WORKBOOK FOR SCREENING OPTIONS TO REDUCE CO_2 EMISSIONS FROM EXISTING POWER STATIONS

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WORKBOOK FOR SCREENING OPTIONS TO REDUCE CO_2 EMISSIONS FROM EXISTING POWER STATIONS

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) has assessed a wide range of technologies that can be used to reduce greenhouse gas emissions from fossil fuel fired power stations. IEA GHG has so far concentrated mainly on technologies for application in new power stations, as they will have the greatest impact in the long term. However, power stations often have long lives, so it may be beneficial to modify some existing power stations to reduce their emissions.

Workbook Description

IEA GHG has produced a "workbook" for initial assessment of the costs and performance of power station retrofits to reduce CO_2 emissions. The workbook was created by Ultra Systems Technology Pty Ltd. of Australia, in collaboration with CSIRO Division of Energy Technology, Pacific Power (International) Pty and NRG Pty.

The workbook consists of two parts:

- A user-friendly software package for use on a personal computer.

- A report which provides background and technical information and instructions for use of the software.

It contains sufficient information for a user to identify a number of options that might be suitable for retrofit to a particular power plant. After using the workbook, the user would have a short-list of options that could be followed up in more detail. The workbook is intended to be used primarily by utility planners and power plant management.

The software package has been developed using Microsoft Excel. It is organised as a number of worksheets, only one of which is displayed at a time. The user is led through the relevant worksheets in a logical sequence so that he can provide the necessary inputs required for the case in question. In many cases if the user does not provide an input (i.e. leaves a cell blank), then the model will revert to a default value. Messages will appear to guide the user in case of unsuitable input or if the user has not provided an essential input. The user can move back and forth between worksheets to change parameters with the model carrying out recalculation whenever parameters are changed.

The inputs that need to be provided by the user consist of technical information about the plant, commercial information and some information on the proposed retrofit. The technical information includes:

- The type of plant
- Power output
- Location
- Fuel type and analysis
- Detailed plant data

The detailed plant data includes, for example, combustion efficiency, excess air level, steam conditions, condenser pressure and turbine heat rate.

The commercial information includes:

- Operating load factor
- The annual fixed charge rate
- Operating and maintenance costs
- Fuel costs

All of this information should be readily available to a plant operator but in case the information is not available, defaults are provided for most parameters. The workbook enables sensitivities to any of the technical and commercial parameters to be quickly and easily evaluated.

It should be recognised that costs of power station retrofits depend on many site specific factors not all of which are included in the workbook. For example, the feasibility and costs of installing retrofit equipment depend on the layout of the existing plant. The model should therefore only be used for initial assessment of options. More detailed site specific studies should be carried out for the most promising options identified using the workbook.

Retrofit Options

The workbook includes the following 22 technical options, ranging from minor refurbishments and changes in operating practices to major upgrades, costing more than the original plant.

Plant modifications:
- Turbine re-blading
- Additional feedwater heaters
- Backpressure reduction
- Boiler back-end temperature reduction
- Upgrade input steam conditions to turbine
- Change to steam feed pump
- Unburnt carbon reduction
- Flue gas oxygen optimisation
- Housekeeping
- Gas turbine (open-cycle) upgrade

External generation:
- Wind power
- Mini-hydro

Plant upgrade:
- Auxiliary gas turbine
- Gas turbine repowering
- Gas turbine conversion to combined cycle
- Supplementary solar energy

Alternative fuels
- Coal to coal
- Coal to gas
- Oil to gas
- Biomass co-firing

Carbon sequestration
- Forestry
- CO_2 capture and storage

"Plant modifications" such as minor refurbishments and changes to operating practices could result in small reductions in CO_2 emissions at low capital cost. In many cases the amount by which emissions could be reduced would depend on the current state of the plant and the extent to which its performance deviates from its design conditions.

A gas turbine could be added to an existing steam cycle power plant, either as an additional unit or as a replacement for the existing boiler. This type of "plant upgrade" could generate a large amount of additional power and reduce specific emissions of CO_2 but the capital cost could be substantial and supplies of natural gas would need to be available. Another type of plant upgrade would be conversion of an existing open cycle gas turbine to a combined cycle. The capital cost would be more than the cost of the open cycle gas turbine but the amount of additional power generated and the reduction in specific emissions would be substantial. The other "plant upgrade" included in the workbook involves using solar thermal energy collectors to preheat water for the steam cycle. This option obviously depends on the local availability of solar energy.

Other ways of utilising renewable energy to reduce specific emissions of CO_2 from an existing plant are to install some wind or mini-hydro generation. The amount of energy that could be generated by these "external generation" options and their cost would depend on the local renewable energy resource.

The "alternative fuels" options included in the workbook can result in significant reductions in CO_2 emissions at relatively low capital costs. Converting a coal fired plant to use natural gas can reduce emissions by around 40%. Even using an alternative coal of similar rank can reduce emissions by around 5% and coal switching can sometimes also improve boiler efficiency, resulting in further emission reductions. Co-firing biomass in an existing coal-fired boiler can reduce CO_2 emissions provided the biomass is from a sustainable source and can be regarded as an essentially zero emission fuel. The proportion of biomass that can be fired in an existing boiler is normally limited to about 10% unless major modifications are made. The overall economics of the alternative fuel options depend strongly on the relative costs of fuels, which is very site specific.

Large reductions in net CO_2 emissions can be achieved by carbon sequestration. The entire CO_2 emissions from a power station can be offset by carbon sequestration in forests but there is a risk that the carbon may be released at some time in the future. Costs of this option depend on the costs and performance of the forest; the default data in the workbook correspond to around US$5/t CO_2. Capture and storage of CO_2 can reduce emissions by up to 90% but it is more expensive; the default costs in the workbook are around $30/t CO_2.

The approximate ranges of performance and costs are summarised in table 1, although it must be emphasised that there is a wide range of costs and emission reductions for each group of options.

Table 1 Summary of costs and emission reduction potentials

	Capital cost, % of cost of new plant	Maximum reduction in specific CO_2 emissions, %
Plant modifications	mostly <5	10
External generation	up to >100	100
Plant upgrades	up to 250	50
Alternative fuels	up to10	40
Carbon sequestration	up to 40	100

Expert Group Comments

Draft versions of the workbook were sent for review to experts, including some members of IEA GHG's Executive Committee and staff at power utilities. Comments provided by the reviewers were taken into account as far as possible in the final version of the model and report. The general view was that model will be a useful tool for screening CO_2 abatement options.

Recommendations

- Members of the IEA Greenhouse Gas Programme are encouraged to distribute the workbook to power utilities within their own countries.

- Power utilities are encouraged to apply greenhouse gas emissions reduction techniques, such as those described in the workbook, to their power stations.

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Workbook for Screening Options to Reduce CO_2 from Existing Power Stations

IEA/CON/01/67

Final Report

prepared for

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COVER SHEET

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Date:	17 April 2002

Signed..
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Director

Workbook for Screening Options to Reduce CO_2 from Existing Power Stations

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1 INTRODUCTION

IEA Greenhouse Gas R&D Programme (IEA GHG) has assessed technologies that can be used to capture, store and utilise CO_2 and is also assessing alternative technologies including renewable energy. The work has so far concentrated mainly on technologies for application in new power stations, as these will have the greatest impact in the long term. However, power stations often have long lives, so it may be necessary and beneficial to also modify some existing power stations to reduce emissions of greenhouse gases.

IEA GHG appointed Ultra-Systems Technology Pty Ltd (***UST***) to carry out a Study with the aim of providing utility planners and power plant management with a self-contained Workbook to assess retrofit options for reducing CO_2 emissions as a "first pass" evaluation. It was intended that the Workbook would contain sufficient information for a user to identify a number of options that might be suitable for retrofit to a particular power plant. After using the Workbook, the user would be able to develop a short-list of options that could be followed up in more detail.

The Workbook has been produced as a paper report and as a software package for use on a personal computer. It contains sufficient information for a user to identify appropriate options that might be suitable for retrofitting to particular power plants. The Workbook is user-friendly and provides a tool for a user to develop a short-list of options, ranked in terms of "value for money", that could be followed up in more detail by the user.

The Workbook has been produced in three parts:

1 *Background and instructions for use,* explaining the purpose of the Workbook, what it can be used for and how to use it.

2 *Technical information,* summarising the characteristics of a range of CO_2 emissions reduction measures, to allow the user to easily compare the different options.

3 *Calculator,* provided as an MS Excel© worksheet and allowing a user to input technical and financial parameters to calculate effective CO_2 reductions and the costs of these reductions.

UST has untaken development of this Workbook in co-operation with CSIRO Energy Technology (CSIRO), Pacific Power (International) Pty Ltd (PPI) and NRG Pty Ltd (NRG):

- ***UST*** was established in 1981 to provide expert services to the Australian energy industry, and are experts in the areas of fuel for power generation and other uses.
- CSIRO are Australia's premier provider of research and development activities, and the Division of Energy Technology are expert in all facets of energy production and use.
- PPI is an engineering consulting business specialising in advanced energy solutions to power utility companies.
- NRG is a specialist energy consulting company assisting equipment vendors, resource owners and energy buyers respectively with sales, assessment and energy contracting.

2 BACKGROUND AND INSTRUCTIONS FOR USE

2.1 INTRODUCTION

The operation of the Workbook is carried out in three parallel calculation streams and input/output facilities, as shown in the flow sheet in Figure 2.1:

1 Details of the Reference plant (yellow boxes).

2 Calculations of the improved plant through the implementation of various options (green boxes).

3 Estimation of costs from the Cost Database (purple boxes).

4 Inputs and outputs (red boxes).

The results of equipment performance and the cost data are used to evaluate the extent of CO_2 reduction and the cost of making that reduction. The user can select the optimum equipment based of the amount, costs and required future reduction of CO_2.

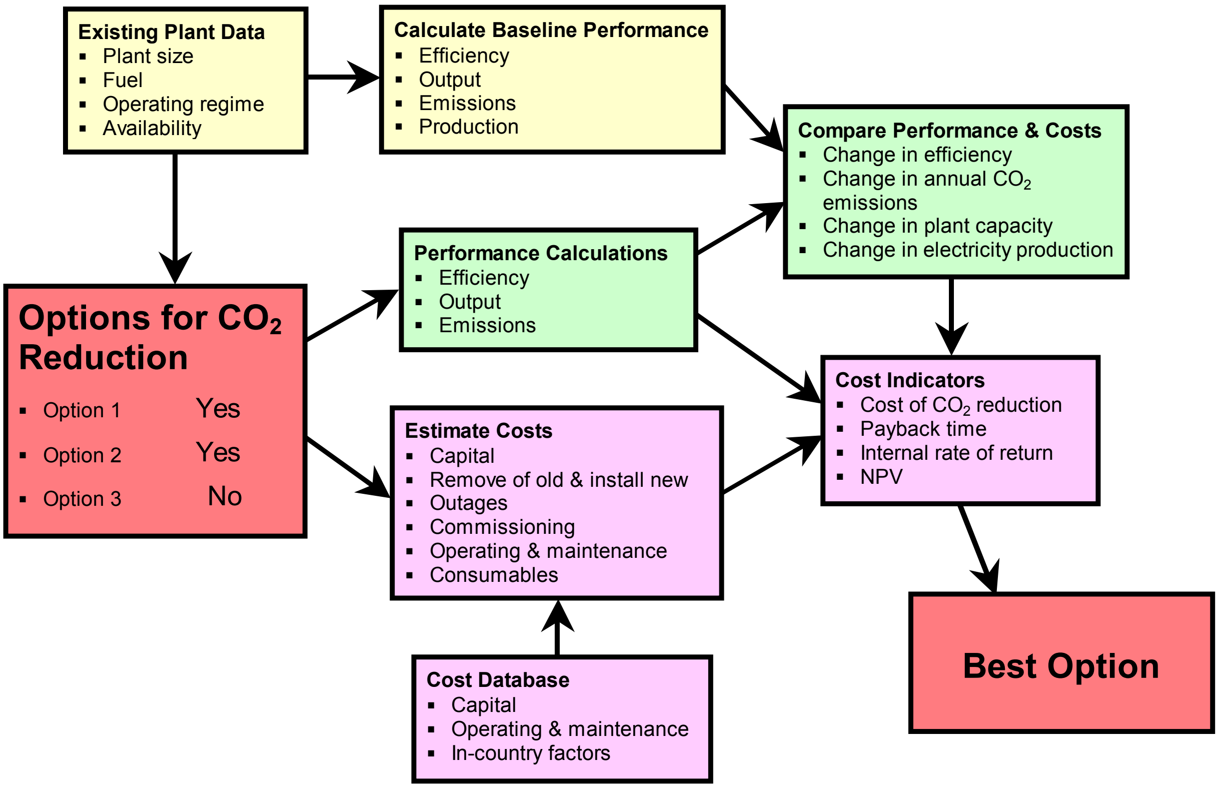

Figure 2.1: Schematic of the Workbook Calculator

This Workbook has been developed as an Excel spreadsheet, using MS Excel 2000. Note that other versions of MS Excel will produce unreliable results and should not be used.

Each worksheet can be printed or otherwise manipulated using the functions provided within MS Excel spreadsheets. However, some areas are protected from editing to ensure that the integrity of the Workbook cannot be compromised.

The operation of the Workbook is arranged across a number of worksheets, only one of which is displayed at a time. The user is taken through the relevant worksheets in a logical sequence so that he/she can provide the necessary inputs required for the case in question. In many cases if the user does not provide an input (ie. leaves a cell blank), then the Workbook will revert to a default value. Messages will appear to guide the user in case of an unsuitable input or if the user has not provided an essential input. Buttons (activated by clicking with the mouse) are provided to take the user to the next worksheet or back to a previous worksheet. The user can move back and forth between worksheets to change parameters, with the Workbook carrying out a recalculation whenever parameters are changed.

2.2 OPTIONS

The options considered in this Workbook are:

2.2.1 Plant modifications

- Turbine re-blading
- Additional feedwater heaters
- Turbine backpressure reduction
- Boiler back-end temperature reduction
- Upgrade input steam temperature conditions to turbine
- Change to steam feed pump
- Unburnt carbon reduction
- Flue gas oxygen optimisation
- Housekeeping
- Open cycle gas turbine upgrade

2.2.2 Plant Upgrades

- Auxiliary gas turbine topping cycle.
- Gas turbine repowering.
- Conversion of gas turbine to combined cycle
- Supplementary solar energy

2.2.3 External Generation

- Wind power
- Mini-hydro

2.2.4 Alternative Fuels

- Coal to gas
- Coal to coal
- Oil to gas
- Biomass co-firing

2.2.5 CO_2 Capture/Sequestration

- Reforestation
- CO_2 scrubbing

In all cases, except for the "Gas turbine upgrade", the retrofit is based around modifications to an existing Rankine cycle plant firing coal or natural gas.

2.3 USING THE WORKBOOK

Details of all the worksheets found in the Workbook are as follows:

2.3.1 "Start" Sheet

This is the first worksheet requiring the user to:

1 Input the power plant's total generating capacity in MWe. The minimum allowable size of plant is 50MWe and the maximum allowable size is 660 MWe.

2 Make selections using the Pick Lists on:

   2.1 The type of plant that is to be retrofitted. Gas turbine or steam cycle and the fuel used: Coal, Oil or Natural Gas.

   2.2 The retrofit option that the user wishes to consider (See Section 2.2).

   2.3 The location of the plant (Asia, Europe etc). Five zones have been provided.

   2.4 Where the retrofit equipment will be constructed (Asia, Europe etc). Three zones have been provided.

To choose an option from a drop-down list box, the user must click the right button of the mouse while its pointer is on the cell in question and then select the "Pick From List…" option.

After input and selections have been made, clicking the mouse on the "OK" button will take the user to the data sheets for input of the fuel and power generating system.

2.3.2 Data sheets

There are two data sheets that require inputs from the user. The first sheet deals with fuel data. Here the user is required to input the full chemical ultimate analysis for the fuel used in his plant. If the user does not have this data then the cells can be left blank and the Workbook will input default values (for the type of fuel selected in the Start sheet) when the user clicks on the NEXT button with his mouse. Clicking on the BACK button will return the user to "Start" sheet.

For all options except "Gas turbine upgrade"[1] there is a second data sheet for input of plant operational and commercial data. This worksheet has three columns of data. The user can input data to the first column to describe his/her current plant, and depending on the retrofit option may be able to input data to the second column describing the retrofitted plant. The user will be prompted to supply essential data on existing plant or the retrofitted plant; otherwise he/she can leave the cells blank. In most cases the user will at least be asked to input the gross heating rate for the steam turbine in existing plant. The third column is reference data that is used if the user decides to leave cells blank in the first two columns. There are three buttons in this worksheet; the NEXT button enables the user to proceed to the next "Results" sheet, the BACK button will return the user to the previous fuel data sheet, and the CLEAR INPUTS button will clear all the inputs in the worksheet so that new data can be entered.

In the "User Commercial Inputs", values are entered to represent existing and planned operations. The parameters that can be entered are:

- *Annual plant capacity factor:* A value to represent the percentage of time the plant runs at full rated output.
- *Existing plant historical cost:* The amount of money originally paid for the existing plant.
- *Plant economic life:* The lifetime assumed for the existing and retrofitted plant assets, to be used in economic calculations – the Workbook assumes a range of 10 to 30 years.
- *Existing plant operating age:* Years elapsed since the existing plant entered full commercial service.
- *O&M costs:* The total costs to operate the plant (labour, contracted out services, emission disposals, spare parts and consumables) expressed as a rate per MWh generated.
- *Fuel cost:* The cost for primary energy supplied to both existing and retrofitted plants. For cases where the retrofit option uses a new primary energy fuel source, the Workbook assumes the retrofit plant fuel cost applies to the new fuel source, and calculates the new fuel cost accordingly.
- *Retrofit plant discount rate:* The interest rate applied to the economic assessment process. For State-owned assets, this may conveniently be set to the long-run inflation rate plus

[1] In the "Gas Turbine upgrade" option, only a single combined data sheet is to be filled in.

Government loan rate, plus (say) 2%, whilst for privately owned assets, the rate is usually higher.

2.3.3 Results sheet

This is the last worksheet in the Workbook where the results of all the calculations are presented. The results are shown in the three columns corresponding to the existing, retrofitted and reference plants as described in the previous data sheet. The costing calculations are based on the difference in specific CO_2 emissions between the existing and the retrofitted plant.

To check the sensitivity of the option to various parameters the user can click on the BACK button to return to the earlier data input sheets. Values can then be changed in these sheets and a recalculation will be performed on pressing the NEXT button.

The Results sheet displays the CO_2 emission savings for the option selected and the CO_2 emissions for the current plant as described by the User. Since the financial rewards of CO_2 reduction are different in every country, the user will need to estimate the indicated savings by the appropriate tax benefit/incentive payment to evaluate the savings for the User's particular situation, and allow comparison with the indicated cost for the retrofit option shown on the Results sheet.

The Result sheet also displays a simplified economic analysis of the retrofit option selected, based on the difference in total life cycle costs for the remaining period of plant life between the existing and retrofitted plant cases. For options where savings can be made through plant efficiency improvements, this analysis usually results in a positive Net Present Value (NPV) for the selected option. For convenience, a simple payback period is also calculated; representing the number of years it would take to pay back the capital cost of the retrofit works through the annual savings achieved. However, for many of the retrofit options in the Workbook, direct economic benefits may not be realised. In these cases, the user must manually calculate the additional benefits of possible CO_2 credits/savings and compare these with the extra cost to construct and operate the selected retrofit option.

2.3.4 Saving Results

When using the workbook it is necessary to always start with the original Workbook as supplied, as this is the only way that the program will then be properly initialised.

Saving the Workbook after it has been used for calculations will produce a file that will not operate satisfactorily when it is subsequently opened. Users should print the relevant sheets during the course of their calculations if they wish to retain a record of the various cases investigated.

2.4 BASES OF CALCULATION FOR HEAT RATE

2.4.1 Plant Heat Rate

The Heat Rate generally measures thermal performance of electricity generating equipment. Broadly, the heat rate is defined as the quantity of heat supplied to the system per unit electric energy output and is normally expressed in terms of MJ/kWh (alternatively BTU/kWh).

However, the value of the heat rate determined for any system depends on the boundaries assumed for the calculation. A number of different definitions are commonly used in industrial practice and it is important that a consistent basis be used. This Workbook works by determining change in heat rate between the base condition and the proposed alternative and also uses user input of the target power plant heat rate for comparison with reference data.

Heat Rate definitions include:

- *Gross Turbine Heat Rate:* defined as the heat input to the turbine divided by generator electrical output.
- *Net Turbine Heat Rate:* defined as the heat input to the turbine divided by the generator electrical output corrected for boiler feed pump power
- *Net Unit Heat Rate:* defined as the heat input to the boiler divided by the generator electrical output less all of the auxiliary power consumption.

Other definitions that may be used include plant net heat rate which allows for auxiliary energy consumed by station auxiliary plant such as fuel handling plant, water supply pumps, office and workshop utilities etc, and annual average plant heat rate which includes for the loss of performance due to part load operation and fuel consumed during start-up.

In this Workbook, where the user is asked to input heat rate, the value required is Gross Turbine Heat Rate while CO_2 reductions are determined based on the Net Unit Heat Rate.

Both Gross Turbine and Net Turbine Heat Rates are calculated differently depending on whether an electric or steam feed pump is used. This ensures that the same turbines will give the same heat rate irrespective of the feed pump used (when making appropriate corrections for losses). The following formulas may be used:

For plant with a **Steam** Feed Pump:

$$Gross\quad Turbine\quad Heat\quad Rate = \frac{Heat\quad in\quad Steam\quad to\quad Turbine}{Generator\quad Output\quad + \quad Feed\quad Pump\quad Turbine\quad Power}$$

$$Net\quad Turbine\quad Heat\quad Rate = \frac{Heat\quad in\quad Steam\quad to\quad Turbine}{Generator\quad Output}$$

For plant with an **Electric** Feed Pump:

$$Gross\quad Turbine\quad Heat\quad Rate = \frac{Heat\quad in\quad Steam\quad to\quad Turbine}{Generator\quad Output}$$

$$Net\quad Turbine\quad Heat\quad Rate = \frac{Heat\quad in\quad Steam\quad to\quad Turbine}{Generator\quad Output\quad - \quad Feed\quad Pump\quad Turbine\quad Power}$$

Of principal interest to the present calculation is the *Unit Net Heat Rate*. The following formula may be used:

$$Unit \quad Net \quad Heat \quad Rate = \frac{Net \quad Turbine \quad Heat \quad Rate}{Boiler \quad Efficiency \times \left(1 - \frac{Percent \quad Auxiliary \quad Power}{100}\right)}$$

For a steam power plant the main items consuming auxiliary power that are typically included in determination of Unit Net Heat Rate include:

- Condensate pumps
- Main and auxiliary cooling water pumps
- Turbine lube oil pumps and associated equipment
- Cooling tower fan power (for plants with forced draft cooling towers)
- Forced draft fans
- Induced draft fans
- Fuel oil pumps (for oil fired plants)
- Pulverising mills (for coal fired plant)
- Flue gas desulphurisation (where fitted)
- Dust collecting plant (for coal fired plant)
- Electrical losses in transformers and cabling

In determining Unit Net Heat Rate, the power consumed in these components is expressed as a percentage of the gross generator output.

2.4.2 High and Low Heating Value of Fuel

An essential part of the calculation of Unit Net Heat Rate is the determination of boiler efficiency. In this Workbook, this is calculated by the loss method where heat losses from the boiler are calculated and are then expressed as a percentage of the heat input to the boiler, determined as the product of the fuel flow and the fuel specific energy.

Fuel specific energy may be expressed as either the higher heating value (HHV) or the lower heating value (LHV). The HHV is determined by combusting the fuel to completion and measuring the energy released on cooling the combustion products to a reference temperature, usually 25°C. The combustion is carried out in a saturated atmosphere such that any moisture in the fuel or any water produced by combustion of hydrogen in the fuel is condensed and the latent heat of evaporation of this moisture is accounted for. The LHV may be calculated from the HHV by subtracting the latent heat of evaporation of the total moisture from the HHV.

Steam plant boiler efficiency may be quoted on either an LHV or a HHV basis and both bases are used in different countries. For example, gas turbine plant efficiency is normally quoted on a LHV basis by convention. Similarly, fuel costs may be quoted as $/MJ on an LHV or a

HHV basis although HHV basis is commonly used for internationally traded fuels including natural gas.

Inputs for fuel specific energy to the Worksheet include:

- Fuel specific energy as both LHV and HHV. If these fields in the Workbook are cleared then values are calculated from the chemical analysis of the fuel by formula.

- Cost of Fuel expressed as $US/MJ HHV basis

- Gross Turbine Heat Rate. As this is determined on the basis of the heat in steam flow to the turbine it is independent of fuel details.

Outputs of the Workbook include:

- Plant Net Heat Rate expressed on a HHV basis

- Overall Plant Efficiency expressed on a HHV basis.

2.4.3 Corrections to Heat Rate

The Workbook operates by determining corrections from the base heat rate for the plant in question for the option under consideration according to:

$$Adjusted \quad Heat \quad Rate = (Correction \quad Factor) \times (Original \quad Heat \quad Rate)$$

These corrections are determined assuming that the plant being analysed is broadly similar to standard practice for power generating plant. However, all individual plants contain certain unique characteristics and therefore the corrections determined in the Workbook are intended as a general indication of the benefits potentially available.

Most manufacturers provide correction curves for individual plants. If these curves are available then corrections determined from such curves may be used in the Workbook in place of the generic calculation.

This facility becomes available when the user proceeds to the calculation sheet. At this point a small screen is seen that lists corrections used in the calculation. If the user has more accurate information, an alternative correction factor may be entered directly to the screen.

2.5 COST DATABASE

The cost database within the Workbook provides all the cost data required to evaluate the economics of each of the options and is described in detail in Section 4.

When nominating the current plant on the user entry screen, the user provides the Region in which the plant is located. The Workbook then adjusts the reference plant costs using a four term correction factor system, comprising:

- Regional manufacturing cost factor.

- Regional transport.

- Regional import tax and agency fee factor.
- Regional labour cost factor for erection and commissioning.

The factors indicated above are an attempt to relieve the user the chore of determining costs. However, some users will want to input their own costs where site-specific aspects are significant. In this case, the Workbook provides the facility for the user to enter his own costs as required to overwrite the default values from the Cost Database (see Section 4.1).

3 OVERVIEW OF CO_2 REDUCTION OPTIONS

3.1 PLANT MODIFICATIONS

3.1.1 Turbine Re-blading

The overall efficiency of a steam turbine is determined largely by the temperature and pressure of the steam at entry to the turbine and the conditions at the turbine exhaust. However all turbines suffer from numerous small internal inefficiencies. Broadly these arise from effects such as:

- Energy Loss due to blade profile effects.
- Energy Loss due to nozzle profile effects.
- Loss due to leakage through shaft seals.
- Loss due to leakage past blade tip.

Modern technology allows the design and manufacture of steam turbine components that yield substantially higher efficiency that those of just a few years ago. Further, it is usual for turbines to gradually loose efficiency over a period of operation from effects such as:

- Blade or nozzle profile change due to formation of deposits.
- Blade or nozzle profile change due to erosion from particles in the steam.
- Increased steam leakage past worn labyrinth seals etc.

In reviewing turbine heat rate, two alternatives are therefore available. In the first case, if the measured heat rate is substantially higher than design, then replacing or repairing existing blades, nozzles or sealing mechanisms can return the plant to the design performance. Alternatively, it is frequently also possible to replace turbine internal components with components of updated design that yield turbine efficiencies substantially above that of the original installation.

Efficiency improvements and economics of upgrade are typically highly specific to each individual unit. A detailed engineering assessment of the unit will be necessary to assess the current condition and to identify the components that will give the highest return on investment. This will usually require full disassembly of the turbine to provide proper access to the component parts.

Typically the major benefits arise in likely order of decreasing effectiveness from:

- Replacement of last row blades from the low-pressure turbine.
- Reduction of leakage past gland and nozzle labyrinths and tip fins.
- Replacement of control stage and reheat first stage nozzles.
- Installation of improved profile blades throughout the turbine.

Replacement of blading, nozzles or other internal components of the turbine requires careful consideration. It is common for the Original Equipment Manufacturers (OEM) to offer upgrades to standard turbines and these are often available with appropriate performance guarantees. Alternatively, third party suppliers are also prepared under some circumstances to provide replacement components.

3.1.2 Additional Feedwater Heaters

Feed heating plant use steam extracted from partway through the turbine, after partial expansion, to heat the feed water entering the boiler. This allows the latent heat in the extracted steam to be recycled to the boiler rather than lost to the condenser and results in an improvement in the efficiency of conversion of heat in the steam to work in the cycle. As some steam that would have otherwise expanded through the remaining steam turbine stages is now extracted and does not do any work there is a slight fall in work output from the turbine.

Steam turbine systems typically have from two to eight feed heaters. The actual number installed depends on an economic evaluation that compares the cost of additional heaters against the benefits in reduced fuel consumption to be gained through the introduction of another heater. Modern high pressure utility plants will typically have multiple feed heaters and high feed water temperatures, industrial and co-generation plants will often have a minimum number and may benefit most from additional heaters.

Introducing additional feed water heaters to the cycle can result in benefits through either increasing feed water temperature or by reducing thermodynamic losses in the cycle. As feed water heaters raise the feed water to near to the saturation temperature of the bled steam that is passed to them, increasing final feed water temperature will require that the new final feed water heater take higher pressure steam than the highest temperature heater currently in service. This will typically require that the new feed heater be installed between the high pressure boiler feed pump and the boiler inlet, the new feed heater would therefore be considered as a high pressure feed heater.

In the case where an additional heater is installed and retains the same final feed water temperature, then the existing bled steam tapping points will cover the full range of temperatures required.

It is necessary to ensure that feed water entering the boiler is deoxygenated to prevent corrosion of boiler and other system components. This is typically achieved in a specialised feed heater termed a de-aerator where steam is injected directly into the feed water such that the resultant feed water approaches saturation temperature at the pressure in the heater. It is important in any changes in the feed heating system that de-aerator performance not be compromised.

3.1.3 Turbine Backpressure Reduction

The steam turbine expands the steam between inlet steam temperature and pressure conditions to exhaust at turbine backpressure conditions. If the backpressure is reduced while maintaining the turbine inlet conditions, then more work can be extracted from each unit of steam and therefore cycle heat rate and greenhouse gas emissions reduce.

The turbine backpressure is controlled by numerous plant and operating variables including the temperature and the flow of the cooling water at inlet to the condenser, the size, cleanliness and construction of the condenser, the efficiency of the air extraction equipment and the pressure drop of the steam flow path from the exit of the last turbine blade row, through the turbine hood and into the condenser.

One of the principal design variables affecting turbine backpressure is cooling water temperature and any reductions in this variable can be translated into a corresponding reduction in backpressure. Alternatively, most existing condensers can benefit from improvements in cleanliness through the installation of on line cleaning systems, increases in cooling water flow or cooling water flow balancing and also attention to air extraction equipment.

It has also been demonstrated that in certain turbines there is excessive pressure drop between the turbine exit and the condenser and flow modelling followed by the installation of flow control devices have made substantial improvements to heat rate.

Steam flow through the turbine exhaust may reach very high velocities such that the flow becomes choked. Under such circumstances a reduction in backpressure will have little effect on the turbine heat rate. However, as this condition is difficult to predict without detailed engineering information of the turbine exhaust layout, no allowance has been made for choked flow in the Workbook. Reference to manufacturers correction curves may assist if these are available for the unit being analysed.

3.1.4 Boiler Back-End Temperature Reduction

The temperature of the combustion gas leaving the plant has a direct impact on boiler efficiency and therefore plant heat rate. For conventional power plants, this temperature is measured at the outlet side of the air preheater, as this is the exit of the last stage where heat is recovered for useful work.

At the design phase, a target boiler exit gas temperature is selected based on an economic balance between the additional capital expenditure required to further reduce this temperature and the economic benefit received through fuel savings. In addition, an overriding consideration is that the final gas temperature must remain above the acid dew point of any acidic gases in the combustion products. For example, it is common for fossil fuels to contain sulphur that converts to sulphuric dioxide during the combustion process and then to sulphuric acid if the gas is below the dew point.

Boiler back end temperature is reduced through the installation of additional heating surface into the boiler. This can be achieved through installation of additional economiser surface where the heat is transferred to the boiler water circuit. This route may be selected if it were desired to modify steam temperatures. More commonly, back end temperature is reduced through the provision of additional air preheater surface. This transfers the incremental recovered heat to the combustion air from where it is available to both water and steam circuits. It is common for air preheaters to have provision made in the initial installation of the provision of additional elements in which case the reduction in back end temperature is greatly simplified.

In considering this option, the impact of reduced back end temperatures on corrosion rates in air preheaters, pollution control equipment such as electrostatic precipitators and ducting and stacks must be considered. Should the modification coincide with the introduction of a lower sulphur fuel then there may be no detrimental effects. However, where the sulphur content in the fuel is maintained, additional corrosion may be expected in these elements and increased maintenance costs may ensue.

3.1.5 Upgrade Input Steam Temperature Conditions to Turbine

The temperature of the steam entering the turbine has a direct effect on turbine efficiency and therefore on plant heat rate. It is not uncommon for steam temperatures to fall below the design point in operating plant with consequent loss of efficiency. Also, it is possible in some plants for steam temperatures to be raised above the nominal design values without seriously compromising plant integrity.

Initially, investigations would focus on ensuring that design steam temperatures were achieved. If this is not the case, then actions that contribute to increasing steam temperatures can include:

- Modification or update to automatic control systems.
- Rehabilitation of burners and other plant items that respond to control system signals such as burner tilt mechanisms where fitted.
- Upgrade or rehabilitation of sootblower systems where fitted.
- Installation of additional superheater or reheater surface.

Where moderate design steam temperatures are used, it is likely that substantial margin exists in the plant components with regard to the life of elements due to thermal effects such as creep or oxidation. If this is the case, then it may be possible to raise steam temperatures above the design values and thereby take a gain in efficiency. In pursuing this option, careful review of the design details and physical condition of the various components in the system must be carried out. Such study would include remaining creep life of components, assessment of material properties of the actual materials used in components through the testing of physical samples taken from the plant and an engineering study of temperatures and pressures actually experienced by the plant. Elements to be considered include superheater and reheater tubes and headers, steam pipes, main and auxiliary valves that operate at full temperature, turbine casings and blades.

3.1.6 Change to Steam Feed Pump

The largest single consumer of auxiliary energy in a steam turbine power plant is normally the boiler feed pump. Improvements in feed pump efficiency therefore flow directly to increased electricity export at the same fuel input and therefore improved heat rate. For larger plants, alternative feed pumps that may be considered include either electric or steam turbine drive feed pumps.

In principal, steam driven feed pumps can provide efficiency benefits as compared to electric feed pumps through the elimination of the losses through auxiliary transformers, cabling and switch gear. Electric feed pumps are also normally fitted with some form of variable speed drive system to allow flexible control of the output control and these systems also introduce efficiency losses through this drive. However, as small steam turbines are relatively inefficient, industry practice has been to provide electric feed pumps to smaller units below some 300 MW.

Under certain circumstances, opportunities may exist for the replacement of the electric drive feed pump with a steam turbine drive pump. If practicable, and assuming that the unit size is sufficient, then efficiency gains may result.

3.1.7 Unburnt Carbon Reduction

While high levels of combustion efficiency are achieved in most power plants, the ash residue from combustion of coal may contain significant quantities of unburnt carbon. This material constitutes a loss of efficiency to the power plant and, as it may be expected to ultimately oxidise to carbon dioxide, is assumed to contribute to carbon dioxide emissions.

On heating, coal decomposes to volatile matter and residual char material. The combustion process then generally follows the sequential steps of heat-up to ignition temperature, devolatilisation and burnout of the residual char. Of these, the residual char burnout step takes substantially longer than either heat up or devolatilisation. Therefore, char burnout is the rate-limiting step and mostly determines the level of unburnt carbon leaving the boiler.

Reduction in unburnt carbon can be achieved through improvements to coal preparation or changes to combustion settings. Coal preparation involves drying and grinding the coal to the correct size. Coal particle size is particularly important for PF combustion where residence time in the combustion zone is limited to a few seconds. Changes to mill set-up such as classifier settings, airflow and roll pressure can therefore have a significant impact on unburnt carbon levels.

Availability of oxygen is also important in determining burnout time. It is therefore important that both oxygen flow to the boiler and distribution of oxygen between different burners are adequate.

In large boilers with multiple burners it is important that the air and fuel are correctly metered between different burners since poor distribution of fuel and/or air between burners is a common cause of high-unburnt carbon levels. Most plants contain devices to balance fuel and air flow between burners and correct setting and maintenance of these devices is essential. It is also important that flame shape and mixing of fuel and air at the burner be correctly maintained and this is also determined by correct burner maintenance and settings

Overall oxygen level is usually set from a measurement of the oxygen content in the flue gas following combustion and comment on its optimisation is contained in Section 3.1.8.

3.1.8 Flue Gas Oxygen Optimisation

Flue gas oxygen level is an important control parameter for all combustion processes. If insufficient oxygen is available then excessive unburnt carbon losses can be expected, either high residual carbon in ash as noted above or high levels of carbon monoxide if gas is the fuel.

However, as excess air levels increase, the heat content in the gases leaving the boiler also increase, resulting in lower boiler efficiency. Optimising flue gas oxygen levels is therefore a balance between heat lost in unburnt carbon and heat lost in the combustion products leaving the boiler.

With perfect combustion, zero excess air would give the highest boiler efficiency. However, experience shows that certain levels of excess air are required for optimum performance. This is due to practical difficulties in balancing fuel and air between burners and due to the time required for complete combustion being related to oxygen levels

Combustion of pulverised coal typically achieves highest combustion efficiency at approximately 20 % excess air, although both higher and lower levels can be found depending on fuel characteristics. Gas typically requires approximately 5% excess air for optimum combustion while oil firing lies between gas and coal in its air requirements.

Operating the plant over a range of oxygen levels and measuring the plant efficiency is the correct procedure to optimise the combustion air requirements. To operate the plant continuously at the optimum level may require investment in burner and fuel preparation equipment and in automatic control software or hardware such as improved oxygen sensing equipment.

3.1.9 Housekeeping

The level of housekeeping in a power plant can contribute significantly to plant efficiency. The main objective is to minimise losses from the plant and to ensure that all plant components operate at their most efficient duty point. Considerations can include:

- *Boiler air leakage* due to poorly fitting access and inspection doors or doors left open or due to failed expansion joints. Boiler excess air level is typically determined by measurement of residual oxygen in the flue gas toward the rear of the boiler. Air leakage into the boiler in front of this location will result in lower oxygen in the combustion chamber for the same indicated oxygen level and therefore elevated unburnt carbon losses. Air leakage into the boiler at any location will contribute to an increase in heat loss from the boiler and an increase in auxiliary power consumption by forced draft and induced draft fans.

- *Drains, valves and steam traps left open or leaking.* Steam contains substantial amounts of energy and relatively minor steam leaks can result in significant energy loss from the system.

- *Steam leaks from valves and turbine glands and seals.* A common cause of steam leakage is excessive leakage along shafts at gland and seals. The energy in this steam is lost from the system and therefore contributes to a reduction in efficiency.

- *Dirty or fouled heat exchangers.* Power plants contain numerous heat exchangers from the main condenser, through coolers on major plant such as generators, to minor air conditioning and oil coolers. Low heat exchanger efficiency can contribute to increases in pumping power requirements and higher auxiliary power consumption. A dirty or fouled main condenser will result in increased condenser backpressure, with consequent detrimental impact on cycle efficiency.

- *Excess auxiliary energy consumption.* Conventional steam power plants can consume up to 10% of the power generated to drive auxiliary equipment. Many of these plant items such as large fans and pumps suffer significant efficiency loss if operated away from their design point. It is important to review operating set points for the main auxiliary plant items to determine if operating settings can be adjusted to improve efficiency.

The Workbook has assumed that the operator will undertake a comprehensive review of all operational plant, and makes good all repairs and adjustments to bring the plant back to design conditions. In carrying out this work, it is assumed that a 2% reduction in heat rate will be achieved.

3.1.10 Open Cycle Gas Turbine Upgrade

Gas turbines have experienced rapid improvements in technology and performance since they became available for power generation. These benefits have come through improvements to efficiency, reliability and operations and maintenance costs.

Open cycle gas turbine plant basically comprises a compressor, combustor, turbine and generator. The compressor takes atmospheric air and increases its pressure, this high-pressure air is introduced to the combustor where fuel is introduced, increasing the combustion products further. The hot, high-pressure combustion products expand through the turbine to produce work, which is used to firstly drive the compressor with excess work available to drive the generator.

The work consumed in the air compressor is normally substantially greater than that remaining available for the generator. Therefore, improvements in compressor efficiency directly increase the available work and plant efficiency. Improvements in turbine efficiency provide similar benefits.

The ability of the turbine to extract energy from the hot combustion products depends primarily on the temperature and pressure of the gas entering the turbine. The combustion temperature of a stoichiometric mix of natural gas and air is substantially above that which the turbine blades can safely withstand and it is standard practice to use large amounts of excess air to reduce gas temperature entering the turbine blades to safe levels. However, this additional air must be compressed to combustor pressure and consumes part of the work output of the turbine, directly reducing plant efficiency.

Substantial improvements have been made in recent years to compressor blade efficiency through the application of specialised design techniques that allow improved blade profiles to be developed and manufactured. Similarly, improvements in metallurgy and blade cooling designs have allowed substantial increases in turbine inlet temperature. These improvements allow current gas turbines to offer significant increases in efficiency and output over that available from a similar machine of only a few years old.

Gas turbines require regular overhaul and replacement of high temperature parts such as turbine blades. It is possible, during such overhaul, to install improved designs of blades and combustors, allowing the benefits of both improved aerodynamic efficiency and improved thermal efficiency to be realised. This option may require that control systems be also upgraded to allow the efficiency benefits to be realised.

The Workbook has assumed that the existing plant has been operated for at least 50,000 hours and is ready for a scheduled major overhaul, at which time, newly designed parts may be fitted. If the plant is more than 5 years old, but less than 10 year, a reduction of 2.5% in heat rate is assumed. If the plant is greater than 10 years old, a reduction in heat rate of 10% is assumed.

3.2 PLANT UPGRADES

3.2.1 Auxiliary Gas Turbine

A number of cycles are possible where a gas turbine is matched to an existing coal, oil or gas fired steam turbine plant. Such arrangements can include:

- *Gas Turbine Auxiliary Drive:* A small gas turbine is installed to drive a major auxiliary of the steam plant with the gas turbine exhaust directed into the forced draft fan inlet. In this case, the gas turbine output will be limited by the power demand of the auxiliary being driven to 1% to 2% of steam turbine output.

- *Auxiliary Gas Turbine:* A gas turbine and heat recovery steam generator (HRSG) is installed with the gas turbine generating power for export. The steam cycle feed water is redirected to the HRSG allowing the original steam turbine feed heaters to be decommissioned. In this case the gas turbine output will be constrained to approximately 25% of the steam turbine original output due to the ability of the steam turbine feed water to absorb the heat available from the HRSG.

- *Gas Turbine Topping Cycle:* An open cycle gas turbine is installed with the gas turbine generating power for export and the exhaust gas delivered directly to the steam turbine boiler. Normal boiler firing is continued to burn the residual oxygen in the gas turbine exhaust gases. However, the high temperature of the gas turbine exhaust gas will require that a low temperature economiser replace the boiler air preheater. The installation of the low temperature economiser in the boiler will, in turn, require the decommissioning of the feed heating system. In this case the gas turbine size will be constrained to a maximum of approximately 35 % of steam turbine output by gas velocities in the boiler.

Of the possible options above, the Workbook only allows consideration of the Auxiliary Gas Turbine option. It was considered that the Gas Turbine Auxiliary Drive option was too small to be of consequence. Also, the Gas Turbine Topping Cycle requires substantial plant modifications to the steam plant while providing only a modest increase in maximum gas turbine size over the auxiliary gas turbine option.

3.2.2 Gas Turbine Repowering

Gas turbine repowering deals with the option where a gas turbine is used to repower an existing coal, oil or gas fired steam turbine plant.

A gas turbine and HRSG are installed of sufficient capacity that the HRSG provides all heat required by the steam turbine. This requires that the original steam turbine boiler and its associated firing equipment be decommissioned. Similarly, due to heat balance considerations, the steam turbine original feed heating equipment would be decommissioned.

In this case, the gas turbine will be required to have approximately twice the output of the steam turbine in order that sufficient steam is produced in the HRSG.

3.2.3 Conversion of Gas Turbine to Combined Cycle

Gas turbines in open cycle have relatively low efficiency and the gas leaving the turbine will contain substantial amounts of energy. Typically, for the larger industrial machines the turbine exit temperature will be in excess of 600°C. At this temperature, opportunity exists for the recovery of this heat through the generation of steam that can in turn generate electricity through a steam turbine. A combination of gas turbine and steam turbine in this arrangement is termed a combined cycle and is widely employed where gas turbine plant is required to operate at high load factor.

Conversion of open cycle gas turbines to combined cycle is commonly done where load factors on the plant make this economic. This requires that a boiler be installed in the duct between the gas turbine exhaust and the stack to generate the steam and that a steam turbine with all associated equipment be installed to consume the steam

A number of changes may be required by the gas turbine. As combined cycle plants would be expected to operate with high load factor, as compared to that of open cycle plant, additional equipment may be required, such equipment as air filtration and fuel preparation equipment. Also, the installation of the heat recovery boiler will raise the pressure at the turbine exhaust, causing a slight loss in turbine efficiency.

In addition to this, the introduction of a steam turbine will require substantial support services if that is not already available on site. This will include cooling water for the condenser, water de-mineraliser for the boiler feed, water treatment facilities for boiler blowdown, appropriate upgrades to control systems and, due to the increase in power export, possibly upgrade to power transmission facilities.

3.2.4 Supplementary Solar Energy

Solar thermal energy can be used to supply a supplementary energy input into a power station. Depending on the solar energy system that is used, pressurised hot water, superheated steam or saturated steam can be used as the working fluid. With such a system, the solar collector can deliver solar heat into the steam or feedwater train of the power station.

Solar thermal input as a retrofit to conventional Rankine Cycle thermal power plants or into a combined cycle gas turbine power plant has been identified and has been investigated by others[2,3], but has not proceeded beyond the feasibility study stage. It does, however, remain as a feasible option for using solar energy for the large-scale generation of electricity and for reducing the greenhouse gas intensity of fossil fuel generation.

A solar thermal energy plant used for large-scale electricity generation consists of the following key components:

- A solar energy collector.

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2 Solar Thermal Working Group, “Scale Up study, “Big Dish” solar Thermal”, 1996.
3 SolarPACES Annual Report, 2000.

- A solar energy receiver that operates as a small boiler. This produces hot water or steam that is delivered into the appropriate location of the condensate or steam system of the power station.

- A conventional steam turbine/alternator that generates electricity using the solar steam.

- Alternatively, the solar collector could operate to produce hot water/saturated steam that would be further heated/evaporated/superheated a conventional boiler.

Depending on its configuration, the solar system would operate in series with or in parallel with the power station boiler.

A number of different solar collector systems have been developed or are undergoing development. These include parabolic dishes, parabolic troughs and Fresnel systems. Dishes and troughs are available commercially but none are commercially proven for providing supplementary energy to a power station. All can be configured to provide hot water or saturated steam while the parabolic dish is the only system that is proven to be capable of providing superheated steam suitable for operating a modern utility steam turbine. The steam or water could be injected at various locations along the steam train, appropriate to its condition as described in Table 3.1.

Table 3.1: Steam or Hot Water Injection Points for Solar Thermal

Working Fluid	Solar Collector	Injection Options
Superheated steam at up to 540°C, 16Mpa	Parabolic dish	Steam at the inlet to the turbine, or at other stages in the turbine depending on steam conditions.
Saturated steam	Parabolic trough or Fresnel system.	Inject into the boiler steam drum, the de-aerator, bled steam or the cold reheat system.
Pressurised water	Parabolic trough or Fresnel system.	Inject into the de-aerator, or feedwater heating system.

There are two key process steps contributing to the overall energy conversion efficiency of generating electricity from the solar energy. These are:

- Conversion of solar energy to thermal energy in the collector/concentrator system;

- Conversion of heat to electricity.

The efficiency of converting solar energy to heat energy is dependent on the collector technology used. For parabolic dishes, this is typically between 60% and 70%, depending on the conditions and the designs of the collector and receiver. For parabolic troughs the efficiency is 40% to 55% and for Fresnel collectors some 50% to 60%[4,5].

Given the wide range of solar collector systems and the lack of commercial experience, a typical value of 55% is selected in the Workbook. This is at the bottom end of parabolic dish efficiency and at the top end of the range for troughs.

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4 Solsearch, "Solar Collection Options for a Solar thermal Electricity Plant in NSW".
5 Winter et al, "Solar Power Plants", 1991.

Once the solar energy is delivered to the steam cycle, its efficiency of conversion to electricity is dependent on the condition of the delivered steam/water, the point of delivery and the heat rate of the steam turbine. Typically, the higher temperature and pressure, the greater will be the efficiency of conversion of the additional solar heat. Also, an adjustment to the energy output must be made for auxiliary plant such as additional pumps. Given the range of options for injecting additional solar heat into the steam/feedwater system, the Workbook assumes a mid-range installation where the solar heat is supplied as saturated steam. In this case the efficiency of conversion of the solar heat is based on the base steam turbine heat rate, discounted by 10% to allow for auxiliaries and the conversion efficiency.

These are key aspects in the use of solar thermal energy as a means of providing supplementary energy to a power station. Prior to using the Workbook, it is recommended that users carry out a preliminary screening study to identify the feasibility and magnitude of this option, as set out in the Appendices.

3.3 External Generation

External generation is the direct generation of electricity from an available renewable primary energy source such as wind or hydro. The electrical energy would be delivered either into the local transmission or distribution network or into the internal power station electrical power system.

3.3.1 Wind Power

Wind energy generation is a commercially proven and reliable technology with new some 4,400 MW of new capacity added in 2000, resulting in a total world capacity of nearly 20 GW. Large commercial wind generators with ratings between 500 kW and 2 MW are in service with utilities worldwide and generators up to 5 MW currently under consideration.

Wind generators located at or near the power station can generate electricity that can be delivered directly to the power station or to the local electricity transmission network. Two key requirements for cost effective electricity generation from wind are the availability of a sufficient wind resource and sufficient area to locate wind turbines.

Key decisions required in evaluating this option are set out in the Appendices.

3.3.2 Mini-Hydro

Hydroelectric generation technology is commercially proven and widely applied as a stand alone, commercial power generation technology at sizes from a few kilowatts up to hundreds of megawatts. It can be used to capture excess energy in water streams in the power station, or its associated infrastructure. Typically, it consists of a water turbine prime mover coupled to a generator with control gear. Depending on size, it could generate at high or low voltage or, if used with a converter/inverter, at variable voltage.

In the Workbook, a mini-hydro option has been added to examine the case where an inlet water flow stream to an existing station has some potential head recovery, or where the existing cooling system has some potential energy recovery. The Workbook does not cover cases where a new hydro site is being examined.

Information required to identify opportunities for hydro generation and to estimate cost and output is set out in the Appendices.

3.4 ALTERNATIVE FUELS

3.4.1 Coal to Gas

If sufficient natural gas supplies may be sourced then carbon dioxide reductions may be achieved through conversion of the boiler from coal firing to gas firing. This can be achieved with minimal change to the steam side of the power cycle although substantial changes on the fireside may be necessary.

Mechanical changes to the plant will at least include installation of appropriate gas receival and metering stations, piping to the boiler, reticulation piping to burners and the burners themselves. It is also likely that changes will be required to electrical and control systems, particularly those around the burner area where upgrade of all electrical equipment such as actuators on valves and burner hardware to a quality appropriate for gas firing will be required. In addition, there may be benefits available in upgrading control instrumentation such as flue gas monitoring and control equipment to allow the boiler to operate safely at lower excess air levels than are possible with coal firing. Gas leak detection equipment would also be required in enclosed areas and around the firing areas

In addition to the mechanical changes, there will also be changes to the operations of the plant. Typically, gas has a less radiating flame than does coal and therefore the heat distribution through the boiler may change from that observed with coal firing. In parallel with this, the ash layer that forms on the furnace wall when firing coal will no longer be present, resulting in an increase in furnace heat absorption efficiency. Therefore, depending on the ash deposition characteristics of the coal, superheat temperatures may to tend to increase. This may cause increased desuperheater spray flow rates, higher metal temperatures and possibly higher gas temperatures leaving the boiler. Engineering for conversion would need to address these issues.

The higher hydrogen content of gas, compared to coal, will result in a reduction in boiler efficiency (HHV basis). As against that, due to the lack of sulphur oxides in the flue gas from gas combustion, the addition of additional air preheating equipment to reduce gas temperature at boiler exit to below that allowable for coal may be possible. In addition, gas combustion can allow operations with substantially lower excess air than allowable for coal and this can be achieved subject to the capability of control systems, flue gas monitoring equipment and boiler casing integrity.

Other commercial issues may need to be addressed. For example, the coal storage that provided backup in case of fuel supply disruption would now no longer be available, and any interruption in gas supply will produce instant loss of load. Gas firing brings hazards from gas explosions that may require upgrade in fire protection systems and procedures. The lack of sulphur in gas may also bring commercial or environmental benefits through, for example, the decommissioning of flue gas desulphurisation operations.

3.4.2 Coal to Coal

The amount of CO_2 emitted on combustion of coal will vary from coal to coal. CO2 emissions will depend on:

- The carbon/hydrogen ratio in the coal.
- The plant efficiency as it is affected by the coal properties.

The Workbook allows entry of different coals and calculates the difference in CO_2 emissions between the reference coal and the proposed coal.

It has been assumed that the plant can burn either coal without modification and that costs will only be reflected in the price of the coal delivered to the power station. Costs of any investigations to source the alternative coals or to assess the impact of coal on the plant have been allowed for although it may be prudent to perform such studies.

3.4.3 Oil to Gas

Carbon dioxide reductions may be achieved through conversion of a boiler from oil firing to gas firing. As with conversion from coal firing this can be achieved with minimal change to the steam side of the power process although substantive changes on the fireside may be necessary.

Mechanical changes to the plant will at least include installation of appropriate gas receival and metering stations, piping to the boiler, reticulation piping to burners and the burners themselves. If the oil system is to be totally decommissioned then oil storage tanks and systems must be cleaned and removed to eliminate environmental and safety hazards.

It is also likely that changes will be required to electrical and control systems, particularly those around the burner area where upgrade of all electrical equipment such as actuators on valves and burner hardware to a quality appropriate for gas firing. In addition there may be benefits available in upgrading control instrumentation such as flue gas monitoring and control equipment to allow the boiler to operate at lower excess air levels than were practicable with oil firing. Gas leak detection equipment would also be required in enclosed areas and around the firing areas

Gas typically has a less radiating flame than does oil firing and therefore the heat distribution through the boiler may change from that observed with oil. Oil fired furnaces are typically designed to the minimum economic size for the highly radiating oil flame and the boiler will therefore produce elevated furnace exit gas temperatures following the conversion to gas. This is expected to require upgrading of superheater tube material and of desuperheater capability

The higher hydrogen content of gas as compared to oil will result in a small reduction in boiler efficiency. As against that, due to the lack of sulphur oxides in the flue gas from gas combustion, the addition of additional air preheating equipment to reduce gas temperature at boiler exit to below that required by oil will be possible.

Other commercial issues may need to be addressed. For example, the oil storage that provided backup in case of fuel supply disruption would now no longer be available; any interruption in gas supply will produce instant loss of load. Gas firing brings hazards from gas explosions that may require upgrade in fire protection systems and procedures. The lack of sulphur in gas may also bring benefits commercial or environmental benefits.

3.4.4 Biomass Co-Firing

Co-firing of biomass with coal or gas can be an effective means of reducing CO_2 emissions as the biomass is deemed to have zero net emissions. However, biomass fuels have a wide variety of properties. Relative to the properties of coal, biomass properties broadly include low bulk density, high volatile content, high moisture content and subsequent low energy values. Thus, the supply of biomass for combustion can be expected to display significantly variable properties due to different source of biomass and variations within the same source due to seasonal changes, effect of soil and climate and the like.

The properties of biomass fuels affect the processes of combustion as well as the performance of the combustion equipment. In a co-firing situation, the properties are very different from that of the coal feed and, as such, will affect the performance of the plant, depending on the amount of biomass that is co-fired. Some of the main issues to consider are:

- Fuel processing, storage and handling.
- Combustion including fuel burnout and boiler efficiency.
- Ash deposition (slagging and fouling).
- Emissions.

For co-firing approximately 5% – 10% by mass of biomass has been used in most projects undertaken in Australia and other places. This is equivalent to 3.5% - 7.0% on an energy basis if wood residues were used for the co-firing or 2.0% - 4.0% if municipal green waste was used. Typically, the limit on the amount of biomass that can be co-fired is generally due to pulveriser capacity.

A number of issues and requirements need to be addressed in the design of a co-firing system, including:

- A separate stockpile area for the biomass, presumably in close proximity to the coal stockpile.
- A metering and blending facility to measure the biomass flow and blend the biomass with the coal.
- The amount of biomass that can be co-fired is limited by the pulveriser capacity, typically 10% by mass biomass is the maximum, however, individual plants should be carefully evaluated in this respect.
- No problems with combustion would be anticipated, provided the biomass could be reduced to a suitable particle size by the pulverisers.
- Boiler efficiency would be reduced slightly due to the higher moisture content of the biomass.

- Biomass fuels with high alkalis may cause problems with ash deposition in the boiler furnace and/or superheaters.
- SO_2 emissions would be low.
- NO_x emissions would be expected to be relatively low with the use of low NO_x burners. The biomass would not increase NO_x emissions over than obtained from coal.

Only direct firing in the boiler is considered in the Workbook. Parallel firing in a new separate biomass boiler, with integration of the steam cycles is another option that may be considered. This option may enable higher percentage biomass substitution or avoid slagging problems in the main boiler. Another option is biomass gasification and combustion of the resulting gas in the existing boiler.

Direct firing in the main boiler will produce the highest efficiency option over a stand-alone option, although the lowest percentage biomass co-firing of the possible options. There are two problems with biomass, one is getting sufficient quantities to co-fire at higher percentages and the other is the technical feasibility of firing some biomass resources such as straw. Realistically, the latter options are seen as having a low potential for success and are not included in the Workbook.

3.5 CO_2 CAPTURE/SEQUESTRATION

3.5.1 Reforestation

This option assumes that there is no modification to the generating plant in terms of configuration or generating capacity. It simply asks user to input details of the power plant and the percentage of CO_2 emissions that are to be offset by growing forests.

It is assumed that the sequestration rate from forestry operations is 200 tonnes CO_2 per hectare over 30 years (and held in perpetuity). Costs are calculated using an NPV of forestation costs of AUS$2,000 per hectare (US$1,040/ha). Therefore the cost of this option is AUS$10/tonne CO_2 sequestered (US$5.20/t). It should be pointed out that this is still a very contentious area in terms of how much CO_2 is actually deemed to be held in perpetuity.

3.5.2 CO_2 Scrubbing

This option assumes that CO_2 is recovered from the flue gases of the power generation plant by the retrofitting of a commercially available amine-based absorption process. The user is asked to input details of the power plant and the percentage of CO_2 removal from the flue gases. The Workbook calculates an energy penalty associated with capture of the CO_2 and subsequent compression and transport to the disposal site.

No allowance has been made for installation/upgrading of SO_2 and NO_x removal systems on the power generation plant. It is assumed that those already installed can meet the specifications for the amine-absorption process. Costs are computed on the basis that the recovered CO_2 is dried, compressed and pumped via a pipeline a distance of 150 km for disposal in a disused gas field at a depth of 2,500 metres.

4 COST DATABASE

4.1 COSTING OF REFERENCE PLANT

The Workbook has costed the various reference plants covered by the study based on values nominated by the US Department of Energy[6]. Whilst prices in 2000/2001 have seen actual plant costs rise, the impact of the events of 11 September 2001 have already seen prices return to the values shown herein, and can be expected to stay at this level until the world economy re-establishes growth. However, it would be expected that the relativity of pricing between alternative fossil fuels would be maintained. For the renewables, increasing interest in wind power and photovoltaic systems is expected to see pricing fall. Clearly, in such periods of commercial volatility and technical innovation, there will be a need to review the price database yearly.

When nominating the current plant on the user entry screen, the user provides the Region in which the plant is located. The Workbook then adjusts the reference plant costs using a four (4) term correction factor system, comprising:

- Regional manufacturing cost factor.
- Regional transport.
- Regional import tax and agency fee factor.
- Regional labour cost factor for erection and commissioning.

In the protected version of the Workbook, the user does not have access to these factors. However, if the user invokes the Workbook password provided, the tables containing the factors can be amended at any time. The password to open the costing tables is "**IEA**".

WARNING!

Changes to the costing tables or any other part of the Workbook could cause catastrophic failure. Please be aware that you..

MAKE CHANGES AT YOUR OWN RISK

4.2 COSTING OF RETROFIT OPTIONS

The Workbook assumes that the user will wish to see the cost and greenhouse gas impact of each of any of the available options, when applied to their own (existing) plant.

Accordingly, each retrofit option provided in the Workbook carries a standardised cost for that option, based on our cost investigations (for details, see Section 4.4). As a basis, US$ pricing has been adopted as the common currency for the Workbook. Also, the USA has been adopted as the base-manufacturing region for each of the retrofit options.

6 US Department of Energy "Assumptions to the Annual Energy Outlook 2001" (Ref: www.eia.doe.gov)

To allow the user to customise the pricing to match local conditions, the Workbook provides an option to nominate the Region in which the retrofit parts are manufactured. For example, this would allow an Asian user of a coal-fired plant manufactured in Asia, to add a gas turbine topping cycle with equipment made in Europe. The Workbook would make appropriate adjustments to the costs to allow for this.

4.3 OPERATIONAL COST COMPARISON

The Workbook provides a simple annualised cost comparison of operational costs "before and after" the selected retrofit option. This requires additional user input, including age and planned economic life of existing plant, O&M costs and evaluation discount rate. Conservative values have been selected as the defaults to allow for differences in the treatment of these common Western assessment parameters in centrally planned economies. Full details are provided in Section 4.4.

The length of outage for the implementation of each retrofit option has also been estimated. Adopting a full "merchant market" approach, the Workbook adds in the cost impact of revenue loss during such outages. Again, this may not be appropriate in all circumstances, and the user is cautioned about adopting these computed values as "IEA endorsement" for further studies on any specific retrofit option.

The Workbook output provides an estimate of annual costs before and after the retrofit option implementation.

4.4 COSTING DERIVATIONS

4.4.1 Reference Plant

The Workbook provides for the user to select any of 22 modifications/additions to an existing plant, as set out in Section 2.1:

- Ten (10) options have been provided "Plant Modification" to modify the existing plant. Accordingly, the reference plant price will be the same for each of these options.

- For four (4) options relating to "Plant Upgrades", the user will again nominate the existing plant and the Workbook will compute the cost of the retrofit option.

- Two (2) options relate to "External Generation" by mini-hydro or wind that are notionally constructed and operated outside the operations of the user's plant under consideration.

- For the four (4) "Alternative fuel" options, the reference plants are assumed to be fossil fired, with these options providing fuel substitution.

- Finally, the two (2) "CO_2 Capture/Sequestration" options can be selected in conjunction with any form of user plant.

Accordingly, the study has developed reference plant pricing of fossil fuelled plants with capacities from 50MW up to 660MW unit rating for:

- Coal firing.

- Oil firing.
- Gas firing.

Costs have been based on a 2-unit development at a greenfields site, and include:

- Site acquisition
- Permits (construction and operating)
- All plant including switchyard
- Contingency
- Interest during construction

The Workbook estimates the reference plant capital costs for different unit sizes from a standard cost/unit size curve used in Australian generation planning for coal fired plants, as shown in Figure 4.1. This form of unit size adjustment curve has also been adopted for the oil and gas fired reference plant pricing.

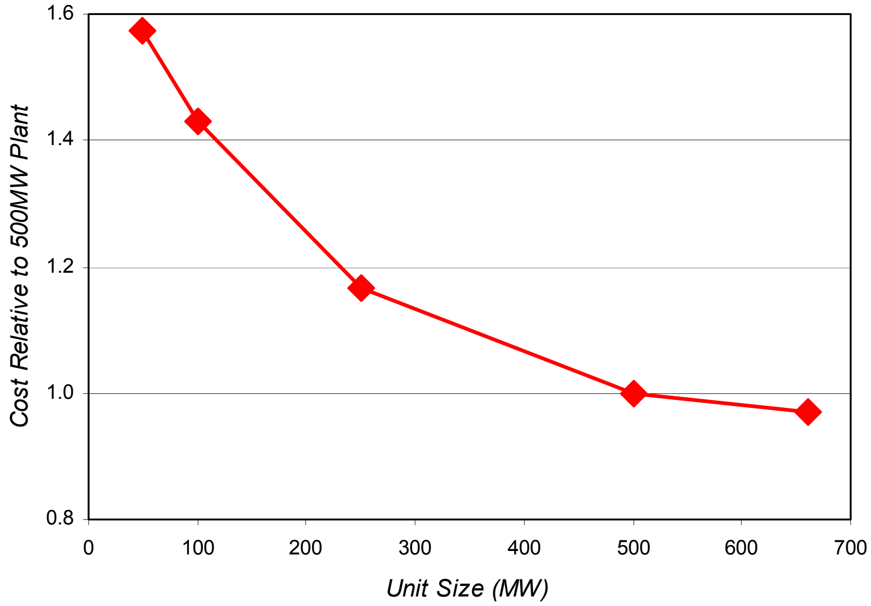

Figure 4.1: Relationship between Coal Fired Plant Cost and Unit Size[7]

Actual reference plant costs have been taken from a well-regarded and routinely upgraded source[6]. The reference plants costs are set out in Table 4.1.

[7] Most costing data in this Workbook has been sourced from private non-reference sources. They have been derived from Australian utility Planning Department curves and are consistent with Australian utility practice.

Table 4.1:Reference Plant Costs

Unit Size **Costs - US$(2001)**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
Pulverised Coal	1542	1402	1144	980	950
Heavy Fuel Oil	1402	1275	1040	891	850
Natural Gas	1373	1248	1018	872	840

Heavy fuel oil plants assumed to cost 91% of pulverised coal plant costs, and natural gas fired conventional thermal plant assumed to cost 89% of pulverised coal plant cost.

4.4.2 Plant Modifications

Turbine Re-blading

This option sees an existing steam turbine shut down, the casings opened, and the fixed and stationary blade paths changed out for new components. Clearly, this option can have many variants, from a simple check of existing blading and replacement of tip seals and labyrinth glands, though to a total re-blade of all fixed and moving blades, incorporating improved designs where appropriate. For the purposes of the Workbook, the latter case has been assumed.

This is a major overhaul event. Parts will need to be ordered well in advance, in most cases up to 12 months, and all specialist tools (eg casing bolt heaters, impact wrenches) brought to the jobsite.

Since all generation capability will be lost during the outage, the study has assumed that three-shifting of refit crews will be adopted to bring the turbine back into service as soon as possible.

Where multiple turbines are to be re-bladed it has been found to be economic to order one complete set of new turbine shafts and diaphragms, which are supplied fully bladed. These are fitted to the first machine, and the existing parts sent back to a machine shop for refurbishment and re-blading. The second machine is then opened and the process repeated. There is a 6 to 8 month pitch between successive units in such a process.

However, as many potential users of this Workbook will be examining single units, the cost benefits of this “follow-on” process have not been assumed in the cost estimates.

The literature has been surveyed for a source of pricing for the re-blading of 50, 100, 250, 500 and 660MW unit size steam turbines. Very limited data has been obtained, and it has proved necessary to derive cost estimates from first principles. Accordingly, the values set out in Table 4.2 have been adopted in the Workbook.

Table 4.2:Turbine Re-Blading Costs

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
Pulverised Coal	1.5	1.0	0.8	0.7	0.67
Heavy Fuel Oil	1.5	1.0	0.8	0.7	0.67
Natural Gas	1.5	1.0	0.8	0.7	0.67

Additional Feedwater Heaters

This option will most usually require the installation of an additional high-pressure (HP) heater above the highest-pressure heater currently installed. Due to the difficulty in adding HP steam tapping points to existing plants this option will therefore require that a suitable high pressure source of steam can be accessed from the turbine to provide the required energy source.

The new feedwater heater would be manufactured off site, and brought to site and fitted in position prior to unit shut down. As a new source of steam heating must be taken from the existing plant, some form of high-pressure pipe work modification will be required. Additionally, the feedwater circuit will require amendment to incorporate the new heater, and controls and settings will need to be calibrated and adjusted once the plant returns to service.

The literature has been surveyed for a source of pricing for the addition of one stage of HP feedwater heating to 50, 100, 250, 500 and 660MW unit size steam turbines. The following values have been adopted herein.

PPI have provided indicative pricing for the addition of one stage of HP feedwater heating to the various sized steam turbines. Accordingly, the values set out in Table 4.3 have been adopted in the Workbook.

Table 4.3: Costs of Adding One LP Stage of Feedwater Heating

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
Pulverised Coal	1.5	1.0	0.8	0.7	0.67
Heavy Fuel Oil	1.5	1.0	0.8	0.7	0.67
Natural Gas	1.5	1.0	0.8	0.7	0.67

Turbine Backpressure Reduction

This option sees steps taken to improve cycle efficiency through backpressure reduction. Of the various options possible, the study has assumed that this would be achieved through a combination of improving condenser tube cleanliness, increasing CW pump flow, and water box flow improvement. Accordingly, for the purposes of pricing this option, it has been assumed that the following works are performed:

- Fit/upgrade Tapprogge-type (recirculating ball) tube cleaning system
- Test and if necessary overhaul CW pumps/motors to achieve design flows
- Remove water boxes, restore/refit flow straighteners, shot-blast and recoat water box lining
- Improve steam flow and eliminate restrictions in turbine exhaust hood.

The literature has been surveyed for a source of pricing for the performance of these works for 50, 100, 250, 500 and 660MW unit size steam turbines. Accordingly, the values set out in Table 4.4 have been adopted in the Workbook.

Table 4.4: Cost of Backpressure Reduction

Unit Size Costs - % of new unit cost	50MW	100MW	250MW	500MW	660MW
Pulverised Coal	0.30	0.25	0.20	0.15	0.14
Heavy Fuel Oil	0.30	0.25	0.20	0.15	0.14
Natural Gas	0.30	0.25	0.20	0.15	0.14

Boiler Back-end Temperature Reduction

This option sees unit efficiency improved by lowering the boiler exhaust gas temperature, hence improving boiler efficiency. Of the various options possible, the Workbook has assumed that the airheater would be increased in size and that the resultant boiler backend temperature would be lowered to within 10°C of the dew point of the worst fuel quality burnt. Note that the Workbook does not calculate the dew point and it is up to the user the evaluate this aspect.

The Workbook has assumed that the ID and FD fans would have adequate capacity to accommodate the new gas flows and pressure drops, and that the boiler heat transfer surfaces would be adequate to meet any revised heat balance requirements.

Some adjustments will be required in the air heater and feedwater heating cycle as a result of these actions, and an allowance has been made to cover the recalibration of the boiler controls.

The literature has been surveyed for a source of pricing for the performance of these works for 50, 100, 250, 500 and 660MW unit size steam turbines. Accordingly, the values set out in Table 4.5 have been adopted in the Workbook.

Table 4.5: Cost of Boiler Backend Temperature Reduction

Unit Size Costs - % of new unit cost	50MW	100MW	250MW	500MW	660MW
Pulverised Coal	0.15	0.11	0.09	0.07	0.07
Heavy Fuel Oil	0.15	0.11	0.09	0.07	0.07
Natural Gas	0.15	0.11	0.09	0.07	0.07

Upgrade Input Steam Temperature Conditions to Turbine

This option sees the cycle efficiency improved by concentrating on the high temperature end of the steam cycle, through attention to securing the maximum possible main (and reheat) steam temperatures. The Workbook assumes that adjustments are made to the furnace operating conditions to achieve design firing rates and temperature distributions, thermal insulation will be checked, and steam leaks will be eliminated. In this Workbook, work is limited to tuning and simple maintenance, rather than extensive outages and plant modification. In this option it is not envisaged that substantial changes to heat transfer surface disposition or materials will be carried out.

The literature has been surveyed for a source of pricing for the performance of these works for 50, 100, 250, 500 and 660MW unit size steam turbines. Accordingly, the values set out in Table 4.6 have been adopted in the Workbook.

Table 4.6: Cost of Upgrading Steam Temperature to Turbine

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
Pulverised Coal	0.65	0.50	0.45	0.40	0.38
Heavy Fuel Oil	0.65	0.50	0.45	0.40	0.38
Natural Gas	0.65	0.50	0.45	0.40	0.38

Change to Steam Feed Pump

This option sees overall cycle efficiency improvement through a reduction in auxiliary power consumption. The works comprise the replacement of the main feed pump electric motor drive by a variable speed condensing steam turbine. For this option it is assumed that the steam supply for this pump is taken from the reheat steam line, with steam exhausting to the main condenser as this minimises costs and the need to modify cooling water circuits.

These works are disruptive on plant operations, as the foundations and pipe work for the new steam turbine are complex. An allowance must also be made for changes to the ICMS.

The literature has been surveyed for a source of pricing for the performance of these works for 50, 100, 250, 500 and 660MW unit size steam turbines. Accordingly, the values set out in Table 4.7 have been adopted in the Workbook.

Table 4.7: Costs to Change from Electric to Steam Feed Pump

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
Pulverised Coal	1.60	1.40	1.25	1.00	0.85
Heavy Fuel Oil	1.60	1.40	1.25	1.00	0.85
Natural Gas	1.60	1.40	1.25	1.00	0.85

Unburnt Carbon Reduction

This option improves cycle efficiency by utilising a higher portion of the carbon in the fuel. The majority of the improvement under this option comes from coal-fired plants, although the general principles apply to both oil and gas fired fossil plants. Reduction in unburnt carbon is achieved through matching fuel particle size with the furnace residence time. Fuel particle size for coal plants requires attention to the pulverising system (or chain grate depth and speed for stoker fired plants) and atomisation systems for oil plant. In gas fuelled fossil plants, since primary and secondary air pressures and flows control the final combustion characteristics, these will also need to be set correctly to achieve correct fuel burnout.

Accordingly within this option, the Workbook assumes that investigations are carried out to determine the source of the problem on the operational plant, and either on-line adjustments or minor offline refurbishments during normal maintenance periods are then carried out to rectify the problem.

The literature has been surveyed for a source of pricing for the performance of these works for 50, 100, 250, 500 and 660MW unit size steam turbines. Accordingly, the values set out in Table 4.8 have been adopted in the Workbook.

Table 4.8: Costs of Reduction in Unburnt Carbon

Unit Size Costs - % of new unit cost	50MW	100MW	250MW	500MW	660MW
Pulverised Coal	0.03	0.02	0.01	0.01	0.01
Heavy Fuel Oil	0.03	0.02	0.01	0.01	0.01
Natural Gas	0.03	0.02	0.01	0.01	0.01

Flue Gas Oxygen Optimisation

This option improves cycle efficiency by ensuring that excess oxygen in the flue gas is reduced to a minimum. The same principle applies to coal-, oil- and gas-fired fossil plants. Flue gas oxygen optimisation is achieved through balancing fuel and air between matching primary and secondary flows and across burners, thus ensuring correct fuel mixing and burnout.

Accordingly within this option, the Workbook assumes that investigations are carried out to determine the flue gas oxygen readings on the operational plant, and on-line adjustments or minor offline refurbishments during normal maintenance periods are then carried out to achieve the design value.

The literature has been surveyed for a source of pricing for the performance of these works for 50, 100, 250, 500 and 660MW unit size steam turbines. Accordingly, the values set out in Table 4.9 have been adopted in the Workbook.

Table 4.9: Cost of Flue Gas Oxygen Optimisation

Unit Size Costs - % of new unit cost	50MW	100MW	250MW	500MW	660MW
Pulverised Coal	0.03	0.02	0.01	0.01	0.01
Heavy Fuel Oil	0.03	0.02	0.01	0.01	0.01
Natural Gas	0.03	0.02	0.01	0.01	0.01

Housekeeping

The Workbook has assumed that the operator undertakes a comprehensive review of all operational plant, and makes good all repairs and adjustments to bring the plant back to design conditions.

Where plant items are out of design tolerances, they are to be repaired/replaced.

The Workbook envisages a “four-week” housekeeping effort, undertaken on the dayshift during routine plant operation. Where an outage is required to attend to a problem (eg main steam valve gland leak), this is scheduled for off-peak times, and a crew is made available to work on the job continuously until completed.

The values set out in Table 4.10 have been adopted in the Workbook.

Table 4.10: Costs for Plant Cycle Housekeeping

Unit Size Costs - % of new unit cost	50MW	100MW	250MW	500MW	660MW
Pulverised Coal	0.03	0.02	0.01	0.01	0.01
Heavy Fuel Oil	0.03	0.02	0.01	0.01	0.01
Natural Gas	0.03	0.02	0.01	0.01	0.01

Open Cycle Gas Turbine Upgrade

This option examines a case where an existing gas turbine plant has operated more than 50,000 hours and is approaching a major overhaul. The Workbook has further assumed that the operator has maintained good relations with the plant maker, and has access to new spare parts built to the latest design.

For many of the common frame sizes supplied by leading gas turbine builders, new fixed and moving blade designs have improved considerably over time, and replacement of older designs at the major overhauls can yield significant savings.

This Workbook has assumed that the existing plant has operated at least 50,000 hours and is ready for a scheduled major overhaul. If the plant is at least 10 years old, then the Workbook has assumed that the higher of the two assumed efficiency improvements can be achieved. If the plant is less than 10 years old, then a lesser improvement is assumed.

In all cases, makers recommended practices for component replacement and skilled supervision have been included in the costing.

The literature has been surveyed for a source of pricing for the performance of these works for 35, 70, 125 and 160MW unit size gas turbines. Due to the IEA target user Groups for this Workbook, the larger “F” class machines have not been costed herein. Accordingly, the values set out in Table 4.11 have been adopted in the Workbook.

Table 4.11: Costs for Gas Turbine Upgrade

GT Unit Size Costs - % of new unit cost	35MW	70MW	125MW	160MW
	27	22	18	14

4.4.3 Plant Upgrades

Auxiliary Gas Turbine

This option examines the case where an existing fossil-fuelled steam cycle plant has its cycle efficiency increased by the addition of a new gas turbine unit, such that the heat in the gas turbine exhaust flows to an HRSG which in turn, heats the steam turbine feedwater and allows the feed heating system to be decommissioned. The bled steam normally used to provide feed heating is now able to expand fully through the turbine resulting in a tendency for steam turbine output to rise. However there are practical limits in the quantity of steam that can be passed through the turbine. Therefore the model assumes that the fuel flow to the boiler is reduced to return the steam turbine to the original unit output.

There are some considerable qualifications with the use of this Workbook option:

- A suitable fuel source for the gas turbine must be available (and may be different to the existing steam cycle plant).
- There must be adequate space around the existing boiler plant to accommodate the gas turbine exhaust duct, HRSG and steam turbine feedwater heating pipework.
- The HRSG will need to be matched to the thermal requirements of the steam turbine plant feed heating cycle.
- The boiler will need to be capable of accepting the gas turbine exhaust in the lower part of the combustion chamber, whilst avoiding structural members, burner boxes and air and fuel ducts.

It is assumed that the gas turbine provides sufficient air for the top up fuel combustion required for the boiler to achieve normal steam production. It has also been assumed that an additional low temperature economiser is fitted to the boiler to compensate for the higher boiler exit gas temperature that would be expected due to the hot air now feeding the boiler.

This option requires extensive site works, with an extended outage for the existing plant. It is perhaps best suited to a small oil fired plant at a location where natural gas has now become available.

The literature has been surveyed for examples of such plants; however there were virtually no such costs available in the public domain. Accordingly, costs have been derived from first principles, based on commercial prices for 35, 70, 125 and 160MW unit size gas turbines and for the separate price of HRSG's (as part of combined cycle plants). However, as the gas turbines are not available in incremental sizes, this option selects the nearest gas turbine size lower than 25% of the users existing steam unit. Thus this option will operate for steam plant unit sizes between 140Mwe and 640Mwe. Accordingly, the values set out in Table 4.12 have been adopted in the Workbook.

Table 4.12: Costs for Auxiliary Gas Turbine

User's Unit Size Range	140MW to 279MW	280MW to 499MW	500MW to 639MW	640MW
Notional GT unit size – MW	35	70	125	160
Cost – based on GT + HRSG – US$m	30	54	80	87

Gas Turbine Repowering

This option examines the case where an existing fossil-fuelled steam cycle plant has its cycle efficiency increased by the retirement of the existing boiler and the addition of a new gas turbine and heat recovery steam generator, thus only retaining the steam turbine of the original plant. (This option is equivalent to the construction of a new combined cycle plant, with the "free supply" of a steam turbine).

There are some issues in establishing the costs for this option.

- The new gas turbine(s) will be rated at twice the size of the existing steam turbine (to match the steam output of the HRSG). As gas turbines are only available in limited sizing, there may be some mis-match between the respective turbine plant designs.

- There may be some steam turbine derating required, depending on the original steam cycle, since an unfired HRSG is limited to relatively modest maximum steam outlet conditions due to restriction in gas turbine exhaust temperatures (ie lower than from a fossil fuelled furnace).
- There may be some issues with bled steam conditions for the existing plant feedwater heaters.

The Workbook has assumed that the gas turbine plant will be selected to provide at least twice the capacity of the user's existing plant, that the existing steam conditions can be met by a modern HRSG design, and that the existing plant feedwater heaters will be disconnected, allowing the steam turbine to produce the original output. Accordingly, due to these restrictions, this option is limited to existing plants in the range of 60 to 160MW.

Table 4.13: Costs for Gas Turbine Repowering

User's Unit Size Range	60MW to 79MW	80MW to 124MW	125MW to 160MW	160MW
Notional GT unit size – MW	125	160	2 x 125	2 x 160
Cost – based on GT + HRSG – US$m	80	87	160	174

Conversion of Gas Turbine to Combined Cycle

The Workbook assumes that an existing open cycle gas turbine is converted to combined cycle operation, through the addition of a new exhaust duct, an unfired heat recovery steam generator, and a condensing steam turbine. Cooling costs have been based on a mechanical-draft cooling tower. Should the user wish to adopt alternative cooling system costs, then the cost sheets can be adjusted accordingly. The values set out in Table 4.14 have been adopted in the Workbook.

Table 4.14: Costs for Conversion of Gas Turbine to Combined Cycle Operation

GT Unit Size Costs - % of new open cycle gas turbine cost	35MW	70MW	125MW	160MW
	240	**200**	**170**	**150**

Supplementary Solar energy[8]

The Workbook adopts a solar thermal reflector system, and the necessary integration with the plant feedwater heating pipe work. Given the wide diversity of end-user plant configurations, the Workbook has adopted a low-pressure solar system, adding energy ahead of the first feedwater heater.

The capital cost of solar thermal reflector fields and associated plant integrated with fossil fuel plant is estimated to be $US1,500/kWe as set out in Table 4.15. This is reported by SolarPACES[9]. Costs reported by DOE[10] for complete solar thermal plants average

[8] This option involves supplementing existing generating plant with external plant systems. Accordingly, the costings shown in the tables are on a per kilowatt basis.

[9] SolarPACES Annual Report, 2000.

$US2,961/kWe. When adjusted for the cost of the power block, this is similar to the SolarPACES result.

Table 4.15: Costs for Supplementary Solar Energy

All Solar Energy Blocks	
Additional plant cost	$US1,500/kW

Annual operating and maintenance costs of solar plant, including reflector cleaning are estimated to be $US0.16/kWh. This is the average of estimates reported by DOE (above) and is similar to $US0.12/kWh reported by SolarPAES.

4.4.4 External Generation[8]

Wind Power

The Workbook adopts a standard unit size of 1MW, at the high end of current designs, but towards the low end of plant cost. Should the end-user nominate a percentage of wind power generation, which leads to a total capacity higher than 1MW, then the Workbook adds further blocks at 1MW each. The capital cost for this option is set out in Table 4.16.

Table 4.16: Costs for Supplementary Wind Power

All wind developments	
Additional plant cost	$US983/kW

Additionally, in any calculation using this option, the default annual capacity factor is assumed to be 25%, a value found to be at the low end of economic feasibility for this class of generator. There is provision for the end-user to over-ride this default ACF, if the site wind characteristics are known.

Annual O&M costs are assessed at US0.01$/kWh.

Mini-Hydro

It should be clearly noted that the Workbook has provided for a limited mini-hydro case only. Independent studies will therefore be necessary to examine nearby (or remote) hydro developments that could be used to offset some of the CO_2 production from the existing thermal plant, and the legal/political basis on which a new development at a remote site will entitle the user to credit the new plant CO_2 savings against the existing plant emissions.

The Workbook covers the case that is internal to the users site boundary, such as where the existing CW makeup supply is situated at a sufficient head relative to the system inlet point, that a small hydro turbine-generator could be adapted. This option also assumes that the return flows in the existing CW system has an excess of head above that required to maintain positive NPSH under all conditions. In both cases, the Workbook prices a new development comprising a hydro turbine close-coupled to the existing CW pump.

[10] www.eid.doe.gov/cneaf/electricity/chg_str_fuel/html/chapter5.html

The capital cost for this option is set out in Table 4.17.

Table 4.17: Costs for Mini-Hydro Generation

All wind developments	
Additional plant cost	$US2,400/kW

Annual O&M is estimated to be negligible.

Additionally, in any calculation using this option, the default annual capacity factor is assumed to be 65%, a value at the low end of economic feasibility for this class of plant. There is provision for the end-user to over-ride this default ACF, if the availability of site water flows is known.

4.4.5 Alternative Fuels

Fuel substitution can offer a cost-effective method to reduce CO_2 emissions, always depending on the relative cost of the existing and replacement fuels, and the CO_2 production quantities of the two fuels.

Coal to Gas

This option examines changing existing coal fuel for a supply of natural gas. The work is assumed to comprise fitting of gas burners and supply pipe work, modifications to the ICMS and some modifications to the boiler tube banks due to the higher heat release in the bottom of the furnace.

Costs are based on the retention of dual fuel firing capability and are set out in Table 4.18.

Table 4.18: Cost of Alternative Fuel – Coal to Gas

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
	6.50	5.50	4.75	4.10	4.05

Coal to Coal

This option examines changing existing coal fuels. The option is assumed to involve no major plant modifications, but instead, the technical and commercial examination of the utilisation costs of an alternative coal fuel. The Workbook prompts the end-user to insert the new coal characteristics, and computes the change in CO_2 production and related production economics. Minor capital charges relating to investigations that might be required to source "low CO_2" or "lower cost" coals are set out in Table 4.20.

Table 4.19: Cost of Fuel Change – Coal to Coal

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
	0.02	0.01	0.01	0.01	0.01

Oil to Gas

This option examines changing an existing oil fuel with coal. The work involved is quite modest. Addition of gas fuel pipe work, burner boxes and boiler front modifications will need to be implemented, and the ICMS may need some modification to allow for the change in fuel heat release characteristics. No plant de-rating has been applied to this option.

Costs are again based on the retention of dual fuel firing capability and are set out in Table 4.20.

Table 4.20: Cost of Fuel Change – Oil to Gas

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
	3.80	3.00	2.50	2.00	1.85

Biomass Co-firing

Fuel extension can offer a cost-effective method to reduce CO_2 emissions, always depending on the relative cost of the existing and replacement fuels, and the CO_2 production characteristics of the two fuels. This option examines extending an existing coal fired plant with biomass fuel.

The work involved is quite modest. A means of on-site storing and handling, and a system for adding the biomass to the coal stream are the major work. The ICMS may also require some adjustment. The major capital works required would include:

- A separate stockpile area for the biomass, presumably in close proximity to the coal stockpile.
- A metering and blending facility measure the biomass flow and to blend the biomass with the coal.

Estimated costs are set out in Table 4.21, based on costs associated with such projects in Australia.

Table 4.21: Cost of Biomass Co-firing

Unit Size **Costs - % of new unit cost**	**50MW**	**100MW**	**250MW**	**500MW**	**660MW**
	0.20	0.17	0.15	0.14	0.13

4.4.6 CO_2 Capture/Sequestration

Reforestation

One option provided that does not relate to plant modifications is the establishment of (or the purchase of rights to an existing) area of forest which is dedicated in perpetuity to the capture and sequestration of CO_2 notionally produced by the operating power plant.

Whilst there remains some controversy over the technical validity of this arrangement, many countries have endorsed this approach within Greenhouse legislation, and a market in CO_2 sequestration has arisen, with inter-country deals already actively traded.

The Workbook provided requires the end-user to insert the required CO_2 annual reduction, and the Workbook then computes the required area of new forest, and cost thereof, as set out in Table 4.22. Where the user has more precise "in-country" data, the cost sheet in the Workbook can be accessed using the password provided, and the entry adjusted.

Table 4.22: CO_2 Sequestration– Cost of New Forest Areas

New Forest Establishment	US$/ha	CO_2 sequestered/ha (Life of forest)	US$/t CO_2 sequestered (Life of forest)
	1,040	200 tonnes	5.20

In keeping with current practice, the forest area is assumed to have a 60-year economic life, and a 1% of initial capital cost/annum operating and maintenance cost. Costs are calculated using an NPV of forestation costs of US$1,040/ha. Therefore the cost of this option is US$5.20/tonne CO_2 sequestered over the life of the forest.

CO_2 Scrubbing

An amine-based scrubbing plant retrofitted to an existing pulverised fuel-fired power plant located in Australia, with a total generating capacity of 525 MWe, has been costed by CSIRO at US$175million. It was designed to capture 411 tonnes/h of CO_2, equivalent to 90% of the CO_2 production from the power plant. In addition to the capital cost, operating and maintenance costs would add US$11.75/tonne captured.

The CO_2 so captured must then be dried, compressed, transported and sequestered. A dedicated plant to handle 411tonnes/h would cost US$88.5million, and could be operated and maintained for a further US$1.95/tonne CO_2.

For this case, the total cost of scrubbing was equivalent to US$28.60/tonne CO_2 including both capital and operating costs.

The installation of a scrubbing device on the outlet flue of a power station will have a significant impact on the overall plant heat rate and the subsequent sent out electricity. This is due to a substantial amount of heat for regeneration of the solvents and power for gas compression etc.

APPENDICES

SCREENING STUDIES

Supplementary Solar Energy

A preliminary screening study, using the methodology below can be used to identify the feasibility and the order of magnitude energy production, cost and carbon dioxide savings for solar thermal supplementary energy. Such a study should be followed up with a more detailed investigation of:

- Solar energy resource available, with special reference to variation on an annual, monthly daily and shorter timeframe variation;
- Appropriate solar collector/receiver system;
- Decision on the appropriate working fluid – superheated steam, saturated steam or hot water;
- Decision on the appropriate injection of water or steam into the steam or feed water circuits of the power station;
- Operational strategies to accommodate the natural variation of solar energy on short and longer term variation (including daily);
- Safety and control aspects of design and operation;
- Commercial benefits that accrue from having solar input;
- Risk analysis.

The general steps in evaluating this option is set out in Table A1.

Table A1: Step Required in Evaluating the Solar Thermal Option

	Step	Details	Notes
1	Identify the solar resource available.	Direct Beam Solar Radiation data is required. Global radiation data is inappropriate.	This information is available from local meteorological authorities and/or by computer modelling.
2	Is the solar resource sufficient?	It is recommended that locations with Direct Beam incident solar radiation (solar energy) in the range 1600 to 3000kWh/m^2/annum or above be considered.	Lower solar radiation levels are not likely to provide sufficient energy for an economic outcome. Incident solar radiation levels above 300 to 400W/m^2 are required to operate the plant.
3	Identify the solar electric capacity (MW) required.	It is recommended in the range 1 to 5% of unit capacity (MW).	This low level is chosen because this approach is commercially unproven. With proven solar plant performance, this can be increased.
4	Calculate the solar energy required.	Solar capacity(thermal) = Solar electric capacity/Collector Effy*E_{THR}/0.9	Collector efficiency ($E_{c)}$ = 55% Heat rate (E_{thr}) = Study value.

	Step	Details	Notes
5	Area of solar collector required.	This is based on a peak solar irradiation of 1000W/m^2. Collector area = Solar capacity (th)/1000	This is a typical value, selected for sizing equipment to cope with the peak solar radiation expected during sunny periods.
6	Solar energy produced	Annual solar electricity generated =Solar Insolation*E_c*E_{ta}*90%	Solar energy is the value for the location. (See Item 2, above) E_c solar collector efficiency. E_{ta} turbo alternator efficiency.
7	Identify area required for the solar collectors.	Allow 2 Ha/MW(e) output. (Pacific Power[11])	This is required for reflectors, ancillary equipment and access for reflector cleaning and maintenance. This area should be unshaded at any time of the day and upwind of stack and cooling tower plume
8	Estimate the capital cost of the solar plant.	This is based on $US1500/kW of solar capacity.	Costs, below.
9	Annual operating and maintenance costs	The costs for the reflector field are estimated	This covers maintenance of all hardware of the solar reflectors and solar steam or water field and reflector cleaning.
10	Carbon dioxide displacement	Base on carbon dioxide from generated energy.	

Wind Power

Key decisions required in evaluating this option are set out in the Table A2.

Table A2: Steps Required in Evaluating the Wind Power Option

No	Information	Notes
1	Identify the wind resource	Identify the wind resource from the local meteorological records from another data source or from local knowledge. While a full evaluation of wind resources is required for project evaluation, a preliminary estimate of the potential of the local wind resource can be determined from the average wind velocity and the velocity distribution. Typically, this needs to be greater than average 6 meters per second.

[11] Pacific Power, 1994. *Solar Thermal Electricity, A Technology Study*.

No	Information	Notes
2	Identify site.	Identify a site/s for locating the wind turbine/s. This should be open to the prevailing wind, and on cleared, level ground with access for construction and operation. Key considerations with regard to the location are: ▪ Elevated sites with slopes on the upwind side of less than 10°; ▪ Clear of natural turbulence; ▪ Access to electricity transmission facilities; It should be located clear of aircraft approach paths, radio and telecommunications links (particularly directional links such as microwaves) and sited so as to minimise adverse environmental impacts. The key environmental considerations are to avoid the flight paths of migratory birds, low visual impact and a sufficient distance from residences or settlements so as not to cause an adverse noise impact. Depending on conditions, this is 300 to 500meters but, in some circumstances, it may be more.
3	Size of wind turbines	This is dependent on the size of wind turbine that can reasonably be located at the site chosen. For an indicative study, a nominal 660kW, utility standard wind turbine is selected. Nominal blade diameter is 40m to 50m.
4	Total wind capacity	The key limitations on wind capacity that can be installed are: The capacity of the electricity transmission infrastructure to carry the energy produced. Site availability and acceptability. For this exercise, it is assumed that nominal 1MW capacity wind turbines will be placed a minimum of approximately 250m apart and located so that they are clear of wake effects during prevailing winds.
5	Annual capacity factor	The annual capacity factor (ACF) of the wind turbine is estimated using the generalised formula: $ACF = (-0.4644v^2 + 14.814v - 46.765)/100$ This relationship is developed from the energy production curves of commercial wind generators of 230kW and 660kW, over the range of wind velocities, 4.5m/sec to 13m/sec. For typical wind resource distributions and for wind generators of this size, this relationship gives results within 10%.
6	Energy production	Annual energy production is calculated using the equation: Energy = Capacity*8760*ACF
7	Capital cost	Unit capital cost of utility wind turbines in USA is $US983/kW[12]. This is estimated, based on costs reported. Total capital cost = Total capacity (MW)*$983.
8	Operating and maintenance cost	The typical operating and maintenance cost for wind generation in USA is 1c/kWh[12].
9	Confirm selection, cost and performance.	The methodology given above is appropriate for preliminary selection. If the results of this preliminary selection process are successful and cost-effective, a more detailed feasibility study should be undertaken. This should include a comprehensive siting study, micro siting, wind turbine selection, environmental investigation, costing and financial evaluation.

[12] US Department of Energy "Assumptions to the Annual Energy Outlook 2001" (Ref: www.eia.doe.gov).

Mini-Hydro

Information required to identify opportunities for hydro generation and to estimate cost and output is set out in Table A3.

Table A3: Steps Required in Evaluating the Mini-Hydro Option

Step	Information	Notes
1	Identify opportunity	Locate locations within the power station or the surrounding water supply or waste water handling system where there is water discharging from pipes or into tanks, basins or water courses or where there is a significant flow of water at pressures in excess of process requirements.
2	Check process and physical conditions.	Ensure that there are no process or physical limitations that would prevent a small hydro plant being installed on the water or process stream.
3	Determine water flow rate and pressure	Flow: This can be measured directly using a flowmeter or by timing the filling a bucket or tank, depending on flow rate. Pressure: Measure the water pressure immediately upstream of the point where the hydro is to be installed. Estimate both the coincident peak flow/pressure conditions and the time averaged flow and pressure on an annual basis. The peak flow/pressure conditions are used to size the hydroelectric generator and average conditions are used to calculate annual energy production. Calculate annual capacity factor (ACF). This is equal to the annual energy produced divided by the nameplate energy capacity for 8760 hours per annum.
4	Calculate size of the hydroelectric generator.	Use the following relationship to size the hydroelectric generator. Power = 8.34*Q*H Where: Q is flow rate in m^3/sec M is head in metres. This is a general relationship that assumes total mechanical and electrical efficiency of the water turbine and generator of 85%. In practice, this will vary with size and type of hydro turbine and generator selected. However, this will produce an indicative result to within +/= 10% from 250kW upwards.
5	Calculate annual electricity production	Use the relationship, Energy = Power*8760*ACF
6	Capital cost	The base cost of $A2,400 is estimated. This is based on Australian experience for small hydro generators with simple installation.
7	Operating and maintenance cost.	Estimated at 2.5% of the capital cost.
8	Confirm cost and performance	Once an initial evaluation of the hydro resource is undertaken, the site and performance should be confirmed by a more detailed siting, performance and cost studies.