RETROFIT OF POWER STATIONS FOR GREENHOUSE GAS ABATEMENT: CASE STUDIES

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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. This assessment 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 also to modify some existing power stations to reduce their emissions.

Examples of power station modifications resulting in lower emissions of greenhouse gases are:

- Efficiency improvements, for example turbine improvements and combined heat and power
- Switching to lower-carbon fuels, for example coal or oil to natural gas
- Use of energy supplies from renewable sources, for example biomass

An alternative way of reducing the impact of existing power stations on the concentration of CO_2 in the atmosphere is to plant or maintain trees, i.e. carbon sequestration in forestry.

This report presents case studies of actual power stations that have been modified in one of these ways. Performance and cost information is presented for each power station, along with descriptions of the station and the modifications that were made. There are many site-specific issues in each of the case studies which will mean that they could not be directly reproduced at other power stations. However, the case studies can be used to illustrate to electricity utilities some options available for reducing emissions of greenhouse gases from their existing power stations.

The individual case study reports were prepared by PB Kennedy and Donkin Limited in the United Kingdom. An overview of the case studies was prepared by Mr S A Moore, a consultant on alternative fuel technologies in the UK.

Approach Adopted

The contractor drew up a list of power stations where it was known that appropriate modifications had been made. Contact was established with the operators to describe the purpose of the work and indicate the data required. The information that the operators were able to supply was then reviewed and the list of case studies was regularly revised to reflect organisations still interested in participating in the project. Where insufficient information was provided, additional requests and site visits were made as appropriate. Individual case study reports were prepared on eight plants. Cost and performance information for each of the cases was calculated based on the actual plant conditions and also on a normalised basis using a common set of assumptions, for example for fuel costs.

The draft case study reports were sent to the power station operators and their comments were included in the final reports. An overview report, comparing the results of the individual cases was then prepared.

The individual case study reports were edited to exclude common sections, and are included as appendices in this report.

Results

Descriptions of the cases and the main results are summarised in table 1. Table 1 includes the actual costs of emissions reduction at the plants on a levelised basis at a 10% discount rate. Table 1 also includes costs adjusted to a normalised basis, which is similar for all of the cases studied. The percentage CO_2 reductions in table 1 are derived from the actual fuel composition and plant efficiencies. CO_2 reductions based on normalised fuel composition were also calculated and are given in the main report but are excluded from table 1 because they are similar to the actual plant data. In the main report the sensitivity to use of a 5% discount rate is examined and costs are also presented on a net present value basis, as this may be of interest to some utilities.

Table 1 Case Descriptions and Results

Description	Location	CO_2 reduction %	Emission reduction cost $/t CO_2	
			Actual	Normalised
Efficiency improvements				
Steam turbine refurbishment and improvement	Germany	2.3	12.8	16.3
Utilisation of waste heat (combined heat and power)	UK	6.0	-45.1	-24.2
Switching to low carbon fuels				
Refurbishment and substitution of fuel oil by gas	UK	19.5	-3.6	-39.4
Replacement of coal and fuel oil by gas	Hungary	39.7	36.9	21.4
Use of energy supplies from renewable sources				
Partial substitution of coal by straw	Denmark	52.3	73.4	22.5
Partial substitution of coal by wood waste	Finland	16.4	-6.3	3.0
Partial substitution of peat by wood waste	Finland	39.6	1.8	2.2
Sequestration by forestry	UK/Brazil	100.0	0.1	0.1

The cases cover a wide range of CO_2 reductions. The efficiency improvement through refurbishment achieves a relatively small CO_2 reduction. The inclusion of a small fraction of combined heat and power (CHP) in a power station to provide heat previously supplied by stand-alone boilers also provides a relatively small CO_2 reduction. The fuel substitution and sequestration cases give relatively large percentage reductions in emissions. The percentage reduction achieved by fuel substitution depends on the degree of substitution- in some of the biomass cases only a small degree of substitution was achieved.

Some of the cases involve large costs for emission abatement (up to $73/tonne of CO_2) but others involve net savings (up to $45/tonne CO_2). Substitution of oil or coal by natural gas in these studies shows a saving or a cost, depending on the type of plant modification and the relative fuel costs. Substitution by biomass shows net costs, the amount depending on the cost of biomass, which varies widely between the cases. In some cases fuel substitution avoids the need for other plant investment, for example installation of flue gas desulphurisation (FGD) but this is not taken into account in the assessments to minimise the effects of site specific issues. The case involving sequestration by forestry has very small costs but other studies by IEA GHG indicate that these low costs may not apply if sequestration was adopted on a large scale, because less favourable sites would have to be used. There is also a risk that carbon sequestered in forests will be emitted to the atmosphere at some time in the future, for example through natural disasters such as forest fires.

Expert Group Comments

Draft versions of the individual case study reports were sent to the power station operators for comment. Comments provided by the operators were included in the final reports. In some cases the operators provided additional information or updated the information they had provided earlier to take account of changes in plant operation. The case study reports were not sent to other external reviewers because the plant operators were judged to be the best able to comment on them.

Main Conclusions

Power station retrofits are very site specific. The following conclusions are based on the limited number of cases assessed in this study.

- The power station refurbishment cases show small percentage reductions in CO_2 emissions. Some of these cases are self-financing, i.e. the fuel cost and other savings are sufficient to pay for the capital cost of the refurbishment.

- The case involving CHP replacement of an existing stand-alone power station and existing heat boilers gives a significant emission reduction and is self-financing. However, this conclusion is partly due to there being an existing demand for heat which is large and near to the power station.

- The cases of substitution of coal or oil by natural gas show substantial emission reductions. In these cases, this option is self-financing, unless coal prices are low.

- Substitution by biomass can provide substantial emission reductions but the extent of substitution depends on the availability of biomass and the type of plant modifications to be made. The cases in this study indicate that substitution by biomass would not be self-financing unless biomass was available at very low or zero cost.

- Forestry sequestration of carbon always involves a net cost but, in the case considered in this study, the cost is low. This option can completely offset the CO_2 emissions from a power station and is available to any power station operator. However, as yet, it is not possible to claim credit under international agreements for the carbon sequestered. There is also a risk that the sequestered carbon may be released due to natural events, such as forest fires. It is expected there will only be a limited number of sites which could show sequestration at costs as low as the case studied here.

Recommendations

- Members of the IEA Greenhouse Gas Programme are encouraged to disseminate the results of these case studies to power generation utilities within their own countries.

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

- Power station operators and suppliers are invited to suggest other cases which would complement the case studies described in this report.

- For the future, these case studies should be incorporated into a workbook, which IEA GHG plans to prepare to enable utility managers to carry out preliminary assessments of a range of retrofit opportunities at their own power stations. This will include a simple computer spreadsheet to enable retrofit opportunities to be assessed using a common set of assumptions selected by the utility.

CONTENTS

ABBREVIATIONS AND UNITS

CCGT	Combined cycle gas turbine
CFB	Circulating fluidised bed (combustor)
CHP	Combined heat and power
FGD	Flue gas desulphurisation
GJ	Gigajoule (10^9)
GWh_e	Gigawatt-hour (electricity)
GWh_{th}	Gigawatt-hour (thermal basis)
HFO	Heavy fuel oil
HHV	Higher heating value
HP/IP/LP	High/intermediate/low pressure (steam)
HRSG	Heat recovery steam generator
LHV	Lower heating value
MJ	Megajoule (10^6)
MW_e	Megawatt (electricity)
MW_{th}	Megawatt (thermal basis)
MWh_e	Megawatt-hour (electricity)
NPV	Net present value
pf	Pulverised fuel
te	tonne

1. INTRODUCTION

Climate change is a key issue for the world at the start of the 21^{st} century. Emissions from combustion of fossil fuels are affecting the climate, with consequences which are, as yet, only poorly understood. However, changes in global temperature, sea-level, water resources and other areas would affect the lives of many people. In recognition of this, governments decided at an international convention held in Kyoto in 1997 to limit emissions of carbon dioxide (CO_2) and other greenhouse gases. The electricity sector is the single largest emitter of CO_2 so it is likely that much of the burden for meeting the changes agreed in Kyoto, and later restrictions, will fall on this industry.

Technologies for reducing emissions from power plant are under development but major changes in generating technology are likely to be applied mainly in new plant. However, for many years to come, the bulk of fuel use, and hence emissions, will take place in existing power plant. So it is also relevant to consider what could be done to reduce emissions from current fossil fuel fired power stations. The work reported in this study is one of a number of projects carried out for the IEA Greenhouse Gas R&D Programme, to investigate reduction of emissions from existing power plant. This study aims to catalogue the experience of power plant owners and operators in making changes to their plant which reduce greenhouse gas (particularly CO_2) emissions. The case studies have been carried out by PB Kennedy and Donkin Ltd and this report summary and analysis has been prepared by Mr S A Moore, consultant. These case studies will provide information to the owners and operators of power stations, illustrating practical experience of making retrofit changes which reduce emissions. The cases show a range of opportunities, discuss some of the practical concerns and indicate the relative effectiveness of the different measures.

The power stations described in this report have been modified or refurbished for commercial reasons but with significant reductions in CO_2 emissions as a consequence. These modifications are described in a series of case studies. They illustrate various options available for reducing CO_2 emissions from the existing plant and provide comparisons of the costs and benefits on a uniform basis.

Seven of the case studies involve retrofit modifications to existing plant. An eighth study examines afforestation as a means of offsetting CO_2 production from fossil fuel combustion, an approach which can be applied to any plant and which has therefore been included for comparative purposes. Including this one, the projects covered by the case studies fall into five generic categories:

- Efficiency improvements in boiler or turbine plant
- Conversion to lower carbon content fuels
- Partial substitution of fossil fuels by fuels from a renewable source
- Efficiency improvement by installation of combined heat and power plant
- Offset of CO_2 emissions by afforestation

The full case studies are reproduced as Appendices to this report.

The authors wish to express their thanks to the following organisations, and their staff, for their willing co-operation and assistance in preparation of these studies:

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- AES
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- Lahti Energia Oy and Imatran Voima Oy
- Metsa Serla

- Entergy
- Budapest Power Company
- RWE Energie

The views expressed in this report are solely those of the authors. Although the data used has been checked with the owners of the plant, the analysis presented here is solely the responsibility of the authors.

2. METHODOLOGY

Selection of Cases

Approaches were made to 14 organisations and companies which had recently undertaken retrofit or other projects leading to a reduction in CO_2 emissions per unit of energy sent out. Of these, 10 expressed interest in participating, although 2 subsequently withdrew.

Following initial responses and preliminary discussions with the potential participants, a more detailed questionnaire was sent out to obtain the technical and economic information required for the study. This information was supplemented as necessary by further discussions and site visits. In some cases the participant was unable to provide all of the data required and the study contractor, PB Kennedy and Donkin, supplemented the available information with estimated data. A draft of the report on each case was reviewed by the owner of the plant before completion and any necessary changes made.

Principal parameters

The principal parameters used to define and evaluate each case study were the capital cost of the project and the pre- and post-project values for:

- Plant output
- Load factor
- Electricity and/or thermal energy sent out
- Thermal efficiency
- Fuel mix and consumption
- Fuel costs
- Operating and maintenance costs
- Greenhouse gas emissions

In practice, directly measured data on greenhouse gas emissions were generally unavailable. CO_2 emissions were therefore estimated on the basis of fuel properties, except that biomass fuels were assumed to produce no net emissions of CO_2. Changes in the emissions of other greenhouse gases from power stations, principally CH_4 and N_2O, were assumed to be negligible for the purposes of this study. Emissions associated with fuel supply were also excluded from this study. These would include emissions associated with coal mining, oil extraction and refining, biomass collection and fuel transport, including leakage of methane from natural gas pipelines.

All cost data were converted from local currency to US $.

Calculation approach

The capital costs for each case were adjusted, where appropriate, to allow for the value of lost production. No adjustment was made where modifications were completed within a scheduled maintenance shut down period, since it was considered that in these circumstances there was no net loss of production.

The adjusted capital costs were then converted to an annual levelised capital charge over the residual lifetime of the plant. Capital charges were calculated for interest (discount) rates of 5% and 10%. No allowance was made for inflation, i.e. the costs are in real terms. The annual capital charges were then combined with any savings or increases in fuel, maintenance or other operating costs to give overall annual costs. These costs were divided by the reduction in annual CO_2 emissions, to give a cost in \$/tonne of CO_2.

Costs were also calculated on a discounted Net Present Value (NPV) basis. This involved converting the annual net operating costs or savings over the residual lifetime of the plant to a net present value using a discount rate of 5% or 10%. The sum of the discounted net operating costs or savings was then added to the capital cost and the total was divided by the total CO_2 emission savings over the life of the plant, to give a cost in \$/tonne of CO_2.

Most of the case studies are site specific and their actual outcomes are strongly influenced by factors such as the local costs of fuel and the plant load factor. To enable direct comparison of the various studies, the calculations were repeated on a normalised basis, using common assumptions in respect of fuel quality, fuel costs, plant lifetime and load factors. Details of these assumptions are given in the tables of Section 4 and in Appendix 1.

Presentation of results

The annual cost or cost saving was compared to the changes in electricity sent out, thermal output and CO_2 emissions to produce 'Figures of Merit', as follows:

- The levelised change in the cost of power sent out, expressed as \$/MWh$_e$.
  This represents the principal commercial evaluation criterion used for electricity generation projects. It allows for any changes in electricity production due to thermal efficiency improvements.

- The percentage reduction in overall CO_2 emissions.

- The change in specific CO_2 emissions, expressed as tonne CO_2/GWh$_e$ sent out.
  For electricity generation projects, this is the principal technical criterion for the overall reduction in greenhouse gas emissions.

- The specific cost of CO_2 emission prevention, expressed as \$/tonne CO_2 abated.
  This is the principal measure of the cost effectiveness of CO_2 abatement, obtained by dividing the change in levelised costs by the change in specific emissions.

Figures of Merit were calculated for each case study on the basis of both the actual plant data and the normalised assumptions, for both of the discount rates and both project evaluation methods. The discussion in Section 4 is based on the calculated results for the annual levelised cost basis. Net present value results are given in Appendix 2.

Detailed individual case study reports are given in Appendices 3 to 10.

3. DESCRIPTION AND SUMMARY OF CASES

Fuel cost and other operating data for many of the plants studied are highly site specific and may not be reproducible at other locations. For this reason the summaries below give the estimated costs of CO_2 abatement based on both the actual plant data and on a normalised basis. Details of the normalisation methodology are given elsewhere in this report.

Case 1 - Refurbishment and conversion from fuel oil to natural gas

The Ballylumford power station, Northern Ireland, is operated by Premier Power Ltd and has a total electrical output capacity of 1080 MW. The majority of this capacity is provided by 3 × 120 MWe and 3 × 200 MWe sets, completed in 1969 and 1974 respectively. These units are conventional reheat boiler steam turbine generators, originally operating on heavy fuel oil. Between 1994 and 1996 they were converted to dual fuel operation with natural gas by fitting low NO_x burners and modifying the boilers to accommodate the different heat distribution. A more general refurbishment of the steam turbines, condensers, feedwater pump and boilers was carried out in parallel with the conversion. The main driver for the conversion was a legislative requirement to reduce SO_2 emissions by 60% and NO_x emissions by 40%, relative to 1980 levels, by 2003.

The conversion and refurbishment did not affect unit capacity or steam parameters, which remained at 125 bar for the 120 MWe units and 165 bar for the 200 MWe unit, both at 540°C. However, the refurbishment increased the net cycle efficiency with fuel oil from 31.8% to 33.0% on net calorific value, resulting in a 3.6% reduction in CO_2 emissions per unit of electricity sent out. The net cycle efficiency with natural gas is 31.5%, leading to a 19.5% reduction in CO_2 emissions per unit of electricity sent out relative to the pre-conversion fuel oil case. Relative to the refurbished fuel oil case the reduction in CO_2 emissions when firing with natural gas is 16.4%.

The capital cost of the modifications, based upon tender documentation, was $25.1 million for the refurbishment work and a further $58.5 million for the conversion to dual firing. The work was carried out during scheduled downtime and there was therefore no direct loss of output, although there was a reduction in the plant utilisation factor due to a reduced call from the grid. The availability and reliability of all units was enhanced by the conversion and there have been savings on maintenance and labour costs. The conversion also avoided the need to operate on low sulphur fuel oil or to fit a flue gas desulphurisation (FGD) unit, with associated operating cost and efficiency penalties, although these ancillary benefits have been excluded in the economic evaluation.

Over a 16 year remnant plant lifetime, the refurbishment part of the project reduces operating expenses so, here, cutting CO_2 emissions produces savings of between 9.9$/te CO_2 abated and 23.9 $/te, depending upon the assumptions made in respect of funding and discount rates. For the combined refurbishment and fuel conversion, the saving is in the range 2.8-8.6 $/te CO_2 abated. When calculated on a normalised basis, these savings are increased to 15.0-30.4 $/te CO_2 and 22.5-42.5 $/te CO_2, respectively.

Case 2 - CO_2 sequestration through afforestation

This case study differs from the others in that it does not involve any modification to generating plant or any comparison with alternative configurations. Instead, the cost of offsetting CO_2 emissions by an equivalent amount of CO_2 sequestration through afforestation is assessed.

AES operates a 230 MWe combined cycle gas turbine (CCGT) plant at Barry, United Kingdom, fired by natural gas. The plant consists of a single train containing a gas turbine, heat recovery steam generator (HRSG), steam turbine and condenser. It is AES policy to promote beneficial environmental and sociological policies and the company therefore invited 'tenders' for its participation in projects involving carbon sequestration and land management. The selected project was the Bananal Island project in Brazil, which is intended to sequester approximately 65 million tonnes of carbon over 30 year. This is approximately the same duration as the power plant lifetime. The overall scheme involves permanent preservation of 200,000 ha of old growth forest, reforestation of 60,000 ha of degraded forest and 1,500 ha of agroforestry and tree-planting in municipalities.

The total project cost for Bananal Island is estimated at $13 million over the 25 year period for which AES will participate. The AES contribution will be approximately $1.0 million, which is 7.5% of the total cost, corresponding to the estimated emissions from the Barry power plant over the period. The project can therefore be considered to result, on a net basis, in the complete elimination of the Barry plant CO_2 emissions. Over the 25 year plant lifetime the cost of CO_2 emission abatement is estimated to lie in the range 0.05-0.14 \$/te CO_2 abated. As there is no modification to the plant in this case, the normalised costs are the same as the actual project values.

Case 3 - Partial substitution of hard coal by straw

The Grenaa CHP plant, Denmark, is operated by the Midtkraft Energy Company and commenced operation in 1992. It consists of a 78 MW_{th} circulating fluidised bed (CFB) boiler plant, originally designed to burn a mixture of hard coal and straw in approximately equal quantities, with in-bed desulphurisation by limestone injection. The electrical export capacity is 17.8 MW, with a thermal export capacity of 60 MW in the form of 210°C process steam and 85°C district heating. In 1998 the plant was modified to allow other types of biomass to be used in pulverised form.

The case study considers the differences between the plant operating on coal alone and on a mixture of 48% coal and 52% straw on a thermal basis. The relevant capital cost is therefore that for the straw unloading, storage and CFB delivery systems, assessed to be approximately $10.5 million. The increase in operating and labour costs associated with the use of straw is estimated from data provided by the plant operator to be approximately $0.8 million annually. The delivered cost of straw to the plant has historically been substantially greater than that of coal on a calorific value basis and additional fuel costs resulting from the use of straw are estimated at $4.1 million annually.

On the assumption that biomass combustion produces no net CO_2 emissions, the overall reduction in CO_2 emissions due to substitution of coal by straw is approximately 52.3%. Over a 25 year remnant plant lifetime the actual cost of CO_2 abatement at this plant is estimated to lie in the range 28.8-73.4 \$/te CO_2 abated, depending upon the assumptions made in respect of funding and discount rates. When recalculated on a normalised basis the cost range is 8.5-22.5 $/te abated.

Case 4 - Partial substitution of hard coal by biomass gasification

The Kymijarvi power station, Finland, is a CHP facility with an electrical output capacity of 210 MW and a district heating thermal output of 240 MW. It is owned jointly by Lahti Energia Oy and Imatran Voima Oy. The majority of the plant capacity is provided by a main 360 MWth boiler with reheat, a 80 MWth heat recovery boiler, a 139 MWe back pressure steam turbine and a 167 MWe condensing steam turbine. The main boiler was originally brought into operation firing heavy fuel oil in 1976, but was converted to coal firing in 1982. Supplementary natural gas firing was introduced in 1986. Between 1997 and 1998 the plant was modified by the installation of a 70 MWth biomass gasifier, the product gas from which is co-fired in the main boiler.

The case study considers the effects of displacing some of the coal fuel to the plant by biomass gasification products, leaving the natural gas consumption unchanged. The gasifier is an atmospheric pressure CFB system, fuelled mainly by wood wastes but also by municipal plastic and cellulosic wastes and by used automobile tyres. Steam conditions were unaffected by the conversion, remaining at 170 bar for the superheater and 40 bar for the reheater, both at 540°C. The overall thermal efficiency was reduced slightly, from 31.3% to 31.1% on a net calorific value basis for electricity and from 49.9% to 49.4% for district heating. Despite this, the overall reduction in CO_2 emissions is estimated to have been 16.4%. This figure is based on the assumption that there were no net emissions from the gasifier fuels.

The capital cost of the gasifier and associated equipment, based upon tender documentation, was $13.9 million. Some expenditure would in any case have been required to reduce sulphur and particulate emissions to meet environmental regulations, although this has not been taken into account in the calculations. Additional operating costs associated with gasifier fuel handling have been broadly offset by a reduction in maintenance requirements associated with fouling and corrosion caused by coal firing. There is an annual fuel cost saving of approximately $2.5 million.

Over a 15 year remnant plant lifetime there is a reduction in operating expenses, to CO_2 abatement for this project generates savings of 4.5-11.3 $/te CO_2 abated, depending upon the assumptions made in respect of funding and discount rates. When calculated on a normalised basis, the range becomes a cost of 3.0 $/te to a saving of 1.6 $/te CO_2 abated. The costs in case 4 are more favourable than in case 3, mainly because there is a high local cost of straw in case 3 and because some waste material, assumed to be available at zero cost, is used as fuel in case 4.

Case 5 - Modification and partial substitution of peat and fuel oil by biomass

The Simpele power station, Finland, is a small industrial power plant operated by Metsa Serla. Completed in 1976, it originally consisted of a 100 MWth conventional pulverised peat boiler, with supplementary fuel oil burners, feeding an 18 MWe back pressure steam turbine and a 14 MWe condensing turbine. In 1997 the boiler was modified to operate as a bubbling fluidised bed fired by peat, bark, wood waste and paper production wastes, again supplemented by fuel oil. The main drivers for the conversion were the increasing unreliability of the peat handling systems and a requirement to reduce emissions.

The conversion and associated refurbishment did not affect the electrical capacity or steam parameters, which remained at 113.5 bar and 535°C. When fired with peat and fuel oil, the boiler operating efficiency was increased from 85.3% to 89.3% on a net calorific value basis, while the electrical cycle generating efficiency was increased from 44.1% to 46.1%. This resulted in a reduction in CO_2 emissions of approximately 4.4% on a like for like basis. When fired with peat and wood wastes, the efficiency gain was reduced. However, on the assumption that the combustion of wastes produced no net CO_2, overall emissions were reduced by approximately 39.6%.

The capital cost of the modification and fuel conversion was approximately $12.4 million. Although some expenditure on desulphurisation equipment would in any case have been required, no credit is taken for this in the study. The cost of lost electrical output during installation is estimated to have been approximately $1.0 million. There have been operating and maintenance cost savings, estimated at approximately \$0.4 million annually. When operating with bark and wastes, partially displacing both peat and fuel oil, the annual fuel cost saving is estimated at approximately \$1.1 million.

Over a 15 year remnant plant lifetime the actual cost of CO_2 abatement for the combined modification and fuel conversion is estimated to lie between a cost of 1.8 \$/te and a saving of 3.1 \$/te CO_2 abated, depending upon the assumptions made in respect of funding and discount rates. When calculated on a normalised basis the range becomes a cost of 2.2 \$/te to a saving of 2.7 \$/te CO_2 abated.

Case 6 - Combined heat and power with steam export

The Saltend power station, United Kingdom, is a combined cycle gas turbine (CCGT) CHP project currently under construction. It will be operated by Entergy and is designed for a nominal power generation capacity of 1200 MWe with a further 150 MWth output of steam to an adjacent chemicals site. It consists of 3 $\times$ 400 MWe trains, each designed around a triple pressure steam cycle and containing one gas turbine, one steam turbine, one generator, one waste heat recovery boiler, cooling water and other ancillary systems. The case study compares the options of operating as a CHP plant and of operating as a conventional CCGT plant for maximum electrical output with no steam export. In the second case, it is assumed that the export steam is replaced by steam produced in an existing separate boiler fired by heavy fuel oil (HFO). The two options have identical steam conditions for the main steam cycle.

Abstraction of steam in the CHP option results in a reduction in net electrical output capacity from 1202 MWe to 1160 MWe, but avoids an annual HFO consumption of approximately 109 kte. The overall net thermal efficiency is increased from 59.1% to 61.7% on a net calorific value basis. Taking into account the substitution of HFO by natural gas, this results in a reduction in CO_2 emissions of approximately 6.0%.

The additional capital cost for the incorporation of steam export facilities in the CHP case is estimated at \$3.3 million. No credit is taken for the avoided capital cost of the HFO boiler, which is assumed to have the same remnant lifetime as the process plant it feeds, or for any FGD equipment which otherwise might have been needed. Maintenance and operating cost savings associated with the closure of the HFO boiler are together estimated at approximately \$0.3 million annually. There is a loss of revenue of approximately \$6.8 million annually due to the reduced electrical output. However, this is more than offset by the substitution of HFO by natural gas, which results in an annual cost saving of approximately \$15.1 million.

This plant is not yet in operation and all data are therefore estimated. Neglecting the loss of revenue due to the reduced power export, there is an expected net saving in the range 18.1-45.8 \$/te CO_2 abated. Taking this lost revenue into account, the net saving becomes 9.7-24.6 \$/te CO_2 abated. Clearly, these savings would be significantly greater if capital or refurbishment costs for the ancillary HFO boiler were taken into account.

Case 7 - Conversion of fuel oil plant to natural gas combined heat and power

The Kelenfold power station in Hungary is operated by the Budapest Power Company. In 1993 the operating plant consisted of four boilers operating on fuel oil and five turbines with a total output capacity of approximately 61 MWe. The plant also supplied steam to industrial and communal users in the area and hot water for district heating. Between 1993 and 1996 one of the original turbines was decommissioned and a 136 MWe natural gas-fired gas turbine was installed, giving a total output capacity of 191 MWe. The four original boilers were replaced by a heat recovery boiler rated at 165 te/h of steam at 400°C and 38 bar (the same steam conditions as previously), in order to be able to meet the steam and district heating load. One of the main drivers for this conversion was the wish to demonstrate a commitment to environmental improvement, as part of Hungary's application for EU membership.

The capital cost of the conversion was approximately $113 million. However, this investment resulted in a large increase in capacity, making a direct comparison of pre- and post-conversion operating economics invalid. The case study therefore assumes that the conversion effectively replaced three existing power stations, each with an output close to the original Kelenfold output capacity of 61 MWe. To avoid introducing undue distortion, the second and third stations are assumed to have run on a fuel mix and at efficiencies typical of the overall Hungarian generating sector. On this basis, the electricity and heat generating efficiency was increased from 69.3% to 74.6%. Annual operating and maintenance costs are estimated to have reduced by approximately $0.5 million in total, with an annual fuel cost saving of $1.9 million, although no direct information is available. No credit is taken for the avoided cost of any refurbishment or FGD installation at existing plants which would otherwise have been necessary. The cost of lost electrical production during construction is neglected.

The conversion resulted in a reduction in CO_2 emissions which is estimated at approximately 39.7% on the equal capacity basis described above, most of this abatement resulting from the fuel substitution. Over a 25 year plant lifetime the actual cost of CO_2 abatement is estimated to lie in the range 11.4-36.9 $/te abated, depending upon the assumptions made in respect of funding and discount rates. On a normalised basis the costs are lower and are estimated to lie in the range 4.2-21.4 $/te CO_2 abated.

Case 8 - Refurbishment and steam turbine upgrading

The Niederaussem power station, Germany, is operated by RWE ENERGIE and has a total electrical output capacity of 2700 MW. The largest and most recent units, constructed and commissioned between 1970 and 1974, are 2 $\times$ 600 MWe sets fired on local brown coal. Between 1996 and 1997, these units were refurbished by fitting low NO_x burners and by replacing the HP and LP steam turbines. This work was undertaken in response to a German governmental and state initiative to reduce CO_2 emissions from brown coal utilisation.

Steam parameters were unaffected by the refurbishment, with conditions at the HP turbine entry remaining at 162.8 bar and 525°C. However, the output capacity was increased from 564 MWe net to 589 MWe net due to the greater efficiency of the new turbines. This increased efficiency was achieved through the fitting stationary and moving turbine blades with new airfoil geometries, increasing the steam exhaust flow section and reoptimising the blade seals, shaft glands and inlet/exhaust sections.

The modifications resulted in an increase in the net cycle efficiency from 36.3% to 37.2% on net calorific value, resulting in a 2.3% reduction in CO_2 emissions per unit of electricity sent out. The capital cost, based upon tender documentation, was $28.2 million. The work was carried out during scheduled downtime and there was therefore no loss of output. There was no change in operating costs other than the benefits associated with the reduced fuel requirement, which include a modest reduction in FGD costs.

Over a 15 year remnant lifetime the actual cost of CO_2 abatement for this project is estimated at 2.4-12.8 $/te abated, depending upon the assumptions made in respect of funding and discount rates. On a normalised basis the cost range is 4.3-16.3 $/te CO_2 abated.

The figures above, and elsewhere in this report, are calculated on the assumption that the annual station output was unaffected by the increase in capacity. An alternative approach is to assume a proportionate increase in annual output. This results in an increased overall fuel consumption, such that there is an increase in total annual CO_2 emissions from the station. Even so, CO_2 emissions per unit of electricity sent out would be reduced and on the normalised basis the CO_2 abatement shows a saving of 5.1 $/te CO_2 abated (levelised costs at 10% discount rate).

4. DISCUSSION OF THE RESULTS

The main features of the 8 case studies are summarised in Table 1, below, for ease of comparison. The principal study results are presented in Table 2 (two pages), which shows the results of the economic evaluations (levelised basis) carried out on both the actual and normalised data. The comparable data on NPV basis is given in Table A2.1 in Appendix 2.

It is evident from Tables 1 and 2 that the case studies cover a wide range of plant types, thermal efficiencies and service duties. Furthermore, the reasons why the plant owners made the modifications vary greatly; although financial motivation is important, in many cases, the drivers for change have been more than purely financial. Some of the important factors which must be taken into consideration when comparing the economic data are described in the first section below, before the effects of the main changes are discussed. In the following sections the consequences are examined for plant efficiency, generating costs, specific CO_2 emissions and CO_2 abatement costs.

Case-specific considerations

Case 1

This relatively large conventional plant had at one time operated at base load but more recently, due to the relatively high cost of HFO, had been operated as middle order capacity. The conversion of the boilers to natural gas was carried out at the same time as a more general refurbishment of the turbines and boilers. The drivers for the refurbishment and conversion include both legislative requirements to reduce non-greenhouse gas emissions and improved operating economics.

Case 2

This is a single stream CCGT plant. No actual modification is involved. The study examines the costs associated with the offsetting of plant CO_2 emissions by afforestation. This scheme is specifically aimed at the reduction of greenhouse gas emissions and the drivers are non-legislative and non-financial.

Case 3

This relatively small plant was built in response to legislative requirements to increase the proportion of CHP in the national energy mix and to increase the utilisation of biomass fuels. The modification considered here is the addition of equipment to enable an increased proportion of the fuel required to be obtained from local biomass and wastes. The driver can be considered to be primarily a response to environmental legislative requirements.

Case 4

This is a large CHP plant, with a substantial district heating output, fired by coal and natural gas. The modification involves the installation of a biomass and waste gasifier to reduce the amount of coal used. Biomass and waste were available locally at lower cost than coal and it would in any case have been necessary to reduce non-greenhouse gas emissions to comply with new limits. The drivers for this conversion can therefore be considered to be both economic and legislative.

Case 5

This is a modest CHP plant dedicated to the needs of a paper mill. The modification involves the retirement of an HFO boiler and the replacement of a conventional pulverised peat boiler with a bubbling fluidised bed fired on peat, wood waste and paper waste. The peat boiler was reaching the end of its useful life, and there was also a legislative requirement to reduce non-greenhouse gas emissions. The drivers for this conversion can therefore be considered to be both economic and legislative.

		Case 1		Case 2		Case 3		Case 4	
Case description		Refurbishment and conversion from HFO		Sequestration through forestation		Partial substitution of coal by straw		Partial substitution of coal by biomass	
		Before	*After*	*Before*	*After*	*Before*	*After*	*Before*	*After*
Fuel type		Fuel oil	Gas	Natural gas		Hard coal	Hard coal Straw Other biomass	Gas Hard coal	Gas Hard coal Biomass Waste
Output capacity	MWe	1080	1080	230	230	18	18	210	210
Annual output	GWh(e) GWh(th)	3550	3550	1713	1713	72 351	72 351	653 1042	653 1042
Net efficiency	% LHV	31.8	31.5	48.0	48.0	88.1	88.1	49.9	49.4
Net CO_2 production	kte/y	3055	2459	748	0	159	76	596	498
Net CO_2 reduction	% $^w/_w$		19.5		100.0		52.3		16.4

		Case 5		Case 6		Case 7		Case 8	
Case description		Conversion from peat to wood wastes		Combined heat and power installation		Replacement of coal and HFO by gas CHP		Refurbishment and turbine improvements	
		Before	*After*	*Before*	*After*	*Before*	*After*	*Before*	*After*
Fuel type		Peat Fuel oil	Peat Wood waste	Natural gas		Fuel oil Hard coal Brown coal	Gas	Brown coal	
Output capacity	MWe	32	32	1202	1160	183	191	564	589
Annual output	GWh(e) GWh(th)	115 348	115 348	8635 1096	8635 1096	803 682	803 682	4712	4712
Net efficiency	% LHV	44.1	45.2	59.1	61.7	69.3	74.6	36.3	37.2
Net CO_2 production	kte/y	242	146	3494	3286	686	414	4501	4396
Net CO_2 reduction	% $^w/_w$		39.6		6.0		39.7		2.3

Table 1 Summary of Cases

Case 6
This is a large CCGT plant, with a relatively small export of steam for process heat, which is currently under construction. The case study compares this with the alternative of using a separate, existing, HFO boiler for the exported steam. It can therefore be considered to be representative of the situation at many large industrial complexes where existing steam producing plant is reaching the end of its life expectancy. The drivers can be considered to be wholly financial.

Case 7
This case differs from the others in that it involves a large increase in capacity, with a variety of small boilers and turbines being replaced by a single combined cycle CHP plant. The difference in capacity is accommodated for case study purposes by assuming that the new plant replaced three smaller plants with a similar total capacity. The main drivers for the new installation were the need to increase generating capacity and the increasing unreliability of the existing equipment, together with a political requirement to demonstrate a commitment to environmental improvement. Note that the efficiency figure given in Table 1 relates only to electricity output. The overall thermal efficiency of the original plants is unknown. That of the new plant is estimated to be 74.6% on the basis of LHV.

Case 8
This is a large base load plant operating on pulverised brown coal. The modifications involve the replacement of the existing steam turbines to increase generating efficiency. The work was carried out in response to a governmental initiative to reduce CO_2 emissions from brown coal utilisation. The main driver can therefore be considered to be legislative requirements rather than financial benefits.

Plant efficiency

The changes in efficiency resulting from the modifications considered are generally small, some being positive, some negative. Efficiency changes are discussed below in respect of the five generic classes of modification covered by these case studies.

Efficiency improvements in boiler, steam or gas turbine plant
Case studies 1 and 8 are relevant. The overall effect of refurbishment and fuel substitution in Case 1 is to reduce thermal efficiency slightly, from 31.8% to 31.5% based on electricity sent out. However, this masks an underlying improvement due to the refurbishment, which is estimated to give an efficiency of 33.0% on a like for like basis firing HFO. In Case 8, turbine refurbishment alone increased the overall thermal efficiency from 36.3 % to 37.2%, with a corresponding increase in output capacity.

Conversion to lower carbon content fuels
Case studies 1 and 7 are relevant. As noted above, the effect in Case 1 of converting an existing boiler from HFO to natural gas was to reduce the thermal efficiency from 33.0% to 31.5% on the basis of electricity sent out. This lower efficiency with natural gas is a result of a reduced boiler efficiency. This is likely to be a common effect when boilers are simply refuelled, since they are unlikely to perform optimally with the new fuel. In contrast, replacement of high carbon fuels by the installation of new gas fired equipment in Case 7 increased the efficiency from 69.3% to 74.6% on the basis of electricity and heat sent out. Again, this is likely to be a generic effect.

Partial substitution of fossil fuels by biomass and waste
Case studies 3, 4 and 5 are relevant. Plant data for Case 3 indicate that the overall thermal efficiency had been increasing steadily with time as a result of incremental improvements. It is therefore impossible to make a like for like comparison and the assumption has been made that the increased substitution of straw for coal which is the basis of the case study had no further effect on thermal

efficiency. In Case 4, the overall thermal efficiency is estimated to have reduced slightly, from 49.9% to 49.4%. This was due to a reduction in boiler efficiency as a consequence of replacing coal with fuel gas from a biomass gasifier. In Case 5, the overall thermal efficiency was increased from 44.1% to 45.2%. The improvement stems from the replacement of an ageing pf boiler by a bubbling fluidised bed boiler, rather than from the fuel substitution. In contrast to Cases 1 and 4, the boiler internals were extensively modified to optimise the performance of the new system.

Efficiency improvement by installation of CHP plant
Case studies 6 and 7 are relevant. In Case 6, the opportunity is taken to utilise waste heat from power generation and the overall thermal efficiency is therefore increased, from 59.1% to 61.7%. In Case 7, the available information is insufficient to allow the original thermal efficiency to be estimated with confidence. However, the installation of integrated CHP plant instead of an ad hoc range of different boilers and turbines is likely to have increased the overall thermal efficiency, which is 74.6% for the new plant. The overall thermal efficiency of CHP plants is greatly affected by the balance between electricity and heat export, which is the explanation for the lower efficiency in Case 6.

Offset of CO_2 emissions by afforestation
Case 2 is the only relevant case study. Since this case involves no actual modifications there is no effect on plant efficiency. This will be true for all similar offset schemes.

Generating costs

The effects of the modifications on generating and steam raising costs are shown in Table 2, at both discount rates and using both the actual and the normalised data. However, whichever of these methods is used, the rank-order of the results (from greatest saving to greatest cost) is more or less the same, as shown in Table 3. The discussion below is therefore based largely on the costs resulting from making the evaluation at 10% discount rate rate, on the basis of the normalised data.

Efficiency improvements in boiler, steam or gas turbine plant
The combination of refurbishment and fuel switching from HFO to natural gas in Case 1 has a highly beneficial impact, reducing the cost of electricity sent out by 6.83 $/MWh (1 $/GWh = 0.1 US cents/kWh). Although the majority of this cost saving arises from fuel switching, the refurbishment alone is estimated to give a benefit of 0.79 $/MWh. In Case 8, however, the efficiency improvement obtained by turbine replacement is less cost effective in purely economic terms. In this case, the cost of electricity sent out is increased by 0.42 $/MWh if the annual output is assumed to be unchanged, although there is a small cost saving, approximately 0.05 $/MWh, if the output is assumed to increase in line with the additional capacity. The capital cost of the refurbishment element of the two cases is similar when expressed as $/annual MWh. The difference in the overall outcome stems from the lower fuel costs for Case 8, where the annual fuel savings are no longer adequate to compensate for capital charges.

		Case 1		Case 2		Case 3		Case 4	
Case description		Refurbishment and conversion from HFO		Sequestration through forestation		Partial substitution of coal by straw		Partial substitution of coal by biomass	
Capital cost	M$	83.6		1.0		10.5		13.9	
Lost production	M$	-		-		-		-	
Actual results									
Remnant lifetime	years	16		25		25		15	
Utilisation factor	%	43		85		62		58	
CO_2 reduction	kte/yr	597		748		83		98	
Electricity output	GWh/yr	3550		1713		72		653	
Interest rate	%	5	10	5	10	5	10	5	10
Capital charges	M$/yr	7.7	10.7	0.1	0.1	0.7	1.2	1.3	1.8
Fuel savings	M$/yr	12.5	12.5	-	-	-4.1	-4.1	2.5	2.5
Other savings	M$/yr	0.4	0.4	-	-	-0.8	-0.8	-0.1	-0.1
Net cost	M$/yr	-5.1	-2.2	0.1	0.1	5.7	6.1	-1.1	-0.6
Levelised cost (electricity)	$/MWh(e)	-1.44	-0.61	0.04	0.06	78.9	94.7	-1.69	-0.94
CO_2 reduction (electricity)	te/GWh(e)	168		436		1153		150	
Cost of abatement	**$/te CO_2**	**-8.6**	**-3.6**	**0.1**	**0.1**	**68.4**	**73.4**	**-11.3**	**-6.3**
CO_2 reduction	% $^w/_w$	19.5		100.0		52.3		16.4	
Normalised results									
Remnant lifetime	years	15		25		25		15	
Utilisation factor	%	65		85		65		65	
CO_2 reduction	kte/yr	937		748		93		107	
Electricity output	GWh/yr	5415		1713		76		676	
Interest rate	%	5	10	5	10	5	10	5	10
Capital charges	M$/yr	8.1	11.0	0.1	0.1	0.7	1.2	1.3	1.8
Fuel savings	M$/yr	47.6	47.6	-	-	0.0	0.0	1.6	1.6
Other savings	M$/yr	0.4	0.4	-	-	-0.8	-0.8	-0.1	-0.1
Net cost	M$/yr	-39.9	-37.0	0.1	0.1	1.6	2.0	-0.2	0.3
Levelised cost (electricity)	$/MWh(e)	-7.37	-6.83	0.04	0.06	21.9	27.7	-0.25	0.48
CO_2 reduction (electricity)	te/GWh(e)	174		436		1230		158	
Cost of abatement	**$/te CO_2**	**-42.5**	**-39.4**	**0.1**	**0.1**	**17.8**	**22.5**	**-1.6**	**3.0**
CO_2 reduction	% $^w/_w$	20.1		100.0		52.3		16.7	

Table 2 Actual and normalised plant results - annual levelised basis

		Case 5		Case 6		Case 7		Case 8	
Case description		Conversion from peat to wood wastes		Combined heat and power installation		Replacement of coal and HFO by gas CHP		Refurbishment and turbine improvements	
Capital cost	M$	12.4		3.3		113		28.2	
Lost production	M$	1.0		-		-		-	
Actual results									
Remnant lifetime	years	15		25		25		15	
Utilisation factor	%	65		85		48		91	
CO_2 reduction	kte/yr	96		209		272		118	
Electricity output	GWh/yr	115		8635		803		4712	
Interest rate	%	5	10	5	10	5	10	5	10
Capital charges	M$/yr	1.3	1.8	0.2	0.4	8.0	12.5	2.7	3.7
Fuel savings	M$/yr	1.1	1.1	9.5	9.5	1.9	1.9	2.2	2.2
Other savings	M$/yr	0.4	0.4	0.3	0.3	0.5	0.5	0.0	0.0
Net cost	M$/yr	-0.3	0.2	9.6	9.4	5.6	10.1	0.5	1.5
Levelised cost (electricity)	$/MWh(e)	-2.56	1.53	-1.11	-1.09	7.00	12.5	0.11	0.3
CO_2 reduction (electricity)	te/GWh(e)	833		24		339		25	
Cost of abatement	**$/te CO_2**	**-3.1**	**1.8**	**-45.8**	**-45.1**	**20.7**	**36.9**	**4.4**	**12.8**
CO_2 reduction	% $^w/_w$	39.6		6.0		39.7		2.3	
Normalised results									
Remnant lifetime	years	15		25		25		15	
Utilisation factor	%	65		85		65		85	
CO_2 reduction	kte/yr	96		337		337		107	
Electricity output	GWh/yr	115		8635		1087		4200	
Interest rate	%	5	10	5	10	5	10	5	10
Capital charges	M$/yr	1.3	1.8	0.2	0.4	8.0	12.5	2.7	3.7
Fuel savings	M$/yr	1.1	1.1	15.1	15.1	4.7	4.7	1.9	1.9
Other savings	M$/yr	0.4	0.4	-6.5	-6.5	0.5	0.5	0.0	0.0
Net cost	M$/yr	-0.3	0.2	-8.3	-8.2	2.8	7.2	0.8	1.8
Levelised cost (electricity)	$/MWh(e)	-2.24	1.85	-0.96	-0.94	2.56	6.63	0.18	0.42
CO_2 reduction (electricity)	te/GWh(e)	838		39		310		26	
Cost of abatement	**$/te CO_2**	**-2.7**	**2.2**	**-24.6**	**-24.2**	**8.3**	**21.4**	**7.1**	**16.3**
CO_2 reduction	% $^w/_w$	39.6		9.3		37.6		2.3	

Table 2 (continued) Actual and normalised plant results - annual levelised basis

Conversion to lower carbon content fuels
As noted above, the conversion from HFO to natural gas in Case 1 has a highly beneficial impact, estimated at approximately 6.04 $/MWh of the total saving for this case of 6.83 $/MWh. This benefit stems from the much lower cost of natural gas, 2.5 $/GJ LHV compared with 3.4 $/GJ for HFO. The lower fuel cost is more than sufficient to compensate for the reduction in boiler efficiency which is caused by the fuel switching. In marked contrast, however, the results for substituting HFO and coal capacity by natural gas CHP in Case 7 indicate a substantial net cost of 6.63 $/MWh. This disbenefit stems from the fact that the cost of natural gas is only slightly lower than the average for the fuel mix used on the original plants. Although there is some additional cost saving due to the greater efficiency of the CHP plant, the total annual fuel cost saving is insufficient to compensate for capital charges.

Partial substitution of fossil fuels by biomass and waste
The three case studies examined here give widely differing results. The substitution of coal by biomass in Case 3 has very poor economics, since the cost of straw is greater than that of coal on a calorific value basis. There is thus no compensation for capital charges and the total cost of the modification is estimated to be equivalent to 27.7 $/MWh of electricity sent out. Case 3 has a relatively low proportion of electricity in its output mix, resulting in an efficiency from fuel to electricity of only 15%. However, even allowing for this, the cost is still high. Case 5 gives a net cost of 1.85 $/MWh$_e$ at a 10% discount rate. This result is very sensitive to discount rate assumptions due to the high capital charge per unit of output and becomes a net saving of 2.24 $/MWh at a 5% discount rate. The main difference between these two cases is that, in Case 5, the substituted peat is higher cost than the wastes used to replace it. In Case 4, there are net costs estimated at 0.48 $/MWh of electricity sent out. The original fuel, coal, is relatively low cost and the fuel cost savings obtained by using wastes are therefore insufficient to compensate for the capital charges. It should be borne in mind, however, that the total outputs from the plants in Cases 3 and 5 are considerably smaller than the outputs for the other cases. This may have adversely affected the economics, although it is likely that biomass projects must of necessity be smaller than many conventional installations due to limited fuel availability.

Efficiency improvement by installation of CHP plant
The results from Case 6 show that the installation of new power plant can offer additional cost savings if the opportunity is taken to export heat for process or district heating purposes. This can be true even where, as in Case 6, the heat duty is met by existing plant. The cost saving in this case is estimated at 0.94 $/MWh. The savings arise from the avoided costs of the fuel that would otherwise be used in the offsite boiler. Although there is some loss of electricity output, this is mitigated to some extent by the fact that the heat exported is lower grade than that required for electricity generation. Even where the original plant utilises low cost fuels, the avoided fuel costs are likely to more than compensate for the lost electricity output and for capital charges. In contrast, replacing existing CHP schemes with new plants may not be cost effective if, as in Case 7, the original fuel mix is relatively low cost. In such cases, as discussed above, cost savings may be outweighed by capital charges. For Case 7, the installation of new CHP plant leads to a cost increase of 6.63 $/MWh electricity sent out. Even when expressed on the basis of the total steam raised, with capital charges based on 5 % interest rates, there is a net cost of 1.40 $/MWh. These net costs would be reduced, but not eliminated, if the evaluation had been carried out on the basis of the higher utilisation factors assumed for Case 6.

		Interest Rate	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Generating Cost	Actual Data	5%	**3**	5	8	**2**	**1**	**4**	7	6
		10%	**3**	4	8	**2**	6	**1**	7	5
	Normalised Data	5%	**1**	5	8	**4**	**2**	**3**	7	6
		10%	**1**	3	8	5	6	**2**	7	4
CO_2 Reduction	per GWh	Actual	5	3	1	6	2	8	4	7
		Normalised	5	3	1	6	2	7	4	8
	% $^w/_w$	Actual	5	1	2	6	3=	7	3=	8
		Normalised	5	1	2	6	3	7	4	8
CO_2 Abatement Cost (per tonne)	Actual Data	5%	**3**	5	8	**2**	**4**	**1**	7	6
		10%	**3**	4	8	**2**	5	**1**	7	6
	Normalised Data	5%	**1**	5	8	**4**	**3**	**2**	7	6
		10%	**1**	3	8	5	4	**2**	7	6

Note: Rankings in **bold** indicate a cost saving

Table 3 Ranking of cases with respect to savings or costs incurred - levelised basis

Offset of CO_2 emissions by afforestation

Investment in offset schemes incurs costs without direct financial benefits in terms of electricity production costs. However, the expenditure involved may be low, as illustrated in Case 2 where the cost is estimated at 0.06 $/MWh sent out. This is a very low proportion of total generating costs. The costs of this scheme are fixed and are unaffected by relative or absolute changes in fuel prices. Offset schemes of this nature therefore appear to offer an abatement option that is likely to be attractive where long term cost stability is an important consideration.

Specific CO_2 emissions

All of the modifications considered here resulted in reduced CO_2 emissions. The specific CO_2 reductions in Table 2 are expressed as tonnes of CO_2 avoided per GWh of electricity sent out. When expressed in this way the results are unaffected by discount rates although they do not reflect other factors, such as the capital investment required. There is some difference between the rankings, as shown in Table 3, but the overall effect is small. As with generating costs, therefore, the discussion below is based largely on the evaluation of the normalised data at the 10% discount rate.

Efficiency improvements in boiler, steam or gas turbine plant

As would be expected, the refurbishment and turbine efficiency improvements in Case 8 show a reduction in specific CO_2 emissions. The benefit is small, however, and is estimated at 26 te/GWh if the annual output remains unchanged or 9 te/GWh if it is assumed to increase in line with capacity. The reduction for Case 1 is somewhat greater, but the majority of the benefit here stems from the simultaneous fuel switching from HFO to natural gas. The contribution due to refurbishment is estimated at only 31 te/GWh. In general, simple efficiency improvements cannot be expected to deliver substantial reductions in specific CO_2 emissions, but may nevertheless be worthwhile.

Conversion to lower carbon content fuels

Cases 1 and 7 involve fuel substitution by natural gas and both result in a substantial reduction in specific fuel emissions, of 174 te/GWh and 310 te/GWh respectively. The difference between the extent of the reductions in these two cases is mainly related to the original fuel, which was HFO in Case 1 and primarily coal in Case 7. Since HFO produces less CO_2 per unit of energy than coal, the scope for emission reduction by fuel substitution is necessarily more limited. Nevertheless, it is clear that fuel switching to natural gas is a highly effective means of reducing CO_2 emissions from existing plants.

Partial substitution of fossil fuels by biomass and waste

The results from those cases which involve substitution by biomass and waste cover a very wide range, from 1230 te/GWh for Case 3 to 838 te/GWh for Case 5 and only 158 te/GWh for Case 4. In part, this stems from the different electricity to total output ratios for the three plants, and the range is considerably reduced when the results are expressed relative to steam raised. The main factor, however, is the extent to which fossil fuel was displaced, which on a thermal basis varied from over 50% in Case 3 to approximately 10% in Case 4. The extent to which the capability to use biomass and waste can be retrofitted to existing plants is always likely to be site specific, but nevertheless it is clear that this approach offers the potential for very large reductions in specific emissions.

Efficiency improvement by installation of CHP plant

The export of heat from a CCGT plant in Case 6 produces a reduction in specific CO_2 emissions of 39 te/GWh electricity. Approximately 20% of this benefit effectively arises as a result of fuel switching from HFO in the redundant process steam raising boiler to natural gas in the CCGT plant. The majority, however, stems from the very high incremental efficiency with which process steam can be raised and exported from the CCGT steam cycle. It should be noted that the steam exported in this case is a relatively small proportion of the total plant output. Greater absolute and specific emission reductions might be obtainable if the steam export was increased.

The CHP plant in Case 7 effectively replaces a similar plant. Although there is a substantial reduction in specific emissions of CO_2, this can be considered to arise solely from a combination of fuel switching and the efficiency improvement obtained with new plant.

Offset of CO_2 emissions by afforestation

The afforestation scheme considered in Case 2 results, in effect, in the complete offsetting of the CO_2 emissions. Since the scheme under consideration is a CCGT plant, this is equivalent to a reduction in specific CO_2 emissions of 436 te/GWh. The area of forest required is 1140 ha/MW of installed capacity. The specific reduction (te/GWh) and the area of forest required (ha/MW) would be higher if applied to plants operating on higher carbon content fuels, such as oil or coal.

CO_2 abatement costs

CO_2 abatement costs are shown in Table 2. They are dependent upon discount rate assumptions and in some cases the normalised results differ significantly from those calculated from the actual operational data. However, when ranked from lowest cost (greatest benefit) to highest cost, the basis of calculation again has little effect, as shown in Table 3. As previously, this discussion is therefore based mainly upon the normalised results for a discount rate of 10%.

Efficiency improvements in boiler, steam or gas turbine plant

The results for Cases 1 and 8 illustrate a very wide range of outcomes from investment in efficiency improvements. For Case 8, there is a significant net cost for CO_2 abatement, equivalent to 16.3 \$/te abated at 10 % discount rate, although there would be a net saving of 5.1 \$/te abated if the annual output increased in proportion to the increase in capacity. For Case 1 there is a substantial cost saving overall, of 39.4 \$/te abated. As previously noted, the majority of this saving results from fuel switching, but the refurbishment element alone is estimated to yield a saving equivalent to 15.8 \$/te CO_2 abated. The difference between the outcomes for the two cases is attributable mainly to the costs of the fuel to the plant, with Case 1 using high cost HFO and Case 8 using low cost brown coal although, in general, relative capital costs are also likely to be important.

Conversion to lower carbon content fuels

As noted above, the fuel switching element in Case 1 leads to a substantial net saving per unit of CO_2 abated. In Case 7, however, there is a net cost of 21.4 \$/te, making this case one of the two least attractive. As discussed previously, the difference between the two cases is that the cost of the original fuel in Case 8 is only slightly greater than that of natural gas, so that fuel cost savings are insufficient to compensate for the cost of capital. It may be possible to infer a general principle that replacement of existing coal fired capacity by new natural gas capacity is unlikely to be cost effective at international fuel prices. Nevertheless, in view of the considerable reduction in CO_2 emissions obtainable it may be attractive on non-economic grounds or if it avoids the need for environmentally related capital investment at the existing plant.

Partial substitution of fossil fuels by biomass and waste
The three cases considered here which involve the replacement of fossil fuels by biomass and waste all result at a 10% discount rate in a net cost per unit of CO_2 abated, the range being from 2.2 - 22.5 \$/te abated. At a 5% discount rate, Cases 4 and 5 give modest cost savings equivalent to 1.6 \$/te and 2.7 \$/te CO_2 abated, respectively. As discussed previously, the main cause of the differences between the cases is the relative costs of the original fuel and the biomass and waste fuel. It is not clear if retrofit biomass schemes are inherently less attractive than natural gas substitution

Efficiency improvement by installation of CHP plant
The CHP installation considered in Case 6 offers a substantial saving of 24.2 \$/te CO_2 abated. In contrast, there is a cost of \$21.4/te abated associated with the replacement of existing CHP plant in Case 7. The causes of this difference are discussed above and relate principally to relative fuel prices. CHP may nevertheless be attractive on non-economic grounds or where a substantial environmentally related investment would otherwise be necessary.

Offset of CO_2 emissions by afforestation
The afforestation scheme of Case 2 offers the complete offset of CO_2 emissions at the very low net cost of 0.1 \$/te CO_2 abated. This cost is unlikely to be affected substantially by unpredictable events such as variations in the relative prices of fuels, although there is a risk that the sequestered carbon may be lost, due for example to forest fires, disease or human activity. Emission offset by afforestation has the advantage of being applicable to any plant, irrespective of type or fuel mix. However, there will be a limited supply of suitable low cost schemes and there are doubts about whether credit can be obtained for some schemes under international agreements.

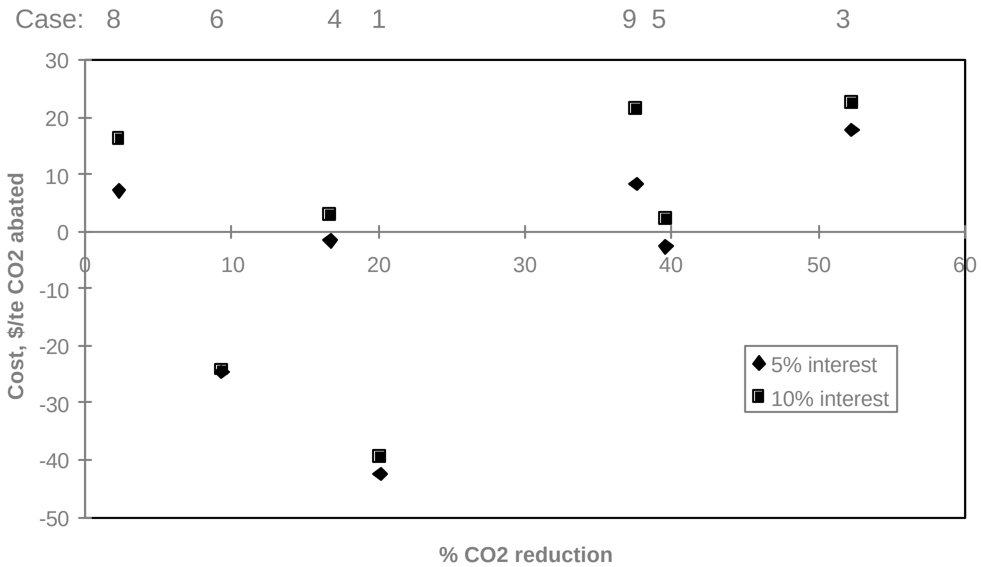

Figure 1 **Variation of cost of abatement with extent of reduction**

Figure 1 summarises the relationship between the cost of CO_2 emission abatement and the extent to which emissions were reduced for the cases studied here. There is a general trend for those approaches which give the highest percentage reduction in emissions to have higher specific costs.

Case 2, the offset of emissions by afforestation, does not follow this trend and offers the potential for the complete elimination of net emissions at a low cost. However, unlike the other cases it does not involve plant modifications and is subject to the risks of loss of sequestered carbon and other concerns noted previously. Case 2 has therefore not been included in figure 1.

5. CONCLUSIONS

Power station retrofits are very site specific. The following conclusions are based on the limited number of cases assessed in this study.

Efficiency

- The refurbishment of old plant can increase its thermal efficiency to a significant extent. Even larger improvements can be obtained if old plant is retired completely and replaced with modern equipment.
- Fuel switching, of any type, is likely to reduce thermal efficiency unless the boiler is simultaneously modified to optimise performance with the new fuel.

Generating costs

- Refurbishment and similar efficiency improvement modifications can provide cost savings per unit of electricity sent out. However, the benefits decrease at lower fuel costs and refurbishment may not be beneficial on purely economic criteria where fuel costs are low.
- The cost effectiveness of fuel switching to natural gas depends on the cost of the original fuel. This must be significantly greater than that of natural gas in order to compensate for capital charges, which may be substantial.
- The cost effectiveness of substituting biomass for fossil fuels in existing plants is likely to be poor on purely economic grounds unless the original fuel is high cost and the substituting biomass is available at low cost. This conclusion may be influenced by the fact that two of the three biomass projects considered here are at relatively small scale.
- Installation of CHP plants is likely to give substantial economic benefit where the opportunity can be taken to export relatively low grade heat and to retire existing thermal plant. However, high capital charges mean that the replacement of existing CHP plant by new gas fired capacity is only likely to be economically viable where the original fuel mix is high cost.
- Offset schemes involving afforestation cannot be self financing in respect of generating costs, but appear to offer a low cost abatement option for which costs can be accurately defined in advance and are independent of fuel price movements. However, the low costs of the case in this study may not apply if such schemes were applied on a large scale because less favourable sites would have to be used. As yet it is not possible to claim credit for the carbon sequestered under international agreements.

Specific CO_2 emissions

- Efficiency improvements in existing power plant can make a contribution to reduced CO_2 emissions but are not, in themselves, likely to have a major impact on emissions.
- Fuel switching from high carbon to low carbon fuels will generally have a significant impact on CO_2 emissions. The benefit will naturally be higher where the carbon content of the original fuel is higher.
- The greatest reduction in net emissions can be expected where it is possible to replace fossil fuels by renewable fuels. However, the extent to which this is possible is likely to be highly case-specific.
- The utilisation of heat from existing power plants, or by analogy the replacement of purely electricity generating stations with CHP plant, can lead to reductions in CO_2 emissions. The extent of the overall reduction will depend to a large extent on the balance between electricity and steam export, but could in principal be comparable with fuel switching, including the partial substitution of fossil fuels by biomass.
- Schemes involving afforestation have the potential to completely offset net emissions of CO_2 over the plant operating lifetime. However, there is some risk that the sequestered carbon could subsequently be released, for example as a result of forest fires or disease in the trees.

CO_2 abatement costs

- The cost effectiveness of efficiency improvements to existing plant can vary over a wide range, from substantial net savings to a net cost per tonne of CO_2 abated. For the examples of efficiency improvement discussed here, the major influence on cost-effectiveness of the project is the cost of fuel. The capital cost per unit of efficiency gain will also in general be an important factor.
- Fuel switching can in some circumstances offer a very substantial net saving per unit of CO_2 abated. Where the original fuel costs are low, however, it may be unattractive on purely economic grounds unless it would otherwise be necessary to make a substantial environmentally related investment.
- Biomass substitution is capable of offering cost savings per unit of CO_2 abated if the cost of capital is low and the biomass fuel is available at low or zero net cost. In other circumstances it may be unattractive on purely economic grounds as a retrofit option. Despite this, it offers the advantage that there are no net emissions from the biomass element of the fuel mix, except for emissions associated with collection and transport of the biomass (which have not been considered here).
- CHP offers substantial cost savings where the overall effect is to displace a high cost fuel. In other circumstances, it may be less cost effective than some of the other options considered in this report.
- Offset schemes involving afforestation offer a low cost option which is independent of relative fuel prices but costs would probably increase substantially if such schemes were applied on a large scale, because less favourable sites would have to be used. Offset schemes offer the additional advantages of being able to reduce net emissions to zero, a target otherwise achievable only by biomass fuelling of the options considered here, and of being applicable to any existing or new plant.

Overall conclusions

A wide variety of schemes that have resulted in reductions in greenhouse gas emissions have been implemented by utilities. Some of these schemes were implemented for commercial reasons, to reduce generating costs, and others were implemented specifically to reduce emissions. Schemes to reduce greenhouse gas emissions from existing power stations are very site specific, so the range of options available at any particular power station are likely to be limited.

Based on the limited number of cases evaluated in this study, the most effective short term means of reducing CO_2 emissions is fuel substitution by natural gas. This is likely to be self financing in many situations, the exception being substitution into existing stations fired by coal at current international prices. Even here, environmental pressures may favour the introduction of natural gas to avoid the need for other capital expenditure.

Fuel substitution by biomass can greatly reduce CO_2 emissions and can, in principle, eliminate net emissions entirely, except for those associated with collection and transport. However, the extent to which substitution into existing plant is feasible is likely to be highly case dependent and there may only be a limited number of suitable opportunities. It appears unlikely that retrofit schemes can be self financing except where the biomass fuel is available at very low or zero cost.

The introduction of combined heat and power schemes to replace separate electricity and thermal plant also offers major reductions in overall CO_2 emissions. Where the existing plant must in any case be replaced due to age, or for other reasons, CHP schemes are likely to be highly cost effective on both conventional economic and abatement cost criteria. Similar benefits are likely to be obtained in situations where it is possible to export heat at low cost from an existing power station.

The refurbishment of existing plant to improve efficiency is unlikely to make a major reduction in CO_2 emissions, but may certainly make a limited contribution. In some circumstances, it may be self financing on conventional economic criteria. However, in comparison with some of the other approaches considered here, it may not be the most effective use of capital.

Finally, offset schemes involving afforestation can in principle result effectively in the complete elimination of net CO_2 emissions and are applicable to any type of plant, whether new or already in operation. However, there is a risk that the sequestered carbon may be released due to natural events, such as forest fires, or human activity. The number of suitable schemes will also be limited and, as yet, it is not possible to claim credit for the carbon sequestration under international agreements.

APPENDIX 1

Detailed basis of study

Economic evaluation conventions

The eight case studies considered here cover a wide range of generating plant types and capacities, with the majority being strongly influenced by local factors other than economics. To facilitate comparison in such cases, a standard set of economic assumptions was developed. The 'normalised' economic evaluations for each case study are based on these assumptions. The following paragraphs outline the most important and comment on some of the implications.

Plant size
The plants considered here vary considerably in size, from 18 MWe to 1200 MWe. As a general principle, the larger projects can be expected to have benefited to some extent from economies of scale. However, retrofit projects are heavily constrained by existing equipment. Costs are therefore highly case dependent and any estimate of costs at a different scale is likely to be unreliable. For this reason the majority of projects have been evaluated at their actual scale. The exception is Case 7, where a single new-build CHP plant has been assumed to replace three much smaller power stations.

Plant lifetime
Four of the case studies involve retrofits and lifetime extensions to existing plant and a remnant plant lifetime of 15 years has been assumed in these circumstances. For those cases which are essentially new building a lifetime of 25 years has been assumed.

Capital costs, fees and contingencies
For the majority of case studies the capital cost estimate has been based upon tender prices. No separate account has been taken of fees, planning costs or general contingency allowances. No credit has been taken for avoided capital costs such as, for example, the cost of installing FGD equipment that would have been necessary in the absence of the modification in question.

Location
The case studies originate from a range of European countries and locations, and construction costs can be expected to have been influenced accordingly. For the actual cost calculations, location factors should have been captured by the use of tender prices for capital costs. It would be desirable for the normalised calculations to use capital, maintenance and other operating costs brought to a common location basis, but in practice this is not possible for disparate projects and has not been attempted here.

Design and construction period
No explicit allowance has been made for the cost of capital during design and construction.

Commissioning and working capital
No explicit allowance has been made for the cost of commissioning or for working capital. An associated cost for retrofit projects is the value of the production lost as consequence of plant disruptions. In the majority of the case studies considered here there were no such disruptions, since the necessary modifications were made during scheduled shut down and maintenance periods. The exception is Case 5, where the cost of lost production has effectively been treated as an addition to the capital cost.

Plant output
In general, annual plant output data are derived from actual operating results. No allowance has been made for the avoided loss of output which might have been incurred by alternative schemes. Minor changes in plant capacity and output are automatically taken into account by the evaluation approach, which expresses the results in terms of costs or benefits per unit of electricity or heat sent out. An exception to this is Case 8, where the main evaluation does not take credit for the increase in output due to turbine efficiency improvements. Comment on the effect of this is made in the text.

Load factor
The majority of the plants considered here operate at intermediate load factors. For these plants, the load factor assumed for normalisation purposes was 65%. This figure should in principle be achievable for all the plants considered here, although it is in some cases substantially higher than the actual operating load factor. For the remaining cases, involving new CCGT capacity or large scale base load plant, a load factor of 85% has been assumed. The load factor has been applied to the rated capacity to obtain the annual production.

Inflation
All costs are treated in real terms.

Currency
All costs have been converted to US$ at the following rates, applicable for 1998.
1$ = 0.60 UK £
1$ = 5.03 Finnish Mk
1$ = 6.29 Danish Kr
1$ = 1.61 German DM

Decommissioning
No allowance has been made for decommissioning or other end-of-life costs.

Taxation and insurance
Taxation regimes are location specific and taxation has therefore been neglected for the purpose of these case studies. Insurance costs are assumed to be included within the capital cost and have not otherwise been taken into account.

Maintenance costs
In those cases where routine or breakdown maintenance requirements were identified as having been affected by the modifications under consideration, allowance has been made for the change in maintenance costs. Such adjustments have been made on a case by case basis in accordance with actual plant experience. No allowance has been made for avoided maintenance costs which might otherwise have been incurred. As noted above, no attempt has been made to normalise maintenance and related costs to a common location basis.

Labour costs
Changes in labour costs have been dealt with on a case by case basis in a manner similar to maintenance costs.

Effluent, emissions and solids disposal
All plants have been assumed to have effluent and aerial emission treatment facilities sufficient to meet the requirements of current EU Directives. Any changes in waste disposal costs have been taken into account. No account has been taken of avoided disposal costs which might have arisen from alternative schemes.

Calorific value
All efficiency calculations are based upon Lower Heating Values (LHV).

Fuel costs and properties
For the actual plant calculations, analytical data and costs applicable to local conditions have been used. For the normalised calculations, however, analytical data applicable to internationally traded fuels have been used, where possible, with costs based on UK conditions. The exceptions are brown coal, peat and wood wastes, for which no UK data are available. Values for brown coal are therefore based on typical mainland European data, while those for peat and wood wastes are based on Finnish experience. The values adopted are shown in Table A1.1.

Calculation of levelised costs

The methodology used for the estimation of levelised costs was as follows:

- The capital cost of the modification under study was determined, generally on the basis of contract documentation. This cost was then increased by the value of any production lost during installation.
- The enhanced capital cost was converted into an annual capital charge using the standard formula for a mortgage type loan repayment:

$$\text{Annual charge} = \text{capital cost} \times I^n \times (I-1)/(I^n - 1)$$

  where n = the plant lifetime in years, I = 1+i and i = the annual interest rate, expressed in decimal form.
- The net annual value of all savings or costs, arising for example from changes in maintenance requirements or from fuel substitution, was determined.
- This figure was added to the annual capital charge to give an overall net annual cost or saving.
- The annual cost or saving was then divided by the annual production of electricity to derive the 'figures of merit'.

		Natural Gas	Fuel Oil	Hard Coal	Brown Coal	Peat	Straw (as fired)	Wood Wastes
Carbon	% w/w db	73.0	84.0	75.6	63.2	55.0	43.8	52.5
Hydrogen	% w/w db			5.6	4.7	5.5	6.0	6.0
Oxygen	% w/w db				22.3	30.5	41.6	40.0
Nitrogen	% w/w db				1.4	1.7	0.7	0.4
Sulphur	% w/w db		2.6	1.1	1.4	0.3	0.5	0.0
Ash	% w/w db			11.1	15.2	7.0	6.9	1.1
Moisture	% w/w ar			10.0	54.0	48.0	16.0	53.5
HHV	MJ/kg	51.3	43.0	27.0	11.0			
LHV	MJ/kg	46.3	40.5	25.5	9.0	9.8	14.0	7.9
CO_2 produced	kg/kg fuel	2.68	3.08	2.49	1.00	1.04	1.61 (Note 1)	0.89 (Note 1)
Cost	$/GJ	2.50	3.40	2.00	1.98	2.90	2.03	2.32

Note 1: These values represent CO_2 produced by combustion. For study purposes, the convention that renewable biomass fuels generate no net emissions of CO_2 has been adopted.

Table A1.1 Summary of standardised fuel properties

APPENDIX 2

Results for NPV-based analysis

Table A2.1 (two pages) presents the results from analyses carried out on a Net Present Value basis.

The methodology used for the NPV calculation was as follows:-

- The net annual value of all savings and additional costs, arising for example from changes in maintenance requirements or from fuel substitution, was determined.
- The discounted lifetime value of this annual cash flow was calculated by multiplying by the appropriate NPV factor, calculated from the equation:

  $$\text{NPV of savings} = \text{Annual saving} \times (1-R^n)/(1-R)$$

  where n = the plant lifetime, in years, R = 1/(1+r) and r = the annual discount rate, expressed in decimal form.
- This figure was added to the capital cost of the modification, including the value of any lost production, to give the overall NPV.
- The NPV was then divided by the lifetime production of electricity to derive the 'figures of merit'.

The main effect of expressing the results on an NPV basis, rather than on an annual levelised basis, is to reduce the magnitude of both the overall costs and benefits when expressed on the basis of \$/te CO_2 abated. This effect is more pronounced at higher interest/discount rates. There are some instances where the relative ranking between two case studies is reversed in the two approaches. However, the discussion and conclusions in the main body of the report remain generally valid for the NPV approach.

		Case 1		Case 2		Case 3		Case 4	
Case description		Refurbishment and conversion from HFO		Sequestration through forestation		Partial substitution of coal by straw		Partial substitution of coal by biomass	
Capital cost	M$	83.6		1.0		10.5		13.9	
Lost production	M$	-		-		-		-	
Actual results									
Remnant lifetime	years	16		25		25		15	
Utilisation factor	%	43		85		62		58	
CO_2 reduction	kte/yr	597		748		83		98	
Electricity output	GWh/yr	3550		1713		72		653	
Interest rate	%	5	10	5	10	5	10	5	10
Fuel savings	M$/yr	12.5	12.5	-	-	-4.1	-4.1	2.5	2.5
Other savings	M$/yr	0.4	0.4	-	-	-0.8	-0.8	-0.1	-0.1
Discounted lifetime saving	M$	146	111	-	-	-73.0	-49.3	26.6	20.5
Overall NPV	M$	62.5	26.9	-1.0	-1.0	-83.6	-59.8	12.7	6.5
Levelised cost (electricity)	$/MWh(e)	-1.10	-0.47	0.02	0.02	46.4	33.2	-1.30	-0.67
CO_2 reduction (electricity)	te/GWh(e)	168		436		1153		150	
Cost of abatement	**$/te CO_2**	**-6.6**	**-2.8**	**0.1**	**0.1**	**40.3**	**28.8**	**-8.7**	**-4.5**
CO_2 reduction	% $^w/_w$	19.5		100.0		52.3		16.4	
Normalised results									
Remnant lifetime	years	15		25		25		15	
Utilisation factor	%	65		85		65		65	
CO_2 reduction	kte/yr	937		748		93		80	
Electricity output	GWh/yr	5415		1713		76		676	
Interest rate	%	5	10	5	10	5	10	5	10
Fuel savings	M$/yr	47.6	47.6	-	-	0.0	0.0	1.6	1.6
Other savings	M$/yr	0.4	0.4	-	-	-0.8	-0.8	-0.1	-0.1
Discounted lifetime saving	M$	523	401			-12.3	-8.3	16.4	12.6
Overall NPV	M$	439	318	-1.0	-1.0	-22.8	-18.8	2.5	-1.3
Levelised cost (electricity)	$/MWh(e)	-5.41	-3.91	0.02	0.02	12.7	10.5	-0.25	0.13
CO_2 reduction (electricity)	te/GWh(e)	174		436		1230		158	
Cost of abatement	**$/te CO_2**	**-31.2**	**-22.5**	**0.1**	**0.1**	**10.3**	**8.5**	**-1.6**	**0.8**
CO_2 reduction	% $^w/_w$	20.1		100.0		52.3		16.7	

Table A2.1 Actual and normalised plant results - NPV basis

		Case 5		Case 6		Case 7		Case 8	
Case description		Conversion from peat to wood wastes		Combined heat and power installation		Replacement of coal and HFO by gas CHP		Refurbishment and turbine improvements	
Capital cost	M$	12.4		3.3		113		28.2	
Lost production	M$	1.0		-		-		-	
Actual results									
Remnant lifetime	years	15		25		25		15	
Utilisation factor	%	65		85		48		91	
CO_2 reduction	kte/yr	96		209		272		118	
Electricity output	GWh/yr	115		8635		803		4712	
Interest rate	%	5	10	5	10	5	10	5	10
Fuel savings	M$/yr	1.1	1.1	9.5	9.5	1.9	1.9	2.2	2.2
Other savings	M$/yr	0.4	0.4	0.3	0.3	0.5	0.5	0.0	0.0
Discounted lifetime saving	M$	17.3	13.3	144.8	97.7	35.5	23.9	23.9	18.4
Overall NPV	M$	3.9	-0.1	141.5	94.4	-77.5	-89.1	-4.3	-9.8
Levelised cost (electricity)	$/MWh(e)	-2.25	0.08	-0.66	-0.44	3.86	4.43	0.06	0.14
CO_2 reduction (electricity)	te/GWh(e)	833		24		339		25	
Cost of abatement	**$/te CO_2**	**-2.7**	**0.1**	**-27.1**	**-18.1**	**11.4**	**13.1**	**2.4**	**5.5**
CO_2 reduction	% $^w/_w$	39.6		6.0		39.7		2.3	
Normalised results									
Remnant lifetime	years	15		25		25		15	
Utilisation factor	%	65		85		65		85	
CO_2 reduction	kte/yr	96		337		337		107	
Electricity output	GWh/yr	115		8635		1087		4200	
Interest rate	%	5	10	5	10	5	10	5	10
Fuel savings	M$/yr	1.1	1.1	15.1	15.1	4.7	4.7	1.9	1.9
Other savings	M$/yr	0.4	0.4	-6.5	-6.5	0.5	0.5	0.0	0.0
Discounted lifetime saving	M$	16.9	13.0	126.1	85.1	77.5	52.3	21.4	16.4
Overall NPV	M$	3.5	-0.4	122.7	81.7	-35.5	-60.7	-6.8	-11.8
Levelised cost (electricity)	$/MWh(e)	-2.02	0.25	-0.57	-0.38	1.31	2.23	0.11	0.19
CO_2 reduction (electricity)	te/GWh(e)	838		39		310		26	
Cost of abatement	**$/te CO_2**	**-2.4**	**0.3**	**-14.6**	**-9.7**	**4.2**	**7.2**	**4.3**	**7.3**
CO_2 reduction	% $^w/_w$	39.6		9.3		37.6		2.3	

Table A2.1 (continued) Actual and normalised plant results - NPV basis

APPENDIX 3

CASE 1

POWER STATION REFURBISHMENT AND FUEL CONVERSION FROM HEAVY OIL TO NATURAL GAS

SECTION 1
PLANT DESCRIPTION

1. PLANT DESCRIPTION

1.1 General

The Ballylumford Gas Conversion Project involves the conversion of 3 x 120 MWe units and 3 x 200 MWe units from operation on Heavy Fuel Oil (HFO) to operation on Natural Gas. The study concentrates upon the conversion of the whole station.

Ballylumford represents an electrical capability of 1080 MWe including gas turbines, or 951 MWe excluding GTs, on the Northern Ireland grid whose total generating capability is 2340 MWe and includes 3 other major stations at Belfast West, Coolkeeragh and Kilroot.

1.2 Plant Prior to Modification

The original power station at Ballylumford was commissioned by Northern Ireland Electricity (NIE) and constructed in two phases. The first phase (Phase 1) was completed in 1969 and comprises of three conventional reheat boiler steam turbine-generator units, each with a maximum continuous rating of 120 MWe. The second phase (Phase 2) was completed in 1974 and comprises of three units of 200 MWE each MCR. The units operated on heavy fuel oil and the design parameters are set out in the following table:

Design	Voltage	Nominal Steam Pressure	Nominal Steam Temperature
120 MW	13.8 kV	125 bar (1825 psi)	540°C (1005°F)
200 MW	15.0 kV	165 bar	540°C

The steam parameters and unit ratings have not been changed on account of the fuel conversion. The steam turbine condensers are direct sea water cooled with a inlet CW temperature range of 8°C to 15°C. The boilers were supplied by Babcock and Wilcox and the steam turbines by GEC.

In addition to the conventional steam plant the station is supplemented by 2 x 60 MWe gas turbine units of aero-derivative type burning distillate oil.

Prior to the conversion Ballylumford power station used heavy fuel oil with Sulphur contents of up to 3%.

A photograph and a diagram of the power station are included at the end of the report to illustrate the visual impact of the station and the steam plant arrangement.

1.3 Brief History and Decision Process

The electricity supply industry in Northern Ireland was privatised during 1992 and 1993.

Prior to 1992 a single state owned utility (Northern Ireland Electricity NIE) was responsible for generation, transmission, distribution and supply of electricity within the province.

After a period of preparation and consultation the transmission and distribution company together with the four generating stations in Northern Ireland, of which Ballylumford was one, were sold by trade sale in 1992. The transmission and distribution company was floated on the stock market in 1993.

Ballylumford Power Station (P.S.) is now owned and operated by Premier Power Ltd (a British Gas Subsidiary) and the station is the most important and largest generating plant in NI supplying approximately 32% of the electricity produced in the province in 1996.

The historical aspects associated with the project were related to the government's objective of introducing a natural gas supply into Northern Ireland and also the desire to privatise the electricity supply industry. Ballylumford P.S. represented a substantial potential gas consumer and therefore assisted in the reinforcement of the case for the provision of gas to the Province and in the fostering of competition in the primary fuel market. The conversion also had the benefit of substantially reducing Sulphur emissions in Northern Ireland and supporting the reductions required under the UNECE Sulphur protocol.

The gas pipeline has been extended beyond Ballylumford towards Belfast in an attempt to encourage the take-up of gas by other users. The construction of the pipeline network to domestic and industrial consumers has been undertaken concurrently with the power station conversion and is phased to continue until 2003. In assessing the case for the pipeline it was estimated that Ballylumford P.S. would take approximately 50% of the pipeline capacity, with 25% taken by a prospective CCGT and 25% by downstream consumers. Premier Power is part owned by British Gas and as such provides a guaranteed customer for the natural gas supplied by them via the Transco pipeline across the Irish Sea from Scotland.

The conversion of the boilers at Ballylumford from HFO to natural gas was undertaken between 1994 and 1996 during the overhaul periods which were 14 weeks for phase 1 units and 16 weeks for phase 2. Two units per year were converted.

The gas interconnection was completed in 1996 and gas was made available to the plant in October of that year.

Although costs mentioned in section 1.6 represent a substantial investment these would be offset by the requirement to reduce SO_2 emissions by 60% before the year 2003 (see 3.8). This would necessitate at least an investment of 50 to 80 M$ based upon the most modern dry lime FGD systems currently available or alternative operation based upon the more expensive low Sulphur HFO. More expensive limestone gypsum FGD systems could increase this to 130 M$.

1.4 Modification Details

The first unit at Ballylumford was commissioned in 1968 and the last in 1976. With a 30 year design life this would indicate that the first unit would now be entering its period of remnant life with the last being in 2006. Investigations of residual/remnant life on other UK coal and oil fired stations has extended operations for a further 10 years beyond the original design life. Thus taking this into consideration together with the reduced fatigue associated with HFO to gas conversions, a life expectancy between 2010 and 2012 should be achievable by all units. This is verified by site data indicating unit retirements between 2013 and 2018 at current loading levels.

The conversion consisted essentially of the fitting of dual fuel low NO_x burners, with oil and gas distribution pipework and modification of the boilers as described below.

The furnaces are front wall fired and furnished with three burners in each of four panels. The furnaces were intrinsically small as built for the 200 MW oil fired units due to the height restriction imposed by planning constraints associated with original consents given for the development of a 6 x 120 MWe station. The gas combustion results in a different heat distribution, particularly in the case of the low NO_x burners with the result that more heat transfer surface was required in the convective sections of the boiler. A new platen superheater incorporating 9% Cr steel was provided and the steam attemperators were redesigned accordingly and the wind box arrangements and the buckstays strengthened. Operation on gas enabled a lower flue gas outlet temperature to be utilised. Fouling and corrosion, and hence maintenance of the downstream components of the gas path were less on account of the cleaner fuel. The induced draft (I.D) fan capacity was upgraded to accommodate the optimisation of air and gas flows through the converted boiler when firing both fuels. A new distributed control system (DCS) incorporating a burner management and control system was installed to replace obsolete electronic controls and a gas leakage detection system was provided for safety reasons.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is predominantly determined by the change in fuel consumption prior and post the gas conversion, taking into account the carbon content of the fuel, plant efficiency and operating regime. The results are given for the whole station burning natural gas and compared with operation on heavy fuel oil. The amounts of CO_2 generated by the combustion of all 'normalised/paradigm' study fuels is addressed in Appendix 1 and since no discrepancies exist between these fuels and site fuels (see sections 1.9.1 & 1.9.2.) no corrections are proposed.

The NO_x reduction achieved as a result of fitting low NO_x dual fuel burners is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Experiments to measure N_2O concentrations in flue gases on other plant have proved unsuccessful and hence any change in the greenhouse gas N_2O is not considered in this case. It should be noted that low NO_x burners would have been fitted at Ballylumford irrespective of the gas conversion in order to comply with the tighter emission consents being applied by the Alkali & Radiochemical Inspectorate (ARI).

1.6 Determination of capital costs

The capital costs have been based upon quotations received by Premier Power from contractors.

An original quotation of £50 million turn-key had been received to convert the PS to gas but it had been decided by Premier Power Ltd to invite bids on an alternative basis i.e. competitive design. From a field of 13 tenderers two were chosen for the final stages, International Babcock & Wilcox with McDermott Engineering Europe and UK Babcock Energy (now Mitsui Babcock). The contract was awarded to International Babcock & Wilcox in 1993 for the sum of £35 million. 35% of the work was financed by a grant from the EU with £22.75 million being raised by Premier Power Ltd and British Government (BG).

Refurbishment work carried out on the steam turbines, condensers, feedwater pump and boilers during the same period was costed at £15 million.

There were no appreciable delays or significant difficulties although the initial outage work on Phase 2 unit 4 boiler front had been underestimated, an additional 4 days had been required in the program before achieving full load. On subsequent units there had been no deviation from the program on the part of the contractor.

It was possible to minimise outage to annual maintenance periods by completion of all work except tie in work whilst the units continued in operation.

1.7 Determination of Fuel, Operating and Maintenance Costs

In comparing net outputs between operation on oil and gas there were minor differences in boiler efficiencies on the 200 MW units. These were detailed by the station owners and are in Section 1.11.

Reduced fouling and corrosion associated with gas firing have enabled savings on maintenance to be achieved as a result of the reduced HFO operational hours.

There are labour savings associated with the reduction per shift of 2 personnel associated with the oil handling plant.

There are also further savings equivalent to one person on day work associated with air heater and oil handling plant maintenance.

The current plant utilisation is such that on phase 2 a unit output of 200 MW is now frequently achieved and the average availability and reliability of all units was enhanced after the conversion.

Privatisation had led to a need to secure greater guaranteed availability whilst fulfilling a requirement for two shifting. The conversion to natural gas was expedient to this need and the periods between boiler inspections was increased to 3 years with the incorporation of some minor changes to operating procedures. In 1997, 600 startups were conducted which were a mixture of cold, warm and hot regimes.

The data on estimated and actual operating fuel consumptions, net output, utilisation and the operating and maintenance costs are itemised under Section 2.

1.8 Changes to Non-Greenhouse Gas Emissions

The decision to fit some low NO_x burners for the combustion of the HFO had been taken by NIE prior to the change of ownership and gas conversion. The cost for this work would have amounted to £15 Million. However, the gas conversion entailed the fitting of dual fuel low NO_x burners. Environmental pressure from the EC had imposed a pre-requisite that by 2003 the SO_2 emissions were to be reduced by 60% and the NO_x emissions by 40% [based on 1980 levels].

The environmental requirements were stipulated by the ARI in accordance with the EC large combustion plant directives such that low NO_x burners were required to achieve 450 mg/Nm³ when firing oil and 350 mg/Nm³ when firing gas with reference to 3% O_2 in dry flue gas. The respective particulate levels are 140 mg/Nm³ and 5mg/Nm³. Phase 1 and 2 meet the criteria on gas although Phase 2 does not quite meet NO_x limits on oil, although it was within the inspector's current requirements.

1.9 Site Fuel data

1.9.1 Natural Gas

The specification for natural gas supplied to Ballylumford site is in accordance with the typical UK supply range data provided by Transco. A specific analysis has been given by site and this represents a typical UK analysis from the St. Fergus gas terminal dated 1990 and does not require any correction factors. Therefore no correction is proposed for the 3% discrepancy in calorific value from the datum UK natural gas given in Appendix 1 and having a GCV of 51.3 MJ/kg (39.5 MJ/Nm^3), NCV of 46.3 MJ/kg and containing 73% carbon by weight.

However the Northern Ireland area incurs additional transportation costs above typical UK gas prices and this is reflected by the higher tariff given below:

NI supply including transport costs 19p/therm $\equiv$ 3.00 $/GJ on NCV

This cost is representative of the main supply contract for the station, although a number of cheaper short term contracts are also in place.

Therefore the 'normalised/paradigm' calculations include a gas cost correction from 19.5 p/therm (3.00 $/GJ) to 16 p/therm (2.5 $/GJ) as well as a correction for the difference in non availability periods from 55 days in NI to 40 days in mainland U.K.

1.9.2 Heavy Fuel Oil (HFO)

The site specification for HFO is based upon a gross calorific value (GCV) of 42 MJ/kg and having an analysis comprising of 84% carbon and 3% Sulphur by weight.

The 2% variation in GCV between the site and datum fuel given in Appendix 1 was considered acceptable and within study tolerances especially since carbon contents of both fuels agreed. Therefore calculations completed in section 2 involve no corrections to the proposed HFO CO_2 emission and cost factors identified for 'normalised' fuels in Appendix 1.

1.10 Combustion Gases

The HFO and NG fuels given previously in 1.9 agree closely with 'normalised/paradigm' data and so no changes are proposed to CO_2 combustion figures under normal conditions to give 3.08 kg and 2.68 kg of CO_2 respectively per kg of fuel.

1.11 Net Plant Efficiency and output information

Indication of the efficiency of plant at Ballylumford prior to conversion is obtained from copies of the Electricity Supply Handbook between 1985 and 1990, where the cycle efficiency of all UK power stations is given, and gives an average of 31.8% over this period with an average load factor of 42.41% on HFO. Premier Power has provided design data giving boiler HFO efficiencies of 88.5% and 88.8% for phase 1 and 2 units respectively in support of these figures.

The conversion and refurbishment work carried out between 1994 and 1996 could be expected to improve the efficiency figures for HFO firing by between 1 and 1.5% on cycle efficiency to between 32.8% and 33.3%. These figures agree closely with the data provided by the operator on boiler and turbine efficiency (see below) and original performance test data. It appears reasonable to assume that post conversion cycle efficiencies are 33% on HFO and 31.5% on NG.

Post conversion unit output and test efficiencies are summarised below:

	Phase 1	**Phase 2**
Net Gen'd output/unit	117MWe	200 MWe
Oil fired gross efficiency	88.4%	88.5%
Gas fired gross efficiency	85.5%	84.3%
Steam turbine efficiency	42.9	42.9

The following plant tabulation shows how the modification program had minimal effect on power generation from Ballylumford during the mid 1990's:-

Year	Utilisation %	Power Generation (GWhso)	Load Factor % of 951 MWe

1992	54.21	3056	36.7
1993	55.91	3516	42.2
1994	55.36	3495	42.0
1995	46.49	2846	34.2
1996	51.90	3329	40.0
1997	-	3640	43.7

Site utilisation data provided above gives an average figure of 52.8% for the 1992 to 1996 period and represents the amount of time that the plant is dispatched by the NI grid company to produce electricity. The associated load factors given represent the actual power generated per annum divided by the hours in a year and the declared output capability of the station.

Taking due consideration of the site modification years unit loading within the station for an average year during this period is estimated at 3550 GWhso or 42.6% load factor.

It is not possible to assess whether the reduced power outputs during 1995 and 1996 are as a result of conversion work or as a result of conservatism by the Northern Ireland grid company in its dispatching of Ballylumford power station. and so no loss of generation/revenue can be apportioned to the modification.

2 RESULTS

2.1 Reference Plant Calculations

Based upon the assumptions discussed in section 1 estimations can be made regarding pre and post conversion fuel consumptions and CO_2 emissions on an annual basis for the station as shown below:

Fuel		Pre conversion	Post conversion	
		HFO	HFO	NG
Annual net power export	GWh_{so}	3550	3550	3550
Net cycle efficiency on NCV	%	31.8	33.0	31.5
Annual heat in steam	GWh	9645.3	9509.7	9529.4
Annual net heat input requirement	GWh	11164	10758	11270
Annual fuel consumption	kte	992	956	895
Annual fuel cost	M$	136.6	131.6	124.2
Annual fuel saving	M$	0	5.0	12.5
Annual generation of CO_2	kte	3055	2943	2459
Annual reduction in CO_2	kte	0	111.1	596.9

These figures indicate 3.6% reduction of CO_2 emissions resulting from the plant refurbishments carried out during conversions and a total 19.5% reduction of CO_2 emissions resulting from the refurbishment and fuel change to natural gas. The terms of supply agreements for natural gas to NI allow for up to 55 days of interruption per annum which effectively moderates post conversion annual CO_2 emissions to around 80.5% of pre-conversion levels.

The capital expenditure associated with the refurbishment and gas conversion of the station have been obtained and summarised in the table below:

Estimated cost of refurbishment	25.1M$
Estimated cost of fuel conversion	58.5M$
Combined cost of refurbishment & conversion	83.6M$

This represents a substantial investment in the station and had to be considered against the future requirement for installation of FGD before the year 2003 (see 1.8) or alternative operation based upon the more expensive low Sulphur HFO.

Financial evaluations contained in the following sections 2.1.1 to 2.1.4 are all based on the reference plant conditions above and the assumptions listed below:-

- conversions and refurbishment work was largely carried out as part of annual maintenance programs and no major additional loss of revenue is appropriate.
- operational and maintenance costs excluding fuel and labour are unaltered.
- remnant life for cost evaluations is taken as 16 years (1994 to 2010 or 1996 to 2012).
- annual discount rates assumed for through life NPV calculations are 5% and 10%.
- loan repayments based on annual interest rates at 5% and 10%.
- labour savings from fuel conversion are approximated to 8 people per annum or £0.25m.

The following financial evaluations include refurbishment using loan capital without discounting (see 2.1.1), refurbishment and conversion using loan capital without discounting (see 2.1.2), refurbishment using equity as capital and discounting through life to give NPV (see 2.1.3), and refurbishment and conversion using equity as capital and discounting through life to give NPV (see 2.1.4.).

2.1.1 Estimated benefits of refurbishment on loan basis.

The following financial evaluation of the station refurbishment is carried out at reference plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		25.1	M$
Number of years remnant life (n)		16	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0923	0.1278	
Annual loan repayment (A_{lr})	2.32	3.21	M$
Annual fuel saving (FS_r)	5.0	5.0	M$
Net annual saving (FS_r-A_r)	2.65	1.79	M$
CO_2 reduction per annum		111.7	Kte
GWh_{so} per annum		3550	GWh_{so}
GWh steam per annum		9509.7	GWh
(i) Levelised saving/cost per GWh_{so}	747.3	495.9	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	31.31	31.31	te/GWh_{so}
(iii) CO_2 prevention saving	23.87	15.84	$/te$CO_2$
(iv) Levelised saving per steam	279.0	185.1	$/GWh
(v) CO_2 reduction per GWh	11.69	11.69	te/GWh

2.1.2 Estimated Benefits of Refurbishment and Fuel Conversion on Loan Basis.

The following financial evaluation of the station refurbishment and conversion is carried out at reference plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

		83.6	M$
Number of years remnant life (n)		16	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0923	0.1278	
Annual loan repayment (A_{LR2})	7.71	10.69	M$
Annual fuel saving (FS_{r+c})	12.48	12.48	M$
Annual Labour saving (LS_{r+c})	0.36	0.36	M$
Net annual saving (FS_{r+c}+LS_{r+c}-A_{LR2})	5.13	2.16	M$
CO_2 reduction per annum		596.9	kte
GWh_{so} per annum		3550	GWh_{so}
GWh steam per annum		9579.4	GWh
(i) Levelised saving/cost per GWh_{so}	1444.5	607.4	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	168.1	168.1	te/GWh_{so}
(iii) CO_2 prevention saving	8.59	3.61	$/te$CO_2$
(iv) Levelised saving on steam	535.3	225.1	$/GWh
(v) CO_2 reduction per GWh	62.31	62.31	te/GWh

2.1.3 Estimated Benefits of Refurbishment on Capital from equity and NPV basis.

The following financial evaluation of the station refurbishment is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

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RESULTS

Cost of refurbishment (C_r)		25.1	M$
Number of years remnant life (n)		16	
CO_2 reduction per annum		111.7	kte
GWh_{so} per annum		3550	GWh_{so}
GWh_{so} over reference plant life		56800	GWh_{so}
Annual heat in steam		9509.7	GWh
Through life heat in steam		152155	GWh
Annual fuel saving (FS_r)		5.0	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	11.3797	8.6061	
Disc'd saving over remnant life (DS_r)	156.54	42.76	M$
NPV saving (DFS_r - C_r)	31.44	17.66	M$
(i) NPV levelised saving	553.6	311	$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	31.31	31.31	te/GWh_{so}
(iii) CO_2 prevention savings	17.68	9.93	$/teCO_2$
(iv) NPV levelised saving on steam	206.6	116.1	$/GWh
(v) CO_2 reduction per GWh	11.69	11.69	te/GWh

2.1.4 Estimated Benefits of Fuel Conversion and Refurbishment using capital from equity and NPV basis.

The following financial evaluation of the station refurbishment and conversion is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % over the remnant life of the station.

SECTION 2
RESULTS

Cost of refurbishment (C_{r+c})		83.6	M$
Number of years remnant life (n)		16	
CO_2 reduction per annum		596.9	kte
GWh_{so} per annum		3550	GWh_{so}
GWh_{so} over reference plant life		56800	GWh_{so}
Annual heat in steam		9579.4	GWh
Through life heat in steam		153270	GWh
Annual fuel saving (FS_{r+c})		14.9	M$
Annual labour saving (LS_{r+c})		0.36	M$
Total annual saving/cost (FS_{r+c} + LS_{r+c})		15.26	M$
Annual Discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	11.3797	8.6061	
Disc'd saving over remnant life (DS_{r+c})	146.1	110.5	M$
NPV saving (DS_{r+c} - C_{r+c})	62.54	26.92	M$
(i) NPV levelised saving	1101	473.9	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	168.1	168.1	te/GWh_{so}
(iii) CO_2 prevention savings	6.55	2.82	$/te$CO_2$
(iv) Levelised saving per GWh	408.0	175.6	$/GWh
(v) CO_2 reduction per GWh	62.31	62.31	te/GWh

SECTION 2
RESULTS

2.2 Normalised Plant Calculations.

The 'normalised' or 'paradigm' project conditions on which the case study is evaluated are summarised below:-

- conversions and refurbishment work was largely carried out as part of annual maintenance programs and no major additional loss of revenue is appropriate.
- operational and maintenance costs excluding fuel and labour are unaltered.
- labour savings from fuel conversion are approximated to 8 people per annum or £0.25m.
- annual discount rates assumed for through life NPV calculations are 5% and 10%.
- loan repayments based on annual interest rates at 5% and 10%.
- 15 year life expectancy
- 65% plant loading utilisation factor corresponding to 5415 GWh_{so}
- typical UK mainland interruptions to NG supplies can be up to 40 days and cost 2.5 \$ GJ on NCV (16p/therm)

The above criteria enables the following generic table, similar to that originally provided in section 2.1, to be reproduced giving the annual power, fuel and CO_2 quantities based upon 'normalised' plant conditions:

		Pre conversion	**Post conversion**	
Fuel		**HFO**	**HFO**	**NG**
Annual net power export	GWh_{so}	5415	5415	5415
Net cycle efficiency	%	31.8	33.0	31.5
Annual heat in steam	GWh	14712.5	14505.6	14611.9
Annual net heat input requirement	GWh	17028	16409	17190
Annual fuel consumption	kte	1513	1458	1358
Annual fuel cost	M$	208	201	161
Annual fuel saving	M$	0	7.6	47.6
Annual generation of CO_2	kte	4659	4489	3722
Annual reduction in CO_2	kte	0	170	940

This gives similar reductions of CO_2 emissions on a percentage basis as those given in 4.1 i.e. 3.6% and 20.2% respectively. The lower potential interruption to UK mainland supplies means a marginal alteration to the annual post conversion CO_2 emissions at 79.9% rather than 80.5% of pre-conversion levels.

2.2.1 Estimated benefits of refurbishment on loan basis.

The following financial evaluation of the station refurbishment is carried out at 'normalised' plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		25.1	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A^n_{lr})	2.42	3.3	M$
Annual fuel saving (FS^n_r)	7.60	7.6	M$
Net annual saving ($FS^n_r - A^n_{lr}$)	5.18	4.3	M$
CO_2 reduction per annum		170	kte
GWh_{so} per annum		5415	GWh_{so}
GWh steam per annum		14505.6	GWh
Merit fig (i) levelised saving	935.1	790.2	$\$/GWh_{so}$
Merit fig (ii) CO_2 reduction	31.31	31.31	te/GWh_{so}
Merit fig (iii) CO_2 prevention saving	30.44	25.24	$\$/teCO_2$
Merit fig (iv) levelised saving on steam	355.8	295.0	$/GWh
Merit fig (v) CO_2 reduction on steam	11.69	11.69	te/GWh

SECTION 2
RESULTS

2.2.2 Estimated Benefits of Refurbishment and Fuel Conversion on Loan basis.

The following financial evaluation of the station refurbishment and conversion is carried out at ‘normalised’ plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Cost of refurbishment & conversion (C_{r+c})		83.6	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A^n_{lr2})	8.05	10.99	M$
Annual fuel saving (FS^n_{r+c})	47.61	47.6	M$
Annual Labour saving (LS^n_{r+c})	0.36	0.36	M$
Net annual saving ($FS^n_{r+c}+LS^n_{r+c}-A^n_{lr2}$)	39.91	36.98	M$
CO_2 reduction per annum		940	Kte
GWh_{so} per annum		5415	GWh_{so}
GWh steam per annum		14611.9	GWh
Merit fig (i) levelised saving	7371	6828.6	$\$/GWh_{so}$
Merit fig (ii) CO_2 reduction	173.5	173.5	te/GWh_{so}
Merit fig (iii) CO_2 prevention saving	42.48	39.35	\$/te CO_2
Merit fig (iv) levelised saving on steam	2731.6	2530.6	\$/GWh
Merit fig (v) CO_2 reduction	64.31	64.31	te/GWh

2.2.3 Estimated Benefits of Refurbishment on Capital from equity and NPV basis.

The following financial evaluation of the station refurbishment is carried out at 'normalised' plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		25.1	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		170	kte
GWh_{so} per annum		5415	GWh_{so}
GWh_{so} over reference plant life		81225	GWh_{so}
GWh steam per annum		14505.6	GWh
GWh steam over ref. Plant life		217584	GWh
Annual fuel saving ($FS^n{}_r$)		7.5	M$
Annual Discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life ($DS^n{}_r$)	82.3	63.4	M$
NPV saving ($DS^n{}_r$ - C_r)	57.2	38.3	M$
Merit fig (i) NPV levelised saving	704.2	471.5	$/$GWh_{so}$
Merit fig (ii) CO_2 reduction	31.31	31.31	te/GWh_{so}
Merit fig (iii) CO_2 prevention saving	22.43	15.02	$/te$CO_2$
Merit fig (v) NPV levelised saving on steam	264.3	176.1	$/GWh
Merit fig (vi) CO_2 reduction	11.69	11.69	te/GWh

2.2.4 Estimated Benefits of Fuel Conversion and Refurbishment using capital from equity and NPV basis.

The following financial evaluation of the station refurbishment and conversion is carried out at 'normalised' plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % over the remnant life of the station.

Cost of refurbishment (C_{r+c})		83.6	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		940	Kte
GWh_{so} per annum		5415	GWh_{so}
GWh_{so} over reference plant life		81225	GWh_{so}
GWh steam per annum		14611.9	GWh
GWh over reference plant life		219179	GWh
Annual fuel saving (FS^n_{r+c})		47.61	M$
Annual labour saving (LS^n_{r+c})		0.36	M$
Total annual saving ($FS^n_{r+c} + LS^n_{r+c}$)		47.97	M$
Annual Discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS^n_{r+c})	522.8	401.3	M$
NPV saving ($DS^n_{r+c} - C_{r+c}$)	439.2	317.7	M$
Merit fig (i) NPV levelised saving	5407.1	3911.8	$/GWh_{so}$
Merit fig (ii) CO_2 reduction	173.5	173.5	te/GW_{so}
Merit fig (iii) CO_2 prevention saving	31.16	22.54	$/te$CO_2$
Merit fig (v) NPV levelised saving on steam	2003.8	1449.7	$/GWh
Merit fig (vi) CO_2 reduction on steam	64.31	64.31	te/GWh

3 DISCUSSIONS AND CONCLUSIONS

Based upon the merit ratings and the normalised values calculated in sections 2.2 & 2.3, it is apparent that significant savings can be made from both plant refurbishment and fuel conversion. The results have been incorporated into the following summary tables for the 10% loan interest and 10% discount cases at both Reference and Normalised plant conditions.

Summary Table at Reference Conditions (3550 GWh_{so} per annum)

Case		Refurbishment		Refurbishment & Conversion	
Loan repayment/equity		LR	E-NPV	LR	E-NPV
Merit Figure	units				
(i)	$/$GWh_{so}$	495.9	311	607.4	473.9
(ii)	te/GWh_{so}	31.31	31.31	168.1	168.1
(iii)	$/te CO_2	15.84	9.93	3.61	2.82

Summary Table at Normalised Conditions (5415 GWh_{so} p.a.)

Case		Refurbishment		Refurbishment & Conversion	
Loan repayment/equity		LR	E-NPV	LR	E-NPV
Merit Figure	units				
(i)	$/$GWh_{so}$	790.2	471.5	6828.6	3911.8
(ii)	te/GWh_{so}	31.31	31.31	173.5	173.5
(iii)	$/te CO_2	25.24	15.02	39.35	22.54

An obvious comparison between the two financial evaluation techniques shows the equity & NPV evaluations of merit figures i and iii to be approximately 60 % of the loan evaluations of the same merit figures.

Merit figure (i) values show significant financial savings per GWh_{so} from both refurbishment and refurbishment and fuel conversion. The saving from refurbishment and fuel conversion is approximately 2.6 times that from refurbishment alone. When compared with the respective capital investments at a ratio of 1 : 3.3 this indicates that refurbishment represents a slightly better proposition than joint refurbishment and conversion. However, at increased load factors associated with 'normalised' conditions the ratio of saving from fuel change increases to approximately 1 : 10 rather than 1 : 2.6. This represents a greater saving from fuel conversion than refurbishment as a proportion of the capital invested. Indications are that the financial benefits obtained from refurbishment and those from refurbishment and conversion swing in favour of fuel conversion at between 45% and 55% load factor for this type of case study.

SECTION 3
DISCUSSIONS AND CONCLUSIONS

As mentioned in the previous paragraph there is an apparent lower financial benefit from fuel conversion than from refurbishment when considered at the site reference level. Justification for fuel conversion becomes more favourable when considered against the additional costs of FGD or low Sulphur fuel oil, which in this case study was considered an external influencing factor.

Merit figure (ii) values give the reduction in CO_2 per GWh of electricity and shows significant improvements from gas conversion and refurbishment rather than refurbishment alone, approximately 6 times that from refurbishment. These benefits are also unaffected by the changes in electricity production since they are directly related to station efficiency.

Merit figure (iii) values show an increase of 1 : 1.6 in the cost per te CO_2 saved when going from the refurbishment to the refurbishment and conversion case.

Therefore strictly from a CO_2 point of view it would appear that refurbishment and efficiency improvements are more beneficial than fossil fuel conversions. This can possibly be explained by the fact that fuel conversions quite often represent a compromise on efficiency for the new fuel in order to minimise capital investment in modifications.

Premier Power Limited staff at Ballylumford Power Station operate, maintain and control the generating plant, in a safe and efficient manner, producing a reliable low cost electricity supply for Northern Ireland Electricity plc (NIE).

Our commitment to the community is demonstrated by values of integrity and social responsibility, being good neighbours and optimising assets as an efficient prudent generator.

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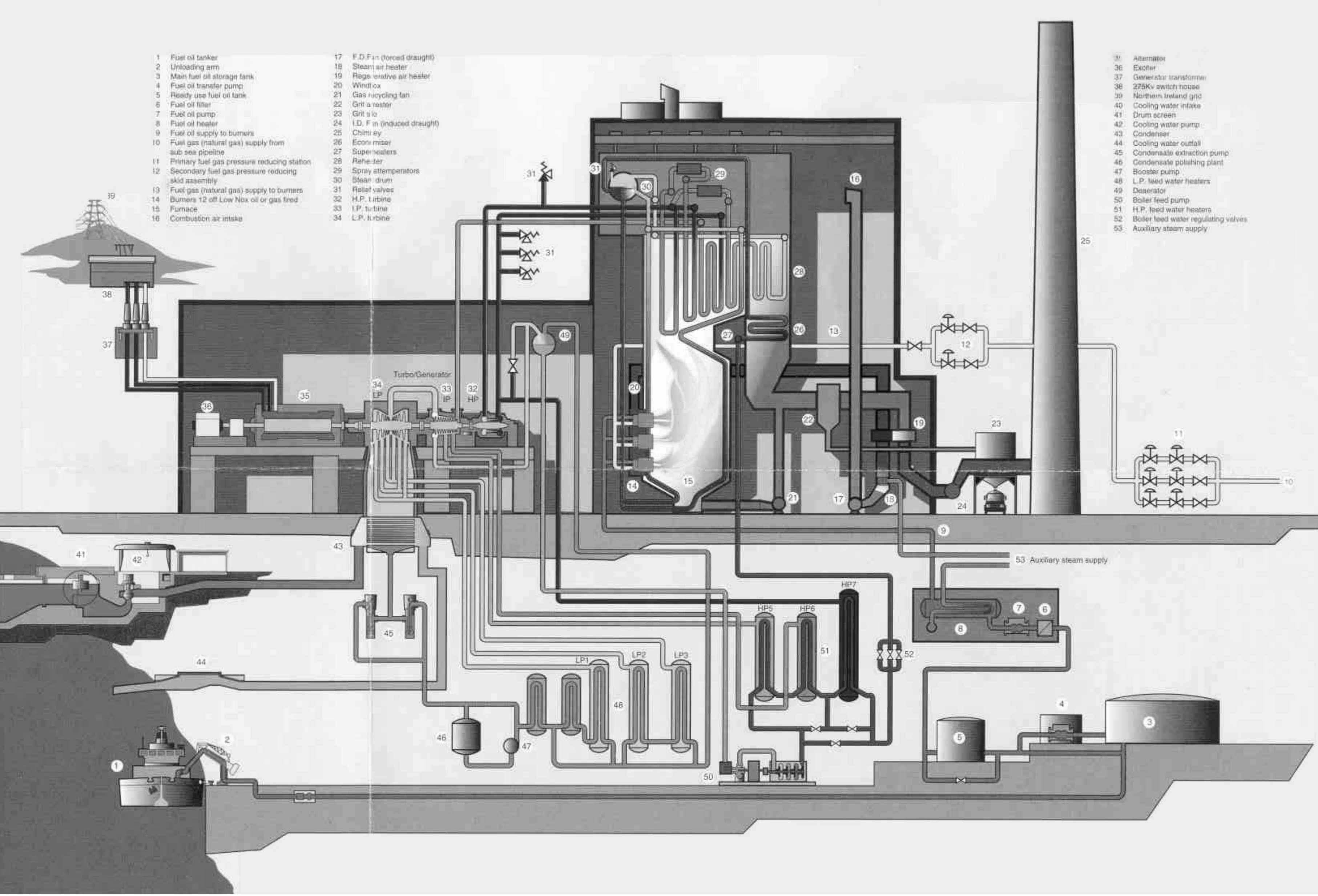


1 Fuel oil tanker
2 Unloading arm
3 Main fuel oil storage tank
4 Fuel oil transfer pump
5 Ready use fuel oil tank
6 Fuel oil filter
7 Fuel oil pump
8 Fuel oil heater
9 Fuel oil supply to burners
10 Fuel gas (natural gas) supply from sub sea pipeline
11 Primary fuel gas pressure reducing station
12 Secondary fuel gas pressure reducing skid assembly
13 Fuel gas (natural gas) supply to burners
14 Burners 12 off Low Nox oil or gas fired
15 Furnace
16 Combustion air intake
17 F.D.F n (forced draught)
18 Stean air heater
19 Rege erative air heater
20 Windl ox
21 Gas recycling fan
22 Grit a rester
23 Grit s lo
24 I.D. F in (induced draught)
25 Chimi ey
26 Econ miser
27 Super heaters
28 Rehe ter
29 Spray attemperators
30 Stean drum
31 Relief valves
32 H.P. t irbine
33 I.P. tu bine
34 L.P. tu rbine
Alternator
36 Exciter
37 Generator transformer
38 275Kv switch house
39 Northern Ireland grid
40 Cooling water intake
41 Drum screen
42 Cooling water pump
43 Condenser
44 Cooling water outfall
45 Condensate extraction pump
46 Condensate polishing plant
47 Booster pump
48 L.P. feed water heaters
49 Deaerator
50 Boiler feed pump
51 H.P. feed water heaters
52 Boiler feed water regulating valves
53 Auxiliary steam supply
Turbo/Generator
34 LP
33 IP
32 HP
53 Auxiliary steam supply
HP5
HP6
HP7
LP1
LP2
LP3

APPENDIX 4

CASE 2

CO_2 SEQUESTRATION THROUGH FORESTATION

SECTION 1
PLANT DESCRIPTION

1. PLANT DESCRIPTION

1.1 General

AES is a worldwide private power producer and has been involved in a recent combined cycle power station development at Barry in South Wales.

The high efficiency associated with this type of modern power plant suggested that technical modifications to the plant in order to reduce annual CO_2 emission would be both difficult and expensive. The AES executives held a significant ideology that their company should promote environmental and sociological policies and this resulted in an investigation of alternative schemes for forestation and the "off-setting" of CO_2 emissions from the AES Barry plant.

1.2 Plant Prior to Modification

As mentioned above no physical modification of the AES Barry power plant is proposed and so detailed descriptions of the plant are not required for this case study.

The plant comprises a single power block consisting of a gas turbine, dual pressure HRSG, steam turbine and condenser all matching the brief technical details given below:-

Gross GT output	MWe	158.9	
Gross ST output	MWe	76.5	
Rated Net plant output	MWe_{so}	229.6	
Guaranteed Net Efficiency	%	49.25	
Normal Operating Net Efficiency	%	48.0	
Cycle Data		HP	LP
Steam Temperature	ºC	512	250
Steam Pressure	bar	67.6	6.25

1.3 Brief History and Decision Process

SECTION 1
PLANT DESCRIPTION

AES reviewed proposals for several projects which had sociological and environmental benefits associated with them. Each of these proposals had been received in response to a 'bid specification' established in a similar manner to those raised for major turnkey projects.

The 'bid specification documents' and 'tender evaluation criteria' were established by Natural Resources International (NRI) at AES request.

The projects evaluated in response to the 'bid specification' were based world wide and included the following examples:-

- Vanuatu - UK foundation for the South Pacific, improvement of logging methods for natural forest on 6000 ha with remedial work in 230 ha.
- Argentina reforestation - ArgenINTA, commercial arm of the national Institute of Agricultural Technology (INTA), planting of 1000 Ha of tree plantations in 3 locations over two years (Chubut, Salta and Chaco).
- Honduras - Teguciagalpa, Zamorano Escuela Agricola Panamericana, planting of 700 ha of native species and improved protection and management of a further 8000 ha.
- Mexico (Proaft & Veracrus) - Tropical Forest Action Program, modest proposal seeking only £ 128000 funds for a 20 ha plantation.
- Uganda (Busoga forestry), new company with plans to plant up to 40000 ha in Uganda.
- Mexico (Chiapas) - University of Edinburgh in association with Union de Credito (farmers association), Ecosur (Federal Research Centre and Future Forests UK), management of 2000 ha and farm forestry on 180 ha.
- Bananal Island (Brazil) – 30 year forestation and management project over an area of rainforest occupying approximately 2.1 million ha and aimed at the sequestration of 65 million tonnes of carbon over the lifetime of the project.

A total of seven projects were evaluated and the Bananal Island afforestation project was chosen as the successful project to be sponsored. The close relationship of the project to the control of CO_2 within the atmosphere and its multifaceted approach to the subject matter, which included considerable local investment, gave it distinct advantages during the evaluation. The project not only encompassed reforestation but included:-

- Educational programs within local schools and communities.
- Facilities for monitoring and policing deforestation activities and these would be non-confrontational and non-aggressive methods.
- Nursery facilities for replantation activities.
- Research facilities for scientific evaluation of carbon sequestration together with development of various agroforestry ecology systems.

1.4 Modification Details

As mentioned previously no modifications are proposed to the power plant and all environmental benefits are associated directly with the afforestation project described in these sections of the report.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is directly associated with the reduction in rates of deforestation together with levels of activities of reforestation. Project reports provided have suggested the following sequestration data be used:-

(i) 280 te C per hectare over 30 years for virgin/preserved forest
(ii) 260 te C per hectare over 30 years for ecotourist forest
(iii) 180 te C per hectare over 30 years for regenerated forest
(iv) 120 te C per hectare over 30 years for agroforestry

1.6 Determination of capital costs

The project costs have been based upon budget quotations received from AES regarding the Bananal Island project.

Since the project is a non profit making scheme AES have established a charity fund which will be utilised to finance their contributions/payments to the project through its 25 year life. The fund is to be established by six biannual £100,000 donations from AES over the first 3 years of the project. The total cost of the 25 year project has been estimated at 13M $ (£8M) of which AES donations will represent 7.5% of this total. The remainder is provided by the Brazilian agencies of IBAMA and Naturatins and other independent financiers. IBAMA and Naturatins contributions to the total project are estimated at 8.65M $ (£5.25M) which is equivalent to 65% of the total cost.

Expenses incurred from on the ground activities in Brazil are to be paid from the AES fund on a biannual basis against detailed invoices identifying individual activities. Actual invoices and payments can then be monitored in accordance with original project budget forecasts and adjustments made for any annual over or under expenditure.

1.7 Determination of Fuel, Operating and Maintenance Costs

Since the power plant operations are unaffected by the afforestation project then two entities can be handled completely independently i.e. fuel, operation and maintenance costs for the power plant remain constant irrespective of events during afforestation.

The capital costs and operating costs associated with planting, policing and other O & M costs are assumed to be inclusive of the capital expenditure in the first 3 year life of the project during which the environment fund is established. The operating and maintenance costs associated with the afforestation project are all included with the figures shown in Section 1.6.

1.8 Changes to Non-Greenhouse Gas Emissions

The forestation project is primarily associated with the reduction of CO_2 from the atmosphere by sequestration of carbon. Other non greenhouse such as SO_x, NO_x and CO are assumed to be unaffected.

1.9 Site Fuel data

1.9.1 Natural Gas

The specification for natural gas supplied to AES Barry site is in accordance with the typical UK supply range data provided by Transco.

Therefore no correction is proposed from the datum UK natural gas having a GCV of 51.3 MJ/kg (39.5 MJ/Nm^3), NCV of 46.3 MJ/kg and containing 73% carbon by weight.

1.10 Combustion Gases

The NG fuels given previously in 1.9 agree closely with 'normalised/paradigm' data and so no changes are proposed to CO_2 combustion figures under normal conditions to give 2.68 kg of CO_2 respectively per kg of fuel.

1.11 Net Plant Efficiency and output information

Indication of the efficiency of plant at AES Barry is obtained from heat balance data where the guaranteed cycle efficiency of the power station is given as 49.25% and this has recently been verified by performance test.

Actual operating efficiencies at the present should be between 47.5 and 48% based on net output and net calorific value. No additional account is taken of degradation effects within the calculations since the operating efficiency used contains a margin of 1.25%

from guarantee values and output changes balance each other with regard to CCGT through life emissions.

The AES Barry plant has been designed on a 25 year lifetime incorporating mixed operating regimes of base loading, weekly cycling and 2 shifting.

It can be assumed that through the 25 year design life of the plant, its load factor is going to be approximately 0.85.

The guaranteed net output of the plant is 229.6 MWe given in Section 1.2

Based upon the above load factor and net plant output, the average annual power output of the plant is estimated at 1713 GWh$_{so}$.

2. RESULTS

2.1 Reference Plant Calculations

Based upon the information available in Section 1, the annual and lifetime fuel and emissions data can be estimated in accordance with the table below:-

		Annual	25 year life
Plant efficiency on NCV	%	48.0	48.0
Power export to grid	GWh_{so}	1713	42,825
Net heat input requirement	GWh	3570	89,250
Fuel consumption	kte	277	6,925
CO_2 generation	kte	748	18,700

Data similar to the above was the basis for the selection of the forestation project. According to forestation project publications the overall project is estimated to give a total carbon sequestration of 64.97 M te over 30 years.

Based upon the proportional 'buy in' to the project representative of AES contributions (7.5%, see section 1.6) this gives them an allocated 4.87 M te carbon sequestration against the AES Barry plant. This can be converted to be equivalent to 17.86 M te of CO_2 emissions using a 44/12 mass correction.

This figure agrees within a 5% accuracy of that estimated from the power plant which is satisfactory for case study evaluations. However, it may be prudent to utilise a median figure of 18.25 Mte CO_2 for the overall case study life time sequestration.

The estimated cost of Bananal Island project to AES is 0.975 M$

2.1.1 Estimated Benefits of Forestation Project on Loan Basis

Since the project fund for AES contributions is raised over the first 3 years of the sequestration project, this and the 25 year plant life period are considered as the possible loan periods for similar projects and so the "figures of merit" for each are evaluated and presented below:-

Merit Fig.	Title	3 years		25 years		Period
		5%	10%	5%	10%	IR

(i)	Levelised saving on power	-209.0	-228.9	-40.4	-62.8	$/GWh$_{so}$
(ii)	CO_2 reduction on power	436.4	436.4	436.4	436.4	teCO_2/GWh$_{so}$
(iii)	CO_2 prevention saving	-0.48	-0.52	-0.09	-0.14	$/te$CO_2$
(iv)	Levelised saving on steam	-193.7	-212.1	-37.4	-58.1	$/GWh
(v)	CO_2 reduction on steam	404.4	404.4	404.4	404.4	teCO_2/GWh

2.1.2 Estimated Benefits of Forestation Project Using Capital From Equity and NPV Basis

This has been evaluated on two life time bases relating to the 3 years of contributions by AES to establish a charity fund or alternatively over the 25 year remnant life of the plant which represents an annual payment of the operator to cover sequestration of his annual emissions of CO_2.

Manipulation of input data to the spreadsheet program being used for evaluations enabled the following results to be obtained:-

Merit Fig.	Title	3 years		25 years		Period
		5%	10%	5%	10%	IR
(i)	Levelised saving on power	-190.3	-190.0	-22.8	-22.8	$/GWh$_{so}$
(ii)	CO_2 reduction on power	436.4	436.4	436.4	436.4	teCO_2/GWh$_{so}$
(iii)	CO_2 prevention saving	-0.44	-0.44	-0.05	-0.05	$/te$CO_2$
(iv)	Levelised saving on steam	-176.3	-176.1	-21.1	-21.2	$/GWh
(v)	CO_2 reduction on steam	404.4	404.4	404.4	404.4	teCO_2/GWh

3. DISCUSSIONS AND CONCLUSIONS

The magnitude of the "merit figures" obtained for this study is significantly different to those obtained for the other case study results. The levelised saving (fig (i)) and the CO_2 reduction per GWh_{so} (fig (ii)) appear reversed compared to other studies and the levelised saving is negative i.e. a cost. Therefore the CO_2 prevention saving not only becomes a negative i.e. cost but is significantly smaller in magnitude.

There are two factors which can be attributed as causing these results:

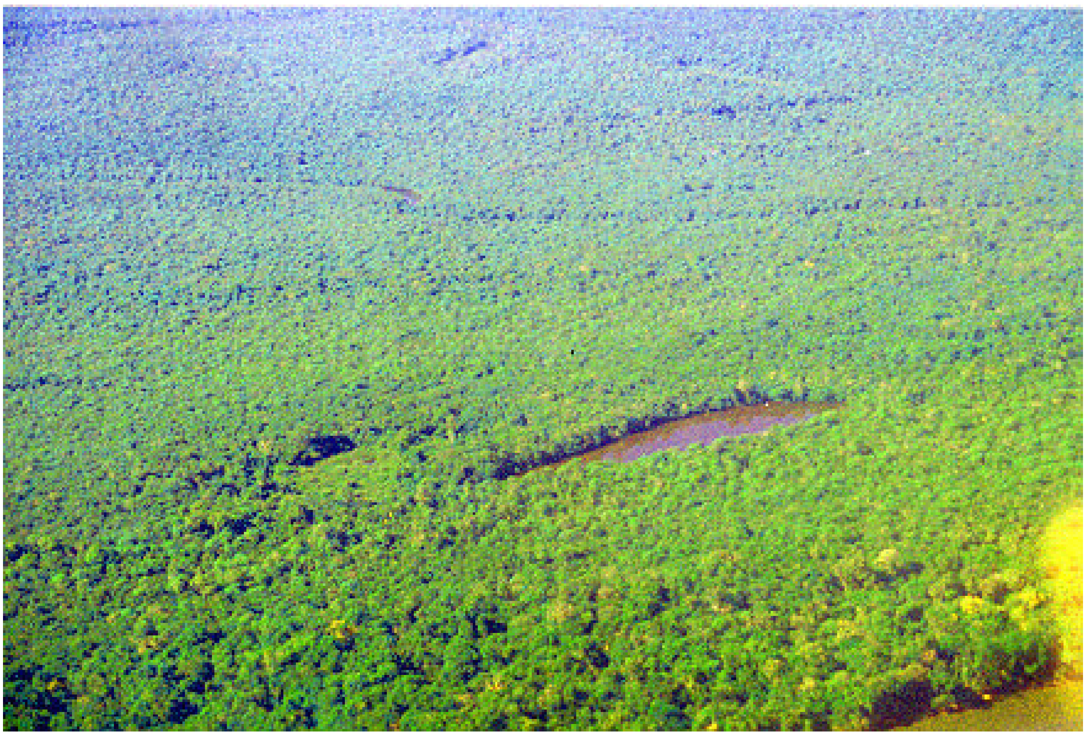
- This study is the only case study to effectively evaluate the complete (100%) reduction of CO_2.
- It is the only case study not driven by financial benefits associated with fuel cost benefits.

These aspects will need to be evaluated further when it comes to comparing this study against others in the overall report.

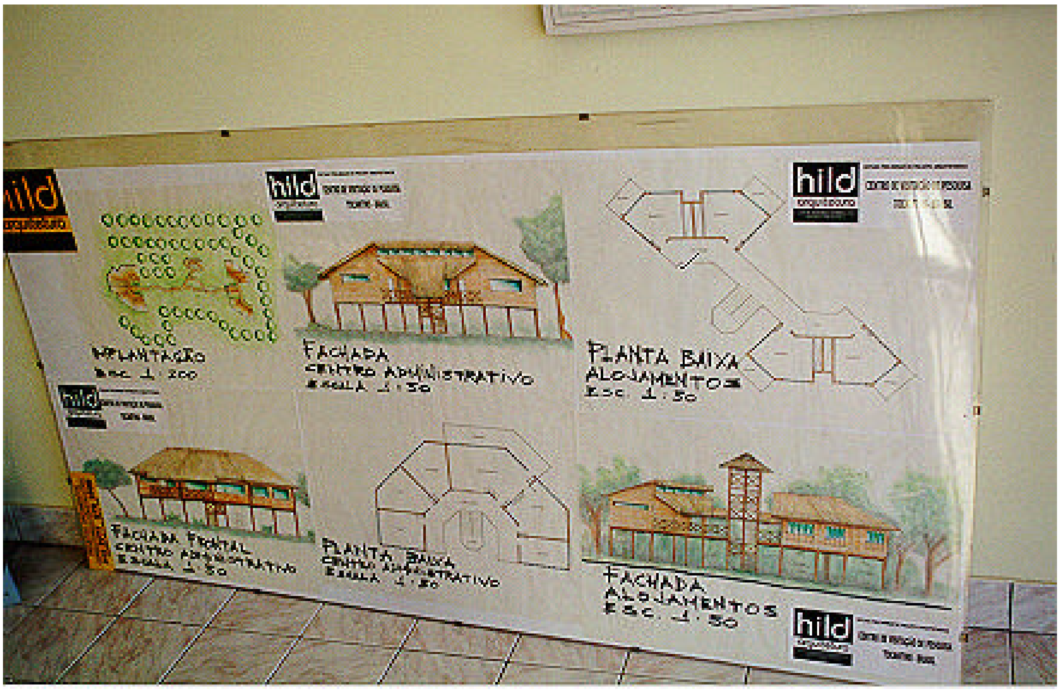
The last merit figure (iii) becomes equivalent to approximately 0.19 $/te C sequestered which is similar to the 0.05 to 0.20 $/te C being advised by various published papers and is in close agreement with operators calculations.

BANANAL ISLAND AND AES BARRY
PHOTOGRAPHS AND CYCLE DIAGRAMS

An example of Bananal Island deforested areas.



An example of Bananal Island untouched forestry areas

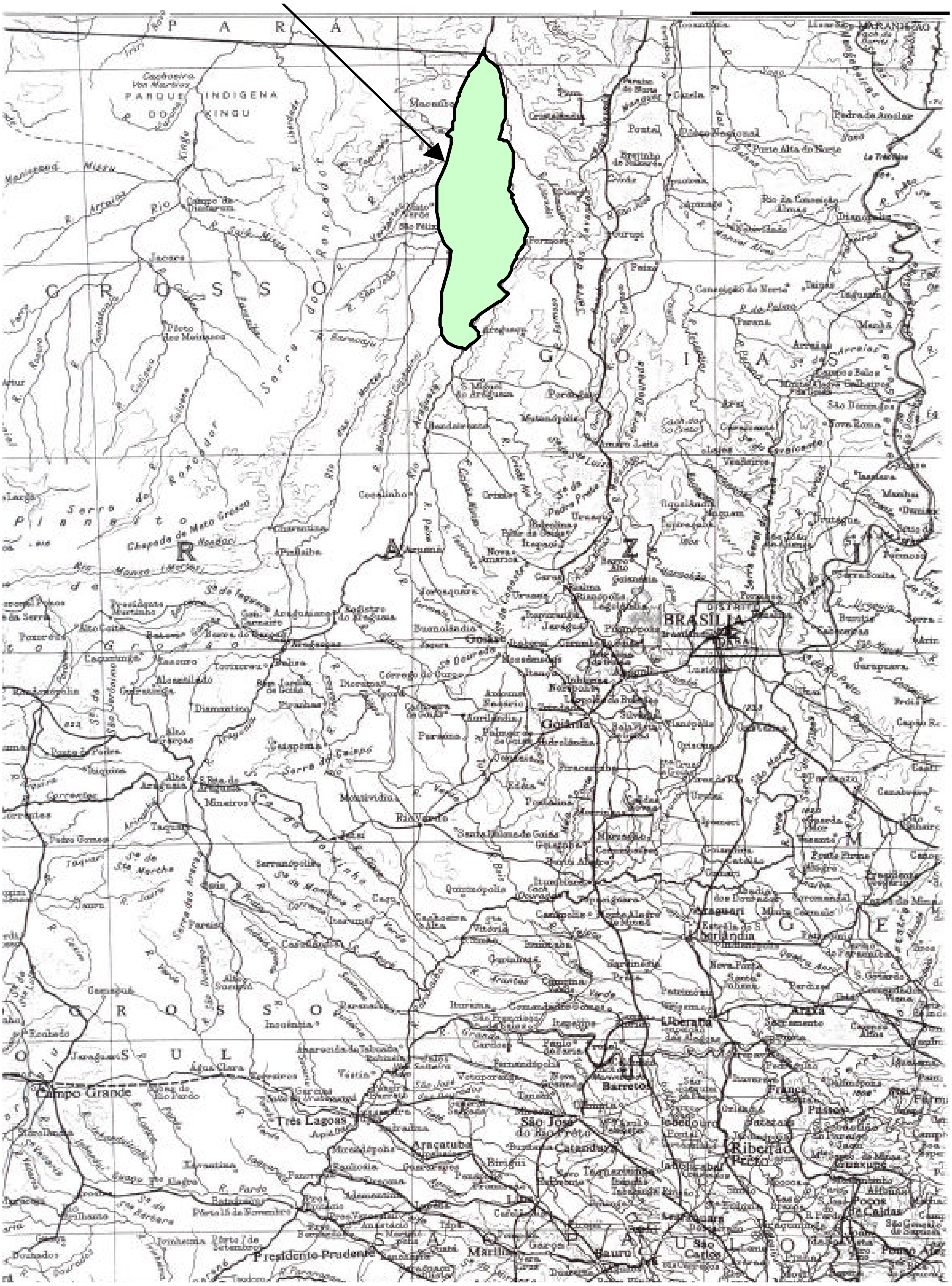


Plans for the new research and education centre

The Agroforestry Nurseries

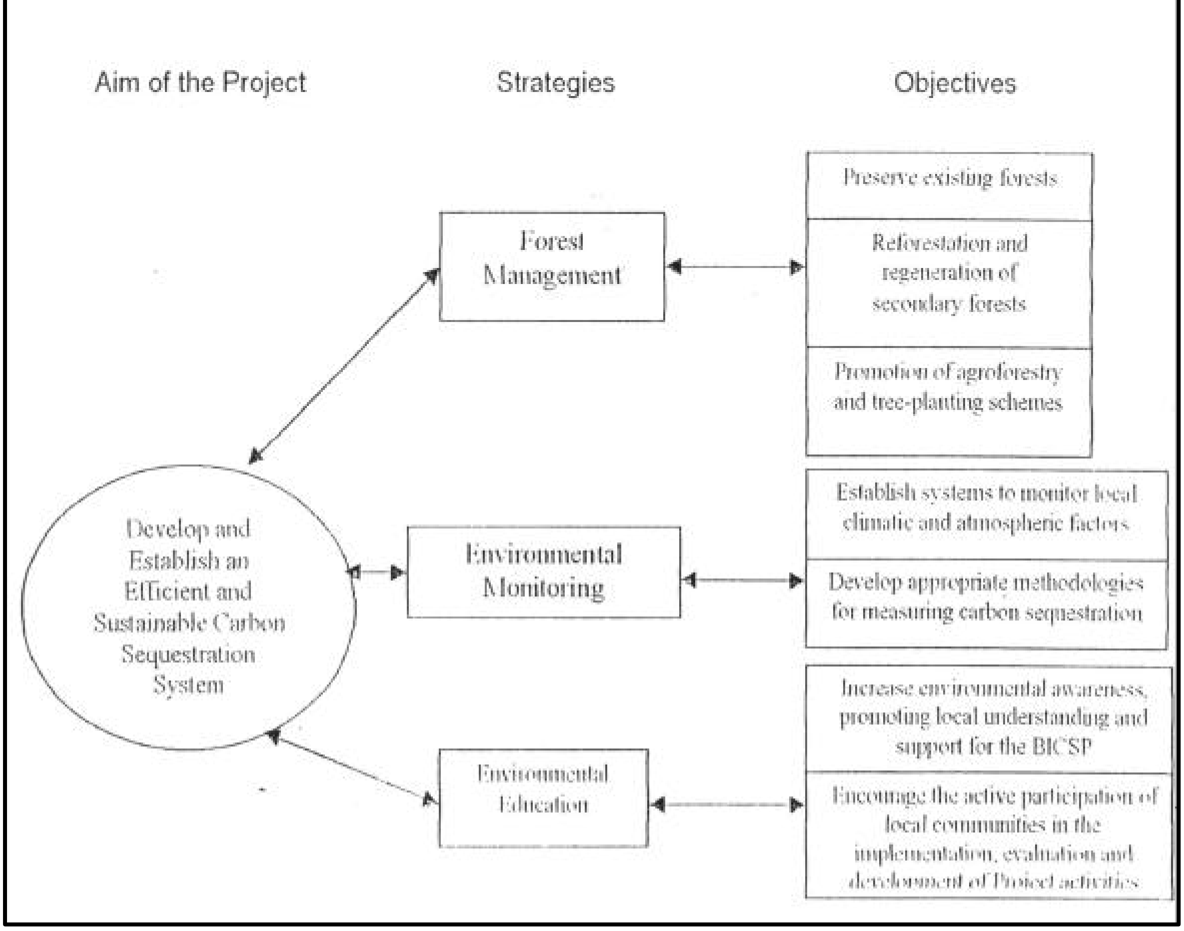
BANANAL ISLAND AND AES BARRY
PHOTOGRAPHS AND CYCLE DIAGRAMS

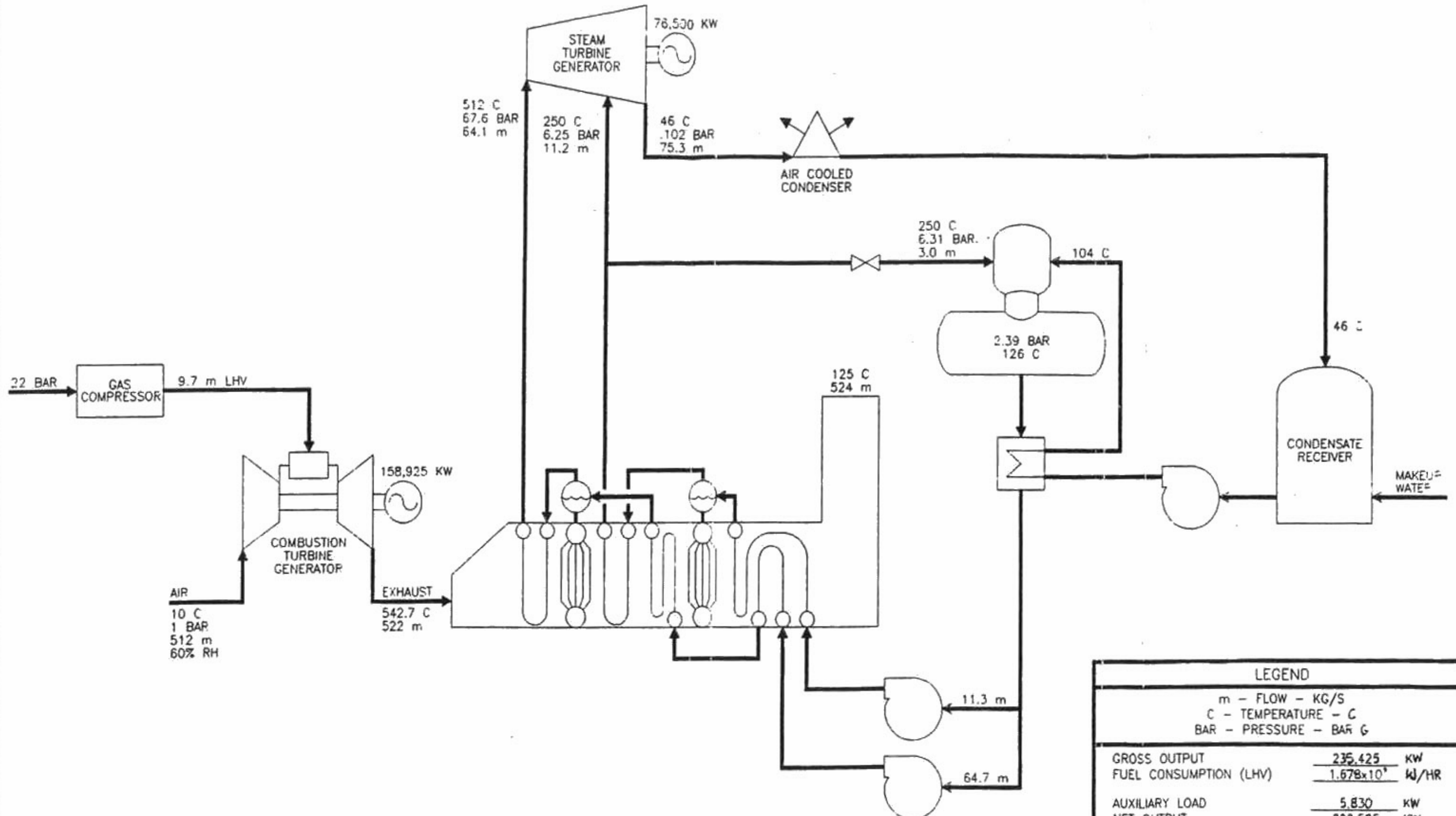
Brazilian location map for Bananal Island forestation project.



Diagrammatic overview of the Bananal Island Sequestration project

Figure 1: Overview of the Bananal Island Carbon Sequestration Project





LEGEND

m – FLOW – KG/S
C – TEMPERATURE – C
BAR – PRESSURE – BAR G

GROSS OUTPUT	235,425	KW
FUEL CONSUMPTION (LHV)	1.678×10^{9}	KJ/HR
AUXILIARY LOAD	5,830	KW
NET OUTPUT	229,595	KW
NET HEAT RATE	7,308	KJ/KWHR

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
D	07-15-96	REVISED	MWJ			
C	04-10-96	REVISED	CCP			
B	04-03-96	REVISED	CCP			
A	03-27-96	PROPOSAL ISSUE	CCP			

TBV POWER

ENGINEER CCP DRAWN SG
CHECKED DATE

AES ELECTRIC LTD.
BARRY CHP PROJECT

HEAT BALANCE – 10 C
GUARANTEE CONDITIONS

PROJECT DRAWING NUMBER
28719-DM-0002
REV D

CODE
AREA

APPENDIX 5

CASE 3

POWER STATION PARTIAL FUEL SUBSTITUTION FROM BLACK COAL TO A COAL AND BIOMASS MIXTURE

SECTION 1
PLANT DESCRIPTION

1. PLANT DESCRIPTION

1.1 General

The Grenaa fuel substitution project on Jutland involves the use of biomass fuel in the form of straw instead of bituminous black coal on a 78MW circulating fluidised bed boiler which provides steam for power generation, district heating and process purposes. The facility is essentially a combined heat and power plant of advanced design and the substitution of the primary fossil fuel by the renewable fuel has steadily increased from 24% energy in 1992 to 52% in 1997 and corresponded to 61250 tonnes.

The approximate electrical output was 20% of the energy exported, the district heating a similar amount and the heat to industrial process 60%.

1.2 Plant Prior to Modification

Prior to the development of the Grenaa co-generation facility the electricity, district heating and local industrial plant steam requirements of the area were essentially provided by the electrical grid network, a well development district heating system and the use of stand alone boilers by the local industrial concerns as a means of providing their own individual steam requirements.

The district heating facilities would require extensive enhancement during the 1990's, and the local energy intensive industries were planning a major expansion. These factors together with institutional and environmental factors provided the necessary impetus for the establishment of the combined heat and power plant at Grenaa.

The alternative option would have been:

- to continue to provide electricity from the grid network, basically generated from central coal fired power stations.
- to extend the supply and distribution network of the district heating system by providing oil fired boilers to supplement an existing straw fired boiler of relatively small capacity, with the industrial consumers continuing to provide their own stand alone boilers.

This alternative would require a major investment in new coal fired plant.

CHP Plant Description:

The coal and biomass fired CHP Grenaa plant is a co-generation facility owned and operated by the Midtkraft Energy Company, who also built the plant, with commercial operation commencing in January 1992.

In essence the plant includes the following main systems:

- a CFB-type boiler plant for mixed-fuel firing. The boiler is equipped with internal desulphurization (limestone injection) and an electrostatic precipitator.
- a conventional back-pressure steam turbine with process steam extraction.
- a hot water storage vessel balancing the process steam and district heat demands.
- storage and pre-processing facilities for biomass and coal.
- An oil-fired stand-by boiler.
- A central plant control system and the necessary service and auxiliary systems.

The main plant parameters are given in the following table:

Boiler capacity	MW_{th}	78
Live steam, SH exist	kg/s	29
	bar	92
	^oC	505
Feedwater temperature	^oC	170
Flue gas stack temperature	^oC	120
Energy input	%	
: coal		40-100
:straw		0-60
:normal mix		50:50
Emissions		
:SO_2	mg/MJ	100
:NO_x	mg/MJ	150
:CO	mg/MJ	200
:Particles	mg/Nm^3	50
Net electric capacity	MW_e	17.8
Process steam	Bar	8.3
	^oC	210
District heat	^oC	85 to 50

The circulating fluidised bed boiler is of Ahlström Pyropower (now Foster Wheeler Energia) design and this concept was adopted due to its capability to accommodate a multi-fuel mix and its favourable combustion and environmental chraracteristics. The boiler is designed for straw and coal ranges up to 60% and 100% respectively.

The controlled extraction back pressure steam turbine and the central plant control systems are of ABB (Asia Brown Boveri) design and manufacture.

The controlled passout provides the process steam and the low pressure steam from the turbine L.P cylinder essentially serves the district heating and plant requirements.

An industrialized straw supply scheme will ensure proper fuel quality and cost effectiveness. Straw is delivered on trucks carrying 24 Hesston-type bales, each of 450kg. The batch is unloaded by automatic cranes, handling 12 bales in one lift. Batch weight and quality (moisture content) are monitored simultaneously during unloading, and the batch is landed either at a storage position or at the fuel feed line to the boiler.

The bale weight and moisture content are prime quality parameters, which relate to processability as well as energy content and consequently to delivery price. Both parameters are dependent upon weather conditions during harvest, bale pressing and interim storage. Quality control is fully computerized. The bales are processed in low energy-consuming shredders and fed pneumatically into the boiler together with coal.

The fuel storage on site has sufficient capacity for 3 days' continuous operation.

A wide range of imported steam coal is provided for the plant. Coal arrives on trucks from the Arhus Coal Terminal, 60km away. Coal is crushed to minus 10mm and fed to the boiler by conventional equipment.

A steam system diagram, photograph and plant layout drawing are given to illustrate the visual impact of the plant and its steam systems.

1.3 Brief History and Decision Process

Initial Considerations

Considerations started in response to a national energy policy initiative in 1986, which committed the Danish power companies to deploy part of their future power capacity extension in the form of local CHP plants for combined district heat and power generation. These plants, which might replace existing heat boilers, should be fired by domestic fuel (biomass, waste or natural gas).

The city of Grenaa had a well-developed district heating system and forecast an increased heat demand of 370 TJ/a by 1995. This increased demand associated with an existing distric heating system encouraged Midtkraft to conduct studies in to identifying Grenaa as a potential site for installation of new CHP capacity in accordance with the above 1986 initiative.

The studies identified an additional market for process steam supply without regulatory restraints on fuel choice. Danisco Paper, one of the larger consumers, was considering plans for a new coal-fired process steam boiler plant (approximately 950 TJ/a) in conjunction with a major extension of their production capacity for waste paper recycling.

These preconditions, together with easy access to large quantities of surplus straw from the nearby agricultural region, led to the adoption of the Grenaa CHP concept. The combined generation of electricity, district heat, and process steam from a single coal and straw-fired plant offered advantages regarding efficiency, economy and environmental impact as compared to separate generation.

Having completed feasibility studies, pilot testing, and contract negotiations on straw supply and thermal energy sales, Midtkraft decided to launch the CHP Grenaa project in November 1989.

It should be added that the contract with Danisco Paper includes the total process steam supply for the company. Previous boilers at the company's premises have been taken over as stand-by capacity. Furthermore, Midtkraft has pursued the business policy of offering process steam supply on similar conditions to other local industries, and also aimed towards a wider range of biomass utilization in the CHP plant by including industrial residues on a commercial basis.

Construction and Operating History

Construction of the CHP Grenaa plant and the associated transmission lines for heat and process steam was executed during November 1989 till end December 1991. Commercial operation started 2 January 1992, and has continued apart from annual maintenance periods of 2-3 weeks duration and unscheduled outages.

Scope of Work

The original CHP Grenaa project included engineering, and commissioning of the complete cogeneration plant at a virgin site in the Grenaa industrial area – and of the associated transmission lines to Danisco Paper and the existing district heat system.

Later tasks included boiler modifications to cope with the problems caused by straw firing, the addition of a fuel facility for other biomass in pulverized form, and the extension of the process steam supply for two new customers.

Work Programme

Major milestones in plant construction and subsequent activities are as follows:

• CHP Grenaa project decision	November 1989
• Start of site preparation	April 1990
• Start construction	May 1990

• Start commissioning	November 1991
• Plant operational, supply of process steam to Danisco Paper and district heat	January 1992
• Major boiler modification (evaporator wing walls)	August 1993
• Boiler loop seals replaced	August 1996
• Process steam supply for Danisco Distillers	June 1997
• Facility added for pulverized biomass	January 1998
• Process steam supply for Grenaa Dampvæveri (textile manufacturer)	July 1998

1.4 Modification Details

The original Ahlström CFB boiler configuration is shown schematically in the diagram at the end of this report. Air preheater and economizer are located in the vertical convective boiler pass. Combustor water walls serve as evaporator. Steam superheating to 505°C is provided in 3 stages. The superheaters, SH1 and 3, are located in the overhead convective pass, whereas the second stage, SH2, is mounted as panels penetrating the combustor freeboard. The particle recirculation loop includes two parallel, hot cyclones and loop-seals.

Operational problems caused by the high chlorine and alkaline content of the fired straw have necessitated some boiler modifications over the years as described below. Evaporator wing walls have been added to the combustor, and the loop-seals have been replaced by fluid-bed heat exchangers of CHEX-type for final superheating. An up-to-date boiler section is shown at the end of this Appendix.

As seen from data provided in Section 1, plant capacity utilization has been relatively low during the first years of operation, which is due to a slower build-up of district heat and process steam demand than predicted. The biomass share has grown steadily, except in 1994, when a straw supply shortage occurred during Spring. Overall plant energy efficiency has increased from 73% (1992) to 88% (1997).

Operational problems have mainly been associated with the boiler plant and caused by the high chlorine and alkaline content of the fired straw. During the early years unsatisfactory process temperature control and subsequent build-up of fouling deposits and superheater corrosion resulted in several tube failures and unscheduled stops for boiler cleaning and repair.

The conditions were improved by a major heat surface modification during August 93. Evaporator wings were added to the combustor rear-wall, and the final superheater and part of SH1 were replaced.

A second major modification was made during the 1996 revision. The loop-seals were replaced by external fluid-bed heat exchangers with CHEX to account for final superheating from 475 to 505°C. By this precaution deposits formation has been stabilized at a low level, enabling full live steam temperature to be maintained.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is determined by the changes in fuel and associated with the coal substitution by biomass. Although the projected heat content of the coal and biomass are similar, the principal benefit with regard to greenhouse gas reduction is the classification of the straw as biofuel and hence zero CO_2 emission fuel. The results in Section 2 are calculated for the whole station burning 100% coal and a representative conversion fuel mixture. The amounts of CO_2 generated by the combustion of all 'normalised paradigm' study fuels are addressed in Appendix 1.

Sections 1.9.1 to 1.9.4 address the discrepancies between the 'normalised' and site fuels in detail.

The NO_x reduction achieved as a result of installing the circulating fluidised bed boiler is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Experiments to measure N_2O concentrations in flue gases on other plant have proved unsuccessful and hence any change in the greenhouse gas N_2O is not considered in this case. Difficult to evaluate is the CH_4 emissions that would have resulted from continued storage and decomposition of the waste straw.

1.6 Determination of Capital Costs

Investment costs in the CHP Grenaa project during 1989-1992 amounted to 390 M Dk plus interest during construction 25 M Dk (current prices). Furthermore, Midtkraft has invested approximately 15 M Dk in subsequent plant modifications.

However, in view of the fact that the case study is being assessed from the coal by biomass substitution aspects, of particular significance is the capital cost of the straw unloading, storage and delivery systems to the CFB boiler. These costs have been assessed to be 66.2 M Dk approximately 10.52 M $.

1.7 Determination of Operating and Maintenance Costs

According to the 1997 account the plant operating and maintenance costs amounted to 22.5 M Dk approximately 3.58 M $.

The additional operating and maintenance costs attributable to the utilisation of straw as a partial fuel substitute of coal was estimated using cost data from years 1995 to 1997. These were analysed and on average found to be 5 M Dk, equivalent to 0.805 M $ per annum. This figure includes all maintenance, consumables and staff costs. The actual final costs are discussed in Section 1.9.

1.8 Changes to Non-Greenhouse Gas Emissions

The utilisation of the circulating fluidised bed boiler enables emission control to be exercised by the inherently low combustion temperature (850°C) and in-bed desulphurisation by limestone injection.

Emission levels at design maximum full load and energy input ratios of 50:50 coal/straw are 100 mg/MJ SO_2, 150 mg/MJ NO_x and 50 mg/Nm^3 particulates. The substitution of straw instead of coal enables the sulphur content of the fuel input to be reduced, the sulphur content of the coal being approximately 0.9% by weight and the straw 0.1%. Hence the required quantity of limestone injected for the SO_x reduction is also reduced.

The plant adequately meets the EEC standards.

1.9 Site Fuel Data

Typical fuel data for the CHP Grenaa plant are summarised in the tables in Sections 1.9.1 and 1.9.2.

Straw properties show large variations from year to year caused by the climatic conditions during growth and the harvest season. The analysis provided in 1.9.2 is given as a typical example for comparison with normalised fuels contained in Appendix 1.

Black coal is purchased by Midtkraft from the international spot market. The analysis given below is presented as typical for supplies which may actually originate from Poland, Chile or South Africa.

The following analysis data was provided by the plant owner Midtkraft and Kennedy and Donkin extrapolated this on an empirical and theoretical basis to enable combustion calculations to be conducted. The results of the fuel investigation were discussed and agreed with the plant operators and are summarised in 1.9.1 and 1.9.2 below and were used in the “actual” case assessment.

1.9.1 Black Coal

As mentioned above the following table gives typical site data for black coal associated with Grenaa actual plant calculations.

Carbon	% by weight	59
Hydrogen	% by weight	4.5
Oxygen	% by weight	9.98
Nitrogen	% by weight	1.0
Sulphur	% by weight	0.9
Ash	% by weight	13.8
Water	% by weight	10.8
Chlorine	% by weight	0.02
Net Calorific Value	MJ/kg	23.60

Actual fuel prices for black coal provided by Midtkraft suggest an average purchase price of 2.3 $/GJ. Whilst the analysis data concurs with range data given within Appendix 1, the cost is significantly greater than the 2.0 $G/J assumed for 'normalised' calculations.

1.9.2 Straw

The following table gives a typical analysis for Danish straw which conforms to the range data given by Appendix 1 except for the oxygen content. This minor difference is considered to be insignificant.

Carbon	% by weight	38.11
Hydrogen	% by weight	5.22
Oxygen	% by weight	37.115
Nitrogen	% by weight	0.605
Sulphur	% by weight	0.10
Ash	% by weight	4.50
Potassium	% by weight	0.90
Chlorine	% by weight	0.45
Water	% by weight	13.0
Net Calorific Value	MJ/kg	14.8

According to the 1997 accounts the total fuel costs for the plant amounted to 50.7 M Dk, approximately 8.06 M $. The coal price is essentially determined by spot market prices and it was found that during 1997 the costs experienced at the plant were such that the cost per energy unit of baled straw was 3 times that of imported coal.

An analysis of the 1997 energy input data, see Section 1.11, and assuming that the calorific value and cost of the other biomass could be considered as straw (8% of the total biomass input) for the purposes of calculation was 6.9 $/GJ for straw. This equated to approximately £60 per tonne for the straw.

The "normalised" case has been based on around a 2.03 $/GJ for straw as a typical UK value, with the respective calorific value of 14.0 MJ/kg and carbon content of 43.8%.

The high cost associated with Danish straw has a substantial influence regarding the financial evaluation of this case study in Section 2.

1.10 Combustion Gases

The analyses and details of the site fuels given previously in Section 1.9 agree closely with the normalised data in Appendix 1 which forms the basis of the normalised/paradigm calculations.

The change in CO_2 emissions simply reflects the CO_2 reduction by substituting about 50% of the coal energy input with biomass.

1.11 Net Plant Efficiency and Output Information

The data regarding the CHP plant energy generation and fuel consumption is provided in the following table, this data being provided by the plant owner.

Year		**1992**	**1993**	**1994**	**1995**	**1996**	**1997**
Process steam	TJ	607	776	988	882	848	1005
District heat	TJ	247	261	272	286	287	260
Net electricity	GWh	50	50	75	69	67	72
Coal	1000 tonnes	38	38	60	43	40	35
	TJ	1083	952	1502	1047	938	825
Straw	1000 tonnes	24	34	25	43	49	56
	TJ	340	475	346	605	701	832
Other biomass	1000 tonnes						5
	TJ						72
Biomass ratio	% energy	24	33	19	37	43	52

The above table illustrates the steady increase of the biomass contribution to the energy input apart from 1994 when a shortage of straw was experienced.

The CHP plant operational record is summarised in the following table, this plant utilisation data being furnished by the owner.

Year		**1992**	**1993**	**1994**	**1995**	**1996**	**1997**

Operation	Hours	7282	7212	8242	7919	7082	7310
Start/stop	Number	31	32	14	16	23	24
Availability	%	83	82	94	90	81	83

Boiler modifications were carried out during 1993 and 1996 and slightly lower operating hours were observed during those years.

An analysis of the energy generated and load demands indicates that the maximum output was achieved during 1997 and in view of the fact that the process steam demand is expected to increase further it has appeared relevant to adopt the 1997 data as the basis for the comparison. Also the biomass ratio is approaching its considered optimum. The following table summarises the reference operating data provided by Midtkraft for 1997.

1997 Operational Data on Annual and Average Load Basis

Operating Hours	7310	
Availability on Annual Hours	83%	
Process Steam	1005 TJ	38.2 MWth
District Heat	260 TJ	9.8 MWth
Heat Load	1265 TJ	48.0 MWth
Heat Export Capability	1580 TJ	60 MWth
Net Electricity	72 GWh	9.85 MW
Electrical Capacity		17.8 MW
Net Total Load		57.8 MW
Average Operating Load		$\frac{57.85}{77.80} = 74.4\%$
Fuel Input Coal Straw Other Biomass	825 TJ 832 TJ 72 TJ	
Total Energy	1729 TJ	65.70 MWth
CHP Plant Efficiency on NCV	$\frac{57.85}{65.70} = 88.1\%$	
Overall Plant Load Factor On Maximum Capacity	= 0.744 x 0.83 = 61.8%	

This information identifies that the reference plant conditions (0.618 load factor) are exceedingly close to normalised conditions (0.65 load factor).

Assuming that the proportions of Power, process steam and district heating, as well as plant efficiency, are the same at 0.65 load factor as at 0.618 load factor gives the following base data for normalised calculations in section 2.2:

Annual process steam production	293.66 GWh
Annual district heat production	75.94 GWh
Annual net power export	75.73 GWh$_{so}$

2. RESULTS

2.1 Reference Plant Calculations

Based upon the information provided and discussed in Section 1, calculations can be made to determine the figures of merit. The data and results for the actual plant operating conditions are itemised below with the comparison evaluated between coal alone and mixed fuel operation.

Fuel		Coal	Coal + Biomass
Annual electricity generation	(GWh_{so})	72	72
Efficiency of plant on NCV	(%)	88	88
Annual process steam production	(GWh)	279.2	279.2
Annual district heat production	(GWh)	72.2	72.2
Total annual energy output	(GWh)	423.4	423.4
Total annual heat input requirement	(TJ)	1732	1732
Coal used as % heat input		100	47.7
Annual coal consumption	(Kte)	73.39	35.01
Biomass used as % heat input		0	52.3
Annual biomass consumption	(Kte)	0	61.21
Annual fuel cost	(M$)	3.95	8.08
Annual fuel saving	(M$)		-4.13
Annual generation CO_2	(Kte)	0	75.74
Annual reduction in CO_2	(Kte)	158.78	83.04
		0	

The above analysis indicates approximately 50% reduction in CO_2 which is consistent with the 50% substitution of the coal by biomass. There has been an increase in the fuel cost in excess of 4 M $ due to the fact that the straw is three times the coal cost per unit of energy input.

The capital costs associated with the straw facilities and equipment together with the increased operating and maintenance costs have been itemised in sections 1.6 and 1.7 and amount to 10.52 M $ and 0.805 M $ p.a. respectively.

2.1.1 Estimated Benefits of Fuel Substitution on Loan Basis

The following financial evaluation of the effects of the fuel substitution for the actual reference plant conditions using capital based on a mortgage type loan basis at 5% and 10% annual interest rates and over a 25 year remnant plant life is detailed below.

Cost of associated straw plant		10.52	M$
Number of years plant life (n)		25	
Loan annual interest rate (i)	5	10	%
Loan factor [I^n x (I-1)/(I^n –1)]	0.0710	0.1102	
Annual loan repayment	0.7464	1.1590	M$
Annual fuel saving	- 4.1308	- 4.1308	M$
Annual O&M saving	- 0.8050	- 0.8050	M$
Total annual saving	- 4.9358	- 4.9358	M$
Net annual saving (incl. loan)	- 5.6822	- 6.0948	M$
CO_2 reduction per annum		83.04	Kte
GWh_{so} per annum (electricity)		72	GWh_{so}
GWh total energy output p.a.		423.4	GWh
(i) Levelised saving per unit power	-78920	-84650	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	1153.3	1153.3	te/GWh_{so}
(iii) Saving per tonne CO_2	- 68.43	- 73.40	$/te CO_2
(iv) Levelised saving unit energy output	-13420.5	14394.9	$/te CO_2
(v) CO_2 reduction per GWh	196.13	196.13	te/GWh

2.1.2 Estimated Benefits of Fuel Substitution on NPV Basis

The following financial evaluation for the case of the fuel substitution on the basis of capital equity and discounting of the annual savings/costs at rates of 5% and 10% over the remnant life of 25 years to express the results on a net present value basis.

Cost of associated straw plant		10.52	M$
Plant life years (n)		25	
CO_2 reduction per annum		83.04	Kte
Total energy output p.a.		423.4	Gwh
Through life energy output		10585	Gwh
Annual fuel saving	- 4.1308	- 4.1308	M$
Annual O&M saving	- 0.805	- 0.805	M$
Total annual saving	- 4.9358	- 4.9358	M$
Annual discount rate (r)	5	10	%
Discount factor [(1-R^n)/)1-R)]	14.7986	9.9847	
Discounted through life savings DS	- 73.0436	- 49.2830	M$
NPV savings (DS – C_t)	- 83.5636	- 59.8030	M$
(i) Levelised saving per unit power	-46400	-33200	$/GWh$_{so}$
(ii) CO_2 reduction per GWh$_{so}$	1153.32	1153.32	te/GWh$_{so}$
(iii) Saving per tonne CO_2	-40.25	-28.81	$/te/$CO_2$
(iv) Levelised NPV saving/energy output	- 7895	- 5649.8	$/GWh
(v) CO_2 reduction per GWh	196.13	196.13	te/GWh
	-		

2.2 Normalised Plant Calculations

The current plant load factor during 1997 is 61.8% and data in the table below is based upon 1997 information prorated to the normalised conditions of 65% load factor. In determining the figures of merit the normalised fuel prices of 2 $/GJ for the coal and 2.03 $/GJ for the straw have been employed.

Fuel		Coal	Coal + Biomass
Annual electricity generation	(GWh)$_{so}$	75.73	75.73
Efficiency of plant on NCV	(%)	88	88
Annual process steam production	(GWh)	293.66	293.66
Annual district heat production	(GWh)	75.94	75.94
Total annual energy output	(GWh)	445.33	445.33
Total annual heat input requirement	(TJ)	1822	1822
Coal used as % heat input		100	47.7
Annual coal consumption	(Kte)	71.44	34.08
Biomass used as % heat input		0	52.3
Annual Biomass consumption	(Kte)	0	68.06
Annual fuel cost	(M$)	3.64	3.67
Annual fuel saving	(M$)	0	-0.03

Annual generation CO_2	(Kte)	178.1	84.97
Annual reduction in CO_2	(Kte)	0	93.16

Since the normalised and reference plant conditions are so close no adjustments are proposed to estimated annual O&M costs.

2.2.1 Estimated Benefits of Fuel Substitution on Loan Basis

The financial evaluation of the effects of the fuel substitution for the normalised fuels using capital based on a mortgage type loan basis at 5% and 10% annual interest rates over 25 year plant life is given below.

Cost of associated straw plant		10.52	M$
Number of years plant life (n)		25	
Loan annual interest rate (I)	5	10	%
Loan factor $[I^n x (I-1)/(I^n-1)]$	0.0710	0.1102	
Annual loan repayment	0.7464	1.1590	M$
Annual fuel saving	-0.02718	-0.02718	M$
Annual O&M saving	-0.805	-0.805	M$
Total annual saving	-0.834	-0.834	M$
Net annual saving (inc. loan)	-1.58	-1.99	M$
CO_2 reduction per annum		93.16	Kte
GWh_{so} per annum (electricity)		75.73	GWh_{so}
GWh total energy output p.a.		445.33	GWh
(i) Levelised saving unit energy output	-3728.4	-4702.8	$/GWh
(ii) CO_2 reduction per GWh	209.2	209.2	te/GWh
(iii) Saving per tonne CO_2	-17.82	-22.48	$/te$CO_2$

2.2.2 Estimated Benefits of Fuel Substitution on NPV Basis

The financial evaluation for the fuel substitution case on the basis of capital equity with discounting of the annual savings/costs at rates of 5% and 10% over the remnant life of 25 years in order to express the carbon dioxide prevention cost as a net present value are itemised below.

Cost of associated straw plant		10.52	M$
Plant life years (n)		25	
CO_2 reduction per annum		88.58	Kte
Total energy output p.a.		423.4	GWh
Through life energy output		10585	GWh
Annual fuel saving	-0.02718	-0.02718	M$
Annual O&M saving	-0.805	-0.805	M$
Total annual saving	-0.83218	-0.83218	M$
Annual discount rate (r)	5	10	%
Discount factor $[1-R^n)/(1-R)]$	14.7986	9.9847	
Discounted through life savings DS	-12.3151	-8.3091	M$
NPV savings (DS – C_t)	-22.8351	-18.8291	M$
(i) Levelised NPV saving/energy output	-2157	-1778.8	$/GWh
(ii) CO_2 reduction per GWh	209.2	209.2	te/GWh
(iii) Saving per tonne CO_2	-10.31	-8.50	$/teCO_2$

3. DISCUSSIONS AND CONCLUSIONS

The Midtkraft cogeneration plant at Grenaa is the first plant of this type in Denmark and is considered to be at the forefront of innovation and development. The design of the CFB boiler, particularly the present modified design entailing a partially water walled furnace and an external bed heat exchanger incorporating superheater elements are of particular interest.

The 1997 load schedule has been taken as the basis for conducting the assessment since it represents a years complete set of data following the boiler modifications coincident with the maximum efficiency and average output achieved by the plant to date, ie. 88% and 58MW respectively.

In meeting this load the plant operated at approximately 75% of rated capacity and the biomass throughput of 61250 tonnes was 55% of the energy input and close to the optimum for the installation.

An increase in plant load would be dependent upon an increase in heat export since the electrical output is also determined by the process steam and district heating loads, the steam system configuration incorporating an extraction – back pressure steam turbine generator. At the present time the thermal export represents about 80% of its design capacity and the average electrical load of 10MW is 55% of the generator rated capacity.

The utilisation of the CFB concept enables the use of limestone injection for controlling the SO_2 emissions and the substitution of straw for coal also promotes a reduction in the SO_2 emission.

The low furnace gas exit temperatures enable low levels of NOx to be achieved and the electrostatic precipitators ensure low particle emissions. The emission levels achieved are well within the EEC directives.

The modifications on the boiler have increased the projected life of the superheater elements from 18 months to 6 years and reduced the fouling taking place. Some trials have taken place to increase the energy input from straw above 60% and up to 70% or 80% but it was found that this led to unacceptable fouling and incomplete burn out.

The figures of merit are summarised in the following tables. It is to be noted that the capital costs of 10.52 M $ and the annual O&M costs of 0.805 M $ used in the assessment concentrate upon those items of plant which have been installed to enable the plant to operate upon a biomass/coal mixture compared to coal only. A plant life of 25 years has been taken since the plant is essentially a new installation. The plant operating hours of 7310 hours represented an availability of 83%.

SECTION 3
DISCUSSIONS AND CONCLUSIONS

Actual Plant Reference Condition. Denmark

Interest and Discount Rates		5%		10%	
Evaluation Basis		Loan	NPV	Loan	NPV
Merit Figure	Units				
(i) Levelised saving per unit power	$/GWh$_{so}$	-78920	-46400	-84650	-33200
(ii) CO_2 reduction per GWh$_{so}$	te/GWh$_{so}$	1153.32	1153.32	1153.32	1153.32
(iii) CO_2 prevention saving per tonne	$/te$CO_2$	-68.4	-40.3	-73.4	-28.8
(iv) Levelised or NPV saving/energy output	$/GWh	-13420.5	-7895	-14394.9	-5649.8
(v) CO_2 reduction/GWh	te/GWh	196.1	196.1	196.1	196.1

Normalised Conditions. UK Fuel Price Basis

Interest and Discount Rates		5%		10%	
Evaluation Basis		Loan	NPV	Loan	NPV
Merit Figure	Units				
(i) Levelised saving per unit power	$/GWh$_{so}$	-20864	-12100	-26311	-10000
(ii) CO_2 reduction per GWh$_{so}$	te/GWh$_{so}$	1230.2	1230.2	1230.2	1230.2
(iii) CO_2 prevention saving per tonne	$/te$CO_2$	-16.96	-9.81	-21.39	-8.09
(iv) Levelised or NPV saving/energy output	$/GWh	-3547.9	-2053	-4474.3	-1692.5
(v) CO_2 reduction/GWh	te/GWh	209.2	209.2	209.2	209.2

The tables illustrate that the CO_2 prevention costs show more favourably by the net present value method and at the normalised fuel prices appropriate to the UK market.

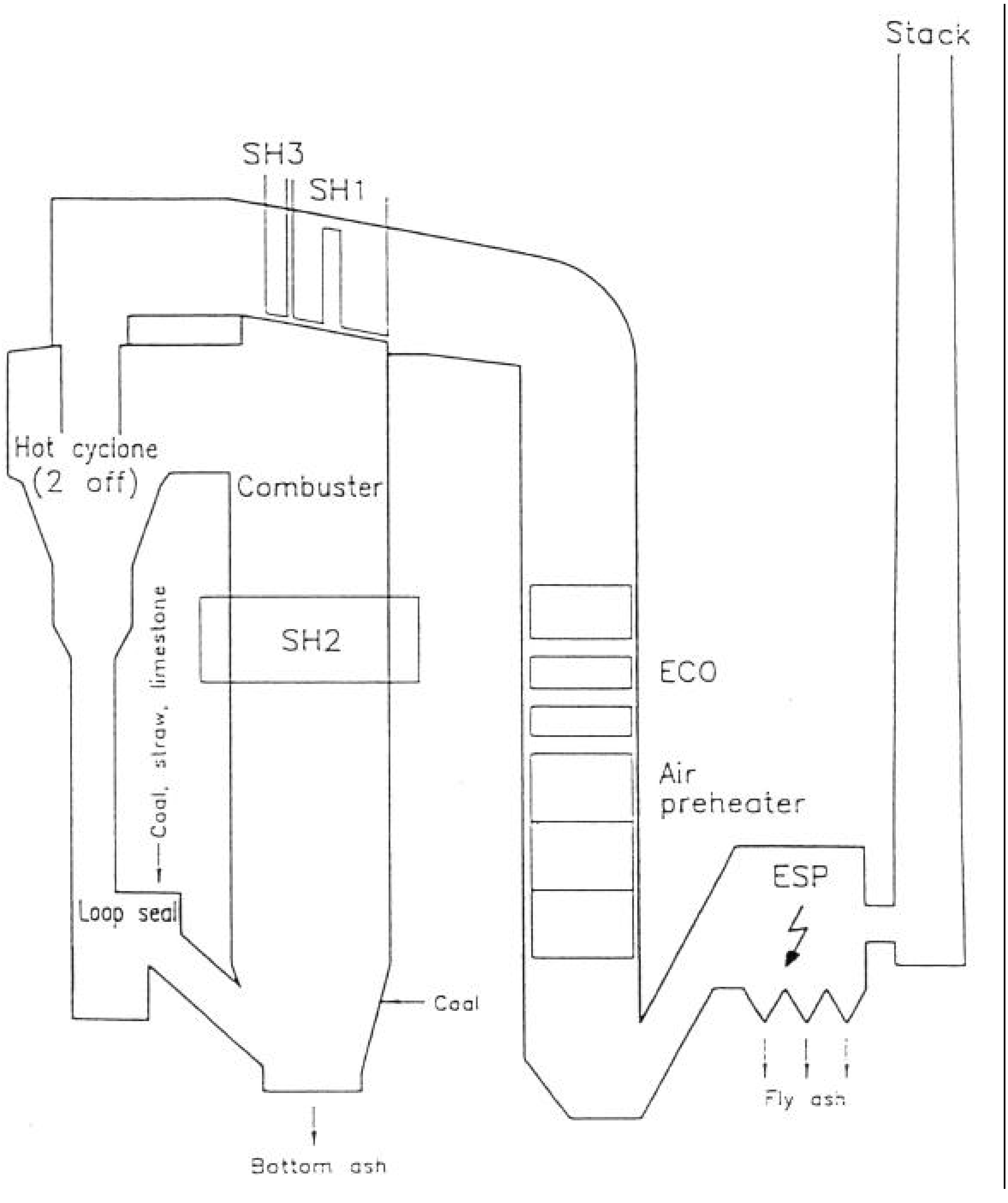
Both reference and normalised calculations give a reduction in CO_2 emissions by approximately 48%.

PICTURES AND DRAWINGS

1. External view of the Grenaa CHP plant.

PICTURES AND DRAWINGS

2. CFB Boiler section.

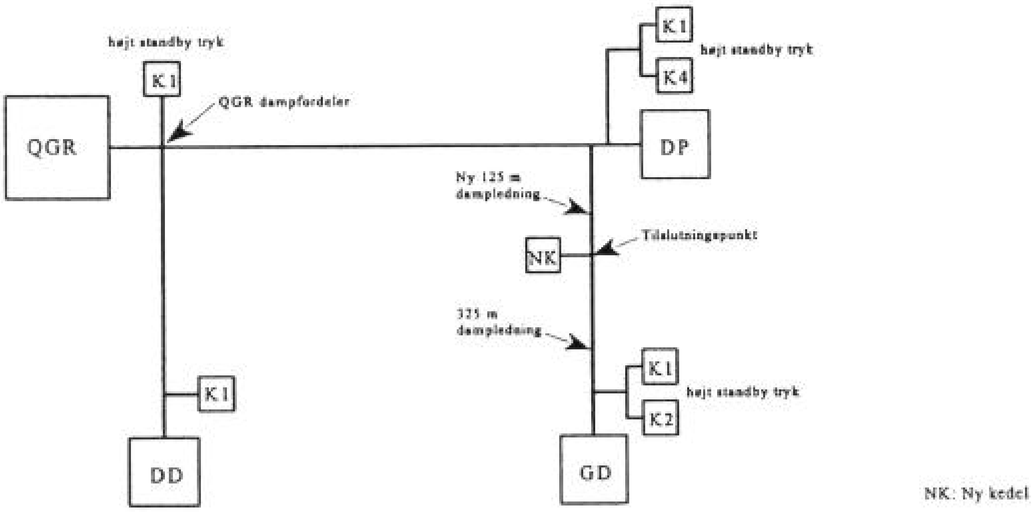


PICTURES AND DRAWINGS

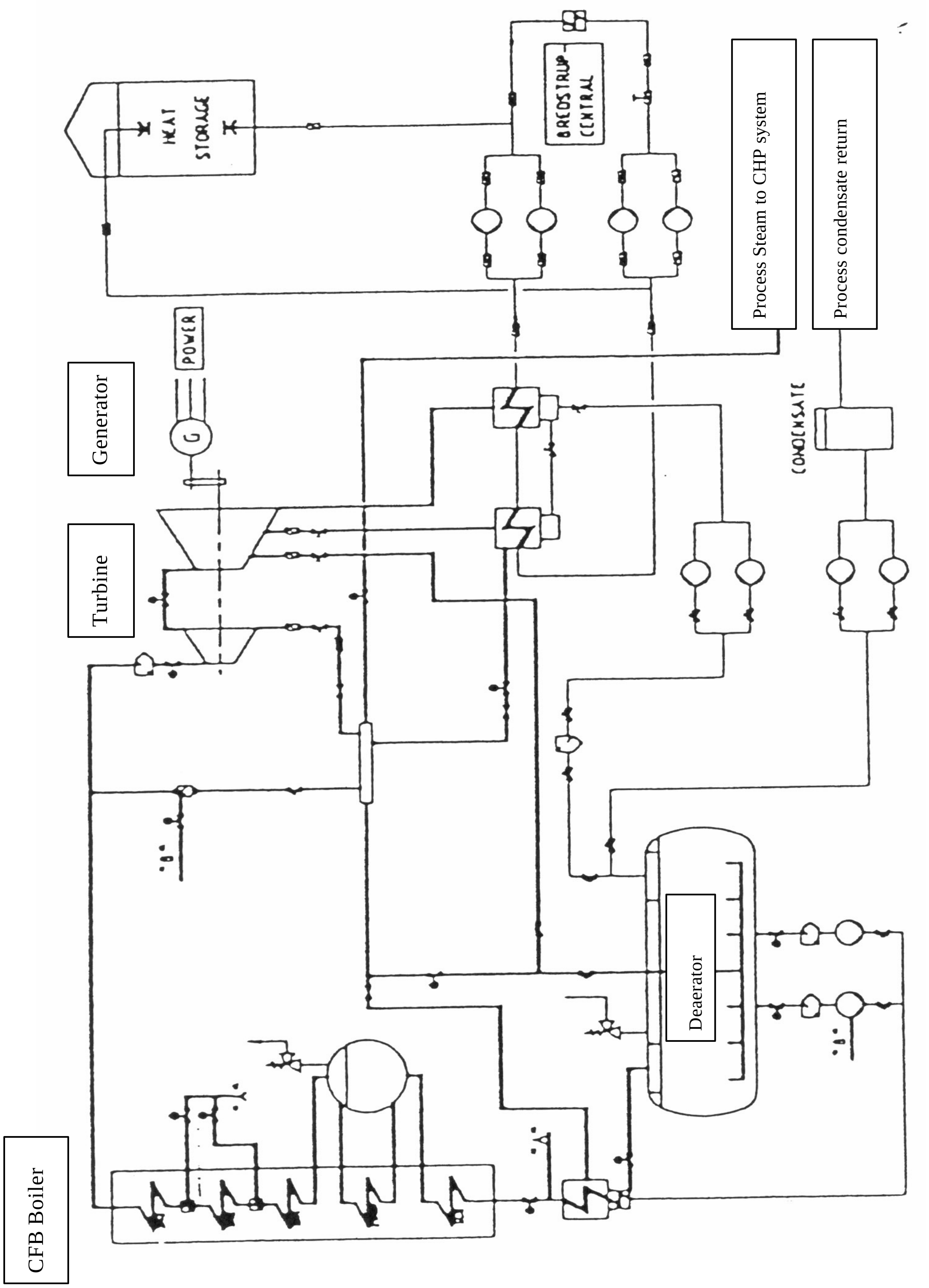
3. Flowsheet for CHP distribution system.

Legend

QGR	: CHP Grenaa plant
DP, DD, GD	: Steam consumers
K1, K2, K4, NK	: Stand-by boilers



4. Grenaa steam system diagram.



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APPENDIX 5

CASE 3

POWER STATION PARTIAL FUEL SUBSTITUTION FROM BLACK COAL TO A COAL AND BIOMASS MIXTURE

1. PLANT DESCRIPTION

1.1 General

The Grenaa fuel substitution project on Jutland involves the use of biomass fuel in the form of straw instead of bituminous black coal on a 78MW circulating fluidised bed boiler which provides steam for power generation, district heating and process purposes. The facility is essentially a combined heat and power plant of advanced design and the substitution of the primary fossil fuel by the renewable fuel has steadily increased from 24% energy in 1992 to 52% in 1997 and corresponded to 61250 tonnes.

The approximate electrical output was 20% of the energy exported, the district heating a similar amount and the heat to industrial process 60%.

1.2 Plant Prior to Modification

Prior to the development of the Grenaa co-generation facility the electricity, district heating and local industrial plant steam requirements of the area were essentially provided by the electrical grid network, a well development district heating system and the use of stand alone boilers by the local industrial concerns as a means of providing their own individual steam requirements.

The district heating facilities would require extensive enhancement during the 1990's, and the local energy intensive industries were planning a major expansion. These factors together with institutional and environmental factors provided the necessary impetus for the establishment of the combined heat and power plant at Grenaa.

The alternative option would have been:

- to continue to provide electricity from the grid network, basically generated from central coal fired power stations.
- to extend the supply and distribution network of the district heating system by providing oil fired boilers to supplement an existing straw fired boiler of relatively small capacity, with the industrial consumers continuing to provide their own stand alone boilers.

This alternative would require a major investment in new coal fired plant.

CHP Plant Description:

The coal and biomass fired CHP Grenaa plant is a co-generation facility owned and operated by the Midtkraft Energy Company, who also built the plant, with commercial operation commencing in January 1992.

In essence the plant includes the following main systems:

- a CFB-type boiler plant for mixed-fuel firing. The boiler is equipped with internal desulphurization (limestone injection) and an electrostatic precipitator.
- a conventional back-pressure steam turbine with process steam extraction.
- a hot water storage vessel balancing the process steam and district heat demands.
- storage and pre-processing facilities for biomass and coal.
- An oil-fired stand-by boiler.
- A central plant control system and the necessary service and auxiliary systems.

The main plant parameters are given in the following table:

Boiler capacity	MW_{th}	78
Live steam, SH exist	kg/s	29
	bar	92
	^oC	505
Feedwater temperature	^oC	170
Flue gas stack temperature	^oC	120
Energy input	%	
: coal		40-100
:straw		0-60
:normal mix		50:50
Emissions		
:SO_2	mg/MJ	100
:NO_x	mg/MJ	150
:CO	mg/MJ	200
:Particles	mg/Nm^3	50
Net electric capacity	MW_e	17.8
Process steam	Bar	8.3
	^oC	210
District heat	^oC	85 to 50

The circulating fluidised bed boiler is of Ahlström Pyropower (now Foster Wheeler Energia) design and this concept was adopted due to its capability to accommodate a multi-fuel mix and its favourable combustion and environmental chraracteristics. The boiler is designed for straw and coal ranges up to 60% and 100% respectively.

The controlled extraction back pressure steam turbine and the central plant control systems are of ABB (Asia Brown Boveri) design and manufacture.

The controlled passout provides the process steam and the low pressure steam from the turbine L.P cylinder essentially serves the district heating and plant requirements.

An industrialized straw supply scheme will ensure proper fuel quality and cost effectiveness. Straw is delivered on trucks carrying 24 Hesston-type bales, each of 450kg. The batch is unloaded by automatic cranes, handling 12 bales in one lift. Batch weight and quality (moisture content) are monitored simultaneously during unloading, and the batch is landed either at a storage position or at the fuel feed line to the boiler.

The bale weight and moisture content are prime quality parameters, which relate to processability as well as energy content and consequently to delivery price. Both parameters are dependent upon weather conditions during harvest, bale pressing and interim storage. Quality control is fully computerized. The bales are processed in low energy-consuming shredders and fed pneumatically into the boiler together with coal.

The fuel storage on site has sufficient capacity for 3 days' continuous operation.

A wide range of imported steam coal is provided for the plant. Coal arrives on trucks from the Arhus Coal Terminal, 60km away. Coal is crushed to minus 10mm and fed to the boiler by conventional equipment.

A steam system diagram, photograph and plant layout drawing are given to illustrate the visual impact of the plant and its steam systems.

1.3 Brief History and Decision Process

Initial Considerations

Considerations started in response to a national energy policy initiative in 1986, which committed the Danish power companies to deploy part of their future power capacity extension in the form of local CHP plants for combined district heat and power generation. These plants, which might replace existing heat boilers, should be fired by domestic fuel (biomass, waste or natural gas).

The city of Grenaa had a well-developed district heating system and forecast an increased heat demand of 370 TJ/a by 1995. This increased demand associated with an existing distric heating system encouraged Midtkraft to conduct studies in to identifying Grenaa as a potential site for installation of new CHP capacity in accordance with the above 1986 initiative.

The studies identified an additional market for process steam supply without regulatory restraints on fuel choice. Danisco Paper, one of the larger consumers, was considering plans for a new coal-fired process steam boiler plant (approximately 950 TJ/a) in conjunction with a major extension of their production capacity for waste paper recycling.

These preconditions, together with easy access to large quantities of surplus straw from the nearby agricultural region, led to the adoption of the Grenaa CHP concept. The combined generation of electricity, district heat, and process steam from a single coal and straw-fired plant offered advantages regarding efficiency, economy and environmental impact as compared to separate generation.

Having completed feasibility studies, pilot testing, and contract negotiations on straw supply and thermal energy sales, Midtkraft decided to launch the CHP Grenaa project in November 1989.

It should be added that the contract with Danisco Paper includes the total process steam supply for the company. Previous boilers at the company's premises have been taken over as stand-by capacity. Furthermore, Midtkraft has pursued the business policy of offering process steam supply on similar conditions to other local industries, and also aimed towards a wider range of biomass utilization in the CHP plant by including industrial residues on a commercial basis.

Construction and Operating History

Construction of the CHP Grenaa plant and the associated transmission lines for heat and process steam was executed during November 1989 till end December 1991. Commercial operation started 2 January 1992, and has continued apart from annual maintenance periods of 2-3 weeks duration and unscheduled outages.

Scope of Work

The original CHP Grenaa project included engineering, and commissioning of the complete cogeneration plant at a virgin site in the Grenaa industrial area – and of the associated transmission lines to Danisco Paper and the existing district heat system.

Later tasks included boiler modifications to cope with the problems caused by straw firing, the addition of a fuel facility for other biomass in pulverized form, and the extension of the process steam supply for two new customers.

Work Programme

Major milestones in plant construction and subsequent activities are as follows:

• CHP Grenaa project decision	November 1989
• Start of site preparation	April 1990
• Start construction	May 1990

• Start commissioning	November 1991
• Plant operational, supply of process steam to Danisco Paper and district heat	January 1992
• Major boiler modification (evaporator wing walls)	August 1993
• Boiler loop seals replaced	August 1996
• Process steam supply for Danisco Distillers	June 1997
• Facility added for pulverized biomass	January 1998
• Process steam supply for Grenaa Dampvæveri (textile manufacturer)	July 1998

1.4 Modification Details

The original Ahlström CFB boiler configuration is shown schematically in the diagram at the end of this report. Air preheater and economizer are located in the vertical convective boiler pass. Combustor water walls serve as evaporator. Steam superheating to 505^{o}C is provided in 3 stages. The superheaters, SH1 and 3, are located in the overhead convective pass, whereas the second stage, SH2, is mounted as panels penetrating the combustor freeboard. The particle recirculation loop includes two parallel, hot cyclones and loop-seals.

Operational problems caused by the high chlorine and alkaline content of the fired straw have necessitated some boiler modifications over the years as described below. Evaporator wing walls have been added to the combustor, and the loop-seals have been replaced by fluid-bed heat exchangers of CHEX-type for final superheating. An up-to-date boiler section is shown at the end of this Appendix.

As seen from data provided in Section 1, plant capacity utilization has been relatively low during the first years of operation, which is due to a slower build-up of district heat and process steam demand than predicted. The biomass share has grown steadily, except in 1994, when a straw supply shortage occurred during Spring. Overall plant energy efficiency has increased from 73% (1992) to 88% (1997).

Operational problems have mainly been associated with the boiler plant and caused by the high chlorine and alkaline content of the fired straw. During the early years unsatisfactory process temperature control and subsequent build-up of fouling deposits and superheater corrosion resulted in several tube failures and unscheduled stops for boiler cleaning and repair.

The conditions were improved by a major heat surface modification during August 93. Evaporator wings were added to the combustor rear-wall, and the final superheater and part of SH1 were replaced.

A second major modification was made during the 1996 revision. The loop-seals were replaced by external fluid-bed heat exchangers with CHEX to account for final superheating from 475 to 505^oC. By this precaution deposits formation has been stabilized at a low level, enabling full live steam temperature to be maintained.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is determined by the changes in fuel and associated with the coal substitution by biomass. Although the projected heat content of the coal and biomass are similar, the principal benefit with regard to greenhouse gas reduction is the classification of the straw as biofuel and hence zero CO_2 emission fuel. The results in Section 2 are calculated for the whole station burning 100% coal and a representative conversion fuel mixture. The amounts of CO_2 generated by the combustion of all 'normalised paradigm' study fuels are addressed in Appendix 1.

Sections 1.9.1 to 1.9.4 address the discrepancies between the 'normalised' and site fuels in detail.

The NO_x reduction achieved as a result of installing the circulating fluidised bed boiler is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Experiments to measure N_2O concentrations in flue gases on other plant have proved unsuccessful and hence any change in the greenhouse gas N_2O is not considered in this case. Difficult to evaluate is the CH_4 emissions that would have resulted from continued storage and decomposition of the waste straw.

1.6 Determination of Capital Costs

Investment costs in the CHP Grenaa project during 1989-1992 amounted to 390 M Dk plus interest during construction 25 M Dk (current prices). Furthermore, Midtkraft has invested approximately 15 M Dk in subsequent plant modifications.

However, in view of the fact that the case study is being assessed from the coal by biomass substitution aspects, of particular significance is the capital cost of the straw unloading, storage and delivery systems to the CFB boiler. These costs have been assessed to be 66.2 M Dk approximately 10.52 M $.

1.7 Determination of Operating and Maintenance Costs

According to the 1997 account the plant operating and maintenance costs amounted to 22.5 M Dk approximately 3.58 M $.

The additional operating and maintenance costs attributable to the utilisation of straw as a partial fuel substitute of coal was estimated using cost data from years 1995 to 1997. These were analysed and on average found to be 5 M Dk, equivalent to 0.805 M $ per annum. This figure includes all maintenance, consumables and staff costs. The actual final costs are discussed in Section 1.9.

1.8 Changes to Non-Greenhouse Gas Emissions

The utilisation of the circulating fluidised bed boiler enables emission control to be exercised by the inherently low combustion temperature (850°C) and in-bed desulphurisation by limestone injection.

Emission levels at design maximum full load and energy input ratios of 50:50 coal/straw are 100 mg/MJ SO_2, 150 mg/MJ NO_x and 50 mg/Nm^3 particulates. The substitution of straw instead of coal enables the sulphur content of the fuel input to be reduced, the sulphur content of the coal being approximately 0.9% by weight and the straw 0.1%. Hence the required quantity of limestone injected for the SO_x reduction is also reduced.

The plant adequately meets the EEC standards.

1.9 Site Fuel Data

Typical fuel data for the CHP Grenaa plant are summarised in the tables in Sections 1.9.1 and 1.9.2.

Straw properties show large variations from year to year caused by the climatic conditions during growth and the harvest season. The analysis provided in 1.9.2 is given as a typical example for comparison with normalised fuels contained in Appendix 1.

Black coal is purchased by Midtkraft from the international spot market. The analysis given below is presented as typical for supplies which may actually originate from Poland, Chile or South Africa.

The following analysis data was provided by the plant owner Midtkraft and Kennedy and Donkin extrapolated this on an empirical and theoretical basis to enable combustion calculations to be conducted. The results of the fuel investigation were discussed and agreed with the plant operators and are summarised in 1.9.1 and 1.9.2 below and were used in the "actual" case assessment.

1.9.1 Black Coal

As mentioned above the following table gives typical site data for black coal associated with Grenaa actual plant calculations.

Carbon	% by weight	59
Hydrogen	% by weight	4.5
Oxygen	% by weight	9.98
Nitrogen	% by weight	1.0
Sulphur	% by weight	0.9
Ash	% by weight	13.8
Water	% by weight	10.8
Chlorine	% by weight	0.02
Net Calorific Value	MJ/kg	23.60

Actual fuel prices for black coal provided by Midtkraft suggest an average purchase price of 2.3 $/GJ. Whilst the analysis data concurs with range data given within Appendix 1, the cost is significantly greater than the 2.0 $G/J assumed for 'normalised' calculations.

1.9.2 Straw

The following table gives a typical analysis for Danish straw which conforms to the range data given by Appendix 1 except for the oxygen content. This minor difference is considered to be insignificant.

Carbon	% by weight	38.11
Hydrogen	% by weight	5.22
Oxygen	% by weight	37.115
Nitrogen	% by weight	0.605
Sulphur	% by weight	0.10
Ash	% by weight	4.50
Potassium	% by weight	0.90
Chlorine	% by weight	0.45
Water	% by weight	13.0
Net Calorific Value	MJ/kg	14.8

According to the 1997 accounts the total fuel costs for the plant amounted to 50.7 M Dk, approximately 8.06 M $. The coal price is essentially determined by spot market prices and it was found that during 1997 the costs experienced at the plant were such that the cost per energy unit of baled straw was 3 times that of imported coal.

An analysis of the 1997 energy input data, see Section 1.11, and assuming that the calorific value and cost of the other biomass could be considered as straw (8% of the total biomass input) for the purposes of calculation was 6.9 $/GJ for straw. This equated to approximately £60 per tonne for the straw.

The "normalised" case has been based on around a 2.03 $/GJ for straw as a typical UK value, with the respective calorific value of 14.0 MJ/kg and carbon content of 43.8%.

The high cost associated with Danish straw has a substantial influence regarding the financial evaluation of this case study in Section 2.

1.10 Combustion Gases

The analyses and details of the site fuels given previously in Section 1.9 agree closely with the normalised data in Appendix 1 which forms the basis of the normalised/paradigm calculations.

The change in CO_2 emissions simply reflects the CO_2 reduction by substituting about 50% of the coal energy input with biomass.

1.11 Net Plant Efficiency and Output Information

The data regarding the CHP plant energy generation and fuel consumption is provided in the following table, this data being provided by the plant owner.

Year		**1992**	**1993**	**1994**	**1995**	**1996**	**1997**
Process steam	TJ	607	776	988	882	848	1005
District heat	TJ	247	261	272	286	287	260
Net electricity	GWh	50	50	75	69	67	72
Coal	1000 tonnes	38	38	60	43	40	35
	TJ	1083	952	1502	1047	938	825
Straw	1000 tonnes	24	34	25	43	49	56
	TJ	340	475	346	605	701	832
Other biomass	1000 tonnes						5
	TJ						72
Biomass ratio	% energy	24	33	19	37	43	52

The above table illustrates the steady increase of the biomass contribution to the energy input apart from 1994 when a shortage of straw was experienced.

The CHP plant operational record is summarised in the following table, this plant utilisation data being furnished by the owner.

Year		**1992**	**1993**	**1994**	**1995**	**1996**	**1997**

Operation	Hours	7282	7212	8242	7919	7082	7310
Start/stop	Number	31	32	14	16	23	24
Availability	%	83	82	94	90	81	83

Boiler modifications were carried out during 1993 and 1996 and slightly lower operating hours were observed during those years.

An analysis of the energy generated and load demands indicates that the maximum output was achieved during 1997 and in view of the fact that the process steam demand is expected to increase further it has appeared relevant to adopt the 1997 data as the basis for the comparison. Also the biomass ratio is approaching its considered optimum. The following table summarises the reference operating data provided by Midtkraft for 1997.

1997 Operational Data on Annual and Average Load Basis

Operating Hours	7310	
Availability on Annual Hours	83%	
Process Steam	1005 TJ	38.2 MWth
District Heat	260 TJ	9.8 MWth
Heat Load	1265 TJ	48.0 MWth
Heat Export Capability	1580 TJ	60 MWth
Net Electricity	72 GWh	9.85 MW
Electrical Capacity		17.8 MW
Net Total Load		57.8 MW
Average Operating Load		$\frac{57.85}{77.80} = 74.4\%$
Fuel Input Coal Straw Other Biomass	825 TJ 832 TJ 72 TJ	
Total Energy	1729 TJ	65.70 MWth
CHP Plant Efficiency on NCV	$\frac{57.85}{65.70} = 88.1\%$	
Overall Plant Load Factor On Maximum Capacity	= 0.744 x 0.83 = 61.8%	

This information identifies that the reference plant conditions (0.618 load factor) are exceedingly close to normalised conditions (0.65 load factor).

Assuming that the proportions of Power, process steam and district heating, as well as plant efficiency, are the same at 0.65 load factor as at 0.618 load factor gives the following base data for normalised calculations in section 2.2:

Annual process steam production	293.66 GWh
Annual district heat production	75.94 GWh
Annual net power export	75.73 GWh$_{so}$

2. RESULTS

2.1 Reference Plant Calculations

Based upon the information provided and discussed in Section 1, calculations can be made to determine the figures of merit. The data and results for the actual plant operating conditions are itemised below with the comparison evaluated between coal alone and mixed fuel operation.

Fuel		Coal	Coal + Biomass
Annual electricity generation	(GWh_{so})	72	72
Efficiency of plant on NCV	(%)	88	88
Annual process steam production	(GWh)	279.2	279.2
Annual district heat production	(GWh)	72.2	72.2
Total annual energy output	(GWh)	423.4	423.4
Total annual heat input requirement	(TJ)	1732	1732
Coal used as % heat input		100	47.7
Annual coal consumption	(Kte)	73.39	35.01
Biomass used as % heat input		0	52.3
Annual biomass consumption	(Kte)	0	61.21
Annual fuel cost	(M$)	3.95	8.08
Annual fuel saving	(M$)		-4.13
Annual generation CO_2	(Kte)	0	75.74
Annual reduction in CO_2	(Kte)	158.78 0	83.04

The above analysis indicates approximately 50% reduction in CO_2 which is consistent with the 50% substitution of the coal by biomass. There has been an increase in the fuel cost in excess of 4 M $ due to the fact that the straw is three times the coal cost per unit of energy input.

The capital costs associated with the straw facilities and equipment together with the increased operating and maintenance costs have been itemised in sections 1.6 and 1.7 and amount to 10.52 M $ and 0.805 M $ p.a. respectively.

2.1.1 Estimated Benefits of Fuel Substitution on Loan Basis

The following financial evaluation of the effects of the fuel substitution for the actual reference plant conditions using capital based on a mortgage type loan basis at 5% and 10% annual interest rates and over a 25 year remnant plant life is detailed below.

Cost of associated straw plant		10.52	M$
Number of years plant life (n)		25	
Loan annual interest rate (i)	5	10	%
Loan factor $[I^n \times (I-1)/(I^n - 1)]$	0.0710	0.1102	
Annual loan repayment	0.7464	1.1590	M$
Annual fuel saving	- 4.1308	- 4.1308	M$
Annual O&M saving	- 0.8050	- 0.8050	M$
Total annual saving	- 4.9358	- 4.9358	M$
Net annual saving (incl. loan)	- 5.6822	- 6.0948	M$
CO_2 reduction per annum		83.04	Kte
GWh_{so} per annum (electricity)		72	GWh_{so}
GWh total energy output p.a.		423.4	GWh
(i) Levelised saving per unit power	-78920	-84650	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	1153.3	1153.3	te/GWh_{so}
(iii) Saving per tonne CO_2	- 68.43	- 73.40	$/te CO_2
(iv) Levelised saving unit energy output	-13420.5	14394.9	$/te CO_2
(v) CO_2 reduction per GWh	196.13	196.13	te/GWh

2.1.2 Estimated Benefits of Fuel Substitution on NPV Basis

The following financial evaluation for the case of the fuel substitution on the basis of capital equity and discounting of the annual savings/costs at rates of 5% and 10% over the remnant life of 25 years to express the results on a net present value basis.

Cost of associated straw plant		10.52	M$
Plant life years (n)		25	
CO_2 reduction per annum		83.04	Kte
Total energy output p.a.		423.4	Gwh
Through life energy output		10585	Gwh
Annual fuel saving	- 4.1308	- 4.1308	M$
Annual O&M saving	- 0.805	- 0.805	M$
Total annual saving	- 4.9358	- 4.9358	M$
Annual discount rate (r)	5	10	%
Discount factor $[(1-R^n)/)1-R)]$	14.7986	9.9847	
Discounted through life savings DS	- 73.0436	- 49.2830	M$
NPV savings (DS – C_t)	- 83.5636	- 59.8030	M$
(i) Levelised saving per unit power	-46400	-33200	$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	1153.32	1153.32	te/GWh_{so}
(iii) Saving per tonne CO_2	-40.25	-28.81	$/te/$CO_2$
(iv) Levelised NPV saving/energy output	- 7895	- 5649.8	$/GWh
(v) CO_2 reduction per GWh	196.13	196.13	te/GWh
	-		

2.2 Normalised Plant Calculations

The current plant load factor during 1997 is 61.8% and data in the table below is based upon 1997 information prorated to the normalised conditions of 65% load factor. In determining the figures of merit the normalised fuel prices of 2 $/GJ for the coal and 2.03 $/GJ for the straw have been employed.

Fuel		Coal	Coal + Biomass
Annual electricity generation	$(GWh)_{so}$	75.73	75.73
Efficiency of plant on NCV	(%)	88	88
Annual process steam production	(GWh)	293.66	293.66
Annual district heat production	(GWh)	75.94	75.94
Total annual energy output	(GWh)	445.33	445.33
Total annual heat input requirement	(TJ)	1822	1822
Coal used as % heat input		100	47.7
Annual coal consumption	(Kte)	71.44	34.08
Biomass used as % heat input		0	52.3
Annual Biomass consumption	(Kte)	0	68.06
Annual fuel cost	(M$)	3.64	3.67
Annual fuel saving	(M$)	0	-0.03

Annual generation CO_2	(Kte)	178.1	84.97
Annual reduction in CO_2	(Kte)	0	93.16

Since the normalised and reference plant conditions are so close no adjustments are proposed to estimated annual O&M costs.

2.2.1 Estimated Benefits of Fuel Substitution on Loan Basis

The financial evaluation of the effects of the fuel substitution for the normalised fuels using capital based on a mortgage type loan basis at 5% and 10% annual interest rates over 25 year plant life is given below.

Cost of associated straw plant		10.52	M$
Number of years plant life (n)		25	
Loan annual interest rate (I)	5	10	%
Loan factor $[I^n x (I-1)/(I^n-1)]$	0.0710	0.1102	
Annual loan repayment	0.7464	1.1590	M$
Annual fuel saving	-0.02718	-0.02718	M$
Annual O&M saving	-0.805	-0.805	M$
Total annual saving	-0.834	-0.834	M$
Net annual saving (inc. loan)	-1.58	-1.99	M$
CO_2 reduction per annum		93.16	Kte
GWh_{so} per annum (electricity)		75.73	GWh_{so}
GWh total energy output p.a.		445.33	GWh
(i) Levelised saving unit energy output	-3728.4	-4702.8	$/GWh
(ii) CO_2 reduction per GWh	209.2	209.2	te/GWh
(iii) Saving per tonne CO_2	-17.82	-22.48	$/te$CO_2$

2.2.2 Estimated Benefits of Fuel Substitution on NPV Basis

The financial evaluation for the fuel substitution case on the basis of capital equity with discounting of the annual savings/costs at rates of 5% and 10% over the remnant life of 25 years in order to express the carbon dioxide prevention cost as a net present value are itemised below.

Cost of associated straw plant		10.52	M$
Plant life years (n)		25	
CO_2 reduction per annum		88.58	Kte
Total energy output p.a.		423.4	GWh
Through life energy output		10585	GWh
Annual fuel saving	-0.02718	-0.02718	M$
Annual O&M saving	-0.805	-0.805	M$
Total annual saving	-0.83218	-0.83218	M$
Annual discount rate (r)	5	10	%
Discount factor $[1-R^n)/(1-R)]$	14.7986	9.9847	
Discounted through life savings DS	-12.3151	-8.3091	M$
NPV savings (DS – C_t)	-22.8351	-18.8291	M$
(i) Levelised NPV saving/energy output	-2157	-1778.8	$/GWh
(ii) CO_2 reduction per GWh	209.2	209.2	te/GWh
(iii) Saving per tonne CO_2	-10.31	-8.50	$/te$CO_2$

3. DISCUSSIONS AND CONCLUSIONS

The Midtkraft cogeneration plant at Grenaa is the first plant of this type in Denmark and is considered to be at the forefront of innovation and development. The design of the CFB boiler, particularly the present modified design entailing a partially water walled furnace and an external bed heat exchanger incorporating superheater elements are of particular interest.

The 1997 load schedule has been taken as the basis for conducting the assessment since it represents a years complete set of data following the boiler modifications coincident with the maximum efficiency and average output achieved by the plant to date, ie. 88% and 58MW respectively.

In meeting this load the plant operated at approximately 75% of rated capacity and the biomass throughput of 61250 tonnes was 55% of the energy input and close to the optimum for the installation.

An increase in plant load would be dependent upon an increase in heat export since the electrical output is also determined by the process steam and district heating loads, the steam system configuration incorporating an extraction – back pressure steam turbine generator. At the present time the thermal export represents about 80% of its design capacity and the average electrical load of 10MW is 55% of the generator rated capacity.

The utilisation of the CFB concept enables the use of limestone injection for controlling the SO_2 emissions and the substitution of straw for coal also promotes a reduction in the SO_2 emission.

The low furnace gas exit temperatures enable low levels of NOx to be achieved and the electrostatic precipitators ensure low particle emissions. The emission levels achieved are well within the EEC directives.

The modifications on the boiler have increased the projected life of the superheater elements from 18 months to 6 years and reduced the fouling taking place. Some trials have taken place to increase the energy input from straw above 60% and up to 70% or 80% but it was found that this led to unacceptable fouling and incomplete burn out.

The figures of merit are summarised in the following tables. It is to be noted that the capital costs of 10.52 M $ and the annual O&M costs of 0.805 M $ used in the assessment concentrate upon those items of plant which have been installed to enable the plant to operate upon a biomass/coal mixture compared to coal only. A plant life of 25 years has been taken since the plant is essentially a new installation. The plant operating hours of 7310 hours represented an availability of 83%.

SECTION 3
DISCUSSIONS AND CONCLUSIONS

Actual Plant Reference Condition. Denmark

Interest and Discount Rates		5%		10%	
Evaluation Basis		Loan	NPV	Loan	NPV
Merit Figure	Units				
(i) Levelised saving per unit power	$/GWh$_{so}$	-78920	-46400	-84650	-33200
(ii) CO_2 reduction per GWh$_{so}$	te/GWh$_{so}$	1153.32	1153.32	1153.32	1153.32
(iii) CO_2 prevention saving per tonne	$/te$CO_2$	-68.4	-40.3	-73.4	-28.8
(iv) Levelised or NPV saving/energy output	$/GWh	-13420.5	-7895	-14394.9	-5649.8
(v) CO_2 reduction/GWh	te/GWh	196.1	196.1	196.1	196.1

Normalised Conditions. UK Fuel Price Basis

Interest and Discount Rates		5%		10%	
Evaluation Basis		Loan	NPV	Loan	NPV
Merit Figure	Units				
(i) Levelised saving per unit power	$/GWh$_{so}$	-20864	-12100	-26311	-10000
(ii) CO_2 reduction per GWh$_{so}$	te/GWh$_{so}$	1230.2	1230.2	1230.2	1230.2
(iii) CO_2 prevention saving per tonne	$/te$CO_2$	-16.96	-9.81	-21.39	-8.09
(iv) Levelised or NPV saving/energy output	$/GWh	-3547.9	-2053	-4474.3	-1692.5
(v) CO_2 reduction/GWh	te/GWh	209.2	209.2	209.2	209.2

The tables illustrate that the CO_2 prevention costs show more favourably by the net present value method and at the normalised fuel prices appropriate to the UK market.

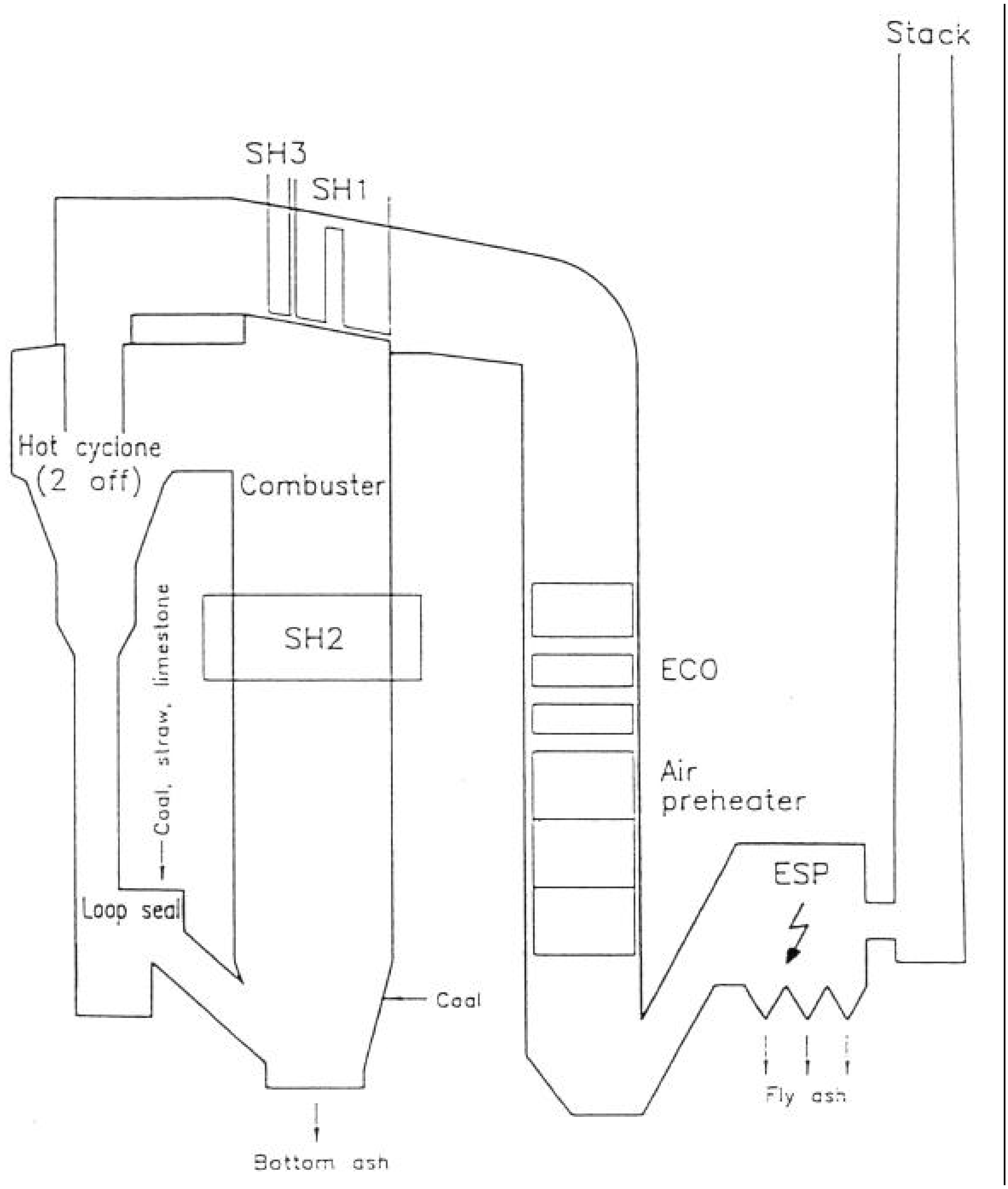
Both reference and normalised calculations give a reduction in CO_2 emissions by approximately 48%.

PICTURES AND DRAWINGS

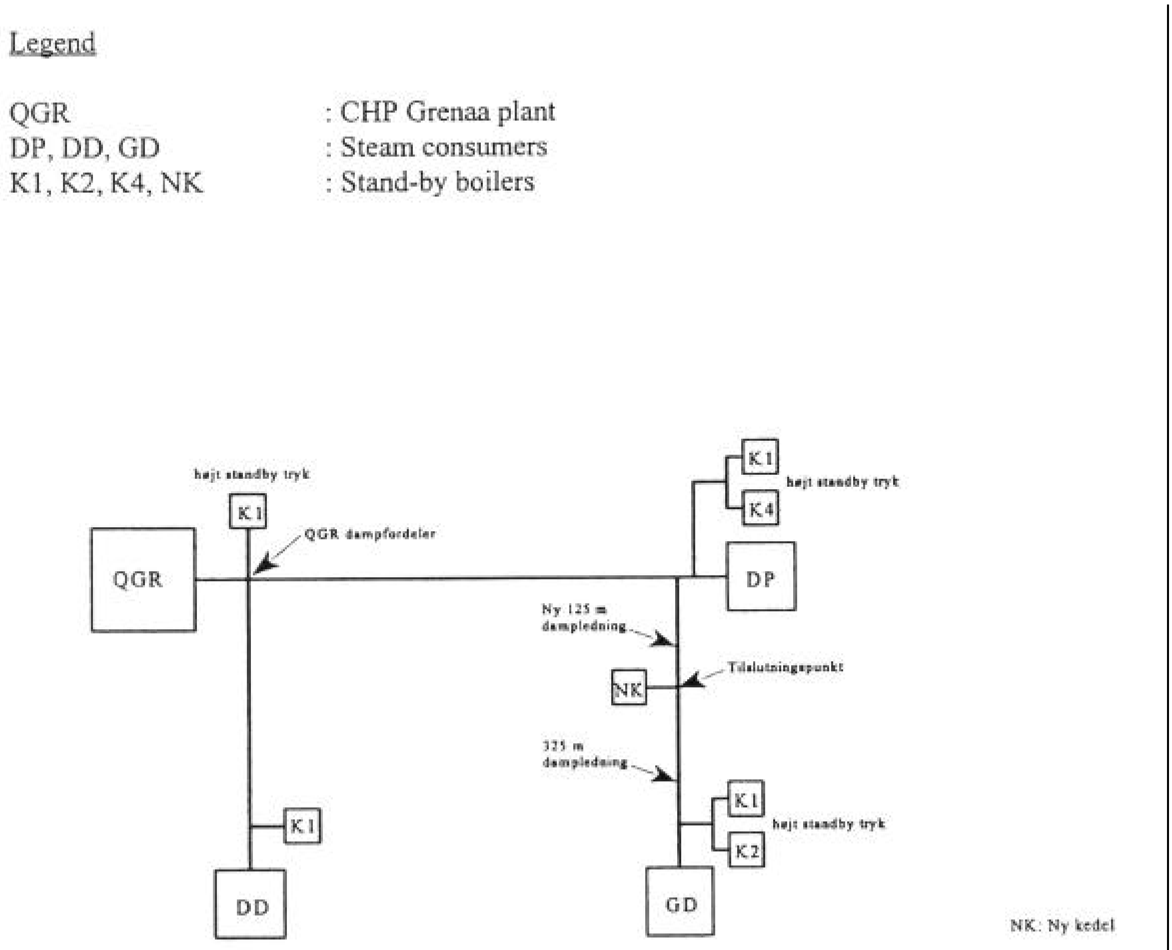
1. External view of the Grenaa CHP plant.

PICTURES AND DRAWINGS

2. CFB Boiler section.

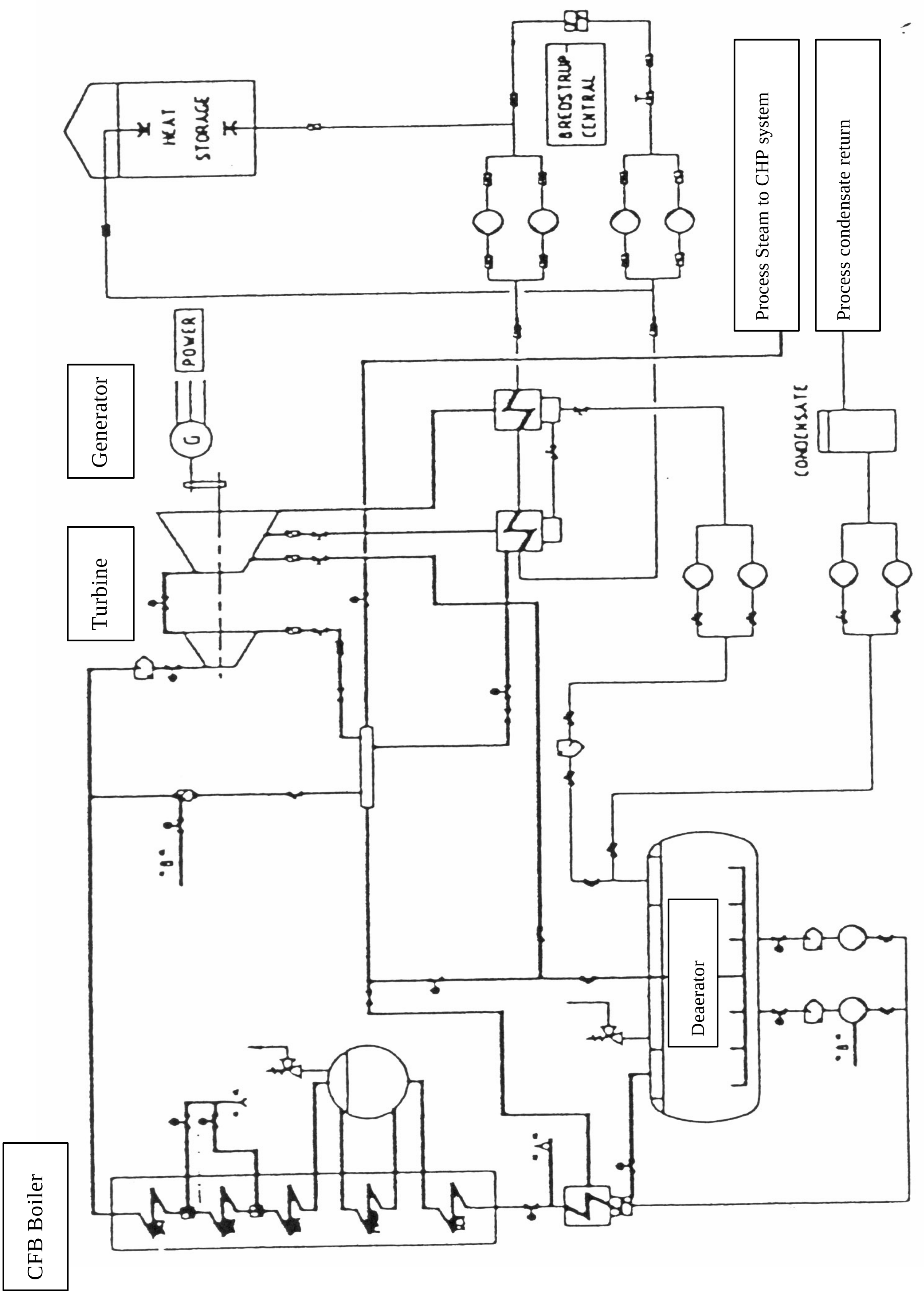


3. Flowsheet for CHP distribution system.



PICTURES AND DRAWINGS

4. Grenaa steam system diagram.



APPENDIX 6

CASE 4

POWER STATION PART FUEL CONVERSION FROM GAS/COAL TO GAS/COAL PLUS BIOMASS (WOOD CHIP & WASTE) GASIFICATION PRODUCTS

1. PLANT DESCRIPTION

1.1 General

The Kymijarvi boiler conversion project involves the modification of the 360MWt once through Benson boiler to utilise the product gases from a circulating fluidized bed gasifier. The study concentrates upon the effects that the conversion has upon emissions from the main boiler plant.

Kymijarvi represents a medium sized power and district heating facility of 210MWe and 240MWt on the central section of the Finnish National Grid. The plant is located just outside the city of Lahti and is jointly owned by Lahti Energia Oy and Imatran Voima Oy under a company called Lahden Lämpövoima.

1.2 Plant Prior to Modification

The main boiler plant prior to modification comprised of a Vereinigte Kesselwerke GmbH once through Benson boiler with reheat. The boiler prior to modification was designed to utilise natural gas and black/hard coal fuels.

The Kymijarvi plant comprises the following items of equipment:

1 x 43 MWe gas turbine
1 x 80 MWt heat recovery boiler
1 x 70 MWt biomass gasifier
1 x 360 MWt main boiler with reheat
1 x 139 MWe back pressure steam turbine with pass out
1 x 167 MWe condensing steam turbine

Steam conditions associated with the main boiler and steam turbines are:

Superheater	-	540^{o}C & 170 bar
Reheater	-	540^{o}C & 40 bar

Photographs and a diagram of the power station are included at the end of this appendix to illustrate the visual impact of the plant both prior and post conversion modifications together with the configuration of the site power & steam system(s).

1.3 Brief History and Decision Process

The original power station at Kymijarvi was designed to burn heavy fuel oil and was brought into commercial operation in April 1976.

In 1979 a study was initiated on the possibility of converting the oil-fired boiler so that it could also operate on solid fuels. Alternative studies considered the conversion of the old boiler against the building of a new boiler plant based around the fuels being peat or coal. Conversion of the old boiler turned out to be clearly more economical in terms of overall costs. Furthermore, it was found that peat was not a viable alternative as there was not enough of it around Lahti. Thus the boiler was converted to achieve its rated load, 125kg/s of steam with coal.

At the end of March 1982 the plant was shut down to carry out the disassembly and installation work needed for the conversion. Electricity was generated for the first time with coal in October 1982. The shutdown for conversion had thus lasted seven months.

When the natural gas network was extended to the Lahti area the decision was made to build a gas turbine and heat recovery boiler plant next to the existing power station. The feed water for the main boiler and the condensate are circulated in the heat recovery boiler so that the steam needed for the feed water preheating plant, and, in part, for the condensate pre-heating plant can be passed through the whole turbine.

It was also decided to supplement the main steam boiler with natural gas burners and gas was first used in the main steam boiler in August 1986. Commercial operation of the gas turbine plant was started in October 1986.

The Finnish equivalent to the U.K. Environment Agency was also applying pressure on the site to reduce its emissions of NO_x, SO_x and particulates from the site.

Investigations in to the remnant life of the boiler showed the plant to be capable of further 15 years of operation.

Similar investigations on the steam turbines, and condenser also indicated 15 years of remnant life.

The continued escalation of fossil fuel prices in recent years encouraged a review of the use of biomass fuels for potential fuel substitution. It was these aspects and studies into the use of biofuels which highlighted the potential improvements possible by the installation of a biomass gasifier. It is this latest conversion involving biomass gasification that is the subject for this case study report on reduction of CO_2 emissions from the plant.

1.4 Modification Details

The gasification of biofuels and co-combustion of gases in the existing coal-fired boiler offers many advantages such as: recycling of CO_2, decreased SO_2 and NO_x emissions, an efficient way to utilise biofuels and recycled refuse fuels, low investment and operation costs, and utilisation of the existing power plant capacity. Only small modifications are required in the boiler and possible disturbances in the gasifier do not shut down the power plant.

An atmospheric CFB gasifier with auxiliary equipment, gas duct, 2 hot gas burners, steel structures, gasifier building, fuel receiving and handling station, limestone and sand feeding system, instrumentation automation, electrification, erection, civil work, bottom ash handling system, commissioning and training was installed at Kymijarvi between April 1997 and February 1998.

The atmospheric CFB gasification system is very simple. The system consists of a reactor where the gasification takes place, of a uniflow cyclone to separate the circulating bed material from the gas and of a return pipe for returning the circulating material to the bottom part of the gasifier. All the above mentioned components are entirely refractory lined. Typically, after the uniflow cyclone hot product gas flows into the air preheater, which is located below the cyclone.

The gasification air, blown with the high pressure air fan, is fed to the bottom of the reactor via an air distribution grid. When the gasification air enters into the gasifier below the solid bed, the gas velocity is high enough to fluidise the particles in the bed. At this stage, the bed expands and all particles are in rapid movement. The gas velocity is so high, that a lot of particles are conveyed out from the reactor into the uniflow cyclone. The fuel is fed into the lower part of the gasifier above a certain distance from the air distribution grid. The incoming biofuel contains 20-60% of water, 39-78% of combustibles and 1-2% of ash.

The operating temperature in the reactor is typically 800-1000°C depending on the fuel and the application. When entering the reactor, the biofuel particles start to dry rapidly and a first primary stage of reaction, namely, pyrolysis occurs. During this reaction fuel converts to gases, charcoal and tars. Part of the charcoal goes to the bottom of the bed and it will be oxidised to CO and CO_2 generating heat. After this, as these aforementioned products flow upwards in the reactor, a secondary stage of reactions take place, which can be divided into heterogeneous reactions, where charcoal is one ingredient in the reactions, and homogenous reactions where all the reacting components are in the gas phase. Due to these reactions among the other reactions a combustible gas is produced, which enters the uniflow cyclone and escapes the system together with some of the fine dust. Most of the solids in the system are separated in the cyclone and returned to the lower part of the gasifier reactor. These solids contain charcoal, which is combusted with the air that is introduced through the grid nozzles to fluidise the bed. This combustion process generates the heat required for the pyrolysis process and subsequent mostly endothermic reactions. The circulating bed material services as heat carrier and stabilises the temperatures in the process.

Fuels will be transported to the power plant in trucks. There is one receiving hall for REF and one receiving station for incoming biofuels.

The REF hall is equipped with a receiving pit having a lamella feeder. Lamella feeder controls the flow to a crusher. Coarse biofuel, which is originated mainly from the wood working industry is also fed in through the REF system. The trucks tip the REF and coarse biofuels on the floor of the hall or directly into the pit. The REF and coarse biofuel will be crushed in the slowly rotating crusher. The underground conveyor at the first receiving bunker transports the REF and the biofuels from the crusher.

The other receiving station is made for the finer biofuel and peat. This biofuel is transported to the site in special trucks. The transport platforms of the trucks are furnished with conveyors. These conveyors discharge the biofuel and peat from the trucks and the fuels fall through a screen down onto the chain conveyor at the bottom of the bunker. The coarser particles separated by the screen will be moved to REF hall for crushing.

The underground conveyor lifts the fuel to the belt conveyor, which has a magnet separator above it. The belt conveyor transports the fuels onto the disk screen. The coarse fuel fractions from the disk screen fall into the final crusher. The fine fractions from the screen and the crushed biofuel will be transported by a chain conveyor to the two fuel storage silos.

The gasification plant is furnished with one storage silo for fuels. Besides storage, this silo is used for homogenisation of the fuel mixture before it is transported into the gasification building. The discharger of the silo has variable speed controls. The biofuel handling process is an important and innovative step in this gasification process.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is determined by both the changes in fuels and efficiency changes associated with the boiler conversion. The carbon content of wood bark/waste is around 42% of that for coal on an as received basis but this is coal marginally over compensated by the corresponding reduction in NCV which is approximately 33% of that for coal. This indicates that actual plant emissions of CO_2 would be minimally increased if it were not for the principal benefit associated with the classification of wood bark/waste as biofuels having zero effective contribution to planetary CO_2 emissions throughout their life cycle. The results in Section 2 are calculated for the whole station burning pre and post conversion fuel mixes together with efficiency changes advised. The amounts of CO_2 generated by the combustion of all 'normalised/paradigm' study fuels is addressed in Appendix 1.

Sections 1.9.1 to 1.9.4 address the discrepancies between the 'normalised' and site fuels in detail.

Experiments to measure N_2O concentrations in flue gases on other plant have proved unsuccessful and hence any change in the greenhouse gas N_2O is not considered in this case. It should be noted that low NO_x burners had been installed on the main boiler prior to installation of the gasifier in order to comply with the tighter emission consents being applied by the Finnish Environment Agency. Difficult to evaluate is the CH_4 emissions that would have resulted from introduction of natural gas to the site.

1.6 Determination of capital costs

The capital costs have been based upon quotations received by Lahden Lämpövoima from contractors including Foster Wheeler.

The gasifier contract was awarded to Foster Wheeler in 1997. The total sum of the project including all areas and own work by Lahden Lämpövoima was 70 million Finnish Marks. This price included for all plant modifications and included for the new outdoor biomass wood waste unloading, storage and conveyor system.

It was possible to minimise outage to the annual maintenance period by completion of all work except tie in work adjacent to the boiler whilst the unit continued in operation. Hence costs associated with lost revenue are not relevant.

1.7 Determination of Operating and Maintenance Costs

In comparing net outputs between operation on coal and coal plus gasification products there were minor differences in boiler efficiencies on the unit. These were advised by the contractor and have been detailed in Section1.11.

Reduced fouling and corrosion features associated with reduced coal firing and the modifications have been balanced by an extra operator associated with fuel unloading & handling.

The current plant utilisation profile is such that the boiler is inoperative during the scheduled summer annual maintenance period and 2 or 3 days per annum unscheduled outages.

During the preceding months to this study, from January 1998, the unit had achieved an availability of 81% with the main plant only shutting down during June and July when electricity is cheap.

The data on estimated and actual operating fuel consumptions, net output, utilisation are itemised under Section 1.11 and 2.

1.8 Changes to Non-Greenhouse Gas Emissions

The decision to fit a circulating fluidised bed gasifier for the combustion of biofuels meant a reduction of furnace combustion temperatures and hence emissions of NO_x to within EEC and Finnish regulatory requirements.

The environmental requirements stipulated by the Finnish Environment Agency for SO_x emissions at the plant continually being reduced and the substitution of coal with biomass coincided with reduced SO_x emissions. The respective particulate levels had also been reduced to 50mg/Nm^3 since the reduced dust burden enabled the precipitator to comfortably achieve these emission limitations whereas the original plant would not have been capable of achieving the new limits being imposed.

The power plant emissions, ashes and fuel were analysed before the start of the gasifier to get the reference value for original plant conditions and emissions. The operation of the gasifier also included a series of similar measurements to evaluate any changes associated with the use of the gasifier.

The following is a short summary of results from those measurements and tests:

- The corrosion probes were clean and no indication of any fouling or corrosion observed.
- The moisture content in the fuel mixture was rather high, 45-56%.
- The carbon content in the gasifier bottom ash is typically 0.1-0.2%.
- The gas quality was as expected.
- The dust content in the gas was 6-8g/Nm^3 (wet gas) and tar content 4-8g/Nm^3 (wet gas). Alkali vapour content in the gas was low 0.1 ppmw (dry gas).
- NH_3 content was 800-1000 mg/Nm^3 and HCN 25-45 mg/Nm^3.

The changes of boiler emissions were of great interest. The short conclusion is that the changes in the emissions are rather low.

- The dust content in the flue gas dropped down from 20 to 10 mg/Nm^3.
- The NO_x content dropped down by 10 mg/MJ.
- The SO_x content dropped down by 20 mg/MJ.
- The HCl content increased by 10 mg/Nm^3 (Cl content in the used coal was below 0.01%).
- No changes in the CO emissions (10-20 mg/MJ).
- The heavy metal contents in the boiler flue gas and ash were very low (mercury below 0.1mg/Nm^3, 0.0004-0.0009 mg/MJ, limit 0.05 mg/MJ).
- The content of PAH, PCDD, PCDF, chlorinated benzenes and chlorinated phenols in the flue gas and ashes was very low.

1.9 Site Fuel Data

The fuels used on site are segregated below in to the major fuels and other fuels which constitute the minor component sources of the total fuel supplied to the gasifier.

These include fossil fuels such as natural gas and coal as well as the various sources of biofuels for the gasifier.

1.9.1 Natural Gas

Natural gas has been supplied to the site through the national pipeline system since 1986 when the gas turbines were installed. No detailed analysis of the natural gas has been provided but a typical LCV has been quoted at 49.1 MJ/kg.

This would suggest a carbon content of approximately 77% by weight. This discrepancy, between the site fuel and the 'normalised' UK natural gases detailed in Appendix 1 means that a CV and carbon content correction factor needs to be evaluated:

$$\text{Site fuel consumption correction based on NCV} = \frac{46.3}{49.1} = 0.943$$

$$\text{Site fuel } CO_2 \text{ emission} = \frac{46.3}{49.1} \times \frac{77}{73} = 0.995$$

Similar to other fuels in Finland two fuel costs tariffs exist depending on whether the fuel is used for electricity or district heat production. The tariffs are 60 and 71 mk/MWh respectively for electricity and district heating use.

The loading information given in section1.11 indicates an approximate average price at site of 3.68 $/GJ.

This suggests that differences between site and normalised calculations will include a 3.68/2.5 i.e. 1.47 cost factor.

1.9.2 Black Coal

Finland has no indigenous black coal reserves and so all supplies are obtained from the international market. The stringent control of SO_x emissions in Finland has meant the necessity to utilise low sulphur coals from Russia, Poland and Columbia having an analysis similar to that below:

GCV	25.05 MJ/kg
NCV	24.12 MJ/kg
Ash	12.04 % Wt as received
Moisture	10.00 % Wt as received

C	61.55 % Wt as received
H	4.07 % Wt as received
S	0.38 % dry ash free

The analysis complies with the ranges given in Appendix 1. Typical costs of black coal in Finland are given as 35 & 71 mk/MWh respectively for power and heat production.

This approximates to a site cost of 3.13$/GJ. The difference between this local cost of fuel and the normalised UK cost of coal results in a site coal cost factor of approximately 1.57.

1.9.3 Wood Wastes and Bark

Information from Finland has indicated the following typical and range of wood supplies used at Simpele and Lahti on a % by weight basis:

	Typical	Range	Basis
C	52.5	50.4 to 54.5	Dry solids
H	6.0	5.9 to 6.2	Dry solids
O	40.0	37.6 to 42.5	Dry solids
N	0.4	0.3 to 0.5	Dry solids
S	0		Dry solids
Ash	1.1	0.4 to 1.7	Dry solids
Moisture	53.5	47 to 60	As fired
NCV (MJ/kg	7.85	6.7 to 9.0	As fired

Typical Finnish costs for these wood based fuels are 42 mk/MWh which equates to 2.32 $/GJ.

The above ranges of analysis are in agreement with other sources of information on various wood analysis and therefore no corrections are proposed.

1.9.4 Other Fuels

These fuels were initially intended to form part of the fuel supplies to the gasifier which would then provide up to 15% of the heat input to the main boiler. Unfortunately subsequent operational experiences during the first year have restricted the heat input contribution of the gasifier to just below this value at between 11 and 13%.

<u>Peat</u>

This fuel was originally identified as a potential fuel for the gasifier but subsequent investigations have concluded that this will not be an economic option.

Data from other Finnish sites has indicated the typical and range of peat supplies available on a % by weight basis as shown in the table on the next page.

	Typical	**Range**	**Basis**
C	55.0		Dry solids
H	5.5		Dry solids
O	30.5		Dry solids
N	1.7		Dry solids
S	0.3		Dry solids
Ash	7.0	0 to 10	Dry solids
Moisture	48.0	40 to 55	As fired
NCV (MJ/kg)	9.8	8.1 to 11.7	As fired

Typical Finnish costs for peat are given as 47 and 56 mk/MWh for electricity and district heating use respectively. These costs equate to 2.6 and 3.1 $/GJ.

The original gasifier design took consideration of the potential use of peat as a gasifier fuel. Since being put in to operation the gasifier has not been used with this fuel and so it has not been considered within evaluations.

No significant reserves of peat are available on the mainland UK. The only UK mining of peat is in parts of Scotland and there are extensive reserves available in Northern Ireland. No data is available from either of these sources.

<u>REF</u>

REF is the term given to the recycled fuel derived from classified refuse obtained from households, offices, shops and construction sites and has a composition in the following ranges:-

Plastics	5-15	% by weight
Paper	20-40	% by weight
Cardboard	10-30	% by weight
Wood	30-60	% by weight

Since these are wastes their cost can be assumed negligible and calorific value data would be variable and only relevant to individual fuel batches.

Tyres.

It was intended to burn old tyres in the gasifier at the design stage but subsequent operations found the high steel content of the tyres gave fouling problems. Therefore use of tyres has been minimised to maintain high availability for the gasifier. The tyres are assumed to have an analysis in accordance with the following specification:

	Minimum	Maximum	Typical	Basis
Carbon	60	80	65	Dry Solid
Hydrogen	3.0	8.0	3.5	Dry Solid
Nitrogen	0.1	0.3	0.2	Dry Solid
Oxygen	1.0	3.0	2.0	Dry Solid
Sulphur	0.7	2.0	1.0	Dry Solid
Chloride	0	0.1	0.1	Dry Solid
Zinc	0.8	3.2	1.6	Dry Solid
Steel	10.0	25.0	21.6	Dry Solid
Ash (ex. steel & zinc)	1.5	5.0	3.5	Dry Solid
Free Moisture	0	3	1.5	Dry Solid
HHV	26.75	34.9	28.8	MJ/kg

Local costs of tyres have been advised at 10 to 25 mk/MWh or equivalent to 0.5 to 1.4 \$/GJ.

1.10 Combustion Gases

The site fuels given previously in 1.9 agree closely with ‘normalised/paradigm’ data in Appendix 1, with the exception of coal and natural gas which includes site corrections stated in section 1.9.1 & 1.9.4.

During, and subsequent to the visit to the Lahti plant, information was provided regarding the proportions of each fuel used both before and after the conversion of the boiler and these are summarised below in % of heat input below:

	Pre Conversion		**Post Conversion**	
	Min.	Max.	Min.	Max.
NG	20.0	40.0	15.0	40.0
Coal	60.0	80.0	45.0	70.0
Wood Waste & Bark	0.0	0.0	7.0	12.0
REF	0.0	0.0	1.0	5.0
Tyres	0.0	0.0	1.0	4.0

The evaluations of CO_2 emission quantities within section 1 of this report are dependant on the chosen fuel ratios used from the operating ranges indicated above. The limited amount of operating experience associated with the Lahti gasifier has meant that no ‘normal’ or ‘preferred’ operating data can be easily determined. A number of factors or explanations come in to play when establishing the fuel ratios associated with normal day to day operation of the Lahti plant and include the following:-

- Individual fuel prices.
- Plant loading conditions
- Environmental tax levies on emissions of CO_2, SO_2 and NO_x.
- Mechanical plant failure and maintenance.

The gasifier has only been in operation since January 1998 and unfortunately this has also coincided with a major equipment failure associated with the gas turbine used on the site. This has resulted in the reduced use of natural gas over the 1998 period. The evaluations completed in section 2 have been based upon the site data for 1997 and the 1998 data has been translated into a sensitivity analysis of results. The pre and post modification fuel ratios that have been used for section 2 evaluations are given in the table following:

	1997		**1998**	
	Pre Conversion	**Post Conversion**	**Pre Conversion**	**Post Conversion**
NG	40.0	40.0	20.0	20.0
Coal	60.0	45.0	80.0	69.0
Wood Waste & Bark	0.0	12.0	0.0	8.0
REF	0.0	2.0	0.0	2.0
Tyres	0.0	1.0	0.0	1.0

The CO_2 emission quantities given in section 2 reflect the above fuel ratios in conjunction with data given in Appendix 1 regarding the quantities of CO_2 produced from each fuel.

1.11 Net Plant Efficiency and Output Information

Lähden Lampövoima provided data giving the typical annual energy balance for the steam and power generation plant at Kymijarvi power station during 1997 and 1998.

	1997	1998	
Heat input from fuel	2087	2023	GWh
Heat as district heating	1042	1000	GWh
Energy as power	653	602	GWh_{so}
Power generated from BP turbine	492	NA	GWh_{so}
Power generated from Cond. Turbine	89	NA	GWh_{so}
Power generated from Gas Turbine	72	NA	GWh_{so}

The main boiler details give it a thermal capability of 360MWt measured as fuel into the boiler. This indicates a typical boiler load factor of between 55 and 62%. The power generated by the back pressure turbine in 1997 represents a load factor of 51% and similarly the condensing steam turbine has a 7% load factor and the GT a 19% load factor. The 1998 data represents an unusual set of data since the gas turbine was not operated for several months due to a generator problem and no breakdown of output from each generator is available.

The data provided from site indicates that the average net efficiency in generating power is between 29.5 and 31.5%. Similarly the average net efficiency in district heating steam generation is 49 to 51%.

No specific data on boiler efficiency has been provided but estimates below by Kennedy & Donkin reflect the contractors advice that net efficiency of the boiler has deteriorated by approximately 0.5% as a result of operation with the post modified fuel ratios.

Estimated efficiency on NCV, 91.6% prior to conversion for gasification.
Estimated efficiency on NCV, 91.1% subsequent to conversion for gasification.

These efficiency estimates also reflect the heat input breakdowns given in section 1.10.

The estimates of pre and post conversion boiler operating efficiency based on 1997 and 1998 site data allow an estimate of the pre and post conversion average power generation efficiencies below:

Year	1997	1998
Pre modified power generation efficiency	31.28	29.95
Post modified power generation efficiency	31.11	29.78

Since the boiler is common to both the back pressure and condensing operations of the turbine it was decided that the boiler should be representative of the overall plant loading factor. Therefore the maximum boiler capability has been utilised to estimate data representative of the 'normalised' 0.65 load factor for this case study.

Assuming no changes, in plant operating efficiency in going from 0.58 to 0.65 load factor the quantities of energy input from fuel, heat as district heating water and energy as power can be estimated as below:

Energy input from fuel	2270 GWh
Heat as district heating water	1121 GWh
Energy as power	676 GWh

1.12 Gasifier Performance and Simulation.

A detailed description of the process and equipment associated with the gasifier is included in section 1.4 of the report.

The following paragraphs look at the process design and simplified methods used within the study to simulate the operations of the gasifier.

The heat energy in the product gas from the gasifier appears in three forms:

- Chemical energy of the gases.
- Sensible heat of gases.
- Carbon dust.

The output capacity of the gasifier is related to the fuel feed rate, and the air feed rate then controls the temperature maintained in the gasifier. Coarse ash is removed from the gasifier using a water cooled bottom ash screw conveyor.

A simplified diagram of the gasifier is provided below and more detailed drawings can be found at the end of this appendix.

The biomass fuel ratios that the gasifier was originally designed to and subsequently has been operated with are given as a heat input percent in the table below:

	Wood & Bark	Waste Wood&Paper	REF	Tyres
Design	27	10	36	27
1998 operating	71.1	12.4	15.1	1.4

The contractor has provided data based on the above average 1998 operating conditions at an average thermal load of 47 MW_t that enables an estimate to be made of the mass ratio of product gas to fuel feed:

$$M_r = \frac{\text{Mass of gasifier product gas.}}{\text{Mass of gasifier fuel supplies.}} = 2.29$$

Energy balance and calorific value data provided by the contractor also verifies this value within a 4 % tolerance as seen by the following:

$$E_r = \frac{\text{Chemical and sensible heat in product gas.}}{\text{Heat in gasifier fuel supply}} = 0.42$$

The inverse of this $1/E_r = 2.37$

Therefore for the purpose of this study it is proposed to use a ratio of **2.33** between the amount of product gas produced per kilogram of fuel supplied.

The range and typical analysis of product gas being sent to the main boiler can be seen in the table below:

	Minimum	Maximum	Typical	Basis
Carbon Dioxide	17.0	19.8	19.3	Dry volume
Carbon Monoxide	4.5	9.0	6.8	Dry volume
Hydrogen	7.0	10.5	8.8	Dry volume
Remnant Hydrocarbons	3.4	6.0	5.1	Dry volume
Nitrogen	50.0	70.0	60.0	Dry volume
Moisture	20.0	60.0	33.0	As fired, wet volume
LHV MJ/Nm^3			2.8	As fired
MJ/kg			2.5	As fired

2. RESULTS

2.1 Reference Plant Calculations based on 1997 data.

Based upon the assumptions discussed in the previous section 1, estimations can be made regarding pre and post conversion fuel consumptions and CO_2 emissions on an annual basis for the 1997 station conditions:

		Pre Conversion	Post Conversion
Fuel		Coal + NG	Coal+NG+gasifier
Annual electricity generation	(GWh_{so})	653	653
Efficiency of power generation on NCV	(%)	31.3	31.1
Annual district heat production	(GWh)	1042	1042
Efficiency of steam production on NCV	(%)	49.9	49.4
Total annual heat input requirement	(TJ)	7513	7554
Annual NG consumption	(kte)	66.05	66.41
Annual black coal consumption	(kte)	186.51	140.64
Gasifier fuel consumption	(kte)	0	113.10
Annual fuel cost	(M$)	23.97	21.45
Annual fuel saving	(M$)	0	2.51
Annual generation CO_2	(kte)	595.6	497.7
Annual reduction in CO_2 emissions	(kte)	0	97.85

Both the 'Efficiency of power generation' and 'Efficiency of district heat production' are a measure of the energy exported as heat or power as a portion of the total net heat input to the plant. The combined efficiency of heat and power production on the site can be obtained by adding both of these figures to give values of 81.2 % and 81.0 % respectively.

These figures indicate a 16.4% reduction of CO_2 emissions resulting from the plant modification and fuel change to biofuels. The capital expenditure associated with the refurbishment and conversion of the station has been obtained and summarised in the table below.

Cost of refurbishment & conversion 13.92 M$

This represented a substantial investment in the station and had to be evaluated against the alternative options of FGD and modification of electrostatic precipitators in order to satisfy continued environmental pressure to reduce sulphur and particulate emissions from the plant.

Reference plant calculations are based on the following assumptions:-

- conversion work was largely carried out during the summer & autumn of 1997 with the period of boiler outage minimised to that associated with normal maintenance resulting in no additional loss of revenue.

- an average annual plant load factor taken as 0.61 related to the thermal capability of the main boiler as a heat input from fuel.

- additional operational and maintenance costs excluding fuel are increased by 0.07 M$ in association with the additional biomass fuel handling & storage facility.

- remnant life for cost evaluations is taken as 15 years (1998 to 2013).

- discount factors assumed for NPV calculations are 5% and 10%.

- interest rates assumed for annual loan repayments are 5% and 10% p.a.

2.1.1 Estimated benefits of conversion on loan basis.

The following financial evaluation of the station conversion is carried out at reference plant conditions using capital based on a mortgage type loan at 5% and 10% annual interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production (PL)		0.0	M$
Total cost of refurbishment(Cr+PL)		13.92	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A_{lr})	1.34	1.83	M$
Annual fuel saving (FS_r)	2.51	2.51	M$
Annual O&M saving (M_s)	-0.07	-0.07	M$
Annual labour saving (L_s)	0.0	0.0	M$
Net annual saving (FS_r-A_r+M_s+L_s)	1.10	0.61	M$
CO_2 reduction per annum		97.85	kte
GWh_{so} per annum		653	GWh_{so}
GWh steam per annum		1911.6	GWh
(i) Levelised saving per GWh_{so}	1690.60	941.50	$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	149.90	149.90	te/GWh_{so}
(iii) CO_2 prevention saving	11.28	6.28	$/te$CO_2$
(iv) Levelised saving on steam	577.30	321.50	$/GWh
(v) CO_2 reduction per GWh steam	51.19	51.19	te/GWh

2.1.2 Estimated Benefits of conversion on Capital from equity and NPV basis

The following financial evaluation of the station conversion is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production		0.00	M$
Total cost of refurbishment		13.92	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		97.85	kte
GWh_{so} per annum		652.80	GWh_{so}
GWh_{so} over reference plant life		9792.00	GWh_{so}
Annual heat in steam		1911.60	GWh
Through life heat in steam		28674.00	GWh
Annual fuel saving (FS_r)		2.51	M$
Annual O&M saving		-0.07	M$
Annual labour saving		0.00	M$
Total annual saving		2.44	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	10.8986	8.3667	
Discounted saving over remnant life (DS_r)	26.64	20.45	M$
NPV saving (DFS_r - C_r)	12.72	6.53	M$
(i) NPV levelised saving per GWh_{so}	1299.5	667.3	$\$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	149.9	149.9	te/GWh_{so}
(iii) CO_2 prevention savings	8.67	4.45	$\$/teCO_2$
(iv) NPV levelised saving on steam	443.8	227.9	$/GWh
(v) CO_2 reduction per GWh steam	51.19	51.19	te/GWh

2.2 Reference Plant Calculations based on 1998 data.

Based upon the assumptions discussed in previous section 1, estimations can be made regarding pre and post conversion fuel consumptions and CO_2 emissions on an annual basis for the 1998 station conditions:

		Pre Conversion	Post Conversion
Fuel		Coal + NG	Coal+ NG+gasifier
Annual electricity generation	(GWh_{so})	602.4	602.4
Efficiency of power generation on NCV	(%)	29.95	29.78
Annual district heat production	(GWh)	999.9	999.9
Efficiency of steam production on NCV	(%)	49.85	49.40
Total annual heat input requirement	(TJ)	7241	7282
Annual NG consumption	(kte)	31.83	32.01
Annual black coal consumption	(kte)	239.66	207.89
Gasifier fuel consumption	(kte)	0.00	79.95
Annual fuel cost	(M$)	22.08	20.34
Annual fuel saving	(M$)	0.00	1.74
Annual generation CO_2	(kte)	624.50	556.58
Annual reduction in CO_2 emissions	(kte)	0	67.91

Both the 'Efficiency of power generation' and 'Efficiency of district heat production' are a measure of the energy exported as heat or power as a portion of the total net heat input to the plant. The combined efficiency of heat and power production on the site can be obtained by adding both of these figures to give values of 79.8 % and 79.2 % respectively.

These figures indicate a 10.9% reduction of CO_2 emissions resulting from the plant modification and fuel change to biofuels.

The capital expenditure associated with the refurbishment and conversion of the station is identical to that in section 2.1:

Cost of refurbishment & conversion 13.92 M$

Reference plant calculations are based on the following assumptions:-

- conversion work was largely carried out during the summer & autumn of 1997 with the period of boiler outage minimised to that associated with normal maintenance resulting in no additional loss of revenue.
- an average annual plant load factor taken as 0.58 related to the thermal capability of the main boiler as a heat input from fuel.
- additional operational and maintenance costs excluding fuel are increased by 0.07 M$ in association with the additional biomass fuel handling & storage facility.

- remnant life for cost evaluations is taken as 15 years (1998 to 2013).
- discount factors assumed for NPV calculations are 5% and 10%.
- interest rates assumed for annual loan repayments are 5% and 10% p.a.

2.2.1 Estimated benefits of conversion on loan basis.

The following financial evaluation of the station conversion is carried out at reference plant conditions using capital based on a mortgage type loan at 5% and 10% annual interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production (PL)		0.0	M$
Total cost of refurbishment(Cr+PL)		13.92	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n$ x $(I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A_{lr})	1.34	1.83	M$
Annual fuel saving (FS_r)	1.74	1.74	M$
Annual O&M saving (M_s)	-0.07	-0.07	M$
Annual labour saving (L_s)	0.0	0.0	M$
Net annual saving (FS_r-A_r+M_s+L_s)	0.33	-0.16	M$
CO_2 reduction per annum		67.91	kte
GWh_{so} per annum		602.4	GWh_{so}
GWh steam per annum		1842.8	GWh
(i) Levelised saving per GWh_{so}	553.10	-258.70	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	112.73	112.73	te/GWh_{so}
(iii) CO_2 prevention saving	4.91	-2.29	$/te$CO_2$
(iv) Levelised saving on steam	180.80	-84.60	$/GWh
(v) CO_2 reduction per GWh steam	36.85	36.85	te/GWh

2.2.2 Estimated Benefits of conversion on Capital from equity and NPV basis

The following financial evaluation of the station conversion is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production		0.00	M$
Total cost of refurbishment		13.92	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		67.91	kte
GWh_{so} per annum		602.40	GWh_{so}
GWh_{so} over reference plant life		9036.00	GWh_{so}
Annual heat in steam		1842.80	GWh
Through life heat in steam		27642.00	GWh
Annual fuel saving (FS_r)		1.74	M$
Annual O&M saving		-0.07	M$
Annual labour saving		0.00	M$
Total annual saving		1.67	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	10.8986	8.3667	
Discounted saving over remnant life (DS_r)	18.25	14.01	M$
NPV saving (DFS_r - C_r)	4.33	0.09	M$
(i) NPV levelised saving per GWh_{so}	478.9	9.8	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	112.7	112.7	te/GWh_{so}
(iii) CO_2 prevention savings	4.25	0.09	$/te$CO_2$
(iv) NPV levelised saving on steam	156.5	3.2	$/GWh
(v) CO_2 reduction per GWh steam	36.85	36.85	te/GWh

2.3 Normalised Plant Calculations based on 1997 data.

Based upon the assumptions discussed in previous section 1 estimations can be made regarding pre and post conversion fuel consumptions and CO_2 emissions on an annual basis for the station under 'normalised' load conditions below:

		Pre Conversion	Post Conversion
Fuel		Coal + NG	Coal+ NG+gasifier
Annual electricity generation	(GWh_{so})	676	676
Efficiency of power generation on NCV	(%)	31.28	31.11
Annual district heat production	(GWh)	1105	1105
Efficiency of steam production on NCV	(%)	49.85	49.4
Total annual heat input requirement	(TJ)	7780	7823
Annual NG consumption	(kte)	67.21	67.58
Annual black coal consumption	(kte)	183.06	138.05
Gasifier fuel consumption	(kte)	0	117.12
Annual fuel cost	(M$)	17.12	15.54
Annual fuel saving	(M$)	0	1.58
Annual generation CO_2	(kte)	637.52	530.96
Annual reduction in CO_2 emissions	(kte)	0	106.6

These figures indicate a 16.7% reduction of CO_2 emissions resulting from the plant refurbishment and fuel change to biofuels.

The capital expenditure associated with the refurbishment and conversion of the station has been obtained and summarised in Section 2.1. The 'normalised' 1997 calculations are based on the following assumptions:-

- conversion work was carried out during the summer & autumn of 1997 within the period of boiler outage allocated for annual maintenance and hence no additional loss of revenue is applicable.
- an average annual plant load factor taken as 0.65 on the capability of the main boiler expressed in terms of heat input as fuel.
- additional operational and maintenance costs excluding fuel are increased by 0.07 M$.
- remnant life for cost evaluations is taken as 15 years (1998 to 2013).
- discount factors assumed for NPV calculations are 5% and 10%.
- interest rates assumed for annual loan repayments are 5% and 10% p.a.

2.3.1 Estimated benefits of conversion on loan basis.

The following financial evaluation of the station conversion is carried out at normalised plant conditions using capital based on a mortgage type loan at 5% and 10% annual interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production (PL)		0.0	M$
Total cost of refurbishment(Cr+PL)		13.92	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A_{lr})	1.34	1.83	M$
Annual fuel saving (FS_r)	1.58	1.58	M$
Annual O&M saving (M_s)	-0.07	-0.07	M$
Annual labour saving (L_s)	0.0	0.0	M$
Net annual saving (FS_r-A_r+M_s+L_s)	0.17	-0.32	M$
CO_2 reduction per annum		106.6	kte
GWh_{so} per annum		676	GWh_{so}
GWh steam per annum		1979.5	GWh
(i) Levelised saving per GWh_{so}	247.5	-475.9	$\$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	157.64	157.64	te/GWh_{so}
(iii) CO_2 prevention saving	1.57	-3.02	$\$/teCO_2$
(iv) Levelised saving on steam	84.5	-162.5	$/GWh
(v) CO_2 reduction per GWh	53.83	53.83	te/GWh

2.3.2 Estimated Benefits of conversion on Capital from equity and NPV basis

The following financial evaluation of the station conversion is carried out at normalised plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production		0.0	M$
Total cost of refurbishment		13.92	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		106.6	kte
GWh_{so} per annum		676	GWh_{so}
GWh_{so} over reference plant life		10140	GWh_{so}
Annual heat in steam		1979.5	GWh
Through life heat in steam		29693	GWh
Annual fuel saving (FS_r)		1.58	M$
Annual O&M saving		-0.07	M$
Annual labour saving		0.0	M$
Total annual saving		1.51	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS_r)	16.44	12.62	M$
NPV saving ($DFS_r - C_r$)	2.52	-1.30	M$
(i) NPV levelised saving per GWh_{so}	248.5	-128.2	$\$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	157.64	157.64	te/GWh_{so}
(iii) CO_2 prevention savings	1.58	-0.81	$\$/teCO_2$
(iv) NPV levelised saving on steam	84.9	-43.8	$/GWh
(v) CO_2 reduction per GWh	53.8	53.8	te/GWh

2.4 Normalised Plant Calculations based on 1998 data.

Based upon the assumptions discussed in previous section 1 estimations can be made regarding pre and post conversion fuel consumptions and CO_2 emissions on an annual basis for the station under 'normalised' load conditions below:

		Pre Conversion	Post Conversion
Fuel		Coal + NG	Coal+ NG+gasifier
Annual electricity generation	(GWh_{so})	676	676
Efficiency of power generation on NCV	(%)	29.95	29.78
Annual district heat production	(GWh)	1105	1105
Efficiency of steam production on NCV	(%)	49.85	49.4
Total annual heat input requirement	(TJ)	8126	8172
Annual NG consumption	(kte)	35.10	35.30
Annual black coal consumption	(kte)	254.92	221.12
Gasifier fuel consumption	(kte)	0	89.72
Annual fuel cost	(M$)	17.06	15.88
Annual fuel saving	(M$)	0	1.18
Annual generation CO_2	(kte)	730.17	650.03
Annual reduction in CO_2 emissions	(kte)	0	80.14

These figures indicate a 11.0% reduction of CO_2 emissions resulting from the plant refurbishment and fuel change to biofuels.

The capital expenditure associated with the refurbishment and conversion of the station has been obtained and summarised in Section 2.1. The 'normalised' 1998 calculations are based on the following assumptions:-

- conversion work was carried out during the summer & autumn of 1997 within the period of boiler outage allocated for annual maintenance and hence no additional loss of revenue is applicable.
- an average annual plant load factor taken as 0.65 on the capability of the main boiler expressed in terms of heat input as fuel.
- additional operational and maintenance costs excluding fuel are increased by 0.07 M$.
- remnant life for cost evaluations is taken as 15 years (1998 to 2013).
- discount factors assumed for NPV calculations are 5% and 10%.
- interest rates assumed for annual loan repayments are 5% and 10% p.a.

2.4.1 Estimated benefits of conversion on loan basis.

The following financial evaluation of the station conversion is carried out at normalised plant conditions using capital based on a mortgage type loan at 5% and 10% annual interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production (PL)		0.0	M$
Total cost of refurbishment(Cr+PL)		13.92	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A_{lr})	1.34	1.83	M$
Annual fuel saving (FS_r)	1.18	1.18	M$
Annual O&M saving (M_s)	-0.07	-0.07	M$
Annual labour saving (L_s)	0.0	0.0	M$
Net annual saving (FS_r-A_r+M_s+L_s)	-0.23	-0.72	M$
CO_2 reduction per annum		80.14	kte
GWh_{so} per annum		676	GWh_{so}
GWh steam per annum		2067.95	GWh
(i) Levelised saving per GWh_{so}	-336.7	-1060.2	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	118.6	118.6	te/GWh_{so}
(iii) CO_2 prevention saving	-2.84	-8.94	$/te$CO_2$
(iv) Levelised saving on steam	-110.1	-346.6	$/GWh
(v) CO_2 reduction per GWh steam	38.75	38.75	te/GWh

2.4.2 Estimated Benefits of conversion on Capital from equity and NPV basis

The following financial evaluation of the station conversion is carried out at normalised plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		13.92	M$
Cost of lost power production		0.0	M$
Total cost of refurbishment		13.92	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		80.14	kte
GWh_{so} per annum		676	GWh_{so}
GWh_{so} over reference plant life		10140	GWh_{so}
Annual heat in steam		2067.9	GWh
Through life heat in steam		31019	GWh
Annual fuel saving (FS_r)		1.18	M$
Annual O&M saving		-0.07	M$
Annual labour saving		0.0	M$
Total annual saving		1.11	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS_r)	12.14	9.32	M$
NPV saving (DFS_r - C_r)	-1.78	-4.60	M$
(i) NPV levelised saving per GWh_{so}	-176.0	-454.1	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	118.55	118.55	te/GWh_{so}
(iii) CO_2 prevention savings	-1.48	-3.83	$/te$CO_2$
(iv) NPV levelised saving on steam	-57.5	-148.4	$/GWh
(v) CO_2 reduction per GWh steam	38.75	38.75	te/GWh

3. DISCUSSIONS AND CONCLUSIONS

The following tables summarise the evaluation criteria behind the judgements given in this section:

At 1997 reference plant conditions:

Interest & Discount rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	\$/GWh	1690.6	1299.5	941.5	667.3
(ii)	te/GWh	149.9	149.9	149.9	149.9
(iii)	\$/teCO_2	11.28	8.67	6.28	4.45
(iv)	\$/GWh	577.3	443.8	321.5	227.9
(v)	\$/GWh	51.19	51.19	51.19	51.19

At 1998 reference plant conditions:

Interest & Discount rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	\$/GWh	553.1	478.9	-258.7	9.8
(ii)	te/GWh	112.7	112.7	112.7	112.7
(iii)	\$/teCO_2	4.91	4.25	-2.29	0.09
(iv)	\$/GWh	180.8	156.5	-84.6	3.2
(v)	\$/GWh	36.85	36.85	36.85	36.85

At normalised plant conditions based on 1997 data:

Interest & Discount rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	\$/GWh	247.5	248.5	-475.9	-128.2
(ii)	te/GWh	157.6	157.6	157.6	157.6
(iii)	\$/teCO_2	1.57	1.58	-3.02	-0.81
(iv)	\$/GWh	84.5	84.9	162.5	-43.8
(v)	\$/GWh	53.8	53.8	53.8	53.8

At normalised plant conditions based on 1998 data:

Interest & Discount rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	\$/GWh	-336.7	-176.0	-1060.2	-454.1
(ii)	te/GWh	118.6	118.6	118.6	118.6
(iii)	\$/teCO_2	-2.84	-1.48	-8.94	-3.83
(iv)	\$/GWh	-110.1	-57.5	-346.6	-148.4
(v)	\$/GWh	38.75	38.75	38.75	38.75

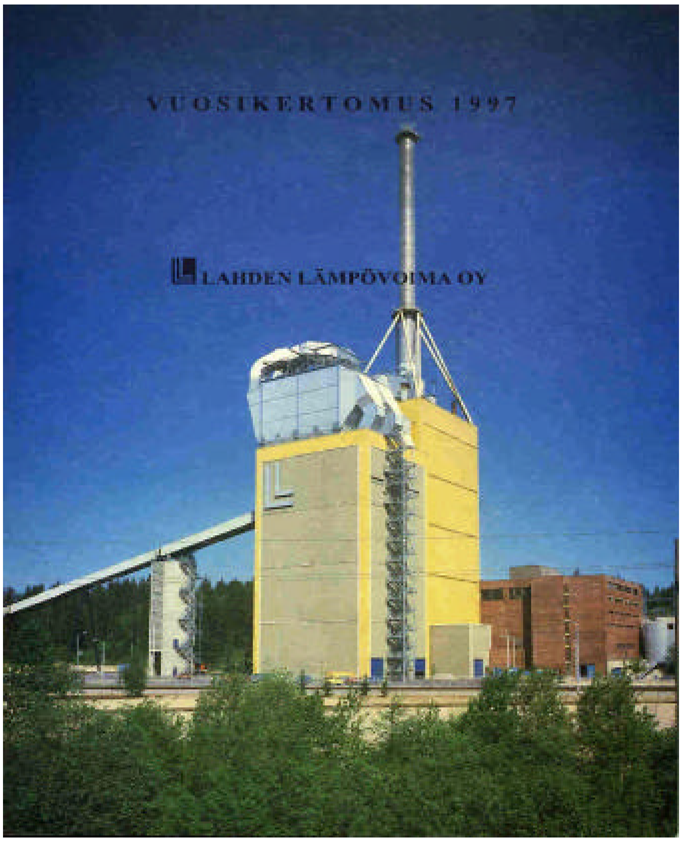
It is apparent from the above tables that although significant reductions in CO_2 emissions can be accomplished (112 to 158 te/GWh$_{so}$) these have incurred significant cost (negative saving) in all of the normalised plant conditions except the 1997 5% loan & discount rate conditions.

Merit figure (iii) above gives the ultimate evaluation of the viability of this case study and shows it to be marginal at between –9 (i.e. cost) and 11 (i.e. saving) \$/teCO_2 reduction in emissions.

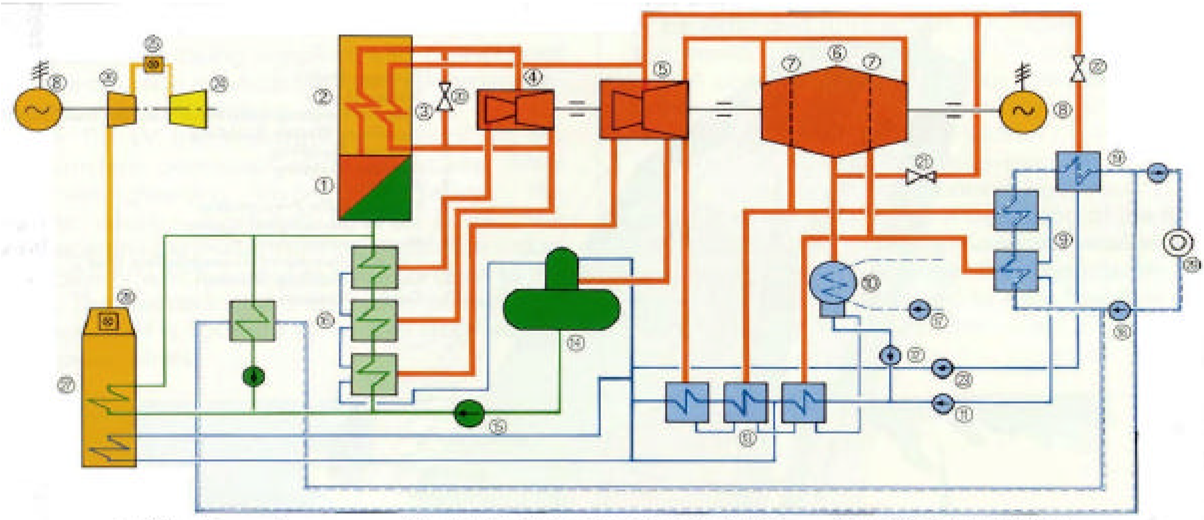
The more favourable evaluation of this case study at reference plant conditions rather than normalised conditions must be associated with the higher fossil fuel costs in Finland which give greater potential for fuel cost savings.

Similar to other case studies the loan evaluation method gives a wider range of merit figures than those obtained from the capital from equity & NPV method.

1. **Kymijarvi power station.**



2. Steam cycle diagram.



1. Boiler Evaporator
2. Superheater
3. Reheater
4. HP Turbine
5. MP Turbine
6. LP Turbine
7. Control Guide Vanes
8. Generator
9. District Heating Heat Exchangers
10. Condenser
11. District Heating Condensate Pumps
12. Main Condensate Pumps
13. Condensate Preheaters
14. Feed Water Tank
15. Feed Water Pumps
16. Feed Water Preheaters
17. Cooling Water Pumps
18. District Heating Circulation Pumps
19. Reduction Heat Exchanger (RHE)
20. HP Reduction Station
21. LP Reduction Station
22. RHE Reduction Station
23. RHE Condensate Pump
24. Gas Turbine Compressor
25. Combustion Chambers
26. Gas Turbine
27. Heat Recovery Boiler
28. Additional Burner
29. District Heating Network

3. Plant Details for Lahti.

GASIFIER DATA

Fuel Input	40 – 70 MW_t, moisture 20 – 50 %
Fuels	Wood Waste Bark Sawdust Originator Classified Refuses (REF) Biomass

MAIN BOILER AND STEAM DATA

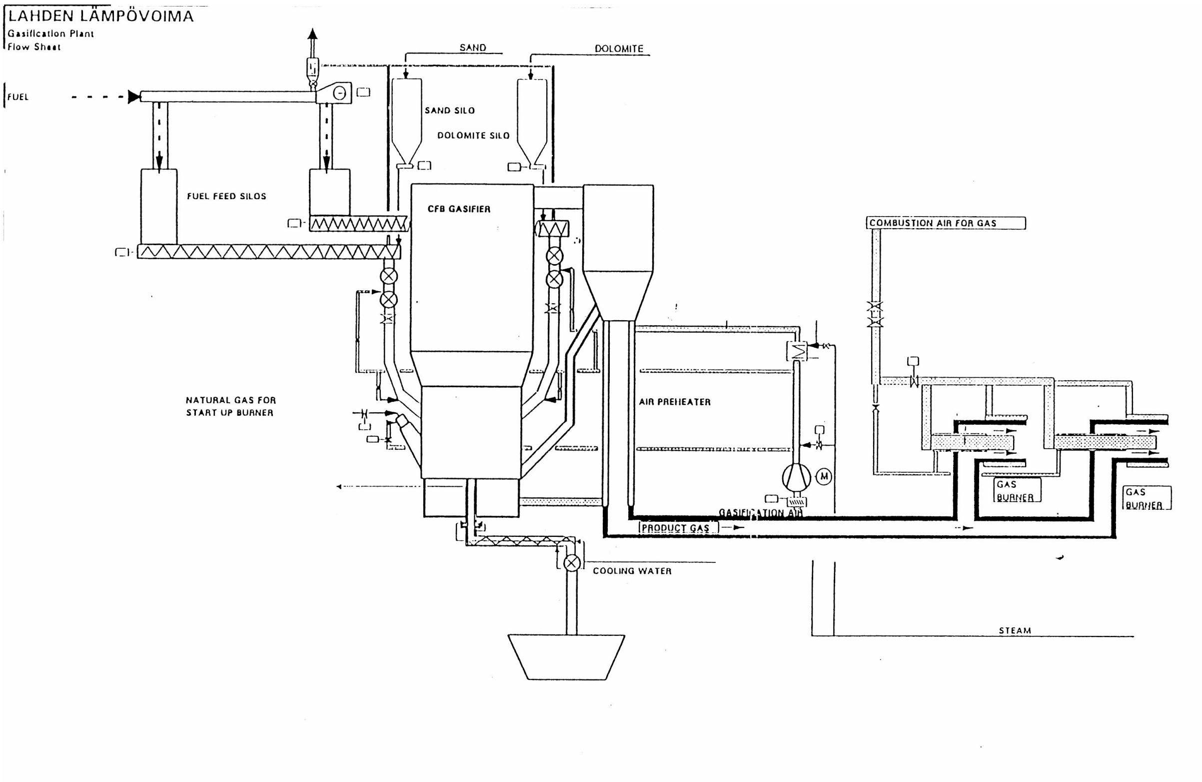
Fuels	Coal, Natural Gas, Gasifier Gas, and Heavy Fuel Oil (redundant)
Boiler type	Once through Benson with reheat.

Total Heat Output	360	MW_t maximum
Steam Flow	125	kg/s
Steam Pressure 170/40	bar	
Steam Temperature	540/540	ºC
Electricity Output	138	MWe
District Heat Output	240	MW_t maximum

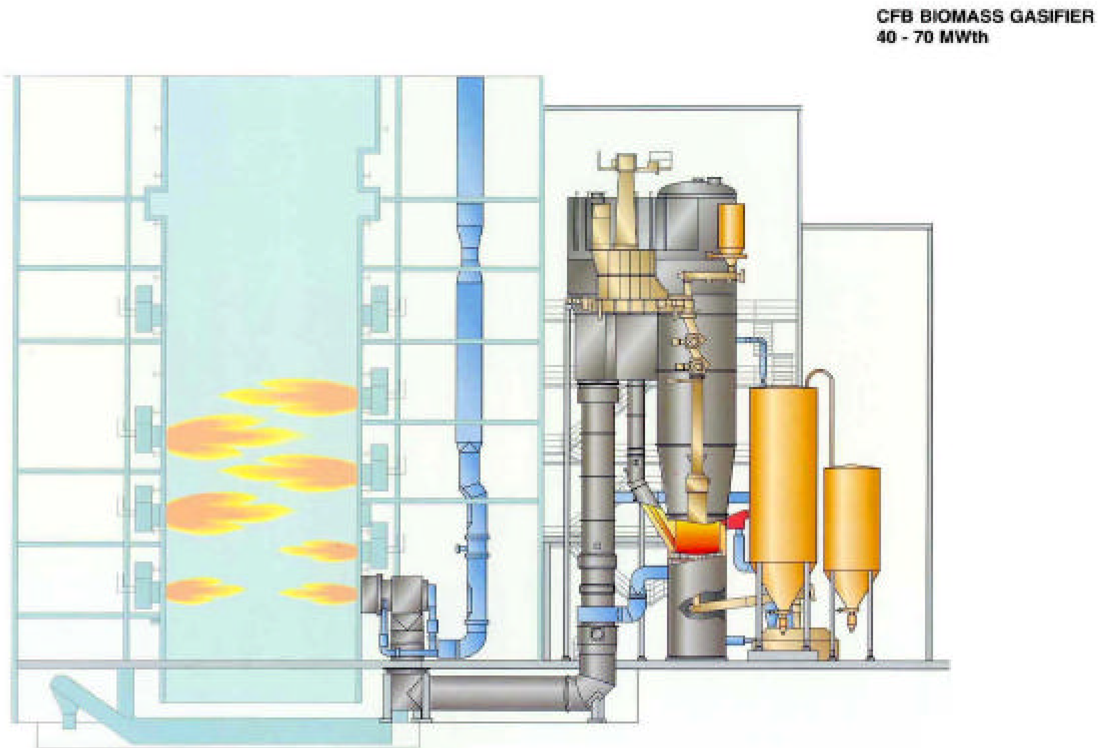
SCHEDULE

Contract Award	January	1996
Start of Erection	April	1997
Commercial Operation	March	1998

4. Gasifier Diagram



5. Gasifier & boiler diagram



APPENDIX 7

CASE 5

POWER STATION MODIFICATION AND FUEL CONVERSION FROM PEAT TO BIOMASS (WOOD CHIP & WASTE)

1. PLANT DESCRIPTION

1.1 General

The Simpele boiler conversion project involves the conversion of 1 x 100MWt unit from operation on peat and Heavy Fuel Oil (HFO) to operation on peat, wood waste, waste paper sludge and HFO. The study concentrates upon the conversion of the boiler from a conventional solid fuel boiler to a bubbling fluidized bed.

Simpele represents a small industrial electrical capability of 33 MWe (including hydro turbines), on the eastern section of the Finnish National Grid.

The plant is on the site of a large paper mill and produces both electricity and process steam for use in the mill.

1.2 Plant Prior to Modification

The original power station at Simpele was commissioned by Ahlstrom and completed in 1976 and comprised of:

- Conventional pulverised peat boiler having capability of 33.3kg/s at 535^0C & 113.5 bar.
- Conventional HFO boiler for producing 20kg/s of 25 bar process steam when the main boiler is on maintenance.
- A 18.3 MWe back pressure steam turbine exhausting to the 5 bar steam header with a 25 bar pass out to the 25 bar steam header.
- A 14 MWe, 25 bar condensing steam turbine using river water cooling and including feedwater/condensate heating and deaeration.

Prior and post to the conversion Simpele power station used heavy fuel oil with sulphur contents of below 1%.

Photographs and a diagram of the power station are included at the end of this appendix to illustrate the visual impact of the plant both prior and post conversion modifications together with the configuration of the site power & steam system(s).

1.3 Brief History and Decision Process

Simpele is a paper mill complex having 3 production facilities generating cardboard, paper and cartons in the following quantities respectively 140kte, 50kte and 9kte per annum. The majority of production from the plant is exported and sales average 1000 million Finnish marks per annum.

Eighteen months ago the whole complex was purchased by Metsa Serla and they conducted studies into options to improve efficiency and productivity. These studies included the steam & power generation facilities as well as the main paper mills.

The conventional pulverised peat boiler was approaching 20 years old and the peat fuel handling systems were proving unreliable and giving excessive maintenance problems.

The Finnish equivalent to the U.K. Environment Agency was also applying pressure on the site to reduce its emissions of NO_x, SO_x and particulates from both boilers but particularly the peat one.

Investigations in to the remnant life of the peat boiler showed the plant to be capable of further 15 years of operation.

Similar investigations on the steam turbines, and condenser also indicated 15 years of remnant life.

The escalation of fossil fuel prices, including local peat, in recent years encouraged a review of the use of biomass fuels for potential fuel substitution. This review identified the potential for the use of wastes from the paper mill waste water treatment plant since this predominantly contained paper and the current on site storage facility was approaching capacity limitations. In association with the paper, cardboard and carton product facilities, wood bark and wood waste was also identified as a potential biomass fuel substitute for peat.

The development of fluidised bed combustion technology provided Metsa-Serla and Foster Wheeler with the opportunity to investigate the most cost effective method of modernising the main boiler at Simpele in order to comply with more stringent emissions legislation, greater fuel flexibility and improved reliability and maintenance.

1.4 Modification Details

Since the original pulverised peat boiler was an Ahlstrom design all the original details were available to Foster Wheeler. Their proposal involved changes/modifications in the following areas of the boiler:-

- Pressure Parts
  - removal of lower furnace walls and headers and replacement with pressure parts associated with a retrofit bubbling fluidised bed.
  - part replacement of downcomers and circulating pipework.

	- removal of integral drum desuperheater and installation of an interstage spray type desuperheater. - installation of cyclone separators within the steam drum.
• Fuel handling plant	- complete new boilerhouse fuel feed system. - new delivery unloading, storage and conveyor system for the biomass wood bark & waste fuels.
• Burners	- renewal of HFO burners for start up & load support.
• Air & fuel gas systems	- modification and modification of FD fan. - new fluidising air fan. - new flue gas recirculation fan. - new ID fan. - new ducts and replacement of bellows & dampers as necessary. - replace tubing in main air heater. - new air preheater utilising previous district heat exchanger. - modification of ESP.
• Bottom ash system	- 3 new water cooled screw conveyors and one ordinary screw conveyor. - new drag chain conveyor and other ancillary equipment.
• Bed make up system	- new sand silo. - new fill lines and feed system.
• Others	- acid cleaning of furnace. - replacement of furnace refactories. - replacement of insulation and cladding as necessary. - new maintenance platforms and bottom constant load supporting system to accommodate additional weight/loads. - replacement electrical and instrumentation. - new DCS. - erosion protection facilities local to tube banks. - installation of a new filter cake (waste sludge) dewatering facility and conveyor system.

The decision to go ahead with the modifications was made in October 1996 and civil work began in March 1997. The new pressure parts were assembled under a temporary shelter outside the boilerhouse. The existing boiler was taken out of service at the beginning of July 1997 and returned to operation 10 weeks later in the middle of September 1997.

The case study consider the alterations associated with the fluidized bed furnace as satisfying the requirements associated with an “Efficiency improvement of boiler plant” and the new fuel handling to be associated with a “Partial substitution of primary fuel from a renewable source”. Therefore this case study satisfies 2 of the 5 types of retrofit identified in the study terms of reference.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is determined by both the changes in fuels and efficiency changes associated with the boiler conversion. Although the carbon content and NCV of both peat and wood bark/waste are similar the principal benefit with regard to greenhouse gas reduction is the classification of wood bark and paper waste sludge as biofuels and hence zero CO_2 emission fuel. The results in Section 2 are calculated for the whole station burning pre and post conversion fuel mixes together with efficiency change evaluations on the original fuel mix. The amounts of CO_2 generated by the combustion of all ‘normalised/ paradigm’ study fuels is addressed in Appendix 1.

Sections 1.9.1 to 1.9.4 address the discrepancies between the ‘normalised’ and site fuels in detail but only HFO requires any correction to be evaluated.

The NO_x reduction achieved as a result of the lower combustion temperature of the fluidised bed boiler and is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Experiments to measure N_2O concentrations in flue gases on other plant have proved unsuccessful and hence any change in the greenhouse gas N_2O is not considered in this case. It should be noted that low NO_x burners would have had to have been considered if the boiler conversion had not been made to comply with the tighter emission consents being applied by the Finnish Environment Agency. Difficult to evaluate is the CH_4 emissions that would have resulted from continued storage and decomposition of the waste water sludge.

1.6 Determination of capital costs

The capital costs have been based upon quotations received by Metsa Serla from contractors including Foster Wheeler.

The contract was awarded to Foster Wheeler in 1997 at the sum of 65 million Finnish Marks. This price included for the ESP modifications but did not include for the new outdoor biomass wood waste unloading, storage and conveyor system or sludge drying system.

The price of the ESP modifications is estimated at 7.55 million Marks and the cost of the biomass unloading, storage and conveyancey systems at 5 million Marks.

This gives a capital expenditure for the changes as below:-

Cost of boiler modifications	57.45 MFMk (11.42M$)
Total cost including modifications for biomass fuel	62.45 MFMk (12.38 M$)

It was possible to minimize outage to the 10 week period by completion of all work except tie in work adjacent to the boiler and whilst the unit continued in operation.

During the 10 week outage period the second 25 bar process steam boiler satisfied all paper mill steam requirements and electricity was bought in at 15 Finnish pence/kWh to cover the paper mill electricity demand of approximately 20 MWe constant load.

1.7 Determination of Fuel, Operating and Maintenance Costs

In comparing net outputs between operation on peat and peat plus biomass there were minor differences in boiler efficiencies on the unit. These were advised by the station and have been detailed in Section 1.11.

Reduced fouling and corrosion features associated with reduced peat firing and the modifications have enabled savings on maintenance to be achieved. This is estimated to be approximately 1.2 million Fn Mk (0.24M$).

There are labour savings associated with the reduction of operating personnel on the plant estimated at 1.0 million FnMk (0.2M$).

The current plant utilisation profile is such that the boiler is only inoperative during the one week annual maintenance period and 2 or 3 days per annum unscheduled outages.

During the preceding 12 months to this study the unit had achieved an availability in excess of 8600 hours i.e. 98%.

The data on estimated and actual operating fuel consumptions, net output, utilisation and the operating and maintenance costs are itemised under Sections 1.11 and 2.

1.8 Changes to Non-Greenhouse Gas Emissions

The decision to fit a bubbling fluidized bed for the combustion of all fuels meant a reduction of furnace combustion temperatures and hence emissions of NO_x to within EEC and Finnish regulatory requirements.

The environmental requirements stipulated by the Finnish environment Agency for SO_x emissions were less than 190 mg/Nm^3 with reference to 3% O_2 in dry flue gas. The respective particulate levels had also been reduced to 50mg/Nm^3. The modifications to the boiler and precipitator enabled the plant to comfortably achieve these emission limitations whereas the original plant would not have been capable of achieving the new limits being impose.

1.9 Site Fuel data

1.9.1 Heavy Fuel Oil (HFO)

The site specification for HFO is based upon a net calorific value (NCV) of 41.8 MJ/kg and having an analysis comprising of 87% carbon and less than 0.5% sulphur by weight.

This analysis represents a very low sulphur heavy fuel oil. Such a fuel oil can only be achieved by mixing greater quantities of distillate fuel oil with conventional heavy fuel oil than is the normal practice in the UK. This data suggests the site HFO is better quality than that used with "normalised" heavy fuel oils given by Appendix 1.

Therefore the following correction factors should be considered as an explanation when comparing differences between "actual" and "normalised" calculations for fuel quantities and CO_2 emissions in section 2.

Site fuel consumption correction $= \frac{40.5}{41.8} = 0.9689$

Site fuel CO_2 emission $= \frac{40.5}{41.8} \times \frac{0.87}{0.84} = 1.0035$

Site fuel costs for HFO have been advised at 53 and 83 mk/MWh dependent on its use for electricity or district heating respectively. These figures equate to 10.5 and 16.5 $/MWh or 2.9 and 4.6 $/GJ. The site energy balance in section 1.11 suggests an average cost at site would be 3.94 $/GJ and site evaluations in section 2 are on this basis.

The "normalised" UK costs of HFO in Appendix 1 are:

2.5%S = 3.4 $/GJ
1.0%S = 4.0 $/GJ

Therefore linear interpolation gives a theoretical cost for 0.5%S HFO = 4.2 $/GJ on the UK market.

This suggests a correction for site fuel oil costs would be between 2.9/4.0 and 4.6/4.0 i.e 0.725 and 1.15 of typical costs for UK 1%S HFO dependent on its use for power or steam. The average site cost of 3.94 $/GJ compares within a 10% tolerance of the 'Normalised' UK fuel cost for 1% S HFO at 4 $/GJ.

1.9.2 Peat

Information from Finland has indicated the following typical and range of peat supplies used at Simpele on a % by weight basis:

	Typical	Range	Basis
C	55.0		Dry solids
H	5.5		Dry solids
O	30.5		Dry solids
N	1.7		Dry solids
S	0.3		Dry solids
Ash	7.0	0 to 10	Dry solids
Moisture	48.0	40 to 55	As fired
NCV (MJ/kg)	9.8	8.1 to 11.7	As fired

Typical Finnish costs for peat are given as 47 and 56 mk/MWh for electricity and district heating use respectively. These costs equate to 2.6 and 3.1 $/GJ.

No significant reserves of peat are available on the mainland UK. The only UK mining of peat is in parts of Scotland and there are extensive reserves available in Northern Ireland. No specific details have been obtained.

1.9.3 Wood Wastes and Bark

Information from Finland has indicated the following typical and range of wood supplies used at Simpele and Lahti on a % by weight basis:

	Typical	Range	Basis
C	52.5	50.4 to 54.5	Dry solids
H	6.0	5.9 to 6.2	Dry solids
O	40.0	37.6 to 42.5	Dry solids

N	0.4	0.3 to 0.5	Dry solids
S	0		Dry solids
Ash	1.1	0.4 to 1.7	Dry solids
Moisture	53.5	47 to 60	As fired
NCV (MJ/kg)	7.85	6.7 to 9.0	As fired

Typical Finnish costs for these wood based fuels are 42 mk/MWh which equates to 2.32 $/GJ.

The above ranges of analysis are in agreement with other sources of information on various wood analysis and therefore no corrections are proposed.

1.9.4 Paper Waste Sludge

This fuel source is unique to the Simpele site and the following analysis data on a % weight basis has been provided.

	Typical	**Basis**
C	35.7	Dry solids
H	4.4	Dry solids
O	25.5	Dry solids
N	1.4	Dry solids
S	0.7	Dry solids
Ash	32.3	Dry solids
Moisture	69	As fired
NCV (MJ/kg)	2.3	As fired

As the sludge is obtained from paper mill waste water treatment processes it can be considered to be free or zero cost. The financial evaluations in section 2 have utilised a cost of 0.01 $/GJ to avoid spreadsheet problems with zero values.

1.10 Combustion Gases

The site fuels given previously in 1.9 agree closely with 'normalised/paradigm' data in Appendix 1, with the exception of HFO which includes site corrections stated in section 1.9.1.

During the visit to the Simpele plant Metsa Serla provided information regarding the proportions of each fuel used both before and after the conversion of the boiler and these are summarised below in % of heat input.

	Pre Conversion	Post Conversion
Heavy Fuel Oil	12.00	5.0
Peat	86.00	55.0
Wood Waste & Bark	2.00	35.0
Waste Paper Sludge	0.0	5.0

CO_2 emission quantities given in section 2 reflect the above fuel ratios in conjunction with data given in Appendix 1 regarding the quantities of CO_2 produced from each fuel.

1.11 Net Plant Efficiency and output information

Metsa Serle provided data giving the typical annual energy balance for the steam and power generation plant at Simpele prior to conversion:

Heat input from fuel	668	GWh
Heat to 110 bar steam	570	GWh
Heat to process steam	348	GWh
Heat in steam for power generation	222	GWh
Power generated from BPT	71	GWh_{so}
Power generated from Cond T	44	GWh_{so}

The main boiler details give it a thermal capability of 100MWt measured as heat into steam. This indicates a boiler load factor of 65%. The power generated by the back pressure turbine represents an approximate 44% load factor and similarly the condensing steam turbine has a 36% load factor.

The data above indicates that the average net efficiency of both turbines in generating power from steam is 51.7%. The operating efficiency of each turbine can be estimated approximately to be 83% for the back pressure turbine and 32% for the condensing turbine but no data is available to verify this accurately.

Boiler performance tests carried out prior to modification (1994) and subsequent to modification (1998) and using the same fuel ratios as indicated for the pre-conversion case in section 1.10 are summarised below:

1994 test efficiency on NCV 89.28%
1998 test efficiency on NCV 90.27%

The heat balance data seen at the beginning of this section indicates that the actual operating efficiency of the boiler was only 85.3% as a result of blowdown and other losses. This is very poor and represents an extremely fouled condition being present before modification. Therefore the post conversion operating efficiency of the boiler is likely to be more accurately represented by a figure of 89.3% based on the same fuel ratios.

These estimates of pre and post conversion boiler operating efficiency allow an estimate of pre and post conversion average power cycle efficiencies at 44.1% and 46.1% respectively. Whilst it is apparent that the site could generate power more efficiently by greater utilisation of the back pressure turbine this is not practical since the condensing turbine has to maintain sufficient load to ensure adequate preheating of boiler feedwater.

Based upon the test and operating efficiencies given on the previous page, the boiler test and operating efficiencies for the post conversion biomass fuel ratios given in section 1.10 have been estimated below:

Estimated post conversion test efficiency	88.4	%
Estimated post conversion operating efficiency	87.4	%

Since the heat/energy balance information provided at site reference conditions coincides with the 'normalised' load factor of 0.65 it is proposed to only complete one set of detailed financial evaluation calculations representing the reference plant conditions. Only summary information of the changes occurring and revised figures of merit associated with normalised conditions are included in section 2.2.

2. RESULTS

2.1 Reference Plant Calculations

Based upon the assumptions discussed in previous section 1 estimations can be made regarding pre and post conversion fuel consumptions and CO_2 emissions on an annual basis for the station:

	Pre Conversion	Post conversion	
Fuel	Peat + HFO	Peat + HFO	Peat +Wood
Annual Electricity Generation (GWh$_{so}$)	115	115	115
Efficiency of Power Generaton on NCV (%)	44.1	46.1	45.2
Annual Process steam production (GWh)	348	348	348
Efficiency of steam production on NCV (%)	85.3	89.3	87.4
Total annual heat input requirement (TJ)	2407.5	2301.0	2349.3
Total annual fuel consumption (kte)	224.3	214.4	290.5
Annual fuel cost (M$)	7.27	6.95	6.13
Annual fuel saving (M$)	0	0.32	1.14
Annual generation CO_2 (kte)	242.0	231.3	146.3
Annual reduction in CO_2 emissions (kte)	0	10.71	95.78

These figures indicate a 4.4% reduction of CO_2 emissions resulting from the boiler modifications carried out and a total 39.6% reduction of CO_2 emissions resulting from the modification and fuel change to biofuels. The capital expenditure associated with the modification and biomass conversion of the station have been obtained and summarised in the table below.

Estimated cost of modification	11.42 M$
Combined cost of modification and fuel conversion	12.38 M$

This represents a substantial investment in the station and had to be considered against the future requirement for installation of FGD before the year 2003. The new modifications would also enable in bed desulphurisation to be considered, if required at a later date.

Indication of the potential ratio between modification cost and fuel conversion cost is given in the above text and calculations are based on the following assumptions:-

- conversions and modification work was largely carried out during the spring and summer of 1997 with the period of boiler outage restricted to a 10 week period where additional loss of revenue is calculated for a 20 MWe load at a rate of 2.98 cents/kWh.

- an average annual plant load factor taken as 0.65 on the steam output capability of the main boiler

- operational and maintenance savings excluding fuel and labour are reduced by 0.24 M$.
- remnant life for cost evaluations is taken as 15 years (1997 to 2012).
- discount factors assumed for NPV calculations are 5% and 10%.
- labour savings from fuel conversion are approximated to 0.2 M$ per annum.
- interest rates assumed for annual loan repayments are 5% and 10% p.a.

2.1.1 Estimated benefits of modification on loan basis.

The following financial evaluation of the station modification is carried out at reference plant conditions using capital based on a mortgage type load at 5% and 10% annual interest rates over the remnant life of the station.

Cost of modification (C_r)		11.42	M$
Cost of lost power production (PL)		1.0	M$
Total cost of modification(Cr+PL)		12.42	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A_{lr})	1.197	1.633	M$
Annual fuel saving (FS_r)	0.32	0.32	M$
Annual O&M saving (M_s)	0.24	0.24	M$
Annual labour saving (L_s)	0.20	0.20	M$
Net annual saving (FS_r-A_r+M_s+L_s)	-0.435	-0.871	M$
CO_2 reduction per annum		10.71	Kte
GWh_{so} per annum		115.0	GWh_{so}
GWh steam per annum		570.8	GWh
(i) Levelised saving/cost per GWh_{so}	-3780	- 7574	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	93.12	93.12	te/GWh_{so}
(iii) CO_2 prevention saving	-40.59	-81.34	$/te$CO_2$
(iv) Levelised saving per steam	- 761.6	- 1526	$/GWh
(v) CO_2 reduction per GWh	18.76	18.76	te/GWh

2.1.2 Estimated Benefits of Modification and Fuel Conversion on Loan Basis.

The following financial evaluation of the station modification and conversion is carried out at reference plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Cost of modification & conversion (C_{r+c})		12.38	M$
Cost of lost power production		1.0	M$
Total cost of modification		13.38	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n -1)\}$	0.0963	0.1315	
Annual loan repayment (A_{LR2})	1.29	1.76	M$
Annual fuel saving (FS_{r+c})	1.14	1.14	M$
Annual Labour saving (LS_{r+c})	0.2	0.2	M$
Annual O&M saving (MS_{r+c})	0.24	0.24	M$
Net annual saving(FS_{r+c}+LS_{r+c}+MS_{r+c}-A_{LR2})	0.29	-0.18	M$
CO_2 reduction per annum		95.78	kte
GWh_{so} per annum		115	GWh_{so}
GWh steam per annum		570.8	GWh
Levelised saving/cost per GWh_{so}	2557	-1530	$/$GWh_{so}$
CO_2 reduction per GWh_{so}	832.9	832.9	te/GWh_{so}
CO_2 prevention saving	3.07	-1.84	$/te$CO_2$
Levelised saving per GWh steam	515.6	-308.6	$/GWh
CO_2 reduction per GWh steam	167.9	167.9	te/GWh

2.1.3 Estimated Benefits of Modification on Capital from equity and NPV basis

The following financial evaluation of the station modification is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of modification (C_r)		11.42	M$
Cost of lost power production		1.0	M$
Total cost of modification		12.42	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		0.71	kte
GWh_{so} per annum		115	GWh_{so}
GWh_{so} over reference plant life		1725	GWh_{so}
Annual heat in steam		570.8	GWh
Through life heat in steam		8562.0	GWh
Annual fuel saving (FS_r)		0.32	M$
Annual O&M saving		0.24	M$
Annual labour saving		0.2	M$
Total annual saving		0.76	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS_r)	8.30	6.37	M$
NPV saving ($DFS_r – C_r$)	-4.17	- 6.05	M$
(i) NPV levelised saving	-2386.5	-3504.8	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	93.12	93.12	te/GWh_{so}
(iii) CO_2 prevention savings	-25.63	-37.64	$/te$CO_2$
(iv) NPV levelised saving on steam	-480.8	-706.2	$/GWh
(v) CO_2 reduction per GWh	18.76	18.76	te/GWh

2.1.4 Estimated Benefits of Fuel Conversion and Modification using capital from equity and NPV basis.

The following financial evaluation of the station modification and conversion is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % over the remnant life of the station.

Cost of modificationbishment (C_{r+c})		12.38	M$
Cost of lost power production		1.0	M$
Total cost of modificationbishment		13.38	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		95.78	kte
GWh_{so} per annum		115	GWh_{so}
GWh_{so} over reference plant life		1725	GWh_{so}
Annual heat in steam		570.8	GWh
Through life heat in steam		8562.0	GWh
Annual fuel saving (FS_{r+c})		1.14	M$
Annual O&M saving		0.24	M$
Annual labour saving (LS_{r+c})		0.20	M$
Total annual saving (FS_{r+c} + LS_{r+c})		1.58	M$
Annual Discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS_{r+c})	17.25	13.25	M$
NPV saving (DS_{r+c} - C_{r+c})	3.87	0.13	M$
(i) NPV levelised saving	2245.8	77.9	$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	832.9	832.9	te/GWh_{so}
(iii) CO_2 prevention savings	2.70	-0.09	$/te$CO_2$
(iv) Levelised saving on steam	452.8	-15.71	$/GWh
(v) CO_2 reduction per GWh	167.91	167.91	te/GWh

2.2 Normalised Plant Calculations

The 'normalised' or 'paradigm' project conditions on which this case study is to be evaluated are summarised below:-

- 15 year life expectancy
- 65% plant loading utilisation factor
- typical UK mainland cost for 1%S HFO is 4.0 $/GJ on NCV

These conditions are almost identical to the reference plant data evaluated in section 2.1. The only variation between 'reference plant' and 'normalised' evaluations are differences associated with the unique nature of low sulphur HFO in Finland. The corrections between this Finnish HFO and a 'normalised' UK low sulphur HFO have been highlighted in section 1.9.1. Therefore the following sections only identify the evaluation data which has changed as a result of the HFO variations.

		Modification	Modification + fuel conversion
Annual fuel saving	M$	0.317	1.11
Annual CO_2 reduction	kte	10.77	96.32

The changes in the above table are reflected in the 'merit figure tables' in the following sections 2.2.1 to 2.2.4.

2.2.1 Plant Calculations for Modification on a Loan Basis

The following table gives a summary of the 'figures of merit' at 'normalised' UK conditions and taking capital on a loan basis:-

		Interest Rate		Units
Merit figure	Title	5%	10%	
(i)	Levelised saving	-3821.2	7615	$/GWh_{so}$
(ii)	CO_2 reduction on power	93.69	93.69	te/GWh_{so}
(iii)	CO_2 prevention saving	- 40.79	-81.28	$/te$CO_2$
(iv)	Levelised saving on steam	-769.9	-1534	$/GWh
(v)	CO_2 reduction on steam	18.88	18.88	te/GWh

2.2.2 Plant Calculations for modification and fuel conversion on a loan basis

The following table gives a summary of the 'figures of merit' of 'normalised' UK conditions for the Modification and Fuel Conversion Case using capital obtained on a loan basis:-

		Interest Rate		Units
Merit Figure	Title	5%	10%	
(i)	Levelised saving on power	2241	-1847	$/GWh_{so}$
(ii)	CO_2 reduction on power	837.6	837.6	te/GWh_{so}
(iii)	CO_2 prevention saving	2.68	-2.21	$/te$CO_2$
(iv)	Levelised saving on steam	451.7	-372.4	$/GWh
(v)	CO_2 reduction on steam	168.9	168.9	te/GWh

2.2.3 Normalised Benefits of Modification on NPV basis

The following table gives a summary of the 'figures of merit' at 'normalised' UK conditions and taking capital as company equity and NPV discounting:-

		Discount Rate		Units
Merit Figure	Title	5%	10%	
(i)	Levelised saving on power	-2416	-3538	$\$/GWh_{so}$
(ii)	CO_2 reduction on power	93.69	93.69	te/GWh_{so}
(iii)	CO_2 prevention saving	-25.79	-37.65	$\$/teCO_2$
(iv)	Levelised saving on steam	-486.9	-710.8	$/GWh
(v)	CO_2 reduction on steam	18.88	18.88	te/GWh

2.2.4 Benefits of Fuel Conversion and Modification on NPV basis.

The following table gives a summary of the 'figures of merit' at 'normalised' UK conditions for the Modification and Fuel Conversion Case using capital from company equity and discounting savings at 5% and 10%:-

		Discount Rate		Units
Merit Figure	Title	5%	10%	
(i)	Levelised saving on power	2016	-254.5	$\$/GWh_{so}$
(ii)	CO_2 reduction on power	837.6	837.6	te/GWh_{so}
(iii)	CO_2 prevention saving	2.41	-0.30	$\$/teCO_2$
(iv)	Levelised saving on steam	406.4	-51.32	$/GWh
(v)	CO_2 reduction on steam	168.9	168.9	te/GWh

3. DISCUSSIONS AND CONCLUSIONS

The following tabulation summarises the data behind the judgements given in this section:-

Boiler modification only:-

Interest & Discount rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	$/GWh$_{so}$	-3821.2	-2416	-7615	-3528
(ii)	te/GWh$_{so}$	93.69	93.69	93.69	93.69
(iii)	$/te$CO_2$	-40.79	-25.79	-81.28	-37.65
(iv)	$/GWh	-769.90	-486.9	-1534.0	-710.8
(v)	te/GWh	18.88	18.88	18.88	18.88

Boiler modification plus fuel conversion:-

Interest & Discount rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	$/GWh$_{so}$	2241	2016	-1847	-254.5
(ii)	te/GWh$_{so}$	837.6	837.6	837.6	837.6
(iii)	$/te$CO_2$	2.68	2.41	-2.21	-0.30
(iv)	$/GWh	451.7	406.4	-372.4	-51.32
(v)	te/GWh	168.9	168.9	168.9	168.9

The majority of the capital investment in this case study is associated with the actual modifications to the boiler in order to convert it to a bubbling fluidised bed boiler. The investment in the biomass fuel handling equipment is small in comparison to the boiler modification cost (approximately 8.7%). This magnitude difference is responsible for the apparent poor evaluation figures for modification without the fuel conversion.

The evaluation figures for the ‘modification and fuel conversion’ case show that the work carried out will be profitable irrespective of the method of obtaining the capital for investment, especially if compared against the external influence associated with the future installation of FGD.

Modification of the boiler without fuel conversion does not look as attractive and its justification can only be considered favourable when compared with the cost for installation of FGD.

PHOTOGRAPHS, DIAGRAMS AND PLANT DETAILS

1. PLANT DETAILS FOR SIMPELE

STEAM DATA

Total Head Output	113 MWth	385 MMBtu/hr
Steam Flow	40 bar	1654 lb/hr
Steam Pressure 115 bar	1654 psig	
Steam Temperature	525°C	977°F

FUEL DATA

	Peat	Bark	Sludge	Oil
Sulphur	0.3%	0%	0.7%	0.5%
Moisture	48.0%	56.0%	69.0%	0.5%
Ash	7.0%	1.7%	32.0%	0.02%
LHV (as received)	9.8 MJ/kg	7.6 MJ/kg	2.3 MJ/kg	41.8 MJ/kg
	4200 Btu/lb	3300 Btu/lb	990 Btu/lb	18000 Btu/kg

DESIGN INFORMATION
Emissions at 6% O_2 dry

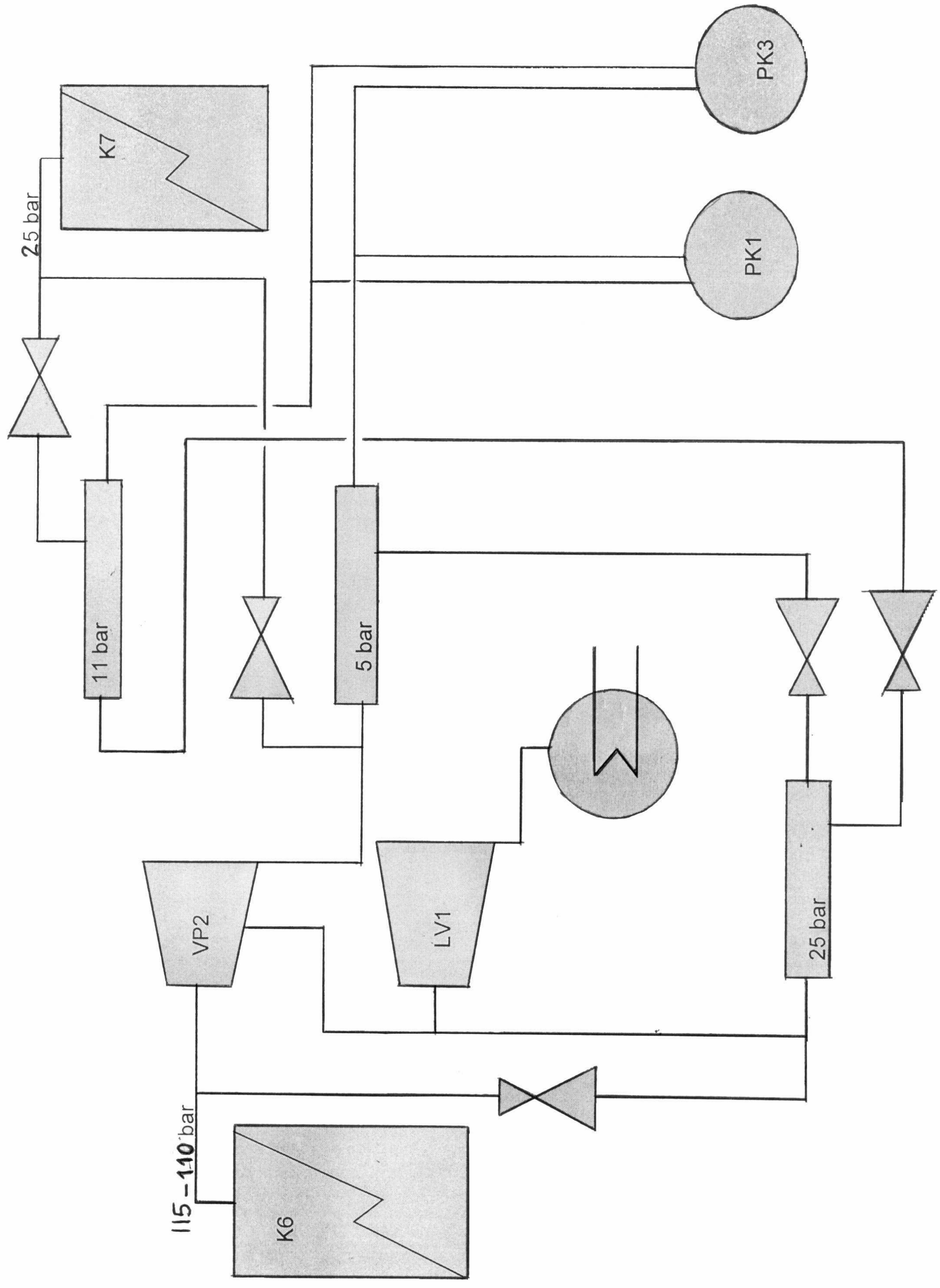
	Peat	Bark
Flue Gas Exit Temperature	170°C	338°F
Boiler Efficiency (DIN 1942)	89.3%	89.3%
NOx Emissions 380mg/Nm^3	0.35lb/MMBtu	
CO Emissions	250mg/Nm^3	0.23lb/MMBtu
Particulate Matter	50 mg/Nm^3	0.05lb/MMBtu

(NOx 1 ppm = mg/Nm^3/2.05 CO 1 ppm = mg/Nm^3/1.25)

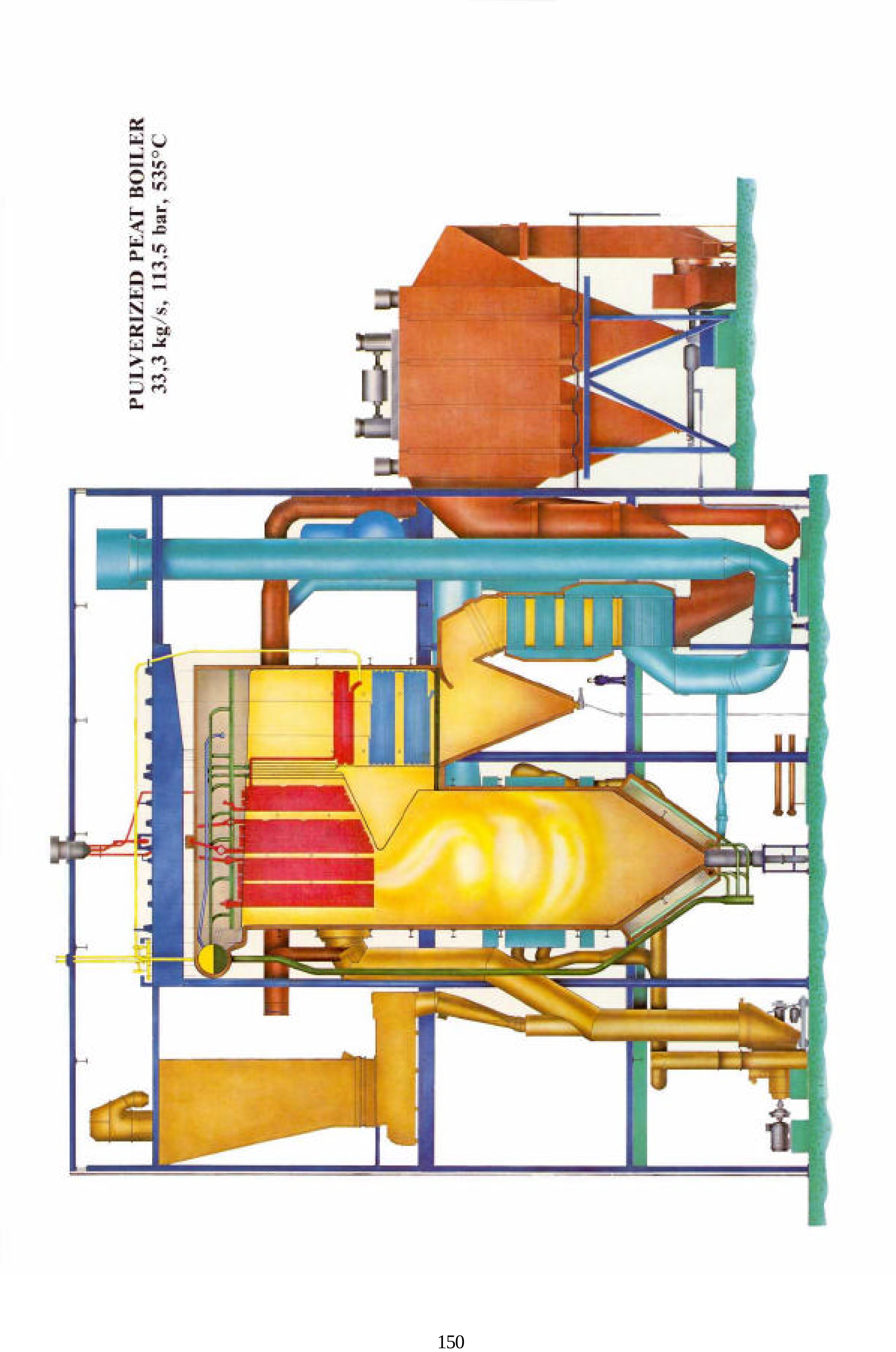
SCHEDULE

Contract Award	December	1996
Start of Erection	July	1997
Commercial Operation	September	1997

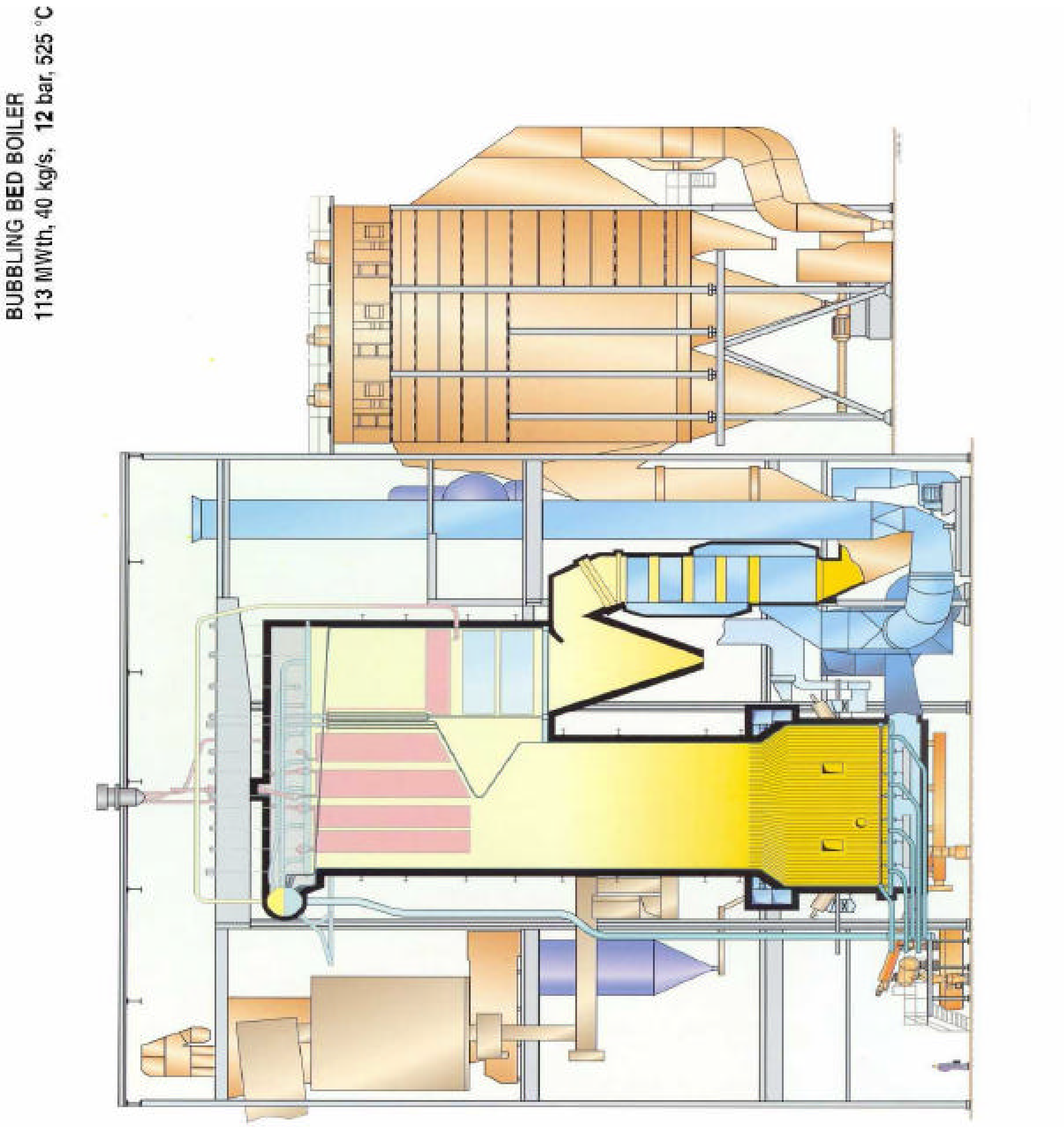
2. STEAM RANGE DIAGRAM.



3. ORIGINAL BOILER SCHEMATIC.



4. NEW BOILER SCHEMATIC.



5. PICTURE OF SIMPELE BOILERHOUSE.

6. PICTURE OF PEAT & BIOMASS UNLOADING & STORAGE PLANT

PHOTOGRAPHS, DIAGRAMS AND PLANT DETAILS

APPENDIX 8

CASE 6

INSTALLATION OF COMBINED HEAT AND POWER PLANT

1. PLANT DESCRIPTION

1.1 General

Saltend power station is a new 1200 MWe combined heat and power station being constructed on the Humber estuary. Performance and heat balance details from Saltend have been used to represent the CCGT plant in scheme A and CHP plant in scheme B below:

Scheme A: 1200 MWe CCGT plant design and separate HFO boiler for process steam supply.

Scheme B: 1160 MWe CHP plant designed around original CCGT plant and satisfying process steam supply from simple steam pressure let down stations.

The site for the power station development is adjacent to a large chemical works owned by British Petroleum (BP) and this forms the source for the significant industrial demands for process steam and power from which the final size of the power station was determined. BP had a number of aging boilers on their site and was looking at the financial viability of replacing these boilers against contracting out their demands for power and steam to the operator of the new power plant.

Both the above schemes represent two of the practical options that British Petroleum and Entergy were faced with in order to satisfy the local power and process steam demands of the site as well as those of the national grid.

Scheme A can be considered as the datum from which modifications are made to represent the reference plant (scheme B) and which is described in the subsequent sections of this report.

1.2 Overall Design

The Saltend Power Station is currently under construction on the BP Chemicals site at Hull, England. The project is being financed and subsequently will be operated by Entergy. The design, manufacture, construction and commissioning of the plant is being undertaken by Raytheon as the lead contractor. The plant shall achieve a nominal power generation of 1200 MWe and steam export up to 190 t/h for industrial process uses.

Saltend power station consists of 3 gas turbine combined cycle power train modules designed around a triple pressure steam cycle. Each module contains one gas turbine, one steam turbine, one generator, one waste heat recovery boiler, cooling water system and balance of plant equipment.

The only common systems cover the fuel gas supply, town's water supply, cooling water make up, cooling water discharge/purge, demineralised water make up, blowdown and waste treatment and compressed air systems.

The plant as presented by Scheme A is designed to operate at a maximum power supply of 1201.6 MW at the connections to the power grid. This represents the Saltend plant operating with no extraction of steam for process demands. The process steam in this scheme is supplied by the HFO fired process steam boiler(s) which in turn imposes a slightly higher auxiliary power consumption on to this scheme.

Scheme B represents the reduced power supply of 1160 MW associated with supplying steam from the power/steam cycle at the maximum process steam load of 190 t/h. In-plant auxiliary power consumption is considered at a magnitude of 2.23 % of plant output capability.

1.3 Process Steam Supply

The process steam is abstracted from the steam cycles of each generating block and delivered to the near by site for BP Chemicals (BPC) at all times, even when the main CHP plant is shut down.

Process steam will be supplied from the header where cold reheat steam from the HP turbine exhaust and the IP steam from the HRSG IP superheater are merged together before being transported to the HRSG reheater. Steam from each CCGT's cold reheat system is delivered to the BPC system at the specified terminal point at the Facility boundary.

The cold reheat header will receive conditioned HP steam from the HP steam bypass through a pressure reducing and desuperheating station in the event of a steam turbine trip.

Steam shall be abstracted from each steam turbine cold reheat line equally to provide BPC with their minimum steam demand of 120 t/h at 20 barg/225 °C at the interface point.

During normal conditions, it is anticipated that BPC will nominate between 140 t/h and 160 t/h of steam. For less frequent intervals the steam demand for BPC may increase to a maximum of 190 t/h.

A maximum of 120 t/h process steam can be supplied from each steam turbine to satisfy the guaranteed supply to BPC when only one steam turbine is in service.

The evaluation data in section 2 represents an annual steam demand of 190 t/h with a load factor of 0.85. This represents a continuous annual flow of 161.5 t/h and can be considered as a reasonable estimate of future BPC demands without any requirement to apply corrections.

1.4 The Reference Scheme and Alternatives

The previous sections give brief descriptions of the different schemes being considered. Calculations of "figures of merit" based upon these parameters can be found in Section 2.

The following subsections give the principal design parameters and conditions upon which each scheme is presented.

1.4.1 Scheme A: CCGT plant with HFO process steam boiler(s).

This is the datum plant arrangement from which the Saltend power station design developed and is aimed at representing a situation where an operator is faced with utilised existing steam boilers alongside a new CCGT power plant. The steam cycle is based upon the reference plant and is given below:

HP steam conditions	540/105	ºC/bar
IP steam conditions	540/30	ºC/bar
LP steam conditions	250/5	ºC/bar

Process steam at export terminal point:

Flowrate	190	te/h
Pressure	20	bar
Temperature	225	ºC

Power Supply	1201.6	MWe

The process steam boiler is assumed to be a water-tube type, HFO fired facility, designed to meet the specification of the process steam with a net thermal efficiency of 89%.

1.4.2 Scheme B: CHP plant design.

The CHP steam cycle data and process steam requirements for this scheme are the same as those shown in Section 1.4.1.

Abstraction of process steam in association with scheme B will therefore cause reductions in power generation of approximately 42.5MWe, which will be generated by other power stations connected with the same grid. Since each IEA GHG case study primarily concerns itself with site emissions of CO2, the effect of lost power on total environmental emissions at other plants is ignored to remain on the same assessment basis as all other case studies. The power loss does adversely affect the financial viability of this scheme and comparisons against the datum scheme A in section 2 have been carried out on two scenarios. The first assumes identical generation data for both schemes and alternately the second takes consideration of this loss of revenue associated with reduced power export capability of the CHP scheme. This enables a sensitivity band to be established for merit figures calculated based on no loss of revenue and with loss of revenue.

1.5 Major Factors Associated with the Comparison Basis

The major factors to be considered during the decision process include the implications of greenhouse and non-greenhouse emissions, power and steam tariff, and capital and operational costs on an identical basis for the supplies of electric power and process steam.

As a CHP plant, heat output is an effective product along with electric power output. It is considered more appropriate to use energy output to cover both heat and power in expression of unit cost or gain when kWh is used.

To make fair appraisal of the two schemes the comparison must first be carried out under identical conditions in terms of electrical power and process steam supplies.

Accordingly, for scheme B, the power deduction caused by process steam supply will be compensated by the financial loss of annual revenue.

1.6 Greenhouse Gas Reduction

The carbon dioxide reduction is predominantly determined by the change in fuel characteristics and consumption between the reference scheme A and alternative scheme B, taking into account the plant efficiency, carbon content and heat value of the fuel. The results are generalised for operation on fixed electric power supply rate and additional steam supply. The amounts of CO_2 generated by the combustion of all 'normalised/paradigm' study fuels is addressed in appendix 1 and since no discrepancies exist between these fuels and site fuels (see sections 1.9.1 & 1.9.2.) no corrections are proposed.

The NO_x reduction achieved as a result of fitting low NO_x combustion equipment without steam/water injection is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Hence any change in the greenhouse gas N_2O is not considered in this case. It should be noted that low NOx combustion equipment would have been fitted to all schemes in discussion irrespective of the fuel types in order to comply with the tighter emission consents being applied by the Environment Agency.

1.7 Non-Greenhouse Gas Emissions

Sulphur oxide (SOx) emissions will only be generated with scheme A, when HFO is fired in the process steam boiler(s). Any figure provided in the assessment is the maximum level since no FGD treatment is included in the study.

The other atmospheric emissions such as particulate are negligible for the cases when natural gas is used for generation.

The scheme A would also produce minimal particulate emission to the atmosphere, but these are assumed to be controlled under the 25 mg/Nm^3 as required by the Environment Agency.

Nitrogen oxide (NOx) emission is minimized by low NOx combustion equipment within both gas turbines and boilers to meet the emission regulations dependent on the type of fuel and in accordance with the EC large combustion plant directives.

1.8 Evaluation of Capital Costs

Since the auxiliary boiler of scheme A is assumed to be existing plant and having a remnant life expectancy in accordance with the CCGT/CHP plant, no account is taken of its replacement or change within capital cost estimates for scheme A.

The capital cost for scheme A and alternative scheme B is assumed to be identical apart from the increased capital cost associated with providing additional pressure reducing stations for the supply of process steam from each block of scheme B.

The cost increase for scheme B is assessed at 3.34 M $ (£ 2 M) based upon the above assumptions.

1.9 Operation and Maintenance

Changes in O&M costs between the two schemes is assumed to be minimal and is only representative of the savings made with regard to the operation and maintenance of the HFO system of the auxiliary boiler.

The saving associated with closure of the HFO system is estimated as:

Maintenance	- 0.08 M $	(£ 0.05 M)
Operating labour	- 0.20 M $	(£ 0.12 M)

1.10 Other Additional Costs Associated with Each Scheme

The only other additional savings or costs identified against the individual schemes is the loss of revenue associated with the reduced power export capability of the CHP plant compared to the CCGT plant.

At a plant load factor of 0.85 associated with this case study the 42.51 MWe represents 316.53 GWh_{so} per annum.

Kennedy & Donkin experience suggests that the net income/profit lost in association with this power is likely to be between 3.3 and 4.9 million pounds. Calculations within this case study have assumed an average of these two values corresponding to 6.82 M $.

This extra cost is used within section 2 to estimate a sensitivity tolerance for merit figure calculations.

1.11 Site Fuel Data

1.11.1 Natural Gas

The fuel analysis for the natural gas supplied to Saltend plant is as follows:-

Mol %	**Typical Average**	**Min**	**Max**
N_2	2.18	0.96	2.21
CO_2	1.27	0.85	2.32
CH_4	90.58	86.86	93.09
C_2H_6	4.27	2.96	6.93
C_3H_8	1.16	0.59	2.35
C_4H_{10}	0.36	0.24	0.5
C_5H_{12}	0.09	0.07	0.09
C_6H_{14}	0.05	0.01	0.05
C_7H_{16}	0.02	0.0	0.03
C_8H_{18+}	0.02	0.0	0.02
Balance	100.00		

The above typical average data gives an LHV of 46.355 MJ/kg and average carbon content of 71.54% by weight.

The specification for natural gas supplied to Saltend site is in accordance with the typical UK supply rage data provided by Transco and no correction is therefore required.

1.11.2 HFO

The HFO analysis used for the scheme A calculations is assumed to be in accordance with those contained within Appendix 1 of this document.

1.12 Output and Efficiency

The greenhouse gas (CO_2) emission of this study is mainly determined by the fuel (natural gas) consumptions except for scheme A where HFO-firing is involved to generate the process steam supply. The associated net efficiency of the process steam boiler is estimated at 89%.

The cycle efficiencies for the CCGT and CHP sectors of schemes A and B remain in accordance with Saltend heat balance data. The scheme A auxiliary power rate is assumed to be 3%, which is slightly greater than 2.23% used for the other scheme because of the use of a separate boiler and associated accessories.

The heat balance diagrams and data available on the Saltend project suggests the following CCGT and CHP plant efficiencies on net calorific value per 400 MWe block:

		CCGT mode	CHP mode
Process steam flow/block	t/h	0	63.3
Equivalent heat in steam	MWt	0	49.06
Net heat input per block	MWt	705.94	705.94
Net electrical output/block	MWe	400.75	386.58
Net efficiency of power gen	%	56.77	54.76
Net efficiency of power & steam gen	%	56.77	61.71

An auxiliary boiler having the following design characteristics has been utilised to assess the contribution to emissions associated with HFO used on this boiler to supply steam as part of Scheme A:

Steam output	t/h	190
Equivalent heat in steam	MWt	147.2
Net heat input to boiler	MWt	165.4
Boiler Net Efficiency	%	89.0

These individual efficiencies can then be recognised to give the following scheme performance data:

		Scheme A (CCGT & AB)	Scheme B (CHP)
Total net heat input	MWt	2283.19	2117.82
Net electrical output	MWe	1202.25	1159.74
Net heat in steam	MWt	147.18	147.18
Net electrical efficiency of scheme	%	52.66	54.76
Net electrical + heat efficiency of scheme	%	59.10	61.71

From this data the following deductions are made:

% heat input from HFO in scheme A	%	7.24
Power generation loss with scheme B	MWe	42.51

Annual reduction in power generation at 0.85 load factor becomes equivalent to 316.53 GWhso per annum or 3.5%.

The annual loss in profits from the power reduction that this represents is estimated as 6.82 M$ per annum.

In order to provide an annual power load that both schemes can achieve, the 0.85 load factor for the CHP scheme B has been used to establish an annual power generation of 8635 GWh_{SO}.

The above information has been utilised to establish calculation data given in section 2 of the report.

2. CALCULATION RESULTS AT NORMALISED CONDITIONS

2.1 Calculations Not Considering Revenue From Loss of Power Export

The reference CCGT/CHP plant for this case study is a new construction and no actual or reference plant data exists. In this section of the report it is proposed to evaluate both schemes at 'normalised' conditions only, but NOT to consider the loss of revenue associated with the plant operating in CHP mode.

The 'normalised' conditions for this case study are represented by the following:-

- Remnant life for cost evaluations is taken as 25 years.
- An average annual plant load factor taken as 0.85 on the power output of the plant at 1160 MWe.
- Operational and maintenance savings excluding fuel and labour are in accordance with section 1.9.
- Interest and discount rates for loan repayment and NPV calculations are 5% and 10%.
- Scheme efficiency figures are from information given in Section 1.12.
- Steam to process for all schemes is 190 te/h.

Based upon the assumptions above and discussed in previous section 1, estimates can be made regarding the fuel consumptions and CO_2 emissions for each scheme on an annual basis for the station:-

		Scheme A	Scheme B
Annual electricity generated by CCGT/CHP plant	GWh_{so}	8635.4	8635.4
Net Efficiency of power generation	%	52.66	54.78
Process steam generation	GWh	1096.0	1096.0
Net Efficiency of steam and power generation	%	59.10	61.71
Total annual heat input requirement	TJ	59034	56770
Annual gas consumption	Kte	1182.7	1226.1
Annual HFO consumption	Kte	105.5	0
Annual fuel cost	M$	151.4	141.9
Annual fuel saving	M$	0	9.51
Annual generation of CO_2	kte	3494.6	3285.9
Annual reduction in CO_2 emissions	kte	0	208.7

These figures indicate a 6.0% reduction of CO_2 emissions resulting from scheme B.

SECTION 2
CALCULATION RESULTS AT NORMALISED CONDITIONS

The changes in capital expenditure represented by schemes B have been obtained (see Section 1.8) and summarised below:-

Increased capital expenditure for scheme B = 3.34 M$ (£2.0M)

This information is used as the basis for the evaluations in the following sections.

2.1.1 Estimated Benefits of Alternative Scheme B on Loan Basis

The following financial evaluation of the alternative scheme B is carried out at normalised plant conditions using capital based on a mortgage type loan at 5% and 10% annual interest rates over the remnant life of the station.

Increase in capital expenditure		3.34	M$
Cost of lost power production (PL)		0	M$
Total cost of refurbishment (Cr+PL)		3.34	M$
Number of years remnant life (n)		25	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n -1)\}$	0.0709	0.11017	
Annual loan repayment (A_{lr})	0.24	0.37	M$
Annual loss of profit from power export change	0	0	M$
Annual fuel saving (FS_r)	9.51	9.51	M$
Annual O&M saving (M_s)	0.08	0.08	M$
Annual labour saving (L_s)	0.2	0.2	M$
Net annual saving (FS_{1r}-A_r +M_s+L_s)	9.55	9.42	M$
CO_2 reduction per annum		208.7	kte
GWh_{so} per annum		8635.4	GWh_{so}
GWh steam per annum		1096	GWh
(i) Levelised saving per GWh_{so}	1105.9	1090.7	$\$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	24.17	24.17	te/GWh_{so}
(iii) CO_2 prevention saving	45.76	45.13	\$/teCO_2
(iv) Levelised saving on steam	981.3	967.8	\$/GWh
(v) CO_2 reduction per GWh steam	21.45	21.45	te/GWh

2.1.2 Estimated Benefits of Alternative Scheme B on Capital As Equity and NPV Basis

The following financial evaluation of alternative scheme B is carried out at normalised plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		3.34	M$
Cost of lost power production		0	M$
Total cost of refurbishment		3.34	M$
Number of years remnant life (n)		25	
CO_2 reduction per annum		208.7	kte
GWh_{so} per annum		8635	GWh_{so}
GWh_{so} over reference plant life		215886	GWh_{so}
Annual heat in steam		1096	GWh
Through life heat in steam		27400	GWh
Annual loss of profit from power export change		0.0	M$
Annual fuel saving (FS_r)		9.51	M$
Annual O&M saving		0.08	M$
Annual labour saving		0.2	M$
Total annual saving		9.79	M$
Annual discount rate $^{(r)}$	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	14.7986	9.9847	
Disc'd saving over remnant life (DS_r)	144.8	97.72	M$
NPV saving (DFS_r - C_r)	141.5	94.38	M$
(i) NPV levelised saving per GWh_{so}	655.4	437.2	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	24.17	24.17	te/GWh_{so}
(iii) CO_2 prevention savings	27.12	18.09	$/te$CO_2$
(iv) NPV levelised saving on steam	581.6	387.9	$/GWh
(v) CO_2 reduction per GWh steam	21.45	21.45	te/GWh

2.2 Calculations Considering Revenue From Loss of Power Export

In this section of the report both schemes are evaluated at 'normalised' condition and taking due consideration of lost revenue associated with the plant operating in CHP mode. This means of evaluation is used to establish a tolerance bond for the 'figures of merit' calculated for this case study.

The only alteration to the assumptions given in section 2.1 is the following assumption related to reduced power export capability of scheme B.

- The loss of revenue associated with reduced 42.5 MWe power export capability at an annual plant load factor of 0.85 is estimated at 6.82 M$ per annum.

Based upon the assumptions above and in previous sections revised estimates can be made regarding the fuel consumptions and CO_2 emissions for each scheme on an annual basis for the station:-

		Scheme A	Scheme B
Annual electricity generated by CCGT/CHP plant	GWh_{so}	8952.0	8635.4
Net Efficiency of power generation	%	52.66	54.76
Process steam generation	GWh	1096	1096
Net Efficiency of steam and power generation	%	59.1	61.71
Total annual heat input requirement	TJ	61198	56770
Annual gas consumption	Kte	1226.1	1226.1
Annual HFO consumption	Kte	109.4	0
Annual fuel cost	M$	157.0	141.9
Annual fuel saving	M$	0	15.06
Annual generation of CO_2	Kte	3622.7	3285.9
Annual reduction in CO_2 emissions	Kte	0	336.8

These figures indicate a 9% reduction of CO_2 emissions resulting from scheme B.

2.2.1 Estimated Benefits of Alternative Scheme B on loan basis.

The following financial evaluation of the alternative scheme B is carried out at 'normalised' plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Increase in capital expenditure		3.34	M$
Cost of lost power production (PL)		0	M$
Total cost of refurbishment (Cr+PL)		3.34	M$
Number of years remnant life (n)		25	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.07095	0.11017	
Annual loan repayment (A_{1r})	0.24	0.37	M$
Annual loss of profit from power export change	6.82	6.82	M$
Annual fuel saving (FS_r)	15.06	15.06	M$
Annual O&M saving (M_s)	0.08	0.08	M$
Annual Labour saving (LS_{r+c})	0.2	0.2	M$
Net annual saving (FS_r-A_{1r}+M_s+L_s)	8.28	8.15	M$
CO_2 reduction per annum		336.8	kte
GWh_{so} per annum		8635.4	GWh_{so}
GWh steam per annum		1096	GWh
(i) Levelised saving per GWh_{so}	959.0	943.8	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	39.0	39.0	te/GWh_{so}
(iii) CO_2 prevention saving	24.59	24.2	$/te$CO_2$
(iv) Levelised saving on steam	851.0	837.5	$/GWh
(v) CO_2 reduction per GWh steam	34.61	34.61	te/GWh

2.2.2 Estimated Benefits of Alternative scheme B on Capital From Equity and NPV Basis

The following financial evaluation of alternative scheme B is carried out at normalised plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10% per annum over the remnant life of the station.

Cost of refurbishment (C_r)		3.34	M$
Cost of lost power production		0	M$
Total cost of refurbishment		3.34	M$
Number of years remnant life (n)		25	
CO_2 reduction per annum		336.8	kte
GWh_{so} per annum		8635.4	GWh_{so}
GWh_{so} over reference plant life		215886	GWh_{so}
Annual heat in steam		1096	GWh
Through life heat in steam		27400	GWh
Annual loss of profit from power export change		6.82	M$
Annual fuel saving (FS_r)		15.06	M$
Annual O&M saving		0.08	M$
Annual labour saving		0.2	M$
Total annual saving		8.52	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	14.7986	9.9847	
Disc'd saving over remnant life (DS_r)	126.1	85.05	M$
NPV saving (DFS_r - C_r)	122.7	81.71	M$
(i) NPV levelised saving per GWh_{so}	568.4	378.5	$\$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	39.0	39.0	te/GWh_{so}
(iii) CO_2 prevention savings	14.58	9.7	$\$/teCO_2$
(iv) NPV levelised saving on steam	504.4	355.9	$/GWh
(v) CO_2 reduction per GWh steam	34.61	34.61	te/GWh

3. DISCUSSIONS AND CONCLUSIONS

The following tabulation summarises the data behind the judgements given in this section for Alternative Scheme B:-

NOT considering lost power export:

Interest and Discount Rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	$/GWh$_{so}$	1105.9	655.4	1090.7	437.2
(ii)	te/GWh$_{so}$	24.17	24.17	24.17	24.17
(iii)	\$/teCO_2	45.76	27.12	45.13	18.09
(iv)	$/GWh	981.3	581.6	967.8	387.9
(v)	te/GWh	21.45	21.45	21.45	21.45

Considering lost revenue from reduced power export:

Interest and Discount Rates		5%		10%	
Evaluation Basis		LR	E-NPV	LR	E-NPV
Merit Figures					
(i)	$/GWh$_{so}$	959.0	568.4	943.8	378.5
(ii)	te/GWh$_{so}$	39.00	39.0	39.00	39.0
(iii)	\$/teCO_2	24.59	14.58	24.2	9.70
(iv)	$/GWh	851.0	504.4	837.5	335.9
(v)	te/GWh	34.61	34.61	34.61	64.61

The combined cycle nature of this case study means that merit figures iv and v in the above tables are slightly misleading when compared with other case studies with conventional steam cycles. This discrepancy arises because electricity is directly generated by the gas turbine(s) without the intermediate use of steam and so the following review is based around merit figures i to iii only.

An external influencing factor that has not been considered within these comparisons is the possible requirement for replacement of the HFO boiler(s) or installation of FGD equipment associated with the supply of process steam in scheme A.

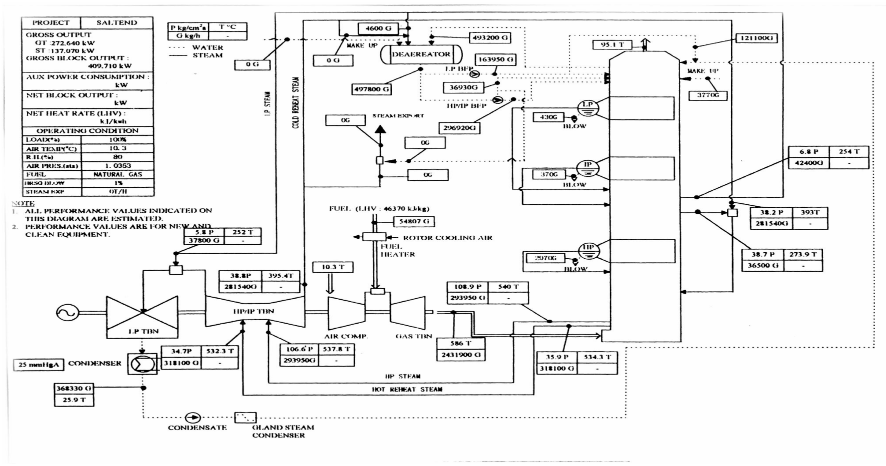
The tables above for alternative scheme B shows that a significant CO_2 emissions saving (24 to 39 te/GWh$_{so}$) can be achieved. The saving of this reduction is significant at between 10 and 45 \$/te CO_2.

SECTION 3
DISCUSSIONS AND CONCLUSIONS

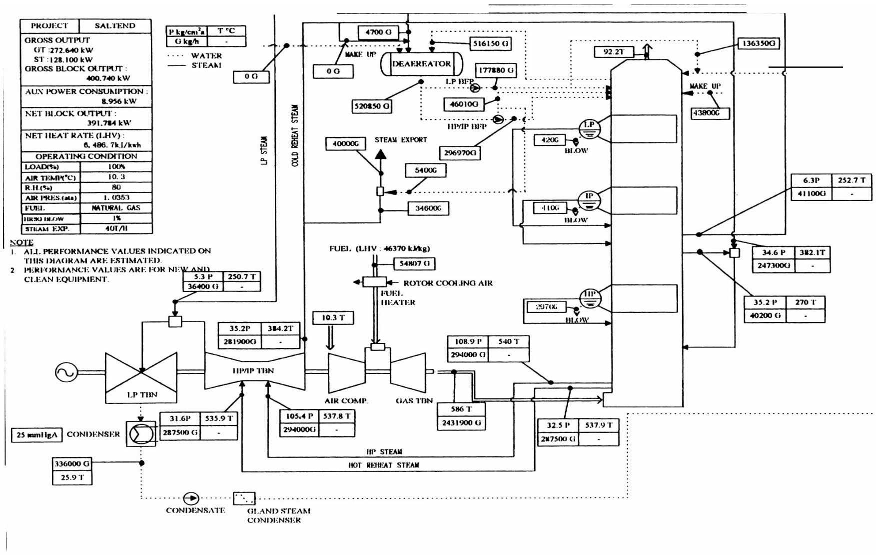
Unlike other case studies the NPV evaluation technique in this instance gives less favorable values than the loan technique by a factor of approximately 50% of loan values.

SALTEND PHOTOGRAPHS AND CYCLE DIAGRAMS

1. Heat balance diagram for one block in CCGT mode.

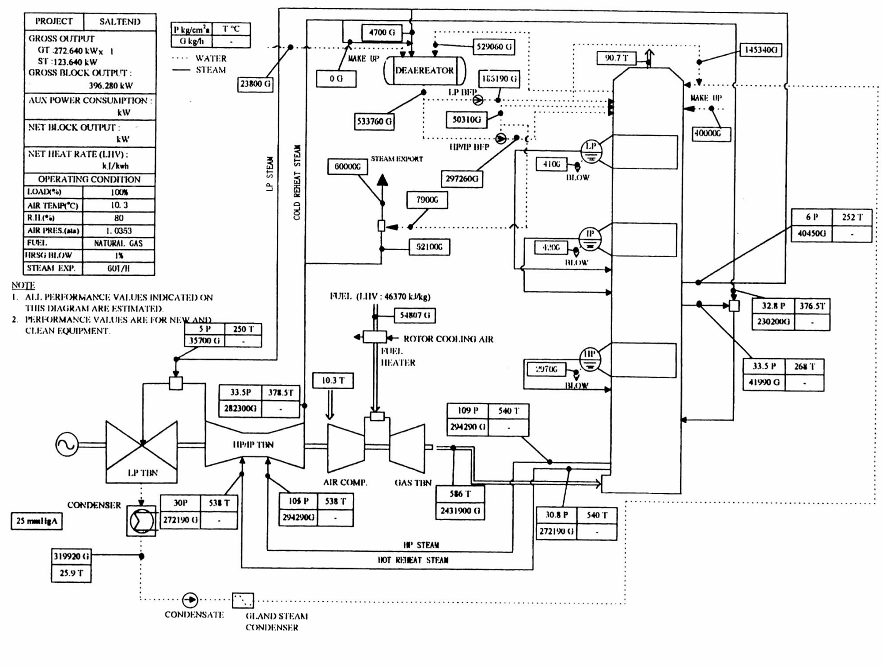


2. Heat balance diagram for one block in CHP mode with 40t/h process steam expor



SALTEND PHOTOGRAPHS AND CYCLE DIAGRAMS

3. Heat balance diagram for one block in CHP mode with 60t/h process steam export.



APPENDIX 9

CASE 7

INSTALLATION OF 191 MWe COMBINED CYCLE BASED HEAT AND POWER PLANT

1. PLANT DESCRIPTION

1.1 General

Kelenfold represents a 190MWe combined heat and power station where a natural gas fired gas turbine and heat recovery boiler has been used to replace old HFO fired boilers.

As a result of the modification to the site there has been a significant change to the site output capability and the approach used to evaluate this is discussed in more detail in Section 1.5.

Kelenfold represents a typical medium sized industrial power, steam and district heating plant as found in many Eastern European countries.

The site was in desperate need of reinvestment to enable the replacement of old equipment with modern, more environmentally friendly plant.

1.2 Plant Prior to Modification

The Kelenfold Power Station of the Budapest Power Company has undergone several major reconstructions and extensions since its operation started in 1914. The power station that was originally built, and later extended with condensing steam turbines, has been gradually transformed into a heating plant from the second part of the 1950's. The steam turbines were mostly manufactured in the 1920's and 1930's, and the heat supply turbines in the 1960's. The last steam turbine was commissioned in 1970. Since this time the only change has been extension of the heat supply system by the addition of hot water boilers. Now the role of the power station has considerably increased, as, in addition to supplying heat to all the housing estates and many industrial plants in South-Buda, the power station is also a major heat supply for industrial and communal consumers in South-Pest.

Although, from the end of the 1960's onwards, the issue of modernising the capital's district heating system and the utilisation of the benefits of cogeneration has been addressed in several studies and government programmes, with special emphasis on the Kelenfold Power Station, these plans have all been aborted.

As a result of the success of combined cycle systems and the rapid deterioration of the steam turbine part of the power station, the gas turbine reconstruction of the power station became the obvious solution. MVMT (legal predecessor of MVM) brought a decision about the preparation of such a construction in the summer of 1989. ERÕTERV started the design work the following year and meetings were held with the 9th District Municipality.

The steam system diagram included at the end of this appendix indicates that during the site lifetime prior to modification there had been a number of different boilers on the site, all producing steam at 38 bar and 400ºC. These boilers comprised of:-

- 6 x 55 te/h boilers;
- 2 x 65 te/h boilers;
- 4 x 80 te/h boilers;

The steam diagram also indicates the presence of five different steam turbines listed below:-

- 1 x 19MWe twin cylinder back pressure steam turbine discharging to the 3.5 bar and 1.2 bar steam headers;

- 2 x 15MWe fully condensing steam turbines at 400 mbar pressure with passout/extraction to the 3.5 bar steam header;

- 2 x 6MWe single cylinder back pressure turbines discharging to the 6 bar steam header but with passout/extraction on to the 15 bar steam header;

The plant remaining in operation in 1993, just prior to the gas turbine modification, comprised of the following:-

- 2 x 65 te/h HFO boilers;
- 2 x 80 te/h HFO boilers;
- 2 x 15 MWe condensing turbines;
- 1 x 19 MWe twin cylinder turbine;
- 2 x 6 MWe back pressure turbine;

The heavy fuel oil used on these boilers at that time is known to have been a nominal 3% sulphur HFO.

1.3 Brief History and Decision Process

The Kelenfold project has been completed based upon an investment programme approved by the World Bank (WB) and European Investment Bank (EIB). This culminated in the signing of the contract for delivery of the main technology and equipment on 21 July 1993.

In the 2 to 3 years prior to this a number of activities had been going on which could be categorised into three procedures:-

- the financial procedure;
- the bidding procedure;

- the licensing procedure.

The financial procedure involved regular meetings between all of the financiers of the Kelenfold project until an agreement was achieved regarding the structure of the financing for the project.

The bidding procedure involved the preparation of bid invitations, obtaining World Bank approval of the invitations, issuing of bidding documents, handing over of contractor bids, preliminary evaluation of bids, final evaluation of bids and obtaining financier approval to enter into contractual negotiations with chosen contractor(s).

The licensing procedure involved establishing a plan of work, providing a detailed arrangement plan, drafting demolition and building application documents, and obtaining approval of the demolition and building application documents.

1.4 Modification Details

All the modifications to the site centred around preparing the existing site to accommodate the building of a 136 MWe gas turbine and heat recovery boiler, as shown by the steam diagram at the end of this appendix.

Clearing of the site and re-routing of essential site services was carried out between July and October 1993. The laying of new foundations for all building and equipment was carried out between November 1993 and April 1994. Erection of all buildings was carried out between April and November 1994. Delivery of the gas turbine was during September of that same year with arrival of the generator two months later. Construction and erection of the HRSG took 12 months, from July 1994 to June 1995. Natural gas was made available to the site in October 1995, and commissioning proceeded up to December 1995. The performance test was satisfactorily completed in February 1996.

The gas turbine was designed to provide 136MWe of electricity, and the HRSG to provide 165 te/h of 38 bar, 400ºC steam.

The poor quality water associated with the river Danube meant that additional strainers and a closed circuit cooling water system had to be provided.

Delays on the new diesel fuel oil (DFO) storage facilities necessitated modifications to the existing plant to enable commissioning to progress according to programme.

1.5 Major Factors Associated with Comparison Basis

The major factor associated with the before and after comparison basis of this case study is the magnitude difference of the electricity export capabilities of the site.

This is summarised below:-

- before modification 61 MWe;
- after modification 191 MWe;

This magnitude of difference was slightly greater than a factor of three. Therefore it was agreed that this case study would be based on three plants of similar size to the original Kelenfold being replaced by one gas turbine based CHP plant.

The original remaining boilers at Kelenfold had all been HFO fired, but it was thought that it may bias the study if all three original plants were assumed to be HFO fired.

Reports in 1998 by Kennedy and Donkin regarding the Hungarian Power Market provided information from 1990 and 1995 which suggested that actual energy consumption for power and heat production were from a mixture of fuels including natural gas, HFO, Black Coal and Brown Coal. Therefore it was decided to make the additional two plants representative of the actual fuel trends at the time of modification, specific details are given in Sections 1.10 to 1.12.

1.6 Greenhouse Gas Reduction

The carbon dioxide reduction of this case study is determined from both the changes in fuels and efficiency changes associated with the boiler conversion. The carbon content of the fossil fuels used and these factors are directly related to any reduction of CO_2 emissions from the site. The results in Section 2 are calculated for the whole station burning pre and post conversion fuel mixes together with efficiency change evaluations on the original fuel mix

Sections 1.10.1 to 1.10.4 address the discrepancies between the 'normalised' and site fuels in detail.

The NO_x reduction achieved as a result of fitting low NO_x combustion equipment without steam/water injection on the GT is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Hence, any change in the greenhouse gas N_2O is not considered in this case.

1.7 Determination of Capital Costs

The participant provided information detailing the overseas and domestic financing associated with the Kelenfold project, as follows:-

- Overseas investment 57 M$;

- Domestic financing 56 M$;
- Total project cost 113 M$.

1.8 Determination of Fuel, Operating and Maintenance Costs

The participant could not provide any details regarding the actual site experience for operation and maintenance or labour savings.

For the purpose of this study, Kennedy and Donkin have assumed annual savings similar to one of the other case studies where the station was converted from HFO to NG.

The estimated savings are given below as:-

- Annual maintenance saving 0.14 M$;
- Annual labour saving 0.36 M$.

1.9 Changes to Non-Greenhouse Gas Emissions

The decision to install a gas turbine and heat recovery boiler at Kelenfold was taken in respect to the Hungarian application for membership of the EU. The EU have requested that nations applying for membership should demonstrate their dedication to environmental improvement by implementing World Bank and EU emissions legislation.

The installation of modern combined cycle technology to EU emission standards can be seen to reduce domestic emissions of other non greenhouse gases such as sulphur and nitrogen dioxides. The installation of gas turbine and heat recovery boilers will also reduce emissions of particulates from the site.

The participant has supplied data indicating the following reduction in SO_x and NO_x emissions from the site as a result of installation of the GT/HRSG plant:-

- SO_x emission in t per annum = 2183 to 11.3 = 99.5% reduction;
- NO_x emission in t per annum = 1318 to 1104 = 16.2% reduction.

1.10 Site Fuel Data

1.10.1 Natural Gas

No detailed analysis of natural gas supplies to the Kelenfold site has been provided.

The following information has been provided regarding the gas calorific value, density and CO_2 generation per kg of gas:-

- Net calorific value 34 MJ/Nm^3 or 45.95 MJ/kg;
- Gas density 0.74 kg/Nm^3;
- CO_2 generation 2.67 kgCO_2/kg NG.

The above CO_2 generation indicates a carbon content in the NG approximately 73% by weight. This is only marginally different to the 73.5% of the datum UK fuels given in Appendix 1 and so no correction is proposed for this.

The 1998 Hungarian Power Market Survey gives an average price for NG to power stations of 1.96 $/GJ (391.8 HUF/GJ).

This is significantly cheaper than the UK price of 2.5 $/GJ.

This suggests that fuel costs between the two evaluation conditions for Hungary and the UK may involve a correction factor approximately 0.78.

1.10.2 Heavy Fuel Oil (HFO)

No information has been provided regarding a detailed analysis of HFO supplies to the site.

The LCV has been provided as 41 MJ/kg. The participant suggests that although previous operation of the plant utilised HFO with a sulphur content of 3% or greater, the plant would now have to use a 1% low sulphur oil.

The 1998 survey of the Hungarian Power Market gives an average cost of HFO to power stations at 2.22 $/GJ (443.5 HUF/GJ), but does not distinguish between high and low sulphur contents.

This is also significantly cheaper than UK costs for HFO at:-

- 3.4 $/GJ for 2.5% S HFO;
- 4.0 $/GJ for 1.0% S HFO.

This suggests that fuel costs between the two evaluation conditions for Hungary and the UK may involve a correction factor of approximately 0.65.

1.10.3 Black Coal

As with the previous fuels, no detailed analysis data for the Black Coal supplies are provided, but a typical LCV for the fuel used at Pecs power station is given as 18 MJ/kg.

Kennedy and Donkin estimate this to represent a coal having approximately 56% carbon by weight.

No other details regarding coal sulphur, moisture or ash contents have been provided.

The local cost of this fuel has been estimated at an average of 1.96 $/GJ (391.6 HUF/GJ).

This black coal would appear to fall outside the typical supply range given for datum black coal supplies in Appendix 1.

However, without considerable research into the sources and their analyses, no comment can be made regarding correction factors.

The typical cost of datum UK black coal is very similar to the above local cost at 2 $/GJ.

1.10.4 Brown Coal

A number of local Hungarian sources are available for brown coal:-

- Borsod brown coal has LCV = 8 MJ/kg;
- Tatabanya brown coal has LCV = 15 MJ/kg.

For the purpose of the study, the 8 MJ/kg fuel has been utilised and assumed to have an as fired carbon content of approximately 25% by weight.

Average brown coal costs taken from the Hungarian survey give a cost of 1.84 $/GJ (368.5 HUF/GJ).

This cost is similar to other European prices for brown coal and would suggest only a marginal correction factor of between 0.9 and 1.0.

The 8 MJ/kg LCV suggests that the coal is within the range data given by Appendix 1.

1.11 Combustion Gases

The site fuels given previously in Section 1.10 agree closely with 'normalised/paradigm' data in Appendix 1, with the exception of black coal, but, due to the lack of details, no correction factor can be estimated.

As mentioned previously in Section 1.5, the evaluation of this case study has been based around replacing the old Kelenfold plant and two other similar size plants representative of typical Hungarian plant by one new gas turbine based CHP plant.

The two other typical Hungarian plants of 61 MWe each are assumed to represent the typical fuel utilisation associated with the whole of the Hungarian Power System after the exclusion of the nuclear components.

The nearest datum year to the Kelenfold project period is 1990 within 1998 Hungarian Power Market survey. The details of fuels consumed within the Hungarian Power Market in 1990 are replicated below in % by heat input.

	From 1998 Report Estimated Fuel Breakdown in 1990	**Corrected to Exclude Nuclear**
Natural Gas	10.0	15.4
HFO	17.0	26.2
Black Coal	12.7	19.5
Brown Coal	25.3	38.9
Nuclear	35.0	0.0

Kelenfold was almost totally HFO fired and so the study has assumed 2 x 61 MWe plants having a fuel breakdown given above and 1 x 61 MWe plant solely HFO fired. This gives an average fuel breakdown for all three original plants as below:-

- NG 10.25%;
- HFO 50.77%;
- Black Coal 13.00%;
- Brown Coal 25.98%.

The participant has given data to suggest that the new gas turbine CHP has utilised 7229594 GJ of heat in 1998 of which 99.87% was NG and 0.13% distillate fuel oil (DFO).

The evaluation method established for this study is based around maintaining constant plant output between both the before and after conditions. In this way, changes in emissions solely result from changes in plant and the fuels fired.

	Pre Modification	**Post Modification**
Natural Gas	10.25	99.87
Distillate	0.0	0.13
HFO	50.77	0.0
Black Coal	13.00	0.0
Brown Coal	25.98	0.0

CO_2 emission quantities given in Section 2 reflect the above fuel ratios in conjunction with data given in Appendix 1 regarding the quantities of CO_2 produced from each fuel.

1.12 Net Plant Efficiency and Output Information

As mentioned in section 1.2, the plant prior to modification included four HFO boilers and four steam turbines. These units remained in situ after installation of the GT and HRSG so that the boilers were available as emergency back up.

Details of these boilers and steam turbines are given in the tables below:-

Boiler				
Serial Number	**Live Steam**			**Heat output (MW_t)**
	Quantity (te/h)	Pressure (bar)	Temperature (°C)	
82	80.0	39.2	400	57.8
9	80.0	39.2	400	57.8
13	65.0	39.2	425	47.9
14	65.0	39.2	425	47.9

Number of Steam Turbines				
	I & II	III	IV	VI
Capacity - rating, MW_e - max, MW_e	 6.0 6.6	 15.0 16.5	 15.0 16.5	 19.0 23.8
Maximum Steamflow, te/h	 86	 103	 103	 200
Extraction - steamflow - pressure, bar	 25 15	 N/A 3.5	 N/A 3.5	 70 (max) 3.5
Take-off - steamflow te/h	 -	 -	 -	 150 (max)
Back pressure - steamflow te/h - pressure, bar	 - 6	 - 0.4	 - 0.4	 35 (max) 1.2

1.12.1 Old Turbine Efficiencies

Since extraction steam flows for turbines III & IV are not given in the previous table it is not possible to calculate/estimate original design efficiencies for these machines.

If it is assumed that the maximum output is with maximum steam flow in a fully condensing mode and no extraction steam then an efficiency of 19.6% can be estimated. This is very low for the design condition of a condensing steam turbine and it is likely that the design position must include for some extraction at 3.5 bar. A simple assumption that the extraction flow is 20 % of the main steam flow then the turbine efficiency is increased to 23.5 %.

The completed data for turbines II & VI have enabled estimates to be made for the range of design efficiencies of these machines, and from which estimates of operating efficiency could be suggested by Kennedy and Donkin. These estimates are summarised in the table below:-

Steam Turbine	**II**	**VI**
Best Design Efficiency Estimate	85.7	88.2
Worst Design Efficiency Estimate	77.5	86.0
Suggested Best Operating Efficiency	83.0	85.0
Suggested Worst Operating Efficiency	70.0	80.0

1.12.2 Old Boiler Efficiencies

The participant has not provided any data giving confirmation of design or operating efficiencies for the old HFO boilers.

Kennedy and Donkin suggest that in many Eastern European countries the operating efficiencies of such boilers can be between 78% and 82%.

1.12.3 New Plant Efficiency and Output

The new gas turbine is rated at 136MWe and its associated HRSG will deliver up to 165 te/h of steam at 38 bar, 400ºC. According to correspondence, only steam turbine I has been retired as a result of the installation of the GT and HRSG. This gives the new plant an output capability of 191 MWe.

It is not evident from information whether any of the old boilers have been decommissioned or whether they remain as emergency standby for the HRSG.

The table below gives some typical operating data for the new plant over the years 1996 to 1998:-

Year	1996	1997	1998

Electricity supplied	GWh_{so}	771	561	803.4
Process steam supplied	TJ	2424	1621	2453.85
District heating supplied	TJ	832	820	N/A
Heat input as fuel	TJ	N/A	N/A	7229.6

The 1998 data in the previous table enables the following estimates of plant efficiency to be made for the site:-

- Efficiency of power production 40.7%;
- Efficiency of steam/heat production 33.9%;
- Site heat and power efficiency 74.6%.

Based upon the declared new plant capability of 191MWe, the 803.4 GWh_{so} generated in 1998 represents a load factor of 0.48. Therefore, at 'normalised' conditions associated with a load factor of 0.65 and no efficiency change, the annual power and heat export shall become:-

- 'Normalised' power supply 1087.6 GWh_{so}
- 'Normalised steam/heat supply 3322.9 TJ.

1.12.4 Derived Old Plant Outputs and Efficiencies

Based on 1998 site generation data the 803.4 GWh_{so} represents an average load of 30.57 MW_e at each of the three old plants.

Since the capacity of each old plant is 61 MW_e, this represents an average load factor of 0.501.

The 30.57 MWe load could be satisfied by operation of the following turbine combinations to give the best and worst possible turbine efficiencies:-

- Steam turbines III or IV plus VI = 56.4%;
- Steam turbines III plus IV plus I or II = 32.1%.

Therefore, an average turbine efficiency for each old plant would be 44.2%.

Utilising the boiler efficiencies suggested in Section 1.12.2 gives a range for the power cycle efficiency on the old plant at between 25.0% and 46.2% and suggests an average of 35.4%.

Based on normalised conditions the 1087 GWh_{so} represents an average load of 41.4 MW_e at each of the three old plants.

Since the capacity of each old plant is 61 MW_e, this represents an average load factor of 0.6787

The 41.4 MWe load could be satisfied by operation of the following turbine combinations to give the best and worst possible turbine efficiencies:-

- Steam turbines III plus IV plus VI = 46.2%;
- Steam turbines III plus IV plus I plus II = 38.2%.
- Steam turbines III or IV plus I plus II plus VI = 61.1%.

Utilising the boiler efficiencies suggested in Section 1.12.2 gives a similar range for the power cycle efficiency on the old plant at between 29.8% and 50.1% and suggests an average of 40.0%.

In order to compare 'normalised' and reference evaluations of the old and new plants on an equal footing with other case studies it was assumed that power cycle efficiencies on the old plant do not change in relation to the change in load factor from 0.48 to 0.65. The value used for the purpose of this case study is 37.5%.

It is also assumed that the ratio of steam to power for the old plant is similar to that for the new CHP plant.

2. CALCULATION RESULTS

2.1 Reference Plant Calculations for Change to Gas Turbine Based CHP

The plant for this case study represents the construction of a new gas turbine and HRSG at an existing site. No actual or reference plant data was provided prior to modification. In this section of the report it is proposed to evaluate both schemes at conditions derived from operation of the new plant and NOT to consider the loss of revenue associated with differences in size, since it is assumed the new plant replaced three old plants.

The reference conditions for this case study are represented by the following:-

- remnant life for cost evaluations is taken as 25 years;
- an average annual plant load factor taken as 0.48 on the power output of the new plant at 191 MWe;
- operational and maintenance savings excluding fuel and labour are in accordance with section 1.9;
- interest and discount rates for loan repayment and NPV calculations are 5% and 10%;
- plant efficiency figures are from information given in Section 1.12;
- fuel data as given in Sections 1.10 and 1.11.

Based upon the assumptions above and discussed in Section 1, estimates can be made regarding the fuel consumption and CO_2 emissions for each scheme on an annual basis for the station:-

		Old	New
Annual electricity generated by CCGT/CHP plant	GWh_{so}	803.4	803.4
Net Efficiency of power generation	%	37.5	40.7
Annual heat generated by CCGT/CHP plant	GWh	681.6	681.6
Net Efficiency of heat & power generation	%	69.3	74.6
Total annual heat input requirement	TJ	7712.5	7106.2
Annual gas consumption	kte	17.20	154.45
Annual DFO consumption	kte	0.0	0.22
Annual HFO consumption	kte	95.5	0.0
Black Coal consumption	kte	55.7	0.0
Brown Coal consumption	kte	250.5	0.0
Annual fuel cost	M$	15.89	14.00
Annual fuel saving	M$	0.0	1.89
Annual generation of CO_2	kte	686.3	414.1

Annual reduction in CO_2 emissions	kte	0.0	272.2

These figures indicate a 39.7% reduction in CO_2 emissions resulting from the installation of the new plant.

The changes in capital expenditure represented by the new plant have been obtained (see Section 1.8) and summarised below:-

- increased capital expenditure = 113 M$.

This information is used as the basis for the evaluations discussed below.

2.1.1 Estimated Benefits of New Plant Scheme on Loan Basis

The following financial evaluation of the new plant is carried out at reference plant conditions using capital based on a mortgage type loan at 5% and 10% annual interest rates over the remnant life of the station:-

Increase in capital expenditure		113	M$
Cost of lost power production (PL)		0	M$
Total cost of refurbishment (C_r+PL)		113	M$
Number of years remnant life (n)		25	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0709	0.11017	
Annual loan repayment (A_{1r})	8.02	12.45	M$
Annual fuel saving (FS_r)	4.34	1.90	M$
Annual O&M saving (M_s)	0.14	0.14	M$
Annual labour saving (L_s)	0.36	0.36	M$
Net annual saving (FS_{1r}-A_r +M_s+L_s)	-5.62	-10.05	M$
CO_2 reduction per annum		272.2	kte
GWh_{so} per annum		803.4	GWh_{so}
GWh steam per annum		1683.9	GWh
(i) Levelised saving per GWh_{so}	-6995	-12511	$$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	338.8	338.8	te/GWh_{so}
(iii) CO_2 prevention saving	-20.65	-36.93	$/te$CO_2$
(iv) Levelised saving per steam	-3815	-6823	$/GWh
(v) CO_2 reduction per GWh steam	184.8	184.8	te/GWh

2.1.2 Estimated Benefits of New Plant Scheme on Capital As Equity and NPV Basis

The following financial evaluation of the new plant is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5% and 10 % per annum over the remnant life of the station:-

Cost of refurbishment (C_r)		113	M$
Cost of lost power production		0	M$
Total cost of refurbishment		113	M$
Number of years remnant life (n)		25	
CO_2 reduction per annum		377.8	kte
GWh_{so} per annum		803.4	GWh_{so}
GWh_{so} over reference plant life		20085	GWh_{so}
Annual heat in steam		1683.9	GWh
Through life heat in steam		36828	GWh
Annual fuel saving (FS_r)		1.90	M$
Annual O&M saving		0.14	M$
Annual labour saving		0.36	M$
Total annual saving		2.40	M$
Annual discount rate $^{(r)}$	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	14.7986	9.9847	
Disc'd saving over remnant life (DS_r)	35.48	23.94	M$
NPV saving (DFS_r - C_r)	-77.52	-89.06	M$
(i) NPV levelised saving	-3860	-4434	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	338.8	338.8	te/GWh_{so}
(iii) CO_2 prevention savings	-11.39	-13.09	$/te$CO_2$
(iv) NPV levelised saving on steam	-2105	-2418	$/GWh
(v) CO_2 reduction per GWh steam	184.8	184.8	te/GWh

2.2 Normalised Plant Calculations for Change to Gas Turbine Based CHP

In this section of the report the new plant is evaluated at 'normalised' conditions as detailed below:-

- an average annual plant load factor taken as 0.65 on the power output of the new plant at 191 MWe.

Note that, apart from an increase in load factor all other assumptions given in Section 2.1 remain unchanged.

Based on the assumption above and those given in Section 2.1, revised estimates can be made regarding the fuel consumption and CO_2 emissions for each scheme on an annual basis for the station:-

		Old	New
Annual electricity generated by CCGT/CHP plant	GWh_{so}	1087.6	1087.6
Net Efficiency of power generation	%	37.5	40.7
Annual heat generated by CCGT/CHP plant	GWh_{so}	923.0	923.0
Net Efficiency of heat & power generation	%	69.33	74.6
Total annual heat input requirement	TJ	10440	9620
Annual gas consumption	kte	23.1	207.5
Annual DFO consumption	kte	0.0	0.29
Annual HFO consumption	kte	130.9	0.0
Annual Black Coal consumption	kte	53.22	0.0
Annual Brown Coal consumption	kte	294.83	0.0
Annual fuel cost	M$	28.80	24.06
Annual fuel saving	M$	0.0	4.73
Annual generation of CO_2	kte	897.3	560.0
Annual reduction in CO_2 emissions	kte	0.0	337.4

These figures indicate a 37.6% reduction in CO_2 emissions resulting from the installation of the new plant.

2.2.1 Estimated Benefits of New Plant Scheme on Loan Basis.

The following financial evaluation of the new plant scheme is carried out at 'normalised' plant conditions using capital based on a mortgage type loan at 5% and 10 % interest rates over the remnant life of the station:-

SECTION 2
CALCULATION RESULTS

Increase in capital expenditure		113	M$
Cost of lost power production (PL)		0	M$
Total cost of refurbishment (C_r+PL)		113	M$
Number of years remnant life (n)		25	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.07095	0.11017	
Annual loan repayment (A_{lr})	8.02	12.45	M$
Annual fuel saving (FS_r)	4.73	4.73	M$
Annual O&M saving (M_s)	0.14	0.14	M$
Annual Labour saving (LS_{r+c})	0.36	0.36	M$
Net annual saving (FS_r-A_{1r}+M_s+L_s)	-2.78	-7.21	M$
CO_2 reduction per annum		337.4	kte
GWh_{so} per annum		1087	GWh_{so}
GWh steam per annum		2280	GWh
(i) Levelised saving per GWh_{so}	-2560	-6634	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	310.2	310.2	te/GWh_{so}
(iii) CO_2 prevention saving	-8.25	-21.39	$/te$CO_2$
(iv) Levelised saving on steam	-1395.5	-3617.6	$/GWh
(v) CO_2 reduction per GWh steam	169.2	169.2	te/GWh

2.2.2 Estimated Benefits of New Plant Scheme on Capital From Equity and NPV Basis

The following financial evaluation of new plant scheme is carried out at normalised plant conditions using capital from company equity and discounting of savings/costs at rates of 5% and 10% per annum over the remnant life of the station:-

Cost of refurbishment (C_r)		113	M$
Cost of lost power production		0	M$
Total cost of refurbishment		113	M$
Number of years remnant life (n)		25	
CO_2 reduction per annum		475.4	Kte
GWh_{so} per annum		1087	GWh_{so}
GWh_{so} over reference plant life		27189	GWh_{so}
Annual heat in steam		2280	GWh
Through life heat in steam		57000	GWh
Annual fuel saving (FS_r)		4.73	M$
Annual O&M saving		0.14	M$
Annual labour saving		0.36	M$
Total annual saving		5.23	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	14.7986	9.9847	
Disc'd saving over remnant life (DS_r)	77.47	52.27	M$
NPV saving (DFS_r - C_r)	-35.53	-60.73	M$
(i) NPV levelised saving	-1306.9	-2233.7	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	310.2	310.2	te/GWh_{so}
(iii) CO_2 prevention savings	-4.21	-7.20	$/te$CO_2$
(iv) NPV levelised saving on steam	-712.7	-1218.2	$/GWh
(v) CO_2 reduction per GWh steam	169.2	169.2	te/GWh

3. DISCUSSIONS AND CONCLUSIONS

The following tabulation summarises the data behind the judgements given in this section for the new plant scheme:-

Reference conditions:

Interest and Discount Rates	5%		10%	
Evaluation Basis	LR	E-NPV	LR	E-NPV
Merit Figures				
(i) $/GWh$_{so}$	-6995	-3860	-12511	-4434
(ii) te/GWh$_{so}$	338.8	338.8	338.8	338.8
(iii) $/te$CO_2$	-20.65	-11.39	-36.93	-13.09
(iv) $/GWh	-3815	-2105	-6823	-2418
(v) te/GWh	184.8	184.8	184.8	184.8

Normalised condition:

Interest and Discount Rates	5%		10%	
Evaluation Basis	LR	E-NPV	LR	E-NPV
Merit Figures				
(i) $/GWh$_{so}$	-2560	-1306.9	-6634	-2233.7
(ii) te/GWh$_{so}$	310.2	310.2	310.2	310.2
(iii) $/te$CO_2$	-8.25	-4.21	-21.39	-7.20
(iv) $/GWh	-1395.5	-712.7	-3617.6	-1218.2
(v) te/GWh	169.2	169.2	169.2	169.2

The combined cycle nature of this case study means that merit figures (iv) and (v) in the above tables are slightly misleading when compared with other case studies with conventional steam cycles and so the following review is based around merit figures (i) to (iii) only.

An external influencing factor that has not been considered within these comparisons is the possible requirement for replacement of the HFO boiler(s) or installation of FGD equipment associated with the continued supply of process steam from the existing HFO boilers.

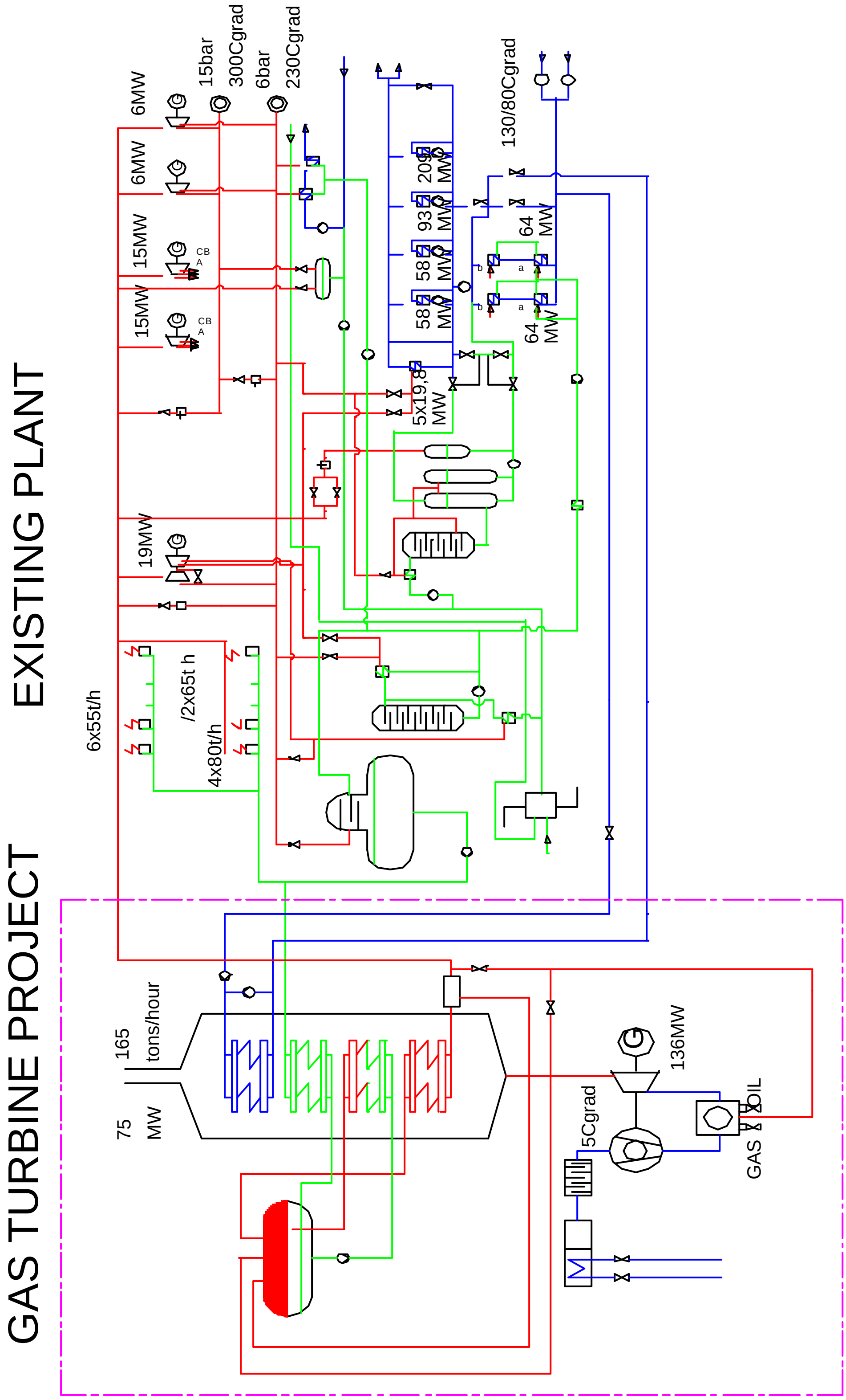
The tables above for both evaluation conditions show that a significant CO_2 emission saving (310 to 340 te/GWh$_{so}$) can be achieved.

However, the large CO_2 reduction above is at a high investment cost and the low cost benefits of the fuel change gives a marginal saving of between –12511 and -1310 $/GWh$_{so}$.

The CO_2 prevention cost (negative saving) for this study is also significant at between –37 and -4.2 $/te CO_2 and is not as favourable as might have been anticipated for a project of this type. This is probably as a result of the low cost of fuels for the reference plant conditions.

As with other case studies the NPV evaluation technique gives more favourable values than the loan technique by a factor of approximately 50% of loan values.

1. Steam range diagram for Kelenfold.



APPENDIX 10

CASE 8

POWER STATION REFURBISHMENT AND STEAM TURBINE EFFICIENCY IMPROVEMENTS

SECTION 1
PLANT DESCRIPTION

1. PLANT DESCRIPTION

1.1 General

The Niederaussem efficiency improvement project/programme currently being implemented by RWE ENERGIE involves the modification of all the 150, 300 and 600 MWe steam turbine units at the above station firing local brown coal. This IEA case study concentrates upon the conversion of one such 600 MWe unit at the station included as part of the overall efficiency improvement project.

Niederaussem currently represents an electrical capability of 2700 MWe on the Rhineland section of the German grid and is owned and operated by RWE ENERGIE who currently have a capability to supply 26.6 GWe of German power demands.

This case study is typical of a number of similar efficiency improvement projects currently being carried out in Germany by various owners and operators. The projects are being partly funded by central German Government and State Government bodies and the station operators. The overall project aims to reduce CO_2 emissions from all German power stations by 25% based upon 1987 levels before the year 2005.

1.2 Plant Prior to Modification

The original power station at Niederaussem comprised of 2 x 150 MWe units built and commissioned between May 1961 and August 1963. The 4 x 300 MWe units were constructed and commissioned between March 1963 and February 1971 and incorporated Benson once through boiler technology. The third phase of the station development included 2 x 600 MWe units having an improved Benson once through steam cycle with reheat design and these were constructed and commissioned between August 1970 and October 1974. These 600 MWe units form the basis of information used within this case study evaluation of the reductions in CO_2 emissions obtained from efficiency improvements on 600 MWe steam turbines. The design parameters for these units are set out in the following table:

Design	Voltage	Nominal Steam Pressure	Nominal Steam Temperature
780 MVA	21 kV	173 bar 162.8 bar (turbine entry)	530°C 525 °C (turbine entry)

The steam parameters have not been changed on account of the efficiency improvements but the output capability of the units after conversion has increased to

640 MWe gross (589 MWe_{so} net). The steam turbine condensers are river water cooled using cooling towers and with an inlet CW temperature range of 8°C to 15°C. The boilers were supplied by Steinmuller and the steam turbines and generators by Siemens KWU.

A photograph and a diagram of the power station are included at the end of this appendix to illustrate the visual impact of the station and the steam plant arrangement for the 600MWe units.

1.3 Brief History and Decision Process

During the early 1990's a series of worldwide conferences were held to discuss the effects that man and industrial pollution is having on global climates. In response to this the German government, in agreement with their state authorities published an internal resolution to reduce their CO_2 emissions. The resolution decreed that Germany would reduce its CO_2 emissions by 25% from datum reference levels in 1987 before the year 2005. Development of reduction techniques should therefore include the industrial sector in general as well as the sectors of transport, travel or households.

In the power industry, as a major source of CO_2 emissions, manufacturers and operators such as RWE ENERGIE were requested to identify what efficiency improvement techniques were available and which power station units were suitable for modifications.

Brown coal fired power stations became a particular focus of attention because of their high environmental profile associated with other pollutants as well as CO_2. RWE ENERGIE and the authorities in the state of Northrhine-Westphalia together announced a CO2 reduction program for the local brown coal worth 20 billion DM for efficiency improvement and research.

Whilst the efficiency improvements were directed towards all unit sizes the 2x600MWe units at Niederaussem were of particular interest because of their large size and fuel type. Inspections of both units were carried out during annual maintenance outages in the summers of 1995 & 1996 with a view to assessing the detailed engineering requirements associated with modification proposals for both units.

1.4 Modification Details

All of the upgrading work was carried out by Siemens Power Generation Group (KWU). It included functional and mechanical design, design by analysis, fabrication and supply of all requisite parts and components as well as performance of all disassembly and reassembly work and commissioning. Increased efficiency was essentially achieved through the use of stationary and moving blades with new airfoil geometry, increasing the steam exhaust flow cross section and by optimizing the blade seals and shaft glands as well as the admission and exhaust sections.

The main purpose of these upgrades was to improve efficiency and heat rate in order to reduce CO_2 emissions and increase turbine output respectively. A new HP turbine was ordered in addition to new LP turbines.

The socket weld joints on the HP inlets of the HP turbine, a barrel-type turbine, were retained as well as the actual inlet elbows. A new turbine having T4 profile blades and twisted blades in the final stages was installed.

The number of seal rings in the barrel casing was reduced from eight to three. Flow contours in the admission and exhaust sections were optimized, as were the blade and shaft seals. In contrast to the old design, the piston balancing steam is not returned through an external piston balancing line but through internal balancing holes in the stationary blade carrier.

The inner casings of the new LP turbines are of modular cast iron design with suspended stationary blade carriers to locate the drum section stationary blading. The subsequent stationary blade rows are located in bolted-on stationary blade carriers of a welded steel design. The last stationary blade rows are hollow with curved blades which optimize mass flow distribution over the entire length of the blade. The outlet cross sections have been increased from $6.3m^2$ to $8m^2$ per flow. As a result, it was also necessary to adapt the exhaust steam cross sections downstream of the outlet diffusers to match the new, larger internals. This was achieved by raising and enlarging the LP hoods.

The LP rotors are monobloc assemblies, having milled inverted t-root blades in the drum section and integral shrouding and three free standing moving blade rows per flow with caulked seal strips.

The new components for these turbines were also dimensioned to allow the existing bearings and, in the case of the LP turbines, the original shaft seals, to be retained. The LP bearings, however, were relined and altered from plain sleeve bearings to journal bearings to accommodate increased bearing loadings resulting from the heavier rotors.

The initial inspection of the unit was carried out from July to September 1996. The LP hoods had already been enlarged during an earlier inspection outage in preparation for upgrading work. Replacement of the HP turbine and the internals of both LP turbines were then to be performed during the next inspection outage.

A delivery time of at least 24 months was allowed for manufactured components. The turbine components were all fabricated at Siemens' Mülheim turbine manufacturing plant and were completed in time for installation. A period of 56 calendar days was set aside for the upgrading work which was carried out during normal inspection outages.

During commissioning the turbines satisfied all operating requirements during their respective periods of trial operation. The customer provisionally accepted the systems on completion of trial operation subject to a two year warranty period. Heat rate measurements of the 600MW units performed by RWE ENERGIE verified the guaranteed values. Measurements performed under guarantee six months after the turbine had resumed power operation showed that it was exceeding the guaranteed value (of power output) by around 0.8 percent.

1.5 Greenhouse Gas Reduction

The carbon dioxide reduction is predominantly determined by the change in plant efficiency and operating regime. The results are given for one 600 Mwe unit burning brown coal and compared with operation on brown coal before modifications. The amounts of CO_2 generated by the combustion of all 'normalised/paradigm' study fuels is addressed in Appendix 1. No indigenous UK supplies of brown coal are available and only minimal discrepancies exist between the normalised fuels (see Appendix 1) and site fuels (see sections 1.9.1 & 1.9.2.) and so no corrections are proposed.

The NO_x reduction achieved as a result of fitting low NO_x dual fuel burners is taken to be principally a reduction in NO_2 since it is assumed that the N_2O proportion is not significant. Installation of low NO_x burners had already been carried out on this boiler and was not part of the capital expenditure associated with the efficiency improvements of this study. Experiments to measure N_2O concentrations in flue gases on other plant have proved unsuccessful and hence any change in the greenhouse gas N_2O is not considered in this case. It should be noted that low NO_x burners would have been fitted on the unit in order to comply with the tighter emission consents being applied by the German Environment Agency.

1.6 Determination of capital costs

The capital costs have been based upon quotations received by RWE ENERGIE from contractors.

The contract was awarded to Siemens KWU in 1996 for the sum of 45.4 million DM.

There were no appreciable delays or significant difficulties experienced in fitting refurbishment work into the annual 56 day outage period of the unit. This meant that no additional loss of revenue was incurred as a result of modifications.

1.7 Determination of Fuel, Operating and Maintenance Costs

No labour savings are associated with the modifications.

The current plant utilisation is such that on the 600MWe unit output of 640 MW is now frequently achieved and the average availability and reliability of all units was enhanced after the conversion.

The data on estimated and actual operating fuel consumptions, net output, utilisation and the operating and maintenance costs are itemised under Section 2.

1.8 Changes to Non-Greenhouse Gas Emissions

The decision to fit low NO_x burners for the combustion of the brown coal had been taken prior to the conversion. Environmental pressure from the EC had imposed a pre-requisite that the SO_2 emissions were to be reduced by 70% and the NO_x emissions by 40% [based on 1980 levels].

The environmental requirements were stipulated by the EC large combustion plant directives such that low NO_x burners were required to achieve 650 mg/Nm³ with reference to 6% O_2 in dry flue gas. The respective particulate levels are less than 50 mg/Nm^3 at the same reference condition.

1.9 Site Fuel data

1.9.1 Brown Coal

Information on the brown coal supplies from the local mine(s) was provided by RWE ENERGIE and is summarised in the table below:-

Elements on % Wt basis	Typical	Range	Basis
C	68.0	65 to 70	Dry ash free
H	5.0	4.9 to 5.1	Dry ash free
O	25.2	25.1 to 25.3	Dry ash free
N	0.8	0.79 to 0.81	Dry ash free
S	1.0	N/A	Dry ash free
Ash	6.0	2 to 12	As received
Moisture	53.3	51 to 58	As received
GCV (MJ/kg)	N/A	N/A	N/A
NCV (MJ/kg)	9.2	7.9 to 10.5	As received

Information from Rheinisch – Westfälisches Institut (RWI) paper number 47 dated June 1997 gives data on typical fuel prices between 1995 and 2000 for the German industrial market. This has been utilised to estimate the price of brown coal below:

Typical mine price: 21 to 26 DM/te
(based upon brown coal having a standard NCV 8.8 MJ/kg and dependent on annual inflation rate considered)

The price paid by any industrial purchaser will include costs for initial separation and drying carried out at the mine together with transportation to the site. In order to be able to compare costs for different fuel types the RWI paper referenced above puts all fuel costs on to a standard basis called the SKE or hard (black) coal equivalent cost based upon a coal with an NCV 29.3 MJ/kg.

A typical price to user: 74 to 92 DM/te
(SKE, normalized to hard coal standard conditions)

Based upon a typical price of 87.5 DM/te for mid 1998 and correcting for the minimal NCV difference between the actual brown coal used in this study and the standard RWI/SKE brown coal, gives a site cost of 3.12 DM/GJ (1.94 $/GJ) for the fuel as detailed in the above sections of the report. This is only marginally different to the figure of 1.98 $/GJ assumed in Appendix 1 as being a typical UK import price for brown coal and so no correction is proposed.

1.10 Combustion Gases

The brown coal fuels previously identified in 3.9 give CO_2 emission figures of between 0.997 and 1.016 kg of CO_2 per kg of fuel dependent on allowances for carbon in ash. Therefore no correction is proposed from the 1.0 kg CO_2 figure associated with the Appendix 1 normalised brown coal analysis.

1.11 Net Plant Efficiency and Output Information

Indication of the efficiency of plant at Niederaussem prior to conversion is obtained from operator RWE ENERGIE and gives an average of 36.33% before with an average load factor of 91.00%.

The refurbishment work carried out between 1996 and 1997 could be expected to improve the efficiency figures for brown coal firing by between 0.8 and 1.0% on cycle efficiency to between 37.1% and 37.3%. These figures agree closely with the data provided by the operator on boiler and turbine efficiency (see below) and original performance test data. It appears reasonable to assume that post conversion cycle efficiencies are 37.2% on brown coal.

Unit output and test efficiencies are summarised below:

Net generated output before modification 564 MWe

SECTION 1
PLANT DESCRIPTION

Net generated output after modification	589 MWe
Brown coal boiler efficiency	88%
Steam turbine efficiency before modification	41.3%
Steam turbine efficiency after modification	42.3%

Site utilisation data provided gives an average figure of in excess of 95% for the period following modification and represents the amount of time that the plant is dispatched by the German grid company to produce electricity. The associated load factors given represent the actual power generated per annum divided by the hours in a year and the declared output capability of the unit.

The site have advised that unit loading subsequent to the efficiency modifications would result in an average yearly unit loading estimated at 4712 GWh_{so}. Based upon the modified unit output capability this represents a 91.3% load factor. However, if this output is related to the original output capability of the unit it represents a 95.4% load factor.

SECTION 2
RESULTS

2 RESULTS

2.1 Reference Plant Calculations

Based upon the assumptions discussed in section 1, estimations can be made regarding pre and post modification fuel consumptions and CO_2 emissions on an annual basis for the unit as shown below:

Fuel	**Pre modification**		**Post modification**	
Annual net power export	GWh_{so}	4712		4712
Net cycle efficiency on NCV	%	36.33		37.2
Annual heat in steam	GWh	10173		9935
Annual net heat input requirement	GWh	41618		40645
Annual fuel consumption	kte	4524		4418
Annual fuel cost	M$	83.24		81.29
Annual fuel saving	M$	0		1.95
Annual generation of CO_2	kte	4501		4396
Annual reduction in CO_2	kte	0		105.3

These figures indicate 2.3% reduction of CO_2 emissions resulting from the plant refurbishments carried out.

The above table of information represents a 91.3% load factor on the post modified unit. As discussed previously in section 1.11, this represents a very high figure for the unit prior to modifications but for all case study evaluations the important consideration is to maintain fixed outputs for both the pre and post modification conditions.

The capital expenditure associated with the refurbishment of the unit has been obtained and summarised in the table below:

Estimated cost of refurbishment 28.2M$

Financial evaluations contained in the following sections 2.1.1 to 2.1.4 are all based on the reference plant conditions above and the assumptions listed below:-

- refurbishment work was largely carried out as part of annual maintenance programs and no major additional loss of revenue is appropriate.
- operational and maintenance costs excluding fuel are unaltered except for reductions in FGD raw materials estimated at 0.028M$.
- remnant life for cost evaluations is taken as 15 years
- annual discount rates assumed for through life NPV calculations are 5% and 10%.

- loan repayments based on annual interest rates at 5% and 10%.

The following financial evaluations include refurbishment using loan capital without discounting (see 2.1.1) and refurbishment using equity as capital and discounting through life to give NPV (see 2.1.2).

2.1.1 Estimated benefits of refurbishment on loan basis.

The following financial evaluation of the station refurbishment is carried out at reference plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		28.2	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A_{lr})	2.72	3.71	M$
Annual fuel saving (FS_r)	2.17	2.17	M$
Annual FGD saving	0.028	0.028	M$
Net annual saving (FS_r-A_r)	-0.52	-1.51	M$
CO_2 reduction per annum		118.4	kte
GWh_{so} per annum		4712	GWh_{so}
GWh steam per annum		11414	GWh
(i) Levelised saving/cost per GWh_{so}	-110.6	-320.9	$/GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	25.12	25.12	te/GWh_{so}
(iii) CO_2 prevention saving	-4.40	-12.77	$/te$CO_2$
(iv) Levelised saving per steam	-46.76	-135.64	$/GWh
(v) CO_2 reduction per GWh	10.62	10.62	te/GWh

2.1.2 Estimated Benefits of Refurbishment on Capital from equity and NPV basis.

The following financial evaluation of the station refurbishment is carried out at reference plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		28.2	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		118.4	Kte
GWh_{so} per annum		4712	GWh_{so}
GWh_{so} over reference plant life		70680	GWh_{so}
Annual heat in steam		11414	GWh
Through life heat in steam		171204	GWh
Annual fuel saving (FS_r)		2.17	M$
Annual FGD saving		0.028	M$
Annual discount rate (r)	5	10	%
Discount factor $\{(1 – R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS_r)	23.93	18.37	M$
NPV saving (DFS_r - C_r)	-4.27	-9.83	M$
(i) NPV levelised saving	-60.43	-139.08	$/$GWh_{so}$
(ii) CO_2 reduction per GWh_{so}	25.12	25.12	te/GWh_{so}
(iii) CO_2 prevention savings	-2.41	-5.54	$/te$CO_2$
(iv) NPV levelised saving on steam	-25.54	-58.79	$/GWh
(v) CO_2 reduction per GWh	10.62	10.62	te/GWh

2.2 Normalised Plant Calculations.

The 'normalised' or 'paradigm' project conditions on which this case study is to be evaluated are summarised below:-

- refurbishment work was largely carried out as part of annual maintenance programs and no major additional loss of revenue is appropriate.
- operational and maintenance costs excluding fuel and labour are unaltered apart from reductions in FGD raw materials estimated at 0.028 M$
- annual discount rates assumed for through life NPV calculations are 5% and 10%.
- loan repayments based on annual interest rates at 5% and 10%.
- 15 year life expectancy

- 85% plant loading utilisation factor corresponding to 4200 GWh_{so} based upon the pre-converted unit.

The above criteria enables the following generic table, similar to that originally provided in section 2.1, to be reproduced giving the annual power, fuel and CO_2 quantities based upon 'normalised' plant conditions:

		Pre conversion	**Post conversion**
Fuel			
Annual net power export	GWh_{so}	4200	4200
Net cycle efficiency	%	36.33	37.2
Annual heat in steam	GWh	10173	9935
Annual net heat input requirement	TJ	41618	40645
Annual fuel consumption	Kte	4524	4418
Annual fuel cost	M$	82.61	80.68
Annual fuel saving	M$	0	1.93
Annual generation of CO_2	Kte	4591	4484
Annual reduction in CO_2	Kte	0	107.4

This gives similar reductions of CO_2 emissions on a percentage basis as those given in 2.1 i.e. 2.3%.

SECTION 2
RESULTS

2.2.1 Estimated benefits of refurbishment on loan basis.

The following financial evaluation of the station refurbishment is carried out at 'normalised' plant conditions using capital based on a mortgage type loan at 5 and 10 % interest rates over the remnant life of the station.

Cost of refurbishment (C_r)		28.2	M$
Number of years remnant life (n)		15	
Loan annual interest rate (i)	5	10	%
Loan factor $\{I^n \times (I-1)/(I^n-1)\}$	0.0963	0.1315	
Annual loan repayment (A^n_{lr})	2.72	3.71	M$
Annual fuel saving (FS^n_r)	1.93	1.93	M$
Annual FGD saving	0.028	0.028	M$
Net annual saving ($FS^n_r - A^n_{lr}$)	-0.76	-1.75	M$
CO_2 reduction per annum		107.4	kte
GWh_{so} per annum		4200	GWh_{so}
GWh steam per annum		10173	GWh
Merit fig (i) levelised saving	-180.2	-416.1	$\$/GWh_{so}$
Merit fig (ii) CO_2 reduction	25.57	25.57	te/GWh_{so}
Merit fig (iii) CO_2 prevention saving	-7.05	-16.27	$\$/teCO_2$
Merit fig (iv) levelised saving on steam	-76.17	-175.88	$/GWh
Merit fig (v) CO_2 reduction on steam	10.81	10.81	te/GWh

2.2.2 Estimated Benefits of Refurbishment on Capital from equity and NPV basis.

The following financial evaluation of the station refurbishment is carried out at 'normalised' plant conditions using capital from company equity and discounting of savings/costs at rates of 5 and 10 % per annum over the remnant life of the station.

Cost of refurbishment (C_r)		28.2	M$
Number of years remnant life (n)		15	
CO_2 reduction per annum		107.4	kte
GWh_{so} per annum		4200	GWh_{so}
GWh_{so} over reference plant life		63000	GWh_{so}
GWh steam per annum		10173	GWh
GWh steam over ref. Plant life		152595	GWh
Annual fuel saving (FS^n_r)		1.93	M$
Annual Discount rate (r)	5	10	%
Discount factor $\{(1 - R^n) / (1 - R)\}$	10.8986	8.3667	
Disc'd saving over remnant life (DS^n_r)	21.36	16.40	M$
NPV saving ($DS^n_r - C_r$)	-6.84	-11.80	M$
Merit fig (i) NPV levelised saving	-108.5	-187.3	$\$/GWh_{so}$
Merit fig (ii) CO_2 reduction	25.57	25.57	te/GWh_{so}
Merit fig (iii) CO_2 prevention saving	-4.25	-7.33	$\$/teCO_2$
Merit fig (v) NPV levelised saving on steam	-45.88	-79.18	$/GWh
Merit fig (vi) CO_2 reduction on steam	10.81	10.81	te/GWh

SECTION 3
DISCUSSIONS AND CONCLUSIONS

3 DISCUSSIONS AND CONCLUSIONS

Based upon the normalised values calculated in sections 2.2 & 2.3, it is apparent that significant savings can be made from plant refurbishment. The results have been incorporated into the following summary tables for both the 5% and 10% loan interest and discount cases at both Reference and Normalised plant conditions.

Summary Table at Reference Conditions (4712 GWh_{so} per annum)

Interest/Discount rate		5%		10%	
Loan repayment/equity		LR	E-NPV	LR	E-NPV
Merit Figure	units				
(i)	$/$GWh_{so}$	-110.6	-60.43	-320.9	-139.08
(ii)	te/GWh_{so}	25.12	25.12	25.12	25.12
(iii)	$/te CO_2	-4.40	-2.41	-12.77	-5.54

Summary Table at Normalised Conditions (4200 GWh_{so} p.a.)

Interest/Discount rate		5%		10%	
Loan repayment/equity		LR	E-NPV	LR	E-NPV
Merit Figure	units				
(i)	$/$GWh_{so}$	-180.2	-108.5	-416.1	-187.3
(ii)	te/GWh_{so}	25.57	25.57	25.57	25.57
(iii)	$/te CO_2	-7.05	-4.25	-16.27	-7.33

An obvious comparison between the two financial evaluation techniques shows the equity & NPV evaluations of merit figures i and iii to be approximately 50 % of the loan evaluations of the same merit figures.

Merit figure (i) values show medium financial costs per GWh_{so} from refurbishment. Indications are that the benefits obtained from refurbishment with regard to CO_2 emissions reduction are achieved at a medium cost to the operator.

Merit figure (ii) values give the reduction in CO_2 per GWh of electricity and shows significant improvements from refurbishment. These benefits are virtually unaffected by the changes in electricity production since they are directly related to station efficiency. The minimal variation between 25.12 te/GWh_{so} and 25.57 te/GWh_{so} is representative of small changes between normalised and reference fuel data.

Merit figure (iii) values show an increase of 1:1.5 in the cost per te CO_2 saved when going from the, ‘reference’ to ‘normalised’ plant conditions.

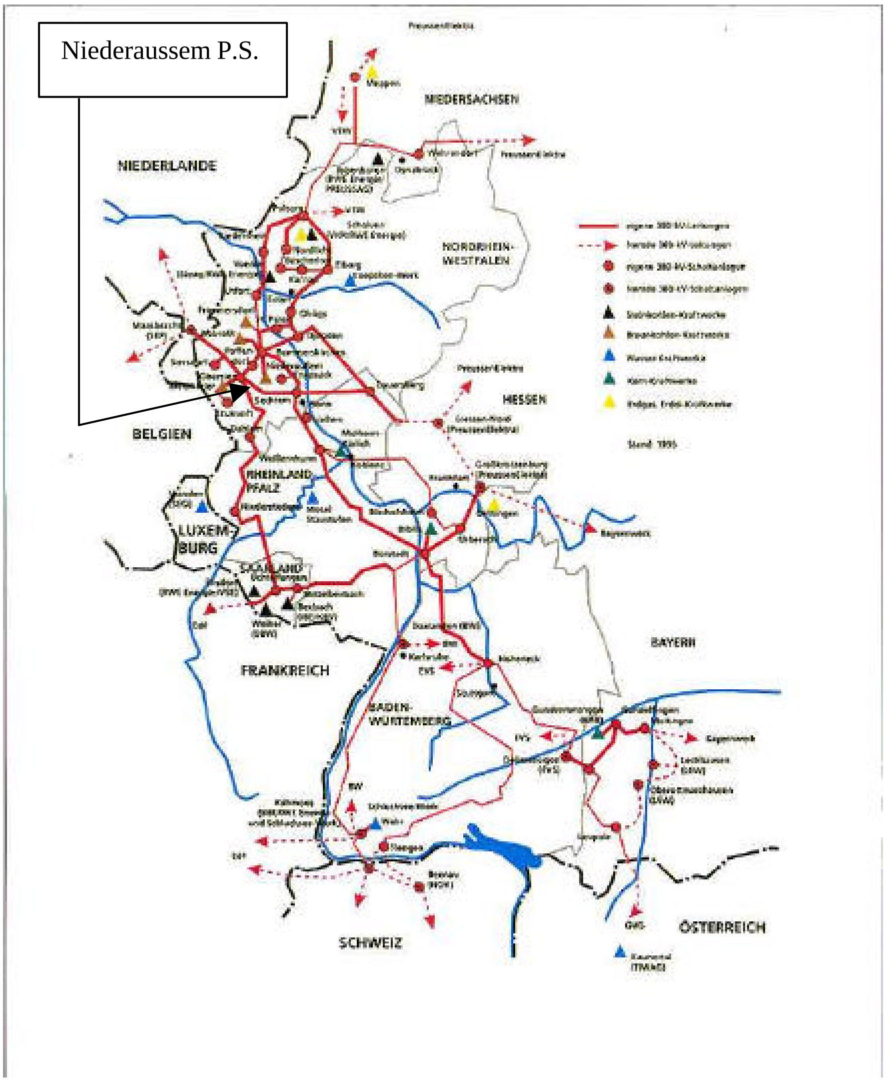
Therefore strictly from a CO_2 point of view it would appear that refurbishment and efficiency improvements are beneficial in reducing CO_2 emissions but the relatively cheap cost of fuel in this case study means that this is obtained at a small financial cost to the operator.

Increases in loan interest rates from 5 to 10% significantly reduce the financial viability of the modifications by a factor between 2.3 and 3.

Increases in discount rates on NPV evaluations also decrease the financial viability of the modifications by a factor between 1.7 and 2.3.

DIAGRAMS AND PHOTOGRAPH OF NIEDERAUSSEM POWER STATION

South German 380 kV national grid system in the Rheinland Pfalz area.



DIAGRAMS AND PHOTOGRAPH OF NIEDERAUSSEM POWER STATION

Niederaussem Power Station.

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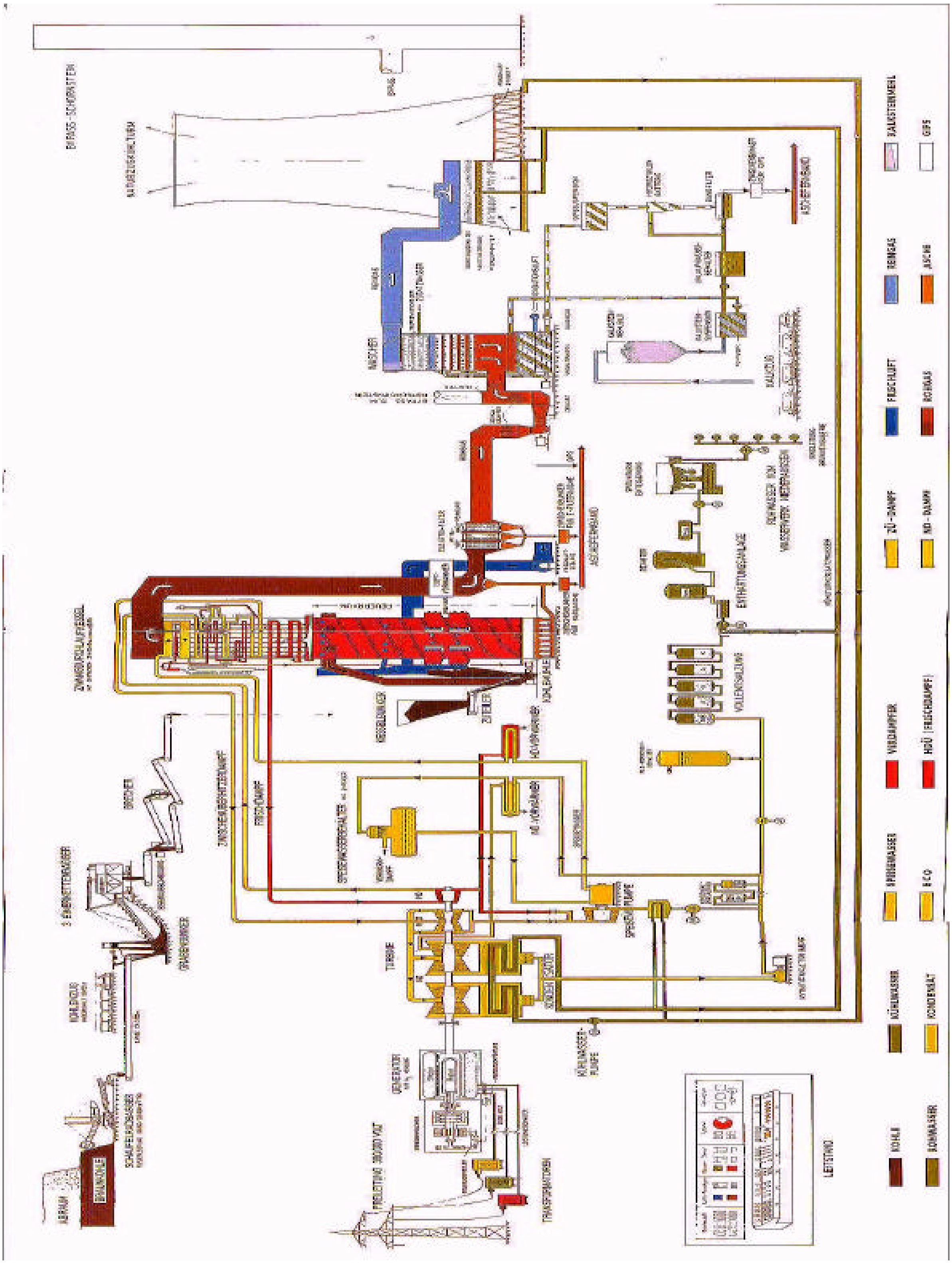
DIAGRAMS AND PHOTOGRAPH OF NIEDERAUSSEM POWER STATION

Steam cycle diagram for the 600 MWe Brown coal units at Niederaussem.



DIAGRAMS AND PHOTOGRAPH OF NIEDERAUSSEM POWER STATION

APPENDIX 11
NORMALISED FUEL ANALYSIS AND COST DATA

Natural Gas

UK natural gas is conveyed along a nation wide distribution system owned and controlled by Transco Ltd. A range of potential gas analysis from Transco is given below on a % volume basis;

Component	Range Minimum	Range Maximum
Carbon Dioxide	0	2.0
Nitrogen	0	5.0
Oxygen	0	1.3
Hydrogen	0	2.0
Methane	87	97.0
Ethane	1	6.0
Propane	0.2	2.0
Butane	0	1.0
Pentane	0	0.15
Hexane	0	0.075
Heptane	0	0.05
Octane	0	0.01
Nonane	0	0.001
Benzene	0	0.03
Toluene	0	0.01
Hydrogen Sulphide (ppmv)	0	3.3
GCV (MJ/kg)	49.7	52.7
GCV (MJ/Nm^3)	38.5	40.3
NCV (MJ/kg)	44.9	47.6
NCV (MJ/Nm^3)	34.7	36.4

Kennedy & Donkin's knowledge of the UK national distribution and costing market for typical industrial users of natural gas indicates that the following prices should be utilised for this project dependent on the type of supply required:-

- UK mainland 15 to 18p/therm ≡ 2.35 to 2.85 \$/GJ on NCV.

For the purpose of the project a cost of 16p/therm ≡ 2.5 \$/GJ on NCV is representative of a typical UK industrial tariff for an interruptible supply for up to 40 days per annum and has been used for 'normalised/paradigm' calculations.

'Normalised/paradigm' calculations have also assumed an average datum UK natural gas having a GCV of 51.3 MJ/kg (39.5 MJ/Nm^3), NCV of 46.3 MJ/kg and containing 73% carbon by weight.

APPENDIX 11
NORMALISED FUEL ANALYSIS AND COST DATA

Heavy Fuel Oil (HFO)

UK supplies of heavy fuel oil are typical to those generally available on the international market. The main criterion for purchase of typical UK supplies of HFO is the sulphur content which can be either 3% or 1% by weight. Analysis data for typical supplies to UK power stations is given below:

Component	Range minimum	Range maximum
Carbon	83.5	86.5
Hydrogen	10.0	13.0
Sulphur	0.5	5.0
Vanadium	0.002	0.06
Ash	0.03	0.1
GCV (MJ/kg)	41.0	44.0
NCV (MJ/kg)	38.5	41.5

Financial Times data for various types of heating and fuel oils in June 1998 indicated the following costs for HFO:-

- For 2.5% S HFO = £85/tonne = 3.4 $/GJ on NCV;
- For 1.0% S HFO = £100/tonne = 4.0 $/GJ on NCV.

The price for 2.5% to 3% S HFO is taken unless otherwise stated, and 'normalised/paradigm' calculations are based upon a fuel within the above specification ranges having a carbon content of 84% by weight, sulphur content of 2.55% by weight and a GCV and NCV of 43.0 MJ/kg and 40.5 MJ/kg respectively.

Black Coal

A typical bituminous black coal specification for international supply can be found below:-

	Typical	Min	Max	
GCV	27	25	29	MJ/kg as received
NCV	25.5	23.5	27.5	MJ/kg as received
Ash	10	8	15	% by weight as received
Moisture	10	8	12	% by weight as received
C	68	60	80	% by weight as received
H	5.0	3.4	8.0	% by weight as received
S	1.0	0.5	1.5	% by weight dry ash free

The openness of the UK coal supply market suggests that UK coal supplies are closely related to general world/international supplies.

Recent DTI publications show a typical UK cost for coal of £33.8/te in 1997.

APPENDIX 11
NORMALISED FUEL ANALYSIS AND COST DATA

Price trend data in the same document suggests that coal costs in 1993 were £42.4/te i.e. reducing at £2.15/te per annum.

This gives the following summary of cost data:-

- DTI estimated to 1998 Ψ £32/te ≡ 2.1 $/GJ on NCV
- CRE max (see Appendix E) ≡ 2.0 $/GJ on NCV
- CRE min (see Appendix E) ≡ 1.5 $/GJ on NCV

Therefore 2.0 $/GJ on NCV (£30/te) is proposed for all 'normalised/paradigm' case study calculations based upon the above coal analysis data.

Brown Coal

These fuels are not indigenous to the UK but the information below reflects information available on typical European sources of lignite and brown coal.

Elements on % Wt basis	Typical	Range	Basis
C	68.0	60 to 76	Dry ash free
H	5.0	2.5 to 7.5	Dry ash free
O	25.2	18 to 30	Dry ash free
N	0.8	0.5 to 2.5	Dry ash free
S	1.0	0.5 to 6	Dry ash free
Ash	6.0	2 to 15	As received
Moisture	53.3	50 to 60	As received
GCV (MJ/kg)	11.0	9 to 15	As received
NCV (MJ/kg)	9.2	7 to 12	As received

In order that brown coal supplies are commercially competitive in the UK, a theoretical price is assumed which is closely linked to the international market prices and is estimated to be slightly cheaper than black coal at 1.98$/GJ based on an NCV of 9.0MJ/kg.

Straw from cereal crops

ADAS laboratories of Cambridge have carried out considerable analysis work regarding UK supplies of hesston bales of straw made from the following types of cereals:

Wheat
Barley
Rye
Oats

The following cereal straw fuel range data has been utilsed for a recent straw fired power plant for the UK and shall be utilised for the purpose of these studies.

APPENDIX 11
NORMALISED FUEL ANALYSIS AND COST DATA

%Weight-dry basis	Design (as blended and fired)	Range (within each bale)
Carbon	43.8	33-47.5
Hydrogen	6.0	5.4-6.5
Oxygen	41.55	40-51
Nitrogen	0.7	0.3-2.25
Sulphur	0.45	0.2-0.86
Chloride	0.6	0.1-1.1
Ash	6.9	3.2-10.6
Gross CV (MJ/kg)	18.2	17.2-19.2
As fired moisture	16.0	7.1-22.6
As fired NCV (MJ/kg)	14.0	12.3-15.9

Associated with the same project, investigations into the costs of UK straw at the power station gates have indicated the following results for hesston bales:

Max. present cost	=	£30/te	=	3.15	\$/GJ on NCV
Min. present cost	=	£11/te	=	1.49	\$/GJ on NCV
Mean present cost	=	£17/te	=	2.03	\$/GJ on NCV

Indications are that individual straw prices can vary significantly dependant on weather conditions prior to harvesting but the above is a good guide and inflation of prices tends to be 2-3% per annum.

Bark and Wood Chips

Various publications and Scandinavian manufacturers information has resulted in the following typical analysis and range data being utilised for the supplies of wood and wood bark from saw mills utilising temperate forestry timber.

Elements on % Wt basis	Typical	**Range**	**Basis**
C	52.5	50.4 to 54.5	Dry solids
H	6.0	5.9 to 6.2	Dry solids
O	40.0	37.6 to 42.5	Dry solids
N	0.4	0.3 to 0.5	Dry solids
S	0		Dry solids
Ash	1.1	0.4 to 1.7	Dry solids
Moisture	53.5	47 to 60	As fired
NCV (MJ/kg)	7.85	6.7 to 9.0	As fired

Typical costs for these wood based fuels are 2.32 \$/GJ based on an NCV of 7.85 MJ/kg.