Wuppertal Institute for Climate, Environment and Energy

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CCS Global

Prospects of Carbon Capture and Storage Technologies (CCS) in Emerging Economies

Final Report

to the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU)

Part IV:

Country Study *South Africa*

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Final Report

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The total report consists of 6 parts:

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List of Abbreviations, Units and Symbols

Abbreviations

af	Annuity factor
AP	Acidification potential
ARA	Amsterdam, Rotterdam, Antwerp
BAFA	German Federal Office of Economics and Export Control
BGS	British Geological Survey
BMU	German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety
BP	British Petroleum
CBM	Coalbed methane
C_{Cap}	Capital costs
C_{fuel}	Fuel costs
C_{max}	Cumulative capacity
$C_{O\&M}$	Operation and maintenance costs
C_{TS}	Specific cost of CO_2 transportation and storage
CCS	Carbon (dioxide) capture and storage
CGS	Council for Geoscience
CTL	Coal to liquid
CH_4	Methane
CO_2	Carbon dioxide
$CO_{2\text{-eq}}$	CO_2 equivalents
CSIR	Council for Scientific and Industrial Research
CSLF	Carbon Sequestration Leadership Forum
DME	Department of Mining and Energy
DOE	Department of Energy
ECBM	Enhanced coalbed methane
EP	Eutrophication potential
ERC	Energy Research Centre
EREC	European Renewable Energy Council
EOR	Enhanced oil recovery
EU	European Union
FFF	Fossil Fuel Foundation
FWAETP	Fresh water aquatic ecotoxicity potential
FOB	Free on board
FOR	Free on rails
GCCSI	Global CCS Institute
GHG	Greenhouse gas
GTL	Gas to liquid
GWP	Global-warming potential
HTP	Human toxicity potential
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle

IRP	Integrated Resource Plan
ISO	International Organization for Standardization
LCA	Life cycle assessment
LCI	Life cycle inventory
LCIA	Life cycle impact assessment
LCIA	Levelised cost of electricity
LPS	Large point sources
LTMS	Long-Term Mitigation Scenarios
LR	Learning rate
MAETP	Marine aquatic ecotoxicity potential
MEA	Monoethanolamine
MDEA	Methyl diethanolamine
NDRC	National Development and Reform Commission
NGO	Non-governmental organisation
NO_X	Mono-nitrogen oxides
N_2O	Nitrous oxide
NYMEX	New York Mercantile Exchange
ODP	(Stratospheric) ozone depletion potential
O&M	Operation and maintenance
OECD	Organisation for Economic Co-operation and Development
PC	Pulverised coal
PCCI	Power Capital Costs Index
POP	Photochemical oxidation potential
PPP	Purchasing power parities
PR	Progress ratio
QHD	Qinhuangdao
R&D	Research and development
RB	Richards Bay
RD&D	Research, development and demonstration
RoD	Record of decision
R/P	Reserve-to-production ratio
SACCCS	South African Centre for Carbon Capture and Storage
SAMREC	South African Mineral Resource Committee
SACRM	South African Coal Roadmap
SANERI	South African National Energy Research Institute
Sasol	South African Coal, Oil and Gas Corporation Ltd.
SCR	Selective catalytic reduction
SO_2	Sulphur dioxide
TETP	Terrestrial ecotoxicity potential
TNO	Netherlands Organization for Applied Scientific Research
UCG	Underground coal gasification
UHV	Upper heating value
UKDECC	UK Department of Energy & Climate Change

U.S.	United States
USA	United States of America
USC	Ultra supercritical
VAT	Value-added tax
w/o	without
WEC	World Energy Council
WI	Wuppertal Institute for Climate, Environment and Energy
ZEP	Zero Emission Fossil Fuel Power Plants

Units and Symbols

a	annum
bbl	barrel
CNY	Chinese yuan
°C	degree Celsius
d	day
el	electric
EUR	euro
g	gramme
GJ	gigajoule
Gt	gigatonne (1 billion tonnes)
GW	gigawatt
h	hour
I	real interest rate
kcal	kilocalorie
kg	kilogramme
km	kilometre
kWh_{el}	kilowatt hour electric
kWh_{th}	kilowatt hour thermal
m	metre
MJ	megajoule (0.278 kWh)
Mt	megatonne (1 million tonnes)
MWh	megawatt hours (1,000 kWh)
n	depreciation period
t	tonne
th	thermal
tkm	tonne-kilometre
tSKE	tonnes of hardcoal equivalent
TWh	terrawatt hour (1 billion kWh)
USD	United States dollar
y	year
ZAR	South African rand
%	per cent
%pt	percentage point

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III. Country Study South Africa

The aim of this study is to explore whether carbon capture and storage (CCS) could be a viable technological option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries have been chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal. The study therefore mainly focuses on CO_2 emissions from coal-based electricity generation, supplemented by a rough analysis of emissions from industry.

The analysis is designed as an integrated assessment, and takes various perspectives. The main objective is to analyse how much CO_2 can potentially be stored securely and for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential is compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis is framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

The following sections present the results of the *South Africa* case study.

First of all, section 26 gives an overview of the status and development of CCS in South Africa. South Africa's potential for CO_2 storage in geological formations is then estimated (section 27). Based on an assessment of existing studies, storage scenarios (S1–S3) are developed to show the range of possible storage capacities. Thirdly, coal development pathways for coal-fired power plants (E1–E3) and industrial sites (I1–I3) are devised (section 28). The aim of this section is to determine how much CO_2 would have to be stored underground in the long term after being captured from power plants and coal-to-liquid (CTL) plants. In the next step, the two estimates are combined (section 29). The aim is to determine how much of the estimated storage capacities could be used for storing CO_2 emissions separated from the flue gas emitted from power plants and industrial sites. Due to the considerable uncertainty surrounding both sources and sinks, qualitative source-sink matching is conducted.

This main analysis is supplemented by an analysis from socio-economic, ecological and resource-strategic standpoints to achieve an integrated assessment of the role CCS could play in South Africa. First, the quality, quantity and geographical locations of coal reserves and resources in South Africa are studied (section 30). This is followed by an assessment of the cost of electricity and CO_2 mitigation of coal-fired power plants, considering CCS and comparing it with the same power plants without CCS (section 31). Next, the environmental (and social) aspects of coal-based power production are considered (section 32). In section 33, the constellation of key CCS stakeholders is assessed by applying semi-standardised, qualitative research interviews together with a standardised survey. The aim is to reflect the willingness of decision-makers to embrace CCS technology in South Africa.

Finally, conclusions from the integrated assessment of CCS are drawn in section 34. Both sections on the provision of coal development pathways and on CO_2 storage capacities in South Africa are based on a general introduction to global CO_2 mitigation scenarios and CO_2 storage issues. These can be found in sections 1 and 4 in Part I of this study, respectively.

26 Status and Development of Carbon Capture and Storage in South Africa

26.1 General Energy Situation in South Africa

South Africa is a medium-sized country, with a total land area of 1,219,090 square kilometres. It is about one third the size of the European Union (EU) and over three times the size of Germany. The country has nine provinces that vary considerably in size. The smallest province is tiny and crowded Gauteng, a highly urbanised region; the largest is the vast, arid and empty Northern Cape, which accounts for almost one third of South Africa's total land area.

South Africa is the largest economy in Africa and the twenty-eighth largest in the world. Its population was 50.6 million in 2011 (Statistics South Africa 2011).

South Africa ranked as the world's fifth largest producer of hard coal, and has a heavily coal-dependent economy, with 94 per cent of electricity production coming from coal. In addition, South Africa meets approximately 30 per cent of its domestic fuel oil demand from converting coal and gas to transportation fuels, accounting for 70 per cent of its greenhouse gas (GHG) emissions. The combination of these factors means that South Africa is as dependent upon coal as any other country in the world, making it the 13th largest emitter of CO_2 in the world. At the global level, South Africa accounts for 1.1 per cent of the world's GHG emissions.

Even though South Africa does not have a quantified emissions limitation and reduction obligation under the Kyoto protocol, the country is endeavouring to demonstrate a responsible approach towards reducing its carbon footprint. South Africa's extensive use of coal means that it could be comparatively far more dependent on CCS than other countries in a carbon-constrained world (Beck et al. 2011).

26.2 Research, Development and Demonstration Projects on CCS in South Africa

In order to speed up the development of CCS in South Africa, the national government has set up an inter-departmental task team. One of the team's tasks is to start devising a regulatory and legal framework for CCS in South Africa, particularly underground CO_2 storage, involving all regulating agencies. The team's inaugural meeting was held in late 2011. The task team, and the topic of CCS in general, is coordinated by the Department of Energy. Other government departments involved in CCS are the Department of Mineral Resources, the Department of Environmental Affairs, the National Planning Commission, the Department of Trade and Industry and the Department of Health (IMBEWU 2011).

Another cornerstone of the institutional setting of South Africa's CCS strategy is the South African Centre for Carbon Capture and Storage (SACCCS). The Centre was established in March 2009 as a division of the South African National Energy Research Institute (SANERI). One of its donors is the South African government, via SANERI (SACCCS 2012). SACCCS has drawn up a roadmap and strategy for CCS development and commercialisation in South Africa, which has been adopted or cited by several official government representatives (DOE 2011a). The roadmap contains the following key milestones:

- Conduct a test injection of CO_2 in 2016 (injection of 10,000 tonnes of CO_2);
- Have a CCS demonstration plant up and running in 2020 (storage of 100,000 tonnes of CO_2;
- Realise commercial operation of CCS in 2025 (1 million tonnes of CO_2 to be stored).

26.2.1 CCS Activities

Research in the field of post-, pre- and oxyfuel combustion is conducted by the Council for Scientific and Industrial Research (CSIR). Regarding geological storage, two onshore basins are considered most promising according to the South African CO_2 Storage Atlas: Zululand basin and Algoa sub-basin (see section 27). These basins are currently being studied in further detail. The detailed report for Zululand basin is being coordinated by SACCCS, whereas the Council for Geoscience (CGS) is conducting the geological work. Despite having been completed, the study has not yet been published due to uncertainties surrounding the injection test site selection. The detailed analysis of the onshore Algoa sub-basin, on the other hand, is part of the SAfeCCS project (work package 2) which commenced in November 2011. This research project is funded jointly by the UK Department of Energy & Climate Change (UKDECC) under the EuropeAid project funding of the European Commission (70 per cent) and SACCS (30 per cent). It is being conducted by BGS (British Geological Survey), TNO (Netherlands Organization for Applied Scientific Research) and SANERI with subcontractors CGS and Petroleum Agency SA. Work on this report commenced in November 2011.

26.2.2 Fields of Use

Retrofitting CO_2 Capture at Operating Fossil-Fired Power Plants

As a first regulatory step towards facilitating the commercialisation of CCS, the national government requires newly built coal-fired power plants to be designed as capture-ready. A precedence in this regard represents the obligation to design the new coal-fired Kusile power plant capture-ready in 2008. In addition to the national government's decision, fulfilling the technical requirements for retrofitting the Kusile plant with CCS was also requested by the World Bank, which co-finances the project and does not wish to be associated with CO_2-intensive coal-based power plants (Eskom 2011a; Fossil Fuel Foundation 2011).

26.2.3 Industrial Processes

No activities are known in this field.

26.2.4 Fuel Production

Coal to Liquid

At present, the world's only commercial large-scale indirect coal liquefaction plants are being operated by the South African Coal, Oil and Gas Corporation Ltd. (Sasol) in South Africa. Their liquid fuel production capacity totals 160,000 barrels per day, which is equivalent to approximately 28 per cent of South Africa's automotive fuel demand. In 2002, Sasol's liquefaction facilities consumed 41.5 million tonnes of coal, or 18 per cent of all domestically produced coal. As such, coal liquefaction constituted the second largest single field of national coal utilisation after electricity generation (South African Department of Minerals and Energy 2005). The evolution of South Africa's coal-based synfuels industry was stimulated by a combination of scarce national oil reserves, abundant domestic coal reserves and both national and international driving forces, such as South Africa's international insulation following international sanctions against the apartheid regime and international oil price crises.

The first South African CTL plant, Sasol I, was located in Sasolburg and commissioned in 1955. It had a daily fuel production capacity of about 30,000 barrels and was based on coal gasification and Fischer-Tropsch synthesis. Due to manifold technical problems, it took until 1960 for the plant to achieve consistent operation. By the time the technical problems had been resolved, however, the construction of additional CTL plants was considered uneconomic. In 1973, the first oil price crisis heralded a new phase of Sasol's synfuels programme. In the following year, the South African government approved Sasol's proposal for a 50,000 barrel per day CTL facility (Sasol II), located on a green field site called Secunda. The Iranian Revolution (which caused disruptions to oil imports) drove the government's decision to build Sasol III, a twin plant of Sasol II with a capacity of 50,000 barrels per day. The combined costs of Sasol II and III amounted to approximately USD 6 billion (Southern States Energy Board 2007). The facilities were commissioned in 1980 and 1982, respectively.

Operation of all CTL plants was supported by an extensive framework of financial incentives, including a floor price for CTL-derived synfuel. All CTL plants are based on gasifier designs and Fischer-Tropsch technologies developed and tested by Sasol. Hence, Sasol is currently the leading provider of CTL technologies, due to its extensive operating experience at its South African plants.

South Africa's CTL industry is widely considered an ideal opportunity for applying CCS, since carbon capture is an integrated process component that reduces the cost penalty of carbon capture and storage. CTL plants are highly CO_2-intensive; the total amount of CO_2 captured (and thereafter released to the atmosphere) at the facilities is estimated to be 50 million tonnes of CO_2 per year, 30 million tonnes of which are highly concentrated (SACCCS 2011a). Sasol recognises the need to mitigate carbon emissions to slow down climate change. By 2020, the company aims to reduce the CO_2 intensity per tonne of product by 20 per cent (compared to the 2005 baseline). Furthermore, absolute emissions for possible new CTL plants commissioned before 2020 or 2030 shall be reduced by 20 or 30 per cent, respectively (with 2005 CTL designs as the baseline) (SACCCS 2011a).

27 Assessment of South Africa's Potential for CO_2 Storage

27.1 Introduction

The aim of this section is to determine the storage potential in geological formations in South Africa. The geological circumstances and location of potential storage sites are described in section 27.2. South Africa's storage potential is estimated in section 27.3. The only existing detailed study is described and discussed on the basis of the different possible storage formations. Based on this assessment, storage scenarios are developed to show the range of possible storage capacities in South Africa (section 27.4).

27.2 Geological Situation in South Africa

The geology of South Africa consists of a very old landmass that is rich in minerals. The country is composed of a central high plateau with an altitude of about 1,000 m (Highveld). To the east and west of the plateau there are coastal lowlands. Fig. 27-1 illustrates the large sedimentary basins, which are metamorphosed and highly complex, making the porosity low. Karoo basin is the largest onshore basin, covering 60 per cent of the land (grey area). It is very thick, up to 12 km in the south, and has a low permeability due to dolerite intrusions. Karoo sediments are shallower to the north and east, which is where coal seams occur.

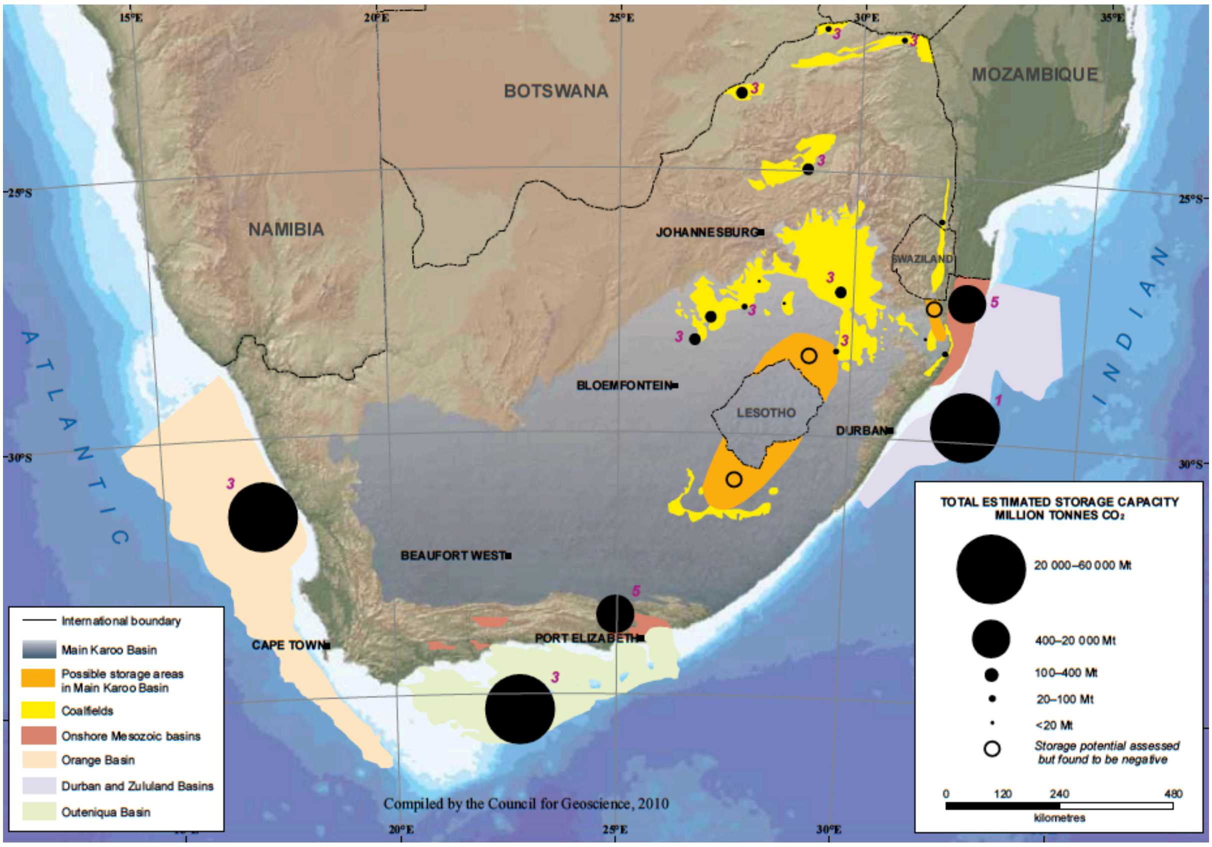


Fig. 27-1 Sedimentary basins in South Africa and potential storage capacity

Source: Viljoen et al. (2010)

The sediments in the central-eastern area are covered by thick sandstones topped by even thicker basaltic lava flows, giving rise to the mountainous kingdom of Lesotho at an altitude of about 4 km. Extensive erosion created vertical cliffs to the east and south-east of this mountainous region. Towards Namibia and Botswana, to the west and north-west of this great escarpment, the plateau gradually drops, extending to the Kalahari Desert.

The late Mesozoic basins are situated mainly offshore and provide potentially higher porosity and permeability (Fig. 27-1). These are Orange, Durban and Zululand and Outeniqua basins (light colours). Nonetheless, the level of geological uncertainty surrounding sedimentary basins is still very high. Whilst the low purple numbers represent low data confidence, highest confidence (5) is estimated only in onshore Mesozoic basins.

Geological experience is available from mineral recovery of substances such as gold, platinum and coal, but only for certain areas. Coal areas are marked bright yellow. South Africa is underlayed by a stable craton, i.e. it is not an earthquake-prone country. Most earthquakes, mainly induced by mining activities, have a magnitude of 1 or 2. Seismic risks are very low in this part of the world.

27.3 Estimates of South Africa's CO_2 Storage Potential

The main study on South Africa's CO_2 storage potential is summarised in section 27.3.1. The results are then described in more detail for oil and gas fields (27.3.2), saline aquifers (27.3.3) and coalfields (27.3.4). This description is discussed for each formation by taking other results and expert interviews into account. In addition, other non-conventional storage options are briefly explained (27.3.5). The analysis closes with a conclusion and an outlook for storage capacity estimates in South Africa (section 27.3.6).

27.3.1 Existing Country-Specific Studies

The storage atlas (Cloete 2010) is the main study on South Africa's CO_2 storage potential. It was released in 2010 and is accompanied by a detailed technical report (Viljoen et al. 2010). This report provides the most complete and up-to-date assessment of CO_2 storage capacity in South Africa. In total, a storage capacity of 150 Gt is estimated for the country (see Tab. 27-1), about 98.5 per cent of which is in offshore aquifers.

Tab. 27-1 Overview of existing effective storage capacity estimates for South Africa

	Viljoen et al. 2010
Oil fields	0.0
Gas fields	0.1
Onshore aquifers	0.8
Offshore aquifers	147.7
Coal seams	1.3
Total	149.9
All quantities are given in Gt CO_2	

Source: Viljoen et al. (2010)

Although it is calculated using efficiency factors, which show the fraction of total pore volume that can effectively be used, uncertainties are large and the parameter selection is undertaken theoretically by evaluating literature studies. Hence, the authors believe capacity is somewhere between theoretical and effective capacity on the techno-economic resource-reserve pyramid (see Fig. 4-6 of Part I). The estimate is considered optimistic by the authors

(Council for Geoscience 2011). In the classification of the present report, it is considered to be the effective capacity.

The storage atlas was developed based on an initial assessment published by Engelbrecht et al. (2004), which was the first public document on CO_2 sequestration in South Africa. It analysed various sequestration options including biomass, CO_2 injection in the water column of the ocean and geological storage. Geological storage was considered the best option, especially in the onshore Karoo basin, which could hold about 20 Gt of CO_2. This first assessment included very incorrect storage capacities (Council for Geoscience 2011). In the storage atlas of 2010, Karoo basin is excluded because its porosity and permeability values are too low.

27.3.2 Oil and Gas Fields

Storage Atlas

The capacity in South Africa’s oil and gas fields is very low, due primarily to the country’s low hydrocarbon resources. In addition, oil and gas field exploration is still in its infancy in South Africa. If only depleted and nearly depleted fields are taken into account, a capacity of 56 Mt of CO_2 in gas fields and 6 Mt of CO_2 in oil fields is yielded. The most promising fields are situated in Outeniqua and Orange basins. By including oil and gas reserves, the gas capacity is increased to 70 Mt, whereas the capacity in oil fields remains the same. The capacity increases to about 200 Mt if the best estimate of contingent resources is considered (Viljoen et al. 2010).

Discussion

There are arguments in favour of and against CO_2 storage in hydrocarbon fields. On the one hand, the storage capacity in oil fields is very low and can be considered negligible for large-scale CCS, although EOR activities could heighten interest in these fields. Relying on current depleted fields, the storage opportunity in gas fields is not very high either and could be used only in the demonstration phase of CCS in South Africa. Hence it will not be considered for CO_2 storage (SACCCS 2011a). Fields in Mozambique are more likely to be used because they will probably be the first in the region to become depleted.

On the other hand, Engelbrecht et al. (2004) mention that, despite its young history, there is long-term potential for CO_2 storage in these fields. By assuming the 50 per cent replacement of oil or gas, about 1 Mt of CO_2/a could be stored in the future. This would equal the CO_2 emissions of a 200 MW coal-fired power plant.

To conclude, storage capacity in South Africa’s oil and gas fields is very low and cannot contribute considerably to CCS development.

27.3.3 Saline Aquifers

Storage Atlas

Viljoen et al. (2010) classify the onshore and offshore aquifers of South Africa and identify the most promising basins by testing their geological suitability. The screening criteria comprise different geological parameters such as tectonic setting, size and depth, faulting intensity, hydrocarbon and coal potential, and infrastructure as well as the connection to CO_2 point sources. Tab. 27-2 provides the resulting rank excluding the presence of coal, which would favour onshore basins. Geological suitability is ranked on a scale from 0 to 1. The five most promising basins, analysed in further detail below, are the three offshore basins of Outenique, Durban/Zululand and Orange and the onshore Zululand and Algoa basins (compare also Fig. 27-1).

Tab. 27-2 Geological suitability of South African sedimentary basins

Basin/area	**Onshore**	**Offshore**	**Geological suitability**	**Rank**
Outeniqua		X	0.91	1
Durban & Zululand		X	0.84	2
Orange		X	0.84	3
Onshore Zululand	X		0.78	4
Onshore Algoa	X		0.76	5
Northern Karoo	X		0.71	6
Molteno-Indwe	X		0.71	7
Southern Karoo	X		0.69	8
Tshipise	X		0.64	9
Durban-Lebombo	X		0.64	10
Springbok Flats	X		0.6	11
Ellisras (Lephalale)	X		0.6	12
Tuli	X		0.56	13
Geological suitability is ranked on a scale from 0 to 1.				

Source: Viljoen et al. (2010)

The *offshore basins* linked to hydrocarbon fields are the most promising, offering the highest storage potential at 147.7 Gt of CO_2 (see Tab. 27-3). This constitutes about 98 per cent of South Africa's estimated storage capacity. These basins include Orange basin (57.1 Gt CO_2), Outeniqua basin (48.4 Gt CO_2) and Durban/Zululand basin (42.3 Gt CO_2).

Tab. 27-3 Effective CO_2 storage capacity in South Africa's sedimentary basins

Aquifer properties		**Algoa**	**Zululand**	**Outeniqua**	**Orange**	**Durban & Zululand**
		Onshore		Offshore		
Net area	km^2	400	200	65,000	118,000	81,000
Net thickness	m	100	110	80	50	60
Average porosity	%	18.8	35.9	15.0	15.0	15.0
Average CO_2 density	kg/m^3	537.5	500	620	645	580
Efficiency factor (average)	%	10	10	10	10	10
Effective storage capacity	Mt	404	395*	48,360	57,083*	42,282

* Calculations for onshore Zululand and offshore Orange basins differ slightly from the report due to rounding errors.

Source: Viljoen et al. (2010)

Onshore storage is related to the most promising basins of Zululand, with 395 Mt of CO_2 storage capacity, and Algoa basin, with 404 Mt. In total, an onshore capacity of 799 Mt is estimated. These basins have a low porosity and permeability, which could lead to difficulties when it comes to the injection operation.

Karoo basin, which is beneath 60 per cent of South Africa's land area, can be considered an unconventional storage site due to its very low permeability. Its capacity has previously been estimated at 20 Gt by Engelbrecht et al. (2004), primarily in the Vryheid formation. However, chances are slim that it will be possible to store CO_2 there (SACCCS 2011a).

The methodology used by Viljoen et al. (2010) to calculate storage capacity is based on the U.S. Department of Energy Storage Atlas (NETL 2010) where *efficiency factors* ranging from 1 to 4 per cent are applied to calculate effective capacities. For South Africa, Viljoen et al. (2010) assume that the net-to-gross value is already included in the area estimate, hence the values in Tab. 27-3 are the aquifers' net storage areas and net thickness. For this reason, the efficiencies applied are increased by between 4 and 16 per cent, with an average efficiency factor of 10 per cent. The calculation presented in Tab. 27-3 includes the average values.

Other parameters are also included in the calculation besides efficiency. The *average CO_2 density* of the studied basins ranges from 500 to 645 kg/m^3. It is lower in onshore than in offshore basins. The average value is included in Tab. 27-3. The *average porosity* is highest in the onshore Zululand basin (36 per cent) and lowest in offshore basins (15 per cent). Regarding storage *area*, offshore basins are much more extensive, but have a lower *net thickness*.

Discussion

During expert interviews, the authors of the South Africa storage atlas considered this calculation to be highly uncertain (Council for Geoscience 2011; SACCCS 2011a). Rather than the assumed 10 per cent efficiency, it could also be 1 to 4 per cent, although the level of uncertainty would still be very high. In the outdated study by Engelbrecht et al. (2004), the onshore geological storage capacity was calculated using a 2 per cent efficiency. Due to this high level of uncertainty, the effective capacity in the onshore basins of Zululand and Algoa is possibly more in the range of 40 Mt each than 400 Mt. This is due to the very low compressibility and the risk of over pressurising the reservoir. If the formation is closed, there will be no space available at all.

To conclude, the experts mention that the selection of the efficiency parameter is more speculation than science. Instead of the 10 per cent applied, efficiencies of 1, 2 or 4 per cent should be selected. This range will be used for the sensitivity analysis of storage capacities (see section 27.4).

27.3.4 Coalfields

Storage Atlas

A main criterion for CO_2 adsorption in coal seams is depth, hence Viljoen et al. (2010) calculate the theoretical capacity at between 300 and 800 m. The injection of CO_2 is linked to the production of coalbed methane, so the capacity is extrapolated from South Africa's methane volume. This leads to a storage capacity estimate of 277 to 1,386 Mt of CO_2 in coal seams, involving very large uncertainties. This capacity is highly dispersed over small coalfields across the country with many discontinuities. In the storage atlas, the capacity for coal seams is assumed to be 1,272 Mt of CO_2.

Discussion

The technology of CO_2 storage in coalbeds is not yet a viable storage mechanism (Sasol 2011a). In addition, there is still no South African industry and market for enhanced coalbed methane (ECBM) exploration. Tests on CO_2 storage in coal seams in Waterburg (Northern South Africa) and Botswana were less promising. In both regions, the permeability of coal is very low. This can only be resolved using new technologies, as a lot of wells would currently be required for injection. So far, CBM extraction is not seen as a perspective for South Africa. This technology is not being studied in any further detail by Sasol at present. Instead, basic research is being conducted at universities meaning that, in the long term, it may be possible to inject CO_2 whilst exploiting coalbed methane (Sasol 2011a).

Another problem arising from CO_2 injection in coal seams is contamination of the fields. If a coal seam is classified as unmineable today, this decision is mainly based on economic parameters. These parameters may change in the future and could lead to a different classification, making the fields economically viable. If CO_2 is stored in the field in the meantime, the coal would be contaminated and could not be mined. Hence there is a competing interest between storage of CO_2 and future coal exploitation (Anglo American 2011a). The same may apply to oil and gas fields.

To conclude, CO_2 storage in South Africa is very challenging due to the lack of adequate technology and experience with coalbed methane recovery as well as the risk of contaminating coalfields. Thus coalfields will not be used to store CO_2 in South Africa, at least in the short to medium term, and are excluded from the storage scenarios.

27.3.5 Non-Conventional Storage

After having described the potential and limitations of CO_2 storage in oil and gas fields, saline aquifers and coal seams, further non-conventional storage options are presented here. These are not considered in the South African storage atlas.

Basalt Formations

An overview of the potential to store CO_2 in basalts was provided recently by IEA GHG (2011). It describes the large uncertainty surrounding basalt storage and identifies no potential for South Africa. However, the dolerite intruded formations in South Africa provide a secondary permeability that could be used once the technology has been developed. At present, this is a long way from being realised.

Gold Mines

South Africa is a large producer of gold, hence depleted gold mines at a depth of 3 to 5 km could be used for CO_2 storage. As with coal, the contamination of gold mines with CO_2 would prohibit future exploitation. However, the price of gold is high and there will always be some gold left. In addition, safety research must be undertaken before considering these mines for CO_2 storage because a plug is required for safe inclusion. Volumetrically, the gold mines would be unable to absorb much CO_2. These problems lead scientists to conclude that gold mines do not represent an opportunity for CO_2 storage (Sasol 2011a).

Underground Coal Gasification

Coalfields in South Africa could become exploitable due to underground coal gasification (UCG). The advantage of this technology is that the CO_2 is retained inside the formation after combustion. Eskom is conducting a UCG test site close to Majuba power station in Volksrust, Mpumalanga. Although coal is abundant at the site, it is locked in compartments. Since it is difficult to mine, underground gasification at a depth of 200 m could be a solution. This is being tested on a small scale. Gas has been used at the power station for two years. Across South Africa, 27 coal seams have been identified for UCG by Eskom (Fossil Fuel Foundation 2011).

In addition to being at a very early stage of development, there are other issues related to UCG in South Africa. UCG causes severe environmental problems, making it unviable in a country with high environmental standards such as South Africa (Anglo American 2011a). Furthermore, the CO_2 could leak into adjacent structures or basins, which is difficult to monitor. In addition, UCG is not a cheap technology. Operators must use oxygen blowing to increase the quality of the gas, which is very energy intensive.

To date, UCG technology has not been developed in South Africa, nor it is clear whether it would contribute to CCS.

27.3.6 Conclusion and Outlook

Major CO_2 storage potential is identified in South Africa's saline aquifers. All other storage options are either too uncertain (coalfields and non-conventional storage) or offer insufficient capacity (oil and gas fields). In the long term, coalfields and low permeability rocks could potentially be used for storage purposes (Sasol 2011a). Hence onshore and offshore sedimentary basins are considered to be the most promising formations, and research focuses on these saline aquifers. Based on the storage atlas results, onshore Algoa and Zululand basins will be further analysed to find a suitable site for test injection. The costs of offshore storage are too expensive at this stage. The test injection is planned for 2016 to obtain a better knowledge of the basin's geology.

A detailed report for Zululand basin is currently being prepared to estimate the effective storage potential. Although it is assumed that this basin has a low permeability, the amount of bore hole data available does not suffice to enable a site for test injection to be chosen yet. It is still unclear whether or not the caprock is thick enough to retain the CO_2 that would potentially be injected into the formation (Council for Geoscience 2011). Hence field work is required to find out more about the area's geology. In addition, a detailed analysis of Algoa basin is part of the SAfeCCS project (see section 26).

Potential in Neighbouring Countries

In addition to the further analysis of domestic storage capacity, experts are discussing storage potential outside the country. There is potential, for example, in Botswana's coalfields using CBM recovery or in the natural gas fields of Namibia and Mozambique. But the regulatory circumstances make it difficult and too complex to export CO_2 to neighbouring countries. Nevertheless, this could be a possibility for the future.

27.4 Development of Storage Scenarios

Three storage scenarios are developed to be able to match storage capacities with the amount of separated CO_2 resulting from the coal development pathways (Tab. 27-4). These consider different assumptions on the storage capacities for oil fields, gas fields and aquifers.

Neither unconventional storage sites nor coal seams are considered for the scenarios because they are deemed to be too uncertain.

Tab. 27-4 Scenarios of effective CO_2 storage capacity in South Africa

Formation	S1: high	S2: intermediate	S3: low
Oil	-	-	-
Gas	0.2	-	-
Onshore aquifers	1	0.3	-
Offshore aquifers	148	59.1	14.8
Total	149.2	59.4	14.8

All quantities are given in Gt CO_2

The efficiency factors selected for aquifers are 10% (S1), 4% (S2) and 1% (S3).

Source: Authors' calculation

The scenarios can be characterised as follows:

1. The *high estimate* (S1) is based on optimistic assumptions by Viljoen et al. (2010). It includes 0.2 Gt of CO_2 storage capacity in gas fields, when the best estimate of contingent resources is considered. The capacity in oil fields is negligible, and sequestration in coal seams is excluded due to the large uncertainties involved. The capacity in aquifers is assumed to be 149 Gt, most of which (148 Gt) is offshore (applying an efficiency factor of 10 per cent). In total, this storage scenario amounts to 149.2 Gt of CO_2.
2. The *intermediate estimate* (S2) calculates oil and gas field capacities based on proven reserves. This yields a capacity of 62 Mt of CO_2 in depleted and near-depleted fields, which is too low for consideration here. Coal seams are excluded due to the existence of too many uncertainties. Thus the intermediate capacity is based solely on saline aquifers. The calculation by Viljoen et al. (2010) is followed, but an efficiency of 4 per cent is applied to both onshore and offshore basins (lower range of the given efficiencies, whilst retaining average values for the other parameters). For onshore aquifers, the capacity amounts to 320 Mt of CO_2. Offshore aquifers provide a much higher capacity of 59.1 Gt. In total, this leads to a capacity of 59.4 Gt.
3. The *low estimate* (S3) includes the same assumption as the intermediate result, with capacity provided in aquifers only. In addition, onshore aquifers are excluded because their capacity is rather low and uncertainties are large. An efficiency of 1 per cent is applied for offshore aquifers. This leads to an offshore capacity of 14.8 Gt of CO_2.

28 CCS-Based Coal Development Pathways for South Africa's Power and Industry Sector

28.1 Introduction

The aim of this section is to determine how much CO_2 emissions may have to be stored underground, depending on different development pathways of South Africa's power plant and industry sector. The *coal development pathways* provided for this purpose indicate a development between a "low carbon" and a "high carbon" strategy in these sectors. For each decade up to 2050, the quantity of coal-fired power plant capacities that could be installed including CCS or retrofitting with CO_2 capture once CCS has become commercially available is investigated. In addition, the contribution of the industrial sector is considered by developing a rough pathway sketching the possible application of CCS in South Africa's industry.

CO_2 emissions captured from power plants and industrial sites are added together. Whereas the annual figures of CO_2 emissions determine the maximum scope of the pipeline infrastructure required for CO_2 transportation, the total amount enables the possible storage capacity required for South Africa to be determined.

The analysis is performed as follows: firstly, a comprehensive analysis of coal-fired power plants currently in operation and officially planned in the near future is conducted (section 28.2). Secondly, based on this analysis coal development pathways are sketched and the number of coal-fired power plants that could be installed in the future is determined (section 28.3). In section 28.4, the quantity of CO_2 that could be separated from these power plants in the decades ahead is estimated. The potential role of industry is then examined by providing rough CCS-based industrial coal development pathways (section 28.5). Finally, the results are summarised and conclusions drawn (section 28.6).

28.2 Current and Projected Coal-Fired Power Plants in South Africa

To consider possible development pathways of South Africa's coal-fired power plants, it is necessary to begin the investigation with a comprehensive analysis of power plants currently in operation and officially planned in the near future. The analysis, conducted by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, is based on annual reports and statistical reports issued by Eskom heritage (Eskom 2011b) and the 2011 status report on capacity expansion projects (Eskom 2011c). Eskom produces 96 per cent of the country's electricity. The figures were updated with the May 2011 issue of the government's Integrated Resource Plan for Electricity and the figures reported in its "Policy Adjusted Scenario" (DOE 2011b). The approach, applied in the following analysis, is as follows:

- Firstly, the power plants currently in operation are analysed with regard to their age. Assuming 50 years of regular operation yields the decommissioning year. Considering the decades ahead and adding together the capacity of only those power plants assumed to be in operation according to this calculation results in the "curve of decommissioning" of the current power plant fleet.
- Secondly, all power plants that will certainly be installed at a later date are added to the capacity of existing power plants, yielding the total capacity in operation per year. In the

case of South Africa, these are the two big 4.3 GW power plants currently being built by Eskom, Medupi and Kusile, coming into operation by degrees between 2013 and 2020.

Fig. 28-1 shows the resulting development between 2010 and 2050 for South Africa, starting with an installed capacity of coal-fired power plants of 37 GW and showing a remaining fleet of 9.4 GW in 2050. The large net increase by 2020 created by Medupi and Kusile power plants is clearly visible. These newly built power plants, also designed to be operated for 50 years, are responsible for the high remaining load in 2050.

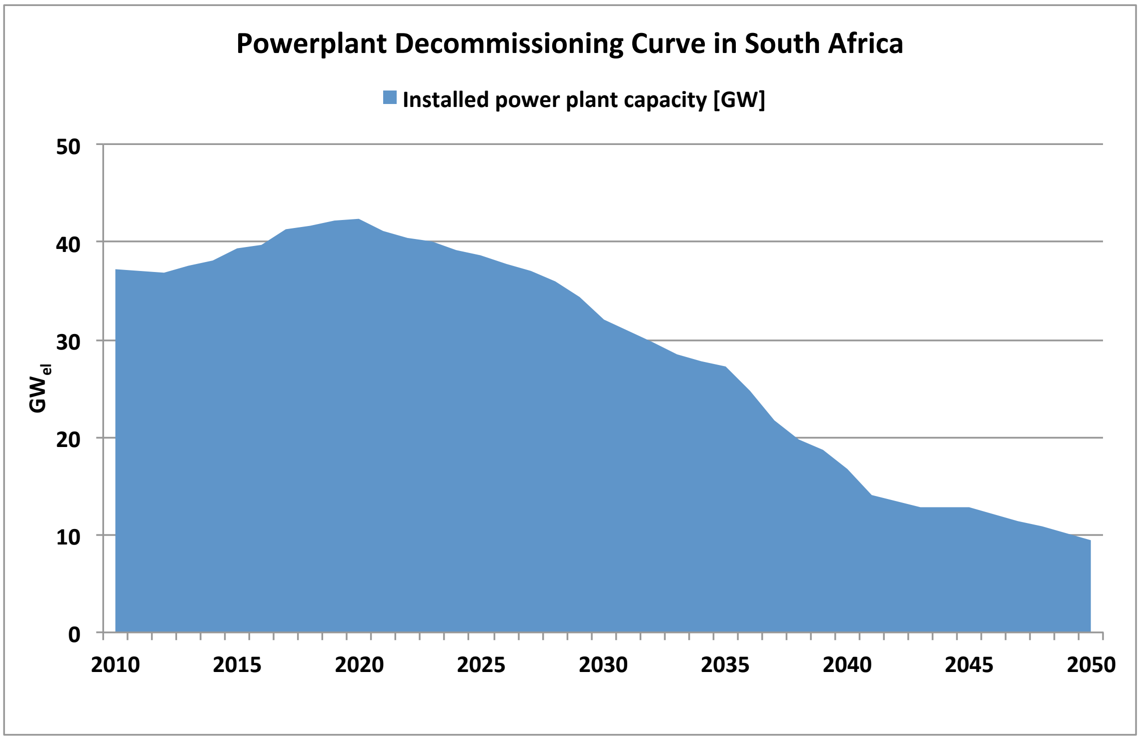


Fig. 28-1 Coal-fired power plants currently in operation in South Africa, according to an analysis of publicly available data

Source: Authors' illustration

Fig. 28-2 illustrates where the provinces, major coalfields and coal-fired power plants are located in South Africa. At present, 80 per cent of these power plants are being operated in Mpumalanga; these are circled in Fig. 28-2. As Fig. 28-3 shows, the significance of Limpopo is increasing due to the large Medupi power station being built near Waterberg coalfield.

Fig. 28-2 Map of South African provinces, major coalfields and coal-fired power plants (circled)

Source: Based on DME (2009)

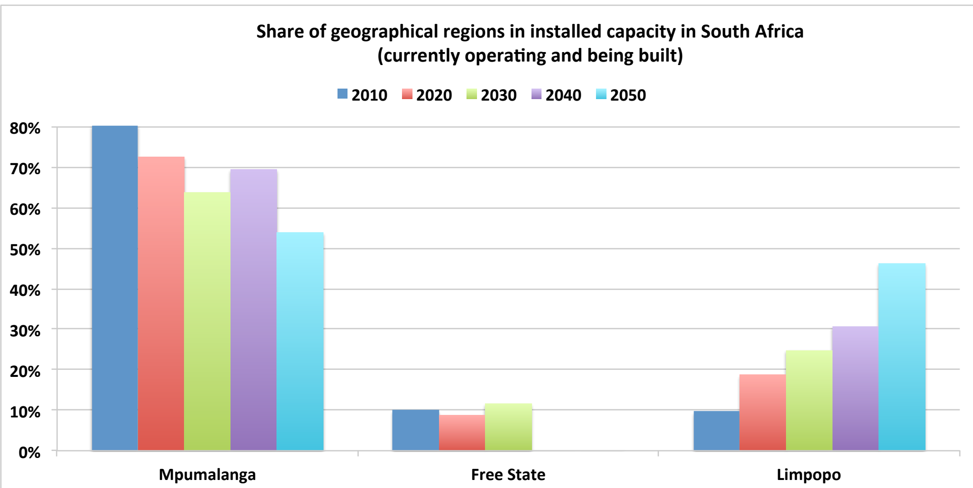


Fig. 28-3 Share of South African provinces in installed coal-fired power plant capacity, currently operating und being built

Source: Authors' illustration

28.3 Long-Term Coal Development Pathways for the Power Plant Sector

28.3.1 Methodological Approach

The quantity of CO_2 emissions potentially available for storage is assessed by applying three substantially different long-term coal development pathways for South Africa. The pathways indicate a power plant development between a “high carbon” and a “low carbon” strategy, as their names *E1: high*, *E2: middle*, *E3: low* suggest. The aim is to investigate the level of CO_2 emissions required for storage with each pathway for each decade up to 2050. To this end, the capacities of coal-fired power plants, both newly built as CCS-based power plants or retrofitted with CO_2 capture when CCS becomes commercially available, have to be explored. The annual amounts of CO_2 emissions to be captured are derived from key parameters such as efficiency, penalty load, construction time of capture facilities and capture rate. The total amount of CO_2 to be captured and stored is determined considering the lifetime of CCS-based power plants. Whereas the *annual figures* determine the maximum scope of the pipeline infrastructure required for CO_2 transportation, the *total amount* yields the possible storage capacity required per power plant, state, region and for the whole of South Africa. This cumulated amount is compared to the storage capacities evaluated in section 27.

It should be noted that the coal development pathways differ from energy scenarios: whilst energy scenarios provide a consistent framework for the analysis of long-term energy strategies, the pathways applied here are taken from different existing scenario studies. They are only used to illustrate the different CCS development pathways in order to obtain an understanding of the level of separated CO_2 emissions that could be available for storage. The project’s remit did not allow new energy scenarios including CCS to be developed from scratch for South Africa.

First of all, a review of all existing energy scenario analyses is undertaken. The preconditions for selecting a study as the basis for the coal development pathway are as follows:

- Scenarios must cover a period up to at least 2050;
- The installed capacity of coal-fired power plants must be published at least for each decade, otherwise the scenarios cannot be used to estimate CCS capacity;
- The capacity of installed power plants in 2010 should not differ too significantly from the current situation.

Tab. 28-1 gives an overview of the long-term scenarios found in the literature. Furthermore, it illustrates how suitable they are for the objective of this study. These scenarios are:

- *Carbon Capture and Storage in Developing Countries: a Perspective on Barriers to Deployment* (Kulichenko and Ereira 2011 on behalf of the World Bank);
- *The Advanced Energy [R]evolution: a Sustainable Energy Outlook for South Africa* (EREC and Greenpeace International 2011);
- *50% by 2030: Renewable Energy in a Just Transition to Sustainable Electricity* (WWF South Africa 2010);
- *Long-term Mitigation Scenarios (LTMS): Strategic Options for South Africa* (Scenario Building Team 2007 on behalf of the Department of Environment Affairs and Tourism South Africa).

Tab. 28-1 Overview of existing long-term energy scenarios for South Africa and assessment of their suitability for this study arranged by year of publication

Year	Scenario	Target year	Coal capacity given	CCS for	Installed CCS capacity	Cumulative stored CO_2 up to target year	CCS share of electricity generation	Decision	Remark
World Bank Sources: Kulichenko and Ereira (2011), vito et al. (2011), Tot et al. (2011) (compiled by Vito [Belgium]; Energetski Institut Hrvoje Požar [Hungary]; Cape Town University's Energy Research Centre [South Africa]) [*1)]									
2011	Reference	*2030*	Yes	---	---	---	---	n.c.	
	Baseline (IRP revised balance scenario)	*2030*	Yes	Natural gas (2025)	Figures for 2020/25/30 0.2–2.4 GW	19 Mt [*1)]	2%	n.c.	
	Baseline with EOR/ECBM	*2030*	Yes	Natural gas	Only figure for 2030: 2.4 GW	23 Mt [*1)] + 4 Mt retrofit	2%	n.c.	
	CO_2 Price Scenarios	*2030*	Yes	Coal: 2025 or (mainly) 2030	Figures for 2025/30 5.9–7.3 GW	162/177/283 Mt [*1)] + 15.4/0/0 Mt retrofit	10–16%	n.c.	
EREC and Greenpeace International Sources: EREC and Greenpeace International (2011) (compiled by German Aerospace Center and ecofys [the Netherlands])									
2011	Reference	2050	Yes	---	---	---	---	**Taken as pathway *E2: middle***	Up to 2030 based on (IEA and OECD 2008a) and updated with figures from IRP (May 2011) (committed and newly built options); updated up to 2050
	Energy [R]evolution	2050	Yes	---	---	---	---	**Taken as pathway *E3: low***	Up to 2030 based on IRP (May 2011) (committed power plants only); updated up to 2050

Year	Scenario	Target year	Coal capacity given	CCS for	Installed CCS capacity	Cumulative stored CO_2 up to target year	CCS share of electricity generation	Decision	Remark
WWF South Africa Source: WWF South Africa (2010) (compiled by Cape Town University's Energy Research Centre [South Africa]))									
2010	Reference Case	*2030*	Yes	---	---	---	---	n.c.	Uses LTMS framework
	Alternative Scenario	*2030*	Yes	---	---	---	---	n.c.	Uses LTMS framework
Department of Environment Affairs and Tourism South Africa Sources: Scenario Building Team (2007), Energy Research Centre (2007); Hughes et al. (2007) (compiled by Cape Town University's Energy Research Centre [South Africa])) *2)									
2007	LTMS Scenario 1 "Growth without constraints"	2050	Yes	---	---	---	---	**Taken as pathway *E1: high***	5 new CTL plants each 80,000 bbl/d=½ Secunda
	LTMS Scenario 2 "Required by Science"	2050							Storylines, no scenarios
	Start now	*???*	---	Synfuels	*No figures*	2 Mt/a	---	n.c.	*3)
	Scale up	*???*	---	Synfuels	*No figures*	23 Mt/a or 20 Mt/a	---	n.c.	*2), *3)
	Use market		---	---	---	---	---	n.c.	
	Reach goal		---	---	---	---	---	n.c.	

Figures in italics: exclusion criteria

n.c. = not considered

*1) Whole of the Southern Africa Region

*2) Starting figure for 2010 is too low (32.8 GW instead of currently installed 38 GW); IRP figures not given at that time.

*3) The low CCS application seems to be a contradiction to the statement that CCS is "included as a major component of energy security strategy" (p. 29)

Source: Authors' illustration

The main conclusions that can be drawn from the assessment are:

- No scenarios exist that go up to 2050 and that include use of CCS for power plants;
- Only one scenario applies CCS for coal-to-liquid plants (20 or 23 Mt CO_2/a), but considers the existing Secunda plant only;
- Two scenarios attempt to achieve climate goals in 2030 and 2050 without using CCS or nuclear energy (EREC and Greenpeace International 2011; WWF South Africa 2010, respectively);
- Only one study is up-to-date compared with the current power plant development plan of the South African government. EREC and Greenpeace International (2011) adapted both the *Energy [R]evolution Scenario* and the IEA WEO 2010 scenario, which is taken as the *Reference Scenario,* to the May 2011 Policy Adjusted Scenario of the Integrated Resource Plan (IRP) for Electricity (DOE 2011b). Since the IRP only covers the period up to 2030, the figures were updated to 2050.

Since no suitable CCS-based scenario is given, coal development pathways E1–E3 are based on scenarios that illustrate a high, middle and low development of coal-fired power plants in South Africa:

- *LTMS Scenario No 1 "Growth without constraints"* by the Scenario Building Team (2007);
- *Reference Scenario* by EREC and Greenpeace International (2011);
- *Energy [R]evolution Scenario* by EREC and Greenpeace International (2011).

These coal development pathways are described in detail in the next section.

28.3.2 Description of Underlying Basic Scenarios

The following approaches are chosen to establish coal development pathways:

- *Pathway E1: high*: The "high carbon" pathway E1 is based on the *Long-Term Mitigation Scenario No 1 "Growth Without Constraints",* developed by the Energy Research Center on behalf of the Department of Environment Affairs and Tourism South Africa (Scenario Building Team 2007). This scenario involves neither a change from current trends nor the implementation of existing policies. Energy demand grows primarily in the industry and transport sector (with one third of industrial fuel use based on electricity).

  LTMS Scenario No 1 assumes an increase in installed power plant capacity from the current level of 37 GW to 120 GW by 2050 (see Fig. 28-4), with a decreasing share of coal (91 GW, or 76 per cent, by 2050) but an increasing share of nuclear energy (17 GW, or 14 per cent).

  The assumption behind the application of CCS in coal development pathway E1 is that the deployment of CCS would have to be as high as possible in the future to decrease the high CO_2 emissions resulting from a strong development of coal-fired power plants.

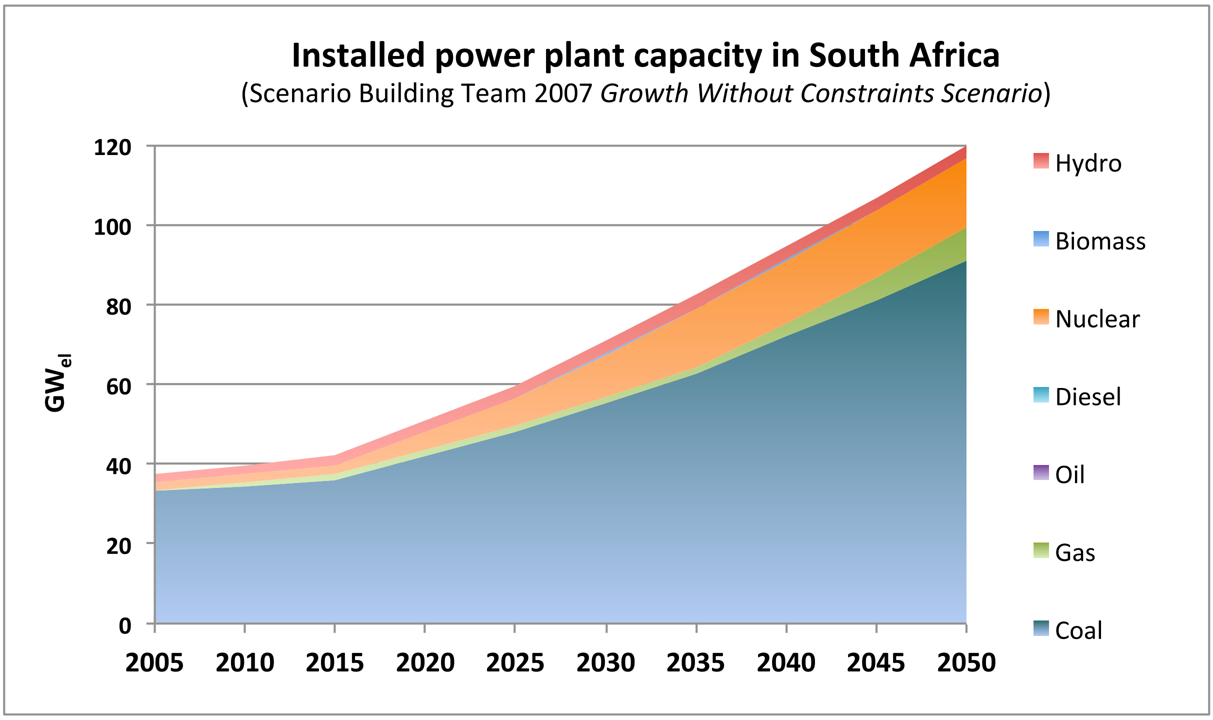


Fig. 28-4 Development of installed power plant capacity in South Africa in the *LTMS Scenario No 1 "Growth without constraints"*

Source: Authors' illustration based on Scenario Building Team (2007) and Hughes et al. (2007)

- *Pathway E2: middle*: The "middle carbon" pathway E2 is based on the *Reference Scenario* as developed in the *Sustainable Energy Outlook for South Africa*, published by EREC and Greenpeace International (2011) (see description of pathway *E3: low,* below). It was originally based on the *World Energy Outlook 2008 Reference Scenario*, published by IEA and OECD (2008a), which takes into account existing international energy and environmental policies. Examples are continuing progress in electricity and gas market reforms, the liberalisation of cross-border energy trade or recent policies designed to combat environmental pollution. Since World Energy Outlook scenarios are only projected to 2035, this scenario was extrapolated to 2050 within EREC and Greenpeace International (2011). After the Policy Adjusted Scenario of the Integrated Resource Plan (IRP) (DOE 2011b) was adopted by the South African government, the reference scenario was updated with the figures reported in the IRP up to 2020, including committed building projects (Medupi and Kusile) and options to build new plants.

  The development between 2010 and 2020 was updated to 2050 (see Fig. 28-5). It is characterised by three principles: firstly, coal-fired capacity will decrease slightly and reach 45 GW from 2030. This means a steady commissioning of new power plants due to the decommissioning of old plants according to Fig. 28-1. The difference to the 2020 status is balanced by an increase in natural gas. Secondly, nuclear power will increase strongly, achieving 12 GW from 2030. Thirdly, renewable capacity will increase from 7.5 GW in 2020 to 37 GW in 2050, according to the development in the IRP.

  The assumption behind the application of CCS in coal development pathway E2 is that the strong increase in both nuclear energy and renewable energies may possibly not occur as quickly as required in the underlying scenario. In this case, the deployment of CCS could be a "fall back" option to compensate for the slowing CO_2 reduction.

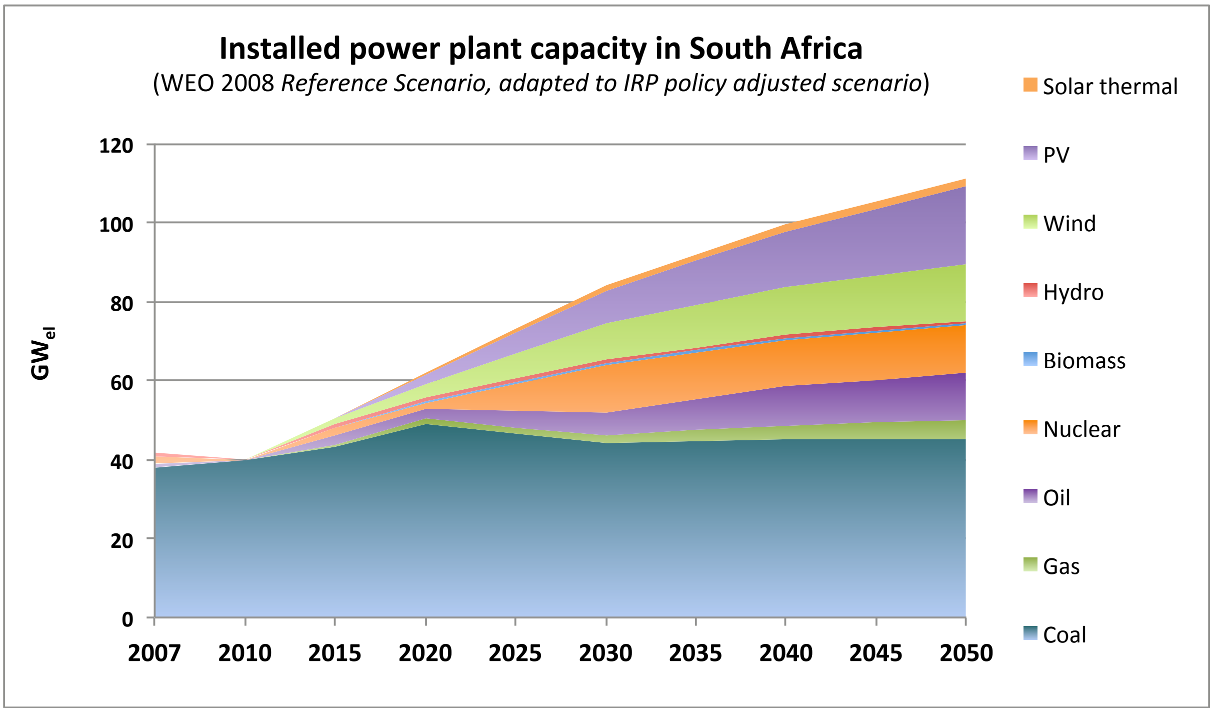


Fig. 28-5 Development of installed power plant capacity in South Africa in the adapted Reference Scenario of WEO 2008

Source: Authors' illustration based on EREC and Greenpeace International (2011)

- *Pathway E3*: *low*: The "low carbon" pathway E3 is based on the *Sustainable Energy Outlook for South Africa*, published by EREC and Greenpeace International (2011). It is an update of the former South African scenario (EREC and Greenpeace International 2009), adapted to the May 2011 Policy Adjusted Scenario of the Integrated Resource Plan (IRP) (DOE 2011b). In contrast to the Reference Scenario outlined above, this scenario considers committed building projects only (Medupi and Kusile), and does not foresee any further new coal-fired power stations in the future. This means a steady decrease in coal-fired power due to the decommissioning of old plants, as visible in Fig. 28-1.

  The South African scenario is part of the global Energy [R]evolution Scenario framework, the target of which is to reduce worldwide CO_2 emissions to 50 per cent below the 1990 level by 2050. This means that per capita emissions are reduced to less than 1.3 tonnes per year, which is necessary to prevent the rise in global average temperature from exceeding a threshold of 2°C. Whilst the scenario is based only on proven and sustainable technologies (renewable energy sources, efficient decentralised cogeneration and energy-saving technologies), both CCS power plants and nuclear power plants are excluded. Whilst the *Energy [R]evolution Scenario* is based on the same projections of population and economic development as the *Reference Scenario* of the International Energy Agency's (IEA) World Energy Outlook 2010, a sharper decrease in energy intensity due to more ambitious energy efficiency measures is assumed.

  In contrast to the *IEA Reference Scenario*, 75 per cent of the electricity produced in South Africa will come from renewable energy sources in 2050. This will lead to an increase in the installed capacity of renewable energy technologies from 2.6 GW in 2010 to 74 GW in 2050 (see Fig. 28-6). The installed coal-fired power plants based on a capacity of 37 GW in 2010 will increase to 41 GW by 2020 according to the IRP, before decreasing finally to 15 GW in 2050.

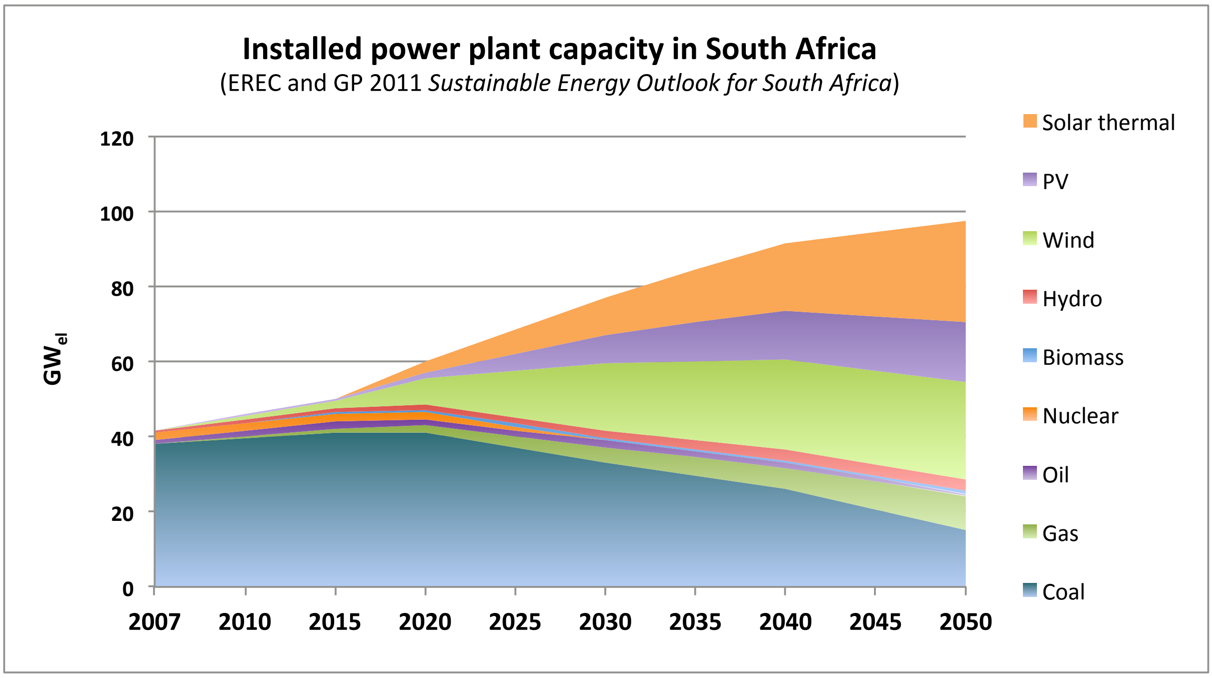


Fig. 28-6 Development of installed power plant capacity in South Africa in the EREC and Greenpeace *Energy [R]evolution Scenario 2011*

Source: Authors' illustration based on EREC and Greenpeace International (2011)

The assumption behind the application of CCS in coal development pathway E3 is that the strong increase in both energy efficiency and the deployment of renewable energies may possibly not occur as quickly as required in the underlying basic scenario. In this case, the deployment of CCS could be a "fall back" option to compensate for the slowing CO_2 reduction.

28.3.3 Comparison of Coal Development Pathways

In Fig. 28-7 and Tab. 28-2, coal development pathways E1 to E3 are compared with regard to their assumptions on the development of coal-fired power plant capacity. In addition, the currently installed power plant capacity development is given. The figure illustrates that all pathways meet the currently installed capacity more or less adequately. Whilst all pathways assume a continuous increase in installed coal-fired power plants by 2020, in the long term they develop according to their specific characteristics: pathway *E1: high* shows a strong increase in coal-based capacity whilst pathway *E2: middle* increases continuously up to 2020 only. In pathway *E3: low,* coal-based capacity decreases continuously after peaking in 2020.

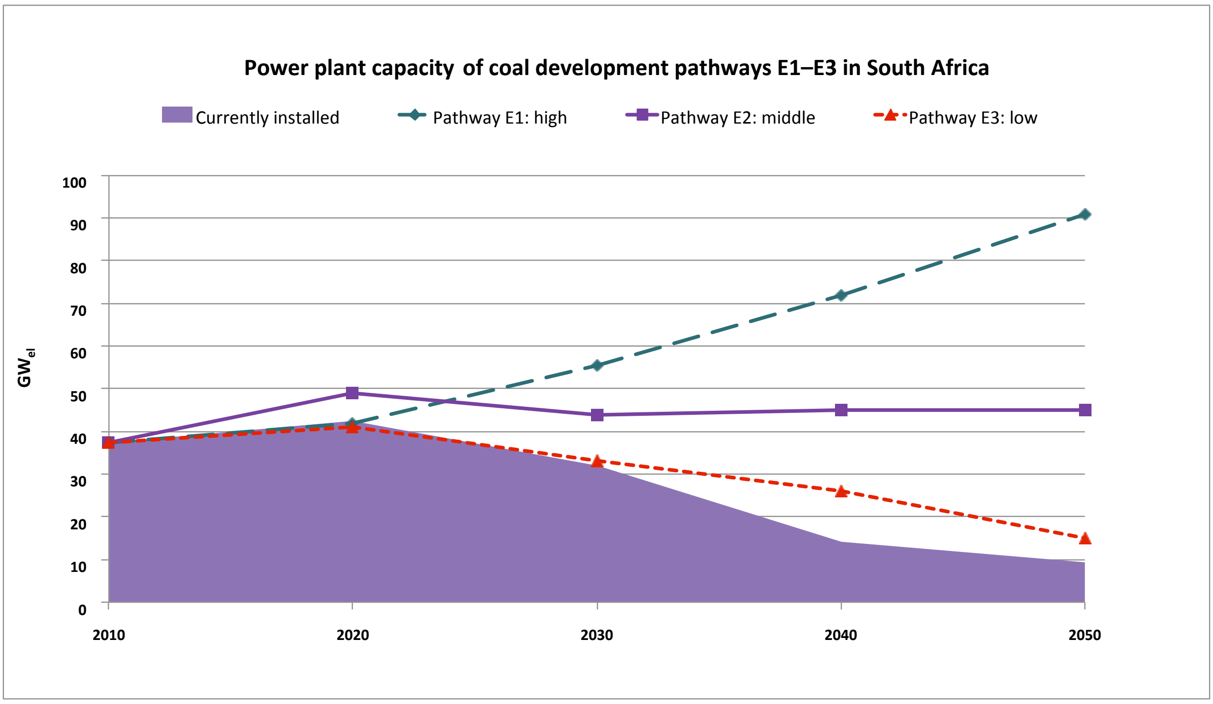


Fig. 28-7 Coal-fired power plant capacity in South Africa, currently installed and envisaged according to three coal development pathways E1–E3

Source: Authors' illustration

Tab. 28-2 Coal-fired power plant capacity in South Africa, currently installed and envisaged according to coal development pathways E1–E3

	2010	2020	2030	2040	2050
Current	37	42	32	14	9
E1: high	37	42	55	72	91
E2: middle	37	49	44	45	45
E3: low	37	41	33	26	15
All quantities are given in GW of installed capacity					

Source: Authors' composition

In Fig. 28-8, the pathways are compared with single figures from other scenarios excluded from this analysis:

- *LTMS Scenarios "Renewable Energy"* and *"Nuclear Energy"* (Hughes et al. 2007), which contain nearly the same coal deployment figures as the *"Growth without constraints" Scenario*;
- The *World Bank scenarios "Reference" and "Baseline"* (vito et al. 2011) which refer to 2030 only. Up to 2020, they follow the Policy Adjusted Scenario of the Integrated Resource Plan (IRP) (DOE 2011b); up to 2030, they develop as pathway *E2: middle* and as a pathway between *E1: high* and *E2: middle*.

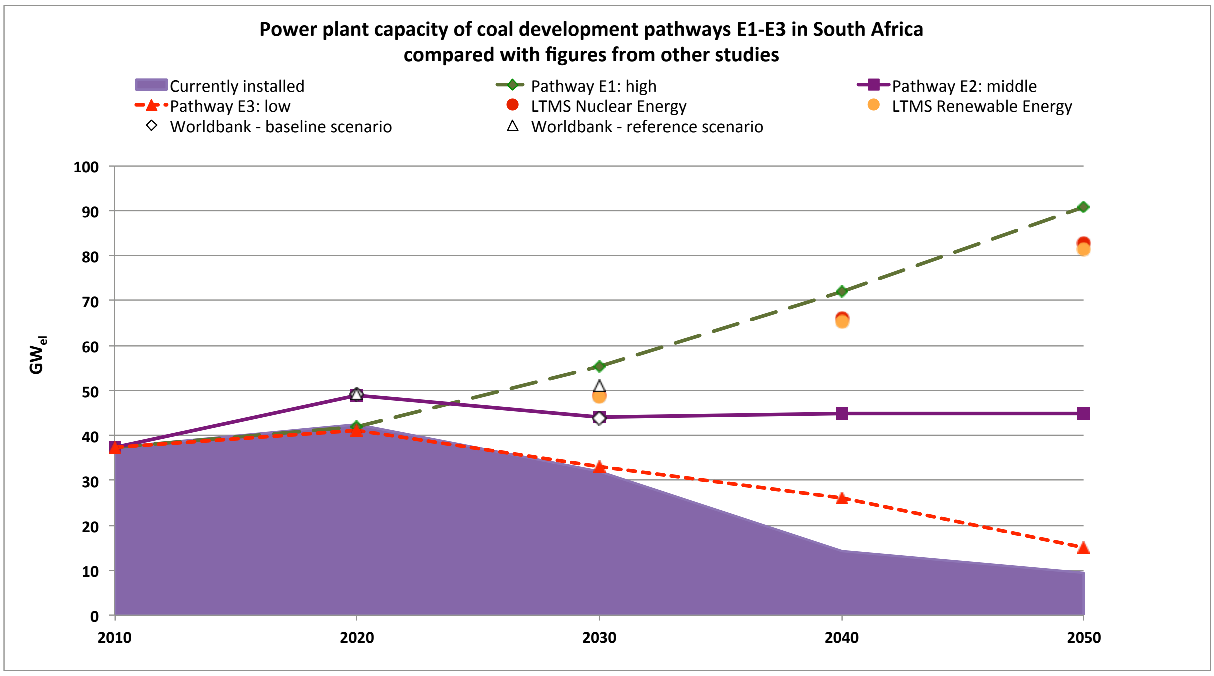


Fig. 28-8 Comparison of coal development pathways E1–E3 with figures from other scenarios in South Africa

Source: Authors' illustration

The coal capacity development illustrated in pathways E1–E3 is taken as the basis for the next step in which an investigation is made into how much CO_2 could be separated in each pathway from the time CCS will be commercially available.

28.4 CO_2 Captured from Coal-Fired Power Plants

28.4.1 Capacity of CCS-Based Power Plants depending on Coal Development Pathways

Basic Assumptions

- **Time of commercial availability** To determine the quantity of CO_2 that could potentially be captured in the future, the possible number of CCS-based power plants is calculated first. Since when CCS will become commercially available is one of the most crucial parameters, this date is varied by way of a sensitivity analysis. *Commercial availability* refers to the time when the complete CCS chain could be in commercial operation, incorporating large-scale CCS-based power plants, transportation and storage. Commercial availability before 2030 seems improbable for South Africa for different reasons:

  Most South African energy experts do not expect CCS to be commercially available in power plants before 2030 (see section 33). Although the South African government recognises the potential of CCS to become an important CO_2 mitigation technology in South Africa and recently announced a "CCS Flagship Programme" (see section 33.2), many hurdles must be overcome over the next one to two decades. Furthermore, South Africa has competing policy targets, such as electrification, affordable electricity supply and resilience to the impacts of climate change (for example water scarcity).

The government's Integrated Resource Plan for Electricity, which outlines South Africa's strategy for the power sector up to 2030, does not include CCS but foresees an expansion of renewable and nuclear energy to meet South Africa's commitments to a low-carbon economy (DOE 2011b).

Furthermore, SACCS' roadmap for a roll-out of CCS in South Africa assumes the commercial operation of CCS in 2025, aiming at one million tonnes of CO_2 to be stored. This amount refers to a power plant of 200 MW only, meaning that up-scaling to a large commercial power plant is required, which may be realised by 2030, or even later.

Some experts from scientific institutions and non-governmental organisations (NGO) also expect a later large-scale availability of CCS at the international level (MIT 2007; Greenpeace International 2008). Even the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) does not expect early commercial projects to be in operation before 2025 in the "standard case" because fully integrated CCS projects, including transportation and storage, would take 6.5 to 10 years to become operational (ZEP 2008). Recently, von Hirschhausen et al. (2012) determined that most demonstration projects planned in the EU have been halted or cancelled or their completion dates are indefinite. However, it seems unlikely that CCS will be applied in South Africa on a broad scale before its deployment has taken off in the industrialised world.

The year 2030 is therefore chosen as the "base case" of the present analysis. This means that CCS will be applied to power plants being built or retrofitted from 2030. To consider possible further delays in the development of the technology, in both industrialised countries and in South Africa, as well as delays in exploration of storage sites, 2035 and 2040 are regarded as sensitivity cases. Tab. 28-3 gives an overview of the resulting pathway combinations.

Tab. 28-3 Sensitivity Analysis I: Varying the time of commercial availability of CCS in South Africa

Commercial	**Coal development pathway**		
availability	**E1: high**	**E2: middle**	**E3: low**
2030	**Base case**	**Base case**	**Base case**
2035	Sensitivity case	Sensitivity case	Sensitivity case
2040	Sensitivity case	Sensitivity case	Sensitivity case

Source: Authors' composition

Furthermore, the following assumptions are considered to be valid for all coal development pathways:

- **Type of power plants** Only supercritical and integrated gasification combined cycle (IGCC) power plants are foreseen for CCS, either retrofitted or newly built. Subcritical power plants are excluded due to their low efficiency (and would be too old to retrofit in any case). Ultra supercritical technology will not be used in South Africa due to problems with the development of materials suitable for 700°C technology (Eskom 2011a). The share of each power plant type is originally based on figures given in the *LTMS Scenario No 1* (Hughes et al. 2007), but the assumptions for IGCC (32 GW in 2035 and 68 GW in 2050) seem quite optimistic. Since IGCC technology is still at the demonstration stage entailing rather high uncertainties, it remains unclear when the technology will become commercially viable. In China, for example, the National Development and Reform Commission (NDRC) has addressed the uptake of the technology rather cautiously due to the higher capital costs incurred compared to advanced PC plants (Minchener 2010). Therefore, the share of IGCC is reduced for 2040 and 2050 and adapted to the development assumed for China (30 per cent in 2040, 40 per cent in 2050). The share of power plants is considered only for calculating the amount of separated CO_2, not for the preceding capacity analysis.

- **Old power plants** Power plants are only retrofitted if the power plants are no older than 12 years (McKinsey 2008). Of the two large power plants currently being built, only Kusile will be worth considering for a retrofit since it was designed “capture-ready” in 2008. The five blocks will come into operation between 2017 and 2020, enabling them to be retrofitted if CCS is introduced in 2030. Kusile will therefore be considered as a CCS-based power plant in 2030 in the base case. However, if CCS is introduced in 2040, Kusile will be too old for retrofitting.

  Regarding power plants that will be built after 2020 and retrofitted later, the following assumptions are made: in the base case, one third of suitable power plants built between 2020 and 2030 will be retrofitted from 2030. In sensitivity case two (CCS from 2040), 50 per cent of suitable power plants built between 2030 and 2040 and 10 per cent of those built between 2020 and 2030 are considered, respectively. The reason for this assumption is that it is unclear whether capture-ready power plants will be built and whether retrofitting will be possible in all cases. Retrofitting would be quite costly and the power plant would have to stand idle for months.

- **New power plants** Since all newly built power plants in South Africa use supercritical technology, they could all theoretically be equipped with CCS. They are all expected to be large point sources (LPS). For this reason, their total number is not reduced further with regard to the minimum size that would be required for CCS. From the time of commercial availability, all LPS will be built as CCS-based power plants.

Tab. 28-4 summarises all figures for the proportions assumed above.

Tab. 28-4 Share of power plants assumed to determine CCS-based power plant capacity

	2020	2030	2040	2050
Share of power plant type (newly built)				
Supercritical	100	90	70	60
IGCC	0	10	30	40
CCS commercially available from 2030				
Newly built power plants that could theoretically be based on CCS	100	100	100	100
Newly built power plants that will be based on CCS	0	0	100	100
Assumed retrofitting rate of CCS	Kusile only	33	0	0
Share of CCS application	Kusile only	33	0	0
CCS commercially available from 2040				
Newly built power plants that could theoretically be based on CCS	100	100	100	100
Share of CCS application if introduced in 2040	0	0	0	100
Assumed retrofitting rate of CCS	0	10	50	0
Share of CCS application	0	10	50	0
All quantities are given in %				

Source: Authors’ composition

- **Location of new power plants** Future CCS-based power plants are distributed proportionately to currently operating power plants, since no plans for any future allocation are known.

The Base Case: CCS available from 2030

Fig. 28-9 shows the resulting CCS-based power plant capacity according to the base case in coal development pathways E1–E3. The figures consist of both newly built CCS power plants and the retrofitted Kusile power plant (4.3 GW). Furthermore, the resulting CCS penalty is illustrated. It should be noted that the figures represent the stock of power plants at the respective time. In the event of CCS this means, for example, that the capacity shown for 2040 is built up between 2030 and 2040. In each of the pathways, the penalty requires an additional power plant capacity of 3 to 17 per cent compared to the total load assumed in the pathways and 22 to 33 per cent compared to the load of power plants equipped with CCS. Tab. 28-5 provides the detailed values.

Tab. 28-5 Installed power plant capacity (with and without CCS), according to coal development pathways E1–E3 in the base case in South Africa (CCS available from 2030)

	2010	2020	2030	2040	2050
E1: high					
Currently installed	37	42	28	10	5
Newly built without CCS	0	0	23	16	16
Newly built with CCS	0	0	0	34	58
Retrofitted with CCS	0	0	4 *)	12	12
[CCS in total	*0*	*0*	*4*	*47*	*70]*
CCS penalty load	0	0	1	8	11
Total	37	42	56	80	102
E2: middle					
Currently installed	37	42	28	10	5
Newly built without CCS	0	7	12	10	10
Newly built with CCS	0	0	0	19	24
Retrofitted with CCS	0	0	4 *)	6	6
[CCS in total	*0*	*0*	*4*	*25*	*30]*
CCS penalty load	0	0	1	4	5
Total	37	49	45	49	50
E3: low					
Currently installed	37	42	28	10	5
Newly built without CCS	0	0	0	0	0
Newly built with CCS	0	0	0	8	8
Retrofitted with CCS	0	0	4 *)	4	4
[CCS in total	*0*	*0*	*4*	*12*	*12]*
CCS penalty load	0	0	1	2	2
Total	37	42	33	24	20

All quantities are given in GW

*) Kusile, which has been designed "capture-ready"

Source: Authors' composition

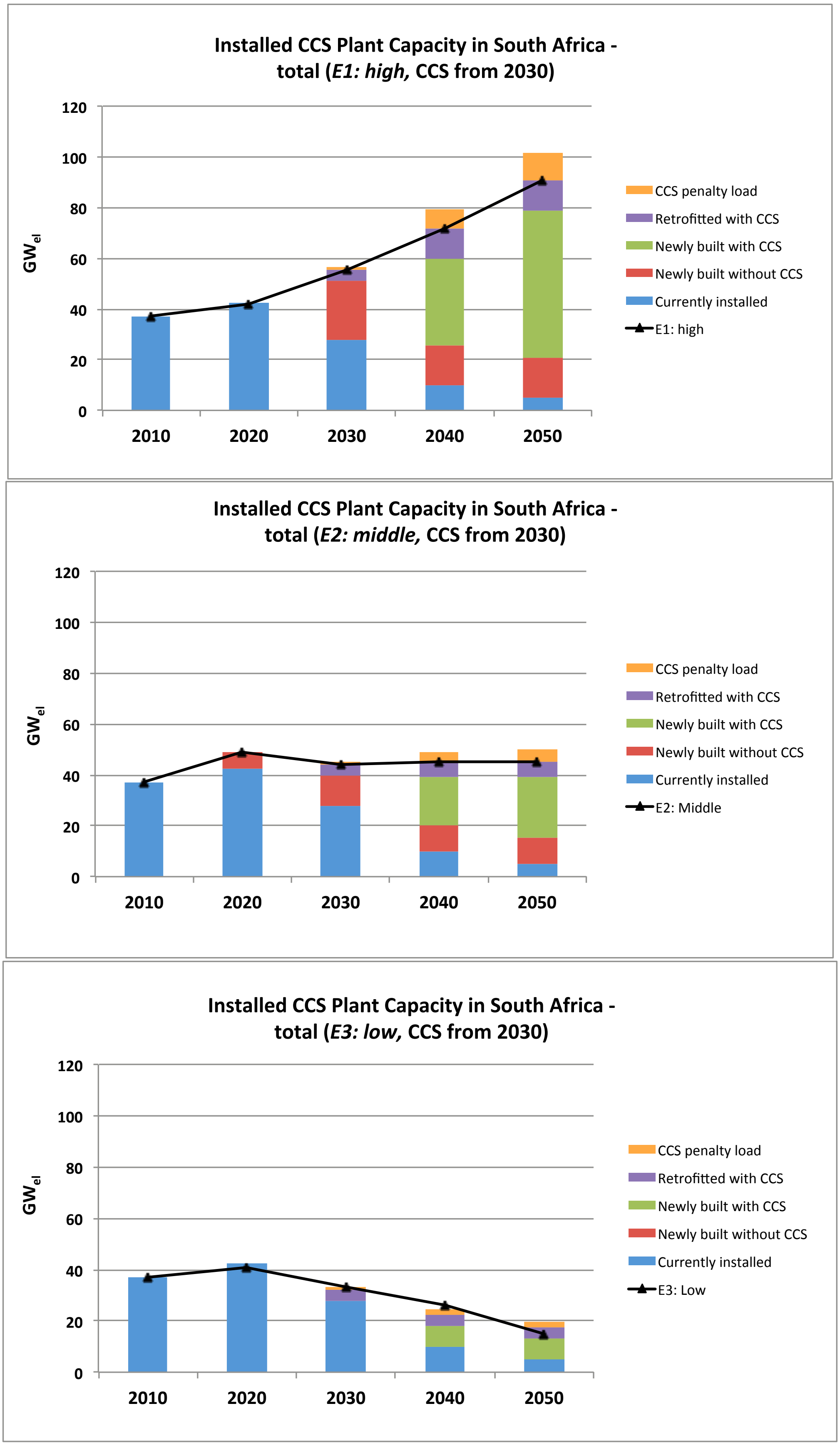


Fig. 28-9 Share of CCS-based power plant capacity and penalty load on total capacity to be installed in the base case in South Africa according to the coal development pathways (CCS available from 2030)

Source: Authors' illustration

28.4.2 Calculating the Quantity of CO_2 to be Captured from Power Plants

In the second step, the quantity of CO_2 that could be separated from both newly built and retrofitted CCS-based power plants is calculated. The calculation is based on the following assumptions:

- **Efficiency of power plants** The assumed efficiencies for supercritical power plants are based on data reported by Eskom for 2010 and 2025 (Eskom 2011a), which comply with most other sources from the literature. In the case of South Africa, it must be considered that only air-cooled technology is used, which decreases the efficiency by 3 percentage points (Eskom 2011a). With IGCC, the efficiency of supercritical power plants increases by 5 percentage points (Tab. 28-6).

Tab. 28-6 Efficiencies assumed for future newly built coal-fired power plants in South Africa

	2010	2020	2030	2040	2050
Supercritical (SC)	38	39	41.5	42	42
IGCC		44	46.5	47	47
All quantities are given in %					

Source: Authors' composition

- **Efficiency losses through CCS** For CO_2 capture and compression an efficiency *loss* ranging from 8.5 to 5 percentage points for the period from 2020 to 2050 is assumed for post-combustion. Pre-combustion ranges from 6.5 to 6 percentage points. This results in an increase in coal consumption between 22 and 15 per cent for the assumed mix of CCS-based power plants between 2030 and 2050. The efficiency losses are derived from various sources (Alstom 2011; IEA and OECD 2009a, 2009b; IEA 2009, 2011; Imperial College 2010; Viebahn 2011). Retrofitting power plants would cost a further efficiency loss of 1.5 percentage points (Viebahn et al. 2010). Combining these figures with the efficiencies of newly built power plants without CCS and the future share of coal-fired power plants (Tab. 28-4) yields the efficiencies for future mixes with and without CCS (Tab. 28-7).

Tab. 28-7 Efficiencies assumed for future newly built coal-fired power plants in South Africa (mix, with and without CCS)

	2010	2020	2030	2040	2050
Mix newly built w/o CCS		39	42	43.5	44
Efficiency penalty post-combustion	12	8.5	7	6	5
Efficiency penalty pre-combustion	8	6.5	6	6	6
Mix newly built, with CCS			35.1	37.5	38.6
Mix newly built, with CCS, retrofit			34.4	38.3	40.1
Efficiencies are given in %, efficiency penalties in % points					

Source: Authors' composition

- **Lifetime of power plants** The technical lifetime, and hence the time available for capturing CO_2 from new power plants, is assumed to be 50 years (Blignaut et al. 2011; DOE 2011b; Eskom 2012). In the event of retrofitting, this equates to a remaining lifetime of a maximum of 32 years.

- **CO_2 capture rate** A CO_2 capture rate of 90 per cent is assumed because it is used most frequently in CCS studies, for example in Dahowski et al. (2009) and Kulichenko and Ereira (2011).
- **Cumulated CO_2** The cumulated amount of CO_2 separated per power plant is calculated by adding the annual CO_2 emissions captured by each power plant over its lifetime.
- **Load factor, capacity factor** Since another crucial parameter is the load factor, this parameter is also varied by way of a sensitivity analysis. As the base case, the figure of 7,000 full load hours for newly built power plants is chosen, which corresponds to a capacity factor of 80 per cent. 6,000 h (69 per cent) and 8,000 h (91 per cent) are regarded as sensitivity cases. Existing figures range between 85 and 88 per cent (Kulichenko and Ereira 2011; Eskom 2011c; Hughes et al. 2007, respectively) but seem too optimistic for the base case. Tab. 28-8 gives a summary of the resulting pathway combinations.

Tab. 28-8 Sensitivity Analysis II: Varying the full load hours (capacity factor) of coal-fired power plants in South Africa

Commercial	Coal development pathway								
availability	E1: high			E2: middle			E3: low		
2030	6,000	**7,000**	8,000	6,000	**7,000**	8,000	6,000	**7,000**	8,000
2035	6,000	7,000	8,000	6,000	7,000	8,000	6,000	7,000	8,000
2040	6,000	7,000	8,000	6,000	7,000	8,000	6,000	7,000	8,000

All quantities are given in h

Cells printed in bold illustrate the base case

Source: Authors' composition

All parameters, including those described above, are summarised in Tab. 28-9.

Tab. 28-9 Basic parameters assumed for calculating captured CO_2 emissions in South Africa

	Unit	Value	Comment
CO_2 capture			
Efficiency loss post-combustion	% pt.	12–5	2010 to 2050
Efficiency loss pre-combustion	% pt.	8–6	2010 to 2050
Additional efficiency loss retrofit	% pt.	1.5	Only if power plant is not older than 12 years.
Capture rate	%	90	
Efficiency			
Mix newly built w/o CCS	%	39–44	2020 to 2050
Mix newly built, with CCS	%	35–39	2030 to 2050
Mix newly built, with CCS, retrofit	%	34–40	2030 to 2050
Load Factor	%	69–91	In Sensitivity Analysis II (equalling 6,000 to 8,000 full load hours)
Technical lifetime	y	50	
Coal quality for South Africa	MJ/kg	19.6	
CO_2 emissions of coal	g/kWh_{th}	347	
Commercial availability of CCS		2030/35/40	In Sensitivity Analysis I

Source: Authors' composition

The Base Case: CCS available from 2030, operating with 7,000 Full Load Hours

The result of the pathway analysis is presented in Tab. 28-10 and Fig. 28-10. For each pathway, the figure shows the increasing amount of separated CO_2 as well as the remaining CO_2 that will not be separated due to the age of the power plants. Tab. 28-10 shows that – depending on the pathway – between 4 and 22 Gt of CO_2 may be available for sequestration in total (second row of table). These figures are calculated assuming only newly built power plants with a technical lifetime of 50 years. Considering only the annual figures (first row of table), between 87 and 455 Mt would have to be transported between sources and sinks in 2050.

Regarding *primary resources*, between 63 and 298 Mt of coal would be required in 2050. Cumulated over the lifetime of all CCS-based power plants, between 5 and 8 Gt of coal would be necessary, calculated using an average net calorific value of the domestically produced coal feedstock of 19.6 MJ/kg (Hughes et al. 2007).

Tab. 28-10 Separated CO_2 emissions and consumption of coal in South Africa, according to coal development pathways E1–E3 in the base case (CCS available from 2030, operation with 7,000 full load hours, lifetime of 50 years)

	Unit	E1: high	E2: middle	E3: low
CO_2 separated annually in 2050	Mt/a	455	194	87
CO_2 separated, cumulated	Gt	22	9	4
Coal consumed annually in 2050	Mt/a	298	159	63
Coal consumed cumulated	Gt	8	6	4
Coal consumed cumulated, w/o CCS	Gt	8	6	4

A net calorific value of 19.6 MJ/kg for South African coal was used to calculate the consumption of coal.

Source: Authors' composition

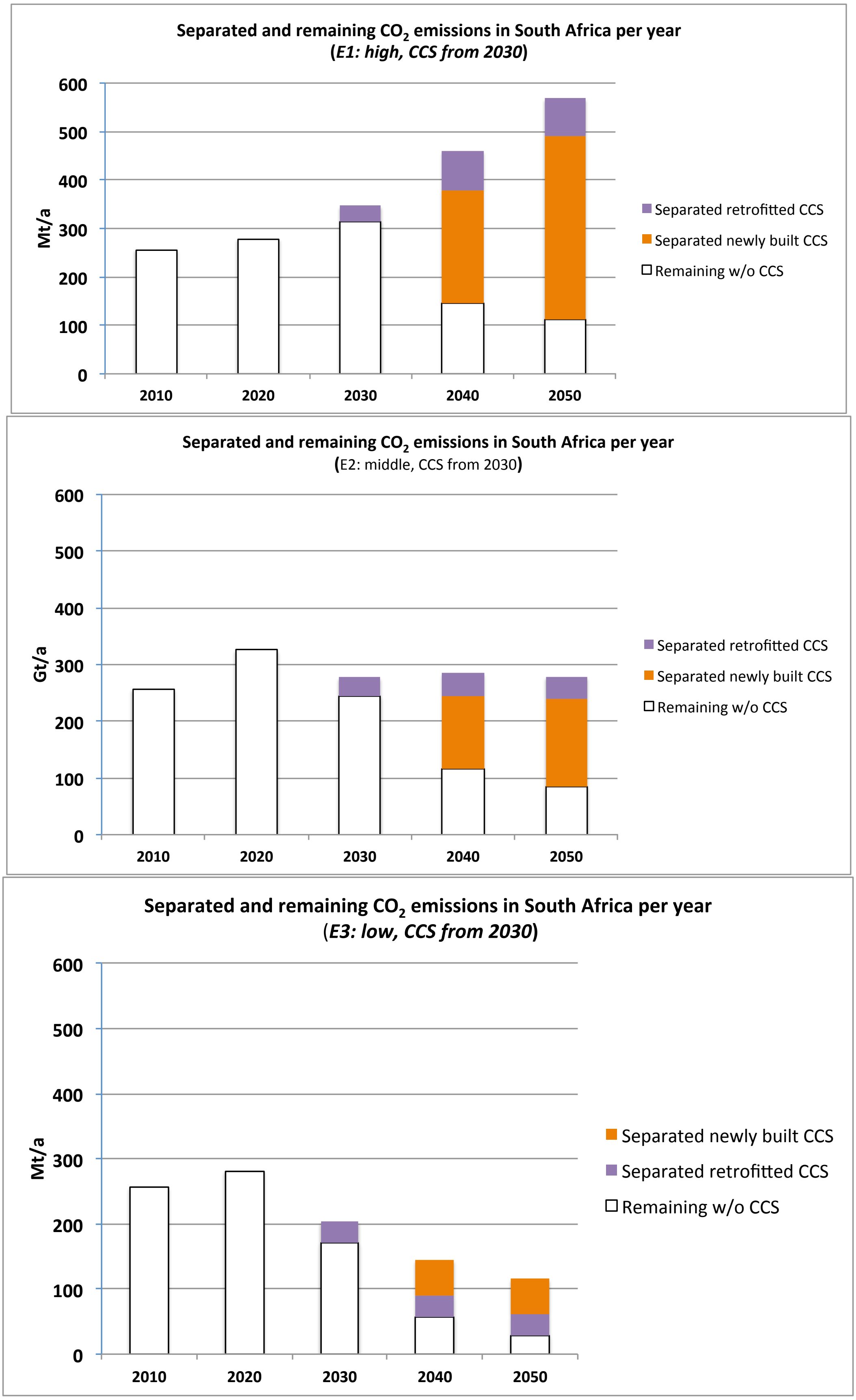


Fig. 28-10 Separated and remaining CO_2 emissions from coal-based electricity production in the base case in South Africa (CCS available from 2030)

Source: Authors' illustration

Sensitivity Cases

Finally, all sensitivity cases are presented. Tab. 28-11 shows the large spectrum between the lowest value (1 Gt CO_2, marked green) and the highest value (27 Gt CO_2, marked red). A general conclusion is that the more CO_2 is separated, the higher the full load hours are and the earlier CCS is available. Considering the two sensitivity cases, the following differences can be seen:

- Varying the operation time by 1,000 full load hours decreases or increases the amount of CO_2 captured by 14 per cent;
- Launching CCS in 2035 or in 2040 instead of in 2030 decreases the quantity of CO_2 captured by 20 to 50 per cent or by 40 to 80 per cent, respectively.

Tab. 28-11 Separated CO_2 emissions in South Africa (cumulated), according to coal development pathways E1–E3 in all sensitivity cases

	6,000 full load hours			7,000 full load hours			8,000 full load hours		
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**
CCS from 2030	19	8	3	**22**	**9**	**4**	**25**	11	5
CCS from 2035	15	6	2	17	7	2	20	8	3
CCS from 2040	11	3	**1**	12	4	1	14	4	1
All quantities are given in Gt CO_2									

Source: Authors' composition

The same is true for the consumption of coal, presented in Tab. 28-12. Depending on the pathway and sensitivity case, between 4 Gt and 10 Gt of coal will be required.

Tab. 28-12 Consumption of coal in South Africa (cumulated), according to coal development pathways E1–E3 in all sensitivity cases

	6,000 full load hours			7,000 full load hours			8,000 full load hours		
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**
No CCS	6	5	4	8	6	4	9	7	5
CCS from 2030	7	5	**4**	**8**	**6**	**4**	**9**	7	5
CCS from 2035	7	5	**4**	8	6	4	**9**	7	5
CCS from 2040	7	5	**4**	8	6	4	**9**	7	5
All quantities are given in Gt of coal A net calorific value of 19.6 MJ/kg for South African coal is used to calculate the consumption of coal.									

Source: Authors' composition

28.5 CO_2 Captured from Industrial Sites

Only little information is available to develop industrial coal development pathways. Only data on efficiency potentials are published for the *non-synfuel industry*. No figures are available on use of CCS in these industries (Kornelius et al. 2007; OECD and IEA 2008).

The situation is different when it comes to South Africa's *CTL industry*. In this case, CCS is widely considered an ideal opportunity for applying CCS since carbon capture is an integrated process component that reduces the cost penalty of carbon capture and storage. CTL plants are highly CO_2-intensive; the total amount of CO_2 currently captured at the facilities is estimated at 50 million tonnes of CO_2 per year, 30 million tonnes of which are highly concentrated (SACCCS 2011a). Other sources report a production of 160,000 barrels per day (bbl/d) from the Secunda plant, which generates 22 to 23 million of tonnes of highly concentrated stream (Kornelius et al. 2007) and which is seen as the only contribution of CCS possible within a low carbon scenario in South Africa (Scenario Building Team 2007). However, some treatment is still required to remove carbide and sulphurous compounds (H_2S) (SACCCS 2011b). Such treatment would lead to additional environmental benefits (Sasol 2011a), which is why additional industrial coal development pathways are devised.

- *Pathway I1: high*: For the “high carbon” pathway I1 the assumption of the *Long-Term Mitigation Scenario No 1 “Growth Without Constraints”* is taken. There, five new CTL plants, each with a capacity of 80,000 bbl/d, which is half of Secunda’s capacity, are commissioned between 2014 and 2038. Since it would take at least six years to construct one plant (Hughes et al. 2007), the commissioning years are assumed to be 2014, 2020, 2026, 2032 and 2038. It is assumed that the existing Secunda plant will be decommissioned before 2030 (Fossil Fuel Foundation 2011), which is why it is excluded from the possible CCS capacity. Otherwise it could be too old, meaning that a retrofit with additional facilities required for CCS would not pay off. As reported in Kornelius et al. (2007), each new CTL plant of the assumed size would produce approximately 11 Mt/a of CO_2 as concentrated stream. The cumulated amount of CO_2 emissions captured per decade and per lifetime of the plants (50 years) is calculated based on this figure.
- *Pathway I2: middle*: For the “middle carbon” pathway I2 it is assumed that only one new CTL plant will be built before 2020, namely the Mafutha plant, which has been under discussion for many years (Fossil Fuel Foundation 2011; Hughes et al. 2007).
- *Pathway I3: low*: No new CTL plants are assumed in the “low carbon” pathway I3.

Tab. 28-13 shows how much CO_2 will be separated from each plant and in total; Tab. 28-14 summarises the cumulated CO_2 emissions for each pathway I1–I3.

Tab. 28-13 Assumptions concerning newly built CTL plants in South Africa and their cumulated emissions in industrial coal development pathways I1–I3

	Total	2020	2030	2040	2050	2060	2070	2080
	Mt	Mt/10a	Mt/10a	Mt/10a	Mt/10a	Mt/10a	Mt/10a	Mt/10a
Highly concentrated CO_2 emissions								
New CTL plant 1		110	110	110	110	110		
New CTL plant 2		110	110	110	110	110		
New CTL plant 3			110	110	110	110	110	
New CTL plant 4				110	110	110	110	110
New CTL plant 5				110	110	110	110	110
Captured CO_2 emissions in pathway I1: high								
CCS from 2030	2,530		330	550	550	550	330	220
CCS from 2035	2,365		165	550	550	550	330	220
CCS from 2040	2,200			550	550	550	330	220
Captured CO_2 emissions in pathway I2: middle								
CCS from 2030	440		110	110	110	110		
CCS from 2035	385		55	110	110	110		
CCS from 2040	330			110	110	110		
Captured CO_2 emissions in pathway I3: low								
CCS from 2030	0							
CCS from 2035	0							
CCS from 2040	0							

Assumptions:
- In pathway I1, five CTL plants are commissioned, namely in 2014, 2020, 2026, 2032 and 2038.
- In pathway I2, only one CTL plant is commissioned in 2014.
- In pathway I3, no new CTL plants are built.
- Each CTL plant has a lifetime of 50 years and provides a highly concentrated annual stream of 11 Mt CO_2.

Source: Authors' composition

Tab. 28-14 Separated CO_2 emissions from industry in South Africa (cumulated), according to industrial development pathways I1–I3 in the three sensitivity cases

	I1: high	I2: middle	I3: low
CCS from 2030	2.53	0.44	0
CCS from 2035	2.37	0.39	0
CCS from 2040	2.20	0.33	0

All quantities are given in Gt CO_2

Source: Authors' composition

28.6 Conclusions

Finally, all sensitivity cases regarding coal development pathways E1–E3 and industrial development pathways I1–I3 are presented (Tab. 28-15). In the base case, the industrially separated CO_2 emissions amount to 10 to 15 per cent (E1/I1: high) and 3 to 5 per cent (E2/I2: middle) of emissions caused by the power sector.

Tab. 28-15 Separated CO_2 emissions in South Africa (cumulated), according to coal development pathways E1–E3 and industrial coal development pathways I1–I3 in all sensitivity cases

	6,000 full load hours			**7,000 full load hours**			**8,000 full load hours**					
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**I1: high**	**I2: middle**	**I3: low**
CCS from 2030	19	8	3	**22**	**9**	**4**	**25**	11	5	2.5	0.4	0
CCS from 2035	15	6	2	17	7	2	20	8	3	2.4	0.4	0
CCS from 2040	11	3	**1**	12	4	1	14	4	1	2.2	0.3	0

All quantities are given in Gt CO_2

Source: Authors' composition

As mentioned above, the figures are not based on the authors' energy scenario analysis. Instead, individual coal development pathways based on different existing energy scenarios were selected. At present, the scenarios published by EREC and Greenpeace International (2011) are the only ones that consider a long-term development up to 2050 and that are based on the actual development of power plants in South Africa. The figures presented should therefore be updated as soon as complete long-term energy scenarios exist for South Africa. These should consider different deployment pathways of CCS and their interaction with an increasing amount of renewables and nuclear energy.

Furthermore, it should be noted that, due to the extent of uncertainty surrounding the future development of South Africa's energy system, an "if ... then" approach was performed. The analysis shows which consequences would have to be accounted for if different strategies (coal development pathways) were realised. In the event of a "high coal" strategy, this would means the huge deployment of facilities for CO_2 capture, transportation and storage within a short period; the "low coal" strategy would imply a moderate deployment, which in itself is ambitious, too.

29 Matching the Supply of CO_2 to Storage Capacities

29.1 Introduction

After having identified possible opportunities for storing CO_2 (section 27) and future coal development pathways for South Africa (section 28), these two estimates are now combined. Due to the extent of uncertainty surrounding sinks in particular, qualitative source-sink matching is conducted. The aim is to determine how much of the estimated storage capacities could be used for storing CO_2 emissions separated from the flue gas of both coal-to-liquid plants and power plants in South Africa. In section 29.2, the storage scenarios are briefly covered. This is followed by a summary of the coal development pathways and the resulting CO_2 emissions (section 29.3). The methodology used for source-sink matching is then given, explained thoroughly and conducted for both power plants and industrial sources (section 29.4). The results of this match are discussed in section 29.5 and a conclusion of the source-sink match is given in section 29.6.

29.2 Overview of Storage Scenarios

For South Africa, the CO_2 storage atlas (Cloete 2010) and the more detailed technical report (Viljoen et al. 2010) provide the best estimates to date, forming the basis for the storage scenarios in the present study. S1, the high scenario, includes the results of the storage atlas (excluding coalfields) with a total estimate of 148.7 Gt of CO_2 (see Tab. 29-1). The intermediate estimate S2 amounts to 59.4 Gt of CO_2 with storage potential in aquifers only. The calculation is based on the storage atlas, but applies a lower efficiency factor of 4 per cent instead of the rate of 10 per cent used there. The most conservative storage scenario S3 applies an efficiency of 1 per cent. In this scenario, only offshore aquifers provide sufficient storage capacity, totalling 14.8 Gt. Gas and oil fields provide insufficient storage capacity in both S2 and S3. As is always the case in scenario modelling, it should be borne in mind that a value given in a scenario does not necessarily mean that this value will be realised at some point. Scenario analyses are usually performed to illustrate roughly how the situation could develop.

Tab. 29-1 Overview of storage scenarios S1–S3 for South Africa

Formation		S1: high	S2: intermediate	S3: low	Distance from emission cluster
		Gt CO_2	Gt CO_2	Gt CO_2	km
Oil		-	-	-	
Gas		0.2	-	-	> 1,000
Onshore aquifers	Algoa	0.4	0.2	-	900
	Zululand	0.4	0.2	-	300–500
Offshore aquifers	Outeniqua	48.4	19.3	4.8	> 1,000
	Orange	57.1	22.8	5.7	> 1,200
	Durban & Zululand	42.3	16.9	4.2	450–600
Total		148.7	59.4	14.8	> 1,000

All quantities are given in Gt CO_2

The efficiency factors selected for aquifers are 10% (S1), 4% (S2) and 1% (S3).

Source: Authors' calculation based on Viljoen et al. (2010)

In addition, Tab. 29-1 includes the approximate distances from the emission cluster in Southern Mpumalanga to the sinks listed. The closest distance is about 400 km to Zululand onshore basin on the east coast. Other basins, such as Outeniqua and Orange offshore basins in the south and south-west, are situated over 1,000 km from the emission cluster (see Fig. 29-1).

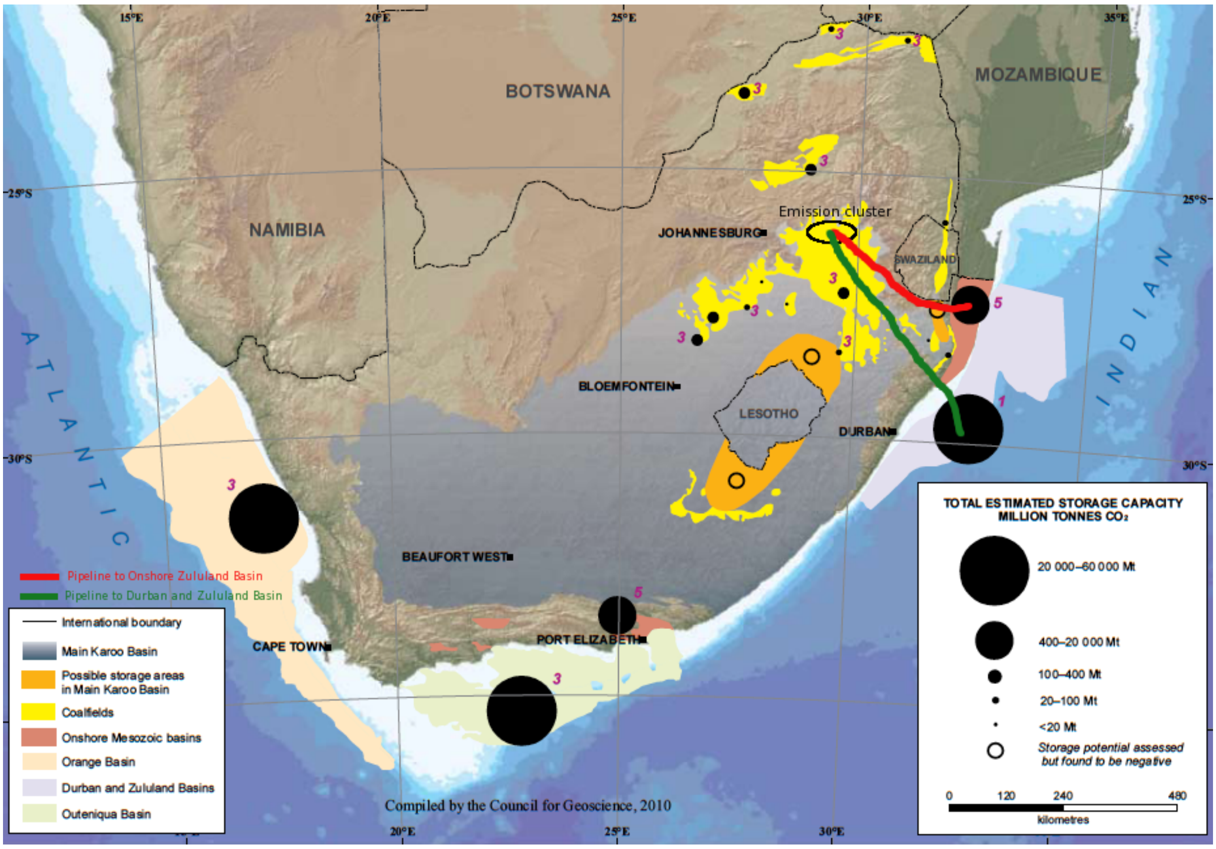


Fig. 29-1 Sedimentary basins in South Africa, potential storage capacity and possible pipelines between CO_2 sources and storage sites

Source: Modified based on Viljoen et al. (2010)

Experts in South Africa are also discussing the possibility of transporting CO_2 to sinks in neighbouring countries such as Botswana and Mozambique. Sasol analysed the potential storage capacities in Mozambique, which are about 600 km from its CTL plants (Council for Geoscience 2011). This is no closer than storing CO_2 on South Africa's coast, and would require a legal framework that is not yet in place, as discussions on CCS have not even started there (SACCCS 2011a).

Considering these long transport distances and the costs that would be involved, only the *onshore Zululand basin* and *offshore Zululand & Durban basin* are selected for source-sink matching (see pipelines in Fig. 29-1 which are drawn arbitrarily and are not based on any current plans). These basins are within 300 to 600 km of the sources. No potential storage capacity in neighbouring countries is considered.

29.3 Overview of Coal Development Pathways

The three coal development pathways described in section 28 are based on different long-term scenario studies for South Africa's future energy situation. However, in contrast to energy scenarios, the pathways are only used to illustrate the different CCS development possibilities to obtain an understanding of the level of separated CO_2 emissions that could be available for storage in the future. The project's remit did not allow new and consistent energy scenarios including CCS to be developed from scratch for South Africa. Furthermore, it was assumed that the current spatial distribution of the power plants and CTL plants will be maintained in the future.

Of the different cases considered in the pathways, only the base case is used for source-sink matching (CCS commercially available from 2030; 7,000 full load hours of operation per year). It is assumed that CCS-based *power plants* will be built up to 2050, when the last power plant with a CO_2 capture unit will be constructed. The emissions are added together for 50 years of operation, meaning that CO_2 is captured from 2030 for the first plants up until 2100, when the units built last in 2050 will be decommissioned. The cumulative emissions between 2030 and 2100 are derived in three pathways: a high coal pathway E1, a middle coal pathway E2 and a low coal pathway E3. In total, it is estimated that 22, 9 and 4 Gt of CO_2 would be captured from power plants for CO_2 sequestration in pathways E1, E2 and E3, respectively.

Concerning industrial sites, only the *synfuel industry* is included by providing industrial coal development pathways that consider different exploitation pathways for CTL plants. The base case considers the commercial availability of CCS from 2030. Again, emissions are added together for 50 years of operation. The cumulative emissions between 2030 and 2100 are derived in three pathways: a high coal pathway I1, a middle coal pathway I2 and a low coal pathway I3. In total, it is estimated that 2.5, 0.4 and 0 Gt of CO_2 would be captured from CTL plants for CO_2 sequestration in pathways I1, I2 and I3, respectively.

Combining both options, the amount of CO_2 captured totals 24.3 (E1+I1), 9.7 (E2+I2) and 4 Gt of CO_2 (E3+I3). Tab. 29-2 presents all sensitivity cases regarding both coal development pathways E1–E3 and industrial development pathways I1–I3.

Tab. 29-2 Separated CO_2 emissions in South Africa (cumulated), according to coal development pathways E1–E3 and industrial coal development pathways I1–I3 in all sensitivity cases

	6,000 full load hours			**7,000 full load hours**			**8,000 full load hours**					
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**I1: high**	**I2: middle**	**I3: low**
CCS from 2030	19	8	3	**22**	**9**	**4**	**25**	11	5	2.5	0.4	0
CCS from 2035	15	6	2	17	7	2	20	8	3	2.4	0.4	0
CCS from 2040	11	3	**1**	12	4	1	14	4	1	2.2	0.3	0

All quantities are given in Gt CO_2

Source: Authors' calculation

Most CO_2 emissions are linked to only one region of South Africa in the southern part of Mpumalanga Province. This is the region where the majority of the country's coal mines are located. To conduct source-sink matching, the industrial production facilities and power plants are clustered and the centre of the cluster is connected virtually via a pipeline to potential storage sites (compare Fig. 28-2).

29.4 Methodology of Source-Sink Matching

The geographic match of sources and sinks is conducted threefold. Firstly, the match is limited to emissions from power plants (section 29.4.1). Secondly, projected emissions from coal-to-liquid facilities are matched with sinks (section 29.4.2). Finally, both emission sources are combined and matched with the two potential storage basins (section 29.4.3).

29.4.1 Matching Emissions from Power Plants

Most of the current power plants are located close together in the south of Mpumalanga, which is why the source-sink match is based on the emission cluster identified above (Fig. 28-2). Tab. 29-3 shows the comparison of storage scenario S1 with coal development pathways E1–E3. First, the onshore Zululand basin is filled with 0.4 Gt of CO_2 in each scenario. The offshore Durban & Zululand basin is then filled until all emissions have been stored. The matched capacity amounts to 22.0, 9.3 and 4.0 Gt of CO_2 for pathways E1, E2 and E3, respectively.

Tab. 29-3 Source-sink match of storage scenario S1 with three different coal development pathways from power plants in South Africa

Formation		**S1: high**	**E1: high** (23.3)	**E2: middle** (9.9)	**E3: low** (4.5)
Zululand	Onshore basin	0.4	0.4	0.4	0.4
Durban & Zululand	Offshore basin	42.3	21.6	8.9	3.6
Total		42.7	22.0	9.3	4.0
All quantities are given in Gt CO_2					

Source: Authors' calculation with data from Viljoen et al. (2010)

Matching the intermediate storage scenario S2 with the identified emissions, a similar picture can be seen for the combination with E2 and E3 (Tab. 29-4) as for S1. All captured emissions in these two pathways (9.3 and 4.0 Gt CO_2) can be stored. Regarding pathway E1, the available storage capacity is insufficient for storing the entire amount of captured emissions. Hence 17.1 Gt of CO_2 is the matched capacity for E1.

Tab. 29-4 Source-sink match of storage scenario S2 with three different coal development pathways from power plants in South Africa

Formation		**S2: intermediate**	**E1: high** (23.3)	**E2: middle** (9.9)	**E3: low** (4.5)
Zululand	Onshore basin	0.2	0.2	0.2	0.2
Durban & Zululand	Offshore basin	16.9	16.9	9.2	3.9
Total		17.1	17.1	9.3	4.0
All quantities are given in Gt CO_2					

Source: Authors' calculation with data from Viljoen et al. (2010)

In contrast to S1 and S2, low storage scenario S3 does not include onshore capacity; hence only 4.2 Gt of CO_2 is available in the offshore Durban & Zululand basin (Tab. 29-5). The total estimated emissions captured therefore exceed the storage space available for E1 and E2. Thus the matched capacity for S3 equals the total storage capacity of 4.2 Gt of CO_2 in these two cases. For E3, it was possible to store the entire quantity of emissions of 4.0 Gt of CO_2.

Tab. 29-5 Source-sink match of storage scenario S3 with three different coal development pathways from power plants in South Africa

Formation		S3: low	E1: high (23.3)	E2: middle (9.9)	E3: low (4.5)
Zululand	Onshore basin	0.0	0.0	0.0	0.0
Durban & Zululand	Offshore basin	4.2	4.2	4.2	4.0
Total		4.2	4.2	4.2	4.0
All quantities are given in Gt CO_2					

Source: Authors' calculation with data from Viljoen et al. (2010)

29.4.2 Matching Emissions from Coal-to-Liquid Plants

The match for South Africa's coal-to-liquid plants is conducted in the same way as for power plants. Emissions from CTL plants are captured in only two out of three industrial coal development pathways, I1 and I2. These amount to 2.4 and 0.4 Gt of CO_2, respectively, cumulated over 50 years of operation. The selected sinks are Zululand and Zululand & Durban basin, resulting in a total storage capacity of 42.7, 17.1 and 4.2 Gt of CO_2 for storage scenarios S1, S2 and S3, respectively. For the source-sink match, each storage scenario is taken separately and combined with the two coal development pathways I1 and I2 (see Tab. 29-6 to Tab. 29-8).

Matching commences by comparing the high storage scenario S1 with pathways I1 and I2. First of all, the onshore Zululand basin is filled with emissions because it is closer to the source and easier to access. In pathway I2, the space available would be sufficient for all of the CO_2 to be injected; this is not the case for I1. Hence for I1, the offshore Zululand & Durban basin is then used to sequester the remaining quantity of emissions.

The onshore capacity turns out to be insufficient when matching emissions from the identified coal development pathways with the intermediate storage scenario S2. Offshore capacity is therefore required to store all of the emissions. This is also the case for the low storage scenario S3, where no onshore capacity is available.

Nonetheless, in all cases, the entire quantity of CO_2 emissions captured can be stored either onshore or offshore in the provided space available in the storage scenarios.

Tab. 29-6 Source-sink match of storage scenario S1 with three different coal development pathways for CTL plants in South Africa

Formation		S1: high	I1: high (2.4)	I2: middle (0.4)	I3: low (0.0)
Zululand	Onshore basin	0.4	0.4	0.4	0.0
Durban & Zululand	Offshore basin	42.3	2.0	0.0	0.0
Total		42.7	2.4	0.4	0.0
All quantities are given in Gt CO_2					

Source: Authors' calculation with data from Viljoen et al. (2010)

Tab. 29-7 Source-sink match of storage scenario S2 with three different coal development pathways from CTL plants in South Africa

Formation		S2: intermediate	I1: high (2.4)	I2: middle (0.4)	I3: low (0.0)
Zululand	Onshore basin	0.2	0.2	0.2	0.0
Durban & Zululand	Offshore basin	16.9	2.2	0.2	0.0
Total		17.1	2.4	0.4	0.0
All quantities are given in Gt CO_2					

Source: Authors' calculation with data from Viljoen et al. (2010)

Tab. 29-8 Source-sink match of storage scenario S3 with three different coal development pathways from CTL plants in South Africa

Formation		S3: low	I1: high (2.4)	I2: middle (0.4)	I3: low (0.0)
Zululand	Onshore basin	0.0	0.0	0.0	0.0
Durban & Zululand	Offshore basin	4.2	2.4	0.4	0.0
Total		4.2	2.4	0.4	0.0
All quantities are given in Gt CO_2					

Source: Authors' calculation with data from Viljoen et al. (2010)

29.4.3 Combined Matching Emissions from Coal-to-Liquid and Power Plants

After having compared the separate emissions from power plants and CTL facilities with potential sinks, the two emissions are combined in this section. The same emission cluster as identified above is used and matched with the Zululand onshore basin and Zululand & Durban offshore basin.

Since emissions captured from CTL plants are only minor in comparison to power plant emissions, a similar picture as in section 29.4.1 is obtained. First of all, the high storage scenario S1 is matched with the three different coal development pathways E1+I1, E2+I2 and E3+I3. Since the available emissions are lower than the total storage capacity, all emissions can be stored. The matched capacity for S1 is therefore 24.3 (E1+I1), 9.7 (E2+I2) and 4.0 Gt of CO_2 (E3+I3).

The intermediate storage capacity S2 is then matched with the three pathways. Qualitatively, the same results are obtained as for power plants. All of the emissions from coal development pathways E2+I2 and E3+I3 can be stored. For the high emission pathway E1+I1, the storage capacity is insufficient and only 17.1 Gt matched capacity is achieved. The other matched capacities are 9.7 (E2+I2) and 4.0 Gt of CO_2 (E3+I3), as in the high storage scenario.

Finally, the low storage scenario is compared to the coal development pathways. There, the emissions can only be fully stored in the low pathway E3+I, which results in a matched capacity of 4.0 Gt of CO_2. Insufficient storage space is available for the other two cases, and the matched capacity equals the available storage capacity (4.2 Gt). This is the same result as for power plants only.

To conclude, if sufficient storage space is available, the matched capacity is slightly higher because CTL emissions are added. This is the case for S1 and partly for S2 (with the exception of E1+I1). In the other cases (S2 with E1+I1 and all matches with E3), the same results are yielded as for power plants only.

29.5 Overall Results

A comparison of storage scenarios and development pathways from both CTL plants and power plants is given below (Tab. 29-9 to Tab. 29-11). The separated CO_2 emissions in each coal development pathway are given at the top of each table. The available storage capacities within a distance of 600 km are shown on the left. The tables are divided into two parts. In the upper part, the calculated matched capacities are shown in the corresponding fields of the table. In the lower part, the share of the estimated corresponding emission pathway and of the corresponding storage scenario is given. This overview shows how much of the available storage space is taken and how much of the CO_2 captured could be sequestered.

Power Plants

In Tab. 29-9, the comparison is performed with emissions captured from power plants, which are much higher than those from CTL plants. This leads to high matched capacities for all coal development pathways. The space utilised for CO_2 sequestration can be seen in the percentage values of "share of effective storage capacity used." Only 3 to 29 per cent of the space is used. This is mainly due to the fact that only two basins are available for storage within the selected range of 600 km.

The "share of emissions to be stored" is 100 per cent in six out of nine cases. Only the match of the low storage scenario S3 with the high and middle pathway E1 and E2 gives a lower share of emissions than 50 per cent.

Coal-to-Liquid Plants

Tab. 29-10 shows that all CO_2 emissions available from CTL plants can be stored, yielding an identical matched capacity in all pathways. The share of effective storage capacity used is very low. The highest share (16 per cent) is estimated for combination I1/S3.

Combining Coal-to-Liquid and Power Plants

As Tab. 29-11 shows, the results of the source-sink match from a combination of coal-to-liquid and power plants is very similar to power plant matching only. The proportion of storage space used increases slightly by 1 percentage point for combinations S1/E1+I1 and S1/E2+I2 only. The share of emissions stored decreases slightly by 1 or 2 percentage points (S3/E2+I2, S3/E1+I1) and 4 or 8 percentage points (S2/E2+I2, S2/E1+I1), respectively. This is due to the increased amount of captured CO_2 emissions available. Qualitatively, the same conclusions can be drawn as for power plants.

Tab. 29-9 Results of matching potential CO_2 emissions captured from power plants with storage scenarios; share of total storage capacity and supply in South Africa

Effective storage capacity scenarios	Power plant emissions from coal development pathways E1: high (22 Gt CO_2)	E2: middle (9 Gt CO_2)	E3: low (4 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (149 Gt CO_2)	22	9	4
S2: intermediate (59 Gt CO_2)	17	9	4
S3: low (15 Gt CO_2)	4	4	4
	Share of effective storage capacity used (%)		
S1: high (149 Gt CO_2)	15	6	3
S2: intermediate (59 Gt CO_2)	29	16	7
S3: low (15 Gt CO_2)	29	29	27
	Share of emissions that can be stored (%)		
S1: high (149 Gt CO_2)	100	100	100
S2: intermediate (59 Gt CO_2)	78	100	100
S3: low (15 Gt CO_2)	19	45	100
The maximum transport distance is assumed to be 600 km.			

Source: Authors' calculation

Tab. 29-10 Results of matching potential CO_2 emissions captured from CTL plants with storage scenarios; share of total storage capacity and supply in South Africa

Effective storage capacity scenarios	CTL emissions from coal development pathways I1: high (2 Gt CO_2)	I2: middle (0.4 Gt CO_2)	I3: low (0 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (149 Gt CO_2)	2	0.4	0
S2: intermediate (59 Gt CO_2)	2	0.4	0
S3: low (15 Gt CO_2)	2	0.4	0
	Share of effective storage capacity used (%)		
S1: high (149 Gt CO_2)	2	0	-
S2: intermediate (59 Gt CO_2)	4	1	-
S3: low (15 Gt CO_2)	16	3	-
	Share of emissions that can be stored (%)		
S1: high (149 Gt CO_2)	100	100	-
S2: intermediate (59 Gt CO_2)	100	100	-
S3: low (15 Gt CO_2)	100	100	-
The maximum transport distance is assumed to be 600 km.			

Source: Authors' calculation

Tab. 29-11 Results of matching potential CO_2 emissions captured from power and CTL plants with storage scenarios; share of total storage capacity and supply in South Africa

Effective storage capacity scenarios	Power plant and CTL emissions from coal development pathways		
	E1+I1: high (24 Gt CO_2)	**E2+I2: middle** (10 Gt CO_2)	**E3+I3: low** (4 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (149 Gt CO_2)	24	10	4
S2: intermediate (59 Gt CO_2)	17	9	4
S3: low (15 Gt CO_2)	4	4	4
	Share of effective storage capacity used (%)		
S1: high (149 Gt CO_2)	16	7	3
S2: intermediate (59 Gt CO_2)	29	16	7
S3: low (15 Gt CO_2)	29	29	29
	Share of emissions that can be stored (%)		
S1: high (149 Gt CO_2)	100	100	100
S2: intermediate (59 Gt CO_2)	70	96	100
S3: low (15 Gt CO_2)	17	44	100

The maximum transport distance is assumed to be 600 km.

Source: Authors' calculation

29.6 Conclusion

The elaborations above show that the estimate of South Africa's storage potential is very uncertain due to a lack of detailed geological data. The Storage Atlas, which is the most advanced estimate for South Africa, provides an available *effective* capacity of 150 Gt of CO_2, nearly all of which results from offshore saline aquifers calculated by applying an efficiency factor of 10 per cent. To consider some of the uncertainties using a sensitivity analysis, three storage scenarios are developed. These mainly differ by the efficiency factors used for the saline aquifer assessment (1, 4 and 10 per cent), which show the fraction of the total pore volume that can effectively be used. Gas and oil fields play a tangential role, whilst storage in coal seams was excluded from all scenarios due to the extent of technical uncertainties involved. This storage possibility is still at the laboratory stage and has not yet been proven to work in situ. Due to the lack of geological data in South Africa, any calculations of storage capacity values can only be highly speculative and therefore should be treated with caution. In total, the effective storage capacity of scenarios S1 to S3 ranges from 15 to 149 Gt of CO_2.

Due to the considerable uncertainty surrounding both sources and sinks, the source-sink match is performed only qualitatively. Given these constraints, storage scenarios S1 to S3 are matched with three coal development pathways E1 to E3 and three industrial coal development pathways I1 to I3, as well as combinations of both. The maximum distance between the sources and sinks is restricted to 600 km, which means that only two basins, *onshore Zululand basin* and *offshore Zululand & Durban basin*, can be used for the source-sink match. This reduces the effective capacity to between 4 and 43 Gt of CO_2.

Matching CO_2 emissions from the coal development pathways with the reduced effective capacity of the three storage scenarios yields the following results:

- With the *lowest effective storage capacity* (S3 = 15 Gt, based on an efficiency factor of 1 per cent for aquifers), 19 to 100 per cent of CO_2 emissions captured from power plants (resulting in 4 Gt) and 100 per cent of emissions captured from CTL plants (resulting in 0.4 to 2 Gt) could be sequestered. For power plants and CTL combined, 17 to 100 per cent of the captured emissions could be stored permanently (resulting in 4 Gt of CO_2). Between 27 and 29 per cent of the storage sites would be filled with emissions from power plants and from power plants combined with CTL emissions; between 3 and 16 per cent of the sinks would be filled with CTL emissions only.
- With the *intermediate effective storage capacity* (S2 = 59 Gt based on an efficiency factor of 4 per cent), 78 to 100 per cent of the CO_2 emissions captured from power plants (resulting in 4 to 17 Gt) and all emissions captured from CTL plants (resulting in 0.4 to 2 Gt) could be sequestered. Between 70 and 100 per cent of the captured emissions could be stored from power plant and CTL facilities combined (resulting in 4 to 17 Gt of CO_2). Between 7 and 29 per cent of the storage sites would be filled with emissions from power plants and from power plants and CTL emissions; between 1 and 4 per cent would be filled with CTL emissions only.
- With the *high effective storage capacity scenario (S1 = 149 Gt,* based on an efficiency factor of 10 per cent) all captured CO_2 emissions (resulting in 4 to 22 Gt for power plants, 0.2 to 4 Gt for CTL plants and 4 to 24 Gt for power plants and CTL plants together) could be sequestered. Between 3 and 15 per cent of the storage sites would be filled with emissions from power plants, between 0 and 2 per cent for CTL emissions and between 3 and 16 per cent for emissions from power plants and CTL.

In general, 100 per cent of emissions can be stored in most cases. The low storage scenario is the only one where – for coal development pathways E1 and E2 – less than 50 per cent of emissions could be stored. The emissions in these pathways could only be fully sequestered with the high storage scenario. The share of effective storage capacity used is less than 30 per cent in all cases because only the two closest sinks with a transport distance of less than 600 km are included in the source-sink match.

It is not clear at present whether CTL plants or power plants would be the preferred “candidates” for a roll-out of CCS. Most South African experts consider CTL to be an ideal opportunity for applying CCS because carbon capture is an integrated process component that reduces the cost penalty of CCS. Also in the Long-term Mitigation Scenarios of the South African government, capturing 22 million tonnes of CO_2 per year from the Secunda plant is the only CCS option considered to date.

In contrast, the South African CCS roadmap allows for a CO_2 test injection of only 10,000 tonnes of CO_2, followed by a small demonstration project in 2020 and a small commercial CCS project in 2025 in which 1 million tonnes of CO_2 would be stored (see chapter 33). CTL has not yet been included in the roadmap. Eskom was requested by the World Bank to design Kusile power plant, which is currently under construction, as “capture-ready.” When it is retrofitted with carbon capture, it will provide between 20 and 24 million tonnes of separated CO_2 per year, which is in the same dimension as Secunda’s CO_2 stream.

However, the oft-cited highly concentrated CO_2 stream of Secunda must be considered under the constraint that the existing CTL plant may be decommissioned around 2030, the time when CCS is expected to become commercially available. Otherwise, it would be too old to make retrofitting viable. For this reason, CTL will only be an option for CCS if new CTL plants are erected, for example, the Mafutha plant which has been under discussion for many years. Mafutha would have half of Secunda's capacity, providing 11 million tonnes of separated CO_2. It could therefore make sense to combine the ideal opportunity of a new CTL plant with setting up a CCS strategy for power plants to start rolling out CCS with Mafutha and Kusile, together delivering 31 to 35 million tonnes of CO_2 per year.

When using other formations other than the selected Zululand basin and Durban & Zululand basin, the relocation of emission sources closer to potential sinks should be considered. As mentioned above, it was assumed in the coal development pathways that the future spatial distribution of both power plants and industrial sites is the same as present because they are closely linked to coal reserves. In general, any relocation of emission sources should take into account how far each medium should be transported. It would be necessary to differentiate between transporting electricity, fuel (coal, lignite or natural gas), separated CO_2 emissions or even cooling water (which could become a serious problem in the event of an increasing number of steam power plants, even without use of CCS). If the overall objective were to store as much CO_2 as possible, an optimisation model is required to determine the cost optimal solution. However, any potential environmental and social problems must also be taken into consideration.

Interpreting these results, two further constraints should be noted:

- In the given source-sink match, only the base case coal development pathways are considered, equating to a commercial availability of CCS from 2030 and an operation of 7,000 full load hours per year for power plants. If CCS availability is delayed to 2035 or 2040, the CO_2 emissions available for storage will be 20 to 50 or 40 to 80 per cent lower, respectively. If an operation of only 6,000 full load hours is yielded (load factor of 69 per cent) or if the optimistic assumption of 8,000 full load hours is achieved (load factor of 91 per cent), the quantity of separated CO_2 emissions would decrease or increase by 14 per cent.

- To date, only a qualitative match of CO_2 sources and sinks has been performed. The transport distances have not been proven in detail, and are based only on rough estimates, taking into account a maximum distance of 600 km. For a more profound assessment, a geographic information system (GIS) should be used and fed with data on the exact locations of power plants and industrial sites. This information could be combined with more detailed information on geological basins, if available in the future, to reduce transport distances between sources and sinks and to increase the certainty of estimates.

In the future, further steps must be taken to achieve a better and more detailed assessment, enabling a "real" matched capacity to be derived:

- Carry out an in-depth investigation of each basin and field to obtain detailed information on the geological underground;

- Determine more detailed locations of possible storage sites within the basins to enable more precise and quantitative source-sink matching to be conducted;

- Derive a practical storage potential (top layer of the storage pyramid) considering economic conditions, potential problems regarding acceptance in the regions concerned and technical feasibility problems.

Finally, the practical capacity will be much lower than the effective capacity derived in this report. Until these details are explored, even the lowest effective storage capacity scenario S3 should not be considered as an upper variant of what could be realised in South Africa – the final figures, and therefore the final results, of source-sink matching may actually be considerably lower.

30 Assessment of the Reserves, Availability and Price of Coal

30.1 Introduction

Up to the early 2000s, South Africa ranked amongst the top five countries with the largest coal reserves worldwide, after which its reserves were revised downwards considerably. This section gives a short description of the development of coal reserves and the history of production. Worsening production conditions indicate an imminent production peak. These tendencies will have a severe impact on the global coal market because South Africa is also one of the world's top coal exporting countries. Finally, a price extrapolation is given based on the scenario assumptions published in the latest World Energy Outlook 2011 of the International Energy Agency (IEA).

30.2 Coal Quality and Coal Washeries

30.2.1 Coal Quality

Most coal seams in South Africa are relatively thick and close to the surface. A quarter of South Africa's bituminous coal is less than 50 m below the surface. Most of the remaining coal is between 50 and 200 metres below surface. Approximately half of production comes from opencast mines. A major problem is the high ash content. This means that all exported coal needs to be washed to reduce the ash content to below 15 per cent. The heating value of exported coal was around 26 MJ/kg (6,200 kcal/kg) in the past. However, average values are declining, with some exported coal having a heating value of around 24.7 MJ/kg (5,900 kcal/kg). Sulphur contents are between 0.6 and 0.7 per cent.

Thermal coal used for domestic power and coal-to-liquid production have much lower calorific and higher ash values. These are mainly supplied from the middle product (known as middlings) obtained in a double washing process. Possibly only one third is run-of-mine coal to the power stations (Eberhard 2011; Falcon 2012). Hughes et al. (2007) reported 19.6 MJ/kg (4,680 kcal/kg), whilst Anglo American states 19 MJ/kg on average used by Eskom (Anglo American 2011a).

30.2.2 Coal Washeries

Coal from the Waterberg field has ash content of 55 to 65 per cent. In general, the high ash content of South Africa's coal requires washing, at least for export purposes. Based on an analysis of coal mining operations, about 50 per cent of South Africa's coal is washed (DME 2009).

30.3 Coal Resources and Reserves

Reserve estimates vary widely from as much as 55 Gt to as little as 15 Gt. About 96 per cent of the reserves are bituminous; the quality of the remainder is metallurgical or anthracite (Eberhard 2011). The oft-cited statistics from BP Statistical Review of World Energy are given below, which are identical to the World Energy Council Reports (WEC). More detailed statistics are provided by the Geological Survey of South Africa and the Department of Mines and Economics. These are discussed below.

30.3.1 Reserve Reporting by World Energy Council

Fig. 30-1 gives the development of proven recoverable coal reserves according to the World Energy Council in its latest editions from 1989 onwards (WEC 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2009, 2010). Up to 2000, the reported reserves remained almost unchanged at about 60 billion tonnes. However, over the last decade the reserves were revised downwards considerably several times. At the end of 2010, reported reserves totalled only half of the amount reported ten years previously.

The dark bars in the figure cover cumulative coal production since 1990. This is to ensure that downwards revisions are due to a reassessment of reserves. The inclusion of cumulative production has only a marginal impact on the reserve assessment. Compared to coal production in 1990, the static reserve-to-production ratio (R/P) in South Africa was still 350 years. Due to the downwards revisions in line with steeply rising coal production, the R/P ratio declined from 350 years to less than 110 years in 2010.

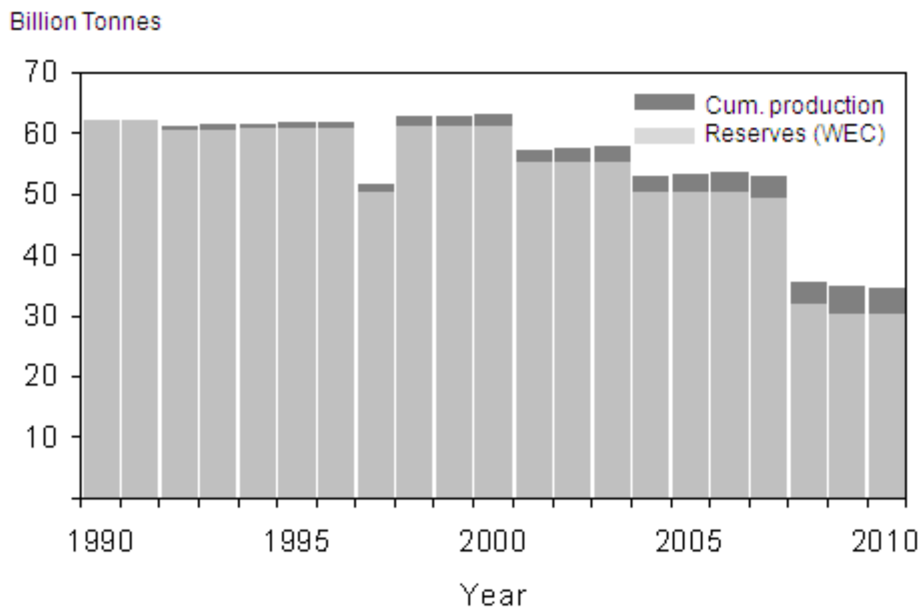


Fig. 30-1 Historical development of "proven recoverable coal reserves" in South Africa, as reported by the World Energy Council and reproduced in BP Statistical Review of World Energy. The cumulative production over the reporting period is added to the reserves

Sources: WEC (1989, 1992, 1995, 1998, 2001, 2004, 2007, 2009, 2010), BP (2010)

30.3.2 Resource Reporting by the South African Geological Survey

Fig. 30-2 shows how "identified resources" developed, as reported by Statistics South Africa. These reserves are based on a reserve assessment by the Geological Survey South Africa in 1987 (Bredell 1987). Later reserves are calculated on that basis (Jeffrey 2005). Each year, annual production is consistently deducted from the remaining reserves at the end of the year. The grey line represents reserves according to the reports of Statistics South Africa published up to 2001 (Statistics South Africa 2008).

In March 2000, a new codification of mineral resource and reserve reporting was established by the South African Mineral Resource Committee, the so-called "SAMREC Code" (SAMREC 2007). Based on this codification scheme, the Minerals Bureau began a reassessment of the coal resource and reserve estimates (Prevost 2003).

Between 2003 and 2005, the Department of Mining and Energy incrementally reduced South Africa's coal reserves from about 50 to 26 Gt. Later revisions resulted in minor reserve adjustments. In the 2007 yearbook, reserves at the end of the year were reported at 27,981 Gt (Statistics South Africa 2008).

Further adjustments according to produced volumes predicted reserves at the end of the year 2010 to be 27,221 Gt (SAMI 2008, 2010). The consistent decline in reserves between 1990 and 2010, including the backdated downwards revisions, is represented by the black line in the figure. For comparison, bars with broken lines represent reserve assessments as reported by the World Energy Council and BP.

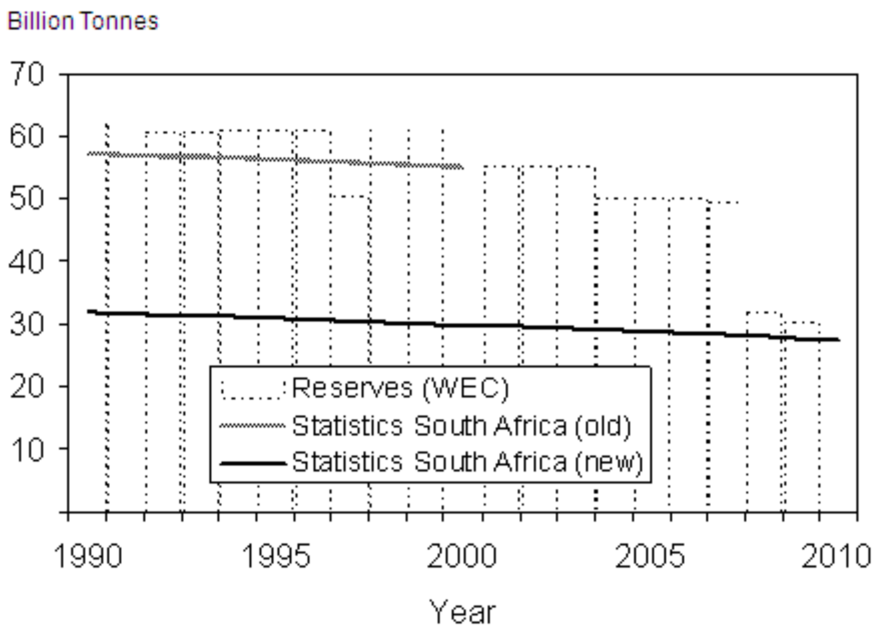


Fig. 30-2 Historical development of "proven recoverable coal reserves" in South Africa, as reported by the World Energy Council and reproduced in BP Statistical Review of World Energy (dotted bars). This is compared to the reserves reported by the South African Department of Mining and Energy (DME)

Sources: WEC (1989, 1992, 1995, 1998, 2001, 2004, 2007, 2009, 2010), BP (2010), SAMI (2008, 2010)

30.3.3 Company Reserves at Individual Mines

About 70 per cent of coal reserves are concentrated in the Waterberg, Witbank and Highveld coalfields. Smaller amounts can be found in the Ermelo, Free State and Springbok Flat coalfields. However, the Witbank coalfield is already maturing (Jeffrey 2005). Fig. 28-2 in section 28 provided a survey of the geographical location of South Africa's coalfields. Based on the old reserve classification, the distribution of reserves is shown in Tab. 30-1.

Although reserves are still sufficient to provide coal for more than 100 years at the present production rate, extraction conditions are deteriorating. This is evident in a more detailed analysis of the company resources of BHP and Anglo. A summary of their reserves is given in Tab. 30-2, which disaggregates reserves and resources into different categories, from proven reserves to inferred resources. These companies' production volume accounts for 40 per cent of total production, the aggregated reserves for about one third.

Tab. 30-1 Distribution of South Africa's coal reserves

Coalfield	Percentage of reserve %	Percentage of current production %
Witbank	22.5	~ 50
Highveld	19.8	~ 20
Waterberg	28	~ 9
Vereeniging-Sasolburg	4	~ 9
Ermelo	8.5	~ 8
Klip River	1.2	< 1
Vryheid	0.4	
Utrecht	1.2	
South Rand	1.3	
Somkhele&Nongoma	0.2	
Soutpansberg	0.5	
Kangwane	0.3	
Free State	9	
Springbok Flats	3.1	
Limpopo	0.2	

Source: Jeffrey (2005)

Tab. 30-2 Classification of BHP and Anglo's reserves

	Proven	Probable	Measured	Indicated	Inferred
Reserves	1,854	750	2,095	2,130	2,106
Cumulative	0	2,604	4,699	6,869	8,934
All quantities are given in Mt coal					

Source: F&F (2010)

Fig. 30-3 shows the further disaggregation into open cast and underground mines. In addition, the contribution of each individual mine is shown. This analysis shows that proven reserves are predominantly concentrated at operating open cast mines. However, future reserves, made up of the categories indicated and inferred, increasingly focus on underground mines. Due to the technological and logistical problems involved, underground mines have a much lower labour productivity than open cast mines. It is therefore obvious that declining production volumes from open cast mines and their continual substitution by underground mines is bound to raise production costs and reduce labour productivity. When these problems can no longer be adequately counteracted by technological progress and increased specific energy consumption, they will result in a declining overall production rate.

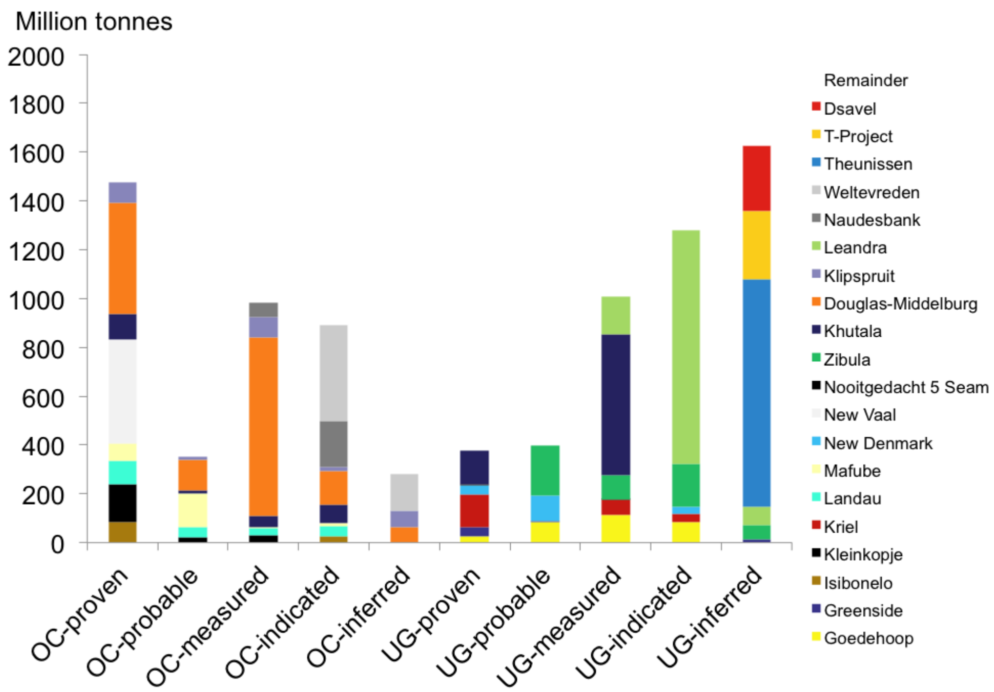


Fig. 30-3 Reserves of coal mining companies attributed to individual mines and classified according to the mine classification (proven, probable, measured, indicated and inferred): OC=open cast mine, UG= underground mine

Source: F&F (2010)

Fig. 30-4 shows South Africa's coal production between 1950 and 2010. Triggered by the high oil prices in the 1970s, coal production increased primarily for electricity and coal-to-liquid production. The supply of coal to fuel production became the dominant driver from around 1976 (see Fig. 30-5). The figure shows the supply of coal to electricity production, liquid fuel production and direct domestic use. In parallel, coal exports also rose during the 1970s, making South Africa a top supplier of the world's coal markets.

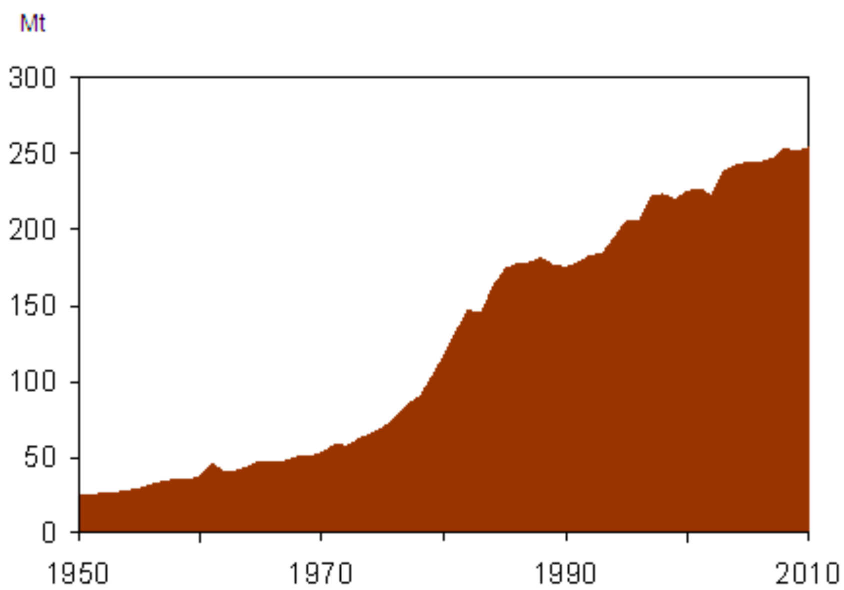


Fig. 30-4 Production of coal in South Africa

Source: DME (2009)

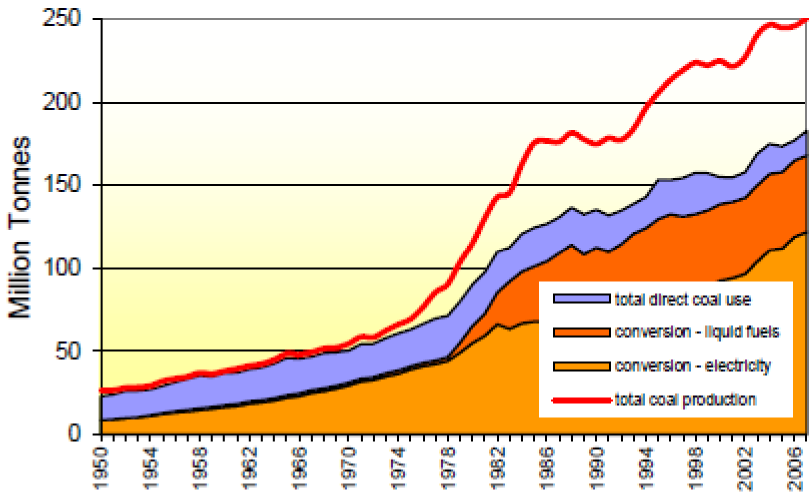


Fig. 30-5 Coal consumption of domestic coal consumers and coal exports from South Africa

Source: Eberhard (2011)

30.3.4 Regional Aspects of Coal Production in South Africa

Almost 40 companies produce coal in South Africa (DME 2009). However, more than 80 per cent of production is mined by the five largest companies. Their 2010 production is given in Fig. 30-6. Anglo American is by far the largest producer, covering 25 per cent of total production. The 30 producers not explicitly shown in Fig. 30-6 account for only 15 per cent of total production.

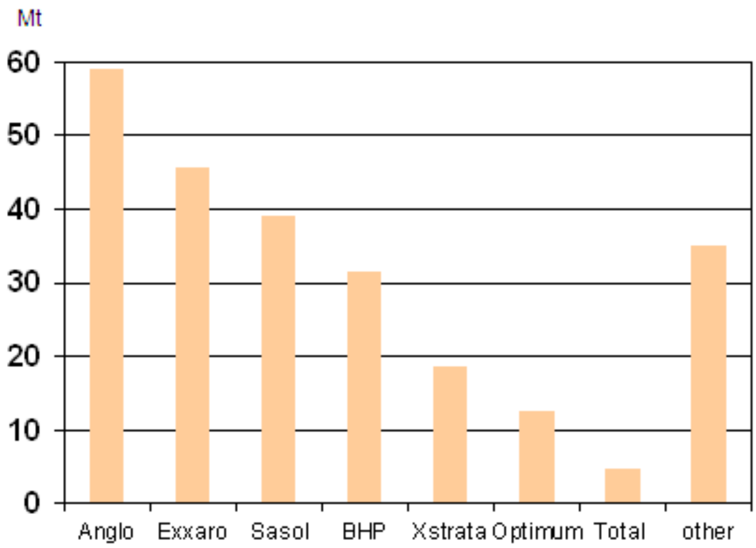


Fig. 30-6 Coal production in South Africa in 2009 attributed to individual mining companies

Source: F&F (2010)

However, important assets of some of the large mining companies are mature. BHP Billiton, ten years ago by far the largest producer, experienced an almost 30 per cent decline in production volumes over the last decade. Since 2001, only Anglo American, Exxaro and the small companies have seen a considerable increase of production volumes. Total production has virtually stagnated for several years. Fig. 30-7 shows how production has developed since 2001.

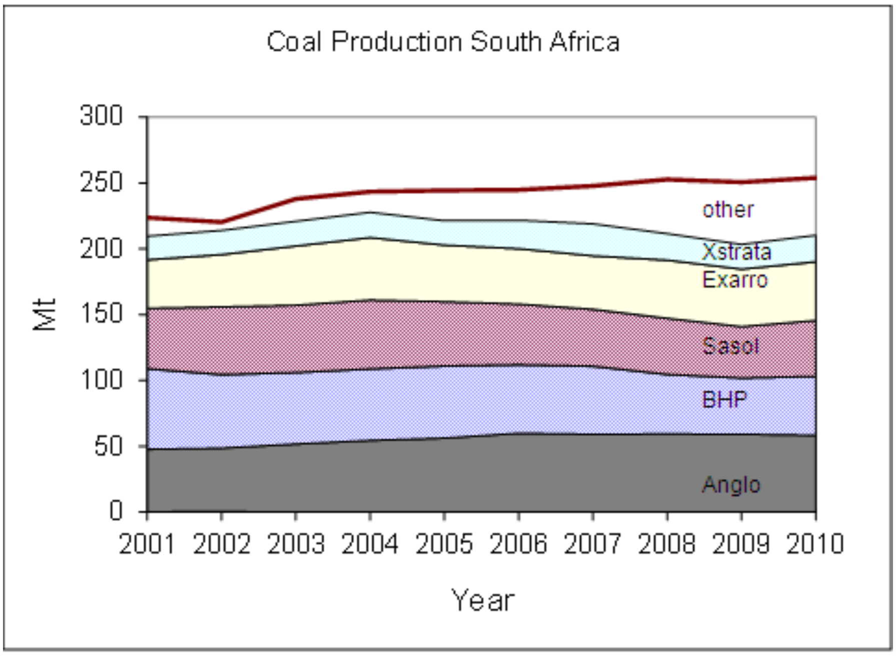


Fig. 30-7 Coal production in South Africa showing the five largest producers

Sources: F&F (2002, 2003, 2004, 2005, 2007, 2008, 2009, 2010)

30.3.5 Productivity

The labour productivity of coal production in South Africa steadily increased up to 2003, when it peaked. Between 2003 and 2010 it declined by almost 30 per cent, or 5 per cent per year. Today it is at the same level as in 1995. The reasons for this decline in productivity are the maturing coal mines, as discussed above (see Fig. 30-3).

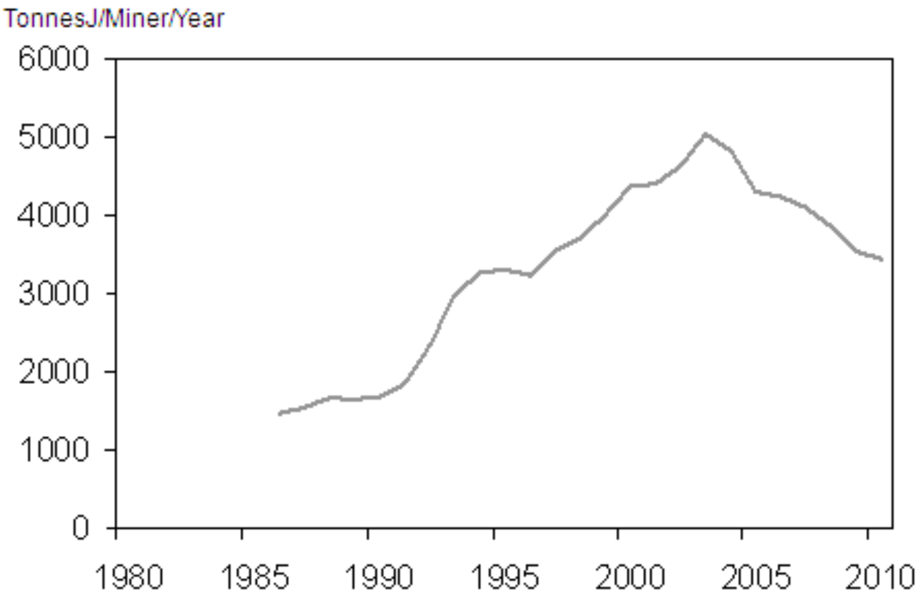


Fig. 30-8 Labour productivity in South Africa's coal mining industry

Sources: (F&F 2008, 2009, 2010; Statistics South Africa 2008)

30.4 Price Development

30.4.1 General Aspects

The market price of coal depends primarily on coal quality, heat content and the efforts required to transport it. Prices for different coal categories should therefore not be compared. Basically, the price per tonne is valid for a specific coal grade. The higher the heating value, the lower the ash and sulphur contents, and the better the consistency of coal, the higher its market value.

Coking coal is traded at much higher prices than non-coking coal. Due to the much higher productivity of open pit mining, these mines perform economically better than underground mines.

Nevertheless, for reasons of comparison, various regional benchmark prices are common. In Europe, the Amsterdam, Rotterdam, Antwerp (ARA) price acts as a benchmark. This is a weighted price for coal imports free on board (FOB) in Amsterdam, Rotterdam and Antwerp. The German Federal Office of Economics and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle – BAFA) publishes the monthly average price for coal imported at the German border, which is usually closely oriented to the ARA price.

Two other marker prices are the export price of South African coal at Richards Bay (the so-called RB Index) and the export price of Australian coal at the Port of Newcastle (the so-called Newcastle Index). In Asia, particularly at Chinese ports, prices are more specific. Import prices should therefore be compared individually for a specific port.

30.4.2 Historical Price Development

In recent decades, the price of coal developed roughly in line with the price of crude oil. It rose during the oil price shocks in 1973 and 1979, followed by an almost 50 per cent price drop after 1980. Around 2000, the price of coal in Europe was at an all-time low of about 30 EUR per tonne. Shortly after 2000, the coal price started to increase steadily, with an interruption around 2003. From 2007 to July 2008, the price of coal more than doubled, followed by a downturn in line with the global economic recession, triggered in part by the high oil and coal prices. In 2009 and 2010, however, the coal price rose again, and is still high compared to the pre-2008 level. Fig. 30-11 shows this development for coal imported at the German border and the ARA price. The BAFA price is converted from its original units of t-hce (tonnes of hard coal equivalent) to physical tonnes by equating 1 t-hce (or tSKE in German) to 29.31 MJ.

In Fig. 30-10 the price comparison focuses on the period from 2007 to 2011. The price for coal imported to Europe (ARA) is compared with prices for coal exported from South Africa (Richards Bay) and the Port of Newcastle (Australia). The price of crude oil on the New York Mercantile Exchange (NYMEX) is shown for comparison.

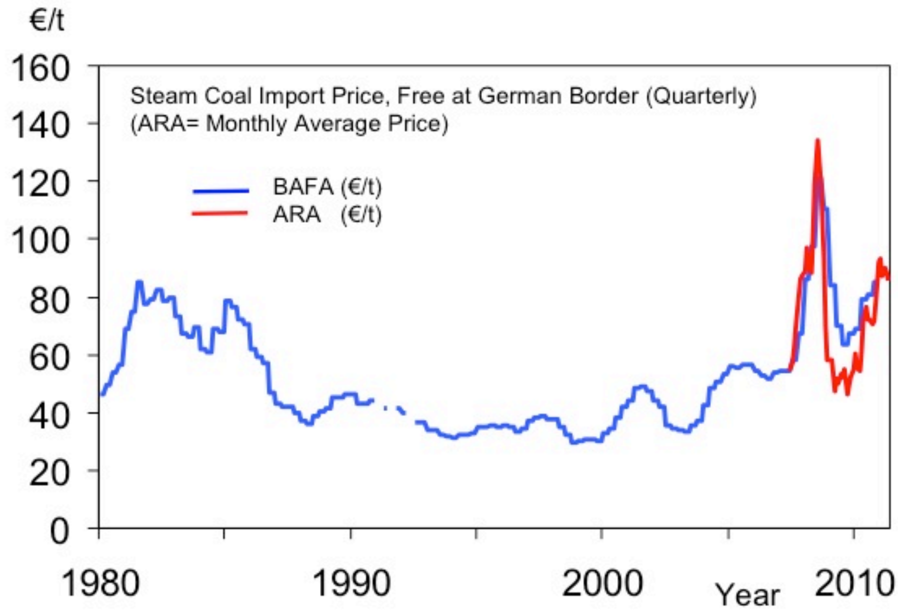


Fig. 30-9 Price development of coal imported to Europe: BAFA = price free at German border; ARA = price free at Amsterdam, Rotterdam, Antwerp

Sources: BAFA (2011) and Global Coal (2010)

The high price for importing coal to Europe in 2007 and 2008 reflects high American export prices combined with high shipping rates. In 2010, the European coal price was below the prices of coal exported from South Africa and Australia for a short period, illustrating the influence of regional market conditions: due to India and China's growing import demand, coal at terminals with orders from these countries cost more than coal from terminals serving European countries, predominantly not in exchange with South Africa and Australia (coal from eastern USA and Canada or from Poland, Russia and Ukraine).

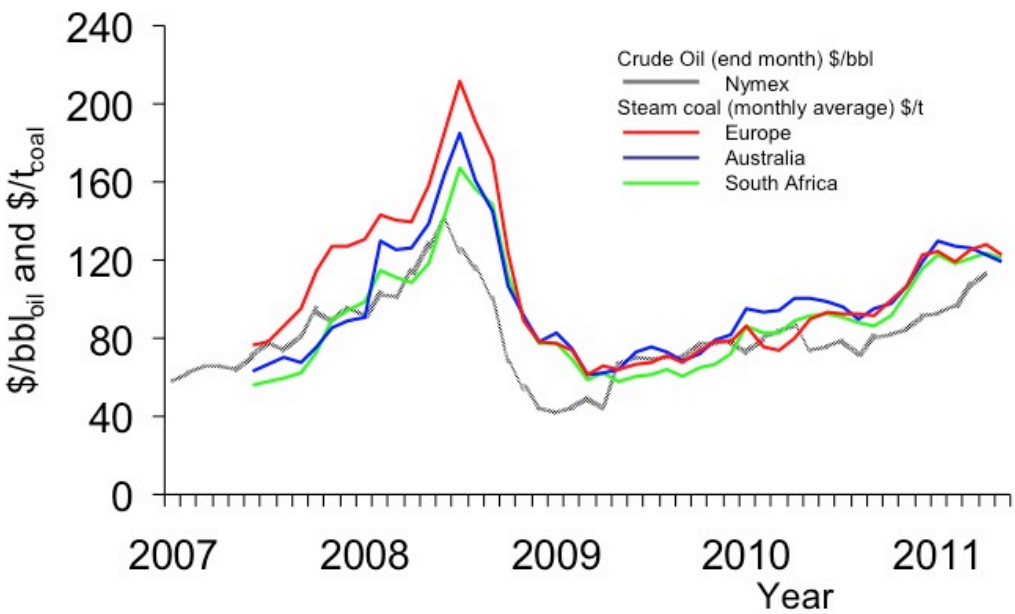


Fig. 30-10 Development of coal prices in Europe, Australia and South Africa compared to the price of crude oil (NYMEX)

Sources: Nymex (2011) and Global Coal (2011)

The price of coal developed roughly in line with the price of crude oil. However, during the price spike in summer 2008, the price of coal rose even more sharply than the price of oil. This could be an indication that the price increase was driven by a direct rise in demand in Asia in addition to the rising price of oil – which certainly triggered some substitution effects. During the second half of 2010, coal prices in Europe (ARA), South Africa (RB) and Australia (Newcastle) almost coincided. Even more importantly, however, during this period coal prices increased more rapidly than oil prices. On a rough scale, oil prices reflect demand for transport needs, whilst coal prices reflect demand for electricity. At that level, it seems that demand for electricity has risen more rapidly than demand for fuel.

Due to the high import prices, China reduced its coal imports in the first four months of 2011 by about 25 per cent against the same period in 2009. According to news media, this resulted in severe electricity shortages in many parts of the country, forcing the government to facilitate imports by reducing taxes and harbour fees (Dradio 2011).

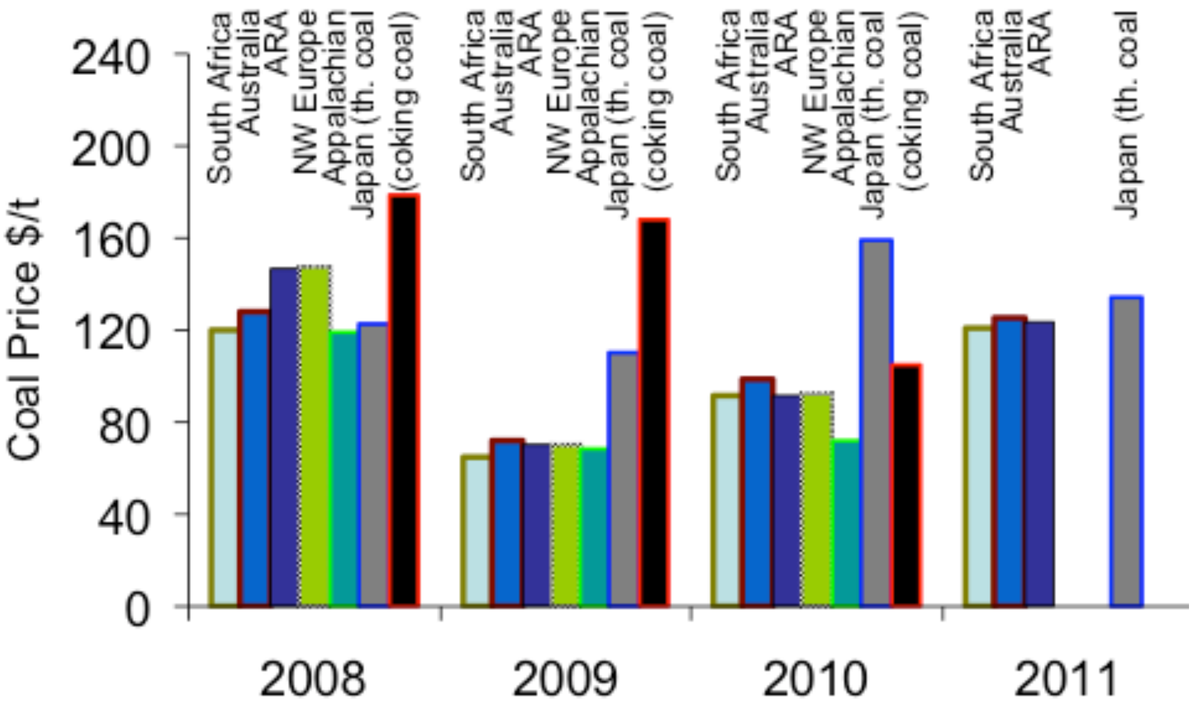


Fig. 30-11 Regional differences in average coal prices from 2008 to 2010. For 2011 only the benchmark prices (South Africa, Australia and ARA) and the latest contract price for Japanese coal are given because no other figures are available yet

Sources: BP (2010), Global Coal (2010) and IFT (2011)

Fig. 30-2 gives a more detailed differentiation of the price of coal by adding prices in eastern USA (Appalachian) and Japan. Annual average prices are taken for this comparison. The price of coking coal is also shown for Japan. It is about 40 per cent above the price for steam coal. The cheap price of Japanese coal compared to European coal in 2008 could be due to shorter transport distances from Indonesia, the main source of Japan's coal supply. In 2009, however, the picture changed. Driven by the global recession, coal prices declined worldwide, except in Japan, where it was virtually identical to those in the previous year. Japan is closest to the developing markets in Asia, where coal demand remained at a high level, even in 2009. Prices rose yet again in 2010. However, these prices are only included in the figure for Richards Bay (South Africa), Newcastle (Australia) and ARA (Amsterdam - Rotterdam - Antwerp), as the data for the other destinations are still incomplete. Only Japanese import coal prices from Indonesia are included as a new contract with Bumi Indonesia at the end of May 2011 was chosen with a record import price of USD 134 per tonne for thermal coal with 24.3 MJ/tonne.

30.4.3 Present Prices of Domestic South African Coal

The price labels used in the following figure are defined in Tab. 30-3.

Tab. 30-3 Typical price labels also used in South Africa

Price	
FOB	Price for coal already loaded onto vessels at named port, including FOR cost, rail or truck freight to port, port charge, VAT charge, profit, etc.
FOR	Price for coal already loaded onto rail cars, including all costs in-curred beforehand (but not the transport cost to buyer's destination). This price is commonly used across China. VAT is included
Ex-mine	Price for coal sold at mine sites. Includes mine mouth price plus a short-distance transport charge to bring the coal to the entrance of the mine. VAT is included

Source: Authors' composition

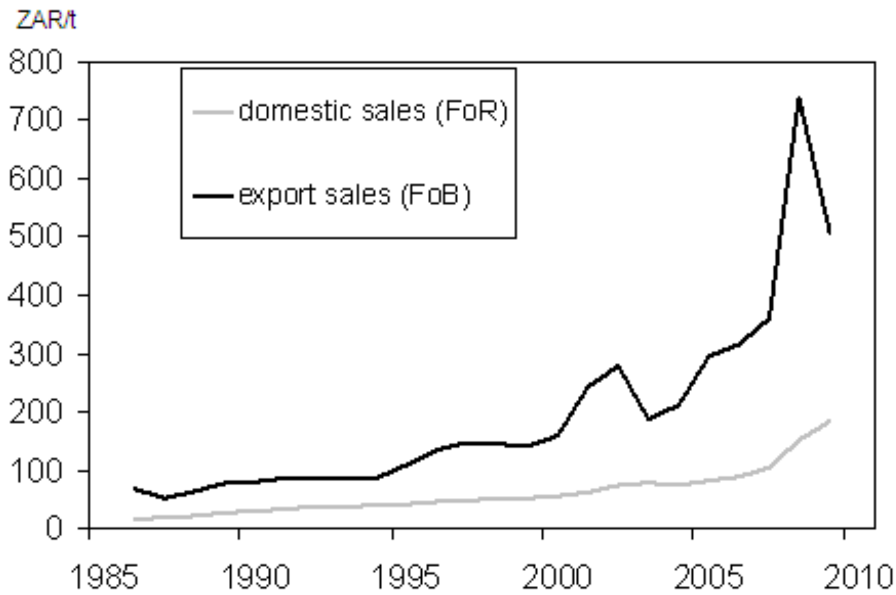


Fig. 30-12 Average sales prices for domestic and export sales of bituminous coal in 2010 (in ZAR/t)

Sources: Statistics South Africa (2008) and SAMI (2010)

30.4.4 Price Difference between Domestic and Exported Coal

To enable comparisons with international coal prices, Tab. 30-4 and Fig. 30-13 show the interbank exchange rate between South African rands (ZAR), euros (EUR) and United States dollars (USD).

Tab. 30-4 Development of Interbank exchange rate from South African rands to euros and United States dollars, respectively, since June 2008

Date	EUR 1 = ZAR	ZAR 1 = EUR	USD 1 = ZAR
29/06/2008	0.090	12.343	0.128
31/07/2008	0.085	11.459	0.136
30/08/2008	0.088	11.360	0.130
29/09/2008	0.085	11.827	0.121
31/10/2008	0.078	12.838	0.099
29/11/2008	0.078	12.850	0.099
30/12/2008	0.077	13.067	0.107
30/01/2009	0.076	13.141	0.098
27/02/2009	0.078	12.815	0.099
31/03/2009	0.079	12.614	0.106
30/04/2009	0.089	11.243	0.118
30/05/2009	0.089	11.241	0.125
30/06/2009	0.092	10.885	0.130
31/07/2009	0.091	11.037	0.128
31/08/2009	0.090	11.114	0.128
30/09/2009	0.092	10.898	0.134
30/10/2009	0.087	11.452	0.129
30/11/2009	0.090	11.142	0.135
30/12/2009	0.094	10.666	0.135
31/01/2010	0.095	10.570	0.132
27/02/2010	0.095	10.505	0.129
31/03/2010	0.101	9.892	0.136
30/04/2010	0.102	9.763	0.136
31/05/2010	0.106	9.455	0.130
30/06/2010	0.107	9.381	0.131
30/07/2010	0.105	9.562	0.136
31/08/2010	0.106	9.404	0.135
30/09/2010	0.105	9.544	0.143
30/10/2010	0.103	9.683	0.143
30/11/2010	0.108	9.271	0.140
31/12/2010	0.113	8.863	0.151
31/01/2011	0.102	9.846	0.139
28/02/2011	0.104	9.640	0.144
31/03/2011	0.104	9.651	0.147
30/04/2011	0.102	9.799	0.152
30/05/2011	0.101	9.871	0.146
30/06/2011	0.101	9.857	0.147
31/07/2011	0.104	9.608	0.148
31/08/2011	0.098	10.180	0.142
30/09/2011	0.093	10.793	0.126
31/10/2011	0.092	10.922	0.128
30/11/2011	0.091	10.957	0.122
31/12/2011	0.095	10.483	0.123

Source: Bundesverband deutscher Banken (2011)

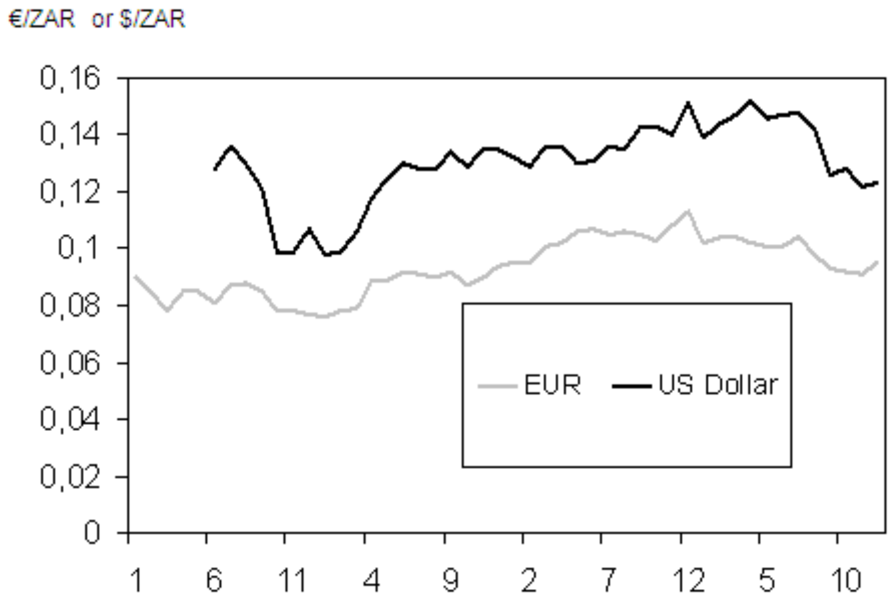


Fig. 30-13 Development of Interbank exchange rate from June 2008 to May 2011 from South African rands (ZAR) to euros and United States dollars, respectively

Source: Bundesverband deutscher Banken (2011)

The comparison with imported coal must also be performed for similar products. Heating value, humidity, ash and sulphur content are, for instance, relevant criteria. Tab. 30-5 portrays these values for South Africa's most important supply sources:, Indonesia, Australia and South Africa.

Tab. 30-5 Quality criteria of coal exported from South Africa, Australia and Indonesia

		RB (South Africa)	**Newcastle (Australia)**	**Kalimantan (Indonesia)**
UHV	kcal/kg	> 5,850 (av. 6,000)	> 5,850 (av. 6,000)	5,300–6,200
	MJ/kg	>24.5 (av. 25.14)	> 24.5 (av. 25.14)	22.2–26
Humidity	%	< 12	< 15 (av. 10)	9–16 (inherent)
Ash content	%	< 15	< 14 (av. 13)	7–16
Sulphur content	%	< 1	< 0.75 (av. 0.6)	< 1
Price on 22 Nov 2010	USD/t	103	107	n.a.
(comp to Fig. 17)	CNY/MJ	27.3	28.3	
Price on 17 Dec 2010	USD/t	115	119	n.a.
(comp to Fig 18)	CNY/MJ	30.2	31.2	n.a.

Sources: Global Coal (2011) and Borneo Coal Indonesia (2010)

In Tab. 30-6, prices at various destinations are compared in USD/t and with a similar heating value of 26.4 MJ/kg. Chinese domestic coal for export at Qinhuangdao (QHD) is much more expensive than coal imported from South Africa, Australia, Kalimantan or even Russia. This is related to enormous Chinese demand, which forced the government to limit export quantities. This is reflected by a corresponding price reaction.

Tab. 30-6 Quality criteria of coal exported from South Africa, Australia and Indonesia

		RB (South Africa)	Newcastle (Australia)	QHD (China)	Kalimantan (Indonesia)	Russland (Pacific)
UHV	kcal/kg	6,300	6,300	6,300	6,300	6,300
	MJ/kg	26.4	26.4	26.4	26.4	26.4
Price (1 January 2009)	USD/t	65	63	76	63	66
Price (31 December 2009)	USD/t	81	86	115	73	88
Price (1 April 2010)	USD/t	88	95	107	73	102

Source: VdKi (2011)

30.4.5 Structural Changes of Coal Import and Export Markets in Asia and South Africa

As South Africa is a net coal exporter, the major import country – China – is also of relevance. The demand for coal has only substantially exceeded domestic production in China for a few years. Fig. 30-14 shows how China's coal imports and exports have developed, portraying major sources and destinations. In the near future, rising structural changes concerning import sources are to be expected because Indonesia – currently China's second most important supply source – will limit its exports. This will affect the prices of coal traded on the global market.

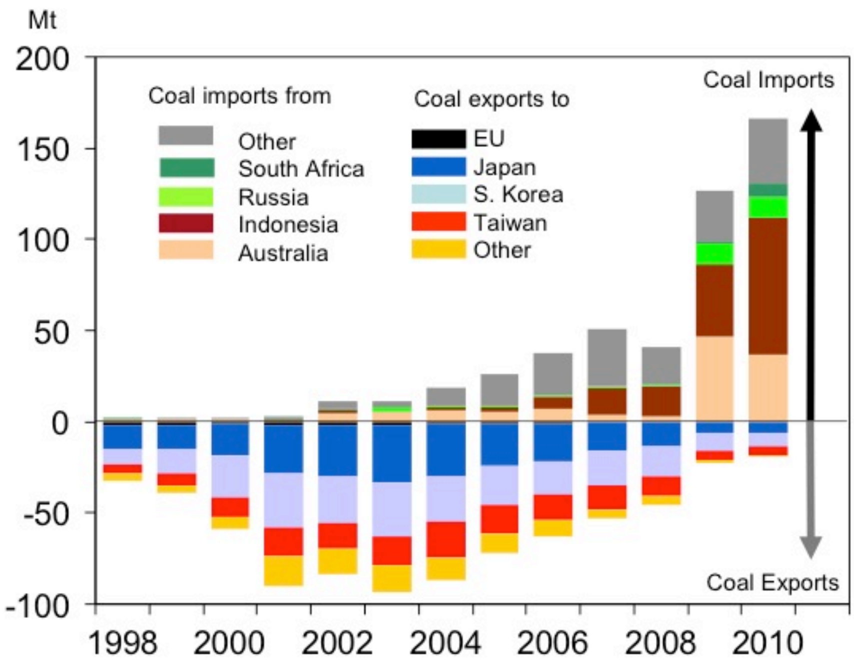


Fig. 30-14 Imports to and exports from China
Sources: VdKi (2006, 2010, 2011)

China imports only small quantities from South Africa. Its most relevant suppliers are Indonesia, Australia and, in the north-eastern part of China, also Russia and Kazakhstan. Due to their size, these growing Chinese supplies affect the entire Asian coal market.

Over the last decade, Indonesia was the preferred importer for non-coking coal, due to the short transport distances involved. In 2009, Indonesia exported a total of 230 Mt of predominantly non-coking coal quality to other countries. This figure cited by the "Verein der deutschen Kohleimporteure" is about 50 Mt above official figures.

The most important importers of Indonesian coal exports in 2010 were China (74.9 Mt), India (44.4 Mt), South Korea (43.2 Mt), Japan (33.1 Mt) and Taiwan (21.9 Mt). Chinese coal imports in particular have risen sharply in recent years, with imports from Indonesia more than quadrupling since 2007, as can be seen in Fig. 30-15 (VdKi 2010).

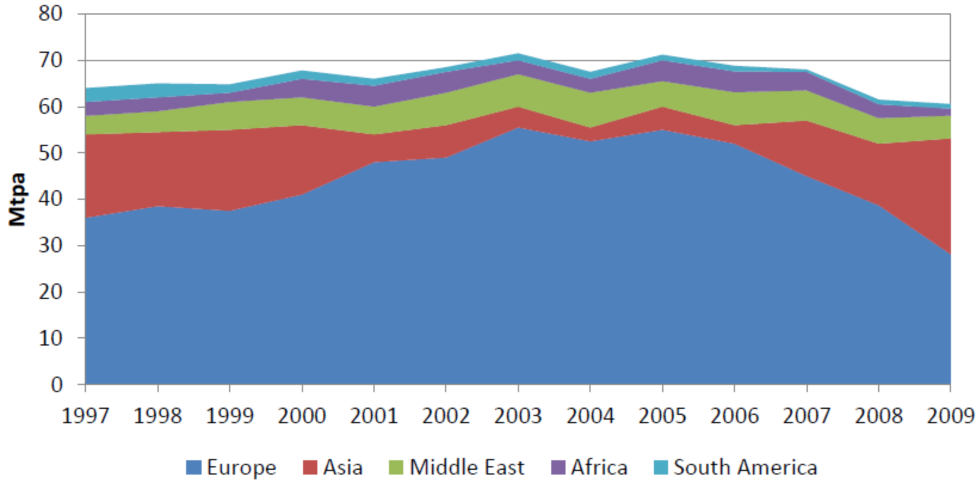


Fig. 30-15 Volume and destination of South Africa's coal exports
Source: Eberhard (2011)

This demand pressure resulted in major increases in the price of coal exported from Indonesia. In addition, the rising domestic demand in Indonesia could result in restrictions on exports. Whilst one year ago it was reported that the government intends to freeze coal exports at 150 Mt, the government's policy is now to reduce exports stepwise to meet domestic demand (UPI 2010). In addition, Indonesia signed a Moratorium on Deforestation at the Deforestation Workshop in Oslo in May 2010, which will be valid for at least the next two years. Part of this agreement is not to allow any new permits for open pit mining areas (Hasan 2010).

Most Australian coal exports are imported by East Asia. In 2009, for instance, China was the largest importer of Australian coal (83 Mt). Thermal coal imports alone grew to 47 Mt, an eightfold increase over the previous year (VdKi 2010). Due to limited export capacities, the Australian export situation remains tight.

Not only India, but also China, Korea, Japan and Taiwan are seeking new sources for future coal imports. For this reason, huge amounts are being invested in constructing a new harbour to increase import capacities (HMS 2010).

South Africa is considered a major supplier. For this reason, increasing quantities of South African exports to India can be expected. However, due to limited export capacities and restrictions in production – even the present export capacity was not exceeded in previous years – South Africa reduced its exports to Europe because it found cheaper sources, either by importing from closer regions or by simple demand destruction. Fig. 30-15 shows how South Africa's coal exports have developed since 1997.

30.4.6 Projection of Coal Price Development

Extrapolating these developments, it is very likely that future price will increase. In this section, an attempt is made to determine a reasonable price extrapolation for the decades ahead. This is carried out in line with oil price projections of the International Energy Agency (IEA) in the latest World Energy Outlook 2011 (IEA and OECD 2011). This seems to be more reasonable than directly taking the coal price projections in WEO 2009, which are believed to be too moderate since they assume that cheaper and abundant coal will still be available in 2030. Tab. 30-7 shows the price assumptions for coal imported by Organisation for Economic Co-operation and Development (OECD) states in 2030 according to various editions of the World Energy Outlook of the IEA published between 1998 and 2009.

Tab. 30-7 Price assumptions for coal import by OECD countries according to various editions of the World Energy Outlook since 1998

Reporting year	1996	1997	2000	2006	2007	2008	2009	2010	2020	2030	2035
WEO 1998	39.3	**37.2**						42	46		
WEO 2002			**35**					39	41	44	
WEO 2004			**38**					40	42	44	
WEO 2007			39.05	**62.87**				56.07	56.89	61.17	
WEO 2008			40.08		**72.84**			120	116.67	110.00	
WEO 2009			41.22			**120.59**		91.05	104.16	109.04	
WEO 2010							**97.3**		130.6	170.2	192.4
WEO 2011							**99.2**		133.5	172.2	194.2

Prices are given in nominal terms in USD/tonne. The base year of the calculations is printed in bold.

Sources: IEA and OECD (1998, 2002, 2004, 2007, 2008a, 2009c, 2010, 2011)

For many years, the price of imported coal in 2030 was estimated at USD 40 to 60 per tonne. In 2008, it increased almost threefold to USD 110 per tonne. Against earlier projections in WEO 2002, the latest coal price adaption for 2030 in WEO 2011 increased by almost 300 per cent!

Tab. 30-8 gives similar price projections for the OECD crude oil import price. Compared with coal imports, the price of crude oil in 2030 rose by 300 per cent between WEO 2002 and WEO 2011.

Tab. 30-8 IEA price assumptions for crude oil imported by OECD countries according to various editions of the World Energy Outlook since 1998 with real figures for each base year

Reporting year	1996	1997	2000	2006	2007	2008	2009	2010	2020	2030	2035
WEO 1998	17.5	**16.1**						17	25		
WEO 2002			**28**					21	25	29	
WEO 2004			**27**					22	26	29	
WEO 2007			32.49	**61.62**				59.03	57.3	62	
WEO 2008			33.33		**69.33**			100	110	122	
WEO 2009			34.3			**97.19**		86.67	100	115	
WEO 2010							**60.4**		127.1	177.3	204.1
WEO 2011								**78.1**	136.4	184.9	211.9

Prices are given in USD/bbl (nominal data with price base of the year, printed in bold).

Sources: IEA and OECD (1998, 2002, 2004, 2007, 2008a, 2009c, 2010, 2011)

Developments in recent years show that the price of coal almost increased in line with – or even more sharply than – the price of crude oil (see Fig. 30-12). The expected demand for imports, mainly by China and India, in combination with declining or flat export volumes from traditional export countries (Indonesia, Vietnam and South Africa), makes it probable that the price of coal will rise at least as sharply as the price of oil in the years ahead.

Tab. 30-9 outlines the development of the price of imported coal, which is in line with the development of oil prices up to 2030, as reported by the IEA in its World Energy Outlook 2011.

Tab. 30-9 Development of the price of coal imported by OECD countries up to 2035

Reporting year		**2010**	**2020**	**2025**	**2030**	**2035**
WEO 2011 (oil price development)	USD/bbl	78.1	136.4	159.8	184.9	211.9
Coal price adaption	USD/tonne	99.2	173.3	203.0	234.8	269.1

The coal import price is adapted to IEA assumptions on the development of the price of imported crude oil.

Source: IEA and OECD (2011)

30.5 Conclusion

The coal reserves of South Africa have been revised downwards several times. At present, reserves are estimated to be between 15 Gt and 27 Gt. The upper range is based on figures by Statistics South Africa, the lower number on an independent analysis (Hartnady 2010). However, the analysis by (Hartnady 2010) is not accepted in South Africa. A new assessment of the national coal inventory of South Africa is currently being prepared (Falcon 2012).

Declining productivity, declining heating value and worsening extraction conditions with a rising share of underground mines indicate that the time when coal could be extracted easily has already passed. The remaining reserves are concentrated in a few coal fields, namely Highveld, Witbank, Ermelo and Waterbank, which contain about 85 per cent of remaining reserves. The development rate of new projects together with the construction of infrastructure will decide whether peak production is close or has already taken place. According to Hartnady (2010), the peak may occur around the year 2020. However, recent production and export statistics suggest that production has almost been flat and exports in decline for several years.

Applying such a scheme, it is apparent that the proven recoverable reserves may not suffice to meet demand in the high case coal development pathway (*E1: high,* see Tab. 28-12). Although only covering power plants installed up to 2050, this pathway would require 7.5 to 8.5 billion tonnes of coal, which would rise to 8.3 to 9.5 billion tonnes in the event of applying CCS. The pathway with the lowest cumulative demand (4 to 5 billion tonnes with *E3: low*) may still allow a rising production rate.

Due to these indicators, it is very likely that coal prices will considerably rise in the future both domestically and for export sales. This is in line with the price development assumptions up to 2035 based on IEA projections as given in the World Energy Outlook 2011. The corridor for coal prices in 2035 may be set between USD 194 and 269 per tonne of coal, the lower price based on the WEO assumption on OECD coal import prices, and the upper price scaled under the assumption that coal prices will rise at the same rate as oil prices.

31 Economic Assessment of Carbon Capture and Storage

31.1 Introduction

This section develops and analyses long-term pathways for the levelised cost of electricity (LCOE) and costs of CO_2 mitigation of hard coal-fired, supercritical pulverised coal (PC) power plants with and without CCS in South Africa. The timeframe of the analysis stops at 2050. In the first step, the basic parameters and key assumptions of the analysis are summarised (section 31.2). The main outcomes of the assessment will be presented in section 31.3. All cost figures are given in United States dollars in 2011, abbreviated to USD (2011).

31.2 Basic Parameters and Assumptions

31.2.1 Power Plant Types and Plant Performance

The cost analysis focuses on hard coal-fired, supercritical PC plants, since this plant type operates at thermal efficiencies, making CO_2 capture viable. South Africa's national electricity utility, Eskom, produces approximately 96 per cent of the country's electricity, and operates 13 coal-fired power stations with an installed capacity of 37,745 MW. Their total net output, excluding power consumed by their auxiliaries and generators currently in reserve storage, is 34,952 MW (Eskom 2011d). Most of South Africa's electricity is currently generated in PC plants. So far, all PC plants in operation in South Africa use subcritical boilers with steam pressures below the critical pressure of water (approximately 218 atmospheres) (Haw and Hughes 2007). Supercritical PC plants raise the pressure beyond the critical pressure of water, leading to a significant increase in plant efficiency.

Haw and Hughes (2007), who made a significant contribution to South Africa's Long Term Mitigation Scenarios (LTMS) and the government's Integrated Resource Plan, consider supercritical PC technology to be one strategic element for reducing the carbon footprint of coal-based electricity production. In a cleaner coal case scenario, they project that by 2018, supercritical PC plants will represent around 9 per cent of the overall installed capacity. 10 GW of supercritical plant capacities are expected to be installed by 2050 (Haw and Hughes 2007).

Despite the limited percentage of installed supercritical plant capacities, the technology has been chosen as the reference technology for this cost analysis because it is technically mature and widely deployed, meaning that existing cost data are relatively reliable. In contrast, an interviewed expert from Eskom voiced clear doubts about the reliability and maturity of ultra supercritical (USC) plants (Eskom 2011a). CO_2 capture and storage is only taken into account for new power plants; retrofitting plants already in operation with CO_2 capture equipment are not considered here. For newly built SC plants without carbon capture and storage, an average net thermal efficiency of 39 per cent is assumed for pre-2020 and 41.5 per cent for post-2020, due to anticipated process optimisations. These efficiencies are taken from Tab. 28-6.

The aforementioned Long Term Mitigation Scenarios expect integrated gasification combined cycle (IGCC) plants to play a very prominent role in the decades ahead. 35 GW of IGCC capacities, or about 43 per cent of all installed capacities, are projected to be operating by 2035. This figure increases to about 80 GW, or about 67 per cent of the total national power generation fleet, by 2050. Following this pathway, the development and costs of IGCC technology would have a strong impact on the economic performance of South Africa's power sector. This analysis, nonetheless, focuses on supercritical PC plants, as IGCC technology is still at the demonstration stage and involves rather high technical and economic uncertainties – although scientists have been developing and testing the technology for several years. It remains unclear whether IGCC technology will become commercially available and achieve a reasonable level of maturity and, if so, when; existing cost data are highly uncertain. For this reason, IGCC is not included in this assessment.

Capturing CO_2 from the flue gas of supercritical PC power plants leads to a significant efficiency penalty as the post-combustion capture processes applied are very energy-intensive. The efficiency penalty chosen for the reference plants considered in this study – about 6 percentage points – is also based on assumptions in section 28. Regarding operating parameters of the CO_2 capture plant, the typical CO_2 capture rate is set at 90 per cent, based on Kulichenko and Ereira (2011). The average lifetime of power plants both with and without CCS is assumed to be 50 years in accordance with the government's Integrated Resources Plan. Figures on average depreciation periods for large-scale power plants in South Africa were hard to find. For this reason, the average depreciation period (25 years) of other major emerging economies, for example China or India, is applied in the case of South Africa. The applied load factor is approximately 80 per cent (equivalent to 7,000 full load hours per year on average), corresponding to the reference case defined in section 28. As in India and China, the other case studies in this project, the commercial availability of CCS in South Africa is expected to be achieved no earlier than 2030. Consequently, only power plants built after 2030 can be equipped with CCS, whereas the South African CCS Roadmap elaborated by SACCCS expects the technology to be ready for commercialisation by 2025, with 1 million tonnes of CO_2 to be captured and stored at that time (SACCCS 2011b).

As in the case studies for China and India, the assumption of CCS not being available in South Africa before 2030 was made based on the observation that the slow progress being made by demonstration projects in industrialised countries is likely to delay the commercialisation and deployment of CCS (compare section 28.4.1).

31.2.2 Development Pathways for the Expansion of Coal-Fired Power Plant Capacities in South Africa

In accordance with the projected development pathways of coal-fired power plant capacities in South Africa and the resulting quantity of CO_2 emissions to be captured by 2050, the economic assessment encompasses three coal development pathways E1–E3, derived from three basic scenario studies (see section 28). As mentioned above, only newly installed capacities are taken into account due to the focus on supercritical PC technology. The coal development pathways are based on the following scenario studies:

- *Pathway E1: high*: Based on the *Long-Term Mitigation Scenario No 1 "Growth Without Constraints,"* developed by the Energy Research Center on behalf of the Department of Environment Affairs and Tourism South Africa (Scenario Building Team 2007). This scenario involves any change from current trends or implementing existing policies, and therefore foresees a massive expansion of South Africa's coal-fired power generating capacity.

- *Pathway E2: middle*: Based on the *Reference Scenario,* developed in the *Sustainable Energy Outlook for South Africa*, published by EREC and Greenpeace International (2011). It was originally based on the *World Energy Outlook 2008 Reference Scenario*. After the Policy Adjusted Scenario of the Integrated Resource Plan (IRP) (DOE 2011b) was adopted by the South African government, the Reference Scenario was updated with figures outlined in the IRP up to 2020, including committed building projects (Medupi and Kusile) and options for new construction. The development outlined between 2010 and 2020 was updated to 2050. The coal-fired capacity will decrease slightly and reach 45 GW from 2030.
- *Pathway E3: low*: Based on the *Sustainable Energy Outlook for South Africa*, published by EREC and Greenpeace International (2011), which is also adapted from the IRP (DOE 2011b). In contrast to the Reference Scenario outlined above, this scenario considers only approved building projects (Medupi and Kusile) and does not foresee any further new coal-fired stations in the future. Hence this scenario expects the coal-fired power capacity to decrease from 2020. It places a strong focus on renewable energy technology and energy efficiency.

31.2.3 Levelised Cost of Supercritical Pulverised Coal Plants in South Africa

31.2.3.1 Method of Calculation

The calculation of the levelised cost of electricity (LCOE) of coal-fired power plants in South Africa – with or without CCS – is based on Equation 31-1

$$LCOE = \frac{\left(C_{Cap} + C_{O\&M}\right) \cdot af}{capacity} + C_{TS} + C_{fuel} \qquad 31\text{-}1$$

where

$$af = \frac{I \cdot (1+I)^n}{(1+I)^n - 1} \qquad 31\text{-}2$$

and

LCOE	= levelised cost of electricity, [LCOE] = US-ct/kWh_{el}
C_{Cap}	= specific capital expenditure, [C_{Cap}] = USD/kW_{el}
$C_{O\&M}$	= specific operating and maintenance costs, [$C_{O\&M}$] = USD/kW_{el}
af	= annuity factor, [af] = %/a
I	= real interest rate, [interest] = %
n	= depreciation period, [n] = a
C_{TS}	= specific cost of CO_2 transportation and storage, [C_{TS}] = USD/kWh_{el}
C_{fuel}	= specific fuel costs (including CO_2 penalty), [C_{fuel}] = USD/kWh_{el}
capacity	= full load hours, [capacity] = h/a

31.2.3.2 Power Plants without CO_2 Capture

Two key cost elements for calculating the cost of electricity of coal-fired power plants are capital costs and costs of operation and maintenance (O&M). In the case of South Africa, capital costs have a particularly high impact on the LCOE due to the rather low fuel costs involved (IEA 2005). The capital costs (C_{Cap}) of supercritical PC plants without CO_2 capture and storage referred to in this study represent the mean value of capital cost figures for this plant type given in several publicly available studies and reports (IEA and NEA 2010; Newbery and Eberhard 2008; Tot et al. 2011). All quoted cost data take into account local circumstances in South Africa. The study by Tot et al. (2011), which is a techno-economic background report for a comprehensive World Bank study on barriers to the deployment of carbon capture and storage in developing countries (Kulichenko and Ereira 2011), was particularly valuable. Here, capital cost data for European coal-fired power plants are adapted to local conditions in South Africa based on purchasing power parities (PPP) for machinery and equipment. PPP reflect the ratio of the costs of a basket of goods in one country to a reference country (Tot et al. 2011).

In recent years, capital costs of large-scale plants have varied significantly due to rising costs for key materials such as steel, equipment and changing financing conditions. In order to balance these variations, cost figures from the given reference studies were streamlined based on the IHS CERA Power Capital Costs Index (PCCI).

Capacities of the considered supercritical PC plants range from 510 MW_{el} to 794 MW_{el}. The capital costs of these plants range from USD 1,984 to 2,328/kW due to economies of scale and different basic assumptions, such as plant design and financing conditions. The cost calculations presented below use the mean value of the given range of capital costs.

Operation and maintenance costs ($C_{O\&M}$) reflect expenditures for auxiliary and operating materials required as well as annual maintenance costs. In this assessment, O&M costs are given as a percentage rate of plant capital costs. O&M costs are assumed to be 4 per cent of capital expenditures based on Finkenrath (2011), who conducted an international cost assessment of CCS plants and used this O&M rate for both industrialised countries and emerging economies.

31.2.3.3 Power Plants with CO_2 Capture

CO_2 capture is by far the most cost-intensive step within the CCS chain. In the following, the increase in capital expenditures and O&M costs resulting from integrating post-combustion capture is added as a relative extra charge to the capital costs or O&M costs of plants without CCS. Capital costs of CCS are assumed to be equivalent to 75 per cent of the capital costs of supercritical PC plants without CCS. This percentage represents the average of additional capital costs required for PC plants with post-combustion capture calculated in studies conducted by Massachusetts Institute of Technology (MIT 2007), Global CCS Institute (2009) and Viebahn et al. (2010). The same studies indicate average increases in O&M expenditures of 83 per cent due to post-combustion CO_2 capture.

31.2.3.4 Annuity Approach

The total capital costs for the power plants considered are allocated to individual years on an annuity basis and related to a kilowatt hour. Both the expected real interest rate and the depreciation period are included in the annuity formula. The annuity factor (af) is calculated according to Equation 31-2.

In this study, an interest rate of 8 per cent and a 25-year depreciation period are assumed. The assumed interest rate is based on the cost report by Tot et al. (2011). For European power plant projects, interest rates are estimated to be lower, at about 6 per cent (Viebahn et al. 2010). As mentioned above, the average depreciation period applied is based on experience from other major emerging economies, such as China or India. The given interest rate and depreciation period lead to an annuity factor of approximately 9 per cent per year.

31.2.3.5 Costs of CO_2 Transportation and Storage

CO_2 can be stored via ship, truck or pipeline; on industrial scales and over large distances, however, transferring gas by pipeline is by far the most viable option. When comparing cost estimates of international studies (Global CCS Institute 2009; McCoy 2008; MIT 2007), the average costs of CO_2 transportation by pipeline can be estimated at about USD 2 per tonne of CO_2 for a distance of 100 km. However, transport costs are affected by location-specific and technical parameters, such as pipeline capacity, terrain conditions (for example, mountainous areas, populated areas, water crossings) and, in particular, transport distance.

For South Africa, Tot et al. (2011) estimate average pipeline transport costs of CO_2 over a distance of 100 km to be about USD 1 per tonne of CO_2. Taking into account the location of future coal-fired power generation capacities and the average distance to potential storage sites as analysed in section 27, this cost assessment assumes an average transport distance of 550 km. Consequently, CO_2 transport costs in South Africa for the assumed average transport distance total approximately USD 5.5 per tonne of CO_2.

The costs of CO_2 storage are based on country- and site-specific assessments by Tot et al. (2011). For this analysis, only saline aquifers are taken into account because they represent the largest share of the national CO_2 storage potential in South Africa. Enhanced recovery options, which offer additional economic benefits, are not taken into account because their potential in South Africa is either very limited (enhanced oil recovery; EOR) or highly uncertain, due to the early stage of development and demonstration (enhanced coalbed methane recovery; ECBM). Considering the location of future coal-fired power plants, two exemplary storage sites – the Zululand Mesozoic basin (onshore east coast) and the Mesozoic Durban basin (offshore east coast) – have been identified. Since a large proportion of South Africa's potential storage sites are located offshore, the latter formation was included in this assessment, leading to rather high mean storage costs. The mean costs of CO_2 storage in these two potential formations are calculated to be about USD 13 per tonne of CO_2. By comparison, international cost figures for onshore and offshore saline aquifer storage range from USD 4 per tonne of CO_2 (Vidas et al. 2009) to about USD 11 per tonne of CO_2 (Global CCS Institute 2009). However, available cost data for CO_2 storage suggest a high impact of site-specific conditions as well as significant uncertainties, which is why they were used for this assessment.

31.2.3.6 Learning Rates

In order to project the costs of PC plants with and without CCS for the decades ahead, experience curves and learning rates are used to model mass market effects and improvements in technology. An experience curve describes how unit costs decline with cumulative production. The progress of cost reduction is expressed by the progress ratio (PR) and the corresponding learning rate (LR). For example, a 90 per cent progress ratio means that costs are reduced by 10 per cent each time cumulative production is doubled. The LR is therefore defined as 10 per cent. In this study, LRs are applied from 2010 for supercritical PC plants without CCS and from 2030 for supercritical plants with CCS.

Supercritical PC plants without CCS are deployed internationally and are technically mature, meaning that only minor improvements are expected to occur in the decades ahead. The presented cost assessment uses experience curves based on international plant development and deployment. This is considered an adequate approach because the main parts of supercritical PC plant equipment for future generating capacities in South Africa will be imported and, thus, based on international learning processes.

The LR and PR for PC plants with and without CO_2 capture are calculated based on a report prepared within the IEAGHG programme (IEAGHG 2006). LRs for PC plants with CO_2 capture are developed in the study. Technology learning is assumed to begin at a capacity of 1 GW_{el} (C_{min}) and projected up to a cumulative capacity (C_{max}) of 729 GW_{el} for PC plants without CCS and 663 GW_{el} for PC plants with CCS. Both C_{max} figures are derived from the development of coal-fired power generating capacities specified in the most recent Blue Map Scenario of the International Energy Agency (IEA 2010). The scenario implies a 50 per cent reduction in CO_2 emissions compared to 2005. By 2050, coal-fired power capacities are estimated to total 729 GW_{el}. This figure encompasses an overall installed capacity of coal-fired CCS plants of 663 GW_{el} – including both newly built plants and PC plants retrofitted with CCS. The capacity of remaining coal-fired plants without CCS in 2050 totals 66 GW_{el}. All plants operating in 2050 are assumed to have been added during the scenario period. Since the power blocks of PC plants with and without CCS plants are virtually identical, PC plants without CCS benefit from learning effects gained from the deployment of PC-CCS units. Hence, C_{max} for PC plants allows for the envisaged capacities of PC plants both with and without CCS in 2050 (729 GW_{el}).

The resulting learning rates for a complete PC plant with CCS are 2.5 per cent (capital costs) and 5.8 per cent (O&M). Regarding individual plant components, the post-combustion CO_2 capture unit and the CO_2 compression plant have rather high LRs, whereas the conventional power block is a mature technology with a low learning potential. Hence, the overall LR of PC plants without CCS is significantly lower, totalling 1.7 per cent (capital costs) and 3.9 per cent (O&M).

Since they are commonplace in the oil and gas industry, pipelines for CO_2 transportation and storage technologies are mature technologies and, hence, offer only limited cost reductions (Junginger et al. 2010). For this reason, this analysis focuses on the learning effects of power plants and CO_2 capture units and excludes learning in the CO_2 transportation and storage phases.

31.2.3.7 Fuel Costs

Only very few long-term scenarios are available for a dynamic price development for domestic hard coal in South Africa. For example, the scenario study by Tot et al. (2011) assumes domestic fuel prices will remain constant in the considered planning horizon from 2010 to

2030. However, many assessments of the LCOE of coal-fired power plants, especially in emerging countries, suffer from a far too conservative estimate of coal prices, which are often based on coal prices strongly controlled and regulated by national governments. However, in the decades ahead an increasing liberalisation of the energy sector, leading to a strong impact on market forces and also on coal prices, may also be expected to occur in emerging countries such as South Africa. Newbery and Eberhard (2008), for example, expect the price of South Africa's coal to steadily increase in the future.

Coal price assumptions in this cost assessment are based on the historic development of South Africa's domestic sales coal price (FOR[1]) from 1985 to 2010, as illustrated in Fig. 30-9. Starting at a price of about USD 1.50 per tonne in 1985, the price of hard coal rose to about USD 28.30 per tonne in 2010. This implies an average annual price increase of approximately USD 1.1 per tonne or USD 10.7 per tonne per decade. Extrapolating this trend to the end of the considered coal development pathway, South Africa's domestic hard coal price is projected to reach approximately USD 71.1 per tonne by 2050. Fig. 31-1 illustrates the resulting fuel cost trend, taking into account different thermal efficiencies of plants with and without CCS.

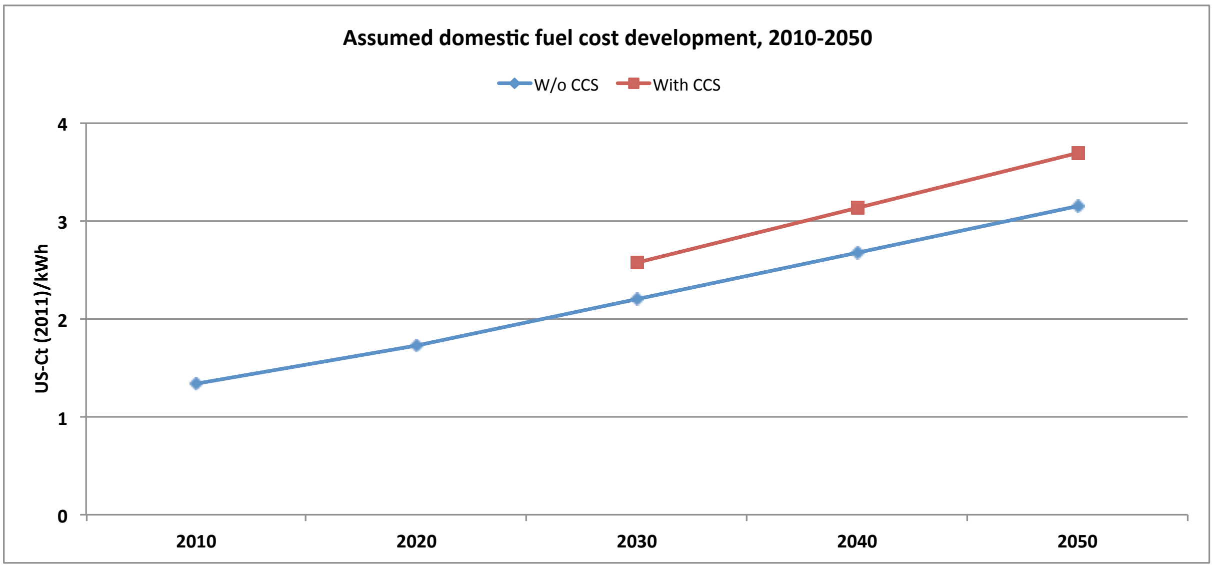


Fig. 31-1 Assumed fuel cost development of South African hard coal with and without CCS, 2010–2050

Source: Authors' illustration

Despite the clearly increasing price trend, the assumed coal price development is moderate compared to other countries. For example, the price of India's coal is estimated to rise to about USD 103 per tonne by 2050.

Unlike the country studies on China and India, the cost analysis for South Africa does not consider the potential cost impact of a growing share of coal imports. This is due to the fact that South Africa is one of the world's largest coal exporting countries after Australia, Indonesia, Russia and Colombia (see section 30). Since the early 1990s, South Africa's coal production has grown nearly 50 per cent. Thus, it is assumed that South Africa's power generation will continue to be based on domestically produced coal in the decades ahead. The qual-

[1] Price for coal already loaded onto rail cars, including all costs incurred beforehand (but not transportation costs to buyer's destination). This price unit is commonly used, VAT is included.

ity of coal mainly used for power generation is expected to be sub-bituminous coal, with an average heating value of 19.59 GJ per tonne (Eberhard 2011); high-quality coal is expected to be used primarily for exports.

31.2.3.8 CO_2 Discharge of Coal-Fired Power Plants with and without CCS

The assumed average emission factor of South African sub-bituminous coal used for power generation is 347 g CO_2 per kWh_{th} (Haw and Hughes 2007). Tab. 31-1 exemplifies the specific discharge of CO_2 from supercritical PC power plants in South Africa with and without CCS based on 100 per cent domestic coal.

Tab. 31-1 Specific CO_2 emissions from supercritical PC plants in South Africa with and without CCS (based on 100 per cent domestically produced hard coal)

Plant type	Time frame	Plant efficiency	Specific CO_2 emissions
		%	g/kWh_{el}
Supercritical PC w/o CCS	Up to 2020	39.0	889
	From 2020	41.5	836
Supercritical PC with CCS	From 2030	35.5	101

Source: Authors' compilation

31.2.3.9 CO_2 Penalty

The economic viability of CCS is strongly affected by the existence or absence of a CO_2 price. In order to indicate the impact of a CO_2 price on the cost of electricity and CO_2 mitigation of supercritical PC plants with and without CCS, a CO_2 price was integrated into development pathway E2: middle. According to EREC and Greenpeace International 2010, emission trading in Kyoto non-annex B countries is assumed to begin by 2020. The South African government has been discussing the introduction of a national carbon-pricing scheme for several years now. However, it is still unclear when such a pricing mechanism and the associated carbon price will be established. Thus, the CO_2 price assumed in this scenario for the timeframe up to 2050 is based on a medium price path for CO_2 certificates, as outlined in Viebahn et al. (2010), BMU (2009) and Horn and Dieckmann (2007). CO_2 prices are added as a penalty to the cost of electricity, taking into account plant efficiency and the CO_2 emission factor of the feedstock mix used (see below).

Tab. 31-2 CO_2 prices and CO_2 cost penalty assumed for South Africa, 2020–2050

	Unit	2020	2030	2040	2050
CO_2 price	$USD_{2011}/t\ CO_2$	42	49	56	63
*CO_2 penalty**					
w/o CCS	USD_{2011}/kWh_{el}	3.50	4.08	4.66	5.24
with CCS	USD_{2011}/kWh_{el}	0.41	0.48	0.55	0.61

*100% domestic coal

Source: Authors' compilation

31.3 Impact of CCS on the Cost of Electricity generated by Coal-Fired Power Plants in South Africa

31.3.1 Levelised Cost of Electricity generated by Supercritical Coal-Fired Power Plants with and without CCS up to 2050 (without CO_2 Penalty)

This section analyses the LCOE of supercritical PC plants in South Africa with and without carbon capture and storage up to 2050, using the parameters defined in the previous sub-sections. The cost calculations presented in this section do not take into account the possibility of a CO_2 penalty; this will be done in section 31.3.2.

Fig. 31-2 illustrates the LCOE of the type of coal-fired power plants considered in the analysed coal development pathways *E1: high*, *E2: middle* and *E3: low* with and without CCS. In the absence of CCS, the figures indicate a growth of LCOE from US-ct 4.53/kWh in 2010 up to US-ct 6.34/kWh in 2050 across the different development pathways, reflecting an increase of about 40 per cent. Rising electricity production costs are mainly due to very limited learning-induced cost reductions in supercritical coal-fired power plants, since these are a mature, widely deployed technology. Furthermore, there are only minor cost variations between the different development pathways because the amount of new generating capacities without carbon capture and storage equipment is declining in all pathways; pathway *E3: low* excludes the erection of new supercritical PC power stations without CCS technology. As a consequence, cost reductions in investment and O&M expenditures resulting from technology learning are more than outweighed by increasing fuel costs.

CCS technology is assumed to be applied at new large-scale coal-fired power plants after 2030, when the technology becomes commercially available. This means that power plants commissioned in 2030 or earlier are not equipped with carbon capture units. Compared to the same plant type without CCS, CCS plants will produce electricity much more expensively by 2050 (*E1: high:* US-ct 9.81/kWh; *E2: middle:* US-ct 9.99/kWh; *E3: low:* US-ct 10.21/kWh). Consequently, the different development pathways indicate a growth of the LCOE ranging from 56 to 61 per cent in 2050 due to CCS. Despite the higher learning potential of CCS plants compared to supercritical PC plants without CCS, reductions in investment and O&M costs are overcompensated by increasing fuel costs. Coal development pathway *E3: low* features the highest LCOE of CCS plants because it envisages a significantly lower overall capacity of CCS plants and, thus, lower cost reductions.

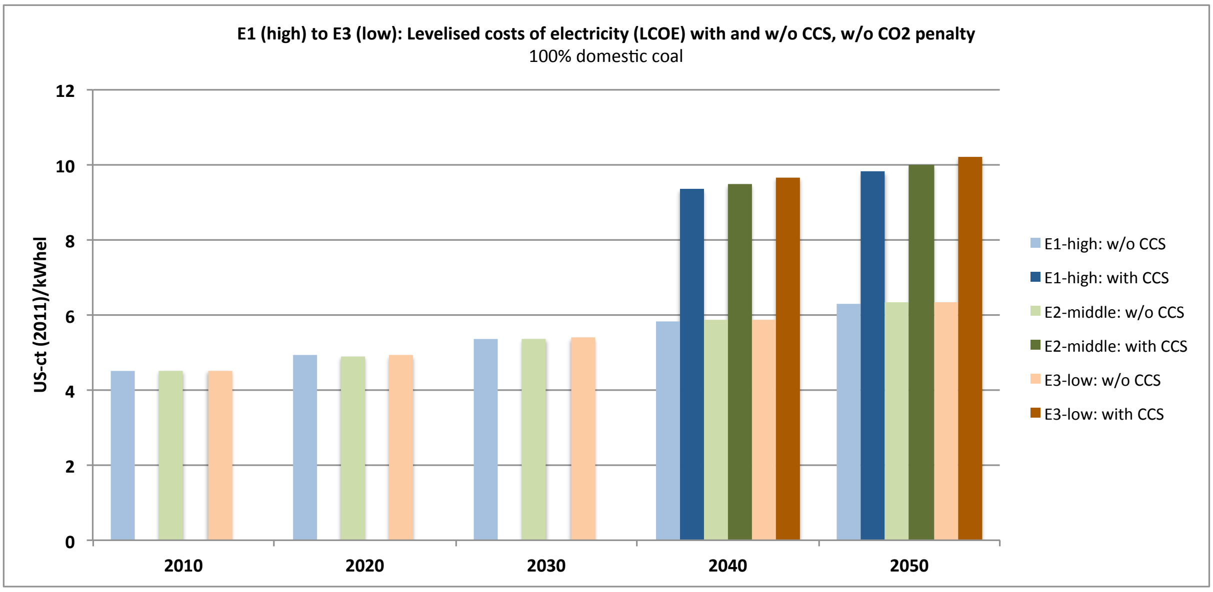


Fig. 31-2 Levelised cost of electricity in South Africa with and without CCS in coal development pathways *E1: high* to *E3: low* up to 2050 without CO_2 penalty

Source: Authors' illustration

The substantial cost penalty of CCS plants is mainly caused by the high capital costs incurred by the capture unit. Furthermore, CO_2 capture processes are very energy intensive and negatively impact upon plant efficiency. The feedstock required to produce one kilowatt hour of electricity and the resulting increase in fuel costs therefore lead to significantly higher fuel costs.

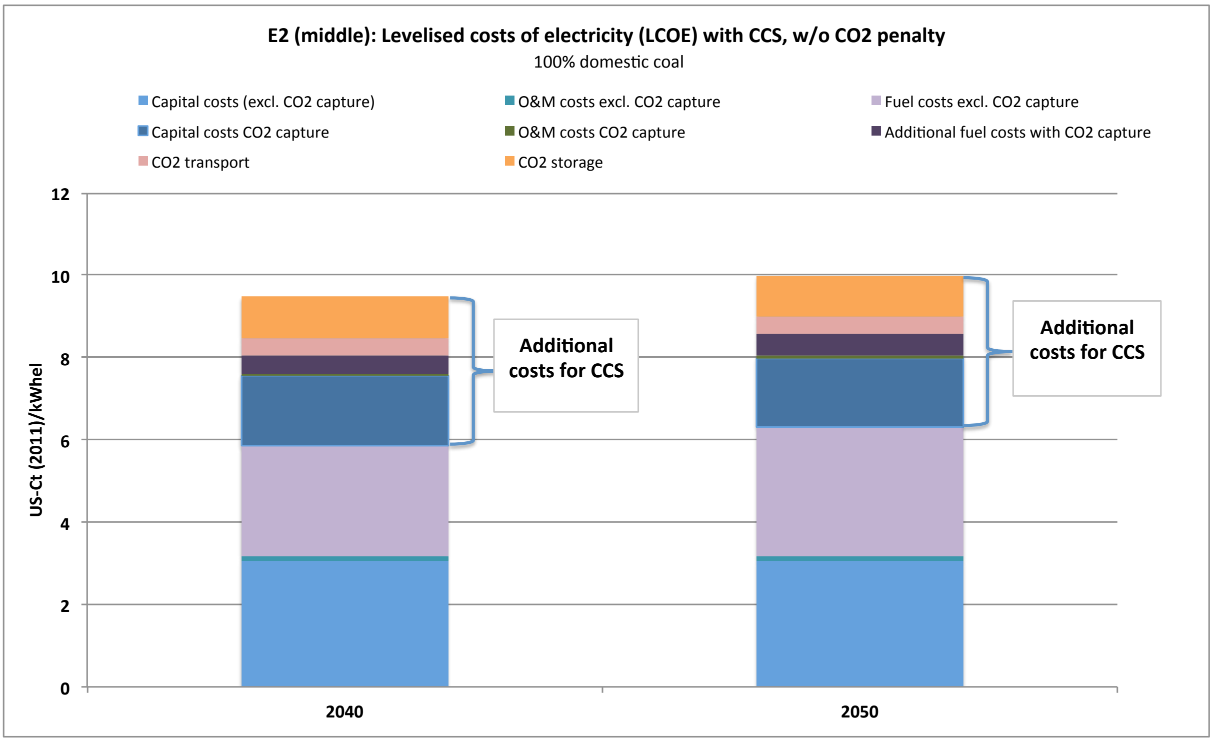


Fig. 31-3 Additions to levelised cost of electricity in South Africa resulting from CCS by cost category in coal development pathway *E2: middle* up to 2050 without CO_2 penalty

Source: Authors' illustration

Fig. 31-3 illustrates the additional costs (specified by cost category) resulting from using CCS for development pathway *E2: middle*. By 2050, CCS implies a cost penalty of US-ct 3.67/kWh.

In accordance with the high capital intensity of CO_2 capture technologies, capital expenditures represent the largest single portion (45 per cent) of the CCS cost penalty. By comparison, Chinese CCS plants have rather lower capital costs due to their cheaper labour and equipment costs compared to international standards. Instead, increasing fuel costs are highly relevant in China. In South Africa, fuel costs constitute the third largest share (14 per cent) of the CCS cost penalty. CO_2 transportation and storage account for 11 per cent and 27 per cent, respectively; O&M costs have a minor impact on the LCOE of CCS plants.

31.3.2 Levelised Cost of Electricity generated by Supercritical Coal-Fired Power Plants with and without CCS up to 2050 (with CO_2 Penalty)

South Africa's national government is currently discussing the introduction of a national CO_2 pricing mechanism, either through a carbon tax or an emission trading scheme. The debate was initiated by the National Treasury in 2010 and continued in the 2011 National Climate Change Response White Paper, which seeks to develop a carbon budget approach within two years of the White Paper's publication in October 2011 (Government of the Republic of South Africa 2011).

Introducing a carbon pricing mechanism could function as a decisive incentive for fitting CCS technology into new coal-fired power plants. In the following, the potential impact of a CO_2 penalty on the LCOE of supercritical PC plants without CCS will be compared with its impact on CCS plants. The CO_2 penalties are exemplarily incorporated into development pathway E2: middle.

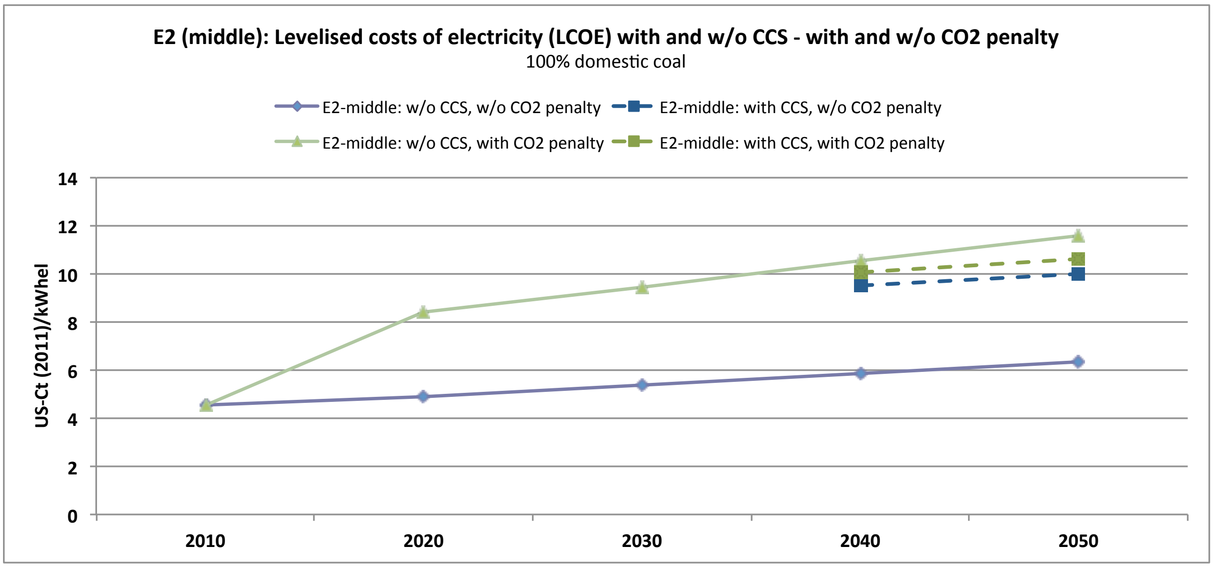


Fig. 31-4 Levelised cost of electricity in South Africa with and without CCS and with and without a CO_2 penalty in coal development pathway *E2: middle* up to 2050

Source: Authors' illustration

Fig. 31-4 shows that, in the absence of a CO_2 penalty (illustrated by the blue line), the LCOE of supercritical PC plants with CCS clearly exceeds that of the same plant type without CCS. When factoring in a CO_2 price (illustrated by the green line), starting at USD 42 per tonne of

CO_2 in 2020 and reaching USD 63 per tonne of CO_2 in 2050, the LCOE of CCS plants is slightly lower than that of non-CCS plants. In 2040, CCS plants will operate with an LCOE of US-ct 10.03/kWh; the LCOE of plants without CCS will be US-ct 10.51/kWh. In 2050, CCS plants (US-ct 10.61/kWh) will also be somewhat more competitive than non-CCS plants (US-ct 11.56/kWh). However, as the economic performance of both plant configurations is rather similar, it is not possible to conclude whether plants with or without CCS will be the more economically viable plants under the assumed political and economic framework conditions. Thus, a more aggressive CO_2 penalty or significant cost reductions in CCS technology would be required to provide a clear incentive for introducing CCS. Comparing the case of South Africa with China, it is evident that the economic barrier to CCS commercialisation is more difficult to overcome in South Africa because capital costs and country-specific calculations of costs for CO_2 transportation and storage are significantly higher than in China.

Fig. 31-5 shows the single additional cost factors of a CCS plant compared to a non-CCS plant in coal development pathway *E2: middle* in 2040 and 2050, assuming the presence of a CO_2 penalty. Fig. 31-6 illustrates the LCOE of non-CCS plants by cost component with a CO_2 penalty. In the latter case, the CO_2 penalty represents by far the single largest cost parameter of the LCOE (US-ct 5.24/kWh), whereas the economic performance of CCS plants is clearly less affected by a carbon pricing scheme (US-ct 0.61/kWh).

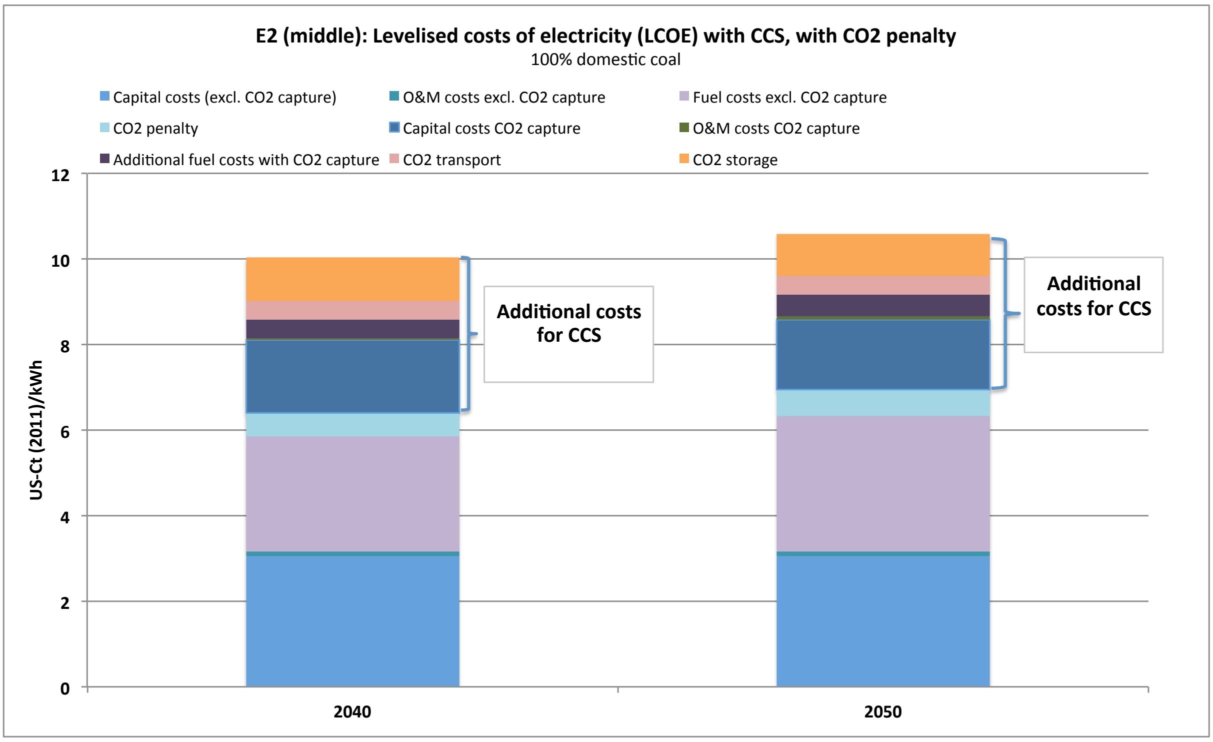


Fig. 31-5 Levelised cost of electricity in South Africa resulting from CCS by cost category in coal development pathway *E2: middle* up to 2050 including a CO_2 penalty

Source: Authors' illustration

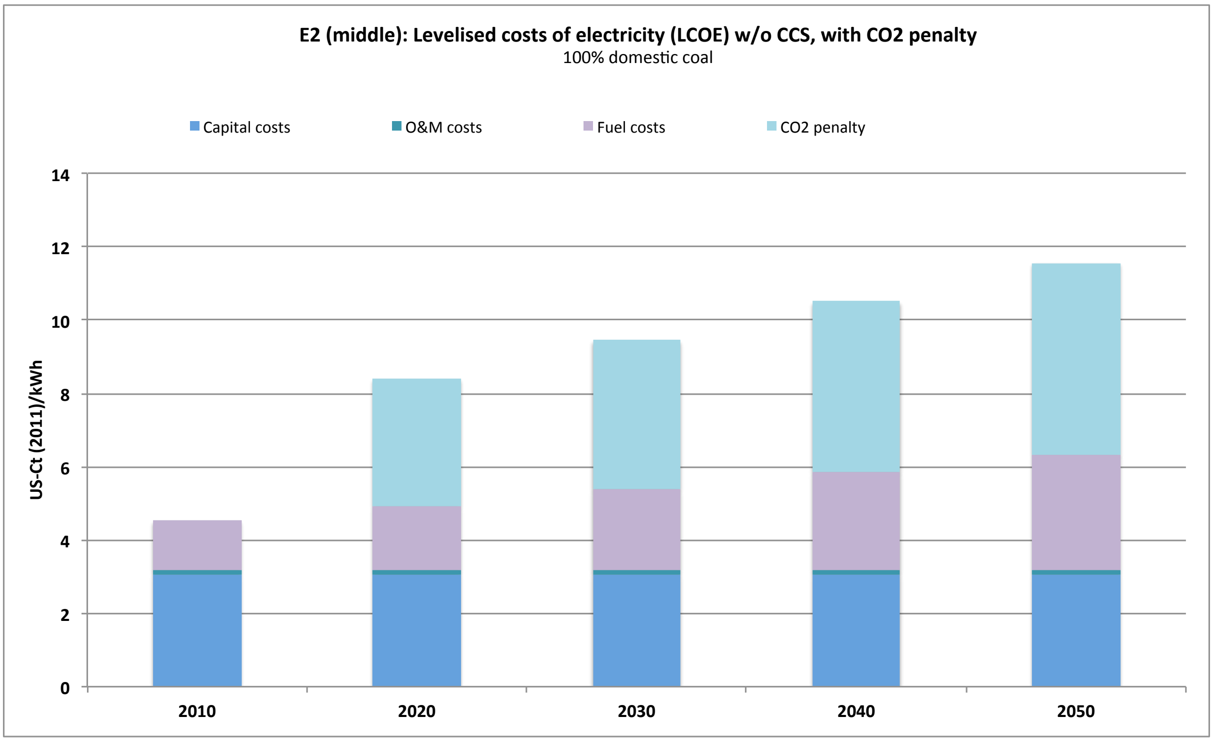


Fig. 31-6 Levelised cost of electricity production in South Africa with and without CCS in coal development pathways *E1: high* to *E3: low* up to 2050 with a CO_2 penalty

Source: Authors' illustration

31.3.3 Comparison of CO_2 Mitigation Costs of Supercritical Coal-Fired Power Plants in South Africa up to 2050 with and without CO_2 Penalty

A frequently used measure for the economic viability of carbon mitigation technologies are costs per tonne of CO_2 avoided (carbon mitigation costs). Fig. 31-7 illustrates the carbon mitigation costs per tonne of CO_2 from supercritical PC plants with CCS in South Africa in 2040 and 2050 for all three scenarios in the absence of a CO_2 penalty. Without a CO_2 penalty, CO_2 mitigation costs range from around USD 48 per tonne of CO_2 to approximately USD 52 per tonne of CO_2 in 2040 and 2050 for the coal development pathways. Development pathway *E1: high* features the lowest CO_2 mitigation costs since a greater quantity of CCS plant capacities is added than in the other scenarios, leading to the highest technology learning effect. As a consequence, development pathway *E3: low* has the highest CO_2 mitigation costs.

In comparison to cost assessment studies for CCS plants in China, the calculated CO_2 mitigation costs of CCS in South Africa are clearly higher, due mainly to the higher plant investment costs in South Africa. In contrast, the CO_2 mitigation costs of CCS in India are roughly the same as those in South Africa (USD 50 to 56/t CO_2 by 2050). India's coal-fired power plants incur high capital costs, since complex conditions for plant operation (e.g. low coal quality) require special plant designs.

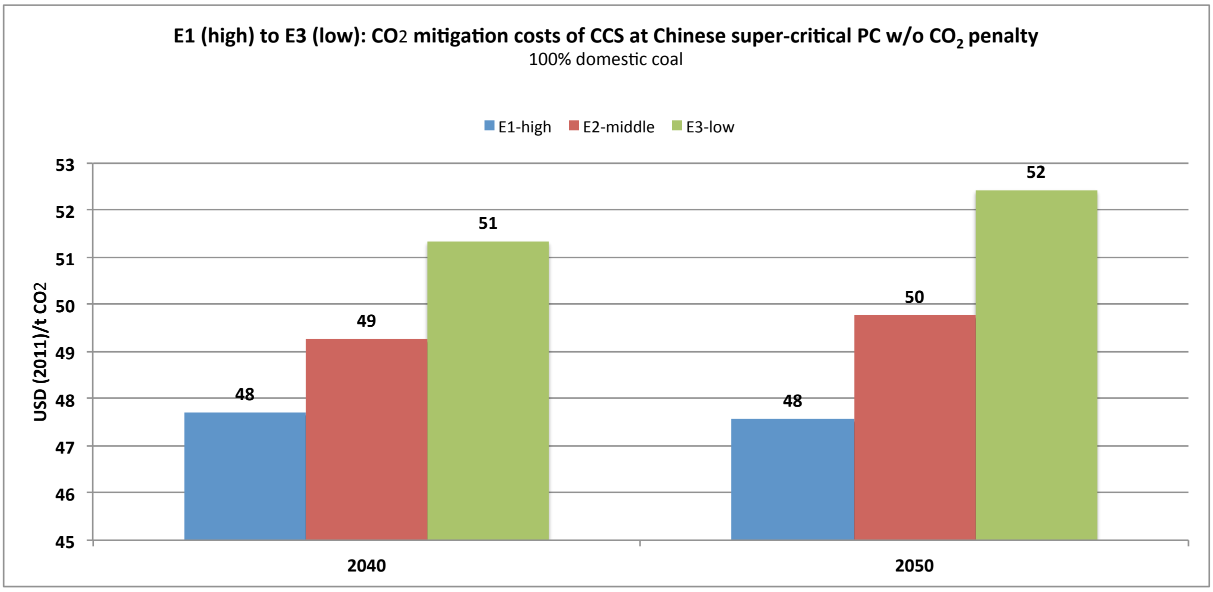


Fig. 31-7 CO_2 mitigation costs of supercritical PC plants in South Africa with CCS and without a CO_2 penalty in coal development pathways *E1: high* to *E3: low*, 2040–2050

Source: Authors' illustration

If, as assumed in this cost assessment, a CO_2 penalty is integrated into the calculation of CO_2 mitigation costs, the picture clearly changes. Fig. 31-8 compares the CO_2 mitigation costs of CCS with and without a CO_2 penalty. It reveals that, in the presence of a CO_2 pricing scheme, CCS plants indicate negative CO_2 mitigation costs in 2040 and 2050. At the same time, operators of non-CCS plants would face substantial CO_2 mitigation costs. CCS plants would therefore be slightly more competitive than non-CCS plants. Nonetheless, a more aggressive price incentive would be required to make the LCOE of CCS plants clearly more economically viable than those of non-CCS plants.

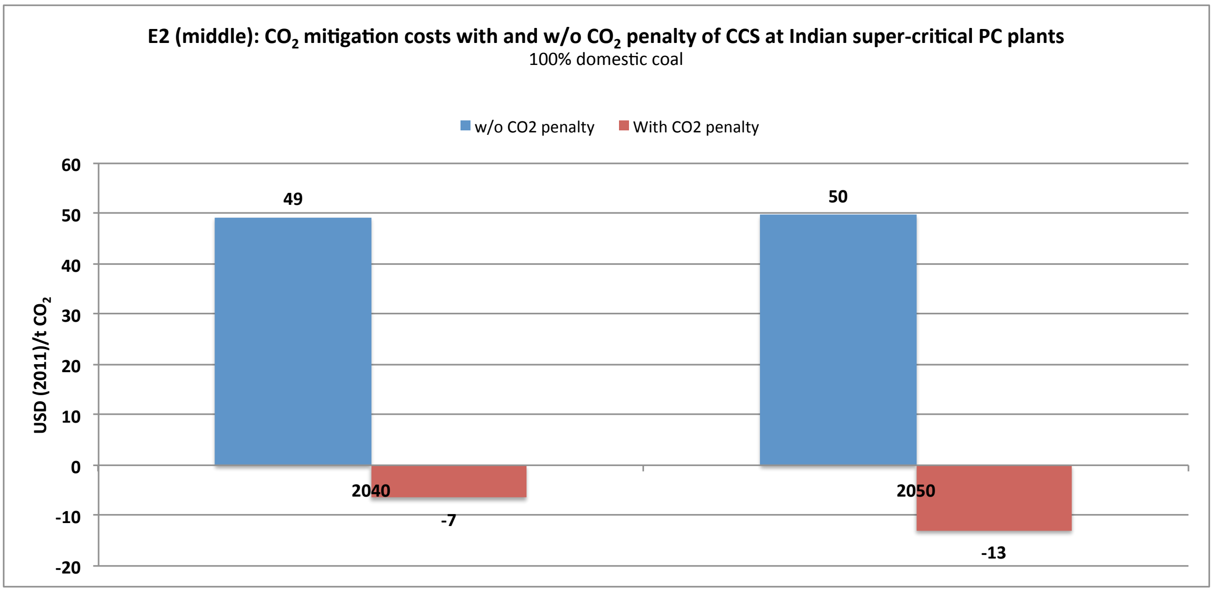


Fig. 31-8 CO_2 mitigation costs of supercritical PC plants in South Africa with CCS in coal development pathway *E2: middle* including a CO_2 penalty, 2040–2050

Source: Authors' illustration

31.4 Conclusions

These cost projections are based on three different pathways for the development of coal-fired power generating capacities in South Africa with and without CCS. The role of coal-fired power plants in these coal development pathways is influenced by different levels of ambition of policy frameworks involving climate protection and sustainable energy. Whereas pathway *E1: high* is based on reference conditions, pathways *E2: middle* and *E3: low* imply more ambitious policy settings. The capacity developments in these three pathways are used as input for calculating learning rates and cost reductions of coal-fired power plants with and without CCS.

The analysis of the levelised cost of electricity (LCOE) of supercritical pulverised coal plants in South Africa shows that by 2050, the LCOE of plants fitted with CCS equipment will exceed that of plants without CCS by 56 to 61 per cent. The precise cost difference depends on the development pathway of coal-fired power plant capacities used as the basis for the present calculation. For example, in the *E2: middle* coal development pathway, the LCOE of a CCS plant total US-ct 9.99/kWh compared to US-ct 6.32/kWh for a non-CCS plant by 2050 in the absence of a CO_2 penalty. High plant investment costs represent 45 per cent of the CCS cost penalty and, thus, are the most significant cost driver. Fuel costs constitute the third largest share (14 per cent) of additional costs, whilst CO_2 transportation and storage account for 11 per cent and 27 per cent, respectively. Storage costs are particularly high in this case study because storage in an offshore formation was assumed due to the high potential of offshore storage sites in South Africa. O&M costs have a minor impact on the LCOE of CCS plants.

Due to higher capital costs, the cost penalty of CCS in South Africa is significantly higher than in other emerging economies such as China. Overall carbon mitigation costs of CCS at supercritical plants in South Africa are estimated to range from USD 48 to 52 per tonne of CO_2 from 2040 to 2050. When factoring in a carbon penalty from 2020 onwards, the competitiveness of CCS plants improves. In 2020, the assumed carbon price is USD 42 per tonne of CO_2, climbing to USD 63 per tonne of CO_2 by 2050. This carbon pricing pathway would be sufficient to compensate for additional costs of CCS. However, it would not provide a particularly strong cost advantage for CCS plants over non-CCS facilities. Consequently, a more aggressive CO_2 penalty or significant cost reductions of CCS technology would be required to provide a clear incentive for CCS usage in South Africa. Furthermore, CCS would face strong competition from other low carbon technologies in a carbon-constrained policy environment, especially from renewable energy technologies, which have much higher learning rates than supercritical PC plants. Thus, a comparison of CCS plants with other low carbon technology options would be required to draw sound conclusions on the economic viability of CCS in a low carbon policy environment.

32 Life Cycle Assessment of Carbon Capture and Storage and Environmental Implications of Coal Mining

32.1 Introduction

At present, no life cycle assessments (LCA) of CCS-based power plants are available for South Africa. To remedy this, an LCA according to the international standard ISO 14 040/44 is performed. An LCA illustrates a "cradle-to-grave" approach in which all energy and material flows that occur during the manufacture, use and disposal of products are modelled (see section 5.3 of Part I). Section 32.2.1 explains the methodological approach; section 32.2.2 provides the basic assumptions and the set of parameters assumed for the LCA. The results are presented in section 32.2.3 and conclusions drawn in section 32.2.4.

Several environmental and social impacts cannot be evaluated in an LCA. For this reason, some implications that especially concern coal mining are highlighted in section 32.3. The commercialisation of CCS would reinforce this impact because CCS-based power plants require 20 to 35 per cent more fuel than those without CCS. Most problems refer to land use, water consumption, air pollution at the mining site and surrounding residential areas, noise, mine waste and – last but not least – social issues resulting from the displacement and resettlement of local communities.

32.2 Life Cycle Assessment of CCS

32.2.1 Methodological Approach

Life cycle assessments are usually performed for existing products or services to enable the best technology with regard to a certain environmental impact category to be selected. However, no commercial CCS-based power plants exist yet. Instead, a *prospective LCA* has to be performed that considers a future situation by updating crucial parameters, such as the power plant's efficiency, to a future situation. A twofold approach is therefore chosen:

- Firstly, a future coal-fired power plant is balanced by updating an existing LCA to future conditions;
- Secondly, the future coal-fired power plant is extended by CO_2 capture facilities, and the transportation and storage of CO_2 is added.

The system boundary of the LCA comprises the complete life cycle, which means mining, power generation and upstream and downstream activities such as the supply of raw material and consumables and the handling of waste. With CCS, the life cycle additionally includes CO_2 capture, transportation and storage (see Fig. 32-1). All material and energy flows are scaled to the output of 1 kWh electricity.

It should be noted that no individual power plant at a selected site is considered because, if at all available, the data only describes the average situation of coal mining or transportation. Hence, the given LCA refers to an average situation in the considered countries, as is usually the case in LCA studies.

The following assumptions and results refer to Deibl (2011), who developed the basic model and performed the LCA.

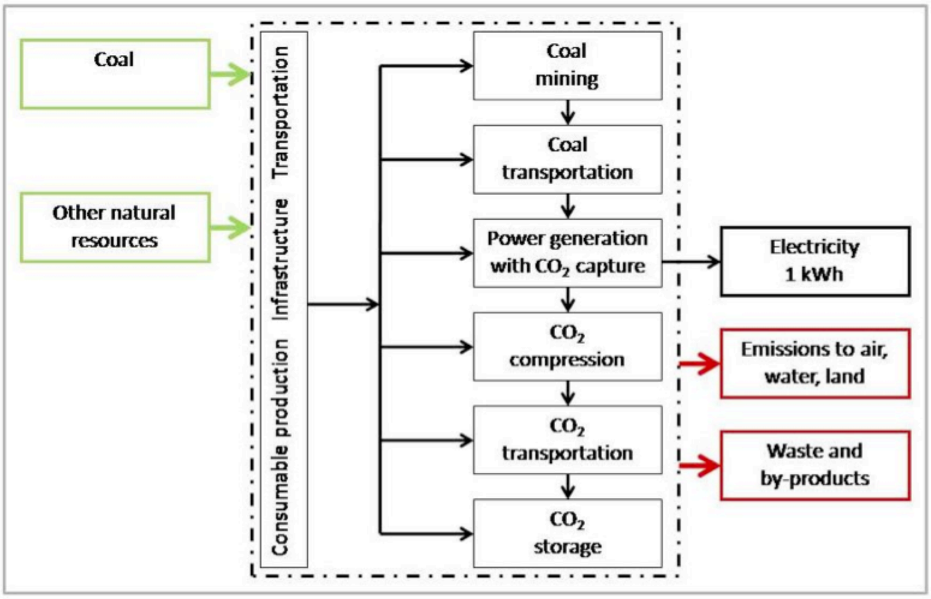


Fig. 32-1 System boundary of the life cycle assessment of coal-fired power plants in South Africa
Source: Deibl (2011) based on Korre et al. (2010)

32.2.2 Basic Assumptions and Parameters

Basic Assumptions

- **Reference year** The LCA refers to 2030, the year in which CCS power plants are assumed to become commercially available in South Africa (see section 28.4.1).
- **Type of power plant** The LCA is performed for supercritical pulverised coal (PC) power plants and for integrated gasification combined cycle (IGCC) power plants because these two types are considered in the coal development pathways for South Africa.
- **CO_2 capture** It is assumed that CO_2 is captured post-combustion using the solvent monoethanolamine (MEA) and pre-combustion using the solvent methyl diethanolamine (MDEA). Although the state-of-the-art solvent for pre-combustion is Selexol (physical absorption) (Walspurger et al. 2011), it is not chosen because no LCA module is available for it in the database used. The manufacture of post- and pre-combustion components is not considered in the LCA because no data is available. However, as Koornneef et al. 2008 showed, the infrastructure contributes only 0.3 per cent to the greenhouse gas emissions of a CCS life cycle. According to the assumptions on decreased energy penalties in 2030 (see Tab. 28-7), the energy required for capture is reduced by 60 per cent in the case of post-combustion and by 50 per cent in the case of pre-combustion capture compared to the figures implemented in the ecoinvent dataset.
- **Storage medium** Deep saline aquifers are assumed to be the storage medium because natural gas and oil fields can be neglected for South Africa.
- **Leakage** It is assumed that no CO_2 is leaked from the underground storage site. A leakage rate of 0.026 per cent per 1,000 km is applied for transportation, which is similar to the leakage rate of natural gas pipelines (Wildbolz 2007).
- **LCA modules** Most of the basic LCA datasets were taken from the international LCA database ecoinvent 2.2 and modified, if necessary (see Tab. 32-1). The LCA dataset for

coal-fired IGCC was taken from Fischedick et al. (2008), where an LCA given by Briem et al. (2004) was implemented and updated with efficiencies assumed for 2030.

Tab. 32-1 Basic LCA modules for South Africa taken from the database ecoinvent 2.2

Parts of life cycle	Module name in ecoinvent	Remark	Modifications
Coal-fired power plants without CCS			
Hard coal supply	Hard coal, at mine [ZA]	100 per cent indigenous coal assumed; without coal fire emissions; average distance specified for South Africa	
Upstream process of power plant; electricity production	Hard coal, combusted in power plant [CN]	Modelling the combustion process of a power plant in China	Modification of SO_2, NO_x and particulate emissions; modification of calorific value
	SO_x retained, in hard coal flue gas desulphurisation [RER]		
	NO_x retained, in SCR [GLO]		
Power plant	Electricity, hard coal, at power plant [CN]	Modelling the efficiency	Update of efficiency for 2030
Components for CCS			
MEA scrubber	Monoethanolamine, at plant [RER]	Production of MEA	
	Sodium hydroxide, 50% in H_2O, production mix, at plant [RER]	Production of NaOH	
	Disposal of raw sewage sludge to municipal incineration [CH]	Incineration of residues	
MDEA scrubber	Monoethanolamine, at plant [RER]	Production of MDEA	
	Disposal of raw sewage sludge to municipal incineration [CH]	Incineration of residues	
CO_2 transportation and storage			
CO_2 transportation	Pipeline, natural gas, long distance, low capacity, onshore [GLO, Infra]	Distance: 550 km; 2 recompression stations	
CO_2 storage		Only energy required for storage is balanced (see parameter definition)	
CN = China; ZA = South Africa; GLO = Global; CH = Switzerland; RER = Europe			

Source: Authors' composition based on Deibl (2011)

Parameters

Tab. 32-2 shows the parameters used for the LCA for South Africa. These are adjusted by parameters used in other sections of this study (for example, the power plants' efficiency).

Tab. 32-2 Parameters used in the LCA of coal-fired power plants in South Africa

Parameter		PC power plant	IGCC power plant	Source
Coal-fired power plants without CCS				
Installed capacity	MW_{el}	600	451	Deibl 2011
Net efficiency	%	41.5	46.5	This study
Full load hours	h/a	7,500		Deibl 2011
Capacity factor	%	85		
Plant lifetime	y	25		Deibl 2011
Type of cooling		Dry		This study
Calorific value of coal	MJ_{th}/kg_{coal}	19.59		This study
GHG emissions from coal fires	kg $CO_{2\text{-}eq}/kg_{coal}$	0		
Methane emissions from coal mining	kg CH_4/kg_{coal}	0.0035		ecoinvent
CO_2 emissions from coal	kg/MJ_{th}	0.0962		This study
CO_2 capture				
Type of capture process		Post-combustion	Pre-combustion	
Concentration of solvent	kg/t CO_2	1.958	0.011	Deibl 2011
Energy required for capture	kWh_{el}/t CO_2	178	119	This study
Energy required for compression	kWh_{el}/t CO_2	92.84		Deibl 2011
CO_2 capture rate	%	90		This study
CO_2 transportation and storage				
CO_2 transport distance	km	550		This study
Energy required for recompressor	kWh/tkm	0.011		Wildbolz 2007
Energy required for CO_2 injection into 800 metre deep saline aquifer	kWh/kg CO_2	0.00668		Wildbolz 2007

Source: Composed and updated from Deibl (2011)

Emissions from Mining

Two main sources of greenhouse gas (GHG) emissions must usually be considered in particular when regarding coal mining: carbon dioxide and other GHG emissions from underground coal fires, and coalbed methane emissions.

- Concerning *coal fires*, the situation has much improved since the fifties. According to the South African Institute of Mining and Metallurgy (2005), three mining areas had been burning since 1953. However, in the meantime they have been reduced to a minimum (Sino-German Coal Fire Research 2012). Therefore, no coal fire emissions are added in the dataset "Hard coal, at mine [ZA]."
- In the ecoinvent dataset "Hard coal, at mine [ZA]" *coalbed methane emissions* are factored in with an emission coefficient of 0.0012 kg CH_4 per kg coal produced. Weighted with a GWP of 25 kg $CO_{2\text{-}eq}$ per kg CH_4, this figure results in a GHG emission coefficient of 0.03 kg $CO_{2\text{-}eq}$ per kg coal. Applying this factor to a power plant's coal consumption of 400 to 500 g/kWh electricity produced (depending on the calorific value and the power

plant's efficiency), coal-bed methane emissions cause additional GHG emissions of 12 to 15 g $CO_{2\text{-eq}}$/kWh.

32.2.3 Results of the Life Cycle Assessment

After determining the material- and energy flows occurring in the whole system, all flows that enter and leave the system are summarised in a life cycle inventory (LCI). The LCI is the basis of the life cycle impact assessment (LCIA) in which the flows are weighted and aggregated to several environmental impact categories. This study applies the internationally acknowledged LCIA method *CML 2001* (Guinée et al. 2002), developed by the Centrum voor Milieukunde in Leiden/Netherlands. Categories – subdivided into GHG emissions and other environmental impacts – are presented below the results of the particular impact.

32.2.3.1 Global-Warming Potential (Greenhouse Gas Emissions)

The impact category global-warming potential (GWP) comprises the impact of all GHGs emitted from the considered system, weighted and aggregated to the unit CO_2-equivalents ($CO_{2\text{-eq}}$). In the case of energy technologies, the most important GHGs are CO_2, methane (CH_4) and nitrous oxide (N_2O), which are weighted with a GWP of 1, 25 and 298 kg $CO_{2\text{-eq}}$ per kg substance, respectively (IPCC 2007). Since the reduction in CO_2 is usually discussed in the CCS debate, both the total GWP and the CO_2 emissions as part of the GWP are shown in this report (Fig. 32-2).

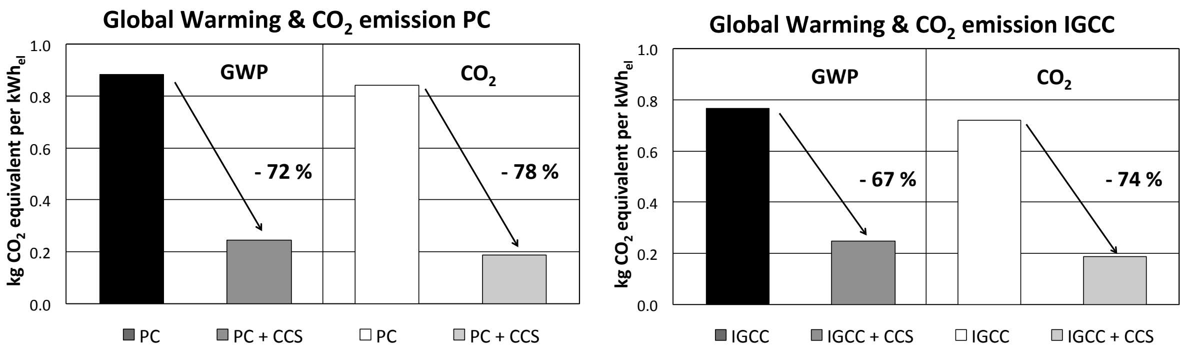


Fig. 32-2 Global-warming potential and CO_2 emissions for PC and IGCC with and without CCS in South Africa from a life cycle perspective

Source: Authors' composition based on Deibl (2011)

CO_2 Emissions

Considering the whole system, CO_2 emissions from a CCS-based power plant are reduced by 78 per cent for PC power plants (second chart) and 74 per cent for IGCCs (fourth chart) compared to a power plant without CCS.

The specific emissions without CCS amount to 841 g CO_2/kWh (PC) and 721 g CO_2/kWh (IGCC). These are reduced to 189 g CO_2/kWh respectively for PC and IGCC.

Total Greenhouse Gas Emissions

Considering the total GHG emissions in the whole system, the reduction rate is 72 per cent for PC power plants (first chart) and 67 per cent for IGCCs (third chart) compared to a power plant without CCS.

The specific GHG emissions without CCS amount to 883 g $CO_{2\text{-eq}}$/kWh (PC) and 770 g $CO_{2\text{-eq}}$/kWh (IGCC). These are reduced to 240 g $CO_{2\text{-eq}}$/kWh (PC) and 250 g $CO_{2\text{-eq}}$/kWh (IGCC).

The overall reduction rates of both CO_2 and GHG emissions are lower than one would expect, when considering a CO_2 separation rate of 90 per cent at the power plant's stack. It is important that not only the CO_2 emissions potentially avoided at the power plant's stack are considered. A CO_2 capture rate of 90 per cent, as assumed in most studies, does not include:

- The excess consumption of fuels that causes more CO_2 emissions, with the consequence that the separated CO_2 emissions are higher than the avoided CO_2 emissions;
- The CO_2 emissions released into the upstream and downstream parts of the system;
- Other GHG emissions released in upstream and downstream processes, the most relevant of which is methane emitted during coal mining.

The figures for South Africa comply with the results of a study by Viebahn (2011) in which he compared five LCA studies performed for European conditions. The meta-analysis shows that an overall reduction in GHG emissions of between 67 and 72 per cent can be expected if applying post-combustion and pre-combustion to hard coal-fired power plants in 2020/25. A more recent analysis by Singh et al. (2011) reveals a similar range (67 to 75 per cent).

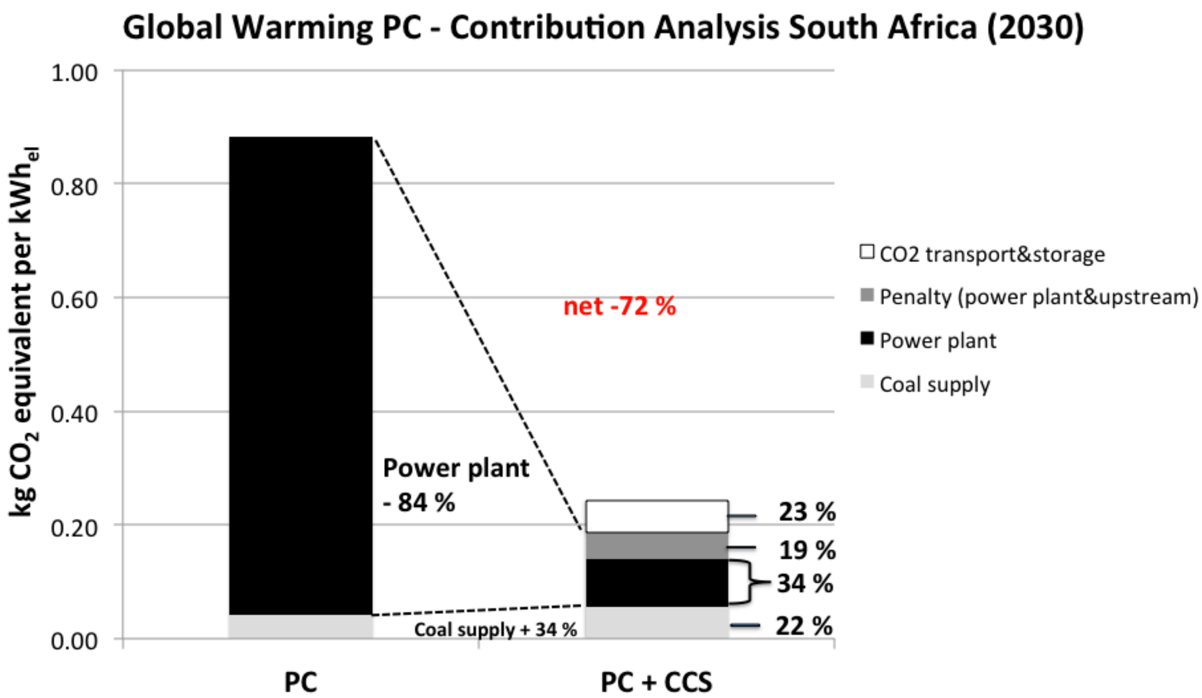


Fig. 32-3 Contribution of individual life cycle phases to the global-warming potential for PC with and without CCS in South Africa

Source: Authors' composition based on Deibl (2011)

Fig. 32-3 shows the contribution of individual life cycle phases with PC power plants (net reduction of 72 per cent). The specific emissions caused by the coal supply increase by 34 per cent whilst those caused by power plants decrease by 84 per cent. The coal supply share increases from 4 per cent without CCS to 22 per cent in the case of power plants with CCS. Emissions from the transportation and storage of CO_2 play a large role (23 per cent) due to the transport distance of 550 km, whilst the share of power plants including CO_2 capture drops to 54 per cent (power plant plus penalty).

32.2.3.2 Further Impact Categories

Fig. 32-4 illustrates the results of the LCIA for other environmental impact categories, described below.

Acidification and Eutrophication

With *acidification potential (AP)*, the environmental performance of PC and IGCC systems increases by 11 and 133 per cent, respectively, with CCS. However, IGCC with CCS scores less than PC without CCS. The *eutrophication potential (EP)* shows a 28 and 29 per cent increase for PC and IGCC, respectively.

The results can be explained by the additional consumption of fuels in the case of CCS. Although the direct SO_2 and NO_X emissions, which cause AP and EP, are also reduced during the CO_2 scrubbing process, their decrease is outweighed by an increase during the upstream process. Other studies also predict a 36 to 80 per cent increase for eutrophication in PC. For acidification, a 10 per cent reduction up to a 46 per cent increase can be found in the literature (Viebahn 2011).

Human Toxicity and Terrestrial Ecotoxicity

Considering the *human toxicity potential (HTP)*, the environmental performance of PC and IGCC systems increases by 45 and 50 per cent, respectively, with CCS. However, IGCC with CCS scores less than PC without CCS. The greater increase in HTP with PC compared to IGCC can be explained in part by MEA production (share of 12.1 per cent), required in the post-combustion process for PC. Since a share of 12.6 per cent is calculated for the scrubbing phase, the dominant process in this phase is the production of MEA.

The *terrestrial ecotoxicity potential (TETP)* shows a 67 and 522 per cent increase for PC and IGCC systems, respectively. Since IGCC with CCS scores less than PC without CCS, the high percentage increase is put into perspective.

Other studies report a 157 to 210 per cent increase in HTP scores and a 57 per cent rise in TETP scores for PC (Viebahn 2011).

Freshwater and Marine Aquatic Ecotoxicity

The results obtained for the *fresh water aquatic ecotoxicity potential (FWAETP)* are similar to those for the *marine aquatic ecotoxicity potential (MAETP)*. Both FWAETP and MAETP increase by 27 per cent for PC and 32 per cent for IGCC with CCS. A 29 per cent reduction in the MAETP and a 46 per cent increase in the FAETP for PC systems can be found in the literature (Viebahn 2011). Again, IGCCs perform noticeably better than conventional power plants.

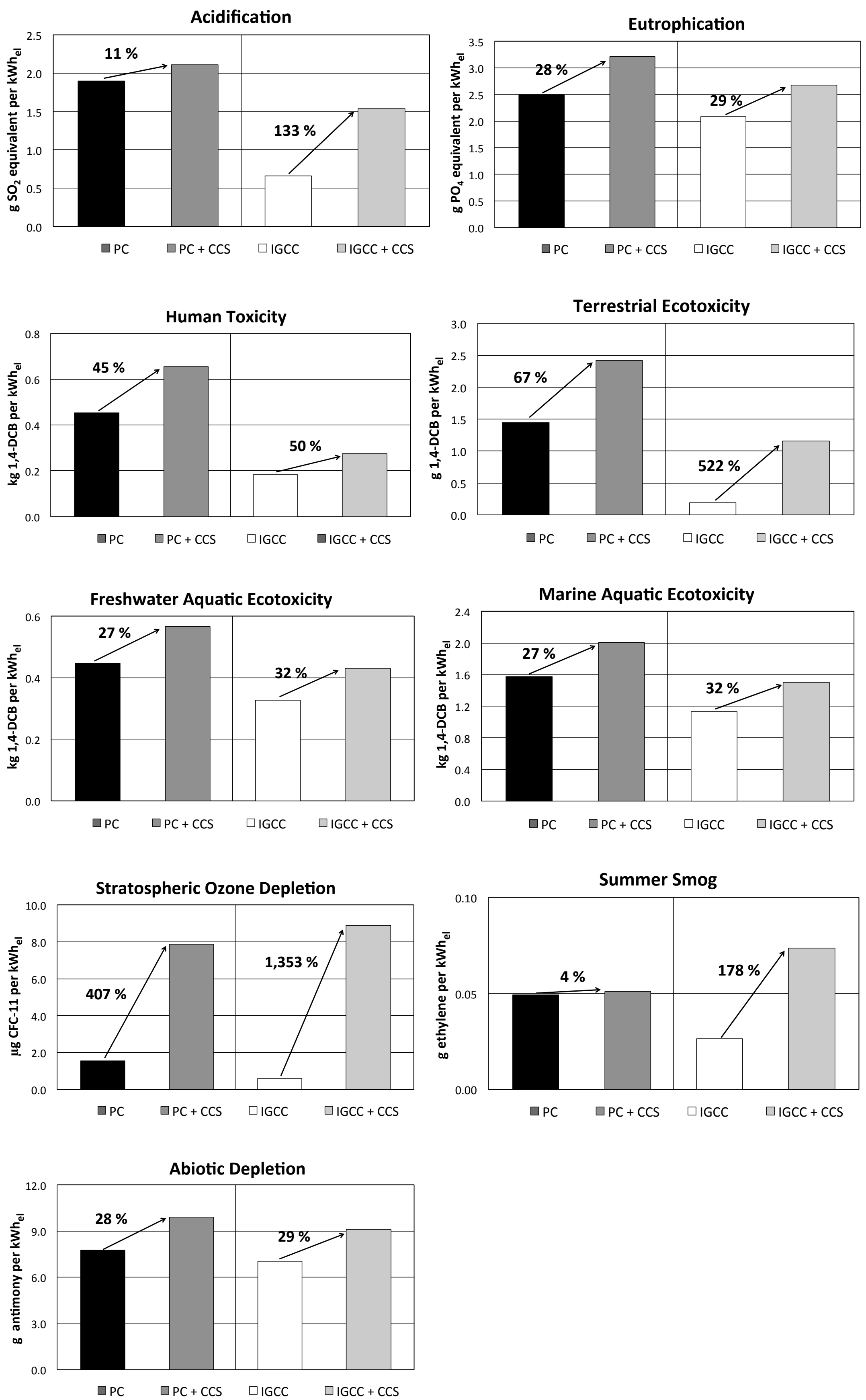


Fig. 32-4 Results of nine impact categories for PC and IGCC with and without CCS in South Africa from a life cycle perspective

Source: Authors' composition based on Deibl (2011)

Stratospheric Ozone Depletion

With the *stratospheric ozone depletion potential (ODP),* a sharp rise is visible when comparing power plants with and without CCS: the environmental performance of PC and IGCC systems increases by 407 and 1,353 per cent with CCS, respectively. A contribution analysis reveals that the reason for this huge increase can be found in the transportation (550 km) and storage phase of the system, whilst for power plants without CCS the ODP is dominated by the coal supply. An increase of only 55 per cent for other PC systems is reported by Viebahn (2011).

Summer Smog

The impact category summer smog (*photochemical oxidation potential, POP*) indicates a slight difference to the other impact categories, as the score of IGCC with CCS is higher than that of PC with CCS. CCS increases the POP by 4 and 178 per cent for PC and IGCC, respectively. The increase in POP is caused by increasing SO_2 and CH_4 emissions released by additional coal transportation and mining.

Other studies calculate a range of -13 to +94 per cent for PC systems (Viebahn 2011).

Abiotic Depletion

Scores for *abiotic depletion* increase by 28 and 29 per cent for PC and IGCC, respectively, when CCS is applied. The reasons for this include the more extensive occupation of land by coal mines and CO_2 pipelines.

32.2.4 Conclusions

A prospective life cycle analysis (LCA) of future CCS-based power plants in South Africa was performed to assess the environmental impacts of CCS. Taking into account a CO_2 capture rate of 90 per cent, PC and IGCC power plants with and without CCS were compared. The results show a decrease in CO_2 emissions by 74 and 76 per cent for PC and IGCC systems, respectively. Total GHG emissions declined by 68 and 71 per cent, respectively. However, all other environmental impact factors increased (acidification, eutrophication, human toxicity, terrestrial ecotoxicity, freshwater and marine aquatic ecotoxicity, stratospheric ozone depletion and summer smog). These results are in line with LCAs performed by other authors, as Viebahn 2011 showed in a meta-analysis of LCAs for future CCS systems in Europe.

In general, two issues are responsible for these results. Firstly, the additional energy consumption of CCS-based power plants (energy penalty) creates greater emissions per kilowatt hour of electricity generated in the power plant. Only CO_2, NO_x and SO_2 are removed from these emissions during the CO_2 scrubbing process. Secondly, the additional emissions caused by upstream and downstream processes have to be considered. Both the excess consumption of fuels and additional processes such as the production of solvents or the transportation and storage of CO_2 cause an increase in several emissions. When these emissions are (partially) removed at the power plant's stack, upstream and downstream emissions dominate the respective impact categories.

However, the absolute scores and general framework of the LCA model must be considered when interpreting the results. A wide range of assumptions for capture, transportation and storage, timing of the CCS process, type of reference power plant and choice of parameters makes it difficult to compare the results with LCAs performed in other studies (Viebahn

2011). Furthermore, it is not possible at present to model the capture process in detail due to the lack of data. Variations of the removal rate of pollutants in particular could alter the results substantially. Regarding this study, further limitations must be borne in mind: only little data exists on the performance of power plants in South Africa. The uncertainty surrounding the future technical development up to the reference year 2030 necessitates the use of assumptions, which could mislead the results. This particularly concerns the assumed power plants' efficiencies and the datasets for modelling the upstream process of coal mining.

32.3 Further Environmental Implications of Coal Mining outside LCA

32.3.1 Land Consumption

Around 49 per cent of coal production currently comes from open cast mines, and 51 per cent from underground mines, whereby the share of underground mining is growing (section 30). Surface mining is either by strip mining, usually using draglines to remove the overburden and later replace it in the mined-out area, or by open cast mining, where the overburden is removed and dumped elsewhere. Open cast mines have a more significant impact on the land and nature than underground mining. Open cast mining is used if coal seams are located near the surface. It is less cost intensive than underground mining and enables coal recovery rates of about 90 per cent. In open cast mining, the earth and rock above the coal seam (called overburden) are broken up by explosives and removed. The exposed coal seam is drilled to make it fracture; then the loose coal is removed (World Coal Institute 2009).

Vast hectares of vegetation in the form of natural forests and crop plantations have been lost to mining. Mining exploitation leads to the loss of usable land, the contamination of plants and soil, and the destruction of the natural landscape, creating open spaces in the ground and generating heaps of rock waste, mine tailings that are difficult to disposed of (Munnik et al. 2010).

32.3.2 Water Consumption and Water Pollution

As mining and other industries in the northern region expand, water demand will grow rapidly. In a water-constrained country such as South Africa, the quality of water determines its suitability for use. The most serious immediate environmental problem in South Africa associated with coal mining is that of acid mine drainage and the pollution of surface and groundwater. Acid mine drainage consists of three interrelated problems: firstly, the pyrite in the rock gives rise to water with a low pH value. This acid water in turn mobilises heavy metals from the environment, in the mine or in the river course from the sediments. Thirdly, treating the water with calcium to raise the pH makes the water more saline (Munnik et al. 2010).

Mining breaks up the rock mass, allowing free access of water and sulphuric acid-producing reactions between iron sulphide (pyrite), present in the coal and its host rocks, and oxygen-bearing water. Acidic water dissolves aluminium and heavy metals, including iron and manganese, which are toxic to animal and most plant life.

In bord and pillar mining, only the pillars come into contact with water. Longwall mining, where the roof is allowed to collapse into the mined out void, increases the contact area and also facilitates the ingress of rainwater. In opencast mining the rock mass is completely fragmented, maximising the contact between water and rock, and is therefore the most acid-producing method of mining. Acid mine drainage acidifies soil and rivers (Eberhard 2011).

Destruction of biodiversity, reduced agricultural production, soil erosion and serious water pollution are now evident in the Olifants River and are beginning to emerge in the Vaal River catchment. The Vaal River is the source of Rand Water's raw water for more than 10 million people.

Hence the Upper Olifants River has been seriously degraded by coal mining. The Loskop Dam, part of a nature reserve on the Olifants River, has experienced the death of fish, turtles and crocodiles, associated with the poor water quality in the river caused by extensive coal mining activities in this area. In addition, two big municipal dams – Witbank and Middelburg – are periodically too salinised to meet drinking water standards (Munnik et al. 2010).

32.3.3 Other Environmental Impacts of Coal Mining

Air Quality

The Mpumalanga province has the largest number of coal pits, concentrated around Witbank, Highveld and Ermelo. This province currently has the worst air quality in the world, largely due to coal mining activities and coal-fired power stations. Most of the coal is low quality and has a high ash content of between 32.5 and 40.4 per cent. The spontaneous combustion of coal mining heaps releases toxic compounds, including carbon monoxide, carbon dioxide, methane, benzenes, toluenes, xylenes, as well as sulphur, sulphur compounds, sal ammoniac, arsenic, mercury and lead.

Coal contains a certain amount of methane, and the deeper the mine, the greater the methane in the coal. As mining proceeds, methane is released into the mine air and eventually discharged into the atmosphere. South Africa emits nearly 7 million tonnes per annum of carbon dioxide equivalents from its underground coalmines (Lloyd 2002).

One of the impacts of burning dumps is the release of sulphur oxides. Sulphur compounds are concentrated in the waste, contributing much more than the equivalent amount of clean coal (Lloyd 2002). Air quality is also affected by coal dust caused by the transportation of coal in huge open trucks (Munnik et al. 2010).

Another environmental impact is caused by the combustion of coal for power plants: this produces a number of by-products, the major one being fly ash. Major elements in fly ash are iron (Fe), aluminium (Al) and silicon (Si), together with significant amounts of calcium (Ca), potassium (K), sodium (Na) and titanium (Ti). In addition, many toxic elements are present such as sulphides, sulphates, carbonates, phosphates and silicates, and clay minerals enrich the inorganic component of coal with elements such as silicon (Si), iron (Fe), sulfur (S) and phosphorus (P). Groundwater and soils are contaminated by these elements and large areas of precipitates mar the environment around ash heaps, which are also a source of corrosive airborne particles (Petrik et al. 2003).

Noise

All mining activities produce very high levels of noise and massive vibrations in the mining area, which constitute a source of disturbance. The availability of large-diameter, high-capacity pneumatic drills, the blasting of hundreds of tonnes of explosives, and so on, are identified as noise-prone activities. Other sources of noise include vehicular and other transport systems. Noise influences work performance and makes communication more difficult. In addition, the fauna in the forests and other areas surrounding the mines/industrial complexes is also effected by noise; it is generally believed that wildlife is more sensitive to noise and vibrations than human beings (Singh 2008).

Mine Waste

The release of mining waste to the environment can result in the profound, generally irreversible destruction of ecosystems. In many cases, polluted sites may never be fully restored because their contamination is so persistent that no remedy is available (Munnik et al. 2010).

Health Risks and Social Issues

Resent research shows that silicosis, other lung diseases and hearing loss are recurring problems amongst ex-miners (Munnik et al. 2010). Mine accidents and the high death rates in the past have improved in recent years. There were 257 injuries in coal mines in 2008 compared to 143 injuries reported in 2009 (Zondi 2009).

Coal mining also has serious social consequences, especially on the movement of people. The migrant labour or hostel system of housing black miners without their families led to a break-up of the fabric of society, as mine workers often acquired local sexual partners, and the spread of AIDS. Miners who spend their lives in hostels and mine villages lose their accommodation and jobs when the mines close.

Blasting is a regular occurrence across the mining areas. There are no limits to blasting intensity in South Africa. In Ermelo, where two mines are very close (500 m to 1 km) to the houses of Wesselton township, 200 cracked houses have been recorded (Munnik et al. 2010).

However, progress is being made in shifting frameworks to address mine closure and mine water management in South Africa, but despite the efforts of the mining industry to change practices to conform to new regulations, areas for improvement remain (Hobbs et al. 2008).

32.3.4 External Cost Assessment

Researchers from the University of Pretoria published a study that calculates the external costs of coal-fired power generation using the example of Kusile, one of two large power plants currently being built in South Africa (Blignaut et al. 2011). In their assessment, they included the effects of coal mining on the environment, such as water consumption and water pollution, loss of agricultural and other ecosystem goods and services, human health impacts, coal transportation and climate change impacts.

Such environmental impacts indicate a significant economic impact, leading to external costs ranging from between ZAR 31 and 61 billion per year. Approximately 70 per cent of these external costs are water-related, followed by 21 per cent for the mining sector and 10 per cent for climate change. These additional costs are associated with coal-fired power plants – if it were possible to shift these costs to investments in renewable energy sources, these investments could probably be recouped from the damage cost of Kusile within 3.5 and about 10 years at the latest (Blignaut et al. 2011).

33 Analysis of Stakeholder Positions

33.1 Approach of Analysis

This section summarises the positions of key players in the South African discourse on CCS in order to sketch a constellation of key stakeholders. The analysis is mainly based on research interviews conducted with experts from science, industry and non-governmental organisations (NGOs). The structure and course of the interviews were defined by a questionnaire that contained open questions, giving respondents the opportunity to freely express their positions and to identify parameters affecting the prospects of CCS in South Africa. However, the questionnaire merely acted as a guideline, and was expanded by supplementary or more detailed questions, matching the respondent's expertise. Hence, the questions posed to the respondent and the course of the interviews were only partially standardised. Comparability of the interviewees' responses is ensured by key questions discussed in all interviews.

In total, Wuppertal Institute discussed CCS with ten South African experts. Tab. 33-1 lists the organisations where representatives were interviewed. The stakeholders interviewed were identified and selected after screening available studies on CCS in South Africa. The analysis of stakeholders' positions that are covered in the following analysis but not by the experts interviewed is mainly based on publicly available statements or documents on CCS issued by the stakeholders concerned. As previously mentioned, the analysis focuses on key stakeholders, and does not claim to give a full picture of relevant CCS stakeholders in South Africa.

Tab. 33-1 List of stakeholders interviewed in South Africa (face-to-face interviews)

Organisation	Date of Interview
Industry	
Sasol	24/10/2011
Eskom	27/10/2011
Anglo American	27/10/2011
Civil Society	
Fossil Fuel Foundation (FFF)	25/10/2011
Greenpeace Africa	31/10/2011
Science, consultancies and think-tanks	
South African Centre for Carbon Capture and Storage (SACCCS)	24/10/2011 25/10/2011
IMBEWU – Sustainability Legal Specialists	27/10/2011
Council for Geoscience	28/10/2011
School of Chemical and Metallurgical Engineering at University of Witwatersrand	31/10/2011

Source: Authors' compilation

33.2 National Government

The South African government has chosen a proactive and ambitious approach to tackle climate change. This was made particularly clear prior to the 17th Conference of the Parties to the United Nations (COP17) in Durban in December 2011, which was hosted and led by the South African government. Shortly before the COP17 in October 2011, the government published its "National Climate Change Response White Paper," which describes South Africa's climate policy objectives and strategies. The South African government declares its recognition of climate change as a major global challenge as well as its willingness "to make a fair contribution to the global effort to stabilise greenhouse gas (GHG) concentrations in the atmosphere at a level that avoids dangerous anthropogenic interference with the climate system within a timeframe that enables economic, social and environmental development to proceed in a sustainable manner" (Government of the Republic of South Africa 2011). South Africa's efforts to reduce its discharge of greenhouse gas emissions is guided by mitigation targets which the President, Jacob Zuma, announced on 6 December 2009 at the Climate Summit in Copenhagen. By 2020 and 2025, South Africa aims to reduce national greenhouse gas emissions by 34 and 42 per cent, respectively, below its business-as-usual emissions growth trajectory (Government of the Republic of South Africa 2011).

In order to comply with the cited mitigation target, the government has developed a wide portfolio of technological and policy strategies. In its 2010 National Climate Change Response Green Paper, the South African government emphasised the need to roll out research, development and demonstration (RD&D) programmes for a number of low carbon technologies, including CCS, and to design a legal framework for use of CCS (Government of the Republic of South Africa 2010). In the 2011 White Paper, CCS technology is explicitly mentioned as a short- to medium-term option for tapping mitigation potentials in South Africa's synthetic fuel industry. South Africa currently has the world's largest coal-fired synfuel industry (coal-to-liquid/CTL) with a daily liquid fuel production capacity totalling 160,000 barrels. This is equivalent to about 28 per cent of South Africa's automotive fuel demand (Vallentin 2009). South Africa's CTL industry is seen as an ideal opportunity for introducing CCS, as carbon capture is an integrated component of coal liquefaction processes based on coal gasification.

In the White Paper on Climate Change, the South African government does not explicitly mention CCS in the context of the power sector, but makes the rather general statement of "shifting to lower-carbon electricity generation options" (Government of the Republic of South Africa 2011), which is considered one of the mitigation options with the biggest medium-term mitigation potential. However, the government's Integrated Resource Plan for Electricity 2010–2030 (DOE 2011c), which outlines South Africa's strategy for the power sector up to 2030, implies that this shift will mainly be achieved by an expansion of renewable and nuclear energy, leading to a more diversified power generation mix. Coal remains an important pillar of South Africa's power sector, but loses its dominant role. CCS is mentioned only very briefly as one technical option that needs to be developed, as it enables the continuation of coal-fired power generation in a carbon-constrained world.

In a recent speech, however, the Director General of the national Department of Energy (DOE) acknowledged the relevance of CCS for South Africa's mitigation strategy, also with regard to the power sector. She pointed out that the continued use of coal is premised on the development of clean coal technologies such as CCS. In order to realise the technology's mitigation potential, the Director General underlined the need to intensify CCS-related research and development efforts (DOE 2011d). This statement is in line with the objective of establishing a "Carbon Capture and Storage Flagship Programme," which is one of the measures in the portfolio of instruments outlined in the White Paper on climate policy. Led by the DOE in partnership with the South African Energy Research Institute (SANERI), the Flagship Programme will primarily foster the development of a carbon capture and storage demonstration plant (Government of the Republic of South Africa 2011).

In order to speed up the development of CCS in South Africa, the national government has set up an inter-departmental task team. One of the team's tasks is to start devising a regulatory and legal framework for CCS in South Africa, especially underground CO_2 storage, with the involvement of all regulating agencies. The team's inaugural meeting was held in late 2011. As with the topic of CCS in general, the task team is coordinated by the Department of Energy. Other governmental departments involved are the Department of Minerals and Resources, the Department of Environmental Affairs, the National Planning Commission, the Department of Trade and Industry as well as the Department of Health (IMBEWU 2011).

Another cornerstone of the institutional setting of South Africa's CCS strategy is the South African Centre for Carbon Capture and Storage (SACCCS). The Centre was established in March 2009 as a division of the South African National Energy Research Institute (SANERI). It is co-funded by the South African government via SANERI (SACCCS 2012). SACCCS has elaborated a roadmap and strategy for CCS development and commercialisation in South Africa, which has been adopted or quoted by several official government representatives (DOE 2011a). The roadmap encompasses the following key milestones:

- Conduct a CO_2 test injection in 2016 (injection of 10,000 t CO_2);
- Have a CCS demonstration plant up and running in 2020 (storage of 100,000 t $CO_{2;}$
- Realise commercial operation of CCS in 2025 (1 million t CO_2 to be stored).

As a first regulatory step towards facilitating the commercialisation of CCS, the national government requires newly built coal-fired power plants to be designed as capture-ready. A precedence in this regard is the obligation to design the new coal-fired Kusile power plant capture-ready in 2008. In addition to the national government's decision, meeting the technical requirements for retrofitting the Kusile plant with CCS was requested by the World Bank, which co-finances the project and does not wish to be associated with CO_2-intensive coal-based power plants (Eskom 2011a; Fossil Fuel Foundation 2011).

Despite the government initiatives described and the steps to support the development of CCS technology in South Africa, the national government seems to be fully aware of the technology's complexity and of the barriers to its implementation. Firstly, the limited proximity of large-point CO_2 sources and potential storage sites would require the long-distance transport of the captured CO_2 by pipeline (estimated average transport distance: 900 to 1,400 km) and, thus, high infrastructure investments. Secondly, the overall costs of CCS and their potential impact on electricity rates constitute a key barrier to CCS for a country that faces substantial social challenges and where the government is being urged to fight poverty and foster job creation. This is especially the case because South Africa has literally no potential to alleviate the costs of CCS via enhanced recovery processes, such as enhanced oil recovery or enhanced gas recovery. Thirdly, CCS is a water-intensive technology, mainly due to the CO_2 scrubbing process, which would put South Africa's already scarce water resources under additional pressure and conflicts with the government's target to save water (Government of the Republic of South Africa 2011).

The fourth barrier to CCS deployment is that implementing CCS demonstration projects on a broad scale would require financial support and incentive mechanisms (Eskom 2011a). With regard to financing and demonstration, the South African government has stated that it would welcome funding by international bodies (for example, the Carbon Sequestration Leadership Forum or the World Bank) (DOE 2011d). Concerning domestic policy mechanisms to directly induce CCS, however, interviewed experts, such as from the Fossil Fuel Foundation (2011), do not expect the national government to install such direct incentives. CCS is more likely to be supported indirectly via a carbon pricing mechanism, such as a carbon tax. The government is presently discussing potential pricing carbon instruments (IMBEWU 2011). The discussion was initiated by a carbon tax discussion paper published by the National Treasury in 2010 (National Treasury of the Republic of South Africa 2010). It was taken further in the 2011 National Climate Change Response White Paper, which seeks to develop a carbon budget approach within two years of the White Paper's publication in October 2011. This approach encompasses the identification of a portfolio of enabling mitigation measures, one of which could be a carbon tax, as well as consultation with the National Treasury and the Departments of Trade and Industry and Economic Development on this matter (Government of the Republic of South Africa 2011).

The fifth challenge for CCS implementation identified by the South African government is regulatory uncertainty due to the lack of a legal framework for underground CO_2 storage. Therefore, the Department of Energy considers it as one of its top priority tasks to close this regulatory gap and to clarify pending legal issues, such as the classification of captured CO_2 as waste or a commodity (DOE 2011a). For this purpose, the government fosters inter-departmental cooperation, mainly by setting up the aforementioned inter-departmental CCS task team.

Due to the highly complex nature of CCS and the implementation barriers discussed, interviewed experts consider CCS an important but low priority element of South Africa's governmental carbon mitigation strategy (Eskom 2011a; Fossil Fuel Foundation 2011; Greenpeace Africa 2011a). Instead, the government seems to prioritise the expansion of renewable energies and nuclear energy (Eskom 2011a; Greenpeace Africa 2011a), which is in line with the priorities set out in the Integrated Resource Plan.

33.3 Industry

Sasol

Sasol is currently operating the world's only commercial-scale CTL industry. The evolution of South Africa's coal-based synfuels industry started in the 1950s. It was stimulated by a combination of scarce national oil reserves, abundant coal reserves and both national and international policy drivers. Important international political driving forces were the two oil price crises in 1973 and 1979/80 and a mandatory oil embargo against South Africa imposed by the United Nations in 1977 to destabilise the apartheid regime (Vallentin 2009). Sasol was established by the national government as a strong industrial force to cope with the high economic risk of CTL plants. From the 1950s to the early 1980s, Sasol erected three CTL plants (one of which was subsequently transformed into a coal-to-chemicals plant). Today, Sasol's coal-based synfuel industry has a total production capacity of 160,000 barrels per day. For several years, Sasol has been considering constructing further CTL capacities. South Africa's Long-term Mitigation Scenarios, published by the Department of Environment

Affairs and Tourism South Africa (2007), even project five additional CTL plants, each with a capacity of 80,000 barrels per day in its *Scenario No 1 Growth Without Constraints*. However, this plan has not yet been implemented, and no new CTL plants have been granted approval by the national government yet.

South Africa's CTL industry is widely considered an ideal opportunity for applying CCS, as carbon capture is an integrated process component that reduces the cost penalty of carbon capture and storage. CTL plants are highly CO_2-intensive; the total amount of CO_2 captured at the facilities is estimated to be 50 million tonnes of CO_2 per year, 30 million tonnes of which are highly concentrated (SACCCS 2011a). Despite these favourable conditions, the degree to which South Africa's CTL industry could help to overcome market entry barriers to CCS is uncertain, as Sasol's CTL plant Secunda is expected to reach the end of its lifetime in the 2030s (Fossil Fuel Foundation 2011), just when CCS is projected to be ready for large-scale operation. Consequently, the lifetime of the Secunda plant would have to be extended by retrofits to offer an early opportunity for CCS usage.

Sasol recognises the need to mitigate carbon emissions to slow down climate change. By 2020, the company aims to reduce the CO_2 intensity per tonne of product by 20 per cent (compared to the 2005 baseline). Furthermore, absolute emissions for potential new CTL plants commissioned before 2020 or 2030 are to be reduced by 20 and 30 per cent, respectively (with the 2005 CTL designs as a baseline) (SACCCS 2011a).

To comply with its internal mitigation targets, Sasol's GHG mitigation strategy envisages a combination of carbon and energy efficiency measures (cleaner technology), renewable energy and renewable feedstock as well as carbon capture and storage (Sasol 2011b). Within this triad, efficiency improvements are prioritised, whereas CCS is considered the logical next step once efficiency potentials have been fully exploited (Sasol 2011a).

Aiming at advancing clean technology solutions, Sasol has established a "New Energies" unit with a total of eight staff, which encompasses a clean coal group that also deals with CCS (Sasol 2011b). Sasol claims to hold significant technical in-house capacities and expertise for realising CCS projects, especially for capturing highly concentrated CO_2 at its CTL plants and the pipeline transportation of CO_2 because the company regularly transfers natural gas by pipeline. To further build up capacities and knowledge on CCS, Sasol is involved in several international CCS consortia and initiatives, such as the Carbon Sequestration Leadership Forum (CSLF). Nationally, Sasol financially supports the South African Centre for Carbon Capture and Storage (SACCCS).

Despite its manifold CCS initiatives, Sasol is lacking in technical expertise in the fields of CO_2 compression and conditioning as well as CO_2 storage. For this reason, public-private partnerships that combine all of the capacities required are considered a prerequisite for implementing integrated CCS projects in South Africa (Sasol 2011a).

Notwithstanding Sasol's considerable experience in transporting gas by pipeline, the company perceives CO_2 transportation as a major bottleneck for CCS technology in South Africa. The average transport distance for CO_2 transfer is estimated to be no less than 400 km (Sasol 2011a). Furthermore, the company has identified non-technical issues, such as the lack of a legal and regulatory framework for underground CO_2 storage as well as financial and political incentives for CCS investments, as important obstacles. A carbon tax on stationary CO_2 emissions, as currently being discussed by the national government, would provide a strong incentive for Sasol to invest in CCS technologies. However, Sasol opposes the introduction of a carbon tax and has requested the national government to recognise its mitigation efforts before imposing a new tax (Sasol 2011a).

Eskom

South Africa's national electricity utility, state-owned Eskom, is one of the largest electricity utilities in the world. In 2008, it ranked thirteenth in the world by generation capacity (Sasol 2011a). Eskom holds a *de facto* traditional public monopoly, producing about 96 per cent of the country's electricity. Furthermore, it owns and operates the national high-voltage grid as well as a significant proportion of the distribution system (World Resources Institute and Prayas Energy Group 2010). Coal-fired base load power stations make up the largest portion of Eskom's plant mix. The utility operates 13 coal-fired power stations with an installed capacity of 37,745 MW. Their total net output, excluding the power consumed by their auxiliaries and generators currently in reserve storage, is 34,952 MW (Eskom 2011b).

To alleviate the carbon footprint of its fossil-based power plant fleet, Eskom has adopted a carbon mitigation strategy comprising the following elements: energy efficiency, optimising thermal efficiencies of power stations, expanding renewable energies, importing power (for example from Mozambique), expanding nuclear energy and CCS (MacColl 2011). Consequently, CCS is only one element in a portfolio of potential solutions. For example, the company operates a small CO_2 capture testing facility. An expert interviewed from Eskom stated that CCS "has a role to play in tandem with energy efficiency, renewables and nuclear deployment" (Eskom 2011a). However, CCS is currently perceived as a high-risk investment by South African industry players (MacColl 2011). This is partly due to the lack of a proven storage solution in South Africa. In order to expand its knowledge on local storage potentials, Eskom participated in developing the South African Carbon Storage Atlas. However, it claims that "the information in this atlas is still at a very coarse resolution and this remains the biggest question at the moment" (MacColl 2011). Furthermore, Eskom calls for financial and political incentives to move into CCS technology. Future power plant investments would only include CCS equipment if future legislation outweighs the costs of CCS (MacColl 2011).

By contrast, Eskom does not consider technological issues a major barrier to CCS deployment as the technology is being developed and demonstrated internationally. Furthermore, Eskom claims to have good in-house capacities and expertise on the technologies involved, and is a member of different CCS initiatives to further build up capacities. For example, Eskom provides financial support to the South African Centre for Carbon Capture and Storage (SACCCS). Furthermore, the utility operates an internal clean coal research programme, which also focuses on efficiency improvements, ultra supercritical pulverised coal technologies and underground coal gasification (Eskom 2011a).

In recent years, Eskom has gained practical experience in designing power stations to be "capture-ready." In March 2008, the government's Record of Decision (RoD) for the new coal-fired Kusile power plant was revised, requesting Eskom to build the plant capture-ready. Eskom was obliged to integrate the possibility of a CCS retrofit into the power plant design, to recognise the international level of technology development in the process and to reflect the status of local information with regard to storage potential (Eskom 2011a). Nonetheless, no secure potential storage site has been identified yet due to a lack of precise information on South Africa's storage potential.

Anglo American

Anglo American is South Africa's largest coal producer and one of the world's largest diversified mining groups. In South Africa, the company operates eight mines, including mines that produce primarily for coal exports and mines with output specifically dedicated to Eskom and Sasol, based on long-term contracts. In 2008, Anglo America's coal production totalled 59.4 million tonnes, 36.2 million tonnes of which were sold to Eskom and 5 million tonnes to Sasol (MacColl 2011).

As a major coal-mining company, Anglo American expects to be strongly exposed to a future climate policy framework in South Africa, which could lead to rising energy prices and the establishment of a carbon pricing system. To this end, Anglo American has developed a climate strategy, encompassing elements for both short-term and long-term improvements. In the first phase of this strategy, Anglo American aims to increasingly integrate the costs of carbon into its business decisions and to develop risk and mitigation plans. In the second phase, it will establish measures to cope with a possible carbon taxation scheme. This includes establishing a low-carbon research programme (Anglo American 2011b).

Anglo American has recognised the potential role of CCS in a carbon-constrained future and is involved in initiatives and consortia engaged in the technology's development and demonstration. Anglo American is a member of the SACCCS, the U.S.-based FutureGen alliance as well as the IEA Clean Coal Centre. Furthermore, the company has contributed funding for the development of the atlas of South Africa's storage potential.

Despite these activities, Anglo American considers the national CO_2 mitigation potential of CCS to be limited, estimating that the technology will contribute no more than 10 per cent of South Africa's total emission reduction, with only one or two power plants being equipped with CCS (Anglo American 2011a).

Petro SA

The Petroleum, Oil and Gas Corporation of South Africa (SOC) Limited (PetroSA) is South Africa's national oil company. It owns, operates and manages the commercial assets of South Africa's petroleum industry. So far, the company has not been as vocal as Eskom and Sasol in South Africa's CCS debate. However, PetroSA provided funding for the compilation of the South African CO_2 Storage Atlas and supports SACCCS. This implies that the company generally backs efforts to research, develop and demonstrate CCS technology.

PetroSA has the potential to play an important role in the national CCS discourse, as the company possesses valuable geological knowledge and expertise about South Africa's oil and natural gas fields, which constitute potential CO_2 storage sites. Furthermore, PetroSA operates large parts of the country's pipeline network for oil and gas transportation. The company also owns and operates a gas-to-liquid (GTL) plant at Mossel Bay, with a daily production capacity of 36,000 barrels. The plant represents a large-point CO_2 source, which could be equipped with carbon capture technology. However, in comparison to Sasol's CTL plants, which produce CO_2 streams with 90 to 98 per cent purity and are widely considered an ideal opportunity for CCS, the Mossel Bay GTL plant generates CO_2 with slightly lower concentrations of 80 to 90 per cent. Nonetheless, the GTL plant's gas stream is still clearly more concentrated and therefore favourable for CO_2 capture than the concentration level of coal-fired power plants (10 to 15 per cent) (Mwakasonda and Winkler 2005).

33.4 Environmental NGOs

The environmental NGOs active in South Africa include not only local NGOs, such as Earthlife Africa and Groundwork, but also international environmental NGOs, such as Greenpeace Africa and WWF South Africa, both of which maintain representative offices in South Africa. CCS technology is not a high-priority topic amongst environmental NGOs. For example, WWF South Africa was the only environmental NGO to join the Second South African Carbon Capture and Storage Week, the most prominent CCS event in South Africa held in Johannesburg in October 2011. Thus, in the following, emphasis is placed on WWF South Africa and Greenpeace Africa, which have issued statements on CCS and coal usage in general in South Africa.

Greenpeace Africa

There has been little discussion on carbon capture and storage amongst international environmental NGOs represented in South Africa (for example Greenpeace, WWF) and local NGOs. However, in line with Greenpeace International's negative stance towards CCS, Greenpeace Africa has clearly expressed its opposition to the technology's demonstration and deployment in South Africa. In response to the national government's White Paper, Greenpeace Africa stated that the government should provide funding for green energy initiatives, rather than launching a CCS Flagship Programme as announced in the White Paper on climate change. Greenpeace Africa argues that the technology is immature and highly cost-intensive. Furthermore, CCS implies a significant energy penalty and would require long-distance CO_2 transport (Business Day 2011). Instead of an end-of-pipe technology such as CCS, Greenpeace Africa clearly endorses a transition towards a low carbon, low risk economy that should be guided by a low carbon development plan (Greenpeace Africa 2011b).

In addition to opposing CCS, Greenpeace Africa is also against the continued use of coal in South Africa for power generation and synthetic fuel production. In 2011, Greenpeace Africa published a report entitled "The True Cost of Coal in South Africa" (Greenpeace International 2009), which analyses the external costs of coal usage and the potential benefits of expanding renewable energies based on a scientific study (Blignaut et al. 2011).

WWF South Africa

Compared to Greenpeace Africa, WWF South Africa has a more nuanced stance on carbon capture and storage. It considers the combination of biomass energy production and carbon capture and storage, which would be able to extract CO_2 from the atmosphere, an option that may be required at a certain stage (WWF South Africa 2010). However, in line with Greenpeace Africa, WWF South Africa also opposes the continued use of coal and, therefore, the erection of new large-scale coal-fired power stations or synthetic fuel plants. WWF South Africa advocates blocking use of the Kusile plant, at least as a conventional pulverised coal plant as currently planned, and opposes the construction of a new CTL plant in Mafuta (WWF South Africa 2011).

33.5 Expert Networks and Knowledge Platforms

Fossil Fuel Foundation and South African Coal Roadmap

The Fossil Fuel Foundation (FFF) is a knowledge and expert network on fossil fuels. In South Africa, the Foundation's work concentrates on coal (Fossil Fuel Foundation 2011), including the coordination and administration of the South African Coal Roadmap (SACRM). The latter is a national initiative supported by the South African government and several stakeholders associated with the coal industry. The initiative aims to assess options and scenarios for the future development of the domestic coal industry, seeking to maximise the economic opportunities for coal utilisation and to elaborate a strategic roadmap on the future of coal (Fossil Fuel Foundation 2012).

The Fossil Fuel Foundation emphasises that coal utilisation should be continued until renewable energies "can supply sufficient energy in a secure, reliable and affordable manner. The burden of proof for this must rest squarely with the technology developers and proponents of renewable energies" (Fossil Fuel Foundation 2010). Against this background, FFF opposes any expanded taxation of coal and CO_2 emissions caps, which could constrain the economic viability of coal utilisation (Fossil Fuel Foundation 2010). Improvements in coal combustion efficiency and CCS technology are considered important measures to adapt coal combustion to a more climate-oriented policy framework (Fossil Fuel Foundation 2010). However, CCS is perceived as a long-term option that is unlikely to become commercialised any earlier than 2030 (Fossil Fuel Foundation 2011).

The conditions for applying CCS are considered most favourable in the CTL industry. However, the interviewed representative of FFF pointed out that there are uncertainties regarding the amount of coal reserves still available at Sasol's CTL plant in Secunda and that the plant may be nearing the end of its lifetime when CCS becomes available on a commercial scale in 2025, as envisaged by South Africa's CCS roadmap. In general, the high costs of CCS are considered the main barrier to the technology's commercialisation, especially as South Africa has extraordinarily low electricity tariffs. In contrast, it is expected that legal and regulatory issues can be resolved (Fossil Fuel Foundation 2011).

33.6 Science

CCS-related activities undertaken by scientific bodies or institutes in South Africa are summarised below. It must be emphasised that the scientific bodies discussed below are explicitly not to be understood as stakeholders or agents that intentionally aim to influence South Africa's CCS debate in favour of or against the deployment of CCS. Scientific bodies are generally understood to be technology neutral. Nonetheless, they are included in this section to enable a wide, complete picture of the CCS community in South Africa to be presented.

South African Centre for Carbon Capture and Storage (SACCCS)

SACCCS was launched in March 2009 in Sandton as a division of the South African National Energy Research Institute (SANERI). The latter was assigned by the Minister of Minerals and Energy to conduct energy, research and demonstration, and is organised as a subsidiary of the state energy company CEF. SACCCS is one of several specialised research centres attached to SANERI that have been founded to facilitate activities in particularly relevant research fields. At the international level, SACCCS is a member of several CCS initiatives, such as the IEA Greenhouse Gas Programme (IEAGHG), the Carbon Sequestration Leadership Forum (CSLF) and the Global CCS Institute (GCCSI) (SACCCS 2011a).

SACCCS is governed by a charter with an initial five-year duration, aiming at becoming the leading authority on CCS-related activities in South Africa and undertaking research, development and capacity-building measures to prepare South Africa for the realisation of CCS projects (SACCCS 2011a). SACCCS is supported not only by the South African national government, but also by the governments of Norway and the United Kingdom. Moreover, it receives grants from industry, including Sasol, Eskom, Anglo Coal, PetroSA, Total, Xstrata Coal and Agence Francaise de Développement.

SACCCS has developed a roadmap for the roll-out of CCS in South Africa by 2025. Part of this roadmap was an initial assessment of the national storage potential in 2004 and the South African CO_2 Storage Atlas, which was finalised in 2010. The next milestones on this path are a CO_2 test injection of about 10,000 tonnes of CO_2 by 2016 and a demonstration project with a CO_2 storage volume of 100,000 tonnes to be realised by 2025. The test injection project involves a comprehensive work programme which, besides technical activities, encompasses a management work package (organisation and conceptualisation of a success criteria workshop, scoping study, development of a test injection business plan), a financial study, research on the legal requirements and framework conditions of underground CO_2 storage, public engagement events and capacity-building activities (SACCCS 2011a).

Council for Geoscience

The Council for Geoscience (CGS) has over 100 years of experience in mapping African geology, mainly in South Africa and Namibia. The CGS is the scientific body mainly responsible for documenting, analysing and collecting data on the geology of South Africa (Council for Geoscience 2012). It employed a total of about 300 staff in several South African states (Council for Geoscience 2011).

CGS first heard of carbon capture and storage at a CSLF meeting in 2006, and finalised a draft report about South Africa's storage capacity in the same year. The report was presented to SANERI with proposals for further research steps. It provided the basis for the more detailed and profound CO_2 Storage Atlas, which was finalised in 2010 (Council for Geoscience 2011). The Atlas contains the following aims (Council for Geoscience 2011):

- Identification of the potential storage capacity;
- Evaluation of all types of storage;
- Publication of a literature-based technical report and a publication for a broader readership.

However, although CGS holds the largest knowledge base on geological CO_2 storage in South Africa, CCS is not one of the Council's key topics; greater focus could be placed on CCS if more capacities and human resources were provided (Council for Geoscience 2011). This is particularly relevant because CGS recognises CO_2 storage as the most important constraint on CCS at this stage, owing to a lack of knowledge (Council for Geoscience 2011).

Energy Research Centre, University of Cape Town

The Energy Research Centre (ERC) of the University of Cape Town is conducting independent research on energy and related topics with a national and global focus. ERC created the

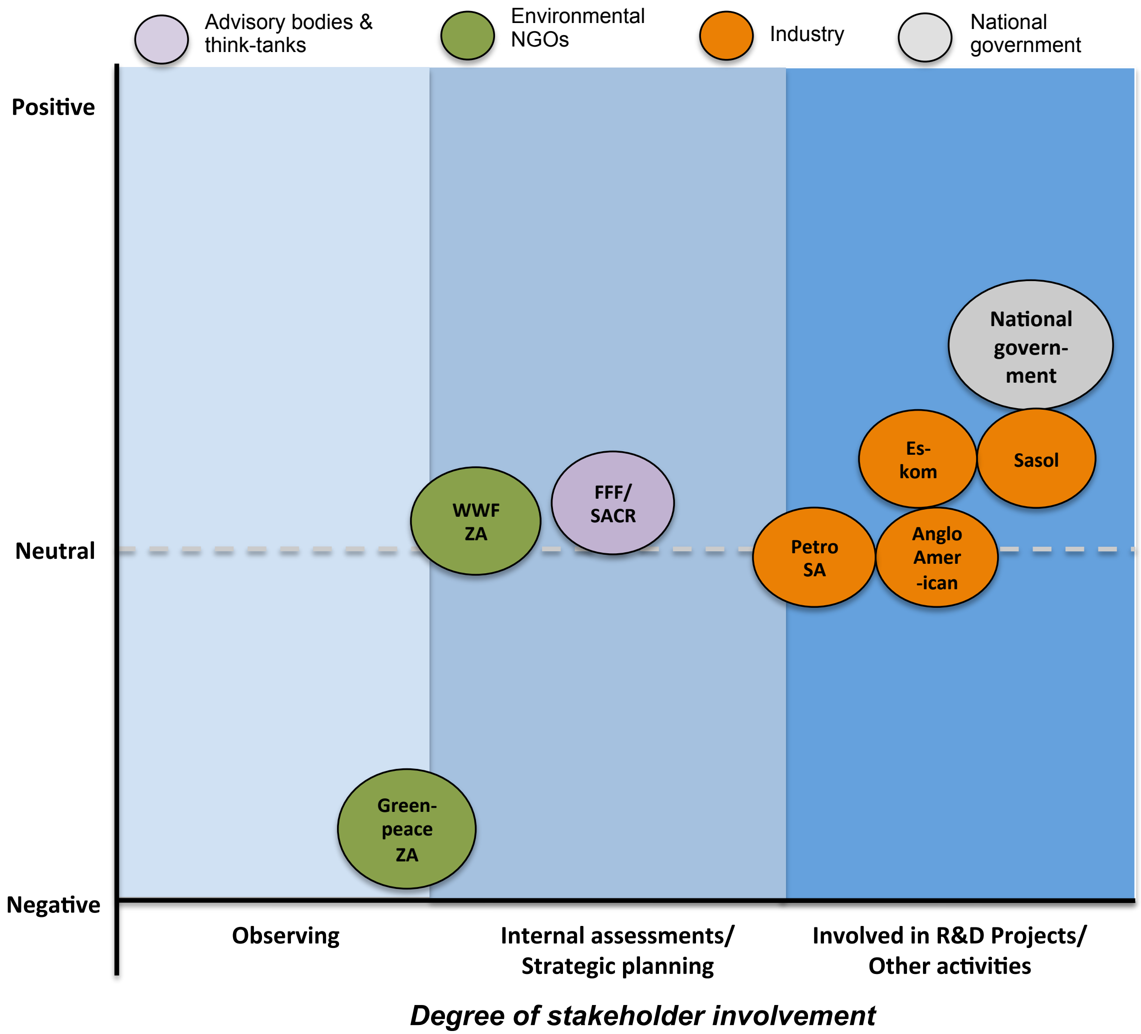
Long Term Mitigation Scenarios, which provided the basis for the government's Integrated Resources Plan.

Carbon capture and storage is not one of the Centre's key research topics at present. However, ERC conducted a research project on carbon capture and storage in South Africa, funded by the World Resources Institute, from November 2004 to March 2005. The study analysed the implications of implementing CCS technology in developing countries (focusing on South Africa) with particular consideration of the technical and institutional prerequisites required to achieve its large-scale implementation. The study concludes that major barriers to realising CCS in South Africa are high costs due to the increasing costs of energy services. CCS is considered a potential option for facilitating the transition of South Africa's high-carbon energy system to a cleaner future, which could furthermore offer an opportunity for technology transfer. However, ERC points out that more research is required to assess CCS in comparison to other carbon mitigation options (Council for Geoscience 2011).

33.7 Summary of Positions of Key Players

The analysis of stakeholder positions and activities on CCS in South Africa shows that key players have taken important action, both with regard to research and development and policy. Fig. 33-1 illustrates the constellation of actors in the South African CCS discourse. The illustration does not include scientific bodies because they are understood per se to be technology neutral. Hence, the South African Centre for Carbon Capture and Storage is not included, although it plays a key role in South Africa's CCS debate. SACCCS coordinates and oversees CCS-related research, development and public outreach activities. By developing a medium-term roadmap for the technology's large-scale implementation, SACCCS has set an important milestone for achieving a well-organised and structured technology development and deployment strategy.

Furthermore, the South African government has chosen a proactive and ambitious approach for fighting climate change and reducing carbon emissions. The government's role as the host of the COP17 in Durban in December 2011 functioned as a catalyst for this development, triggering the launch of the National Climate Change Response White Paper. In this paper, the government recognised the potential for CCS to become an important CO_2 mitigation technology in South Africa and announced a CCS Flagship Programme. This implies that CCS development and demonstration activities are generally welcomed and supported by the national government. Besides these rather favourable political framework conditions, South Africa's coal-fired synthetic fuel industry is widely considered an ideal opportunity that could facilitate CCS implementation, as it regularly produces large streams of nearly pure CO_2. Therefore, most of the experts interviewed consider the CTL industry to be the primary user of CCS in South Africa. Since CO_2 capture is an integrated process component of CTL, Sasol, the operator of South Africa's CTL plants, has expertise and experience in many elements of the CCS technology chain. Many of the experts interviewed regard Sasol's CTL plants as the primary testing field for CCS technology, although they may be at the end of their lifetime or too old for retrofitting by the time the technology becomes available for large-scale use.



Abbreviations

FFF: Fossil Fuel Foundation
SACR: South African Coal Roadmap
WWF: World Wildlife Fund

Fig. 33-1 Constellation of key CCS stakeholders in South Africa

Source: Authors' illustration

With regard to CO_2 mitigation in the power sector, the Director General of the Department of Energy has also acknowledged the potential role of CCS. However, several respondents stated that the national government seems to prefer nuclear energy and renewable energies as options for power generation in a carbon-constrained future. Nonetheless, coal-fired power plants with CCS could play a role in South Africa for the following reasons: firstly, the government intends to maintain coal combustion as an important element of the national power mix since coal represents a secure and economically viable domestic energy source, whereas confidence in the potentials and reliability of renewable energies seems to be rather limited. Secondly, coal-fired power plants were obliged to be designed as capture-ready due to pressure from the World Bank, which provided co-funding for the plant. Thirdly, the national government is currently discussing the introduction of a carbon pricing mechanism, such as a carbon tax. If the carbon tax outweighed the costs of CCS, and therefore economic risks, Eskom or Sasol would seriously consider using CCS technology.

In addition to these economic and political conditions, however, many respondents emphasised that limited knowledge on potential CO_2 storage sites and long distances between CO_2 sources and storage regions could be important barriers to the implementation of CCS. Hence, more research on these fields is required to project the prospects of CCS in South Africa. Furthermore, CCS implies potential conflicts with other important policy objectives of the national government, for example affordable electricity rates, reducing water usage and improving the efficiency of electricity generation to ensure the whole population has access to electricity.

34 Integrative Assessment of CCS

34.1 Overall Conclusions on the Prospects of CCS in South Africa

Aim of the Study

The aim of this study was to explore whether carbon capture and storage (CCS) could be a viable technological option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries were chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal. For this reason, the study mainly focused on CO_2 emissions from coal-based electricity generation supplemented by a rough analysis of emissions from industry.

The analysis was designed as an integrated assessment, and takes various perspectives. The main objective was to analyse how much CO_2 can potentially be stored securely and for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential was compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis was framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

Results of Storage Capacity Assessment

This report shows that in the case of *South Africa* it is not possible to answer these questions fully based on the currently available data and expertise. The analysis reveals that the main constraint on the deployment of CCS in South Africa is the lack of detailed knowledge about potential storage sites.

In order to yield *effective* storage capacities, which reduce the theoretical capacity of aquifers to the total pore volume that can effectively be used, efficiency factors have to be applied. Since the real efficiency factors are not known, an “if ... then” approach was applied to show how the effective storage capacity will vary depending on different efficiency factors. To this end, three storage scenarios *S1: high*, *S2: intermediate* and *S3: low* were developed based on efficiency factors of 1, 4 and 10 per cent. In additional to aquifers, a small capacity of gas fields was considered. The results range from 15 to 149 Gt of *effective storage potential*. However, when the maximum distance between CO_2 sources and the potential storage site was restricted to roughly 600 km (larger distances would significantly affect the cost balance and create infrastructural barriers), only two basins could be used for the source-sink match. Thus the effective capacity drops to between 4 and 43 Gt of CO_2. In any case, due to the lack of geological data in South Africa, any calculations of storage capacity quantities can only be highly speculative and therefore should be treated with caution.

Deriving of the Quantity of CCS-CO_2 available for Storage

In order to be able to estimate the relevance of the derived figures, the range of CO_2 storage capacities was compared with the cumulated amount of CO_2 emissions that could potentially be captured from power plants and coal-to-liquid plants in the long term. Due to the extent of uncertainty regarding the future development of South Africa’s energy system, again, an “if ...

then" analysis was performed. Firstly, three long-term coal development pathways for power plants *E1: high*, *E2: middle* and *E3: low* were devised. These pathways, based on existing energy scenarios for South Africa, project different trends of coal-based power plant capacities, ranging from 15 to 91 GW installed capacity in 2050. These pathways were supplemented by three industrial development pathways for coal-to-liquid plants *I1: high*, *I2: middle* and *I3: low*. Next, each pathway was used to calculate how much CO_2 could be separated based on the assumption that CCS in South Africa could possibly be commercially available from 2030.

Results of Source-Sink Match

Finally, a source-sink match was performed assuming a maximum transport distance of 600 km. The results indicate that the separated CO_2 emissions in most of the coal development pathways could be stored under the aforementioned premises. The low storage scenario S3 is the only case where – for both the high and middle coal development pathway – less than 50 per cent of emissions could be stored. However, the effective storage potential is reduced further to a *practical storage potential*, taking into account economic conditions, potential problems concerning acceptance and technical feasibility problems. However, these parameters cannot be assessed properly until specific CCS projects are planned.

If, therefore, more detailed assessments of South Africa's storage potential verify the high storage scenario S1 in the future and if the practical capacity is not considerably lower, a large quantity of CO_2 emissions derived from the high development pathways E1 and E2 could be stored. On the other hand, if the low storage scenario S3 reflects the country's effective storage potential most realistically and its practical capacity turned out to be much lower than the effective capacity, it would only be possible to sequester a fraction of the separable CO_2 emissions.

Further Assessment Dimensions

The matching of CO_2 sources and geological sinks provides an indicative framework illustrating how much CO_2 could be sequestered given technical and geological constraints. To complete the picture, a supplementary technology assessment considering socio-economic and ecological conditions in the respective countries was prepared in this study.

- First of all, there is a significant economic barrier to achieving the economic viability of CCS in South Africa under current conditions and the assumed CO_2 price development. In order to generate a clear cost incentive for CCS, a higher CO_2 price than that assumed in this study or significant cost reductions of CCS technology would be required.
- Since the proven recoverable coal reserves in South Africa were revised downwards by more than 50 per cent in the early 2000s, a high coal development pathway could lead to significant constraints and rising coal prices in the medium term, exacerbated by the increased consumption of coal in the event of CCS.
- The coal penalty incurred by CCS associated with upstream greenhouse gas emissions leads to a reduction in total GHG emissions of only 67 to 72 per cent. Even if these figures were to improve in the future, the negative impacts in all other environmental categories would rise.
- On the other hand, key players have taken important action with regard to both CCS research and development and policy. The South African government recognises CCS as a

potentially important CO_2 mitigation technology in South Africa. But CCS also implies potential conflicts with other important policy objectives, such as affordable electricity rates, reducing water usage and improving the efficiency of electricity generation to enable the whole population to have access to electricity.

Results of Integrated Assessment of CCS in South Africa

In Tab. 34-1 the results presented for the individual assessment dimensions are assembled so that an integrated assessment can be undertaken. The effect of each assessment dimension on the future role of CCS is ranked between 1 and 5 in five categories. While the highest score (5) illustrates a strong incentive for CCS, the lowest score (1) represents a strong barrier to CCS development.

Tab. 34-1 Integrated assessment of CCS in South Africa – assessing the individual dimensions in a range from 1 (strong barrier to CCS) to 5 (strong incentive for CCS)

Assessment dimension	**Categorisation of sub-dimensions**	**Incentive or barrier to the future role of CCS in South Africa**
Storage capacity	High storage scenario	5
and source-sink match	Intermediate storage scenario	5
	Low storage scenario	2
Assessment of coal reserves		2
Cost assessment	Low CO_2 price development	1
	Assumed CO_2 price development	3
	Higher CO_2 price development	4
Ecological assessment	Reduction in CO_2 emissions per kWh of electricity	4
	Reduction in total GHG emissions per kWh of electricity	4
	Impact on other environmental impact categories	1,5
	Impacts on local environment and health	2
Stakeholder analysis	Current perspective	3,5
	Long-term prospects	4

GHG = greenhouse gas

The classification is undertaken using indicators 1 to 5, where 5 illustrates a strong incentive for CCS development in each country and 1 represents a strong barrier to CCS.

Source: Authors' composition

Fig. 34-1 presents the results for South Africa. For the crucial parameters – storage capacity and cost development – the lines above the columns project the range within which these could develop in the event of different framework conditions or assumptions.

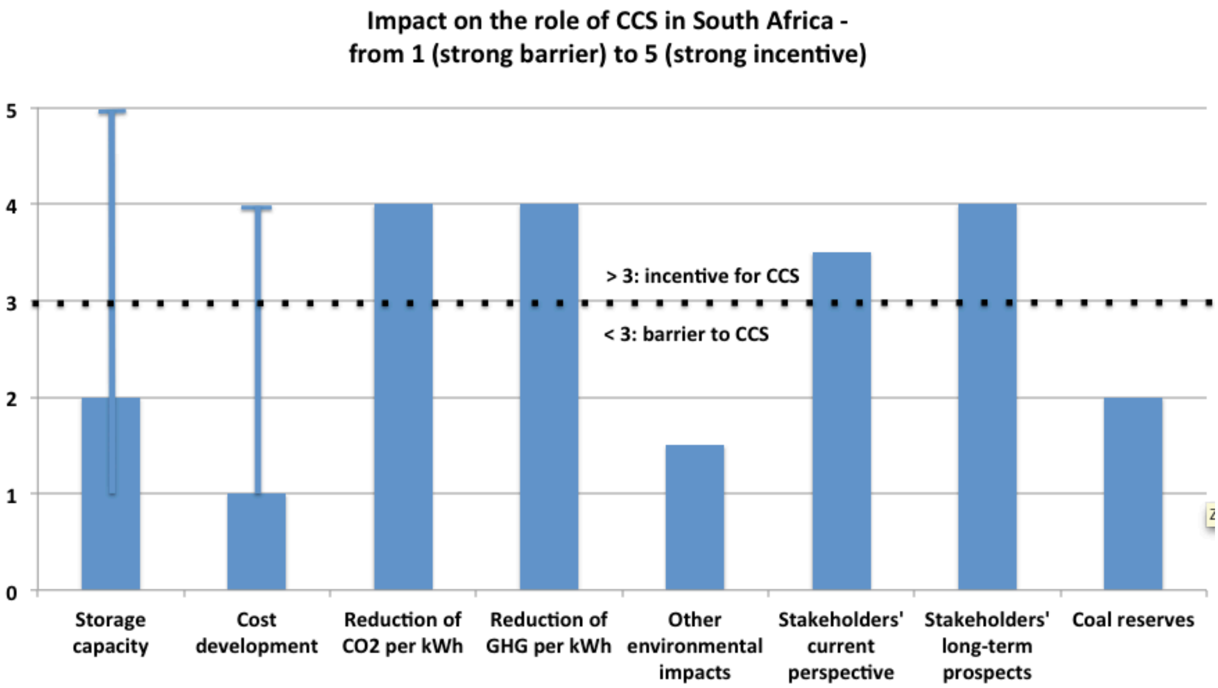


Fig. 34-1 Integrated assessment of the role of CCS in South Africa, including the possible impact variations of storage capacity and cost development

Source: Authors' illustration

Existing scenario studies for South Africa reveal different strategies for meeting the future growing demand for electricity:

- One option is to make a considerable effort to achieve drastic improvements in *energy efficiency* together with an ambitious increase in the use of all forms of *renewable energy*. The *Energy [R]evolution Scenarios* from EREC and Greenpeace, for example, show that such pathways would continue to need conventional coal-fired power plants in order to satisfy energy needs over the next two or three decades but, nonetheless, the climate targets calculated in these scenarios for China would be met without using CCS and nuclear energy. However, such a scenario poses a significant challenge in that renewable energies would have to be systematically integrated into the current energy system. This would be a complex process which would depend on numerous factors.
- The second option is to pursue a fossil fuel-based policy, supplemented by varying shares of nuclear energy or renewable energies. Examples of such a policy choice are the *Long-term Mitigation Scenarios* and the World Bank scenarios. Due to the striking dominance of coal-fired power generation in South Africa's electricity sector, CCS technology implies a high degree of compatibility with the predominating technology regime and, thus, could play a prominent role in such long-term CO_2 mitigation scenarios for South Africa, which follow the second option. Without CCS, a highly coal-based path would be unable to reduce fossil-related carbon dioxide emissions as substantially as required by climate scientists. However, a precondition for opting for CCS would be the commercial viability of CCS, a decrease in CCS-based electricity costs, long-term policy support and a sufficient amount of proven and safe storage capacity

In order to overcome the existing barriers to the deployment of CCS in South Africa, local experts and decision-makers have made it clear that the industrialised world would need to make a stronger commitment in terms of technology demonstration and implementation. Furthermore, a substantial cost reduction and mechanisms for technology cooperation and transfer to developing countries and emerging economies would be essential.

34.2 Summary of the Assessment Dimensions in Particular

34.2.1 CO_2 Storage Potential

Storage Assessment and Source-Sink Matching are High Speculative due to a Lack of Geological Data

The elaborations above show that the estimate of South Africa's storage potential is very uncertain due to the lack of detailed geological data. To yield *effective* storage capacities that reduce the theoretical capacity of aquifers to the total pore volume that an effectively be used, efficiency factors have to be applied. The Storage Atlas, which is the most advanced existing estimate for South Africa, provides an available *effective* capacity of 150 Gt of CO_2, nearly all of which results from offshore saline aquifers calculated by applying an efficiency factor of 10 per cent.

Since the real efficiency factors are not known, an "if ... then" approach is applied to show how the effective storage capacity varies depending on different efficiency factors. To this end, three storage scenarios *S1: high*, *S2: intermediate* and *S3: low* were developed based on different efficiency factors of 1, 4 and 10 per cent. Gas and oil fields play a tangential role, whilst storage in coal seams was excluded from all scenarios due to the extent of technical uncertainties. This storage possibility is still at the laboratory stage and it has not yet been proven to work in situ. The results range widely from 15 to 149 Gt of *effective storage potential* (Tab. 34-2). However, due to the lack of geological data in South Africa, any calculations of storage capacties can only be highly speculative and therefore should be treated with caution.

Tab. 34-2 Scenarios of effective CO_2 storage capacity in South Africa

Formation	S1: high	S2: intermediate	S3: low
Oil	-	-	-
Gas	0.2	-	-
Onshore aquifers	1	0.3	-
Offshore aquifers	148	59.1	14.8
Total	149.2	59.4	14.8

All quantities are given in Gt CO_2

The efficiency factors selected for aquifers are 10% (S1), 4% (S2) and 1% (S3).

Source: Authors' calculation

This range of CO_2 storage capacity was compared with the cumulated quantity of CO_2 emissions that could potentially be captured from power plants and coal-to-liquid plants in the long term. Due to the extent of uncertainty about the future development of South Africa's energy system, again, an “if ... then” analysis was performed. First of all, three long-term coal development pathways for power plants *E1: high*, *E2: middle* and *E3: low* were devised. These pathways, based on existing energy scenarios for South Africa, project different trends of coal-based power plant capacities, ranging from 15 to 91 GW installed capacity in 2050. These pathways were supplemented by three industrial development pathways for coal-to-liquid plants *I1: high*, *I2: middle* and *I3: low*. Next, each pathway was used to calculate how much CO_2 could be separated, based on the assumption that CCS could be commercially available from 2030 in South Africa.

In general, 100 per cent of emissions could be stored in most cases. The low storage scenario S3 is the only case where – with coal development pathways E1 and E2 – less than 50 per cent of emissions could be stored. The emissions in this pathway could only be fully sequestered with the high storage scenario. Tab. 34-3 shows the results for the combination of coal development and CTL development pathways E1+I1 to E3+I3.

Tab. 34-3 CO_2 emissions that could be stored as a result of source-sink matching in South Africa

	Power plant and CTL emissions from coal development pathways		
Effective storage capacity scenarios	**E1+I1: high** (24 Gt CO_2)	**E2+I2: middle** (10 Gt CO_2)	**E3+I3: low** (4 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (149 Gt CO_2)	24	10	4
S2: intermediate (59 Gt CO_2)	17	9	4
S3: low (15 Gt CO_2)	4	4	4
	Share of effective storage capacity used (%)		
S1: high (149 Gt CO_2)	16	7	3
S2: intermediate (59 Gt CO_2)	29	16	7
S3: low (15 Gt CO_2)	29	29	29
	Share of emissions that could be stored (%)		
S1: high (149 Gt CO_2)	100	100	100
S2: intermediate (59 Gt CO_2)	70	96	100
S3: low (15 Gt CO_2)	17	44	100
The maximum transport distance is assumed to be 600 km.			

Source: Authors’ calculation

At present, it is not clear whether CTL plants or power plants would be the preferred “candidates” for a roll-out of CCS. Most South African experts consider CTL to be an ideal opportunity for applying CCS as carbon capture is an integrated process component that reduces the cost penalty of CCS. In addition, capturing 22 million tonnes of CO_2 per year from the Secunda plant is the only CCS option considered so far in the Long-term Mitigation Scenarios of the South African government.

In contrast, the South African CCS roadmap allows for a CO_2 test injection of only 10,000 tonnes of CO_2, followed by a small demonstration project in 2020 and a small commercial CCS project in 2025, storing 1 million tonnes of CO_2. CTL has not yet been included in the roadmap. Eskom was requested by the World Bank to design Kusile power plant, currently under construction, as “capture-ready.” When it is retrofitted with carbon capture, it will provide between 20 and 24 million tonnes of separated CO_2 per year, which is in the same dimension as Secunda's CO_2 stream.

However, the oft-cited highly concentrated CO_2 stream from Secunda must be seen under the constraint that the existing CTL plant may be decommissioned around 2030, the time when CCS is expected to become commercially available. Otherwise, it would be too old, making a retrofit unviable. CTL will therefore only be an option for CCS if new CTL plants are erected, such as the Mafutha plant, which has been under discussion for many years. Mafutha would have half of Secunda's capacity, providing 11 million tonnes of separated CO_2. Therefore it could make sense to combine the ideal opportunity of a new CTL plant with setting up a CCS strategy for power plants to starting the roll-out of CCS with Mafutha and Kusile, together delivering 31 to 35 million tonnes of CO_2 per year.

If formations other than the selected Zululand basin and Durban & Zululand basin are used, the relocation of emission sources closer to potential sinks should be reconsidered. As mentioned above, it was assumed in the coal development pathways that the future spatial distribution of both power plants and industrial sites is the same as at present because they are closely linked to coal reserves. In general, any relocation of emission sources should take into account which medium should be transported how far. It would be necessary to differentiate between the transport of *electricity*, *fuel*, separated *CO_2 emissions* and even *cooling water* (which could become a serious problem in the event of more steam power plants, even without the use of CCS). If the overall objective was to store as much CO_2 as possible, an optimisation model would be required to find the cost optimal solution. However, possible environmental or social problems must also be taken into consideration.

Interpreting these results, two further constraints should be noted:

- In the given source-sink match, only the base case energy scenarios are considered, equating to a commercial availability of CCS from 2030 and an operation of 7,000 full load hours per year in the case of power plants. If CCS is available later, in 2035 or 2040, CO_2 emissions provided for storage will be 20 to 50 or 40 to 80 per cent lower, respectively. If an operation of only 6,000 full load hours is achieved (load factor of 69 per cent) or if the optimistic assumption of 8,000 full load hours is realised (load factor of 91 per cent), the quantity of separated CO_2 emissions would decrease or increase by 14 per cent.
- To date, CO_2 sources and sinks have only been preliminarily matched. Transport distances have not been proven in detail and are based only on rough estimates, taking into account a maximum distance of 600 km. In a further elaboration of this study, a geographic information system (GIS) should be used and fed with data on the exact locations of power plants and industrial sites. This information could be coupled with more detailed information on geological basins, if available in the future, to reduce transport distance between sources and sinks and to increase the certainty of estimates.

In the future, further steps must be taken to achieve a better and more detailed assessment, enabling a "real" matched capacity to be derived:

- Carry out an in-depth investigation of each basin and field to obtain detailed information about the geological underground;

- Determine more detailed locations of possible storage sites within the basins to enable more precise, quantitative source-sink matching to be conducted;
- Derive a practical storage potential (top layer of the storage pyramid) considering economic conditions, possible acceptance problems in the regions concerned and technical feasibility problems.

Finally, the *practical* capacity will be much lower than the effective capacity discussed in this report. Until these details are explored, even the lowest effective storage capacity scenario S3 should not be considered as an upper variant of what could be realised in South Africa – the final figures, and therefore the final results, of source-sink matching may actually be considerably lower, taking into account economic conditions, potential problems concerning acceptance and technical feasibility problems.

34.2.2 Supplementary Technology Assessment

Decreasing Coal Reserves Lead to increasing Coal Prices in the Future

The coal reserves of South Africa were revised downwards several times. At present, the reserves are estimated to be between 15 and 27 Gt. Declining productivity, declining heating value and worsening extraction conditions with an increasing proportion of underground mines suggest that the time when it was easy to extract coal has passed. The remaining reserves are concentrated in a few coal fields, namely Highveld, Witbank, Ermelo and Waterbank, which cover about 85 per cent of all remaining reserves. The speed at which new projects can be developed, together with construction of infrastructure, will decide whether peak production is approaching or has already taken place. According to Hartnady (2010), the peak may occur around 2020. However, recent production and export statistics suggest that production has been almost flat exports in decline for several years.

Based on these indicators, it is very likely that coal prices will rise considerably in the future, both for domestic and export sales. This is in line with the price development assumptions up to 2035 based on IEA projections, as reported in the World Energy Outlook 2011. The corridor for coal prices in 2035 could be between USD 194 and 269 per tonne of coal, the lower price being based on the WEO assumption on OECD coal import prices, the upper price on the assumption that coal prices will rise at the same rate as oil prices.

No Clear Economic Advantage of CCS-Based Plants

The presented cost projections are based on three different pathways for the development of coal-fired power generating capacities in South Africa with and without CCS. The role of coal-fired power plants in these coal development pathways is influenced by different levels of ambition in policy frameworks for climate protection and sustainable energy. Whereas pathway *E1: high* is based on reference conditions, pathways *E2: middle* and *E3: low* imply more ambitious policy settings. The capacity developments in these three pathways are used as input to calculate learning rates and cost reductions of coal-fired power plants with and without CCS.

The analysis of the levelised cost of electricity (LCOE) of supercritical pulverised coal plants in South Africa shows that, by 2050, the LCOE of plants fitted with CCS equipment exceeds that of plants without CCS by 56 to 61 per cent. The precise cost difference depends on the development pathway of coal-fired power plant capacities used as the basis for the given calculation. For example, in the *E2: middle* coal development pathway, the LCOE of a CCS plant totals US-ct 9.99/kWh compared to US-ct 6.32/kWh for a non-CCS plant by 2050 in the absence of a CO_2 penalty. High plant investment costs represent 45 per cent of the CCS cost penalty and, thus, are the most significant cost driver. Fuel costs constitute the third largest share (14 per cent) of additional costs, whilst CO_2 transportation and storage account for 11 per cent and 27 per cent, respectively. Storage costs are particularly high in this case study because storage in an offshore formation was assumed due to the high potential of offshore storage sites in South Africa. O&M costs have a minor impact on the LCOE of CCS plants.

Due to higher capital costs, the cost penalty of CCS in South Africa is significantly higher than in other emerging economies such as China. This can be observed when factoring in the introduction of a carbon pricing scheme from 2020 onwards. In 2020, the assumed carbon price is USD 42 per tonne of CO_2, increasing to USD 63 per tonne of CO_2 by 2050. Fig. 34-3 shows that, in the presence of the assumed carbon penalty, the LCOE of CCS plants in coal development pathway E2 is only slightly lower in both 2040 and 2050.

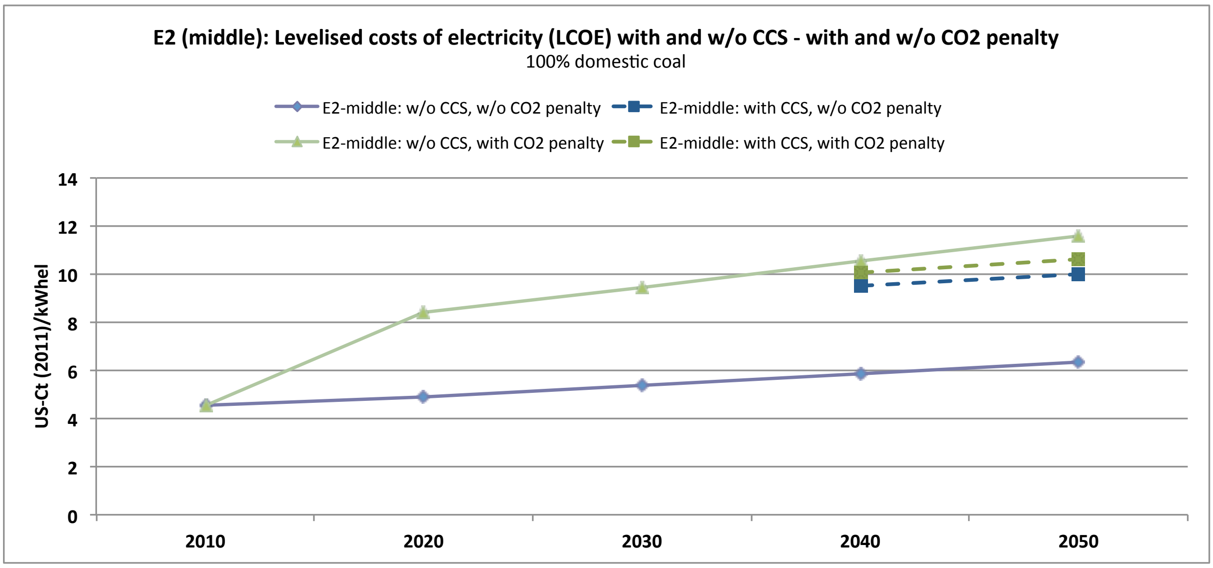


Fig. 34-2 Levelised cost of electricity in South Africa with and without CCS and with and without a CO_2 penalty in coal development pathway *E2: middle* up to 2050

Source: Authors' illustration

This result is reinforced when considering CO_2 mitigation costs. Based on the three considered coal development pathways, overall CO_2 mitigation costs of CCS at supercritical plants in South Africa are estimated to range from USD 48 to 52 per tonne of CO_2 from 2040 to 2050, respectively. When introducing a CO_2 pricing pathway as mentioned above, the carbon price would be sufficient to compensate for the additional costs of CCS. However, it would not provide a particularly strong cost advantage of CCS plants over the LCOE of non-CCS facilities, which include significant additional costs for a CO_2 penalty. Consequently, a more aggressive CO_2 penalty or significant cost reductions in CCS technology would be required in order to provide a clear incentive for CCS use in South Africa. Furthermore, CCS would face strong competition from other low carbon technologies in a carbon-constrained policy environment, especially from renewable energy technologies that have much higher learning rates than supercritical PC plants. Thus, a comparison of CCS plants with other low carbon technology options would be required to be able to draw sound conclusions on the economic viability of CCS in a low carbon policy environment.

Large Reduction in Greenhouse Gases but Increase in Other Environmental Impacts

To assess the environmental impacts of CCS, a prospective life cycle analysis (LCA) of future CCS-based power plants in South Africa was performed. With a CO_2 capture rate of 90 per cent, PC and IGCC power plants with and without CCS were compared. The results show a 78 and 74 per cent decrease in CO_2 emissions for PC and IGCC systems, respectively. Total greenhouse gas emissions are reduced by 72 and 67 per cent, respectively. However, all other environmental impact factors increase (acidification, eutrophication, human toxicity, terrestrial ecotoxicity, freshwater and marine aquatic ecotoxicity, stratospheric ozone depletion and summer smog). From a global perspective, these results are in line with LCAs performed by other authors for future CCS systems. Fig. 34-3 shows the results of CO_2 emissions and total greenhouse gas emissions.

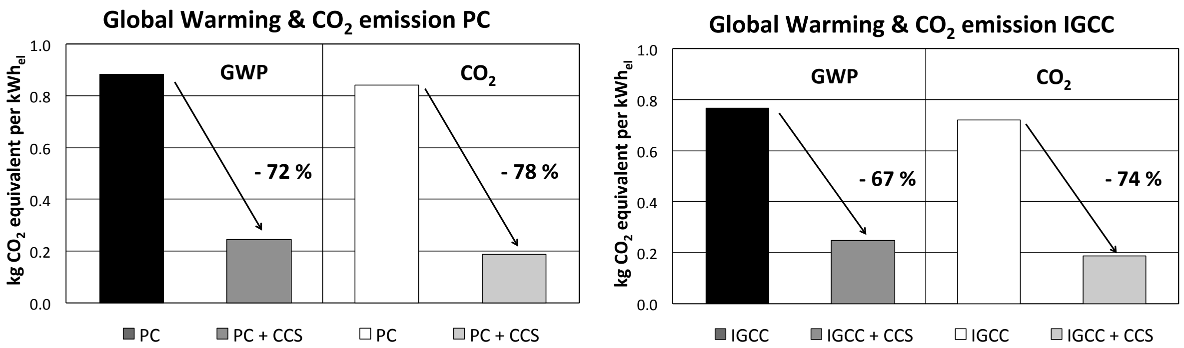


Fig. 34-3 Global-warming potential and CO_2 emissions from PC and IGCC with and without CCS in South Africa from a life cycle perspective

Source: Authors' illustrations based on Deibl (2011)

In general, two issues are responsible for these results. Firstly, the additional energy consumption required by CCS-based power plants (energy penalty) causes more emissions per kilowatt hour of electricity generated in the power plant. Only CO_2, NO_x and SO_2 are removed from these emissions during the CO_2 scrubbing process. Secondly, additional emissions caused by upstream and downstream processes must be considered. Both the excess consumption of fuels and additional processes such as the production of solvents or the transportation and storage of CO_2 cause an increase in several emissions. When these emissions are (partially) removed at the power plant's stack, upstream and downstream emissions dominate the respective impact categories.

However, the absolute scores and the general framework of the LCA model have to be considered when interpreting the results. A wide range of assumptions for capture, transportation and storage, timing of the CCS process, type of reference power plant and choice of parameters makes it difficult to compare the results with LCAs performed in other studies. Furthermore, it is not possible at present to model the capture process in detail due to the lack of data. Variations of the removal rate of pollutants in particular could alter the results considerably. With regard to this study, a number of further limitations must be borne in mind: only little data exists on the performance of power plants in South Africa. The uncertainty surrounding the future technical development up to the reference year 2030 necessitates the use of assumptions, which could mislead the results. This is particularly the case for the assumed power plants' efficiencies and the datasets for modelling the upstream process of coal mining.

Furthermore, coal mining leads to manifold ecological and social problems, which are not covered by LCAs. A commercialisation of CCS would reinforce these impacts since CCS-based power plants require 20 to 35 per cent more fuel than those without CCS. Most problems refer to land use, water consumption, air pollution at the mining site and surrounding residential areas, noise, mine waste and – last but not least – social issues resulting from the displacement and resettlement of local communities.

A recent study calculated the external costs of coal-fired power generation using the example of Kusile, one of two large power plants currently being built in South Africa. The study included the effects of coal mining on the environment such as water consumption and water pollution, loss of agricultural and other ecosystem goods and services, human health impacts, coal transportation and climate change impacts. Such environmental impacts indicate a significant economic impact, leading to external costs ranging from between ZAR 31 and 61 billion per year. Approximately 70 per cent of the external costs are water-related, followed by 21 per cent for the mining sector and 10 per cent for climate change. All these costs would increase in the event of CCS due to the greater consumption of coal and water.

Stakeholders' Ambitious Attitude towards CCS

The analysis of stakeholder positions and activities on CCS in South Africa shows that key players have taken important action, both with regard to research and development and policy. Having established the South African Centre for Carbon Capture and Storage, South Africa possesses an institutional body that coordinates and oversees CCS-related research, development and public outreach activities. By developing a medium-term roadmap for the technology's large-scale implementation, SACCCS has set an important milestone for achieving the well-organised and structured technology development and deployment strategy.

Furthermore, the South African government has chosen a proactive and ambitious approach to fight climate change and reduce carbon emissions. The government's role as the host of the COP17 in Durban in December 2011 acted as a catalyst for this development, triggering the launch of the National Climate Change Response White Paper. In this paper, the government recognised the potential for CCS to become an important CO_2 mitigation technology in South Africa and announced a CCS Flagship Programme. This implies that activities for CCS development and demonstration are generally welcomed and supported by the national government. In addition to these rather favourable political framework conditions, South Africa's coal-fired synthetic fuel industry is widely considered an ideal opportunity that could facilitate CCS implementation because it regularly produces large streams of nearly pure CO_2. For this reason, most of the experts interviewed consider the CTL industry to be the primary user of CCS in South Africa. Since CO_2 capture is an integrated process component of CTL, Sasol, the operator of South Africa's CTL plants, has expertise and experience in many elements of the CCS technology chain. Hence, many of the experts interviewed regard Sasol's CTL plants as the primary testing field for CCS technology, even though the plants may be at the end of their lifetime or too old for retrofitting when the technology becomes available for large-scale use.

With regard to CO_2 mitigation in the power sector, the Director General of the Department of Energy has also acknowledged the potential role of CCS. However, several respondents stated that the national government seems to prefer nuclear energy and renewable energies as options for power generation in a carbon constrained future. Nonetheless, coal-fired power plants with CCS could play a role in South Africa for the following reasons: firstly, the government intends to maintain coal combustion as an important element of the national power mix because coal is a secure and economically viable domestic energy source, whereas confidence in the potential and reliability of renewable energies seems to be rather limited. Secondly, coal-fired power plants were obliged to be designed capture-ready following pressure from the World Bank, which provided co-funding for the plant. Thirdly, the national government is currently discussing the introduction of a carbon pricing mechanism, such as a carbon tax. If the carbon tax outweighed the costs of CCS, and therefore the economic risks involved, Eskom or Sasol would seriously consider using CCS technology.

In addition to these economic and political conditions, however, many respondents emphasised that limited knowledge about potential CO_2 storage sites and long distances between CO_2 sources and storage regions could be important obstacles to CCS implementation. Hence, more research is required in these fields to project the prospects of CCS in South Africa. Furthermore, CCS implies potential conflicts with other important policy objectives of the national government, for example affordable electricity rates, reducing water usage and improving efficiency of electricity generation to give the whole population access to electricity.

35 Literature

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