# REQUIREMENTS FOR A SUSTAINABLE GROWTH OF THE NATURAL GAS INDUSTRY IN SOUTH AFRICA

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# REQUIREMENTS FOR A SUSTAINABLE GROWTH OF THE NATURAL GAS INDUSTRY IN SOUTH AFRICA

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A thesis submitted to the Faculty of Engineering and the Built Environment, University of the Witwatersrand, in fulfilment of the requirements for the degree of Doctor of Philosophy

**JOHANNESBURG, 2006**

**DECLARATION**

I, Joseph Kwasi Asamoah, hereby solemnly declare that this thesis is my own unaided work. To the best of my knowledge, it fulfils the requirements of the degree of Doctor of Philosophy in Engineering in the University of the Witwatersrand, Johannesburg. No other university has previously examined this thesis for any degree.

Signature……………………………………………………….

Date…………………………………………………………

## ABSTRACT

South Africa's energy economy is dominated by coal, which produces relatively high emissions of greenhouse and noxious gases during combustion. This causes environmental problems that may lead to health risks that are cause for concern. In this thesis, various propositions are tested about whether in the Cape Metropolitan Area natural gas is a lower cost energy source than coal for generating base load power within a specified range of capacity factors under different scenarios.

The problem being investigated is the uncertainty about the quantified effect that revenue from monetised carbon dioxide credits and inclusion of damage costs would have on the breakeven selling price of electricity, if natural gas were substituted for coal for generating base load power in the above Area.

The research procedure entailed conceptualising and developing technical details of four power generation scenarios and reviewing various tools for cost-benefit analysis. Next, a Te-Con Techno-Economic Simulator model and screening curves were selected from a suite of potential tools. The power generation cost profiles for coal and natural gas were determined, followed by sensitivity analysis. The model was populated and used to compare the life-cycle economic performance of coal and natural gas technologies.

Natural gas emerged as a lower cost energy source than coal for generating base load power within a specified range of capacity factors under all the scenarios. This thesis recommends the following: the introduction of tax holidays and favourable capital equipment depreciation regimes to stimulate natural gas exploration; the use of natural gas as an energy source to promote small-scale enterprises in communities contiguous to gas transmission pipelines; in addition, electricity prices should reflect damage costs in order to internalise externalities associated with power generation.

The contribution to knowledge is the innovative way of financing the gas-fired power generation project by using the monetised carbon dioxide credits under the novel Clean Development Mechanism to redeem a bank and a shareholders' loan. This could result in reducing the loan payment by 4.3 years, saving 38 % in interest payments and allow scarce finance available for project funding to be extended to other projects to the advantage of national economic development.

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**NOMENCLATURE**

| | |
|---|---|
| Agenda 21 | Agenda for the twenty first century |
| ARR | annual revenue requirement |
| bbl/d | barrels per day |
| bcm | billion cubic metres |
| bcm/a | billion cubic metres per annum |
| BESP | Breakeven selling price of electricity |
| BEST | basic electricity support tariff |
| BTU | British thermal unit |
| C | carbon |
| CC | carbon dioxide credits |
| C$ | Canadian Dollar |
| CAMALA | Cape Metropolitan Area Local Authorities |
| capex | capital expenditure |
| CBO | community-based organisation |
| CCGT | combined-cycle gas turbine |
| CDCE | Campbell Davies Consulting Engineers |
| CDM | Clean Development Mechanism |
| CEF | Central Energy Fund |
| cf | capacity factor |
| cif | cost insurance and freight |
| c/kWh | cents (South African) per kilowatt-hour |
| COP | Conference of the Parties |
| CSD | Commission on Sustainable Development |
| DC | damage costs |
| DEAT | Department of Environmental Affairs and Tourism |
| DG | Director-General |
| DME | Department of Minerals and Energy |
| DMEA | Department of Minerals and Energy Affairs |
| EBSST | electricity basic services support tariff |
| EMS | environmental management system |
| ENH | National Hydrocarbons Company of Mozambique |
| ERC | Energy Research Centre |
| ERI | Energy Research Institute |

| | |
|---|---|
| ESI | Electricity Supply Industry |
| EIA | Energy Information Administration (United States) |
| EIC | Ecoenergy International Corporation |
| ESMAP | Energy Sector Management Assistance Programme |
| ExternE | external costs of energy |
| FC | Fixed cost |
| G77 | Group of Seventy-Seven Countries |
| GEDA | Gauteng Economic Development Agency |
| GEF | Global Environment Facility |
| GHG | greenhouse gases |
| GTL | gas-to-liquid fuels |
| IDZ | industrial development zone |
| IeC | integrated energy centre |
| IEO | International Energy Outlook |
| IGU | International Gas Union |
| IISD | International Institute for Sustainable Development |
| IMCSA | International Marketing Council of South Africa |
| INC | Intergovernmental Negotiating Committee for a Framework Convention on Climate Change |
| IPP | Independent Power Producers |
| IQ | intelligence quotient |
| IRP | integrated resource planning |
| ISEP | Integrated Strategic Electricity Planning |
| KZN | KwaZulu-Natal |
| LA21 | Local Agenda Twenty-one |
| LEAP | Long-range energy alternatives planning system |
| LHV | low heating value |
| LNG | liquefied natural gas |
| MA | Masachussetts |
| mcm | mega cubic metre |
| MEPC | Minerals and Energy Policy Centre |
| PJ/a | petajoules per annum |
| $m^3/d$ | cubic metres per day |
| Mtoe | mega tonnes of oil equivalent |
| MWe | megawatts of electricity |

| | |
|---|---|
| N2 | second national highway |
| NEPAD | New Partnership for African Development |
| NER | National Electricity Regulator |
| NGV | natural gas vehicles |
| $Nm^3/h$ | cubic metre per hour at normal conditions |
| $NO_x$ | oxides of nitrogen |
| NRCan | Natural Resources Canada |
| OC | Overnight cost |
| p.a. | per annum |
| PBMR | pebble bed modular reactor |
| PC | price of coal |
| PetroSA | Petroleum, Oil and Gas Corporation of South Africa |
| PF | pulverised fuel coal-fired |
| PF-FGD | pulverised fuel coal-fired with flue gas desulphurisation |
| PG | price of natural gas |
| $PM_{10}$ | particulate matter less than ten microns |
| Psia | pounds per square inch absolute |
| PWR | pressurised water reactor |
| R | Rand |
| Rc/kWh | Rand cent per kilowatt-hr |
| R/kWh | Rand (South African) per kilowatt-hour |
| Rm | million Rand |
| $R/m^2$ | Rand per square metre |
| SA | South Africa |
| SADC | Southern African Development Community |
| SANEA | South African National Energy Association |
| SDI | spatial development initiative |
| SEA | Strategic Environmental Assessment |
| SESSA | Sustainable Energy Society of Southern Africa |
| SEZ | special economic zone |
| SHEQ | safety, health, environment and quality |
| SHS | solar home system |
| SPCC | Selling price cost of carbon dioxide credits |
| Statssa | Statistics South Africa |
| Synfuel | synthetic fuel |

| | |
|---|---|
| USA | United States of America |
| USDOE | Department of Energy (United States) |
| US$/y | United States dollars per year |
| UCT | University Cape Town |
| UNCED | United Nations Conference on Environment and Development |
| UNFCCC | United Nations Framework Convention on Climate Change |
| USEIA | United States Environmental Information Agency |
| USEPA | United States Environmental Protection Agency |
| VAT | Value added tax |
| VC | Variable cost |
| WAGP | West African gas pipeline |
| WEC | World Energy Council |
| WRI | World Resources Institute |
| WSSD | World Summit on Sustainable Development |

# 1. GENERAL INTRODUCTION

This chapter provides the milieu of this thesis including the problem being investigated, propositions, scope, and the importance of the study, research procedure, expected research contribution to the field of knowledge and the structure of this thesis.

## 1.1 Context of the problem

South Africa has a relatively undeveloped natural gas industry that is dominated by the conversion of gas-to-liquid fuels at the PetroSA refinery in Mossel Bay. As at January 2004, natural gas provided less than 2% of South Africa's primary energy requirements. The relatively small-size and the lack of diversification of the natural gas industry in South Africa is partly attributed to the availability and dominance of relatively cheap coal that supplies about 75% of the primary energy requirements, including the generation of 92% of electricity from pulverised fuel coal-fired power stations (Surridge, 2000).

The price of coal in South Africa does not yet include the cost of social and environmental externalities. An externality or external cost arises when the social and economic activities of a group of persons have an impact on another group, which is not fully accounted for (European Commission, 2003). However, coal – the dominant primary energy carrier in South Africa – is underpinned by large investments in infrastructure, plant and equipment.

Relatively large natural gas reserves that have been proven in both Mozambique (60 billion cubic metres) and Namibia (40 million cubic metres) can supply South African energy markets. Agreements reached between the governments of South Africa and Mozambique, Sasol and ENH (the National Hydrocarbons Company of Mozambique) facilitated the piping of natural gas from Temane gas fields in Mozambique to South Africa commencing in February 2004 (Van Huyssteen, 2004). Natural gas from Mozambique is being used partially to substitute for coal at Sasol's Secunda Synthetic Fuel Plant and to completely substitute for coal as a feedstock for producing synthetic crude oil and chemicals at the Sasolburg Plant.

Natural gas resources have recently been discovered at Ibhubesi (West Coast of South Africa) (Berge, 2004) and exploratory work is ongoing mainly along the western coastline to find more natural gas (Mbendi, 2000). The Ibhubesi resources could form a basis for developing a potentially viable natural gas industry in South Africa, provided ongoing tests prove that these reserves consist of sufficient commercial quantities.

In future, Natural Gas from the Kudu gas fields in Namibia could be used to supply energy to a suggested combined-cycle gas turbine power station in the Cape Metropolitan Area and to augment natural gas feedstock to the PetroSA refinery.

At the policy level, there is support from the South African Government for growing the natural gas industry. This conclusion is elicited from the *White Paper on the Energy Policy of the Republic of South Africa, 1998*. The White Paper states *inter alia* that "The development of the gas industry will stimulate inter-fuel competition, provide environmental benefits through lower emissions in contrast to coal and oil, provide greater options for industrial thermal applications, and increase the diversity of fuel supplies and hence improve South Africa's energy security" (DME, 1998).

## 1.2 Problem statement

The utilisation of coal for the generation of electricity, the manufacture of synthetic fuels and for industrial, commercial and domestic applications causes environmental problems, which can lead to health hazards and increase the burden of global climate change. Coal combustion releases noxious gases that pollute the environment and may result in adverse health impacts and proportionately high emissions of greenhouse gases, which add to the global climate change burden.

According to Scorgie *et al*. (2004), "Total direct health costs related to fuel usage and inhalation exposures to fuel burning emissions were estimated to be in the order of 4.4 billion 2002 Rand per annum across health effects, conurbations and source groupings." Power generation is estimated to be responsible for approximately 5% of the total direct health costs in South Africa (Scorgie *et al*., 2004)

South Africa is under pressure from the international community to reduce its relatively high anthropogenic emissions of greenhouse gases (Surridge, 2000). The bulk of South Africa's anthropogenic emissions of greenhouse gases emanate from the coal combustion at pulverised fuel coal-fired power stations to generate power. South Africa is a developing country and has no commitments to reduce its anthropogenic emissions of greenhouse gases under the United Nations Framework Convention on Climate Change. Its participation in the Convention is based on the "no-regrets" principle. This means that its participation is contingent on the decrease and minimisation of environmental impacts commensurate with cost effectiveness and positive cash flows. South Africa contributes 1.6% of global anthropogenic emissions of greenhouse gases (DME, 1998). In the long-term, an energy carrier and/or technology are/is required to offset the anthropogenic emissions of greenhouse gases and noxious gases associated with electricity generation.

To minimise the externalities associated with power generation, it is necessary to diversify the generation of electricity with sustainable options. The installation of a combined-cycle gas turbine power station, which uses natural gas, with Clean Development Mechanism (CDM) revenue is among proposed options. Natural gas has a high ratio of hydrogen to carbon relative to coal and contains comparatively less impurities, hence its ability to abate emission of greenhouse and noxious gases. South Africa has excess power generation capacity, which has been diminishing with time as demand for power has been increasing. Thus, additional generation capacity would be required by South Africa to maintain the increasing demand for power. In the short-term, an energy carrier and/or technology that has relatively short lead time to install is required to generate base load power to avert a potential shortfall in electricity supply.

If a combined-cycle gas turbine power station is built in the Cape Metropolitan Area to generate base load power instead of a pulverised fuel coal-fired power station, there should be abatement in the emission of carbon dioxide. Owing to the fact that the price of coal in South Africa does not yet include the cost of social and environmental externalities, electricity generated by coal is not cost-reflective. Internalising externalities of power generation using damage costs would increase the cost of power generation – making electricity relatively more expensive for industries, commercial establishments and end-users. Woolf as cited in Furtado (1999) states that damage costs – a representation of the monetary benefit of environmental protection – provide benefits of avoiding environmental externalities to society.

Economic benefits would accrue to the suggested power station in the Cape Metropolitan Area by monetising the abated carbon dioxide credits under the CDM.

The effect that revenue from monetised carbon dioxide credits and inclusion of damage costs would have on the breakeven selling price of electricity, if natural gas substituted coal for generating base load power in say the Cape Metropolitan Area, were examined using propositions in section 1.3.

## 1.3 Propositions

The following propositions were crafted for the substitution of natural gas for coal for generating base load power.

### *1.3.1 Proposition 1*

Natural gas is a lower cost energy source than coal for generating base load power within a specified range of capacity factors.

### *1.3.2 Proposition 2*

Monetising accrued carbon dioxide credits makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors.

### *1.3.3 Proposition 3*

Internalising externalities by accounting for damage costs makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors.

### *1.3.4 Proposition 4*

Internalising externalities by accounting for damage costs and monetising accrued carbon dioxide credits make natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors.

It must be pointed out that proposition 4 would be true if either proposition 2 or 3 were verified (figure 1.1).

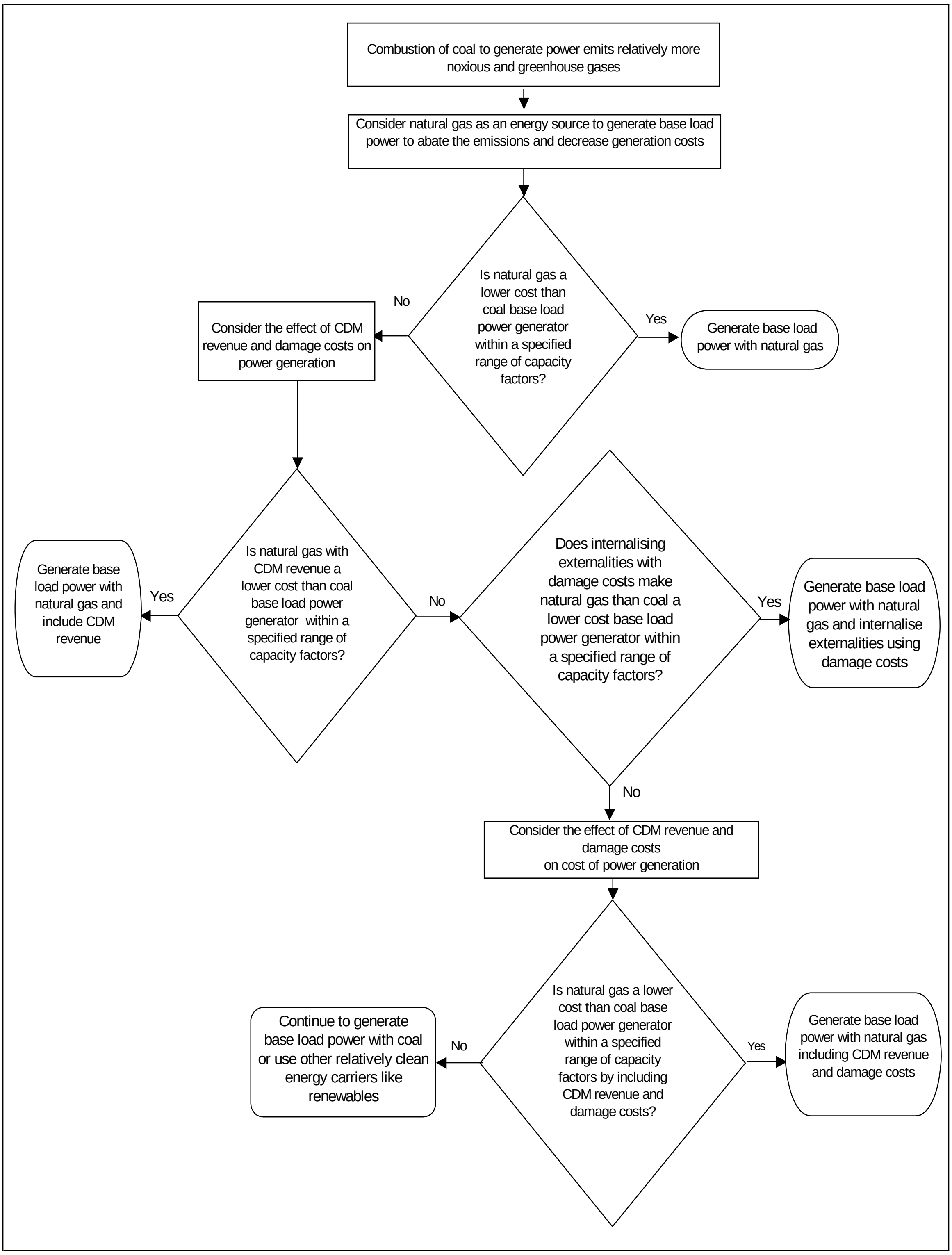



Figure 1.1 Decision flow sheet for propositions.

Source: Developed by the author.

## 1.4 Delimitations

This research study focuses exclusively on the prerequisites to grow the natural gas industry in South Africa in a manner in which the “triple bottom line” concept is adhered to and managed. The triple bottom line is a framework that is used to measure business performance, and captures the range of values that organisations must embrace – economic, environmental and social (IISD, 2002). This thesis is not a comparative study relating to sustainable growth of the natural gas industry in South Africa vis-à-vis sustainable growth of the industry in other countries around the world.

Several proven technologies are available globally for generating power including pulverised fuel coal-fired and combined-cycle gas turbine. However, in this thesis, only pulverised fuel coal-fired (with and without flue gas desulphurisation facility), and combined-cycle gas turbine are considered, due to the fact that pulverised fuel coal-fired technology is dominant in the South African electricity sector, whilst combined-cycle gas turbine may be a potential power generation technology for use in South Africa.

To determine the economic benefits to the South African economy of the reduction in carbon dioxide emissions, resulting from substituting natural gas for coal in base load power generation, a “social accounting matrix” could not be used due to the fact that abatement in greenhouse gases has not yet been commoditised in South African Accounts. A social accounting matrix integrates data from the South African Accounts with data on transactions between industries, households and other institutions (Townsend and McDonald, 1997). The Te-Con Techno-Economic Simulator model was used solely to determine and compare life-cycle economic performance of a combined-cycle gas turbine with the conventional pulverised fuel coal-fired power station under various scenarios. Additional delimitations are the existence of very few academic studies in the formal literature on the natural gas industry in South Africa, and the absence of a coherent policy on sustainable development of the industry in South Africa.

## 1.5 Assumptions

In undertaking this research study, certain assumptions were made. The growth of the natural gas industry is premised on the successful transmission of natural gas to South Africa from at least one of the gas fields either in Mozambique or Namibia, as well as proven reserves in natural gas fields at Ibubhesi on the West Coast of South Africa. The first condition has been satisfied already, following the piping of natural gas from Mozambique to South Africa starting from February 2004 (Lourens, 2004).

It is assumed however, that it would be cost effective to introduce natural gas to the western part of South Africa (Western Cape and southern Cape) because it does not have access to significant conventional energy resources like coal. The concentration of coal reserves is in the eastern part of South Africa (Mpumalanga, Free State and KwaZulu-Natal).

The suggestion of building a combined-cycle gas turbine in the Cape Metropolitan Area is based on the assumption of the successful transmission of natural gas from the Kudu gas field in Namibia and/or from future proven natural gas reserves at Ibhubesi on the West Coast of South Africa.

### 1.6 Research procedure

The research procedure employed in this study entailed conceptualising and developing technical details of four power generation scenarios and reviewing various tools for cost-benefit analysis. Next a cost-benefit tool, numerical techno-economic simulator model, and screening curves were selected from a suite of potential tools, followed by populating the techno-economic model with data to determine and compare life-cycle economic performance of a combined-cycle gas turbine with a conventional pulverised fuel coal-fired power station under the four scenarios. Input information to the Te-Con Techno-Economic Simulator Model was processed by algorithms in the model to produce life-cycle economic performance indicators for both coal and natural gas technology pairs. The comparison was based on performing "iterative zeroing" – a simulation method to determine the breakeven selling price of electricity. Screening curves were used to compare average capacity costs as a function of capacity factor. Sensitivity analyses were conducted on annual revenue requirements with respect to changes in fuel prices, and on the breakeven selling price of electricity with regard to variations in the selling price of carbon dioxide credits and damage costs jointly and severally. The scenarios used were a base case combined-cycle gas turbine (*scenario 1*); a combined-cycle gas turbine with CDM revenue (*scenario 2*); a combined-cycle gas turbine with externalities accounted for by damage costs (*scenario 3*); and combined-cycle gas turbine with CDM revenue and externalities accounted for by damage costs (*scenario 4*).

A comparative analysis of the damage costs associated with coal and natural gas combustion in power stations was undertaken by using damage costs to account for social and environmental externalities. Furthermore, the results of a study on the estimation of externality costs on power generation in Germany (Friedrich and Bickel, 2001) were compared with the results of a study on externalities in electricity generation in South African (van Horen, 1996b). In addition, both an overview of the development of the Te-Con model and a review of the natural gas industry in other countries were undertaken.

The procedure included the identification of key parameters of the suggested combined-cycle gas turbine power station with CDM revenue in the Cape Metropolitan Area. In addition, an analysis was done on the aims, development and objectives of the CDM.

## 1.7 Importance of the study

Coal has immensely contributed to the industrial development of South Africa, but its adverse environmental effects may lead to health risks. According to Surridge (2000), South Africa faces many challenges through pressure from the international community. The latter wants South Africa to take on voluntary commitments to reduce its anthropogenic emissions of greenhouse gases (GHG) under the United Nations Framework Convention on Climate Change (UNFCCC). In future, the relatively high man-made emissions of GHG in South Africa may compel the Member of Parties of the UNFCCC to institute a mandatory cap, when the emission burden profiles of developing countries are reassessed.

Locally, it is necessary to minimise acute respiratory illnesses arising mainly from the coal combustion in households. Furthermore, the potential for acid rain, poor visibility and adverse health effects resulting from gaseous emissions from coal-based industries and power stations needs to be reduced. Therefore, it is pertinent to evaluate cost-effective technologies and the use of less carbon-intensive fuels that could produce relatively cheap power in South Africa.

A proposed solution is to substitute some of the applications of coal as a primary energy resource in South Africa with natural gas. It is proposed to substitute coal with natural gas for generating future base load capacity. In addition, natural gas – a comparatively clean source of energy with relatively high calorific value – could be supplied to meet the energy needs of spatial development initiatives that are relatively far from coal supply routes. This could assist the progress of those development initiatives, contributing to job creation.

The need to prolong the lifespan of PetroSA’s gas-to-liquid fuels refinery at Mossel Bay could be met by supplying more natural gas to the plant because by 2007 the dedicated “F-A” and “E-M” gas fields’ reserves are expected to be exhausted. The recent natural gas discoveries and increased exploratory activities off the shores of South Africa (EIA, 2005a) could assist in prolonging the lifespan of this refinery. Starting from February 2004, natural gas is being piped from Mozambique to South Africa for use mainly at the Sasol Synfuel plants. According to Nakićenović *et al*. (2000), natural gas is the cleanest of all hydrocarbon sources of energy. It is highly efficient and its reserves may be available for a long time. Therefore, it is pertinent to study the prerequisites that could facilitate the growth of the natural gas industry in South Africa in a sustainable manner.

The aim of this research study is to explore the opportunities available for the growth of the natural gas industry and the prospects for increased use of natural gas in South Africa, and the conditions that are germane to achieve this in a sustainable manner. In addition, the study aims to determine the sensitivity of power generation costs, the breakeven selling price of electricity compared to changes in the selling price of coal and gas, carbon dioxide credits and damage costs (environmental externalities) in South Africa.

This study will contribute to the global efforts being made to encourage and promote the use of less polluting energy carriers to minimise the burden of man-induced emissions of greenhouse gases that are causing global climate change. This study will determine the quantity of carbon dioxide abated by the combined-cycle gas turbine power station within the 10-year crediting period and the appropriate utilisation of the monetised carbon dioxide credits. An important outcome of this study will be to establish the relative cost of generating electric power using coal and gas. Another outcome will be a quantitative assessment of the effects of damage costs and monetised carbon dioxide credits on the breakeven selling price of electricity and of the contribution made by monetised carbon credits to the total revenue stream of a combined-cycle gas turbine power station. This assessment will be undertaken on electricity produced by both pulverised fuel coal-fired and combined-cycle gas turbine power generators. This outcome could inform government policy on electricity pricing. In addition, the outcome could inform the decision-making process of Independent Power Producers planning to invest in power generation in South Africa using relatively clean sources of primary energy, especially natural gas.

## 1.8 Expected research contribution to the field of knowledge

The expected contribution to the field of knowledge is the innovative way of financing a power generation project by using the novel CDM revenue from monetised carbon dioxide credits to redeem a bank and a shareholders' loan, which results in reducing the bank loan payment by a number of years and saves a percentage of interest payments. This arrangement allows the limited finance available for project funding to be extended to other projects to the benefit of national economic development.

In addition, this thesis could assist the South African Government, the national electricity utility (Eskom) and Independent Power Producers to make informed decisions about the choice of natural gas to generate electric power to forestall the anticipated shortfall from 2010 onwards in base load capacity.

### 1.9 Definition of sustainable growth

The thesis title contains the keyword – sustainable growth – which provides a proper description of the main topic and delimits the investigation. Sustainable growth has the following contextual meaning in this thesis: It demands a balance between the elements of economic viability, social equity and environmental stewardship, thus ensuring holistic growth even at the micro-level and growth that leads to the diversification of the natural gas industry.

### 1.10 Structure of the thesis

This thesis is made up of the following seven chapters:

**Chapter 1** sets the scene for the whole thesis and includes a description of the problem being investigated, propositions, scope, importance of the study, assumptions of the study, research procedure, expected research contribution to the field of knowledge and structure of this thesis.

**Chapter 2** provides the development, aims and objectives of the Clean Development Mechanism (CDM) and gives an overview of the development of the techno-economic model. It includes a comparative analysis of the results of two recent studies done internationally and in South Africa on externality costs in the power generation sector. A study on externality costs involving a fuel switching project in electricity generation in Ontario, Canada is also considered. Chapter 2 includes a comprehensive view on cost benefit analysis, screening curves and sensitivity analysis. In addition, this chapter provides details on the instigation of sustainable development, areas of focus of the World Summit on Sustainable Development (WSSD) and a review of the natural gas industries in other countries.

**Chapter 3** provides an overview of South Africa's energy sector including the natural gas industry. This chapter discusses key Government interventions in the energy sector.

**Chapter 4** examines proven natural gas reserves, markets, the gas chain and enabling environment that can facilitate the growth of the natural gas industry in South Africa in a sustainable manner. This chapter provides an indication of the potential for long term substitution of coal with natural gas including opportunities for using natural gas in spatial development initiatives and natural gas reticulation as a catalyst for rural development. Furthermore, this chapter presents environmental management, safety and health issues relating to the natural gas industry, and discusses the potential for acquiring carbon dioxide credits using piped gas from Mozambique.

**Chapter 5** examines future annual base load requirements for South Africa under different growth rate scenarios of electricity demand. This chapter examines several tools to determine and compare the relative cost and life-cycle economic performance of using pulverised fuel coal-fired with and without flue gas desulphurisation and combined-cycle gas turbine power stations for generating base load power in the Cape Metropolitan Area, under various combined-cycle gas turbine power station scenarios. The problem is analysed and the propositions are tested in this chapter.

**Chapter 6** discusses the comparative life-cycle economic performance of the pulverised fuel coal-fired and the combined-cycle gas turbine power station scenarios for generating base load power with the assistance of the techno-economic modelling undertaken in chapter 5. In addition, this chapter discusses sensitivities of annual revenue requirements to changes in the fuel price including sensitivity analyses of the breakeven selling price of electricity to the selling price of carbon dioxide credits and damage costs in chapter 5. The discussion includes the potential role of monetised carbon dioxide credits in redeeming debt and differences in damage costs.

**Chapter 7** draws conclusions from the other chapters, provides recommendations for a sustained growth of the natural gas industry in South Africa and the results of this thesis, including its contribution to the field of knowledge. Chapter 7 makes a suggestion for a future research study.

# 2. BACKGROUND AND LITERATURE REVIEW

This chapter provides the development, aims and objectives of the Clean Development Mechanism (CDM) and gives an overview of the development of the techno-economic model. It includes a comparative analysis of the results of two recent studies done internationally and in South Africa on externality costs in the power generation sector. A study on externality costs involving a fuel switching project in electricity generation in Ontario, Canada is also considered. Chapter 2 includes a comprehensive view on cost benefit analysis, screening curves and sensitivity analysis. In addition, this chapter provides details on the instigation of sustainable development, areas of focus of the World Summit on Sustainable Development (WSSD) and a review of the natural gas industries in other countries.

There are few academic studies in the formal literature on sustainable development of the natural gas industry in South Africa. In the absence of a coherent policy on sustainable development of the natural gas industry in South Africa, the majority of the material reviewed for this thesis was gleaned from contemporary literature of emerging science and technology. This methodology is germane to this study as linkages of energy and sustainable development are embedded in new and dynamic fields.

## 2.1 CDM

### *2.1.1 Development*

In the 1980s, scientific evidence linking greenhouse gas emissions from anthropogenic activities to the risk of global climate change started to arouse public concern. A series of international conferences held by governments echoed this concern by issuing calls for a global treaty to deal with the problem. Responding to this call, the UN General Assembly established in 1990 the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change (INC). Subsequently, the INC drafted the Convention and adopted it on 9 May 1992 at the UN Headquarters in New York. In June 1992, the Convention called the "United Nations Framework Convention on Climate Change (UNFCCC)" was opened for signature at the Rio de Janeiro Earth Summit and entered into force on 21 March 1994. The Convention and any related legal instruments that the Conference of the Parties (COP) may adopt have an ultimate objective of achieving the "Stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner" (Climate Change Secretariat, 2002).

Early in June 1995, the first Conference of the Parties (COP) – the supreme body of the Convention – was held in Berlin. In December 1997, at its third session in Kyoto, the COP adopted the Kyoto Protocol – committing developed countries to reduce their joint emissions of greenhouse gases by at least five percent by the period 2008-12 (Climate Change Secretariat, 2002).

### *2.1.2 Aims and objectives*

On 16 March 1998, the Kyoto Protocol was opened for signature of the Parties. The Protocol entered into force on 16 February 2005, ninety days after being ratified by at least 55 Parties to the Convention, which include developed countries responsible for at least 55% of the total carbon dioxide emissions from this industrialised group (Climate Change Secretariat, 1998). A Clean Development Mechanism (CDM) was first defined during the third Conference of the Parties (COP 3). The objectives of the CDM are "To assist Parties not included in Annex 1 in achieving sustainable development and in contributing to the ultimate objective of the Convention, and to assist Parties included in Annex I in achieving compliance with their quantified emission limitation and reduction commitments under article 3." Annex-I refers to developed countries Parties to the Convention, and article 3 sets out the text of Joint Implementation in the Kyoto Protocol (Climate Change Secretariat, 1998).

Inclusion of the CDM in the Protocol came after a hard and drawn out negotiating process. The CDM draws upon and establishes a middle ground compromise between the "Emissions Trading/Joint Implementation" proposal advocated by most Annex-I countries (plus Costa Rica), and a non-compliance penalty/compensation mechanism. The latter mechanism was forwarded through a "Clean Development Fund" proposal by developing countries, that is the Group of Seventy-Seven Countries and China (G77/China) (Aslam, 1998). According to Haites and Aslam (1999), the Kyoto Protocol sets up three mechanisms enabling countries with emissions limitation commitment (such as an Annex B Party) to meet their commitment at lower cost by co-operating with other Parties. The three mechanisms are "Joint Implementation," "Clean Development Mechanism" and "International Emissions Trading."

### *2.1.3 Key criteria*

The CDM's key criterion is that the reduction in emissions must be "additional to any that would occur in the absence of the certified project activity" (Climate Change Secretariat, 1998). The word "additional" is ambiguous, as it does not stipulate how rigidly evaluation of reductions in emissions should be applied. This has led the word "additional" to be given various different interpretations by proponents of the CDM. The World Wild-Life Fund for Nature proposes that for a project activity to procure certified emission reduction units (CERs), it must be undertaken principally to reduce or offset GHG emissions. This negates the inclusion of projects that have commercial benefits whilst contributing to emission reductions with CDM revenues (Stewart, 2000).

Other terms such as, "baseline" – "reference" or "business-as-usual scenario" – have been introduced to refer to GHG emission before "additional" reductions. The baseline or the "counter-factual" refers to the emissions that occur but for, or without, the CDM project activity. Thus, the quantified emission reduction achieved by a CDM project activity is the difference between the emissions that would have occurred without the project, and the emissions that occur due to the project (UNFCCC Secretariat, 2001).

In 2001, at the 7th Conference of the Parties, the Marrakesh Accords and Marrakesh Declaration that emerged from the meeting shed some light on "additionality" by stating, "A CDM project activity is additional, if anthropogenic emissions of greenhouse gases by sources are reduced below those that would have occurred in the absence of the registered CDM activity." Furthermore, it was also stated that the "baseline for a CDM activity is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity" (UNFCCC Secretariat, 2001).

## 2.2 Instigation of the concept of sustainable development

During the first decade of the UN, environmental concerns were neglected by the international agenda. The agenda focused instead on the creation of an inventory of the global natural resources available for development and explored ways to ensure that exploitation was beneficial to developing countries in particular. The 1960s witnessed the crafting of agreements regarding marine pollution, particularly oil spills that resulted from major tanker accidents. There has been a marked paradigm shift since the 1990s and the UN has been a leading advocate for environmental concerns and a chief proponent of new concepts – particularly, sustainable development (UN, 1998).

For the first time in 1972, the connection between economic development and environmental degradation was placed on the international agenda at the UN Conference on Human and Development in Stockholm. Consequently, UNEP – the leading global environmental authority and a global advocate for action to protect and improve the environment – was set up. In the eighties, the Member States of the UN reached agreements in the domain of environmental concerns culminating in the birth of the "United Nations Convention on the Protection of the Ozone Layer" and the "Convention on the Control of Transboundary Movement of Hazardous Waste and their Disposal" (UN, 1998).

### *2.2.1 World Commission on Environment and Development*

In 1983, the task given to the World Commission on Environment and Development by the General Assembly of the UN – "a global agenda for change" – led to marked awareness of the need for sustainable development. The degradation and the erosion of the quality of life through humankind's interactions with the environment show that global activities in sustainability have not been strong, despite the international rhetoric. Just as the challenge of reconstruction after the Second World War underpinned the post-war international economics, the challenge of identifying sustainable development paths ought to be the thrust of the search for multilateral solutions to our problems, including a structured international economic system of co-ordination and co-operation (Brundtland, 1987).

Scientists consistently draw attention to urgent and complex problems that have a direct bearing on mankind's survival – threats of global warming, depletion of the ozone layer, desertification, and a loss of biodiversity and so on. Whilst most of the developed countries are capable of dealing with some of the adverse impacts of unsustainable development, many developing nations appear to be trapped in a downward spiral of connected economic and ecological decline (Brundtland, 1987).

### *2.2.2 Rio Earth Summit and Agenda 21*

Global environmental issues started to receive greater attention after the report of the Brundtland Commission – "Our Common Future" – was published in 1987, culminating in the Rio Earth Summit. Here, in June 1992, Agenda 21 (an agenda for the 21$^{st}$ century) – a comprehensive plan for global action in the fields of sustainable development – was adopted (Department of Environment (Norway), 2001a).

Additionally, the Summit adopted the “Rio Declaration on Environment and Development”, a definitive declaration on the rights and responsibilities of States; and the “Statement of Forest Principles” that provide guidelines for global sustainable management of forests. Governments at the Rio Summit outlined a detailed blueprint for action in Agenda 21, which is the UN’s action plan for the attainment of sustainable development. The four main aims of Agenda 21 are:

- Meeting the current needs of the majority of the World’s population;
- Securing the basis of life for coming generations through sustainable management of the natural resources;
- Ensuring active participation of all groups in the community in shaping policies for sustainable development; and
- Providing the means of implementing Agenda 21 (Department of Environment (Norway), 2001a).

If the blueprint is implemented, activities that would protect and renew the crucial environmental resources on which mankind depends would be increased. Areas for action include protecting the atmosphere, combating desertification, preventing air and water pollution, promoting safe use and management of toxic wastes and halting depletion of fish stocks (UN, 1998).

The task of implementing Agenda 21 was given to the UN, which has embarked on steps aimed at integrating the concept of environmentally-sound development into all pertinent policies and programmes. Two bodies – The Commission on Sustainable Development (CSD) (1993) and the Inter-Agency Committee on Sustainable Development (1992) – were created within the UN to ensure full support for global implementation of Agenda 21 (UN, 1998). The CSD is an effective institution for sustainable development, and provides a forum where governments and NGOs can share information about possible initiatives, discuss the dearth of financial resources and access to technological innovation. The CSD was given the task of monitoring the activities of national governments, international organisations and actors from the private sector (French, 2000).

The various sectoral issues under Agenda 21 were monitored between 1994 and 1996 for early implementation. It has emerged that cross-sectoral issues need to be monitored on a yearly basis for action in sectoral areas to be effective. Cross-sectoral areas include:

- Critical elements of sustainability (trade and environment – patterns of production and consumption, demographic dynamics and combating poverty);
- Financial resources and mechanisms;
- Education, science, transfer of environmentally-sound technologies, technical co-operation, capacity-building;
- Decision-making; and
- Activities of major groups such as business and labour (UN, 1998).

Member countries of the UN engage in detailed planning of Local Agenda 21 (LA21) – sustainable development goals and strategies implemented at the community level to institutionalise sustainable development. LA21 is undertaken in districts, cities, villages and institutions of learning. It consists of a plan for global action in fields of sustainable development including action plans and the periodic presentation of state of the environment reports by governments, cities and local governments. LA21 is a process for agreeing and implementing local sustainable development action plans for the 21st century, in partnership with the local community. It should be built into everything that local authority and other organisations do, like financial probity or value for money. Local Agenda 21 should be at the centre of good local governance (DEFRA, 1998).

### *2.2.3 Earth Summit + 5*

In 1997, the implementation of Agenda 21 came under scrutiny at the 19th Special Session of the UN General Assembly Special Session in New York. A report was made by UNEP concerning the continuing deterioration of the environment and the fact that environmental problems remain deeply embedded in the socio-economic fabric of nations in all geographical areas of the world. Consequently, delegates pledged that by the next review, during the WSSD, Johannesburg, South Africa, greater progress would have been achieved in promoting sustainable development. One positive outcome emerging from the Earth Summit + 5 was the establishment of the International Environmental Forum on Forests for monitoring proposals on the implementation of a central forum on forests, including the legal agreement that may be required to ensure the sustainable development of forests (UN, 1998).

## 2.3 WSSD

### 2.3.1 Theme and areas of focus

WSSD, also known as Earth Summit 2, was organised in Johannesburg from 26th August to 4th September 2002. The Summit had the leitmotif "People, Planet and Prosperity". Prior to the Summit, a series of preparatory committee meetings were held in various parts of the World with a view to solicit wide-ranging stakeholder inputs to the agenda of the Summit. In May 2002, the UN Secretary-General put forward five specific areas of focus: water and sanitation; energy; health; agricultural production; and biodiversity and ecosystem management (appendix A), where concrete results were deemed both essential and achievable (network-2002. 2002). The objectives set up for these areas and their outcomes are presented in appendix A.

### 2.3.2 Achievements and failures

WSSD focused on the pillars of sustainable development – economic development, environmental stewardship and social equity – unlike the Rio Earth Summit that placed more emphasis on the environment. The Summit was successful, as it managed to place sustainable development firmly on the global agenda and reached agreement on certain pertinent areas. Some of the specific achievements of the Summit were:

- The agreements on sanitation;
- The restoration of fisheries;
- Abating the loss of biodiversity; and
- The setting up of a goal to develop food strategies for Africa and the promotion of corporate responsibility (World Coal Institute, 2002).

However, in my view, there was dissatisfaction in the field of energy, which was one of the areas of focus. The Summit failed to set a time-based target for the contribution of renewables to energy supply, even though the final agreement urged all governments to significantly increase the global share of renewable energy resources. The success of the Summit can only be sustained if the concepts put forward are implemented. In addition, it is my view that a review in 2007 of the thematic areas of the Summit would determine whether their implementation has been achieved meaningfully, in particular, progress towards enhancing the global share of renewable energy resources.

## 2.4 Development of the Te-Con Techno-Economic Simulator model

### *2.4.1 Introduction*

Essentially, man is a model-building being. A model is a convenient way of representing total experience. From that experience (or model) it can be deduced whether it fits into a pattern and law. If this is the case, the model can be used to show how such patterns and laws can be used to predict the future. The scientific method, as applied to modelling, is usually described (at least in operational research terms) as: problem formulation; model construction; solution derivation; solution testing; solution control; and solution implementation. The process is cyclic and the steps overlap with each other (Rivett, 1972).

According to Rivett (1972), a techno-economic model attempts to describe both the physical aspects of a process, such as mining, manufacture and beneficiation with the financial outcomes of such operations expressed in terms of capital investment, operating costs, funds and cash flows. Because models are largely employed to raise the financial capital for a project, the final results are expressed in monetary terms in such standard forms as balance sheets and income statements. In the latter case, it is of importance to observe the accounting conventions of conservatism, realisation, objectivity, consistency, full disclosure and materiality.

According to Doppegieter and du Toit (1996), energy modelling which is regarded as a system of processes that interact with each other provides outputs that basically support policy analysis in terms of providing the evaluation of the impacts of various policy decisions. Thus, modelling has to begin from the basis of a clearly identified and plausible set of comprehensible policy options and criteria. Energy scenarios which are components of energy modelling are important tools for consistent energy decision- and policy-making. Scenarios assist in exploring key issues, uncertainties, assumptions and linkages in the system under scrutiny; thereby providing important inputs to energy modelling.

There is an underlying interdependence in all economic activities in the sense that inputs are bought in order to produce outputs, which are then sold. Stimulating any given sector of an economy leads to a rise in the need for more inputs, which also stimulates the sector producing the inputs, and so on. These inter-sectoral linkages are basic to the operation of an economy, and need to be considered when any impact of the economy is being analysed (Asamoah *et al*, 2002).

### *2.4.2 Model development*

The Te-Con Techno-Economic Simulator model is proprietary and consists of a number of modules that can be plugged in and unplugged to provide the required configurations. It is one of the tools examined in chapter 5 of this thesis to determine and compare the life-cycle economic performance of various combined-cycle gas turbine power station scenarios and a pulverised fuel coal-fired power station. The Te-Con Techno-Economic Simulator was developed by Henry Simonsen based on modelling experience in research institutions, banks and a power utility between 1984 and 1994. Several written variants of the model have been used to evaluate *inter alia* gold and coal mines in Botswana, and aluminium and steel smelters, prototype nuclear reactors and nuclear fuel production facilities in South Africa (H. Simonsen, personal communication, 4 July 2003),

The development of a library of modules for the model facilitates timely and hence cost-efficient, assessment of projects at conceptual, pre-feasibility and feasibility (bankable) stages. Taking a simulation approach to modelling provides a degree of flexibility combined with utility. The model does not pre-empt the use of more suitable and simpler algorithms where applicable. The word “simulation” refers to any analytical method that imitates a real-life system, especially when other analyses are too mathematically complex or too difficult to reproduce (Crystal Ball, 2000).

### *2.4.3 Model Structure*

Each of the two main components of the Te-Con model – technical and financial – are further subdivided into modules that accept inputs, perform specific operations on the data and then provide outputs which may be final or sequential (H. Simonsen, personal communication, 4 July 2003).

### *2.4.4 Technical*

The object of the technical component is to accept the physical (and monetary) inputs to the model for processing in a fashion that simulates the project that is the object of potential investment with acceptable accuracy. The simulation approach was originally adopted to provide a solution to problems where mapping onto a mathematical language and employing the language and the constraints of mathematics proved inadequate.

There are three reasons for using simulation are the following:

- When the problem is too complex to be solved by employing mathematical or statistical techniques. For example, the assumptions that require stating a problem in symbolic form such as non-linearity may be too severe.
- To gain understanding of a complex situation.
- To deal with problems, which do not yet exist in the real world (Rivett, 1972).

According to Rivett (1972), the application of simulation requires an understanding of the following:

- The basic logical connections between the successive states of the system under observation;
- Identification of available decision ranges for any state of the system;
- Understanding of the transitional probabilities from one state of the system to another; and
- Understanding what changes in transitional probabilities are effected by decisions.

The simulation process is assisted in the Te-Con model by the employment of an add-in computer programme called @RISK. The Palisade Corporation, USA, developed @RISK – advanced risk analysis for spreadsheets – in 1996. @RISK uses simulation, sometimes referred to as “Monte Carlo simulation” to undertake a risk analysis (Mullins *et al*., 2002). “Monte Carlo Simulation” randomly generates values for uncertain variables repeatedly to simulate a model (Crystal Ball, 2000). When the @RISK computing algorithm is employed, single point variable inputs are replaced with data ranges and the selected output is then expressed in probabilistic terms as a result of iterative calculations employing the full range implicit in each variable (Mullins *et al*., 2002)

### *2.4.5 Financial*

The financial component of the model employs the outputs from the technical simulator to produce a set of standard financial records such as the income statement, balance sheet, cash flow statement and financial ratios. These comprise the database used to evaluate a project by potential financiers (Rivett, 1972).

## 2.5 Cost-benefit analysis

Cost-benefit analysis is concerned with the costs and benefits to society generated by an investment project. It is used in both public and private sectors. Cost-benefit analysis has its roots in the middle of the nineteenth century when economists began to connect the theory of consumers' surplus – the difference in the amount that a consumer would be willing to pay for a commodity and the amount he or she actually pays – with the net gain by communities from government projects (Mullins *et al*., 2002).

Cost-benefit analysis is widely used around the world to assess the monetary costs and benefits of policies and projects. Recently, attempts have been made to incorporate the environmental impacts of projects and policies within the cost-benefit analytical process to improve the quality of government decision-making by influencing policy obligations for environmental friendly projects. Despite the fact that advances have been made in the application of cost-benefit analysis, problems persist in its application to environmental issues, including the monetary valuation of environmental assets such as national parks and clean rivers (Hanley, 1999).

The total social costs of any project are the entire incremental costs related to it. These include the cost of resources used by the project and the indirect costs – external costs – which the project imposes on the community. The real cost of the resources that the project uses are the social sacrifices involved in taking them away from alternative uses – their opportunity costs (Abelson, 1979).

## 2.6 Screening curves

The Electric Power Research Institute (EPRI) as cited in Koomey *et al*. (1990) claims that in the past, utility planners used screening curves for preliminary analysis of the cost of new supply options. The curve was obtained for supply alternatives from a set of plots with each one showing capacity factor on the x-axis and annual power plant cost (fuel plus capital) per unit kilowatt-hour on the y-axis. The y-intercept gives the annualised capital costs whilst the slope of the curve gives the variable cost of operating the plant. A limitation of a screening curve is the fact that it is a single year "snapshot" premised on certain fuel price assumptions. A power purchase from other utilities or from Independent Power Producers may be included on a screening curve. A screening curve establishes the envelope within which a supply alternative may be economic, thereby reducing the number of options to analyse. If for example, the projected cost curves of new supply technologies fell below the envelope, these options would call for additional analysis. Notwithstanding the fact that this tool may be rudimentary, it serves to "screen out" uneconomic options.

Screening curves evaluate the cost of generating electric power at various average levels of production or load factors (capacity factors) over the life of the plant (NER, 2004). According to Stoft (2002), screening curves show average cost as a function of capacity factor in a graph. The intercept on the y-axis gives fixed costs, whilst variable cost is provided by the slope. The average cost provides the average cost of a megawatt-hour of generating capacity. Screening curves allow comparison of generation costs by taking into account three factors – fixed cost, variable cost and load duration (which is determined by the capacity factor of the generator).

## 2.7 Sensitivity Analysis

Resource planning has to deal with several conflicting objectives, a wide range of options and pervasive uncertainty. In this context, it is necessary to deal with dominance as well as finding plans to represent reasonable trade off among multiple conflicting objectives. A traditional resource planning approach provides a robust (and flexible) plan established on the basis of an analysis of risk from either under- or over investment within a range of forecast demand from electricity over a specified planning prospect (NER, 2004).

In order to establish the sensitivity of a project's outcome to variations in a limited number of key input variables, project evaluators normally perform a selective sensitivity analysis. During the analysis, likely high and low values (best and worst) outcomes for the variable whose sensitivity is being sought are selected. The limitations with regard to the number of input parameters in selective sensitivity analysis are overcome to a great extent by using general sensitivity analysis. A general sensitivity analysis is premised on the derivation of a probability distribution of likely outcomes (Mullins *et al*., 2002).

## 2.8 A comparative analysis of externality studies in Germany and South Africa

### *2.8.1 Previous studies*

Literature pertaining to the theory of externalities and environmental evaluation and its application to the practical externality problems emanating from energy sectors of industrialised and developing countries was reviewed extensively in Van Horen's research study (Van Horen 1996b). This study focused in particular on externality studies in the electricity generation and the household consumption sectors. Van Horen's study was the first to analyse in depth the externalities in both household consumption and electricity generation sectors in South Africa.

The brief study of Dutkiewicz and de Villiers in 1993 as cited in van Horen (1996b) compared the social costs of various generation options but did not include detailed economic analysis. Subsequently, Spalding-Fecher and Matibe (2003) expanded on the previous analysis of the external costs of power generation in South Africa. The latter study presents a quantitative analysis of air pollution impacts on human health, damages from greenhouse gas emissions and avoided health costs from electrification and a qualitative discussion of other impacts.

### *2.8.2 Methodology*

In this section of the literature review, a comparative analysis is made of the damage costs discussed in recent studies on the estimation of external costs of electricity production in Germany (Friedrich and Bickel, 2001), and of the damage costs of externalities in a South African power station (Van Horen, 1996b). The German study forms part of the "ExternE" (or external costs of energy) European Research Network of the EU. ExternE has been active since the beginning of the nineties. Its goal is to quantify the external costs of energy before they are internalised. ExternE made it possible for different fuels and technologies for electricity and transport sectors to be compared (European Commission, 2003). According to Friedrich and Bickel (2001), ExternE had been undertaken for the EU region over the past ten years with participation of researchers drawn from 12 EU member states. For the electricity sector, ExternE was designed to quantify the socio-economic costs of different forms of generating electricity using fossil, nuclear and renewable energy sources (Friedrich and Bickel, 2001).

The "impact pathway" approach was used both in van Horen's research study (1996b) and ExternE. Friedrich and Bickel (2001) state that "impact pathway" relates to the sequencing of events that link a burden to an impact followed by an evaluation. In this approach, the chain of causal relationships commences from the emission of a burden through transport and chemical conversion in the environment to the impacts on different receptors, such as crops, building materials and human beings. Resulting welfare losses are finally transferred into monetary values based on the concept of welfare economics (Friedrich and Bickel, 2001).

### *2.8.3 Models*

In ExternE, an EcoSense model has been developed to represent the implementation of the impact pathway approach in an integrated computer tool. In EcoSense, there is provision for harmonised air quality and impact assessment models including a comprehensive set of relevant input data for the whole of Europe, allowing site-specific bottom-up impact analysis. EcoSense has been used to estimate external costs from electricity generation and transport of passengers and goods in a large number of case studies in all EU countries. Three types of air quality models – Windrose Trajectory Model, Source Receptor Ozone Model and Industrial Source Complex Model are included in EcoSense. The Industrial Source Complex Model is a Gaussian plume model used for transport modelling of air pollutants on a local scale (Friedrich and Bickel, 2001).

Van Horen's research study (1996b) used the EXMOD model to estimate external costs in both the electricity generation and household sectors. Rowe as cited in van Horen (1996a) indicated that EXMOD is a user-friendly computer model, which could be used for the calculation of external costs for specific electricity resource options. EXMOD was used solely to calculate the health impact of air pollution emissions for only three pollutants – $SO_2$, $NO_x$ and particulates – for which data were available in South Africa. A characteristic of EXMOD that necessitated its use by van Horen (1996b) is its ability to model transport of air pollutants after their emission from power stations, till their deposition or distribution to human beings. However, a number of problems were encountered with the application of EXMOD's air quality models to South African conditions. Uncertainty exists over the applicability of dose-response functions derived in the US to South African populations. Despite the fact that dose-response functions constitute an important step in the damage function approach, no epidemiological studies had previously derived these relationships for South Africa. Nevertheless, any over- or understatement in the dose-response functions would be compounded throughout subsequent steps in the valuation exercise. There is some uncertainty regarding the atmospheric modelling approach used for the valuation of health impacts of air pollution (van Horen, 1996b).

The atmospheric models contained in EXMOD used a Gaussian plume type of dispersion model for approximating the dispersion of emissions from power station stacks (van Horen, 1996b). The Gaussian plume type of dispersion model performs similar functions as the Industrial Source Complex Model of EcoSense. Turner as cited in Van Horen (1996b) indicated that air quality experts in Eskom are of the opinion that actual conditions on the Highveld (the high grassland region of North East South Africa) are not properly represented by this kind of model due to the presence of inversion layer and mixing patterns. This degree of uncertainty is unavoidable, as there were no available atmospheric models in the public domain, designed specifically for South African conditions (Van Horen, 1996b). However, dose-response models have been assembled and critically reviewed by expert groups within the ExternE project, based on state-of-the-art studies in the field of health effects, impact on plants and on building materials (Friedrich and Bickel, 2001).

### *2.8.4 Externality indicators and values*

ExternE studies on external costs of power generation in Germany deal with quality changes of air, soil, water and physical impacts (Friedrich and Bickel, 2001) whilst external costs given in Van Horen's study are based on air pollution (Van Horen, 1996b). The damage costs used in the ExternE Project are associated with noise, health, materials and crops. Thus, ExternE studies on external costs in Germany are more inclusive than those of Van Horen as the former accounts for more physical impacts and damage costs. Adapted values from the quantified marginal external costs of electricity production in Germany gave the damage costs for coal-fired power stations as about R0.06/kWh in 2001. The corresponding value from van Horen's study adjusted to 2001 gives a value of R0.08 (based on an inflation rate of 6% per annum). Lee as cited in Van Horen (1996a) indicated that externality studies employ different methodologies, which account largely for the different numerical valuations yielded.

### *2.8.5 Uncertainty and gaps*

Rabl *et al.* (1998) state that the uncertainties in the impact pathway approach is so large that many people are doubtful about the usefulness of its results. Despite this, the former claim further that the usefulness depends on the decisions that are being evaluated. Before discussing the uncertainties in the impact pathway approach, it is necessary to distinguish the uncertainties from deviations of current results in comparison with earlier results. Firstly, substantial methodological development has taken place in the last decade from top-down to a site-dependent bottom-up approach or with respect to the monetary valuation of health effects. Secondly, contemporary knowledge about for example the health impact changes the results. In particular, emerging knowledge that fine particles can cause chronic diseases leading to a reduction in life expectancy changed the results significantly. A change due to methodological development can be seen as natural rather than a problem (Friedrich and Bickel, 2001).

Rabl and Spadaro, as cited in Friedrich and Bickel (2001) stated that uncertainties in the input data could be analysed by means of statistical methods. The largest uncertainties are found in the exposure-response function for health impacts and the value of a life year lost. However, due to limited knowledge, current research is directed at reducing these uncertainties (Friedrich and Bickel, 2001). Van Horen's study (1996b) alludes to this uncertainty. Another uncertainty stems from the fact that basic assumptions like discount rate, valuation of damage in different parts of the World and treatment of risks with large impacts or treatment of gaps have to be made (Friedrich and Bickel, 2001). Both Van Horen (1996b) and Friedrich and Bickel (2001) allude to the relatively high uncertainty about global warming impacts. According to Friedrich and Bickel (2001), gaps can be closed and uncertainties reduced by undertaking further research on for example, contingent valuation and epidemiological studies.

## 2.9 A study on externality costs on fuel switching project in Ontario

This study was based on an independent cost benefit analysis of the financial costs, environmental and health damages involving four electricity generation scenarios. The scenarios were as follows: base case (coal-fired generation), all gas (use of gas generation), nuclear/gas (generation through a combination of new gas and refurbished nuclear) and stringent controls (coal-fired generation with a new emission control technology). The air pollution from coal-fired power generation facilities is known to be the cause of several types of environmental damages including vegetation damage, corrosion of materials, acidification of aquatic and terrestrial ecosystems and global climate change. The total cost of generation provided an indication of the minimum average amount that society was prepared to pay for the generation of this electricity to be worthwhile (DSS Management Consultants Inc. *et al*, 2005).

### *2.9.1 Health damages*

The standard methodology used involved the following main parameters:

- Ambient air pollution intensity to which the population at risk is likely to be exposed
- The demographics of the exposed population (especially age)
- The baseline incidence rates for major illnesses
- Relative risks for specific health outcomes for sensitive segments of the population exposed to air pollution
- Economic cost factors for each category of illness (DSS Management Consultants Inc. *et al*, 2005).

Expected mortality and morbidity cases attributable to exposure to air pollution were used jointly as indicators for health damages for all scenarios. It was established that by switching from the base case to the nuclear/gas scenario, 660 premature deaths, 920 hospital admissions,1,090 emergency room visits and 331,000 minor illnesses cases could be reduced to 5 premature deaths, 12 hospital admissions, 15 emergency room visits and 2,500 minor illness cases per annum. The average annual damages ranged from a low of C$0.4 billion for scenario 3 to a high of C$ 3.0 billion for scenario 1. The implication is that implementing scenario 3 would lead to an annual average benefit (avoided health damages) of C$2.6 billion (DSS Management Consultants Inc. *et al*, 2005).

#### *2.9.2 Environmental damages*

In addition to the environmental damages listed under section 2.9 as caused by air pollution resulting from coal-fired generation, this study includes additional environmental damages caused by ozone and PM10 to household materials (soiling) and agricultural production losses (wheat, corn, tobacco and soybean). A CALPUFF model was used for the estimation of ambient air quality at a census division level of spatial resolution. Subsequently, these air quality forecasts were input into an Air Quality Valuation Model (AQVM) to generate physical and monetary estimates of damage costs to agricultural production and household materials. The environmental damages range averagely from a low of C$45 million for the nuclear/gas to a high of C$371 million for the base case scenario. This implies that implementing the nuclear/gas scenario results in an average benefit of C$ 323 million per annum (DSS Management Consultants Inc. *et al*, 2005).

### 2.10 Natural gas

It is my view that understanding global natural gas consumption and its operations is essential to understanding how the natural gas industry would evolve in a sustainable manner in South Africa. The subsequent chapters will show the linkages between natural gas and sustainable development.

#### *2.10.1 Natural gas occurrences*

Natural gas is derived from plant life grown on terra firma, unlike oil that comes from marine algae. The gas consists of smaller molecules, is more mobile and more difficult to capture than oil, and requires better seals (for instance salt or permafrost). To date, virtually all natural gas that has been used has come from “conventional” gas found in conjunction with oil (EcoSystems, 2000).

“Natural gas” – the most important gaseous fuel resource – is a generic term for gases that are commonly associated with petroliferous geological formations. In the modern era, William Hart first transported gas from a well to multiple consumers in Freedonia, New York State in the

United States in 1820. Since the Second World War, the natural gas industry has developed into a multinational hydrocarbon fuel industry, similar to the oil industry (Melvin, 1987).

Currently, it is estimated that natural gas reserves constitute more than 95% of oil equivalent reserves, an increase from the estimated 50% of oil equivalent in 1970. Piped natural gas consists largely of methane (85-95% by volume) and occurs in abundance in many parts of the World, including the United Kingdom, Europe, the United States, Canada, South America and Russia. Some natural gas fields also contain ethane, butane and propane. Methane is marketed as natural gas and ethane as chemical feedstock, whilst propane or butane is marketed as liquefied petroleum gas (Australian Gas Industry, 2001).

The distribution of the World's total proven gas reserves of 179,530 billion cubic metres (bcm) at the end of 2003 is skewed (table 2.1) in favour of the Middle East and Europe & Eurasia.

**Table 2.1 Distribution of the World's total estimated proven gas reserves at end 2004.**

| Region | Volume, ($10^3$ bcm) | Percentage | Ratio of proven reserves to production |
|---|---|---|---|
| Middle East | 72.83 | 40.6 | - |
| Europe & Eurasia | 64.02 | 35.7 | 60.9 |
| Africa | 14.06 | 7.8 | 96.9 |
| Asia Pacific | 14.21 | 7.9 | 43.9 |
| North America | 7.32 | 4.1 | 9.6 |
| South & Central America | 7.10 | 4.0 | 55.0 |
| **Total World** | **179.53** | **100.0** | **66.7** |

Source: BP (2005).

### *2.10.2 Natural gas types*

Natural gas exists in several forms in nature. "Non-associated" natural gas occurs in reservoirs with no or a minimal amount of crude oil, and is richer in methane but leaner in heavier molecular weight hydrocarbons and condensate materials. Natural gas existing as a free gas or gas in crude oil solution is referred to as "associated" gas or "gas cap" (when found in contact with crude petroleum). Natural gas is referred to as "dissolved" gas if it is in solution with the crude petroleum. Associated natural gas is normally characterised by lower methane content than the non-associated type gas, but richer in higher molecular weight paraffinic constituents. Recovery from associated gas requires separation from the petroleum at lower separator pressures, involving high expenditure for compression. "Gas condensate" that may occur in the gas phase in the reservoir contains relatively high amounts of the heavy molecular weight liquid hydrocarbons – usually called natural gasoline (Speight, 2003).

**Table 2.2 General composition of 'wet' and 'dry' natural gas.**

| Constituents | Composition (volume %) | | |
|---|---|---|---|
| **Hydrocarbons** | **'Wet'** | **range** | **'Dry'** |
| Methane | 84.6 | | 96.0 |
| Ethane | 6.4 | | 2.0 |
| Propane | 5.3 | | 0.6 |
| Isobutane | 1.2 | | 0.18 |
| n-Butane | 1.4 | | 0.18 |
| Isopentane | 0.4 | | 0.14 |
| n-Pentane | 0.2 | | 0.06 |
| Hexane | 0.4 | | 0.10 |
| Heptane | 0.1 | | 0.08 |
| **Non – hydrocarbons** | | | |
| Carbon dioxide | | 0-5 | |
| Helium | | 0.0-0.5 | |
| Hydrogen Sulphide | | 0-5 | |
| Nitrogen | | 0-10 | |
| Argon | | 0.0-0.05 | |
| Radon, krypton, xenon | | Traces | |

Source: Speight (1993).

Legend: "Wet" gas contains relatively high amounts of higher-molecular-weight hydrocarbons. "Dry" gas contains relatively low amounts of higher-molecular-weight hydrocarbons. In quantitative terms, "wet" gas contains more than 3.79 x $10^{-3}/28m^3$ of gasoline vapour (higher-molecular-weight paraffins), whilst "dry" gas contains less than 3.79 x $10^{-3}/28m^3$ of gasoline vapour (higher-molecular-weight paraffins) (Speight, 1993).

### 2.11 Natural gas industries in other countries

It is my view that review of the development of the natural gas industry in both developed and developing countries is pertinent, as it would assist to benchmark the growth of the same industry in South Africa, in particular on policy and regulatory issues.

### 2.11.1 United States of America

In 1994, the nation's proven reserves contained 4639 billion cubic metres (bcm) of natural gas which was distributed as follows: Texas (22%), Off Shore Gulf of Mexico (21%), New Mexico (10%), Oklahoma (8%), Wyoming (7%) and others (36 %) (EIA, 1998).

Companies in the USA were encouraged to build gas transmission and distribution systems as a way of developing the natural gas industry by the promise of an exclusive franchise in selected areas. The sale of synthetic gas into small urban distribution networks in the Northeast, the West and Midwest signalled the emergence of a natural gas industry in the USA. Gas was used for lighting until the late 1980s, when it was replaced by electricity. Subsequently, natural gas was used for space heating, and later residential use. The Natural Gas Act of 1998 heralded the beginning of Federal regulation of the natural gas industry, leading to the authorisation of the Federal Power Commission to regulate the interstate gas transmission. The long distance pipeline-building boom of the 1920's was based on the technological advances in pipeline construction. However, after the lull in the pipeline construction during the Great Depression of the late 1920s, it was stimulated during World War II. During this period, the Tennessee Gas Transmission Company was given special privileges to construct a natural gas pipeline linking the Gulf Coast to the Appalachian Region. Natural gas transmitted by this pipeline was used for the enrichment of uranium for making atomic bombs (Van Vactor and Johnson, 1996).

In the USA, coal-bed methane provides at least 6% of its natural gas reserves, a figure that may double, according to predictions by geologists. It is estimated that the extraction of only 15% of coal-bed methane in the USA could meet its natural gas needs for 11 years. The hub of the emerging coal-bed methane industry is south-western Colorado and northern New Mexico (Wöstmann, 2001).

The growing demand for natural gas in the USA is indicated by the increasing number of gas pipelines from other countries under the auspices of natural gas integration. Some of the interconnected gas pipelines include those between the USA and Canada (the Alliance pipeline), the USA and the Sable Island field, off Nova Scotia (the Maritimes and Northeast pipeline) and the USA and Mexico, which supports a smaller volume of natural gas trade in both directions (EIA, 2000)

### 2.11.2 Australia

Offshore waters dominate the production and exploration of natural gas in Australia. The initial success of oil discoveries in the 1960s by Esso and BHP (now BHP Billiton) in the Gippsland Basin in the Bass Strait, off the coast of Victoria, which saw several activities in exploration in the eighties, has gradually moved westwards. Currently, the waters off the North West coast of Western Australia dominate the exploration scene. The growing domestic market in Western Australia has been supplied by this project since 1984 (Energy Publications, 2001).

Two main types of gas used in Australia for energy purposes are natural gas and liquefied petroleum gas. However, natural gas is preferred by businesses and households. The North West Shelf Gas Project near Karratha in Western Australia exports 7.5 million tonnes of liquefied petroleum gas to markets such as Japan and earns more than $1,600 million (cost insurance and freight) per annum. In addition, Australia designs, builds and exports gas appliances such as hot water systems and gas meters; including the export of technical and engineering services (Australian Gas Association, 2001).

The natural gas industry in Australia is rapidly expanding, and the deregulation of the gas markets has produced significant growth in consumption, especially in the eastern states, a trend that is expected to continue. It is envisaged that natural gas will experience aggressive competition for the generation of electricity in Australia through cogeneration (combined heat and power generation) plants (Allen, 1997).

In addition to the use of natural gas in Australia for household cooking and heating, gas is used to power natural gas vehicles from pressurised containers. Statistically, Australia's natural gas reserves, excluding coal-bed methane, are enough to last about 91 years, at current levels of production. In January 2000, there were 10 natural gas vehicle (NGV) refuelling stations that were open to the Australian public. These stations were also available for refuelling home appliances. In 1999, there were 1,902 NGVs in Australia, including taxis, buses, trucks, forklifts, cars, vans, utilities and a cargo ship. At the end of 2000, the global population of NGVs was over one million (Australian Gas Industry, 2001).

### 2.11.3 United Kingdom

The UK controls a major part of North Sea natural gas production. When the natural gas production in the UK lags consumption, the difference is made up from pipeline gas supplies from the North Sea, Algeria and Russia (Van Vactor and Johnson, 1996). An estimated 759 billion cubic metres (bcm) of natural gas reserves are in the UK, most of which are in non-associated gas fields located off the English coast in the Southern Gas Basin, near the Dutch sector of the North Sea (USEIA, 2001).

Whilst the UK's first imported natural gas from the Norwegian sector of the North Sea began in 1974, its exports began in 1992 when the Markham field in the Southern North Sea started producing gas. A 230-kilometre long pipeline (The UK-Belgium Interconnector) connects Bacton on the East Coast of the UK to Zeebrugge in Belgium. The movement of gas to and from the UK (imports and exports) through this interconnector is based on the price of natural gas in the UK and the international markets in continental Europe (Williamson and Taylor, 2001).

The deregulation in 1986 of the UK natural gas industry was intended to pave the way for new entrants and competition in all but the pipeline segment of the industry. However, because British Gas was privatised as a vertically integrated company to speed up transactions and maximise the sale proceeds, this did not occur. In 1989, to improve competition, the Office of Gas Regulation introduced the 90:10 rule, prohibiting British Gas from contracting more than 90% of gas deliveries from any field on the continental shelf of the UK. This arrangement did not improve competition much and in 1996, British Gas pre-empted further regulatory intervention by splitting its assets into two companies: Centrica (for gas production, sales and supply business) and the BG Public Limited Company (Plc) (for transportation and storage business), completing the separation or "demerger" in 1997 (Juris, 1998).

Over the past few decades, the United Kingdom's fuel consumption mix has undergone marked changes – oil's share of total energy consumption has remained steady, while since 1980, coal's share of total energy consumption has declined by 57%. Natural gas and, to a lesser extent, nuclear energy have replaced the relatively large share of coal in the total fuel mix in the 1960s. In 1998 in the UK, there was emission of 147.4 million metric tonnes of carbon, a reduction from the 1990 emission of 167.4 million metric tonnes of carbon from fossil fuel-generation sources. This is a reflection of the fuel switch from the more carbon-intensive coal to less carbon-intensive fuels, such as natural gas (USEIA, 2001).

Further improvement in air quality in the UK has resulted from the use of natural gas vehicles (NGVs). In March 2001, there were 500 NGVs in use in Britain whilst the global figure was over one million. The relatively low number of NGVs in Britain stemmed from the fact they involve a small fuel cost savings because of the lack of financial incentives to switch to natural gas as a road fuel, and the existence of fewer fuelling facilities for NGVs. However, this has changed since the excise duty on compressed natural gas was reduced by 25% in the UK. The use of compressed natural gas would improve air quality in the UK (Natural Gas Vehicles Association, 2001).

### *2.11.4 Developing countries*

In many developing countries, there have been considerable under utilisation and wastage of natural gas due to flaring, domestic market limitations and the huge investments and sizable minimum reserves that are required to support export projects. Thus, the potential of natural gas to contribute to economic growth and recovery and its beneficial impact on the environment is not achieved. The use of natural gas in developing countries will be increased through a number of transformations and regulatory interventions. These include the creation of domestic market opportunities for gas, the establishment of legal and regulatory frameworks that are conducive to new investment and protect consumers, and the mitigation of perceived risks through the structuring of finance (World Bank Group, 2001a).

According to the World Bank, the quantity of natural gas flared globally each year (virtually all of it in developing countries or economies-in-transition) is equal to the combined power generation in Africa and Latin America (World Bank Group, 2001b).

Bolivia

Natural gas was discovered in Bolivia at a site at ItaÚ in 1999. The total natural gas reserves grew from 220 billion cubic metres (bcm) in 1998 to 670 bcm in 1999, much of which is exported to Brazil and Argentina. Bolivia sells natural gas in its raw form with no value addition such as the firing of local thermal power plants. Due to privatisation of the petroleum sector in the mid-1990s and the reduction in taxes paid by petroleum companies on new production sites, new developments in the natural gas industry will be of more benefit to private operators than the Bolivian treasury. Despite its relatively large natural gas reserves, Bolivia cannot maximise its gas export potential due to the preferential rights that were granted to Petrobras under a 20-year Bolivia-Brazil gas sales contract. The contract requires Bolivia to export its production through a 3,000-km pipeline between Santa Cruz, Bolivia, and Sao Paolo’s industrial centre (Inter Press Service, 1999).

The following are among the social, environmental and logistical issues that confront the Bolivia-Brazil pipeline project:

- Endangering of important ecosystems by the pipeline;
- The clearing of forests and vegetation for the construction of the pipeline;
- Difficulty in restricting vehicular access to the new rights-of-way (the access "road" created for the construction of the pipeline); and
- Damage to local infrastructure.

The pipeline project has set up standards for project level coordination among the banks by establishing an *ad hoc* environmental committee among all the financing agencies. Public pressure through civil organisations on the banks and sponsors eventually led to improvements in the project's monitoring system, stronger oversight and better communication between stakeholders and project sponsors (Hamerschlag, 1999).

Malaysia

In January 2001, Malaysia's proven natural gas reserves stood at 2760 billion cubic metres, which at the production of about 410 billion cubic metres per year would sustain the natural gas supply for about 67 years (Gas Malaysia, 2003). For the period 1996 to 2000, natural gas supplied 37.1% of the primary commercial energy, a figure that is expected to increase to 39.9% by 2005. The increased consumption of gas is due to its increased use in combined-cycle gas turbines that was responsible for 78.7% of the total gas use in 2000. The preference of gas over other energy carriers is supported by continued government promotion, under the eighth Malaysian Plan (2001-2005) (Gas Malaysia, 2001).

East Asia utilises relatively less gas than Europe or North America. Whilst the colder climate of the northern countries may be a contributing factor to the energy consumption differential, the lack of an integrated international gas grid linking growth points in the Asian region inhibits the consumption of gas. Recently, the building of pipelines to link the region has been proposed. Some of the envisaged pipeline grids are:

- A link to supply southern China and Chinese Taipei with gas from southeast Asia;
- International pipelines from the offshore Thailand-Malaysia Joint Development Area (under construction) and another to bring gas from the Natuna gas field, Indonesia, to Singapore; and

- The proposed Asian Gas Grid project to link Indonesia's Natuna gas field to Shanghai, China, incorporating existing gas networks in Malaysia, Indonesia and Thailand, and possibly Vietnam.

It is expected that with its projected rapid increase in gas demand, China could absorb the bulk of gas exported through the new system (EIA, 2000a).

Nigeria

Nigeria is ranked tenth largest gas producer worldwide with a gas reserves-to-production ratio estimated to be about 120 years. Nigeria has a natural gas reserve of 3680 billion cubic metres (bcm) that constitutes 2.6% of global reserves. However, about 65% of the associated gas that accounts for 70% of gas production is flared – thus, increasing the burden of global anthropogenic emissions of greenhouse gases. The government has instituted a policy to stop gas-flaring by 2008. This would lead to improvements in environmental conditions and health, including a reduction in respiratory illnesses near refineries. The beneficial effects of the developments in the natural gas industry can be realised if a gas policy is enacted and gas infrastructure is installed. In 1985, Nigeria began a liquefied natural gas project on Bonny Island with a capacity of 5.7 metric tonnes a year. The plant was commissioned in 1999 and was expected to earn Nigeria about US$750 million a year (Asamoah, 2001b).

Additional to the liquefied natural gas project, other developments are proposed in Nigeria's natural gas industry – the West African Gas Pipeline (WAGP) and the trans-Saharan gas pipeline projects. The WAGP project involves the proposed piping of Nigerian natural gas through a 960-kilometre gas pipeline to the neighbouring countries of Benin, Togo and Ghana. This project would produce a market for some of the gas that Nigeria flares at its refineries, and is expected to bring in an investment of US$1.8 billion and create about 20,000 direct jobs in West Africa (Asamoah, 2000a).

# 3. THE SOUTH AFRICAN ENERGY SECTOR AND GAS INDUSTRY

Chapter 3 provides an overview of South Africa's energy sector including gas industry. This chapter discusses key Government interventions in the energy sector.

## 3.1 Introduction

The South African energy sector is dominated by coal due to its relatively abundant reserves, and its comparative cheapness in comparison with other energy carriers. South African proven coal reserves rank seventh in the World in terms of quantity (BP, 2004).

During the isolation of South Africa by the UN, it had to rely on its natural resources for its energy needs and thus developed a huge infrastructure for exploiting and utilising the coal reserves. This infrastructure includes Sasol's coal-to-liquid fuels plants, numerous pulverised fuel coal-fired power stations and facilities for using coal as a feedstock for metallurgical industries and for domestic combustion. In addition, the construction of a gas-to-liquid fuels refinery, PetroSA (formerly Mossgas) at Mossel Bay, helped to minimise the impact of economic sanctions imposed on South Africa, as it assisted to meet its partial liquid fuels requirements. Furthermore, South Africa is gradually seeking to diversify its energy sector with new and renewable sources of energy – especially solar and wind energy – and improve its energy efficiency. These initiatives create opportunities for trading in carbon dioxide credits through reduction and avoidance of man-made emissions of greenhouse gases (C. Grobbelaar, personal communication, 16 March, 2003).

## 3.2 Energy carriers

South Africa is endowed with several primary energy carriers that include biomass, coal, hydro, solar, wind, natural gas and crude oil. Some of the primary energy carriers are transformed into secondary forms such as electricity, liquid fuels and briquettes.

The distribution of energy carriers in South Africa is skewed in favour of urban centres where there is relatively easy access to most primary and secondary energy carriers, whilst rural areas have access to mainly bio-fuels, paraffin and candles (Eskom, 1999a). In 2000, about 79% of the primary energy consumption (figure 3.1) was derived from coal. Imported crude oil and renewables constitute about 10% and 5.5% respectively of the primary energy requirements of

South Africa. The least developed of the six main primary energy sources are hydro and gas, which contribute 0.5% and 1.7% respectively of the total primary energy consumption.

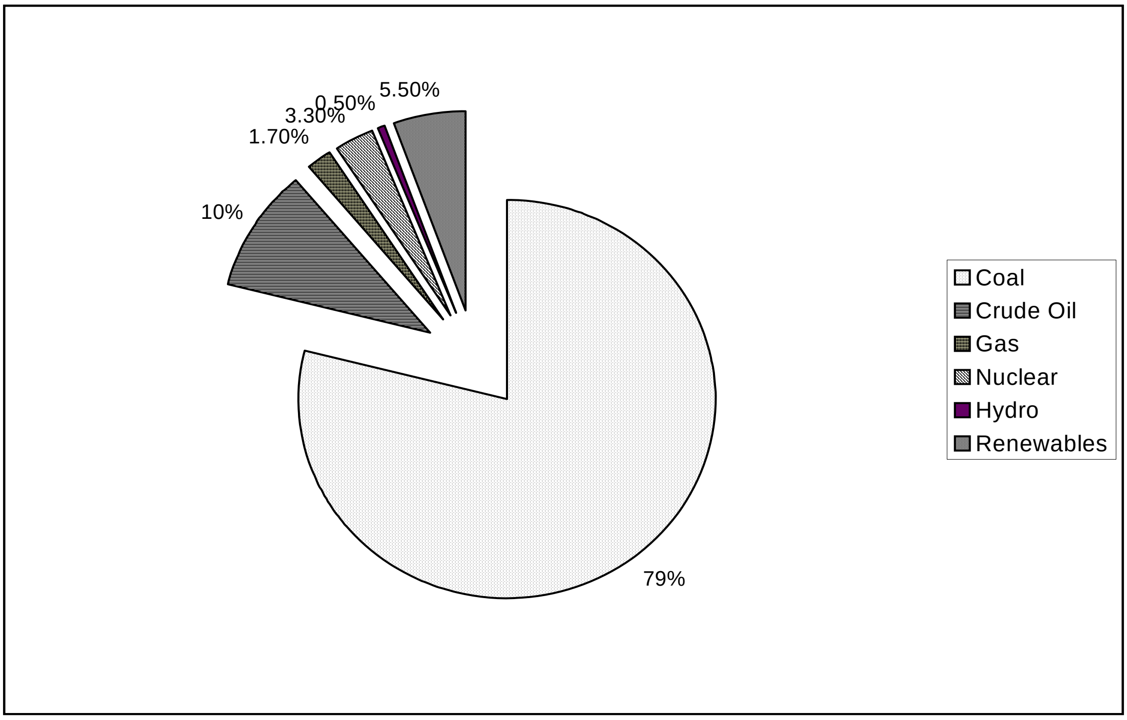



Figure 3.1 South Africa's primary energy consumption, 2000.
Source: Adapted from DME (2002a).

### *3.2.1 Coal*

South Africa has recoverable coal reserves of 55,3 billion tonnes – equivalent to 5.6% of the estimated global total. Most of the coal deposits consist of bituminous thermal grade with 0.9% metallurgical quality and 0.8% anthracite. The high-grade bituminous coal reserves are being depleted, for sale to foreign markets, at a faster rate than those of the low-grade category. South African coal is characterised by relatively high ash content. In some power station feedstocks, ash content of the coal used to generate power is as high as 40%. However, the sulphur content of the coal is less than 1% (Doppegieter *et al*., 2000).

As at 2000, South Africa had stockpiled about 800 million tonnes of discard coal in various locations. About 68 Mt of discard coal is stockpiled per annum in South Africa. In 2001, the Department of Minerals and Energy undertook a project – "Potential Government intervention to significantly reduce the amount and impact of discard coal" – to find uses for discard coal (C. Grobbelaar, personal communication, 16 March 2003). This project concluded that discard coal could be used as a power station feed, gasified or liquefied to produce secondary energy carriers used for making briquettes or for road surfacing. Additionally, the project revealed that discard coal could be used by Independent Power Producers to generate electricity in competition with Eskom and municipal generators. To motivate the utilisation of discard coal (and minimise associated hazards), the study recommended the introduction of incentives such as tax holidays, halving the waiting period for departmental approval of Environmental Management Plans and the subsidisation of input resources by Government (Badger Mining and Consulting, 2003). The main source of discard coal in South Africa is the upgrading of run-of-mine coal to comply with international market requirements. Estimates indicate that about 60% of discard coal can be reclaimed and utilised for energy purposes (Doppegieter *et al*., 2000).

Of the total coal sales of 220.4 mega tonnes (Mt) in 1999, 93.4 Mt were used for the generation of electricity with 51.3 Mt consumed in commerce and industry (including synthetic liquid fuels (figure 3.2). In the same year, 154.2 Mt of coal was sold inland whilst 66.2 Mt were exported. Eskom and Sasol are the major users of domestic coal in South Africa for the generation of electricity and synthetic liquid fuels respectively (Doppegieter *et al*., 2000). Eskom uses an average of about 40% of the saleable coal produced in South Africa to generate electricity, whilst about 30% is exported (figure 3.2). Inland coal sales that stood at approximately 136 million tonnes in 1990 showed a decreasing trend till 1992 and then increased steadily till 1997. Thereafter, the inland coal sales decreased almost linearly from about 160 million tonnes to about 154 million tonnes in 1999. Amount of coal used to generate electricity showed an increasing trend from 1992 to 1997, then levelled off. It is apparent that this period coincides with accelerated electrification of low-cost houses including informal dwellings. Considering the fact that about 68 million tonnes of coal is discarded annually, mainly in the form of duff and undersized coal, it is inferred that about 25% of the run-of-mine coal was discarded in the period 1990 to 1999.

Future variations in the quantities of coal used by the above companies would depend on several factors. For Eskom, the factors are the Government's objective of universal provision of electricity to all households in South Africa, the use of alternative energy carriers (such as natural gas) and technologies to generate electricity and the possibility of introducing carbon or energy tax. The factors for Sasol are co-feeding and fuel switching of coal at the synthetic fuel plants at Secunda and Sasolburg respectively with natural gas, possibility of introducing carbon or energy tax and level of demand for synthetic fuels in South Africa.

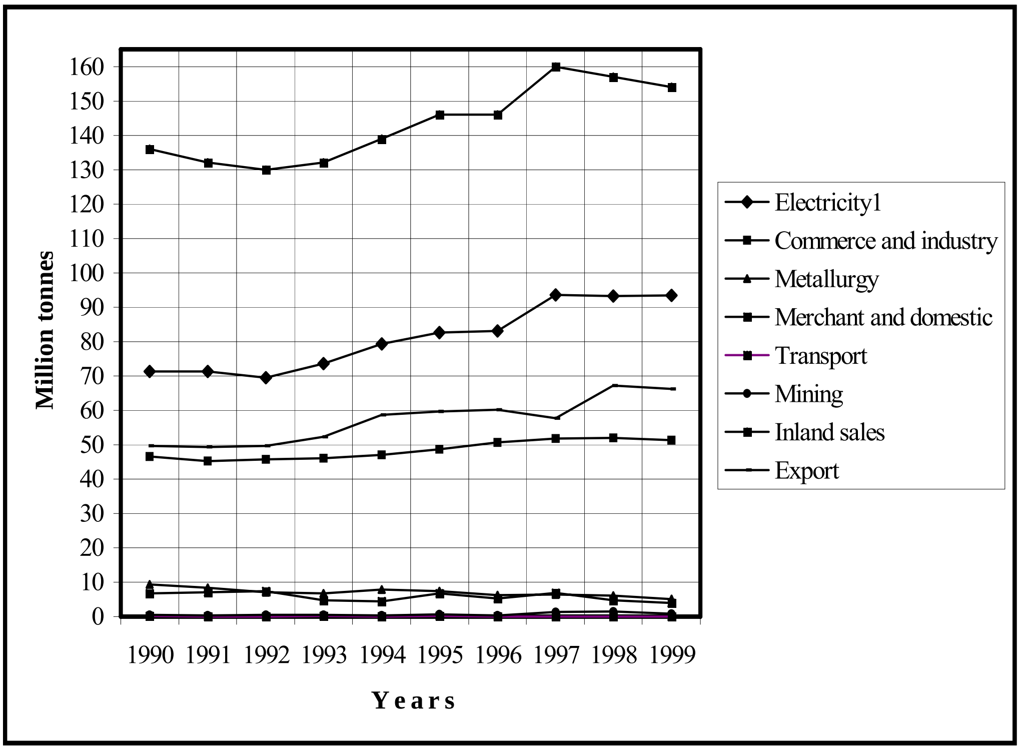



Figure 3.2 Sectoral trends in South African coal sales from 1990-1999. .

Source: Adapted from Doppegieter *et al*. (2000).

Legend: Electricity1 excludes Sasol's electricity. '90 stands for 1990.

### *3.2.2 Liquid fuels*

Because proven crude oil reserves are rare in South Africa, it relies on imported crude oil and liquefaction of both coal and natural gas for its primary liquid fuel requirements. In May 1998, South Africa started producing 25,000 barrels per day (bbl/d) of crude oil from the Oribi oil field, south of Mossel Bay – accounting for about 7% of the national requirements of approximately 360,000 bbl/d. Imported crude oil makes up about 60% of the local liquid fuel requirements and of the balance, about 33% is obtained from the synthetic fuel plants of Sasol (coal-to-liquid fuels) and PetroSA (gas-to-liquid fuels) (Cooper, 1998).

The relatively small Sasol synthetic fuels plant initiated in 1955 in Sasolburg was expanded in the late 1970s with the construction of two plants in Secunda. Currently, Sasol has a synthetic fuel capacity of about 150,000 bbl/d (crude oil equivalent) and produces *inter alia* gasoline, diesel, solvent gas, liquefied petroleum gas and a number of chemical feedstocks (SANEA, 1998).

PetroSA's refinery, the World's first commercial plant to produce liquid fuels from gas, started production in 1993, and currently produces the equivalent of 45,000 barrels of finished product a day. The plant is fed by two gas fields named "F-A" and "E-M", which are located 85 km to the south of Mossel Bay and 49 km to the west of F-A respectively. The E-M gas field is expected to prolong the life of PetroSA to about 2007. The F-A and E-M gas fields are estimated to have 26.3 and 16.7 billion cubic metres of gas respectively. (Ruffini, 2000a).

South Africa, a major refining nation in Africa, has a current total refining capacity (excluding synthetic fuel plants) of 466,547 bbl/d. The refined products are sold both in the local market and exported mainly to East Africa, Indian and Atlantic basin markets. In August 1999, Sasol and Total Oil Company jointly announced the undertaking of a $123-million expansion project at its Natref refinery. The project, which was expected to increase the refining capacity at Natref by nearly 17,000 bbl/d, and aims to produce low-sulphur diesel, was completed by mid-2002 (EIA, 2000b).

South African Petroleum Industry Association, which consists of the major oil companies in South Africa, is aware of the potential impact of its activities on the environment and the hazards caused to society. The association has therefore put a number of measures in place, through its Industry Environment Committee, to control any incidence of pollution, including:

- The positioning of oil spill response equipment at all ports and harbours;
- The positioning of 43 oil spill response trailers along land transport routes;
- The development of new specifications for storage tanks and pipes at service stations to prevent leakage;
- The support of research projects to determine the effects of vehicle emissions on urban air quality; and
- The introduction of scientifically based clean-up goals for contaminated land and groundwater.

The oil companies and the other lubricant-marketing companies also collect and re-use lubricating oils to reduce the threat of environmental contamination, through an initiative called "Recovery of Oil Saves the Environment". Additionally, the Paraffin Safety Association of Southern Africa – established in 1995 – provides child resistant lids and bottles and conducts intensive safety education programme in order to minimise the incidence of paraffin ingestion among young children (A. Moldan, personal communication, 10 September, 2003).

### *3.2.3 Natural gas*

South Africa has gas reserves of 22.1 billion cubic metres (bcm), which constitutes about 9% of the total reserves in Southern African Development Community (EIA, 1999). However, due to the development of new technologies and ongoing exploratory activities by both local and international companies, the gas reserves are likely to increase. The producing gas reserves are in offshore gas fields located in the Bredasdorp Basin, South of Mossel Bay. The recent discovery of the Ibhubesi gas field off South Africa's West Coast is bound to increase the gas reserve figures. Forest Oil is developing the Ibhubesi gas field in partnership with Anschutz (both Denver-based) and Mvelaphanda Energy (a South African Black Economic Empowerment group). Gas has been found in fourteen out of the eighteen gas wells drilled so far at the Ibhubesi gas field (Marrs, 2001).

The Ibhubesi gas field, offshore the western coastline, had an estimated total gas reserves of 85 bcm as at November 2000. The exploratory well at Ibhubesi yields 0,85 mega cubic metres (Mcm) of natural gas per day. According to Forest Oil, gas production that is expected to begin after 2004 may be channelled towards regional electricity production (EIA, 2000b). However, because of the relative proximity of Ibhubesi to the PetroSA gas-to-liquid fuels plant, the Ibhubesi gas could provide feedstock to the plant, thus extending the life of the plant beyond the current prediction of 2007.

With the excess electricity peak capacity in South Africa expected to be exhausted in 2007, the current increase in interest in natural gas may prove opportune from the perspective of electricity generation. According to Eddie Kanda of Eskom, it is projected that natural gas would generate a considerable amount of electricity in South Africa by 2010, thus modifying its coal-based energy profile to that in which natural gas is the future source of electricity generation (Venter, 2001).

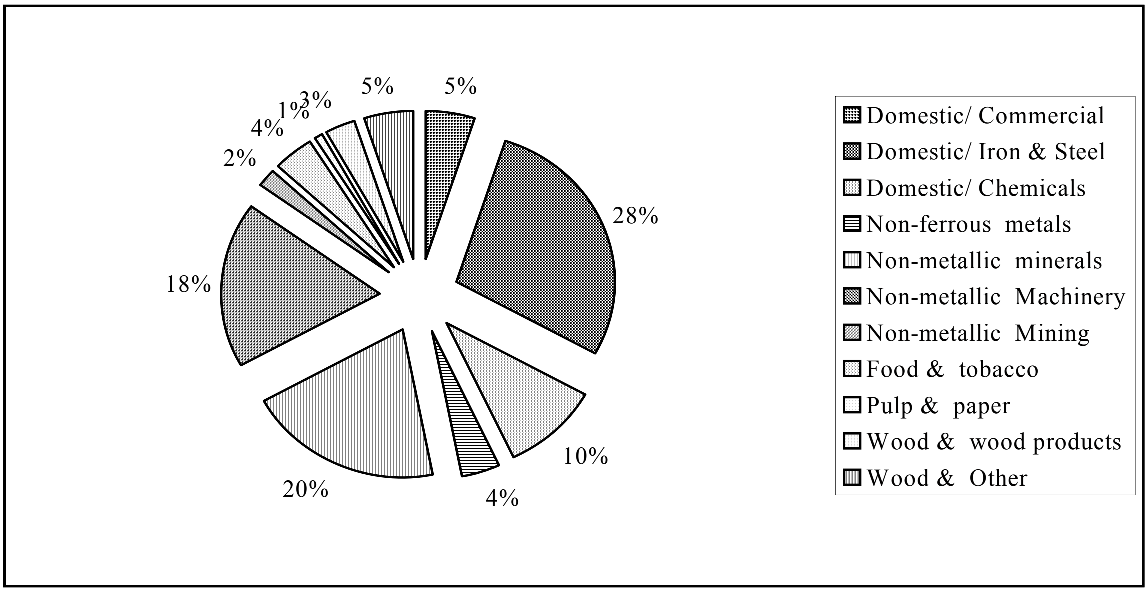



Figure 3.3 Gas end-use in the SA economy.
Source: Horvei (2001).

### *3.2.4 Renewables*

South Africa has abundant yet under-exploited and less utilised renewable resources with the exception of biomass, which is used extensively by rural communities. However, after the democratic transformation of South Africa in 1994 and lifting of sanctions, emphasis has shifted from supply side to demand side issues involving the provision of clean, affordable and available energy resources to all sections of the community (DME, 1998). South Africa has realised that this goal cannot be achieved through conventional energy carriers alone, but through a combination of the latter and new and renewable sources of energy.

It is estimated that biomass contributes about 10% of South Africa's primary energy demand. Solar power has immense potential to contribute to its energy requirements, whilst wind energy is currently being investigated as a source of power (SANEA, 2003).

In 1998, Eskom's Resources and Strategy Group launched the South African Bulk Renewable Energy Generation (SABRE-gen) project for multi-megawatt grid connected generation systems to find out whether renewable energy could provide viable solutions to the future energy needs of South Africa (Darrol, 2001).

The average solar radiation in South Africa is between 4,8 and 6,9 kWh/m$^2$ per day. This is among the highest in the World. Annual global 24-hr solar radiation averages about 220 W/m$^2$ in South Africa compared with 150 and about 100 W/m$^2$ in parts of the USA and Europe respectively (SANEA, 1998). Thus, this energy carrier has great potential for the energy economy of South Africa through application in photovoltaics and solar thermal appliances, especially solar water heaters. Solar water heaters have a potential market in low-income housing - expected to grow as the housing backlog in South Africa is addressed. During 1996, the use of solar systems for the provision of non-grid electricity in schools increased substantially, with almost 26% of electrified schools receiving solar systems (SANEA, 1998). Under the programme of universal provision of electricity to all households in South Africa by the year 2010 (Mlambo-Ngcuka, 2001b), solar home systems (SHS) are increasingly being used especially in remote areas. Despite the fact that solar home systems are not designed for thermal applications, the relief they bring to rural communities has social, economic and environmental benefits, as SHS are relatively sustainable.

By the end of 2000, a joint venture between Eskom and Shell had installed 6,000 SHS in the northeastern part of the former Transkei (Eastern Cape Province) and the southern KwaZulu-Natal Province, using photovoltaic technology (Gothard, 2000). This project, which was subsequently rolled out by the DME in KwaZulu-Natal, Eastern Cape and Limpopo provinces aimed at improving the lifestyle of the previously disadvantaged communities.

The potential for wind energy varies from one location to another in South Africa, with the west coastal areas and the Drakensberg Escarpment showing the greatest potential. In the past, small windmills for pumping water from wells and boreholes were extensively used in the more arid and commercial farming areas of South Africa. The Darling Independent Power Producer (IPP) is planning to generate 5 MW wind power at a farm near Darling in the Western Cape. The selected site, Moedmaag Koppie, frequently has wind speeds in excess of 7,5 metres per second (m/s). The Department of Minerals and Energy (DME) has declared the Darling wind farm a national demonstration project to allow it to be used to identify, develop and update pertinent strategies and regulations on how to handle IPP issues in general. Darling holds promise of key economic, social and environmental benefits to South Africa. Some of these benefits are:

- The creation of jobs (in developed countries, 15-19 jobs are created for each megawatt of electricity produced, whilst the job creation potential is doubled in relatively more labour-intensive countries such as South Africa).
- The avoidance of the release of carbon dioxide and other polluting gases into the atmosphere (Table 3.1).

- Savings on the fossil fuels (Darling is expected to save around 100,000 tons of coal in its operational lifetime).
- Savings of about 650 million litres of water, otherwise used in generation of electricity by coal.
- Improvement in the health of South Africans by reducing exposure to emissions from domestic coal combustion and wood.

The Darling project is deemed a low technical and innovation risk endeavour, because in addition to support of the DME and the Development Bank of Southern Africa, it incorporates application of a well-developed technology from Europe (Asamoah, 2001a). One of the project's problems is Eskom's decision to pay 19 cents/kWh instead of the demanded 38 cents/kWh during the power purchase agreement discussions (Darrol, 2001). However, potential financial support from the Global Environment Facility may lower the financial costs of the project. In 2003, Eskom established a wind energy research and demonstration facility at Klipheuwel (near Darling) with three 1-MW wind turbines to test performance of the turbines under similar conditions as at Darling. Considering the fact that the two wind farms are near to each other, one would have expected that only one wind farm would have been established to test the performance of wind turbines. However, Eskom claims that the site for the Darling wind farm is not as suitable as Klipheuwel for testing wind turbines. In my view, from a strategic perspective, it might have been difficult for the owners of Darling and Eskom to work together, as the former was instigated as a business venture, whilst Eskom is motivated by research to establish the characteristics and operating parameters of wind turbines under local conditions.

**Table 3.1 Avoided emissions and savings on resources by the Darling wind farm.**

| Resource/Emission | Wind-generated electricity replacing coal-generated electricity. Lifetime savings (25 years) |
|---|---|
| Coal | 348,476 tons |
| Water | 868 million litres |
| Carbon dioxide | 652,912 tons |
| Sulphur dioxide | 5,339 tons |
| Nitrogen oxides | 2,658 tons |
| Particulate emission | 322 tons |

Source: Adapted from Oelsner (2002).

It is estimated that significant wave energy potential exists along the Cape coastline. However, no exploration has taken place yet. Whilst an estimated total average power of 56,800 MW is available along the entire coastline, there is uncertainty whether any of this potential could be realised on a large scale in the medium-term due to cost considerations (DME, 2001).

For energy from ocean currents, preliminary investigations have revealed existence of considerable potential in the Agulhas Current, which is one of the strongest currents in the World. This current, which is about 150 km wide and flows at 6 metres/second, passes down the eastern seaboard of South Africa and is estimated to be capable of producing some 2000 MW of electricity. Currently, the technology that uses turbines for generating electricity in marine environments is being piloted in various global sites. For the Agulhas Current, it is necessary to undertake assessments to establish its suitability for using this technology (DME, 2002b).

Almost all the refuse in South Africa is disposed off in landfill sites. For instance, in the Reef area of Gauteng – the most feasible area for incineration of refuse from large municipalities – it is estimated that approximately 17 PJ per annum energy could be produced by combustion of waste. In addition, net energy realisable from sewage-derived methane in South Africa would be about 36 MWh per annum for generating electricity and 96 MW for heating purposes annually (DME, 2001).

The importance the South African Government attaches to harnessing renewable energy resources culminated in the release of a “White Paper on the Promotion of Renewable Energy and Clean Energy Development: Part One – Promotion of Renewable Energy” in August 2002. The Government’s long term goal as indicated in this White Paper is the establishment of a renewable energy industry that produces modern energy carriers to offer sustainable, fully non-subsidised alternative to fossil fuels in future. The Government acknowledges the fact that the proportion of final energy demand currently provided by renewable energy has emanated mainly from use of wood and animal waste for cooking and heating, due to poverty. To start on a planned path towards achieving the long term goal, the Government has set a target of attaining “An additional 10,000 GWh (0.8 Mtoe) renewable energy contribution to final energy consumption by 2012, to be produced mainly from biomass, wind, solar and small-scale hydro.” According to the Government, the target will be achieved through a phased and flexible strategy. A number of “early win” investments spread across comparative low-cost technologies such as biomass-based cogeneration including technologies with relatively large-scale application such as solar water heating, wind and small-scale hydro have been earmarked. These initial investments will reduce the subsidy requirements for the promotion of renewable energy (DME, 2002b).

The Government envisages that as the cost of coal-based power generation increases with the need for future additional capacity, the financial viability of renewable energy technologies would improve – reducing the subsidy needed per unit of power generated by renewable energy. A strategy plan on renewable energy will be developed by the Government to convert the goals and deliverables set in the White Paper into a practical implementation plan. In the short term, the White Paper on the promotion of renewable energy and clean energy development identifies solar, wind, biomass (including bio-fuels) and hydropower as energy carriers that should be developed further and implemented to meet the proposed target of renewable energy generation. However, for the long-term the White Paper suggests that efforts should be directed at harnessing substantial wave, tidal and ocean current resources for power generation, adding that fuel cells would become commercially viable in future (DME, 2002b).

### *3.2.5 Nuclear energy*

The uranium resources of South Africa, which amount to 218 kilo tonnes, make up 9,4% of the global total, and are the fourth largest in the World. Approximately 93% of the uranium produced in 1993 was a by-product of gold mining, while the rest was a by-product of base metal mining. In 1997, 1,324 tonnes of uranium oxide was produced, dropping by 14,1% to 1,138 tonnes in 1998. Due to the strong connection between gold and uranium production, a reduction in the mining of gold will increase the cost at which uranium is produced – leading to the erosion of South Africa's uranium export capacity (Doppegieter *et al*., 2000).

South Africa operates the only nuclear-fired power station on the African continent – Koeberg, at Dynefontein in the Western Cape. It consists of two units, each having a three-loop Framatome Pressurised Water Reactors (PWR), with a rating of 965 MWe. The two units have a combined output of 1,840 MWe (Asamoah, 2002a). This plant demonstrates the use of nuclear energy for peaceful purposes, and is strategically placed near Cape Town, a fast growing metropolis, with high-energy demands. The choice of this site assists to avoid high losses in transmitting power from Mpumalanga where most of South Africa's pulverised fuel coal-fired power stations are situated.

Eskom is currently developing and testing the pebble bed modular reactor (PBMR) for both local and international use to generate electricity. It consists of a relatively small (110 MW) nuclear power module that creates less spent fuel than the PWR of Koeberg. The PBMR is characterised by relatively high safety standards and uses a helium coolant, a graphite moderator and ceramic fuel pellets that allow the reactor to be operated at very high temperatures. The elevated temperatures allow the reactor to convert more energy to electricity, thus boosting its efficiency. Other features of the PBMR include its minimal environmental impact, relatively small size and the fact that it can be produced in modules (Asamoah, 2002a). The PBMR has been the subject of a number of criticisms by non-governmental organisations, including:

- That South Africa has an excess electricity capacity;
- The apparent lack of transparency in the public participation process;
- The perceived waste of public funds on a technology that is unproven; and
- That the safety of the plant is uncertain.

For Eskom, the PBMR – one of a number of possible electricity generation scenarios – is worth considering, in the light of the predicted need for new peak capacity around 2007. Furthermore, the interest shown by some overseas companies through equity shareholding in the PBMR project lends it some credibility, and provides Eskom with much needed morale booster to continue with the project. The local equity shareholders' include Eskom Enterprises and the Industrial Development Corporation (Chalmers, 2002).

### *3.2.6 Electricity*

South Africa has a mix of electricity generation power plants that use coal, hydro, gas and nuclear energy as sources of power. Eskom's 17 pulverised fuel coal-fired power stations of which 3 are mothballed are found mostly near the pithead of coalmines. Most of the power stations are in the Mpumalanga Highveld (near Witbank) and produce high atmospheric pollution in the form of particulate emissions and sulphur dioxide.

**Table 3.2 Eskom's electricity generation in 2003 by fuel.**

| Energy Source | Capacity (Net) | | Production, | |
|---|---|---|---|---|
| | **MWe** | **%** | **GWh** | **%** |
| Coal | 32,066 | 88.6 | 194,046 | 92.3 |
| Nuclear | 1,800 | 5.0 | 12,663 | 6.0 |
| Pumped storage | 1,400 | 3.9 | 2,732 | 1.3 |
| Hydro | 600 | 1.6 | 777 | 0.4 |
| Gas | 342 | 0.9 | - | 0.0 |
| **Total** | **36,208** | **100** | **210,218** | **100.0** |

Source: Eskom (2003a).

In 2003, about 90% of the total Eskom's net capacity of 36,208 MWe was provided by coal, which also accounted for about 92% of the production of 210,218 GWh of electrical energy. The pulverised fuel coal-fired power stations in South Africa are not fitted with flue gas desulphurisation facilities, but since South African coal has low sulphur content, the emission of sulphur oxides is relatively low. Eskom has drawn plans to fast track the refurbishment of the three-mothballed pulverised fuel coal-fired power stations to keep pace with the relatively high-expected growth in electricity sales (Kohler, 2004).

The impact of electricity generation on the atmosphere and consumption of natural resources is provided by table 3.3.

**Table 3.3 Environmental implications and resource consumption**

| Resource/Emissions[3] | Quantity |
|---|---|
| Coal usage, kg | 0.50 |
| Water usage, l[1] | 1.29 |
| $CO_2$ emissions, kg[2] | 0.90 |
| $SO_2$ emissions, g[2] | 8.22 |
| $NO_X$ emissions, g[2] | 3.62 |
| Ash produced, g | 142.01 |
| Ash emitted (to the atmosphere), g | 0.28 |

Source: Eskom (2003a).

Legend: [1]Calculation of figures is based on total energy produced by Eskom power stations.
[2]Annual figures are calculated based on coal characteristics and power station design parameters.
[3]Based on usage of 1 kWh of coal-generated electricity in 2003.

Total annual emissions of greenhouse and acid precursor gases due to pulverised fuel coal-fired generation of electricity (table 3.4) are shown for the period 2000-2004. Variations in emissions of carbon dioxide and nitrogen oxides correlate well with those in electrical energy leaving pulverised fuel coal-fired power stations. It is worthy of mention that, modelled emissions of carbon dioxide in 2000 accounted for 45% of the total 359 million tonnes of greenhouse gases emitted by man-made activities in South Africa (ERI, 2002b).

It is forecast that there will be a decreasing trend of the emissions of greenhouse gases from Eskom's power stations as South Africa increasingly uses less carbon-intensive energy carriers and efforts are made to abate the emission of GHG to procure certified emission reduction units (CERs) under the CDM.

**Table 3.4 Greenhouse and acid precursor gas emissions by Eskom, 2000-2004.**

| Gas | Units | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|---|
| Carbon dioxide | $10^6$ Tonnes | 161 | 169 | 175 | 190 | 198 |
| Nitrous oxide | Tonnes | 2,093 | 2,154 | 2,246 | 2,580 | 2,924 |
| Sulphur dioxide | $10^3$ Tonnes | 1,505 | 1,500 | 1,494 | 1,728 | 1,779 |
| Nitrogen dioxide | $10^3$ Tonnes | 674 | 684 | 702 | 760 | 797 |
| Coal-fired stations | $10^9$ kWh (net) | 172.4 | 175.2 | 181.7 | 194.0 | 202.2 |

Source: Adapted from Eskom (2005).

## 3.3 The gas industry in South Africa

### *3.3.1 Introduction*

Gas used in South Africa, other than for conversion to liquid fuels, is produced from the oil refineries, the synthetic fuel factories of Sasol and wells in the Bredasdorp Basin, offshore Mossel Bay. Gas from these wells is used for conversion into liquid fuels at the PetroSA refinery in Mossel Bay. Few gas reticulation systems in major urban areas supply industrial and commercial firms and households with gas. However, there is strong pressure to grow the market involving the use of gas in the form of liquefied petroleum gas in gas cylinders in households.

South Africa has great potential for increasing its use of natural gas, as indicated by:

- The enactment of the Gas Act (Act No. 48 of 2001) (Minister of Minerals and Energy, 2002) to facilitate the harmonisation of regional gas policies and the establishment of binational agreements.
- The use of natural gas from Mozambique as a feedstock in Sasol's synfuel plants at Secunda and Sasolburg starting from February 2004.
- The possible piping of natural gas from Namibia by a consortium led by Energy Africa to feed a suggested combined-cycle gas turbine power station that is to be constructed in the Cape Metropolitan Area as well as other industrial applications.

The piping of natural gas into South Africa including distribution and reticulation is likely to increase its use for industrial, commercial and power generating activities in South Africa due to:

- The ease of utilising piped gas;
- The sustainability of a supply that suits continuous applications; and
- The relative environmentally friendliness of natural gas compared to other fossil fuels.

### *3.3.2 Supply*

*PetroSA*

The South African Government has formed a new parastatal, PetroSA, after merging parts of the Strategic Fuel Fund (which manages and maintains the strategic crude oil reserves of South Africa) and Soekor (the state's petroleum and gas exploration and development firm). PetroSA is an integrated oil and gas exploration, production, refining and trading company. The formation of PetroSA was characterised by a long complicated process involving the establishment of common financial frameworks, changes in tax paying status and the development of sound business plans (Mlambo-Ngcuka, 2001c). It was formed because of the duplication in the functions of Soekor and Mossgas, existence of inefficiencies within the two organisations and the need for transformation in the liquid fuels industry. The merger should result in increased sustainability in the otherwise volatile global environment in the petroleum and gas enterprise (CEF, 2001).

The benefits from the merger will be achieved by co-operation and economies of scale, leading to considerable contribution to the macro-economy of South Africa. A brief description of the offshore platform, separation of condensates and compression of natural gas before piping to the PetroSA refinery is found in appendix F.

The products from the synthetic oil units include synthetic light oil, decant oil, propylene, alcohols, butylenes and higher olefins. The alcohols require minimal additional processing. The refinery processes butane, stabilised condensate and the synthol products into the following products: leaded 97 octane petrol, unleaded 95 octane petrol, diesel, kerosene, heavy fuel oil, liquefied petroleum gas and propane. Subsequently, the petrol and distillates are blended and piped to tank farms at Voorbaai, about 15 kilometres away from the refinery. About 80% of Mossgas' petrol, diesel and distillates are shipped to Port Elizabeth and East London, with the remaining leaving Mossel Bay by rail and road to the neighbouring areas. Mossgas exports alcohol solvents to Europe, North America and Asia Pacific. Because of the low-sulphur content of the diesel produced at the plant, there are plans to ship it to California, where even strict environmental standards are likely to be met (Ruffini, 2000a).

Mossgas uses stringent environmental management criteria in dealing with wastes and effluents. For instance, the flow rate of all effluents pumped from its refinery to the sea from April 2000 to April 2001 (figure 3.4) shows average flow rates significantly below the permitted value of 600 $m^3/hr$ by the national regulatory authority. In addition, the reaction water that is produced as an effluent stream in the alcohol recovery unit undergoes treatment in the reaction water treatment plant. PetroSA samples and monitors the ambient and exposure levels of volatile organic compounds, sulphur oxides and hazardous air pollutants to determine any potential exposure of its operations to the community (Mossgas, 2001).

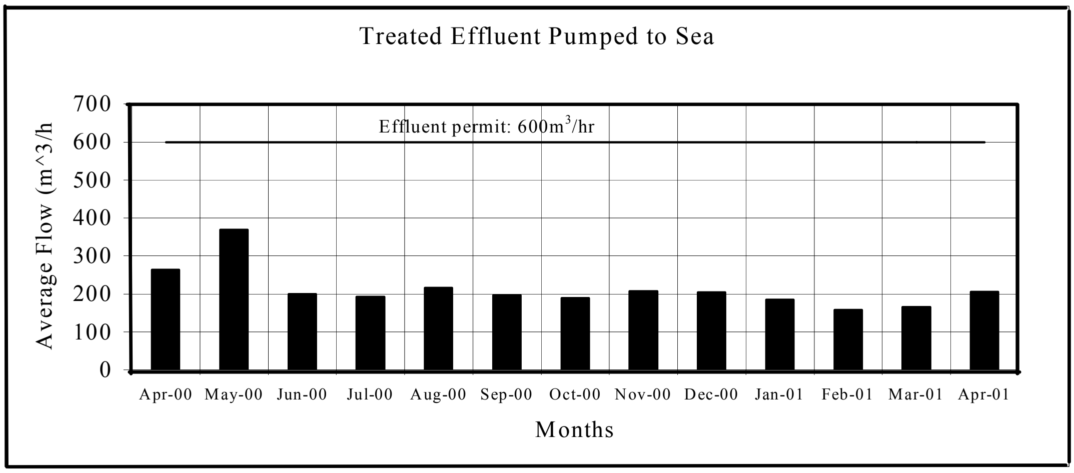



Figure 3.4 Treated effluent pumped to sea by Mossgas: April 2000-April 2001.
Source: Mossgas (2001).

Legend: Mossgas is currently part of PetroSA.

*Egoli Gas*

The acquisition of Metro Gas in August 2001 by Cinergy Global Power and Egoli Empowerment Holdings under a new name – Egoli Gas – saw the creation of the first independent municipal services provider in the Greater Johannesburg Metropolitan area. Egoli Gas has 1,200 kilometres of gas pipelines and serves approximately 12,500 consumers in the Greater Johannesburg area, covering Zandfontein and Midrand in the north, Lenasia and Orange Farm in the south, and Roodepoort in the west to Germiston in the east. Egoli Gas buys hydrogen-enriched gas from the Sasolburg synthetic fuel plant. This gas is stored at Langlaagte at high-pressure bulk storage with an automatic intake and distribution controls. The gas is distributed to consumers after piping it to low-pressure holders at Cottesloe (Crankshaw, 2001).

Before distribution to consumers, the gas is mixed with a carefully determined volume of air to ensure complete combustion – thus avoiding wastage during the heating process, while keeping exhaust heat losses due to air to a minimum. The quality of gas is consistently maintained in a pure state to prevent clogging and corrosion due to sulphur dioxide – thereby reducing the maintenance required on equipment and enhancing the lifespan thereof. The virtually sulphur-free gas is distributed to the industrial, domestic and commercial sectors, where it is typically used in bakeries, food production, powder coating, automotive systems and metal works. The gas is used in additional commercial concerns such as shopping centres, restaurants and hospitals, with the shopping mall sector presenting a huge market potential (Crankshaw, 2001).

Egoli Gas has plans to enhance its domestic market using piped natural gas from Mozambique. One advantage of natural gas over the current town gas supply from Sasolburg is the relatively high calorific value of the former (36 $MJ/m^3$), in comparison to the hydrogen-rich town gas, which has a calorific value of 19 $MJ/m^3$ (Giesen, 2001). The proposed conversion of Sasol's town gas network to natural gas in 2004 poses challenges for Egoli Gas. Among these is the need to change its network and user-base to natural gas and to convert current burners to handle the flame characteristics of natural gas (Crankshaw, 2001).

The proposed extension of the natural gas network to the historically disadvantaged areas is likely to produce benefits in health, social, environmental and economic spheres. Historically, these areas used low-grade coal and biomass for their thermal energy, resulting in high incidences of respiratory illnesses and poor visibility. The introduction of natural gas could stimulate the growth of enterprises in these areas, thereby reducing unemployment and crime while improving available financial resources. The marketing efforts of Egoli Gas are currently targeting potential commercial and industrial energy users as well as schools (Crankshaw, 2001).

*Sasol Gas*

In 1994, Gascor (now Sasol Gas) was established as a "Section 21" non-profit organisation, because South African tax regulations classify gas pipelines as permanent installations with no allowable depreciation. Gascor acted solely as an agent of Sasol Oil – the owner of the gas it transports – through which it could remit its depreciation cost back to Sasol as part of transport costs. The initial pipelines were built from Sasolburg to the industrial areas of Krugersdorp and Springs (TAU, 1995a). Sasol Gas owns over 700-km gas transmission and distribution pipelines, and supplies piped gas to industrial customers in the Witbank and Middelburg areas from their synthetic fuel plants at both Sasolburg and Secunda (ESMAP, 1995).

A section of the pipeline system of Petronet, a division of Transnet, has been diversified to transport natural gas. This section of Petronet's pipeline system is called Lilly line. It is 600 kilometres long, has capacity of 23 PJ/ at 59 bar and transports methane rich gas from Secunda to the Durban area. Currently, the Lilly Line is running at 50% capacity. However, the Lilly line has sufficient capacity to cope with the 'ramp up' from the Mozambique gas project (DME, 2005).

The current sectoral division of Sasol Gas' markets shows metals, which have 44% of the market share as the dominant sector (figure 3.5). Manufacturing is the smallest sector with a market share of 6%. The gas market is expected to grow from current 80 to 120 PJ/a in 2008, with Sasol's own consumption (43%) in the synfuel plants constituting the largest sector (Figure 3.6). From figure 3.1, natural gas accounts for 1.6% of the total primary energy consumption in South Africa. However, when the gas market grows to 120 PJ/a in 2008 (figure 3.6), natural gas will increase to about 4% of the total primary energy demand (Manyathi, 2004). It is expected that 43% of Sasol's gas will be used to supply the new facilities installed in the expansion at its factories in Secunda and for complete replacement of coal in Sasolburg. The metal industry is expected to account for 17% of the gas market. The smallest users of the gas will be the food and commercial industries that will collectively account for 3% of the natural gas market.

The expansion of the network of Sasol Gas to Durban South area has significant positive environmental implications because of the area's current high levels of pollution. Pollutants exceeding guidelines include sulphur, nitrous oxide and carbon monoxide (Ruffini, 2000a). It is envisaged that the substitution of current fuels with piped gas in some of the industrial operations in Durban South will lighten the environmental burden, particularly in the adjacent residential suburb of Merewent. This will enhance initiatives in Durban to minimise atmospheric emissions.

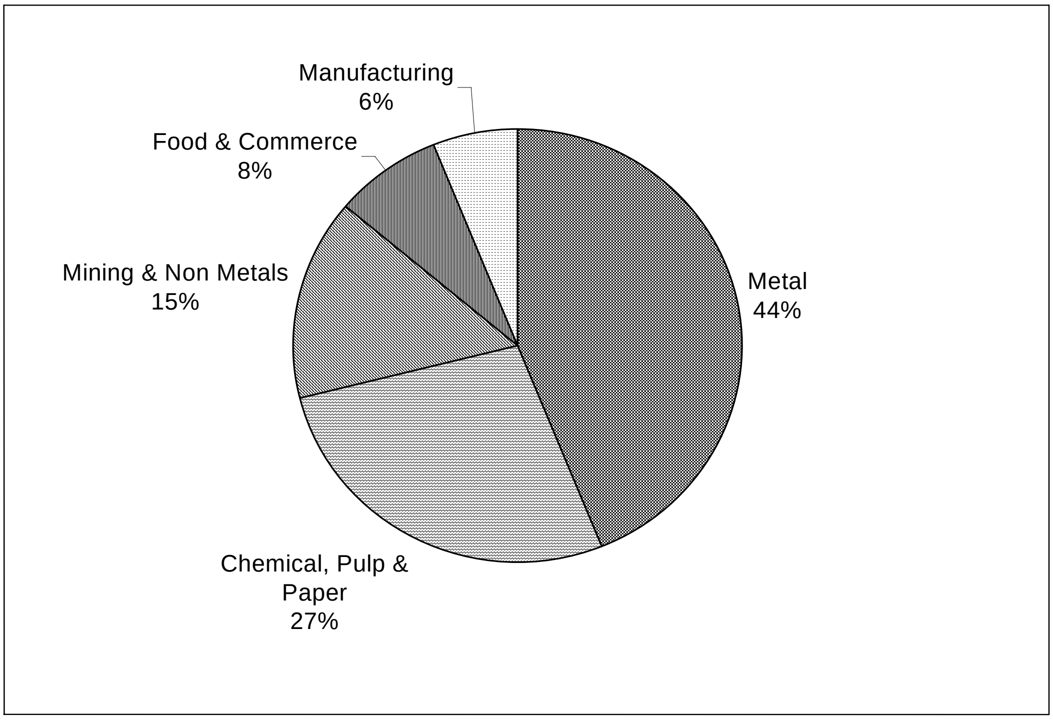



Figure 3.5 Sasol's current gas market.

Source: Gokul and Goapeng (2001).

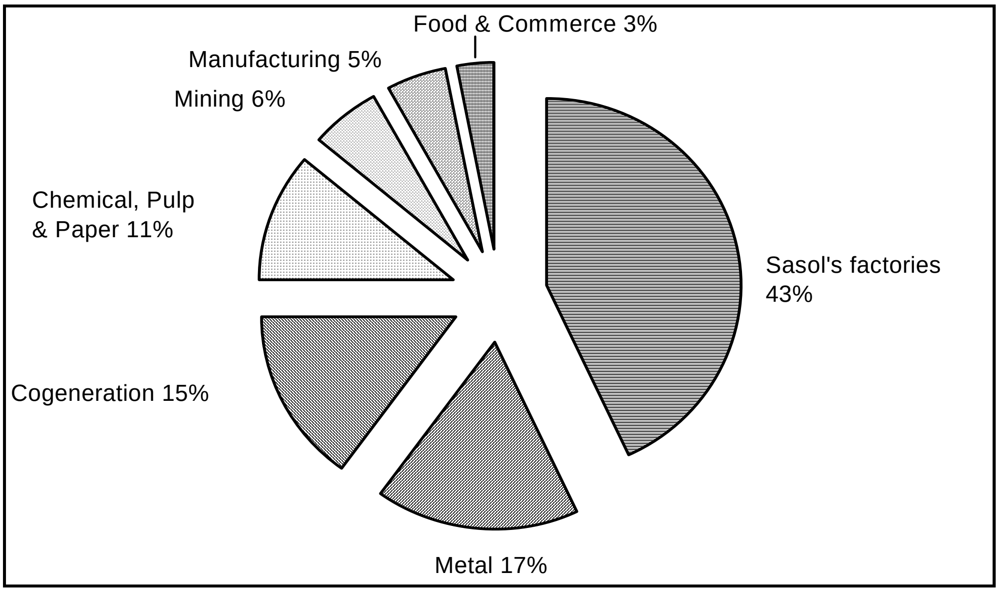



Figure 3.6 Sasol's 2008 gas markets.

Source: Gokul and Koapeng (2001).

The conversion to pipeline gas will produce the following and other fuel switches in industry:

- The replacement of the illuminating paraffin-fired steam boiler at Beacon Sweets and Chocolates at Jacobs, Durban, with gas.

- The substitution of piped gas for heavy fuel oil used to raise steam at the Mondi Paper factory in Merebank, Durban.
- The supply of online gas to Bayer Limited's chrome tanning salts plant at Merebank, Durban. The environmental standards achieved in this plant will enable the plant to be competitive on global markets because of the clean-burning energy source.
- The replacement of liquefied petroleum gas at the Bevcan and Divpac divisions of Crown Nampak in Durban with gas. This use of piped gas will improve efficiency in the curing and drying processes and allow gas storage tanks to be decommissioned.

Another significant milestone in the switch to piped gas was the delivery of gas to Alusaf's Bayside Smelter at Richards Bay in November 1996 (Ruffini, 2000b). In August 2000, Engen Oil Company began to convert to methane-rich gas to replace the oil previously used at its Durban refinery. This switch to a gas-fired refining process follows the outcry from residents of suburbs south of the harbour, near the Engen facility, concerning the level of sulphur dioxide emissions in the air (EIA, 2000b).

Sasol Gas supplies two types of coal-derived gas to the markets – high-energy methane rich and low-energy hydrogen rich gases. Every year, Sasol Gas supplies over 29 million gigajoules of pipeline gas to approximately 700 industrial customers. In all, 160,000 $m^3$ per hour of gas is delivered to end-users in the following industries: metal, chemical, paper and pulp, mining, food, commercial and manufacturing (Pedersen and Doyle, 2001).

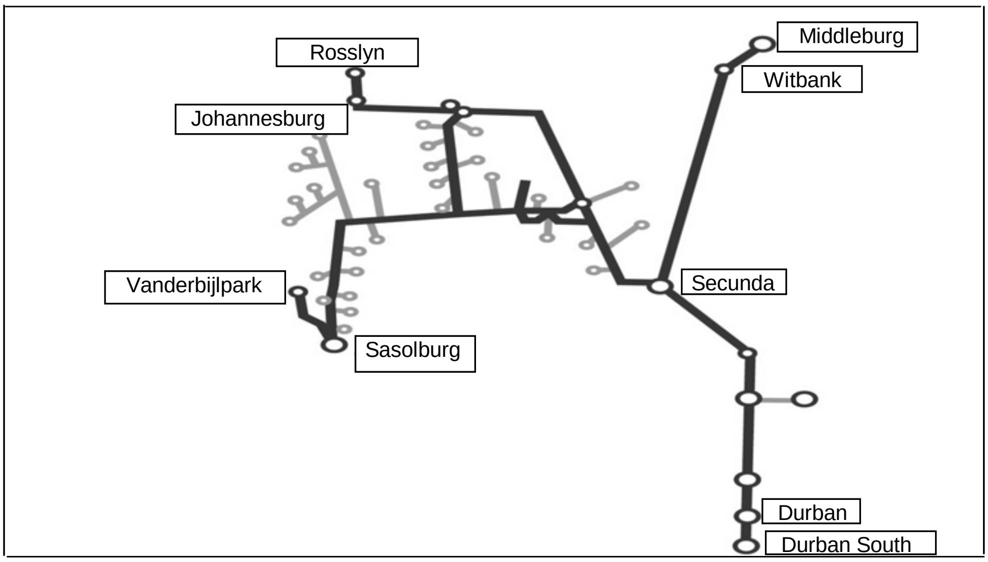



Figure 3.7 Schematic layout of Sasol's main gas pipeline network.

Source: Gokul and Koapeng (2001).

*Cape Gas*

Cape Gas, now defunct, had a distribution network consisting of domestic, commercial and industrial customers in the older suburbs of Cape Town. Originating as the Cape Town and District Gas, Light and Coke Company, established in the 1840s, Cape Gas distributed around 0.4 petajoules (PJ) of low energy (17.68 MJ/m$^3$) coal gas per annum. Cape Gas faced several problems including increasing rail tariffs, more labour demands and fewer prospects for increase in sales (TAU, 1995a). However, the possibility of piping natural gas from the Kudu and from the recently discovered Ibhubesi gas fields means that Cape Gas could be revived as a natural gas distributor. Cape Gas had a number of unsuccessful initiatives in the past. These included attempts to import liquefied natural gas (LNG) from Algeria – a project that was abandoned because of its high cost and public outcry about the construction of a terminal – and the unsuccessful attempt to take over the then Johannesburg gas department (now Egoli Gas). Furthermore, no agreement was reached when Cape Gas negotiated with PetroSA to purchase LNG from their onshore works (TAU, 1995a). These failures contributed to the demise of Cape Gas.

*Petronet*

Petronet, a subsidiary of Transnet and a South African parastatal, established in 1965, manages and operates over 3,000 kilometres of high pressure steel pipelines that transport petrol, jet fuel, diesel, crude oil and gas mainly in the eastern part of South Africa. Petroleum and gas products enter the pipeline at Durban, Sasolburg and Secunda, and subsequently transported to 18 delivery stations and depots in 5 provinces. The reconfiguration of Petronet's pipeline network in 1995 enabled it to transport gas (Mbendi, 2001). Petronet is responsible for providing the infrastructure for the transportation of bulk petroleum by pipeline in South Africa, including the supply of all the crude oil to the inland refinery, Natref. Furthermore, Petronet transports approximately 70% of refined products out of refineries in Natal and 87% of refined products out of Secunda (SANEA, 2001).

*Other*

Igas is a subsidiary of the Central Energy Fund (CEF) and acts as the official agent of the South African Government for the development of the hydrocarbon gas industry in South Africa, comprising liquefied natural gas (LNG) and petroleum gas (LPG) (CEF Group of Companies, 2002).

A small-scale gas operation, Port Elizabeth Gas, involves the distribution of a blend of liquefied petroleum gas and air to Port Elizabeth. This gas operation, converted from a small town gas system, is approximately the same size as the erstwhile Cape Gas (ESMAP, 1995).

### *3.3.3 Demand*

The delivery of services to previously disadvantaged communities and the move from a predominant supplier of raw materials to that of supplier of both secondary- and tertiary-processed materials are major priorities of the South African Government. These priorities lead to challenges in the demand for energy resources in South Africa. As urbanisation increases and standard of living improves in South Africa, there is a shift from demand for non-commercial and non-monetised to more commercial forms of energy – in particular electricity, petroleum products and gas. Furthermore, the Government's aim to offer universal access to electricity by the year 2010 (Mlambo-Ngcuka, 2001a) is bound to increase demand for both grid and non-grid energy resources.

Due to the above measures, the DME is developing an implementation strategy for the Electricity Basic Services Support Tariff (EBSST) (Mlambo-Ngcuka, 2001b), which involves the provision of a free monthly allocation of 40 MWh of electricity per household. This plan was initiated with pilot projects in nodal areas and metropolitan centres prior to a phased rollout in the 2002/2003-financial year (Mlambo-Ngcuka, 2001a).

In my view, the ongoing campaign to build over 3 million houses in South Africa has significantly increased energy demand. Under this scheme, the government built over 1 million homes between 1994 and 2000. Enhanced lifestyle sophistication, rapid urbanisation and technological development have produced corresponding increases in the use of appliances and equipment, most of which are powered by electrical energy, thus increasing demand for electricity.

In South Africa, there is relatively low demand for natural gas by end-users relative to other energy carriers (figure 3.8). However, it is envisaged that the commenced piping of natural gas from Mozambique to South Africa will increase the demand of this energy carrier by end-users.

*Total energy demand*

The South African economy may be categorised into six major sectors: industry, agriculture, commerce, residential, transport and other. The total sectoral energy demand for 2000 (figure 3.9) is 3,054 PJ.

At 42%, industry consumes more than twice the amount of energy demanded by any other sector in 2000. This relatively high-energy demand by that sector contributes significantly to the high-energy intensity of South Africa in global terms. The “non-energy” category refers to the use of coal, oil and wood to manufacture chemicals, plastics and paper.

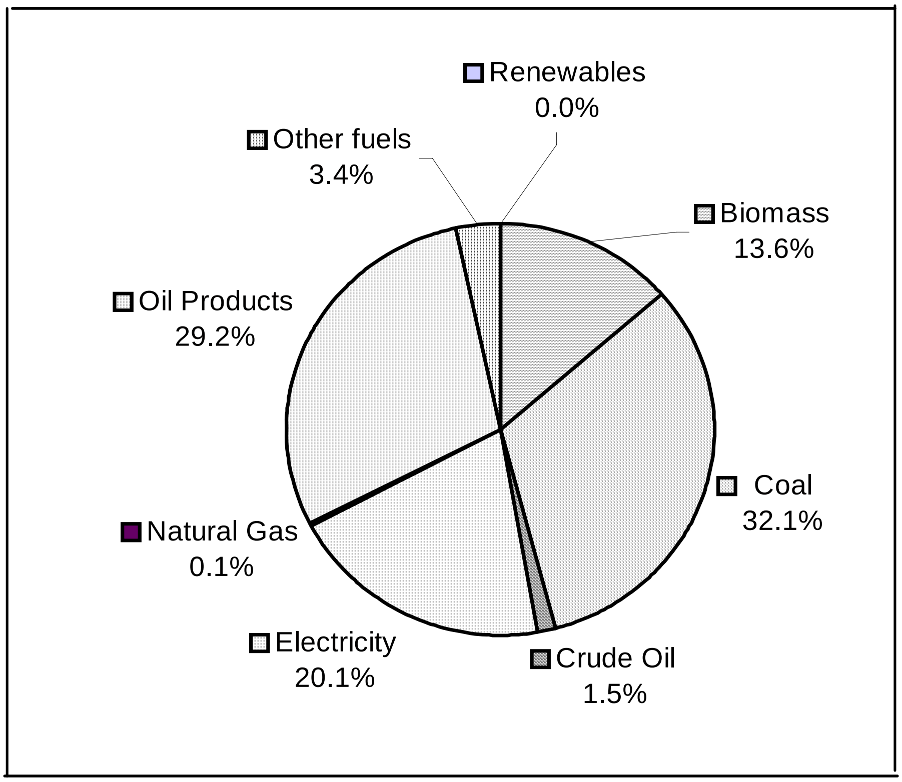



Figure 3.8 End-user energy demand in South Africa by fuel, 2000.

Source: ERI (2002a). The Energy Research Institute (ERI) is currently called Energy Research Centre (ERC).

*Industrial*

In the year 2000, industries in South Africa had a total fuel consumption of 1,325 (ERI, 2002b) (figure 3.10). The biggest consumers of energy in industry are iron and steel, and chemicals. The energy economy of South Africa is dominated by relatively cheap and abundant coal, and the macro-economy by energy-intensive industries such as: extraction of minerals, aluminium production and metallurgical processes, which collectively account for the relatively high consumption of energy in the industrial sector. Other factors that contribute to the high consumption of energy in industry are:

- The use of older and less efficient plant; equipment and appliances;
- Obsolete technology; and
- Poor efforts at improving energy efficiency and demand-side management in industry.

In my view, the fact that South Africa's electricity and coal – the biggest energy carriers used in industry – are among the cheapest in the World bestows a comparative advantage with respect to prices of South Africa's exports. However, the generation of electricity by coal and the coal combustion in industry lead to adverse environmental effects that in turn affect the economy.

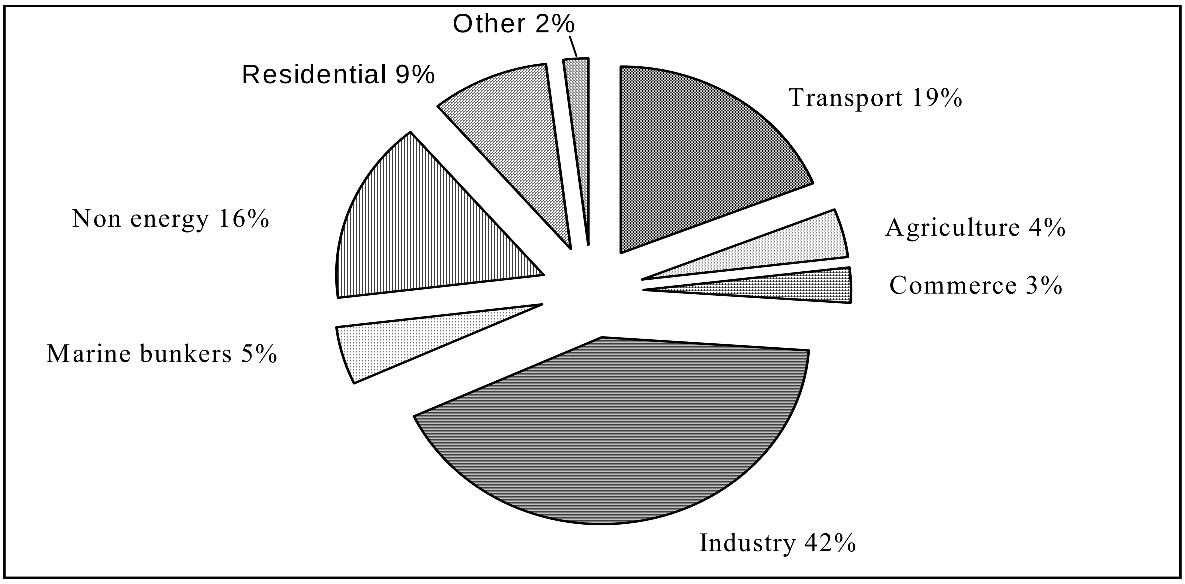



Figure 3.9 Sectoral final energy demand for South Africa in 2000
Source: ERI (2002a).

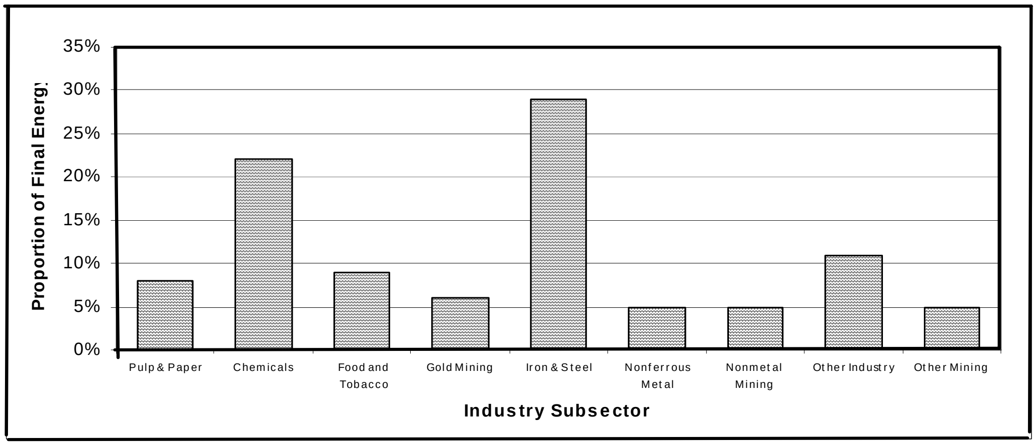



Figure 3.10 Final energy demand by industry sub-sector, 2000.

Source: ERI (2002a).

The industrial energy demand by fuel (figure 3.11) shows the dominance of coal and the non-utilisation of natural gas. In South Africa, electricity provides about a third of the energy used in industry. Due to the fact that about 92% of the electricity in South Africa is generated by pulverised fuel coal-fired power stations, there is appreciation of the importance of coal in its macro-economy.

*Commercial*

In the commercial sector – shops, offices, hotels, government, education, museums, hospital and financial institutions – energy is mainly used for space heating, air-conditioning and lighting. It is expected that the sector's relatively low energy consumption may increase as the sectoral economy is expected to grow faster than the GDP. However, improvement in building design, efficient lighting and plans to improve energy efficiency could contribute to savings in this sector (ERI, 2000c).

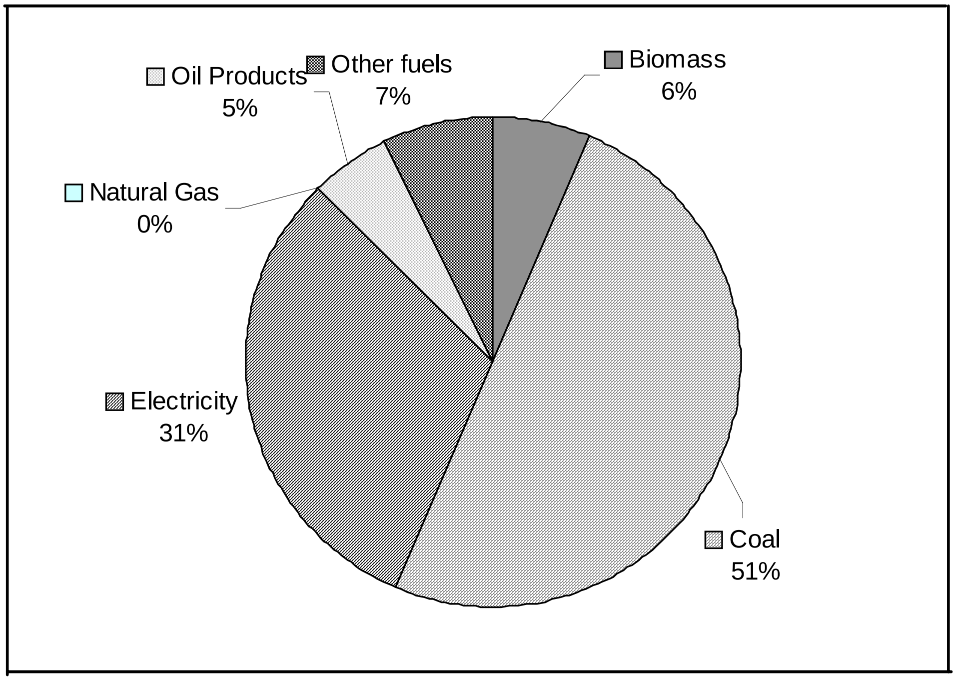



Figure 3.11 Industrial energy demand by fuel, 2000.
Source: ERI (2002a).

*Transport*

The transport sector plays a very important role in South Africa's macro-economy, moving people and goods and facilitating communications. Distances between places of work and residential areas and intercity travelling have a correlation with the demand for energy for transport. The social engineering of the apartheid regime often left the homes of the historically disadvantaged people over 15 kilometres from their places of work. This produced a need for motorised transport (Doppegieter *et al*., 1996), which translates into a demand for more transport fuel mainly in the form of petroleum. The transport sector's consumption of petroleum products increased between 1992 and 1997, reaching 74.6% of the final energy demand in 1997 (Cooper, 1998). The predominant fuels used in the transport sector (table 3.5) are petrol (gasoline) and diesel – accounting for 57.5% and 29.4% respectively of the energy for transport in 2000. Land passenger and land freight were the most dominant use of fuel and accounted for 66.8 and 22.3% respectively of the energy use by transport mode (figure 3.6). The transport sector used 577 PJ of energy or 19% of the final energy demand in South Africa in 2000.

**Table 3.5 Energy use for transport in 2000, by fuel type.**

| Fuel | Demand, PJ | Energy demand % |
|---|---|---|
| Aviation Gas | 1.1 | 0.2 |
| Coal | 0.6 | 0.1 |
| Diesel | 169.6 | 29.4 |
| Electricity | 12.4 | 2.1 |
| Fuel Oil | 0.0 | 0.0 |
| Jet fuel | 61.0 | 10.6 |
| LPG | 0.0 | 0.0 |
| Paraffin | 0.4 | 0.1 |
| Petrol | 331.9 | 57.5 |
| **Total** | **577.1** | **100.0** |

Source: ERI (2002a).

**Table 3.6 Energy use for transport in 2000, by transport mode.**

| Mode | Demand, PJ | Demand, % |
|---|---|---|
| Air transport | 62.1 | 10.8 |
| Land passenger | 385.6 | 66.8 |
| Land freight | 129.0 | 22.3 |
| Other | 0.4 | 0.1 |
| **Total** | **577.1** | **100.0** |

Source: ERI (2002a).

The strategic importance of South Africa's petroleum sector in the past led to much government regulation – a legacy that is yet to be changed. However, any future deregulation of the petroleum sector is dependent on the attainment of sustainable ownership of the petroleum industry by Black Economic Empowerment companies (DME, 1998).

Land passenger accounts for a comparatively high demand of 66.8% of the energy for transport by fuel in 2000 (table 3.6). The contribution of the transport sector to photochemical smog has grown 1.5 times within the last decade globally, and is responsible for 75% of the total emissions. The share of the transport sector's contribution to global warming potential has increased from less than 20 to more than 25% (European Network of Energy Agencies, 1998).

In my view, the following practices may lead to a reduction in the demand for oil by the transport sector in South Africa:

- Car pooling;
- The building of more sidewalks to encourage pedestrianisation;
- Improvement in the reliability and efficiency of public transport and high mass transport modes;
- The building of lanes for non-motorised transport;
- Changes in driving habits; and
- Improvements in road design.

In South Africa, emissions from the transport sector account for about 23% of carbon dioxide emissions from final energy use (IEA, 1997). On a full cycle basis, transport emissions are high due to the high percentage of gasoline and diesel produced by Sasol from coal. The manufacture of synthetic fuel from coal is about 33% efficient. Smog formation in South Africa is caused by the accumulation of large quantities of particulates in the atmosphere, as revealed by recent studies such as the Cape Town Brown Haze project (Wickling-Baird *et al.*, 1997) and the former DMEA's (now DME) particulate source apportionment studies. In Soweto, where background domestic emissions are known to be relatively high, traffic emissions account for between 25 and 47% of ambient particulate concentrations from winter to summer respectively (IEA, 1996).

The partial switching from leaded to unleaded fuel in South Africa has concomitant environmental implications. A relatively high proportion of the motorcars operating in South Africa are old and do not have catalytic converters. In addition, most new motorcars are not equipped with catalytic converters, thus use of unleaded gasoline may increase both pollution and engine wear. Future regulations may require the fitting of catalytic converters to all vehicles.

*Agriculture*

This thesis examined energy carriers used by both large-scale and small-scale farmers. The energy used for subsistence farming is included in domestic energy demand and relies mainly on muscle power – both human and animal. The agricultural sector (figure 3.9) uses 4% (107.1 PJ) of the final energy demand (ERI, 2002b).

The extensive use of traction and transport in large-scale farming is indicated by the fact that liquid fuels, particularly diesel, supply about three-quarters of the commercial agriculture's energy needs. Other activities such as lighting and refrigeration are powered by electricity, while diesel is used in pumping and for tasks involving removal of hulls of farm products (DME, 1998). The most consumed energy carrier (table 3.7) was diesel, accounting for 58.9 PJ (54.7%), followed by electricity at 21.2 PJ (19.7%).

**Table 3.7 Demand for energy carriers in the agriculture sector, 2000.**

| Energy carrier | Demand, PJ | Demand, % |
|---|---|---|
| Coal | 9.2 | 8.6 |
| Diesel | 58.9 | 54.7 |
| Electricity | 21.2 | 19.7 |
| Fuel Oil | 0.1 | 0.1 |
| LPG | 0.8 | 0.7 |
| Petrol | 3.6 | 3.3 |
| Paraffin | 3.0 | 2.8 |
| Biomass | 10.8 | 10.0 |
| **Total** | **107.6** | **100.0** |

Source: ERI (2002a).

Whilst the bulk of the agricultural produce for both local consumption and export is produced by commercial farmers, the role of traditional or subsistence farming in providing employment and livelihood for many rural black communities needs to be recognised through the provision of adequate energy. In general, large-scale farmers have easier access to energy supplies and technologies, but their main challenge is energy efficiency. On the other hand, subsistence farming lacks access to modern energy services, as well as rural schools, clinics, water, roads, communication, services and agricultural extension officers (DME, 1998). Energy efficiency and conservation are dominant factors that affect the cost of energy per unit output and return on investment.

Biomass constitutes about 11% of the energy demand in the agricultural sector (table 3.7) and provides most of the energy requirements of the rural communities in South Africa. Not much attention has been paid to this non-commercial source of energy, which is the dominant energy carrier in rural areas. The unbridled harvesting of trees for woodfuel by mainly women and children contributes to environmental degradation. The potential for agricultural, forestry and agro-forestry products, by-products and residues as sources of modern biofuels needs to be explored, taking into account the fact that South Africa is water-stressed.

*Domestic*

There is great variety in the use of energy carriers in households in urban and, to a lesser extent, in rural areas. Urban households have access to and can afford commercial energy carriers like electricity, liquefied petroleum gas, illuminating paraffin, low-smoke fuels and sometimes solar panels. However, rural households do not always have such access and rely on dung, crop residues, woodfuel, batteries, candles and illuminating paraffin. The price of commercial energy carriers, even in places where they are available often makes them not viable for rural households where communities often spend a higher proportion of their incomes on satisfying their energy needs than their urban counterparts.

Again, the development of a modern industrial urban society at the expense of rural communities under the apartheid government affected the supply of energy services to the rural households. Whereas government aims to provide universal access to electricity in South Africa by the year 2010 (Mlambo-Ngcuka, 2001a), the application of electricity in the rural and poor households is constrained by the high cost of electrical appliances, and their relatively high operating cost for thermal applications like cooking and space heating (DME, 1998).

The household energy consumption for 2000 amounted to 284.2 PJ, which was approximately 9% (table 3.8) of the total energy used during the year. Electricity contributed less than 40% of household energy consumption whilst wood and coal constituted 30% and 20% respectively. The relatively high incomes of the urban dwellers mean that they can afford to buy electrical appliances, thus increasing the demand for electricity. As urbanisation increases and income levels including access to information technology of the historically disadvantaged persons increase, the demand for electricity is expected to increase as well. The relatively high demand for wood is a reflection of the fact that wood is the most common energy carrier in the rural areas of South Africa. Because thermal energy consumption constituted 82% (233PJ) of the total household energy consumption for 2000, there is a low demand for solar home systems (SHS), which do not provide energy for thermal applications (figure 3.9). However, as government increasingly subsidises the use of non-grid electricity and remote area power supply schemes are introduced, the use of renewable energy would be increased.

**Table 3.8 Residential energy by fuel, 2000.**

| Energy carrier | Demand, PJ | Demand, % |
|---|---|---|
| Coal | 58.0 | 20.4 |
| Electricity | 107.0 | 37.6 |
| LPG | 4.7 | 1.7 |
| Natural Gas | 0.0 | 0.0 |
| Paraffin | 25.3 | 8.9 |
| Solar | 0.2 | 0.1 |
| Vegetable Wastes | 4.3 | 1.5 |
| Wood | 84.7 | 29.8 |
| **Total** | **284.2** | **100.0** |

Source: ERI (2002a).

**Table 3.9 Residential energy by activity, 2000.**

| Activity | Demand, PJ | Demand, % |
|---|---|---|
| Cooking | 113.4 | 39.9 |
| Lighting | 15.4 | 5.4 |
| Other | 35.1 | 12.4 |
| Space heating | 90.8 | 31.9 |
| Water heating | 29.5 | 10.4 |
| **Total** | **284.2** | **100.0** |

Source: ERI (2002a).

Electricity consumption in the domestic sector – about 16% of total electricity consumption – was relatively stable prior to 1994. However, this figure has increased thereafter, due to the accelerated programme of residential electrification (ERI, 2002b).

**Table 3.10 Percentage of households electrified per province at the end of 2003.**

| Province/Country | Rural | Urban | Total (urban and rural) |
|---|---|---|---|
| Eastern Cape | 40.7 | 99.6 | 63.5 |
| Free State | 54.2 | 88.4 | 77.6 |
| Gauteng | 25.9 | 67.2 | 64.9 |
| KwaZulu-Natal | 44.5 | 71.6 | 59.6 |
| Mpumalanga | 70.9 | 86.7 | 77.5 |
| North West | 57.8 | 100.0 | 74.6 |
| Northern Cape | 79.1 | 96.1 | 89.8 |
| Limpopo | 64.8 | 97.5 | 69.4 |
| Western Cape | 65.4 | 85.5 | 83.2 |
| South Africa | 53.7 | 79.1 | 69.0 |

Source: NER (2003).

As seen in table 3.10, the Northern Cape and Western Cape have the highest percentage of electrified households. This may be due to a relatively high rate of urbanisation. There is significant imbalance in the percentage of electrified households in the rural and urban areas of the provinces of the Eastern Cape and North West due to the relative remoteness of communities from the national grid. Trends in the electrification of both urban and rural areas of South Africa from 1995 to 2002 are depicted by figure 3.12. The percentage of urban households electrified for the period has shown an increasing and decreasing trend. For rural areas, there is a persistent increase in percentage of electrified households from 1995 to 2002. The total percentage of electrified households in South Africa followed the same trend as that of the rural households over the period 1995 to 2002. The number of electrified households in South Africa rose from 50% by the end of 1995 to 68% by the end of 2002.

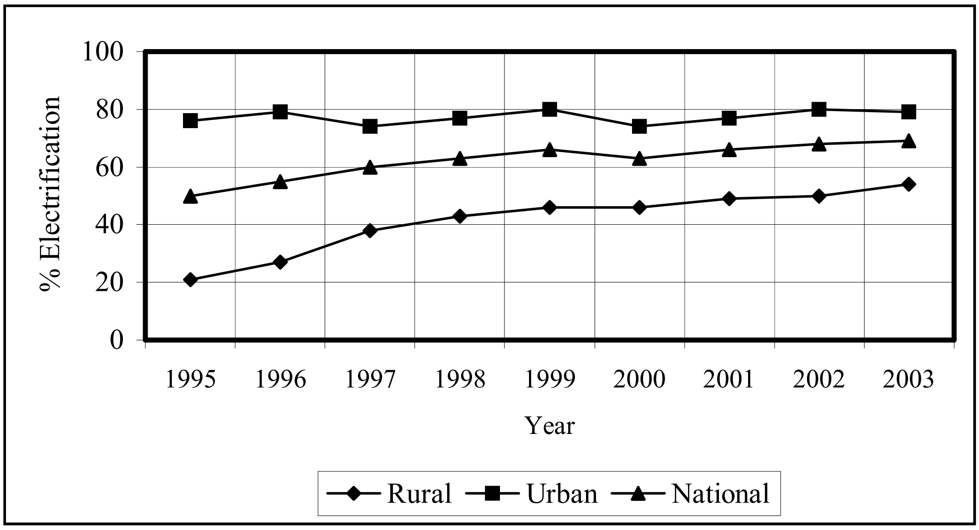



Figure 3.12 Trends in electrification of households in urban and rural areas, 1995-2003. Source: NER (2003).

**Table 3.11 Pollutants from domestic fuels.**

| Pollutant (Kg/TJ delivered) | Coal | Wood | Natural gas |
|---|---|---|---|
| Sulphur dioxide | 2,200 | 30 | Negligible |
| Total and reparable suspended particulates | 280 | 2,700 | 0.5 |
| Nitrogen oxides | 460 | 100 | 10 |
| Hydrocarbons | 2,200 | 6,800 | 5 |
| Carbon monoxide | 27,000 | 17,000 | 250 |

Source: ERI (2002a).

It is revealed that natural gas is the most environmentally benign with respect to total and respirable suspended particles, nitrogen oxides, hydrocarbons and carbon monoxide of the three energy carriers (table 3.11). Research conducted by the CSIR and the Medical Research Council in 1993 indicated that an estimated 24 million people in South Africa were exposed to levels of air pollution comparable to those experienced in the London Fog of 1952, which resulted in a considerable number of deaths. The research was conducted on coal-burning households in Sebokeng and farm workers that burnt coal in the former Transvaal. The focus of the research was on the risk factors for exposure to respiratory illnesses in children aged 8-12 years who were exposed to air pollution from these traditional energy sources (Terblanche *et al.,* 1993). It emerged that for children living in coal- and wood-burning households, there was an increased risk of 290% for developing upper respiratory illnesses and 420% for developing lower respiratory illnesses during summer and winter (Terblanche *et al*., 1992).

### 3.4 Energy efficiency

South Africa is richly endowed with deposits of minerals and coal. Historically, the economic development of South Africa has focused on the extraction and processing of these natural resources. This has led to the development of a national economy with relatively high dependence on energy as its driving force – resulting in the mainstay of its industries being those associated with energy-intensive activities like iron and steel production.

In recent years, energy efficiency has considerably gained in importance and has been recognised as one of the most cost-effective ways of meeting the demands of sustainable development (DME, 2004).

The White Paper on Energy Policy of 1998 gives a mandate to the DME to support energy efficiency through various means (DME, 1998). Despite South African Government's limited capacity to undertake energy efficiency programmes, the DME will finalise and consolidate considerations to ensure proper leadership in the sector. The DME has crafted an "Energy Efficiency Strategy of the Republic of South Africa" to contribute towards affordable energy for all, and to reduce the effects of energy usage upon human health and the environment.

The strategy sets a national target for energy efficiency improvement of 12% by the year 2015 – based on forecast of national energy demand at that time, and therefore allows for current expectations of growth in the economy. In addition to the national target, the strategy sets up sectoral targets for final energy demand reduction for industry, commercial and public building, residential and transport (DME, 2004).

### 3.5 Interventions by Government

Since 1994, the South African Government intervened in the energy sector (appendix B) a number of times in the supply of energy resources and services to previously disadvantaged communities, the bulk of who reside in rural communities and townships. According to the energy policy, the South African Government is committed to the promotion of access to affordable and sustainable energy services for disadvantaged households, small farms, small businesses, schools and clinics in its rural areas and a wide range of other community establishments. The Government's interventionist stance is supported by its primary role as a policy making and a regulatory body, as well as its secondary role as a facilitator of the supply of energy services (DME, 1998).

### 3.6 Discussion

The relatively huge accumulation of discard coal in South Africa adds to the environmental burden of mining coal. This burden poses threats in terms of contamination of surface and underground water, occupation of land that could otherwise be put to beneficial uses and spontaneous combustion. Spontaneous combustion can cause bush fires, leading to emissions of noxious and greenhouse gases.

As South Africa endeavours to attain universal access to electricity by the year 2010, the proportion of electricity in the final energy demand is likely to increase. By contrast, the proportion of demand for biomass is likely to decrease, as urbanisation increases. A programme of accelerated residential electrification has increased the number of households electrified from a relatively low of 34% in 1994 to a comparatively high of 68% at the end of 2002. The programme of accelerated residential electrification has increased demand for peak power, putting pressure on the electricity generation sector.

The increasing trend in the percentage of electrified households, particularly of low-income households and informal settlements in South Africa, is an indication of the progress made by the Government's accelerated residential electrification drive, since the attainment of majority rule.

Despite the comparative abundance of renewable energy resources in South Africa, particularly solar, they have been underutilised, except biomass, which provides the bulk of the energy used by rural communities. However, under Eskom's "South African Bulk Renewable Energy for Generation" programme, renewable energy carriers like solar and wind are increasingly being harnessed for bulk generation of electricity on pilot basis.

The paucity of the contribution by natural gas to end-user energy demand in South Africa is manifest by the fact that in 2000, natural gas accounted for 0.1% (figure 3.8) of this category. Additionally, natural gas was not used by industry in 2000; hence it's nil contribution to industrial energy demand in that year (figure 3.11). However, with the current piping of natural gas from the Temane gas fields in Mozambique to Secunda, South Africa, this situation will change as this gas is earmarked mainly for industrial and commercial use. In fact, as Sasol ramps up the transmission of natural gas to South Africa from 80 PJ/annum to 120 PJ/annum in

2008 (figure 3.6), more gas will be used for industrial and commercial applications. It is envisaged that if natural gas were piped to South Africa from the Kudu natural gas field, and the Ibhubesi natural gas resources are found in commercial quantities, the industrial, commercial and domestic application of this energy carrier would increase further.

# 4. GROWING THE NATURAL GAS INDUSTRY IN SOUTH AFRICA

Chapter 4 examines proven natural gas reserves, markets, distribution and enabling environment that can facilitate the growth of the natural gas industry in South Africa in a sustainable manner. This chapter provides an indication of the potential for long term substitution of coal with natural gas, including opportunities for using natural gas in spatial development initiatives and natural gas reticulation as a catalyst for rural development. Furthermore, this chapter presents environmental management, safety and health issues relating to the natural gas industry, and discusses the potential for acquiring carbon dioxide credits using piped gas from Mozambique.

## 4.1 Introduction

Although growth of an industry is based primarily on supply and demand, the rollout of infrastructure that is pertinent to the operations of the industry plays a vital role in developing a market. The massive coal infrastructure established in South Africa resulted from its determination to be self sufficient in energy resources, thereby partially negating the adverse impacts that the mandatory economic sanctions would have inflicted on its macro-economy. Similarly, the global drive towards cleaner forms of energy, distributed generation, the diversification of energy resources and convenience of utilisation provide motivation for South Africa to develop alternative energy carriers such as natural gas and renewables. For sustainable growth in the natural gas industry, there have to be anchor projects in which the triple-bottom-line elements are mutually balanced and managed.

## 4.2 Utilisation of pipeline natural gas

South Africa has had a natural gas industry since 1993, when PetroSA’s gas-to-liquid fuels refinery at Mossel Bay (formerly Mossgas) began operations (Alexander’s Gas and Oil Connections, 2001). The industrial use of natural gas, particularly for transformation to liquid fuels in South Africa is relatively recent, compared to the use of other energy carriers such as coal and electricity. However, liquefied petroleum gas in the form of bottled gas has long been used in South Africa for industrial, commercial and domestic applications. It is envisaged that with appropriate rollout of reticulation systems and effective marketing efforts, use of natural gas can be increased across all sectors of South Africa’s economy now that the Temane-Secunda pipeline has been operationalised. Increased use of natural gas depends on how it performs in inter-fuel competition, particularly its ability to replace some of the current coal applications. Table 4.1 provides potential applications for which pipeline natural gas can be utilised in South Africa.

**Table 4.1 Applications and products of pipeline gas.**

| Applications | End products through the use of pipeline gas |
|---|---|
| Heat treatment | Steel |
| Forging | Building bricks |
| Melting and casting | Foods |
| Paint drying | Sheet and moulded glass |
| Galvanising | Fertilisers |
| Baking | Ceramics |
| Steam generation | Non-ferrous metals |
| Power generation | Refractories |
| | Foundry products |
| | Chemicals |
| | Paint |
| | Paper |

Source: M. Koapeng, personal communication, 12 May 2003

### 4.3 Growth nodes

South Africa has identified several areas as growth nodes for spatial development initiatives (SDIs). Using SDIs, the government is committed to fostering sustainable industrial development in places where the highest incidences of poverty and unemployment occur. The SDI programme consists of eleven local SDIs, four industrial development zones (IDZs) and a second generation SDI. The SDIs are intended to provide extensive support in places where socio-economic conditions demand concentrated government assistance, and where there is existence of inherent economic potential. Some of these initiatives involve development of economic processing zones (EPZs) and transboundary corridors into vibrant economic centres, and revamping of economically depressed areas through investments. The SDIs (table 4.2) – based on public-private partnerships – can serve as growth nodes for the natural gas industry through supply of relatively cleaner energy to power development. South Africa's SDIs are at different stages of development, but there is much industrial and commercial activities taking place. The goal of the three tiers of government – national, provincial and local – for the SDIs is to ensure the acceleration of investments and the maximisation of synergies between different types of investments (International Marketing Council of South Africa, 2002).

**Table 4.2 Sectoral spatial development initiatives in South Africa.**

| Sectors | Spatial Development Initiatives | Geographic area | Significant milestones/projects |
|---|---|---|---|
| Industrial | ▪ KwaZulu-Natal (KZN)<br><br>▪ Fish River | ▪ KZN - South Eastern part of South Africa. It involves projects at the Durban and Richards Bay ports.<br>▪ Fish River – Coastal areas between Port Elizabeth and East London. | ▪ By 1998, the Fish River SDI had attracted 9 new commercial operations creating 500 jobs;<br>▪ R156 million was invested; and<br>▪ Projects being considered include the auto-industry, supplier development, timber processing and forestry. |
| Agro-tourism | ▪ Lubombo<br><br>▪ Wild Coast | ▪ Lubombo-eastern Swaziland, southern Mozambique and northern part of KZN.<br>▪ Wild Coast – Outside East London to Port Edward in KZN. | ▪ A major road has been built through the SDI linking the N2 Highway in South Africa to Maputo and the upgrading of secondary roads.<br>▪ Projects are based on agro-tourism. 11 tourism-related investments have been made. 7 forestry and 14 agricultural projects are under consideration. |
| Sectoral Mix<br>▪ Transport; and<br>▪ Industrial. | Maputo Development Corridor | ▪ Witbank in South Africa through Nelspruit to Maputo in Mozambique | Key infrastructure include:<br>▪ N4 toll road;<br>▪ Upgraded railway line from Ressano Garcia to Maputo;<br>▪ Upgraded port at Maputo; and<br>▪ Upgraded telecommunications. |

| Sectors | Spatial Development Initiatives | Geographic area | Significant milestones/projects |
|---|---|---|---|
| Industrial Development Zone (IDZs) | ▪ Coega/East London.<br>▪ Saldanha. | ▪ Coega/East London - eastern Seabord of South Africa.<br>▪ Saldanha – part of the West Coast Initiative (from Atlantis to the north of Vredendal). | ▪ Coega/East London – first purpose-built IDZ; and<br>▪ Projects earmarked include zinc refinery, steel mill, fertilizer, cement, electrolytic manganese dioxide (for batteries), aluminium smelter and petrochemical plants. |
| ▪ Industry,<br>▪ Information technology<br>▪ Telecom-munications and<br>▪ Cultural activities. | Gauteng Special Economic Zone (SEZ) | ▪ Gauteng Province | ▪ Second Generation SDIs; and<br>▪ Blue IQ Initiative. |

Source: IMCSA (Undated).

## 4.4 Gas resources and markets

It is noteworthy that some of the SDIs are in close proximity to the natural gas resources and markets (figure 4.1). For instance, the SDI in KZN can be supplied with natural gas by conversion of the current coal gas pipeline from Secunda to Durban South through Richards Bay. Additionally, projects in the Maputo Development Corridor can be supplied with energy from natural gas through the existing Secunda-Middelburg coal gas pipeline after conversion.

Two scenarios of supply of natural gas for industrial and commercial projects exist for the Wild Coast, Fish River and Coega/East London SDIs – the extension of the Secunda-Durban South pipeline to Coega near Port Elizabeth, or the piping of natural gas from the Kudu and/or Ibhubesi gas fields (if reserves were proven in commercial quantities) in future, to East London depending on cost-effectiveness and timing. However, gas from Kudu and Ibhubesi is expected to be piped in 2007/8 to markets in the Cape. Projects in the Saldanha Industrial Development Zone (IDZ), the West Coast and PetroSA's gas-to-liquid fuel (GTL) refinery at Mossel Bay can be powered with natural gas from Kudu, Ibhubesi and other potential resources on the West coast. To minimise losses in transmitting power from Mpumalanga to the Western Cape including the costs involved in transporting coal thereof, a combined-cycle gas turbine power stations could be built in the Mossel Bay and Cape Town areas.

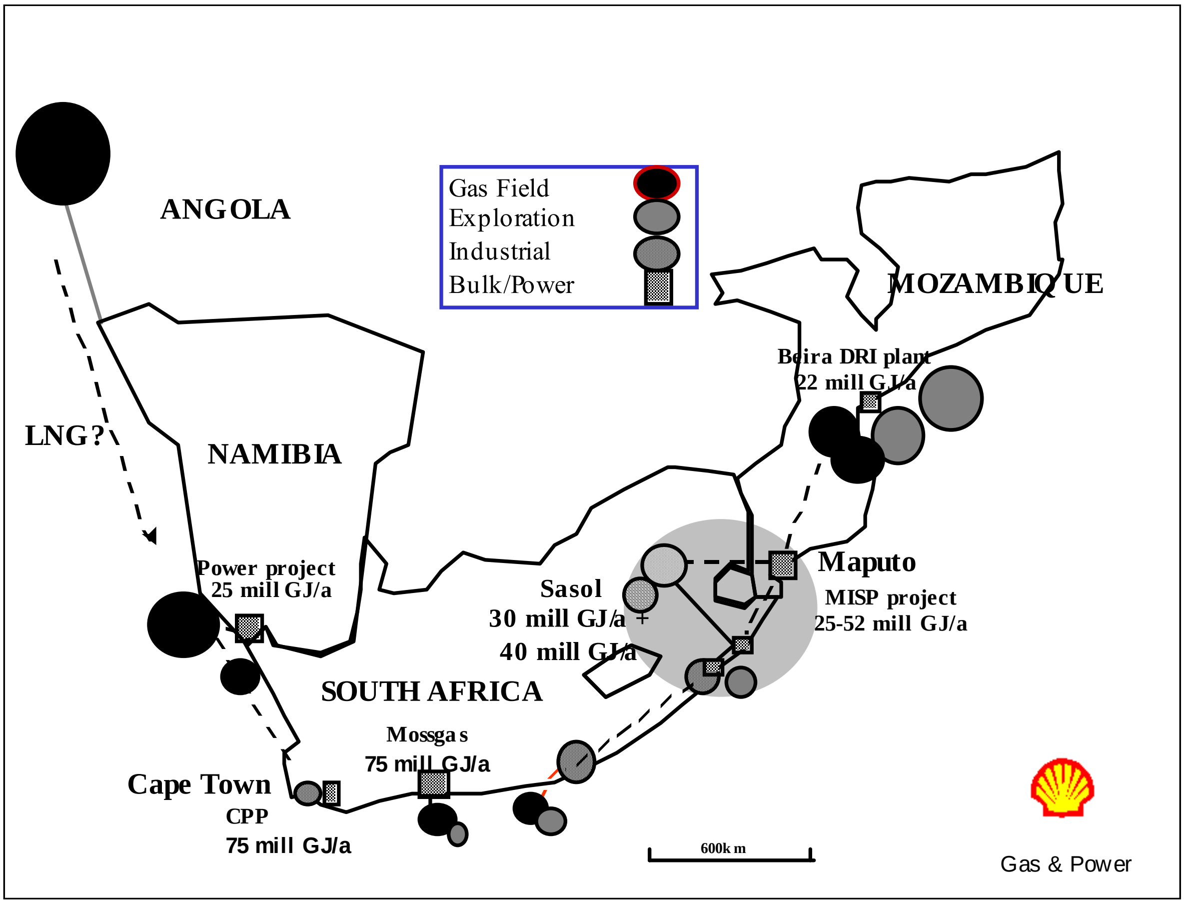



Figure 4.1 Gas resources and markets.

Source: Horvei (2001)

More power will be required in the Eastern Cape Province, with the ongoing development of infrastructure and industrial complexes at Coega near Port Elizabeth. However, there is no significant source of power in the province, apart from the marginal Port Rex (East London) peaking plant, which has a capacity of 171 MW. In future, natural gas could be used to generate power for supplying the growing industrial complex and infrastructure in the province.

It would be cost effective to introduce natural gas to the western part of South Africa (Western Cape and southern Cape), which does not have access to significant conventional energy resources. There are concentrations of coal reserves in the eastern part of South Africa

(Mpumalanga, Free State and KwaZulu-Natal). Prior to the arrival of natural gas from Mozambique, there was already a coal gas market in the eastern part of South Africa supplied by Sasol Gas. According to the Gas Infra-Structure Plan (DME, 2005), South Africa has strategically been partitioned into eastern and western parts for the purposes of the natural gas market, and takes into account the location of the gas reserves, markets and the need to minimise the cost of putting gas infrastructure in place. The potential to develop a gas market in the western part of South Africa requires closer examination of prospective anchor projects. The following are possible anchor projects that would support gas markets in the Western Cape and southern Cape:

*Western Cape*

- A minerals beneficiation hot briquette iron merchant supply in Saldanha, Western Cape;
- The establishment of a gas-to-liquid fuels (GTL) refinery at Saldanha, Western Cape;
- The building of an 800-MW combined-cycle gas turbine (CCGT) power station at Saldanha, Western Cape; and
- The construction of a 1,200-2,000 MW CCGT power station in Cape Town.

*Southern Cape*

- The supply of piped natural gas to the PetroSA refinery at Mossel Bay for GTL transformation;
- Construction of a 800 MW CCGT power station at Mossel Bay; and
- The supply of natural gas to the Coega Development Project for various industrial applications (Ibhubesi Gas, 2003).

Under the Special Economic Zone (SEZ), the Gauteng Provincial Government has earmarked R1.7 billion towards the advancement of technology, transport, high-value added manufacturing and tourism. By contrast, Gauteng has a large number of projects which can potentially use gas and which are already identified by the Blue IQ program (GEDA, 2002a). These projects are:

- The Vlakfontein Gold Mine with estimated gold reserves of 55 tons, which is scheduled for exploitation by a joint venture involving a South African company and a foreign company;

- The expansion of production of a small company manufacturing paint, printing ink and dyes to cope with increased demand from both local and foreign patrons. A joint venture partnership is sought for this expansion;
- A joint venture being sought to manufacture granular chemical fertilizers using 80% local and 20% imported raw materials. About 80% of the fertilizers are to be sold locally; and
- Seeking a joint venture to establish an atomised aluminium powder production factory for the explosives industry (GEDA, 2002b).

One requirement for sustaining the natural gas industry is an ample supply of easily accessible gas. Exploratory activities for natural gas, particularly off the western coast of South Africa, augur well for the future development of the natural gas industry in western part of the country. It is noteworthy that after completing a study of the west Coast, Sasol Petroleum applied for a full exploration sublease - implying that the initial investigation produced promising results (Marrs, 2002).

If the natural gas reserves at Ibhubesi, the resources off Saldanha Bay and elsewhere on the West Coast were found to be in commercial quantities, a significant contribution would be made to the growth of the industry, particularly in the western part of South Africa. The South African Cabinet has decided to undertake a multimillion Rand deep-sea study that would support an application to the UN to extend its continental shelf. This study would also contribute to the growth of the industry it unearthed more natural gas resources (Kahn, 2002).

## 4.5 Development of natural gas transmission pipelines in South Africa

A number of transmission pipelines are to be built in South Africa to satisfy the anticipated market developments. They are categorised into four main phases, each with a number of sub-phases. These phases are shown in figure 4.2 and described in table 4.3. Phase 1 was completed in December 2003. Test gas from this pipeline landed in South Africa in February 2004 (Lourens, 2004). If the other phases are completed in future, a fully integrated pipeline network will link major economic centres with upstream supplies of gas, enabling the transportation of gas from any inlet flange in the system to any outlet flange where a market exists (DME, 2005).

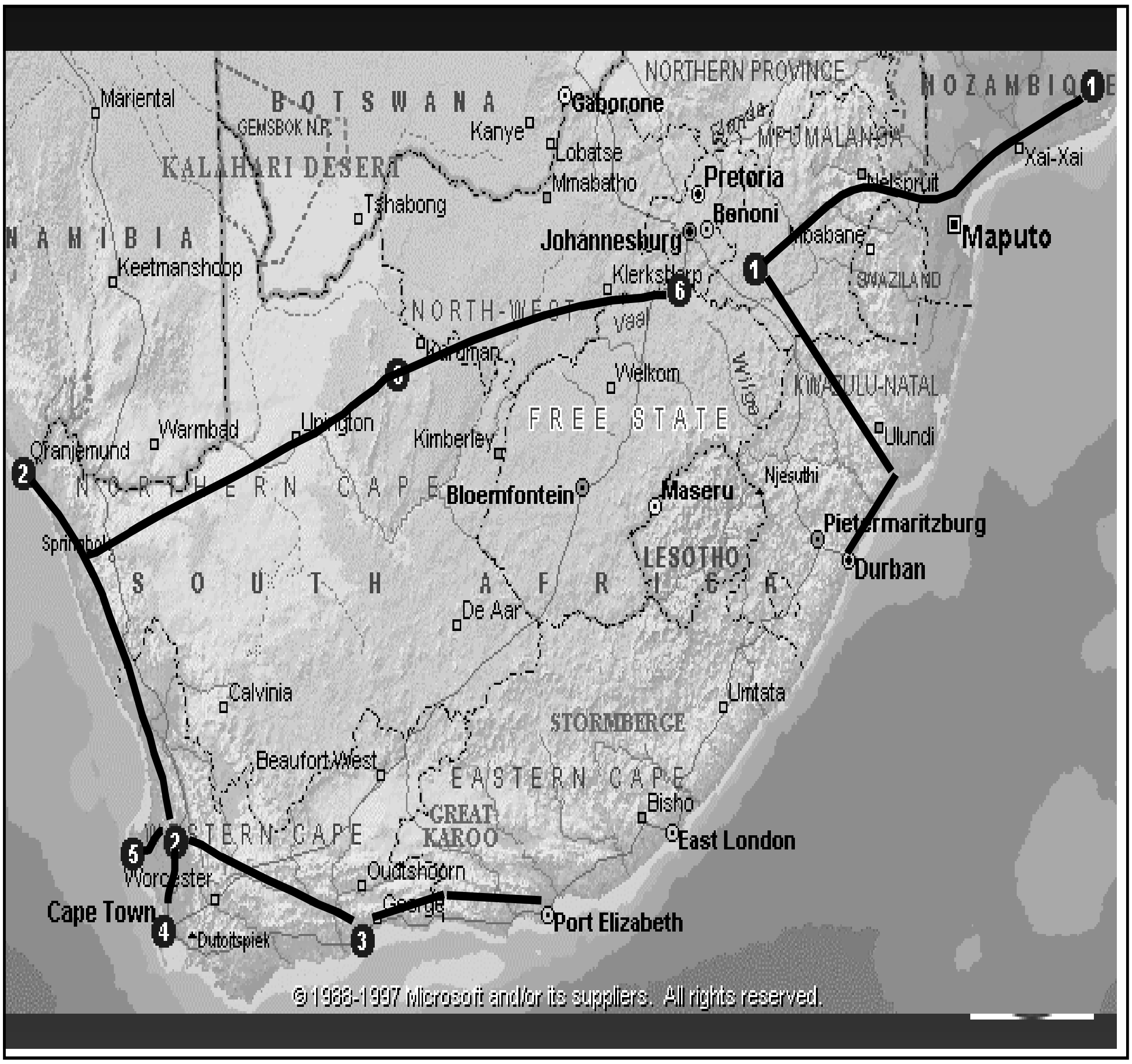



Figure 4.2 Natural gas transmission pipelines – phases.

Source: Crompton (2001).

**Table 4.3 Phases: Projected development of natural gas infrastructure, South Africa.**

| Phase | Description | Reference to figure 4.2 and Specifications | Year of completion |
|---|---|---|---|
| 1 | The Temane-Secunda Transmission Pipeline[1] | Line 1-1<br>Diameter of pipe – 58.4cm,<br>Length – 949km,<br>Cost – US$590m. | 2004 |
| 2 | The Kudu-Western Cape Transmission Pipeline | Line 2-2<br>Diameter of pipe – 58.4cm,<br>Length – 630km,<br>Cost – US$360m. | Not yet started |
| 3 | The Northern Cape-Gauteng Transmission Pipeline | Line 6-6<br>Diameter of pipe – 66.0cm,<br>Length – 1151km,<br>Cost – US$600m. | Not yet started |
| 4 | The Coastal Transmission Pipeline | Line 2-3<br>Diameter of pipe – 50.8cm,<br>Length – 350km,<br>Cost – US$283m. | Not yet started |

Source: Adapted from Crompton (2001).

Legend: [1]The Secunda-Temane transmission pipeline was completed by Sasol in December 2003. The actual length of the pipeline is 865 km with a cost of US$1.2 billion including a central processing facility in Temane and ancillary projects (Roux, 2004).

## 4.6 Prospects for carbon dioxide credits from piped Temane gas

The Central Energy Fund (CEF) and World Bank have jointly studied the possibility of supplying natural gas from the Temane-Secunda gas transmission pipeline to low-income areas, particularly in the Mpumalanga Province. The study assessed the possibility of procuring carbon dioxide credits from the abatement in emissions of greenhouse gases (GHG) by switching from the use of more carbon-intensive fuels to natural gas. The study revealed that the demand for commercial energy on the Lowveld was marginal, whilst the relatively industrialised Highveld consumed much more energy. Thus, the procurement of carbon dioxide credits could be pursued for gas projects in the Highveld (COWI *et al*., 2002b).

As indicated in Appendix C, the combustion of natural gas has lower emission of GHG than the coal combustion, making switching from coal to natural gas a potential project for procurement of carbon dioxide credits under the CDM. Thus, the piping of natural gas to South Africa through the Temane-Secunda pipeline starting from February 2004 can offer several different types of GHG emission reduction activities, hence the procurement of certified emission reduction units. These are associated with:

- The Temane-Secunda pipeline;
- Small projects along the Temane-Secunda pipeline; and
- Fuel switching at the Sasol Synthetic Fuels plant (COWI *et al.*, 2002b).

### *4.6.1 The Temane-Secunda pipeline*

The Temane-Secunda natural gas pipeline could entitle Sasol to carbon dioxide credits, as it promotes projects and industries that use natural gas so reducing the emission of GHG, as opposed to using more carbon-intensive energy carriers. Gas pipelines enable the capture and economic utilisation of natural gas that would otherwise have been flared or vented, thus minimising the emission of methane (COWI *et al*., 2002b).

### *4.6.2 Small projects along Temane-Secunda pipeline*

Natural gas projects could be developed along swathes of the pipeline, including rural electrification, household energy consumption changes, industrial power generation and other industrial uses (for kilns, boilers and other applications). Natural gas could displace the use of other forms of energy carriers (coal, diesel, woodfuel or paraffin) that can lead to the reduction in the anthropogenic emission of GHG. Thus, the small projects are likely to qualify for carbon dioxide credits under the CDM (COWI *et al*, 2002b).

### *4.6.3 Fuel switching at Sasol's Synthetic Fuel plant*

Natural gas will replace coal at Sasol's Synthetic Fuels plant in Secunda, in future expansion, thus reducing the emission of GHG from it (COWI *et al*., 2002b) and will completely replace coal at the Sasolburg plant where the feeder Sigma Colliery is virtually exhausted.

The above three projects may be eligible for the award of certified emission reduction units, because the resulting emissions are lower than would have occurred in the absence of the fuel switching. However, my view is that in each of these cases, a set of criteria on additionality and sustainable development need to be satisfied under the scrutiny of internationally certified organisations – designated operational entities – and the South African Designated National Authority of the CDM.

### 4.7 South African coal lifespan scenario

According to Surridge *et al.* (1994) the ratio of proven reserves to annual production is a common indicator of the lifespan of fossil fuels. However, this is an inadequate measure for two reasons. Firstly, the neglect of future changes in production levels in response to external influences and secondly, the critical periods when demand exceeds production. After attaining a peak production period in an increasing demand environment, energy needs deficit have to be satisfied by alternative energy carriers. After this period, production starts to decline. Thus, in the long-term coal should be taken as a transitional fuel.

Surridge *et al.* (1994) further claim that on a macro-scale, annual production of coal follows a Gaussian profile. South Africa has about 55 billion tonnes of proven coal reserves and about 115 billion tonnes of coal resources. Using a scenario of annual coal production of approximately 180 million tonnes in 1993, increasing at say 2% per annum till peak production and decreasing at say 2% after peak production, peak production is reached in 2055. The peak annual production for this scenario is 550 million tonnes. Considering the fact that coal production in South Africa started in 1870 (Prevost, 2004) and using the above scenario it means that it could take about 185 years for peak production to be attained in 2055. It is inferred that after 2055, based on the above scenario, it will take another 185 years to exhaust the coal reserves and that South Africa has about 236 years more to produce coal from 2004. For the short- to medium-term, a 2% rate of change of annual coal production appears a realistic rate of increase and decrease. However, in the long-term this figure may not be sustained (Surridge *et al*., 2004).

### 4.8 Ratio of the energy content of coal to natural gas reserves/resources

An appropriate comparison of coal reserves to natural gas reserves is to measure the ratio of the energy content. As stated in section 1.1, South Africa has access to natural gas reserves in Mozambique due to a bilateral gas agreement. In this comparison, the natural gas reserves include those of Mozambique and Namibia (DME, 2003).

From table 4.4, it is clear that the energy content of coal reserves and resources in South Africa outweighs the energy content of cumulative natural gas reserves and resources in South Africa, Mozambique and Namibia.

**Table 4.4 Comparison of energy content of coal and natural gas reserve/resources.**

| Reserve/Resources | Quantity | Calorific value | Energy content (PJ) | Ratio of natural gas/coal (energy content) |
|---|---|---|---|---|
| Coal reserves (South Africa) | 55 billion | 22 MJ/kg | 1,210,000 | 0.4% |
| Natural gas reserves (South Africa, Mozambique and Namibia) | 120 bcm | 41 MJ/$m^3$ | 4,920 | |
| Coal resources (South Africa) | 115 billion | 22 MJ/kg | 2,503,000 | 0.9% |
| Natural gas resources (South Africa, Mozambique and Namibia) | 560 bcm | 41 MJ/$m^3$ | 22,960 | |

Source: Adapted from DME (2003).

### 4.9 Long-term substitution of coal with natural gas for power generation

The long-term sustainability of the natural gas industry in South Africa depends on the magnitude of its natural gas reserves and those of the neighbouring countries (table 4.5), which are accessible for local utilisation.

Sasol has planned to pipe 120 petajoules per annum (PJ/a) natural gas into South Africa from the gas fields at Pande and Temane in Mozambique by 2008 (Roux, 2004). Officially, Sasol has been piping gas from Mozambique since 26 March 2004, and has enough proven reserves to last for 17 years. A programme has been put in place to prove additional reserves (DME, 2005).

A 1,600-MW CCGT power station requires about 100 PJ/a, which approximates to about 3 bcm/a (DME, 2003b). By inference, a 2,250 MW gas-fired power station (used as capacity for modelling a combined-cycle gas turbine as a substitute for pulverised coal-fired power station in the Cape Metropolitan Area in chapter 5) uses about 4 bcm/a. Thus, in my view, the combined current natural gas reserves of South Africa and Namibia (60 bcm) could last for about 15 years if supplied exclusively to the 2,250-MW CCGT power station in the Cape Metropolitan Area. It is also my view that to augment the quantity of gas immediately available to South Africa from its own reserves and those in Namibia, for use particularly in the western part of South Africa, the latter could import liquefied natural gas from Angola. This initiative would be supported by a provision in the Energy Policy, which prohibits restrictions to be placed on the quantity of gas that may be imported from SADC countries (DME, 1998).

**Table 4.5 Southern African proven natural gas reserves in 2003.**

| Country | Natural gas (bcm) | Coal bed Methane (bcm) | Total (bcm) |
|---|---|---|---|
| Angola | 140 | not available | 140 |
| Botswana | not available | 358[1] | 358 |
| Mozambique | 60 | not available | 60 |
| Namibia | 40 | not available | 40 |
| South Africa | 20 | positive tests | 20 |
| Zimbabwe | 0.00 | 840[2] | 840 |
| **Total** | **260** | **1,198** | **1,458** |

Source: Adapted from DME (2005).

Legend: [1]EIA (2005).

[2] N. Nziramasanga, personal communication, 31 October 2005.

## 4.10 Oil and gas resources offshore South Africa

### *4.10.1 Estimates of oil and gas resources*

Offshore petroleum exploration acreage of South Africa is depicted in Figure 4.3, with areas of predominantly gas potential highlighted in red, excluding the areas of current gas and oil production within Block 9. The northern and central sections of the Orange Basin are regarded as a world-class gas province, with the deepwater extension and the southwestern part of the Orange Basin falling within a potential oil province. Many exploration leads have been mapped in the open acreage north of Blocks 2A and 2C (jointly called Block 1) adding up to a "low estimate" of 31 bcm, a "best estimate" of 99 bcm and "high estimate" of more than 283 bcm in place. Additionally, the cumulative prospective resources of Blocks 2A and 2C have a variation from 45 bcm (low estimate) to 207 bcm (best estimate) to greater than 736 bcm (high estimate). Gas discoveries have a confirmation of "best estimate" for contingent resources with a total of 51 bcm. Furthermore, several mapped leads in the remaining part of the Orange Basin to the South add up to "best estimate" of 241 bcm prospective resources. Generally, the Western Bredasdorp Basin (west of block 9) is considered to be an oil province with wet gas potential, with prospective resources calculated to be about 28 bcm ("best estimate"). The possibility of significant gas resources being discovered and commercially produced has been increased by the return of international oil and gas exploration companies to South Africa. Pioneer and PetroSA are pooling together their efforts with the aim of appraising and developing several gas discoveries in the Bredasdorp Basin (Block 9) thereby extending the lifespan of the synfuel refinery at Mossel Bay (Roux, 2005).

In the East Coast, blocks 17/18 are the only places where petroleum reserves needs to be proven. Prospective resource “high estimate” for gas are more than 57 bcm in place. A “high estimate” for oil is of the order of 5 billion barrels (Roux, 2002).

For the South Coast, a number of blocks show various degrees of some wet gas potential. Block 7 is normally regarded as an oil province with some wet gas potential and prospective resources calculation of 28 bcm (“best estimate”). All oil prospects may contain a gas cap, in particular in the eastern section. Block 9 has a Petroleum Agency’s “best estimate” for gas of over 198 bcm and 1 billion barrels of oil. For contingent resources, the “best estimate” for gas is 48 bcm. With respect to the southern parts of blocks 10, 11A and 12A, there is a calculation of 85 bcm and 1 billion barrels of gas and oil respectively (“best estimate”). In the deep-water frontier area of block 11B and 12B, the total high estimate figure is approximately 963 bcm (“high estimate”). Whereas deepwater areas are considered to favour expulsion of oil, a large untested basin floor fan complex may contain 4 billion barrels (“best estimate”). Furthermore, a “high estimate” of prospective resources of oil in the deep-water area is up to 8 billion barrels. Suitable gas accumulation exists in block 13 with prospective resource of possibly 28.3 bcm (“high estimate”). Block 14 is considered as a potential oil province with an upside potential of 1 billion barrels. In block 2A, Forest’s Ibhubesi field has an estimated “reserves” of 8.4 bcm, whilst block 9 P50 gas reserves are cumulatively estimated at 22.4 bcm (Roux, 2002).

Resource classification system and definitions are found in appendix I.

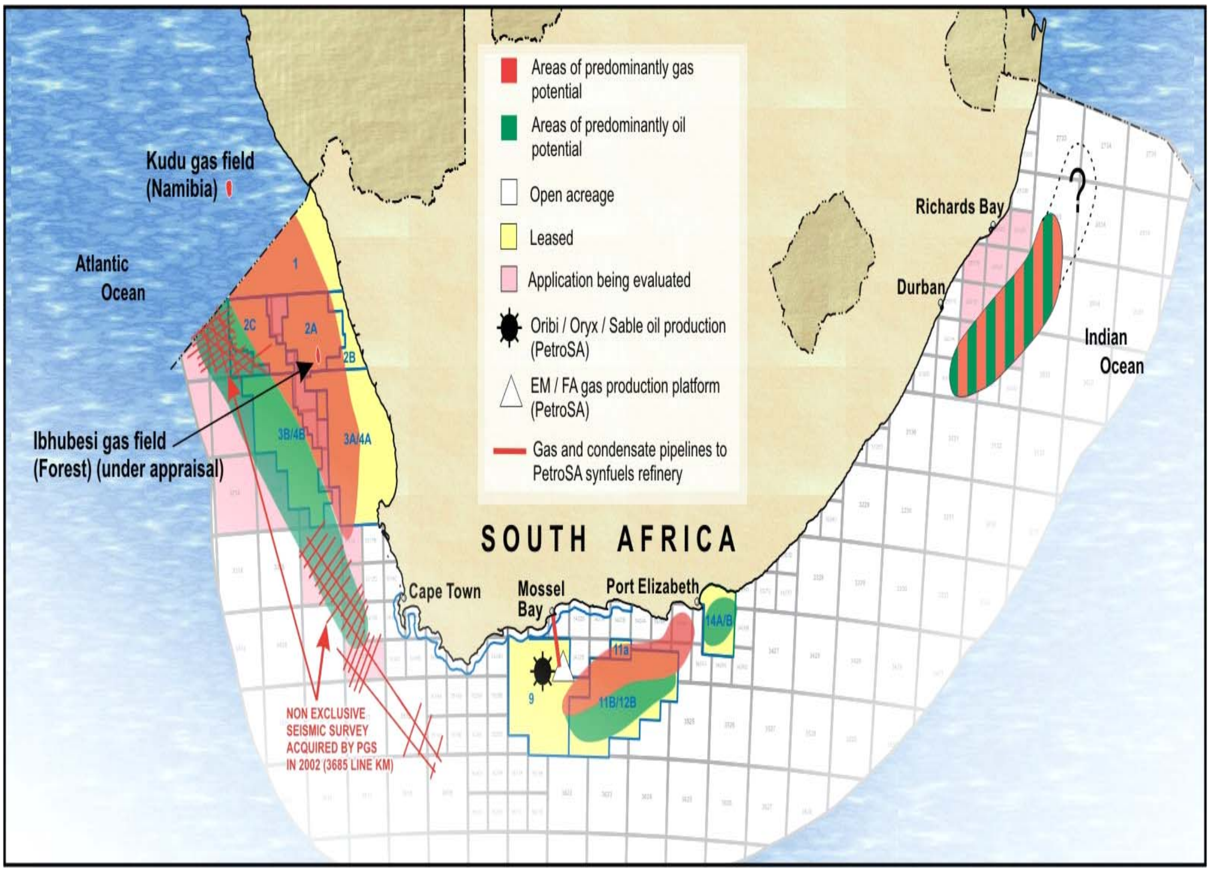



Figure 4.3 Offshore petroleum exploration acreage of South Africa.

Source: Roux (2005)

### *4.10.2 Natural gas discovery and exploratory activities*

The national oil company – PetroSA – has made various natural gas discoveries on block 9 (figure 4.3) within the Bredasdorp Basin. Three significant fields have been discovered on block 9 that includes Oribi, Oryx and Sable fields. In 2001, PetroSA and Pioneer Natural Resources Boomslag discovery jointly tested at a rate of 3,120 bbl/d of oil, $7.8 \times 10^{-4}$ bcm of natural gas per day and 300 bbl/d of condensate. Furthermore, in March 2000, an offshore natural gas discovery was made off South Africa's border with Namibia in block 2A. Forest Oil Corporation, Anschultz and Mvelaphanda (a BEE company) explore this field, known as Ibhubesi. PetroSA purchased a 30% share in the Ibhubesi field, which was estimated at 450 bcm in 2003. Sasol will hold the rights to blocks 3A and 4A till 2011. BHP-Billiton took control of 90% of sublease for block 3B/4B in 2002, with a Colorado-based Global Energy Company owning the formal rights. Petroleum Geo-Services and Petroleum Agency SA made an announcement of a joint co-operation agreement to promote deepwater exploration acreage in block 2B and acreage west of blocks 5 and 6 in 2002. The South African government provided US$213 million in 2004 to fund exploration in fields offshore Mossel Bay, particularly the E-M field in order to extend the lifespan of the gas-to-liquid project at Mossel Bay (PetroSA) (EIA, 2005a). In my view, the latter shows political support to find more natural gas in South Africa.

### 4.11 Catalysing rural development with natural gas reticulation

Access to reliable energy carriers contributes to economic growth, and the availability of cheap, abundant and appropriate energy carriers stimulate economic activities. In South Africa, low-income households use less convenient and often unhealthy forms of energy carriers such as woodfuel, coal, batteries, illuminating paraffin and candles even if they had access to electricity (DME, 1998). It is envisaged that the reticulation of communities along swathes of the natural gas pipelines will provide them with access to a relatively clean and convenient energy carrier that would catalyse growth of industries and other commercial activities. The reticulation of these communities, including the employment of rural dwellers on projects related to the laying of the pipelines, would contribute to social equity.

The South African Gas Act promotes equity in its rules concerning the reticulation of communities located along swathes of the natural gas pipelines. The Act exempts this activity from licensing from the Gas Regulator, although licences have to be acquired from local municipalities under less stringent conditions. Reticulation is defined in the Act as the division of bulk gas supplies and the transportation of bulk gas by pipelines with a general operating pressure of up to 2 bars to points of final consumption, and any other activity incidental thereto (Minister of Minerals and Energy, 2002).

A community micro-utility (figure 4.4) can be introduced to ensure the sustainability of reticulation systems and the continued supply of natural gas to rural areas. This involves using a well-designed remote area power supply (consisting of non-grid electricity) system to empower communities through involvement in ownership, installation, operation, management, maintenance and expansion. A micro-utility encourages the active participation of a community in the day-to-day operation and management of a standalone non-grid electricity system. This concept may assist to minimise the culture of non payment for services and the incidences of illegal electricity connections, because a micro-utility would be owned and managed by the community. The former practices were prevalent in townships during the apartheid era. The personnel to run the micro-utility are selected by the community, which in turn presents all complaints to the General Manager. The community micro-utility works on the *build, operate and transfer system* whereby the company contracted to build the system transfers skills for operating and maintaining it to the community with the help of non-governmental organisations and community-based organisations (CBOs).

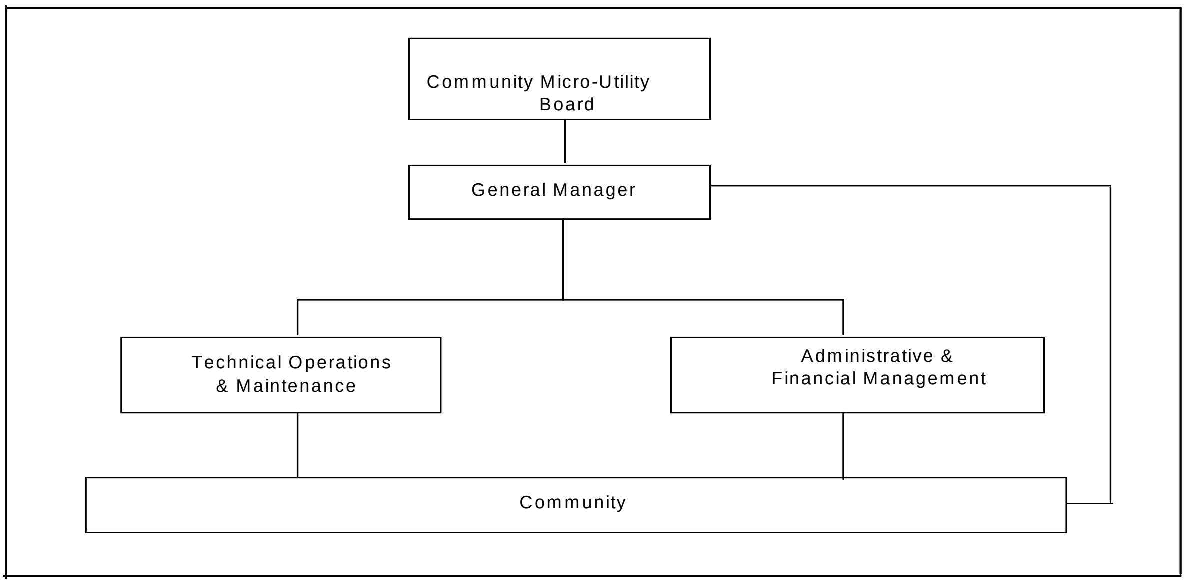



Figure 4.4 A simplified organogram of the community micro-utility.
Source: Omega Scientific Research (1999)

One advantage of the community micro-utility over the national utility system is the fact that the tariffs for billing are set by the community board that also supervises the collection of bills. The community leader or chief is the chairperson of the board. To minimise corruption, the elected board members may serve for only two years and are only eligible for re-election once. The tariffs are set up on the principles of sustainability, in that the bills collected should be enough to pay the remuneration of the line officers and also to maintain, improve and expand the system (Omega Scientific Research, 1999).

This system can be applied to other services like the management of reticulated water, waste disposal and local telecommunications services. The local government can play a major role in setting up the micro-utility and ensuring the development of skills in the community to manage and maintain it. It runs on democratic principles and allows citizens to participate in the provision of services. This model can enhance the delivery of services and promote the government's Integrated Strategic Rural Development Plan (ISRDP), which is South Africa's blueprint for service delivery at the local government level (Zondi, 2003).

### 4.12 Environmental management, safety and health issues

A requirement for the natural gas industry to be sustainable is the putting in place of proper environmental stewardship in its relevant facilities and systems including upstream and downstream processes like gas winning, purification, storage, piping, distribution, reticulation and end-use. These processes must be grounded on sound environmental management principles that do not compromise safety and health issues. The following environmental management tools and processes can be used in the industry:

- Strategic Environmental Assessment (SEA);
- Environmental Impact Assessment;
- Environmental Auditing;
- Life-cycle Analysis; and
- Environmental Performance Evaluation (Environmental Reporting).

To avoid merely symptomatic treatment of environmental problems, the principles of Strategic Environmental Assessment (SEA) should be applied in the policy and planning stages of the industry. Environmental Impact Assessment is a prerequisite for all developmental projects in South Africa, and requires the consent of the public and final approval by the Department of Environmental Affairs and Tourism. The disadvantages of Environmental Impact Assessment are that it is undertaken late in the planning stage of a project, is often mired in controversy between environmentalists and project owners and in some cases characterised by political interference, making the final decision seen as biased. In situations where SEA is properly applied, only limited Environmental Impact Assessment may be necessary and thus avoid controversy. Although SEA is not a statutory requirement in South Africa, it is gradually gaining popularity and likely to be regarded as a prerequisite for future developmental planning processes. The advantage of SEA over the Environmental Impact Assessment is that it allows an assessment of the influence of a project on the environment at all levels of the initial strategic decision-making processes (DEAT and CSIR, 2000).

An Environmental Management System (EMS), which consists of a continual cycle of policy making, planning, implementation, reviewing and improvement is necessary at all the facilities and systems of the natural gas industry (Stapleton *et al*., 2001).

There are numerous examples of why EMS is needed. For example, it is possible that leakages would occur along the “right-of-way” (the access ‘road’ created for the construction of the pipelines) to the point of use during the piping of natural gas over long distances, like in the case of the Temane-Secunda pipeline. However, since natural gas is much lighter than air, leaked gases are quickly dispersed, posing virtually no danger. The hazards associated with the pipelines and storage equipment apart from leakages include corrosion, explosion and poisoning requiring the enforcement of stringent safety regulations, which cover steel length, wall-thickness and testing schedules. Pigs (devices that are pushed through a pipe to examine it for corrosion and defects) are to be used for standard monitoring and testing procedures. Hydrotesting – the use of pressurised water under tightly controlled conditions (Caldicott and Hill, 2000) – can be used for the same purpose.

As another example, many accidents that occur in the natural gas industry are caused by third parties operating near buried pipelines and by *force majeure* such as earthquakes or earth tremors. Because pipelines cover longer distances, there are many places where third-party interference and damage can occur. For instance, subsistence farmers trying to till the new "rights-of-way" while other people attempt to use this 'road' for vehicular access, posing hazards. Whilst patrolling all the pipelines on a daily basis would not be feasible, damage and accidents can be avoided if they were given periodic surveillance including security fencing to ward off intruders. Although natural gas is the cleanest of all the fossil fuels, its combustion in poorly ventilated homes causes indoor air pollution that is harmful to human health. The particulate matter (especially, the respirable $PM_{2.5}$) consisting of soot, carbon black and oily grime, which are produced when natural gas undergoes combustion, causes asthma and breathing difficulties in women and children (Gascape Publications, 1997).

### 4.13 Gas markets and the organisation of a gas chain

Apart from its performance relative to other fuels, the growth of the natural gas industry in South Africa depends on the resilience of the gas value chain and the strength of gas markets. The viability of a natural gas industry depends on the gas value chain in which several links form a continuous system. Any flaw in the chain affects the whole system. Thus, there is less logistical flexibility in the gas value chain from the burner tip to the gas wells. The existence of and the need for an interconnected system in the natural gas industry make it capital intensive, including a tendency towards monopoly (Nore, 2001).

In South Africa, Sasol has a ten-year monopoly in both production and transmission, in return for a pricing cap on the gas from the Temane-Secunda pipeline (Dykes, 2004). This concession was intended to bring investments to the industry. It is envisaged that after ten years, the use of natural gas would have gained popularity in South Africa, on condition of more accessible proven reserves being found.

In addition to the growth nodes that can provide the anchor projects identified in section 4.3, there is the need to establish a gas market. The market dynamics that affect the natural gas value chain need to be properly assessed and catered for to avoid failure of the chain. The natural gas market may be divided into the three main segments:

- Electricity generation;
- Bulk heating/cooling; and
- Feedstock for production of chemicals and other synthetic materials.

In each of these segments, several factors should be considered: the geographical spread of consumption, load factor of the consumption, concentration of consumption on large sites, and the price-setting mechanisms. Evaluation of the three segments in terms of these factors would assist in gauging the potential risks that role players in the natural gas industry face (Trichem Consultants, 1993).

According to Nore (2001), a gas chain can be organised into the following four distinct models with respect to ownership of the elements in the chain:

**Model 1: Full vertical integration**

One company owns all the elements in the gas chain.

**Model 2: One company is in charge of transmission and distribution:**

The company (usually state-owned) dictates volumes and prices to producers and consumers.

**Model 3: The transmission company as trading company:**

The transmission company sells gas to large industries, regional transmission companies and distribution companies. Tariffs are not regulated and pipeline access is restricted non-discriminately. Pipelines may be constructed by anyone, subject to minimum technical standards.

**Model 4: Non-integrated, with regulated transmission sector**

The different parts of the gas chain are separately organised. The distribution companies and end-users enter into gas purchase contracts directly with producers; and the regulator sets the principles for use of transmission lines (access and tariffs). The advantages and disadvantages of the four models are presented in table 4.6 (Nore, 2001).

**Table 4.6 Advantages and disadvantages of gas organisations.**

| Model | Advantages | Disadvantages |
|---|---|---|
| 1. Full vertical integration | ▪ Optimisation;<br>▪ Potential economies of scale to be captured; and<br>▪ If state-owned, all the rents go the state. | ▪ Difficulty in managing big organisations;<br>▪ Lack of profit motive;<br>▪ Lack of specialisation;<br>▪ No monitoring of natural monopoly in transmission and distribution; and<br>▪ Mistakes have amplified effects. |
| 2. One company is in charge of transmission and distribution | ▪ Avoidance of possible private monopoly abuse | ▪ Government replaces market forces through case-by-case decisions;<br>▪ Planning is difficult for producers; and<br>▪ Difficulty in assessing producers' risks and profit. |
| 3. Transmission company is a trading company | ▪ Incentives to invest in transmission capacity; and<br>▪ Potential to increase gas supply due to long-term commitments by transmission/trading company. | ▪ Tendency for transmission company to abuse monopoly power against producers, distributors, and end-users; and<br>▪ Lack of competition with other natural gas producers. |
| 4. Non-integrated, with regulated transmission sector | ▪ End users and distribution companies get access to several gas sellers;<br>▪ Potential downward pressure on prices (if supply surplus);<br>▪ Good contracts may be better than internal management relationships; and<br>▪ A limit to profits in transmission may benefit consumers and/or producers. | ▪ There is a reduced incentive for transmission companies to invest in new capacity, and to utilise economies of scale;<br>▪ There is ability by transmission companies' to pool contracts, thereby reducing long-term off-take, which increases the risk of the producer;<br>▪ Complicated regulation; and<br>▪ Increases in production by producers require higher rate of return. If supply is cost- driven, supply will be reduced. |

Source: Nore (2001).

It is not easy to determine which gas chain model is the "best". Whilst choice depends on historical reasons, the following criteria are normally considered before a choice is made:

- Incidence of the abuse of power;
- Encouragement of competition, and the economically efficient operation of the industry;
- Potential for expansion;
- Manageable role of the state, vis-à-vis an over ambitious role; and
- Simplification of the role of the state regulatory body.

While there is a global trend towards "unbundling" and privatisation, this is not necessarily the best option, particularly in Third World countries (Nore, 2001)

## 4.14 The Gas Act

A major boost to the sustainable growth of the natural gas industry is the enactment of a Gas Act (Act No. 48 of 2001), which promotes the universal use of gas by communities and houses through reticulation and associated trading activities. It seeks to promote the orderly development of the piped gas industry and establishes a national regulatory framework with a national gas regulator as the custodian and enforcer of the national regulatory framework (Minister of Minerals and Energy, 2002). The establishment of the Act is a follow-up of the White Paper on Energy Policy (1998). The relevant section states that a gas regulatory authority will be established to implement a minimal regulatory regime consistent with the development of a competitive gas industry through granting licences for the transmission, storage, distribution and trading of piped gas (Department of Minerals and Energy, 1998). The Minister of Minerals and Energy will appoint all the five members of the national gas regulator who will work on part-time under a chairperson (Minister of Minerals and Energy, 2002).

## 4.15 Other enabling environment provisions

In addition to the Gas Act, two other enabling environment provisions have been brought to the fore by Government to facilitate the uptake of the natural gas industry. These are a "Petroleum Pipeline Bill" and a "Gas Infra-Structure Plan." These are provided below.

### *4.15.1 Petroleum Pipeline Bill*

The Petroleum Pipeline Bill provides *inter alia* substance to a section in the White Paper on Energy Policy for South Africa on the transmission of natural gas, which prevents monopolistic abuse of pipelines by requiring non-discriminatory open access to uncommitted pipeline capacity, transparent tariffs and disclosing of cost and pricing information to a gas regulatory body (Minister of Minerals and Energy, 2003).

#### *4.15.2 Gas Infra-Structure Plan*

A Gas Infra-Structure Plan is meant to be a strategy for the development of the natural gas industry in South Africa, and would be used by the Government for articulating its broad policy and development goals. Additionally, the Gas Infrastructure Plan aims to provide the basic arrangement of the development of South Africa's gas industry in its formative stage (5 or 10 years). The plan should undergo regular revision and chart the course of the gas industry on the basis of the latest developments. The critical aspect of the plan is the timing of various investments and the trade offs made to align the gas value chain (DME, 2005).

### 4.16 Integrating continent-wide development through natural gas

There are attempts by African leaders to promote collective action within a coherent framework to address the continent's lack of development, under the auspices of the New Partnerships for African Development (NEPAD). This can succeed if an integrated approach were adopted (Geib, 2002). Since energy is regarded as an essential factor of economic growth, any initiative involving energy systems with the capacity for trans-boundary linkages and benefits for the African continent is important.

The fact that development of infrastructure is a priority of NEPAD gives impetus to the development of energy systems that can power the economic development of the continent (De Witt, 2004). The existence of natural gas in strategic locations on the continent can initially assist with sub-regional and secondly with continent-wide development. It is therefore envisaged that the natural gas reserves in Namibia, Angola, Mozambique, Nigeria, Tanzania, Algeria, Libya, Egypt and others can assist to promote the development of a continent-wide power system that can lead to the industrialisation of the continent. The West African Gas Pipeline project (intended to provide natural gas for generating electricity in Ghana, Togo and Benin) is included in the NEPAD short-term action plan (World Bank Information Centre, 2003).

### 4.17 Conclusion

The growth of the natural gas industry in South Africa would be aided by the potential use of natural gas as a source of energy for economic activities in the spatial development initiatives (SDIs) and industrial development zones, including its use for bulk generation of electricity.

The existence of natural gas reserves in Mozambique and Namibia, the ongoing evaluation of natural gas resources at Ibhubesi (for its commercial value) and the exploratory activities, in particular, offshore western coastline of South Africa augur well for the potential growth of the natural gas industry.

The enactment of a Gas Act that makes provision for the appointment of a natural gas regulator, the crafting of the Petroleum Pipeline Bill and the Gas Infra-Structure Plan provide enabling environment for the growth of the natural gas industry in South Africa. The social equity aspects of the piping of natural gas from Mozambique to South Africa are being addressed through implementation of the studies that have been undertaken to explore the possibility of supplying the gas to low-income areas, along swathes of the pipeline. Furthermore, implementation of environmental management systems to ensure environmental stewardship in all natural gas facilities and adherence to health and safety standards are germane to a sustainable growth of the natural gas industry.

Natural gas being piped from Temane to Secunda can be used to supply energy to the projects earmarked for the KwaZulu-Natal (KZN) SDI, in particular to a gas-fired power station at Richards Bay, to the Durban South Industrial Basin and to the projects in the Lubombo SDI. With the piping of natural gas from Mozambique to South Africa in early 2004, projects being promoted under the auspices of the Special Economic Zone of the Gauteng Provincial Government can be supplied with natural gas to meet some of their energy requirements. Additionally, the joint venture companies being sought under the Special Economic Zone would provide opportunities for investment by Black Economic Empowerment companies.

Sasol was provided with a ten-year monopoly in both production and transmission in return for a pricing cap on the gas from the Temane-Secunda pipeline. This concession is intended to bring investments in the industry. In my view, the “non-integrated with regulated transmission sector” gas chain model may be appropriate for South Africa, as it promotes free trade after the ten-year monopoly period.

The ratios of energy content of proven natural gas reserves and resources to coal, which are 0.4% and 0.9% respectively, indicates the relative dominance of coal as an energy carrier in South Africa.

# 5. MODELLING SUBSTITUTION OF COAL WITH NATURAL GAS IN POWER GENERATION

Chapter 5 examines future annual peak load requirements for South Africa under different growth rate scenarios of electricity demand, and uses screening curves to select a generator. This chapter examines several tools to assist in determining and comparing the relative costs and life-cycle economic performance of using pulverised fuel coal-fired with and without flue gas desulphurisation and combined-cycle gas turbine power stations for generating base load power in the Cape Metropolitan Area, under various combined-cycle gas turbine power station scenarios. The problem (section 1.2) is analysed and the propositions (section 1.3) are tested in this chapter.

The propositions which are tested in section 5.12 are based on the following common assumptions that allow meaningful comparison to be made for generating base load power by coal and natural gas: life-cycle of 15 years; 100% residual value of land; 6.7% rate of depreciation of fixed assets (excluding land) with a 0% residual value. The choice of these assumed values are explained in appendix D.

## 5.1 Introduction

Whereas South Africa has comparatively more gas markets, Mozambique has more proven natural gas reserves than South Africa. This situation made it necessary for the South Africa Government to negotiate gas trade agreements with Mozambique, Sasol and (the National Hydrocarbons Company of Mozambique) to pipe natural gas to South African gas markets starting from February 2004. Natural gas from the Pande and Temane gas fields will reduce the use of polluting coal as a major feedstock at Sasol's twin petrochemical plants at Secunda. By using natural gas from Mozambique, the current use of coal will drop from about 7.0 to 1.7 million tons a year. At the Sasolburg plant, coal gasification facilities are being transformed into natural gas refining to use gas from Mozambique (Van Huyssteen, 2004). The use of natural gas was estimated to result in a 35% reduction in the emission of noxious gases – oxides of nitrogen and sulphur dioxide – from Sasol's plants (Lourens, 2004).

According to Surridge (2000), South Africa is under pressure from the international community to reduce its relatively high anthropogenic emissions of greenhouse gases. It is my view that

South Africa can derive a benefit from this pressure by harnessing opportunities for increasing its GDP through the sale of carbon dioxide credits from Clean Development Mechanism projects. Investments in CDM projects can stimulate the potential for providing foreign direct investment to boost South Africa's macro-economy. The pertinent issue is whether South Africa could optimise its comparative advantage in environmental issues using the energy sector as a driver. In this case, the energy sector may provide a potential solution to the environmental and health problems arising out of the coal combustion by substituting some of its applications with natural gas.

## 5.2 Generation of power in the Cape Metropolitan Area using coal or natural gas

To properly compare the cost-effectiveness of using coal and natural gas for electrical power generation, cost-benefit analysis is made on two hypothetical power stations – pulverised fuel coal-fired and combined-cycle gas turbine in the Cape Metropolitan Area (Western Cape Province). The reasons for choosing the Western Cape and the Cape Metropolitan Area in particular are as follows:

- The Western Cape is relatively far from South Africa's major coal fields. Thus, the cost of transporting coal to a new pulverised fuel coal-fired power station in the province will be relatively high.
- From a demand-side perspective, more power is required in the Cape Metropolitan Area due to the fact that the economy of the Western Cape has grown since 1984 when the Koeberg nuclear power station, located near Cape Town, could supply all the power needed in the Western Cape throughout the year (Eskom, 2003b). However, significant losses will be incurred should it be necessary to transmit power to the Cape Metropolitan Area over a relatively long distance mainly from the pulverised fuel coal-fired power stations in Mpumalanga.
- The 180-MW Athlone pulverised fuel coal-fired power station in the Cape Metropolitan Area has problems with cost effectiveness, environmental protection and worker health and safety. This power station spends 75% of its coal costs on transport by railing coal from the coalfields of Mpumalanga. It experiences a considerable amount of down time and has declining thermal efficiency (Pape, 2001). Thus, the ability of the Athlone power station to supply the envisaged high demand for power in the Cape Metropolitan Area is reduced (Eskom, 2003b).

### 5.3 Relevance of the CDM to power generation in South Africa

In May 2002, South Africa ratified the Kyoto Protocol and thus became eligible to participate in the CDM process. The decision and authority for building power stations is determined by South African Government policy. The Government has already signalled its intention to allow Independent Power Producers to operate in South Africa and build new generation capacities. The government intends to introduce a measure of competition into the electricity supply industry (ESI) that is currently dominated by Eskom (Mlambo-Ngcuka, 2001d). It is my view that, considering the novelty of the CDM and the fact that the Government's intention on Independent Power Producers is recent, the building of a power station and acquisition of carbon dioxide credits under the CDM should be subjected to cost-benefit analysis (figure 5.1).

Cost-benefit analysis provides a logical framework for the evaluation of projects, and so aids the decision-making process (Mullins *et al*., 2002). Undertaking cost-benefit analysis would provide an opportunity to compare alternative energy carriers in power generation. In my view, a CDM project has both social and environmental benefits, beside potential financial benefits. In addition, a CDM project is a logical follow-up to the Government's ratification of the Kyoto Protocol.

The substitution of natural gas for coal in power generation results in abating anthropogenic emissions of greenhouse gases, in particular carbon dioxide, as indicated by determination of the baseline (appendix C). The revenue generated by monetising carbon dioxide credits from a CDM project would improve the profitability of the power station (see sections 5.9 and 5.11).

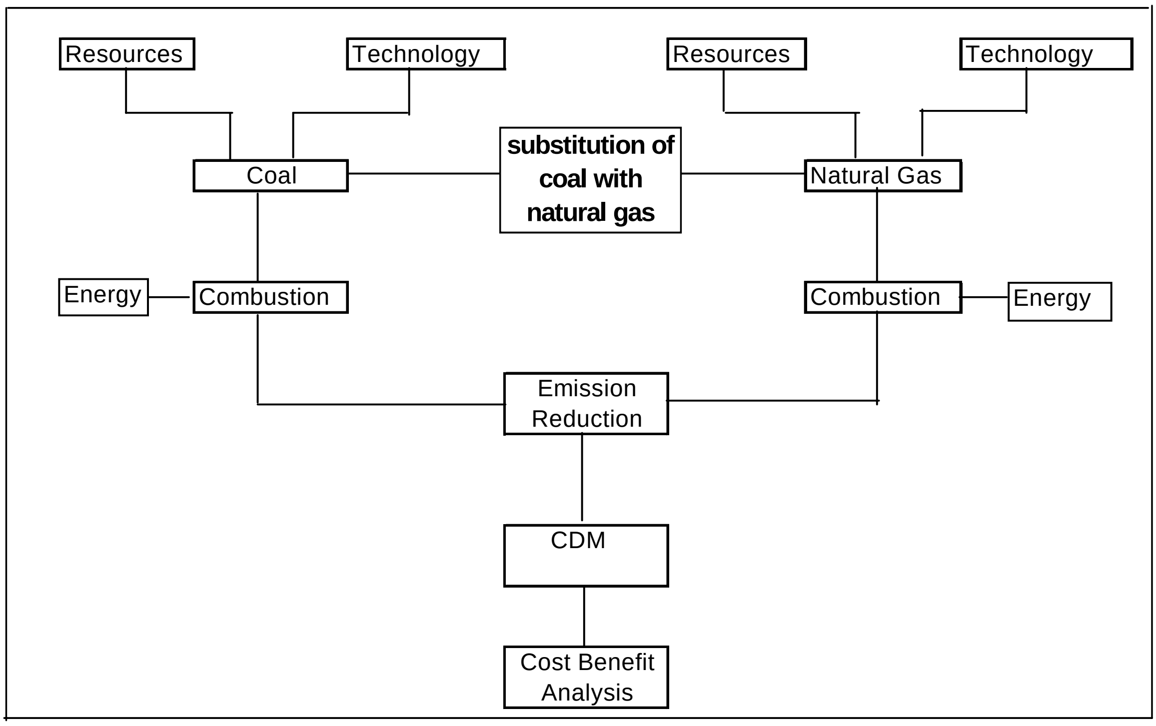



Figure 5.1 Flowsheet of the substitution of coal with natural gas under the CDM.

Source: Developed by the author.

### 5.4 Projected peak demand in South Africa

To facilitate the examination of an indication of the time that peak load capacity would be required in South Africa, a simplistic projection is undertaken to determine the magnitude of peak loads needed, based on three annual growth rate scenarios in power demand – 1.5, 2.8 and 4.0% (NER, 2001). The peak load capacity projection is examined from 2002 to 2015 (table 5.1)

A similar projection of peak load capacity with demand-side management (DSM) taken into account is provided in table 5.2.

**Table 5.1 Growth scenarios for peak power demand in South Africa ($10^3$ MW).**

| | % | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Projected peak demand | 1.5 | 31.62 | 32.1 | 32.58 | 33.07 | 33.56 | 34.07 | 34.58 | 35.09 | 35.62 | 36.16 | 36.70 | 37.25 | 37.81 | 38.37 |
| | 2.8 | 31.62 | 32.51 | 33.42 | 34.35 | 35.31 | 36.30 | 37.32 | 38.36 | 39.44 | 40.54 | 41.68 | 42.85 | 44.05 | 45.28 |
| | 4.0 | 31.62 | 32.89 | 34.20 | 53.57 | 36.99 | 38.47 | 40.01 | 41.62 | 43.28 | 45.00 | 46.81 | 46.68 | 50.63 | 52.65 |
| Net excess capacity | 1.5 | 4.59 | 4.11 | 3.63 | 31.43 | 2.65 | 21.43 | 16.32 | 11.14 | 0.59 | 0.05 | **-0.49** | -1.04 | -1.60 | -2.17 |
| | 2.8 | 4.59 | 3.70 | 2.79 | 1.86 | 0.89 | **-0.10** | -1.11 | -2.16 | -3.23 | -4.34 | -5.47 | -6.64 | -7.84 | -9.07 |
| | 4.0 | 4.59 | 3.32 | 2.01 | 0.64 | **-0.78** | -2.26 | -3.80 | -5.40 | -7.07 | -8.80 | -10.60 | --12.47 | -14.42 | -16.44 |

Legend: Based on Eskom's net capacity of 36, 208 MW, and peak demand on integrated Eskom system of 31, 621 MW both in 2002 (Eskom, 2002).
DSM – Demand-side management.

Source: Developed by author.

**Table 5.2 Growth scenarios for peak power demand in South Africa ($10^3$ MW) with DSM.**

| | % | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Projected peak demand | 1.5 | 31.45 | 31.93 | 32.41 | 32.90 | 33.39 | 33.89 | 34.41 | 34.92 | 35.45 | 35.99 | 36.53 | 37.08 | 37.64 | 38.20 |
| | 2.8 | 31.45 | 32.34 | 33.25 | 34.18 | 35.14 | 36.13 | 37.15 | 38.19 | 39.27 | 40.37 | 41.51 | 42.67 | 43.87 | 45.11 |
| | 4.0 | 31.45 | 32.72 | 34.03 | 35.40 | 36.82 | 38.30 | 39.84 | 41.44 | 43.11 | 44.84 | 46.64 | 48.51 | 50.46 | 52.48 |
| Net excess capacity | 1.5 | 4.76 | 4.28 | 3.80 | 3.31 | 2.82 | 2.31 | 1.80 | 1.28 | 0.76 | 0.22 | **-0.32** | -0.87 | -1.43 | -2.00 |
| | 2.8 | 4.76 | 3.87 | 2.96 | 2.03 | 1.06 | 0.08 | **-0.94** | -1.99 | -3.06 | -4.16 | -5.30 | -6.47 | -7.67 | -8.90 |
| | 4.0 | 4.76 | 3.49 | 2.18 | 0.81 | **-0.61** | -2.09 | -3.63 | -5.23 | -6.90 | -8.63 | -10.43 | -12.30 | -14.25 | -16.27 |

Legend: Based on table 5.1 and on Eskom's official DSM savings of 4,255 MW on a 25-year period, starting in 2004 (Eskom, 2005).

Source: Developed by author.

In 2002, South Africa had excess power generation capacity of about 4,588 MW which has been diminishing with time as the demand for power has been increasing. Thus, additional peak load generation capacity would be required to maintain the increasing demand for power when this excess capacity is exhausted.

The years corresponding to the highlighted (bold) net excess capacity figures in table 5.1 indicate when additional peak load generating capacity will be required for the three growth scenarios in power demand in South Africa, due to the fact that the excess capacities are negative. Thus, additional peak load generating capacity will be required in 2006, 2007 or 2012, depending on which of the three respective growth rate scenarios (4.0, 2.8 or 1.5%) is the most probable.

According to Eskom's Annual Report for 2005, South Africa will require additional peak capacity in the year 2007, based on the existing capacity system (Eskom and non-Eskom including decommissioning), without taking DSM into account (Eskom, 2005). The year 2007, identified as the period in which additional peak load capacity would be required (table 5.1) thus correlates with the 2.8% (moderate) growth rate in power demand It may therefore be inferred that the 2.8% growth rate in power demand scenario is the most probable within the 2002 to 2015 planning period. From 1998 to date, observed peak power demand in South Africa is growing at a rate of over 1,000 MW per annum (Eskom, 2005). However, as efforts are made to improve demand-side management including improvement in energy efficiency, the peak power demand growth rate should drop to less than a 1,000 MW per annum. The official figures for DSM are 4255 MW savings over a 25-year period (2004 to 2029) (Eskom, 2005). Assuming a yearly DSM savings of about 170 MW, and extrapolating the period to cover 2002 to 2015, a different set of figures for projected demand and excess capacity are obtained as shown in table 5.2. It is anticipated that the net effect of the DSM measures, such as load shifting, interruptible load and energy efficiency improvement (mainly in the residential, commercial and industrial sectors, including mining) under the auspices of Eskom (Surtees, 2000) would be to delay the onset of the time when more peak capacity would be required and/or reduce the quantity thereof required. Thus, the net effect of the DSM measures for the planning period 2002 to 2015 is as follows:

- Annual projected peak demand is reduced by about 170 MW
- Annual excess capacity is increased by about 170 MW
- Additional peak load capacity is required in 2008 for the growth rate of 2.8%

The inference is that taking DSM measures into account could increase the magnitude of the excess capacity annually by about 170 MW over a 25-year period (2004-2029), leading to a postponement by one year (from 2007 to 2008), of the need for additional peak load capacity in South Africa for the most probable growth rate of 2.8%.

## 5.5 Examination of modelling tools

A number of tools were examined prior to modelling the substitution of natural gas for coal for power generation. This was done with the aim of selecting the best tools to use to determine the economic benefits to the South African economy in general from the reduction in carbon emissions resulting from the substitution. Furthermore, the tools were examined to find out their suitability for comparing power generation costs; immediate economic benefits to electricity consumers and economic benefits to investors putting up a plant to substitute natural gas for coal for electricity generation. The following tools were examined:

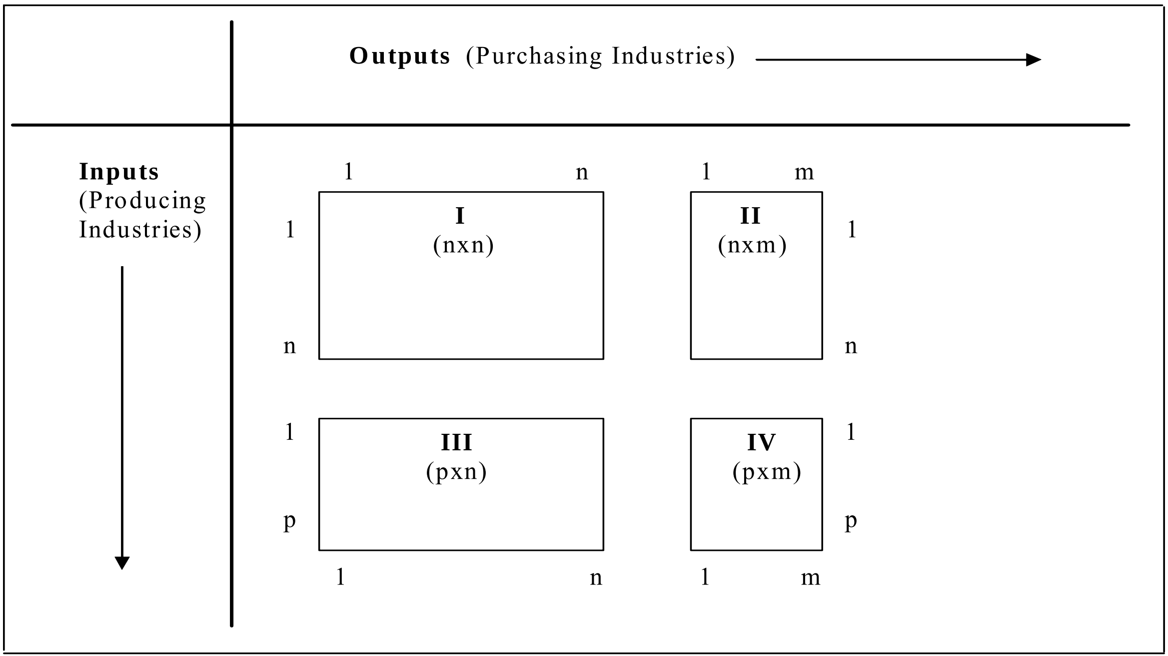
- Social accounting matrix (SAM)
- An accounting framework – LEAP (Long-range energy alternatives planning system)
- Screening curves
- Te-Con Techno-Economic Simulator (which also performs standard financial calculations)

### *5.5.1 Social accounting matrix*

One way of analysing an impact on the economy of a country such as South Africa, is to transform a system of input-output relationships, for example the social accounting matrices (SAM) or input-output tables, into economic models as the basis for general equilibrium analysis. The SAM differs from the input-output tables in one important feature. In addition to information on the interdependence among the different sectors of the economy that are taken up in the input-output tables, the SAM also includes detailed information on the income and spending patterns of households. Given the importance of income distribution in South Africa at present it is desirable to make use of SAMs wherever possible rather than input-output tables. The SAM is based on input-output analysis originally instigated by Leontief (Asamoah *et al*, 2002). A modern input-output table is compiled by an official authority for a country and is an economic tool that enables a system of national accounts to be extended, classified and depicted in a tabular format. It provides the basis for a broad and rapidly developing economic practice - input-output analysis. In South Africa, it is produced by Statistics South Africa (Mullins, 2002).

The layout of a typical input-output table is depicted in table 5.3. This table is divided horizontally into a processing and payment sector, and vertically to distinguish between intermediate users of goods, factors of production and final users. Quadrant I records inter-industry transactions, whilst quadrant III provides the payment by industries to the factors of production. Quadrant II gives the final demand for goods and services produced, whilst quadrant IV provides the direct sales of factors of production to end-users.

**Table 5.3 Input-output table**




Source: Asamoah *et al.* (2002).

The classical input-output equation is

$$X = [I-A]^{-1} \cdot Y \tag{5.1}$$

where Y and X are vectors of final demand and output respectively, and A is a matrix of coefficients representing inter-sectoral transfers.

The Leontief Model in mathematical summary (Input-Output Analysis)

The open static Leontief model is derived from two sets of mathematical relationships, which are:

1. A set of accounting identities or balancing equations

The total purchases made by a sector equal the aggregate sales of that particular sector. These balancing equations are of the following form:

$$X_i = x_{i1} + x_{i2} + \ldots.. + x_{in} + Y_i \tag{5.2}$$

Where: $i = 1, 2, 3, ..... n$

$Xi$ = total number of units of commodity i produced by sector i

$xij$ = the number of units of commodity i required by sector j

$Yi$ = the exogenous or final demand for commodity i.

2. The structural equations

These state the assumption of fixed technical coefficients, aij; the assumption being that inputs into each sector is a direct function of the level of output of that sector. Compared to the n balancing equations there are $n^2$ structural equations of the form:

$$x_{ij} = a_{ij}X_j \qquad (5.3)$$

where: $i,j = 1, 2, 3, ..... n$

$X_j$ = total output of industry j

$a_{ij}$ = technical coefficient defined by $x_{ij}$ and $X_j$.

Each technical coefficient, aij therefore gives the amount of purchases from each industry i to support one unit of output of industry j.

Substituting the structural equations into the balancing equations yields the following equation:

$$X_i = a_{i1}X_1 + a_{i2}X_2 + ..... + a_{in}X_n \qquad (5.4)$$

Where: $i = 1, 2, 3, ..... n$

which can be written in vector form as

$$X = AX + Y \qquad (5.5)$$

Where: $X = [Xi]$, $A = [aij]$ and $Y = [Yi]$.

The general solution of the Leontief model yields by matrix inversion:

$X = [I - A]^{-1}.Y$ (as provided above)

$$\text{or } X = BY \qquad (5.6)$$

where B = [$b_{ij}$].

These bij's give per unit value of delivery to final demand made by the industries listed along the top of the inter-industry matrix and the total input directly and indirectly required from industries listed at the left of the matrix (Asamoah *et al*., 2002)

Expert advice was sought from L. Mulder and C. Williams (personal communications, 26 October 2003) to find out the appropriateness of using the SAM to determine the economic costs and benefits to the South African economy of carbon dioxide credits accruing from substituting gas for coal in power generation. It emerged from the discussions with the two experts that the South African SAM tables had not yet commoditised abatement in greenhouse gas emissions (carbon dioxide credits). Thus the information was unavailable that was needed from the social accounting matrix to facilitate the determination of the economic costs and benefits to South Africa's macro-economy of selling carbon dioxide credits under the CDM. After further detailed discussions with specialists (J. van Heerden and J. Blignaut, 27 October 2003), it was decided to use cost-benefit analysis as the basis for determining the immediate economic benefits of substituting coal with natural gas for generating electricity to electricity consumers and to investors.

### *5.5.2 An Accounting Framework – LEAP*

An accounting framework allows construction of plausible "what if" energy scenarios followed by running a model. This leads to a decision as to whether different options would lead to lower costs or not (Heaps, 2002). In this thesis, LEAP (Long-range energy alternatives planning system), an accounting framework, was examined as a tool for cost benefit analysis. LEAP is a scenario-based energy-environment modelling tool that has applications in energy demand, energy supply, resources, cost-benefit analysis and non-energy sector emissions (Heaps, 2002). LEAP allows cost-benefit analysis to be undertaken on an energy system such as the substitution of coal with natural gas for generating power (Heaps, 2002). However, due to its inability to produce economic performance parameters including balance sheet, sales, income statement, cash flow statement and ratio analysis LEAP could not be used in this thesis. It is graphically presented by figure 5.2

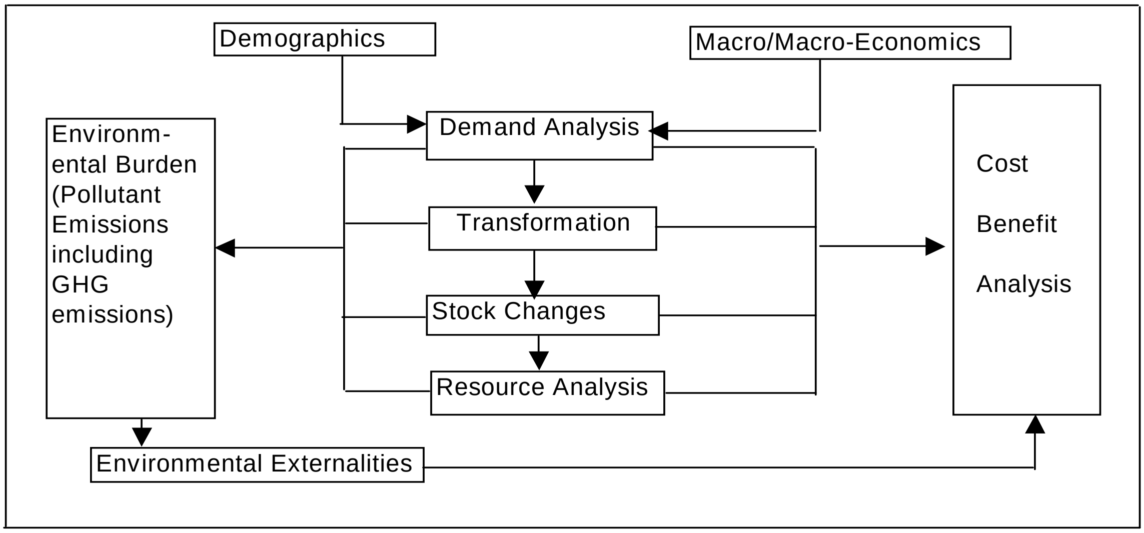



Figure 5.2 A schematic presentation of LEAP.

Source: Heaps (2002).

### *5.5.3 Screening curves*

Conventionally, screening curves plot annual revenue requirement per kilowatt (ARR) (levelised cost (NER, 2004)) as a function of capacity factor – percentage utilisation which is determined by the duration of the load. The fixed-cost component of the ARR is given by the overnight cost amortised ("levelised") over the plant's life. The overnight cost (OC) is the present-value cost of the plant in economic terms. The OC is the amount that has to be paid up front as lump sum in order to pay completely for its construction. The formula for amortisation is given as:

$$FC = r.OC/(1-e^{-rT}) \approx r.\ OC/(1-1/(1+r)^{T}) \qquad (5.7)$$

The formula for ARR is given by

$$\text{Screening curves: } ARR = FC + cf \times VC \qquad (5.8)$$

where FC is the fixed cost,

r is the discount rate (interest rate), and

T is the life of the plant (years).

VC is the variable cost.

(The accuracy of the fixed costs [as an approximation] is improved by using monthly instead of annual compounding in the second formula. This is done by changing r to r/12 and T to 12T) (Stoft, 2002).

### *5.5.3 Te-Con's Techno-Economic Simulator Model*

Te-Con Techno-Economic Simulator model is a generic model that comprises, inter alia, several relationships (H. Simonsen, personal communications, 4 July 2005) as found in appendix J. The development of the model is elaborated in section 2.4.2. The model employs a techno-economic approach where operating parameters are given financial values and employed in conventional accounting processes to produce "books-of-accounts" as required by financing institutions (figure 5.4).

One of the more important concerns of an engineering-economic analysis is the quantity and disposition of working capital. The management of working capital requires a major managerial involvement in most companies. Failure to efficiently employ working capital is a common cause of business failure. Gross working capital can be defined as total current assets while net working capital is comprised of current assets minus current liabilities (See Figure 5.3). Current assets usually amount to more than half of the total assets of a company (Holland and Wilkinson, 1999).

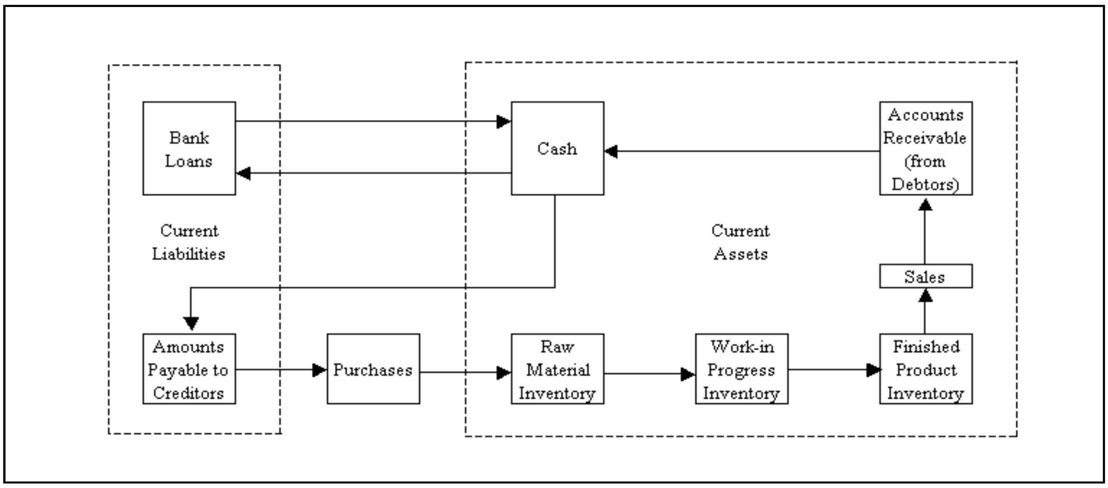



Figure 5.3 Flow of working capital in relation to current liabilities and current assets.
Source: Holland and Wilkinson (1999).

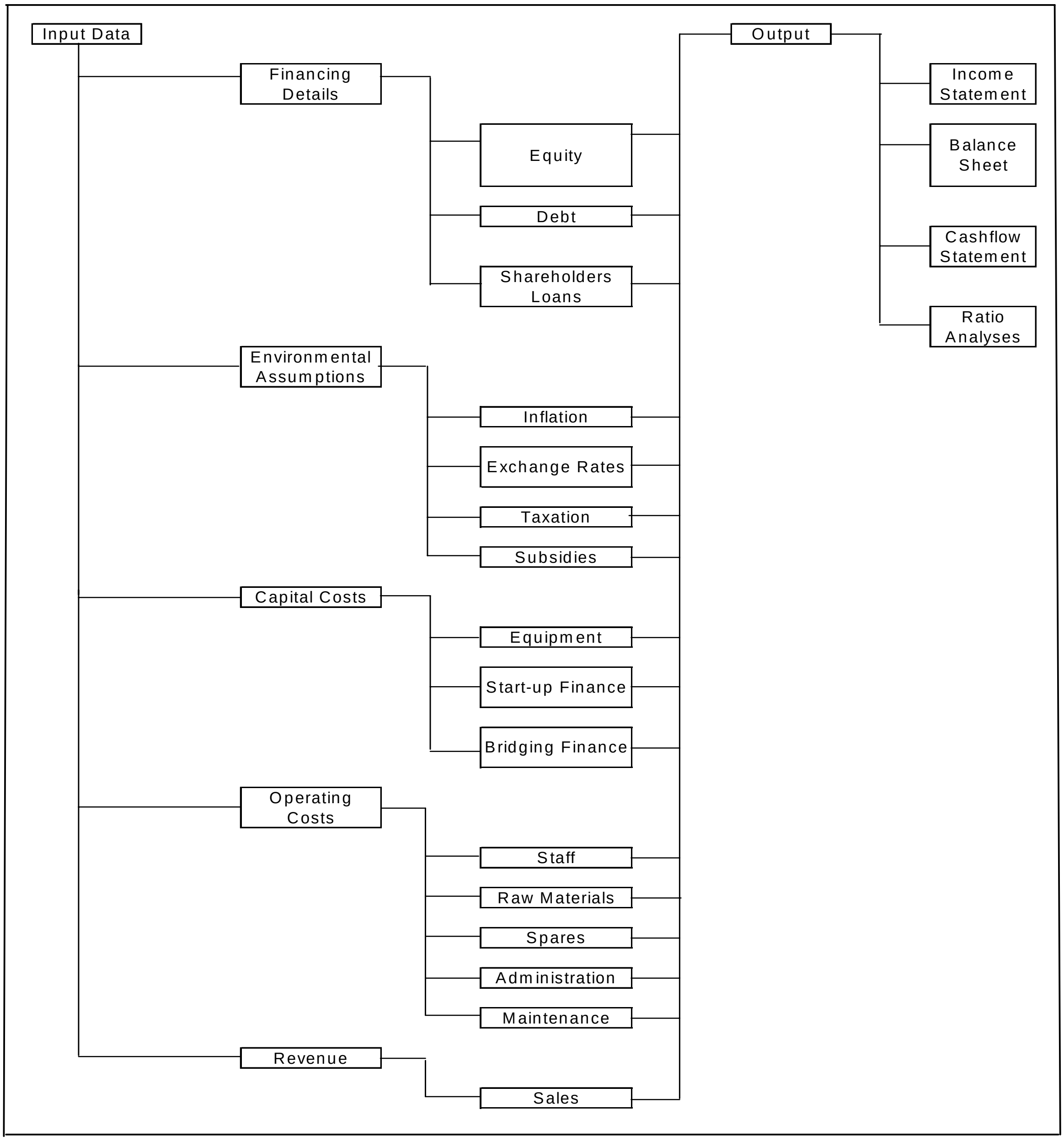



Figure 5.4 Components of the Te-Con Techno-Economic Model.

Source: Te-Con Consultants (2004).

In section 5.11, the Techno-economic simulator model is used to undertake cost-benefit analysis (life-cycle economic performance of technologies/fuel types) of the substitution of coal with natural gas for generation of base load capacity in the Cape Metropolitan Area.

## 5.6 Modelling costs and benefits of generation technologies/fuel types

In modelling the life-cycle economic performance of technology/fuel types, discounting is undertaken to calculate the present value of a stream of costs and benefits associated with the project. If benefits exceed costs in each time period, the net present value is positive for the discount rate that is used (Hanley and Spash, 1993).

Two tools, "Te-Con Techno-Economic Simulator" model (graphically depicted in figure 5.4) and screening curves, which plot average cost as a function of capacity factor (Stoft, 2002) were selected out of the four tools examined in section 5.5 due to their capability to determine and compare the life-cycle economic performance of pulverised fuel coal-fired (PF) and combined-cycle gas turbine (CCGT) power stations and to determine the relative cost of electric power generation. The comparison of the generation costs was undertaken by considering fixed costs, variable costs and capacity factors. The capacity of the PF and CCGT power stations is 2,250 MW. The choice of 2,250 MW is premised on the "baseline optimised" plan principle of least cost. In this plan, a new generation technology of 3 x 750 MWe CCGT using Kudu (Namibia) gas is among various electricity generation options in South Africa (Howells *et al*., 2002). The use of Kudu gas to generate electricity in the Cape Metropolitan Area is preferred to using gas from Temane (Mozambique), as Kudu is relatively close to the Western Cape. In the Te-Con Techno-Economic model, revenues and initial cash outlays are treated as cash inflows, whilst payments of dividends, interest and for services are regarded as cash outflows.

The difference in emissions between a PF and a CCGT power station represents the reduction in emissions that is obtained by building a CCGT instead of the former. The reduced greenhouse gas emissions would need to be certified by operational entities, which are designated by the Conference of the Parties serving at Meeting to the Parties to the Kyoto Protocol (Climate Change Secretariat, 1998). This could be traded as carbon dioxide credits under the CDM. The traded credits would be monetised to generate additional annual income stream for the owners and investors of the CCGT power station.

The four power station scenarios evaluated in the techno-economic analysis are:

- A base case combined-cycle gas turbine (*scenario 1);*
- A combined-cycle gas turbine with CDM revenue *(scenario 2);*
- A combined-cycle gas turbine with externalities accounted for by damage costs (*scenario 3*);
- A combined-cycle gas turbine with CDM revenue and externalities accounted for by damage costs (*scenario 4).*

Inputs to the model are characterised as technical (generation, fuel, capital and operating costs) and financial (debt, equity). The first point of comparison is the capital expenditure on plants required to generate the same quantity of electricity using different fuel types – gas and coal in this case – and associated technologies (combined-cycle gas turbine and pulverised fuel coal-fired with and without emission abatement equipment). As shown in figure 5.3, project viability is dependent on the generation of operating finance by a surplus of current assets over current liabilities. The failure to maintain such liquidity results in recourse to bridging finance, a very expensive exercise. The balance between equity finance and loan finance, for expenditure of a capital nature, must be maintained. Debt finance does have the advantage of providing a "tax shield". A projected increase in both interest rates and share price suggests the employment of long term debt rather than shares. On the other hand a projected sharp increase in share price would suggest the issue of mostly shares with long term debt being employed at a later stage in the project (Finnerty, 1986).

The capital required for all power stations scenarios is raised in part by equity through ordinary shares, with each share being sold at a premium and through debts – shareholders' loan and bank loan. It must be stated that the financing of the power stations are arranged such that their assets are always more than their current liabilities. In this way, the need for a bank bridging finance (with its comparatively high interest rate) is avoided. Other capital costs include purchasing land and the provision of infrastructure. Operating and maintenance costs are based on the capacity of the power stations and the duration of the operations. The input information is processed by algorithms in the model to produce life-cycle economic performance parameters including balance sheet, sales, income statement, cash flow statement and ratio analysis under "environmental" assumptions – inflation, exchange rates and taxation.

The relative advantage of one technology/fuel over another is quantified by comparing the life-cycle economic performance indicators based on the operating scenarios of the power stations. The techno-economic analyses of the power station scenarios are based on the period from January 2005 to December 2019. The modelling is based on a 15-year power plant life-cycle instead of the usual 25 years due to an apparent limitation to the natural gas reserves to which South Africa has access. Tables 5.4 and 5.5 record the input data for the analyses. Additional input data used in the techno-economic simulator modelling and key parameters of the CCGT with CDM revenue scenario are found in appendix D.

To facilitate comparison of the technologies, construction of the power stations has been assumed to have the same lead time. Similarly, other parameters like size and cost of land, and load factor for all the technologies have been equalised. All the power stations start producing and selling electricity in 2007. The two power stations that are initially considered for generating base load power are described in sections 5.8 and 5.10.

**Table 5.4 Financial input data and assumptions for the power stations.**

| | PF/PF-FGD | CCGT |
|---|---|---|
| Starting date | January 2005 | January 2005 |
| Power station life-cycle (years) | 15 | 15 |
| Number of months to complete facility construction | 29 | 29 |
| Generation (test) starting date | July 2007 | July 2007 |
| Inflation rate, % | 6.06[1] | 6.06[1] |
| Generation (commercial) starting date | September 2007 | September 2007 |
| Full production starting date | November 2007 | November 2007 |
| Date of end of project | December 2019 | December 2019 |
| Share capital details | | |
| No. of shares authorised | $400.0 \times 10^6$ | $200.0 \times 10^6$ |
| No. of shares issued | $60.0 \times 10^6$ | $70.0 \times 10^6$ |
| Par value of share (Rand) | 200.00 | 90.00 |
| Authorised share capital (Rand) | $80.0 \times 10^9$ | $18.0 \times 10^9$ |
| Issued share capital (Rand) | $12.0 \times 10^9$ | $6.3 \times 10^9$ |
| Premium per share (Rand) | 5.00 | 9.00 |
| Value of ordinary share premium (Rand) | $300.0 \times 10^9$ | $630.0 \times 10^9$ |
| Shareholders' loan (Rand) | $2.5625 \times 10^9$ | $1.2375 \times 10^9$ |
| Interest rate on shareholders' loan, % | [2]14.75 | [2]14.75 |
| Bank loan (Rand) | $2.5625 \times 10^9$ | $1.2375 \times 10^9$ |
| Interest rate on bank loan, % | [2]15.75 | [2]15.75 |
| Total initial capital employed (Rand) | $17.425 \times 10^9$ | $9.405 \times 10^9$ |
| Initial gearing factor<br>(ratio of debt to total assets) | 0.4167 | 0.3571 |

Source: Input data of Te-Con Techno-Economic Simulator Model.

Legend: [1]Adapted from Statssa (2005).
[2]B. McIntyre, personal communication, 10 January 2004.

**Table 5.5 Input estimates of capital and running costs of power stations**

| | **Power station parameters and costs** | | **Explanations/Basis/Sources** |
|---|---|---|---|
| | **PF/PF-FGD** | **CCGT** | |
| **Fixed asset (excluding land)** | | | For depreciation of fixed assets |
| Initial capital costs, billion Rand | 16.704[1] (PF-FGD) 16.458[2] (PF) | 7.801[1] 8.228[2] | [1] See appendix D1 for calculation of capital costs per unit size. The pair PF-FGD/CCGT was adapted from similar plants in New Zealand (see bottom of table) that included a formula for computing the overnight costs. The difference in capital cost per unit size between PF-FGD and PF stems from the extra cost of the FGD facility. The difference between the initial capital costs of the two CCGTs stems from the fact that the formula used for adjusting the New Zealand CCGT plant size included a scaling factor (see appendix D1). [2]Details of the PF/CCGT pair were obtained from Eskom sources (Eskom *et al*., 2004b) with standardised capital costs per unit energy provided by B. McIntyre of Eskom, Head Office (Megawatt Park, Sunninghill, South Africa). Screening curves, power curves and several life-cycle economic performance indicator tables have been provided to facilitate the comparison of the power plant pairs. |
| **For reinvestment and replacement of fixed assets** | | | Fixed assets (excluding) land) |
| Rate of depreciation, % | 6.7 | 6.7 | See table D5, appendix D |
| Percentage of fixed assets after life-cycle, % | 0 | 0 | See table D5, appendix D |
| | | | Method: Diminished balance |
| **Land** | | | |
| Size, $m^2$ | $(32 \times 10^4)$[1] | $(32 \times 10^4)$[1] | Rate of depreciation = 0.0% |
| | | | Residual value (% of original cost) = 100.0% Method: Straight line |
| Cost of land, R/$m^2$ | 20[1] | 20[1] | |
| Total cost of land, million Rand | 6.40[1] | 6.40[1] | |
| **Electricity generation** | | | |
| Power station nominal capacity, MW | 2,250 | 2,250 | |

| | Power station parameters and costs | | Explanations/Basis/Sources |
|---|---|---|---|
| | **PF/PF-FGD** | **CCGT** | |
| Power generation, kW | 2.25 x $10^6$ | 2.25 x $10^6$ | Based on plant capacity |
| Hours per day | 24 | 24 | |
| Projected selling price of electricity in 2007 R/kWh) | 0.23 | 0.23 | Based on Eskom's average selling price of electricity of approximately R0.15/kWh in 2002 (Eskom, 2002) and projected at 8.56%[1] increase per annum (this is about 2.5% above inflation of 6.06%). |
| Fixed operating and maintenance (O&M) costs, R/MWh | 99.53 PF-FGD)[2] 98.06 (PF)[1] | 40.60[2] 49.03[1] | Based on amortisation formula (Stoft, 2002). These suffixes refer to the corresponding plants whose capital costs have been explained (above) in this table. |
| Variable O&M costs, R/MWh | 11.46 | 72.06 | Same as fuel cost (Stoft, 2002) |
| Fuel costs in 2003 (US$/GJ) | 0.53[4] | 3.35[5] | Prices as at December 2003 |
| Energy output/a, G | 17,739 | 17,739 | Based on plant capacity |
| Assumed efficiency of Power stations | 0.34[1] | 0.55[3] | |
| Energy from fuel/a, GWh | 52,174 | 32,253 | Based on Energy output/a and efficiency of power stations |
| Exchange Rate, R/US$ | 5.9753 | 5.9753 | Adapted from Oanda Corporation (2005). |

Sources: [1] B. McIntyre, personal communication, 10 January 2004.
[2] Adapted from East Harbour Management Services (2002).
[3] Stockholm Environmental Institute-Boston (2003).
[4] X. Prevost, personal communication, 23 September 2005
[5] Eskom *et al*. (2004b)

## 5.7 Power stations (1)

### *5.7.1 Conventional pulverised fuel coal-fired*

The conventional pulverised fuel coal-fired (PF) power plant without gaseous emission abatement facility is considered in this section of the thesis. In a pulverised fuel coal-fired power station, finely ground coal is injected into the lower part of a combustion chamber. The coal particles burn in suspension to release heat that is transferred to water tubes in the combustion chamber walls. This produces a high pressure and a high temperature steam that is fed into a turbine that in turn drives a generator to produce electricity (DG of Energy and Transport (EU), 1997).

This power station employed in the study has an installed capacity of 2,250 MW and efficiency of 34%. It is water-cooled and run as a base load plant due to its combination of relatively high capital cost and low fuel costs (Eskom *et al*., 2004b).

### *5.7.2 Combined-cycle gas turbine (1)*

The combined-cycle gas turbine power station being modelled in this section is similar to the one described below (section 5.9.2). It has an installed capacity of 2,250 MW with efficiency of 55% (Stockholm Environmental Institute-Boston, 2003) and operates on pipeline gas. However it could operate on liquefied petroleum gas as well. The suffix (1) refers to the CCGT pant data obtained from Eskom sources (Eskom *et al*., 2004b). Characteristics of a combined-cycle gas turbine, emission abatement facility and efficiencies as a function of inlet temperature are found in appendix G.

The lead times of the PF and CCGT power stations are analysed in appendix K.

## 5.8 Modelling PF and CCGT power plants

In preliminary techno-economic modelling, project financial performance is found to respond, particularly, to three parameters – the price of fuel, the price of carbon dioxide credits and damage costs – were found to be very susceptible to change. These parameters are subjected to sensitivity testing (explained further in appendix J) as indicated below to find out how they affect the annual revenue requirement and the breakeven selling price of electricity. A series of tables and related screening curves that show the variation/function of annual capacity requirements versus capacity factor (cf) under the four scenarios are provided below for power plant configuration pairs – pulverised fuel coal-fired (PF) as well as combined-cycle gas turbine (CCGT) (figure 5.5) and pulverised fuel coal-fired with flue gas desulphurisation (PF-FGD) and CCGT (figure 5.26). Further tables and screening curves are generated employing sensitivity analyses techniques to establish annual revenue requirements with respect to changes in fuels (coal and natural gas) prices (figures 5.6; 5.7; 5.8; 5.9). Furthermore, several tables and power curves are presented to show how changes in the selling price of carbon dioxide credits (SPCC) and changes in the value of damage costs (DC) affect breakeven selling price of electricity (BESP) (figures 5.10-5.25; 5.32-5.50).

The outputs presented in this section are based on the methodology in Stoft (2002).

*Scenario 1 A base case combined-cycle gas turbine*

As given in section 5.5.3, the equation for calculating fixed costs is given as:

$FC = r.OC/(1-e^{-rT}) \approx r.\ OC/(1-1/(1+r)^{T})$ (5.7)

and the equation for ARR is given by

ARR = FC + cf x VC

Where cf = capacity factor (5.8)

**Table 5.6 ARR at various capacity factors (PF/CCGT).**

| Capacity factor (cf) | PF ARR (R/MWh) | CCGT ARR (R/MWh) |
|---|---|---|
| 0.00 | 98.06 | 49.03 |
| 0.10 | 99.22 | 56.69 |
| 0.20 | 100.37 | 64.35 |
| 0.30 | 101.52 | 72.01 |
| 0.40 | 102.67 | 79.67 |
| 0.50 | 103.82 | 87.33 |
| 0.60 | 104.98 | 94.99 |
| 0.70 | 106.13 | 102.64 |
| 0.80 | 107.28 | 110.30 |
| 0.90 | 108.43 | 117.96 |
| 1.00 | 109.58 | 125.62 |

Source: Developed by author based on methodology in Stoft (2002).

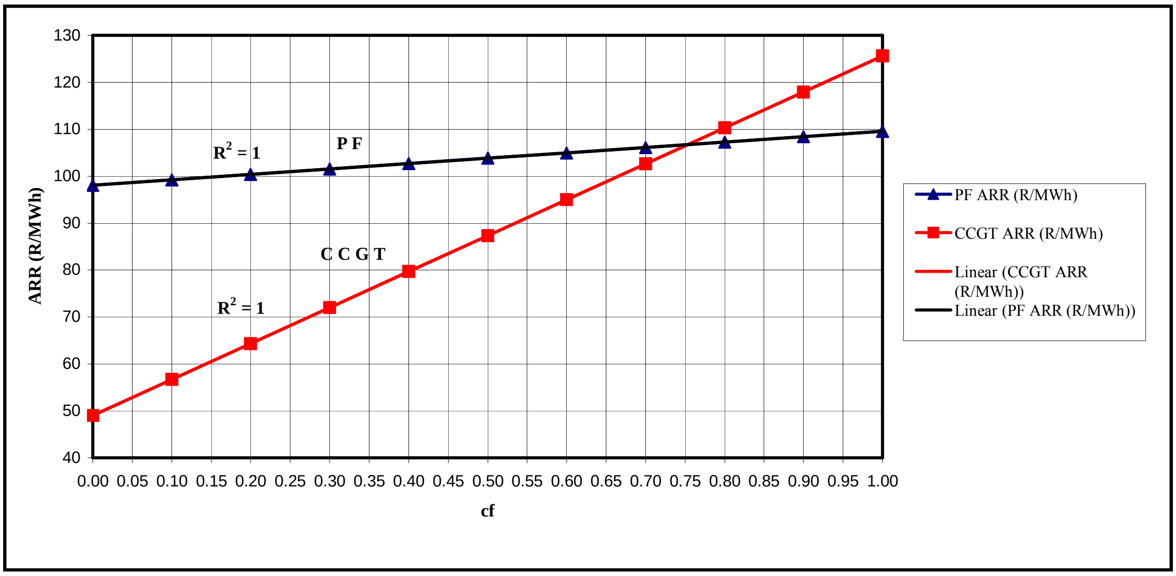



Figure 5.5 Screening curves (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comment**: These screening curves illustrate the regimes in which PF and CCGT power stations dominate. Below a 0.75 cf value, gas is the preferred option in terms of ARR.

Equations

PF

$$y = 11.522x + 98.063 \tag{5.9}$$

$R^2 = 1$

CCGT

$$y = 76.59x + 49.032 \tag{5.10}$$

$R^2 = 1$

Finding the co-ordinates of the point of intersection of the two lines 5.9 and 5.10

$11.522x + 98.063 = 76.59x + 49.032$

$x = (98.063 – 49.032)/(76.59 – 11.522)$

$x = 0.7535$

Substituting this value for x into equation 5.9 gives y = 106.74

Thus, at the approximate point (0.75, 106.74), the annual revenue requirements and capacity factors of PF and CCGT are the same.

**Table 5.7 Variations in ARR to +/-5% change in fuel prices (PF/CCGT).**

| cf | PF ARR (-5% CP) (R/MWh) | PF ARR (CP) (R/MWh) | PF ARR (+5% CP) (R/MWh) | CCGT ARR (-5% GP) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (+5% GP) (MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 98.06 | 98.06 | 98.06 | 49.03 | 49.03 | 49.03 |
| 0.10 | 99.16 | 99.22 | 99.27 | 56.31 | 56.69 | 57.07 |
| 0.20 | 100.25 | 100.37 | 100.48 | 63.58 | 64.35 | 65.12 |
| 0.30 | 101.35 | 101.52 | 101.69 | 70.86 | 72.01 | 73.16 |
| 0.40 | 102.44 | 102.67 | 102.90 | 78.14 | 79.67 | 81.20 |
| 0.50 | 103.54 | 103.82 | 104.11 | 85.41 | 87.33 | 89.24 |
| 0.60 | 104.63 | 104.98 | 105.32 | 92.69 | 94.99 | 97.28 |
| 0.70 | 105.73 | 106.13 | 106.53 | 99.96 | 102.64 | 105.32 |
| 0.80 | 106.82 | 107.28 | 107.74 | 107.24 | 110.30 | 113.37 |
| 0.90 | 107.91 | 108.43 | 108.95 | 114.52 | 117.96 | 121.41 |
| 1.00 | 109.01 | 109.58 | 110.16 | 121.79 | 125.62 | 129.45 |

Source: Developed by author based on methodology in Stoft (2002).

Legend: CP – coal price

GP – gas price

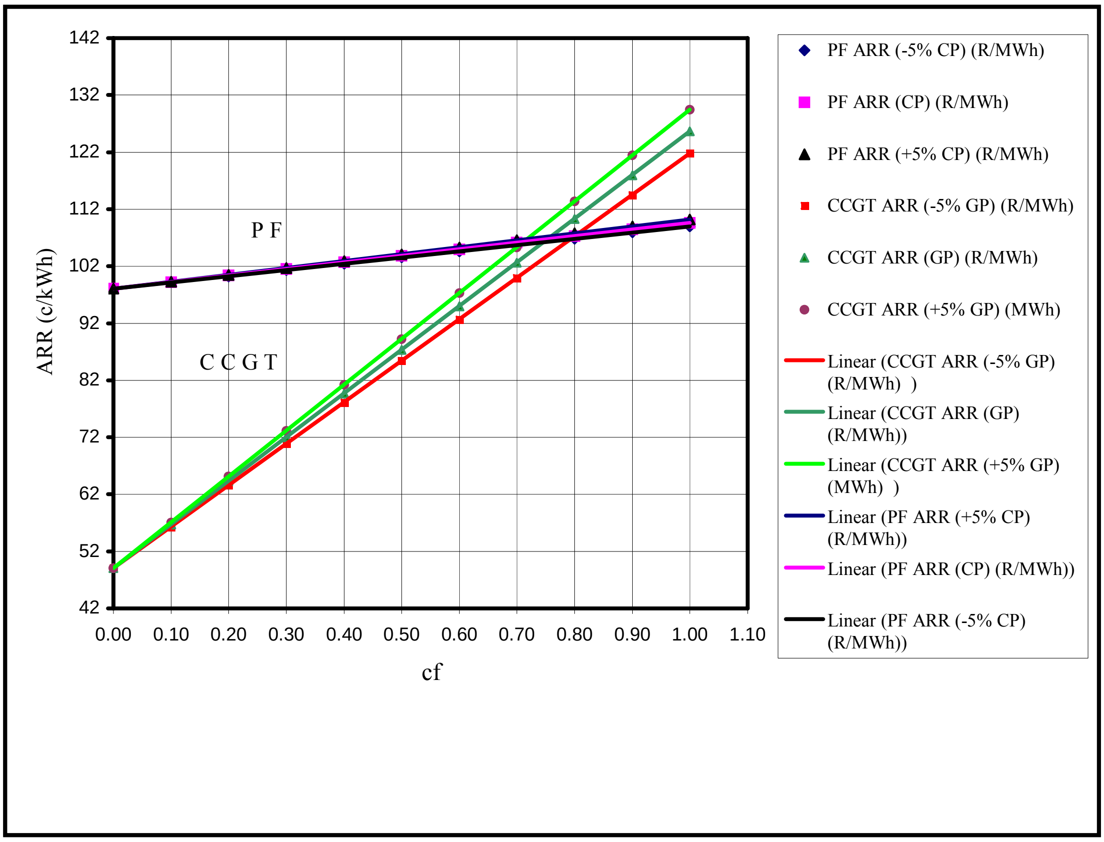



Figure 5.6 Sensitivities of ARR to +/-5% change in fuel prices (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.8 Variations in ARR to +/-10% change in fuel prices (PF/CCGT).**

| cf | PF ARR (-10% CP) (R/MWh) | PF ARR (CP) (R/MWh) | PF ARR (+10% CP) (R/MWh) | CCGT ARR (-10% GP) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (+10% GP) (MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 98.06 | 98.06 | 98.06 | 49.03 | 49.03 | 49.03 |
| 0.10 | 99.10 | 99.22 | 99.33 | 55.92 | 56.69 | 57.46 |
| 0.20 | 100.14 | 100.37 | 100.60 | 62.82 | 64.35 | 65.88 |
| 0.30 | 101.17 | 101.52 | 101.87 | 69.71 | 72.01 | 74.31 |
| 0.40 | 102.21 | 102.67 | 103.13 | 76.60 | 79.67 | 82.73 |
| 0.50 | 103.25 | 103.82 | 104.40 | 83.50 | 87.33 | 91.16 |
| 0.60 | 104.28 | 104.98 | 105.67 | 90.39 | 94.99 | 99.58 |
| 0.70 | 105.32 | 106.13 | 106.93 | 97.28 | 102.64 | 108.01 |
| 0.80 | 106.36 | 107.28 | 108.20 | 104.18 | 110.30 | 116.43 |
| 0.90 | 107.40 | 108.43 | 109.47 | 111.07 | 117.96 | 124.86 |
| 1.00 | 108.43 | 109.58 | 110.74 | 117.96 | 125.62 | 133.28 |

Source: Developed by author based on methodology in Stoft (2002).

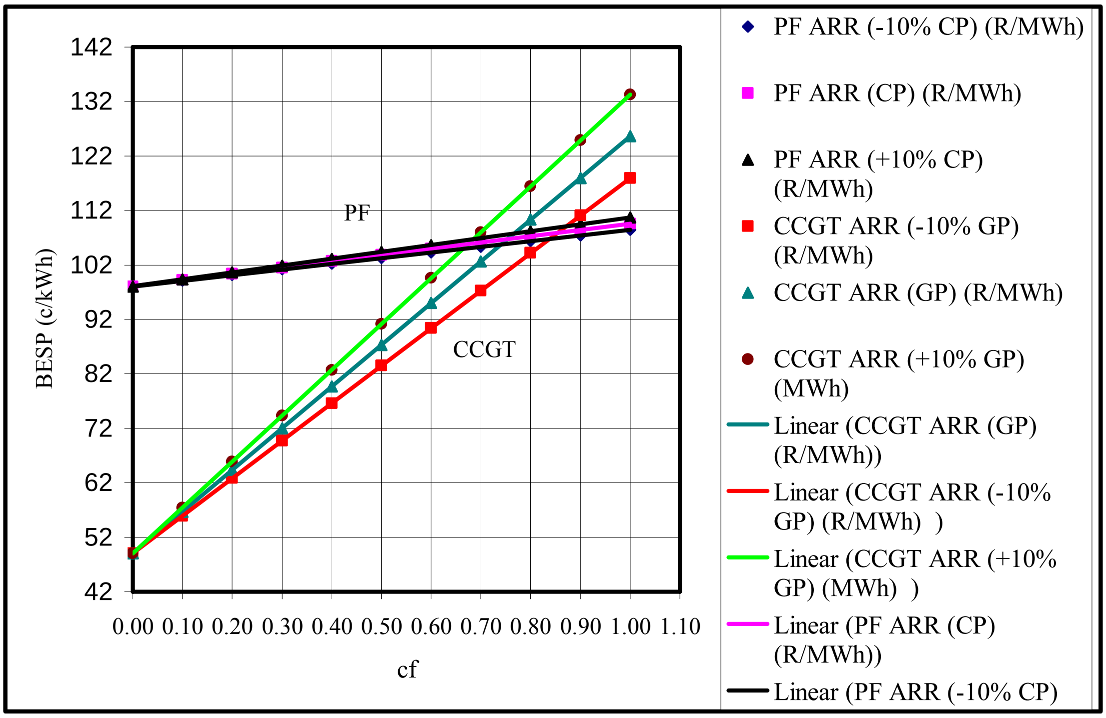



Figure 5.7 Sensitivities of ARR to +/-10% change in fuel prices (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.9 Variations in ARR to +/15% change in fuel prices (PF/CCGT).**

| cf | PF ARR (-15% CP) (R/MWh) | PF ARR (CP) (R/MWh) | PF ARR (+15% CP) (R/MWh) | CCGT ARR (-15% GP) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (+15% GP) (MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 98.06 | 98.06 | 98.06 | 49.03 | 49.03 | 49.03 |
| 0.10 | 99.04 | 99.22 | 99.39 | 55.54 | 56.69 | 57.84 |
| 0.20 | 100.02 | 100.37 | 100.71 | 62.05 | 64.35 | 66.65 |
| 0.30 | 101.00 | 101.52 | 102.04 | 68.56 | 72.01 | 75.45 |
| 0.40 | 101.98 | 102.67 | 103.36 | 75.07 | 79.67 | 84.26 |
| 0.50 | 102.96 | 103.82 | 104.69 | 81.58 | 87.33 | 93.07 |
| 0.60 | 103.94 | 104.98 | 106.01 | 88.09 | 94.99 | 101.88 |
| 0.70 | 104.92 | 106.13 | 107.34 | 94.60 | 102.64 | 110.69 |
| 0.80 | 105.90 | 107.28 | 108.66 | 101.11 | 110.30 | 119.49 |
| 0.90 | 106.88 | 108.43 | 109.99 | 107.62 | 117.96 | 128.30 |
| 1.00 | 107.86 | 109.58 | 111.31 | 114.13 | 125.62 | 137.11 |

Source: Developed by author based on methodology in Stoft (2002).

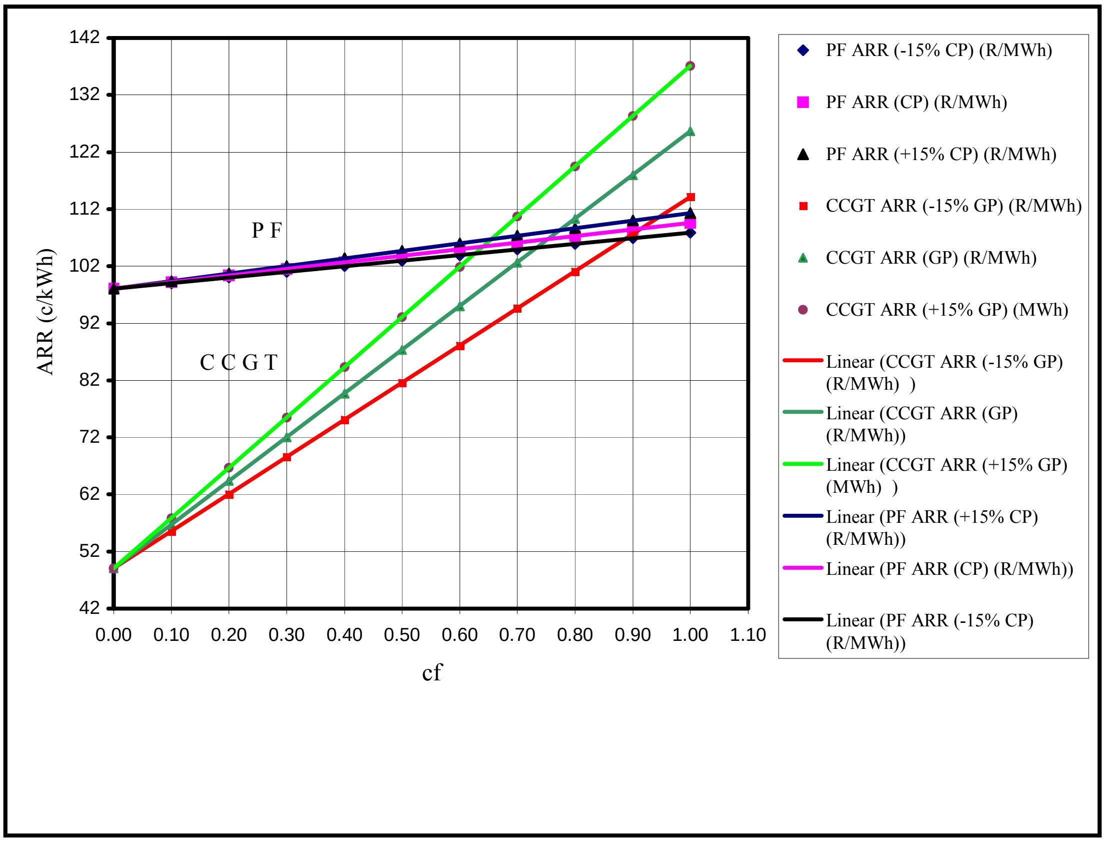



Figure 5.8 Sensitivities of ARR to +/-15% change in fuel prices (FG/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.10 Variations in ARR to +/20% change in fuel prices (FG/CCGT).**

| cf | PF ARR (-20% CP) (R/MWh) | PF ARR (CP) (R/MWh) | PF ARR (+20% CP) (R/MWh) | CCGT ARR (-20% GP) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (+20% GP) (MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 98.06 | 98.06 | 98.06 | 49.03 | 49.03 | 49.03 |
| 0.10 | 98.98 | 99.22 | 99.45 | 55.16 | 56.69 | 58.22 |
| 0.20 | 99.91 | 100.37 | 100.83 | 61.29 | 64.35 | 67.41 |
| 0.30 | 100.83 | 101.52 | 102.21 | 67.41 | 72.01 | 76.60 |
| 0.40 | 101.75 | 102.67 | 103.59 | 73.54 | 79.67 | 85.79 |
| 0.50 | 102.67 | 103.82 | 104.98 | 79.67 | 87.33 | 94.99 |
| 0.60 | 103.59 | 104.98 | 106.36 | 85.79 | 94.99 | 104.18 |
| 0.70 | 104.52 | 106.13 | 107.74 | 91.92 | 102.64 | 113.37 |
| 0.80 | 105.44 | 107.28 | 109.12 | 98.05 | 110.30 | 122.56 |
| 0.90 | 106.36 | 108.43 | 110.51 | 104.18 | 117.96 | 131.75 |
| 1.00 | 107.28 | 109.58 | 111.89 | 110.30 | 125.62 | 140.94 |

Source: Developed by author based on methodology in Stoft (2002).

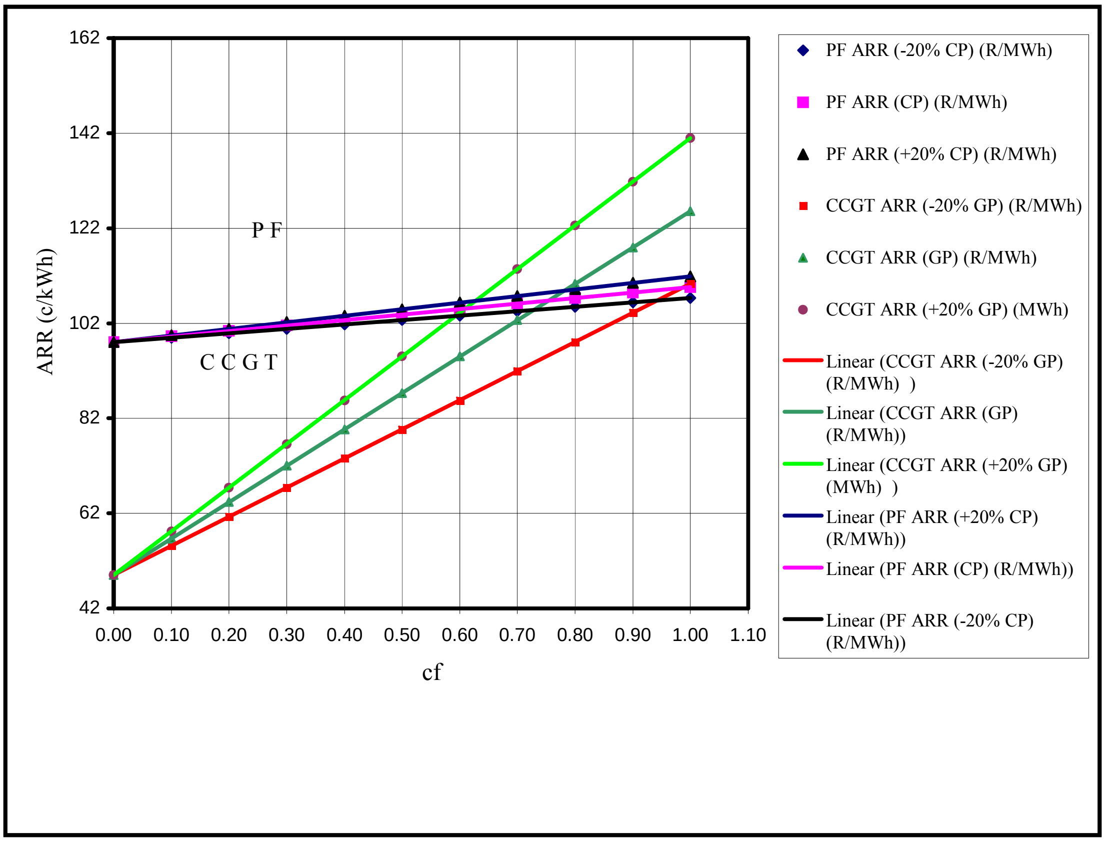



Figure 5.9 Sensitivities of ARR to +/-20% change in fuel prices (FG/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comments:** The ARRs for CCGT are more sensitive than those for coal-fired power stations. At a 20% uncertainty band the gas/coal equilibrium point varies between cf values of 0.60 to 1.00.

*Scenario 2 A combined-cycle gas turbine with CDM revenue*

**Table 5.11 Effect of SPCC on BESP (PF/CCGT).**

| cf | PF BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (SPCC) (c/kWh) |
|---|---|---|---|
| 0.10 | 106.51 | 67.16 | 59.33 |
| 0.20 | 58.60 | 41.11 | 34.40 |
| 0.30 | 42.62 | 32.43 | 26.14 |
| 0.40 | 34.64 | 28.08 | 22.01 |
| 0.50 | 29.85 | 25.50 | 19.54 |
| 0.60 | 26.65 | 23.78 | 17.89 |
| 0.70 | 24.37 | 22.55 | 16.71 |
| 0.80 | 22.66 | 21.62 | 15.83 |
| 0.90 | 21.33 | 20.90 | 15.15 |
| 1.00 | 20.26 | 20.33 | 14.61 |

Source: Developed by author based on methodology in Stoft (2002).

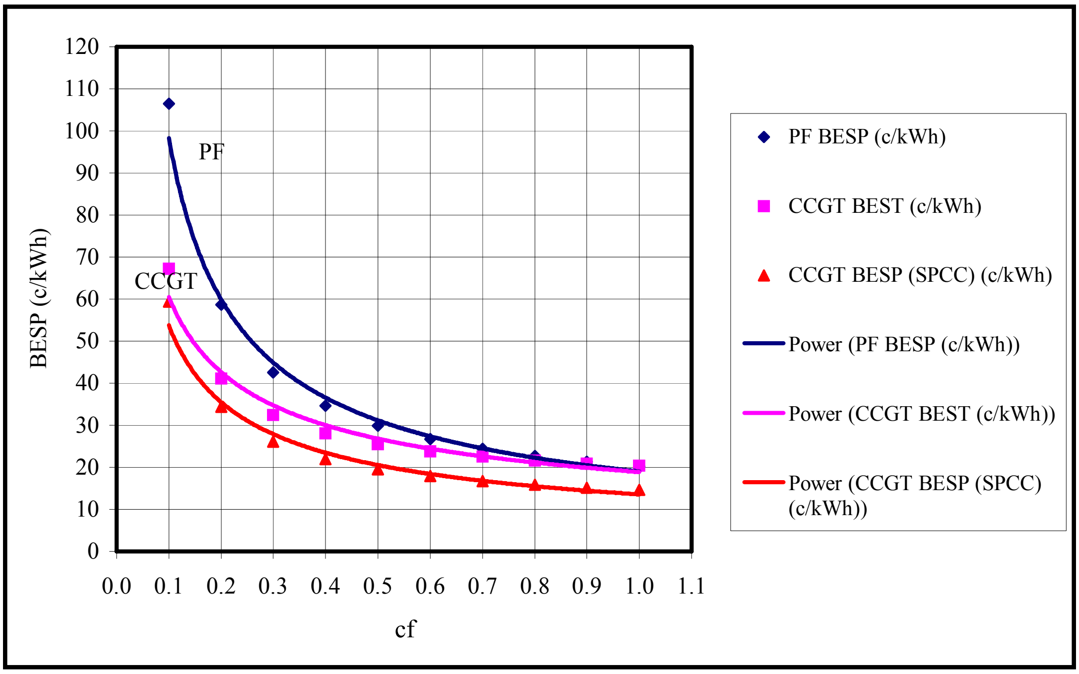



Figure 5.10 Effect of SPCC on BESP (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

Legend: BESP – Breakeven selling price of electricity

SPCC – Selling price of carbon dioxide credits

**Comment**: Although CCGT enjoys an advantage over PF in BESP terms, the CCGT advantage is enhanced by revenue provided by SPCC.

**Table 5.12 Variations in BESP to +/- 5% change in SPCC (PF/CCGT).**

| cf | PF BESP (c/kWh) | CCGT BESP ( - 5% SPCC) (c/kWh) | CCGT BESP (SPCC) (c/kWh) | CCGT BESP (+5% SPCC) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 106.51 | 59.61 | 59.29 | 59.01 |
| 0.20 | 58.60 | 34.68 | 34.40 | 34.12 |
| 0.30 | 42.62 | 26.41 | 26.15 | 25.86 |
| 0.40 | 34.64 | 22.28 | 22.01 | 21.73 |
| 0.50 | 29.85 | 19.81 | 19.53 | 19.26 |
| 0.60 | 26.65 | 18.16 | 17.89 | 17.61 |
| 0.70 | 24.37 | 16.99 | 16.71 | 16.44 |
| 0.80 | 22.66 | 16.11 | 15.83 | 15.56 |
| 0.90 | 21.33 | 15.42 | 15.15 | 14.88 |
| 1.00 | 20.26 | 14.88 | 14.61 | 14.33 |

Source: Developed by author based on methodology in Stoft (2002).

Legend: BESP – breakeven selling price of electricity

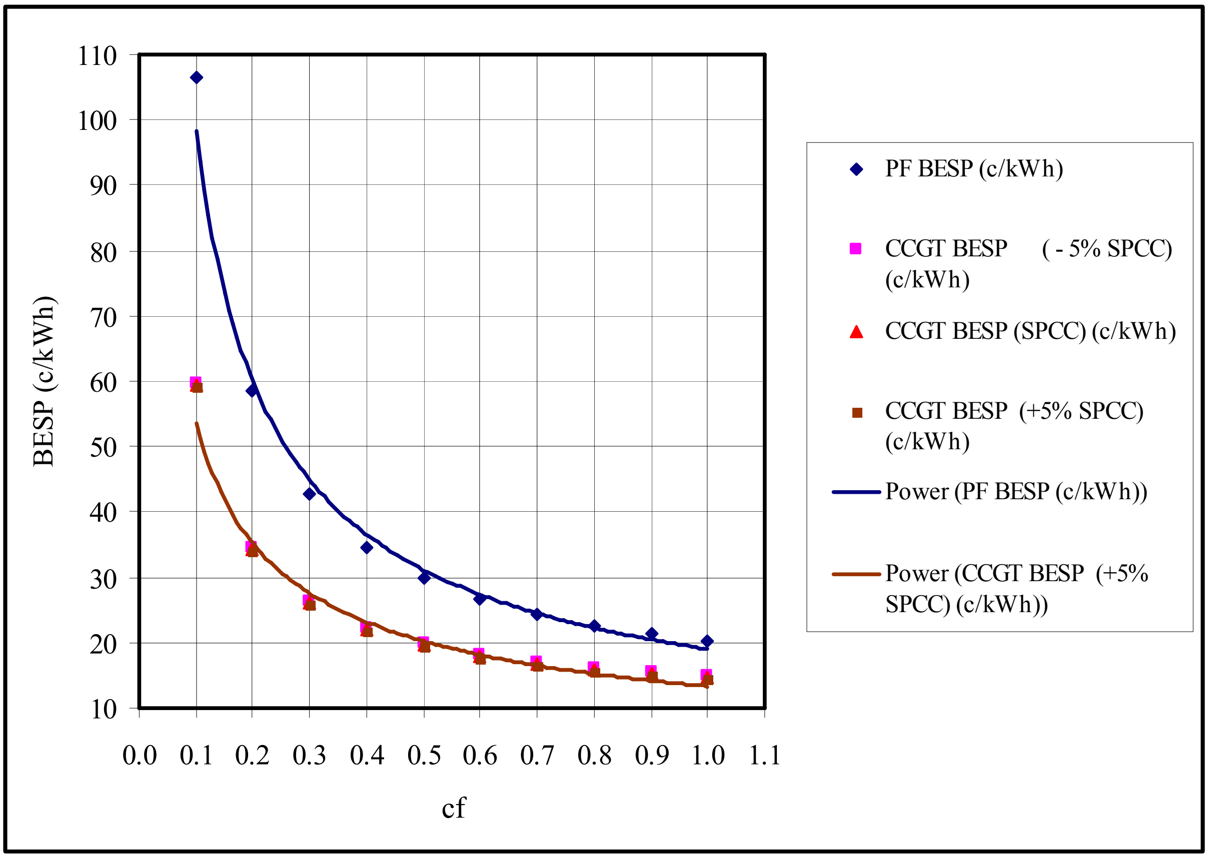



Figure 5.11 Sensitivities of BESP to +/-5% change in SPCC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.13 Variation in BESP to +/-10% change in SPCC (FG/CCGT).**

| cf | PF BESP (c/kWh) | CCGT BESP (-10% SPCC) (c/kWh) | CCGT BESP (SPCC) (c/kWh) | CCGT BESP (+10% SPCC) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 106.51 | 59.90 | 59.30 | 58.71 |
| 0.20 | 58.60 | 34.95 | 34.40 | 33.84 |
| 0.30 | 42.62 | 26.69 | 26.13 | 25.58 |
| 0.40 | 34.64 | 22.56 | 22.01 | 21.46 |
| 0.50 | 29.85 | 20.08 | 19.53 | 18.98 |
| 0.60 | 26.65 | 18.44 | 17.89 | 17.34 |
| 0.70 | 24.37 | 17.26 | 16.71 | 16.17 |
| 0.80 | 22.66 | 16.38 | 15.83 | 15.29 |
| 0.90 | 21.33 | 15.70 | 15.15 | 14.61 |
| 1.00 | 20.26 | 15.15 | 14.61 | 14.06 |

Source: Developed by author based on methodology in Stoft (2002).

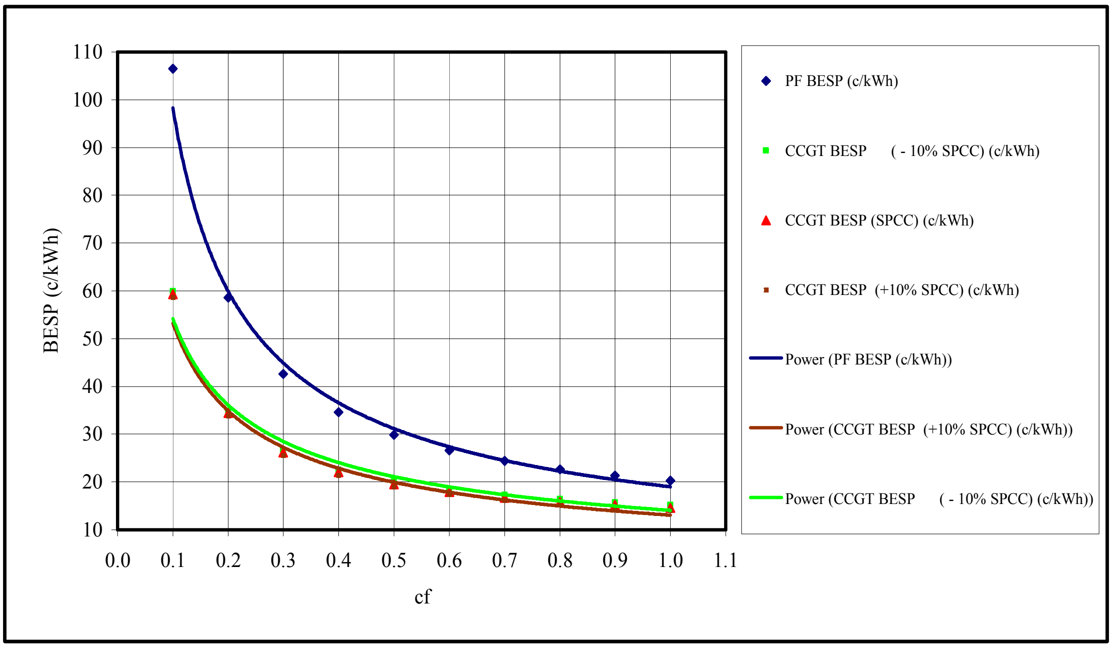



Figure 5.12 Sensitivities of BESP to +/-10% change in SPCC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.14 Variations in BESP to +/-15% changes in SPCC (PF/CCGT).**

| cf | PF BESP (c/kWh) | CCGT BESP (-15% SPCC) (c/kWh) | CCGT BESP (SPCC) (c/kWh) | CCGT BESP (+15% SPCC) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 106.51 | 60.18 | 59.29 | 58.44 |
| 0.20 | 58.60 | 35.21 | 34.40 | 33.57 |
| 0.30 | 42.62 | 26.96 | 26.13 | 25.31 |
| 0.40 | 34.64 | 22.83 | 22.01 | 21.18 |
| 0.50 | 29.85 | 20.36 | 19.53 | 18.71 |
| 0.60 | 26.65 | 18.71 | 17.89 | 17.07 |
| 0.70 | 24.37 | 17.53 | 16.72 | 15.90 |
| 0.80 | 22.66 | 16.65 | 15.83 | 15.02 |
| 0.90 | 21.33 | 15.97 | 15.15 | 14.34 |
| 1.00 | 20.26 | 15.42 | 14.61 | 13.81 |

Source: Developed by author based on methodology in Stoft (2002).

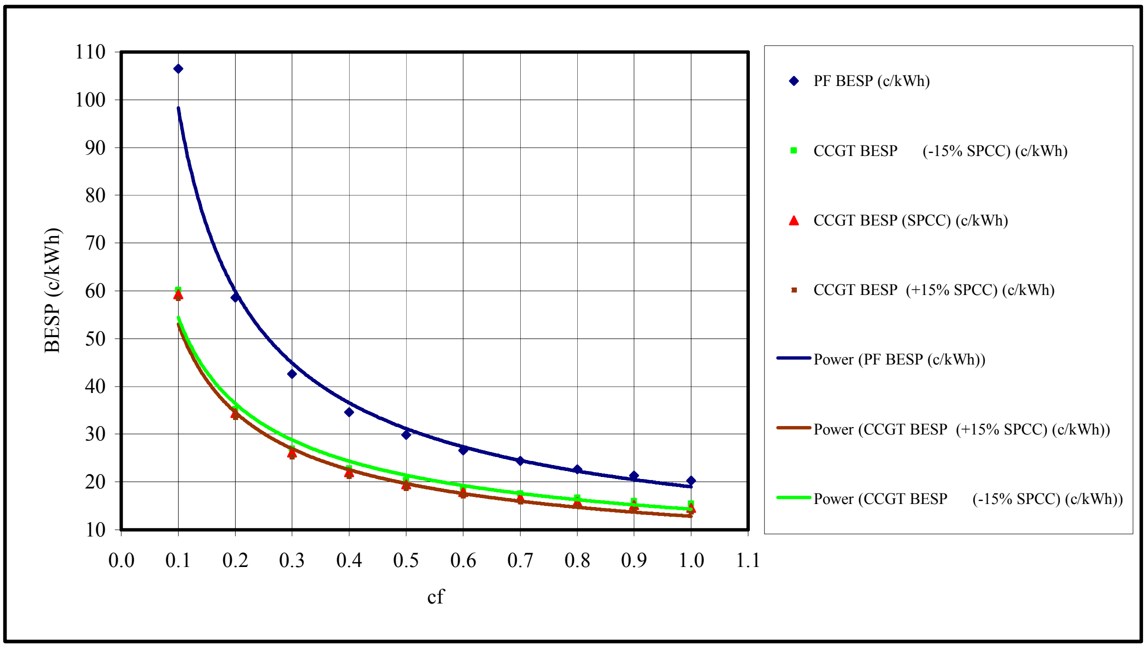



Figure 5.13 Sensitivities of BESP to +/-15% changes in SPCC (FG/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.15 Variations in BESP to +/-20% changes in SPCC (PF/CCGT).**

| cf | PF BESP (c/kWh) | CCGT BESP (-20% SPCC) (c/kWh) | CCGT BESP (SPCC) (c/kWh) | CCGT BESP (+20% SPCC) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 106.51 | 60.46 | 59.29 | 58.16 |
| 0.20 | 58.60 | 35.51 | 34.40 | 33.29 |
| 0.30 | 42.62 | 27.24 | 26.13 | 25.03 |
| 0.40 | 34.64 | 23.11 | 22.01 | 20.91 |
| 0.50 | 29.85 | 20.63 | 19.53 | 18.44 |
| 0.60 | 26.65 | 18.98 | 17.89 | 16.80 |
| 0.70 | 24.37 | 17.81 | 16.72 | 15.63 |
| 0.80 | 22.66 | 16.92 | 15.84 | 14.75 |
| 0.90 | 21.33 | 16.24 | 15.15 | 14.06 |
| 1.00 | 20.26 | 15.69 | 14.61 | 13.56 |

Source: Developed by author based on methodology in Stoft (2002).

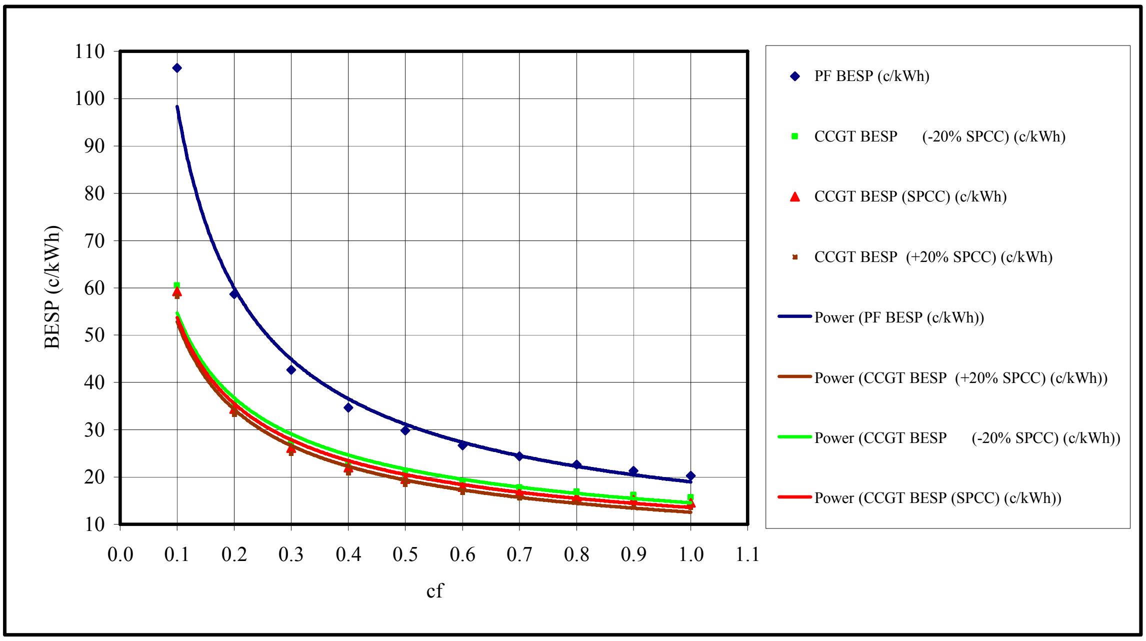



Figure 5.14 Sensitivities of BESP to +/-20% changes in SPCC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comment**: Variances of up to 20% in SPCC have a comparatively minor impact on the cf/BESP relationship for CCGT, which remains superior to PF over the full range.

*Scenario 3 A combined-cycle gas turbine with externalities accounted for by damage costs*

**Table 5.16 Effect of damage costs on BESP (PF/CCGT).**

| cf | PF BESP (c/kWh) | PF BESP (DC) (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC) (c/kWh) |
|---|---|---|---|---|
| 0.1 | 106.51 | 111.37 | 67.16 | 69.37 |
| 0.2 | 58.6 | 63.40 | 41.11 | 43.32 |
| 0.3 | 42.62 | 47.41 | 32.43 | 34.63 |
| 0.4 | 34.64 | 39.42 | 28.08 | 30.32 |
| 0.5 | 29.85 | 34.63 | 25.5 | 27.73 |
| 0.6 | 26.65 | 31.42 | 23.78 | 26.01 |
| 0.7 | 24.37 | 29.14 | 22.55 | 24.77 |
| 0.8 | 22.66 | 27.42 | 21.62 | 23.85 |
| 0.9 | 21.33 | 26.09 | 20.9 | 23.13 |
| 1.0 | 20.26 | 25.02 | 20.33 | 22.56 |

Source: Developed by author based on methodology in Stoft (2002).

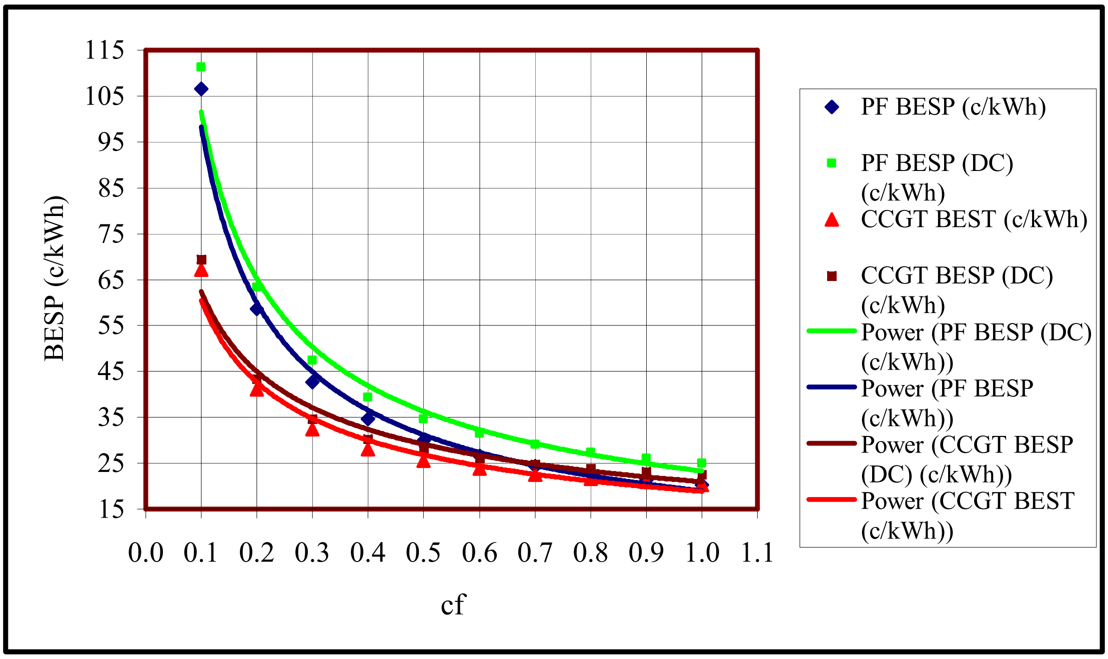



Figure 5.15 Effect of DC on BESP (PF/CCGT)

DC – damage

**Comments:** DC impacts on both PF and CCGT generation to the extent that CCGT with DC exhibits little advantage over PF without DC, at least in the +0.7 cf region.

**Table 5.17 Variations in BESP to +/-5 changes in DC (PF/CCGT).**

| cf | PF BESP (DC -5%) (c/kWh) | PF BESP (DC) (c/kWh) | PF BESP (DC +5%) (c/kWh) | CCGT BESP (DC-5%) (c/kWh) | CCGT BESP (DC) (c/kWh) | CCGT BESP (DC +5%) (c/kWh) |
|---|---|---|---|---|---|---|
| 0.1 | 111.13 | 111.37 | 111.61 | 69.26 | 69.37 | 69.48 |
| 0.2 | 63.16 | 63.40 | 63.64 | 43.20 | 43.32 | 43.43 |
| 0.3 | 47.19 | 47.41 | 47.65 | 34.52 | 34.63 | 34.74 |
| 0.4 | 39.18 | 39.42 | 39.65 | 30.21 | 30.32 | 30.43 |
| 0.5 | 34.39 | 34.62 | 34.86 | 27.62 | 27.73 | 27.84 |
| 0.6 | 31.19 | 31.42 | 31.66 | 25.89 | 26.01 | 26.12 |
| 0.7 | 28.90 | 29.14 | 29.37 | 24.66 | 24.77 | 24.89 |
| 0.8 | 27.18 | 27.42 | 27.66 | 23.74 | 23.85 | 23.96 |
| 0.9 | 25.85 | 26.09 | 26.33 | 23.02 | 23.13 | 23.24 |
| 1.0 | 24.78 | 25.03 | 25.26 | 22.45 | 22.56 | 22.67 |

Source: Developed by author based on methodology in Stoft (2002).

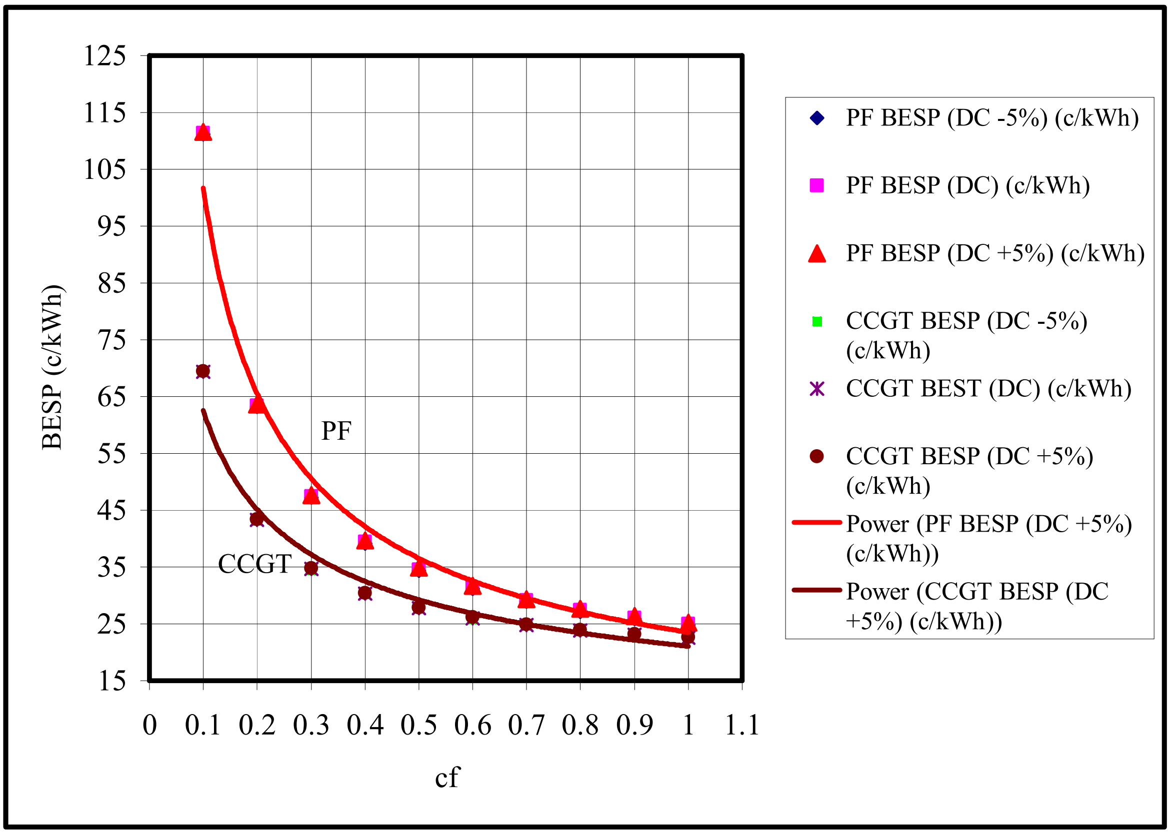



Figure 5.16 Sensitivities of BESP to +/- 5% changes in DC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.18 Variations in BESP to +/-10 changes in DC (PF/CCGT).**

| cf | PF BESP (DC -10%) (c/kWh) | PF BESP (DC) (c/kWh) | PF BESP (DC +10%) (c/kWh) | CCGT BESP (DC -10%) (c/kWh) | CCGT BESP (DC) (c/kWh) | CCGT BESP (DC +10%) (c/kWh) |
|---|---|---|---|---|---|---|
| 0.1 | 110.89 | 111.37 | 111.85 | 69.15 | 69.37 | 69.59 |
| 0.2 | 62.92 | 63.40 | 63.88 | 43.09 | 43.32 | 43.54 |
| 0.3 | 46.95 | 47.42 | 47.89 | 34.41 | 34.64 | 34.86 |
| 0.4 | 38.94 | 39.42 | 39.89 | 30.09 | 30.32 | 30.54 |
| 0.5 | 34.14 | 34.62 | 35.10 | 27.51 | 27.73 | 27.95 |
| 0.6 | 30.95 | 31.42 | 31.90 | 25.79 | 26.01 | 26.23 |
| 0.7 | 28.66 | 29.14 | 29.61 | 24.55 | 24.77 | 25.00 |
| 0.8 | 26.94 | 27.42 | 27.90 | 23.62 | 23.85 | 24.07 |
| 0.9 | 25.61 | 26.09 | 26.57 | 22.91 | 23.13 | 23.35 |
| 1.0 | 24.54 | 25.03 | 25.50 | 22.33 | 22.56 | 22.78 |

Source: Developed by author based on methodology in Stoft (2002)

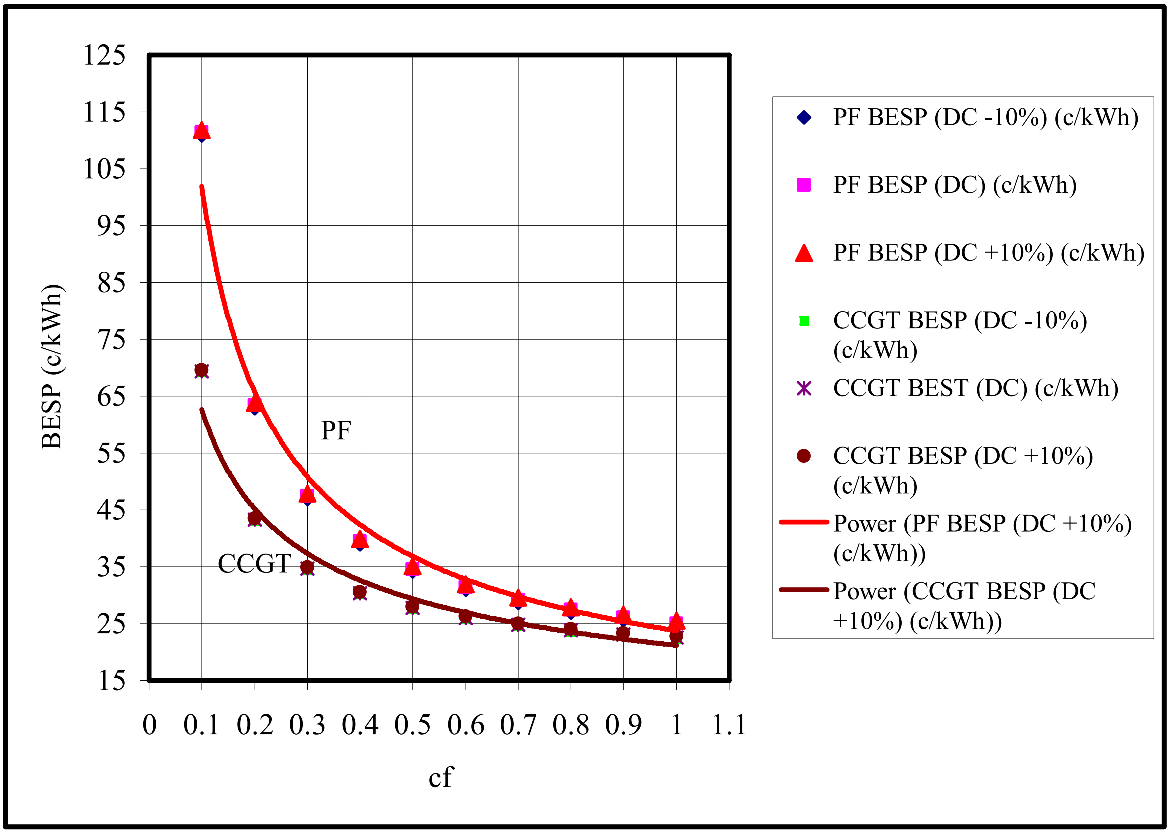



Figure 5.17 Sensitivities of BESP to +/- 10% changes in DC (PF/CCGT)

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.19 Variations in BESP to +/-20 changes in DC (PF/CCGT).**

| cf | PF BESP (DC -20%) (c/kWh) | PF BESP (DC) (c/kWh) | PF BESP (DC +20%) (c/kWh) | CCGT BESP (DC -20%) (c/kWh) | CCGT BESP (DC) (c/kWh) | CCGT BESP (DC +20%) (c/kWh) |
|---|---|---|---|---|---|---|
| 0.1 | 111.13 | 111.37 | 111.61 | 69.26 | 69.37 | 69.48 |
| 0.2 | 63.16 | 63.4 | 63.64 | 43.2 | 43.32 | 43.43 |
| 0.3 | 47.19 | 47.41 | 47.65 | 34.52 | 34.63 | 34.74 |
| 0.4 | 39.18 | 39.42 | 39.65 | 30.21 | 30.32 | 30.43 |
| 0.5 | 34.39 | 34.62 | 34.86 | 27.62 | 27.73 | 27.84 |
| 0.6 | 31.19 | 31.42 | 31.66 | 25.89 | 26.01 | 26.12 |
| 0.7 | 28.9 | 29.14 | 29.37 | 24.66 | 24.77 | 24.89 |
| 0.8 | 27.18 | 27.42 | 27.66 | 23.74 | 23.85 | 23.96 |
| 0.9 | 25.85 | 26.09 | 26.33 | 23.02 | 23.13 | 23.24 |
| 1.0 | 24.78 | 25.03 | 25.26 | 22.45 | 22.56 | 22.67 |

Source: Developed by author based on methodology in Stoft (2002).

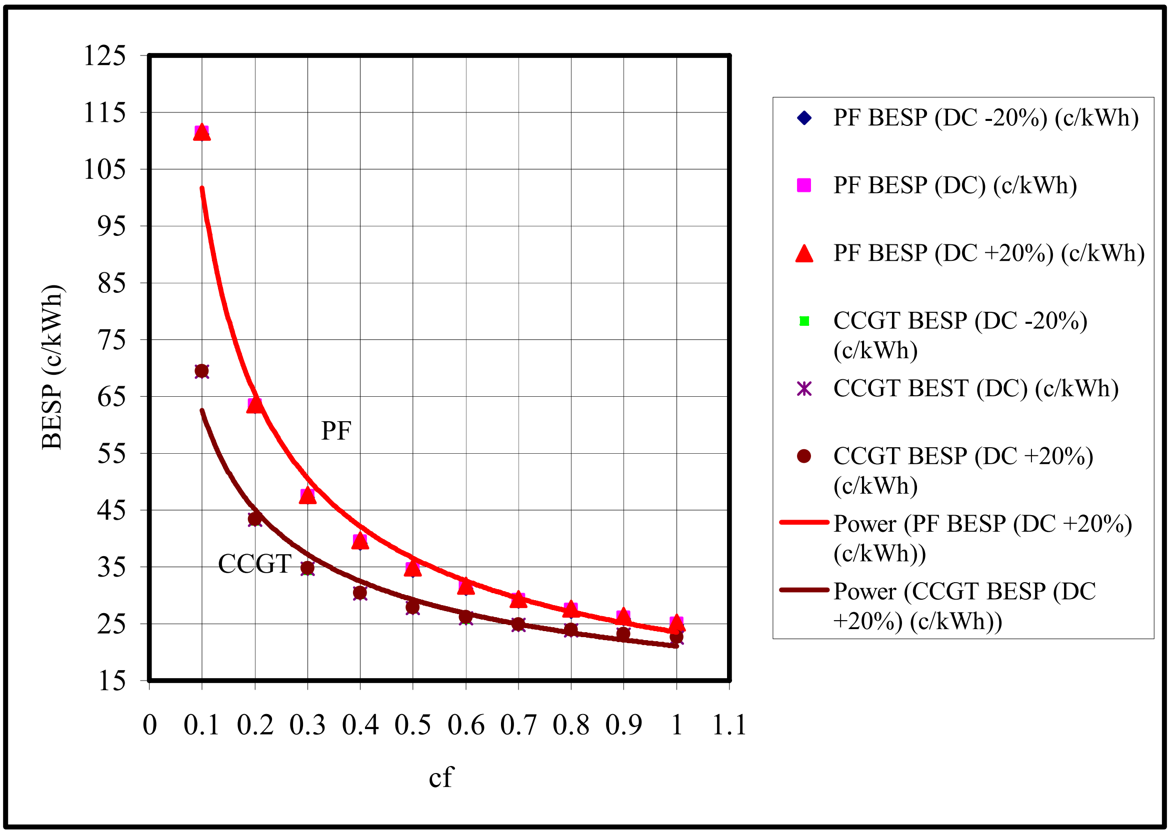



Figure 5.18 Sensitivities of BESP to +/- 20% changes in DC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.20 Variations in BESP to +/-30% changes in DC (PF/CCGT).**

| cf | PF BESP (DC -30%) (c/kWh) | PF BESP (DC) (c/kWh) | PF BESP (DC +30%) (c/kWh) | CCGT BESP (DC -30%) (c/kWh) | CCGT BESP (DC) (c/kWh) | CCGT BESP (DC +30%) (c/kWh) |
|---|---|---|---|---|---|---|
| 0.1 | 110.41 | 111.37 | 112.32 | 68.71 | 69.39 | 70.03 |
| 0.2 | 62.45 | 63.40 | 64.35 | 42.65 | 43.32 | 43.98 |
| 0.3 | 46.45 | 47.41 | 48.36 | 33.96 | 34.63 | 35.30 |
| 0.4 | 38.46 | 39.41 | 40.37 | 29.65 | 30.32 | 30.99 |
| 0.5 | 33.67 | 34.62 | 35.57 | 27.06 | 27.73 | 28.40 |
| 0.6 | 30.47 | 31.42 | 32.37 | 25.34 | 26.01 | 26.67 |
| 0.7 | 28.19 | 29.14 | 30.09 | 24.11 | 24.77 | 25.44 |
| 0.8 | 26.47 | 27.43 | 28.38 | 23.18 | 23.85 | 24.52 |
| 0.9 | 25.14 | 26.09 | 27.05 | 22.46 | 23.13 | 23.80 |
| £1.000 | 24.07 | 25.02 | 25.98 | 21.89 | 22.56 | 23.23 |

Source: Developed by author based on methodology in Stoft (2002).

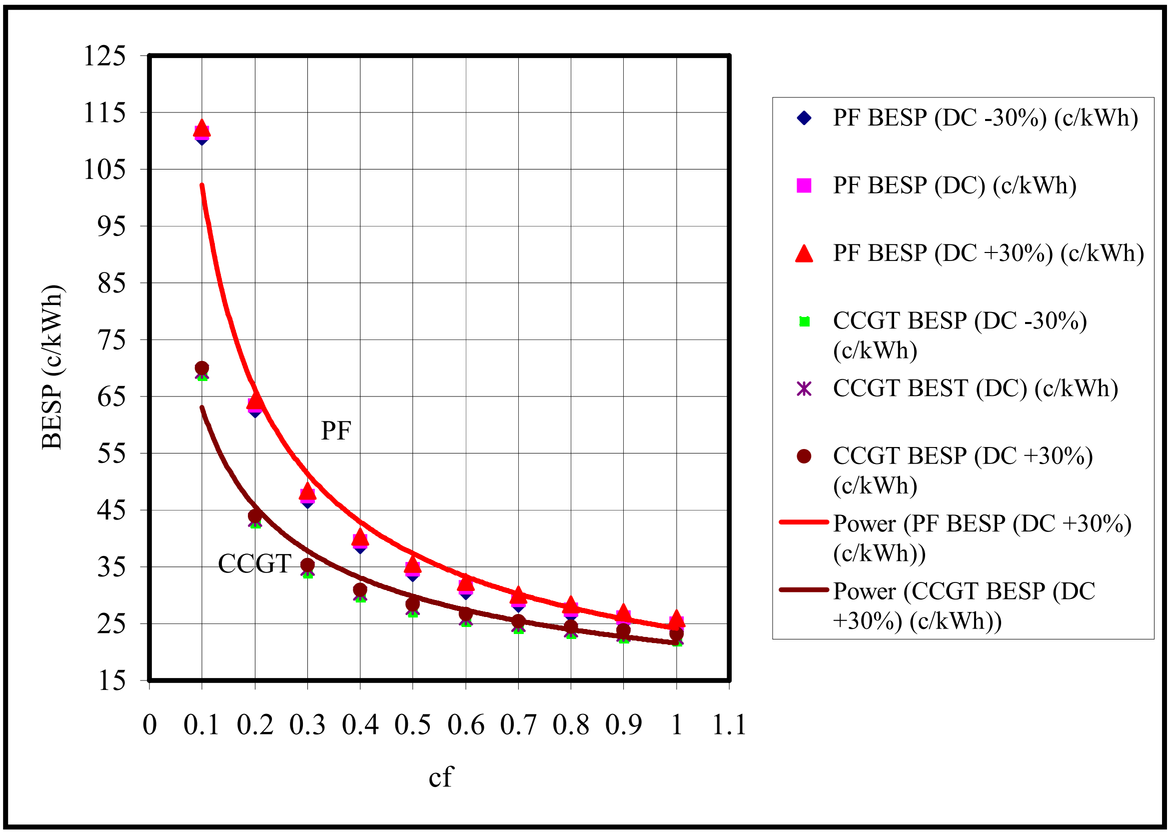



Figure 5.19 Sensitivities of BESP to +/- 30% changes in DC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comment:** Variances in DC, up to 30%, do little to change the relative positions of PF and CCGT generation expressed in terms of cf and BESP.

*Scenario 4 A combined-cycle gas turbine with CDM revenue and externalities accounted for by damage costs*

**Table 5.21 Effect of SPCC and DC on BESP (PF/CCGT).**

| cf | PF BESP (DC) (c/kWh) | CCGT BESP (DC) (c/kWh) | CCGT BESP (SPCC, DC) (c/kWh) |
|---|---|---|---|
| 0.10 | 111.30 | 69.39 | 62.13 |
| 0.20 | 63.38 | 43.32 | 38.32 |
| 0.30 | 47.41 | 34.63 | 30.38 |
| 0.40 | 39.42 | 30.32 | 26.41 |
| 0.50 | 34.63 | 27.73 | 24.03 |
| 0.60 | 31.44 | 26.01 | 22.44 |
| 0.70 | 29.16 | 24.77 | 21.31 |
| 0.80 | 27.44 | 23.85 | 20.41 |
| 0.90 | 26.11 | 23.13 | 19.69 |
| 1.00 | 25.05 | 22.56 | 19.11 |

Source: Developed by author based on methodology in Stoft (2002).

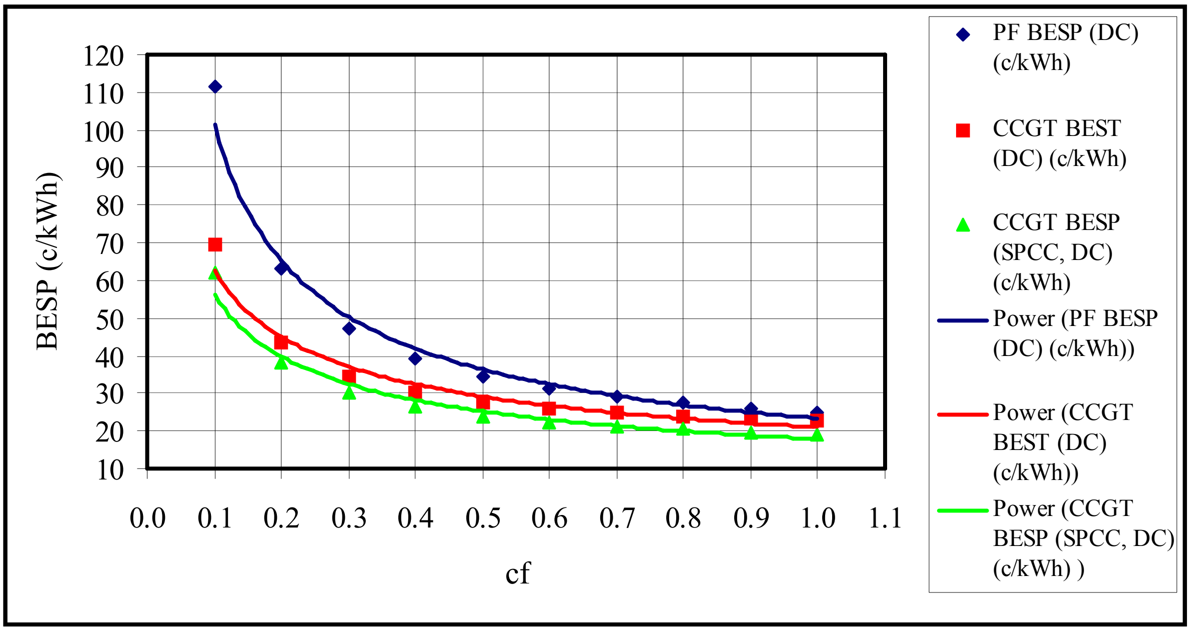



Figure 5.20 Effect of SPCC and DC on BESP (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.22 Variations in BESP to +/- 5% changes in both DC and SPCC (PF/CCGT).**

| cf | PF BESP (DC) (c/kWh) | CCGT BESP (SPCC -5%, DC -5%) (c/kWh) | CCGT BESP) (SPCC, DC) (c/kWh) | CCGT BESP (SPCC +5%, DC +5%) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 111.30 | 62.16 | 62.13 | 62.10 |
| 0.20 | 63.38 | 38.35 | 38.32 | 38.29 |
| 0.30 | 47.41 | 30.41 | 30.38 | 30.35 |
| 0.40 | 39.42 | 26.44 | 26.41 | 26.38 |
| 0.50 | 34.63 | 24.06 | 24.03 | 24.00 |
| 0.60 | 31.44 | 22.47 | 22.44 | 22.42 |
| 0.70 | 29.16 | 21.34 | 21.31 | 21.28 |
| 0.80 | 27.44 | 20.44 | 20.41 | 20.37 |
| 0.90 | 26.11 | 19.72 | 19.69 | 19.65 |
| 1.00 | 25.05 | 19.15 | 19.11 | 19.08 |

Source: Developed by author based on methodology in Stoft (2002).

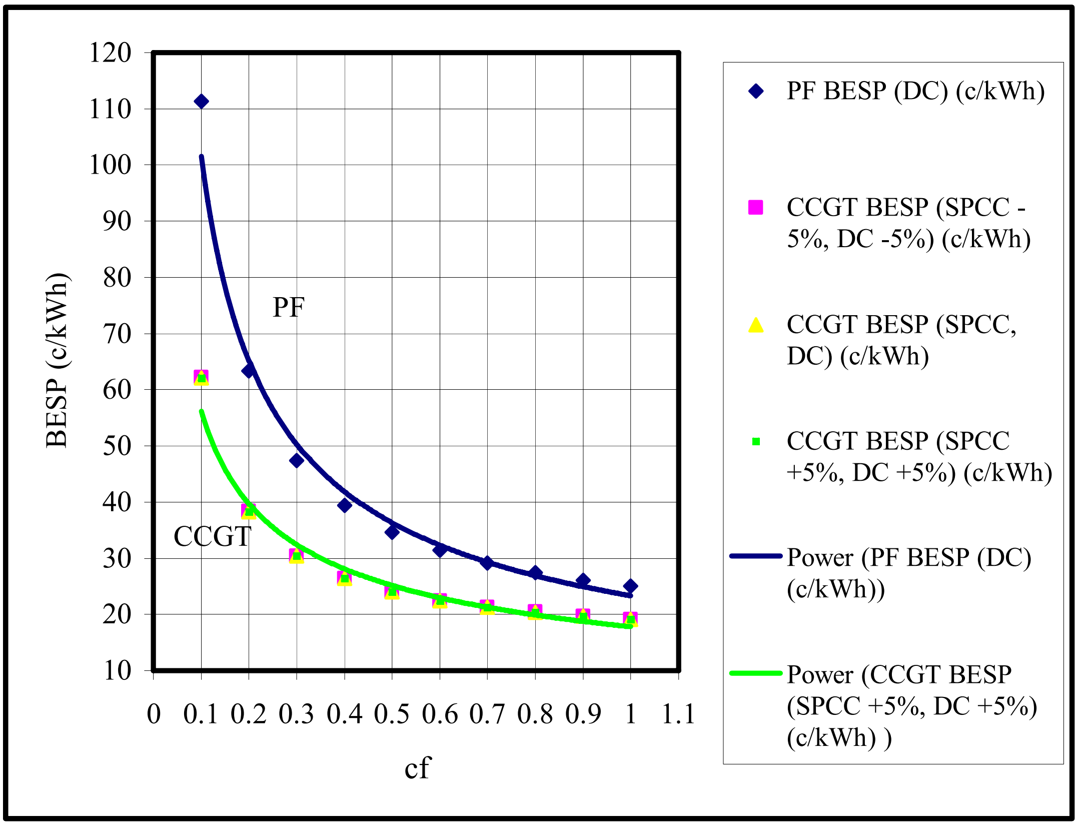



Figure 5.21 Sensitivities of BESP to +/-5% changes in both DC and SPCC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.23 Variations in BESP to +/- 10% changes in both DC and SPCC (PF/CCGT).**

| cf | PF BESP (DC) (c/kWh) | CCGT BESP (SPCC -10%, DC -10%) (c/kWh) | CCGT BESP) (SPCC, DC) (c/kWh) | CCGT BESP (SPCC +10%, DC +10%) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 111.30 | 62.19 | 62.13 | 62.07 |
| 0.20 | 63.38 | 38.38 | 38.32 | 38.26 |
| 0.30 | 47.41 | 30.44 | 30.38 | 30.33 |
| 0.40 | 39.42 | 26.47 | 26.41 | 26.35 |
| 0.50 | 34.63 | 24.09 | 24.03 | 23.97 |
| 0.60 | 31.44 | 22.50 | 22.44 | 22.39 |
| 0.70 | 29.16 | 21.37 | 21.31 | 21.25 |
| 0.80 | 27.44 | 20.48 | 20.41 | 20.33 |
| 0.90 | 26.11 | 19.76 | 19.69 | 19.61 |
| 1.00 | 25.05 | 19.18 | 19.11 | 19.04 |

Source: Developed by author based on methodology in Stoft (2002).

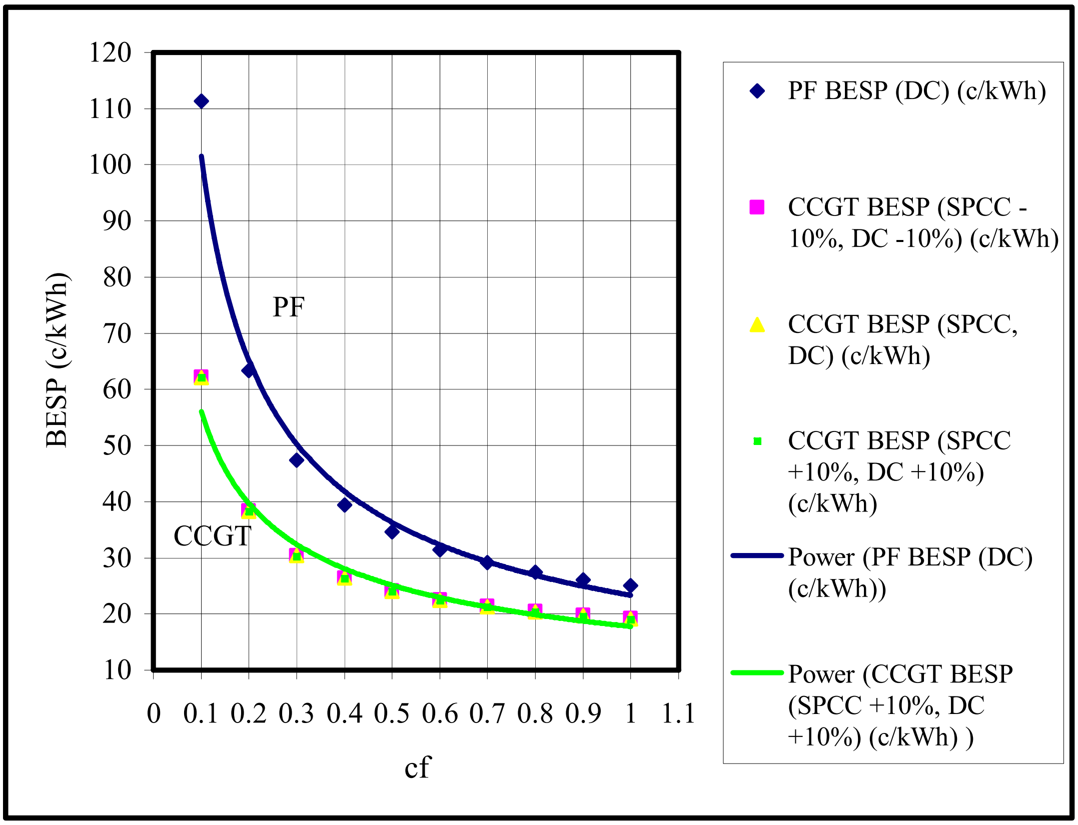



Figure 5.22 Sensitivities of BESP to +/-10% changes in both DC and SPCC (PF/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.24 Variations in BESP to +/- 15% changes in both DC and SPCC (PF/CCGT).**

| cf | PF BESP (DC) (c/kWh) | CCGT BESP (SPCC -15%, DC -15%) (c/kWh) | CCGT BESP) (SPCC, DC) (c/kWh) | CCGT BESP (SPCC +15%, DC +15%) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 111.30 | 62.22 | 62.13 | 62.04 |
| 0.20 | 63.38 | 38.41 | 38.32 | 38.23 |
| 0.30 | 47.41 | 30.47 | 30.38 | 30.30 |
| 0.40 | 39.42 | 26.50 | 26.41 | 26.32 |
| 0.50 | 34.63 | 24.12 | 24.03 | 23.94 |
| 0.60 | 31.44 | 22.53 | 22.44 | 22.36 |
| 0.70 | 29.16 | 21.40 | 21.31 | 21.22 |
| 0.80 | 27.44 | 20.52 | 20.41 | 20.30 |
| 0.90 | 26.11 | 19.80 | 19.69 | 19.58 |
| 1.00 | 25.05 | 19.22 | 19.11 | 19.00 |

Source: Developed by author based on methodology in Stoft (2002).

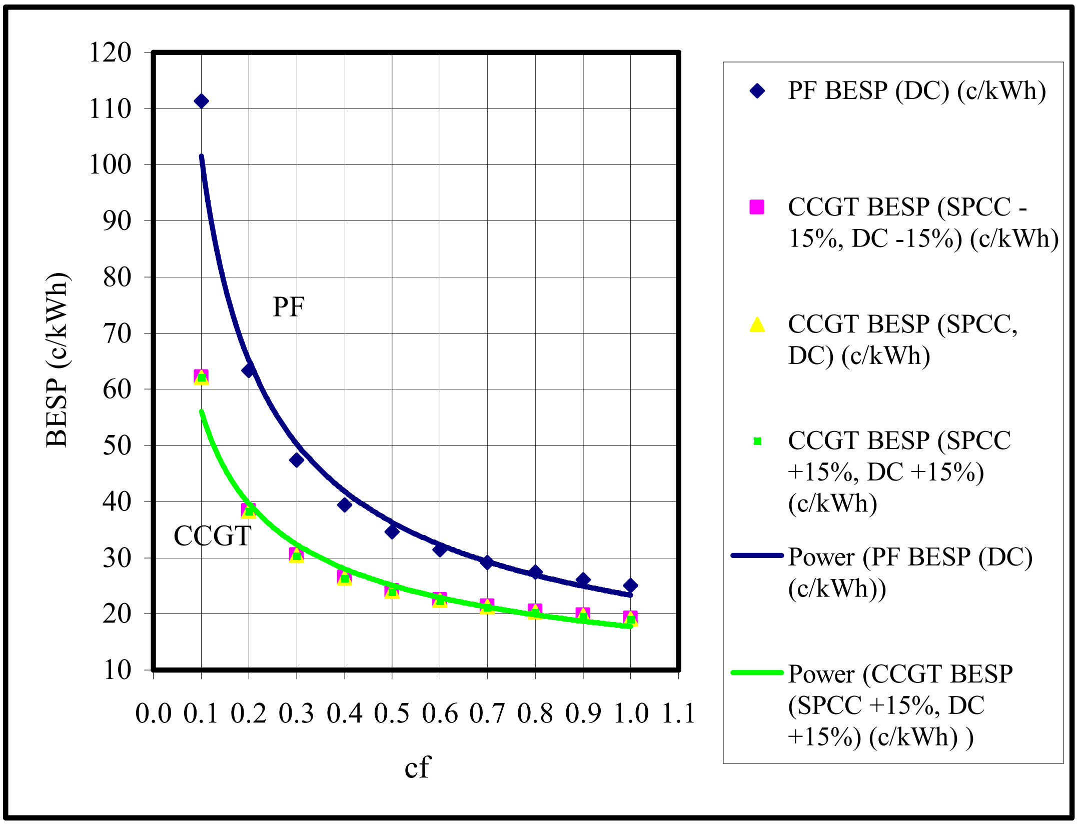



Figure 5.23 Sensitivities of BESP to +/-15% changes in both DC and SPCC (PF/CCGT).
Source: Developed by author based on methodology in Stoft (2002).

**Table 5.25 Variations in BESP to +/- 20% changes in both DC and SPCC (PF/CCGT).**

| cf | PF BESP (DC) (c/kWh) | CCGT BESP (SPCC - 20%, DC -20%) (c/kWh) | CCGT BESP) (SPCC, DC) (c/kWh) | CCGT BESP (SPCC +20%, DC +20%) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 111.30 | 62.25 | 62.13 | 62.01 |
| 0.20 | 63.38 | 38.44 | 38.32 | 38.20 |
| 0.30 | 47.41 | 30.50 | 30.38 | 30.27 |
| 0.40 | 39.42 | 26.53 | 26.41 | 26.30 |
| 0.50 | 34.63 | 24.15 | 24.03 | 23.91 |
| 0.60 | 31.44 | 22.56 | 22.44 | 22.33 |
| 0.70 | 29.16 | 21.43 | 21.31 | 21.19 |
| 0.80 | 27.44 | 20.55 | 20.41 | 20.26 |
| 0.90 | 26.11 | 19.83 | 19.69 | 19.54 |
| 1.00 | 25.05 | 19.26 | 19.11 | 18.97 |

Source: Developed by author based on methodology in Stoft (2002).

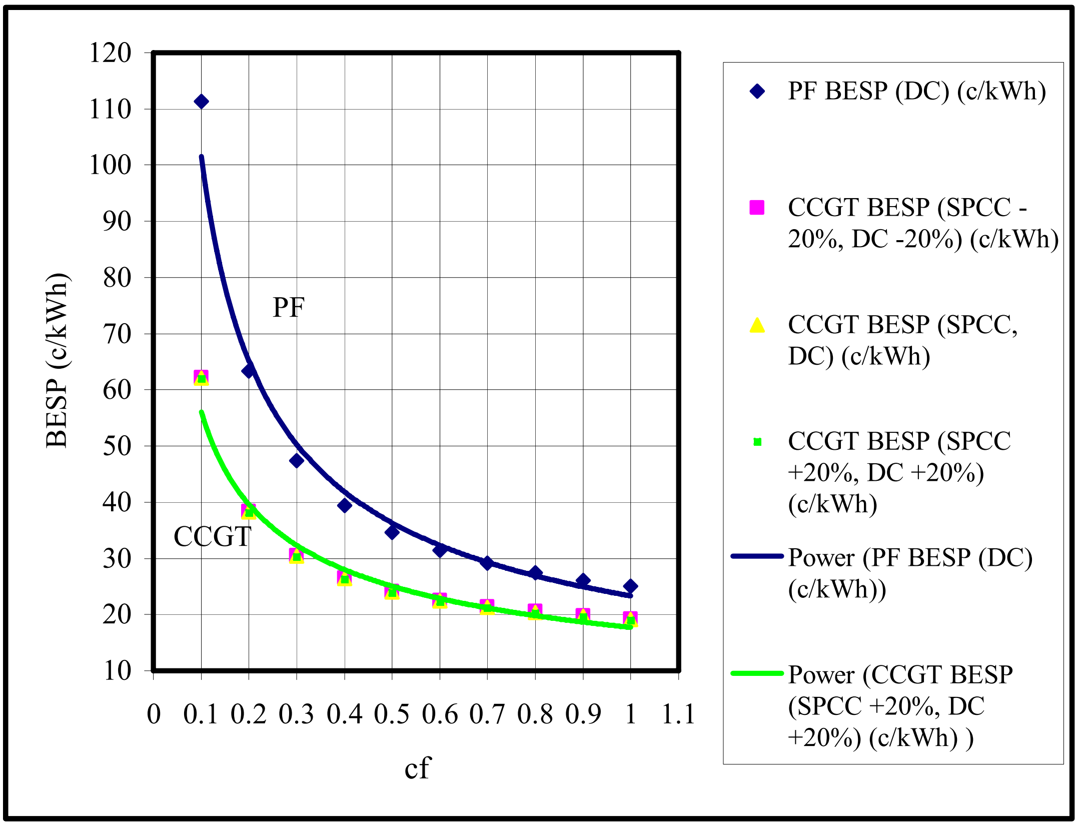



Figure 5.24 Sensitivities of BESP to +/-20% changes in both DC and SPCC (PF/CCGT).
Source: Developed by author based on methodology in Stoft (2002).

**Table 5.26 Variations in BESP to +/- 30% changes in both DC and SPCC (PF/CCGT).**

| cf | PF BESP (DC) (c/kWh) | CCGT BESP (SPCC -30%, DC -30%) (c/kWh) | CCGT BESP) (SPCC, DC) (c/kWh) | CCGT BESP (SPCC +30%, DC +30%) (c/kWh) |
|---|---|---|---|---|
| 0.10 | 111.30 | 62.31 | 62.13 | 61.95 |
| 0.20 | 63.38 | 38.50 | 38.32 | 38.14 |
| 0.30 | 47.41 | 30.56 | 30.38 | 30.21 |
| 0.40 | 39.42 | 26.59 | 26.41 | 26.24 |
| 0.50 | 34.63 | 24.21 | 24.03 | 23.86 |
| 0.60 | 31.44 | 22.62 | 22.44 | 22.27 |
| 0.70 | 29.16 | 21.49 | 21.31 | 21.11 |
| 0.80 | 27.44 | 20.63 | 20.41 | 20.19 |
| 0.90 | 26.11 | 19.91 | 19.69 | 19.47 |
| 1.00 | 25.05 | 19.33 | 19.11 | 18.89 |

Source: Developed by author based on methodology in Stoft (2002).

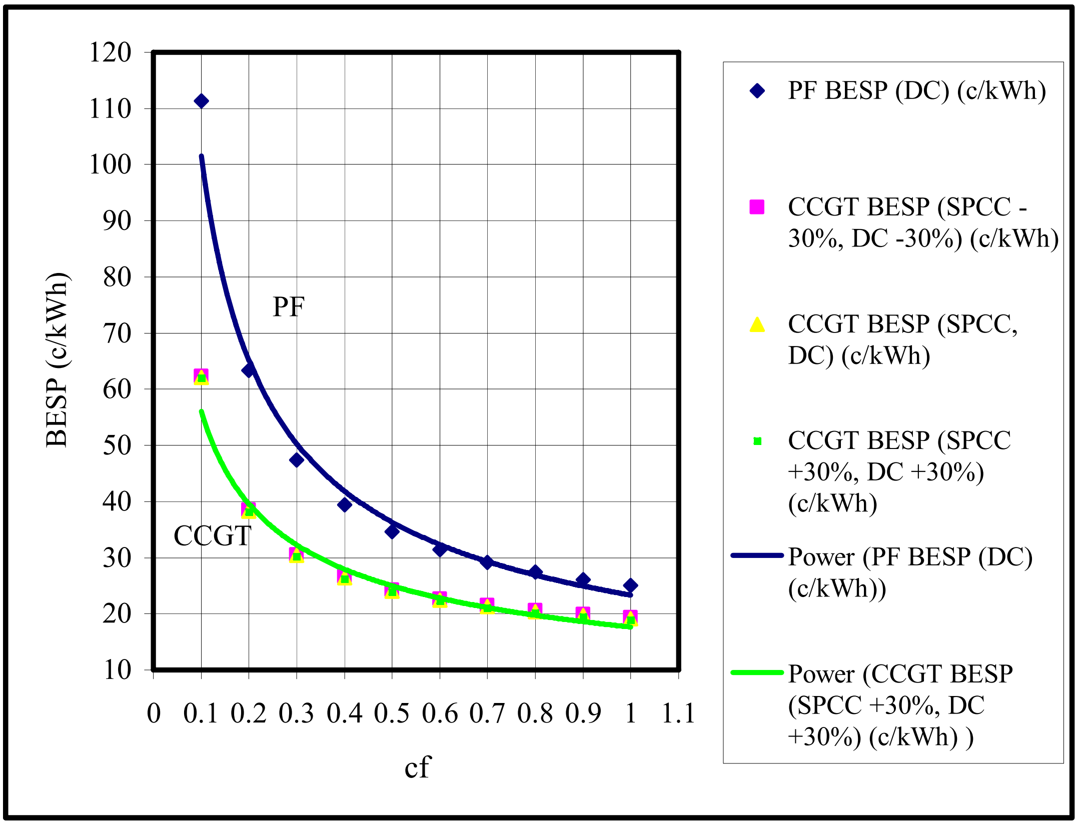



Figure 5.25 Sensitivities of BESP to +/-30% changes in both DC and SPCC (PF/CCGT).
Source: Developed by author based on methodology in Stoft (2002).

**Comment**: Combinations of DC and SPCC tend to favour CCGT more than PF in terms of cf/BESP relationships. This is mainly explained by the fact that PF does no have SPCC, a benefit; whilst DC is a cost.

## 5.9 Power stations (2)

### *5.9.1 Pulverised fuel coal-fired with flue gas desulphurisation*

In the pulverised fuel coal-fired generating plant with a flue gas desulphurisation (PF-FGD) power station, which is modelled in this section of the thesis, coal is burnt in a boiler to produce steam, which is fed into a steam turbine coupled to an electrical generator. The emission controls consist of electrostatic precipitators or bag houses and a flue gas desulphurisation (FGD) facility, which limit pollutants to permitted levels (East Harbour Management Services, 2002). The installed capacity of this power station is 2,250 MW and it operates at an efficiency of 34%. The description of flue gas desulphurisation facility is provided in appendix G1.

### *5.9.2 Combined-cycle gas turbine (2)*

The current strong demand for efficient and clean power generation capable of meeting tougher environmental regulations and energy saving prerequisites has focused global attention on the combined-cycle gas turbine. In addition, the gas turbine is considered as one of the effective measures to control the emissions of greenhouse gases (Aoki, 2000).

In the combined cycle gas turbine power station which is modelled in this section of the thesis, the combustion of natural gas takes place in a gas turbine coupled to an electrical generator. Exhaust heat from the gas turbine is passed into a heat recovery steam generator (HRSG), which can be fired or unfired. The steam is then fed to a conventional steam turbine to provide a secondary source of power (East Harbour Management Services, 2002). The installed capacity of this power station is 2,250 MW and it operates at an efficiency of 55%.

Generally, economic considerations dictate that CCGT be used for base load generation, with the minimum load factor determined by the fixed component of fuel costs (Eskom *et al*., 2004b). Furthermore, combined-cycle gas turbines have better thermal efficiency levels and are, therefore, regarded as suitable for non-peaking applications due to potential constraints imposed by gas contracts (take or pay), even though they could technically be used as load-followers (Eskom *et al*., 2004a). In this thesis, the CCGT is taken as a base load technology.

## 5.10 Modelling PF-FGD and CCGT power plants

Estimation of the capital costs of the PF-FGD and CCGT plants are found in appendix D1.

*Scenario 1 A base case combined-cycle gas turbine*

The equations used here for fixed cost (FC) and annual revenue requirement (ARR) are the same as (5.7) and (5.8) above.

**Table 5.27 ARR at various capacity factors (PF-FGD/CCGT)**

| cf | PF-FGD ARR (R/MWh) | CCGT ARR (R/MWh) |
|---|---|---|
| 0.00 | 99.53 | 40.60 |
| 0.10 | 100.69 | 48.26 |
| 0.20 | 101.84 | 55.92 |
| 0.30 | 102.99 | 63.58 |
| 0.40 | 104.14 | 71.23 |
| 0.50 | 105.30 | 78.89 |
| 0.60 | 106.45 | 86.55 |
| 0.70 | 107.60 | 94.21 |
| 0.80 | 108.75 | 101.87 |
| 0.90 | 109.90 | 109.53 |
| 1.00 | 111.06 | 117.19 |

Source: Developed by author based on methodology in Stoft (2002).

Legend: PF-FGD – Pulverised fuel coal-fired with flue gas desulphurisation.

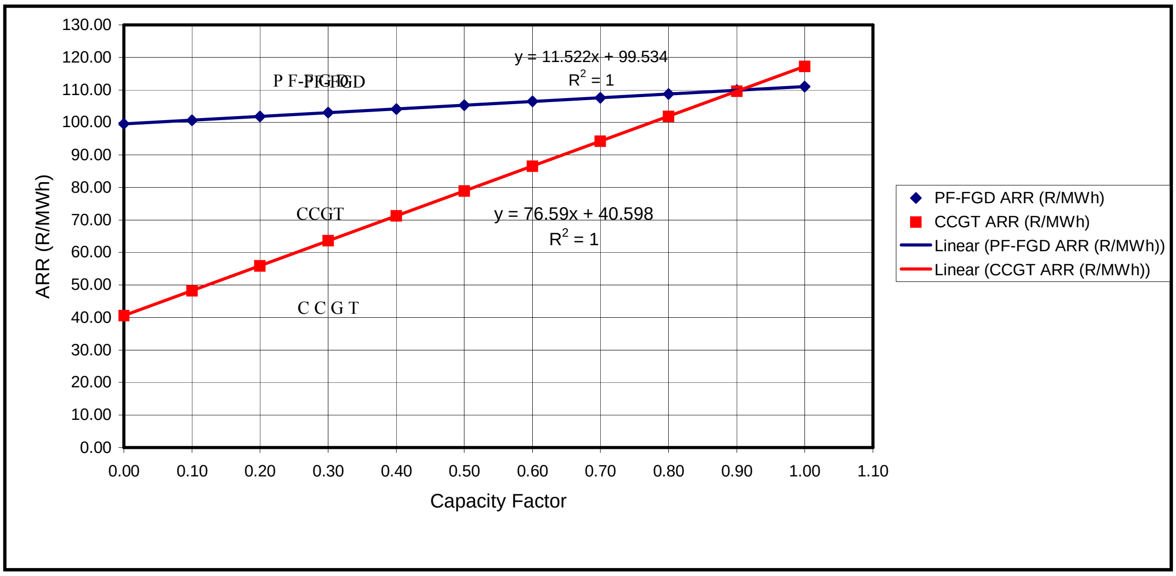



Figure 5.26 Screening curves (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comment:** The introduction of the added cost of FGD pushes the equilibrium value between PF-FGD and CCGT from a cf of about 0.75 (see figure 5.5) to one of approximately 0.91.

Equations of ARR vs cf

PF-FGD

$$y = 11.522x + 99.534 \tag{5.11}$$

CCGT

$$y = 76.59x + 40.598 \tag{5.12}$$

Finding the co-ordinates of the point where ARRs and cfs of PF-FGD and CCGT are equal

This is given by solutions to x and y of the equations 5.11 and 5.12

i.e. $11.522x + 99.534 = 76.59x + 40.598$

$x = 0.9057$

$y = 109.970$

Thus the co-ordinates of the point of intersection are approximately (0.91, 199.97).

*Screening curves with sensitivity analysis on the price of fuel*

**Table 5.28 Variations in ARR to +/5% change in fuel prices (PF-FGD/CCGT).**

| cf | PF-FGD ARR (CP - 5%) (R/MWh) | PF-FGD ARR (CP) (R/MWh) | PF-FGD ARR (CP +5%) (R/MWh) | CCGT ARR (GP -5%) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (GP +5%) (R/MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 99.53 | 99.53 | 99.53 | 40.60 | 40.60 | 40.60 |
| 0.10 | 100.63 | 100.69 | 100.74 | 47.87 | 48.26 | 48.64 |
| 0.20 | 101.72 | 101.84 | 101.95 | 55.15 | 55.92 | 56.68 |
| 0.30 | 102.82 | 102.99 | 103.16 | 62.43 | 63.58 | 64.72 |
| 0.40 | 103.91 | 104.14 | 104.37 | 69.70 | 71.23 | 72.77 |
| 0.50 | 105.01 | 105.30 | 105.58 | 76.98 | 78.89 | 80.81 |
| 0.60 | 106.10 | 106.45 | 106.79 | 84.25 | 86.55 | 88.85 |
| 0.70 | 107.20 | 107.60 | 108.00 | 91.53 | 94.21 | 96.89 |
| 0.80 | 108.29 | 108.75 | 109.21 | 98.81 | 101.87 | 104.93 |
| 0.90 | 109.39 | 109.90 | 110.42 | 106.08 | 109.53 | 112.98 |
| 1.00 | 110.48 | 111.06 | 111.63 | 113.36 | 117.19 | 121.02 |

Source: Developed by author based on methodology in Stoft (2002).

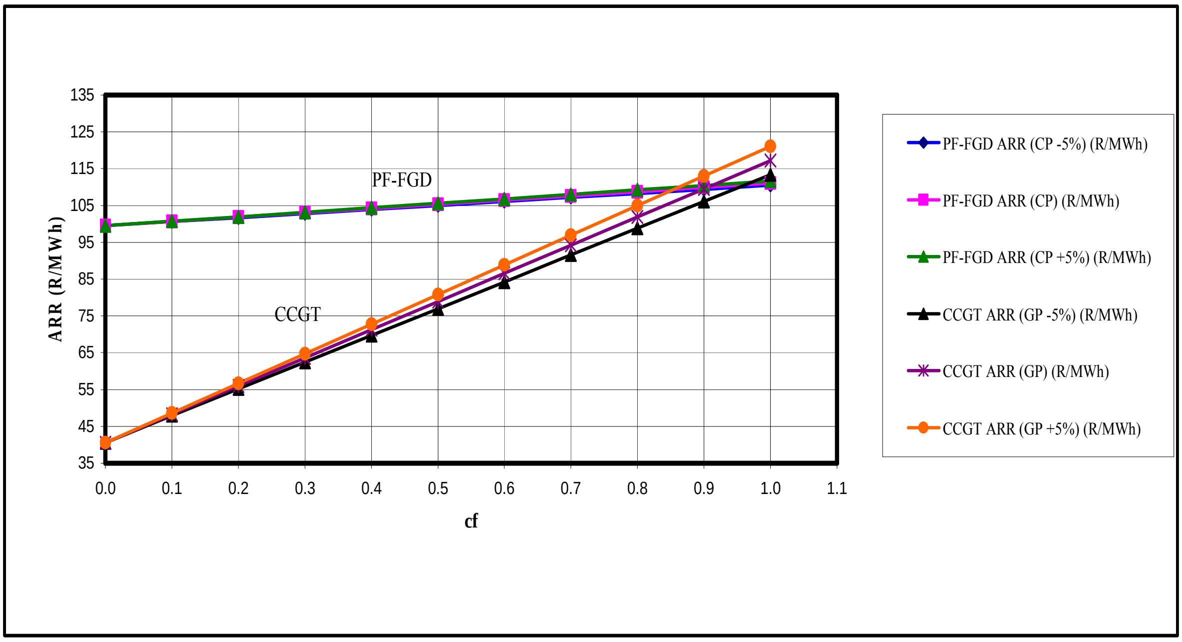



Figure 5.27 Sensitivities of ARR to +/-5% changes in fuel prices (PF-FGD/CCGT).
Source: Developed by author based on methodology in Stoft (2002).

**Table 5.29 Variations in ARR to +/-10% changes in fuel prices (PF-FGD/CCGT).**

| cf | PF-FGD ARR (CP -5%) (R/MWh) | PF-FGD ARR (CP) (R/MWh) | PF-FGD ARR (CP +5%) (R/MWh) | CCGT ARR (GP -5%) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (GP +5%) (R/MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 99.53 | 99.53 | 99.53 | 40.60 | 40.60 | 40.60 |
| 0.10 | 100.57 | 100.69 | 100.80 | 47.49 | 48.26 | 49.02 |
| 0.20 | 101.61 | 101.84 | 102.07 | 54.38 | 55.92 | 57.45 |
| 0.30 | 102.64 | 102.99 | 103.34 | 61.28 | 63.58 | 65.87 |
| 0.40 | 103.68 | 104.14 | 104.60 | 68.17 | 71.23 | 74.30 |
| 0.50 | 104.72 | 105.30 | 105.87 | 75.06 | 78.89 | 82.72 |
| 0.60 | 105.76 | 106.45 | 107.14 | 81.96 | 86.55 | 91.15 |
| 0.70 | 106.79 | 107.60 | 108.41 | 88.85 | 94.21 | 99.57 |
| 0.80 | 107.83 | 108.75 | 109.67 | 95.74 | 101.87 | 108.00 |
| 0.90 | 108.87 | 109.90 | 110.94 | 102.64 | 109.53 | 116.42 |
| 1.00 | 109.90 | 111.06 | 112.21 | 109.53 | 117.19 | 124.85 |

Source: Developed by author based on methodology in Stoft (2002).

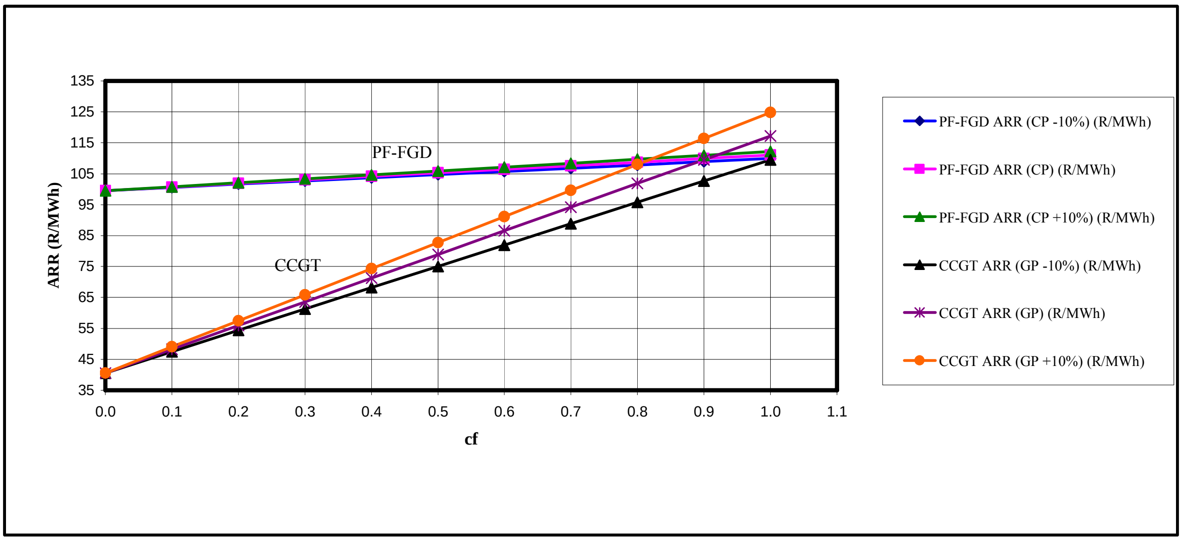



Figure 5.28 Sensitivities of ARR to +/- 10% changes in price of fuels (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.30 Variations in ARR to +/-15% changes in fuel prices (PF-FGD/CCGT).**

| cf | PF-FGD ARR (CP - 15%) (R/MWh) | PF-FGD ARR (CP) (R/MWh) | PF-FGD ARR (CP +15%) (R/MWh) | CCGT ARR (GP -15%) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (GP +15%) (R/MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 99.53 | 99.53 | 99.53 | 40.60 | 40.60 | 40.60 |
| 0.10 | 100.51 | 100.69 | 100.86 | 47.11 | 48.26 | 49.41 |
| 0.20 | 101.49 | 101.84 | 102.18 | 53.62 | 55.92 | 58.21 |
| 0.30 | 102.47 | 102.99 | 103.51 | 60.13 | 63.58 | 67.02 |
| 0.40 | 103.45 | 104.14 | 104.83 | 66.64 | 71.23 | 75.83 |
| 0.50 | 104.43 | 105.30 | 106.16 | 73.15 | 78.89 | 84.64 |
| 0.60 | 105.41 | 106.45 | 107.48 | 79.66 | 86.55 | 93.44 |
| 0.70 | 106.39 | 107.60 | 108.81 | 86.17 | 94.21 | 102.25 |
| 0.80 | 107.37 | 108.75 | 110.13 | 92.68 | 101.87 | 111.06 |
| 0.90 | 108.35 | 109.90 | 111.46 | 99.19 | 109.53 | 119.87 |
| 1.00 | 109.33 | 111.06 | 112.78 | 105.70 | 117.19 | 128.68 |

Source: Developed by author based on methodology in Stoft (2002).

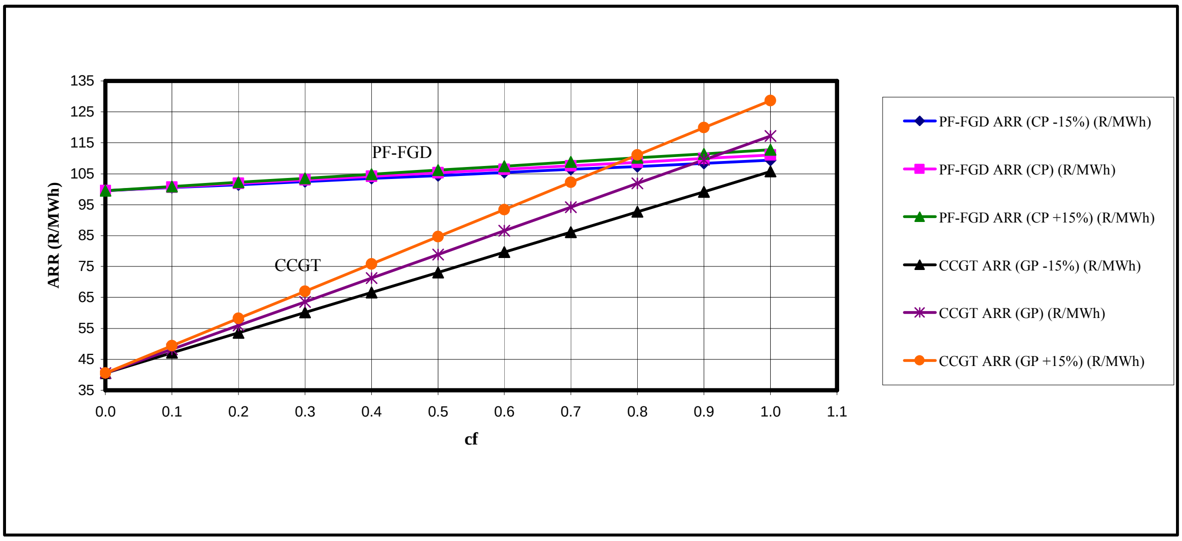



Figure 5.29 Sensitivities of ARR to +/- 15% changes in price of fuels (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comments**: Fuel price variance impacts more on CCGT than PF-FGD generation. An additional 20% increase in gas price could drop the CCGT/PF-FGD intersection from 0.90 to 0.70 in cf terms.

**Table 5.31 Variations in ARR to +/-20% changes in fuel prices (PF-FGD/CCGT).**

| cf | PF-FGD ARR (CP - 20%) (R/MWh) | PF-FGD ARR (CP) (R/MWh) | PF-FGD ARR (CP +20%) (R/MWh) | CCGT ARR (GP -20%) (R/MWh) | CCGT ARR (GP) (R/MWh) | CCGT ARR (GP +20 %) (R/MWh) |
|---|---|---|---|---|---|---|
| 0.00 | 99.53 | 99.53 | 99.53 | 40.60 | 40.60 | 40.60 |
| 0.10 | 100.46 | 100.69 | 100.92 | 46.73 | 48.26 | 49.79 |
| 0.20 | 101.38 | 101.84 | 102.30 | 52.85 | 55.92 | 58.98 |
| 0.30 | 102.30 | 102.99 | 103.68 | 58.98 | 63.58 | 68.17 |
| 0.40 | 103.22 | 104.14 | 105.06 | 65.11 | 71.23 | 77.36 |
| 0.50 | 104.14 | 105.30 | 106.45 | 71.23 | 78.89 | 86.55 |
| 0.60 | 105.06 | 106.45 | 107.83 | 77.36 | 86.55 | 95.74 |
| 0.70 | 105.99 | 107.60 | 109.21 | 83.49 | 94.21 | 104.93 |
| 0.80 | 106.91 | 108.75 | 110.60 | 89.62 | 101.87 | 114.12 |
| 0.90 | 107.83 | 109.90 | 111.98 | 95.74 | 109.53 | 123.31 |
| 1.00 | 108.75 | 111.06 | 113.36 | 101.87 | 117.19 | 132.51 |

Source: Developed by author based on methodology in Stoft (2002).

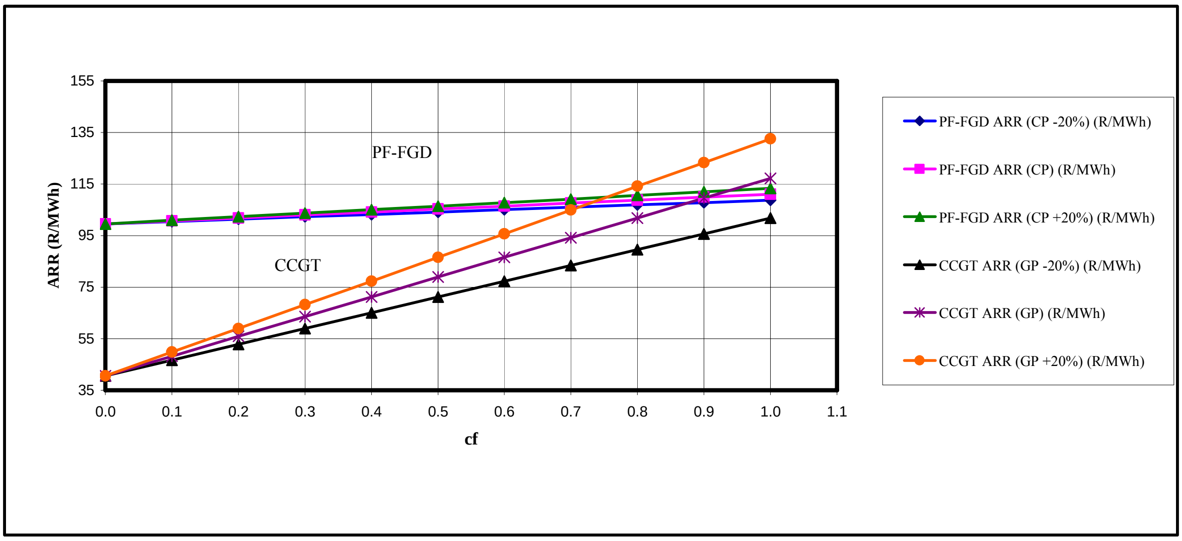



Figure 5.30 Sensitivities of ARR to +/- 20 changes in price of fuels (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

*Scenario 2 A combined-cycle gas turbine with CDM revenue*

**Table 5.32 Effect of SPCC on BESP (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC) |
|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 53.33 |
| 0.20 | 59.30 | 35.40 | 32.56 |
| 0.30 | 43.13 | 28.47 | 25.63 |
| 0.40 | 35.05 | 25.01 | 22.17 |
| 0.50 | 30.20 | 22.94 | 20.09 |
| 0.60 | 26.97 | 21.55 | 18.70 |
| 0.70 | 24.65 | 20.56 | 17.71 |
| 0.80 | 22.92 | 19.82 | 16.97 |
| 0.90 | 21.58 | 19.24 | 16.39 |
| 1.00 | 20.50 | 18.78 | 15.92 |

Source: Developed by author based on methodology in Stoft (2002).

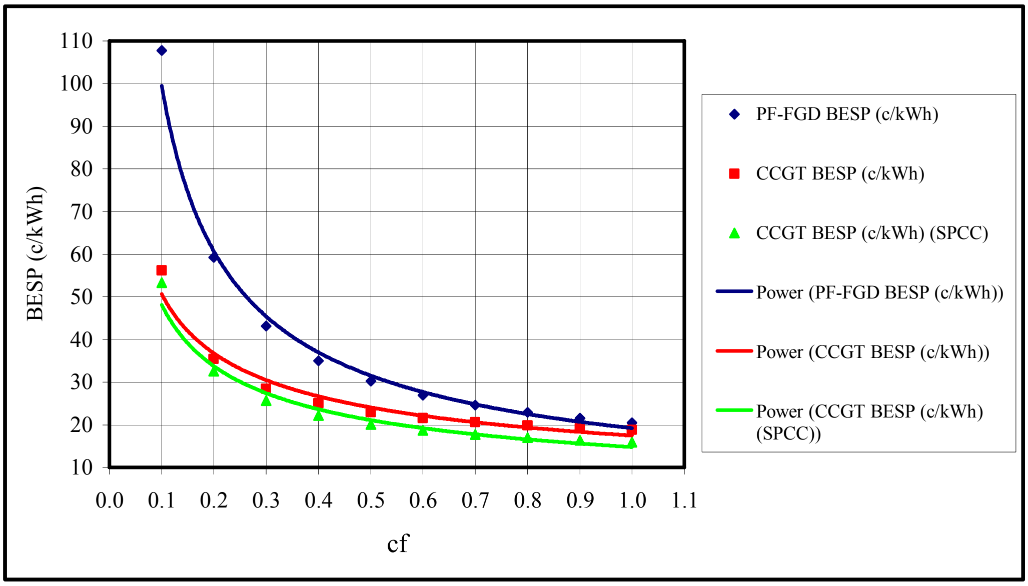



Figure 5.31 Effect of SPCC on BESP (PF-FGD/CCGT)

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.33 Variations in BESP to +/-5% changes in SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC-5%) | CCGT BESP (c/kWh) (SPCC) | CCGT BESP (c/kWh) (SPCC+5%) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 53.47 | 53.33 | 53.19 |
| 0.20 | 59.30 | 35.40 | 32.70 | 32.56 | 32.41 |
| 0.30 | 43.13 | 28.47 | 25.77 | 25.63 | 25.49 |
| 0.40 | 35.05 | 25.01 | 22.31 | 22.17 | 22.02 |
| 0.50 | 30.20 | 22.94 | 20.23 | 20.09 | 19.94 |
| 0.60 | 26.97 | 21.55 | 18.85 | 18.70 | 18.56 |
| 0.70 | 24.65 | 20.56 | 17.86 | 17.71 | 17.57 |
| 0.80 | 22.92 | 19.82 | 17.11 | 16.97 | 16.82 |
| 0.90 | 21.58 | 19.24 | 16.53 | 16.39 | 16.24 |
| 1.00 | 20.50 | 18.78 | 16.07 | 15.92 | 15.78 |

Source: Developed by author based on methodology in Stoft (2002).

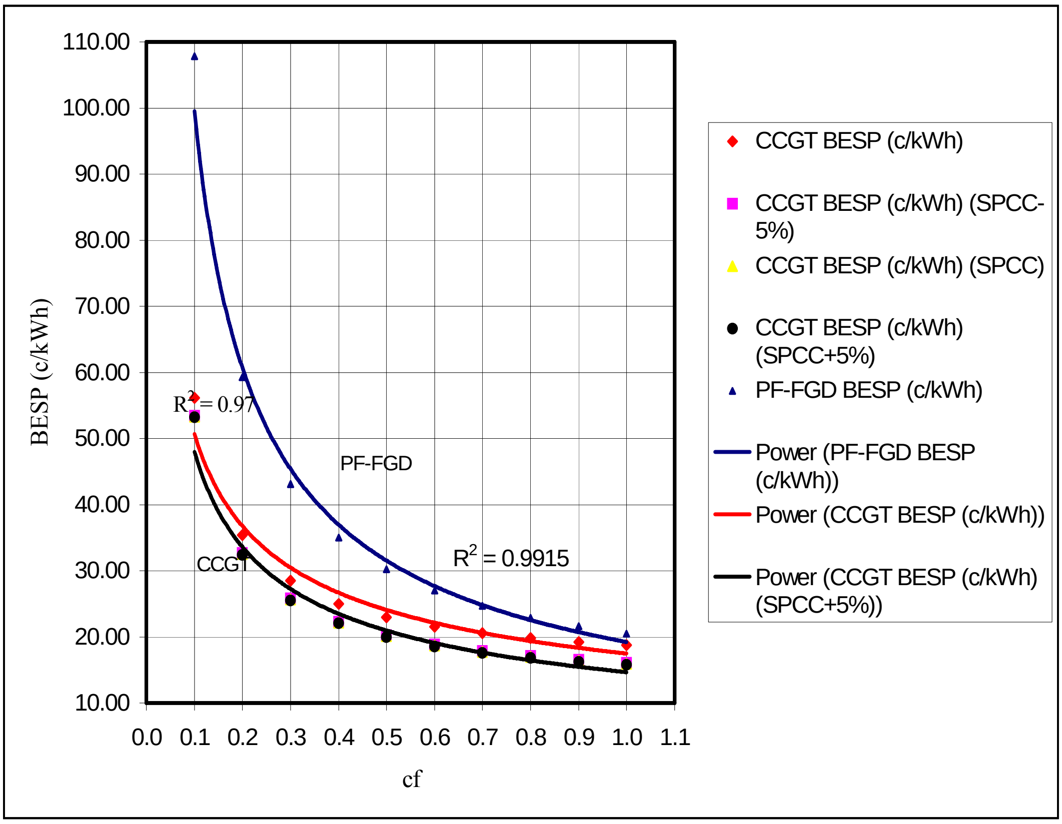



Figure 5.32 Sensitivities of BESP to +/- 5% changes in SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.34 Variations in BESP to +/-10% changes in SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC-10%) | CCGT BESP (c/kWh) (SPCC) | CCGT BESP (c/kWh) (SPCC+10%) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 53.61 | 53.33 | 53.04 |
| 0.20 | 59.30 | 35.40 | 32.84 | 32.56 | 32.27 |
| 0.30 | 43.13 | 28.48 | 25.92 | 25.63 | 25.35 |
| 0.40 | 35.05 | 25.01 | 22.45 | 22.17 | 21.88 |
| 0.50 | 30.20 | 22.94 | 20.37 | 20.09 | 19.80 |
| 0.60 | 26.97 | 21.55 | 18.99 | 18.70 | 18.42 |
| 0.70 | 24.65 | 20.56 | 18.00 | 17.71 | 17.43 |
| 0.80 | 22.92 | 19.82 | 17.26 | 16.97 | 16.68 |
| 0.90 | 21.58 | 19.24 | 16.67 | 16.39 | 16.10 |
| 1.00 | 20.50 | 18.78 | 16.21 | 15.92 | 15.64 |

Source: Developed by author based on methodology in Stoft (2002).

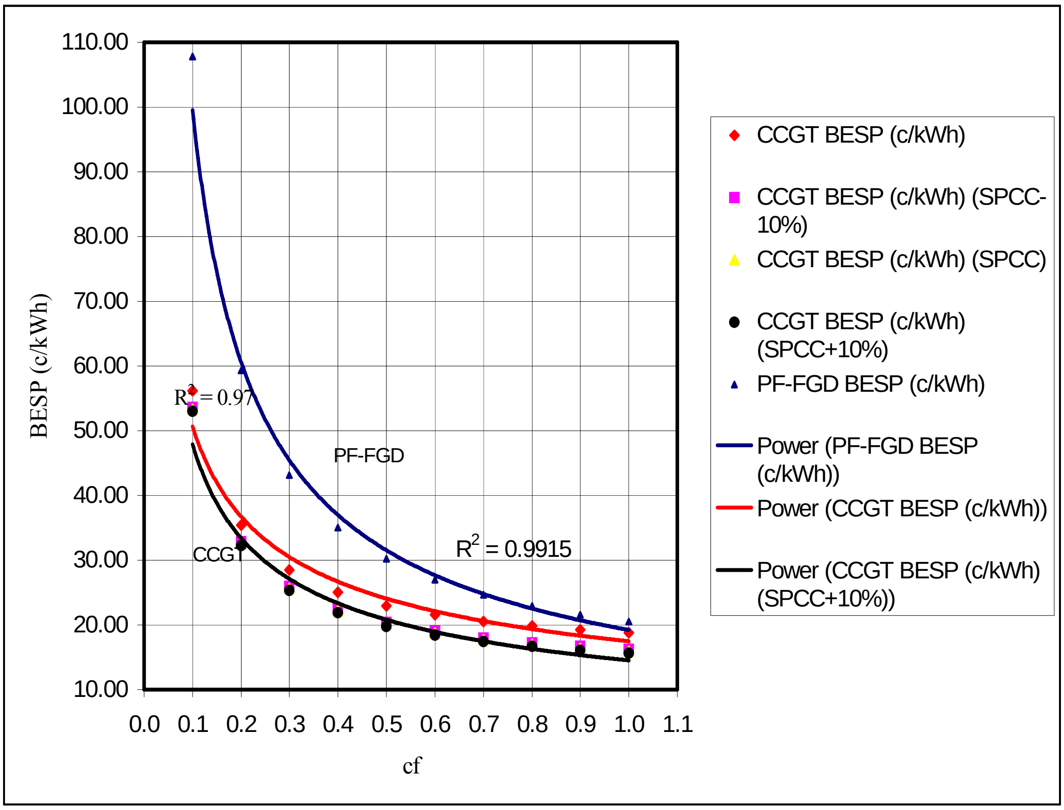



Figure 5.33 Sensitivities of BESP to +/- 10% changes in SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.35 Variations in BESP to +/-15% changes in SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC-15%) | CCGT BESP (c/kWh) (SPCC) | CCGT BESP (c/kWh) (SPCC+15%) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 53.76 | 53.33 | 52.90 |
| 0.20 | 59.30 | 35.40 | 32.98 | 32.56 | 32.13 |
| 0.30 | 43.13 | 28.48 | 26.06 | 25.63 | 25.20 |
| 0.40 | 35.05 | 25.01 | 22.60 | 22.17 | 21.74 |
| 0.50 | 30.20 | 22.94 | 20.52 | 20.09 | 19.66 |
| 0.60 | 26.97 | 21.55 | 19.13 | 18.70 | 18.27 |
| 0.70 | 24.65 | 20.56 | 18.14 | 17.71 | 17.28 |
| 0.80 | 22.92 | 19.82 | 17.40 | 16.97 | 16.54 |
| 0.90 | 21.58 | 19.24 | 16.81 | 16.39 | 15.96 |
| 1.00 | 20.50 | 18.78 | 16.35 | 15.92 | 15.50 |

Source: Developed by author based on methodology in Stoft (2002).

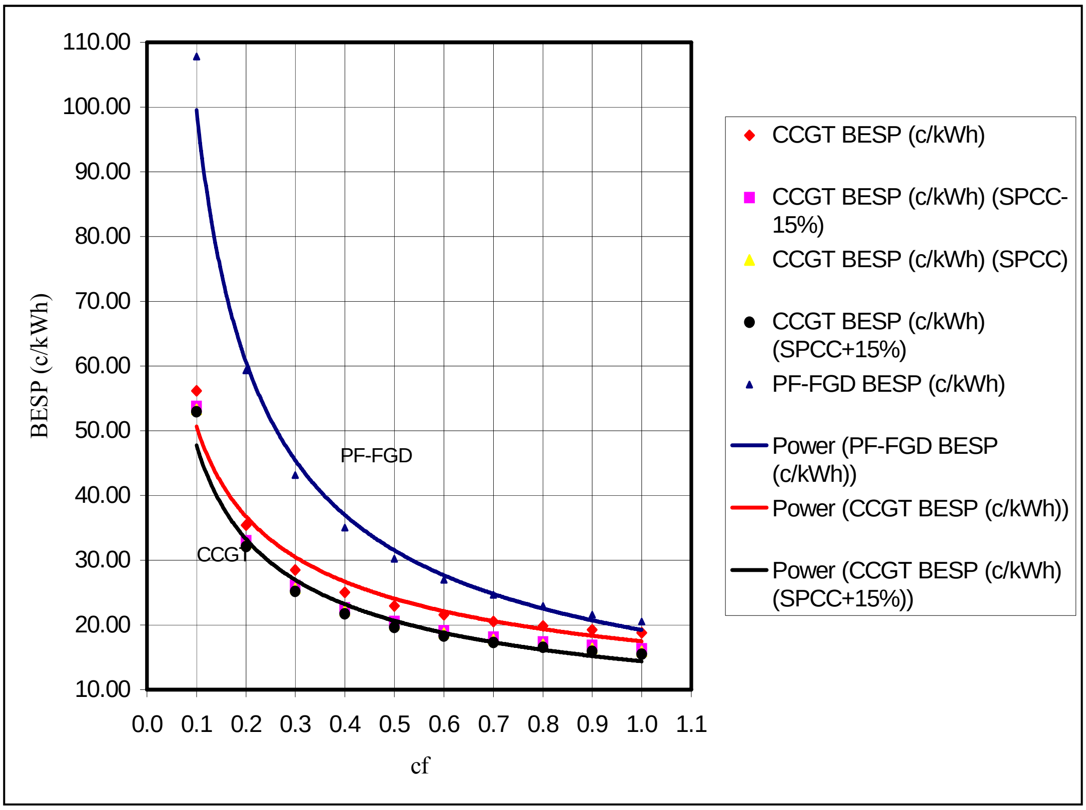



Figure 5.34 Sensitivities of BESP to +/- 15% changes in SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.36 Variations in ARR to +/-20% changes in SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC-20%) | CCGT BESP (c/kWh) (SPCC) | CCGT BESP (c/kWh) (SPCC+20%) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 53.90 | 53.36 | 52.76 |
| 0.20 | 59.30 | 35.40 | 33.12 | 32.56 | 31.99 |
| 0.30 | 43.13 | 28.47 | 26.20 | 25.63 | 25.06 |
| 0.40 | 35.05 | 25.01 | 22.74 | 22.17 | 21.60 |
| 0.50 | 30.20 | 22.94 | 20.66 | 20.09 | 19.52 |
| 0.60 | 26.97 | 21.55 | 19.27 | 18.70 | 18.13 |
| 0.70 | 24.65 | 20.56 | 18.28 | 17.71 | 17.14 |
| 0.80 | 22.92 | 19.82 | 17.54 | 16.97 | 16.40 |
| 0.90 | 21.58 | 19.24 | 16.96 | 16.39 | 15.82 |
| 1.00 | 20.50 | 18.78 | 16.50 | 15.93 | 15.35 |

Source: Developed by author based on methodology in Stoft (2002).

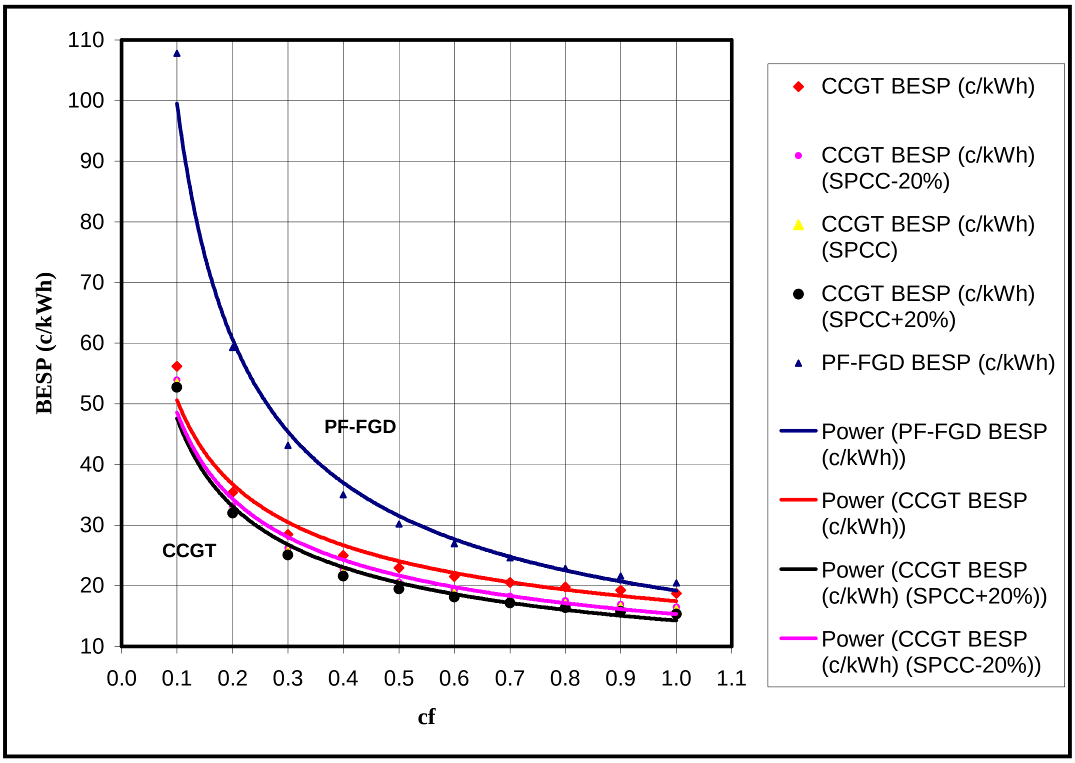



Figure 5.35 Sensitivities of BESP to +/- 20% changes in SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.37 Variations in BESP to +/-30% changes in SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC-30%) | CCGT BESP (c/kWh) (SPCC) | CCGT BESP (c/kWh) (SPCC+30%) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 54.18 | 53.33 | 52.48 |
| 0.20 | 59.30 | 35.40 | 33.41 | 32.56 | 31.70 |
| 0.30 | 43.13 | 28.48 | 26.49 | 25.63 | 24.78 |
| 0.40 | 35.05 | 25.01 | 23.02 | 22.17 | 21.31 |
| 0.50 | 30.20 | 22.94 | 20.95 | 20.09 | 19.23 |
| 0.60 | 26.97 | 21.55 | 19.56 | 18.70 | 17.85 |
| 0.70 | 24.65 | 20.56 | 18.57 | 17.71 | 16.86 |
| 0.80 | 22.92 | 19.82 | 17.82 | 16.97 | 16.11 |
| 0.90 | 21.58 | 19.24 | 17.24 | 16.39 | 15.53 |
| 1.00 | 20.50 | 18.78 | 16.78 | 15.92 | 15.07 |

Source: Developed by author based on methodology in Stoft (2002).

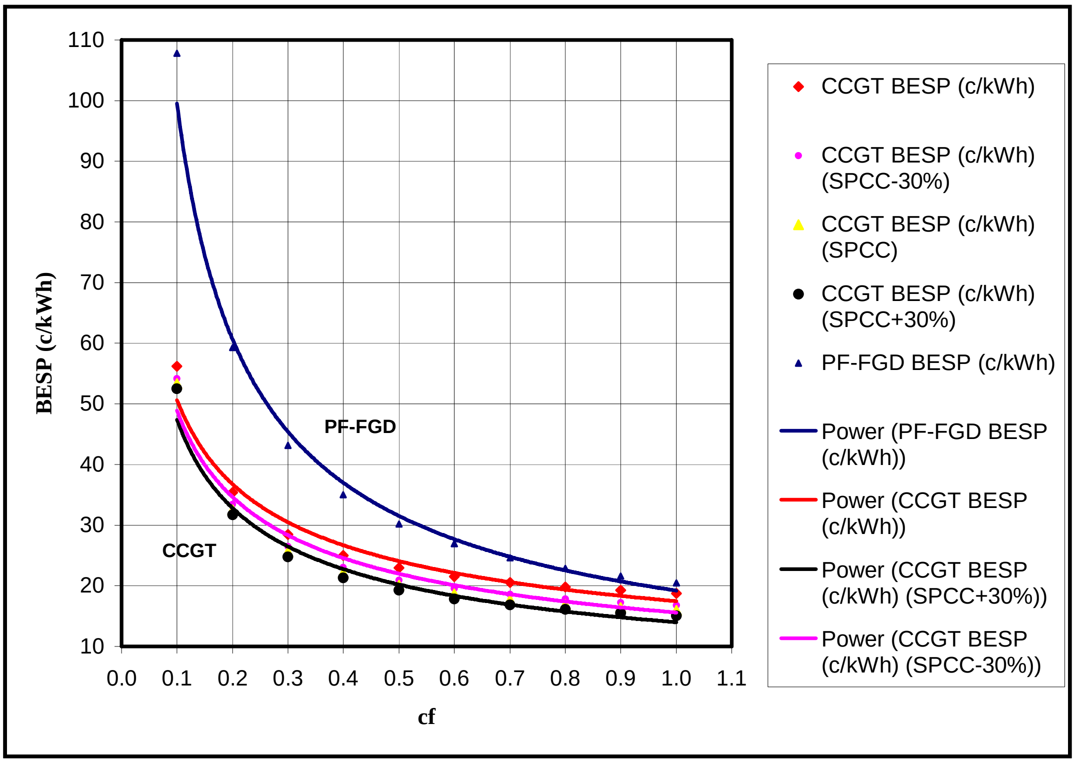



Figure 5.36 Sensitivities of BESP to +/- 30% changes in SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.38 Variations in BESP to +/-40% changes in SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (c/kWh) (SPCC-40%) | CCGT BESP (c/kWh) (SPCC) | CCGT BESP (c/kWh) (SPCC+40%) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 54.47 | 53.33 | 52.19 |
| 0.20 | 59.30 | 35.40 | 33.69 | 32.56 | 31.42 |
| 0.30 | 43.13 | 28.48 | 26.77 | 25.63 | 24.49 |
| 0.40 | 35.05 | 25.02 | 23.31 | 22.17 | 21.03 |
| 0.50 | 30.20 | 22.94 | 21.23 | 20.09 | 18.95 |
| 0.60 | 26.97 | 21.55 | 19.85 | 18.70 | 17.56 |
| 0.70 | 24.65 | 20.56 | 18.85 | 17.71 | 16.57 |
| 0.80 | 22.92 | 19.82 | 18.11 | 16.97 | 15.83 |
| 0.90 | 21.58 | 19.24 | 17.53 | 16.39 | 15.25 |
| 1.00 | 20.50 | 18.78 | 17.07 | 15.92 | 14.78 |

Source: Developed by author based on methodology in Stoft (2002).

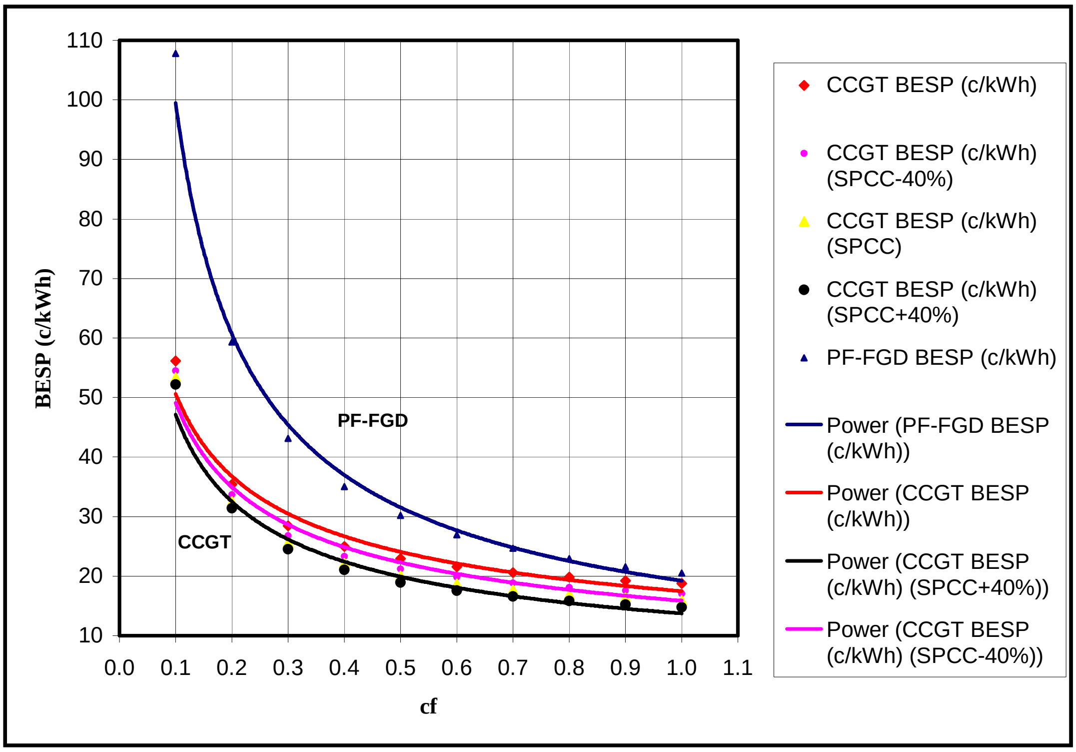



Figure 5.37 Sensitivities of BESP to +/- 40% changes in SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

*Scenario 3 A combined-cycle gas turbine with externalities accounted for by damage costs*

**Table 5.39 Effect of DC on BESP (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) (DC) | CCGT BESP (c/kWh) (DC) |
|---|---|---|
| 0.10 | 110.39 | 61.24 |
| 0.20 | 61.89 | 38.43 |
| 0.30 | 45.73 | 30.82 |
| 0.40 | 37.65 | 27.02 |
| 0.50 | 32.80 | 24.74 |
| 0.60 | 29.57 | 23.22 |
| 0.70 | 27.26 | 22.13 |
| 0.80 | 25.53 | 21.32 |
| 0.90 | 24.18 | 20.68 |
| 1.00 | 23.10 | 20.17 |

Source: Developed by author based on methodology in Stoft (2002).

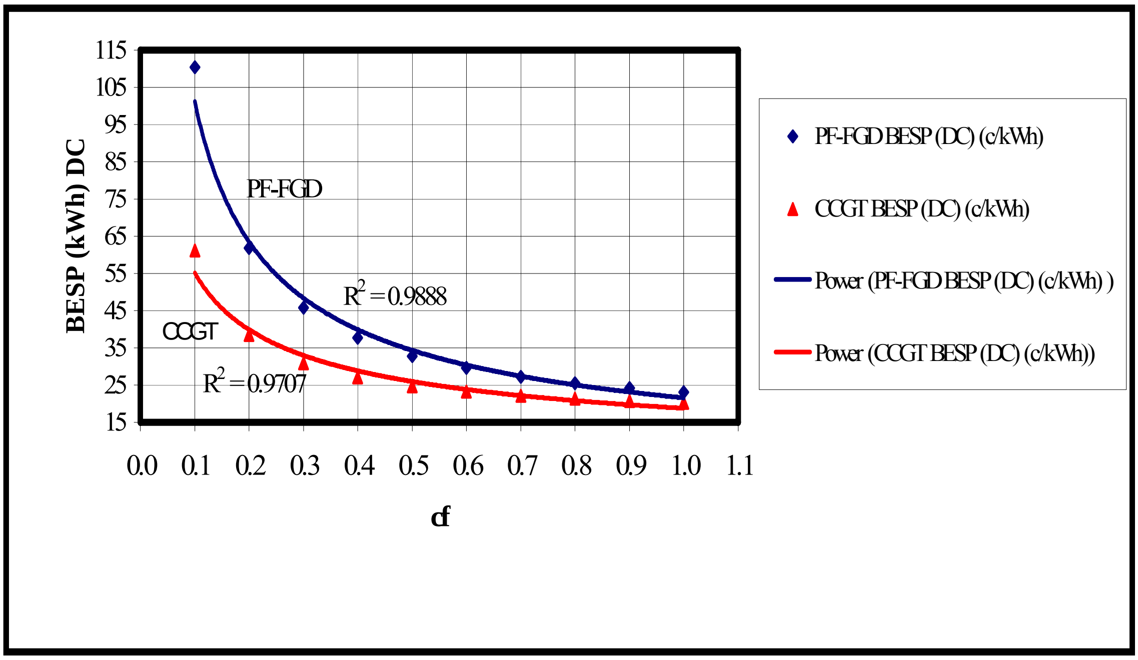



Figure 5.38 Effect of DC on BESP (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.40 Variations in BESP to +/- 5% changes in DC (PF-FGD/CCGT).**

| cf | PF-FGD (DC -5%) BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | PF-FGD (DC +5%) BESP (c/kWh) | CCGT (DC - 5%) BESP (c/kWh) | CCGT (DC) BESP (c/kWh) | CCGT (DC +5%) BESP (c/kWh) |
|---|---|---|---|---|---|---|
| 0.10 | 110.29 | 110.39 | 110.49 | 56.66 | 56.66 | 56.73 |
| 0.20 | 61.79 | 61.89 | 62.00 | 35.89 | 35.93 | 35.96 |
| 0.30 | 45.62 | 45.73 | 45.83 | 28.97 | 29.00 | 29.04 |
| 0.40 | 37.54 | 37.65 | 37.75 | 25.51 | 25.54 | 25.57 |
| 0.50 | 32.70 | 32.80 | 32.90 | 23.43 | 23.46 | 23.50 |
| 0.60 | 29.45 | 29.57 | 29.67 | 22.04 | 22.08 | 22.11 |
| 0.70 | 27.15 | 27.26 | 27.36 | 21.05 | 21.09 | 21.12 |
| 0.80 | 25.43 | 25.53 | 25.63 | 20.31 | 20.34 | 20.38 |
| 0.90 | 24.08 | 24.18 | 24.28 | 19.73 | 19.76 | 19.80 |
| 1.00 | 23.00 | 23.10 | 23.20 | 19.27 | 19.30 | 19.34 |

Source: Developed by author based on methodology in Stoft (2002).

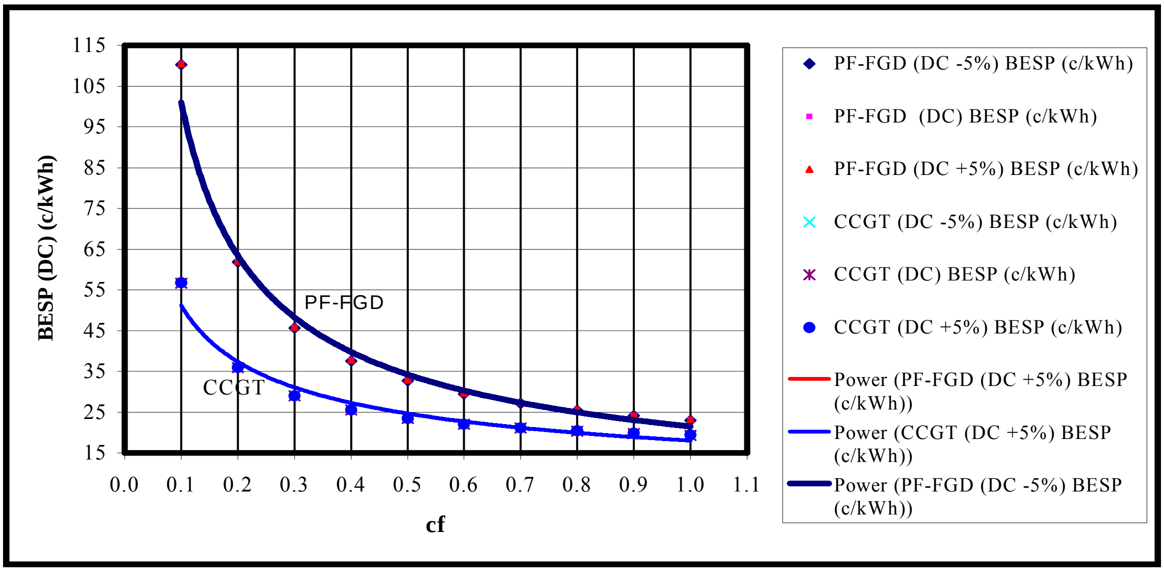



Figure 5.39 Sensitivities of BESP to +/- 5% changes in DC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.41 Variations in BESP to +/- 10 changes in DC (PF-FGD/CCGT).**

| cf | PF-FGD (DC -10%) BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | PF-FGD (DC + 10%) BESP (c/kWh) | CCGT (DC - 10%) BESP (c/kWh) | CCGT (DC) BESP (c/kWh) | CCGT (DC + 10%) BESP (c/kWh) |
|---|---|---|---|---|---|---|
| 0.10 | 110.18 | 110.39 | 110.60 | 56.63 | 56.70 | 56.77 |
| 0.20 | 61.69 | 61.89 | 62.10 | 35.86 | 35.93 | 35.99 |
| 0.30 | 45.52 | 45.73 | 45.93 | 28.93 | 29.00 | 29.07 |
| 0.40 | 37.43 | 37.65 | 37.85 | 25.47 | 25.54 | 25.61 |
| 0.50 | 32.60 | 32.80 | 33.00 | 23.39 | 23.46 | 23.53 |
| 0.60 | 29.35 | 29.57 | 29.77 | 22.01 | 22.08 | 22.14 |
| 0.70 | 27.05 | 27.26 | 27.46 | 21.02 | 21.09 | 21.15 |
| 0.80 | 25.32 | 25.53 | 25.73 | 20.28 | 20.34 | 20.41 |
| 0.90 | 23.97 | 24.18 | 24.38 | 19.70 | 19.76 | 19.83 |
| 1.00 | 22.90 | 23.10 | 23.31 | 19.23 | 19.30 | 19.37 |

Source: Developed by author based on methodology in Stoft (2002).

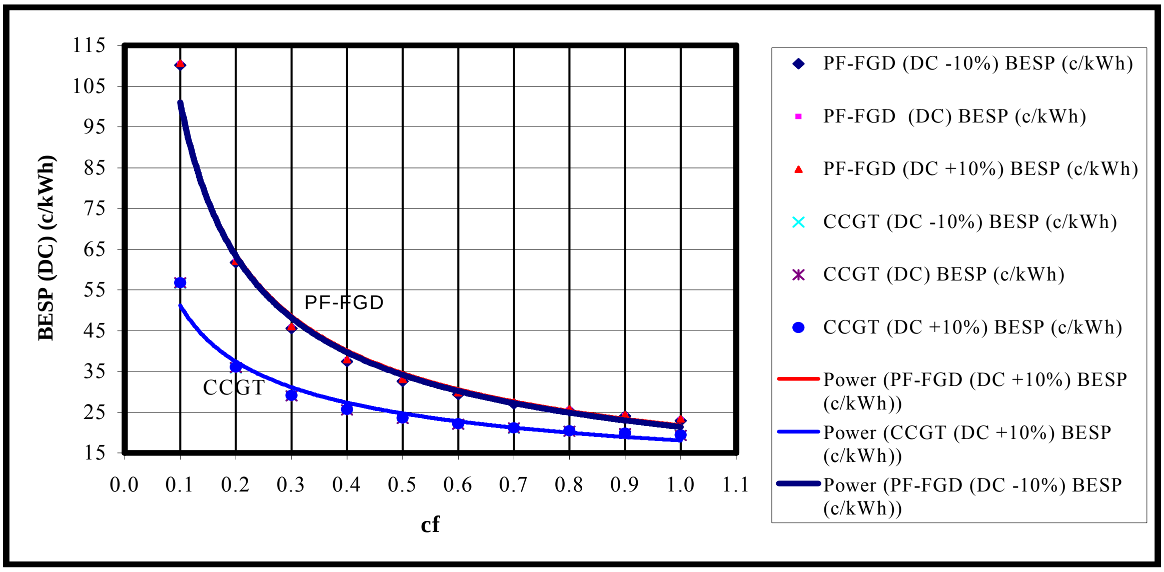



Figure 5.40 Sensitivities of BESP to +/- 10% changes in DC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.42 Variations in BESP to +/- 15% changes in DC (PF-FGD/CCGT).**

| cf | PF-FGD (DC -15%) BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | PF-FGD (DC + 15%) BESP (c/kWh) | CCGT (DC - 15%) BESP (c/kWh) | CCGT (DC) BESP (c/kWh) | CCGT (DC + 15%) BESP (c/kWh) |
|---|---|---|---|---|---|---|
| 0.10 | 110.08 | 110.39 | 110.70 | 56.57 | 56.70 | 56.80 |
| 0.20 | 61.58 | 61.89 | 62.20 | 35.82 | 35.93 | 36.03 |
| 0.30 | 45.42 | 45.73 | 46.04 | 28.90 | 29.00 | 29.10 |
| 0.40 | 37.33 | 37.65 | 37.96 | 25.44 | 25.54 | 25.64 |
| 0.50 | 32.49 | 32.80 | 33.11 | 23.36 | 23.46 | 23.56 |
| 0.60 | 29.25 | 29.57 | 29.87 | 21.97 | 22.08 | 22.18 |
| 0.70 | 26.95 | 27.26 | 27.57 | 20.99 | 21.09 | 21.19 |
| 0.80 | 25.22 | 25.52 | 25.83 | 20.24 | 20.34 | 20.45 |
| 0.90 | 23.87 | 24.18 | 24.49 | 19.66 | 19.76 | 19.87 |
| 1.00 | 22.79 | 23.10 | 23.41 | 19.20 | 19.30 | 19.40 |

Source: Developed by author based on methodology in Stoft (2002).

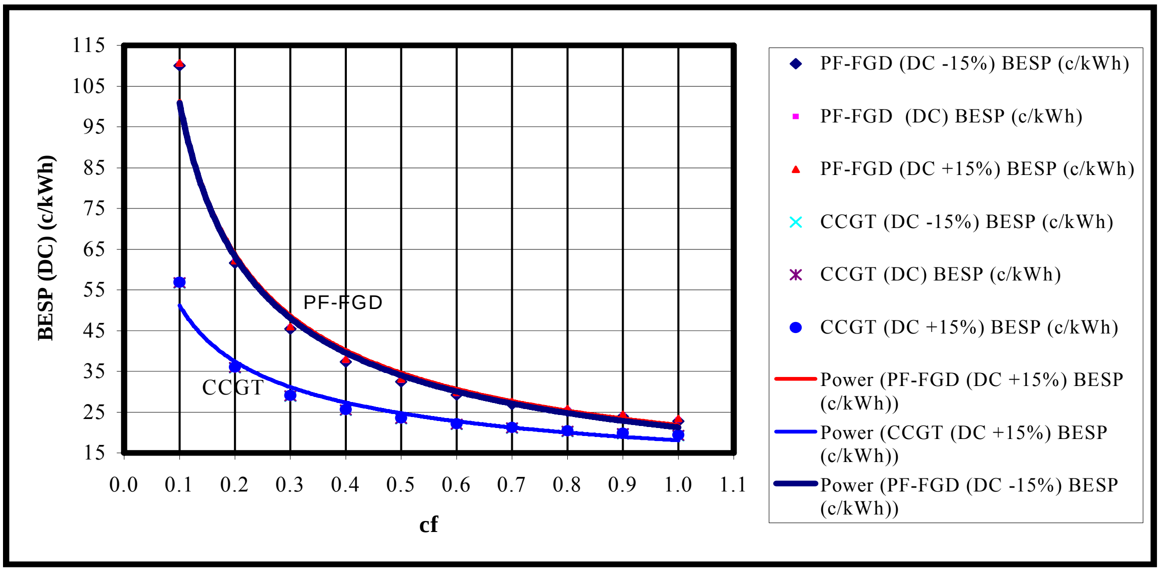



Figure 5.41 Sensitivities of BESP to +/- 15% changes in DC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.43 Variations in BESP to +/- 20% changes in DC (PF-FGD/CCGT).**

| cf | PF-FGD (DC -20%) BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | PF-FGD (DC +20%) BESP (c/kWh) | CCGT (DC -20%) BESP (c/kWh) | CCGT (DC) BESP (c/kWh) | CCGT (DC +20%) BESP (c/kWh) |
|---|---|---|---|---|---|---|
| 0.10 | 109.98 | 110.39 | 110.80 | 56.57 | 56.70 | 56.84 |
| 0.20 | 61.48 | 61.89 | 62.31 | 35.79 | 35.93 | 36.06 |
| 0.30 | 45.31 | 45.73 | 46.14 | 28.87 | 29.00 | 29.14 |
| 0.40 | 37.23 | 37.65 | 38.06 | 25.40 | 25.54 | 25.68 |
| 0.50 | 32.39 | 32.80 | 33.21 | 23.32 | 23.46 | 23.60 |
| 0.60 | 29.15 | 29.57 | 29.98 | 21.94 | 22.08 | 22.21 |
| 0.70 | 26.85 | 27.26 | 27.67 | 20.95 | 21.09 | 21.22 |
| 0.80 | 25.11 | 25.52 | 25.94 | 20.21 | 20.34 | 20.48 |
| 0.90 | 23.77 | 24.18 | 24.59 | 19.63 | 19.76 | 19.90 |
| 1.00 | 22.69 | 23.10 | 23.51 | 19.17 | 19.30 | 19.44 |

Source: Developed by author based on methodology in Stoft (2002).

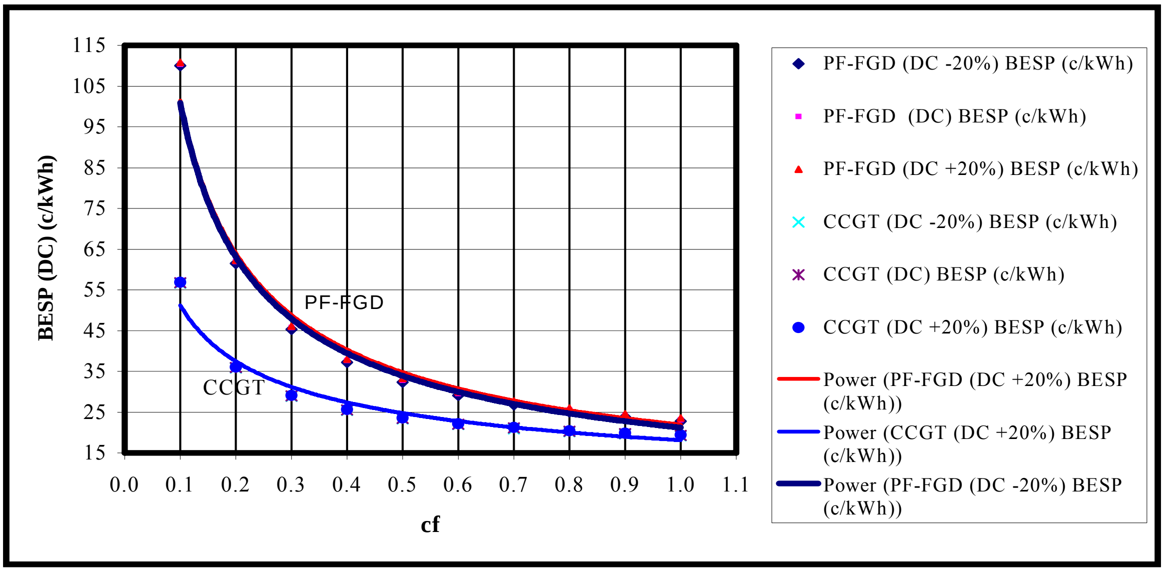



Figure 5.42 Sensitivities of BESP to +/- 20% changes in DC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.44 Variations in BESP to +/- 30% changes in DC (PF-FGD/CCGT).**

| cf | PF-FGD (DC -30%) BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | PF-FGD (DC +30%) BESP (c/kWh) | CCGT (DC - 30%) BESP (c/kWh) | CCGT (DC) BESP (c/kWh) | CCGT (DC +30%) BESP (c/kWh) |
|---|---|---|---|---|---|---|
| 0.10 | 109.77 | 110.39 | 111.01 | 56.49 | 56.70 | 56.90 |
| 0.20 | 61.28 | 61.89 | 62.51 | 35.72 | 35.93 | 36.13 |
| 0.30 | 45.11 | 45.73 | 46.35 | 28.80 | 29.00 | 29.21 |
| 0.40 | 37.03 | 37.65 | 38.26 | 25.34 | 25.54 | 25.74 |
| 0.50 | 32.18 | 32.80 | 33.41 | 23.26 | 23.46 | 23.67 |
| 0.60 | 28.95 | 29.56 | 30.18 | 21.87 | 22.08 | 22.28 |
| 0.70 | 26.64 | 27.26 | 27.87 | 20.88 | 21.09 | 21.29 |
| 0.80 | 24.91 | 25.53 | 26.14 | 20.14 | 20.34 | 20.54 |
| 0.90 | 23.56 | 24.18 | 24.80 | 19.56 | 19.77 | 19.97 |
| 1.00 | 22.49 | 23.10 | 23.72 | 19.10 | 19.30 | 19.51 |

Source: Developed by author based on methodology in Stoft (2002).

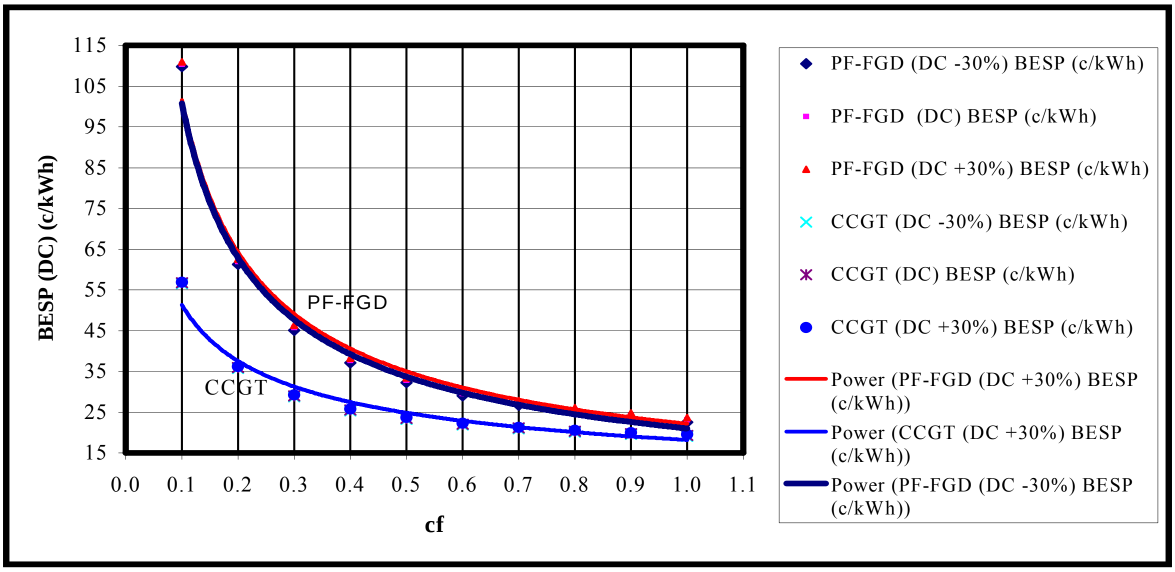



Figure 5.43 Sensitivities of BESP to +/- 30% changes in DC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.45 Variations in BESP to +/- 40% changes in DC (PF-FGD/CCGT).**

| cf | PF-FGD (DC -340%) BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | PF-FGD (DC +40%) BESP (c/kWh) | CCGT (DC -40%) BESP (c/kWh) | CCGT (DC) BESP (c/kWh) | CCGT (DC +40%) BESP (c/kWh) |
|---|---|---|---|---|---|---|
| 0.10 | 109.57 | 110.39 | 111.21 | 56.43 | 56.70 | 56.97 |
| 0.20 | 61.07 | 61.89 | 62.72 | 35.65 | 35.93 | 36.20 |
| 0.30 | 44.91 | 45.73 | 46.55 | 28.73 | 29.00 | 29.28 |
| 0.40 | 36.82 | 37.65 | 38.47 | 25.27 | 25.54 | 25.81 |
| 0.50 | 31.97 | 32.80 | 33.62 | 23.19 | 23.46 | 23.73 |
| 0.60 | 28.75 | 29.56 | 30.39 | 21.80 | 22.08 | 22.35 |
| 0.70 | 26.43 | 27.26 | 28.08 | 20.81 | 21.09 | 21.36 |
| 0.80 | 24.70 | 25.53 | 26.35 | 20.07 | 20.34 | 20.62 |
| 0.90 | 23.36 | 24.18 | 25.00 | 19.49 | 19.77 | 20.04 |
| 1.00 | 22.28 | 23.10 | 23.92 | 19.03 | 19.30 | 19.57 |

Source: Developed by author based on methodology in Stoft (2002).

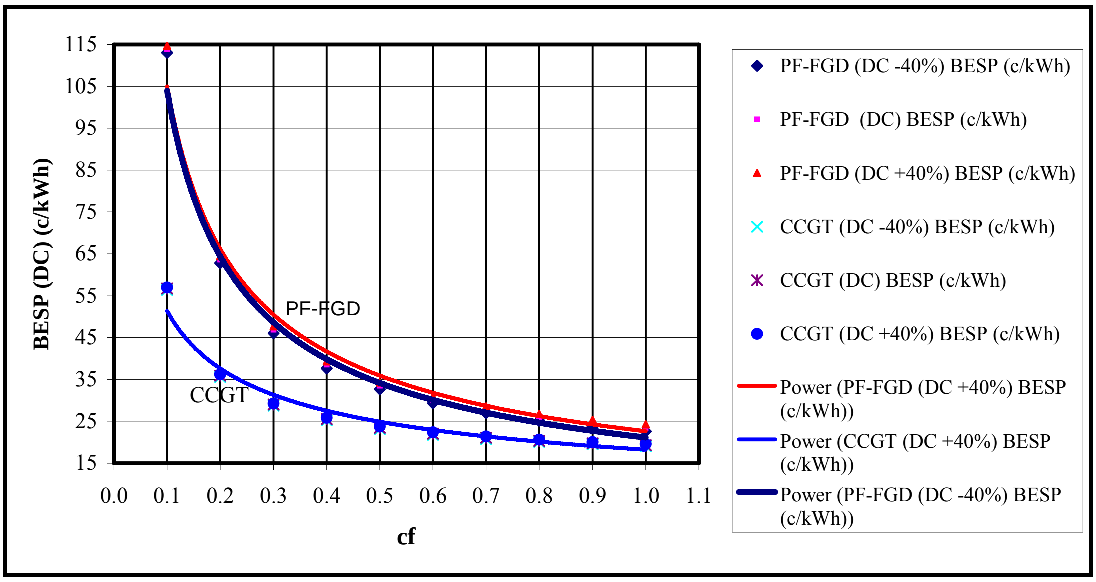



Figure 5.44 Sensitivities of BESP to +/- 40% changes in DC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comments:** The BESP values have more impact on PF-FGD than CCGT under a range of DC values. This is due to the fact that the DC value of PF-FGD is three times that of the CCGT.

*Scenario 4 A combined-cycle gas turbine with CDM revenue and externalities accounted for by damage costs*

**Table 5.46 Effect of DC and SPCC on BESP (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | PF-FGD (DC) BESP (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) |
|---|---|---|---|---|
| 0.1 | 107.82 | 56.17 | 110.39 | 54.01 |
| 0.2 | 59.30 | 35.40 | 61.89 | 33.24 |
| 0.3 | 43.13 | 28.48 | 45.73 | 26.31 |
| 0.4 | 35.05 | 25.02 | 37.65 | 22.85 |
| 0.5 | 30.20 | 22.94 | 32.80 | 20.77 |
| 0.6 | 26.97 | 21.55 | 29.56 | 19.38 |
| 0.7 | 24.65 | 20.56 | 27.26 | 18.39 |
| 0.8 | 22.92 | 19.82 | 25.53 | 17.65 |
| 0.9 | 21.58 | 19.24 | 24.18 | 17.07 |
| 1.0 | 20.50 | 18.78 | 23.10 | 16.61 |

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.47  Variations in BESP to +/-5% changes in DC and SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC-5%, SPCC-5%) (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) | CCGT BESP (DC+5%, SPCC+5%) (c/kWh) |
|---|---|---|---|---|---|
| 0.1 | 107.82 | 56.17 | 54.12 | 54.01 | 53.90 |
| 0.2 | 59.30 | 35.40 | 33.35 | 33.24 | 33.13 |
| 0.3 | 43.13 | 28.48 | 26.42 | 26.31 | 26.21 |
| 0.4 | 35.05 | 25.02 | 22.96 | 22.85 | 22.74 |
| 0.5 | 30.20 | 22.94 | 20.88 | 20.77 | 20.66 |
| 0.6 | 26.97 | 21.55 | 19.49 | 19.38 | 19.28 |
| 0.7 | 24.65 | 20.56 | 18.50 | 18.39 | 18.28 |
| 0.8 | 22.92 | 19.82 | 17.76 | 17.65 | 17.54 |
| 0.9 | 21.58 | 19.24 | 17.18 | 17.07 | 16.96 |
| 1.0 | 20.50 | 18.78 | 16.71 | 16.61 | 16.50 |

Source: Developed by author based on methodology in Stoft (2002).

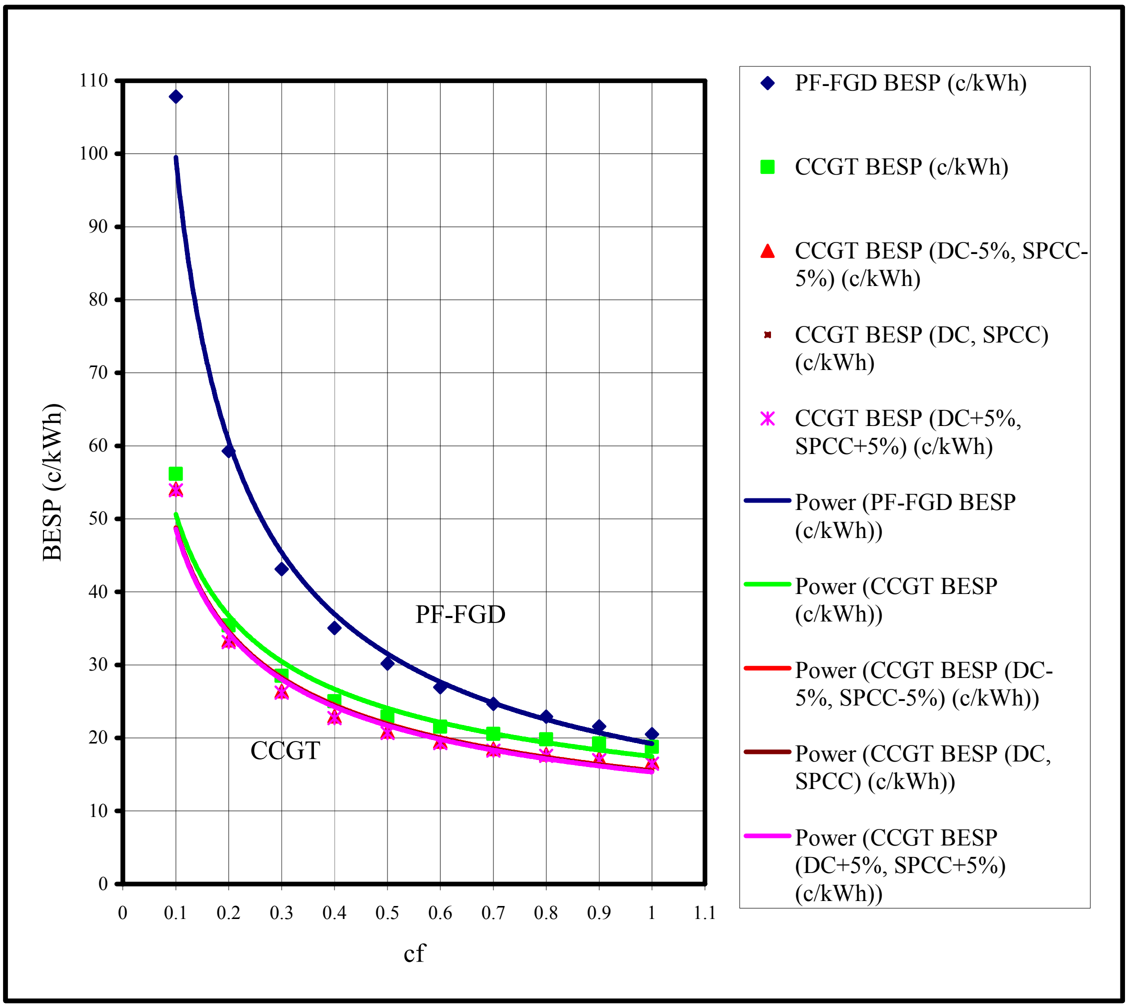



Figure 5.45 Sensitivities of BESP to +/- 5% changes in DC and SPCC (PF-FGD/CCGT).
Source: Developed by author based on methodology in Stoft (2002).

**Table 5.48 Variations in BESP to +/-10% changes in DC and SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC-10%, SPCC-10%) (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) | CCGT BESP (DC+10%, SPCC+10%) (c/kWh) |
|---|---|---|---|---|---|
| 0.1 | 107.82 | 56.17 | 54.23 | 54.01 | 53.80 |
| 0.2 | 59.30 | 35.40 | 33.46 | 33.24 | 33.02 |
| 0.3 | 43.13 | 28.48 | 26.53 | 26.31 | 26.10 |
| 0.4 | 35.05 | 25.02 | 23.07 | 22.85 | 22.63 |
| 0.5 | 30.20 | 22.94 | 20.99 | 20.77 | 20.55 |
| 0.6 | 26.97 | 21.55 | 19.60 | 19.38 | 19.17 |
| 0.7 | 24.65 | 20.56 | 18.61 | 18.39 | 18.18 |
| 0.8 | 22.92 | 19.82 | 17.87 | 17.65 | 17.43 |
| 0.9 | 21.58 | 19.24 | 17.29 | 17.07 | 16.85 |
| 1.0 | 20.50 | 18.78 | 16.82 | 16.61 | 16.39 |

Source: Developed by author based on methodology in Stoft (2002).

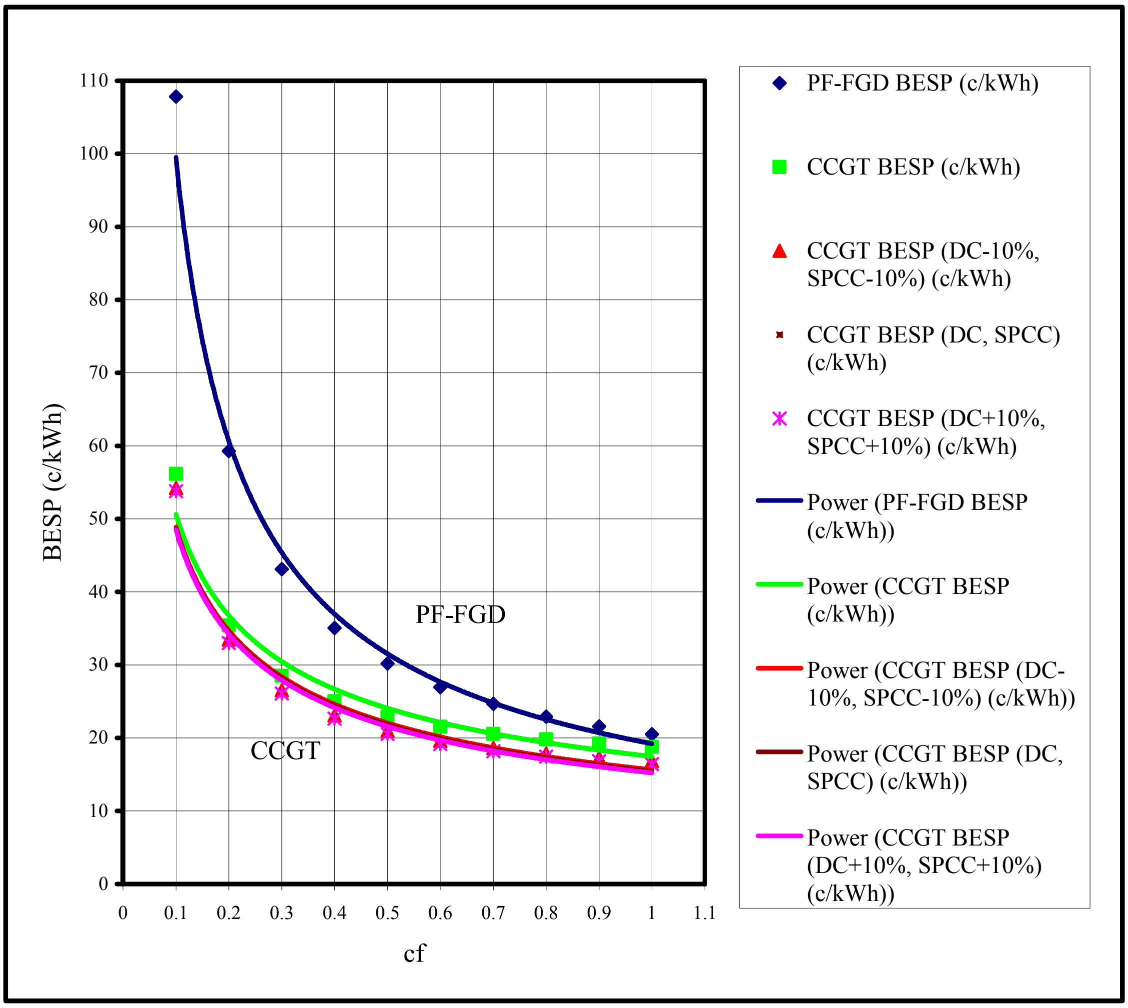



Figure 5.46 Sensitivities of BESP to +/- 10% changes in DC and SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.49 Variations in BESP to changes of +/-15% in DC and SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC-15%, SPCC-15%) (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) | CCGT BESP (DC+15%, SPCC+15%) (c/kWh) |
|---|---|---|---|---|---|
| 0.1 | 107.82 | 56.17 | 54.34 | 54.01 | 53.69 |
| 0.2 | 59.30 | 35.40 | 33.56 | 33.23 | 32.92 |
| 0.3 | 43.13 | 28.47 | 26.64 | 26.31 | 25.99 |
| 0.4 | 35.05 | 25.02 | 23.18 | 22.85 | 22.52 |
| 0.5 | 30.20 | 22.94 | 21.10 | 20.77 | 20.45 |
| 0.6 | 26.97 | 21.55 | 19.71 | 19.38 | 19.06 |
| 0.7 | 24.65 | 20.56 | 18.72 | 18.39 | 18.07 |
| 0.8 | 22.92 | 19.82 | 17.97 | 17.65 | 17.32 |
| 0.9 | 21.58 | 19.24 | 17.40 | 17.07 | 16.74 |
| 1.0 | 20.50 | 18.78 | 16.93 | 16.61 | 16.28 |

Source: Developed by author based on methodology in Stoft (2002).

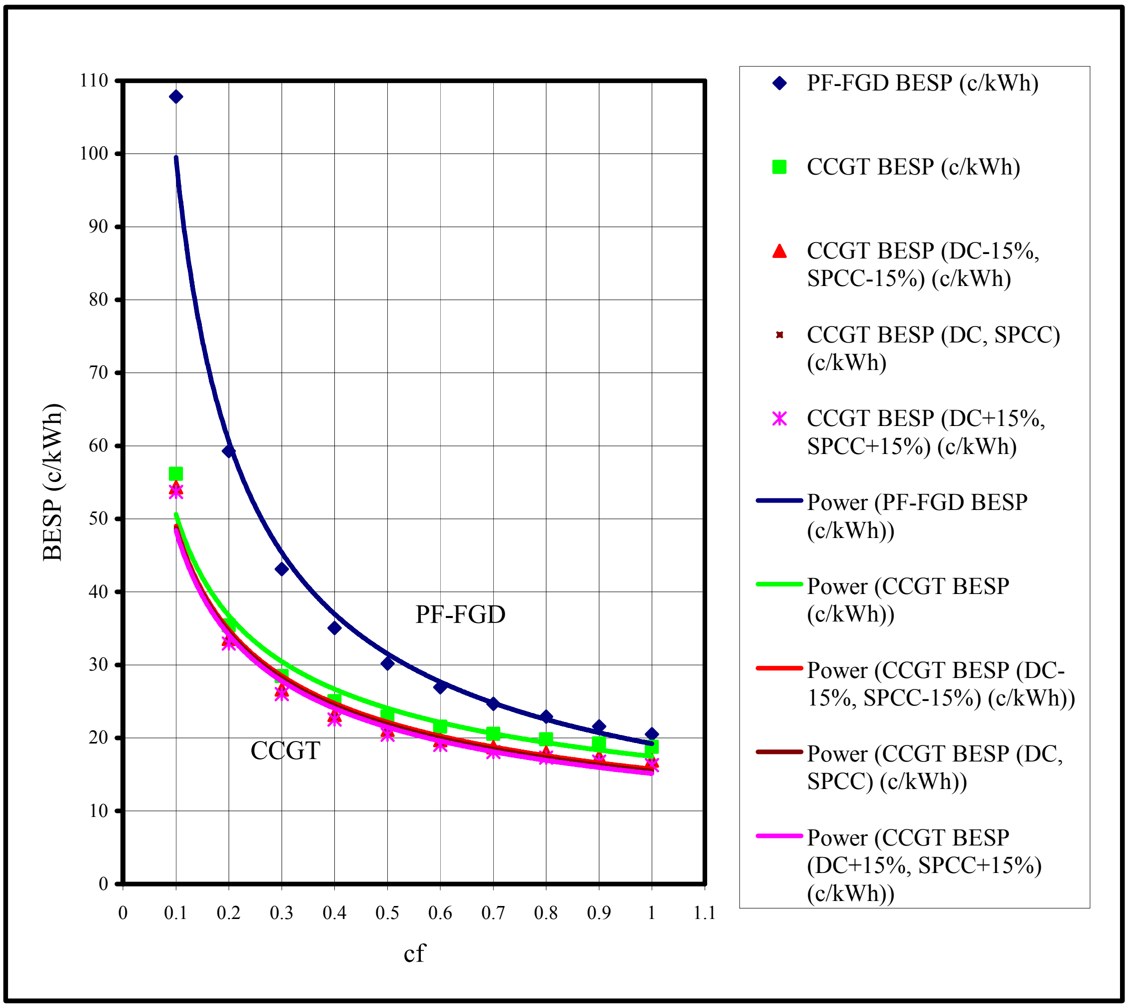



Figure 5.47 Sensitivities of BESP to +/- 15% changes in DC and SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.50 Variations in BESP to changes of +/-20% in DC and SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC-20%, SPCC-20%) (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) | CCGT BESP (DC+20%, SPCC+20%) (c/kWh) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 54.44 | 54.01 | 53.58 |
| 0.20 | 59.30 | 35.40 | 33.67 | 33.24 | 32.81 |
| 0.30 | 43.13 | 28.47 | 26.75 | 26.32 | 25.88 |
| 0.40 | 35.05 | 25.02 | 23.29 | 22.85 | 22.42 |
| 0.50 | 30.20 | 22.94 | 21.21 | 20.77 | 20.34 |
| 0.60 | 26.97 | 21.55 | 19.82 | 19.38 | 18.95 |
| 0.70 | 24.65 | 20.56 | 18.83 | 18.39 | 17.96 |
| 0.80 | 22.92 | 19.82 | 18.08 | 17.65 | 17.22 |
| 0.90 | 21.58 | 19.24 | 17.50 | 17.07 | 16.64 |
| 1.00 | 20.50 | 18.78 | 17.04 | 16.61 | 16.17 |

Source: Developed by author based on methodology in Stoft (2002).

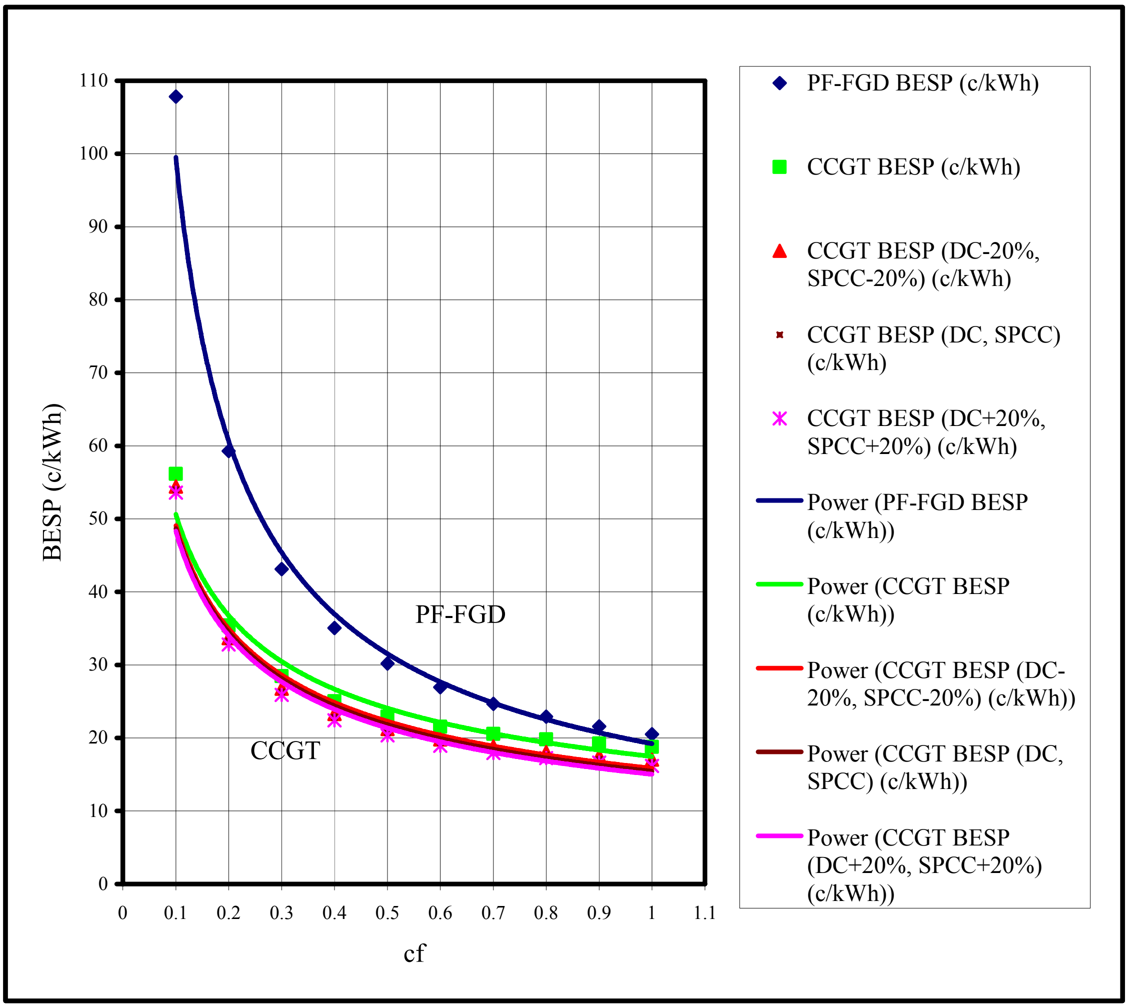



Figure 5.48 Sensitivities of BESP to +/- 20% changes in DC and SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.51 Variations in BESP to +/-30% changes in DC and SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC-30%, SPCC-30%) (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) | CCGT BESP (DC+30%, SPCC+30%) (c/kWh) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 54.66 | 54.01 | 53.36 |
| 0.20 | 59.30 | 35.40 | 33.89 | 33.24 | 32.59 |
| 0.30 | 43.13 | 28.47 | 26.96 | 26.32 | 25.67 |
| 0.40 | 35.05 | 25.02 | 23.50 | 22.85 | 22.20 |
| 0.50 | 30.20 | 22.94 | 21.42 | 20.77 | 20.12 |
| 0.60 | 26.97 | 21.55 | 20.03 | 19.38 | 18.73 |
| 0.70 | 24.65 | 20.56 | 19.04 | 18.39 | 17.74 |
| 0.80 | 22.92 | 19.82 | 18.30 | 17.65 | 17.00 |
| 0.90 | 21.58 | 19.24 | 17.72 | 17.07 | 16.42 |
| 1.00 | 20.50 | 18.78 | 17.26 | 16.61 | 15.95 |

Source: Developed by author based on methodology in Stoft (2002).

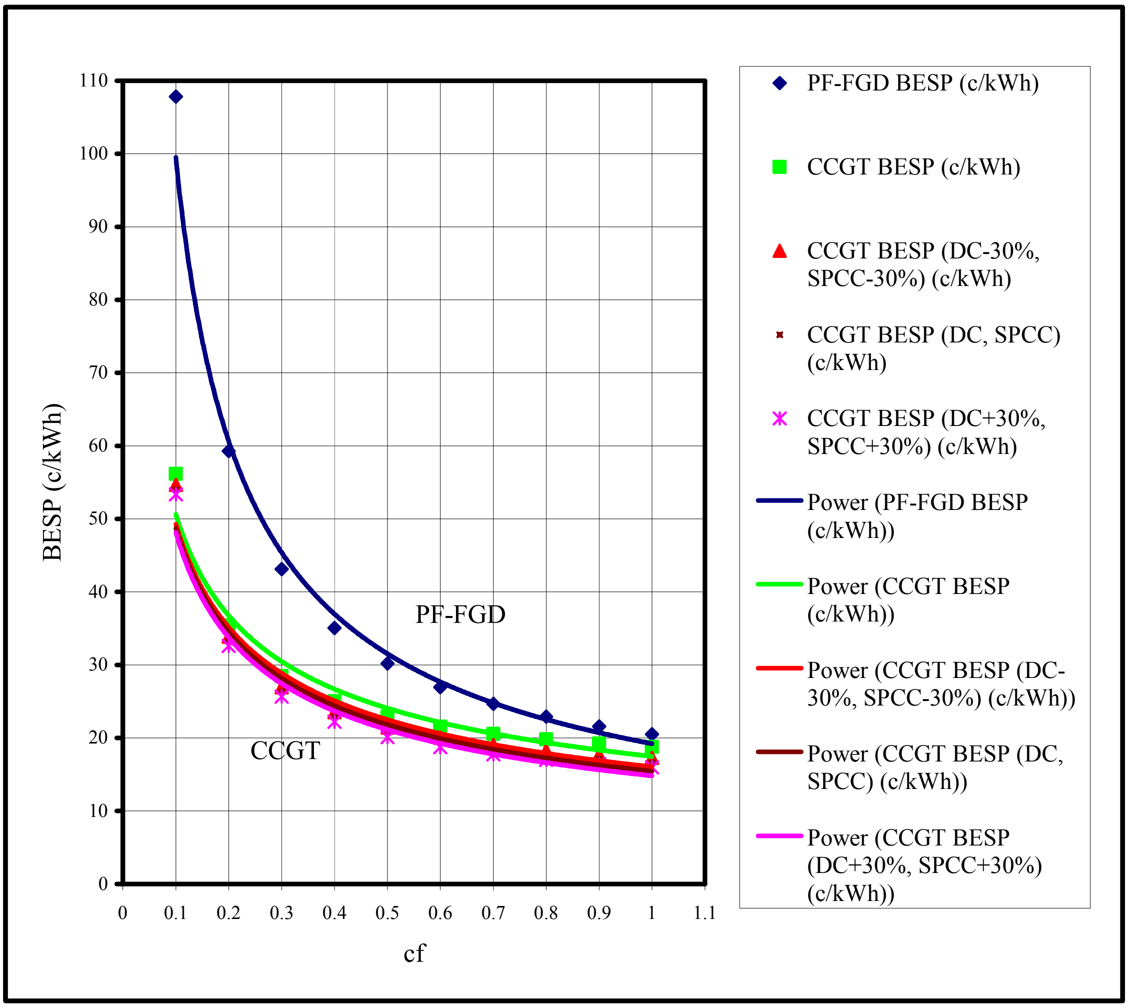



Figure 5.49 Sensitivities of BESP to +/- 30% changes in DC and SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Table 5.52 Variations in BESP to +/- 40% changes in DC and SPCC (PF-FGD/CCGT).**

| cf | PF-FGD BESP (c/kWh) | CCGT BESP (c/kWh) | CCGT BESP (DC-40%, SPCC-40%) (c/kWh) | CCGT BESP (DC, SPCC) (c/kWh) | CCGT BESP (DC+40%, SPCC+40%) (c/kWh) |
|---|---|---|---|---|---|
| 0.10 | 107.82 | 56.17 | 54.88 | 54.01 | 53.15 |
| 0.20 | 59.30 | 35.40 | 34.10 | 33.24 | 32.37 |
| 0.30 | 43.13 | 28.47 | 27.18 | 26.32 | 25.45 |
| 0.40 | 35.05 | 25.02 | 23.72 | 22.85 | 21.98 |
| 0.50 | 30.20 | 22.94 | 21.64 | 20.77 | 19.90 |
| 0.60 | 26.97 | 21.55 | 20.26 | 19.38 | 18.52 |
| 0.70 | 24.65 | 20.56 | 19.26 | 18.39 | 17.53 |
| 0.80 | 22.92 | 19.82 | 18.52 | 17.65 | 16.78 |
| 0.90 | 21.58 | 19.24 | 17.94 | 17.07 | 16.20 |
| 1.00 | 20.50 | 18.78 | 17.47 | 16.61 | 15.74 |

Source: Developed by author based on methodology in Stoft (2002).

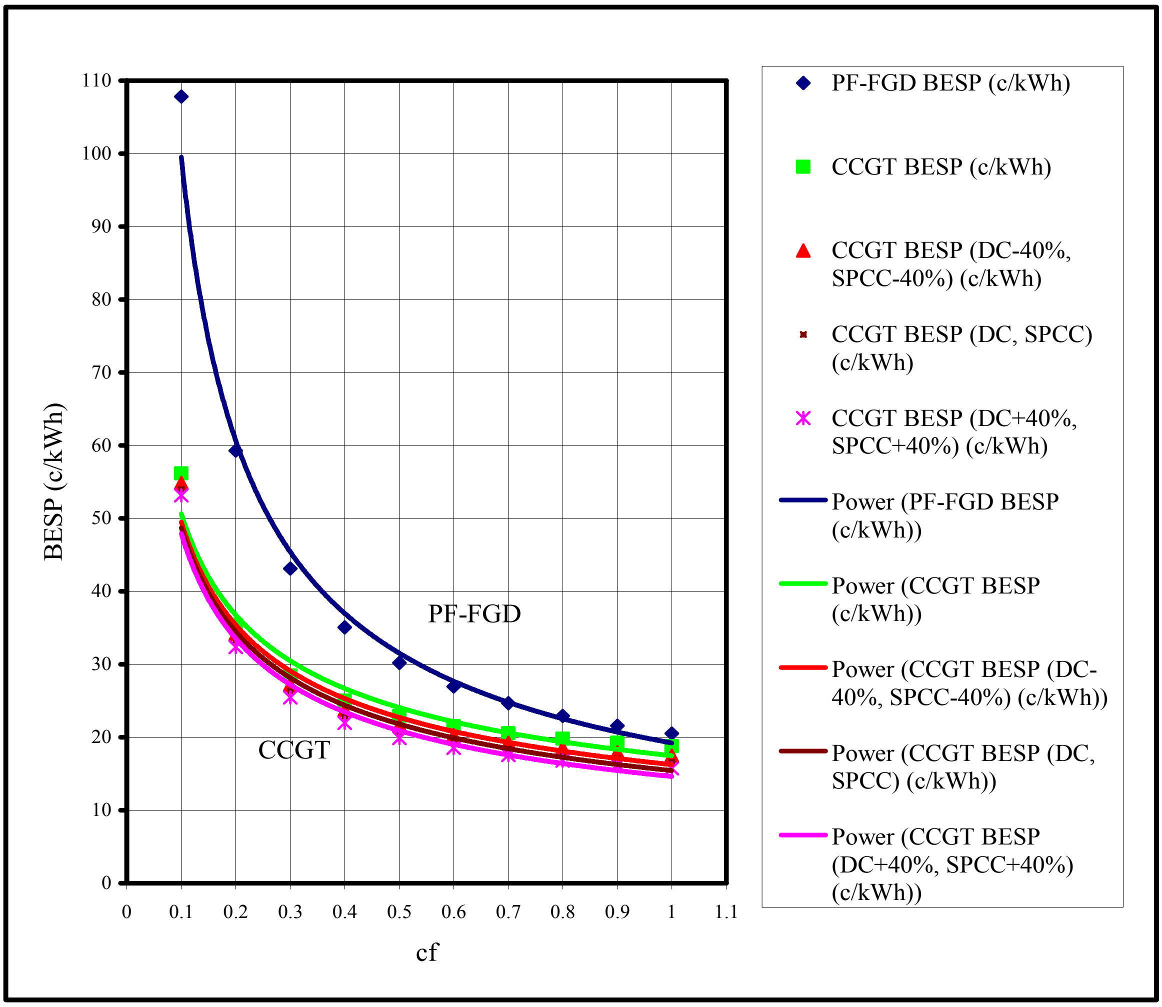



Figure 5.50 Sensitivities of BESP to +/- 40% changes in DC and SPCC (PF-FGD/CCGT).

Source: Developed by author based on methodology in Stoft (2002).

**Comments**: DC and SPCC value variances cause CCGT to approach, but remain relatively low to PF-FGD in BESP terms. The favourable BESP values of the CCGT are attributed mainly to more significant contribution from SPCC (a benefit) than DC (a cost) to BESP values. Numerically, SPCC per unit value is higher than that of DC.

## 5.11 Comparison of the life-cycle economic performance of the power stations

The economic performance indicators (tables 5.53-5.86) are used to evaluate the economic performance of the power stations as defined in appendix E. The selling price of electricity used as an input in the Te-Con Techno-Economic Simulator model is based on Eskom's average selling price of electricity of approximately R0.15/kWh in 2002 (Eskom, 2002). Initially, a selling price of electricity of R0.23/kWh was assumed, this being the same as Eskom's projected average selling price of electricity in 2007 using 8.56% per annum increase in prices (H. Simonsen, personal communications, 19 October 2005).

Most of the tables indicated below provide the life-cycle economic performance of the power stations at the breakeven selling price (unit cost of generating) of electricity of the relevant technology/fuel at selected capacity factors.

**Table 5.53 Life-cycle economic performance indicators of PF/CCGT (0.75 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Selling price of electricity, R/kWh | [1]0.23 | [1]0.23 |
| Investors' rate of return, % | 4.0 | 9.0 |
| Net present value, billion Rand | -5.5 | 1.0 |
| Discounted payback time, years | >15 | 13.1 |
| Average return on investments, % | 4.9 | 10.0 |
| Average return on shareholders' equity | 5.7 | 12.3 |
| Average du Pont return on net worth, % | 5.8 | 12.3 |

Source: Output from modelling.

Legend: [1] Based on Eskom's projected selling price of electricity in 2007 and adapted from Eskom Annual Report (2002).
>15 means that the discounted payback time is beyond the life-cycle of 15 years.
The 0.75 cf corresponds to the approximate point at which the ARR of the PF and the CCGT have the same value (see figure 5.5).

**Comments:** The investors' rate of return value for the PF is less than 8% (risk-free Treasury bond rate, see table D2, appendix D). This accounts for the relatively poor life-cycle economic performance of PF in relation to CCGT.

**Table 5.54 Life-cycle economic performance indicators of PF-FGD/CCGT (0.91 cf)**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Selling price of electricity, R/kWh | [1]0.23 | [1]0.23 |
| Investors' rate of return, % | 8.9 | 12.7 |
| Net present value, billion Rand | 1.5 | 4.8 |
| Discounted payback time, years | 13.8 | 10.4 |
| Average return on investments, % | 10.1 | 14.7 |
| Average return on shareholders' equity | 12.0 | 20.5 |
| Average du Pont return on net worth, % | 11.9 | 20.5 |

Source: Output from modelling.

Legend: The 0.91 cf corresponds to the approximate point at which the ARR of the PF-FGD and the CCGT have the same value (see figure 5.26).

[1]Based on Eskom's projected selling price of electricity in 2007 and adapted from Eskom Annual Report (2002).

**Comments**: The life-cycle economic performance indicators of CCGT are more favourable than those of PF-FGD. This is a reflection of the fact that CCGT is a lower cost power generator for capacity factors between 0.1 and 0.91 for the PF-FGD/CCGT plant pair (figure 5.26).

*Life-cycle economic performance indicators at breakeven selling price of electricity under Scenario 1*

**Table 5.55 Life-cycle economic performance indicators of PF/CCGT (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.28 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | 14.6 |
| Average return on investments, % | 9.9 | 9.1 |
| Average return on shareholders' equity | 12.1 | 10.8 |
| Average du Pont return on net worth, % | 12.1 | 10.9 |

Source: Output from modelling.

**Comment**: The fact that CCGT exhibits a lower breakeven selling price of electricity emphasises the lower cost of CCGT as a power generator than PF at a cf of 0.4 (see figure 5.5).

**Table 5.56 Life-cycle economic performance indicators of PF-FGD/CCGT (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.36 | 0.26 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 15 | 13.3 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 9.2 | 11.9 |
| Average du Pont return on net worth, % | 10.6 | 11.9 |

Source: Output from modelling

**Comment:** The CCGT is a lower cost power generator than PF-GD. In addition, CCGT has better returns.

**Table 5.57 Life-cycle economic performance indicators of PF/CCGT (0.6 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.31 | 0.24 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | 14.4 |
| Average return on investments, % | 9.9 | 9.0 |
| Average return on shareholders' equity | 12.2 | 10.9 |
| Average du Pont return on net worth, % | 12.1 | 10.8 |

Source: Output from modelling.

**Comments:** The breakeven selling price of electricity is reduced for both generators by an increase in capacity compared to the figures of the 0.4 cf. This is due to the fact that to generate the same amount of revenue, an increase in capacity factor translates to a reduction in the price of electricity.

**Table 5.58 Life-cycle economic performance indicators of PF-FGD/CCGT (0.6 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.28 | 0.22 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.9 | >15 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 9.2 | 12.1 |
| Average du Pont return on net worth, % | 10.7 | 12.1 |

Source: Output from modelling

**Comments**: The increase in cf causes a reduction in the breakeven selling price of electricity. With the exception of discounted payback time, CCGT has better life-cycle economic performance than PF-FGD.

**Table 5.59 Life-cycle economic performance indicators of PF/CCGT (0.9 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.22 | 0.21 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.9 | 11.8 |
| Average return on investments, % | 9.2 | 8.92 |
| Average return on shareholders' equity | 9.2 | 10.98 |
| Average du Pont return on net worth, % | 10.7 | 10.92 |

Source: Output from modelling

**Table 5.60 Life-cycle economic performance indicators of PF-FGD/CCGT (0.9 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.22 | 0.20 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.9 | 12.9 |
| Average return on investments, % | 9.2 | 9.4 |
| Average return on shareholders' equity | 9.2 | 12.3 |
| Average du Pont return on net worth, % | 10.7 | 12.3 |

Source: Output from modelling**.**

**Comment:** The convergence of the breakeven selling prices of electricity at 0.9 cf confirms the pattern common to the power curves (of the sensitivity analysis).

*Life-cycle economic performance indicators at breakeven selling price of electricity under Scenario 2*

**Table 5.61 Life-cycle economic performance indicators of PF/CCGT (SPCC) (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.22 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | >15 |
| Average return on investments, % | 9.9 | 9.6 |
| Average return on shareholders' equity | 12.1 | 11.6 |
| Average du Pont return on net worth, % | 12.1 | 11.6 |

Source: Output from modelling.

**Comment:** The contribution made by the CDM revenue (through SPCC) to the total revenue of the CCGT plant has significantly reduced its breakeven selling price of electricity relative to that of PF.

**Table 5.62 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC) (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.36 | 0.26 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | >15 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 10.7 | 11.9 |
| Average du Pont return on net worth, % | 10.7 | 11.9 |

Source: Output from modelling.

**Comments**: Even at this relatively low capacity factor for base load power plants, the two plants show favourable life-cycle economic performance indicators (except the discounted payback time). However, the CCGT has better performance indicators than PF-FGD due to extra contribution from SPCC.

**Table 5.63 Life-cycle economic performance indicators of PF/CCGT (SPCC) (0.6 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.31 | 0.18 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | >15 |
| Average return on investments, % | 9.9 | 9.3 |
| Average return on shareholders' equity | 12.2 | 11.5 |
| Average du Pont return on net worth, % | 12.1 | 11.5 |

Source: Output from modelling.

**Comment:** The increase in capacity factor has resulted in the reduction in breakeven selling price of electricity (BESP) for both plants. However, the reduction in BESP of the CCGT plant is more pronounced due to the contribution from increased CDM revenue.

**Table 5.64 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC) (0.6 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.28 | 0.22 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 10.8 | 12.1 |
| Average du Pont return on net worth, % | 10.7 | 12.1 |

Source: Output from modelling.

**Comment**: The decrease in returns of the PF-FGD plant relative to the returns of the PF (table 5.60) is due to the fact that the PF-FGD has relatively high overnight cost than the PF.

**Table 5.65 Life-cycle economic performance indicators of PF/CCGT (SPCC) (0.9 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.26 | 0.15 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | >15 |
| Average return on investments, % | 10.0 | 8.9 |
| Average return on shareholders' equity | 12.3 | 11.3 |
| Average du Pont return on net worth, % | 12.3 | 11.4 |

Source: Output from modelling**.**

**Comment**: PF benefits more from the higher BESP with respect to the returns. However, the CCGT is a lower cost generator of power.

**Table 5.66 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC) (0.9 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.22 | 0.19 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.9 | >15 |
| Average return on investments, % | 9.2 | 9.4 |
| Average return on shareholders' equity | 10.8 | 12.3 |
| Average du Pont return on net worth, % | 10.8 | 12.3 |

Source: Output from modelling.

**Comment**: The superior performance of the CCGT (despite an unfavourable discounted payback time) is attributed to the increased revenue from monetised carbon dioxide credits at a relatively high capacity factor.

*Life-cycle economic performance indicators at breakeven selling price of electricity under Scenario 3*

**Table 5.67 Life-cycle economic performance indicators of PF/CCGT (DC) (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.27 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 9.9 | 8.5 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 12.1 | 11.9 |
| Average du Pont return on net worth, % | 12.1 | 11.9 |

Source: Output from modelling.

**Comment**: The introduction of damage costs has a marginal effect on the performance of the two plants due to the low DC values (see table 6.3).

**Table 5.68 Life-cycle economic performance indicators of PF-FGD/CCGT (DC) (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.27 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 10.8 | 11.9 |
| Average du Pont return on net worth, % | 10.7 | 11.9 |

Source: Output from modelling.

**Comment**: The fact that PF-FGD has a marginally higher overnight cost than that of PF has contributed to the marginal decrease in average return in shareholders' equity and average du Pont return on net worth (see table 5.64).

**Table 5.69 Life-cycle economic performance indicators of PF/CCGT (DC) (0.6 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.28 | 0.26 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.2 | 9.0 |
| Average return on shareholders' equity | 10.8 | 10.9 |
| Average du Pont return on net worth, % | 10.7 | 10.8 |

Source: Output from modelling.

**Comment**: The returns for both plants are similar. However, the CCGT is a lower cost generator of power than the PF (see figure 5.5).

**Table 5.70 Life-cycle economic performance indicators of PF-FGD/CCGT (DC) (0.6 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.31 | 0.23 |
| Investors' rate of return, % | 8.0 | 8 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.2 | 9.5 |
| Average return on shareholders' equity | 10.8 | 12.1 |
| Average du Pont return on net worth, % | 10.7 | 12.1 |

Source: Output from modelling.

**Comment**: With the exception of the discounted payback time, CCGT has a better economic performance than the CCGT (see figure 5.5).

**Table 5.71 Life-cycle economic performance indicators of PF/CCGT (DC) (0.9 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.22 | 0.23 |
| Investors' rate of return, % | 8.0 | 8 |
| Discounted payback time, years | 14.8 | 14.2 |
| Average return on investments, % | 9.2 | 9.0 |
| Average return on shareholders' equity | 10.8 | 11.0 |
| Average du Pont return on net worth, % | 10.8 | 11.0 |

Source: Output from modelling.

**Comment**: The increase in the revenue due to increase in the capacity factor outweighs the increase in costs due to increased damage costs.

**Table 5.72 Life-cycle economic performance indicators of PF-FGD/CCGT (DC) (0.9 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.25 | 0.20 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.3 | 9.4 |
| Average return on shareholders' equity | 10.9 | 12.3 |
| Average du Pont return on net worth, % | 10.8 | 12.3 |

Source: Output from modelling.

**Comment**: The relatively higher capacity factor contributes to a significant reduction in the BESP.

*Life-cycle economic performance indicators at breakeven selling price of electricity under Scenario 4*

**Table 5.73 Life-cycle economic performance indicators of PF/CCGT (SPCC/DC) (0.4 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.28 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | >15 | >15 |
| Average return on investments, % | 9.9 | 8.9 |
| Average return on shareholders' equity | 12.1 | 10.6 |
| Average du Pont return on net worth, % | 12.1 | 10.5 |

Source: Output from modelling.

Comments: The PF is a higher cost generator of electricity than the CCGT. However, it has a better life-cycle economic performance.

**Table 5.74 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Capacity factor | 0.4 | 0.4 |
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.26 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.2 | 8.8 |
| Average return on shareholders' equity | 10.8 | 10.5 |
| Average du Pont return on net worth, % | 10.7 | 10.5 |

Source: Output from modelling.

**Table 5.75 Life-cycle economic performance indicators of PF/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Capacity factor | 0.6 | 0.6 |
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.23 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 11.1 | 14.9 |
| Average return on investments, % | 14.6 | 8.8 |
| Average return on shareholders' equity | 19.2 | 10.6 |
| Average du Pont return on net worth, % | 19.1 | 10.5 |

Source: Output from modelling.

**Comment**: The increase in capacity factor resulted in a reduction in the breakeven selling price of electricity of the CCGT.

**Table 5.76 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Capacity factor | 0.6 | 0.6 |
| Breakeven selling price of electricity, R/kWh | 0.31 | 0.22 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.2 | 8.7 |
| Average return on shareholders' equity | 10.8 | 10.5 |
| Average du Pont return on net worth, % | 10.7 | 10.5 |

Source: Output from modelling.

**Table 5.77 Life-cycle economic performance indicators of PF/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Capacity factor | 0.9 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.26 | 0.23 |
| Investors' rate of return, % | 8.0 | 8 |
| Discounted payback time, years | >15 | 10.4 |
| Average return on investments, % | 10.0 | 12.0 |
| Average return on shareholders' equity | 12.3 | 15.2 |
| Average du Pont return on net worth, % | 12.3 | 15.1 |

Source: Output from modelling.

**Table 5.78 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Capacity factor | 0.9 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.25 | 0.19 |
| Investors' rate of return, % | 8.0 | 8.0 |
| Discounted payback time, years | 14.8 | >15 |
| Average return on investments, % | 9.3 | 8.5 |
| Average return on shareholders' equity | 10.9 | 10.5 |
| Average du Pont return on net worth, % | 10.8 | 10.5 |

Source: Output from modelling.

**Comment:** The higher cf value accounts for the relatively low breakeven selling prices of electricity. In this case, PF-FGD has a better life-cycle economic performance.

In the following series of 8 tables (5.79 – 5.86), the performance of the power station configuration pairs was simulated at arbitrary prices, which are R0.02/kWh above breakeven prices under each scenario at constant capacity factors. These simulations were done to provide an idea about the viability and extent of potential profitability of the power stations.

*Life-cycle economic performance indicators of power stations when electricity is sold above breakeven selling price of electricity under scenario 1*

**Table 5.79 Life-cycle economic performance indicators of PF/CCGT (0.60 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Selling price of electricity, R/kWh | 0.41 | 0.41 |
| Investors' rate of return, % | 13.4 | 18.0 |
| Discounted payback time, years | 7.8 | 6.1 |
| Average return on investments, % | 14.4 | 18.2 |
| Average return on shareholders' equity | 17.9 | 23.6 |
| Average du Pont return on net worth, % | 17.8 | 23.5 |

Source: Output from modelling.

**Comments:** Both plants have favourable returns at the selling price of electricity of R0.41/kWh. However, CCGT has better returns.

**Table 5.80 Life-cycle economic performance indicators of PF-FGD/CCGT (0.60 cf).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Selling price of electricity, R/kWh | 0.30 | 0.30 |
| Investors' rate of return, % | 9.22 | 14.6 |
| Net present value, billion Rand | 2.11 | 7.0 |
| Discounted payback time, years | 13.5 | 8.0 |
| Average return on investments, % | 10.4 | 15.9 |
| Average return on shareholders' equity | 12.4 | 23.7 |
| Average du Pont return on net worth, % | 12.3 | 23.7 |

Source: Output from modelling.

**Comment:** Whilst the two plants have favourable life-cycle economic performance indicators, the net present value of the CCGT is about three times that of the PF-FGD.

*Life-cycle economic performance indicators of power stations when electricity is sold above breakeven selling price of electricity under scenario 2*

**Table 5.81 Life-cycle economic performance indicators of PF/CCGT (SPCC) (0.60 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Selling price of electricity, R/kWh | 0.41 | 0.41 |
| Investors' rate of return, % | 13.4 | 22.5 |
| Net present value, billion Rand | 11.1 | 20.2 |
| Discounted payback time, years | 7.8 | 5.7 |
| Average return on investments, % | 14.4 | 25.6 |
| Average return on shareholders' equity | 17.9 | 38.8 |
| Average du Pont return on net worth, % | 17.8 | 38.8 |

Source: Output from modelling**.**

**Comment**: The CCGT has better performance indicators than the PF. The net present value of the CCGT is about two times that of the PF.

**Table 5.82 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Capacity factor | 0.60 | 0.60 |
| Selling price of electricity, R/kWh | 0.38 | 0.38 |
| Investors' rate of return, % | 12.4 | 23.9 |
| Net present value, billion Rand | 8.7 | 17.1 |
| Discounted payback time, years | 9.2 | 6.2 |
| Average return on investments, % | 13.5 | 26.0 |
| Average return on shareholders' equity | 16.6 | 42.4 |
| Average du Pont return on net worth, % | 16.5 | 42.4 |

Source: Output from modelling.

**Comment:** The relatively good results of the CCGT plant make it the medium choice for generating base load power.

*Life-cycle economic performance indicators of power stations when electricity is sold above breakeven selling price of electricity under scenario 3*

**Table 5.83 Life-cycle economic performance indicators of PF/CCGT (DC) (0.60 cf).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Selling price of electricity, R/kWh | 0.41 | 0.41 |
| Investors' rate of return, % | 13.4 | 17.0 |
| Net present value, billion Rand | 11.1 | 12.3 |
| Discounted payback time, years | 7.8 | 6.4 |
| Average return on investments, % | 14.4 | 17.5 |
| Average return on shareholders' equity | 17.9 | 22.5 |
| Average du Pont return on net worth, % | 17.8 | 22.4 |

Source: Output from modelling.

**Comment:** A comparison of these performance indicators and those found under scenario 1 (table 5.79) confirms the marginal effect of damage costs on the indicators.

**Table 5.84 Life-cycle economic performance indicators of PF-FGD/CCGT (DC).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Capacity factor | 0.60 | 0.60 |
| Selling price of electricity, R/kWh | 0.41 | 0.41 |
| Investors' rate of return, % | 12.7 | 20.3 |
| Net present value, billion Rand | 8.5 | 15.9 |
| Discounted payback time, years | 10.5 | 6.2 |
| Average return on investments, % | 15.33 | 23.1 |
| Average return on shareholders' equity | 20.39 | 34.8 |
| Average du Pont return on net worth, % | 20.37 | 34.9 |

Source: Output from modelling.

*Life-cycle economic performance indicators of power stations when electricity is sold above breakeven selling price of electricity under scenario 4*

**Table 5.85 Life-cycle economic performance indicators of PF/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF | CCGT |
|---|---|---|
| Capacity factor | 0.60 | 0.60 |
| Selling price of electricity, R/kWh | 0.41 | 0.41 |
| Investors' rate of return, % | 13.4 | 18.1 |
| Net present value, billion Rand | 11.1 | 14.5 |
| Discounted payback time, years | 7.8 | 6.1 |
| Average return on investments, % | 14.4 | 18.2 |
| Average return on shareholders' equity | 17.9 | 23.7 |
| Average du Pont return on net worth, % | 17.8 | 23.5 |

Source: Output from modelling.

**Table 5.86 Life-cycle economic performance indicators of PF-FGD/CCGT (SPCC/DC).**

| Life-cycle economic performance indicator/measure | PF-FGD | CCGT |
|---|---|---|
| Capacity factor | 0.60 | 0.60 |
| Selling price of electricity, R/kWh | 0.41 | 0.41 |
| Investors' rate of return, % | 12.7 | 18.7 |
| Net present value, billion Rand | 8.5 | 15.7 |
| Discounted payback time, years | 10.5 | 6.0 |
| Average return on investments, % | 15.33 | 18.7 |
| Average return on shareholders' equity | 20.39 | 24.3 |
| Average du Pont return on net worth, % | 20.37 | 24.1 |

Source: Output from modelling.

## 5.12 Summary

This section presents an interpretation of the results obtained under the scenarios assumed for the power plant configurations pairs - PF/CCGT and PF-FGD/CCGT.

**PF/CCGT**

It was found under scenario 1 that for generating base load power, natural gas was a lower cost source of energy than coal for capacity factors between 0 and approximately 0.75. Thus, the proposition "Natural gas is a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is verified. However, it must be pointed out that coal is a lower cost energy source than natural gas for generating base load power for capacity factors between approximately 0.75 and 1.00.

**PF-FGD/CCGT**

It emerged under scenario 1 that for generating base load power, natural gas was a lower cost source of energy than coal for capacity factors between 0 and approximately 0.91.

Therefore, proposition 1; "Natural gas is a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is confirmed. Nevertheless, for capacity factors between approximately 0.91 and 1.00, coal is a lower cost energy source than natural gas for generating base load power.

**PF/CCGT**

For scenario 2, natural gas was established as a lower cost source of energy than coal for generating base load power for capacity factors between 0.1 and 1.0. As a result, proposition 2; "Monetising accrued carbon dioxide credits makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is corroborated.

**PF-FGD/CCGT**

In the case of scenario 2, natural gas was found to be a lower cost source of energy than coal for generating base load power for capacity factors between 0.1 and 1.0. For that reason, proposition 2; "Monetising accrued carbon dioxide credits makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is validated.

**PF/CCGT**

Under scenario 3, natural gas was established as a lower cost source of energy than coal for generating base load power for capacity factors between 0.1 and 1.0. Based on that, proposition 3; "Internalising externalities by accounting for damage costs makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is confirmed.

**PF-FGD/CCGT**

With respect to scenario 3, natural gas emerged as a lower cost source of energy than coal for generating base load power for capacity factors between 0.1 and 1.0. Thus, proposition 3; "Internalising externalities by accounting for damage costs makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is verified.

**PF/CCGT**

For scenario 4, natural gas was found to be a lower cost source of energy than coal for generating base load power for capacity factors between 0.1 and 1.0. Therefore, scenario 4; "Internalising externalities by accounting for damage costs and monetising accrued carbon dioxide credits make natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is confirmed. This result can be expected due to the fact that scenario 4 is contingent on the verification of either scenarios 2 or 3. Both scenarios 2 and 3 have already been validated.

**PF-FGD/CCGT**

With respect to scenario 4, natural gas was established as a lower cost source of energy than coal for generating base load power within a capacity factor between 0.1 and 1.0. Therefore scenario 4; "Internalising externalities by accounting for damage costs and monetising accrued carbon dioxide credits make natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors" is validated. This result can be expected due to the fact that scenario 4 is contingent on the verification of either scenarios 2 or 3. Scenarios 2 and 3 have been confirmed.

It must be pointed out that the proposition for scenario 1 holds equally true, after several sensitivity analyses were conducted on annual revenue requirements with respect to changes in fuel prices ranging from +/- 5% to +/- 20% for both plant configuration pairs. The propositions for scenarios 2, 3 and 4 were also confirmed when various sensitivity analyses involving BESP with respect to changes in SPCC and DC, severally and jointly, ranging from +/- 5% to +/- 40% were undertaken.

The results of modelling the life-cycle economic performance of the technology/fuel types are discussed and analysed in chapter 6.

# 6. DISCUSSION OF THE SIMULATION MODELLING

This chapter discusses the comparative life-cycle economic performance of the pulverised fuel coal-fired and the combined-cycle gas turbine power station pairs for generating base load power with the assistance of the techno-economic modelling undertaken in chapter 5. In addition, this chapter discusses sensitivities of annual revenue requirements to changes in fuel price including sensitivity analysis of breakeven selling price of electricity to selling price of carbon dioxide credits and damage costs in chapter 5. The discussion includes the potential role of monetised carbon dioxide credits in redeeming debt and differences in damage costs.

## 6.1 Review of the screening curves and the life-cycle economic performance

### *6.1.1 Screening curves*

In chapter 5, screening curves and power curves were used to determine the relative costs involved in generating base load power using the plant configuration pairs PF/CCGT and PF-FGD/CCGT under the following scenarios: a base case combined-cycle gas turbine; a combined-cycle gas turbine with CDM revenue; a combined-cycle gas turbine with externalities accounted for by damage costs; and a combined-cycle gas turbine with CDM revenue and externalities accounted for by damage costs. These scenarios were crafted to test various propositions on whether natural gas is a lower cost energy source than coal for generating base load power within a specified range of capacity factors. Additionally, the Te-Con Techno-Economic Simulator was used to compare the life-cycle economic performance of the power plant configuration pairs. The power curves (BESP vs. cf) for scenarios 2 to 4 were found to be asymptotic for capacity factors between 0 and 0.1. Within this capacity range, BESP values tended to be infinite. Practically, a base load power plant would be operated at relatively high capacity factors (greater than 0.1), in comparison with peaking plants.

### *6.1.2 Life-cycle economic performance*

In sections 5.9 and 5.11, the comparative costs of generating base load power using pulverised fuel coal-fired (with and without flue gas desulphurisation (FGD) facility – emission abatement equipment) and combined-cycle gas turbine technologies were undertaken with the assistance of screening curves. The point of intersection of the screening curves facilitated the determination of the range of capacity factors within which gas-based power generation was cheaper.

The life-cycle economic performances of the power station pairs – conventional pulverised fuel coal-fired (PF) and combined-cycle gas turbine (CCGT) as well as PF with FGD and CCGT – were determined by doing simulations on the Te-Con model using various electricity prices – breakeven selling prices and prices that are R0.02/kWh higher than the breakeven price. "Iterative zeroing" – a simulation method to determine the breakeven selling price of electricity – was used. The simulation started with finding the life-cycle economic performance of the PF and CCGT power stations at a selling price of electricity of R0.23/kWh, comparable to Eskom's projected selling price of electricity in 2007 (section 5.11). At this price, all four power stations with the exception of the PF operated profitably, as they had positive net present values. This can be explained by the fact that through simulation of the Te-Con model, it was found that the breakeven selling price of electricity of the PF plant at 0.75 cf was Rc23.43/kWh (Rc is Rand cents) which is greater that R0.23/kWh.

Sensitivity analyses on annual revenue requirements (ARR) with respect to variations in price of fuel (which represent variable costs) produced significant results. It was noted that within the same percentage range of variable natural gas and coal prices, the ARR for natural gas was more sensitive to variation in prices of natural gas than those for coal. This is due mainly to the fact that the gradient of the screening curve for CCGT was about 6.6 times bigger than that of PF. There was a similar situation with the CCGT and PF-FGD pair. It must be stated that the ratio of natural gas price to that of coal is about 6.3. Additionally, sensitivity of ARR to price variation was enhanced with increase in the magnitude of the price variation. As the price variation increased, cones of variation (formed by the lower and upper limits of ARR) were produced around the original screening curves for both CCGT and the corresponding PF or PF-FGD. The intersecting cones of variation produced a relatively broad band of capacity factors within which ARR varied much less. In each of the four power station configurations, the apex of the cone was the fixed cost, which is provided by the amortisation formula found in Stoft (2002):

$$FC \approx r.\ OC/(1-1(1+r)^{T}) \tag{5.7}$$

The fixed cost component of ARR for the coal technologies were twice those of the natural gas technologies. This is due to the fact that fixed cost is directly proportional to "overnight cost" (OC), which is the present-value cost of the plant (Stoft, 2002). In general, the OC of the coal technology was at least twice that of the corresponding natural gas technology.

In the case of the breakeven selling price of electricity (BESP), sensitivity analysis did not change the fact that at capacity factors between 0.1 and 1.0, the coal technology had a higher BESP than the corresponding natural gas technology. Again, the sensitivities of the BESP were more enhanced as the absolute values of the variations with respect to the selling price of carbon dioxide credits (SPCC) and damage costs (DC) increased for all natural gas and coal technology pairs.

Each power station in the pairs PF/CCGT and PF-FGD/CCGT (except the PF) produced favourable life-cycle economic performances, when simulated with a selling price of electricity R0.23/kWh. This price is significant as it is the projected selling price of electricity by Eskom in 2007 based on the 2002 figure of R0.15/kWh (Eskom, 2002) with a projected increase of 8.56% per annum. However, in each of the two pairs of power station configurations, the CCGT performed better on all the selected indicators at the specified capacity factors than the PF and PF-FGD respectively.

### *6.1.3 Summary of the Life-cycle economic performance indicator/measure*

The tables in this section provide a summary of life-cycle economic performance indicators with respect to the scenarios presented in section 5.11.

**Table 6.1 PF at various capacity factors and corresponding BESP.**

| Life-cycle economic Performance indicator/measure | PF | PF | PF |
|---|---|---|---|
| cf | 0.4 | 0.6 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.39 | 0.31 | 0.26 |
| Investors rate of return, % | 8 | 8 | 8 |
| Net present value, billion Rand | 0 | 0 | 0 |
| Discounted payback time, years | >15 | >15 | >15 |
| Average return on investments, % | 9.9 | 9.9 | 10 |
| Average return on shareholders equity | 12.1 | 12.2 | 12.3 |
| Average du Pont return on net worth, % | 12.1 | 12.1 | 12.3 |

Source: Output from modelling
Legend: BESP – Breakeven selling price of electricity

**Comments:** Increase in capacity factor is associated with a decrease in breakeven selling price of electricity. This confirms trends in the power curves in chapter 5. There is no discernible trend in the returns as they vary marginally.

**Table 6.2 PF generation at a capacity factor of 0.6 and various electricity prices.**

| **Life-cycle economic Performance indicator/measure** | **PF** | **PF** |
|---|---|---|
| cf | 0.6 | 0.6 |
| Selling price of electricity, R/kWh | 0.31 | 0.41 |
| Investors rate of return, % | 8 | 13.4 |
| Net present value, billion Rand | 0 | 11.1 |
| Discounted payback time, years | >15 | 7.8 |
| Average return on investments, % | 9.9 | 14.4 |
| Average return on shareholders equity | 12.2 | 17.9 |
| Average du Pont return on net worth, % | 12.1 | 17.8 |

Source: Output from modelling

**Comment:** Increasing the selling price of electricity above breakeven selling prices results in a better life-cycle economic performance.

**Table 6.3 Breakeven prices for PF-FGD at various capacity factors**

| **Life-cycle economic Performance indicator/measure** | **PF-FGD** | **PF-FGD** | **PF-FGD** |
|---|---|---|---|
| cf | 0.4 | 0.6 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.36 | 0.28 | 0.22 |
| Investors rate of return, % | 8 | 8 | 8 |
| Net present value, billion Rand | 0 | 0 | 0 |
| Discounted payback time, years | >15 | 14.8 | 14.9 |
| Average return on investments, % | 9.2 | 9.2 | 9.2 |
| Average return on shareholders equity | 10.7 | 10.8 | 10.8 |
| Average du Pont return on net worth, % | 10.7 | 10.7 | 10.8 |

Source: Output from modelling

**Comment:** This table shows a similar pattern with regard to returns as in table 6.1.

**Table 6.4 PF-FGD at 0.6cf and various electricity selling prices.**

| Life-cycle economic performance indicator/measure | PF-FGD | PF-FGD |
|---|---|---|
| cf | 0.6 | 0.6 |
| Selling price of electricity, R/kWh | 0.28 | 0.30 |
| Investors rate of return, % | 8 | 9.22 |
| Net present value, billion Rand | 0 | 2.11 |
| Discounted payback time, years | 14.8 | 13.5 |
| Average return on investments, % | 9.2 | 10.4 |
| Average return on shareholders equity | 10.8 | 12.4 |
| Average du Pont return on net worth, % | 10.7 | 12.3 |

Source: Output from modelling

**Comment:** This table reinforces the fact that selling electricity above breakeven selling prices leads to improvement in economic performance indicators.

**Table 6.5 CCGT at various capacity factors.**

| Life-cycle economic performance indicator/measure | CCGT | CCGT |
|---|---|---|
| cf | 0.4 | 0.6 |
| Breakeven selling price of electricity, R/kWh | 0.28 | 0.24 |
| Investors rate of return, % | 8 | 8 |
| Net present value, billion Rand | 0 | 0 |
| Discounted payback time, years | 14.6 | 14.4 |
| Average return on investments, % | 9.1 | 9.0 |
| Average return on shareholders equity | 10.8 | 10.9 |
| Average du Pont return on net worth, % | 10.9 | 10.8 |

Source: Output from modelling

**Comment:** Whilst capacity factor has an inverse relationship with breakeven selling price of electricity, the returns at breakeven points vary only marginally.

**Table 6.6 CCGT at 0.6cf and various electricity selling prices.**

| Life-cycle economic performance indicator/measure | CCGT | CCGT | CCGT |
|---|---|---|---|
| cf | 0.6 | 0.6 | 0.6 |
| Selling price of electricity, R/kWh | 0.24 | 0.30 | 0.41 |
| Investors rate of return, % | 8 | 14.6 | 18 |
| Net present value, billion Rand | 0 | 7 | 14.1 |
| Discounted payback time, years | 14.4 | 8 | 6.1 |
| Average return on investments, % | 9 | 15.9 | 18.2 |
| Average return on shareholders equity | 10.9 | 23.7 | 23.6 |
| Average du Pont return on net worth, % | 10.8 | 23.7 | 23.5 |

Source: Output from modelling

**Comment:** By increasing the selling price of electricity above the BESP, all the performance indicators showed improvements except average return on shareholders equity and average du Pont return on net worth which initially improved and then decreased marginally.

**Table 6.7 CCGT with CDM revenue at various capacity factors.**

| Life-cycle economic performance indicator/measure | CCGT + SPCC | CCGT +SPCC | CCGT +SPCC |
|---|---|---|---|
| cf | 0.4 | 0.6 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.22 | 0.18 | 0.15 |
| Investors rate of return, % | 8 | 8 | 8 |
| Net present value, billion Rand | 0 | 0 | 0 |
| Discounted payback time, years | >15 | >15 | >15 |
| Average return on investments, % | 9.6 | 9.3 | 8.9 |
| Average return on shareholders equity | 11.6 | 11.5 | 11.3 |
| Average du Pont return on net worth, % | 11.6 | 11.5 | 11.4 |

Source: Output from modelling

**Comment:** Increase in capacity factors as discussed above has the effect of reducing the BESP. However, returns vary marginally with BESP.

**Table 6.8 CCGT with CDM Revenue at 0.6 and various electricity selling prices.**

| Life-cycle economic performance indicator/measure | CCGT +SPCC | CCGT + SPCC |
|---|---|---|
| cf | 0.6 | 0.6 |
| Selling price of electricity, R/kWh | 0.18 | 0.41 |
| Investors rate of return, % | 8 | 22.5 |
| Net present value, billion Rand | 0 | 20.2 |
| Discounted payback time, years | >15 | 5.7 |
| Average return on investments, % | 9.3 | 25.6 |
| Average return on shareholders equity | 11.5 | 38.8 |
| Average du Pont return on net worth, % | 11.5 | 38.8 |

Source: Output from modelling

**Comment:** Increase in the selling price of electricity above BESP results in improved returns, more so with contributions from monetised carbon dioxide credits.

**Table 6.9 CCGT with damage costs and BESP at various capacity factors.**

| Life-cycle economic performance indicator/measure | CCGT+DC | CCGT + DC | CCGT + DC |
|---|---|---|---|
| cf | 0.4 | 0.6 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.27 | 0.26 | 0.23 |
| Investors rate of return, % | 8 | 8 | 8 |
| Net present value, billion Rand | 0 | 0 | 0 |
| Discounted payback time, years | 8.5 | >15 | 14.2 |
| Average return on investments, % | 9.5 | 9.0 | 9.0 |
| Average return on shareholders equity | 11.9 | 10.9 | 11.0 |
| Average du Pont return on net worth, % | 11.9 | 10.8 | 11.0 |

Source: Output from modelling

**Comment:** A decrease in the BESP results in an increase in the payback time.

**Table 6.10 CCGT with damage costs and various electricity prices at 0.6 cf.**

| Life-cycle economic Performance indicator/measure | CCGT + DC | CCGT +DC |
|---|---|---|
| cf | 0.6 | 0.6 |
| Selling price of electricity, R/kWh | 0.26 | 0.41 |
| Investors rate of return, % | 8 | 20.3 |
| Net present value, billion Rand | 0 | 15.9 |
| Discounted payback time, years | >15 | 6.2 |
| Average return on investments, % | 9 | 23.1 |
| Average return on shareholders equity | 10.9 | 34.8 |
| Average du Pont return on net worth, % | 10.8 | 34.9 |

Source: Output from modelling

**Comment:** A comparison of table 9 with table 10 shows that DC has a marginal effect on economic performance indicators

**Table 6.11 CCGT with SPCC and DC at BESP at various capacity factors.**

| Life-cycle economic Performance indicator/measure | CCGT + SPCC + DC | CCGT + SPCC + DC | CCGT + SPCC + DC |
|---|---|---|---|
| cf | 0.4 | 0.6 | 0.9 |
| Breakeven selling price of electricity, R/kWh | 0.28 | 0.23 | 0.23 |
| Investors rate of return, % | 8 | 8 | 8 |
| Net present value, billion Rand | 0 | 0 | 0 |
| Discounted payback time, years | >15 | 14.9 | 10.4 |
| Average return on investments, % | 8.9 | 8.8 | 12 |
| Average return on shareholders equity | 10.6 | 10.6 | 15.2 |
| Average du Pont return on net worth, % | 10.5 | 10.5 | 15.1 |

Source: Output from modelling

**Comment:** There is a phenomenal increase in the average return on shareholders equity and average du Pont return on net worth when cf increases from 0.6 to 0.9.

**Table 6.12 CCGT with CDM credits, DC and various electricity prices at 0.6 cf.**

| Life-cycle economic performance indicator/measure | CCGT + SPCC + DC | CCGT + SPCC + DC |
|---|---|---|
| cf | 0.6 | 0.6 |
| Selling price of electricity, R/kWh | 0.23 | 0.41 |
| Investors rate of return, % | 8 | 18.7 |
| Net present value, billion Rand | 0 | 15.7 |
| Discounted payback time, years | 14.9 | 6 |
| Average return on investments, % | 8.8 | 18.7 |
| Average return on shareholders equity | 10.6 | 24.3 |
| Average du Pont return on net worth, % | 10.5 | 24.1 |

Source: Output from modelling

**Comment:** A higher selling price of electricity results in relatively high returns.

## 6.2 Carbon dioxide credits

As stated in section 1.2, "if a combined-cycle gas turbine power station were built say in the Cape Metropolitan Area to generate base load power instead of a pulverised fuel coal-fired power station, there should be abatement in the emission of carbon dioxide". The following sections look at various aspects of this abatement.

### *6.2.1 Transaction costs in a CDM project*

Transaction costs are incurred in a CDM project before accruing carbon dioxide credits. Transaction costs of a CDM project consist of the following costs: search; negotiation; baseline determination; validation; review; monitoring; verification; certification; enforcement; transfer and registration (Stronzik, 2001). The crediting period and transaction costs for carbon dioxide credits and other information used in the Te-Con Techno-Economic modelling for the estimation of carbon dioxide credits are found in table D2, appendix D.

Transaction costs (table D2, appendix D) on 1 tonne of reduced carbon dioxide are about 7% of the current selling price of a tonne of carbon dioxide credits. In my view, if more projects were pooled together and the number of accredited CDM consultants and designated operational entities increase in future, it is expected that the transaction costs per tonne of abated carbon dioxide would decrease, thereby increasing the net contribution of monetised carbon dioxide credits to the net revenue of the CCGT with CDM revenue scenario.

### *6.2.2 Contribution of monetised carbon dioxide credits to total revenue*

It is further stated in section 1.2 that “economic benefits would accrue to the suggested power station in the Cape Metropolitan Area by monetising the abated carbon dioxide credits under the Clean Development Mechanism”. The contribution of monetised carbon dioxide credits to the revenue stream of the CCGT power station at various selling prices of electricity is depicted in tables 6.13 and 6.14. It can be inferred from these tables that the total net revenue from monetised carbon dioxide credits does not depend on the price of electricity, but on the capacity factor. In addition, the average percentage net revenue from monetised carbon dioxide credits to total net revenue is about 9%.

**Table 6.13 Contribution of monetised CC to total revenue of CCGT at 0.6 cf**

| Selling price of electricity (R/kWh) | Net monthly contribution of monetised carbon dioxide credits (Rb) | | Total net revenue from monetised carbon dioxide credits (Rb) | Total net revenue of power station (Rb) | Percentage of net revenue from monetised carbon dioxide credits to total net revenue (%) |
|---|---|---|---|---|---|
| | Minimum | Maximum | | | |
| 0.29 | 0.009 | 0.138 | 7.977 | 67.120 | 12.0 |
| 0.31 | 0.009 | 0.138 | 7.977 | 73.641 | 11.0 |
| 0.33 | 0.009 | 0.138 | 7.977 | 80.161 | 10.0 |
| 0.35 | 0.009 | 0.138 | 7.977 | 86.682 | 9.0 |
| **Average** | | | | | |
| 0.32 | 0.009 | 0.138 | 7.977 | 76.901 | 10.5 |

Source: Output from modelling.

Legend: The selling price of carbon dioxide credits was taken as US$7.23/tonne (Hamburg Institute of International Economics, 2005).
CC – carbon dioxide credits

**Table 6.14 Contribution of monetised CC to total revenue of CCGT at 0.4 cf**

| Selling price of electricity (R/kWh) | Net monthly contribution of monetised carbon dioxide credits (Rb) | | Total net revenue from monetised carbon dioxide credits (Rb) | Total net revenue of power station (Rb) | Percentage of net revenue from monetised carbon dioxide credits to total net revenue (%) |
|---|---|---|---|---|---|
| | **Minimum** | **Maximum** | | | |
| 0.37 | 0.006 | 0.092 | 5.318 | 62.135 | 9.0 |
| 0.39 | 0.006 | 0.092 | 5.318 | 66.482 | 8.0 |
| 0.41 | 0.006 | 0.092 | 5.318 | 70.828 | 8.0 |
| 0.43 | 0.006 | 0.092 | 5.318 | 75.176 | 7.0 |
| **Average** | | | | | |
| 0.40 | 0.006 | 0.092 | 5.318 | 68.655 | 8.0 |

Source: Output from modelling.

### *6.2.3 Redemption of shareholders' and bank loans using monetised credits*

In a post-Kyoto world, the use of coal for power generation is becoming environmentally unacceptable. In South Africa, coal is a preferred energy fuel since the resulting low cost electricity is an inducement to investors to locate their projects in the country (H. Simonsen, personal communication, 2 December 2005). In this thesis, the capital expenditure and operating expenditure of the PF, PF-FGD and CCCT power plants are financed by equity, bank loan and shareholders' loan**.** In my view, debt comes at a great cost to business. It is therefore in the financial interest of the shareholder's of a business to redeem all forms of debt, if funds are available. This section looks at the simultaneous redemption of the bank and shareholders' loans (figures 6.1 and 6.2 respectively) using accrued monetised carbon dioxide credits. From the Te-Con Techno-economic simulator model, payment of the loans started in January 2005 (A in figure 6.1 for bank loan and $^{1}$A in figure 6.2 for the shareholders' loan). The two loans are of the same magnitude (see table 5.4). Monetised carbon dioxide credits would start to accrue when electricity is generated by the CCGT power station in September 2007. The monetised carbon dioxide credits will immediately be used to redeem the two loans from September 2007 (indicated by B and $^{1}$B). During the redemption period, fifty percent of the monetised carbon credits will be used to pay for the bank loan and the remaining fifty percent for paying the shareholders' loan. Without monetised carbon dioxide credits, both loans will be fully paid in November 2014 (D and $^{1}$D). However, with carbon dioxide credits (shown by the steeper sections of the lower curves), the loans are paid off in November 2009 (C and $^{1}$C), that is after 5 years. The significance of this is that the use of carbon dioxide credits reduces the payment of each loan by 4.3 years and saves about 38% in interest payments. The net savings in interest payments was R895 million. In my view, considering the fact that the CDM is a global novelty and just taking off in South Africa, the payment of loans using monetised carbon dioxide credits is an innovation.

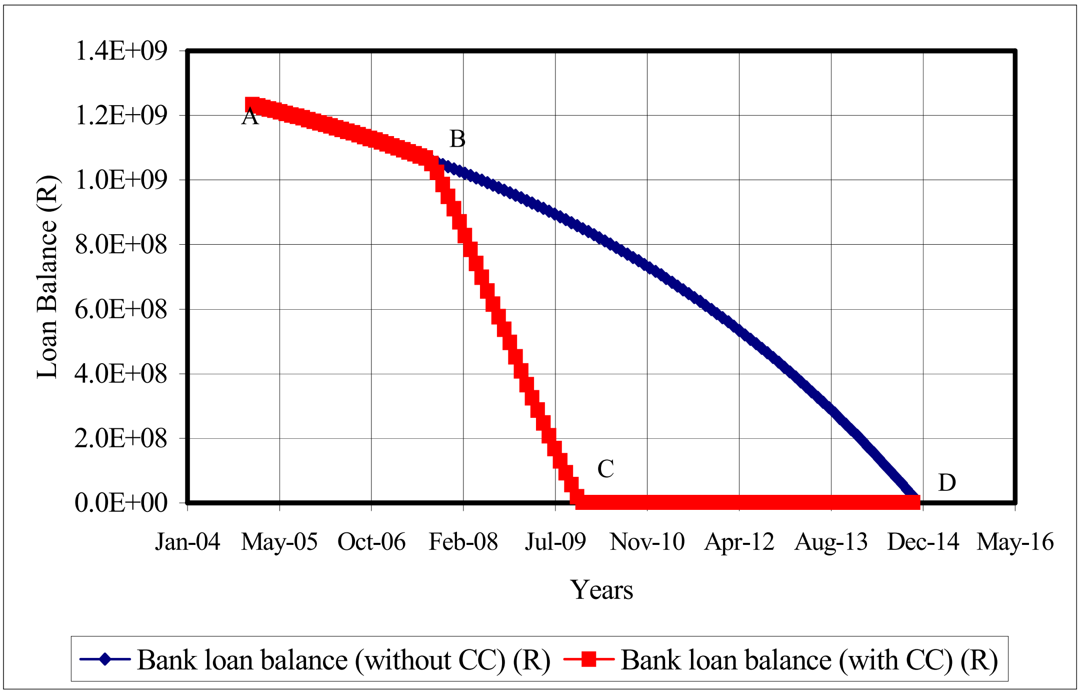



Figure 6.1 The bank loan balance profile during redemption.

Source: Output from modelling.

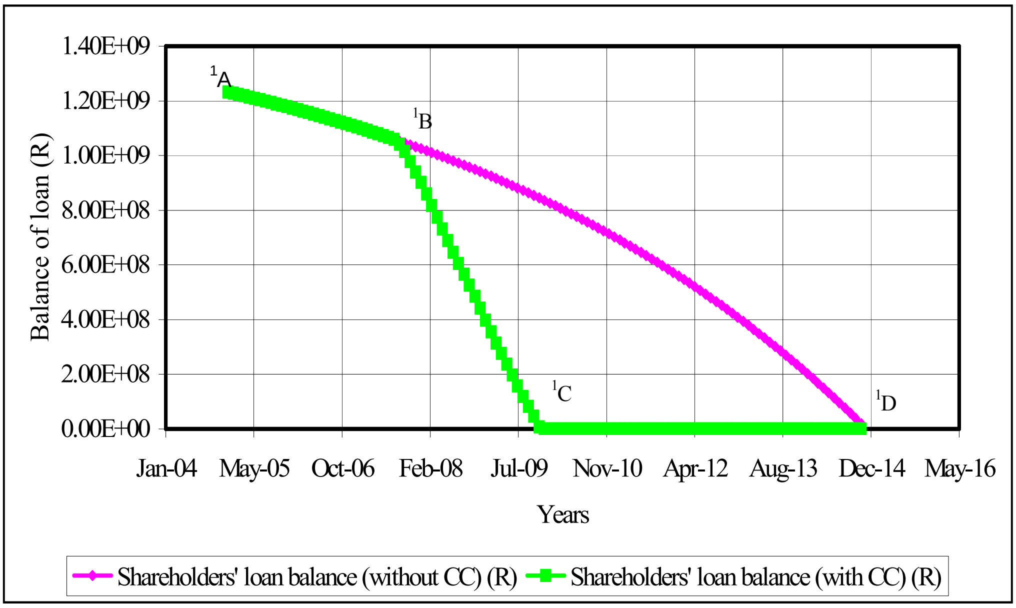



Figure 6.2 The shareholders' loan balance profile during redemption.
Source: Output from modelling.

Project finance is a scarce commodity in that there are always more projects than available finance. Therefore any financing process that extends the finance resource base to cover more projects may be advantageous to South Africa. Lowering the cost of project financing and enhancing a project's income stream through monetised carbon dioxide credits, while using damage costs to internalise externalities permit the introduction of more environmentally acceptable gas-fired electricity generation as a substitute for coal at the higher generation cost regime (H. Simonsen, personal communication, 2 December 2005).

### 6.3 Forecasting coal and natural gas prices

In my view, the Rand equivalent price of natural gas may vary most with time among all the operating costs of running the power stations. The reason is that natural gas is priced in US Dollar and its Rand equivalent is more susceptible to global currency trends, volatilities and socio-economic conditions. The price of coal and natural gas at the end of 2003 were 0.53 and US$3.35/GJ (table 5.6) respectively, making natural gas about 6.3 times more expensive per unit energy than coal. Additionally, it is my view that the ratio of the estimated natural gas price to that of coal in South Africa is relatively high in comparison with similar ratios in Japan and the US that range from 2.70 to 4.52 US$/GJ and from 2.32 to US$ 3.16/GJ respectively (appendix H). Simulations on the Te-Con model reveal that at a breakeven selling price of electricity of R0.29/kWh, the CCGT plant could sustain a maximum natural gas price level of US$7.20/GJ and still make it a cheaper source of energy than coal for generating base load power within the capacity factor range of 0 to 0.75. This price level gives a price ratio of natural gas to coal of about 13.6 times, which is about twice the current price ratio of the fuels. This then provides a sensitivity margin by which natural gas would be a lower cost energy source for generating base load power in South Africa, provided that the price of coal does not rise disproportionately to negate this ratio. If the price of natural gas was reduced relative to that of coal, the former would still be a cheaper source of energy for generating base load power, making a CCGT plant perform even better than the corresponding PF or PF-FGD plant. The price of the coal that may be used in the hypothetical PF power station would be sourced in South Africa and denominated in the local currency – Rand.

Figure 6.3 below provides a forecast of local bituminous coal sales prices from the year 2002 to 2030 (see table H4, appendix H). The forecast is based on the historical average bituminous local coal prices from 1970 to 2002 (DME, 2002c) (table H3, appendix H). The forecast was determined by plotting average coal prices in Rand/ton (R/t) against time (year). The plot produced an almost exponential function. The mean of the historical average coal sales prices (table H3, appendix H) adjusted with the producer price index (Statssa, 2005) was determined and used for the forecasting. The forecast shows coal prices rising exponentially according to the equation:

$$y = 2\text{E-}96e^{0.1122x} \tag{6.1}$$

$$R^2 = 1 \tag{6.2}$$

Where y is the average coal price in R/t and x = year. $R^2$ is the sampling coefficient of determination. The fact that $R^2 = 1$, shows the strong correlation between y and x. It is my view that coal, like any other commodity, has a life-cycle which tends to a normal distribution. Therefore, the exponential trend exhibited by figure 6.3 is representative of an earlier phase of the life cycle of coal. In addition, it is my view that a similar forecast may not easily be made for natural gas as it has only been trading publicly since 2004, when Sasol initially piped natural gas to South Africa from Mozambique (Lourens, 2004). The natural gas that has been produced from by PetroSA has been used in its operations for conversion to synthetic liquid fuels with no sales to the public or industry. A couple of historical prices are required to make any meaningful and reliable forecast of natural gas prices. However, according to A. Dirker (Personal communication, 19 July 2004), the price of natural gas is linked to that of crude oil. This implies that the price of natural gas would track volatility trends in the price of crude oil.

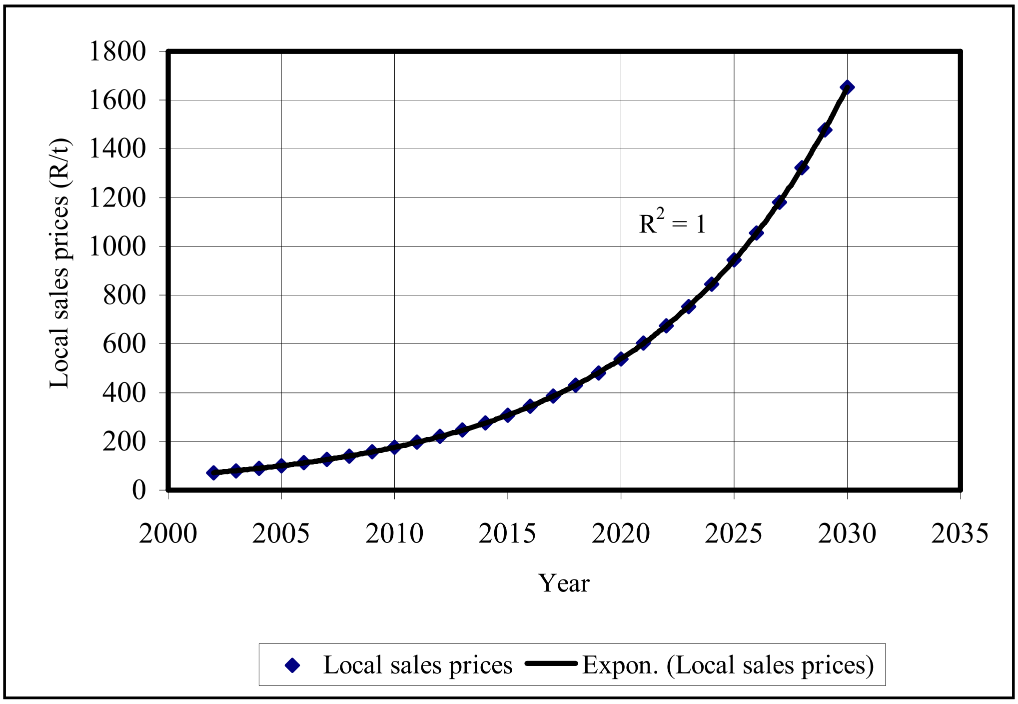



Figure 6.3 Forecast of average bituminous coal local sales prices (2002 – 2030).
Source: Adapted from DME (2002c).

## 6.4 Mathematical correlations

### *6.4.1 PF/CCGT power station configuration pair*

Adaptation of the screening curves (Stoft, 2002) revealed the existence of near perfect correlation between breakeven selling price of electricity and capacity factor. The correlation almost perfectly conforms to a power function of the form:

$$y = ax^{-c} \tag{6.3}$$

where y is the breakeven selling price of electricity, x is the capacity factor, with a and c being constants.

The correlations were determined for the power station configuration pairs for the power station situations: scenario 2 – *a combined-cycle gas turbine with CDM revenue*; scenario 3 – *a combined-cycle gas turbine with externalities accounted for by damage costs;* and scenario 4 – *a combined-cycle gas turbine with CDM revenues and externalities accounted for by damage* *costs*. Scenario 1 was dealt with through ARR versus cf, which produced a linear correlation. This was shown in sections 5.9 and 5.11

*Scenario 2*

CCGT

$$y = 15.981x^{-0.5314} \quad (6.4)$$

$$R^2 = 1.0 \quad (6.5)$$

*Scenario 3*

PF

$$y = 23.331x^{-0.6385} \quad (6.6)$$

$$R^2 = 0.9864 \quad (6.7)$$

CCGT

$$y = 20.586x^{-0.4546} \quad (6.8)$$

$$R^2 = 0.9696 \quad (6.9)$$

*Scenario 4*

PF

The equations for this are the same as under scenario 3.

CCGT

$$y = 17.842x^{-0.4978} \quad (6.10)$$

$$R^2 = 0.9754 \quad (6.11)$$

where y and x are as defined above and $R^2$ = sampling coefficient of determination in each case. In each case, $R^2 \approx 1$, providing confirmation of the strong correlation between breakeven selling price of electricity and capacity factor.

### *6.4.2 PF-FGD/CCGT power station configuration pair*

Correlations similar to those found in section 6.4.1 are indicated below.

*Scenario 2*

CCGT

$y = 17.471x^{-0.462\ 2}$ (6.12)

$R^2 = 0.97$ (6.13)

*Scenario 3*

PF-FGD

y = 21.565x-0.6712 (6.14)

R2 = 0.98(6.10) (6.15)

CCGT

y = 18.765x-0.4686 (6.16)

R2 = 0.9707 (6.17)

Scenario 4

PF

The equations are the same as in scenario 3

CCGT

$y = 15.433x^{-0.4992}$ (6.18)

$R^2 = 0.9741$ (6.19)

The variables y, x and R and the significance of the value of $R^2$ are the same as discussed under section 6.2.1.

## 6.5 Damage costs

Resources for the Future report of Oak Ridge National Laboratory as cited in Lee (1995) discusses why estimates of externalities of fuel cycles undertaken by several studies produce different results. The reasons given for the differences in the results are use of different methods and data sources, differences among power plants, upstream activities of the fuel cycles, sites where power generation and other fuel-cycle activities takes place and the wind direction with respect to the location of power plants.

According to section 2.8.1, some studies (Van Horen (1996b), Dutkiewicz and de Villiers in 1993 as cited in Van Horen (1996b) and Spalding-Fecher and Matibe (2003)) have been undertaken in South Africa on externalities associated with power generation. However, in my view, none of these studies came out with definitive damage costs concerning generation of power using natural gas and coal in South Africa. In the light of this, three sets of damage costs values from three studies in Germany, New Zealand and Canada were examined with a view to adapting them for use. In table 6.15 below, variations in the damage costs values for coal are of the order of a factor of 25 and the corresponding value for gas is 12. To reflect the variations in the set of damage costs values, sensitivity analysis of the breakeven selling price of electricity with respect to damage costs were undertaken in section 5.10 to account, to some extent, for the differences in damage costs as stated above.

**Table 6.15 Damage cost of electricity generation using coal and gas.**

| Energy carrier | Damage cost, R/kWh |
|---|---|
| Coal | 0.06[1], 0.0253[2] and 0.621[3] |
| Gas | 0.03[1], 0.0084[2] and 0.099[3] |

Sources: [1]Adapted from Friedrich and Bickel (2001) (Germany).
[2]Adapted from East Harbour Management Services (2002) (New Zealand).
[3]Adapted from DSS Management Consultants Inc. and RWDI Air Inc (2005) (Canada).

Legend: [1]These adapted damage costs (Germany study) were used in modelling PF/CCGT.
[2]These adapted damage costs (New Zealand study) were used in modelling PF-FGD/CCGT.

In my view, the verification of all the propositions on substituting natural gas for coal for power generation has a major significance to the electricity supply industry in South Africa. This verification and the relatively favourable life-cycle economic performance of CCGT could assist the South African Government, the national electricity utility (Eskom) and Independent Power Producers to make informed decisions concerning choice of future base load power generating scenarios, using natural gas to forestall anticipated shortfall in base load capacity from 2010.

# 7. CONCLUSION AND RECOMMENDATIONS

Chapter 7 draws conclusions from the other chapters, provides recommendations for a sustained growth of the natural gas industry in South Africa and states the results of this thesis, including its contribution to the field of knowledge. Chapter 7 makes a suggestion for a future research study.

## 7.1 Natural gas in the global energy mix

The increased use of natural gas in South Africa will be driven not only by local scenarios but also by global imperatives in the context of global optimism about the role of natural gas in the energy mix. According to the International Energy Outlook (IEO), natural gas is the fastest growing component of primary global energy consumption and over the period 1997-2020, global gas utilisation is projected to more than double, reaching 4680 billion cubic metres. Correspondingly, the share of gas in the total energy consumption is bound to increase from 22% in 1997 to 29% in 2020 (Asamoah, 2002b).

Despite their potential, technologies used to harness new and renewable sources of energy have not been developed economically to the extent that these energy carriers are able to provide the bulk of the energy requirements of the world. It may take a considerable length of time to achieve this. Thus, fossil fuels may continue to dominate the global energy sector for some time. However, the imperatives of sustainable development and the quest to mitigate the anthropogenic emissions of greenhouse gases will stimulate the use of relatively clean energy carriers and the application of comparatively clean technologies.

As legislation for environmental stewardship is enforced, particularly in the more polluting industries, there is a tendency to switch from coal to relatively more environmentally friendly energy carriers such as natural gas. The introduction of a carbon tax in South Africa, particularly on coal, could make it easy for natural gas to compete even more favourably with coal. However, due to the marked use of coal for the generation of electricity in South Africa (resulting in its being relatively cheap in comparison with global prices), the introduction of a carbon tax on coal could adversely affect access to a relatively cheap source of energy (in particular for poorer households); and the affordability of locally produced goods and services.

## 7.2 Natural gas issues as a policy lever

According to the Bill of Rights of the constitution of the Republic of South Africa, everyone has a right to an environment that is not harmful to his or her health or wellbeing. However, the apparent unsustainable use of coal, which dominates the energy sector in South Africa, produces noxious pollutants that foul the atmosphere. The coal combustion in households contributes 36% of South Africa's particulate emissions, although it accounts for 3% of its annual coal consumption (Surridge, 2003). According to Scorgie *at al*. (2004) total direct health costs in 2002 Rand associated with burning coal in households and for power generation on the Mpumalanga Highveld are R97.9 and R132.4 million per annum respectively. Natural gas can be used as a policy lever to improve the natural environment polluted from coal combustion. This can be done by the South African Government through promotion and use of economic instruments to enhance increased utilisation of natural gas in industry, commerce and households.

The Department of Minerals and Energy (DME) has put in place the Gas Act (Minister of Minerals and Energy, 2002) that defines the roles of the various actors in the gas industry. The Gas Act of South Africa makes provision for the reticulation of communities along swathes of the gas transmission pipeline from Mozambique to South Africa. Recently, the Central Energy Fund and the World Bank conducted a study on the supply of reticulated gas to low-income areas of Mpumalanga, which are along swathes of this pipeline (COWI *et al*., 2002b). If the recommendations of the study were implemented, there would be access to a modern energy carrier by the communities in those areas.

When the envisaged Kudu-Western Cape pipeline comes on stream, communities near the "right-of-way" (the access "road" created for the construction of the pipelines) could acquire access to gas to provide energy for both domestic use and for development of small, micro and medium enterprises. This could promote social equity and enhance sustainability. The diversification of energy supply is essential as it allows choice and increases inter-fuel competition. Before the relatively environmentally friendly new and renewable sources of energy become the norm in South Africa, natural gas could serve as a transitional fuel.

## 7.3 Prospects for increased use of natural gas in South Africa

The following provide opportunities for increasing the use of natural gas in South Africa:

- Spatial development initiatives and export processing zones;
- Increased exploration activities in areas within the territorial borders and close to South Africa, in particular offshore the western coastline;
- Enabling instruments such as the Gas Act, the Petroleum Pipeline Bill and the Gas Infra-Structure Plan**;**
- Potential confirmation of natural gas in commercial quantities at Ibhubesi gas fields;
- Setting up of Gas Commissions with Mozambique and Namibia;
- Access to and piping of natural gas from the gas fields of Namibia; and
- The completed Mozambique-South Africa gas transmission infrastructure and the subsequent piping of natural gas to Secunda starting from the first quarter of 2004.

## 7.4 Conclusion

South Africa's economy is dominated by coal, which contributes about 75% of its primary energy demand. Prior to January 2004, natural gas supplied about 1.6% of the primary energy demand. However, natural gas is expected to play a more significant role in the energy economy, after it was piped from Mozambique to South Africa starting from the first quarter of 2004. The South African Government has put in place several intervention mechanisms to ensure equitable and affordable access to cleaner forms of energy, particularly in the previously disadvantaged communities. Natural gas is one of the energy carriers that could aid the Government's decision to diversify the power generation sub-sector of the energy economy. It is clean burning and could be used in a combined-cycle gas turbine for power generation. A combined-cycle gas turbine (CCGT) power station would have the following advantages compared to the pulverised fuel coal-fired power stations that produce the bulk of South Africa's electricity:

- It is more environmentally benign;
- Has higher efficiency;
- Comes in a wider range of economic sizes;
- Can be located in environmentally sensitive areas;
- Has less water requirements;
- Construction lead times are relatively short**,** so capacity planning is less uncertain; and

- Has a relatively low capital requirement.

The growth of the natural gas industry could assist to extend the operational lifespan of PetroSA's gas-to-liquid fuels refinery by supplying feedstock to the plant. Dedicated gas fields supplying the refinery are expected to be exhausted in 2008.

Due to the proximity of some of the spatial development initiatives (SDIs) to the recently laid natural gas pipeline from Temane to Secunda, sustainable growth of the SDIs may be enhanced through access to a cleaner energy resource like natural gas. This would reduce air pollution and may improve the health of communities that are contiguous to those SDIs.

Increased use of natural gas would be possible if more accessible proven natural gas reserves were found, investments are attracted to the industry, relatively extensive and reliable natural gas infrastructure is put in place and fuel switching from other energy carriers, in particular coal, occurs.

A barrier to the sustainable growth of the natural gas industry in the long-term is the limited proven natural gas reserves in South Africa and in both Mozambique and Namibia as at now. South Africa has access to the latter reserves because of the bilateral gas agreements it has with those countries. Natural gas could substitute for coal in the short-term to medium-term for the generation of electricity in the Cape Metropolitan Area. However, in the long-term more proven and accessible natural gas reserves have to be found in South Africa, in Namibia or liquefied natural gas could be imported from Angola or elsewhere for this substitution and other uses. The prospects for finding more natural gas offshore the western coastline look promising due to several "best estimate" and "high estimate" figures provided by Petroleum Agency SA with regard to the classification of offshore resources. In addition, Block 9 P50 gas reserves have been estimated cumulatively at 22.4 bcm, whilst Forest's Ibhubesi "reserves" have been estimated at 8.4 bcm (Roux, 2002).

There are increased exploration activities in areas within the territorial borders and close to South Africa, in particular offshore the western coastline. These estimates and exploratory activities may auger well for growth of the natural gas industry in South Africa.

### *7.4.1 Results of this thesis*

One significant result of this thesis is an independent cost-benefit analysis of the financial costs, economic benefits and environment damage costs associated with the four electricity generation scenarios. These results estimate the costs and benefits associated with the following attractive characteristics of the gas industry from an energy perspective with regard to gas industry:

- Stimulating inter-fuel competition;
- Provision of environmental benefits through lower emissions in contrast to oil and coal;
- Increasing diversity of fuel supplies and hence improving South Africa's energy security.

These challenges, including others, commit the Government to the establishment of a suitable climate to facilitate the development of the gas industry (DME, 1998).

At R0.23/kWh – which is Eskom's projected selling price of electricity in 2007 (the same year that the modelled plants are supposed to commence generating electricity) – all the four power stations with the exception of the PF operated profitably, as they had positive net present values. This can be explained by the fact that through simulation of the Te-Con model, it was found out that the breakeven selling price of electricity of the PF plant at 0.75 cf was Rc23.43/kWh (Rc is Rand cents) which is greater that R0.23/kWh.

It was found that that the breakeven selling price of electricity had an almost perfect power function relationship with capacity factor on the basis of the methodology of Stoft (2002). It was established that the net monetised carbon dioxide credits made a contribution of about 9 % to the net revenue (sales from electricity and monetised carbon dioxide credits) of the CCGT power station. Through forecasting, it emerged that the average price of bituminous coal had an exponential function relationship with time in the earlier phase of the life cycle of coal.

Furthermore, it was established that the use of monetised carbon dioxide credits allowed the bank loan and shareholders' loan to be paid off about 4.3 years earlier, resulting in a savings in interest payment of about 38%. The net savings in interest payments was R895 million. It is inferred that taking DSM measures into account increases the magnitude of the excess capacity annually by about 170 MW over a 25-year period (2004-2029), leading to a postponement by one year (from 2007 to 2008), of the need for additional peak load capacity in South Africa for the most probable growth rate of 2.8%.

Proposition 1 of this thesis: "Natural gas is a lower cost energy source than coal for generating base load power within a specified range of capacity factors." was verified. In addition, proposition 2: “Monetising accrued carbon dioxide credits makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors” was confirmed as well. Proposition 3: “Internalising externalities by accounting for damage costs makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors” and proposition 4: “Internalising externalities by accounting for damage costs and monetising accrued carbon dioxide credits makes natural gas a lower cost energy source than coal for generating base load power within a specified range of capacity factors” were validated. These propositions were based on the assumption of a 15-year life-cycle, 6.7% rate of depreciation of fixed assets (excluding land), zero residual value of fixed assets and 100% recovery of land at the end of the life-cycle of the power stations. Finally, this thesis could be of assistance to the South African Government, the national electric power utility (Eskom) and Independent Power Producers in making informed decisions concerning the choice of natural gas to generate electric power to forestall the anticipated shortfall in base load capacity from 2010.

### *7.4.2 Contribution to the field of knowledge*

The contribution to the field of knowledge is the innovative way of financing the gas-fired power generation project by using the monetised carbon dioxide credits under the novel CDM to redeem a bank and a shareholders’ loan that results in reducing the loan payments by 4.3 years, saving 38 % in interest payments. This would allow scarce finance available for project funding to be extended to other projects to the advantage of national economic development.

## 7.5 Recommendations

**Use of natural gas in the Spatial Development Initiatives**

Natural gas should be used to provide energy to the Spatial Development Initiatives and Industrial Development Zones that are relatively close to the transmission pipelines and far from coal supply routes.

**Promotion of small, micro and medium enterprises**

Natural gas should be used as a source of energy for the promotion of small, micro and medium enterprises, in addition to being used in households and in communities along swathes of the transmission pipelines. This could be done through reticulation systems off the transmission pipelines. Small, micro and medium enterprises may help to create jobs in rural areas and thus minimise the influx of the unemployed to urban centres.

**Promoting a continental power grid through NEPAD**

The goal of NEPAD to develop the continent economically from within would be enhanced if countries co-operated with one another and share resources. African countries producing oil and gas flare or vent natural gas beyond safety requirements. Such wasted resources could be used to generate more power and then fed into a continent-wide electricity grid. This would assist to promote investments and the growth of economic activities in Africa.

**Negotiations with Angola to ship LNG to South Africa in future**

The future growth of the natural gas industry in South Africa is dependent on available natural gas reserves. Angola has natural gas reserves of 140 bcm, the highest in the SADC sub-region, much of which is flared. South Africa should negotiate supply of liquefied natural gas from Angola, in addition to what it is currently piping from Mozambique and what it could potentially pipe from Namibia. This would enhance the long-term sustainability of the natural gas industry in South Africa. This recommendation is in support of the White Paper on Energy Policy of South Africa, which prohibits restrictions on the quantity of gas that may be imported from SADC countries (DME, 1998).

**Incentives for exploration for natural gas**

Access to more natural gas resources is vital to South Africa’s energy economy. Apart from supplying energy to new projects, the capex on the PetroSA refinery at Mossel Bay needs to be sustained. The refinery needs reliable sources of natural gas by 2008, the time the dedicated gas fields (F-A and E-M) are expected to be exhausted. Economic instruments like tax holidays and favourable capital equipment depreciation regimes must be introduced to stimulate exploration of natural gas. In addition, operating costs incurred in the exploration for natural gas should be written off.

**Growth of the natural gas industry in South Africa to promote regional economic integration**

The growth of the natural gas industry in South Africa should be used as a catalyst to promote regional economic integration through the stimulation of industrial and commercial activities in the neighbouring countries from where South Africa sources natural gas.

**Promotion of co-generation**

It would be highly beneficial to South Africa if future gas-fired power stations were built using co-generation (combined heat and power) technology. This would minimise the relatively high-energy intensity of South African goods and increase the competitiveness of South Africa exports in overseas markets, whilst conserving natural resources.

**Basis of a hydrogen economy**

The natural gas industry in South Africa should be developed to form the basis of a hydrogen economy, which is being promoted as the energy carrier for the future (Asamoah, 2000b). Natural gas should be reformed to produce hydrogen – necessary for the operation of a fuel cell – a relatively cleaner source of energy that could boost distributed generation of electricity.

**Internalising externalities**

Inclusion of damage costs in the price of electricity to account for externalities makes a combined-cycle gas turbine a lower cost generator of base load power than a coal-fired power station in South Africa. Thus, an incentive to substitute for coal with natural gas for power generation is to institute an externality tax on the price of electricity generated from coal.

**Gas chain model**

It is recommended that when Sasol's 10-year monopoly in production and transmission of natural gas from Mozambique ends, the "non-integrated with regulated transmission sector" gas chain model be adopted by South Africa, as it promotes free trade.

**Incentives to attract Independent Power Producers to invest in power generation**

South Africa needs relatively large investments in the electricity supply industry to generate future capacity as the current excess capacity gets exhausted. From this research study, it is inferred that the future depreciation rates of fixed assets excluding land that the National Electricity Regulator in South Africa allows in the electricity generation industry would affect the breakeven selling price of electricity. It is therefore recommended that to attract foreign direct investment into the electricity supply industry, incentives like tax breaks and favourable depreciation rates for fixed assets excluding land be introduced by the South African Government to motivate and incentivise overseas investors. This is necessary considering the imminent exhaustion of the excess power supply capacity and the relatively high cost involved in building new power stations.

Most of the above recommendations are premised on the availability of relatively abundant proven natural gas reserves that are accessible to South Africa. Currently, there are limited natural gas reserves in South Africa including those in Mozambique and potentially from Namibia (as discussed in sections 4.8 and 4.9). However, with several exploratory activities taking place within the territorial waters of South Africa, there are prospects of finding more proven natural gas reserves in future. Additionally, South Africa could import liquefied natural gas to meet its needs.

## 7.6 Suggestions for future research study

It is suggested that a future research study should focus on the determination of definitive damage costs associated with power generation in South Africa using coal and natural gas as energy carriers. This would contribute significantly to finding the real costs involved in generating power by using these energy carriers and associated technologies. The knowledge of the real costs involved in generating power would facilitate the crafting of cost reflective electricity tariffs.

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# APPENDIX A FOCAL AREAS AND OUTCOMES FROM WSSD

Appendix A provides a summary of the objectives, major outcomes and commitments associated with the specific areas which were the focus of the World Summit on Sustainable Development (WSSD).

| Specific Area | Objective | Key Outcomes, Commitments and Timetables |
|---|---|---|
| **Water and Sanitation** | The provision of access to<br>▪ At least 1 billion people lacking clean drinking water; and<br>▪ 2 billion people who lack proper sanitation | ▪ Halving the proportion of people with no access to safe drinking water by the year 2015 (reaffirmation of Millennium Development Goal). |
| **Energy** | ▪ To provide access to over 2 billion people who do not have access to modern energy services;<br>▪ Promote renewable energy;<br>▪ Reduce over consumption of energy; and<br>▪ Ratify the Kyoto Protocol to address climate change. | **Renewables**<br>▪ The diversification of energy supply; and<br>▪ The substantial increase of the global share of renewable energy sources to increase its contribution to total energy supply.<br>**Access**<br>▪ To improve access to reliable, affordable, economically viable, socially acceptable and environmentally-sound energy services; and<br>▪ Resources that are sufficient to attain Development Goals, including the goal of halving the proportion of people in poverty by 2015.<br>**Markets**<br>▪ Removal of market distortions and the restructuring of taxes including the phasing out of harmful subsidies;<br>▪ To support efforts to improve the functioning, transparency and information about energy markets with respect to both supply and demand; and<br>▪ To ensure consumer access to energy services.<br>▪ Efficiency |

| Specific Area | Objective | Key Outcomes, Commitments and Timetables |
|---|---|---|
| | | ▪ To put in place domestic programmes for energy efficiency, with the support of the international community; and<br>▪ To accelerate the development and dissemination of energy efficiency, energy conservation technologies, and the promotion of research and development. |
| **Health** | ▪ To address the effects of toxic and hazardous materials;<br>▪ To reduce air pollution that kills 3 million people each year; and<br>▪ The lowering of the incidence of malaria and African Guinea worm associated with water pollution and poor sanitation. | ▪ Enhancement of health education to attain improved health literacy on a global basis by 2010;<br>▪ The reduction by 2015 of infant and young child mortality rates by two thirds, maternal mortality rates by three quarters of the rates prevailing in 2000;<br>▪ Reduction in the prevalence of Human-Immuno Deficiency Syndrome among young men and women aged 15-24 by 25% in the most affected countries by 2005 and globally by 2010; and<br>▪ Combating of malaria, tuberculosis and other diseases. |
| **Agricultural production** | ▪ Working to reverse land degradation affecting two thirds of the world's agricultural production. | ▪ The US will invest $90 million in agriculture programmes. |

Source: UN (2003)

## APPENDIX B INTERVENTIONS IN THE ENERGY SECTOR.

Appendix B provides some of the interventions initiated by the Department of Minerals and Energy in the Energy Sector to enhance delivery of services mainly to previously disadvantaged communities.

| Intervention | Rationale and Mechanism | Timing |
|---|---|---|
| **Rural non-grid electrification through concessionaires** | ▪ The remoteness of some rural areas from the national grid makes it unfeasible to supply them with grid electricity;<br>▪ Non-grid electrification through solar home systems is to be used in three provinces: Eastern Cape, KwaZulu-Natal and Limpopo; and<br>▪ Each of the six concessionaires is to provide homes with non-grid electricity over a period of 18 months. In addition to this, paraffin (kerosene) and LPG are also to be provided. | ▪ The first concessionaire agreement between Solar Vision (a concessionaire) and Eskom was signed on March 26, 2002 (SESSA, 2002); and<br>▪ By November 2003, the remaining concessionaires had signed their agreements with DME/Eskom. |
| **Low-smoke fuels programme** | ▪ The combustion of D-grade coal in households in township (mainly in Gauteng, Mpumalanga and the Free State, particularly in inefficient and poorly maintained stoves leads to the emissions of smoke, oxides of sulphur and oxides of nitrogen;<br>▪ Emissions cause respiratory illnesses, headaches, coughing, asthma, *etc;*<br>▪ The Department of Minerals & Energy (DME) instigated a low-smoke fuels programme in 1994, aimed at providing low-smoke fuels to minimise the impact of the combustion of D-grade coal;<br>▪ A macro-scale experiment in 1997 revealed that particulate emissions from combustion of D-grade coal could be reduced by 56%, using low-smoke fuels. | A strategy aimed at reviewing the least cost options to achieve a decrease in household air pollution, and its impact to acceptable levels has been approved by the Minister of Minerals and Energy after a stakeholders' forum on 11 March 2002 (C. Grobbelaar, personal communication, 10 April 2003). |
| **Black Economic Empowerment (BEE) in the liquid fuels sub-sector** | It is the intention of the government that BEE companies own 25% of the assets of the liquid fuels industry before it is regulated. | ▪ This has not been achieved yet. It is ongoing; and<br>▪ It is expected that the target would be reached by 2010. |

| Intervention | Rationale and Mechanism | Timing |
|---|---|---|
| **Basic Electricity Support Tariff (BEST)** | ▪ The DME is developing an implementation strategy for the Basic Electricity Support Tariff (BEST) (Mlambo-Ngcuka, 2001b); and<br>▪ Under BEST, the government is to provide the initial 50 MWh consumption of electricity free of charge. | ▪ The implementation plan under BEST was initiated with pilot projects in nodal areas and metropolitan centres, culminating in a phased rollout in the 2002/2003 financial-year (Mlambo-Ngcuka, 2001b);<br>▪ To study the practicality of the implementation plan, the University of Cape Town (UCT) researched the project between October 2001 and February 2002, with funding from the DME;<br>▪ The study investigated the intended purpose, costs, benefits and implementation of a Basic Electricity Support Tariff (BEST), previously known as the Electricity Basic Support Services Tariff (EBSST), and before that, the Poverty Tariff;<br>▪ The research project was intended to advise Eskom, the DME and the government of South Africa on these issues to enable the necessary decisions to be made for the phased implementation of BEST during 2002/2003;<br>▪ It should be noted that while the research report has been submitted to the DME and other stakeholders, the results and findings have not necessarily been accepted (Yelland, 2002). |
| **Integrated Energy Centres (IeCs) and Poverty** | ▪ To bring energy services – fuels and appliances – to the disadvantaged communities and to address economic, health, environmental and other needs (DME, 2002b). | ▪ The rollout of IeCs began in 2002. A minimum of 7 IeCs is earmarked for 2004 (Mlambo-Ngcuka, 2004). |

## APPENDIX C DETERMINATION OF BASELINE

Appendix C provides the approach used in the determination of baseline for the substitution of natural gas for coal using combined-cycle gas turbine under the CDM.

The Marrakesh Accords (Decision 17/CP.7 on modalities and procedures) provides three approaches for choosing the most appropriate baseline methodology for a project activity. The third approach – the average emissions of similar activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 percent of the their category (UNFCCC Secretariat, 2001) - is deemed germane to this thesis. One important issue to consider in undertaking a CDM project is to seek a balance between minimising transaction costs and environmental integrity. In this thesis, a multi-project baseline for the electric power generation sector in South Africa is used, as it is considered appropriate to provide such a balance, whilst being compatible with the above approach.

A key decision in the determination of baselines is to identify the plants to be included in the baseline, as the performance of the potential CDM projects would be measured against them. In computing any multi-project baseline, it is pertinent to consider information from recently constructed plants (backward-looking approach) in the previous five years, which also represent the best available technology. For practical reasons, the backward-looking approach is not appropriate to South Africa, as only one power station – Majuba – has been built in the last seven years. In this analysis, a baseline determination that includes near future plants is selected. These include the recommissioning of two mothballed power stations, two new units of Majuba, the importation of hydropower, and a new gas plant. From Eskom's Integrated Electricity Plan 6, these units are to be initiated between 2000 and 2005 (Winkler *et al*., 2000).

In determining the baseline, some key decisions need to be made about the power sector. These are:

- The set of plants to include in the reference scenario. The necessary information for each plant is the fuel input (GJ per annum) and the electrical output (TWh per annum). By combining this information with the thermal capacity of the fuel, the carbon content (kg C/kWh) can be computed;

- The set of power plants with which the potential CDM project should be compared. In this case, it is pertinent to know whether a new gas plant should perform better than the average power station in the whole sector, better than the average fossil fuel-fired plant or better than other gas-fired plants. Thus, a comparison can be made between a CDM project and other plants using the same fuel (*fuel-specific*), to all fossil fuelled plants (*all fossil*) or to the whole electricity generation sector (*sector wide*); and
- Whether to compare the CDM project against the average, better-than-average, or best plants. After the carbon intensity of the plants in the reference scenario is known, increasingly stringent benchmarks – from weighted average through 25th and 10th percentiles up to the best plant – can be constructed. The carbon intensity of these benchmarks is expected to be lower. Thus, to receive certified emission reduction units, the CDM project would have to show progressively lower carbon intensity as displayed in Figure C1 (Spalding-Fecher, 2002).

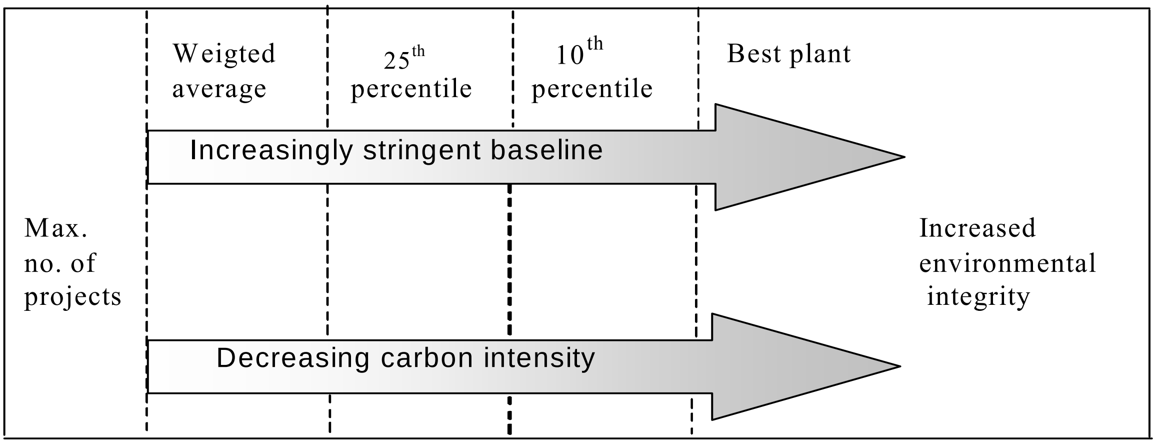



Figure C1. Baseline stringency and environmental integrity.
Source: Spalding-Fecher (2002).

**Table C1 Key characteristics of a "near future" baseline.**

| | Majuba unit 5 | Majuba Unit 6 | Mothballed coal 1 | Mothballed coal 2 | New gas | Imported hydro |
|---|---|---|---|---|---|---|
| Capacity, MW | 713 | 713 | 570 | 870 | 736 | 400 |
| Efficiency assumed, % | 34 | 34 | 30 | 30 | 55 | |
| Annual generation (TWh) | 3.78 | 3.78 | 3.02 | 3.02 | 8.41 | 1.84 |
| Annual Fuel use (GJ) | | | | | | |
| Coal<br>Natural Gas | 39,511,269 | 39,511,269 | 36,252,666 | 55,333,017 | <br>55,097,107 | <br>None |
| Carbon intensity, kg C/kWh | 0.295 | 0.295 | 0.338 | 0.338 | 0.100 | 0.0 |

Source: Energy and Development Research Centre from developed data in NER (1999), Eskom (1996; 1998 and 1999).

**Table C2 Energy and carbon intensities for the "near future" approach.**

| | | | Weighted Average** | Percentile 25% | Percentile 25% | Best plant |
|---|---|---|---|---|---|---|
| Fuel Specific | Energy intensity, MJ/kWh | Coal | 11.72 | 10.90 | 10.46 | 10.46 |
| | | Gas | 6.55* | 6.55* | 6.55* | 6.55 |
| | Carbon intensity, kgC/kWh | Coal | 0.316 | 0.307 | 0.295 | 0.295 |
| | | Gas | 0.100* | 0.100* | 0.100* | 0.100 |
| All fossil | Energy intensity, MJ/kWh | | 0.259 | 0.100 | 0.100 | 0.100 |
| | Carbon intensity, kgC/kWh | | 0.270 | 0.128 | 0.100 | 0.100 |
| Sector wide | Carbon intensity, kgC/kWh | | 0.228 | 0.052 | 0.000 | 0.000 |

Source: Adapted from Spalding-Fecher, ed (2000).

Legend: *Based on one plant only. **Weighted average of plants in the reference scenario, not all South African plants.

The baseline intensities for energy and carbon are indicated in table C2. Only best plant shows a value for gas, since percentiles or a weighted average cannot be calculated from a single plant. Hydropower has no "fuel", thus no fuel-specific intensities are provided. Baseline for a CDM project is provided by carbon intensity (Winkler *et al.,* 2000).

The weighted average carbon-intensity of the plants in this reference scenario, 0.228 kg C/kWh, is lower than the average for all the plants (Spalding-Fecher, 2002). According to Eskom's Annual Report 2002, the total electricity produced in 2000 was 189,307 GWh (net) and the total carbon dioxide emitted from the pulverised fuel coal-fired power stations was 161.2 million tons (Eskom, 2002). This gives a carbon intensity of 0.85 kg $CO_2$/kWh, which is equivalent to 0.232 kg C/kWh. Thus, the average carbon intensity of the mix of Eskom's plants in 2000 was less than 2% higher than the reference scenario of near future plants (Spalding-Fecher, 2002).

Additionally, from Eskom's Annual Report 2002, total carbon dioxide emitted from the pulverised fuel coal-fired power stations was 175.2 million tons and total electricity produced was 197,737 GWh (net). This gives a carbon intensity of 0.242 kg C/kWh, which is 6% higher than the reference scenario of near future plants. The fuel-specific carbon intensity for gas, 0.100 kg C/kWh is lower than the all-fossil or sector wide intensity, which includes coal (Spalding-Fecher, 2002).

# APPENDIX D ADDITIONAL INFORMATION USED IN THE ECONOMIC MODELLING

Appendix D gives extra information used in the Te-Con Techno-Economic Simulator modelling and in the screening curves for the power station scenarios. This appendix includes calculations of the adjusted capital costs per unit size including key parameters of suggested CCGT with CDM revenue.

*D1. Adjustment of capital costs per unit size*

Specific capital costs normally apply to a plant which is close to the plant size that is quoted. Scaling factors are used for plants that are different sizes. Capital costs have a tendency to obey power laws with respect to size.

Estimation of the capital cost of a plant is given by the formula

$$C = C_{known} \times (S_{known}/S)^{n}$$

Where $C_{known}$ is the known cost

C is the unknown cost

$S_{known}$ is the known size

S is the size of the plant for which cost is to be calculated

n is the scaling factor

PF-FGD

$S_{known}$ = 400 MW

$C_{known}$ = NZ$ 2,330/kWh

S = 2,250 MW

n = 0.26

$C = 2,330 * (400/2250)^{\wedge 0.26}$

= NZ$ 1,436.55/kWh (Sept 2001 rates)

= US$ 1015/kWh

CCGT

$C = 856 * (400/2250)^{\wedge 0.22}$

= NZ$585.39/kWh (September 2001 values)

= US$ 414/kWh (January 2005)

Source: Adapted from East Harbour Management Services (2002).

**Table D2 Rates and taxes**

| Item | Value/Rate, % |
|---|---|
| Income tax | 40.0 |
| Ordinary dividend | 25.0 |
| Secondary corporate tax | 12.5 |
| Value added tax (VAT) | 14.0 |
| Risk-free Treasury bond rate | [1]8.0 |
| Inflation | 7.43 |
| Standard deviation on inflation | 1.0 |

Source: H. Simonsen, personal communication, 4 July 2003.

Legend: [1]The risk-free Treasury bond rate is the rate that the bank offers on Government Treasury bonds (H. Simonsen, personal communication, 2 December 2005).

**Table D2 Information used by the model for determining carbon dioxide credits.**

| Combined-cycle gas turbine (CCGT) power station | | | |
|---|---|---|---|
| **Item** | **Calculations** | **Value** | **Units** |
| Plant capacity | | 2,250 | MW |
| Capacity factor | | Variable | % |
| Baseline for CCGT[1] | | 0.228 | KgC/kWh |
| Carbon intensity of new gas (CCGT)[2] | | 0.100 | KgC/kWh |
| Abated $CO_2$ | 0.128 x 44/12 | 0.469 | kg $CO_2$/kWh |
| Crediting period[1] | | 10 | Years |
| Initial selling price of $CO_2$[2] | | 7.23 | US$/tonne $CO_2$ |
| Assumed increase in selling price of $CO_2$ | | 5.00 | % p.a. |
| Transaction costs | | 0.52 | Euros/ tonne $CO_2$ |
| Exchange rate | | 5.9753 | R/US$ |
| Exchange rate | | 7.86 | R/Euros |

Source: Developed by author based on Stronzik (2001).

Legend: [1]A once-off carbon dioxide crediting period of 10 years is taken, due to the fact that the life-cycle of the CCGT plant is 15 years. The choice of crediting period minimises uncertainty about the nature and shape of the Kyoto Protocol after 2012 (Curnow and Goldblatt, 2004).

[2] The mean price of a tonne of carbon dioxide equivalent. The average price per tonne of carbon dioxide equivalent is taken as 5.5 Euro (US$7.23/tonne) (Hamburg Institute of International Economics, 2005).

**Table D3 Key parameters of suggested CCGT power station with CDM revenue.**

| Parameter | Value/Description |
|---|---|
| Project objectives | The project aims to generate base load power in the Cape Metropolitan Area (Western Cape Province) using natural gas from Kudu and/or Ibhubesi. This is to satisfy the expected increase in demand for power in the Cape Metropolitan Area as South Africa is projected to require additional base load generating capacity from 2010 (Eskom *et al*., 2004a). The choice of CCGT over PF is due to its relative short construction time, environmental friendliness and its lower capital cost. |
| Project location | Cape Town or its environs |
| Type of project | $CO_2$: Fuel switching |
| Project Baseline Methodology | A multi-project baseline for the electric power generation sector in South Africa based on "the average emissions of similar activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 percent of their category" (UNFCCC Secretariat, 2001). |
| Monitoring methodology and plan | The natural gas input to the gas turbine is to be monitored monthly and entered into a tracking database. The monthly values of natural gas would be used to predict greenhouse gas emission reduction due to the CDM project. |
| Crediting period | The project seeks certified emission reduction units under article 12 of the Kyoto Protocol from September 2007 to August 2017 i.e. (10 years). |
| Estimated $CO_2$ reduction | 83.2 million tonnes |
| Sources of certified emission reduction units | The savings in carbon dioxide emissions as a result of switching from coal to natural gas – a less carbon-intensive fuel. |
| Sustainable development impact | • Saving energy resources as CCGT is more thermally efficient than PF technology;<br>• Reducing emissions of ambient air pollution; and<br>• Reducing the amount of water required for power generation as CCGT uses less water than PF. |
| Project financing | The required R8.3 billion for the CCGT with CDM revenue is raised through equity and debt. |
| Project revenues | The project would generate gross revenue of R 174.3 billion by selling electricity at R33.00/kWh. About 7.5% of this revenue (R13.1 billion) is generated from the sale of carbon dioxide credits. |
| Host country approval | The project would be presented to the Designated National |

| Parameter | Value/Description |
|---|---|
| | Authority at the Department of Minerals and Energy for endorsement. |
| Electricity generation (test) starting date | July 2007 |
| Electricity generation (commercial) starting date | September 2007 |

Source: Developed by author based on EcoSecurities (2004) and the inputs and outputs modelling.

**Table D4 Efficiencies of various technologies.**

| Technology | Pulverised coal-fired | Gas turbine | CCGT |
|---|---|---|---|
| Efficiency, % | 34 | 25 | 55 |

Source: Stockholm Environmental Institute-Boston (2003)

**Table D5 Input data on prepositions**

| Parameter | Value | Comments/Reference |
|---|---|---|
| Life-cycle of power station | 15 years | Plant life is taken as 15 years (due to current estimates of available reserves) (section 4.9). |
| Rate of depreciation of fixed assets (excluding land) | 6.7% | This is taken is the percentage of the reciprocal of the life-cycle of power plant (B. McIntyre, personal communication, 10 January 2004). The straight-line method of depreciation is used (NER, 2002). |
| Residual value of fixed assets (excluding land) | 0% | Straight-line depreciation method is used (B. McIntyre, personal communication, 10 January 2004). Book value of assets is nil after 15 years. |
| Residual value of land | 100% | Land is not depreciated and is fully recoverable at the end of the life-cycle of power station (International Power, 2001). |

# APPENDIX E DEFINITIONS OF LIFE-CYCLE ECONOMIC PERFORMANCE INDICATORS

Appendix E provides definitions of the key life-cycle economic performance indicators used to compare the performance of the power stations in the techno-economic modelling.

**Average return on investments** – The ratio of average profit to total investments (assets) (Lothian and Small, 1991).

**Internal rate of return** – The rate of return on an asset investment (the discount rate that gives a nil net present value on an asset investment).

**Net present value** – The present value of future returns discounted at the marginal cost of capital less the present value of the cost of investment.

**Discounted payback time** – The length of time required for the net revenue of an investment to return the cost of the investment, taking time value of money into account.

**Average return on shareholders' equity** – The ratio of net profit after taxes to net worth.

**Average du Pont return on net worth –** The average net income after tax on an investment as a percentage of average shareholders' interest. Shareholders' interest is the sum of shareholders' capital and reserves. The average shareholders' interest is given by shareholders' interest at the beginning of the financial year plus the shareholders' interest at the end of the financial year divided by two. The du Pont system is a method of analysis crafted to show the relationship between return on investment, asset turnover and profit margin (Weston and Brigham, 1979).

# APPENDIX F DESCRIPTION OF OPERATIONS AT THE PETROSA REFINERY

Appendix F provides a summary of the unit processes at the PetroSA refinery at Mossel Bay.

PetroSA operates an offshore production platform that reaches 114 metres above sea level and stands in 105-metre deep seawater at the F-A gas field. Twenty-four piles fix the jacket of the platform that weighs 14,500 tons to the ocean floor. The platform and its support system are designed to withstand storm waves of up to 24 metres - gales that blow up to 170 kilometres per hour and very strong currents. It has a boom module that carries a stack for safety discharge and the flaring of excess gas. A wellhead module receives liquids from the wells at a pressure of 8,000 kilopascals and a temperature of 90$^{o}$C. The separation of condensates from cooled vapour and the removal of water from the gas occur in the process module, producing gas that is subsequently chilled to -10$^{o}$C to remove the last traces of condensates. Next, a compression module compresses the gas before piping it to the PetroSA plant onshore. Another module of the plant with a diesel standby unit generates power using gas turbine generators. Two pipelines with diameters of 405 and 203 millimetres supply the onshore plant with gas and condensate respectively. The PetroSA plant consists of a gasloop, a unit for processing gas received from offshore prior to refining, a refinery and two 115-metre high flare stacks – one for production and the other for emergencies. The gasloop is capable of receiving 195,000 Nm$^3$/h of landed gas and 51 t/h of landed condensate (Ruffini, 2000a).

# APPENDIX G CHARACTERISTICS OF A CCGT AND A FLUE GAS DESULPHURISATION FACILITY

Appendix G provides descriptions of the characteristics of the combined cycle gas turbine, the flue gas desulphurisation facility and trends in the efficiency of gas turbines as a function of inlet temperatures.

## *Appendix G1 Combined-cycle gas turbine.*

In a combined-cycle gas turbine (CCGT) power station, one or more gas turbine generators are equipped with heat recovery steam generators to capture exhaust heat from the gas turbine. The heat recovered is used to raise steam to power a steam turbine that drives a generator producing additional power. A combined-cycle gas turbine is characterised by relatively high thermal efficiency compared to other combustion-based technologies (Northwest Power Planning Council, 2002).

Gregory and Roger as cited in Nakićenović *et al.* (2000) estimate that efficiencies of 71-73% are achievable within a reasonable period on a lower heating basis, and around 65-68% on a higher heating basis. The energy content of natural gas can be given on a higher heating or lower heating value basis. Higher heating value is inclusive of the heat of vaporisation of water formed as a product of combustion; whist lower heating value does not include that value (Taftan Data, 1998). A graph of efficiencies of combined-cycles versus firing temperatures is provided by figure H1.

In a combined-cycle gas turbine, emission of high oxides of nitrogen – a limitation to the use of elevated temperatures – can be overcome by the use of dry low-$NO_x$ combustion technology. A selective catalytic reduction system can be used in the heat recovery steam generator to reduce the emission of oxides of nitrogen. Besides, an oxidation catalyst can be used in the steam generator to control the emission of carbon monoxide. One significant benefit of the CCGT is the relatively low quantities of emissions of carbon dioxide, a result of the high thermal efficiency of the technology and the low carbon-hydrogen ratio of the primary constituent of natural gas – methane (Northwest Power Planning Council, 2002).

## *Appendix G2 Flue gas desulphurisation facility*

A flue gas desulphurisation facility (FGD) takes flue gases from a power station and treats them to remove sulphur dioxide ($SO_2$). Ducts are provided to carry the treated gases from the FGD plant for discharge to the atmosphere. Next, flue gases are passed through a limestone slurry spray in which the slurry reacts with most of the $SO_2$ in the gases to form calcium sulphite in absorber towers of the facility. The spray falls back into the lower section of the absorber tower, which acts as storage for the re-circulating slurry, where air is blown into the stored slurry. Chemical reaction takes place between oxygen in the air and calcium sulphite to form calcium sulphate, which is generally known as "gypsum". The gypsum slurry is subsequently extracted from the base of the absorber towers and dewatered. The dewatered gypsum is kept in storage and then transported from the site. The water extracted in the gypsum dewatering process is used to make fresh limestone slurry which is fed back to the absorber towers (Atkins Environment, 2002).

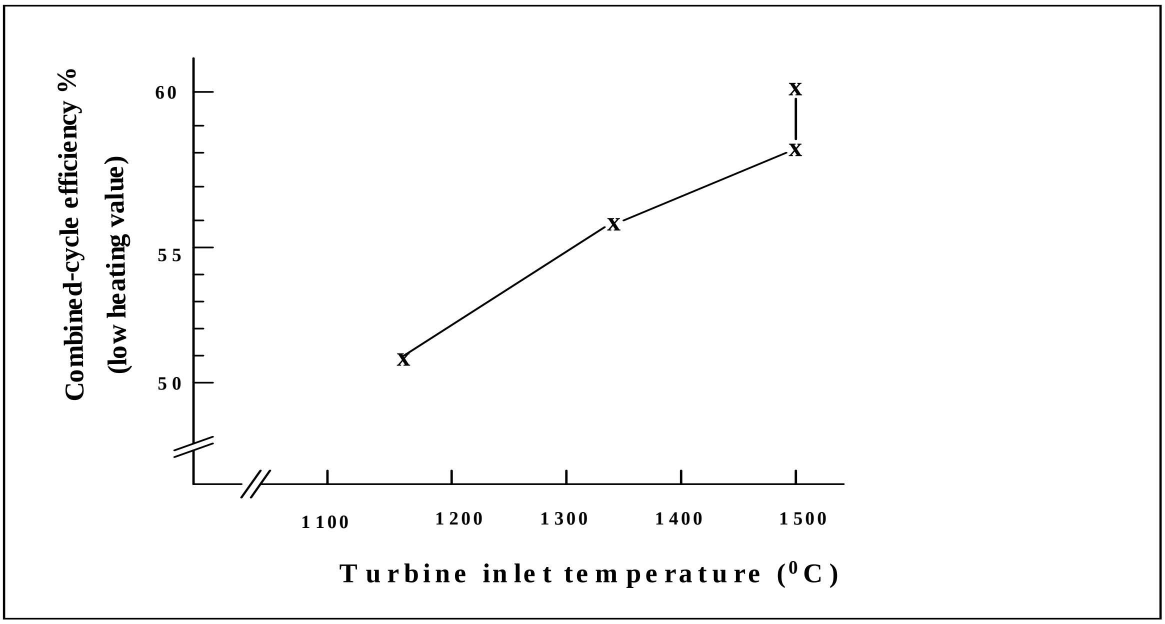



Figure G1 A trend in combined-cycle efficiency with firing temperature.

Source: Adapted from Aoki (2000).

Legend: Heating value is defined as the amount of heat emitted when a fuel is completely burnt in a steady-flow process and the products are returned to the state of the reactants. The heating value depends on the phase of water/steam in the combustion products. The heating value is known as "higher heating value" if water were in a liquid form. However, the heating value is called "lower heating value" when water is in a vapour form (Taftan Data, 1998).

## APPENDIX H COMPARISON OF COAL AND NATURAL GAS PRICES

Appendix H provides a comparison of coal and natural gas prices in two countries, trends in the price of US LNG imports from Nigeria and historical prices of local bituminous coal sales.

**Table H1 Comparison of US natural gas and steam-electric utility coal prices.**

| | 2000 | | 2001 | | 2002 | | 2003 | | 2004 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Price US$/GJ | Price Ratio (NG/Coal) | Price US$/GJ | Price Ratio (NG/Coal) | Price US$/GJ | Price Ratio (NG/Coal) | Price US$/GJ | Price Ratio (NG/Coal) | Price (US$/GJ) | Price Ratio (NG/Coal) |
| **Natural gas** | 4.01 | 3.58 | 3.86 | 3.39 | 3.16 | 2.70 | 5.34 | 4.52 | 5.55 | 4.47 |
| **Coal** | 1.12 | | 1.14 | | 1.17 | | 1.18 | | 1.24 | |

Source: Adapted from BP (2005).

**Table H2 Comparison of Japan LNG and steam coal import prices**

| | 2000 | | 2001 | | 2002 | | 2003 | | 2004 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Price (US$/GJ) | Price Ratio (NG/Coal) | Price (US$/GJ) | Price Ratio (NG/Coal) | Price (US$/GJ) | Price Ratio (NG/Coal) | Price (US$/GJ) | Price Ratio (NG/Coal) | Price (US$/GJ) | Price Ratio (NG/Coal) |
| **Natural gas** | 4.47 | 3.15 | 4.40 | 2.82 | 4.05 | 2.66 | 4.52 | 3.16 | 4.9 | 2.32 |
| **Coal** | 1.42 | | 1.56 | | 1.52 | | 1.43 | | 2.11 | |

Source: Adapted from BP (2005).

Legend: Prices are cif – cost insurance freight (average prices)

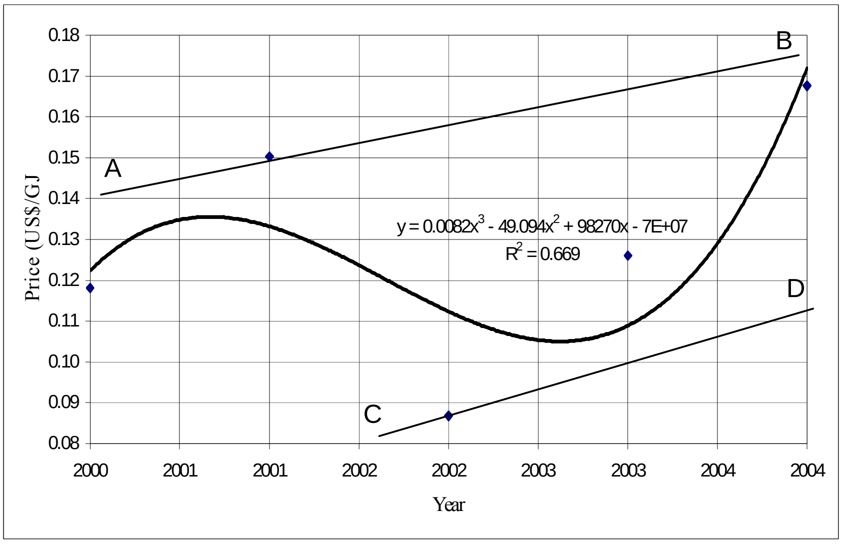



Figure H1  Trends in the price of US LNG imports from Nigeria.

Source: EIA (2005b).

Legend: It is envisaged that the prices would lie within the limits bounded by the parallel lines AB and CD.

**Table H3  Historical prices of local bituminous coal sales**

| Year | Prices of local sales of bituminous coal, R/t |
|---|---|
| | (FOR) |
| 1970 | 1.9 |
| 1971 | 1.9 |
| 1972 | 2.1 |
| 1973 | 2.3 |
| 1974 | 2.8 |
| 1975 | 4.1 |
| 1976 | 5.8 |
| 1977 | 6.9 |
| 1978 | 7.7 |
| 1979 | 8.3 |
| 1980 | 9.4 |
| 1981 | 11.4 |
| 1982 | 12.9 |
| 1983 | 12.9 |
| 1984 | 14 |
| 1985 | 15.37 |
| 1986 | 17.21 |
| 1987 | 19.16 |
| 1988 | 21.72 |
| 1989 | 27.25 |
| 1990 | 30.41 |
| 1991 | 33.48 |
| 1992 | 37.8 |

| Year | Prices of local sales of bituminous coal, R/t |
|---|---|
| | (FOR) |
| 1993 | 38.86 |
| 1994 | 39.34 |
| 1995 | 42.9 |
| 1996 | 45.93 |
| 1997 | 47.69 |
| 1998 | 51.86 |
| 1999 | 52.65 |
| 2000 | 56.13 |
| 2001 | 62.06 |
| 2002 | 68.9 |

Source: Adapted from DME (2002c).

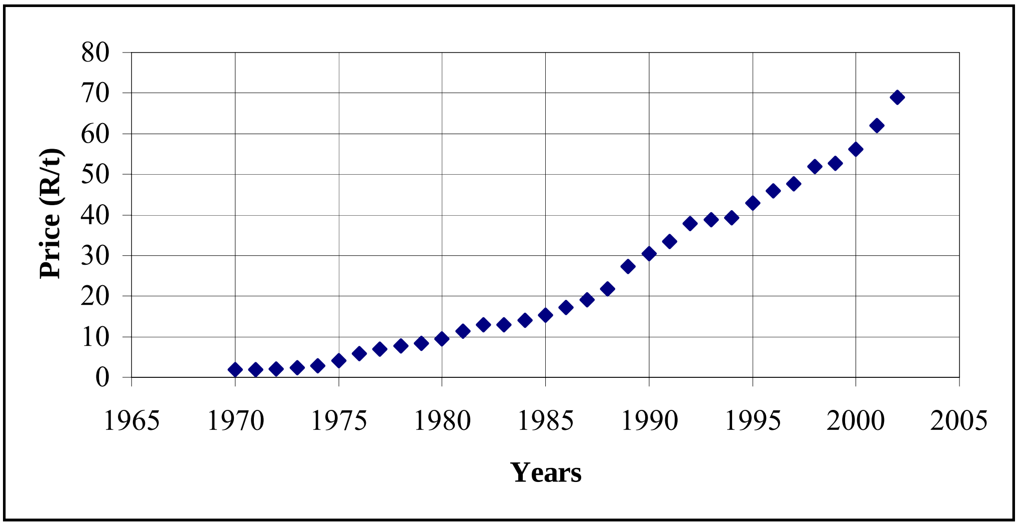



Figure H2 Plot of historical price of local bituminous coal sales, 1993-2002.
Source: Adapted from DME (2002c).

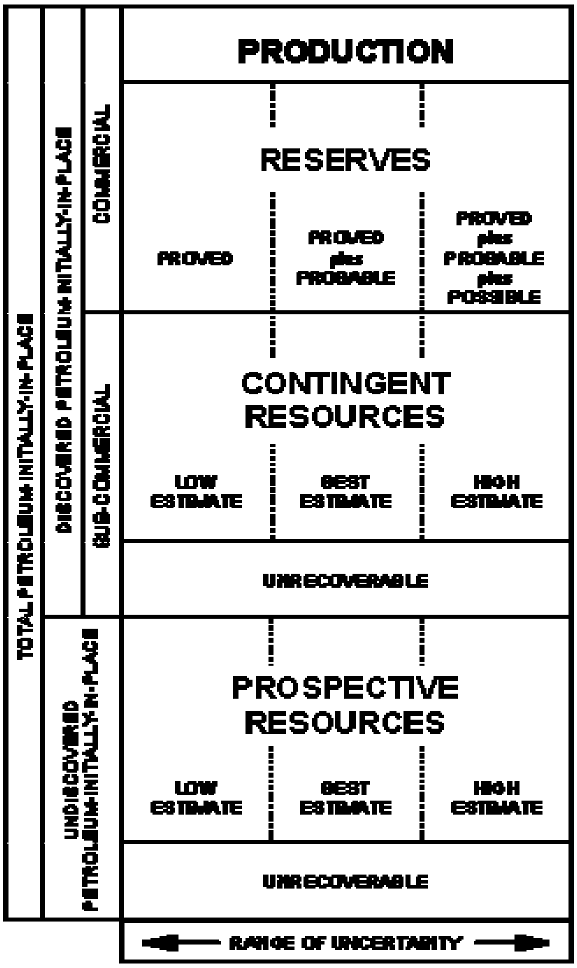
**Table H4 Forecast of average bituminous coal sales prices in South Africa**

| Year | Local sales prices |
|---|---|
| 2002 | 71.48 |
| 2003 | 79.96 |
| 2004 | 89.46 |
| 2005 | 100.08 |
| 2006 | 111.96 |
| 2007 | 125.26 |
| 2008 | 140.13 |
| 2009 | 156.77 |
| 2010 | 175.38 |
| 2011 | 196.21 |
| 2012 | 219.51 |
| 2013 | 245.57 |
| 2014 | 274.73 |
| 2015 | 307.35 |
| 2016 | 343.84 |
| 2017 | 384.67 |
| 2018 | 430.34 |
| 2019 | 481.44 |
| 2020 | 538.60 |
| 2021 | 602.55 |
| 2022 | 674.10 |
| 2023 | 754.14 |
| 2024 | 843.68 |
| 2025 | 943.86 |
| 2026 | 1055.93 |
| 2027 | 1181.31 |
| 2028 | 1321.57 |
| 2029 | 1478.49 |
| 2030 | 1654.04 |

Source: Developed by author and based on DME (2002c)

## APPENDIX I RESOURCE CLASSIFICATION SYSTEM AND DEFINITIONS

Appendix I presents the nomenclature and definitions used in the classification of petroleum resource and reserves.




**Reserves** are defined as those quantities of petroleum, which are determined to be commercially recoverable from known accumulations from a given date forward.

Reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining (Figure 3).

**Contingent Resources** are those quantities of petroleum, which are estimated, on a given date, to be potentially recoverable from known accumulations but are not currently considered commercial.

**Prospective Resources** are those quantities of petroleum, which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations. These are generally high risk and huge estimates, which require further exploration efforts.

Figure I1. Resource classification system.
Source: Roux (2005).

# APPENDIX J RELATIONSHIPS IN THE TE-CON TECHNO-ECONOMIC SIMULATOR MODEL

Appendix gives the functional relationship of the variables used in the techno-economic model, write up on annual costs and sensitivity analysis.

Relationships of the variables used in the Te-Con Techno-Economic model are provided by the following equations:

$$A_{CI} = A_S - A_{TE} \quad \text{(J1)}$$

$$A_{IT} = (A_{CI} - A_D - A_A)t \quad \text{(J2)}$$

$$A_{NCI} = A_{CI} - A_{IT} \quad \text{(J3)}$$

$$A_{CF} = A_{NCI} - A_{TC} \quad \text{(J4)}$$

$$A_{TE} = A_{GE} + A_{ME} \quad \text{(J5)}$$

$$A_{GP} = A_S - A_{ME} - A_{BD} \quad \text{(J6)}$$

$$A_{NP} = A_{CI} - A_{BD} \quad \text{(J7)}$$

$$A_{NNP} = A_{NCI} - A_{BD} \quad \text{(J8)}$$

$$A_{NP} = A_{GP} - A_{BD} \quad \text{( J9)}$$

$$A_{GE} = A_{FGE} + A_{VGE} \quad \text{(J10)}$$

$$A_{ME} = A_{FME} + A_{VME} \quad \text{(J11)}$$

$$A_{NP} = R(C_S - C_{VE}) - A_{FE} \quad \text{(J12)}$$

$$R_B = A_{FE}/(C_S - C_{VE}) \qquad (J13)$$

where

$A_{CI}$ = Annual cash income (R)

$A_S$ = Revenue from annual sales of product (R)

$A_{TE}$ = Total annual cost of producing and selling product (R)

$A_{NCI}$ = Net annual cash income (R)

$A_{IT}$ = Annual amount of tax (R)

$A_D$ = Annual writing down allowance (R)

$A_{FE}$ = Annual fixed expenditure (R)

$A_A$ = Annual amount of any other allowance (R)

$A_{TC}$ = Annual expenditure of capital (R)

$A_{CF}$ = Net annual cash flow (after tax) (R)

$A_{GE}$ = General expense (R)

$A_{ME}$ = Manufacturing cost (R)

$A_{GP}$ = Gross annual profit (R)

$A_{NP}$ = Net annual profit (R)

$A_{BD}$ = Balance sheet net annual depreciation charge (R)

$A_{FGE}$ = Fixed annual general expenses (R)

$A_{VGE}$ = Variable annual general expense (R)

$A_{FME}$ = Annual fixed manufacturing expenses (R)

$A_{VME}$ = Annual variable manufacturing expenses (R)

$A_{FE}$ = Annual fixed expense (R)

$C_S$ = Unit sales price

$C_{VE}$ = Variable unit sales cost

R = Annual sales volume

$R_B$ = Breakeven annual production rate

t = Fractional tax rate

Holland and Wilkinson (1999).

*Annual costs*

The relationships among various annual costs are illustrated diagrammatically in Fig.J1. Whilst the top half of the diagram illustrates the approach of an accountant; the bottom half is considered to be of more value to the engineer. The net annual cash flow ($A_{CF}$) does not include any provision for balance-sheet depreciation ($A_{BD}$) and is used in two methods of profitability assessment: the net-present value (NPV) method and the discounted-cash-flow-rate-of-return (DCFRR) method. In both methods, depreciation is provided for by calculations which include capital recovery. In the comparison of process alternatives, it is important that the economic studies should highlight the areas most susceptible to change. Generally, sales (and profits) are less easily predicted than expenses. Capital and processing costs can be estimated with some degree of accuracy. Usually, errors in these estimates have a smaller effect than changes in sales price, sales volume, and the costs of raw materials and distribution (Holland and Wilkinson, 1999).

*Sensitivity analysis*

Examination of the effects of variations in costs and prices is known as sensitivity analysis. The objective is to establish those factors to which the profitability of a project is most sensitive. It is usually not as difficult to predict expenses as either profits or sales; whilst reasonably accurate estimates could be made of capital costs and processing costs. However, errors in these estimates have a correspondingly lesser effect than variations in sales volumes, sales price and costs of raw materials and distribution (Holland and Wilkinson, 1999).

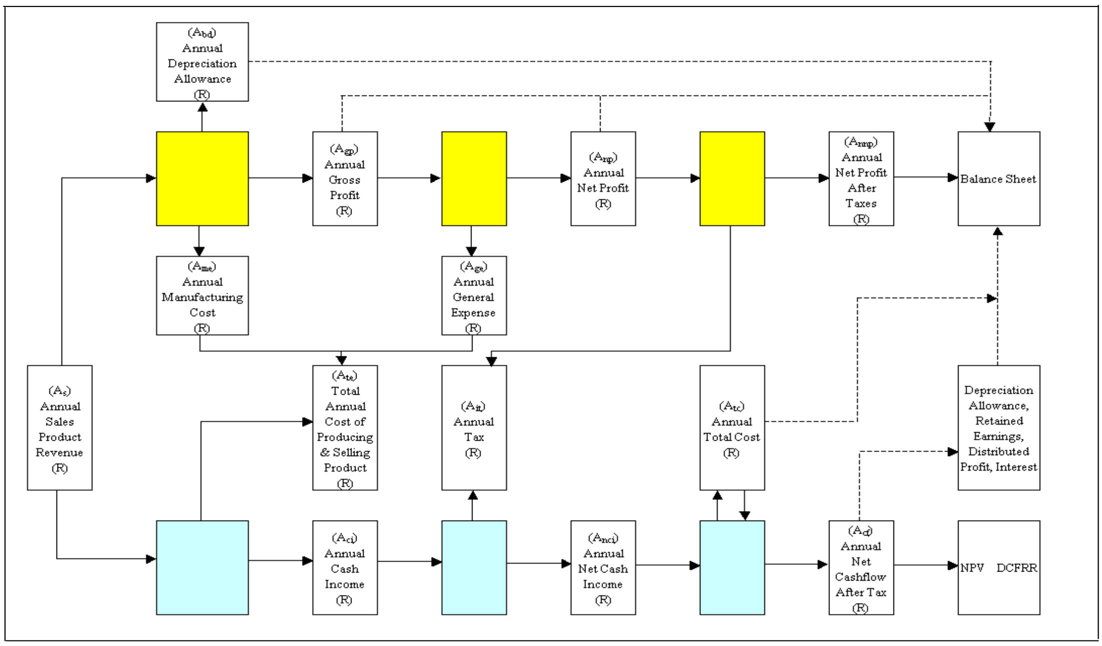



Figure J1 Relationship between annual costs, annual profits and cost flows for a project.
Source: Holland and Wilkinson (1999).

Legend: The yellow blocks in the top half of the diagram (with no labels) represent accounting activities that take place to produce the outputs (those with labels) in that half.

The light blue blocks in the bottom half (with no labels), which are of interest to the engineer, represent engineering processes that lead to the outputs (those with labels) in that half.

## APPENDIX K LEAD TIMES OF POWER STATIONS

Appendix K provides a comparison of the lead times of PF and CCGT power stations and a fast track CCGT type.

The National Integrated Resource Plan 2003/4 Reference Case report indicates that base load power stations are required by South Africa for commercial operation from 2010 (Eskom *et al*., 2004a), which is about five years from now. In South Africa, large standardised pulverised fuel coal-fired power stations have been the base load station of choice. Majuba power station, the last station to be built in South Africa was completed in the late 1990s. Pulverised coal technology is mature and is not expected to decrease markedly in costs over time as more plants are built. Combined-cycle gas turbine technology has had commercial applications around the world. According to a "CAMALA study" as cited in Eskom *et al*. (2004b), there has been an investigation for its deployment in South Africa, with pre-feasibility studies already undertaken. With CCGT technology being commercially mature, costs may not reduce appreciably over time as more plants are built. A combined-cycle gas turbine power station can use either liquefied natural gas or piped gas. Estimates of the lead times for pulverised fuel coal and CCGT power stations are provided in table K1. The lead time for a pulverised fuel coal power station is about eleven years and that for a CCGT is about eight years. However, a fast track option for a CCGT power station has a lead time of five years. Considering the fact that investigation for the deployment of CCGT in South Africa and several pre-feasibility studies have already been undertaken, it is assumed that it could take five years to build a CCGT power station, using the fast track option (Eskom *et al*., 2004b). This means that a CCGT power station to supply future base load capacity could be built by 2010, if a start was made in 2005.

**Table K1 Analyses of lead times for PF and CCGT power stations.**

| | **PF (year)** | **CCGT (year)** | **CCGT (fast track), (year)** |
|---|---|---|---|
| Concept formulation | 1 | 1 | 1 |
| Feasibility study, including plant design, environmental impact assessment, site selection, costing, project planning and preparation for fuel and development of business case | 4 | - | - |
| Feasibility study, including plant design, environmental impact assessment, site selection, costing project planning, preparations for gas pipeline and harbour for receiving gas | - | 4 | 1 |
| Investment, procurement and construction | 4 | 3 | 3 |
| Delays during concept formulation, feasibility and construction phase | 2 | - | - |
| **Total** | **11** | **8** | **5** |

Source: Adapted from Eskom *et al*. (2004b).