CRITERIA FOR TECHNICAL AND ECONOMIC ASSESSMENT OF PLANTS WITH LOW CO_2 EMISSIONS

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CRITERIA FOR TECHNICAL AND ECONOMIC ASSESSMENT OF PLANTS WITH CO_2 CAPTURE

Background

The IEA Greenhouse Gas R&D Programme (IEA GHG) undertakes studies to assess technologies for abatement of greenhouse gas emissions. IEA GHG has concentrated on CO_2 Capture and Storage (CCS) applied to power generation but it has also assessed CCS in other industries and will compare the relative merits of CCS and alternative greenhouse gas abatement options. Soon after IEA GHG started operation in 1991 it produced a set of standard technical and economic criteria for assessment of power plants with capture to ensure that its studies are undertaken on a consistent basis, as far as possible. These criteria have continued to be used since then, with some minor modifications.

In the time since IEA GHG was set up, economic conditions have changed, knowledge of CCS and other technologies has increased and IEA GHG has been undertaking increasingly detailed studies. In response to these changes IEA GHG has decided to revise and expand its assessment criteria. As a starting point IEA GHG's criteria for new power plants with CO_2 capture have been updated and some general guidelines for assessment of other types of plant with CO_2 capture have been included. These changes are described in this report. Future work will look to expand the criteria to encompass retrofit of CO_2 capture, the full CCS chain including CO_2 transport and storage and non-CCS energy technologies. In the mean time a notional cost of CO_2 transport and storage shall be assumed and sensitivities to a range of costs shall be assessed.

IEA GHG's original power plant assessment criteria relate to a standard location in the Netherlands. This will continue to be IEA GHG's standard power plant location but criteria have been developed for a range of alternative locations to enable study contractors to produce sensitivity cases for alternative locations if required, to enable IEA GHG's members to apply study results to different local conditions.

Study Description

When developing its revised and expanded assessment criteria IEA GHG wanted to ensure consistency with criteria used by other leading organisations, as far as reasonably possible. Probably the leading other organisation in the field of assessment of power generation technologies over many years has been the Electric Power Research Institute (EPRI), which has developed assessment criteria for power generation technologies for its members. IEA GHG co-sponsored EPRI to provide a report entitled 'Power Plant CO_2 Emission Capture – Engineering Economic Evaluation Methodology Guidelines'[1]. IEA GHG has used criteria from this report and another report produced independently by EPRI[2] to help expand its own standard assessment criteria. Because of confidentiality issues IEA GHG is not able to distribute copies of EPRI's Engineering Economic Evaluation report.

During the course of the collaboration with EPRI, IEA GHG organised a workshop in Sydney, Australia which involved participants from EPRI (USA), Australia, Japan and the Netherlands. The discussions at and after the workshop helped to identify changes which needed to be made to IEA GHG's criteria and helped to provide information for the alternative locations. Information from major studies on CCS undertaken by other organisations, including EU collaborative R&D programmes, the NZEC study on plants in China and a study on Ultra Mega Power Plants in India were also taken into account when specifying IEA GHG's revised criteria.

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[1] Power Plants CO_2 Emission Capture – Engineering Economic Evaluation Methodology Guidelines, EPRI, Palo Alto, CA: 2008. 1018050.

[2] Program on Technology Innovation: Integrated Generation Technology Options. EPRI, Palo Alto, CA: 2008. 1018329.

IEA GHG's criteria were originally developed for new power plants with CO_2 capture. Most of IEA GHG's capture studies have so far been on power plants but more studies will be undertaken in future on capture at other types of industrial plant. IEA GHG's assessment criteria have therefore been expanded to provide general guidelines for assessment of other types of industrial plant with CO_2 capture.

IEA GHG considered producing standard assessment criteria for CO_2 storage to complement its criteria for power generation and capture plants and enable the full CCS chain to be assessed. However, the wide diversity of local conditions for CO_2 storage and the relatively high degree of uncertainty in the criteria values meant that it was considered inappropriate to produce storage criteria at this time. However, IEA GHG and others are undertaking various studies on CO_2 storage which should help to increase the level of knowledge and IEA GHG may in future produce criteria for CO_2 storage.

IEA GHG has a remit to undertake studies to assess the relative merits of alternative low-CO_2 technologies. IEA GHG's revised criteria are relevant to these studies but they will need to be expanded further. The alternative technologies could include well established technologies and emerging technologies which are currently at an early stage of development. For the early stage technologies a simple comparison would normally be appropriate because of the high level the uncertainty. For the established technologies it is recommended that detailed assessments should be undertaken in the context of an overall energy supply system because the relative merits of each technology will depend on the extents to which other technologies are used, for example the load factors of each type of plant will depend on the other types of plants in the energy system. IEA GHG is planning to initiate discussions on operating flexibility of CCS plants and electricity system interactions. Following these discussions IEA GHG will work on defining a methodology for comparison of CCS and established low-CO_2 electricity generation technologies.

Results and Discussion

IEA GHG's revised technical and economic assessment criteria are described and tabulated in Appendix 1. Appendix 1 is a stand-alone document which can be distributed to IEA GHG's study contractors.

The derivation of the criteria and the changes which have been made to IEA GHG's original criteria is discussed in more detail below.

Technical Analysis

Plant location and ambient conditions

The standard plant location continues to be a coastal site in the North East of the Netherlands. Some additional information has been included e.g. the maximum and minimum ambient conditions, and the site battery limits and method of fuel delivery have been more clearly defined.

The nominal net power output has been increased slightly from 750MW to 800MW to reflect the typical unit sizes offered by pulverised coal and natural gas combined cycle plant suppliers. As before, it is emphasised that this is only a nominal power output and the actual output may be different as it depends in some cases on the sizes of standard commercial gas turbines.

Fuel analysis and heating value

The standard coal (Australian internationally traded open-cast bituminous coal) has been retained but the standard natural gas analysis has been revised because the original analysis had un-typically high concentrations of C_2+ hydrocarbons (13.9 vol%). The new analysis has a lower C_2+ concentration (8.1 vol%) and is consistent with that used in some European collaborative R&D programmes. The analyses used in US studies typically have even lower concentrations of C_2+ hydrocarbons, reflecting typical US natural gas compositions.

IEA GHG has used Lower Heating Value (LHV) as its standard for fuel heating value and plant efficiency, in common with normal European practice. However, Higher Heating Value (HHV) is more commonly used for coal fired plants in several other countries, including the USA, Japan and Australia. IEA GHG will continue to use LHV as its standard but will also quote plant performance on an HHV basis, for the benefit of the countries which normally use HHV.

Plant capacity

In general, economies of scale favour larger plants but smaller plants have the advantages of being better able to match load growth and have lower capital outlays, which translate to reduced risk. The optimum plant size must consider the economics and compatibility of the unit size within the electric system, not merely reflect economies of scale. In IEA GHG's original criteria, devised in the early 1990s, the capacity was set at 500MWe net output, which at that time was considered to be a typical size for a single-boiler pulverised coal power plant. In practice it was not always possible to match this plant capacity because for some technologies the plant capacity depends on the capacities of standard commercial equipment, particularly gas turbines. In 2003 the nominal plant capacity was increased to 750MWe, which was the approximate output of an IGCC or natural gas combined cycle plant containing two state-of-the-art gas turbines. It was also considered to be a more reasonable size for a new ultra supercritical pulverised coal plant, the sizes of which had been increasing over the years. Since then the sizes of gas turbine combine cycle plants has continued to increase and 800MWe has emerged as a common commercial size for new ultra supercritical coal fired power plants. 800MWe will therefore be used as the new nominal plant capacity in IEA GHG's criteria. This is the upper end of the size range specified in EPRI's report[1]. Larger coal fired units of over 1000MW have been built in some countries, notably Japan, but they are not yet common worldwide. Natural gas combined cycle units with outputs of around 500MWe, such as the Siemens 8000H, are stating to be introduced to the market. If such turbines are selected for future IEA GHG studies, a 2-module plant should be specified and a higher net power output accepted.

Utilities often plan to install two or more units at a given plant site, either at the same time or consecutively. This can result in lower costs, through use of common plant facilities and construction labour and services. IEA GHG's studies, in common with those of EPRI, focus on single module plants (except for gas turbine-based plants which are assumed to be 2-module plants to achieve a consistent plant output). The cost of multiple module plants would normally be less than the costs quoted in IEA GHG's studies. If IEA GHG wishes to compare the costs of fossil fuel plants and costs of other technologies which normally have significantly larger unit sizes, for example nuclear power plants, IEA GHG's costs of fossil fuel plants should be adjusted to take account of the economies of scale of larger multiple unit plants. For comparison with technologies which normally have smaller unit sizes, such as some renewable generation technologies it is not necessary to scale down the size of fossil fuel plants, because to do so would result in unrealistic plant sizes. For industrial plants other than power generation, the plant size should be a typical size for the particular type of plant. The size will be decided on a case-by-case basis.

Addition of CO_2 capture has implications for plant net power output. For technical and economic analyses it can either be assumed that the power output or the fuel feed rate of plants with and without capture are the same, or some compromise between the two. There is no obviously correct approach and the most suitable approach may be different for different technologies. For gas turbine-based plants with pre-combustion capture it is reasonable to assume that the gas turbine is kept fully loaded in all cases. This means that a plant with capture has a higher fuel feed rate and a lower net power output. For gas turbine-based plants with post combustion capture the gas turbine fuel feed and power output remain unchanged and the net power output is reduced. For coal-based plants with post combustion capture the fuel feed rate could be increased but this may result in a boiler that is larger than that which would be considered acceptable by the boiler supplier or utility. IEA GHG's assessment criteria will therefore specify that the fuel feed rate of plants with and without capture will be the same except for cases where it is necessary to have a different fuel feed rate to fully load a gas turbine. In most cases this will result in a lower net power output from plants with capture. This is the same as in recent EPRI studies.

The output and efficiency of power plants depend on ambient conditions. In general both are lower at higher than average temperature. A reduced power output at high ambient temperature is less of a concern in countries such as the Netherlands where the peak power demand is usually in winter but it is more of a concern in countries such as Australia, Japan and much of the USA where the peak power demand is at the hottest times, due to demand for air conditioning. IEA GHG's studies have provided performance data based on annual average ambient conditions in the Netherlands. In view of the summer peak demand in the USA, EPRI's report states that the generating unit must be designed to provide a rated output at maximum ambient temperature, even though efficiency may be reduced. Alternatively, the derated output of the generating unit must be calculated and costs presented on the basis of $/kW of derated capacity under maximum temperature conditions. IEA GHG's studies at alternative locations will calculate the power output, efficiency and costs at average ambient conditions. Calculating performance and costs at maximum ambient conditions will require more effort and IEA GHG will decide whether or not this is worthwhile on a case-by-case basis.

Power output and efficiency degradation

The output and efficiency of a power plant degrades over time. Degradation can depend on how a plant is operated and, in the case of gas turbines, ambient air quality. Maintenance such as gas turbine compressor washing can recover some of the losses. Equipment manufacturers are continually improving the performance of their products and some of their improvements can be retrofitted to existing plants during overhauls. Taking into account degradation and technology improvements, IEA GHG assumes for simplicity that on average over their lifetime, plants will operate at their original design performance.

CO_2 capture

IEA GHG originally specified 85% CO_2 capture. Most CCS process and project developers are focussing now on a minimum of 90%, which may be because such percentage capture can be achieved without significant extra cost per tonne of CO_2 and because targets for global greenhouse gas emission reduction are becoming increasingly severe, putting greater emphasis on the need for high percentage capture. IEA GHG's standard percentage CO_2 capture will therefore be set at 90%. For some technologies such as oxy-combustion higher percentage capture can be easily achieved and in such cases the percentage capture should not be artificially lowered to satisfy IEA GHG's criteria. In some other cases the incremental cost of capturing as much as 90% may be considered to be excessive and if so a lower limit may be used subject to agreement by IEA GHG. This should be considered in particular for plants such as natural gas combined cycle plants which have substantially lower CO_2 emissions per kWh than coal fired plants.

CO_2 shall be delivered from the power plant site by pipeline at a pressure of 11.0MPa, as in IEA GHG's original criteria, and a temperature of ≤30°C. In some cases higher pressures may be required but because CO_2 is already a high density fluid at 11 MPa little energy is required to pump it to higher pressures if required. The sensitivity to CO_2 pressure may be assessed in some studies, at the request of IEA GHG.

No buffer storage of CO_2 shall be included within the power station battery limits. It is assumed that the CO_2 transport and storage system can accommodate any variations in the quantity of CO_2 delivered by the capture plant. This assumption may be revised in future following analysis of the capabilities of CO_2 transport and storage systems.

The alternative method of transporting CO_2 is by ship, as a refrigerated liquid. This will be the specified method at one of IEA GHG's alternative plant locations. At that site it will be assumed that the power plant is located adjacent to a port and CO_2 shall be liquefied on-site. For the purposes of coal delivery IEA GHG assumes that its standard site in the Netherlands is not immediately adjacent to a port, so if ship transport of CO_2 were to be assessed for that site it would be assumed that CO_2 would be delivered from the power plant site to a port by pipeline at elevated pressure. Liquefaction would take place at the port. Buffer storage of CO_2 and loading of ships shall be considered to be part of the CO_2 transport system, outside the battery limits of the capture plant.

CO_2 purity
IEA GHG's original criteria did not specify CO_2 purity. CO_2 purity requirements depend on technical factors related to CO_2 transport and storage including corrosion, hydrate formation and health and safety, and regulatory requirements. Regulatory requirements are still evolving and it is emphasised that IEA GHG's specification should not set a standard for regulatory purposes. IEA GHG's specifications are derived from various sources, particularly European collaborative R&D programmes. The water specification is to ensure there is no free water and hydrate formation. The limits on concentrations of inerts are to reduce the volume for compression, transport and storage (inerts could have a disproportionate impact on the volume of compressed CO_2) and to limit the increase in Minimum Miscibility Pressure (MMP) in Enhanced Oil Recovery (EOR). The maximum hydrogen concentration is set at 4% but it is expected that the concentration will normally be lower to limit the loss of energy and economic value. The H_2S, SO_2, NO_X and CO limits are set from a health and safety perspective. The O_2 limit is tentative in view of the lack of practical experience on effects of O_2 in underground reservoirs. In some studies IEA GHG may request an assessment of the sensitivity of performance and costs to CO_2 purity.

Environmental performance
The emissions to air of SO_X, NO_X and particulates are those that apply for new power plants in the Netherlands, as reported at the Sydney workshop. These are lower than the current EU Large Combustion Plant Directive requirements (SO_X, NO_X and particulate emissions of 200, 200 and 30 mg/Nm^3, 6% O_2 respectively). In some studies an assessment of the sensitivity to environmental emissions standards may be requested. More stringent standards for conventional pollutants may reduce the cost of CO_2 capture because it will reduce the cost of additional gas cleaning that is attributable to CO_2 capture.

Cooling water system
A once-through seawater cooling water system shall be used for major cooling duties such as steam turbine condensers. The inlet and outlet ducts are within the site battery limits. A secondary fresh water cooling system may be used for some smaller process cooling duties. This is unchanged from IEA GHG's original criteria.

Turndown and load following
Generally a minimum turndown of 50% is desirable for power plants. IEA GHG will in future include specifications for minimum turndown and ramp rates depending on the likely requirements of future electricity systems.

Economic Analysis

Date
Costs of power generation and process plants in general have been very volatile, in particular with large increases between 2003 and early 2008 due mainly to high raw materials prices and a tight market for equipment and services. The impact of the recent economic downturn on plant prices is currently unclear. It is therefore important that IEA GHG's study reports specify the date of the cost estimates, e.g. 1stQ 2009.

Currency
IEA GHG selected the US$ as the currency in which to quote study results because in the 1990s the currency of the Netherlands, IEA GHG's standard plant site, was not one of the main global currencies. Since then the Netherlands has adopted the Euro, which has become established as a major global currency. Some of IEA GHG's study contractors, particularly those based in Europe, have produced their cost estimates using their in-house cost databases denominated in Euros.

There have been large fluctuations in currency exchange rates in recent years, which mean that translation of costs between currencies using market rates can result in misleading conclusions. This is particularly so if there have been multiple translations, for example if a cost was originally estimated in Euro and converted to $ at the time when the study was carried out, and was converted back to Euros at a later date after a large change in the exchange rate. It is therefore recommended that cost estimates in IEA GHG's study report shall be presented in the main currency in which they were produced, preferably US$ or Euros. If the costs are not estimated in US$ the headline costs (capital cost/kW, electricity cost per kWh and costs of CO_2 captured and CO_2 avoidance per tonne of CO_2) shall be converted to US$ using the current market exchange rate and shall be included in IEA GHG's study overview along with the costs in the original currency. The exchange rate used for conversion shall be clearly stated in the report.

Constant versus current money values

Economic analyses can be conducted in current money values, including inflation, or constant money values, not including inflation. In general utilities' business investments are analysed in current money values because the estimated costs will more closely approximate the actual costs when they occur. The values can therefore form the basis for budgeting future expenditures. However the effects of inflation can obscure real cost trends. Constant money value analysis is more often used for comparison of technologies to avoid the results being clouded by the effects of inflation. A disadvantage of constant money value analysis is that it requires the use of interest rates expressed in constant money values, which can be a cause of confusion. There may be a tendency to think that interest rates used in the analysis are too low because they are incorrectly compared with actual current money value rates.

IEA GHG has always undertaken its assessments in constant money values, i.e. assuming zero inflation, and will continue to do so. Comparisons of energy technologies published by EPRI and most other organisations are also in constant money values.

Capital cost

Capital costs of power plants are often quoted on different bases which make it difficult to compare costs from different sources. In the past IEA GHG quoted a single headline capital cost which included owner's costs. Interest during construction, working capital and start-up cost were not included in the headline capital cost but they were taken into account in the cash flow calculation of electricity costs. IEA GHG will in future bring its published capital cost data into line with those of EPRI, US DOE and various others by quoting Total Plant Cost (TPC) and Total Capital Requirement (TCR). TPC includes direct materials, labour and other site costs, engineering fees and contingencies. TCR includes TPC, interest during construction, owner's costs, working capital and start-up costs. Interest during construction shall be calculated from the plant construction schedule and an interest rate which will be assumed to be the same as the discount rate. Owner's costs include the costs of feasibility studies, land purchase, obtaining permits, arranging financing and other miscellaneous costs. Owner's costs shall be calculated as a percentage of TPC. IEA GHG will bring its calculation of start-up costs into line with EPRI's report and start-up costs will be included in the TCR. Working capital will include stocks of fuel and other consumables.

IEA GHG's TCR will be based on the central discount rate and fuel price but it should be recognised that TCR depends on these parameters.

Contingency and state of development

IEA GHG's cost estimates are normally for 'nth plants' based on current knowledge of the technology, i.e. commercial plants built after the initial technology demonstration plants. Commercial demonstration plants will normally have higher costs, due for example to relatively high design and permitting costs, conservative design, a limited range of equipment suppliers and relatively low initial plant operating availability. IEA GHG's studies will normally not include the additional costs for 1st-of-a-kind commercial demonstration plants.

A project contingency shall be added to the capital cost to give a 50% probability of a cost over-run or under-run. Contractors may add a level of contingency which in their judgement is sufficient to achieve this. In the absence of better information from the study contractor the default value for project contingency should be 10% of the installed plant cost (i.e. the Total Plant Cost excluding contingency). This is unchanged from IEA GHG's original criteria.

Most of the processes which IEA GHG assesses are at or approaching commercial introduction and the processes and equipment are reasonably well defined. However, IEA GHG also assesses process at an early stage of development whose design, performance and costs are highly uncertain. For the assessment of such processes an additional process contingency should be added to allow for unforeseen cost increases which occur during process development. The appropriate level of process contingency shall be agreed between the contractor and the IEA GHG study manager.

Decommissioning cost

For fossil fuel and CCS plants the net cost of de-commissioning shall be assumed to be zero, in line with EPRI's report. The salvage value of equipment and materials is assumed to be equal to the costs of dismantling and site restoration. In many cases plant sites are not abandoned but are re-used. If the assessment criteria are used to assess other technologies which are known to have significant net de-commissioning costs, the cost should be included in the technology assessment.

Construction expenditure schedule and interest during construction

The plant construction times and expenditure schedules contained in IEA GHG's original criteria have been retained. Expenditure is assumed to take place at the end of each year and interest during construction payable in a year is calculated based on money owed at the end of the previous year.

Pre-production costs

Pre-production costs cover operator training, equipment checkout, changes in equipment, extra maintenance and inefficient use of fuel and other materials during startup. IEA GHG's original criteria did not include pre-production costs, although a reduced load factor was assumed for the first year of operation. IEA GHG's criteria have now been modified to include pre-production costs based on EPRI's report criteria. EPRI's report specifies one month of fixed operating and maintenance labour, administrative and support labour costs but it is stated that this has in practice increased in recent years and it could be as high as two years due to new staff being hired before commissioning of the plant. As a compromise, IEA GHG has specified three months of labour costs in its pre-production costs criteria.

Cost of electricity and CO_2 emissions abatement

IEA GHG's assessments calculate a cost of electricity (or other product) levelised over the life of the plant. This is the average price of electricity which would be necessary over the life of the plant to give a zero net present value.

Cost of CO_2 emissions avoidance

The cost of avoiding CO_2 emissions is calculated by comparing the costs and emissions of a plant with CCS and the costs and emissions of a reference case, using the following equation:

$$\text{Cost of emissions avoidance} = \frac{\text{Electricity Cost}_{\text{CCS}} - \text{Electricity Cost}_{\text{Reference}}}{\text{Emissions}_{\text{Reference}} - \text{Emissions}_{\text{CCS}}}$$

The cost of emissions avoidance is per tonne of CO_2. The electricity cost is per MWh and the emissions are in term of tonnes CO_2 per MWh.

The reference case may be based either on the same type of generation technology as the plant with CCS or it may be the type of power plant that a utility company would build in the absence of any constraints on CO_2 emissions. In most of IEA GHG's studies the reference case has been the same generation technology without CCS, because costs have been available on a consistent basis. However, if information is available on a consistent basis for the type of power plant that a utility company would build in the absence of any constraints on CO_2 emissions, the cost of emissions avoidance should also be calculated using this reference case.

Discount rate and capital charge factor

IEA GHG's original assessment criteria specified that a 10% discount rate in constant money values should be used and the sensitivity to a 5% rate should be assessed.

EPRI's report assumes the debt:equity ratio for power plants is 50:50 and the costs of debt and equity are 7.5% and 11.5% in current dollars, resulting in a total annual return of 9.5% in current money values. The annual return in constant dollars is 6.8%. The after tax discount rate, taking into account US taxation rates, is 5.4%.

European CCS collaborative R&D programmes normally use a discount rate of 8% and various other recent published reports have used similar rates.

IEA GHG's original 10% discount rate now appears to be relatively high compared to rates assumed for power plants by most other organisations. IEA GHG's standard discount rate will be changed to 8%. 10% and 5% i.e. IEA GHG's two original discount rates will be assessed as sensitivities. The sensitivity cases will provide some consistency with IEA GHG's earlier studies and will provide sensitivities both above and below the standard rate, which was not the case in IEA GHG's original criteria.

EPRI's report points out that different technologies require different returns on capital and different discount rates, depending on their perceived risk. IEA GHG's studies shall use the standard discount rates for all fossil fuel power plants but if it appears that certain technologies may require higher discount rates additional sensitivity cases may be assessed.

It should be noted that IEA GHG includes insurance and property taxes as an operating cost but EPRI and some other organisations that have derived their assessment methodologies from EPRI's include these costs in their 'capital charges'. IEA GHG and EPRI's capital charges should therefore not be compared directly.

It is generally recognised that discount rates that are appropriate for commercial projects with lifetimes of the order of 25 years are not necessarily appropriate for much longer timescales because of the greater uncertainties regarding global economic performance in the very long term and concerns regarding intergenerational equity[3]. Some energy technologies incur costs long after energy production has ceased, for example for CCS some very long term monitoring of CO_2 storage sites may be required and for nuclear power there are significant decommissioning and waste storage costs long after plant closure. Some economists favour using hyperbolic discount rates which decrease over time but for simplicity IEA GHG recommends that a discount rate of 2% should be used for costs incurred after plant closure and sensitivities to discount rates of 8% (the commercial plant discount rate) and zero should be assessed.

Plant life

Fossil fuel power plants often have long lives, in some cases over 50 years. However it is important to undertake economic assessments assuming shorter lives because investors want to be able to see that they will be able to get a return on their investments over shorter time periods, particularly in uncertain times. IEA GHG's original criteria specified a plant life of 25 years and this will continue to be used but the sensitivity to a 40 year life will also be assessed. It should be emphasised that these are not necessarily the physical lives of the plant. If IEA GHG assesses technologies which have physical lives shorter than 25 years then the actual plant lives should be used.

Operating load factor

The operating load factor is the annual output of the plant divided by the rated output at the average ambient conditions. The load factor will depend on the technical availability of the plant and the requirements of the electricity grid. IEA GHG's original criteria specified a load factor of 85% for coal

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[3] Discounting the benefits of climate change mitigation: How much do uncertain rates increase valuations?, R Newell and W. Pizer, report by Pew Centre on Global Climate Change, December 2001.

fired plants and 90% for gas fired plants. EPRI' report assumes an 85% load factor for its 'base load' plants.

In IEA GHG's studies it shall be assumed that fossil fuel power plants with and without CCS will operate at 'base load' at a load factor of 85%. Plants should normally be designed to have availability at least as high as 85% and appropriate equipment sparing should be included to achieve this. In exceptional cases a lower availability and load factor may be acceptable but this would need to be agreed with the IEA GHG project manager. A lower load factor is assumed for the first year of operation, to allow for start-up and de-bugging.

In the early years of CCS development it was assumed that all CCS plants would operate continuously at base load. More recently it has become apparent that there will be a large expansion in the use of variable renewable electricity generation technologies such as wind, solar and marine energy and in some regions there may also be an expansion in the use of nuclear energy. These energy sources have relatively low marginal operating costs and in the case of nuclear they are normally unable to operate with a high degree of flexibility. As a consequence fossil fuel plants, including those with CCS, may have to operate at lower load factors, although electricity prices may be relatively high during the times they are called upon to operate and revenue may be obtained from ancillary services so the plant profitability would not necessarily be worse. Gas fired plants which normally have relatively high marginal operating costs may have lower load factors than coal fired plants. EPRI's report assumes 30-50% load factor for 'intermediate' load plants. Operating at low load factors may incur additional costs, including reduced efficiency during part load operation, energy consumption during start-up and shut-down and higher wear and reduced lifetime of equipment due to load changes. The magnitude of these costs will depend on how the plant is operated, for example the same low load factor could be achieved by operating most of the time at reduced output or operating part of the time at high load factor and shutting the plant down for the rest of the time. IEA GHG's studies will normally not analyse operation at load factors significantly lower than the plant availability but this may be included in some studies on technologies which are aimed at the intermediate and peak load generation markets.

In common with IEA GHG's original criteria, the load factor in the first year of service shall be assumed to be 60% (or 30% in the 40% load factor sensitivity case) to allow for start-up and de-bugging.

Fuel prices

IEA GHG's original criteria specified coal and natural gas prices but this is becoming more difficult as fuel prices have become increasingly volatile in recent times. Even coal prices which have historically been relatively stable have fluctuated widely, for example European prices have fluctuated within a range of about 60 and over 200 $/t in the last year alone. In view of this variability the base cases in IEA GHG's recent studies have tended to be based on the most up to date market prices and sensitivities to fuel prices have been presented to facilitate comparison with results from other studies.

It is recommended that IEA GHG's future studies should be based on current delivered fuel prices, to make the results directly relevant to policy makers, but costs should also be calculated using standard fuel prices to facilitate comparisons between different IEA GHG studies. Sensitivity graphs should be presented showing the relationship between fuel price and cost of electricity and cost of CO_2 emissions avoidance.

IEA GHG undertakes some studies in which fuels other than coal and natural gas are used, including petroleum coke, biomass and wastes. Appropriate prices for such fuels should be specified by the study contractor, in agreement with the IEA GHG project manager, who should take into account prices used in other IEA GHG studies.

In general IEA GHG's studies are based on plants that are self sufficient in electricity but in some studies, particularly on industrial plants, electricity is assumed to be imported from the grid. The value of imported electricity should be the cost of generation in an 800MW fossil fuel (normally coal) power plant with CCS. In the calculation of the net CO_2 emissions avoided, the CO_2 emissions associated with imported electricity should be added to the plant's own direct CO_2 emissions. If the cost and emissions of imported electricity are particularly significant in the study, a sensitivity case should be assessed in which imported electricity is assumed to be generated in a fossil fuel power plant without CCS.

Insurance and local property taxes

In IEA GHG's original assessment criteria these costs were each assumed to be 1% of TPC per year, in line with EPRI's report, and this will not be changed. The cost assigned for insurance covers regulatory costs which were identified as a significant cost item during the Sydney workshop. It should be noted that when IEA GHG has provided a breakdown of the overall operating costs it has included insurance and local property taxes in the category of 'fixed operating costs', along with for example maintenance and labour costs but EPRI includes insurance and property taxes in its capital charge factor, along with debt payments and payments to equity holders. IEA GHG will continue to include insurance and local property taxes in the fixed operating cost category.

Maintenance costs

IEA GHG's original criteria recommended annual maintenance costs of 4% of plant cost for solids handling plant and 2% for plant handling gases and liquids but there has been uncertainty regarding which classification to use for some sections of plant, e.g. pulverised coal boilers. In recent years IEA GHG's study contractors have in practice often estimated maintenance costs based on their own best judgement.

EPRI's report shows the following ranges of annual maintenance costs as a percentage of TPC:

Corrosive and abrasive slurries	5 – 10+
Severe (solids, high pressure and temperature)	3 – 6
Clean (liquids and gases only)	1.5 - 4
General facilities and steam electrical systems	1 - 3

EPRI points out that maintenance costs depend on the type of plant, with 'minimum capital cost' plants generally having higher maintenance costs. EPRI's report states that maintenance cost estimates are typically developed by the contractor with concurrence of the EPRI project manager, which is in line with recent IEA GHG practice.

Annual maintenance costs as a percentage of Total Plant Cost from some recent published studies on power plants with and without CO_2 capture are shown in table 1. The maintenance costs for PC plants in table 1 imply the use of cost factors towards the bottom end of those shown above by EPRI's report. The relatively low maintenance costs for PC plants are confirmed by advice given to IEA GHG by one of its European utility sponsors, based on their own operating experience. Costs are higher for IGCC plants, reflecting the relatively high maintenance costs of gasifiers and high temperature/high pressure gas treating plant. One of the reasons for the relatively high costs for IGCC in reference 6 was that an annual cost of 5% was assumed for the gas turbine combined cycle plant, reflecting the use of a Long Term Service Agreement. IEA GHG recommends that maintenance costs are estimated by study contractors based on their own experience with concurrence of the IEA GHG project manager. Indicative maintenance cost factors for PC, IGCC and NGCC plants based on table 1 are included in IEA GHG's criteria, to help IEA GHG's project managers to avoid major discrepancies between studies carried out by different contractors.

Table 1 Maintenance cost factors

Type of plant	Capture	Reference	Annual maintenance cost, % of TPC
Supercritical Pulverised Coal	Yes	DOE-NETL (post combustion)[4]	1.64
	Yes	DOE-NETL (oxy-combustion)[5]	1.68
	Yes	EPRI[6]	1.34
	Yes	Canadian[7]	1.39
	No	European[8]	1.50
Natural Gas Combined Cycle	No	DOE-NETL[1]	2.03
	Yes	DOE-NETL[1]	1.79
	Yes/No	Jacobs –IEA GHG[9]	1.82
	No	European[5]	3.27
IGCC	Yes	DOE-NETL[1] (GE gasifier)	2.86
	Yes	DOE-NETL[1] (Shell gasifier)	2.51
	Yes	EPRI[3] (E-Gas)	2.02
	Yes	European[5]	1.93
	Yes	Jacobs –IEA GHG[6] (GE gasifier)	2.09
	Yes	Foster-Wheeler-IEA GHG[10] (Shell gasifier)	3.50
	Yes	Foster-Wheeler-IEA GHG[7] (GE gasifier)	3.43

IEA GHG assumes that maintenance costs are fixed, i.e. they do not depend on load factor, in line with EPRI's report. In practice some costs will decrease with load factor but others will increase, particularly if the plant undertakes frequent start-ups and shut-downs. Maintenance costs will vary from year to year, for example because many modern plants have shutdowns for major overhauls only every 3 years. Costs may also be relatively high in early years when the plant is being de-bugged and in later years when more equipment needs replacing but for simplicity IEA GHG assumes that maintenance costs remain constant throughout the plant life.

Operating labour

The numbers of operating staff shall be estimated by the study contractor. A 5 shift working pattern shall be assumed. If not estimated in detail, an allowance of 20% of the operating labour costs shall be included to cover supervision. The 'fully burdened' cost of labour, including social security payments, was estimated to be €50k per person-year in a major study undertaken for IEA GHG in 2003. To allow for inflation, the cost shall be assumed to be €60k in 2009. The labour cost shall be further adjusted in future to account for inflation.

Administrative and support labour

In IEA GHG's original criteria, administrative and support labour was not quoted as a separate item in the cost estimates but 30% was added to the operating labour cost to account for administrative and support labour. Administrative and support labour associated with maintenance labour was assumed to be included in the maintenance cost. In EPRI's studies the cost of administrative and support labour is quoted as a separate item and it is assumed to be 30% of the total operating and maintenance labour cost. The maintenance labour cost is assumed to be 40% of the total maintenance cost. To provide greater consistency with EPRI's studies and studies carried out by various other organisations and to make it

[4] Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE-NETL-2007/1281, May 2007.
[5] Pulverized Coal Oxycombustion Power Plants, DOE-NETL-2007/1291, October 2007.
[6] Updated Cost & Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, EPRI report 1004483, December 2002.
[7] Confidential Canadian study.
[8] Confidential European study.
[9] Retrofit of CO_2 Capture to Natural gas Combined Cycle Power Plants, IEA GHG report 2005/1, January 2005.
[10] Potential for Improvement in Gasification Combined Cycle Power Generation with CO_2 Capture, IEA GHG report PH4/19, May 2003.

clear that the cost of administrative and support labour has been included, IEA GHG's studies will be brought into line with EPRI's report criteria.

Chemicals and consumables
Chemicals consumptions shall be estimated by the study contractor. In most cases the specific costs of chemicals and consumables shall also be estimated by the contractor but unlike in the past, prices of limestone and water which can be particularly significant materials are specified in IEA GHG's criteria. IEA GHG's standard site uses once-through sea water cooling and it is assumed that sea water is available at no cost apart from the cost of an inlet duct, which shall be included in the plant capital cost.

By-products and wastes
The main material outputs from power stations are ash, slag, gypsum and sulphur. In some cases these materials can be sold as by-products but in other cases they will incur a disposal cost. The opportunities to sell by-products are likely to decrease if more power plants producing these materials are built and markets become saturated. IEA GHG assumes that disposal of ash, slag, gypsum and sulphur will have a zero net cost. Some types of plant, particularly those with CCS, produce special wastes which require disposal. The cost of disposal of any special wastes shall be estimated by the contractor.

CO_2 transport and storage
CO_2 transport and storage is an essential part of CCS so it is important that the costs are included in technical and economic assessments. In future IEA GHG intends to produce a set of standard criteria for assessment of CO_2 transport and storage. Until these criteria are produced a notional cost of €10/tonne of CO_2 stored shall be assumed. The costs of CO_2 transport and storage are highly site specific. Sensitivities to costs of zero and €20/t shall be assessed. The zero cost case shall show just the cost of CO_2 capture and it could represent enhanced oil or gas production with modest revenues. In some studies IEA GHG may request additional sensitivity cases with negative net transport and storage costs, representing enhanced oil or gas production with high revenues.

Alternative Plant Locations

IEA GHG's members are increasingly interested in applying the results of IEA GHG's studies to their own countries. Preliminary assessment criteria for alternative locations have therefore been specified. Study contractors could be asked to produce technical and economic assessments for some or all of the alternative locations as sensitivity studies if required. It is proposed that alternative locations will be assessed in IEA GHG's studies only if there is a specific interest from the local member, in order to limit the cost of studies. The following locations have been selected to give a broad range of local conditions in countries were CCS may be used to a significant extent. Data availability was also a factor in the choice of locations.

Locations using bituminous coal
- US (North East) inland location – local coal
- Australian (East) inland location – local coal
- Japanese coastal location – international coal
- Chinese coastal location – local coal
- Indian coastal location – international coal
- Indian inland location – local coal

Locations using low rank coals
- US inland location - Power River sub-bituminous coal
- Australian (Victoria) inland location - local brown coal
- German inland location - local brown coal

Wherever reasonable, IEA GHG's standard criteria for the Netherlands site shall be used for alternative locations, to minimise the amount of additional work required. The main sources of criteria values for the alternative locations are as follows:

USA:	EPRI study for IEA GHG
Australia:	EPRI study for IEA GHG and IEA GHG Australian Consortium
Germany:	IEA GHG study on low rank coals
Japan:	IEA GHG Sydney workshop
China:	NZEC study on CCS plants in China
India:	Mott MacDonald study on CO_2 capture ready UMPPs in India

In some cases IEA GHG used supplementary data from other sources to provide a complete set of criteria values. The criteria values for the alternative locations are preliminary and they will be finalised in consultation with local organisations at the time when IEA GHG commences its first study for the alternative locations. In particular, the labour costs and productivity and discount rate and load factor will need to be finalised.

The US environmental emissions specifications are according to the New Source Performance Standards (NSPS) as amended in February 2006. The coal mercury content is assumed to be 0.15 ppm (dry) and it is assumed that all of the mercury enters the gas phase. For the India case, the NO_X specification is that which could be achieved by use of low-NO_X burners. World Bank limits are 750 mg/Nm^3 (6% O_2). Emissions of SO_X would not breach the World Bank limit of 2,000 mg/Nm^3 (6% O_2) but it is expected that in case of international funding plants would require FGD. The SO_X limits for the Chinese case are from the NZEC study. In Australia the emission limits are set on the basis of dispersion modelling. In practice FGD is not used although the maximum coal sulphur content is set for some stations. NO_X normally does not exceed 1500-2500 mg/Nm^3 (a limit of 1500mg/Nm^3 has been assumed by IEA GHG). The emission limits for Germany are the EU Large Combustion Plant Directive limits. The emission limits for Japan have been assumed to be the same as for the Netherlands, as a preliminary assumption.

The output and efficiency of power plants depends on ambient conditions. In general both are lower at higher than average temperature. For some studies of plants at alternative locations where the peak power demand coincides with high ambient temperatures IEA GHG may specify that plant performance and costs should also be calculated at a higher than average ambient temperature. The study scope of work will specify whether this is required.

For the Japanese site it is assumed that the captured CO_2 shall be transported by ship as a refrigerated liquid. CO_2 liquefaction is included within the battery limits of the capture plant but buffer storage and loading of ships shall be considered to be part of the CO_2 transport system and outside the battery limits of the capture plant.

Conclusions and Recommendation

IEA GHG has produced a revised set of criteria for assessment of plants, particularly power plants with CO_2 capture, making use of information from EPRI and others.

The revised criteria should be used by IEA GHG for its future studies. Other organisations are encouraged to use the criteria to provide consistency of results.

Preliminary criteria have been specified for alternative locations and these should be finalised with local organisations at the time when IEA GHG undertakes its first study for each alternative location. Other alternative locations could be considered in future, at the request of IEA GHG's members.

As a follow on to this report IEA GHG will assess the feasibility of providing standard assessment criteria for CO_2 transport and storage and it will develop methodologies for comparing the relative merits of CCS and alternative low-CO_2 technologies.

APPENDIX 1

Criteria for Technical and Economic Assessment of Plants with Low CO_2 Emissions

IEA GREENHOUSE GAS R&D PROGRAMME

Criteria for Technical and Economic Assessment of Plants with Low CO_2 Emissions

Version C-1
May 2009

TECHNICAL CRITERIA

Plant location

IEA GHG's standard plant location is a coastal site in the North East of the Netherlands. Criteria for some alternative locations are also provided, as described later.

There shall be no restrictions on plant area and no special construction requirements or constraints on delivery of equipment. The site shall be level with minimum site preparation required. Provision of rail lines, roads, fresh water supply and high voltage electricity transmission lines, high pressure CO_2 and natural gas pipelines up to be the battery limits of the plant shall be outside the scope of the plant cost estimates.

Fuel analyses and supply

IEA GHG's standard coal is an Eastern Australian internationally traded open-cast coal. Coal shall be delivered from a port to the plant site by unit trains. Natural gas shall be delivered by high pressure pipeline. Plant performance analysis should be based on the design coal analysis but when calculating equipment sizes it should be recognised that power plants use fuels with a range of analyses.

Fuel heating value basis

IEA GHG's studies shall use Lower Heating Value (LHV) as the standard. Plant performance and efficiency shall also be quoted on an HHV basis, for the benefit of countries that normally use HHV. The definition of LHV shall be the HHV minus the latent heat of vaporisation of moisture in the fuel and the water produced by combustion of the hydrogen contained in the fuel.

Plant capacity

The nominal net power output shall be 800MWe, which is a typical size for new ultra supercritical coal fired power plants and which is also the approximate output of 2-module natural gas combined cycle plants. In practise it is not always possible to match this net power output because for some technologies the output depends on the capacities of standard commercial equipment, particularly gas turbines. Natural gas combined cycle units with outputs of around 500MWe are starting to be introduced to the market. If such turbines are selected for future studies, a 2-module plant should be specified and a higher net power output should be accepted.

The fuel feed rate of plants with and without CO_2 capture will be the same except for cases where it is necessary to have a different fuel feed rate to fully load a gas turbine, e.g. IGCC. In most cases this will result in a lower net power output from plants with capture.

For the standard Netherlands site the plant performance shall be calculated based on the annual average ambient conditions. For the economic assessment the plant shall be assumed to operate at its design performance with no performance degradation over time but some equipment oversizing, for example of fans and flue gas treating equipment may be necessary to counter the effects of degradation on plant output.

If IEA GHG wishes to compare the costs of fossil fuel plants and costs of other technologies which normally have significantly larger unit sizes, for example nuclear power plants, it is recommended that IEA GHG's costs of fossil fuel plants are adjusted to take account of the economies of scale of larger multiple units plants. For comparison with technologies which normally have smaller unit sizes, such as some renewable generation technologies, it is not necessary to scale down the size of fossil fuel plants.

For industrial plants other than power generation the plant size should be a typical size for the particular application. The size will be decided on a case-by-case basis.

CO_2 capture

IEA GHG's standard percentage CO_2 capture will be 90%. For some technologies such as oxy-combustion higher percentage capture can be easily achieved and in such cases the percentage capture should be whatever can be reasonably achieved by the technology. In some other cases a lower percentage capture may be specified subject to agreement by IEA GHG's project manager, if the incremental cost of capturing as much as 90% of the CO_2 is considered to be excessive. This could be considered in particular for plants such as natural gas combined cycle plants which have lower CO_2 emissions per kWh than coal fired plants.

CO_2 shall be delivered from the power plant site by pipeline at a pressure of 11.0MPa and a temperature of $\leq$30°C. The sensitivity of performance and costs to CO_2 delivery pressure shall be assessed in sensitivity cases if requested.

No buffer storage of CO_2 shall be included within the power plant battery limits. It shall be assumed that the CO_2 transport and disposal system can accommodate any variations in the quantity of CO_2 delivered by the capture plant.

CO_2 purity

CO_2 purity requirements depend on technical factors related to CO_2 transport and storage including corrosion, hydrate formation and health and safety, and regulatory requirements. The water specification is to ensure there is no free water and hydrate formation. The limits on concentrations of inerts are to reduce the volume for compression, transport and storage and limit the increase in Minimum Miscibility Pressure (MMP) in Enhanced Oil Recovery (EOR). The maximum hydrogen concentration is set at 4% but it is expected that the concentration will normally be lower to limit the loss of energy and economic value. The H_2S, SO_2, NO_X and CO limits are set from a health and safety perspective. The O_2 limit is tentative in view of the lack of practical experience on effects of O_2 in underground reservoirs. In some studies an assessment of the sensitivity of performance and costs to CO_2 purity may be requested.

Environmental performance

The maximum emissions to air of SO_X, NO_X and particulates are those that apply for new power plants in the Netherlands. These are lower than the current EU Large Combustion Plant Directive requirements. In some studies an assessment of the sensitivity to environmental emissions standards may be requested.

Cooling water system

A once-through seawater cooling water system shall be used for major cooling duties such as steam turbine condensers. The inlet and outlet ducts are within the site battery limits. A secondary fresh water cooling system may be used for some smaller process cooling duties if the contractor considers that has practical and economic advantages.

ECONOMIC CRITERIA

Currency

Cost estimates in IEA GHG's study reports shall be presented in the main currency in which they were derived, preferably Euros or US$. If the costs are not derived in US$ the headline costs (capital cost/kW, electricity cost per kWh and costs of CO_2 captured and CO_2 avoidance per tonne of CO_2) shall be converted to US$ using the current market exchange rate and the $ costs shall be included in IEA GHG's study overview, along with the costs in the original currency. The exchange rate used for conversion shall be clearly stated in the study report. The date of the cost estimate should be stated to at least the nearest quarter year in study reports.

Capital cost

Capital costs shall be estimated by the study contractor, making use of information from process licensors and equipment suppliers where appropriate. Up to date information should be used as far as possible and the date of the cost estimates shall be clearly stated in the study report.

IEA GHG's reports shall include Total Plant Cost (TPC) and Total Capital Requirement (TCR). TPC is the installed cost of the plant including contingencies. A breakdown of TPC into the costs of major process units shall be provided and if possible the costs of each process unit shall be broken down into direct materials, construction costs, other costs, EPC services and contingency. Initial charges of catalysts and chemicals shall be estimated for each process unit and costs shall be included in the Total Plant Cost.

TCR includes TPC, interest during construction, owner's costs, spare parts, working capital and start-up costs.

- Interest during construction shall be calculated from the plant construction schedule and an interest rate which will be assumed to be the same as the discount rate. Expenditure shall be assumed to take place at the end of each year and interest during construction payable in a year shall be calculated based on money owed at the end of the previous year.
- Owner's costs cover the costs of feasibility studies, surveys, land purchase, permitting, arranging financing and other miscellaneous costs. Owner's costs shall be calculated as a percentage of TPC and shall be assumed to be all incurred in the first year of construction, allowing for the fact that some of the costs would be incurred before the start of construction.
- Spare parts shall be calculated as a percent of TPC. It is assumed that spare parts have no value at the end of the plant life due to obsolescence.
- Working capital includes inventories of fuel and chemicals (materials held in storage outside of the process plants). It is assumed that the cost of these materials shall be recovered at the end of the plant life.
- Start-up costs consist of:
  - 2 percent of TPC, to cover modifications to equipment that will be needed to bring the unit up to full capacity.
  - 25% of the full capacity fuel cost for one month, to cover inefficient operation that occurs during the start-up period
  - Three months of operating and maintenance labour costs, to include training
  - One month of catalysts, chemicals and waste disposal costs.

When undertaking sensitivity studies it should be noted that TCR depends on the discount rate and fuel price.

For fossil fuel and CCS plants the salvage value of equipment and materials shall normally be assumed to be equal to the costs of dismantling and site restoration, resulting in a zero net cost of decommissioning. If there are known to be significant net costs of de-commissioning these should be included.

Contingency and state of development

The cost estimates should be for 'nth plants' based on current knowledge of the technology, i.e. they are commercial plants built after the initial technology demonstration plants. Additional costs normally associated with 1st-of-a-kind commercial plants shall be excluded.

A project contingency shall be added to the capital cost to give a 50% probability of a cost over-run or under-run. Contractors shall add a level of contingency which in their judgement is sufficient to achieve this. In the absence of better information from the study contractor the default value for project contingency should be 10% of the installed plant cost (i.e. the Total Plant Cost excluding contingency).

For processes which are at a very early stage of development and whose design, performance and costs are highly uncertain an additional process contingency should be added. The appropriate level of process contingency, if any, shall be agreed between the contractor and the IEA GHG study manager.

Cost of electricity and CO_2 emissions abatement

IEA GHG's studies shall calculate the cost of electricity (or other product) levelised over the life of the plant. This is the average price of electricity that would be necessary over the life of the plant to give a zero net present value.

Cost of CO_2 emissions avoidance

The cost of avoiding CO_2 emissions is calculated by comparing the costs and emissions of a plant with CCS and the costs and emissions of a reference case, using the following equation:

$$\text{Cost of emissions avoidance} = \frac{\text{Electricity Cost}_{CCS} - \text{Electricity Cost}_{Reference}}{\text{Emissions}_{Reference} - \text{Emissions}_{CCS}}$$

The cost of emissions avoidance is per tonne of CO_2. The electricity cost is per MWh and the emissions are in term of tonnes CO_2 per MWh.

The reference case can be based either on the same type of generation technology as the plant with CCS or it can be the type of power plant that a utility company would build in the absence of any constraints on CO_2 emissions. In most of IEA GHG's studies costs of the same type of plant with and without capture are estimated and the plant without capture should be used as the reference plant. If information is available on a consistent basis for the type of power plant that a utility company would build in the absence of any constraints on CO_2 emissions, the cost of emissions avoidance should also be calculated using this reference plant.

Industrial plants other than power plants

For assessment of industrial plants other than power plants the reference case should be the same type of plant without capture. The cost of capture should be expressed as the increase in the cost of the primary product, e.g. steel, cement or chemical, and costs per tonne of CO_2 captured and emissions avoided.

Power plants produce all of the power and steam that they consume internally but this is not always so for other industrial plants. If power has to be imported, the emissions associated with generation of that power should be taken into account in the calculation of the quantity of CO_2 emissions avoided. The main options for calculating the emissions associated with imported electricity are:

- The average emissions of the grid that supplies the electricity
- The emissions of a fossil fuel plant without CCS
- The emissions of a fossil fuel plant with CCS

IEA GHG recommends using the emissions associated with an 800MW coal fired plant with CCS because IEA GHG can provide cost data for such plants produced using its standard assessment criteria and in future most fossil fuel power plants are likely to include CCS. However, it is recommended that sensitivities to the other two options should also be assessed. It is important that the cost assumed for imported electricity corresponds to the type of plant assumed for the calculation of CO_2 emissions.

For plants that import or export steam, the value of the steam and its associated CO_2 emissions shall normally be calculated based on the quantity of electricity that could be produced from the steam.

Discount rate

IEA GHG's standard discount rate shall be 8% in constant money values. Sensitivities to discount rates of 10% and 5% shall be assessed.

In practice the required discount rate depends on the perceived level of risk, which may be different for different technologies. IEA GHG's studies shall use the standard discount rates for all fossil fuel power plants but if it appears that certain other technologies may require higher or lower discount rates, the effects may be assessed in sensitivity cases if required.

Discount rates that are appropriate for commercial projects with lifetimes of the order of 25 years are not necessarily appropriate for much longer timescales because of uncertainty regarding future discount rates. For simplicity, a discount rate of 2% shall be used for costs incurred after plant closure and sensitivities to discount rates of 8% (the commercial plant discount rate) and zero shall be assessed. The only significant costs incurred after plant closure are likely to be for decommissioning, waste disposal and monitoring.

Plant life

A standard plant life of 25 years shall be used for economic assessments unless there are technical reasons why a shorter life is necessary for particular types of plant. The sensitivity to a 40 year life shall be assessed. These plant lives are for the purposes of economic assessment and they are not necessarily the maximum physical lives of the plant.

Operating load factor

The operating load factor is the annual output of the plant divided by the rated output at the average ambient conditions. The load factor will depend on the technical availability of the plant and the requirements of the electricity grid. IEA GHG's standard assumption for fossil fuel power plants with and without CCS plants is that the plant will operate at 'base load' at a load factor of 85%. Plants shall normally be designed to have availability at least as high as 85%. Appropriate equipment sparing shall be included to achieve this. In exceptional cases, where excessive sparing of major items would be required, a lower availability and load factor may be acceptable but this would need to be agreed with the IEA GHG project manager. It shall be assumed that electric power is available at the site for start-up purposes.

Operation at lower load factors may be assessed in some studies at the request of IEA GHG.

The load factor in the first year of service shall be assumed to be 60% (or 30% in the 40% load factor sensitivity case) to allow for start-up and de-bugging.

Fuel prices

IEA GHG's base case fuel prices shall be the current delivered coal and natural gas prices. Appropriate prices for other fuels such as biomass, wastes and petroleum coke should be specified by the study contractor, in agreement with the IEA GHG project manager, who will take into account any prices used in other IEA GHG studies.

Costs shall also be calculated using a set of standard fuel prices to facilitate comparisons between different IEA GHG studies and sensitivity graphs shall be presented showing the relationship between fuel price and cost of electricity and cost of CO_2 emissions avoidance.

Insurance and local property taxes

The total annual cost of insurance and local property taxes shall be assumed to be 2% of TPC. This also covers miscellaneous regulatory and overhead costs. This item is classed as a 'fixed operating cost', independent of load factor.

Maintenance costs
Maintenance costs shall be estimated by the study contractor based on its own experience, with concurrence of the IEA GHG project manager. Indicative maintenance cost factors for PC, IGCC and NGCC plants are included in IEA GHG's criteria, to help avoid major discrepancies between studies carried out by different contractors.

For simplicity IEA GHG normally assumes that maintenance costs remain constant throughout the plant life but if a particular technology requires periodic replacement of major plant items the cost should be included in the economic assessment.

IEA GHG assumes that maintenance is a 'fixed operating cost', although it is recognised that in practice some costs will decrease with load factor but others will increase, particularly if the plant undertakes frequent start-ups and shut-downs.

Operating labour
The numbers of operating staff shall be estimated by the study contractor. A 5 shift working pattern shall be assumed. If not estimated in detail, an allowance of 20% of the operating labour costs shall be included to cover supervision. The 'fully burdened' cost of labour, including social security payments, shall be assumed to be €60k in 2009. The labour cost shall be adjusted in future to account for inflation. Operating labour is classed as a 'fixed operating cost'.

Administrative and support labour
Administrative and support labour shall be assumed to be 30% of the operating and maintenance labour. Maintenance labour shall be assumed to be 40% of the overall maintenance cost, hence the cost of administrative and support labour shall be 30% of the operating labour plus 12% of the total maintenance cost. Administrative and support labour is classed as a 'fixed operating cost'.

Chemicals and consumables
Chemicals consumptions shall be estimated by the study contractor. In most cases the specific costs of chemical and consumables shall also be estimated by the contractor but prices of limestone and water, which are particularly significant materials, are specified in IEA GHG's criteria. IEA GHG's standard site uses once-through sea water cooling and it is assumed that this is available at no cost apart from the cost of inlet and discharge ducts, which shall be included in the plant capital cost. Chemicals and consumables are a 'variable operating cost'

By-products and wastes
The net costs of disposal of ash, slag, gypsum and sulphur shall be assumed to be zero. Some types of plant, particularly those with CCS, produce special wastes which require disposal. The cost of disposal of any special wastes shall be estimated by the contractor.

CO_2 transport and storage
CO_2 transport and storage is an essential part of CCS so it is important that the costs are included in technical and economic assessments. The costs of CO_2 transport and storage are highly site specific. A notional cost of €10/tonne of CO_2 stored shall be assumed as the base case and sensitivities to costs of zero and €20/t shall be assessed. The zero cost case shall show just the cost of CO_2 capture and it could represent enhanced oil or gas production with modest revenues. In some studies IEA GHG may request additional sensitivity cases with negative net transport and storage costs, representing enhanced oil or gas production with high revenues.

ALTERNATIVE PLANT LOCATIONS

IEA GHG's assessment criteria values for alternative locations are the same as those for the standard Netherlands location except for criteria which are significantly different, for example ambient conditions, coal analyses, emissions standards and labour costs.

The criteria values for alternative locations are preliminary and they will be finalised in consultation with local organisations at the time when IEA GHG commences its first study for the alternative locations. In particular, the labour costs and productivity and discount rate and load factor will need to be finalised.

The output and efficiency of power plants depends on ambient conditions. In general both are lower at higher than average temperature. For some studies of plants at alternative locations where the peak power demand coincides with high ambient temperatures IEA GHG may specify that plant performance and costs should also be calculated at a higher ambient temperature. The study scope of work will specify whether this is required.

For the Japanese site it is assumed that the captured CO_2 shall be transported by ship as a refrigerated liquid. CO_2 liquefaction is included within the battery limits of the capture plant but buffer storage and loading of ships shall be considered to be part of the CO_2 transport system and outside the battery limits of the capture plant.

TECHNICAL CRITERIA

Plant location	
Country	Netherlands
Plant site	Coastal
Site condition	Clear, level, no special civil works
Seismic risk	Negligible
Ambient conditions	
Temperature (dry-bulb, average), °C	9
Maximum temperature, °C	30
Minimum temperature, °C	-10
Humidity (average), %	60
Pressure (average), kPa	101.3
Plant capacity	
Net power output (nominal) MWe	800
Turndown	≥50%
Raw material and product delivery and dispatch	
Coal and limestone delivery	Unit train
Natural gas delivery	Pipeline
Coal and limestone storage capacity, days at full load	30
Ash disposal	Adjacent landfill or processing plant outside battery limits
Electricity frequency, Hz	50
Grid connection voltage, kV	380
Cooling water system	
Type	Once-through sea water cooling
Sea water inlet temperature, °C	12
Maximum sea water outlet temperature, °C	19
Coal analysis	
Coal type	Eastern Australia, open cast bituminous
Moisture (as-received), wt%	9.5
Ash (as-received), wt%	12.2
Carbon (dry ash free), wt%	82.5
Hydrogen (dry ash free), wt%	5.6
Oxygen (dry ash free), wt%	8.97
Nitrogen (dry ash free), wt%	1.8
Sulphur (dry ash free), wt%	1.1
Chlorine (dry ash free), wt%	0.03
HHV (as-received), MJ/kg	27.06
LHV (as-received), MJ/kg	25.87
Hardgrove index	45
Ash analysis, wt%	
SiO_2	50.0
Al_2O_3	30.0
Fe_2O_3	9.7
CaO	3.9
TiO_2	2.0
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7
Ash fusion temp (reducing), °C	1350
Natural gas analysis	

Methane, vol%	89.0
Ethane, vol%	7.0
Propane, vol%	1.0
Butane, vol%	0.1
Pentane, vol%	0.01
CO_2, vol%	2.0
Nitrogen, vol%	0.89
Pressure, MPa	7
HHV, MJ/kg	51.473
LHV, MJ/kg	46.502
Efficiency basis for presentation of results	
Standard basis	LHV
Sensitivity basis	HHV
Emission limits	
SO_2, mg/Nm^3 (6% O_2)	100
NO_X, mg/Nm^3 (6% O_2) (measured as NO_2)	100
Particulates, mg/Nm^3 (6% O_2)	10
CO_2 capture	
CO_2 capture, %	$\geq$90
CO_2 maximum impurities (vol. basis)	
H_2O	500ppm
N_2 /Ar	4%
O_2	100ppm
CO	0.2%
CH_4 and other hydrocarbons	4%
H_2S	200ppm
SO_2	100ppm
NO_2	100ppm
Total non-condensibles	4%
CO_2 conditions – pipeline transport	
Pressure, MPa	11
Maximum temperature, °C	30
CO_2 conditions – ship transport	
Pressure, MPa	0.7
Temperature, °C	-55

ECONOMIC CRITERIA

Total Plant Cost (TPC)	
Plant materials and labour costs	To be estimated by the contractor
Engineering contractor's fees	To be estimated by the contractor
Project contingency, % plant cost (default value)	10%
Total Capital Requirement (TCR)	
Owners costs and fees, % of TPC	7
Interest during construction	From expenditure schedule and discount rate
Spare parts	0.5% of TPC
Construction times, years	
Coal and lignite power plants	3
Natural gas combined cycle plants	2
Expenditure schedule, % per year	
Coal power plants	20/45/35
Natural gas combined cycle plants	40/60
Start-up costs	
Maintenance and operating and support labour costs	3 month
Maintenance materials	1 month
Chemicals, consumables and waste disposal costs	1 month
Fuel cost, % of full load	25% of 1 month
Modifications	2% of TPC
Working capital	
Coal and other solid fuel stocks, days at full load	30
Chemicals and consumables, days at full load	30
Decommissioning cost	0
Load factor	
All except year 1, %	85
Year 1, %	60
Discount rate	
Plant construction and operation, %	8
Costs incurred after shut-down, %	2
Operating life	
Base case, years	25
Fuel prices	
Coal and natural gas prices	Current delivered prices
Other fuels (biomass etc)	Study-specific basis
Fixed operating costs	
Maintenance costs	Estimated by contractor
Indicative costs, % of TPC/y – pulverised coal plants	1.5
– NGCCs	2.2
– IGCCs	2.5
Operating labour cost, €k/person-year	60
Number of operators	Estimated by contractor
Number of operating shifts	5
Administrative/support labour, % of operating labour	30
Administrative/support labour, % of maintenance cost	12
Variable operating costs	
Raw process water, €/m^3	0.2
Limestone, €/t	20
Other chemicals and consumables	Estimated by contractor
Ash, slag, gypsum and sulphur net disposal cost	0
Special waste disposal costs	Estimated by contractor
CO_2 transport and storage, €/tonne CO_2 stored	10

SENSITIVITY CASES

IEA GHG specifies that sensitivities to certain economic parameters should be assessed. Each sensitivity will normally only be assessed assuming the base case values for all other criteria.

Criteria	Base case	Sensitivities	
Fuel prices	Current prices	-50%	+100%
- standard coal price, €/GJ (LHV)		2	
- standard natural gas price, €/GJ (LHV)		6	
Discount rate, %	8	5	10
Discount rate after plant closure (if there are significant costs), %	2	8	0
Plant life, years	25	40	
CO_2 transport and storage cost, €/tonne stored	10	0	20

Further sensitivities to particularly significant criteria may be undertaken in specific studies, at the request of IEA GHG. Criteria could include:

- Plant size
- CO_2 purity
- CO_2 pressure
- Environmental emission standards
- Operating load factor
- The type of reference plant for calculation of CO_2 abatement cost
- Waste disposal costs
- By-product values
- The prices of imported electricity and steam and their associated CO_2 emissions
- Additional costs incurred due to intermediate load cycling operation

ALTERNATIVE LOCATIONS – BITUMINOUS COALS

Country	**Australia**	**Japan**	**India**	**India**	**China**	**USA**
Plant site	East coast	Kanto			Tianjin	Mid-West
	Inland	Coastal	Inland	Coastal	Coastal	Inland
Cooling system	Dry cooling	Once-through sea water cooling	Natural draught cooling towers	Once-through sea water cooling	Once-through sea water cooling	Natural draught cooling towers
Average temperature, °C	20	15	35	35	15	15
Pressure, kPa	99	101.3	99	101.3	101.3	99
Humidity (average), %	60	75	60	60	60	60
Sea water temperature	-	19	-	25	15	-
Seismic risk	Negligible	Severe	Negligible	Negligible	Severe	Moderate
Net power output, MWe	500	1000	800	800	800	800
Coal type	Australian domestic	Australian export (IEA standard)	Singrauli	Australian export (IEA standard)	Shenhua	Illinois No.6
Coal delivery	Unit train	Ship	Unit train	Ship	Unit train	Unit train
CO_2 transport	Pipeline	Ship	Pipeline	Pipeline	Pipeline	Pipeline
Electricity frequency	50 Hz	60 Hz	50 Hz	50 Hz	50 Hz	60 Hz
Emissions basis	mg/Nm^3 (6% O_2)	mg/Nm^3 (6% O_2)	mg/Nm^3 (6% O_2)	mg/Nm^3 (6% O_2)	mg/Nm^3 (6% O_2)	lb/MMBtu
SO_X	No FGD	100	400	400	400	1.4
NO_X	1500	100	600	600	450	1.0
Particulates	50	10	50	50	50	0.015
Mercury	-	-	-	-	-	20x10^{-6} lb/MWh
Load factor, %	TBA	85	TBA	TBA	65	85
Discount rate	8	4	TBA	TBA	TBA	8
Operating labour cost	TBA	TBA	TBA	TBA	TBA	US$75k/y

ALTERNATIVE LOCATIONS – LOW RANK COALS

Country	**Germany**	**Australia**	**USA**
Plant site	Rheinland	Victoria	Mid-west
	Inland	Inland	Inland
Cooling system	Natural draught cooling towers	Dry cooling	Natural draught cooling towers
Average temperature, °C	9	20	15
Pressure, kPa	99	99	99
Humidity (average), %	60	60	60
Sea water temperature	-	-	-
Sea water return temp	-	-	-
Seismic risk	Negligible	Negligible	Moderate
Net power output, MWe	800	500	800
Coal type	Rhein brown coal	Victoria brown coal	Powder River sub-bituminous
Coal delivery	Conveyor	Conveyor	Unit train
CO_2 transport	Pipeline	Pipeline	Pipeline
Electricity frequency	50 Hz	50 Hz	60 Hz
Emissions basis	mg/Nm^3 (6% O_2)	mg/Nm^3 (6% O_2)	lb/MMBtu
SO_X	200	No FGD	1.4
NO_X	200	1500	1.0
Particulates	30	50	0.015
Mercury	-	-	66x10^{-6} lb/MWh
Load factor, %	85	85	85
Discount rate	8	8	8
Operating labour cost	€60k/y	TBA	US$75k/y

ALTERNATIVE COAL ANALYSES

Country	**Australia**	**Japan**	**India**	**China**	**USA**	**USA**	**Germany**	**Australia**
Coal rank	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous	Sub-bituminous	Brown coal	Brown coal
Coal source	Australia	Australia	India	China	USA	USA	Germany	Australia
Coal type	Domestic	Export	Singrauli	Shenhua	Illinois No.6	Powder River	Rhein	Victoria
Ultimate analysis, wt% as-received								
Moisture	9.0	9.5	9.38	11.00	12.25	31.00	50.7	60.0
Ash	26.0	12.2	39.39	14.00	10.97	5.50	3.5	1.3
Proximate analysis, wt% dry-ash-free								
Carbon	84.4	82.5	75.56	80.44	79.45	76.40	68.4	69.4
Hydrogen	5.4	5.6	5.09	4.83	5.54	5.12	5.0	4.9
Oxygen	7.61	8.97	16.92	13.25	9.02	16.83	25.2	24.8
Nitrogen	1.9	1.8	1.46	0.93	1.63	1.02	0.8	0.6
Sulphur	0.69	1.1	0.97	0.55	4.27	0.63	0.5	0.3
Chlorine	-	0.03	-	-	0.09	-	0.09	-
HHV, MJ/kg ar	22.47	27.06	15.35	23.83	25.53	19.38	12.26	10.60
LHV, MJ/kg ar	21.47	25.87	14.57	22.76	24.29	17.90	10.50	8.70
Hardgrove index	50	45	50	TBA	51	-	-	-