at MCR	483	MW_e	
Unit Heat Rate	10.55	MJ/kWh	Enter value in MJ/kWh (typ. value is 10.55MJ/kWh)
Unit Load Factor	40	%	
Total Annual Power Available	4231080000	kWh	
Number of Years Operating	10.0	years	
Cost of Electricity	5.00	p/kWh	Enter price in p/kWh (typ. price is 5p/kWh)
Fuel Oil Cost	2.30	£/GJ	Enter price in £/GJ (1998 price is £2.3/GJ)
Cost of Landfill Ash	8.70	£/te	Enter price in £/te (1998 price is £8.70/te)
Price of Saleable Ash	3.00	£/te	Enter price in £/te (1998 prices is £1-15/te)
Proportion of Total Ash Sold Before FGR	0	%	Enter proportion sold as a percentage
Capital Cost	1	£/kW_e	Enter price in £/kW_e (1998 price is £1-2W_e)
Reduction Achieved	40	%	Enter reduction in % (typical reduction is 40%)

4.1 Capital Costs

4.1.1 Cost for Reduced NO_x Emissions

NO_x Emissions at MCR	871	mg/Nm^3	Enter emission (limit = 650mg/Nm^3)
Mass Flow of Flue Gas	704.35	kg/s	
Volume Flow of Flue Gas	543.79	m^3/s	
Density of Flue Gas	1.30	kg/m^3	
Total NO_x Produced at MCR	59747	te	
Total kWh Generated at MCR	1.692E+10	kWh	
Capital Cost of Technology	483000.00	£	
Difficulty Factor	1.2		Relates to Difficulty of Installation Range 1-1.4
Total Capital Cost of Technology	579600.00	£	
Levelised Capital Cost of Technology	677083.50	£	
NO_x Reduction Achieved	40	%	
Capital Cost/te NO_x Removed	28.33	£/te NO_x Removed	
Capital Cost/kWh Generated	0.004	p/kWh	

4.2 Operating and Maintenance Costs

4.2.1 Cost for Increased Auxiliary Power

Additional FGR Fan Power Requirement	850	kW	Enter estimated value
Total Additional Power Requirement	29784000	kWh	
Added Power Reqt Cost/te NO_x Removed	90.47	£/te NO_x Removed	
Added Power Reqt Cost/kWh Generated	0.013	p/kWh	

4.2.2 Cost of Increased Steam Attemperation

Cost of Attemperation	0	kJ/kWh
Increase in Attemperation	100	%

Incr.Steam Attemp.Cost/te NO_x Removed	0.00 £/te NO_x Removed
Incr.Steam Attemp.Cost/kWh Generated	0.000 p/kWh

4.2.3 Cost for O & M Fixed Labour

Est. O & M Costs for oil-fired Plant	0.07 p/kWh	Ref: EPRI
Total O & M Costs Before FGR	18019113 £	
Increase in O & M Costs Due to FGR	0.5 %	
Increase in Total O & M Costs Due to FGR	90096 £	
Fixed Labour Costs/te NO_x Removed	5.47 £/te NO_x Removed	
Fixed Labour Costs/kWh Generated	0.0008 p/kWh	

4.3 Summary of Economic Analysis of FGR

4.3.1 Credits

	p/kWh	£/te NO_x Removed
Operation and Maintenance Credits		
No Direct Credits Identified for FGR	0.000	0.00
TOTAL CREDIT OF FGR	**0.000**	**0.00**

4.3.2 Costs

	p/kWh	£/te NO_x Removed
Capital Costs		
Reduced NO_x Emissions	0.004	28.33
Operation and Maintenance Costs		
Increased Auxiliary Power	0.013	90.47
Increased Steam Attemperation	0.000	0.00
Fixed O & M Labour	0.001	5.47
TOTAL COST OF FGR	**0.018**	**124.27**

4.3.3 Economic Outcome

TOTAL ECONOMIC COST OF FGR	**0.018**	**124.27**

4.4 Summary of Economic Assumptions

Station Name	Station A
Boiler Type	Front Wall-fired
Timeframe for Evaluation (*n*)	10.0 Years
Unit Load Factor	40 %