thirsty energy

Modeling the Water-Energy Nexus

How Do Water Constraints Affect Energy Planning in South Africa?

WORLD BANK GROUP

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Acknowledgments

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Abbreviations

BAU	Business-as-usual
Bn	Billion
CCGT	Combined cycle gas turbine
CFB	Circulating fluidized bed
CH4	Methane
CO_2	Carbon dioxide
CTL	Coal-to-liquids
CSIR	Council for Scientific and Industrial Research
CSP	Concentrating solar (thermal) power
DEA	Department of Environmental Affairs
DWAF	Department of Water Affairs and Forestry (now DWS)
DWS	Department of Water and Sanitation (preceded by the Department of Water Affairs which followed the restructure of the former DWAF ministerial portfolio)
ERC	Energy Research Centre (of the University of Cape Town)
FGD	Flue gas desulfurization
Gt	Gigaton
GTL	Gas-to-liquids
GHG	Greenhouse gas
GW	gigawatt
IAM	Integrated assessment model
IBT	Interbasin transfers
IEP	Integrated energy plan
IEW	International Energy Workshop
IRP	Integrated Resource Plan
Mm^3	Million cubic meters
mm	Millimeter
Mt	Million tons
MW	Megawatt
MWSC	Marginal water supply cost (curve)
NO_x	Nitrogen oxides
OM	Operating and maintenance (cost)
PPD	Peak-plateau-decline (of emissions)
PJ	Petajoule (10^{15} joules)
PV	Photovoltaics (solar)
PWTC	Primary water treatment costs
R	South African rand
RE	Renewable energy
SO_x	Sulfur oxides
SWTC	Secondary water treatment costs
TDS	Total dissolved solids
TRMC	Total regional marginal cost (of water)

UCE	Unconstrained emissions (scenario)
UNFCCC	United Nations Framework Convention on Climate Change
UWC	Unit water cost
WEC	World Energy Council
WSA	Water supply area
WSC	Water supply cost
WSR	Water supply region
ZLED	Zero liquid effluent discharge

$ indicates U.S. dollars.

Overview

Connecting the Water and Energy Sectors

Water and energy are often entwined in the sense that the use of one depends on the availability of the other. Decision making in one sector significantly affects the other, but those effects often are not taken into account in traditional sector-based planning processes. The sustainable supply of services from these two interdependent resources therefore constitutes a set of integrated challenges commonly referred to as the water-energy nexus. Improving our understanding of the complex interdependencies of the water-energy nexus and developing appropriate tools to assist decision makers with future infrastructure planning are essential for continued sustainable development in the face of the uncertainties posed by climate change.

The World Bank has embarked on a global initiative called Thirsty Energy to help countries tackle the challenges of managing the water-energy nexus in an integrated manner, starting with the energy sector as an entry point. A primary aim is to demonstrate the importance of combined energy and water modeling, planning, management, and decision making and to develop practical methodologies that can be applied to operational tools. This report presents the results from the development of a new water and energy modeling tool to support integrated decision making in South Africa and offers a proof of concept for the integration of energy and water planning tools. The results are presented as a first step toward understanding the implications of integrated water-energy modeling and are not intended as a definitive policy study, which would require more rigorous sensitivity analysis. Nevertheless, the findings presented here should be of great interest to policy makers.

South Africa represents an ideal case study of the challenges that the Thirsty Energy initiative is designed to address. South Africa is a water-stressed country that is also experiencing a crisis of electricity supply. The sustainability of water and energy supplies is uncertain, as is the impact of shortages on social well-being, the national economy, and the environment, particularly in the context of climate change. Fully understanding the contours of the water-energy nexus is therefore particularly relevant for South Africa.

In contrast to many other developing countries, South Africa has long had processes for long-term planning related to the supply of energy and water. Planning for one has historically taken into account the cost and scarcity of the other, though to varying degrees. For example, the state-owned utility, Eskom, has a policy known as "zero liquid-effluent discharge" and has made significant historical investments in dry cooling for coal-fired power plants and plans to use dry cooling for all future plants. Additionally, the National Water Resources Strategy and other water resources planning studies consider the future water needs of the power sector. This has resulted in the development of an integrated system of large dams and interbasin transfers to ensure a reliable water supply to the energy sector (among others). The South African situation therefore provided a unique opportunity for the Thirsty Energy Initiative to develop and demonstrate methodologies for integrated water-energy planning.

Overview of the Modeling Methodology

This case study is the first time the cost of water supply has been assessed in a sectorwide energy supply expansion plan.[1] By documenting the methodology, the authors aim to help energy sector planners and modelers properly incorporate water constraints in their work.

The South African TIMES model (SATIM),[2] a public domain energy systems model developed by the University of Cape Town's Energy Research Centre (ERC), was selected as the basis for the development of a water-smart energy planning tool as an important first step towards an integrated water-energy planning methodology. SATIM is a national model built using the TIMES modeling platform, a partial-equilibrium linear optimization framework capable of representing an entire energy system, including its economic costs and emissions.

The South Africa case study presented in this report documents the development of a "water smart" version of SATIM (SATIM-W), depicted in figure O.1, in which the water needs of the energy sector and the options available to meet those needs (bulk water infrastructure and alternative sources such as desalination) are represented by information derived from a detailed water-basin model. The wealth of water-planning datasets and cost curves available from South Africa's Department of Water and Sanitation (formerly the Department of Water Affairs and Forestry) and supported by local water modeling experts serve as the main data source on water for this purpose.

A key feature of the developed SATIM-W model is that it regionalizes power generation, refining, and energy resource supply, thereby introducing a spatial dimension to the water demands of the energy sector. It also contains a regionalized structure of the basins and delivery infrastructure that would be required to supply the energy sector and assesses the impact of meeting those needs on the cost of supplying water.

Given that virtually all water in South Africa is allocated, any future demand for water in the energy sector will require new water infrastructure. SATIM-W tracks regional water demands and the need for new regional water infrastructure, including interregional exchange possibilities, to better understand the impact of water supply costs on the energy sector. It produces a least-cost energy supply plan through 2050 that minimizes the cost of both energy and water supply. Because the planning, design, and construction of infrastructure requires long term engagement, the results from such a planning exercise can help to ensure the timely planning of investments for the delivery of water to the energy sector.

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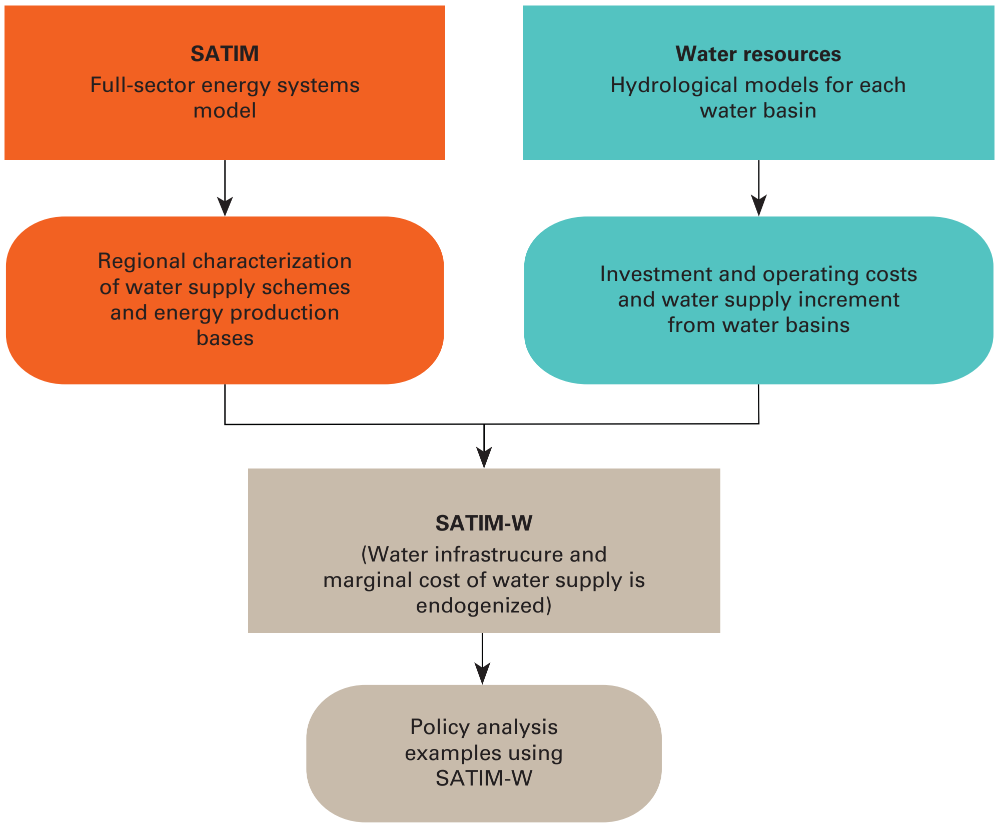
[1] A recent study by the National Renewable Energy Lab (http://www.nrel.gov/docs/fy15osti/64270.pdf) looked only at water consumption by power plants; it did not consider major water infrastructure investments or the water needs of energy activities other than power plants.

[2] TIMES is a partial-equilibrium linear-optimization model developed under the auspices of the International Energy Agency's Energy Technology Systems Analysis Program capable of representing an entire energy system, tracking the flow of commodities (including energy, materials, emissions, demand services, and water) through the system, and determining the capital stock requirements of all technologies embodied in the system including economic costs.

Figure O.1 South African Water-Energy Nexus Modeling Framework



The scenarios selected for analysis reflect main drivers of investment uncertainty in water and energy supply that are of key importance to South Africa. Specifically, the SATIM-W model has been used to examine the following questions facing the country.

- How does accounting for regional variability in water availability and the associated infrastructure costs of water supply in different regions affect future energy planning?
- Is the current policy of dry cooling for new coal-fired power plants economically justified?
- How do stricter environmental controls affect coal investments in the Waterberg region?
- How does a dry climate affect coal investments in the Waterberg region?
- How does the cost of water affect shale gas production?
- In a carbon-constrained world, what is the likelihood of stranded assets?
- Why does SATIM-W select concentrating solar power (CSP) with wet cooling in the Orange River Basin?

Initial Findings on the Water-Energy Nexus

This case study has yielded some important general findings on the broader impacts of modeling the water-energy nexus. They point to the potential benefits of further development of the SATIM-W model and of the concept of the water-energy nexus as a critical consideration in planning.

General Findings

The most important message of the report is that taking into account the regional variability of water supply and the associated costs of water supply infrastructure has a very significant impact on the optimal mix of energy technologies and on greater efficiency and sustainability in water use.

Taking into account the regional variability and the associated costs of water supply infrastructure yields suggestions for optimal energy technology investments that are different from the results reached when variability and costs are not included or when an average water supply cost is applied to all energy technologies irrespective of where they are located and regardless of likely water supply options.

Energy sector policies can have significant implications for investments in water supply infrastructure and can lead to stranded water supply investments—and vice versa. However, if decision makers plan in a more integrated manner they can ensure the robustness of water supply for energy and for other water users, thus maximizing the value of both energy and water infrastructure investments.

Accounting for the differences in the costs of the physical infrastructure necessary to provide water for energy in different regions of the country better integrates water and energy planning and decision making. However, other aspects of the water-energy nexus remain unaddressed. These include the harder-to-quantify aspects of the value of water in a particular region, among them potential conflicts between water uses, opportunity costs from other sectors, and effects on water quality. Further investigation is needed to know how planning tools can best account for these aspects.

Water system planning models (generally at the basin level) can provide data on the costs and availability of specific water supply and infrastructure options. These can be explicitly represented in a water-smart national energy system model to derive water supply cost curves that can impact decisions on energy production.

In terms of modeling the water-energy nexus, this case study demonstrates that a national-level energy systems optimization model can be regionalized in terms of energy resource supply and power plant locations, and the regional costs and limitations for water supply infrastructure can be incorporated to create a water-smart planning tool. The process used for the South Africa model can be adapted to other national energy system planning models.[3]

[3] A second Thirsty Energy case study is underway in China, with results expected before the end of 2017.

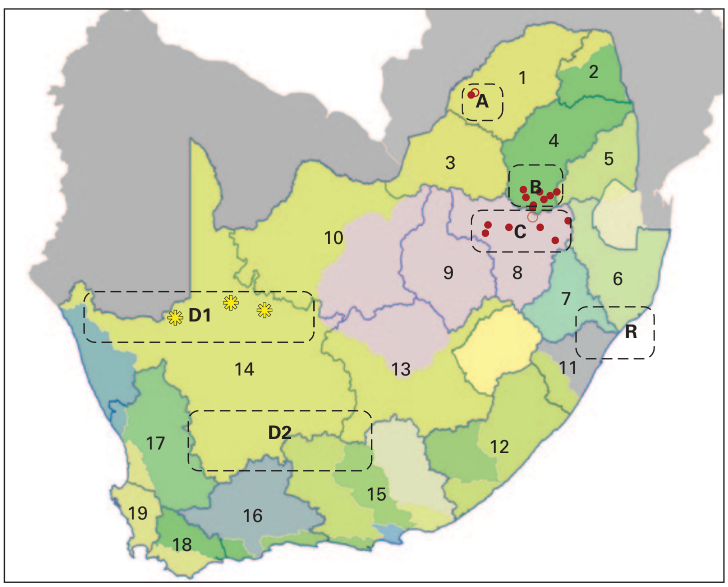
It is clear that the effects of climate change and climate-related policies will have a significant impact on both water and energy planning, so they must be taken into account in plans that purport to address the water-energy nexus.

Findings for South Africa

The following findings of this report are specific to the water-energy nexus in South Africa. They are discussed with reference to specific SATIM-W model scenarios constructed around policy options and investment decisions in both energy and water supply. Thus the findings are primarily illustrative and serve to showcase how SATIM-W can be used to inform policy formulation and decision-making for the energy sector with consideration of the impacts of water supply costs.

Because of the regional nature of many of the key findings, a map of South Africa's water management areas and energy producing regions is provided in map O.1.

Map O.1 South Africa's Water Management Areas and Energy Producing Regions



WMA index

1 Limpopo
2 Luvuvhu to Letaba
3 Crocodile to Marico
4 Olifants
5 Inkomati
6 Usuthu to Mhlatuze
7 Thukela
8 Upper Vaal
9 Middle Vaal
10 Lower Vaal
11 Mvoti to Umzimkulu
12 Mzimvubu to Keiskamma
13 Upper Orange
14 Lower Orange
15 Fish to Tsitsikamma
16 Gouritz
17 Olifants to Doorn
18 Breede
19 Berg

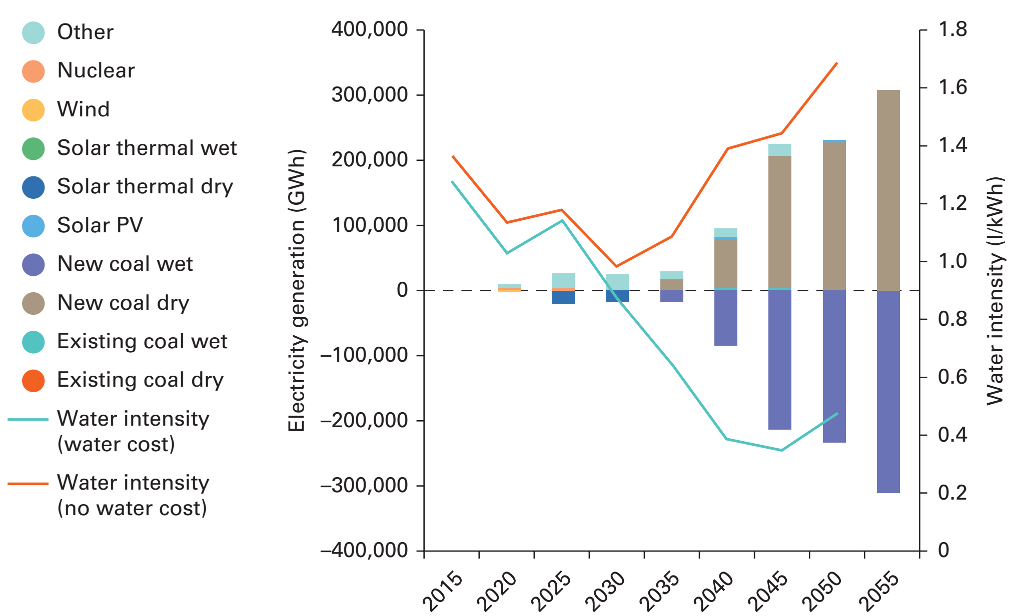
Source: Adapted from DWAF 2012.
A: Waterberg (Lephalale).
B: Mpumalanga, Witbank.
C: Mpumalanga, Secunda.
D1: Northern Cape, Upington.
D2: Northern Cape, Karoo.
R: Richards Bay Coal Export Terminal.

The commissioning of dry-cooled rather than wet-cooled coal-fired power stations appears economically justified when taking into account future water infrastructure supply costs

Even in water-scarce countries such as South Africa, wet-cooled power stations are often considered to be more cost effective than dry-cooled power stations owing to their lower investment costs and higher net generation efficiency. However, when regional water costs are taken fully into account (as under the SATIM-W Reference scenario with water costs), dry-cooled power stations yield the optimal cost solution for South Africa.

Even though it increases the cost of electricity from coal power plants, Eskom's dry cooling policy is really in the economic interests of the country. As shown in figure O.2, when regional water availability and infrastructure supply costs are fully considered in the model (Reference [Water Cost]), dry-cooling is the preferred option for new coal power plants, particularly in the Waterberg region where the remaining economically viable coal reserves are located. This dry-cooling policy has a significant impact on the power sector water intensity which could either reach a peak of

Figure O.2 Difference in Electricity Generation by Type and Water Intensity for Reference (Water Cost) and Reference (No Water Cost)



1.65 l/kwH by 2050 based on the Reference (No Water Cost) scenario, or 0.5 l/kWh based on the Reference (Water Cost). In the Reference (Water Cost) scenario, the power sector's cumulative water consumption for 2010–50 drops by 9,338 Mm^3 (77.34 percent) with just a modest increase (0.84 percent) in the total discounted energy system cost.[4]

The Waterberg region provides a good example of the importance of accounting for water cost in energy planning and highlights the specific regional challenges of the water-energy nexus. In Waterberg, the energy sector is the largest water user, with power plants accounting for the largest share. If water costs were not taken into account in energy-system planning through 2050, water consumption would rise from 45 Mm^3 in 2015 to almost 900 Mm^3 by 2050, with power plants approaching 80 percent of the ttal water consumption in the region. Under the contrary scenario, by contrast, power plant water consumption[5] drops to less than 100 Mm^3 by 2050 and total water consumption in the region is about 250 Mm^3.

Other than the water consumed by power plants, the two Reference scenarios have similar total system cost, energy supply expenditures, and primary and final energy consumption results.

Interestingly, the Reference scenario with water costs produces slightly more CO_2 emissions than the scenario without water costs, despite generating 1.3 percent less electricity with coal and 2 percent more with renewable energy (RE) technologies, chiefly wind and solar photovoltaics (PV), which require no water to generate electricity. The higher CO_2 emissions stem from the higher unit emissions of dry-cooled coal plants.

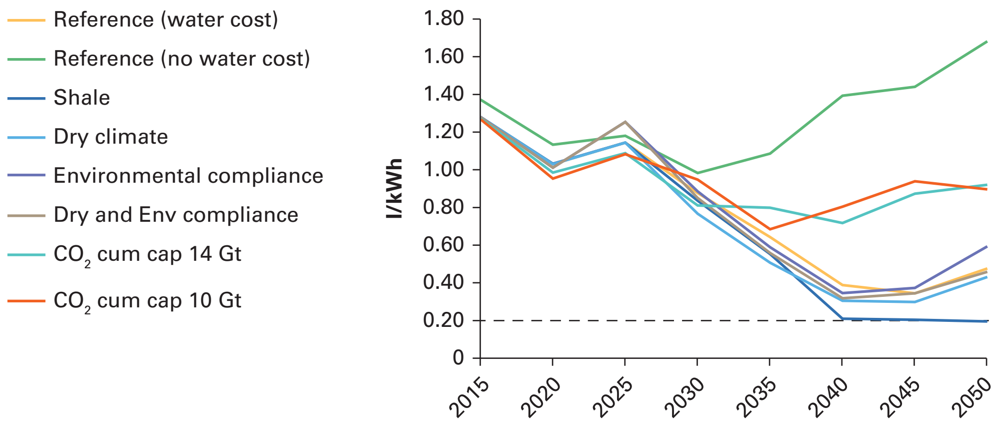
The increase in total system cost for the Reference scenario with water costs is only 1.1 percent because of the relatively small share of water supply infrastructure costs compared with all other investments and expenditures for energy in the supply and demand sectors. Investment costs for water supply infrastructure account for 40 percent of the increase, while water system supply and operating costs account for the remaining 60 percent.

The water intensity of the power sector under other scenarios is close to the intensity level generated by the Reference scenario with water costs (figure O.3), except in the case of the scenarios based on targets for reducing greenhouse gas (GHG) emissions, where the model favors use of some CSP plants using wet cooling for reasons explained in the last finding presented in this section.

[4] The total discounted energy system cost is the sum of the present value of all energy system investments (both for supply and demand), financing costs, fuel costs, and operating and maintenance costs.

[5] Note that because of Eskom's ZLED policy, all power plant water use is consumptive.

Figure O.3 Impact on Power Sector Water Consumption under Various Scenarios



Stricter environmental controls on coal technologies can have various effects on energy and water infrastructure investments, depending on region, highlighting the importance of addressing the water-energy nexus at the regional level

Stricter environmental controls (Environmental Compliance scenario) reduce investment in coal-based energy supply and associated water supply infrastructure in the Lephalale area of Limpopo province, as current emissions regulations requiring flue gas desulfurization (FGD) for existing coal power plants and new coal-to-liquids (CTL) plants prove to be a major investment disincentive. This scenario accelerates the retirement of the existing coal plants starting in 2030, with more solar PV coming online to replace it. It also results in a significant reduction in new CTL plant capacity, compared with the Reference (Water Cost) scenario. This leads to higher imports of petroleum products and a deferment of new water supply schemes in Waterberg that were driven mainly by water demand from CTL plants. Postponement of those schemes could have a wider impact on economic development in the area, such as new mines and industries that would also depend on the new water supply infrastructure.

The result of this scenario again highlights the importance of looking at the water-energy nexus to avoid suboptimal or even misguided investments in one sector or another. In this scenario, the cumulative (2010–50) demand of water for power plants increases by 2.34 percent, in part given the extra water needed for the FGD systems. However, the water needs of the whole energy sector drop by 1.59 percent in this scenario because new CTL plants are not built and, as a result, less coal is mined.

On the other hand, requiring existing power stations to retrofit with FGD systems has little impact on the Upper Vaal and Olifants water supply schemes. This is because non-energy water requirements are the main drivers of investment in water infrastructure in this region, where most existing coal power plants are located.

Future water supply schemes commissioned under the Reference (Water Cost) scenario appear sufficient to also meet demand generated by the FGD retrofits required for to meet current regulations to reduce sulfur dioxide emissions for existing coal-fired power plants in the Upper Vaal and Olifants water management areas. The Reference (Water Cost) scenario adds a new water supply scheme in 2020, which is more than adequate to provide the relatively small amount of water needed for FGD systems in the Olifants region, where most existing power plants are located.

On the other hand, the demand for water for FGD systems for new power plants in the Waterberg region would trigger the need for new water infrastructure and justify the development of a new pipeline to the area.

Requiring all power plants to incorporate FGD systems could increase water consumption by the power sector by 65 million cubic meters per year (a 0.6 percent increase). However, it would have a positive impact on the environment.[6]

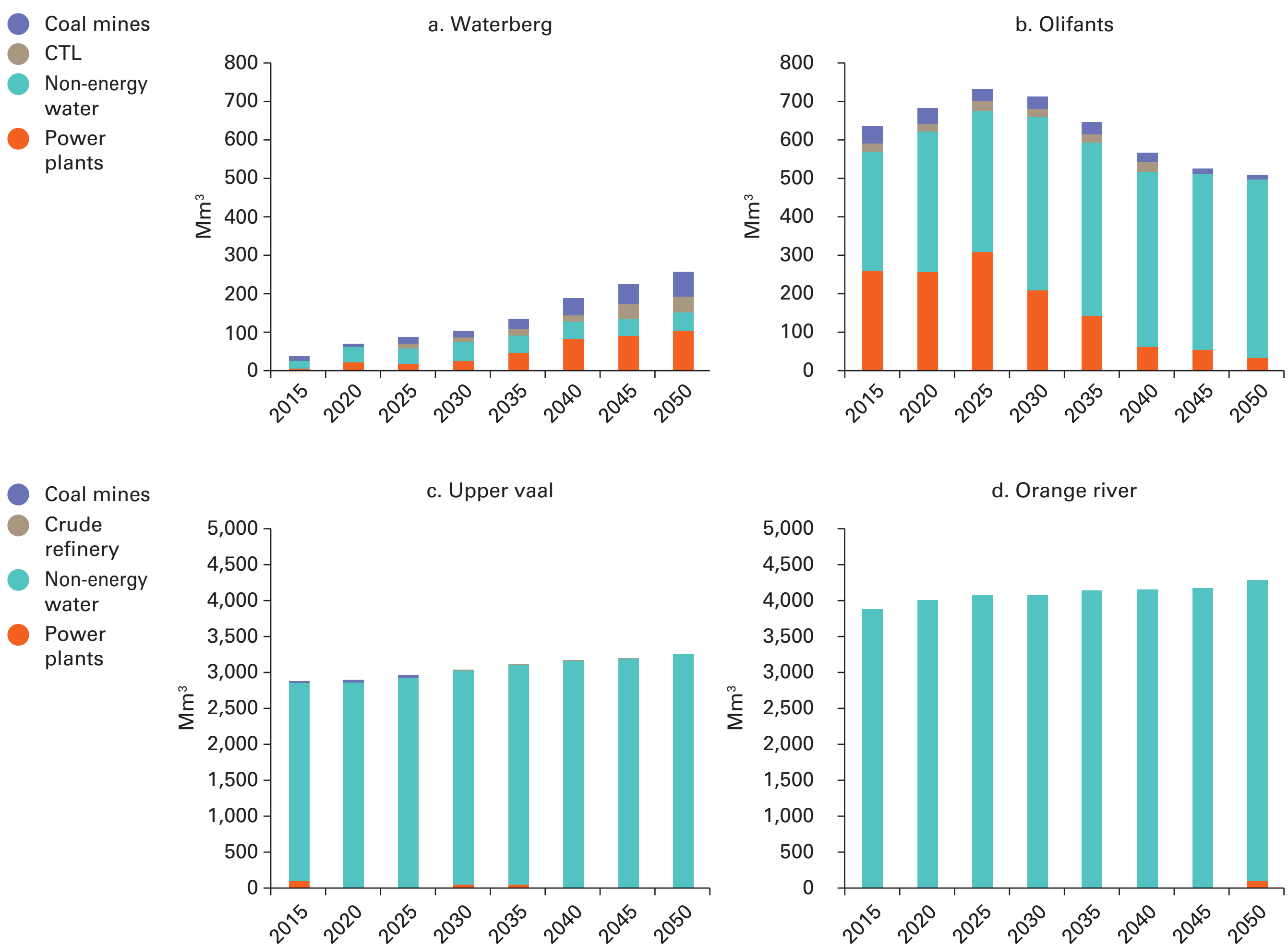
The waterberg region is the region where the water-energy nexus is most evident and critical

In the Waterberg region, a large share of water goes to the energy sector. Under the Reference (Water Cost) scenario, water consumption by power plants will account for about 40 percent of all demand in 2050, whereas coal mines consume about 25 percent and CTL plants and non-energy uses consume equal shares of the remaining 35 percent. Given that all energy sector uses account for more than 80 percent of the water demand in the region (figure O.4), it is no surprise that the region is sensitive to energy policy changes. A deep dive in this particular region may be justified in future work, particular as significant concerns surround the impacts of energy-related water consumption on agriculture production and tourism.

Declining water quality in the Waterberg region threatens expansion of the energy sector and would result in increased investments in RE technologies elsewhere. The extent to which new power plants and CTL production occur in the Waterberg region are shown by the model to be significantly affected by the cost of treating low-quality water. As water quality drops (because of rising salinity or contamination with industrial pollutants), the increased costs of treating that water become more substantial,

[6] For this initial study, only wet FGD systems were modeled (see Appendix H), the cost of waste disposal and sorbent still needs to be incorporated in the model, and the total increase in costs for the system need to be further examined.

Figure O.4 Water Supply Breakdown in Each Energy Area of Interest



Note: CTL = coal to liquids; Mm^3 = millions of cubic meters.

making other energy technologies become more economically attractive. In the Water Quality scenario the increased cost of treatment associated with lower-water quality results in a decrease in capacity of new coal power plants of approximately 7 GW (16 percent of total capacity) by 2050 compared with the Reference (Water Cost) scenario. To replace it, an additional 9 GW of RE capacity is built (solar thermal and solar PV in approximately equal shares) along with a further 2 GW of combined-cycle gas turbine (CCGT) power plants using imported liquefied natural gas from regional suppliers to balance the system load for the higher levels of RE. Similarly, when the water quality cost is internalized, there is a 20 percent reduction (approximately 100 PJ/year or 60 thousand barrels a day) in new CTL capacity by 2050, resulting in increased imports of refined oil products.

Shale gas appears to be quite attractive for electricity generation but will require investment in additional water supply infrastructure for major development and careful consideration of broader water-related risks

While current world prices for oil and gas may deter exploitation of shale gas in South Africa, SATIM-W looks at long-term trends. Shale gas production starts in 2025 at about 111 PJ and rises to 582 PJ in 2050 under Reference conditions. However, with climate change policies, shale gas production ramps up to more than 735 PJ. Given the energy-security benefits of domestic production, shale gas will most certainly receive further consideration as a way to diversify South Africa's energy mix, while decreasing its GHG emissions, but this will require careful consideration of the water-energy nexus and broader social and ecological impacts.

Using the limited data available, the model suggests that the use of shale gas for power generation under the Shale Gas scenario will grow at a similar rate once the costs of supplying water are taken into account. In other words, the cost of water (which was only partially modeled in this case study due to lack of data) does not appear to be the main driver of decisions about whether to invest in shale gas to generate power. However, regional water supply costs could potentially double in certain regions because of demand from shale gas production, thereby affecting not only the producers but other water users as well through lowering of the groundwater table and increased risks for surface and groundwater pollution.

Under the modeled scenario, an assumed limit on on-site groundwater usage of 1 Mm^3/year (see section 6) leads to a reliance on trucked water for in the early stages of development for the shale gas sector, resulting in relatively high water supply cost. However, the construction of a pipeline in 2030 to bring water into the shale production area reduces the cost of supply by about 95 percent, and this assumed lower cost accelerates shale gas development. In this scenario, cumulative water consumption of the power sector between 2010 and 2050 decreases by 14.9 percent, as given that coal power plants are replaced by CCGTs, which consume less water. Cumulative water needs for the overall energy sector also decrease by 9.76 percent.

However, it is important to note that, because of a lack of data for South Africa, in this preliminary analysis the potential costs of (a) treatment and disposal of return-flow effluent (which will further increase production costs) and (b) distribution or delivery of water supply are not fully reflected in the model. That is, the model considered only a high level estimate of the bulk water supply to the region and did not account for the significant cost of distributing the water to individual wells.

When these considerations are fully incorporated and modeled, the water implications for shale gas extraction and utilization may vary from the results reflected in this analysis.

Policies limiting carbon emissions may strand some water-energy infrastructure but could make water available (at higher cost) for other users if planned accordingly

The model indicates, not surprisingly, that coal-fired and CTL generation would be directly affected by a cumulative carbon cap on energy emissions by 2050. A 10 Gt limit would reduce CTL output dramatically, resulting in an increased reliance on imported refined petroleum products, which would replace 80 percent of existing CTL production by 2025. The remainder of the lost CTL production comes from increased production in existing refineries. Although a 14 Gt limit allows the existing CTL facility to operate at full capacity until 2025, there still is an increase in imports of finished petroleum products owing to a lack of investment in new CTL capacity in the Waterberg region. In contrast, the existing and planned coal power plants are less at risk under the 14 Gt limit, as these coal assets remain operational for their entire production life, although no new coal power plants would be commissioned under this scenario. In contrast, a 10 Gt limit would reduce the operating life of the committed coal-fired power plants by at least 15 years, with decommissioning occurring by 2035. Their capacity would be replaced by new nuclear plants. In addition, the 10 Gt limit shifts electricity production from the Waterberg to the Orange River region, where the model calls for CSP technology instead.

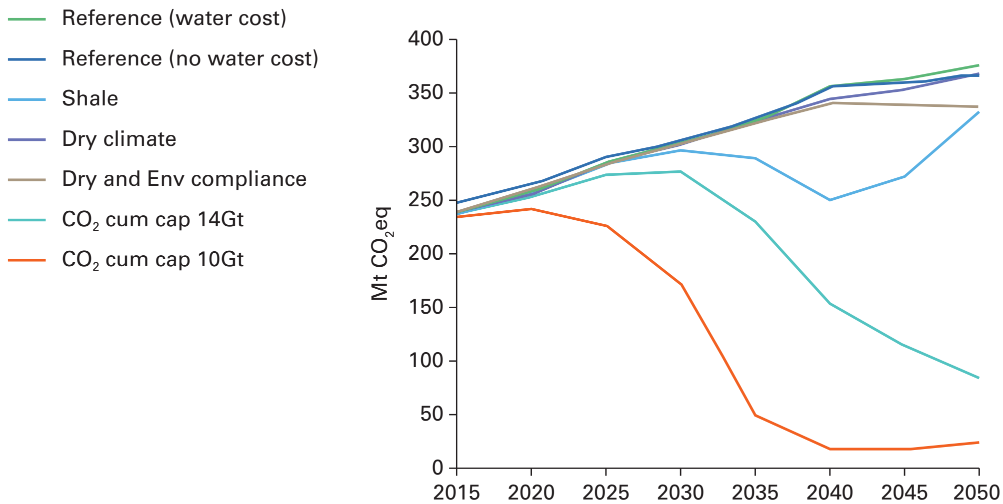
Both CO_2 Cap scenarios also affect investment in water supply infrastructure in the Waterberg region, since the region's coal-based energy sector provides much of the funding for the water infrastructure. If the sector's water demands are greatly reduced, the associated water infrastructure may not be built. As water demand from non-energy sectors grows in this region, however, the missing investment from the power sector pushes up the costs of water supply by 2035. Meanwhile, other users have access to additional water, since the existing supply capacity is underutilized. This again points out the connections between the energy sector's water needs and appropriate sizing and timing for the associated infrastructure.

Interestingly, both CO_2 Cap scenarios increase the cumulative (2010–50) water needs of the power sector significantly (by 21 percent and 25 percent). This occurs because the model chooses wet-cooled CSP as the replacement for coal. However, the water needs of the energy sector as a whole increase by just 4 percent and 3 percent, given the decrease of activity in the coal industry (coal mining, CTLs) as the CO_2 caps kick in.

Figure O.5 depicts projected GHG emissions under various policy scenarios, including the two CO_2 Cap scenarios. Because the Reference scenario already includes demand-side improvements in energy efficiency, the other scenarios examined show only small changes from the Reference scenario. The shale gas scenario shows some temporary reductions, but these rebound after 2040 and by 2050 are close to the Reference value.

Figure O.5

Trajectory of GHG Emissions by the Power Sector under Various Scenarios



The highly integrated nature of the south african water supply system creates some resilience to the impact of climate change, but increasing temperatures may affect the efficiency of dry-cooled systems

Projected changes in regional climate (reduced water availability and increased ambient temperature) are expected to shape investment in energy and water supply, compounding the effects of a policy limiting carbon emissions. Under the Dry Climate scenario, increases in water demand traceable to the warmer and drier climate expected from 2030 will trigger faster and larger investments in water infrastructure, which will raise the average cost of water supply. However, the ability to meet demand will not be not strongly affected, owing to South Africa's integrated water supply network, which enables the transfer of water from areas of high rainfall (such as Lesotho) or substantial urban return flows (such as Johannesburg) to water-scarce regions such as the Waterberg. On the other hand, rising temperatures may affect the efficiency of future dry-cooled coal and CSP plants and increase demand for water in older, wet-cooled plants, a possibility that was not factored into this analysis (see section 4). Further analysis of the effects of climate change on the water-energy nexus is required.

The development of CSP in the arid orange river region does not appear to be constrained by water supply, given the small share of the energy sector in the region's water consumption

A valuable insight gained from combining the CO_2 Cap and Dry Climate scenarios is that expansion of CSP capacity in the region supplied by the Orange River system does not appear to be constrained by water supply, despite being an arid region generally. This is because the bulk of the water comes from the highlands of Lesotho. Here, wet cooling is initially favored even in the Reference (Water cost) scenario. A significant shift to dry cooling occurs only after 2040, when the effects of climate change are compounded by the added pressure of a dry climate or by the development of shale gas in the region.

SATIM-W selects wet-cooled CSP in the Reference (Water Cost) scenario and also in the CO_2 Cap scenarios. However, in the combined Dry and 10 Gt CO_2 Cap scenarios the model selects dry-cooled CSP. Lower water demand under the combined scenario relative to the Reference scenario is accompanied by a rise in water costs. This increased cost is sufficient to have the CSP plants switch from wet-cooled to dry-cooled technology.

SATIM-W's choice of wet-cooled CSP in the Reference (Water Cost) scenario appears to reflect the small effect of CSP's water demand on the region's marginal supply costs of water. Water demand in this region is dominated by non-energy demands, particularly agriculture and a large interbasin transfer, which means that a significant water supply scheme will have to be built regardless of changes in energy technology. However, the cost of water from this supply scheme increases when dry-cooled CSP is selected, because the investment cost must be amortized over a smaller base of users. This suggests that the increased *cost* of water, not the *scarcity* of water in the region, is a determinant in the choice of technology.

The foregoing results demonstrate the value of the SATIM-W model as a component of an integrated assessment methodology that can better inform decision makers of the potential costs, benefits, and risks of alternative policies and technology choices under a range of possible future conditions. In particular, the results demonstrate the possibility of identifying major investments that could become stranded down the road. Employing an integrated planning approach that looks systematically at the development of both the water and energy sectors could help avoid such costly and unproductive outcomes.

The SATIM-W model described in this report is an important first step toward an integrated approach to water-energy planning, one in which trade-offs, synergies, and opportunities are assessed together. The model's initial applications, as described here, have clearly demonstrated the importance and value of employing an integrated planning platform to ensure that water and energy investments are intelligently planned in a least-cost manner. The comprehensive approach made possible by SATIM-W should be further developed so that it becomes the norm in policy formulation. This will be particularly important as countries determine how their GHG reduction commitments will be realized in a way that contributes directly to achieving related Sustainable Development Goals.

01

Why the Water-Energy Nexus and Why South Africa?

> Water is *a finite, vulnerable and essential resource, essential to sustain life, development and the environment.* (Bates and others 2009)
>
> *Energy, to be sure, is only one of the fundamental issues that challenge us. But if we don't get energy right the other issues will be insoluble.* (Patterson 2007)

Vital for life, water and energy are critical aspects of any economy. They also are tightly entwined: access to one often depends on availability of the other, and the infrastructure required to supply us with both resources is interconnected. Yet despite the strong interdependence of the two sectors, they are often managed independently (Hussey and Pittock 2012). Only an integrated approach to the links between the two sectors can yield national policies and regulations that will permit economic growth to proceed in a sustainable way (Bazilian and others 2011; Rodriguez and others 2013).

In many places around the world, the energy required to meet water supply needs is significant and growing. In the United States, the state of California receives 30 percent of its water supply from groundwater sources. Demand for electricity to pump that groundwater during the summer is greater than the energy needed to power all other water conveyance systems combined (Bennett and Park 2010). In northern India, farmers abstract groundwater using heavily subsidized electricity, resulting in a vicious cycle of electricity demand and water scarcity as the water table drops and groundwater must be pumped up from greater depths (IAEA 2009). In the Middle East and North Africa, desalinized sea water is an important source of potable wate for the region. However, it is produced using energy-intensive processes (Cooley 2011). Desalination technology is expanding to other regions as well. In China, vast quantities of water are moved from the country's water-abundant south to the drier, energy-intensive north (DUT 2004), with the associated large energy needs to transport the water.

Weather and climate change are affecting energy production. In the United States, the Brown's Ferry Nuclear Power Plant on the Tennessee River (which uses once-through cooling), often experiences warm river flows. At such times, the temperature of the water at the plant's cooling intakes approaches or exceeds the Alabama water-quality criterion (US DoE 2006; NRC 2012), requiring the plant to shut down.

In 2013, all six units of the 1,130 MW Parli thermal power plant in Maharashtra, India, were shut down because of severe water scarcity across the Marathwada region, which caused the basin behind the Khadka dam supplying the plant to "almost dry up" (Rajput 2013). The economic damage was estimated at $4 billion.

Ultimately the costs of water constraints on power are passed to consumers. In 2010, the reduced availability of the Brown's Ferry plant cost customers of the Tennessee Valley Authority $50 million (Ingram and others 2013). The cooling systems of the Brown's Ferry, Sequoyah, and Vermont Yankee nuclear plants have recently been equipped with supplemental cooling towers to reduce outlet temperatures in the summer months (NRC 2012)—at a further cost to customers. In Germany, "electricity price is significantly impacted by both a change in river temperatures and the relative abundance of river water" (McDermott and Nilsen 2012).

In many parts of the world, growing demand, deteriorating water quality, and climate change have combined to make usable water scarcer, posing a threat to energy production (WEC 2010). Similarly, growing demand for water requires investment in more energy-intensive technologies such as interbasin transfers, desalination, and rehabilitation and reuse of waste water (Hussey and Pittock 2012), all of which increase demand for energy (and for the water needed to produce it). Unless these additional demands can be met through alternative energy options, the increasing energy demands will result in increased production of greenhouse gases (GHG), further contributing to the problem of climate change and potentially worsening water shortages.

Thirsty Energy: Toward Integrated Planning for the Global Water-Energy Nexus

This networked system of resource trade-offs is known as the water-energy nexus—a critical part of the larger "sustainability nexus" that includes food as well. Indeed, the interconnected nature of energy and water supply infrastructure, the great uncertainty associated with future water supply and energy needs in the light of climate change, and the pressure on both energy and water to support (rapid) economic growth, particularly in less developed countries demands that an integrated approach be taken to ensure optimal strategic water-energy resource planning. Recognizing the challenge it poses, the World Bank has embarked on Thirsty Energy, an initiative designed to bring together specialists in water and energy in key developing countries to explore advanced approaches to integrated water-energy planning and to demonstrate the policy relevance of the analysis and findings emerging from those approaches.

Launched in January 2014, Thirsty Energy helps countries integrate water constraints into their energy sector planning and better address other water and energy challenges. Under this initiative, the World Bank selected South Africa for its initial work to demonstrate the importance of combined approaches to water and energy planning, development and management, along with analytical methodologies that can be applied to better inform coordinated decision-making in both realms. Investigating the significance of water-energy linkages and how they affect water and energy planning requires that energy-system models take water costs and constraints into account and, similarly, that water supply models take full account of energy considerations. This report examines the impacts of including water supply and infrastructure costs into an energy planning model to support integrated decision making in one country—South Africa—and offers a proof of concept for the integration of energy and water planning tools. The results are presented as a first step toward understanding the implications of integrated water-energy modeling and are not intended as a definitive policy study, which would require more rigorous sensitivity analysis. Nevertheless, the findings presented here should be of great interest to policy makers.

This report documents the development of a "water smart" SATIM model (SATIM-W) in which water supply and bulk infrastructure options are represented in relation to energy infrastructure. The model is based on the wealth of water-related planning and cost data available from South Africa's Department of Water Affairs and Sanitation (formerly Water Affairs and Forestry), supported by local water-modeling experts. SATIM-W generates a national (but region-based) water-infrastructure expansion plan as it determines the least-cost path toward an integrated water-energy system, explicitly building in the cost of water required for energy and the cost of energy required for water supply.

SATIM-W is based on SATIM, a public-domain energy systems model developed by the University of Cape Town's Energy Research Centre (ERC). SATIM (for South Africa TIMES model) is a national energy-system model built using the TIMES model generator, which was developed under the auspices of the International Energy Agency's Energy Technology Systems Analysis Program.[1] TIMES is a partial-equilibrium linear-optimization model capable of representing an entire energy system, tracking the flow of commodities (including energy, materials, emissions, demand services, and water) through the system and determining the capital stock requirements of all technologies embodied in the system including economic costs.

The detailed methodology for deriving cost curves and technology data for current and future bulk water infrastructure suitable for integration into SATIM is detailed in section 5, with water demand assumptions explained in appendix A. The detailed methodology of actual integration into SATIM, including the water demands of energy infrastructure, is detailed in appendix F. The essence of this preliminary work can be found in IEW (2015). This report summarizes some of this background, while focusing on the results obtained from investigations into key policy questions in the power sector using the integrated water-energy SATIM-W model.

The Rationale for South Africa: A Compelling Example of the Water-Energy Nexus

South Africa is struggling to achieve an ambitious development agenda (box 1.1). Presently, it is consuming its resources in an unsustainable and emissions-intensive manner using aging infrastructure (Coetzer 2012; Gaunt 2010). Power shortages in 2007–08 had a direct impact on economic growth (Eberhard 2008), and current shortages of electricity are likely to have similar economic consequences (NERSA 2015b). The dilemma of planning for economic growth in an energy-constrained environment is exacerbated by the prospect of shortages of water. In the country's economic and industrial heart, referred to as the Vaal Triangle, industry has expressed concern that a drought in the near future could have drastic economic consequences (Davies 2012).

[1] IEA-ETSAP is an international community operating under an IEA implementing agreement that uses long-term energy scenarios to analyze energy and environmental problems (IEA 2011, 2015; Giannakidis and others 2015).

Box 1.1 South Africa: Basic Facts

South Africa is an upper-middle-income developing country with a per capita GDP of R73,715 per person ($5,941 at the prevailing exchange rate). Coexisting with large-scale poverty is a modern urban economy with an advanced service sector and an energy-intensive industrial base reliant on large domestic mineral resources. Annual average growth from 2003 was 4.6 percent per year until 2008, when the global financial crisis depressed economic growth in a large portion of the world, including South Africa. GDP growth has averaged 1.9 percent since 2008, a value significantly below the development goals set out in the National Development Plan 2030, which specifies 5 percent per year (NDP 2012). The National Development Plan was drafted by the National Planning Commission and offers a long-term perspective on the future of South Africa. It envisages a desired destination and identifies the role different agents in the economy should play to achieve the end goal of eliminating poverty and reducing inequality by 2030.

Projections of growth for beyond 2014 have continuously been revised downward (standing at 2.1 percent for 2015; IMF WEO 2015), which is typically attributed to continued labor unrest and low global commodities prices, as well as slow growth in key trading partners and power shortages. In the short- to medium-term, GDP growth rates are projected to change very little, with projections to 2030 ranging from 2.5 to 4 percent (Merven and others 2015).

The South African population was 52 million people in 2011 (StatsSA 2011 Census), with 60 percent living in urban areas (NPC 2011b). The population grew 21 percent between the 1996 and 2011 censuses, and the National Development Plan identifies rapid urbanization as a major challenge: South Africa will need to make provision for eight million new urban residents by 2030 (NPC 2011b). Population growth—used in the model that is the subject of this report as a driver for a number of energy services, including passenger transport and household demand—is based on recently developed country-specific probabilistic population projections from the United Nations Population Division (Raftery and others 2012).

Throughout the twentieth century the South African economy shifted from a primarily rural, agricultural economy, to an urban, industrial one. This shift was initially based on mining, followed by a transition to an energy-intensive, minerals-based industrialized economy based on coal and imported crude oil. Over the past 20 years, South Africa has been steadily transitioning toward an economy dominated by the tertiary sector, which has increased from 57 percent of GDP in 1984 to 70 percent of GDP today (Altieri and others 2015).

From a sectoral perspective, the agricultural sector is unlikely to grow, partially because of water shortages. Mining activities, which dominate the secondary sector, face strong pressure from unions and uncertain government policies as well as global price fluctuation. However, as discussed below, the potential for shale gas exploration and development could result in a boost to the secondary sector.

And, increasingly, the uncertainties introduced by global climate change further complicate the picture. To ensure that South Africa's growth aspirations remain viable, coordinated planning of the supply and use of energy and water is essential.

South Africa has processes for planning the infrastructure needed to supply both energy and water under the auspices of the Department of Energy and Department of Water and Sanitation, respectively. Planning for each resource has, to varying degrees, taken into account the cost and scarcity of the other, but modeling of the infrastructure of both systems has not yet been integrated. Eskom already has a policy of "zero liquid-effluent discharge"; it has made a historical investment in dry-cooling for thermal plants and embraced a policy of dry cooling for all future plants. South Africa is therefore uniquely positioned as a candidate for the Thirsty Energy Initiative to develop and demonstrate integrated water-energy planning.

Energy demand forecasts rely heavily on assumed projections of growth of gross domestic product (GDP), including the relative contribution of primary, secondary, and tertiary sectors to that growth, along with population growth and improvements in energy intensity. The compounding effect of GDP and population drivers over a long planning horizon can have a very significant effect on energy demand. Economic sectors vary markedly in their energy intensity of GDP (metals processing is high, for example, and the services sector low), so understanding an economy's evolving structure is important to understanding future energy demand.

The current update to the Integrated Resource Plan (DoE 2013) assumes GDP growth rates of 2.9 to 5.4 percent, resulting in a range of annual average electricity demand increases of 1.3 to 2.8 percent, depending on assumptions about energy efficiency. Currently, demand for electricity exceeds supply, resulting in planned load shedding, which hinders economic growth. The commissioning of two new coal-fired power stations at Medupi and Kusile over the next few years will provide sufficient capacity to reduce load shedding.

The water demands for electricity generation in South Africa are well documented by Eskom, the primary South African electric utility (Eskom 2008; SEI 2012). South Africa's Integrated Resource Plan[2] includes water availability as a criterion in assessing power-generation alternatives. In addition, the country's generalized water scarcity was the main driver of Eskom's decision to stop building wet-cooled coal power plants. Dry-cooling systems reduce by up to 90 percent the amount of water consumed by a power plant; however, they reduce the plant's efficiency. The decision to shift to dry cooling reflected the utility's social obligation not to shrink unduly the supply of water available for other uses, including the environment.

[2] This statement refers to the IRP2010 (2011) which is the only officially sanctioned release.

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Water in South Africa

South Africa is a water-scarce country. Annual availability of fresh water is less than 1,000 m^3 per capita, compared with 4,000 m^3 per capita or more in countries with abundant water resources. With average rainfall of about 450 mm/year (the world average is 860 mm/year) and uneven distribution of water resources (DWAF 2004), South Africa has an annual mean runoff value of only 40 mm per capita, one-seventh of the global average of 260 mm, and rainfall and river flow are seasonal and highly variable. An indicator of the regional diversity of water supply is that about 20 percent of the country produces 70 percent of the runoff (CSIR 2012).

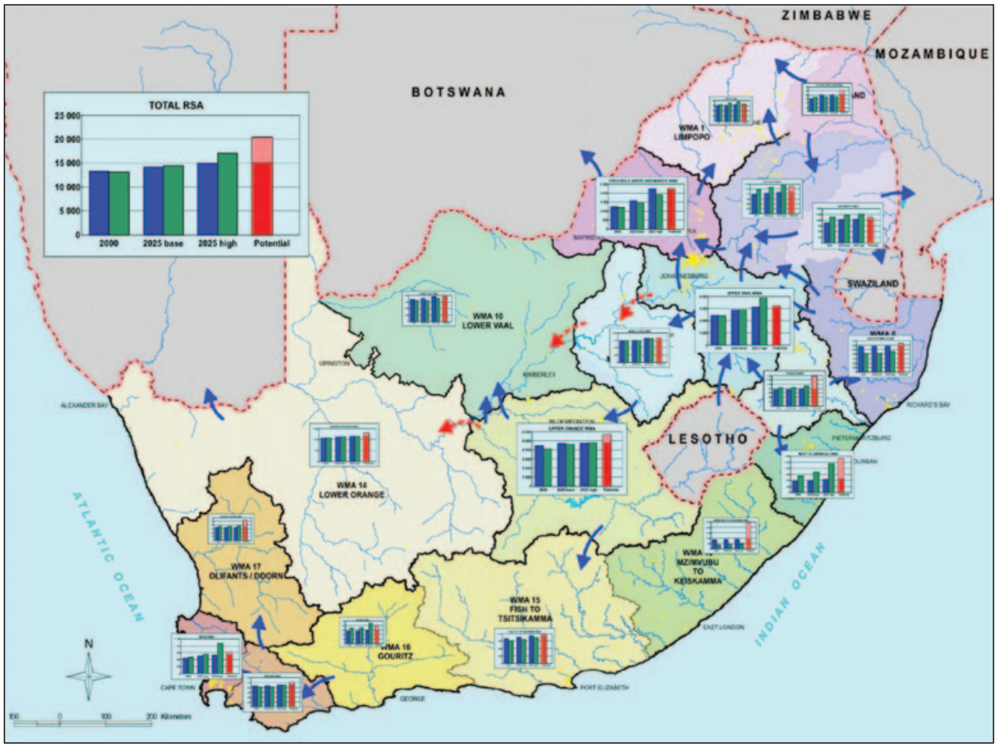
In South Africa, as in many other developing countries, agriculture accounts for the largest share of water withdrawals (at about 60 percent of the total), followed by households (27 percent) industry (about 7.5 percent, including the power and mining sectors) and other (about 5.5 percent) (DWAF, 2004). Water for power generation, which represents about 2.5 percent of all water use in the country, is considered a strategic use and therefore is supplied at a very high level of assurance. The share of water allocated to the energy sector differs widely from region to region; for example, 23 percent of the water in the Olifants catchment goes to supply the coal-fired power stations in the region. The energy sector accounts for up to 54 percent of future water demand in the Lephalale area, largely because of planned development of new coal-fired power stations and other industries.

Most of South Africa's key economic centers, including the urban and industrial center of Gauteng and key mining areas and power stations, are located in areas of low water availability far from major water sources. As a result, local demand exceeds local supply. However, South Africa has a highly integrated bulk water supply system that includes large dams and many interbasin transfers to balance supply and demand (map 2.1). Given the complexity of water-resource management in South Africa, it is not surprising that the country has the most large dams in Africa and the eighth-highest number of large dams globally (ICOLD 2015).

Management of water resources is overseen by the Department of Water and Sanitation (DWS), formerly known as the Department of Water Affairs and Forestry. Water management areas (WMA) are administrative regions established by DWS to decentralize administration of water resources to the catchment level. The boundaries of WMAs do not necessarily align with provincial borders or catchment basins. There are 19 WMAs (shown clearly in map 2.2), but consolidation will soon reduce their number to nine. For example, the Upper Vaal will be combined with the Middle and Lower into the Vaal WMA (DWAF 2009).

Water resources are managed by the DWS in conjunction with municipalities. The DWS periodically conducts assessments to reconcile supply and demand using forecasted growth in demand and constraints in supply to determine available management options. In a manner similar to the national transmission and distribution of electricity, interbasin water transfers mitigate regional supply constraints and have

Map 2.1 Water Availability and Demand, with Major Interbasin Transfers, Nationally and by Water Management Area



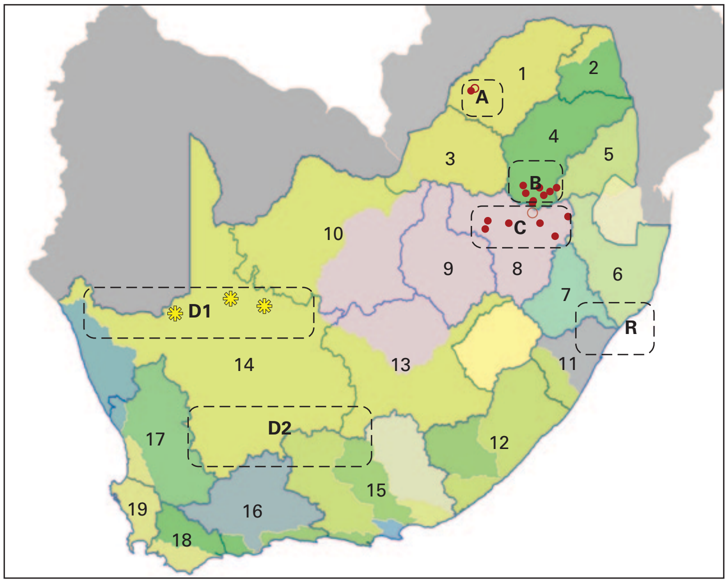
Source: DWAF 2008.

Note: Blue bars = resource availability in each water management area; Green bars = total demand; Red bars = resource development potential; Blue arrows = major interbasin transfer schemes, including transfers for power generation and international exports.

been critical to economic growth and development, particularly by providing water for power generation. However, because of the great geographic variation in water supply and demand, DWS assesses the country's regional water supply systems independently.

Appendix A details water requirements by region.

Map 2.2 South Africa's Water Management Areas (WMA) and Water Supply Regions (WSR) of Interest



WMA index

1 Limpopo
2 Luvuvhu to Letaba
3 Crocodile to Marico
4 Olifants
5 Inkomati
6 Usuthu to Mhlatuze
7 Thukela
8 Upper Vaal
9 Middle Vaal
10 Lower Vaal
11 Mvoti to Umzimkulu
12 Mzimvubu to Keiskamma
13 Upper Orange
14 Lower Orange
15 Fish to Tsitsikamma
16 Gouritz
17 Olifants to Doorn
18 Breede
19 Berg

Source: Adapted from DWAF 2012.
Notes: A: Waterberg (Lephalale); B: Mpumalanga, Witbank; C: Mpumalanga, Secunda; D1: Northern Cape, Upington; D2: Northern Cape, Karoo; R: Richards Bay Coal Export Terminal.

Water for Energy

Demand for water varies greatly by region. For example, in the Waterberg coal region of Limpopo province, demand is dominated by the dry-cooled Matimba coal-fired power station (4.3 million m^3 annually) and its supplier, the Grootgeluk coal mine, which uses water to wash coal (9.9 million m^3 annually). Together these two demands account for approximately 40 percent of current water withdrawals in the district. Energy sector withdrawals may grow to 75 percent by the year 2030 if further developments in coal-based energy supply are pursued (Aurecon 2014). Approximately 20 percent of current water withdrawals in the Waterberg region are directly attributed to electricity generation, much higher than the national water balance, where the electricity sector accounts for approximately 2 percent of total water withdrawals (DWAF 2012). Given Eskom's policy of zero liquid-effluent discharge, energy sector withdrawals equal consumption (that is, no water is returned to the water body).

The water supply infrastructure in each WMA is highly localized and distinct. It includes the civil engineering undertaken to implement water supply systems that cater to multiple users across economic sectors. The supply systems typically comprise multiple schemes that may span multiple WMAs. Schemes are an amalgam of discrete projects, such as an interbasin transfer for providing additional water to a water supply system.

The term water supply region (WSR) is used in this study to refer to a geographic region of interest for purposes of the study, rather than a formal or legal entity. Five WSRs (A,B,C,D and R) were identified after an assessment of the locations of the energy resources in South Africa (discussed in section 3) and with consideration of siting requirements for the power and refining sectors. The regions are shown in map 2.2, and the resources found in those regions are identified in table 2.1. A more detailed discussion of the selection of these WSRs is found in section 5.

Each WSR is serviced by an integrated supply network or system that may span more than one WMA and consist of multiple schemes, each of which contributes to the total supply system for that region. For example, the Vaal River Eastern Subsystem, a subsystem of the integrated Vaal River system, supplies water to users in the Upper Vaal, Olifants, and, in future, Limpopo WMAs. An example of the distinction between WMA and WSR is that shale gas mining and concentrated solar power generation may occur in the same WMA but incur different water costs because they will likely be supplied by different WSRs.

Table 2.1 Water Supply Regions (WSR) and Linked Energy Activities in SATIM-W

WSR	WMA	Region	Activity
A	Limpopo	Waterberg (Lephalale)	• Open-cast coal mining • Coal thermal power plants with FGD option • Coal-to-liquids refineries
B	Olifants	Mpumalanga, Witbank	• Open-cast and underground coal mining • Coal thermal power plants with FGD option • Coal-to-liquids refineries
C	Upper Vaal	Mpumalanga, Secunda	• Open-cast and underground coal mining • Coal thermal power plants with FGD option • Inland gas thermal power plants • Inland gas-to-liquids refineries
D1	Lower Orange River	Northern Cape, Upington	• Concentrated solar thermal power plants
D2	Lower/Upper Orange River	Northern Cape, Karoo	• Shale gas mining • Gas thermal power plants • Inland gas-to-liquids refineries
R	n/a	Richards Bay Coal Export Terminal	• Coastal open-cycle coal power plants with seawater cooling and seawater FGD option

Note: FGD = flue gas desulfurization.

Table 2.2 Location of Recent and Near-Term Committed Power Generation Projects in South Africa

Plant Type	Name	Location	Estimated to Come Online	Capacity (MW)	Likely Water Management Area	Likely Water Source
New Coal	Medupi (Eskom)	Lephalale (Waterberg)	2017	4,800	Limpopo	Mokolo Dam and Crocodile West
	Kusile (Eskom)	Delmas (Central Basin)	2020	4,800	Olifants	Upper Komati and Vaal Systems
	4+ IPP Projects of max. 600MW each[a]	Central Basin or Waterberg[c]	2021	2,500	Olifants or Limpopo	Upper Komati and Vaal Systems
Concentrated Solar Power	REIPPP, 8 projects[b]	88% in NC, 12% in FS	From 2015 onward	700	Lower Orange	Lower Orange
Wind	REIPPP, 36 projects[b]	44% in EC, 26% in NC, 18% in WC, 8% in KZN, 5% in FS	From 2013 onward	3,461	Various	Various
Solar PV	REIPPP, 45 projects[b]	63% in NC, 12% in NW, 6% in WC, 5% in EC, 5% in FS, 5% in LM, 4% in MP	From 2013 onward	2,315	Mostly Lower Orange	Mostly Lower Orange

Note: REIPPP = Renewable Energy Independent Power Producer Programme. EC = Eastern Cape; WC = Western Cape; NC = Northern Cape; NW = North West; FS = Free State; MP = Mpumalanga; LM = Limpopo; KZN = Kwazulu-Natal. Percentages indicate the technology's share of total capacity in the region.

a. https://ipp-coal.co.za.

b. This is for Rounds 1 to 4 of the REIPPP program. Most projects in Rounds 1 and 2 are operational. Most Round 3 projects are under construction. Round 4 projects are in the approvals, planning, and financing phases (http://www.energy.org.za/knowledge-tools/project-database).

c. Seven projects have applied for the first stage of environmental approval, of which all but one are in the Central Basin (Emalahleni and Delmas) or Waterberg (Lephalale) coal producing areas. The exception is located in the Umtshezi Municipal area in Kwazulu-Natal and has not yet been approved. 2,510 MW of the 4,660 MW in capacity applied for has passed environmental approval. The proposed Central Basin plants are fluidized bed combustion plants using discard coal (Burton 2015; Engineering News 2015).

Many of Eskom's existing coal-fired power stations are supplied with water from the Integrated Vaal and the Upper Olifants systems. With respect to electricity generation, the key regions for future water-for-energy demand are Upper Olifants, the Integrated Vaal System, the Waterberg region, the Mokolo Dam/Crocodile West System, and the Orange River System. The power stations built since 2013 under the Renewable Energy Independent Power Producer Programme or planned for development through 2021 are shown in table 2.2, together with their likely location, WMA, and primary water source.

Generation sites were a key consideration in developing the South African TIMES water-smart (SATIM-W) model because the energy-only version of the model was not regionally disaggregated. To be water-smart, the model first had to be disaggregated into regions aligned with the WMAs because water issues are consummately local and because the cost of supplying water to an energy site depends on its location. The locations for new generation shown in table 2.2 reflect the fact that resources for power generation are regionally concentrated, with future coal reserves within the Olifants and Limpopo WMAs and the best solar resources in the Lower Orange WMA. Wind resources, by contrast, are far more distributed, but because wind power is a marginal consumer of water plant locations have an insignificant impact on water demand. Section 3 contains a discussion of water needs by type of energy technology.

The regional water demands are discussed in detail in appendix A, which includes estimates of future demand. Energy sector demands are significantly less than domestic and industrial demands in the Vaal System and less than irrigation demands in the Orange System. They are more dominant in the Olifants system and, potentially, in the Waterberg system.

Non-Energy Water Needs

Because SATIM-W focuses on major water delivery schemes that serve more than the energy sector, it is essential to include projected non-energy demands. For that reason, the water requirements of non-energy sectors are aggregated in SATIM-W. They are specified exogenously based on estimates derived from basin-level models. Future water demands for the non-energy sectors were then determined by regression analysis of historical usage and midterm forecasts, as summarized in appendix A, and the resulting estimates of non-energy demands were held constant throughout the analysis. However, caution is needed when regressing against macroeconomic indicators in a top-down approach to project demand for both energy and water as this could distort regional water requirements. The water usage of the energy supply sectors is determined endogenously by the model. Agricultural demands were kept constant in accordance with regional allocations (appendix A) on the assumption that these have likely reached their practical limit.

As the role of non-energy demands can be highly variable and has a major impact on requirements for water infrastructure, an important area for future work is endogenizing non-energy water demands to give SATIM-W some flexibility (within limits) to reallocate non-energy water consumption—taking into account fees for the transfer of water rights that could be used, for example, to promote water conservation.

03

Energy in South Africa

For decades electricity in South Africa was cheap, owing to overcapacity. But serious supply interruptions in March 2014, following several months of interruptions in 2008, brought energy to the forefront of public debate. Popular concern about the environment and about the safety of nuclear power have complicated the picture, as has the need to spur economic growth to alleviate unemployment, poverty, and inequality. Today South Africa faces the daunting task of finding the best mix of energy solutions to achieve all of these goals.

Energy planning in South Africa is highly centralized. Planning occurs at stipulated intervals for electricity and primary energy supply, both of which are mandated in law as functions of the Department of Energy (DoE). The planning processes have elicited vigorous public participation and brought a great deal of information into the public domain about the unfolding energy landscape and how policy decisions and trade-offs are made.

This section summarizes South Africa's energy supply sector to provide a context for the policy environment in which South African TIMES model "water smart" (SATIM-W) and other models can be applied. More details appear in appendix B.

Resource Supply

Coal is the engine of South Africa's economy, accounting for nearly 70 percent of primary energy supply. Coal is an important international export (75 Mt/year) and fuels 92 percent of South Africa's electricity generation (IEA 2014; DoE 2006). In addition, about 16 percent of the country's demand for liquid fuel is met by Sasol's synthetic coal-to-liquids plant at Secunda. Estimates of South Africa's recoverable coal reserves range from 32,000 Mt (Prevost 2014) to 49,000 Mt (SACRM 2013), the world's sixth-largest (SACRM 2013), with a reserve/production ratio of more than 200 years. Most of the water needed for coal mining is used to wash the coal before it is delivered to power plants.

Exploration to assess the potential for shale gas extraction by hydraulic fracturing (fracking) is in the initial stages. In the absence of conclusive exploration data, estimates of reserves span a very broad range from 17 to 485 trillion cubic feet (US EIA 2013; SAPA 2014; SAOGA 2014). Because large amounts of water are required for shale gas production, water's availability, price, and treatment must be taken into consideration when assessing the potential of this form of energy. South Africa's Karoo region, where the greatest shale gas potential is believed to lie, is an extremely water scarce and ecologically sensitive area in which municipalities and farmers depend on groundwater (de Wit 2011; WWF 2015). No data exists for South Africa on the costs of treatment and disposal of flow-back effluent from shale gas exploration and extraction. Alternative water-sourcing options such as on-site recycling and use of saline water were not part of the current analysis, but they should be considered in any follow-on analysis.

In South Africa, uranium ore is generally low in quality and is extracted only in tandem with gold and copper (World Nuclear Association 2015). Most of the

Table 3.1 Water Use Rates for Resource Extraction

Resource Supply	Water Usage (Estimated Volumes of Fresh Water)	
Coal Mining	m^3/t	Mm^3/PJ
Waterberg (A)	0.2730	0.0031
Central Basin (B and C)	0.05	0.0024
Shale Gas Extraction		
All Regions	NA	0.017

ore is exported. Eskom procures enriched uranium on the international market to fuel its single nuclear power plant at Koeberg (IAEA 2010). As the extraction of uranium occurs in conjunction with gold mining, both its water requirements and its production of acid mine drainage (Naicker, Cukrowska, and McCarthy 2003) are grouped in SATIM-W with gold mining as part of industrial energy demand and non-energy water requirements.

Water consumption estimates for coal mining in the Waterberg (Region A in map 2.2 and table 3.1) are based on detailed analysis conducted by Golder and Associates for the Exxaro mine, while the estimates for the Central Basin (regions B and C) are taken from the South African Coal Road Map.

Data on water consumption for shale gas production were taken from the Barnett shale region of the United States, which is one of the largest in the nation and similar in geological composition to the Karoo region of South Africa, where significant shale gas resources are believed to exist (Vermeulen 2012). To obtain an average or levelized water withdrawal rate for shale gas extraction, the estimated total volume of water withdrawn over a given production span for the Karoo region was used. Assuming cumulative shale gas production of 1 trillion cubic feet (Tcf) (~1,000 PJ), the water-use intensity of shale gas extraction in the Karoo is estimated at 17,000 m^3/PJ. Of course, the water intensity of extraction will be influenced by many factors, such as local geology, so this value is subject to refinement.

The Electricity Sector

Electricity supply is dominated by Eskom, which also functions as the system operator and owns and operates the transmission network and the distribution networks outside those owned and managed by the large cities. Eskom operates 27 power stations with a total nominal capacity of 41.9 GW, of which 85 percent of the capacity is coal-fired.

The balance of capacity is provided by nuclear, open-cycle gas turbine, hydro, and pumped-storage power plants (ESKOM 2013). In an attempt to address energy diversification, environmental concerns, and economic growth aspirations, energy sources such as nuclear, gas, and renewables are being examined as alternatives by the DoE through legislated planning processes augmented by wide-ranging ministerial discretion, including the power to make “determinations” as to the future generation mix. Eskom retails directly to consumers and municipal distributors. As a monopolistic retailer, it is obliged to purchase from a growing pool of independent power producers. The purchase price is determined by the DoE through a competitive bidding process that is independent of Eskom.

The granting of independent power generation licenses through public procurement has become a feature of electricity policy, with three rounds of the Renewable Energy Independent Power Producer Program awarded, a fourth round in process, and projects from Rounds 1 and 2 already generating electricity (see table 2.2). Procurement processes with predefined targets for independent fossil-fueled and nuclear capacity are also underway, with nuclear vendors’ offerings having been reviewed by the DoE (GCIS 2015) and the first respondents to the DoE’s request for proposals from coal-based independent power producers having passed the environmental approval stage.

The 2010 Integrated Resource Plan (IRP) is South Africa’s official generation capacity procurement policy. The plan’s Policy Adjusted Scenario, based on the results of modeling using a least-cost optimization systems model similar to SATIM, that maps out the capacity required to meet assumed demand through 2030. It includes an administrative decision to impose 9.6 GW of nuclear capacity as a fixed assumption, with the first 1.6 GW to come online in 2023. The reasoning, as stated in the IRP, was “to account for the uncertainties associated with the costs of renewables and fuels” and to “provide acceptable assurance of security of supply in the event of a peak oil-type increase in fuel prices and ensure that sufficient dispatchable base-load capacity is constructed to meet demand in peak hours each year” (DoE 2011). Three coastal sites for future nuclear plants—Banatamsklip and Duinefontein in the Western Cape and Thyspunt in the Eastern Cape—have been identified thus far, and they have undergone environmental impact assessments (Van Wyk 2013; World Nuclear Association 2015). It can be assumed that plants here would use seawater for cooling, as is the case with Koeberg. The cost of the seawater supply infrastructure is included in the nuclear plant costs, and the seawater itself is assumed to have no cost, so its use is not tracked in SATIM-W.

Further complicating the policy landscape of future energy supply sources is the growth in distributed generation. The national energy regulator, NERSA, is drafting rules for small-scale embedded generation (NERSA 2015a). The Small-Scale Embedded Generation Programme of the City of Cape Town is now buying power fed to the grid, and total rooftop photovoltaics (PV) capacity in South Africa increased from 10 MW to over 30 MW over the 12 months ending March 2015 (Donnelly 2015).

On average in South Africa, 1 kWh of electricity consumes about 1.4 liters of water (Eskom 2011), a water intensity that is within the range of the world average of

Table 3.2 Water Intensity of South African Power Generation Options

Power Plant Type	Cooling Type	Raw Water Use (l/kWh)	Boiler Water Use (l/kWh)	WSR	Climatic Zone
Coal-Fired Existing	Wet closed cycle	2.04 to 2.38	0.062 to 0.12	B Olifants	Cold interior
Coal-Fired Existing	Indirect-dry	0.12	0.07	B Olifants	Cold interior
Coal-Fired Existing	Direct dry	0.12	0.02	A Limpopo	Hot interior
New Supercritical Coal-Fired	Direct dry	0.12	0.02	A Limpopo	Hot interior
New Coal-Fired with FGD	Direct dry	0.32	0.02	A Limpopo	Hot interior
New Coal-Fired with CCS	Direct dry	0.18	0.025	A Limpopo	Hot interior
Open-Cycle Gas Turbine	NA	0.02	NA		
Combined-Cycle Gas Turbine	Direct dry	0.013			
Combined-Cycle Gas Turbine with CCS	Direct dry	0.019			
CSP	Direct dry	0.3	0.06	A Limpopo	Hot interior
CSP	Hybrid cycle	0.4 to 1.7	0.06	A Limpopo	Hot interior
CSP	Wet closed cycle	3.0	0.06	A Limpopo	Hot interior
Solar PVa	NA	NA	NA	NA	Distributed
Wind	NA	NA	NA	NA	Distributed
Nuclear	Once-through seawater	NA	NA	NA	Coastal

Note: WSR = water supply region; FSD = flue gas desulfurization; CCS = carbon capture and sequestration; NA = not applicable; CSP = concentrating solar power.
a. Water to wash solar PV panels is currently not tracked in SATIM-W.

1.2–1.5 liters/kWh (UN WWAP 2014). Furthermore, water demands from the predominantly wet-cooled, closed-loop thermal power plant fleet are somewhat below the typical median intensity of about 1.7 liters/kWh, as reported by the National Renewable Energy Laboratory for subcritical coal power plants cooled by wet recirculating cooling (Macknick and others 2011). The detailed water consumption of existing power stations and other key metrics are presented in appendix G.

The country's stock of large coal-fired power plants utilizes a mix of dry-cooling and closed-cycle wet-cooling. Including the dry-cooled units of the Majuba and Groovlei plants, which have both wet- and dry-cooled units, the existing net capacity of dry-cooled units is approximately 9,700 MW. This accounts for about 30 percent of Eskom's coal plant stock. The commissioning of the Medupi and Kusile plants would increase the contribution of dry-cooled net capacity to about 18,000 MW, approaching 50 percent of Eskom's coal-based capacity. As in the case of the Kusile and Medupi plants, all new power plants are to be of supercritical design (Eskom 2011).

The country possesses considerable solar energy resource potential in the arid north, as well as favorable wind resources along its coastline (Hagemann 2008; Fluri 2009), and utility-scale concentrating solar (thermal) power (CSP), solar-PV, and wind power plants have emerged as coal alternatives. The arid Northern Cape province offers the highest potential for utility-scale CSP generation, estimated at 500 GW in total (Fluri 2009), after considering sunshine availability, proximity to transmission lines, and suitable terrain, vegetation, and land use. Some analyses have projected a CSP capacity of close to 40 GW by 2045 under a scenario of high nuclear costs (DoE 2013). Under the country's Renewable Energy Independent Power Producer Programme, which aims to reduce the country's dependence on coal through renewable energy generation of up to 19 GW by 2030 (DoE 2013), a total of 400 MW of renewable capacity has been allocated, and three plants totaling 200 MW have been commissioned, although they are not yet operational. All three plants use dry-cooling technology; their primary water consumption is for mirror washing. Boiler make-up is estimated to account for 20 percent of the total water requirements.

The power sector has been identified as a potential strategic consumer of gas as part of the strategy to move away from reliance on coal. With regard to existing and future generation technologies, both open-cycle gas turbine and combined-cycle gas turbine plants are considered. Several different sources of gas are possible, including Mozambique (imported over land), coastal imported liquefied natural gas, and indigenous shale gas, should mining proceed. The "Big Gas" scenario of the yet-to-be-approved update to the IRP suggests that nearly 70 GW of gas-based generation capacity by 2050 could be possible, given that shale availability can drive the price of natural gas down to R50/GJ by 2035, with supply augmented by regional conventional sources (DoE 2013).

South Africa has one 1.8 GW nuclear power plant, Koeberg, located approximately 30 km north of Cape Town. Koeberg employs once-through seawater cooling for its two pressurized water reactors. Owing to the current practice of exporting domestic uranium ore and importing processed fuel rods, uranium extraction is essentially decoupled from domestic energy supply. The demand for uranium as represented in SATIM-W is for processed fuel rods and does not reflect local mining activity. Therefore, as noted above, the energy and water requirements of uranium mining are grouped with gold mining in SATIM-W, as part of industrial energy demand and non-energy water requirements.

Table 3.2 provides a summary of water-intensity data for existing and new power plant options in South Africa. For more details see appendix G. Note that owing to Eskom's zero discharge policy, all power plant water use is consumptive.

Refining of Liquid Fuels

Liquid fuel production in South Africa involves six domestic refineries, four conventional and two synthetic fuel (synfuel) plants:

- Three coastal conventional crude oil refineries: Sapref, Enref, Chevref
- One inland conventional crude oil refinery: Natref
- One coastal synthetic gas-to-liquids refinery: PetroSA (reduced gas supply has necessitated supplementary light crude distillate feedstock)
- One inland synthetic coal-to-liquids refinery: Sasol-Secunda.

The coastal crude refineries are grouped together in SATIM-W because they have similar product slates and operating inputs. Diesel and kerosene dominate the product slate of the inland crude refinery; gasoline that of the two synthetic refineries a gasoline heavy slate. For that reason, they are characterized separately in SATIM-W. Synthetic fuel refining plants can use either the coal or natural gas resource discussed above. These plants include numerous discrete chemical-processing units operating in close interaction and requiring both ancillary energy and water services. The resulting products are energy, water, and emissions intensive, particularly in the case of coal-to-liquid refining. However, because no South African refinery uses once-through cooling, oil refining in South Africa is, on average, relatively water efficient in global terms (Pearce and Whyte 2005), although the synthetic refineries are considerably more water intensive. Table 3.3 shows the relative production and water intensity of South African liquid fuels refineries.

Table 3.3 Water Intensity of South African Liquid Fuels Refineries

Plant Type	Specific Water Intake (m^3/toe intake)	Specific Water Intake (m^3/TJ product out)
Refineries	0.51–0.67	14
Gas-to-Liquid	2.9	92
Coal-to-Liquid	8.6	394

04

Water-Energy Challenges Facing South Africa's Energy Sector

This study involved integrating a representation of water supply into an energy systems model to better reflect the interdependent nature of the water–energy nexus. The water challenges facing the energy system were therefore of primary interest. This section explores important water-energy stress points from the perspective of the energy system.

Water Consumed in the Production of Energy

Although power generation directly accounts for only about 2 percent of South Africa's demand for water (DWA 2013), it represents about 15 percent of gross domestic product (GDP) (GCIS 2015). Power generation is also considered to be a key strategic industry, requiring secure supplies of good-quality water. Many of the country's interbasin transfer (IBT) schemes were developed specifically to supply water to power plants. An example of the complex system of IBTs developed to supply water to some of the coal-fired power stations is shown in figure 4.1.

These IBTs ensure a reliable supply of water and, in many cases, are necessary to provide water of sufficient quality. Water available near the power stations is often naturally hard or of poor quality owing to mining and industrial activity.

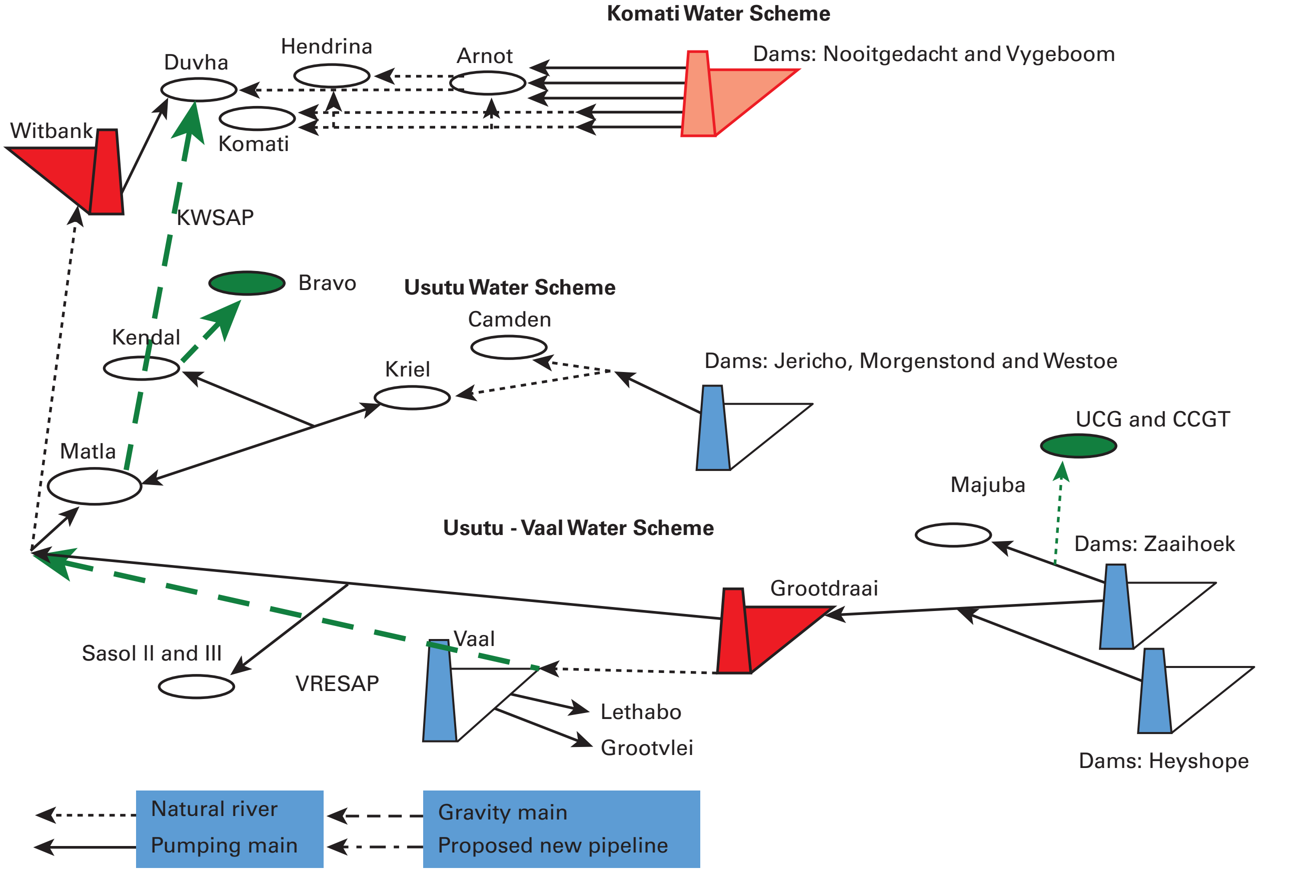
The extraction and utilization of energy commodities requires water. Coal mining, for example, in addition to typical uses such as dust suppression, requires water for coal washing, a process that raises the calorific value of mined coal by reducing its ash content. About half of the coal mines in South Africa are underground and require pumping for dewatering as they usually occur below the water table. To treat acid mineleachate, some mines have commissioned water treatment plants for the safe discharge of mine effluent or to supply potable water to neighboring municipalities.[1] The Department of Water and Sanitation requires that all mines have a water-management plan.

Although many mines are noncompliant, a more stringent legal environment is expected, as treatment of mine water comes to be seen as a mandatory practice, following the model of air quality emissions, as discussed below.

South Africa's rights-based constitution places a responsibility on the state to ensure clean and safe air and water. Recently this has seen stricter enforcement by means of regulations stipulating minimum emissions standards for particulate matter, sulfur dioxide (SO_2), and nitrogen oxides (NO_x), with compliance deadlines in 2015 at moderate levels for all existing plants and stricter levels for plants licensed after 2010. All plants have to meet the stricter levels by 2020 (Government of

[1] The requirement for treatment of leachates is included in the Environmental Compliance scenario of this study, as detailed in appendix G.

Figure 4.1 Water Supply Schematic for ESKOM Power Stations as Part of the Integrated Vaal River System



Source: Eskom.
Note: Red dam icon indicate water transfers from another WMA. VRESAP = Vaal River Eastern Subsystem Augmentation Project; KWSAP = Komati Water Scheme Augmentation Project.

South Africa 2013).[2] Air emissions control technologies that mitigate SO_x generally increase a fossil-fuel power plant's water consumption. This may also apply to NO_x control systems if steam injection is opted for rather than low temperature combustion technologies.

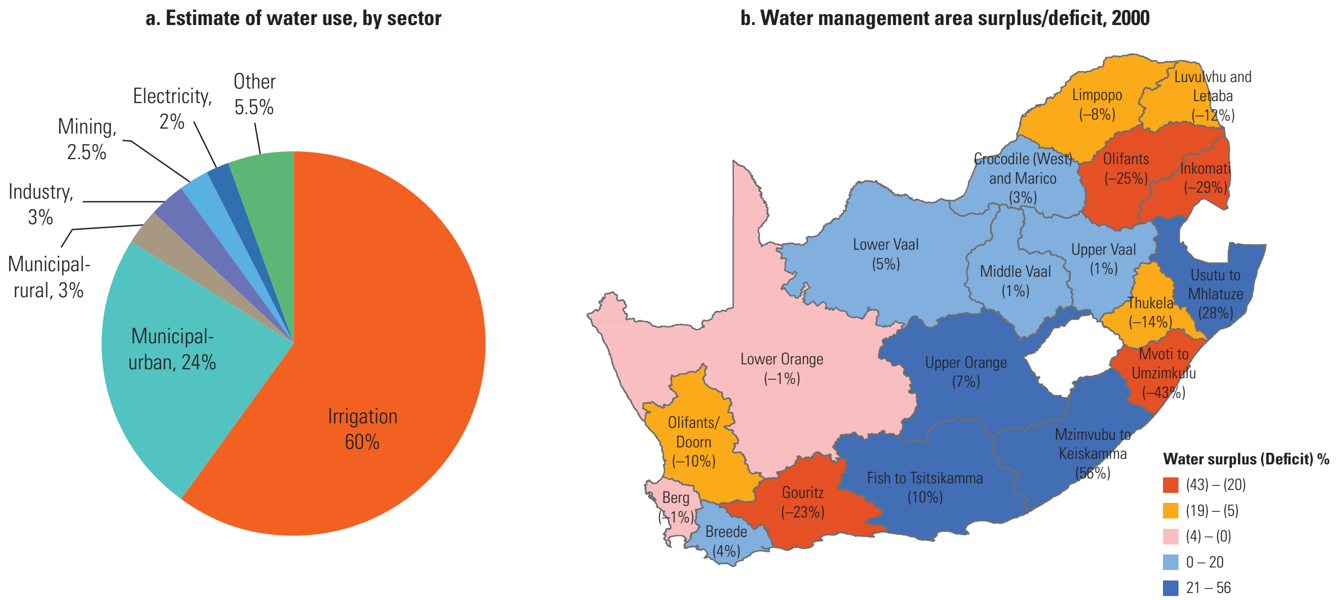
[2] Air-quality technologies that mitigate SO_2 emissions generally increase a fossil-fuel power plant's water consumption. This may also apply to NO_x control systems if steam injection is chosen over low-temperature combustion technologies.

Currently, local coal-fired power plants, for example, do not control flue gas emissions, other than for particulate matter (Eskom 2009, 2012). Of the new capacity under construction, the Kusile plant will employ wet flue gas desulfurization (FGD), whereas Medupi will be retrofitted with this technology, which will be fully operational six years after commissioning (Eskom 2012, 2014). The Integrated Resource Plan of 2010 assumed all new coal capacity to be fitted with FGD, which suggests this is firm policy for coal capacity beyond Medupi and Kusile (DoE 2011). Existing plants, given low sulfur levels in the low-ash coal used, all meet the 2015 compliance levels for SO_2 but would require FGD retrofitting to meet the 2020 compliance levels (Eskom 2009, 2012, 2014). However, after Eskom argued that high capital costs, long outage times (estimated at 120–150 days), constraints on supply of limestone sorbent, and water scarcity militate against FGD retrofitting (Eskom 2009), applications for a five-year postponement of SO_2 regulations were granted in February 2015 to all affected Eskom plants by the Department of Environmental Affairs (Mdluli 2015). It remains unclear whether any fleet retrofit of FGD will take place. But a scenario with stricter regulations that force new and old plants to be retrofitted with FGD systems was included in the analysis so as to understand their impact on the energy sector and on water resources. For more information on FGD systems, see appendix H.

Historically, cheap high-ash and low calorific-value coal for electricity has been supplied directly to "mine-mouth" generating plants via conveyor from adjacent mines, keeping electricity production costs relatively low. However, as existing mines approach their production limits, new exploitations of less-economical coal deposits, will be required to meet future growth in domestic electricity demand. The remaining economical reserves are in the Waterberg region, north of the existing mining-industrial complex. New generation plants located here would all require investment in transmission and distribution infrastructure, as well as water supply infrastructure. The extent of the latter is contingent on growth in coal-derived energy supply for both domestic and export markets. Coal supply for domestic use is modeled separately from coal for export. An upper bound is imposed on potential coal exports, but that bound is never reached because future exports decay as less-expensive options are depleted.

At the same time, existing water supply systems are at or approaching their capacity, with 97 percent of existing water supply systems already allocated. Agriculture (irrigation) uses 60 percent of water withdrawals (DWAF 2004) (figure 4.2). However, as seen in the map of figure 4.2, the national water allocation masks regional disparities in water supply. Also, the national summary does not reflect regional sectoral composition. For example, in the northern Limpopo (Waterberg) region, where vast new coal deposits are located, energy production accounts for close to half of water withdrawals and may grow to be the dominant regional water consumer should coal-based energy supply expand. In the populous industrial heartland of the Vaal region, by contrast, the energy sector is an almost insignificant consumer on a relative basis, accounting for less than 1 percent of withdrawals, although a significant portion is exported to other catchments to supply to energy producers.

Figure 4.2 Estimate of National Water Allocation by Sector and Region



Source: DWAF 2004.

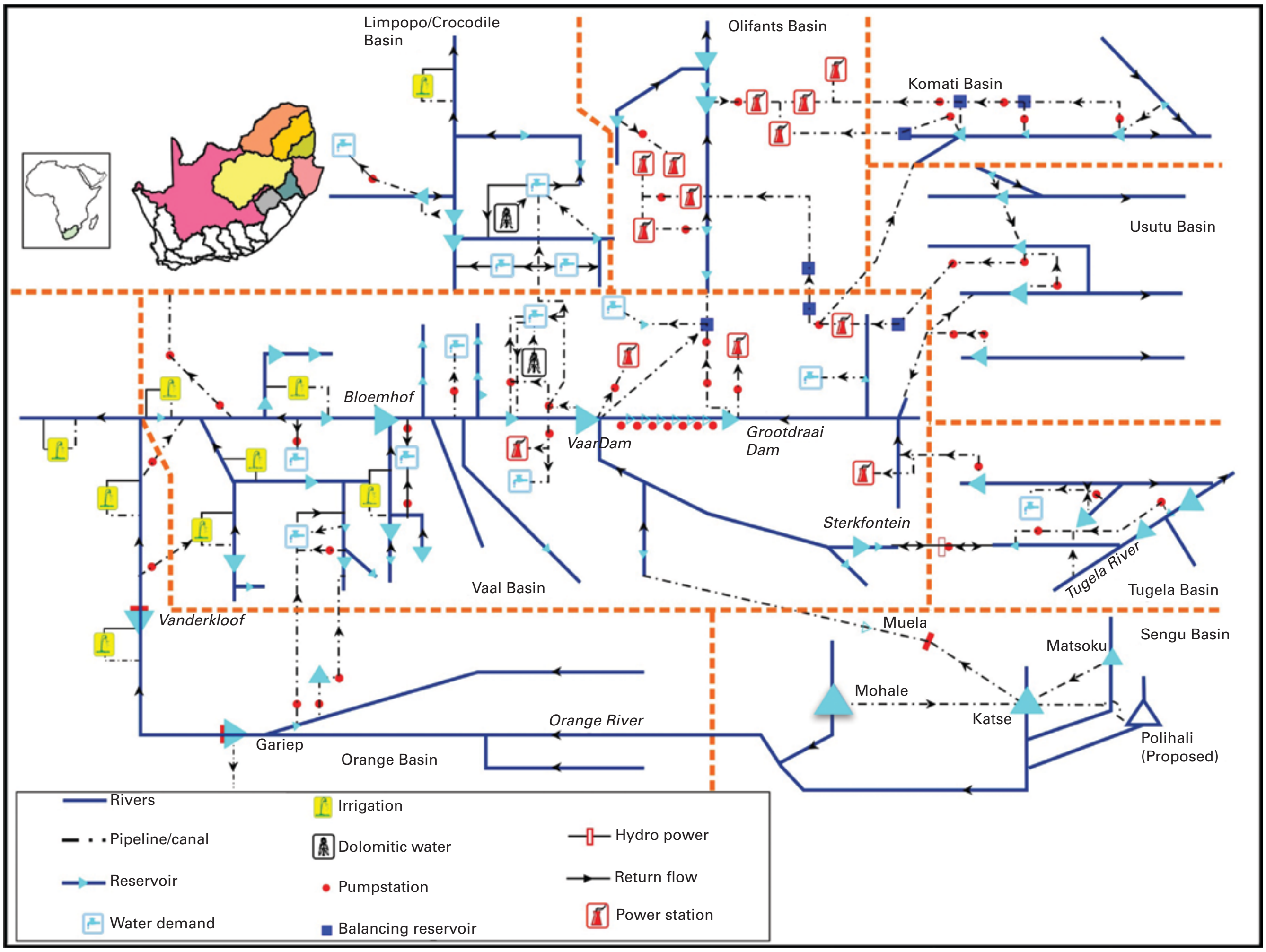
Shortfalls in regional water supply are compensated for by the construction (existing and planned) of large-scale water transfers.

Figure 4.3 represents the interconnected water supply schemes in each water basin, along with the power plants, water pumping demands, irrigation demands, and other water demands.

Eskom's practice of zero liquid-effluent discharge encourages the use of dry cooling in new coal plants, even though dry-cooled plants are on average 10 percent more capital intensive and 2 percent less efficient than wet-cooled plants, and therefore more coal intensive, with higher atmospheric pollutant loads (EPRI 2007a; EPRI 2007b; Mielke, Anadon, and Narayanamurti 2010). Thus, the benefit of reduced water consumption at a dry-cooled power plant comes at the cost of increasing other environmental burdens.

All this points to the need for regional data detailed enough to illuminate the water supply and transfer implications of alternative power plant location. South African TIMES model "water smart" (SATIM-W) accomplishes exactly this by embedding the various water supply options in the least-cost planning platform, so that the cost of water is fully captured as decisions about energy investments are made.

Figure 4.3 Power Sector Reliance on Water



Source: DWAF 2006.

Water Quality

In addition to the volumes of water necessary and available, attention must be paid to the quality of water available, which affects its utility. The Council for Scientific and Industrial Research states that "the biggest threat to sustainable water supply in South Africa is not a lack of storage but the contamination of available water resources through pollution" (CSIR 2012). Poor water quality affects power stations by increasing the need for onsite water purification. At the Duvha power station, a diversion pipeline was constructed to bypass polluted areas of the Olifants river system at a cost of R1.5 billion. Desalination plants can increase water costs by R10 to R20 per megaliter (excluding brine disposal). Proposed water transfers from the Crocodile River to the Waterberg would supply water of lower quality than the existing local supply and would require further treatment for power plants. Poor water quality would require power plants to manage additional effluent in order to adhere to Eskom's policy of zero liquid-effluent discharge. Moreover, degraded water sources no only, but also require additional treatment in order to be used, which requires additional energy, thus raising its cost. In this study, in response to concerns along these lines expressed by stakeholders at a review workshop, p the impact of poor water quality was examined by means of a sensitivity analysis that assumes increased treatment needs in areas where it is known that there is a high risk of water quality degradation (see appendix D).

Future Climate Change Impacts

Sub-Saharan Africa is considered to be highly vulnerable to climate change. But although there is general agreement that temperatures will continue to rise, much uncertainty surrounds the potential impact of climate change on precipitation (Schulze 2006). The prevailing consensus is that drying is likely to occur in the western part of the South Africa, particularly in the southwestern Cape, while the eastern parts of the country would receive more precipitation, with some potential for seasonal shifts (DEA 2013a).

Thus, climate change may or may not affect the availability of water for power plant cooling and other uses, but it very well could affect the efficiency of cooling through increased temperatures, which, in turn, could increase the relative benefits of wet-cooled over dry-cooled power stations. However, an analysis of the efficiency response to temperature for the new dry-cooled Medupi station showed that plant efficiency is stable for more than a three-degree rise in ambient temperature. Because these coal-fired plants are located in such arid environments, they have been over engineered, so no impacts of increasing temperatures were modeled in SATIM-W. This is a potential area for future research, however, especially if the potential for periodically very high temperatures is considered.

Rising temperatures are also likely to lead to higher demands from competing water users, notably agriculture (irrigation). Increasing temperatures and changing stream-flow dynamics could also negatively affect water quality, already a concern for power stations and other water users in South Africa and requiring, in some cases, additional water for dilution (DWAF 2009).

A recent review of existing climate models identified a variety of possible future scenarios for South Africa as part of the Long Term Adaptation Scenarios flagship research program of the Department of Environmental Affairs (DEA 2013a), which is discussed in more detail in appendix C. The results of this study—in particular the range of potential effects of climate change on the average annual water supply for each of South Africa's administrative water-management areas and on average annual runoff for different catchments—were used to construct a dry-climate scenario suggestive of climate change to explore what could be the impact on the energy sector of decreased water supply and increased water demand. The assumptions behind this and other scenarios are discussed in more detail in appendix D.

An important result from the Long Term Adaptation Scenarios study was the observation that South Africa's national water supply system, which is the result of many years of proactive planning to deal with a high level of natural variability in water resources and is highly integrated because of the extensive use of IBTs, appears to provide a relative high level of resilience to future climate change, although possibly at the cost of higher pumping rates and negative effects on environmental flow requirements (Cullis and others 2014; DEA 2013a, 2014). The potential effects of climate change on the water-energy nexus will need ongoing investigation to assess adaptation options, specifically for the power sector.

05

Integrating Water and Energy Planning: The SATIM-W Model

The South African TIMES "water smart" (SATIM-W) model developed and applied in the study reported here is based on SATIM, which was derived from the TIMES modeling platform developed, promoted, and used under the auspices of the International Energy Agency's Energy Technology Systems Analysis Program (IEA-ETSAP).[1] SATIM is a detailed representation of the supply and demand components of South Africa's national energy system, from resource extraction to end-use services such as heating, cooling, lighting, passenger travel, powering of industrial motors. It contains a multitude of energy transformation technologies. For example, the model includes the extraction, transmission, and distribution of gas and coal for electricity generation; the transmission and distribution of electricity; and the consumption of electricity by end-use technologies to supply energy services, including the energy requirements for water pumping and water treatment. Technologies are linked by commodities and characterized by techno-economic parameters such as efficiency, investment (along with capital and operational costs), maximum availability, plant life, and so on. Technologies are further organized by sector (supply, refining, power, buildings/households, industry, and transportation) and type. The model solves for the optimal configuration of technologies and resources that will satisfy the growth in demand for electricity and other energy commodities at the subsector level in equilibrium, assuming perfect foresight and competition.

Growth in demand for energy services in South Africa is projected for specific sectors in accordance with established drivers, such as overall gross domestic product (GDP) growth, the relative contribution to that growth of each demand sector, population growth, and other sector-specific growth factors or elasticities. For example, the representation of the residential sector divides households into electrified and nonelectrified households and, within those categories, into low-, middle-, and high-income households. Demand for energy services within a category is assumed to be proportional to the population in that category, with GDP growth determining per capita income and thus demand. In SATIM, the demand for useful energy services is imposed exogenously, and the model determines which commodities and technologies to deploy to meet those demands at the least cost. In this way the model determines the size and sequencing of long-lived energy infrastructure investments, the rates of utilization of available resources, and the short-lived devices that are needed to deliver energy services to the consumer at the lowest present-value-cost over the planning horizon examined.

Because SATIM solves for the least-cost chain of supply extending from resource extraction to transmission, distribution, and end-use demand devices, it could be readily modified to incorporate the representation of water infrastructure as a component of the energy system supply chain.

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[1] More detailed documentation of SATIM can be found at: http://www.erc.uct.ac.za/Research/esystems-group-satim.htm. TIMES stands for The Integrated MARKAL/EFOM System. ETSAP is the IEA's longest-running implementing agreement. See http://iea-etsap.org/web/index.asp for more information on ETSAP, the TIMES modeling platform, and global user community.

The Beginnings of the SATIM-W Model

Historically, SATIM accounted for the water consumption of the power sector only by including the estimated water-intensity of electricity generation plants. It did not consider regional disparities in water supply and costs, nor the water usage of other energy technologies, such as coal mining and shale gas production. Nor did it include water treatment requirements.

To remedy this shortcoming, individual water supply options, including major investments in dams and transfer projects and water supply energy needs, were incorporated into the model to capture the water-energy interplay. The modified model was dubbed SATIM-W. Incorporating a regional water costs and quality allows SATIM-W to examine potential trade-offs arising from:

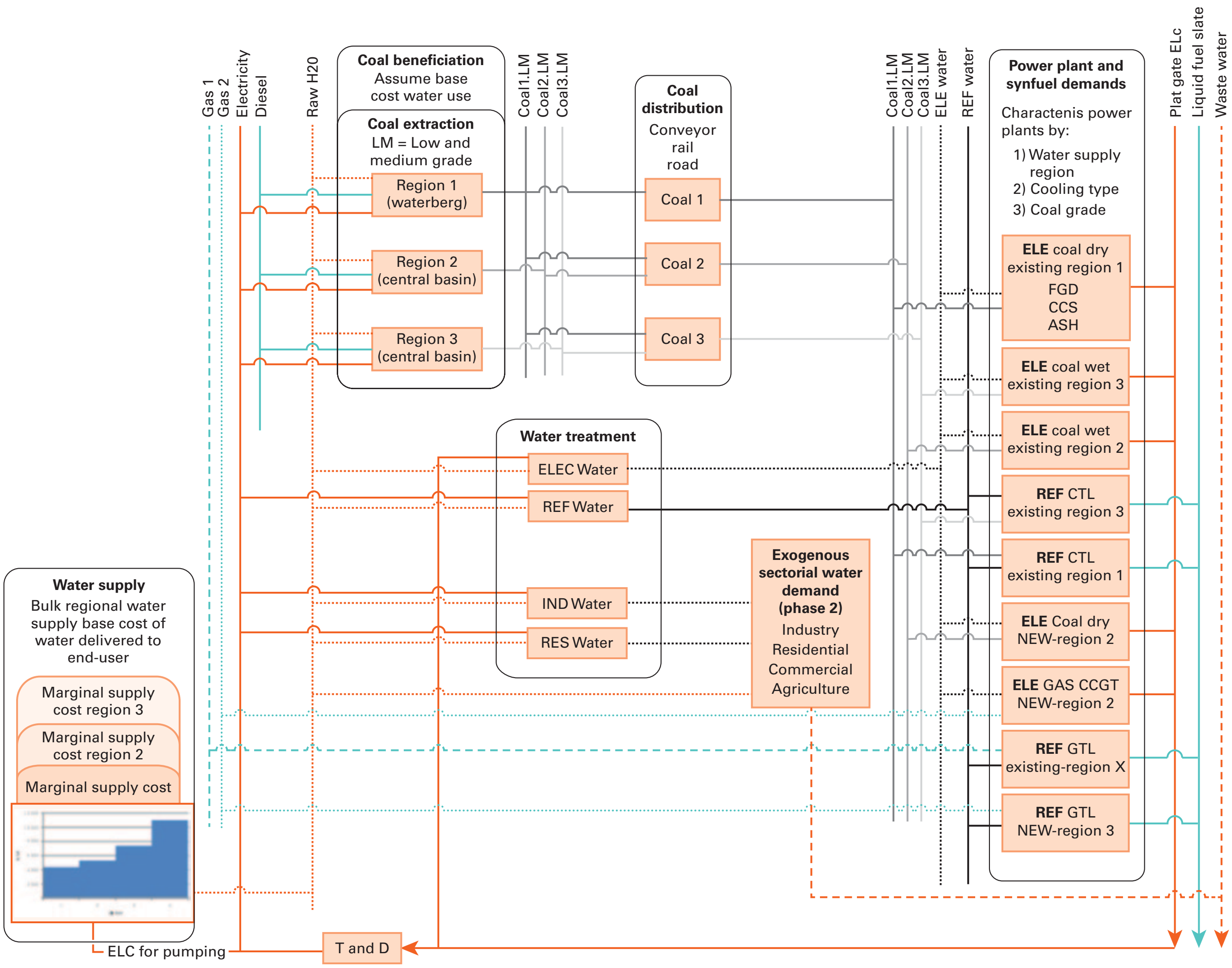
- Fuel extraction and processing (e.g., coal washing and shale gas extraction)
- The consumption and treatment of water for cooling and steam circuits in thermal plants
- Cleaning and other water services required by all types of power plants
- The additional (marginal) treatment required for water of poorer quality entering the supply system as new water supply schemes are implemented in response to growing demand
- Air quality standards and end-of-pipe technologies that require water (e.g., flue gas desulfurization).

Figure 5.1 illustrates a section of the water-energy diagram for SATIM-W, showing the supply, conversion, and end-use processes for supply of energy and water to the power sector. Specifically, this diagram shows how water-energy complexities are handled including, from left to right and top to bottom:

- Regional water supply cost (WSC) curves (including the cost and incremental supply of new infrastructure) from which the marginal cost of water supplied in each region and for each period is endogenously determined
- Water and energy requirements for coal mining and cleaning, as well as the treatment of discharged water.
- Coal is transported and water moved as needed to meet demand.
- The water consumption demands of the power and liquid fuel sectors are endogenously determined, whereas non-energy water needs are fixed exogenously; the combination determine how much water must ultimately be delivered.
- Electricity, liquid fuels, and renewables (not shown in the figure) then provide the final energy needed to meet energy service demands in each of the end-use sectors (agriculture, residential, commercial, industry, and transport).

SATIM-W is thus responsive to the regional cost and availability of water and energy supply, connecting them to a single national representation of the energy demand sectors and providing complete coverage of the water-energy nexus.

Figure 5.1 Partial Illustrative SATIM-W Water-Energy Diagram



Note: CCGT = combined cycle gas turbine; CCS = carbon capture and storage; CTL = coal-to-liquids; ELC = distributed electricity; ELCC = generated electricity; ELE = electricity sector; ELEC = electricity; FGD = flue gas desulphurization; GTL = gas-to-liquids; IND = industry; REF = liquid fuel refineries; RES = residential/domestic; T and D = transmission and distribution of electricity.

Spatially Aligning the Water-Energy Systems in SATIM-W

To produce a water-smart model of the energy system we needed to match energy options with their respective water regions. The spatial dislocation between water and energy supply options, and the fact that some energy technologies are located in areas with easier and cheaper access to water, are good reasons for representing water supply with appropriate regional detail. The availability of water and the cost of supplying it vary greatly from region to region. The need to transfer water over large distances to supply power stations can be very costly, pushing up the cost of supplying energy. Competing demands from other sectors, treatment requirements, and utilities' financing costs for existing bulk-supply infrastructure also influence the cost of the water needed to produce energy.

With increasing demands over time, the costs of supplying water are likely to increase as existing options are exhausted and more expensive options are required. The costs of future schemes will vary by location, potentially resulting in very different costs for water that may influence the choice of optimal energy supply options. In addition, significant external costs may arise in connection with water quality and ecological risk, particularly in dry regions. These are important considerations that are best handled by water-basin models, and one of the challenges of this study was determining how best to represent all of the costs associated with the delivery of water for energy based on the water supply prices provided from the basin models.

One of the factors behind the choice of South Africa for this study was that industrialization in a water-scarce environment has resulted in a strong legacy of water engineering, planning, and modeling, with crucial information available in reports published by the Department of Water and Sanitation (DWS). Our depiction of future water infrastructure schemes has drawn extensively from a DWS report that estimates the ultimate marginal cost of water supply for different regions of South Africa (DWA 2010a), developing regional cost curves for water supply as a function of total demand. After accounting for recent developments, we integrated these into the energy supply chains represented in SATIM-W as the costs of the different options, solving for an optimal future water-energy supply mix that accounts for a realistic future cost of water supply, as reflected by current plans and knowledge of local practitioners.

The first step in developing SATIM-W was to determine the appropriate level of spatial disaggregation required to explore WSC impacts and interdependencies on the energy supply side. As discussed in Section 2, the regional spread of recent and committed power generation projects and their proximate water supply systems show four regions of interest (A,B,C and D). A fifth region (R) was added to give the model the option of transporting coal by rail to the coast and using seawater to cool future coal-fired capacity in the event that fresh water costs become high enough to make this viable. Thus five water supply regions (WSR) corresponding to major water supply systems were identified and deemed sufficient to represent the likely spatial spread of fresh-water-intensive energy supply infrastructure over the time horizon of 2050. Separate WSCs were developed for each of the regions and integrated into SATIM-W.

The water needs of existing and future coastal crude oil refineries are not explicitly represented in the regions of interest in this study, since the existing coastal refineries are relatively water efficient and, in the case of Durban's SAPREF and Cape Town's Chevron refinery, already make extensive use of recycled municipal waste water, as discussed in section 3 (SAPREF 2011; Chevron 2015; Pearce and Whyte 2005). New refineries are most likely to be located along the coast and can potentially use seawater cooling. Water use by the existing inland refineries, notably the crude-fed Natref located in the Upper Vaal water-management area (Region C in map 2.2) and the Sasol Coal-to-Liquids plant located in the Upper Olifants area (Region B in map 2.2), are included in SATIM-W. A detailed parameterization of the refinery technologies in SATIM-W is presented in appendix G.

Modeling water-treatment requirements for coal power plants was not needed, as all Eskom plants (wet- and dry-cooled) operate under Eskom's zero discharge policy. This study addressed the treatment of acid mine drainage from coal mines only. Expansion of the model to include wastewater treatment from other sectors is a possible follow-on activity.

Regional Water Supply Cost Curves

The cost of supplying water for energy is determined from four separate components: the supply, infrastructure, delivery (transmission and distribution), and treatment requirements. The latter three are presented here as amortized annual costs:

Scheme Supply Cost = Capital$_{\text{(Scheme + Delivery)}}$ + Fixed OM (%Capital)$_{\text{(Scheme + Delivery)}}$ + Var OM$_1$ (Energy cost of conveyance (endogenous))$_{\text{(Scheme + Delivery)}}$ + Var OM$_2$ (Administrative & Water Treatment charges)

The capital, fixed, and variable operating and maintenance (O&M) components are calculated separately in each WSR for each water supply scheme (e.g., dam, interbasin transfer) for purposes of determining the potential regional WSC—also called the unit water cost (UWC) in traditional water basin models[2]—which takes into account the current and future water supply options identified for each region (DWA 2010a). SATIM-W then weights each water supply and delivery option (or scheme) and chooses the combination and timing that deliver the needed water at the least cost, resulting in the determination of the marginal water supply cost (MWSC). As a result, the MWSC as determined by the model will vary from period to period in response to constraints placed on the system by specific policy scenarios.

The cost of delivering water to power plants is based on estimates of the cost of deploying and managing major water supply and transfer schemes, but it does not capture final details (and associated costs) that can be determined only when a specific

[2] WSC in SATIM-W differ slightly from conventional UWC in that the WSCs use the technical rather than economic lifetime to amortize capital construction cost. Given the relatively long physical lifetime of water infrastructure, SATIM-W currently undercosts the annualized payments for these investments (though it does so evenly for each scheme). Adjustment to use the economic lifetime is an important follow-on action.

site is identified. This is also true for fracking and concentrating solar (thermal) power (CSP), where the exact locations and method of water delivery have not been determined. But in both cases these details are rather small compared with the other costs of each scheme.

The water supply schemes are developed according to the *Revised Water Pricing Strategy for Raw Water* (DWA 2013), using data provided in the analysis of the ultimate cost of supplying water in South Africa (DWA 2010a). Where possible these costs have been updated with more recent cost estimates for specific schemes and regions (Aurecon 2011; Coleman and others 2007; DWA 2010b, 2010c, 2013; DWAF 2009). The same studies were also used to update non-energy demands in each WMA.

Looking more specifically at the components of the WSC, each individual component is determined on an annual basis in rands per cubic meter (R/m^3), as described below. The cost of each scheme, organized by WSR, is the sum of all component costs, where:

- **Capital** consists of (a) infrastructure costs of water supply schemes, which cover the development and use of bulk water supply infrastructure, including the cost of planning and design, capital loan repayment, and annual depreciation, and (b) water delivery costs, which include the capital costs for transporting water from the nearest bulk water source to the location of a power plant or mine.
- **Fixed O&M** consists of (a) water-resource-management charges, that is, the charges required to manage water resources within the designated WMA, and (b) the O&M costs involved in transporting water from the nearest bulk water source to a power plant or mine.
- **Var O&M$_1$** consists of the energy costs (EC) of supplying water, which include the water-pumping costs associated with (a) the raw water supply scheme and (b) the delivery of water to the power station or mine. The electricity cost for water supply is calculated within SATIM-W based on the power sector technology and fuel choices made in each scenario.
- **Var O&M$_2$** consists of the following additional charges as appropriate: (a) waste-discharge mitigation, which cover the charge incurred for discharging water containing waste into a water resource or onto land, and (b) primary and secondary water-treatment costs, which include the additional cost of treating water to a basic water quality standard (primary) plus the additional treatment (secondary) of a portion of the water requirements to a higher level of quality through, for example, the use of reverse osmosis (RO) to reduce the salinity of the source water.

Table 5.1 presents the estimated infrastructure costs of bulk supply of water for various schemes identified by DWS in each region. The table also includes a breakdown of the estimated UWC of each water supply scheme in terms of capital repayment (CUC), depreciation (ADC), O&M costs (OMC) and EC, the last of which, for these estimates, is based on the weighted average cost of generation. Note that the data for each step represent the incremental cost and supply for implementing that step. The net UWC is the weighted average of all water schemes up to that point. The variability in the net UWC for each region is an indication of the relative scarcity of water and the costs associated with developing the resource or transporting additional water in to the

Table 5.1 Estimated UWC for Planned Bulk Water Supply Infrastructure

Water Supply Region	Scheme Description	ID	Scheme Yield (2010)	Energy Requirement	Capital Cost	Annual O&M Cost	CUC*	ADC$	OMC	EC#	UWC	Net UWC
			(M.m³/year)	(kWh/m³)	(R10⁶)	(R10⁶)	(R10⁶)	(R10⁶)	(R10⁶)	(R10⁶)	(R/m³/year)	(R/m³/year)
Waterberg (Lephalale)	Existing	A0	25									0.60%
	Mokolo Phase 1	A1	29	0.85	1,759	4.7	224	13	5	12	8.9	8.89
	Mokolo-Crocodile Phase 2	A2	75	0.8	8,174	21.7	1,042	61	22	30	15.4	15.40
	Reuse and transfer from Vaal[d]	A3	126	0.87	1,216	3.2	155	9	3	55	1.8	10.98
	Transfer from Vaal[d]	A4	90	1	2,562	6.8	327	19	7	45	4.4	13.64
	Desalination of seawater[e]	A6	100	13.82	20,896	55.4	2,664	157	55	691	36	33.67
Upper Olifants	Existing[f]	B0	400									1.42%
	Vaal Eskom transfer[f]	B0-X	230									1.42%
	Olifants Dam	B1	55	0	1,241	3.3	158	9	3	0	3.1	3.11
	Use of acid mine drainage[e]	B2	31	2.2	1,637	4.3	209	12	4	34	8.4	6.37
	Transfer from Vaal River[g]	B3	190	1.07	4,281	11.3	546	32	11	102	3.6	8.06
	Desalination of seawater[g]	B5	100	13.82	14,210	37.7	1,812	107	38	691	26	24.47

Upper Vaal	Existing	C0	3,523									0.44%
	LHWP II (Polihali Dam)[h]	C1	437	0	11,947	31.7	1,523	90	32	0	3.8	3.76
	Use of acid mine drainage[e]	C2	38	2.51	1,820	4.8	232	14	5	48	7.8	5.85
	Thukela-Vaal Transfer	C3	522	3.35	21,976	58.2	2,802	165	58	874	7.5	7.47
	Orange-Vaal transfer Boskraai Dam (55 percent)	C4	289	1.99	15,671	41.5	1998	118	42	287	8.5	8.47
	Mzimvubu transfer scheme	C5	631	4.38	41,568	110.2	5,300	312	110	1,382	11.3	11.26
	Desalination of seawater[e]	C7	100	13.6	7,831	20.8	998	59	21	680	18	15.58
Lower Orange	Existing	D0	4,131									0.17%
	Boskraai Dam (55 percent)	D1	515	0	2,678	7.1	341	20	7	0	0.7	0.72
	Boskraai Dam (full yield)	D2	422	0	3,286	8.7	419	25	9	0	1.1	1.07
	Mzimvubu kraai Transfer	D3	165	5.26	4,370	11.6	557	33	12	434	6.3	6.28
	Desalination of seawater	D4	100	14.1	11,175	29.6	1425	84	30	705	22	22.43

Note: CUC = capital repayment cost; ADC = depreciation cost; OMC = operation and maintenance cost; EC = energy cost; UWC = unit water cost.
[a] Annual capital loan repayment over a period of 25 years at 12 percent interest.
[b] Assumes 30 percent depreciation portion and an average lifetime of 40 years.
[c] Based on R0.50/kWh electricity cost. Percentage reflects tariff prices in 2010 rands.
[d] Requires additional cost of transfer to Lephalale (~ 9.2 ZAR/m^3).
[e] Excludes R2/m^3 water treatment cost.
[f] Generation-weighted average cost of water to power stations applied.
[g] Additional cost of water from LHWPII (~ 9.2 ZAR/m^3).
[h] Excludes cost for hydropower station.

Table 5.2 Estimated UWC for Delivery of Water from Major Supply Schemes to Power Plants

Water Supply Region	Description of Final Delivery from Bulk Water Scheme to Power Plant	ID	Annual Supply (Mm^3)	Capital Cost (R x 10^6)	O&M Cost (R x 10^6/year)	Energy Requirement (kWh/m^3)	Fuel Cost (R10^6)	CUC[a] (R10^6)	ADC[b] (R10^6)	OMC (R10^6)	EC[c] (R10^6)	UWC (R/m^3/year)
Waterberg (Lephalale)	Gravity pipeline from Lephalale	A1	30	73.6	0.20	0		11	0.55	0.20	0	0.39
Upper Olifants	Pipeline from Olifants dam	B1	30	2,656.5	7.04	0.41		400	19.92	7.04	6.15	14.44
	Import Vaal Dam; pipeline from dam in Upper Olifants	B2	30	405.8	1.08	0.41		61	3.04	1.08	6.15	2.38
	Reuse acid mine drainage; pipeline from dam in Upper Olifants	B3	30	405.8	1.08	0.41		61	3.04	1.08	6.15	2.38
	Zambezi water; pipeline from Mokopane	B4	30	3,165.2	8.39	1.38		477	23.74	8.39	20.7	17.66
Lower Orange	CSP; pipeline pumping directly from Orange River	D1	0.27	5.6	0.01	0.32		1	0.04	0.01	0.0432	4.07
	Hydraulic fracturing; road transport	D2	0.015	1.3	0.06		1.6	0	0.01	0.06	1.63	113.38
	Hydraulic fracturing; pipeline	D3	3	8,173.8	21.66	1.3		341	61.30	21.66	32.5	9.13
	Hydraulic fracturing; groundwater	D4	0.1	2.6	0.01	4.01		0	0.02	0.01	0.2005	2.27

Note: CSP = concentrating solar (thermal) power; CUC = capital repayment cost; ADC = depreciation cost; OMC = operation and maintenance cost; EC = energy cost; UWC = unit water cost.

[a] Annual capital loan repayment over a period of 25 years at 12 percent interest.

[b] Assumes 30 percent depreciation portion and an average lifetime of 40 years.

[c] Using R0.50 /kWh electricity cost in 2010 rands.

region to meet increasing demands for energy and other users. Table 5.2 provides similar information for major schemes for delivering water to the four regions critical to future power generation.

What is interesting is that the cost of future bulk water supply infrastructure in the Waterberg is an order of magnitude higher, for lower yields, compared with the Orange River supply schemes, highlighting the sometimes extreme regional disparities in the cost of water supply. The tables also show how the cost of supplying water can rise steeply with the deployment of discrete schemes to meet water supply requirements. It is also interesting to note the very high costs of delivering water from the Orange River for hydraulic fracking, whether by truck or pipeline. Finally, note that the energy required for desalination includes the energy needed to pump water from the coast. Hence it is significantly higher than the energy required for the desalination alone. This is considered as the ultimate marginal cost of water supply for all readions in South Africa (DWA 2010a).

Incorporating the Cost of Water into SATIM-W

As part of an integrated water-energy planning approach, the SATIM-W model can help to ensure timely delivery of water supply and treatment infrastructure for the energy sector. It is an energy sector planning tool that considers water supply as a critical component of decision making. SATIM-W is *not* a tool that can be used for water planning (which must be done at a more granular basin level). Furthermore, it considers non-energy water needs as fixed inputs.

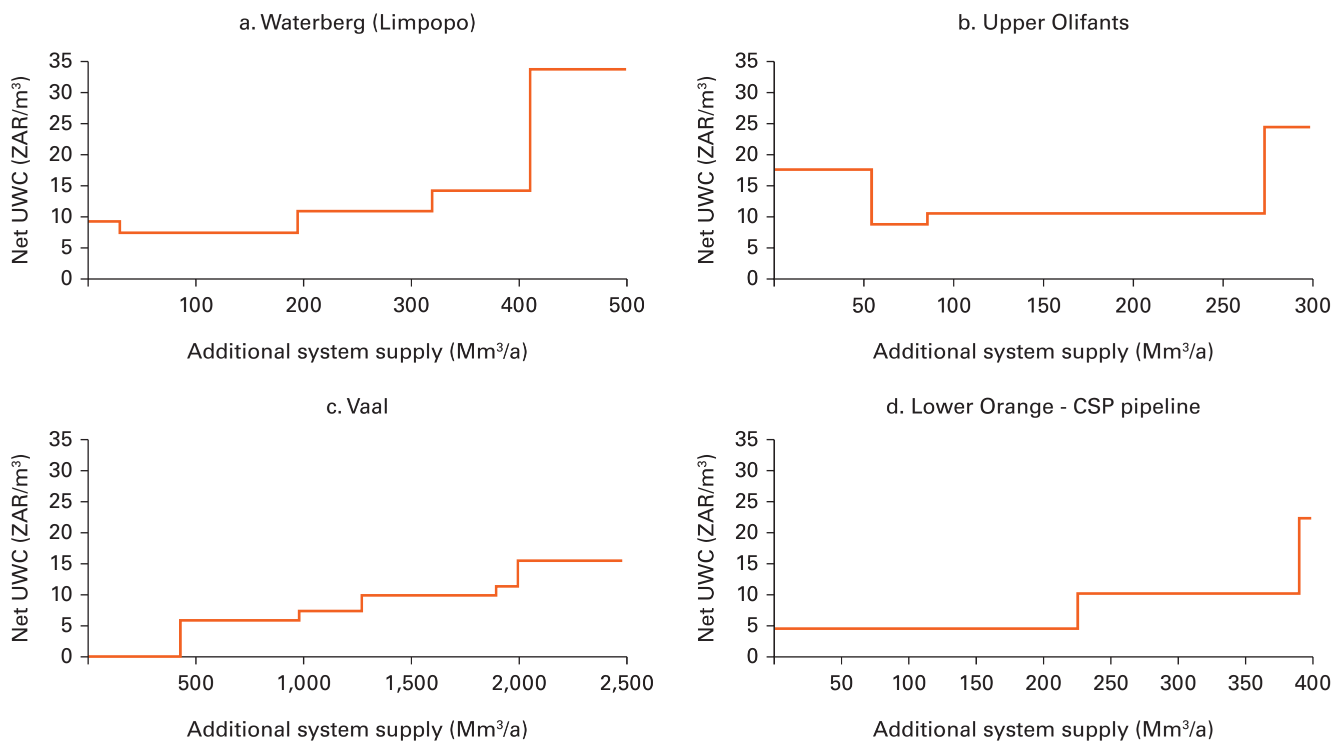
That said, water needs for energy often determine the timing and provide critical capital for expansion of water infrastructure. Therefore, because SATIM-W can assess the impact of changes in water needs for energy, it is highly useful for planning purposes.

The cost of supplying water is shown in figure 5.2 in the form of WSC curves for the supply schemes identified for each WSR as a function of the total yield supplied by each additional supply option. These curves show the incremental increase in water supply attained and the cost of the next water supply scheme necessary to meet increasing demand in each of the critical WSRs.

Figure 5.2 illustrates the estimated costs of supplying water supply based on fixed assumptions about the price of electricity required to treat and transport water and the implementation timeline of specific supply schemes. Note that in some cases a more-expensive scheme must precede a less-expensive one in order to deliver additional water (e.g., in Waterberg and Upper Olifants).

All water supply components characterized by the WSC curves in each region are incorporated into SATIM-W. This approach makes it possible to compute a scenario-specific dynamic cost curve, since the price of energy is endogenously determined and water supply schemes are commissioned as needed to meet the requirements of the

Figure 5.2 Increasing Net Unit Water Supply Cost Necessary to Increase the Available Yield in Different Key Water Supply Regions of South Africa to Meet Increasing Demands for Water



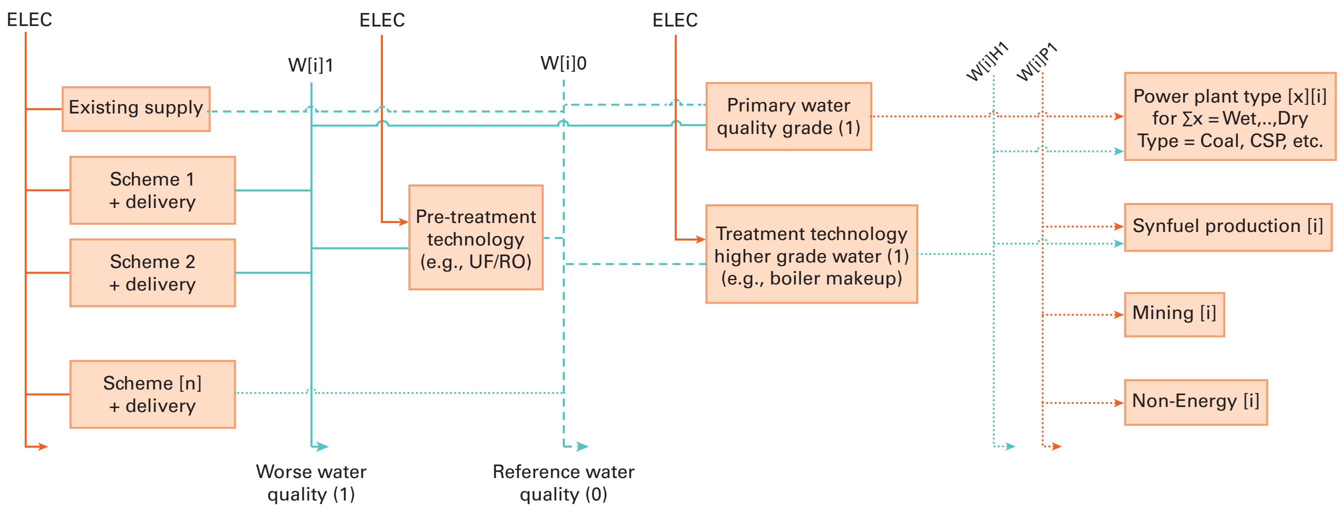
Source: Adapted from Aurecon 2011; Coleman et al. 2007; Cullis et al. 2014; DWA, 2010a, 2010b, 2010c; DWAF 2013.
Note: UWC = unit water cost; WSC = water supply cost.

energy system and fixed non-energy demands. (Water demand assumptions are explained in appendix A.) Thus by choosing the appropriate schemes, SATIM-W generates the MWSC that enables the model to determine least-cost planning solutions at the water-energy nexus. SATIM-W also represents interregional water transfer schemes by linking specific regional supplies to water demands throughout the country.

Because the commissioning of schemes is done within the national energy supply system, the investment choice and timing of energy supply technologies are influenced by the cost and timing of water supply schemes. The reciprocal water-energy investment-decision cycle occurs simultaneously, resulting in the least-cost configuration for the integrated water-energy nexus over the entire planning horizon.

Figure 5.3 illustrates the general method of representing a WSR in SATIM-W, where each scheme, water pre- and post-treatment process, and water-consuming energy

Figure 5.3 A Generic Water Supply System in SATIM-W



process is individually depicted, along with the required energy (electricity) inputs required to deliver the needed water. For a further explanation on how the regional WSCs were incorporated into SATIM-W, see appendix F.

Having noted these limitations of the current representation of water in SATIM-W, one area for follow-up is to bring more water allocation decision-making into the framework to examine. For example, analyzing the trade-offs involved in transferring irrigation water rights to the power sector, considering the crop reductions and economic losses that may result as well as water-conservation opportunities in other sectors to free up water for the energy sector.

06

Exploring South Africa's Water-Energy Planning Challenges: The Scenarios

The nine scenarios selected for this case study provide important insights into the pressing policy questions raised by South Africa's water and energy systems. The scenarios are described in the next subsection. The ensuing subsections present answers to a series of policy questions arrived at by running the scenarios through the South African TIMES model "water smart" (SATIM-W) model. A detailed explanation of the modeling results can be found in appendix E.

Scenario Development

The primary value of integrated water-energy planning is to support decision making. This is done here through the exploration of scenarios that simulate the impact of possible policies and technology choices of significance to the country. The scenarios shown in table 6.1 capture the main areas of investment uncertainty in water and energy supply. The process by which these scenarios were developed is discussed in detail in appendix D. Analysis of the scenarios showcases how SATIM-W can be used to inform and guide the policy formulation and decision making in the energy sector, and the interdependency between energy sector planning and water infrastructure planning.

The following sections summarize the analysis results through answers to a series of questions, arising from key decisions that could shape the future of South Africa's energy and water systems. For each of the scenario clusters a summary metrics table, along the lines of table 6.2, highlights the cumulative change in key results

Table 6.1 Study Scenarios

Name	Description
Reference (No Water Cost)	Status quo planning continues but does not include the regional variability in water supply cost in energy planning.
Reference (Water Cost)	Status quo planning continues and includes the regional variability in water supply cost in energy planning.
Shale Gas	Shale-gas extraction occurs in the Orange River region. A total of 40 Tcf of gas is estimated to be economically recoverable.
Dry Climate	Regional water supplies and non-energy water demands are adjusted from the Reference scenario to reflect a drier climate (increasing water demand and decreasing water supply), affecting the unit water supply cost of regional schemes (see appendix D, table D.1)
Water Quality	The quality of the water transferred from Regions B and C to Region A (see figure 2.3) is lower than that of local supplies, requiring additional treatment costs for demineralization (e.g., of make-up water for boilers).

(continued)

Table 6.1 Study Scenarios *(continued)*

Name	Description
Environmental Compliance	This scenario entails: • Retrofitting existing coal power plants with wet flue gas desulfurization (FGD) (appendix H) • Fitting existing and new coal-to-liquids refineries with semi-dry circulating fluidized bed (CFB)-FGD technology • Operating all combined-cycle gas turbines with wet control of nitrogen oxides in accordance with data from Electric Power Research Institute submitted to Eskom • Building in the increased costs to coal mines treating water discharged into the environment • Inclusion of the Water Quality scenario.
Dry Climate + Environmental Compliance	A water stress case in which water demands and costs rise across sectors. Includes the Water Quality scenario.
CO_2 Cumulative Cap 14Gt	Imposition of a carbon budget limiting cumulative national greenhouse gas emissions to 14 Gt by 2050 (see note).
CO_2 Cumulative Cap 10Gt	Imposition of a stricter carbon budget limiting cumulative national greenhouse gas emissions to 10 Gt by 2050.

Note: South Africa has committed to a "Peak-Plateau-Decline" emissions pathway as the country's "intended nationally determined contribution" as determined at the December 2015 Conference of Parties to the United Nations Framework Convention on Climate Change (Altieri and others 2015).

Table 6.2 Summary Metrics

Metrics	Units	Description
System Cost	2010 MZAR (x 1,000)	Total discounted cost of the entire water-energy system
Expenditure–Supply	2010 MZAR (x 1,000)	Payments for energy
Primary Energy	PJ	Total primary energy supply (including imports, PJ equivalent for renewables)
Final Energy	PJ	Total final energy consumed to meet all energy service demands
Power Sector CO_2 Emissions	Mt	Total CO_2 emissions of power sector
Power Plant Builds	GW	Total gigawatts of new capacity added
Power Plant Investment	2010 MZAR (x 1,000)	Total cost of new power plants
Water to Power Plants	Mm^3	Amount of water delivered to the power sector
Total Water for Energy	Mm^3	Total water consumed by the energy system

Note: MZAR = millions of South African rands; PJ = petajoule (10^{15} joules); Mm^3 = millions of cubic meters.

over the 2010–50 planning horizon. The table generally shows the units Reference value, the alternate scenarios' values and the percent (percent) difference from the Reference. The complete set of all the metrics for all the scenarios is provided at the end of appendix E.

Key Features of the Reference (Water Cost) Scenario

The SATIM-W Reference scenario with water costs included—referred to as Reference (Water Cost)—is the modeled evolution of the integrated water-energy system in the absence of alternative policies or technology advancement and assuming water demands and yields are not significantly affected by climate change over the study's time horizon. It serves as the point of comparison against which the costs and benefits of the other scenarios will be evaluated.

The evolution of South Africa's electricity generation mix between 2010 and 2050 under this scenario is shown in figure 6.1. The 2010 mix is almost 90 percent coal-based, with a variety of renewable, nuclear, natural gas, and oil technologies supplying the remainder. By 2050, the share of coal-based power has diminished from almost 90 percent to 65 percent, while the renewable share, comprised of concentrating solar, solar photovoltaics (PV), wind, and hydropower technologies, accounts for 25 percent of generation. Imported electricity grows from 3.4 percent to 8.2 percent, while nuclear shrinks from 5 percent to less than 1 percent, given the costs assumed for this scenario.

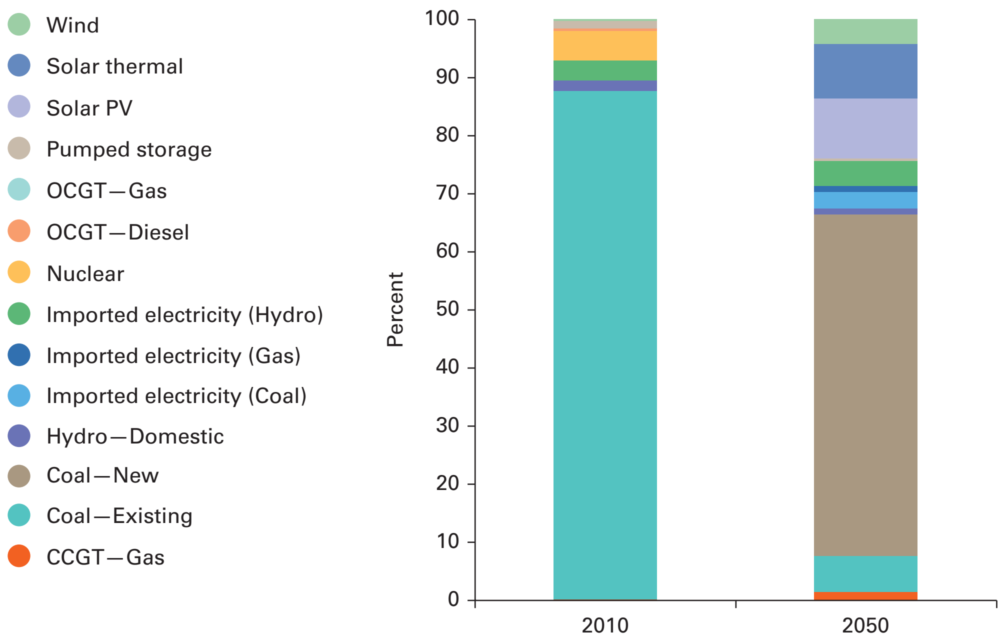
The portfolio of technologies supplying this electricity comprises 42 GW of new supercritical coal, 3 GW of fluidized bed combustion capacity utilizing discard coal, 9 GW of wind, 30 GW of utility-generated and distributed solar PV, and 10 GW of concentrating solar (thermal) power (CSP) with storage. Note that hydropower, both domestic and imported, remains the same, at about a 5 percent share.

Regional water supply in the Reference (Water Cost) scenario varies significantly by region in both volume and end-use applications, as shown in figure 6.2. The Waterberg region has the lowest total consumption and the greatest share of water going to energy activities, growing from 36 percent in 2015 to 82 percent in 2050, split between power plant cooling, coal mines, and coal-to-liquids (CTL) plants. The Olifants region, which initially has 10 times the amount of consumption, sees water for energy decline from about 50 percent to about 7 percent in 2050 because new coal power plants are dry-cooled. In both the Vaal and the Orange River regions, water consumption is four to eight times that in the Olifants region, and water for energy in both regions is an insignificant percentage of the total.

The price of water supply also varies significantly by region, as shown in figure 6.3. The prices in the Waterberg are higher by up to a factor of ten than in other regions,

Figure 6.1

Comparison of Reference (Water Cost) Electricity Generation Portfolios, 2010 and 2050



Note: CCGT = combined cycle gas turbine; OCGT = open-cycle gas turbine.

Figure 6.2

Water Supply Breakdown in each Energy Area of Interest under the Reference (Water Cost) Scenario

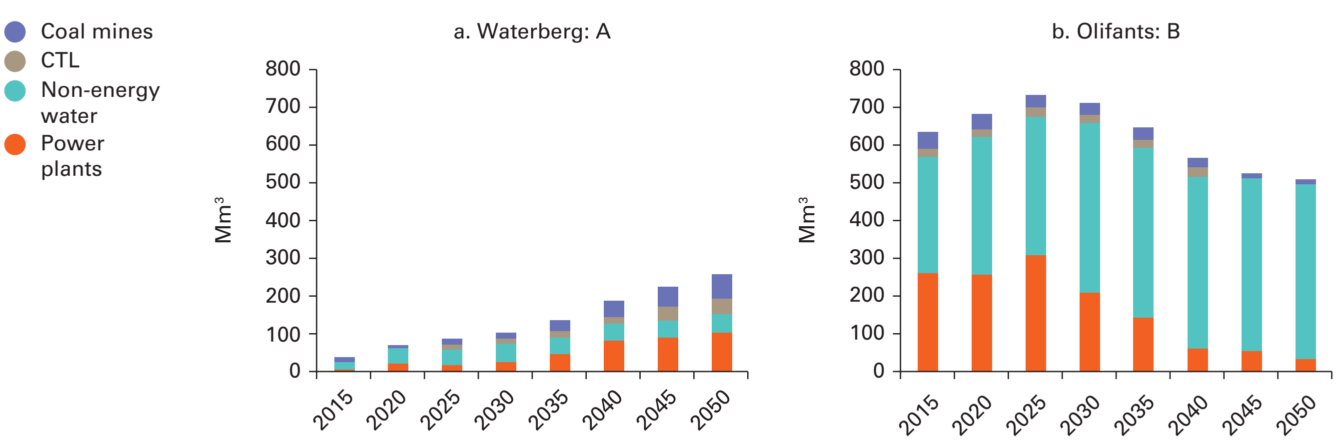


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Figure 6.2 Water Supply Breakdown in each Energy Area of Interest under the Reference (Water Cost) Scenario *(continued)*

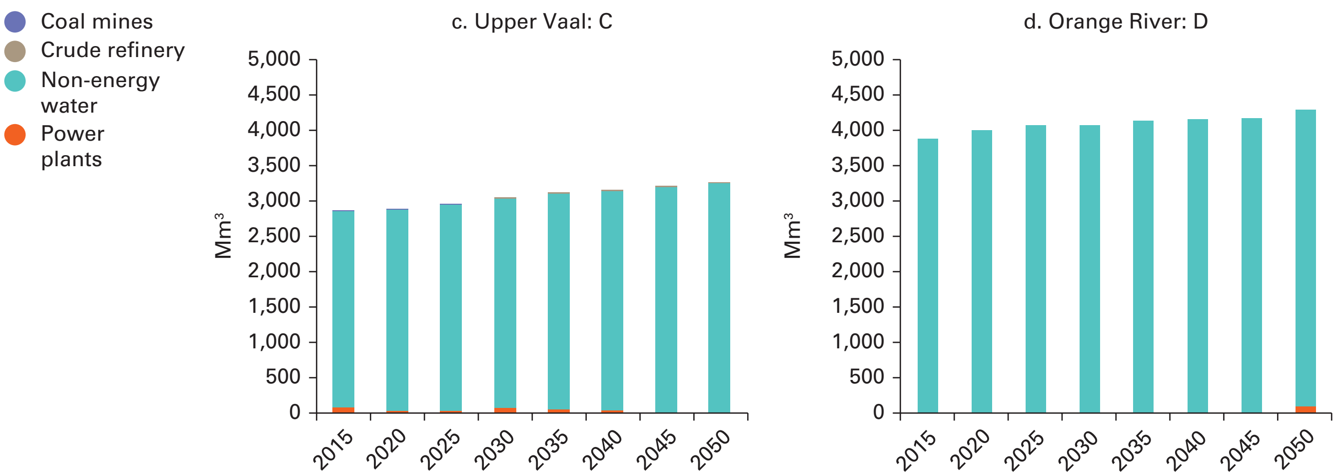
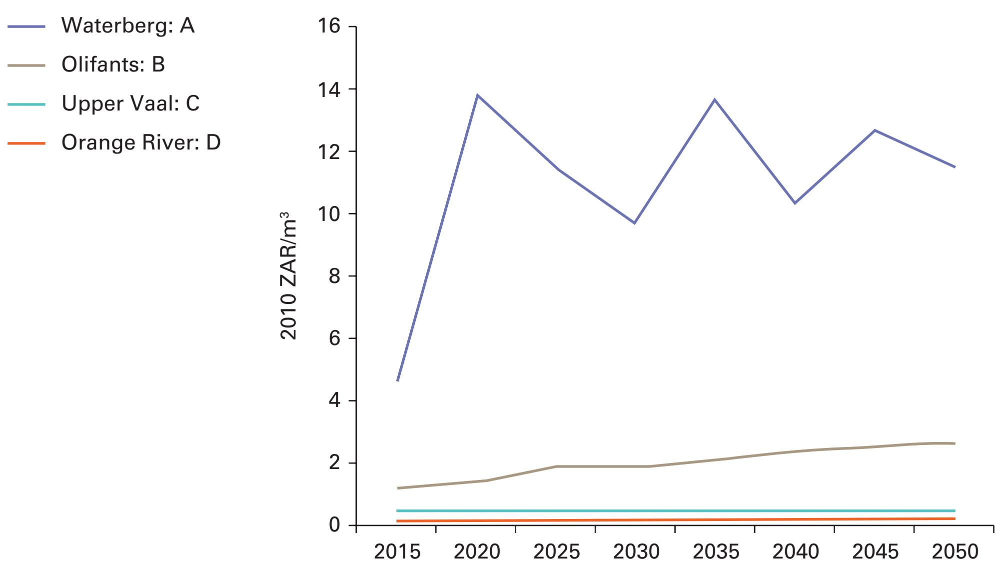


Figure 6.3 Regional Water Supply Costs under the Reference (Water Cost) Scenario



primarily owing to the lower volumes of water being supplied, but the price also fluctuates with periodic investments, which increase unit water cost in steps, followed by declining unit costs as demand increases over time.

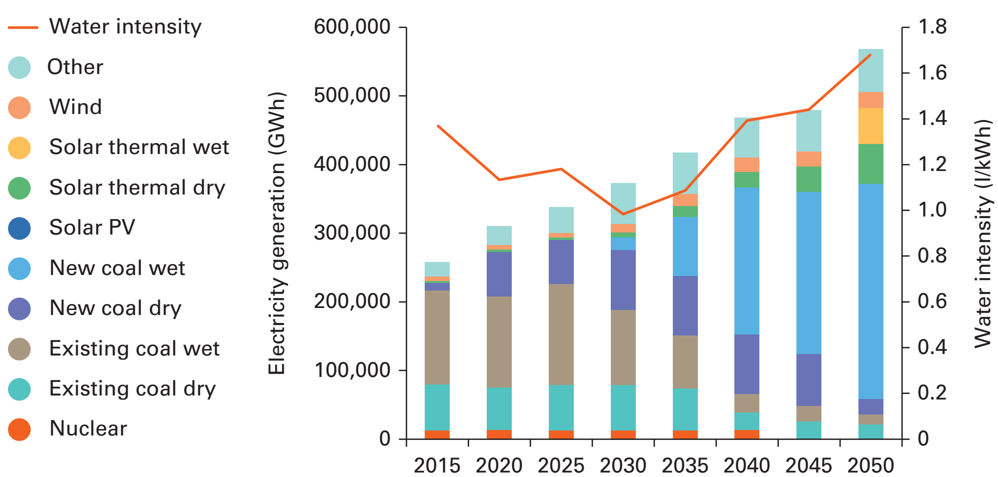
Is the Current Policy of Dry-Cooling for Coal Power Plants Economically Justified?

South Africa's first foray into dry cooling for coal-fired power plants occurred in the late 1960s in response to concerns over water security. Dry cooling for new coal thermal plants is Eskom's current policy. As demonstrated below, it is indeed the least-cost policy for the country.

In the Reference (No Water Cost) scenario, water supply costs and constraints are not factored into planning. Figure 6.4 illustrates this scenario, showing a clear preference for new wet-cooled coal power plants[1] owing to their higher operating efficiencies and lower capital costs. In the Reference (Water Cost) scenario, by contrast, where full

Figure 6.4

Electricity Generation by Type (with Water Intensity) under the Reference (No Water Cost) Scenario



[1] In South Africa all inland wet-cooled power plants are of recirculating closed-cycle design and operate with zero liquid-effluent discharge, such that water withdrawals are consumptive. Therefore, it is assumed in the modeling that new wet-cooled power plants situated inland adhere to a similar design and practice.

consideration is given to the costs of supplying water to power plants and energy resource industries, there is an all-out shift to dry cooling (figure 6.5).

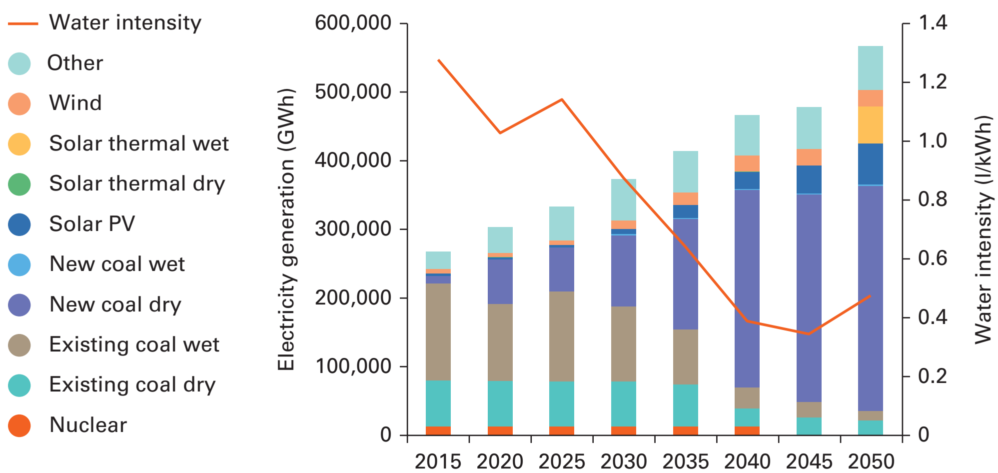
Figure 6.4 also shows that in the Reference (No Water Cost) scenario, the water-intensity of generation increases from an average value of 1.4 l/kWh in 2015 to 1.7 l/kWh in 2050. Although the average water-intensity of generation decreases from 2015 to 2030, as existing wet-cooled plants are retired and 8.6 GW of committed dry-cooled plants are commissioned, the fact that all new coal plants after that date are wet cooled causes the water intensity of generation to increase steadily. However, in the Reference (Water Cost) scenario (figure 6.5), the preference for dry-cooled technology leads to a dramatic decline in water intensity as the dry-cooled coal power plants replace the retiring wet-cooled stock. This modal shift to dry-cooled technology is primarily driven by the availability of relatively cheap coal in the water-scarce Waterberg region, where expensive water-transfer investments would have to be made to support wet-cooled coal power plants. Therefore, when water costs are taken into account, the most cost-effective option is new dry-cooled power plants that utilize the cheap coal available in the Waterberg.

This result reinforces the understanding that Eskom's noneconomic decision to employ dry cooling for new coal power plants is indeed the least-cost policy for the country.

The electricity generation mix in the two scenarios is essentially the same except for the method of cooling coal-fired power plants. Interestingly, in both of the reference scenarios there is a notable increase in water consumption in 2050 owing the commissioning of wet-cooled CSP plants in the Orange River region. Approximately

Figure 6.5

Electricity Generation by Type (with Water Intensity) under the Reference (Water Cost) Scenario



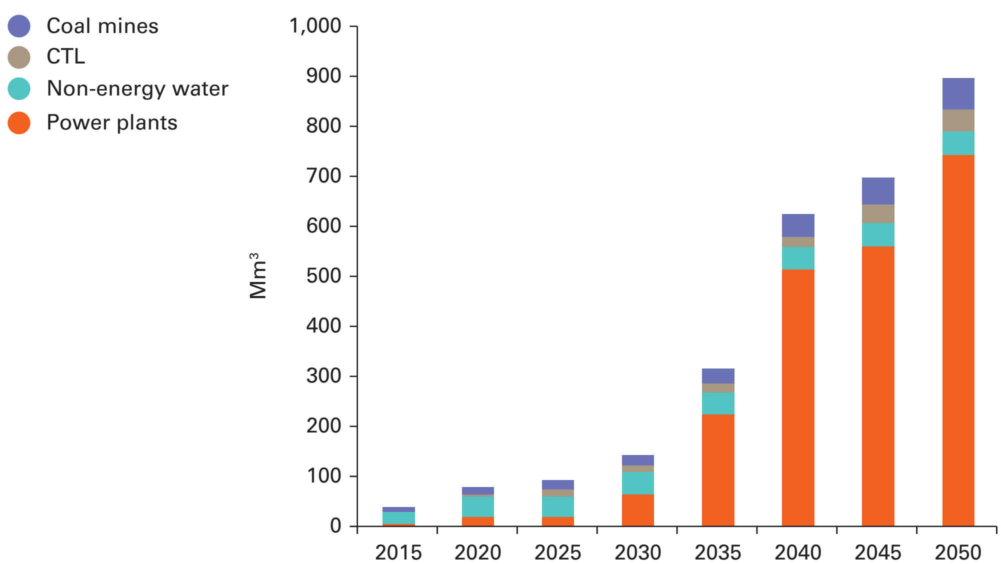
110 Mm^3/year of water would be required to support 10 GW of wet-cooled CSP capacity, providing about 10 percent of electricity supply. However, the water required for wet-cooled CSP in that region is dwarfed by the demands of the non-energy sectors, which total 4,200 Mm^3/year (figure E.1 in appendix E). Electricity generation in this region would consume only 3 percent of total water requirements in 2050, and investment decisions in water infrastructure are driven by the needs of the non-energy sectors. SATIM-W does not currently consider value-based allocations of water to energy versus agriculture, and one of the follow-on activities is to develop more economic and demand linkages between energy and non-energy water demands.

The Reference (Water cost) scenario increases total system cost by only about 1.1 percent over the Reference (No Water Cost) scenario, owing to the relatively small proportion of water supply infrastructure costs compared with all other investments and expenditures for energy in the supply and demand sectors. Investment for water supply infrastructure accounts for 40 percent of this increase, while water-system supply and operating costs account for the remaining 60 percent.

Because such a large share of the water available in the Waterberg region goes to the energy sector, many of the following results will focus on that region, which often showed the greatest response to the scenario being examined. Figure 6.6

Figure 6.6

Water Consumption by Type in the Waterberg Region under the Reference (No Water Cost) Scenario



shows the breakdown of total water consumption in the Waterberg region for the Reference (No Water Cost) scenario. Power plant water consumption dominates, approaching 80 percent of total supply by 2050. Figure 6.7 shows that when water costs are included, power plant consumption drops by a factor of seven, while coal mines consume very slightly less (as coal remains the main power plant fuel, with only the cooling technology switching). The other sectors are unaffected.

Table 6.3 summarizes the key cumulative metrics (2010 to 2050) from the two Reference scenarios. The total system cost, energy supply expenditures, and primary and final energy consumption are quite similar, with the most dramatic difference being the water consumed by power plants, which is cumulatively 77 percent lower (more than 9,300 Mm^3) in the Reference (Water Cost) scenario. Interestingly, this does not result in significantly higher power plant investment costs. The Reference (Water Cost) scenario also produces slightly higher CO_2 emissions despite generating 1.3 percent less electricity with coal and 2 percent more with renewable technologies. This results from the higher unit emissions associated with the dry-cooled coal plants that are adopted when water costs are taken into account.

Figure 6.7

Water Consumption by Type in the Waterberg Region under the Reference (Water Cost) Scenario

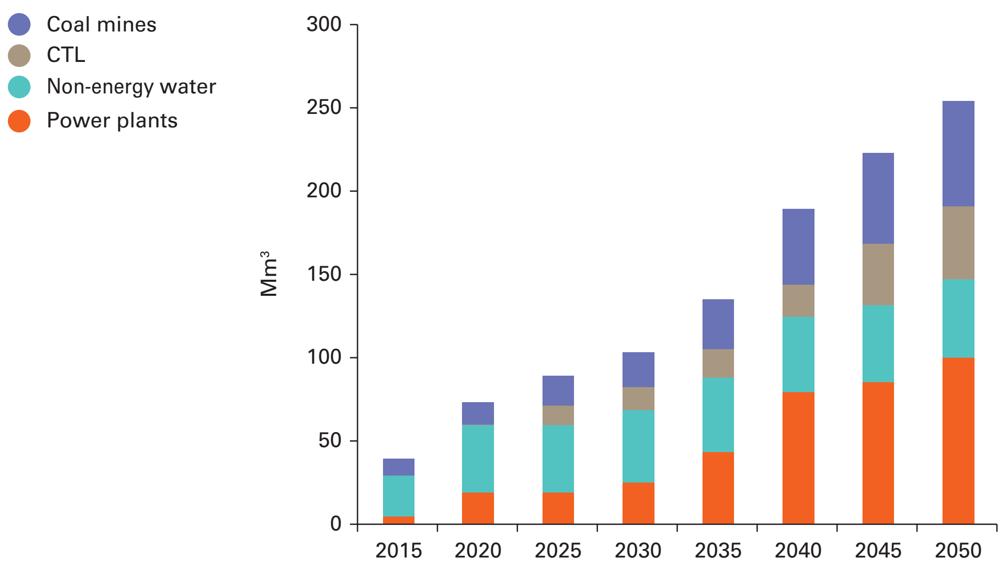


Table 6.3 Summary Metrics for Reference (Water Cost) and Reference (No Water Cost) Scenarios (Cumulative Values, 2010–50)

Scenario Results	Units	Reference (Water Cost)	Reference (No Water Cost)	Percent Change
System Cost	2010 MZAR (x 1,000)	7,646	7,582	–0.84
Expenditure–Supply	2010 MZAR (x 1,000)	11,650	11,639	–0.09
Primary Energy	PJ	335,500	336,508	0.30
Final Energy	PJ	157,084	157,039	–0.03
Power Sector CO_2 Emissions	Mt	13,756	13,751	–0.03
Power Plant Builds	GW	134	131	–1.84
Power Plant Investment Difference	2010 MZAR (x 1,000)	2,670	2,639	–1.14
Water to Power Plants	Mm^3	12,074	21,412	77.34
Total Water for Energy	Mm^3	16,265	25,412	57.82

Note: MZAR = millions of South African rands; PJ = petajoule (10^{15} joules); Mm^3 = millions of cubic meters.

How Do Stricter Environmental Controls Affect Coal Investments in the Waterberg Region?

Economical coal deposits in the Waterberg region are the key driver for siting new coal mines, coal power plants, and CTL plants in the region. Measures to improve air and water quality, as embodied in the Environmental Compliance scenario, require flue gas desulfurization (FGD) for existing coal power plants and all CTL plants. This requirement affects the operating efficiency and water intensity of both types of plants, an effect that is particularly critical in the Waterberg. Although the Reference (Water Cost) scenario increases capacity derived from CTL plants by more than 500 PJ per year, the Environmental Compliance scenario limits it to 100 PJ/year (figure 6.8). Water quality, which is a component of the Environmental Compliance scenario, slightly reduces the capacity of CTL plants owing to the increased cost of supplying water. However, the greatest impact is due to the FGD requirements. For this initial study, only wet FGD systems were modeled (see appendix H), based on the detailed information from the Medupi plant, and Eskom's current preference for the proven wet technology. Also, the cost of waste disposal and sorbent still needs to be incorporated into the model, and the total increase in system costs needs to be further examined.

Figure 6.9 shows that the lack of new CTL capacity under the Environmental Compliance scenario reduces the requirement for new water supply schemes in the Waterberg as compared with the Reference (Water Cost) and Water Quality scenarios.

Figure 6.8

New Coal-to-Liquids Capacity under Three Scenarios

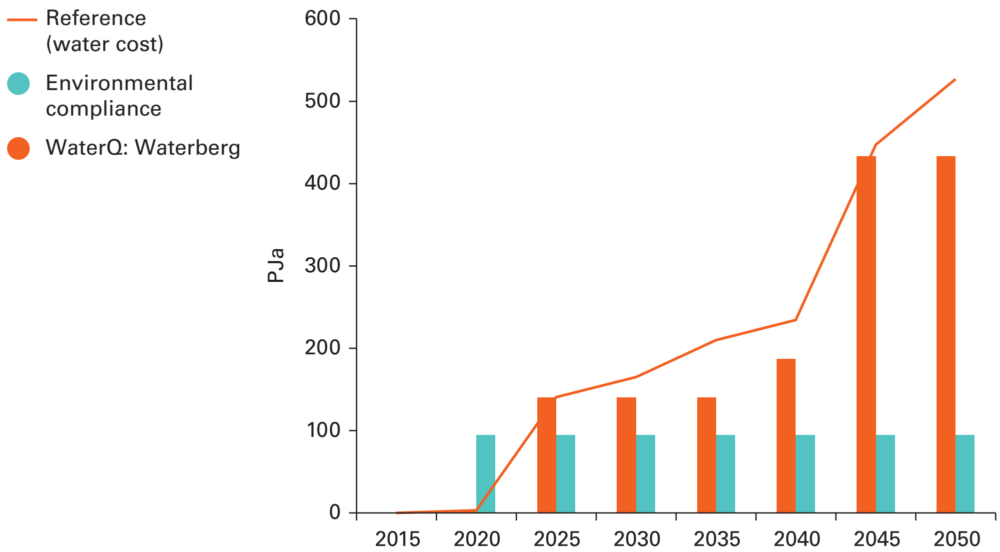
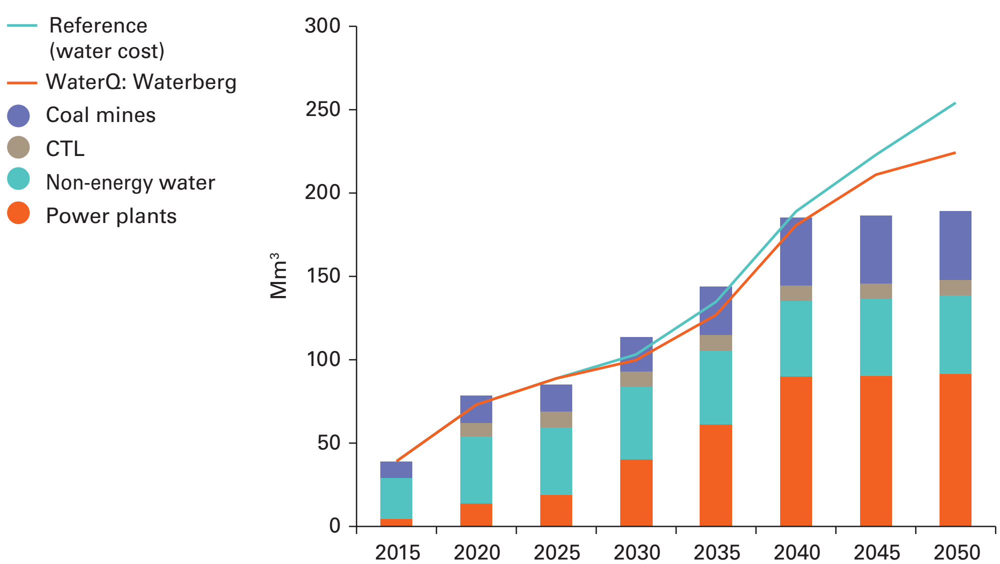


Figure 6.9

Water Demand in the Waterberg Region under the Environmental Compliance Scenario Compared to the Reference (Water Cost) and Water Quality Scenarios



Note: CTL = coal-to-liquids.

Figure 6.10 New Coal Capacity in the Waterberg Region under Reference (Water Cost), Water Quality, and Environmental Compliance Scenarios

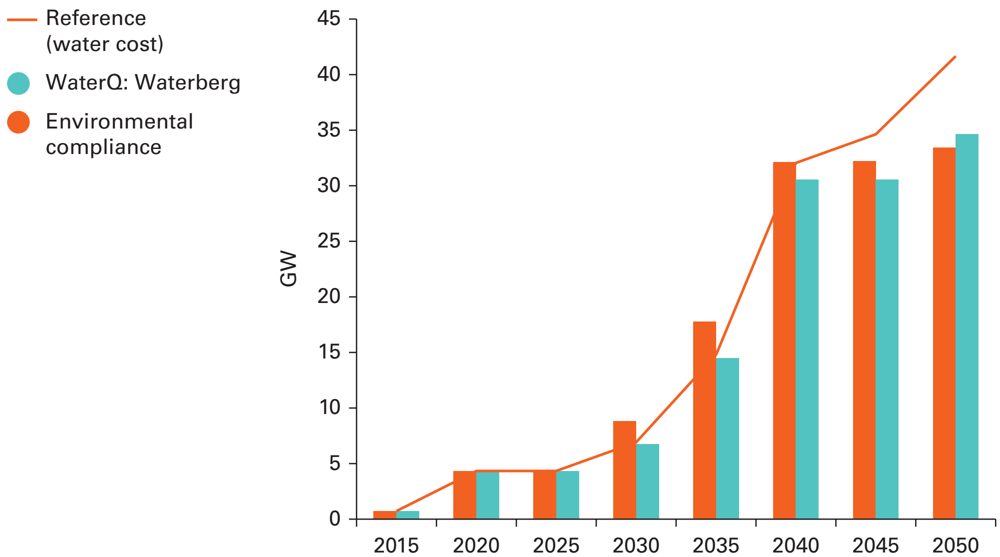


Figure 6.10 shows the impact on new coal power plant capacity in the Waterberg, where the increased cost of water treatment begins to decrease new coal plant capacity after 2040, resulting in a drop of ~7 GW from the Reference (Water Cost) scenario. However, in the Environmental Compliance scenario, which includes water quality, new coal power plant capacity is slightly higher because of water freed up by CTL plants that are not built. This somewhat intuitive result highlights the value of employing a multi-sector planning model of the energy system, one that captures and quantifies the interplay between the sectors.

How Does a Dry Climate Affect Coal Investments in the Waterberg Region?

The Dry Climate scenario has a CTL build-out similar to that of the Reference (Water Cost) scenario. Similarly, the Dry Climate + Environmental Compliance scenario also limits the construction of CTL capacity to 100 PJ/year. The Dry Climate scenario alone has little impact on new CTL capacity, largely because of the limited impact of climate change on bulk water supply.

One impact of the Dry Climate scenario is early retirement of wet-cooled coal capacity in the Olifants and Upper Vaal regions owing to increased water demands from the non-energy sectors. This results in an additional 2 GW of dry-cooled coal capacity in the Waterberg in 2050 relative to Reference (Water Cost) scenario (figure 6.11).

However, this small change in capacity hides the change in the coal power plant mix that results from the Dry Climate scenario, particularly starting in 2030. Under the Dry Climate scenario, all existing wet-cooled plants and the older, less efficient, dry-cooled plants, as well as the 800 MW of new wet-cooled plants, are replaced by new dry-cooled plants (figure 6.12). This is due primarily to the competition for water from the non-energy sectors, which, as discussed in appendix C, increases by an average of 11 percent from 2030 to 2050 in the Central Basin, where the existing plants are located. In the Dry Climate and CO_2 constrained scenarios, there is almost no new investment in coal-fired generation, so a dry climate has no significant impact on investment in coal-fired power generation.

Table 6.4 summarizes the key cumulative metrics (2010 to 2050) from the Dry Climate and Environmental Compliance scenarios. The Dry Climate scenario accelerates the shift to dry-cooled coal plants through early retirement of existing wet-cooled plants; cumulative water use decreases by 6.4 percent. By contrast, the Environmental Compliance scenario reduces investment in both new coal and new CTL capacity in the Waterberg, thereby cutting the requirement for new water supply schemes in that

Figure 6.11

New Coal Capacity in the Waterberg Region under the Dry Climate Scenario and Reference (Water Cost) Scenario

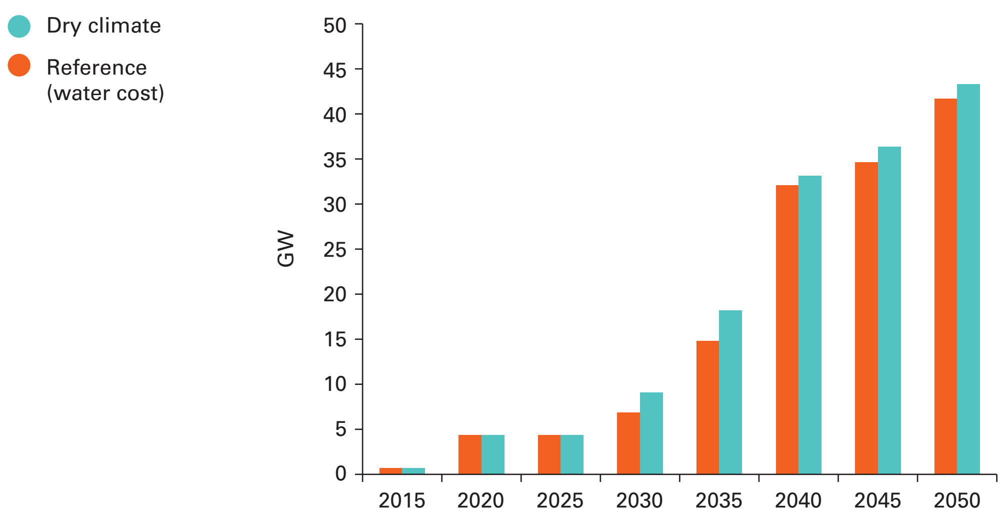


Figure 6.12

Difference in Installed Capacity Between Dry Climate and Reference (Water Cost) Scenarios

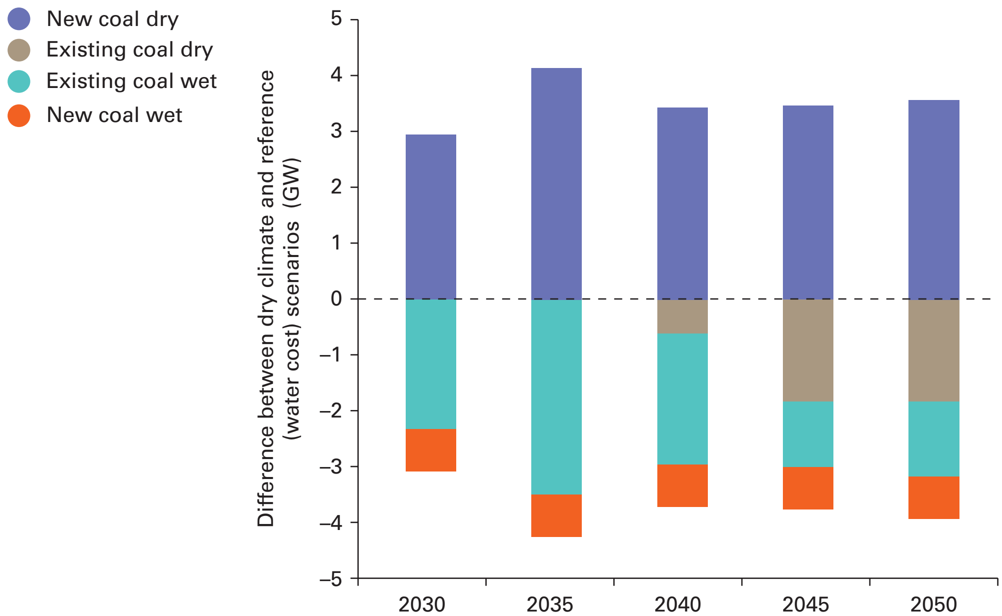


Table 6.4

Summary Metrics for Dry Climate and Environmental Compliance Scenarios (Cumulative Values, 2010–50)

Scenario Results	Units	Reference (Water Cost)	Dry Climate	Percent Change	Environmental Compliance	Percent Change	Dry Climate + Env. Compliance	Percent Change
System Cost	2010 MZAR (x 1,000)	7,646	7,647	0.00	7,703	0.78	7,703	0.74
Expenditure–Supply	2010 MZAR (x 1,000)	11,650	11,622	–0.24	11,955	2.62	11,934	2.43
Primary Energy	PJ	333,500	333,514	–0.59	322,607	–3.84	321,995	–4.03
Final Energy	PJ	157,083	156,993	–0.06	157,051	–0.02	156,905	–0.11
Power Sector CO_2 Emissions	Mt	13,756	13,533	–1.62	13,359	–2.89	13,249	–3.34

(continued)

Table 6.4 Summary Metrics for Dry Climate and Environmental Compliance Scenarios (Cumulative Values, 2010–50) *(continued)*

Scenario Results	Units	Reference (Water Cost)	Dry Climate	Percent Change	Environmental Compliance	Percent Change	Dry Climate + Env. Compliance	Percent Change
Power Plant Builds	GW	134	130	–2.82	131	–1.7	132	–1.77
Power Plant Investment	2010 MZAR (x 1,000)	2,670	2,747	2.90	2,664	–0.22	2,673	0.14
Water to Power Plants	Mm^3	12,074	11,302	–6.39	12,356	2.34	11,783	–2.41
Total Water for Energy	Mm^3	16,265	15,453	–4.99	16,007	–1.59	15,428	–5.14

Note: MZAR = millions of South African rands; PJ = petajoule (10^{15} joules); Mt = millions of tons; Mm^3 = millions of cubic meters.

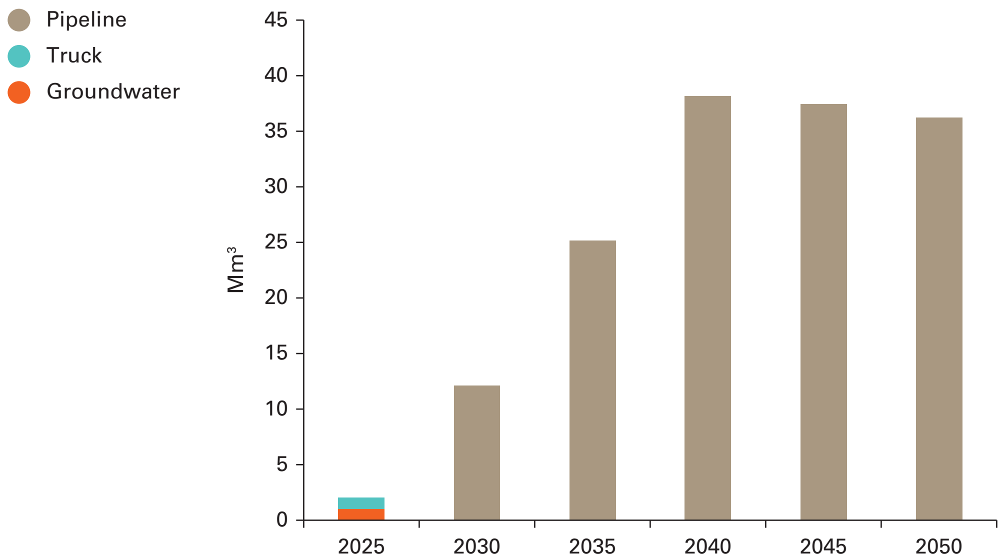
region, but new generation (coal and CSP) is shifted to other regions, raising the amount of water supplied for power generation but bringing a 1.6 percent decrease in overall water for energy.

How Does the Cost of Water Affect Shale Gas Production?

For this report, the data on water supply costs were suspect, and no data were available for the cost of treating return-flow effluent from shale gas production in South Africa. Therefore, the current SATIM-W treatment of shale gas production and the following scenario results must be viewed as preliminary. Under the Shale Gas scenario, shale gas production increases to just over 15 billion m^3 per annum and comes to account for more than 6 percent of total primary energy.

In the Shale Gas scenario, there is an initial reliance on groundwater (~1 Mm^3/year) and trucking (~300 km per round-trip) for water delivery in the absence of a pipeline, resulting in a relatively high water supply cost (figure 6.13). The construction of a pipeline in 2030, at a cost of R7.5 billion ($600 million), dramatically lowers the cost of water and accelerates shale gas development in the region. However, as noted, the costs of treatment and disposal of flow-back effluent from shale gas exploration and

Figure 6.13 Water Supply for Shale Gas Production, by Mode



extraction are not fully reflected in the current analysis. Later iterations of the model shall include these costs.

The Shale Gas scenario significantly increases power generation from natural gas compared with the Reference (Water Cost) scenario (figure 6.14). Use of shale gas utilization for power generation grows at a similar rate whether or not the cost of water is taken into account (figure 6.15). The slight increase in the capacity of shale gas power plants when water costs are included results from a corresponding decrease in coal power plant capacity. The new combined cycle gas turbine (CCGT) plants built under the Shale Gas scenarios are all dry cooled, as CCGT plants have lower water requirements and suffer less efficiency loss with dry cooling. However, this result may change once more accurate water cost data and the cost of treating shale gas return-flow effluent is included in the model.

Table 6.5 summarizes the key cumulative metrics (2010 to 2050) for the Shale gas scenario. It is interesting to note that cumulative water supply for shale gas production is 9.8 percent of all water use for energy in that scenario. The overall water needs for energy actually drop slightly under the Shale Gas scenario, as less water is devoted to the coal industry and power plants (since CCGT plants require less water than Coal plants).

Figure 6.14 Electricity Supply Portfolio with Shale Gas

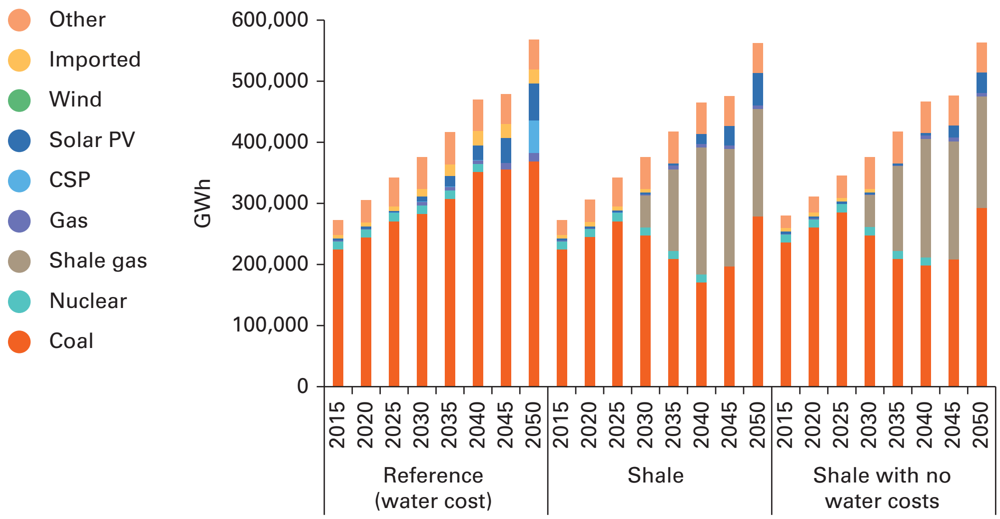


Figure 6.15 New Shale Gas Power Plant Builds with Shale Gas Availability

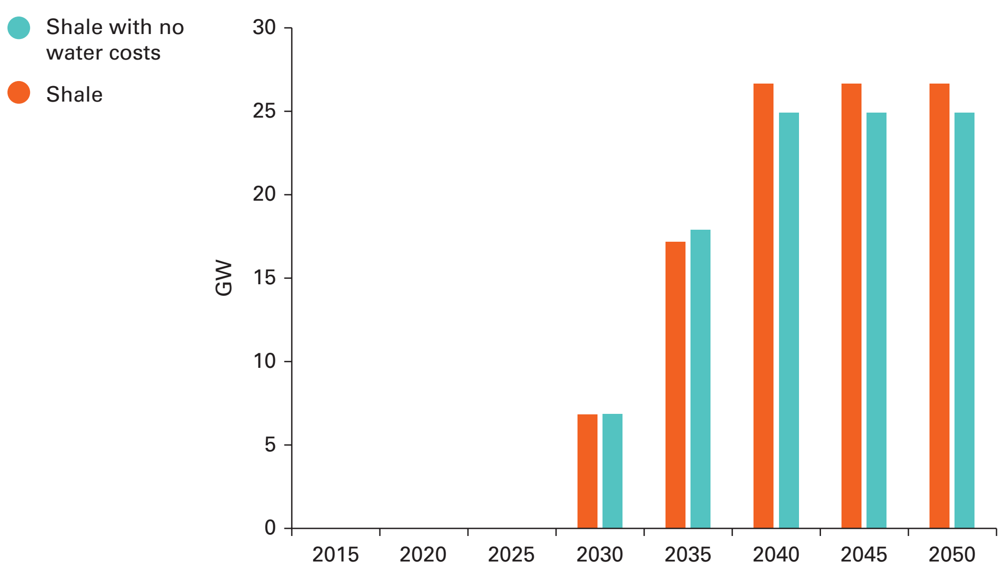


Table 6.5 Summary Metrics for Shale Gas Scenario (Cumulative Values, 2010–50)

Scenario Results	Unit	Reference (Water Cost)	Shale Gas	Percent Change
System Cost	2010 MZAR (x 1,000)	7,646	7,597	–0.65
Expenditure—Supply	2010 MZAR (x 1,000)	11,650	12,217	4.87
Primary Energy	PJ	333,500	331,025	–1.33
Final Energy	PJ	157,083	157,453	0.24
Power Sector CO_2 Emissions	Mt	13,756	12,540	–8.84
Power Plant Builds	GW	134	117	–12.42
Power Plant Investment Difference	2010 MZAR (x 1,000)	2,670	1,935	–27.52
Water to Power Plants	Mm^3	12,074	10,275	–14.90
Water to Shale Production	Mm^3	0	1,435	NA
Total Water for Energy	Mm^3	16,265	14,677	–9.76

Note: MZAR = millions of South African rands; PJ = petajoule (10^{15} joules); Mt = millions of tons; GW = gigawatts; Mm^3 = millions of cubic meters.

In a Carbon-Constrained World, what Is the Likelihood of Stranded Assets?

Building a system-wide carbon constraint into SATIM-W in the form of a cumulative CO_2 cap makes it possible to identify the most cost-effective path to mitigating energy sector CO_2 emissions in response to international climate change obligations and national policy. Two scenarios were investigated: a cumulative cap of 14 Gt of CO_2 equivalent by 2050, which is in line with the country's current international commitments,[2] and a 10 Gt CO_2 equivalent cumulative cap, which models a more aggressive policy that might be followed if South Africa's trading partners mitigated aggressively and applied pressure to limit embedded emissions in the country's exports. These scenarios highlight the potential impact of the two policies on energy sector and water supply investments, as well as the potential for stranded assets as a consequence.

[2] South Africa has committed to a "Peak-Plateau-Decline" emissions pathway as the country's "intended nationally determined contribution" as determined at the December 2015 Conference of Parties to the United Nations Framework Convention on Climate Change (Altieri and others 2015).

Regarding energy supply investments, both scenarios produce no new investment in CTL capacity, compared with more than 500 PJ per year in the Reference (Water Cost) scenario. In addition, the operation of the existing CTL plant is affected (figure 6.16). The 14 Gt CO_2 Cap scenario reduces production at the plant to zero by 2040, five years earlier than in the Reference scenario. If a 10 Gt CO_2 Cap is implemented, production at the plant is completely halted by 2025, 20 years before the scheduled decommissioning date.

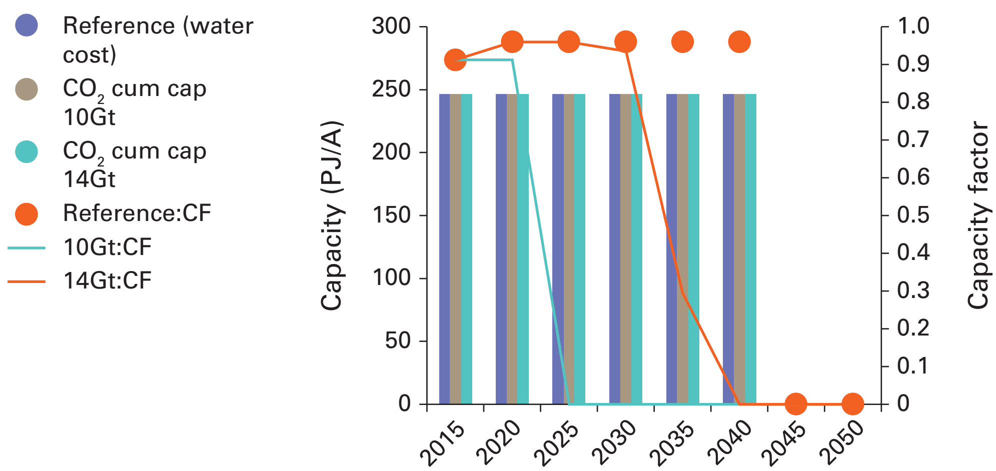
The reduction in CTL capacity is substituted by an increased reliance on imported petroleum products (figure 6.17) and crude oil (figure 6.18).

The 10 Gt CO_2 Cap scenario relies heavily on early imports of refined petroleum products, substituting for 80 percent of existing CTL production in 2025, with the remainder coming from increased production in the existing refineries. Although the 14 Gt CO_2 Cap scenario allows the existing CTL plant to operate at full capacity in 2025, there is still an increase in imports of finished petroleum products owing to a lack of investment in new CTL capacity in the Waterberg. The bulk of refinery capacity is situated along the coast (~80 percent) and therefore does not affect the water supply system for this analysis.

Unlike CTL facilities, which have very high CO_2 emissions per unit output, existing and committed coal power plants are less at risk of being stranded under the 14 Gt CO_2 Cap scenario. In the Waterberg, the existing plants remain operational for their entire technical life (figure 6.19), although their operation stops by 2050. In the Central Basin

Figure 6.16

CTL Utilization under the Two Carbon-Constrained Scenarios and the Reference (Water Cost) Scenario



Note: CF = Capacity factor; CTL = coal-to-liquids.

Figure 6.17

Imported Petroleum Products under Carbon-Constrained Scenarios (Difference from the Reference [Water Cost] Scenario)

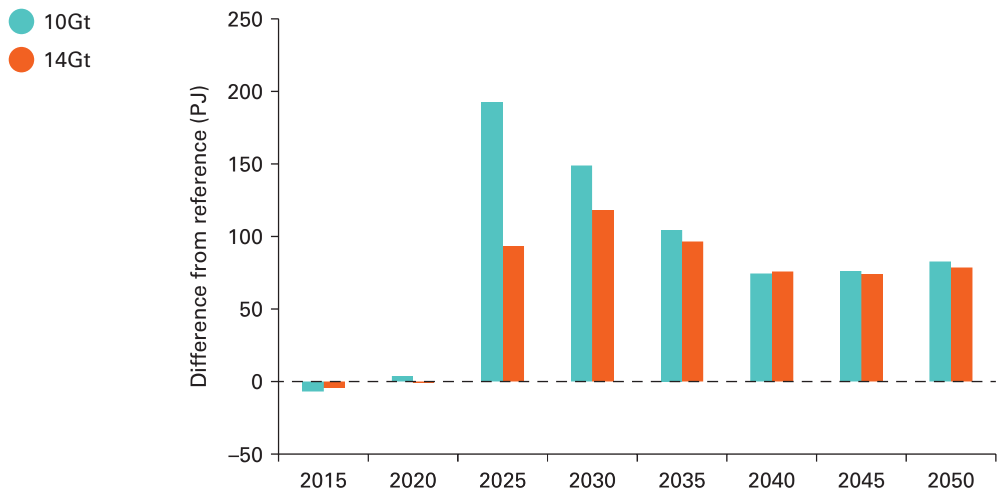


Figure 6.18

Crude Oil Production under Carbon Constrained Scenarios (Difference from the Reference [Water Cost] Scenario)

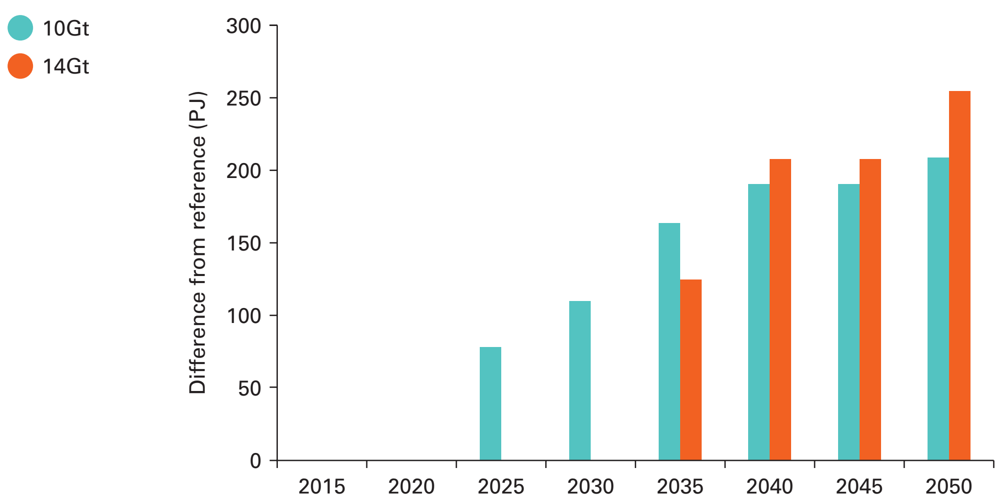
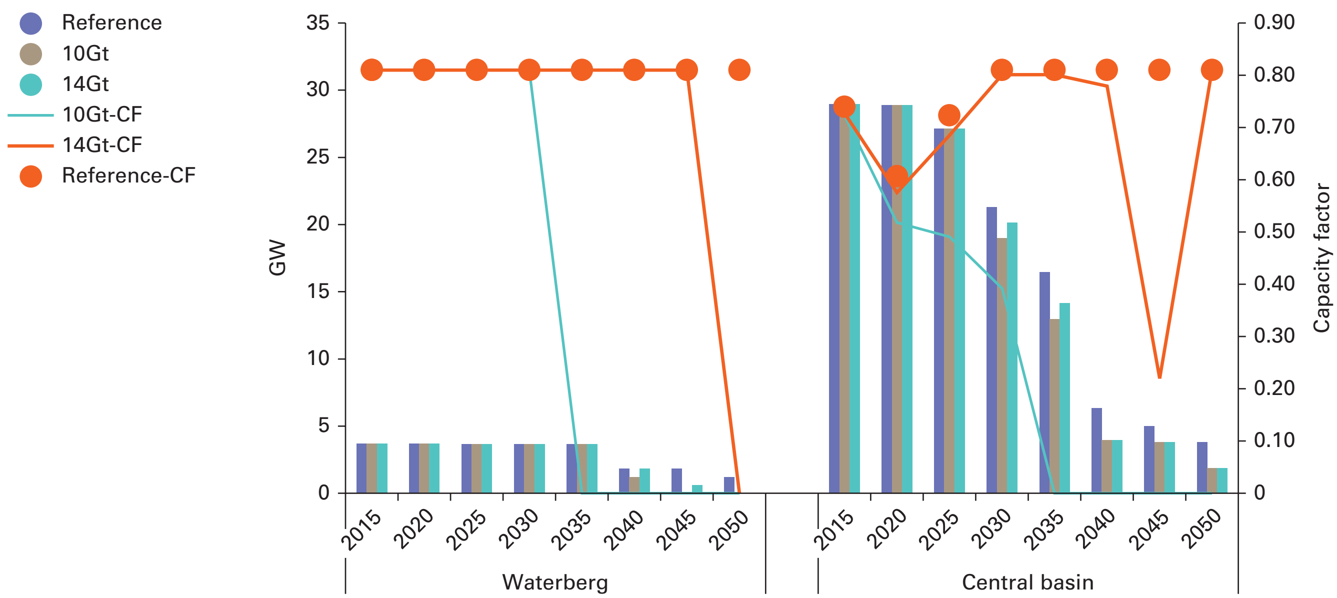


Figure 6.19

Existing Coal Capacity with Production Factors under the Two Carbon-Constrained Scenarios and the Reference (Water Cost) Scenario

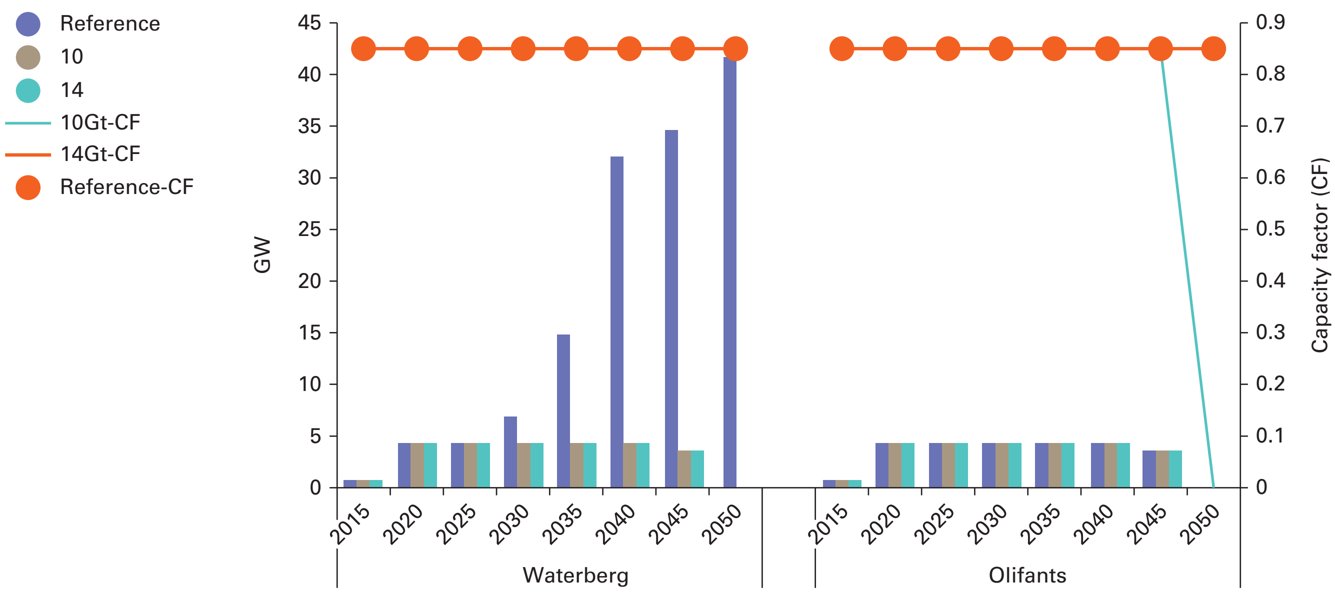


(Upper Vaal and Olifants), existing coal plant utilization is highly variable from 2040 onward. After 2040 only 4 GW of existing coal plants remain operational in the Central Basin, comprising both wet- and dry-cooled plants in roughly equal shares. Soon after, the wet-cooled plants are effectively mothballed. The capacity factor of the residual coal fleet increases in 2050 once the wet-cooled plants reach the end of their life and the 1.22 GW of dry-cooled coal plant remains operational.

Under the 10 Gt CO_2 constraint, by contrast, there is indeed a risk of significant stranded coal assets because the scenario requires early retirement of the existing coal plants, which are replaced by new nuclear plants. In addition, the 10 Gt CO_2 Cap scenario shifts electricity production from the Waterberg to the Orange River region. Although the capacity of wet-cooled stock in the Central Basin is similar to that of the Reference (Water Cost) scenario in 2025, electricity production drops by 30 percent. The stock is retired by 2035, with idle capacity of 4 GW from 2040 onward.

New coal power plants in the Olifants appear most at risk under the 10 Gt CO_2 Cap scenario, as they cease production earlier than plants located in the Waterberg (figure 6.20). The regional coal price is a likely factor in the preferential early retirement of plants in the Olifants, because Waterberg coal is more economical. In both scenar-

Figure 6.20 New Coal Capacity with Production Factors under the Two Carbon-Constrained Scenarios and the Reference (Water Cost) Scenario

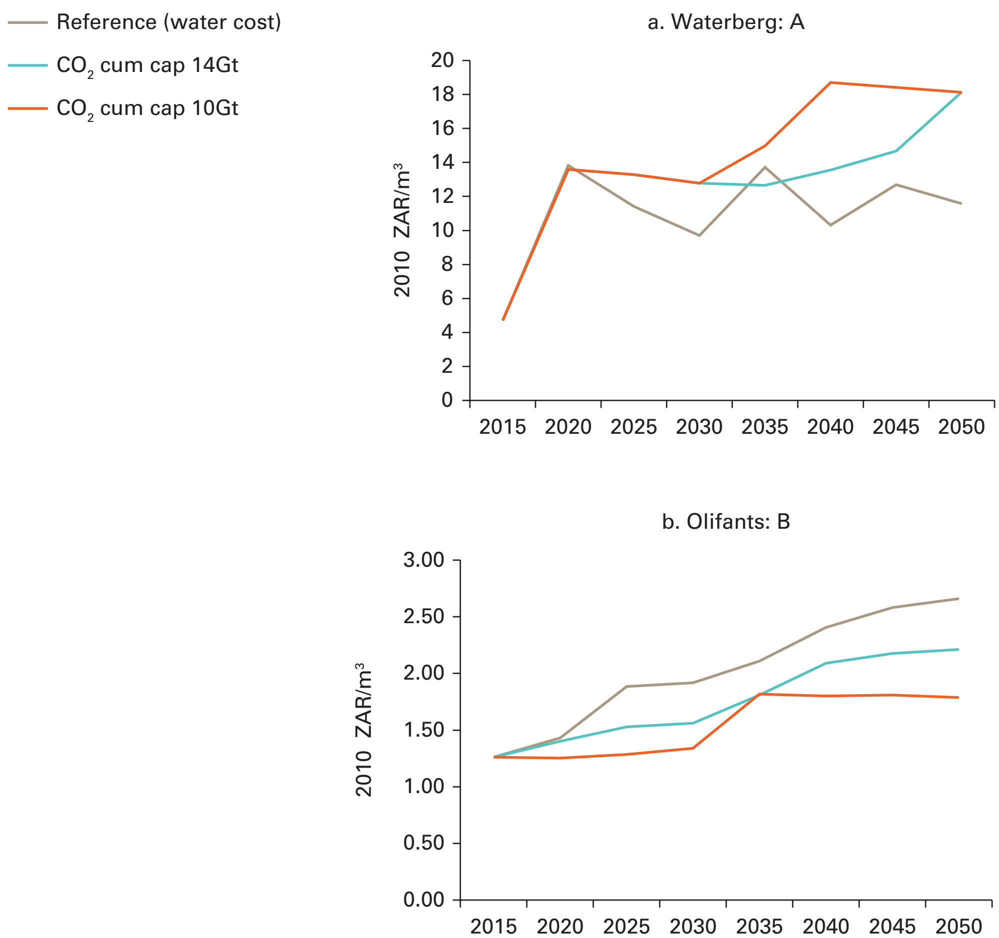


ios, 3 GW of new fluidized bed combustion capacity is built and operates over the planning period.

Water supply infrastructure for the Waterberg is also at risk of being underutilized if a CO_2 mitigation policy is implemented. The cost of water supply increases markedly after 2040 for the 14 Gt scenario and after 2030 for the 10 Gt Cap scenario (figure 6.21) because of the early closure of coal-fired capacity. This effectively increases costs for the remaining users, as the supply system is being underutilized. Conversely, the figure shows that the cost of water in the Olifants region under the carbon-constrained scenarios decreases relative to the Reference scenario, with the stricter 10 Gt CO_2 cap also reducing costs relative to the 14 Gt cap in both cases owing to the early retirement of older wet-cooled coal plants.

The summary metrics for the two carbon-constrained scenarios relative to the Reference scenario are shown in table 6.6. Notable are the large increases in power plant investments: 24 percent for the 14 Gt scenario and 82 percent for the 10 Gt scenario. The system cost differences, which aggregate and discount all supply and demand side costs, show a much smaller overall impact, although the 2.86 percent increase for the 10 Gt scenario is significant relative to the impact of the other

Figure 6.21 Water Supply Costs in Coal-Rich Regions under the Two Carbon-Constrained Scenarios and the Reference (Water Cost) Scenario



Note: ZAR/m³ = South African rands per cubic meter.

scenarios investigated. This is due to power plant investments being offset by reductions in primary energy use traceable to the increased role of renewables.

Significant increases in water consumption by power plants reflect the shift to wet-cooled CSP generation in the Orange River Region, where water is relatively cheaper, although, as discussed in the next section, when the stresses of climate change and shale gas mining in the region are factored in, the model shifts to dry-cooled CSP, which is less water intensive.

Table 6.6 Summary Metrics for 10 Gt and 14 Gt Cumulative CO_2 Cap Scenarios (Cumulative Values, 2010–50)

Scenario Results	Units	Reference (Water Cost)	CO_2 Cum Cap 14Gt	Percent Change	CO_2 Cum Cap 10Gt	Percent Change
System Cost	2010 MZAR (x 1,000)	7,646	7,686	0.51	7,865	2.86
Expenditure–Supply	2010 MZAR (x 1,000)	11,650	11,765	0.98	10,941	-6.90
Primary Energy	PJ	333,500	284.385	-15.24	266,639	-20.52
Final Energy	PJ	157,083	156,008	-0.68	154,452	-1.67
Power Sector CO_2 Emissions	Mt	13,756	9,330	-32.18	6,120	-55,51
Power Plant Builds	GW	134	189	26.49	189	40.88
Power Plant Investment	2010 MZAR (x 1,000)	2,670	3,318	24.28	4,872	82.49
Water to Power Plants	Mm^3	12,074	14,592	20.85	15,073	24.84
Total Water for Energy	Mm^3	16,265	16,941	4.16	16,753	3.00

Note: MZAR = millions of South African rands; PJ = petajoule (10^{15} joules); Mt = millions of tons; GW = gigawatts; Mm^3 = millions of cubic meters.

Why Does SATIM-W Select CSP with Wet Cooling in the Orange River Basin?

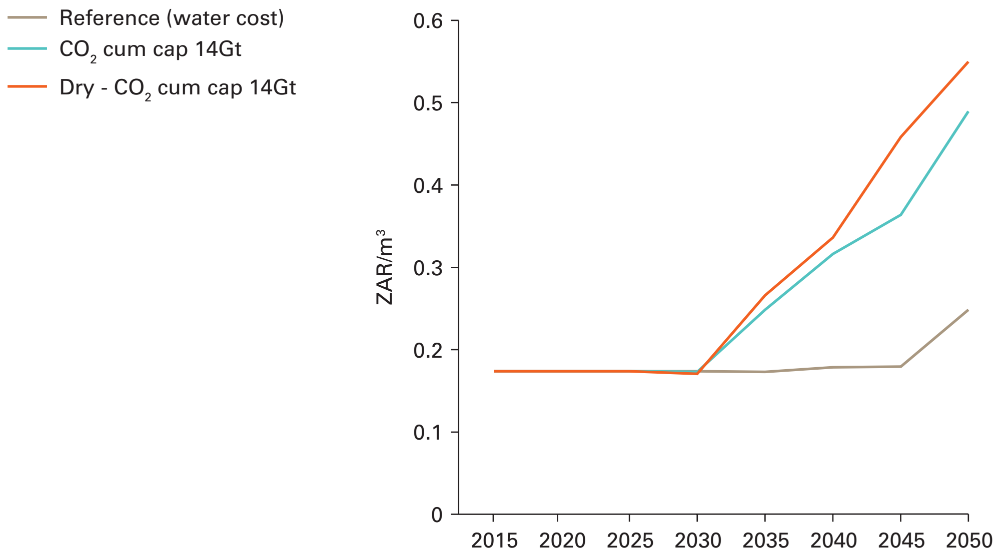
Several scenarios were examined to better understand why SATIM-W selects wet-cooled CSP in the Reference (Water Cost) scenario. In particular, two scenarios are illustrative. The 14 Gt CO_2 Cap scenario also selects wet-cooled CSP, but the Dry Climate + 14 Gt CO_2 Cap scenario selects dry-cooled CSP. However, the resulting reduction in water demand is accompanied by an increase in water cost (figure 6.22).

The reason for the increased water cost can be understood by examining the investment decisions for water supply infrastructure in the Orange River region under these scenarios. A stricter carbon cap results in increased investment in water supply infrastructure in the Orange River region relative to the Reference scenario (figure 6.23). These incremental water supply investments in the Orange River are due to a shift to CSP rather than coal under a carbon-constrained scenario, which shifts generation to the Orange River region. These investments begin in 2030 to support large-scale implementation of CSP starting in 2040.

However, water demand in this region, which is still dominated by non-energy demands, requires construction of a significant water supply scheme in all scenarios.

Figure 6.22

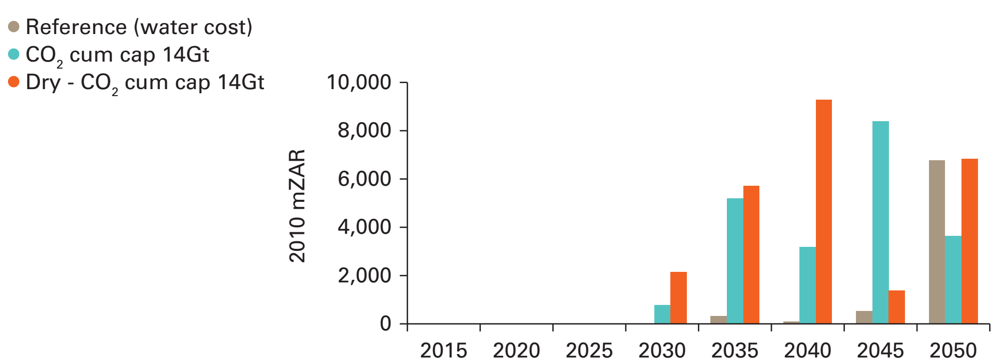
Water Supply Costs for Orange River under Three Scenarios



Note: ZAR/m³ = South African rands per cubic meter.

Figure 6.23

Lump-Sum Investments in Water Supply Infrastructure in the Orange River Region



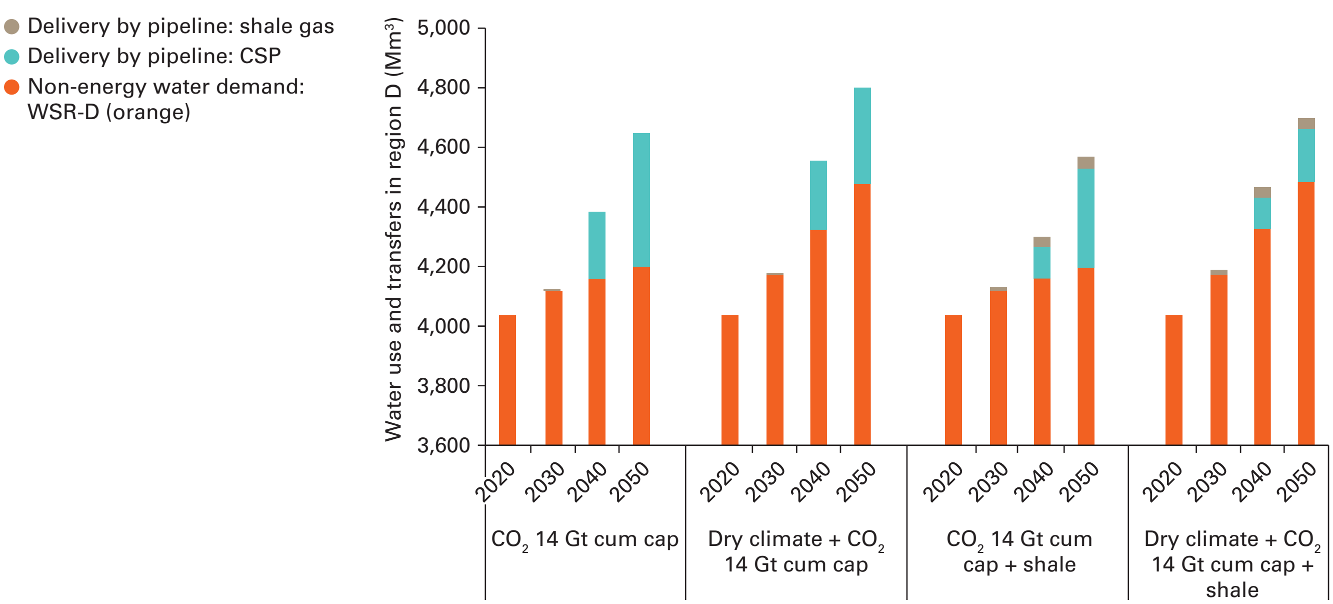
Note: MZAR = millions of South African rands.

However, this water supply scheme is not operating at full capacity when the decision is made to invest in dry-cooled CSP. This suggests that the increased cost of water is a determining factor in the choice.

Figure 6.24 illustrates the increased demand from non-energy sectors under the Dry Climate scenario, which causes a degree of regional water stress in the Orange River region. This stress is slightly exacerbated by the advent of shale gas extraction, which takes place largely in this region. The increased demand triggers further investment in water infrastructure, which causes average water costs to rise enough to move some of the investment in CSP to dry-cooled technology (figure 6.25).

The summary metrics for the 14 Gt Cap scenario under the effects of climate change (14 Gt Cap + Dry Climate scenario) show only small reduction in the increased water intensity from the shift to CSP based production in the Orange River region (table 6.7). Essentially, the water supply system appears to be resilient to climate change's effects on water supply and demand as currently understood, although increased water costs provoke changes in the optimal mix of wet- and dry-cooled coal and CSP technologies.

Figure 6.24 Water Use and Transfers in the Orange River Water Management Area



Note: WSR-D = water supply region D.

Figure 6.25 Annualized Investment in Water Infrastructure in the Orange River Basin and Impact on the Average Cost of Water

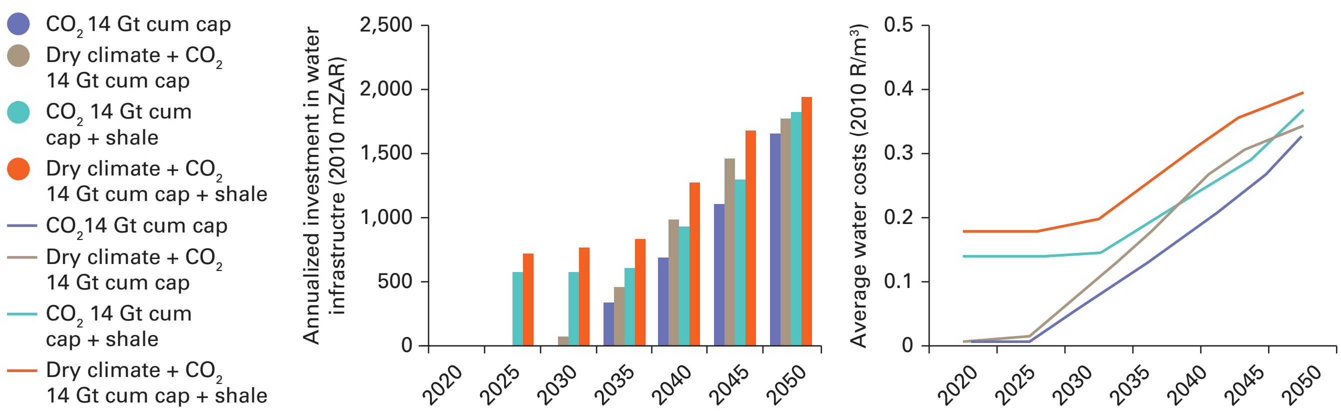


Table 6.7 Summary Metrics for Combinations of the Dry Climate, Shale Gas, and 14 Gt Carbon Cap Scenarios

Scenario Results	Units	Reference (Water Cost)	Dry + C14Gt	Percent Change	Shale + C14Gt	Percent Change	Shale + Dry + C14Gt	Percent Change
System cost	2010 MZAR (x 1,000)	7,646	7,691	0.59	7,635	-0.15	7,631	-0.14
Expenditure—supply	2010 MZAR (x 1,000)	11,650	11,785	1.16	12,124	4.07	12,141	4.20
Primary energy	PJ	333,500	284,548	-15.19	285,203	-14.99	285,054	-15.04
Final energy	PJ	157,083	156,007	-0.69	156,148	-0.60	156,199	-0.56
Power sector CO_2 emissions	Mt	13,756	9,337	-32.12	9,294	-32.44	9,299	-32.40
Power plant builds	GW	134	170	27.08	157	17.54	157	17.42
Power plant investment	2010 MZAR (x 1,000)	2,670	3,321	24.36	2,759	3.35	2,742	2.73
Water to power plants	Mm^3	12,074	13,801	14.31	111,734	-2.81	10,615	-12.08
Total water for energy	Mm^3	16,265	16,145	-0.73	14,532	-10.65	13,412	-17.54

Note: C14Gt = 14 Gt Carbon Cap scenario; MZAR = millions of South African rands; PJ = petajoule (10^{15} joules); Mt = millions of tons; GW = gigawatts; Mm^3 = millions of cubic meters.

07

Conclusions

The study reported here used new tools to examine the water-energy nexus and to explore the possibilities of integrated energy and water planning. The approach applied to the case of South Africa can be readily adapted to enable other countries to tackle their water-energy management challenges in a more integrated manner. A second study is already underway in China.

Conclusions about the general approach to modeling the water-energy nexus and specific conclusions relating to the South African case study are summarized below.

General Findings

A critical finding of the study is that a national-level model for the optimization of energy systems can be readily regionalized to represent the locations of energy resources and power plants. The regional costs and constraints of water supply can be incorporated into the energy model to create a water-smart energy sector planning tool. In this study, options for new infrastructure to supply water to the energy sector were explicitly represented with their costs and availability.

For the first time, as a result, a representation of the full cost of water supply has been incorporated into a sectorwide energy system expansion plan that takes into account the regional variability of water availability that needs to be addressed through the development of additional water supply infrastructure.[1] The case study highlights the importance of the spatial component of energy and water resources—particularly in a country such as South Africa, where water availability varies widely from region to region—and the potential impacts this has on the overall cost of different energy technologies.

The model used in the study, known as South African TIMES model "water smart" (SATIM-W), makes it possible to understand what water infrastructure will be needed for the energy sector, while continuing to meet non-energy water needs; when and where investments will have to be made; and how much it will cost to supply the needed water.

Given that the planning, design, and construction of infrastructure requires long-term engagement, the case study demonstrates that the SATIM-W model is a valuable tool within an integrated planning approach that can help to ensure timely investments and delivery of water supply and treatment infrastructure for the energy sector.

Another important finding is that water-system planning models, which generally take a basin-level approach, can provide data on the costs and feasibility of specific options for bulk water supply and infrastructure. Such cost and availability information is explicitly represented in the SATIM-W framework to derive water supply cost curves

[1] A recent study by National Renewable Energy Lab (http://www.nrel.gov/docs/fy15osti/64270.pdf) looked only at power plant water consumption. It estimated water costs from various sources, but did not consider major water infrastructure investments.

pertinent to decisions about energy production. As noted in section 5 of this report, SATIM-W separately calculates the capital, fixed, and variable operating and maintenance costs and energy requirements of each water supply region and every water supply scheme to arrive at the regional cost of supplying water. SATIM-W then weights each water supply and delivery option (or scheme) and chooses the combination that delivers the needed water at the least cost, resulting in a determination of the marginal water supply cost. Thus, the model takes into account the spatial locations of proposed energy technologies and the water-related factors (availability and infrastructure) on which these technologies will depend.

The model generates significantly different energy technology investment results when the cost of water supply infrastructure is taken into account (compared to the case where the costs of supplying water are not considered. For example, dry cooled power plants are selected in water-scarce regions and significant reductions in water consumption are achieved.

The study investigated several policy scenarios specific to South Africa. The results show that specific energy sector policies can have significant implications for new investment in water supply infrastructure and, in some cases, can strand water supply investments (and vice versa), reinforcing the importance of planning the water-energy nexus in an integrated manner. Further development of the SATIM-W model and its application to water and energy planning should be explored in subsequent phases of the World Bank's Thirsty Energy Initiative, which produced this report.

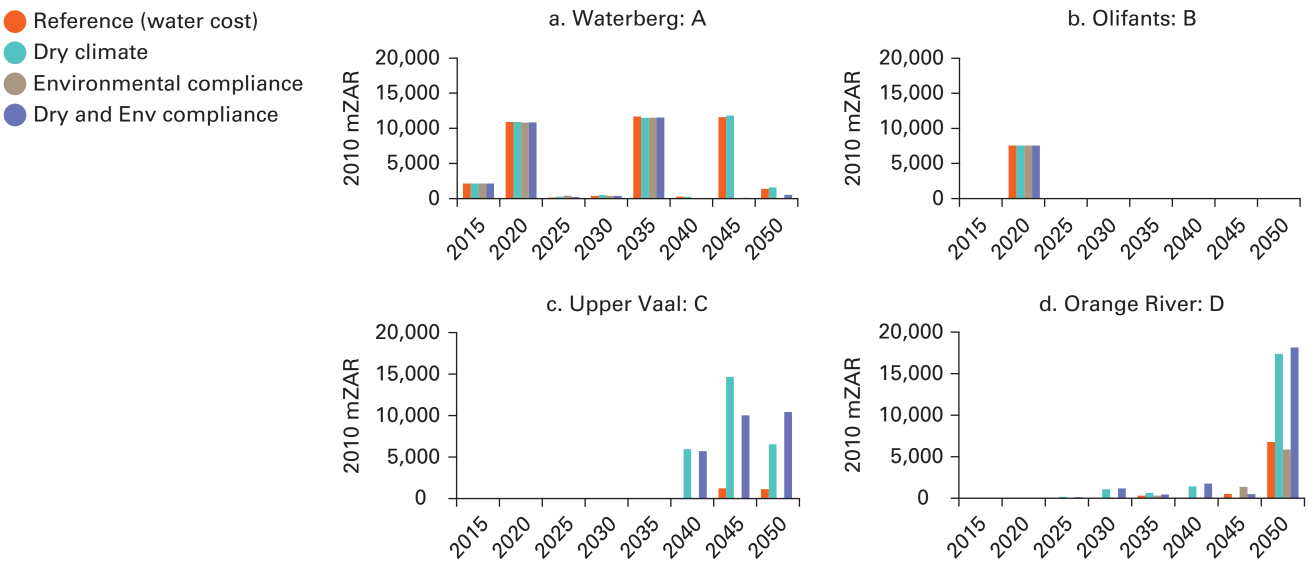
Findings for South Africa

Water for power in South Africa is supported by major interbasin transfers. Water and energy planning must therefore take into account the significant regional variability in water availability and the associated cost of water supply infrastructure. Even though the amount of water consumed by the energy sector is a small percentage of all water used nationally, it has already changed the regional water picture in South Africa—in one region, Waterberg, energy comprises over 40 percent of all water demand.

In addition to demonstrating the benefits of integrated energy and water management planning, this report provides important insights into the costs and benefits of policy scenarios that reflect the uncertainties of water and energy supply in South Africa. These scenarios showcase how SATIM-W can inform energy sector policy making, giving full consideration to the costs of supplying water. In addition, as noted, the study results identify conditions that could result in stranded water or energy assets.

Decisions about South Africa's future energy mix will have significant consequences for water-resource planning. SATIM-W identifies the water needs of the energy sector by region and quantifies the amount and timing of specific investments in water infrastructure needed over time. Virtually all water in South Africa is allocated, and future demands will require new infrastructure to avoid taking water away from existing users or compromising social and ecological sustainability in the relevant catchment.

Figure 7.1 Lump-Sum Investment in New Water Supply Infrastructure in the Four Regions under Four Scenarios



Note: The scenarios are explained in table 6.1.

Figure 7.1 shows the timing of water infrastructure investments in key regions and under several scenarios. Olifants does not show much variation from one scenario to another, but Upper Vaal and Orange River will require significant new investments, particularly under the Dry Climate scenario. An integrated approach to water-energy planning can help to ensure timely investment and delivery of water supply and treatment infrastructure for the energy sector, while also reducing the likelihood of stranding major energy or water assets.

When water costs are not taken into account in energy planning, SATIM-W calls for building wet-cooled coal-fired power plants, generating a 77.34 percent increase in cumulative water consumption for power generation and a 57.87 percent increase in cumulative water needs for the energy sector as a whole. But, given the distance between coal reserves and available water supplies in South Africa, as well as interregional variability in water availability, SATIM-W demonstrates that dry cooling makes economic sense in South Africa once the cost of water supply infrastructure (e.g., inter-basin transfers) is taken into account, *even though dry cooling decreases power plant efficiency*. This finding confirms the soundness of the decision by South Africa's primary utility, Eskom, to employ dry cooling, a decision originally made for environmental and social reasons.

The generation mix is roughly similar for the Reference scenario, whether or not water cost is incorporated.[22] Renewable energy generation contributes less than 10 percent until 2040, and no new nuclear power capacity is built. However, in the reference scenario with water costs the power sector generates 1.3 percent less electricity with coal and 2 percent more with renewable technologies.

The additional investment cost of requiring flue gas desulfurization (FGD) systems at existing coal power plants[33] and new coal-to-liquids (CTL) refineries under two scenarios—Environmental Compliance and Dry Climate + Environmental Compliance—dramatically reduces investment in CTL plants. Under these scenarios, coal-powered capacity declines by 75 percent in 2050 as compared with the Reference scenario. In addition, the FGD requirement leads to earlier retirement of 2 GW of wet-cooled coal power plant capacity by 2030 and reduces investment in new coal plants by 3 to 4 GW in the 2045 and 2050 periods. In the Environmental Compliance scenario, overall water use by the power sector actually increases by just 2.3 percent, as CTL refineries and coal plants are replaced by more than 5 GW of solar photovoltaic (PV) capacity and 1.2 GW of concentrating solar (thermal) power (CSP).

The development of shale gas resources under the Shale Gas scenario significantly increases power generation from natural gas compared with the Reference (Water Cost) scenario. Although significant investment in water supply is required for major shale gas development, the cost of water as represented in SATIM-W does not appear to enter into the decision of whether to invest in shale gas for power generation. The model shows a preference for shale gas generation over generation from wind and CSP—it calls for neither of the latter when shale gas is utilized. In the Shale Gas scenario, cumulative water consumption (2010–15) of the power sector decreases by 14.9 percent as coal power plants are replaced by combined-cycle gas turbine plants. Cumulative water needs for the overall energy sector also drop by 9.76 percent. However, the authors consider this finding preliminary, because the cost of treating return-flow effluent is not yet included in the model for lack of data. This analysis also does not include pollution risks for other water users from shale gas development. A deeper dive into the issues posed by shale gas production is planned.

National climate change policy will have consequences for water-resource and energy planning:

- *The study's two CO_2 Cap scenarios reduce coal consumption and increase renewables from wind, solar PV, and wet-cooled CSP with storage.* These scenarios also defer any new investment in CTL plants. Interestingly, both CO_2 Cap scenarios significantly increase the cumulative water needs of the power sector over the 2010–50 period (increases of 21 percent for the 14 Gt scenario and 25 percent for the 10 Gt scenario) because the model chooses wet-cooled CSP generation. However, the

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[2] The scenarios discussed here are introduced and explained in chapter 6 of the study report.

[3] FGD for new coal plants is part of the Reference scenarios.

overall water needs of the energy sector rise by just 4 percent and 3 percent with lower activity in the coal industry (coal mining, CTLs). In the 10 Gt CO_2 Cap + Dry Climate scenario, some CSP capacity shifts to dry cooling, pushing down water use for power by 10 percent.

- *The CO_2 Cap scenarios have the potential to strand coal assets.* The 14 Gt CO_2 Cap scenario reduces production at the existing CTL plant from 96 percent to 30 percent by 2035, with the plant decommissioned five years earlier than in the Reference scenario. In the 10 Gt CO_2 Cap scenario, production at the plant is completely halted by 2025, 20 years before scheduled decommissioning. Existing and committed coal power plants are less at risk under the 14 Gt CO_2 Cap scenario and remain operational for their entire production life. By contrast, the 10 Gt CO_2 Cap scenario entails early retirement of the existing coal plants and shifts electricity production from the Waterberg to the Orange River region. The stock of existing coal plants is retired by 2035, with idle capacity of 2 GW in 2050 under both CO_2 Cap scenarios.
- *The CO_2 Cap scenarios also have the potential to strand water supply assets.* These scenarios affect the cost of supplying water differentially, by water basin. Investment in coal power plants in the Olifants region appears most at risk under the 10 Gt CO_2 Cap scenario, as such plants cease operation earlier than those located in the Waterberg region. As a consequence, the cost of water in the Olifants region decreases. However, the cost of water in the Waterberg region rises as the water supply system comes to be underutilized owing to the early closure of coal-fired capacity, which effectively increases costs for the remaining users. This suggests that water supply infrastructure for the Waterberg is also at risk of being overbuilt if CO_2 mitigation policy is carried through. However, if water and energy resources are planned in a more integrated manner, this issue could be foreseen and the water could be redirected to other uses.

Planning for a drier climate (owing to climate change) would move investments forward, according to the model. Earlier investments in solar PV increase its capacity by 1 GW in 2050. Approximately 2 GW of new dry-cooled coal capacity are added in the Waterberg region early on, offsetting the retirement of 3 GW of existing coal capacity by 2050. Under the Dry Climate scenario, accelerated investments in solar PV (which requires minimal amounts of water) and in dry cooling for thermal power plant result in a 6.39 percent decrease in water consumption for power generation and a 5 percent decrease in the water needs of the energy sector as a whole. Under this scenario, CO_2 emissions are also reduced by 1.6 percent, suggestion that early mitigation and adaptation policies could make South Africa more resilient to a drier climate.

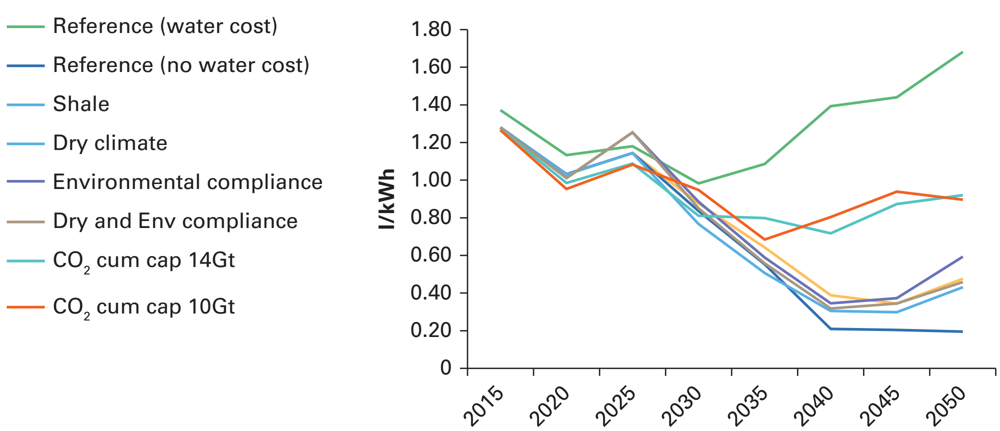
In contrast to coal capacity, wet-cooling is favored for CSP plants under the Reference (Water Cost) scenario. The results from the combination of the CO_2 Cap, Dry Climate, and Shale Gas scenarios suggest why wet-cooled CSP is favored in the Orange River region, despite its general aridity: the region's water supply comes from Lesotho and does not depend on local runoff. That supply, however, is highly dependent on future demands from other users. For example, when the effects of climate change are compounded by the added pressure of shale gas mining in the region, the model calls for a significant shift to dry-cooled CSP as the cost of water rises because of added demand from shale gas producers. In the Dry Climate + CO_2 Cap scenario, the shift to dry-cooled CSP is accompanied by an increase in the cost of water tied to underutilization of infrastructure built largely in response to non-energy needs. Therefore, although the model chooses wet cooling for CSP plants under the Reference scenario, dry-cooling policies may still make sense in order to ensure make the system more resilient to future uncertainty.

South Africa's water supply already demonstrates substantial resilience to regional climate change effects as these are currently understood. Regional water supply disparities that could result from climate change are mitigated by the flexibility of a nationally integrated water supply network. Indeed, most scenarios, with the exception of the 10 Gt CO_2 Cap scenario, result in changes in system cost that are less than 1 percent. At almost 3 percent, the change induced by the 10 Gt CO_2 Cap is a notable outlier. In the context of the study, this finding highlights the potential resilience of the national system, but not necessarily of individual regional systems, particularly those that are not well integrated. In addition, trade-offs between the power sector, urban water supply, and water for agriculture need to be further explored, particularly for the key systems (e.g., the Vaal and Orange River).

As shown in figure 7.2 the water intensity of the power sector under other scenarios is close to the intensity level generated by the Reference scenario with water costs, except in the case of the scenarios based on targets for reducing greenhouse gas (GHG) emissions, where the model favors use of some CSP plants using wet cooling.

Figure 7.2

Water Intensity of the Power Sector under the Scenarios Analyzed



These findings exemplify how integrated and regionally disaggregated water-energy modeling and analysis can better inform decision makers of the potential costs, benefits, and risks of alternative policies and technology choices under a range of possible water and energy conditions. In particular, the analysis demonstrates the importance of identifying a water-smart energy development plan in which infrastructure investment levels and water supply cost are taken fully into consideration. The analysis also demonstrates the possibility of identifying major infrastructure investments that could become stranded by future policy changes, shifting demands, or the relative efficiency of technologies used in different regions of the country, enabling planners to formulate hedging strategies aimed at minimizing the likelihood of such potentially costly and economically suboptimal missteps.

Next Steps

The SATIM-W model described in this report is an important first step toward an integrated approach to water-energy planning, one in which trade-offs, synergies, and opportunities are assessed together. Several different policy regimes were examined, and some limited sensitivity analysis performed. Although this case study captures the main uncertainties needed to prove the concept, institutional and technical follow-on activities have been identified to improve the quality of the results. A workshop is planned to bring energy and water stakeholders from government and the private sector together to review the case study results and discuss appropriate next steps.

Additional work in the following technical areas would improve various aspects of the model and further expand the coverage and insights to be derived from its use. These areas include:

- Harmonizing the growth assumptions driving non-energy water demands and energy demands, which currently come from two different modeling frameworks (SATIM-W and water-use models) that are only broadly internally consistent.
- Examining in more detail the economics of FGD retrofits for existing coal plants. This will require refinements to model the costs of FGD feedstock and disposal and the reduction in plant availability during FGD retrofitting.
- Evaluating the impact on the energy sector of delays in the commissioning of water infrastructure.
- Incorporating into SATIM-W a more detailed and disaggregated representation of non-energy water consumption in order to examine water-reallocation schemes, demand elasticity to cost, and the impact of water-use efficiency and demand side management interventions.
- Incorporating wastewater streams, treatment plants, and related infrastructure from other sectors in addition to coal mining.
- Incorporating into SATIM-W the cost of treatment options and handling of return-flow effluent in connection with shale gas production.

- Linking to an economic model to assess the impact of water-energy trade-offs on the economy as a whole, including the impacts on jobs, gross domestic product, and affordability.
- Linking water to a variety of biofuel feedstocks and other aspects of land use and food production in terms of both water and energy,
- Exploring approaches to incorporating the externality costs of power production, including health and environmental effects and the opportunity costs of water allocation and use.
- Better exploring the potential impacts and associated risks of future climate change.
- Using multiple techniques to examine future uncertainties—among them scenario sensitivity analysis, multi-stage stochastics, and Monte Carlo analysis.

The foregoing results demonstrate the value of the SATIM-W model as a component of an integrated assessment methodology that can better inform decision makers of the potential costs, benefits, and risks of alternative policies and technology choices under a range of possible future conditions. In particular, the results demonstrate the possibility of identifying major investments that could become stranded down the road. Employing an integrated planning approach that looks systematically at the development of both the water and energy sectors could help avoid such costly and unproductive outcomes.

The model's initial applications, as described here, have clearly demonstrated the importance and value of employing an integrated planning platform to ensure that water and energy investments are intelligently planned in a least-cost manner. The comprehensive approach made possible by SATIM-W should be further developed so that it becomes the norm in policy formulation. This will be particularly important as countries determine how their GHG reduction commitments will be realized in a way that contributes directly to achieving related Sustainable Development Goals.

Appendix A

Water Demand in South Africa

Upper Olifants

The Olifants catchment is almost fully utilized (table A.1), with a deficit predicted by 2030 (table A.2), This shortfall will be hastened with the introduction of an ecological reserve (2020–25), which will reduce the water available for abstraction (that is, the process of taking water from a source) by about 200 Mm^3 per year. Power generation now accounts for 23 percent of demand in the Upper Olifants. Despite plans for additional power generation in the catchment, Eskom foresees little growth in total demand because water-cooled power stations will be replaced by dry-cooled plants. Planners expect that after about 2025 water demand for power generation in the catchment may even decrease.

Table A.1 Olifants System Water Requirements, 2010

Management Zone	Irrigation (Mm^3/a)	Domestic and Industrial (Mm^3/a)	Mining (Mm^3/a)	Power Generation (Mm^3/a)	Total Requirements (Mm^3/a)	Total Available resource (Mm^3/a)
Upper Olifants	254	109	21	228	612	618
Middle Olifants	93	39	24	0	156	227
Lower Olifants	161	21	36	0	218	202
Total	508	169	81	228	986	1,047

Source: Aurecon 2011.

Table A.2 Olifants Water Balance, 2030

Management Zone	Total Water Resource (Mm^3/a)	Water Requirement (Mm^3/a)	EWR[a] (Mm^3/a)	Water Balance (Mm^3/a)
Upper Olifants	618	648	80	–110
Middle Olifants	227	214	51	–38
Lower Olifants	202	230	69	–97
Total	1,047	1,092	200	–245

Source: Aurecon 2011.
a. Environmental Water Requirements (EWR): minimum releases to support aquatic ecology.

There exists only limited potential for water resources development to meet the future water supply deficit within the catchment, after which the demand will have to be met by transfers from outside the catchment. The options include:

- Olifants River Dam: To be built in the middle Olifants, near Rooipoort.
- Ekurhuleni effluent: East Rand effluents, treated for phosphate levels, could be pumped into the Olifants.
- Acid mine drainage (AMD) reuse: The acidic water that is being discharged from unused coal mines in the upper Olifants can be treated and reused to meet the water demand in municipalities;
- Vaal Dam imports: Transfers from the Vaal River System to the Upper Olifants are another option; the infrastructure would require a pipeline and pump station
- Desalination: Technically feasible, seawater desalination may be prohibitively expensive
- Transfer from the Zambezi: For this to be feasible from a cost perspective it would need to be part of a scheme that supplied Lephalale and Pretoria as well as the Upper Olifants.

The Ekurhuleni effluent and Vaal Dam options would expedite augmentations to the Vaal. In addition, water yields in the Upper Olifants could increase by 16.1 Mm^3/a if invasive alien plants (IAPs) are eradicated and illegal irrigation suppressed.

Integrated Vaal System

The Integrated Vaal System extends beyond the catchment boundaries of the Vaal River and supplies water to approximately 12 million people, mainly in Gauteng. The system also supplies water for Eskom's coal-fired power stations, Sasol's petrochemical plants in Mpumalanga, and various mines in the North West and Free State provinces. The Waterberg coalfields being developed near the town of Lephalale in the Limpopo water management agency (WMA) (DWAF 2009) will also get their water from the Vaal.

Currently, many of Eskom's coal-fired power stations are supplied with water from the Integrated Vaal System (table A.3). Although Kusile power station is under construction and an additional power station is planned for the Olifants catchment, the water transfers from the Upper Komati and Vaal Systems will be increased to meet the demands of these new power stations and the water balance of the Olifants River system itself will not be affected by these developments. The water supply to the existing coal power stations in the Upper Olifants is estimated at 228 Mm^3/a (Aurecon 2011).

Transfers from the Lesotho, Thukela, Zaaihoek, and Usutu schemes all affect the water quality for the Grootdraai and Vaal dams. Although the water quality of the transfers is currently of an acceptable quality, there is a concern that in the future the quality

Table A.3 Water Abstractions for Vaal System Power Stations

Catchment	Power Station	Water Supply (Mm³)
Komati	Arnot, Hendrina, Komati, Duvha	94
Usutu	Camden, Kriel, Matla	51
Usutu-Vaal	Duvha, Kriel, Tutuka, Matla, Kendel	88
Vaal	Lethabo, Grootvlei	52

Source: Eskom 2012.

of the water in Grootdraai Dam will deteriorate due to AMD water from closed mines and that the salinity will increase from the Vaal Barrage to Bloemhof Dam due to urbanization and mine discharges (DWAF 2009). The water quality assessment showed that Vaal Dam, Vaal Barrage and Bloemhof Dam are eutrophic to hypertrophic, and require significant additional releases of high quality water from the Lesotho Highland Water Project (LHWP) to maintain an acceptable water quality standard.

To meet the increasing water demand driven by development in Gauteng, the Vaal River System was augmented via major inter-basin transfer schemes from higher rainfall areas such as the upper Thukela and Usuthu River and the Orange River in Lesotho via the LHWP. See table A.4 for the water requirements in the Vaal system.

Because the system is already overallocated, augmentation is the only way forward. Options include:

- Treatment and reuse of AMD water: The acidic water that is being discharged from coal mines can be treated and reused to meet water demand;
- LHWP Phase II: Polihali Dam
- Orange-Vaal transfer (Boskraai Dam with phased pipelines)
- Thukela-Vaal transfer: Mielietuin and Jana dams
- Mzimvubu-Vaal transfer
- Zambezi-Vaal transfer, and
- Desalination of seawater.

Table A.4 Vaal System Water Requirements, 2010–30

Major User Group	Annual Water Requirements (Mm^3/a)				
	2010	2015	2020	2025	2030
Rand Water	1,338	1,417	1,481	1,568	1,666
Mittal Steel	17	17	17	17	17
Eskom	381	407	416	417	417
Sasol (Sasolburg)	27	30	33	37	41
Sasol (Secunda)	104	108	112	117	123
Midvaal Water Company	35	35	35	35	35
Sediberg Water	41	41	41	42	43
Other towns and industries	163	167	167	167	168
Vaalharts/lower Vaal irrigation	542	542	542	542	542
Other irrigation	599	500	500	500	500
Wetland/river losses	326	327	329	330	331

Source: Coleman and others 2007.

Lephalale (Waterberg) Area—Crocodile West/Mokolo System

Water demand in the area will leap with the development of the Waterberg coalfields west of Lephalale, the construction of several coal-fired power stations and the establishment of other industrial users such as Sasol. The expected growth in demand is presented in table A.5. Although power generation currently accounts for about 18 percent (or 4.3 Mm^3/year), of overall water demand, by 2030 Eskom's power stations will demand 79 Mm^3/year, with an additional 20 Mm^3/year required for coal mining and 15 Mm^3/year for independent power producers (IPP). This is a total 113 Mm^3/year, or 54 percent of the future demand.

As with developments elsewhere in the region, demand has been stalled by construction delays related to the water-transfer pipeline. See the recalibration of demand for the early period (2009–15) and the extrapolation in appendix C (figure C.3, regional water demands for the aggregated non-energy sectors).

Table A.5 Lephalale System Water Requirements

Major User Group	Annual Water Requirement (Mm³/year)									
	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Eskom	4	4	5	7	9	11	14	51	78	78
IPPs	0.0	0.4	1	1	2	4	13	16	16	16
Coal mining (power generation)	0.0	0.0	1	3	4	5	7	14	20	20
Other mining projects	3	3	4	5	7	9	11	17	16	19
Sasol (Mafutha 1)	0	0	0.4	6	7	10	25	44	45	44
Municipality[a]	5.6	5.9	7.7	8	9	10	10	13	14	14
Subtotal	13	14	19	32	40	53	85	161	194	198
Irrigation	10	10	10	10	10	10	10	10	10	10
Total[b]	23	24	29	42	51	64	95	172	205	208

a. Adapted from Dhemba 2013.
b. Values may differ due to rounding errors.

The available water resources in the area are already over allocated. Future demand will be met, initially, from the underutilized Mokolo Dam and then via transfers from the Crocodile West catchments. Transfers of water from the Crocodile to the Waterberg coalfields will come from the return flows from Gauteng's northern urban and industrial areas (DWA 2010c). The Crocodile West reconciliation study shows, however, that this return flow may be insufficient; impacts on the Reserve and flows to the Limpopo must therefore be considered (DWA 2010c).

- Feasible options for future water supply augmentation to the Lephalale area include:Mokolo-Crocodile Augmentation Project Phase 1: Mokolo Dam;
- Mokolo-Crocodile Augmentation Project Phase 2: Crocodile West;
- Effluent reuse from the Vaal catchment;
- Transfer from Vaal system: from Vaal Dam;
- Zambezi transfer;
- Desalination of seawater.

Orange River System

The Orange River System has a 0.9 million km^2 catchment area and flows west from the Lesotho Highlands to the Atlantic Ocean. The catchment has a west–east rainfall gradient; with mean annual precipitation (MAP) in some areas of the Northern Cape being below 100 mm per annum near the Atlantic coast. In Lesotho some parts of the Orange catchment have MAPs in excess of 1,200 mm per annum (Schulze 2006). The natural runoff for the Orange River basin has been estimated at 11,600 Mm^3/year. The current day runoff that is discharged at the river mouth has been estimated at 5,500 Mm^3/year.

Concentrated solar power (CSP) and the recovery of shale gas will be the principal drivers of future energy and water demand in the Lower Orange catchment. The Orange River water requirements are summarized in table A.6.

Hydraulic fracturing (or fracking) to access the shale gas deposits in the Karoo requires water, and water is scarce in this region, with many towns already facing water shortages. The Orange River (or one of its tributaries) is the nearest large surface-water source. In order to develop a provisional total regional marginal cost (TRMC) for fracking, it has been assumed that water will be obtained from the Gariep Dam and transported to the likely site. The alternative of using local groundwater resources is also considered, although the availability of groundwater is uncertain and requires detailed analysis.

With agriculture and industry both creating higher demand, the Orange River catchment is seeing its water quality deteriorate. The water quality is also dependent on the

Table A.6 Orange River System Water Requirements

Major User Group	Annual Water Requirement (Mm^3/year)			
	2012	2015	2020	2025
Irrigation	2,229	2,284	2,382	2,466
Domestic/urban demand	217	268	288	311
Lesotho Highlands Transfer Katse Dam to Vaal Dam	713	780	780	780
River requirements	615	615	615	615
Operating requirements	180	180	180	180
River mouth environmental requirement	288	288	288	288

source of the water; that is, if the Orange River is the largest contributor to the flow, the turbidity and salinity of the water is usually high and if the Vaal River is the main contributor then nutrient levels increase (DWAF 2009).

Currently the water balance of the Orange River system shows a slight surplus (DWA 2010b). By 2020, however, the system is expected to be in deficit due to expected increases in demands and additional augmentation options will be required. The feasible augmentation options include:

- Boskraai Dam,
- Mzimvubu-Kraai transfer: Ntabelanga Dam, and
- Desalination of seawater.

Appendix B

Energy and South Africa

After decades of cheap electricity due to over-capacity, supply interruptions occurring for a few months in 2008 and restarting with greater intensity in March 2014, have brought energy to the forefront of public debate. This together with public concerns about environmental degradation and the safety of nuclear power, have made energy supply a contested policy arena. Meanwhile, the country struggles with evaluating the many options for creating future supply, while facing immense pressure to grow the economy and alleviate developmental problems wrought by unemployment, poverty, and inequality. Strategic energy-supply planning in South Africa is highly centralized; planning processes are scheduled at stipulated intervals for electricity (Integrated Resource Plan, IRP) and primary energy supply (Integrated Energy Plan, IEP) mandated in law as functions of the Department of Energy (DoE). These processes prompt vigorous public participation and also introduce vast amounts of information into the public sphere not only about how policy is made as a general matter but also the tradeoffs considered in South Africa's unfolding energy landscape. This section summarizes this context for the policy environment where models like South African TIMES model "water smart" (SATIM-W) can be applied.

Resource Supply

The major energy-supply options are described in the subsections that follow.

Coal

Coal is the engine of South Africa's economy, accounting for nearly 70 percent of the country's primary energy supply. It is an important export product at 75 Mt/year and provides 92 percent of the fuel for electricity generation (DoE 2006; IEA 2014). In addition, around 16 percent of domestic liquid fuel demand is produced by Sasol's synthetic coal-to-liquids (CTL) plant at Secunda. Estimates of South Africa's recoverable coal reserves range from 32,000 Mt (Prevost 2014) to 49,000 Mt (SACRM 2013), making them about the world's sixth-largest (SACRM 2013) with a reserve/production ratio of more than 200 years.

In 2012 South Africa's total salable coal production was 258 Mt, of which 76 Mt was exported; Eskom utilized 125 Mt and Sasol 44 Mt, while the remaining 13 Mt was used directly in local industry (including pulp and paper, cement, and iron and steel; Chamber of Mines of South Africa 2013). On top of salable production, a further 25 percent of uneconomical mine product is stored as discard material. Coal discards are largely a byproduct of the export beneficiation process whereby ash content is minimized through mostly water-based washing to improve the calorific value of coal (SACRM 2011).

The water needs for coal mining mainly take the form of water needed to wash the coal prior to delivery to the power plants.

Oil and Gas

In 1965 the South African government agency Soekor undertook exploratory drilling to assess the country's onshore oil and gas resources. Exploration of the inland Karoo region was most active from 1965 to 1975; 24 boreholes were developed, leading to the discovery of shale gas deposits (Vermeulen 2012). Although economically unviable in an era of conventional drilling technology, the deposits may have potential for extraction by hydraulic fracturing (fracking); government and industry have been engaged in protracted negotiations over rights, and reserves are estimated at 17–485 trillion cubic feet (SAOGA 2014; SAPA 2014; US EIA 2013). This broad range reflects the lack of conclusive data from exploratory forays.

Water needs and impacts of oil and gas extraction. Shale gas production requires large amounts of water. Its availability, price and treatment requirements need to be taken into consideration when assessing a potential role for shale gas in South Africa, particularly considering that the Karoo region is an extremely water scarce and ecologically sensitive area supporting a vulnerable marginal agriculture dependent on groundwater (de Wit 2011; WWF 2015). Alternative water sourcing options such as on-site recycling and use of saline water have not been considered in the current analysis, but will be investigated in any follow-on analysis.

Uranium

Uranium is extracted in tandem with gold and copper (World Nuclear Association 2015). Although the quality of the uranium ores is generally low in South Africa, it is cheaply extractable; beneficiation (the recovery of material from low-grade ore) has been sporadic depending on the world market. Eskom procures enriched uranium for its single nuclear power plant Koeberg from the international market (IAEA 2010).

Water needs and impacts of uranium mining. The extraction of uranium is identified as an additional source of water pollution with escalating levels of dissolved uranium in surface waters reported where gold and uranium mining occurs (Winde 2009). Furthermore, gold mining, which is the dominant activity, is another source of acid mine drainage (AMD) and contamination of ground water with heavy metals (Naicker, Cukrowska, and McCarthy 2003). The impact of gold and uranium mining on the quality of water resources requires further study to better inform assessments of the impact of these mining activities with models like SATIM-W. Therefore, the energy and water requirements of uranium mining are grouped with gold mining, as part of industrial energy demand and non-energy water requirements in SATIM-W.

Electricity Sector

Eskom dominates electricity supply in South Africa. Acting as the system operator, Eskom also owns and operates the transmission network and the distribution networks outside those owned and managed by the large cities. Its 27 power stations produce a total nominal capacity of 41.9 GW, of which 85 percent is coal-fired. The balance of capacity is provided by nuclear, open-cycle gas turbine (OCGT), hydro, and pumped-storage power plants (Eskom 2013). In an attempt to address energy diversification, environmental degradation, and economic growth, the DoE is examining nuclear, gas, and renewables as alternatives through the legislated planning processes of the IEP and IRP; these processes are bolstered by wide-ranging ministerial powers that include the scope to determine the future generation mix. Eskom retails directly to consumers and municipal distributors. More recently, as a monopolistic retailer, Eskom is obliged to purchase from a growing pool of independent power producers (IPPs). The DoE determines the purchase price through a competitive bidding process independent of Eskom.

The granting of independent power-generation licenses by public procurement process has become a feature of electricity policy. Three rounds of the Renewable Energy Independent Power Producer Program (REIPPP) have been awarded, and a fourth is underway. Projects arising from rounds 1 and 2 are already generating electricity (see table 2.2). Procurement processes with predefined capacity targets are underway for independent, fossil fueled and nuclear power plants (nuclear is more controversial); nuclear vendor offerings have been reviewed by the DoE (GCIS 2015). The first respondents to the DoE's coal IPP Request for Proposals have passed the environmental approval stage (see II-2, above).

South Africa's procurement policy for generation capacity can be found in the 2010 IRP. This takes the form of the "Policy Adjusted Scenario" (which is based on the results of modeling using a similar least-cost optimization systems model to SATIM) that maps out the capacity required to meet assumed demand to 2030. A decision was made to impose 9.6 GW of nuclear capacity as a fixed assumption with the first 1.6 GW of capacity to come online in 2023. The IRP explains that this assumption was "to account for the uncertainties associated with the costs of renewables and fuels" and to "provide acceptable assurance of security of supply in the event of a peak oil-type increase in fuel prices and ensure that sufficient dispatchable baseload capacity is constructed to meet demand in peak hours each year" (DoE 2011).

Three coastal sites for future nuclear plants, Banatamsklip and Duinefontein in the Western Cape and Thyspunt in the Eastern Cape have been identified thus far, and they have undergone Environmental Impact Assessments (Van Wyk 2013; World Nuclear Association 2015). It can be assumed that plants here would use seawater cooling as is the case with Koeberg.

Further complicating the policy landscape of future energy supply sources is the growth in distributed generation; the National Energy Regulator (NERSA) is drafting the regulatory rules for Small-Scale Embedded Generation (NERSA 2015a). The Small-Scale Embedded Generation Programme (SSEG) of the City of Cape Town is now buying power fed to the grid, while total rooftop photovoltaics (PV) capacity in South Africa increased from 10 MW in 2014 to over 30 MW in March 2015 (Donnelly 2015).

Water Needs of the Power Sector

On average in South Africa, 1 kWh of electricity consumes about 1.4 liters of water (Eskom 2011). The world average is 1.2–1.5 liters/kWh (UN WWAP 2014). Furthermore, water demands from the predominantly wet-cooled closed loop thermal power plant fleet are somewhat below the typical mean intensity of 1.7 liters/kWh reported by National Renewable Energy Laboratory (NREL) for subcritical coal power plants cooled with wet-recirculating systems (Macknick and others 2011). Water consumption and other metrics for existing power stations are detailed in "Coal mine wastewater treatment" section in appendix G.

Coal-Fired Power Plants

The country's fleet of large coal-fired power plants utilizes a mix of dry-cooling and closed-cycle wet-cooling. Including the dry-cooled units of the Majuba and Groovlei plants, which have both wet- and dry-cooled units, the existing net capacity of dry-cooled units is approximately 9,700 MW. This accounts for about 30 percent of Eskom's coal plant stock. The commissioning of the Medupi and Kusile plants would increase the contribution of dry-cooled net capacity to ca. 18,000 MW, approaching 50 percent of Eskom's coal-based capacity. As in the case of the Kusile and Medupi plants, all new power plants are to feature supercritical design (Eskom 2011).

Renewable Energy Plants

The country possesses considerable potential for solar energy in the arid north; the coastline has favorable wind resources (Fluri 2009; Hagemann 2008). As a result, the commissioning of utility-scale plants that rely on concentrated solar power (CSP), PV, and wind power have emerged as alternatives to coal. The arid Northern Cape Province offers the highest potential for utility-scale CSP generation, estimated at 500 GW in total (Fluri 2009), after considering available sunshine, proximity to transmission lines, terrain, vegetation, and land use. Thus, the challenge for solar power (and CSP in particular) is no different in South Africa than elsewhere: The best locations are far from water and transmission infrastructure. These are not insurmountable barriers, however, as we can see from our analysis here and from the plans under consideration. For a scenario with high nuclear costs, the as-yet unapproved IRP (DoE 2013) projected a maximum CSP capacity of close to 40 GW by 2045.

South Africa's REIPPP aims to reduce the country's dependence on coal by allocating up to 19 GW in capacity to renewable-energy generation by 2030 (DoE 2013). Of a potential allocation of 3.3 GW of CSP capacity by 2030, a total of 400 MW has been allocated in the recent, third round of the program's bidding process. Of this pool, 200 MW of CSP has already been commissioned, though it is not yet operational. The 200 MW of CSP commits to build three plants in the Northern Cape, including

150 MW of parabolic trough (KaXu), 50 MW central receiver (Khi), and 50 MW of parabolic trough (Bokpoort). For these dry-cooled plants, water is needed for mirror washing; boiler makeup water is estimated at 20 percent of the total requirement for water.

Gas-Fired Plants

The power sector is a potential strategic consumer of gas in the future as part of the move away from coal. Existing and future generation technologies include both open- and combined-cycle gas turbine (OCGT and CCGT) plants. Gas can be sourced in a number of ways, including the inland import of gas from Mozambique, coastal imported liquefied natural gas (LNG), and indigenous shale gas in the event fracking proceeds. Although not yet approved, the IRP's big gas scenario suggests nearly 70 GW of gas-based generation capacity by 2050 could be achieved given that shale could drive the price of natural gas down to R50/GJ by 2035, with supply boosted by regional conventional sources (DoE 2013).

Nuclear Plants

South Africa has one nuclear power plant, producing 1.8 GW, in Koeberg, about 30 km north of Cape Town. Koeberg employs once-through seawater cooling for its two pressurized water reactors. Owing to the current practice of exporting domestic uranium ore and importing processed fuel rods, uranium extraction is essentially decoupled from the domestic energy supply sector. The demand for uranium in SATIM-W is that of processed fuel rods and does not reflect local mining activity. Therefore, as noted above, the energy and water requirements of uranium mining are grouped with gold mining as part of industrial energy demand and non-energy water requirements in SATIM-W.

Refining of Liquid Fuels

Liquid fuel production in South Africa involves six domestic refineries, four conventional and two synthetic fuel (synfuel) plants:

- Three coastal conventional crude oil refineries: Sapref, Enref, Chevref
- One inland conventional crude oil refinery: Natref
- One coastal synthetic gas-to-liquids refinery: PetroSA (reduced gas supply has necessitated supplementary light crude distillate feedstock)
- One inland synthetic CTL refinery: Sasol-Secunda.

The coastal crude refineries are grouped together in SATIM-W because they have similar product slates and operating inputs. Diesel and kerosene dominate the product slate of the inland crude refinery; gasoline that of the two synthetic refineries a gasoline heavy slate. For that reason, they are characterized separately in SATIM-W. Synthetic fuel refining plants can use either the coal or natural gas resource discussed above. These plants include numerous discrete chemical-processing units operating in close interaction and requiring both ancillary energy and water services. The resulting products are energy, water, and emissions intensive, particularly in the case of CTL refining. However, because no South African refinery uses once-through cooling, oil refining in South Africa is, on average, relatively water efficient in global terms (Pearce and Whyte 2005), although the synthetic refineries are considerably more water intensive. Table B.1 shows the relative production and water intensity of South Africa's liquid fuels refineries.

South Africa's first CTL plant, or Sasol 1, was fully operational in the mid-1950s. In the wake of the 1973 oil crisis, the country commissioned Sasol 2, followed by Sasol 3 in 1983 with rising crude oil prices. Located in the Upper Vaal, Sasol 1 was converted to non-energy chemical production from natural gas feedstock and is

Table B.1 Relative Output and Water Intensity of South African Liquid Fuels Refineries

Refinery Name	Location	Typical Feedstock Intake (toe/month)	Typical Annual Production (TJ)	Specific Water Intake (SWI) (m^3/toe intake)	Specific Water Intake (m^3/TJ product out)	Specific Water Intake, Excluding Wastewater Recycling (m^3/TJ Product Out)
SAPREF	Durban	668,000	330,000	0.59	14	9[a]
ENREF[b]	Durban	412,500	204,000	0.51–0.67	13–17	—
CHEVREF[b]	Cape Town	389,500	192,000	0.51–0.67	13–17	1.3–5.3[c]
Natref[b]	Sasolburg	341,000	203,000	0.6	12	—
PetroSA GTL[b]	Mossel Bay	154,000	58,000	2.9	92	—
Sasol CTL[d]	Secunda	655,000	236,000	8.6	394	—

a. Assumes 1900 Ml of 4750 Ml total annual water consumption is reclaimed water from waste water treatment facility (SAPREF 2011).
b. SA Crude refinery range from Pearce and Whyte 2005, adjusted down by 5.7 Ml/day supplied from Potsdam municipal sewage treatment works (Engineering News 2006). Actual water intake is likely to be at the low end of the range because wastewater is reported to supply all refinery process needs (Chevron 2015).
c. SWI estimated from (Pearce and Whyte 2005).
d. SWI assumes 255 Ml/day intake to Sasol Secunda (DWAF 2009).

therefore included in the Industry sector and not represented in the SATIM-W supply sector. Sasol 2 and Sasol 3 in Secunda are the country's remaining CTL plants. The Secunda plants rely on coal feedstock, supplemented with natural gas; plant design limits the share of gas. In 2006, the total CTL production capacity in South Africa was approximately 125,000 barrels of oil equivalent per day, or roughly 246 petajoules (PJ) per annum. Of the total output, 93 percent is used for liquid fuels. Although located in Secunda, in the Upper Vaal water management agency (WMA) (Region C), water supply for the CTL refineries is sourced from the Upper Olifants.

In 2006 the PetroSA plant in Mossel Bay had a GTL production capacity of approximately 45,000 barrels per day, or around 60 PJ per annum. By 2011 production decreased to around 45 PJ per annum owing to declines in indigenous gas production. The PetroSA refinery is on the coast and uses reaction and cooling water from the Wolwedans Dam, discharging treated effluent through an ocean outfall pipe. The plant does not use seawater for cooling, other than in times of drought when it can be supplied by an auxiliary desalination plant (Cloete 2015).

Air Emissions from South Africa's Coal-Intensive Energy Supply

South Africa's coal-intensive electricity generation and synthetic liquid fuels production have high environmental and health externalities that taint their economic and energy security benefits. This analysis does not report on the local air pollutants from coal use, although it examines the impacts brought by flue gas desulfurization (FGD) systems. The study reports on Greenhouse Gas (GHG) emissions given their importance to potential future policy decisions. In 2010 national GHG emissions were estimated to be on the order of 500 million tons (Mt) of carbon dioxide equivalent (CO_2 eq.). Coal-based electricity generation directly contributed 60 percent to the total, while CTL synfuel production contributed 5 percent (DEA 2013c). The release of CO_2 owing to the spontaneous combustion of discarded coal stores, in addition to methane (CH_4) released through coal extraction, add another 1 percent to the national GHG inventory (Cook 2013). fuel combustion alone, CO_2 emissions made South Africa the 18th-highest emitter worldwide in 2010 (IEA 2012).

In 2010 South Africa's per capita fuel combustion CO_2 emissions of 6.94 tons/capita placed lower, at 40th in the world; by comparison the United States and Australia emitted over 17 tons/capita (IEA 2012). South Africa was, however, ranked the 15th most carbon-intensive economy in the world, emitting 0.73 kg CO_2/USD(2005) gross domestic product (GDP) purchasing power parity. The global average was 0.4. This ranking reflects continued dominance of exports by energy-intensive sectors, in particular mining and metals processing. The coal-intensive energy supply furthermore results in comparatively high emissions of particulate matter, oxides of nitrogen (NO_x), oxides of sulfur (SO_x—predominantly SO_2) although South African coal on average exhibits relatively low sulfur content (<1 percent).

Appendix C

Future Climate Change Impacts

With respect to climate change, Sub-Saharan Africa is thought to be one of the more vulnerable regions in the world. Although there is general agreement that temperatures will continue to rise, uncertainty remains about precipitation trends. Four possible scenarios have been identified by the Long-Term Adaptation Scenarios (LTAS) developed by the flagship research program of the Department of Environmental Affairs (DEA 2013a):

- Warmer (<3˚C above temperatures for 1961–2000) and wetter, with more frequent and extreme rainfall
- Warmer (<3˚C above temperatures for 1961–2000) and drier, with increasingly frequent drought and somewhat more frequent extreme rainfall
- Hotter (>3˚C above temperatures for 1961–2000) and wetter, with much more frequent extreme rainfall
- Hotter (<3˚C above temperatures for 1961–2000) and drier, with substantial increases in drought and somewhat greater frequency of extreme rainfall.

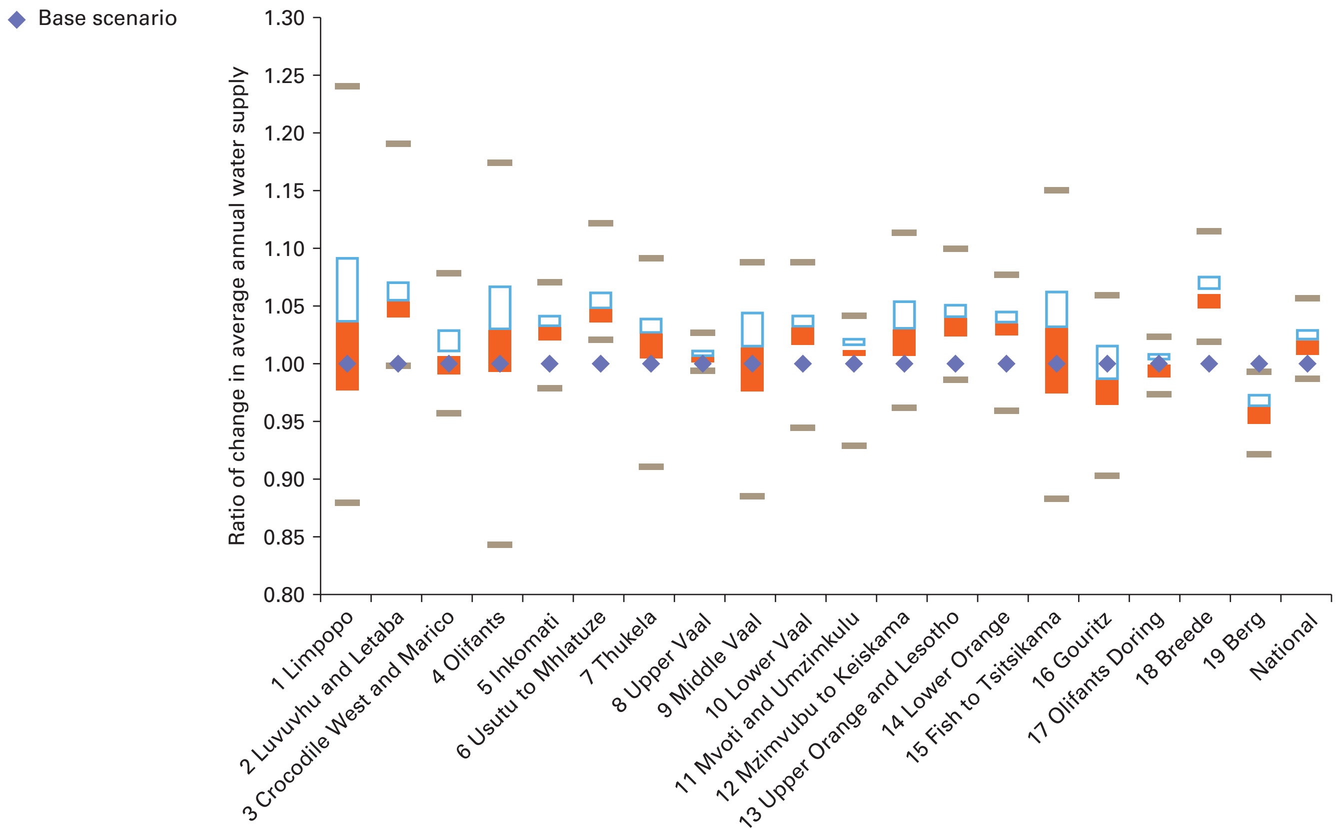
The LTAS concluded that temperatures will continue to rise, but the level of increase would be dependent on the outcomes from global mitigation efforts. Under a business-as-usual scenario, South Africa faces a hotter future, with average increases of >3˚C by the end of the 21st century. In the event of improved global cooperation, then significant reductions in Greenhouse gases (GHGs) will mean merely a warmer future for South Africa. For both scenarios, potential impacts would affect all regions; inland areas would experience greater increases than coastal zones and the mountains.

Under both the "hotter" and "warmer" futures, precipitation remains the great unknown, although it was generally agreed that variability would increase under both scenarios; the hotter scenario would bring greater variability. Precipitation and its impacts would vary across regions.

Water Supply

The LTAS studied the biophysical impacts across a range of climate futures, using a rainfall runoff model at a quaternary scale. Also of use was a water-resources yield model configured at a secondary-catchment scale for all of South Africa, including the major water-supply infrastructure, dams, and Interbasin transfers (IBTs) (DEA 2014). These national models were used to investigate the potential impacts on water supply to the urban, industry and agriculture sectors in each water management agency (WMA), and they were used to contribute to an Integrated Assessment Model (x) assessing the potential economic impacts of climate change at a national scale and at the level of individual WMAs. This study found that South Africa national water supply system, highly integrated as a result of its IBTs and designed to deal

Figure C.1 Impacts of Climate Change on Average Annual Water Supply, by Water Management Area



Source: Cullis et al. 2015
Note: The boxes in this graph represent the upper and lower quartiles and the rectangles represent the maximum and minimum value from all model scenarios.

with highly variable conditions, appears to be resilient even in the face of climate change. There will likely be a cost, however, in greater pumping rates and negative impacts on environmental flow requirements (DEA 2013a). The LTAS shows the potential impacts of climate change on the average annual water supply for each of the 19 WMAs (figure C.1).

Figure A.2 (see appendix A, showing the Orange River system) shows both the ratio of change in the average annual water supply from 2040 to 2050 for each WMA and the total for South Africa. A range of possible climate futures is presented under the unconstrained emissions scenario (UCE). On average, the results show the potential for slight increases in total water supply (+2.3 percent) by 2050 and a range of impacts on different WMAs. For example, all scenarios show a likely reduction in the average annual water supply to Cape Town, part of the Berg WMA (WMA 19).

Water supply to Gauteng (WMA 3 and 8) is not significantly impacted by climate change, primarily as a result of the integrated nature of the Vaal system, as well as the increase in supply as a result of the construction of the Polihali Dam in Lesotho. In short, the economic model found climate change had only a limited impact on the national economy through the water sector (DEA 2014).

It is important to note that the above results are based on a national-scale analysis, although results are presented at the secondary-catchment and WMA levels. This analysis simplified the water-supply infrastructure and other local impacts on precipitation, catchment runoff, and water supply. The analysis used time-series simulations to model impacts on the average annual supply; it did not consider the effects of particular occurrences during critical periods nor the potential for more frequent droughts or extreme events. More specific results in selected WMAs or catchments would require more detailed water-supply models, as well as stochastic analysis of alternative baseline and future scenarios.

Coal-Fired Power Stations

Coal-fired power stations would likely be built in catchments A (Limpopo), B (Olifants) and C (Vaal). Although there is uncertainty regarding the average annual runoff by 2050, these catchments can anticipate median impacts ranging from no change to small increases.

Future concentrated solar power (CSP) plants will be located in the Orange River basin (D). There, the median impact of only 5 percent reduction in catchment runoff will be complicated by a range of potential impacts that in some areas will bring as much as 50 percent reductions.

Irrigation Demand

While there is a wide range of uncertainty regarding the impacts of climate change on precipitation and catchment runoff across the country, the consensus is that higher temperatures will almost certainly mean more evaporation (and thus more irrigation) across all regions of the country.

In the UCE scenario, average median increases in evaporation (at 6.4 ± 1.9 percent) are predicted across secondary catchments. Some wet scenarios show small reductions in irrigation from the Limpopo (A), Olifants (B), Vaal (C) and Orange (D) catchments; dry scenarios show average annual irrigation increasing by 25 percent.

Hydropower Potential

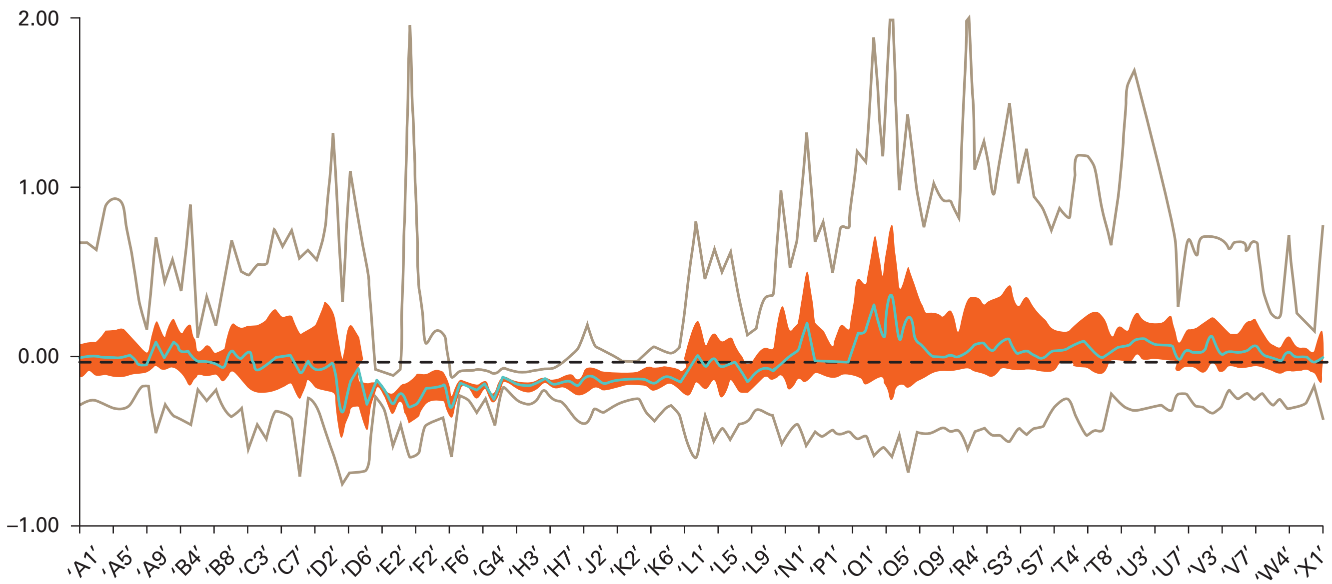
Hydropower does not play a major role in the country's energy production. Although reduced hydropower production at existing stations is a possibility; more hydropower could be gained by retrofitting existing dams where models predict more rain and run-off (DEA 2014). This latter scenario should be investigated further. Another major source of hydropower is from outside of South Africa where the potential impacts of climate change, particularly on the flow in the Zambezi River, should also be considered as this provides a potential large renewable energy source for South Africa.

Summarizing, climate change will likely reduce the availability of water and increase its relative cost given competing needs, and likely increases from other users, particularly agriculture. However, the Department of Water and Sanitation (DWS) has a range of potential water supply augmentation options available in order to meet future increases in demand. Given the importance of power production to the country, if there is a reduction in the available yield from existing water sources due to climate change, South Africa will likely see the implementation of alternative, more expensive water supply augmentation options, as well as higher unit costs of these schemes as they will deliver less water at the same price.

Catchment Runoff

Regional climate modeling of possible climate futures to assess t impact on the average annual runoff for different catchments across the country is summarized in figure C.2. The results show impacts of the unconstrained scenario from 2040 to 2050 for secondary catchments, indicated by the horizontal axis. A reduced streamflow is shown for the western half of the country (D to K) and in particular the catchments of the southwestern Cape (F, G, and H), where all the climate models show reduced streamflows. In contrast, large increases in runoff are possible for the east coast (Q to W), which could result in greater flooding.

Figure C.2 Climate Change Impacts on Runoff, by Catchment, 2040–50: The Unconstrained Scenario



Source: Cullis et al. 2015.
Note: The range of potential impacts of climate change on the average annual catchment runoff for all secondary catchments owing to the unconstrained emission scenarios relative to the base scenario is shown. The solid line indicates the median impact of all the climate scenarios. Shading and solid lines represent the range of potential impacts. The dashed line indicates a reduction of approximately 3.6% in the median impact on the average annual precipitation for all secondary catchments across the country.

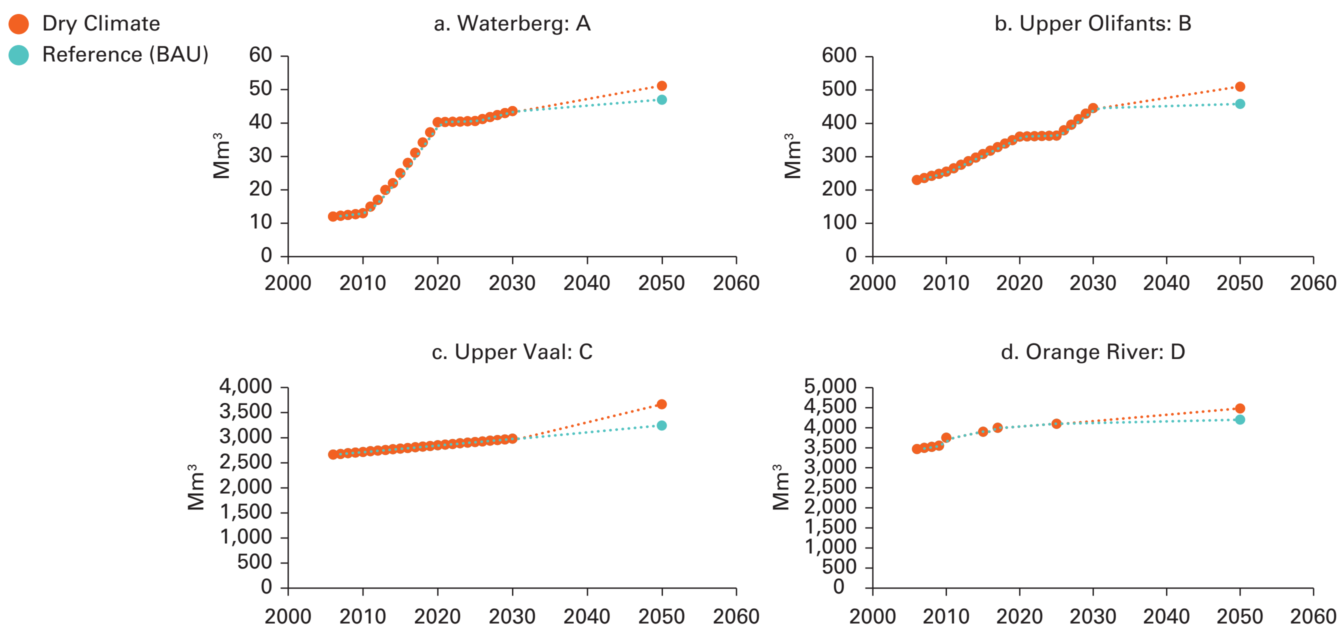
Representing the Water Demands of the Non-Energy Sectors in SATIM-W

The information pertaining to regional water demand as previously detailed is adapted for inclusion in the South African TIMES model "water smart" (SATIM-W) model as follows:

- The energy sector components (e.g., coal mines, refineries, power plants, etc.) are subtracted as these are incorporated directly in SATIM-W; and
- The remaining data is extrapolated and adjusted to approximate suggested values for the year 2050 (DWA 2010a).

Figure C.3 depicts regional water demands for the aggregated non-energy sectors (the Reference and Dry Climate scenarios), as seen in SATIM-W. The assumptions for the Dry Climate Scenario for SATIM for water supply and demand is discussed in Appendix D: Scenario Development and Key Assumptions.

Figure C.3 Regional Water Demands for the Aggregated Non-Energy Sectors (Reference and Dry Climate Scenarios)



Source: Adapted from Aurecon 2011; Coleman et al. 2007; Cullis et al. 2014; DWA 2010a, 2010b, and 2010c; and DWAF 2013.

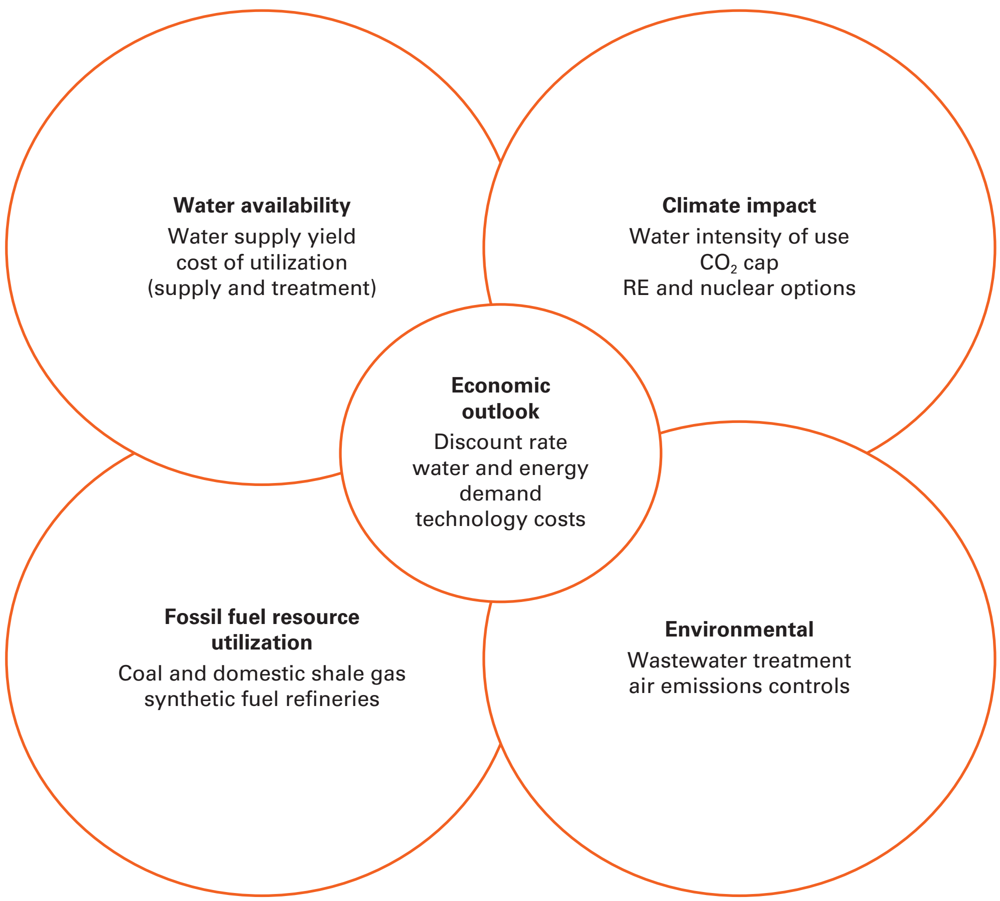
Appendix D

Scenario Development and Key Assumptions

The South African TIMES "water smart" (SATIM-W) model was used to examine the choice of future energy supply technologies in a water-constrained landscape. Figure D.1 illustrates the intersecting dimensions that affect policy for the water-energy sectors. In this section we look at different scenarios for policy and investment strategies to help gain insights into the South Africa energy sector. Outcomes are then compared with the Reference scenario (Water Cost) in an effort to evaluate the costs and benefits of different policy options, and their possible impacts.

Policy themes are collated into five cases that highlight the main drivers of investment uncertainty in water and energy supply. The scenarios developed to frame the

Figure D.1 Scenarios Exploring the Water-Energy Nexus



South African water-energy dialogue for each of these themes are summarized in table 6.1 and discussed below.

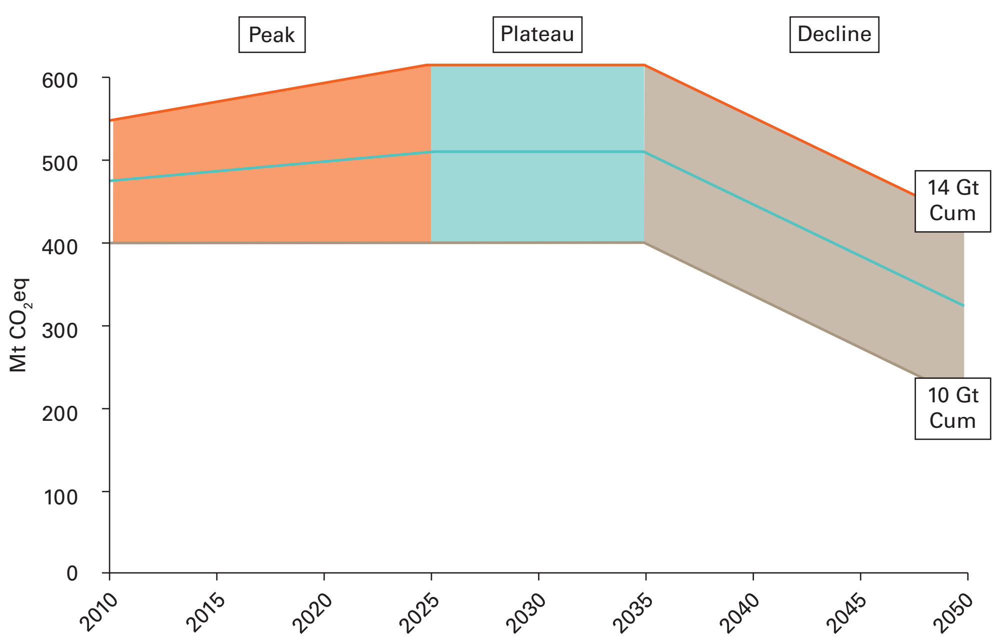
Scenarios

Greenhouse Gas Mitigation

In December 2015 at the Conference of Parties of the United Nations Framework Convention on Climate Change (UNFCCC), South Africa committed to an emissions pathway termed peak-plateau-decline (PPD), which is the country's Intended Nationally Determined Contribution (INDC) to this world body. This commitment was modeled as the imposition of carbon budgets limiting cumulative national Greenhouse gas (GHG) emissions to 14 Gt by 2050. A more restrictive budget of 10 Gt, which is indicative of South Africa's contribution to limit the global temperature increase to 2°C, was also examined (see figure D.2).

Figure D.2

Peak-Plateau-Decline (PPD) Emissions Trajectory for South Africa



Source: National Business Initiative.

Table D.1 Climate Impacts on Water Supply and Demand in 2050 Applied in SATIM-W

WMA	SATIM-W WSR	Dry Climate (*percent*)	
		Water supply	Water demand
Limpopo (Waterberg)	A	–2.0	8.9
Upper Olifants	B	–0.5	11.4
Upper Vaal	C	0.4	13.0
Orange	D	2.8	6.7

Dry Climate Scenario

As explained in Annex C, Climate change will stress South Africa's water supply and demand across regions and table D.1 summarizes the assumptions that SATIM takes into account for the "Dry Climate Scenario" for water supply and demand. These are modeled for the four regions of interest, utilizing the 0.25 percent estimates from the long-term adaptation scenarios (LTAS) (see appendix C). A sensitivity analysis was done for the water stress scenario to help identify possible risks or necessary alternative decisions relative to the energy sector. In the model, changes in supply and demand as outlined below are applied from 2030. This scenario is not an exhaustive exploration of climate change impacts. It does intend, however, to analyze the effects of a potential drier climate.

Shale Gas Scenario

Explored in this scenario is the role shale gas might play in the supply of primary energy, and the consequent improvement of South Africa's energy security and diversification. Although not yet comprehensively surveyed, recoverable shale gas reserves in the Karoo region are estimated at 30 trillion cubic feet (Tcf) of potential reserves by the Petroleum Agency of South Africa (SAOGA 2014) and as much as 390 Tcf of unproved technically recoverable resources by the US Energy Information Administration (US EIA 2013), with the latest public figure at 36 Tcf (Peyper 2015). This study limits shale gas extraction to 40 Tcf.

Environmental Compliance Scenario

This scenario examines recent legislative amendments requiring stricter air emissions controls for power plants, along with best practices in water management for coal mines.

At present, water management best-practices are only applied to coal mining. A similar approach to shale-gas mining will be included in the next phase, examining the processing and disposal of produced water.

Power plant emissions controls have focused on reducing flue stack emissions of particulate matter (Singleton 2010). Recent legislation to improve local air quality includes restrictions on combustion byproducts. Of particular concern is the emission of sulfur dioxide (SO_2) owing to its high concentration in flue gas and its deleterious effects on the environment and public health.

The legislative provisions relevant to coal thermal power plants are summarized in table D.2.

Existing power plants had been expected to comply with the new emissions standards by 2015; new plants will have to comply by 2020. A petition to the government has, however, postponed the application to most of the existing fleet of coal plants (SAOGA 2014). SATIM-W includes flue gas desulfurization (FGD) for new power stations; the Environmental Compliance scenario (ENV) applies the minimum emissions standards to existing power plants. To date, none of the existing plants have FGD retrofits, and in light of the delay, the ENV is applied only in 2025.

Table D.2 Air Emission Standards Applicable to Electricity Generation in South Africa

National Environmental Management: Air Quality Act No. 39, 2004

Solid fuels combustion installations used primarily for steam raising or electricity generation

Pollutant	Existing plant	New plant
Particulate matter (PM)	100	50
Sulfur dioxide (SO_2)	3,500	500
Oxides of nitrogen (NO_x)	1,100	750

Note: All installations with design capacity equal to or greater than 50 MW heat input per unit, based on the lower calorific value of the fuel used.

In addition to FGDs' cost and water requirements, the ENV inflates the cost of coal production to reflect the management of mine water. A cost of 3 ZAR/ton of coal with an electricity requirement of 3 kWh/m^3 is estimated.

Water Quality

Preliminary analysis of water quality is limited to the Waterberg (Region A) and is based on Eskom's analysis of water from the Crocodile River for demineralized water production (Eskom 2008). Furthermore, water quality remains constant over the planning period.

The question of whether available water resources will limit futureenergy-supply choices in South Africa depends on the policy decisions made for an uncertain future. The selected model scenarios serve to inform such policy dialogue by highlighting key areas of focus and the factors that may affect future policy decisions.

Key Assumptions

Expectations for exogenous growth over the planning period are shown in figure D.3, and they assume a national average gross domestic product (GDP) growth rate of 3.1 percent per annum. The tertiary sector, which relies predominately on electricity, is expected to be the main driver of economic growth. The transport sector, which consumes the bulk of liquid fuels is expected to grow fourfold.[1]

In this study, GDP was projected to grow at an annual average rate of 3.3 percent, with the relative share of the primary, secondary, and tertiary sectors changing little over time.

Table D.3 lists the prices in the model for primary commodities.

[1] It is important to note that at present there is high demand for diesel from OCGT plants, which are utilized at mid-merit capacity to assist with the current deficit in electricity capacity.

Figure D.3 GDP Growth Assumptions by Sector

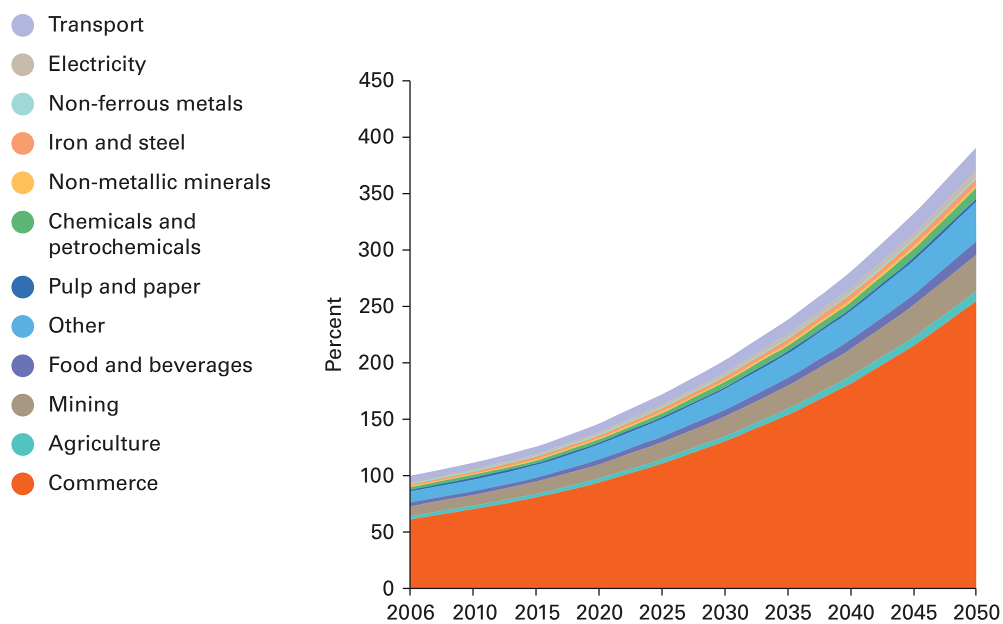


Table D.3 Primary Commodity Prices in SATIM-W

Commodity prices	**Units**	**2015**	**2030**	**2050**
Coal region A (existing)	ZAR/t[c]	126	176	176
Coal region A (new)	ZAR/t[1]	—	360	360
Coal region B/C (existing-1)[a]	ZAR/t[1]	179	248	248
Coal region B/C (existing-2)[b]	ZAR/t[1]	473	611	611
Coal region B/C (new)	ZAR/t[1]	—	588	588
Shale gas extraction	ZAR/GJ	—	51	51
Crude oil	ZAR/GJ	108	134	145
Import diesel	ZAR/GJ	129	162	175
Import petrol	ZAR/GJ	134	170	183

Source: 2010 ZAR.
a. Tier1: Eskom product only.
b. Tier2: Dual product mine linked to Eskom.
c. Assuming a calorific value of 21 MJ/kg.

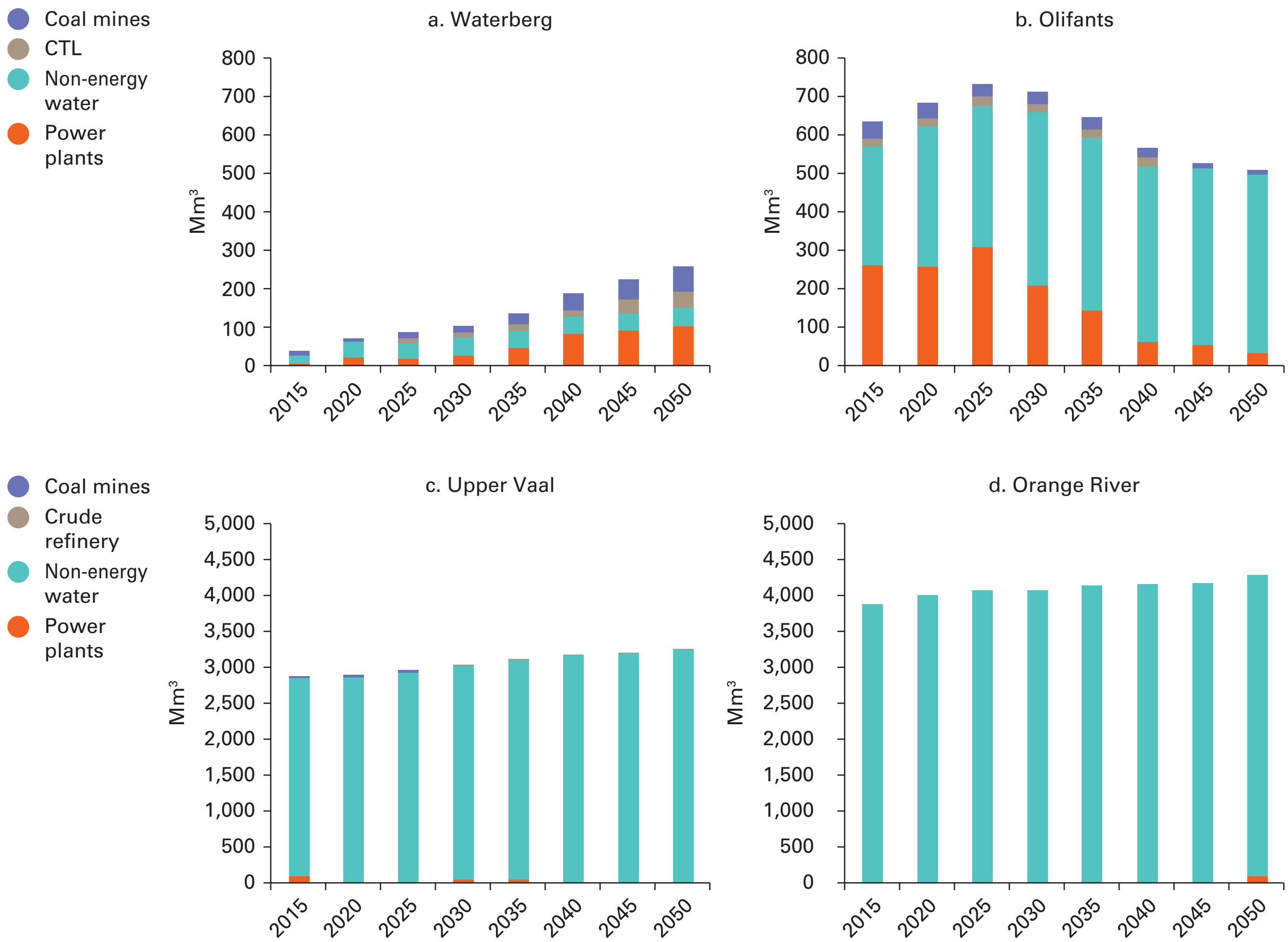
Appendix E

Detailed Modeling Results

As shown in figure E.1, demand from the non-energy sectors is the main driver of new infrastructure for water supply (that is, with the exception of the Waterberg region). The demands of the energy-supply sectors are dwarfed by the demand for water in the Orange and Upper Vaal regions, largely because of agricultural activity in the Orange River and the expected growth in domestic and industrial demand in the Upper Vaal.

The (Upper) Olifants is the sole region to experience a decline in water demand because the existing wet-cooled power plants are predominately located in that region, and their retirement is responsible for the reduction in demand. Agricultural demand

Figure E.1 Regional Water Demands by Supply Sector



dominates in the region, accounting for approximately 50 percent of the total water requirement; household and industrial demand is 30 percent of the total. A small portion of the decline in water demand from the energy supply sector is due to the retirement of the existing coal-to-liquids (CTL) facility, and a migration of coal mining to the Waterberg from the period 2030–35 as less-economic coal deposits are abandoned in the Olifants and Upper Vaal in favor of Waterberg coal.

The water requirements in the Upper Vaal for energy supply are less than 1 percent of the total. The two existing coal plants will be retired between 2040 and 2045. In addition, the country's sole inland crude oil refinery consumes 0.65 Mm^3/year, or 0.02 percent of the total water demand predicted through 2050.

As discussed above, the Orange River region will add 10 GW of wet-cooled Concentrating solar power (CSP) capacity by 2050. The additional wet-cooled capacity will call for less than 3 percent of the total regional water supply.

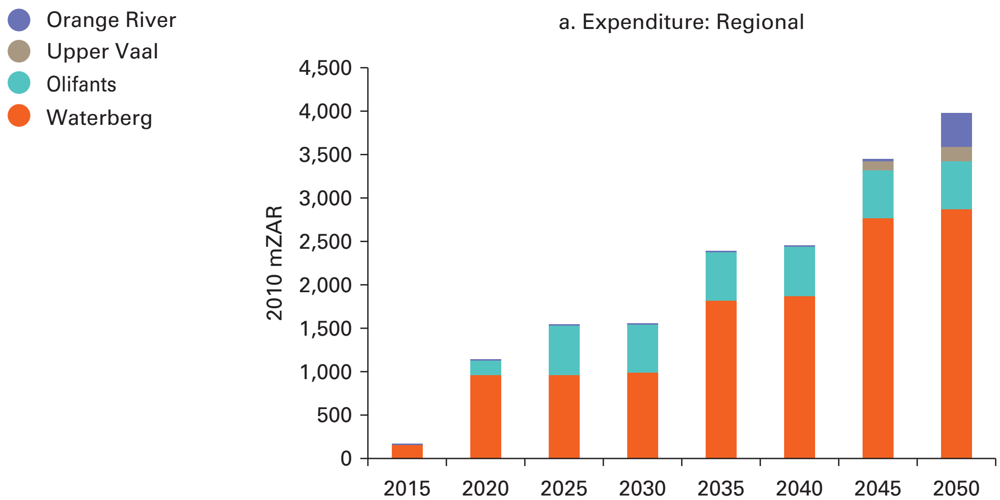
In contrast, more than 80 percent of future water supply to the Waterberg is attributed to the energy-supply sector. Power generation accounts for 40 percent of this total. New CTL plants in the region would consume close to 20 percent of the water supply, while coal mines that use wet-beneficiation would total 25 percent. Water demand in the Waterberg will spike due to continued demand for coal and the construction of new coal plants. Dry-cooled plants will curtail demand, as previously discussed, reducing the total water-supply requirements to a potential maximum of 260 Mm^3/year by 2050.

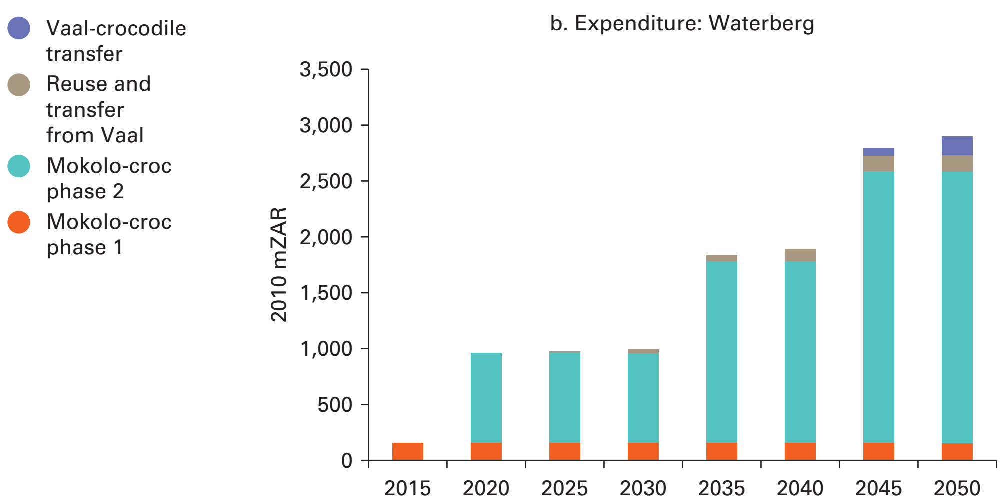
The contrast between the Waterberg and other regions in the annual investment expenditure required for bulk water supply is shown in figure E.2. The regional expenditure on infrastructure for water supply to reconcile projected demand is concentrated in the Waterberg. Figure E.2 shows the breakdown of the water-conveyance infrastructure required in the Waterberg for water transfers to this arid region. Additional supply options are facilitated by the interconnected regional system.

The lack of natural causeways around the Waterberg will require substantial investment in supply pipelines for interregional water transfers. This is evident in the relative sizes of the Phase 1 and Phase 2 supply schemes (figure E.2). The Phase 2 supply schemes refer to multiple pipelines commissioned to meet local demand, whereas Phase 1 relates to the investment in local pipeline infrastructure to fully utilize the existing local supply system. The additional investment required to establish supply options, such as the transfer of return flows from the City of Johannesburg (that is, reuse and transfer from Vaal), represent a much smaller expenditure.

Investments in water-supply infrastructure will lead to increased water-supply costs. The cost of water in the Waterberg can be expected to leap if the growth of coal supply proceeds unabated. Figure E.2 shows the annualized average unit cost of water supply in each region, and these costs can be compared to the expenditures shown in figure E.1. For the Waterberg region, the peaks for the average water-supply cost arise from the lump sum invested in pipelines for water transfers. The peaks in the supply cost are observed as the newly commissioned water supply infrastructure is initially underutilized, or operated at a low supply capacity. The unit cost of water-supply decreases with gains in water volumes; transferred until the existing supply capacity is reached, necessitating new investment for continued exploitation of coal in the Waterberg.

Figure E.2 Annual Investment in Water Supply Infrastructure





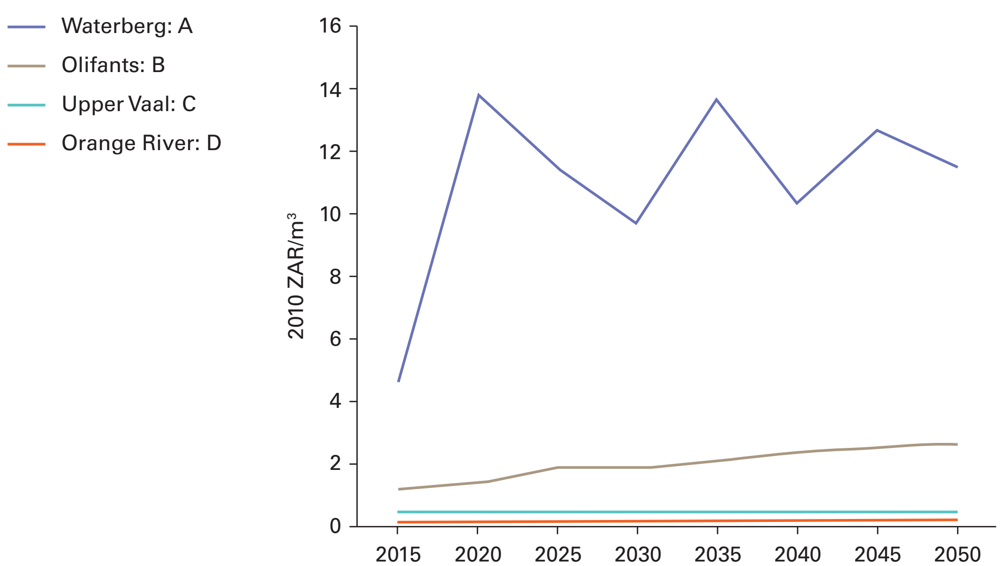
In contrast, the average supply cost for the other regions is not expected to experience a similar escalation (figure E.3). Non-energy demand is responsible for cost increases for water supply to the Olifants. The expenditure stems from additional water transfers from the Vaal River system with interim use of treated acid mine drainage (AMD) water as 2020 nears. The option of an additional dam in the Olifants is avoided. The average cost of water in the Olifants effectively doubles over this period from a base cost of R1.3/m^3. The base cost is derived from the existing weighted average tariff to power plants (weighted by generation), which regionally ranges from 50c to R4/m^3. The weighting is required as in this analysis power plants are not individually modeled, but represented by regional categories.

The Orange River region is home to agriculture. The incremental demand for water here will increase the supply cost by approximately 40 percent through to 2050, from a base of 17c/m^3 to 25c/m^3. The increases predicted for 2045 will be driven by demand for wet-cooled CSP in this region.

In the Waterberg, the average supply cost of R4.70/m^3 in 2015 assumes the implementation of a fully operational Phase 1. The cost is an approximate 700 percent increase to the existing local supply tariff of 60c/m^3 (2010 ZAR) for the local dry-cooled Matimba power plant.

A point of clarification: the supply cost would not necessarily reflect the price paid via the tariff. The tariff is usually structured to recover costs over 20 years; thereafter one sees a return-on-assets component. Furthermore, tariffs differ by consumer

Figure E.3 Average Regional Water Supply Costs



category. In reality, the energy-supply sectors in the Waterberg may be liable for tariffs higher than the costs tabled in this analysis, as the bulk of investment relates to energy supply. Agriculture and domestic consumers reliant on the local supply system would be subject to a lower tariff. Therefore, the average supply costs in this analysis are indicative of future water tariffs that may be required for timely investment in regional water supply infrastructure.

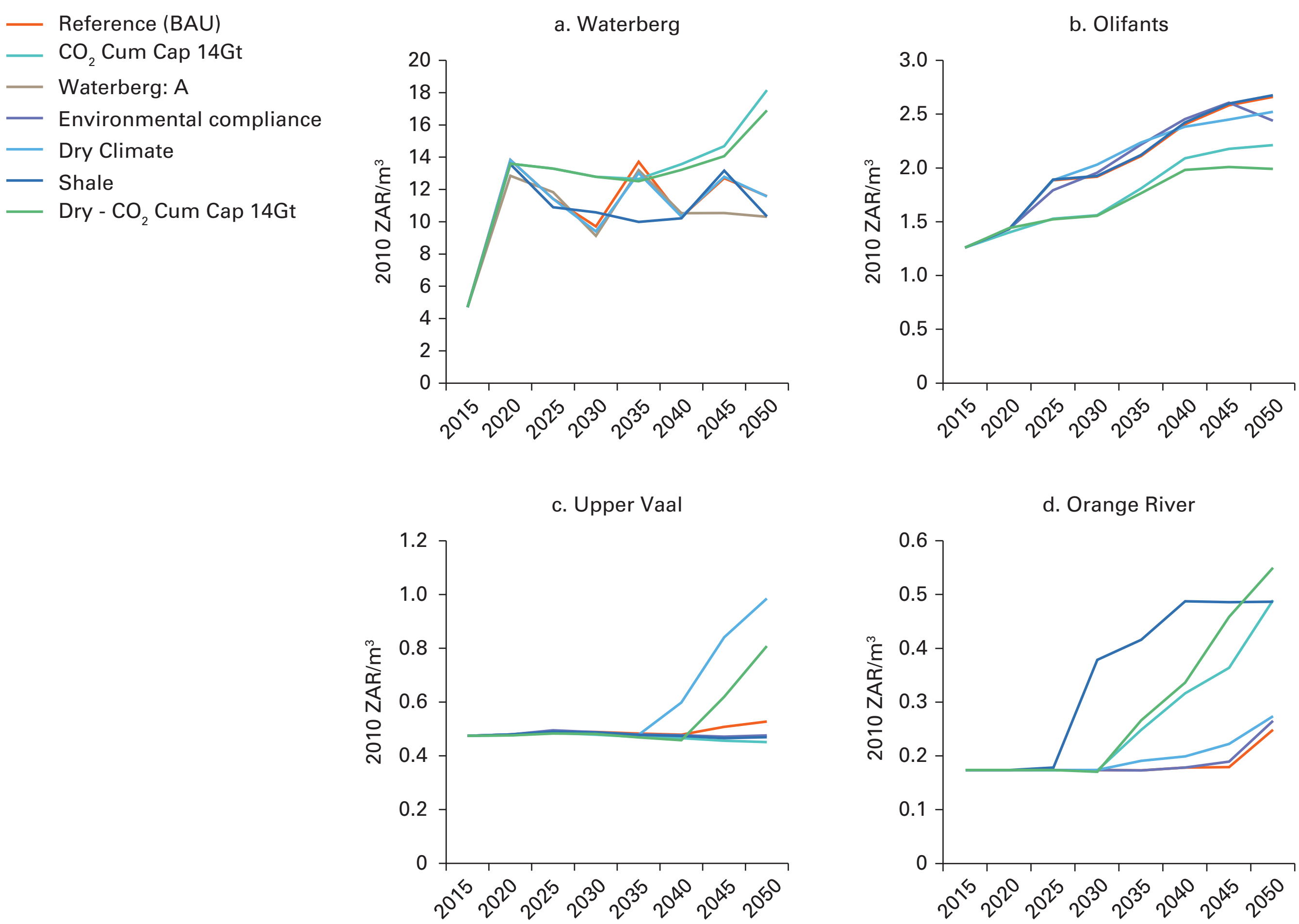
It is also important to note that current water demand from the non-energy sectors is included in aggregate, modeled without consideration for reallocations or interventions to reduce demand. A refinement of the model incorporating the disaggregation of water demand from the non-energy sectors may therefore result in deferred investment in regional water-supply infrastructure as water-use efficiency and value-added usage improve. But because investment in the arid Waterberg requires conveyance infrastructure (and demand is primarily driven by energy supply), one doubts that further consideration would affect investment needs in this region.

Carbon Cap Scenarios

Carbon policies seek to limit total cumulative emissions over the planning horizon, in line with the nation's United Nations Framework Convention on Climate Change (UNFCCC) intended nationally determined contributions (INDC) and share in a future where the mean increases in global temperature are no more than 2°C.

In all regions except the Upper Vaal, water-supply costs rise over time when a carbon cap is applied. The Carbon Cap scenarios (green and orange) cut the use of hydrocarbon fuel—coal, gas, and crude oil from refineries (figure E.4). Decreased use of hydrocarbon fuels will lead to the underutilization of the Waterberg's water conveyance infrastructure; this in turn would cause spikes in the unit cost of water. The more carbon-restrictive scenario (10 Gt CO_2 cap) would involve mothballing existing and newly commissioned coal plants, and in turn drastically cut water supply requirements in the Waterberg and Olifants, the regions of coal-intensive energy supply. In the Waterberg, the Carbon Cap scenarios produce the highest water costs, but in the Olifants region these scenarios cut water costs because existing coal plants are retired early. As previously discussed, the cost of water in the Olifants region is driven by demand from the non-energy sectors, and this remains true across all scenarios. A restriction on new investment in coal due to the carbon cap effectively shifts the cost of supply to the Orange River region owing to greater impetus for CSP capacity. A rise in the unit water cost is observed from 2030 under the 14 Gt CO_2 cap, and even sooner, 2025, for the stricter 10 Gt CO_2 cap. Although the unit water cost approximately doubles over the planning period, the Orange River region remains the lowest-cost region for water supply, with the maximum cost of bulk water supply approaching 50 c/m^3.

Figure E.4 The Projected Regional Average Cost of Water Supply



In the Carbon Cap scenarios, earlier investment in the renewable energy technology portfolio (solar and wind) is required. A 10 Gt carbon budget would also require investment in 10 GW of new nuclear power capacity by 2035. The Carbon Cap scenarios raise the cost of electricity by 30 to 50 percent in the near-term (2015–25), and by 40 percent to 70 percent in the latter period (2020–35), with the higher range attributed to the more restrictive 10 Gt carbon budget. Both the 14 Gt CO_2 cap and the 10 Gt CO_2 Cap scenarios converge to 60 percent above that of the reference cost of 70c (2010) /kWh in 2050.

The Dry Climate + Environmental Compliance Scenario

The Dry Climate + Environmental Compliance scenario, which represents the extreme water stress scenario, is shaped primarily by Environmental Compliance scenario and to a lesser extent by climate-induced changes to water supply and demand. Figure E.5 highlights the similar, cost optimal, power plant portfolio when comparing the Reference case to that of the dry Climate case.

Figure E.5

Comparison of Generation Capacity for Coal and Renewable Energy Portfolio

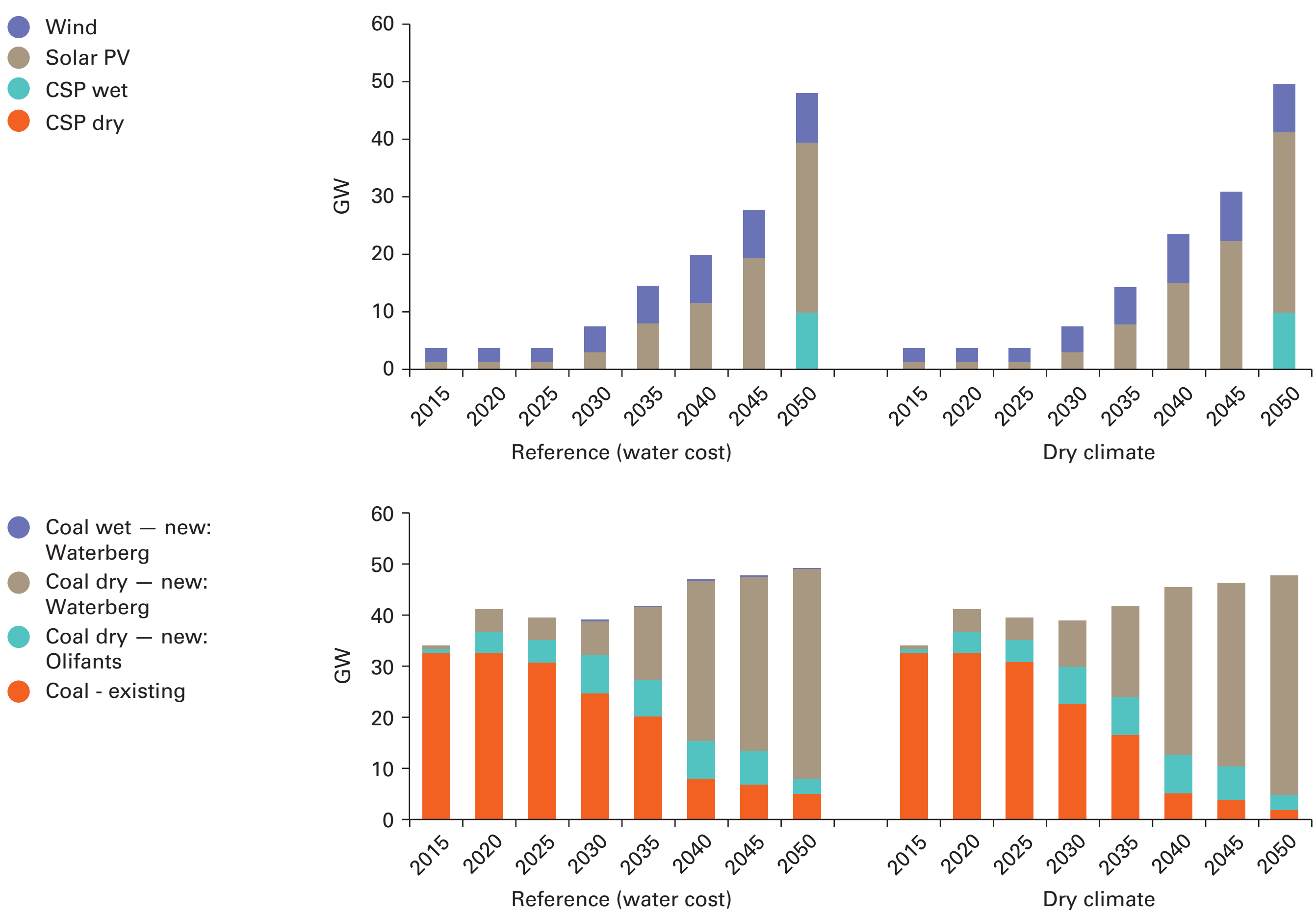
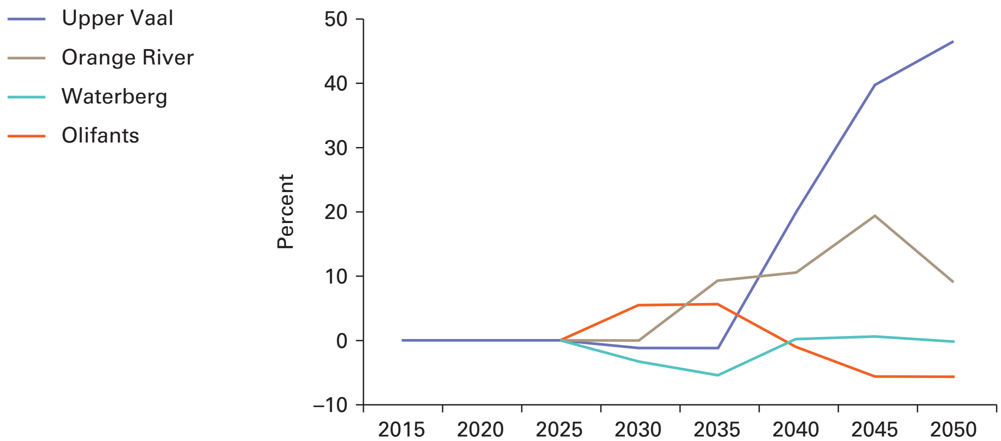


Figure E.6 **The Relative Cost of Water Supply under the Dry Climate Scenario and Reference (Water Cost) Scenarios**



Model results for the regional impact of climate change on water demand suggest that a change in the unit cost of water cost would likely manifest in the Upper Vaal and Orange River which is largely because of increased demands by the non-energy sectors (figure E.6).

The dip in water cost seen for the Waterberg stems from the early retirement of the older wet-cooled coal plants under a "warmer and drier" climate in the Olifants and Upper Vaal and the shift to new dry-cooled coal plants in the Waterberg. Approximately 2 GW of new stock will be added to the Waterberg, and 3 GW of existing plant will be retired early by 2050. The decrease in cost reflects the increased utilization of water infrastructure.

The Environmental Compliance scenario introduces treatment of lower water quality water transfers to the Waterberg, which reduces power sector investment after 2040 (section 6). The increased cost of treatment associated with demineralized water production for boilers further reduces the attractiveness of coal-based energy supply (section 6). In addition, we include flue gas desulfurization (FGD) technology on new CTL plants that are not considered in the Reference scenario. The FGD technology, unlike the wet-based process for power plants,[11] is presumed to be of semidry circulating fluidized bed design due to concerns over space restrictions for the existing plants (SRK 2014).

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[1] The current model represents the cost of FGD as an annualized cost incurred over the technical life of the plants. Since emissions regulations are enforced in 2025, the model implementation may be responsible for the earlier investment in new CTL for the Environmental Compliance scenarios as compared to the reference in 2020. The model has perfect foresight of commodity demand and supply costs over the planning horizon and opts for new CTL capacity without environmental costs by 2020 in order to minimize the cost of liquid fuel supply over the planning period. The earlier capacity results in a marginally cheaper cost of production for diesel in

Furthermore, as discussed in section 6, additional water treatment costs as inter-region transfers are presumed to be of lower quality. The lower quality water requires pre-treatment for demineralized use as boiler makeup fluid and for process use (i.e., stream generation for the Fischer-Tropsch process). The associated cost increase for treated water is equal to the marginal cost of water treatment for demineralized use for water transferred from the Crocodile River (Eskom 2008).[22]

Retrofitting existing coal plants with FGD technology results in an earlier retirement profile, which reduces the regional water demand and defers investment in new water supply (see Appendix D.2.1). The added cost of FGD retrofits makes the existing wet-cooled power plants less economically attractive compared with the Reference scenario, where life extension of these plants is seen.

The Investment Impact of Flue Gas Desulfurization Retrofits on Power Stations

This appendix explores in some more detail the environmental compliance issues facing the electricity sector (section 6).

South African coal power plants have not yet installed (FGD) technology. But, as noted in the previous section, recent legislative amendments to improve local air quality include stipulations to control the emission of combustion byproducts. Dry FGD systems have lower capital costs but higher maintenance costs: the reagent is more expensive and waste disposal is required. Singleton (2010) identified a local preference for wet FGD systems because of lower lifecycle costs. Therefore, the FGD control technology representation in South African TIMES model "water smart" (SATIM-W) is presently restricted to the wet FGD process for all coal power plants. But this raises the following questions:

- Is water supply a limiting factor on FGD retrofits, and if not, when could water be supplied?
- Will the additional demand significantly affect regional water cost?
- How will retrofits affect electricity prices?

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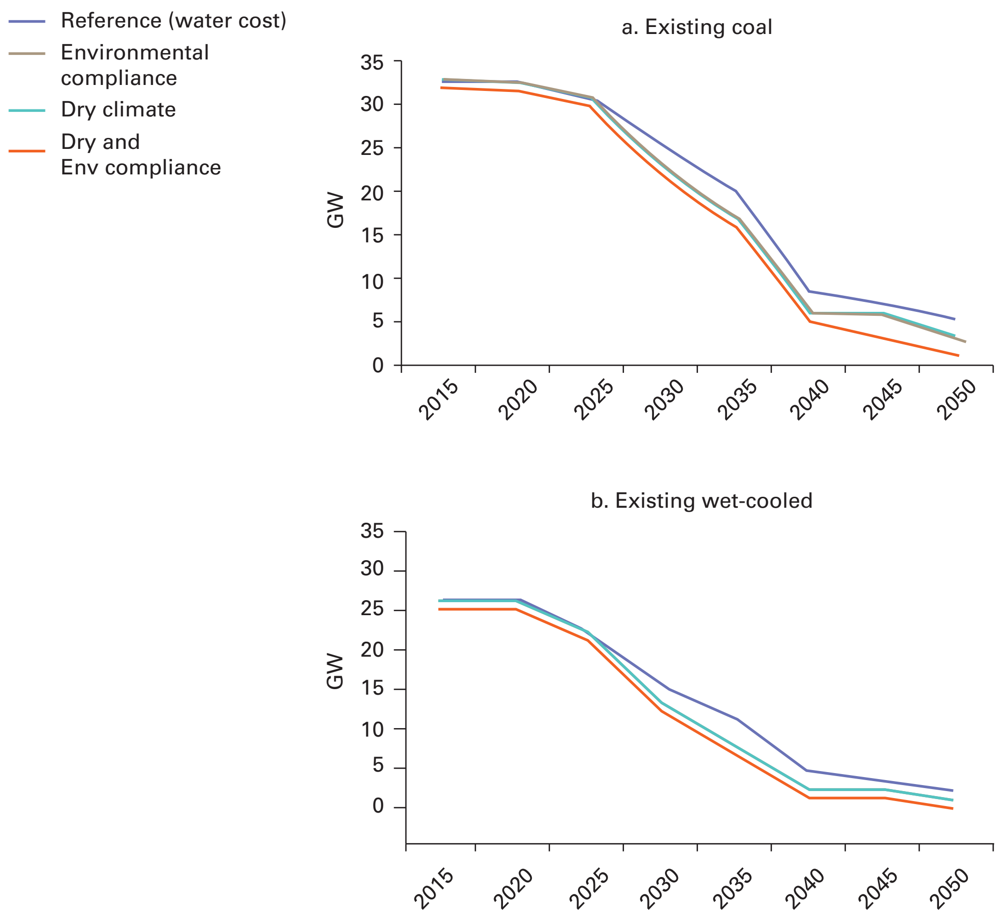
in 2020 than in the reference. This artifact suggests that a refinement to the CTL parameterization may be warranted in future, although this should have a minimal effect on the model results as it would only forestall the additional capacity until 2025.

[2] The model supplies water consumers with equal priority. As a result, due to the lower cost of supply, lower quality imported water is effectively transferred to the local non-energy sectors, while higher-quality local water is utilized for electricity and synfuel production. The water quality is unchanged over the planning period in the model, and therefore the results discussed here are indicative of how one level of water quality would alter planning decisions. In future work, the model could be refined to include a variation in water quality with time. This could result in either a further reduction in new coal and CTL capacity, or an escalation in local production (e.g., electricity and diesel) if regional capacity is increased as the energy supply sector would incur the cost of treating imported water of lower quality.

In considering the above questions, it is useful to start by examining the retirement profile of existing coal capacity after the minimum emissions standards are applied (Environmental Compliance scenario) and under changing climate (Dry Climate scenario) (figure E.7, top). Located in the Upper Vaal and Olifants, the existing stock competes with the non-energy sectors, for which the water demands are greater. Starting in 2025, FGD retrofits result in earlier retirement of existing wet-cooled plants—compared with the Reference case, approximately 2 GW by 2050 (figure E.7, bottom). For the Dry Climate case, life extension of existing plants by retrofitting FGD only appears attractive for existing dry-cooled plant in the Waterberg where coal costs are lower.

Figure E.7 Existing Coal Capacity Retirement Profile



The regional lump sum investment cost for water supply is displayed in figure E.8. Investments are largely influenced by the dry climate case and the FGD retrofits to occur in 2025. The near-term water supply requirement in the Olifants is met with treated local AMD and additional transfers from the Vaal. These supply schemes are commissioned in the Reference scenario and appear sufficient for the Environmental Compliance and Dry Climate cases as well.

The increased water investments in the Upper Vaal and Orange regions are driven by the non-energy sectors response to the Dry Climate scenario. The decrease in the cost of water for an Environmental Compliance case results from the earlier retirement of existing wet-cooled capacity allowing for the reallocation of the water. Investment in water supply infrastructure in the Upper Vaal is delayed as a result.

Figure E.9 summarizes the key water and energy performance indicators. With the FGD retrofits by 2025, power generation becomes more water intensive. The value of 1.25 l/kWh is 10 percent higher than the reference 1.14 l/kWh. By 2040 the earlier retirement of stock decreases the water intensity by a similar amount

Interestingly, the rise in water intensity by 2050 is attributed to the commissioning of a large wet-cooled plant in the Olifants (4 GW) for the Environmental Compliance scenario. Also contributing to the rise is the additional 1 GW of CSP, which appears by 2045. As a result, the water intensity rises 25 percent from the reference value of

Figure E.8 Investment in New Water Supply Infrastructure in Four Regions and under Four Scenarios

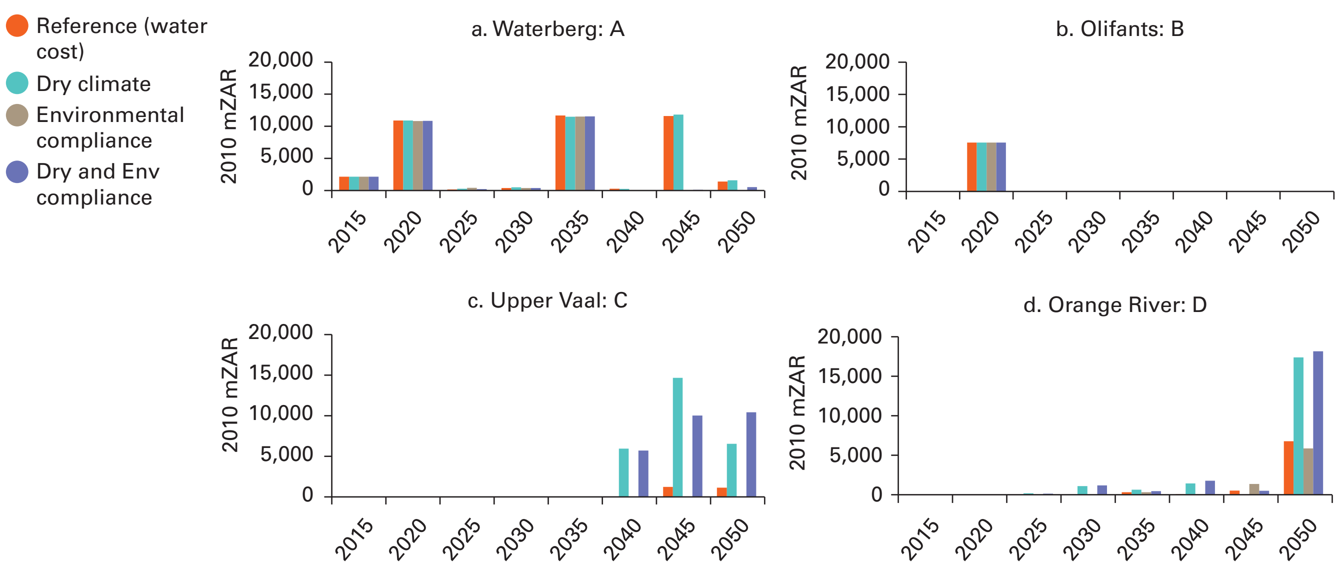
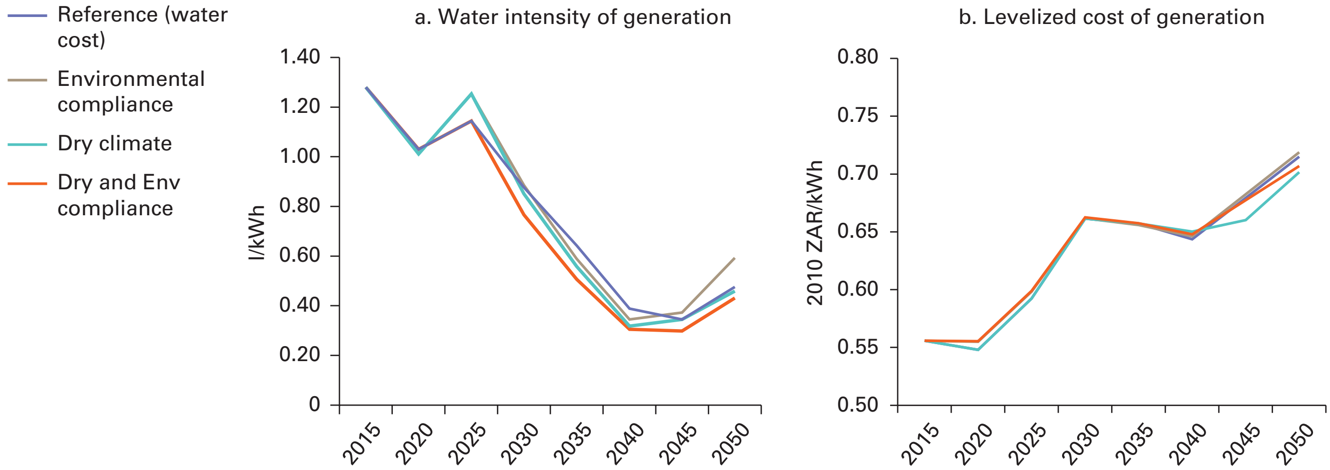


Figure E.9 Water and Energy Performance Indicators



0.48 l/kWh to 0.6 l/kWh during this period (2045–50). The cost of electricity remains stable relative to the Reference when considering the effect of the Environmental (right panel) with no discernible deviation. The deviation observed for the Dry Climate case is 3 percent less than Reference, 0.68–0.72 ZAR/kWh for 2045–50. This reduction is attributed to the increase in new coal capacity of 2 GW in the Waterberg.

Shale Gas Scenario

By reducing imports, shale gas could increase energy security and diversification. By displacing coal, it could lower greenhouse gas (GHG) emissions. But at what cost, with how much more water, and by realizing how many of these possible benefits? The availability of shale gas results in an earlier and sharper rise in water supply costs in the Olifants and Orange river regions as additional investment in water distribution is needed via pipeline and trucking. In contrast, the Shale Gas scenario lowers the investment required in the Waterberg's water supply and defers new investment until the later period (2040–50) as new coal power capacity is postponed.

Table E.1 Summary of Metrics for All Scenarios

Scenario	System Cost		Expenditure - Supply		Primary Energy		Final Energy	
	2010 MZAR	%	2010 MZAR	%	PJ	%	PJ	%
Reference (Water Cost)	7,646,424		10,292,329		271,328		137,619	
Reference (No Water Cost)	7,586,054	–0.8	10,305,355	0.1	272,963	0.6	137,692	0.1
Shale	7,596,528	–0.7	10,789,282	4.8	266,866	–1.6	137,938	0.2
Dry Climate	7,650,921	0.1	10,264,548	–0.3	270,009	–0.5	137,625	0.0
Environmental Compliance	7,706,204	0.8	10,493,846	2.0	263,463	–2.9	137,598	0.0
Dry & Env Compliance	7,707,238	0.8	10,491,493	1.9	263,394	–2.9	137,582	0.0
CO_2 Cum Cap 14Gt	7,690,468	0.6	10,396,514	1.0	232,447	–14.3	136,870	–0.5
CO_2 Cum Cap 10Gt	7,864,939	2.9	9,788,172	–4.9	214,162	–21.1	135,996	–1.2
Dry - CO_2 Cum Cap 14Gt	7,691,459	0.6	10,394,483	1.0	232,434	–14.3	136,859	–0.6
Shale - CO_2 Cum Cap 14Gt	7,634,836	–0.2	10,783,381	4.8	232,656	–14.3	136,991	–0.5
Shale + Dry - CO_2 Cum Cap 14Gt	7,635,963	–0.1	10,803,641	5.0	232,601	–14.3	137,015	–0.4

Power Sector CO_2 Emissions	Power Plant Builds		Power Plant Investment Difference		Water to Power Plants		Total Water Supply Difference	
Mt	**GW**	**%**	**2010 MZAR**	**%**	**Mm³**	**%**	**Mm³**	**%**
12,242	134		2,721,555		11,093		11,093	
12,293	131.3	–2.0	2,686,286	–1.3	17,910	61.5	17,910	61.5
11,143	117.6	–12.2	1,945,647	–28.5	9,841	–11.3	9,841	–11.3
12,111	130.2	–2.8	2,864,136	5.2	10,421	–6.1	10,421	–6.1
12,004	131.0	–2.2	2,818,024	3.5	11,158	0.6	11,158	0.6
11,991	131.4	–1.9	2,821,338	3.7	10,898	–1.8	10,898	–1.8
9,000	169.7	26.7	3,429,681	26.0	12,785	15.3	12,785	15.3
6,035	188.7	40.9	5,455,992	100.5	13,097	18.1	13,097	18.1
8,994	170.2	27.1	3,430,417	26.0	12,485	12.6	12,485	12.6
8,924	157.4	17.5	2,666,723	–2.0	10,387	–6.4	10,387	–6.4
8,938	158.2	18.1	2,652,661	–2.5	9,938	–10.4	9,938	–10.4

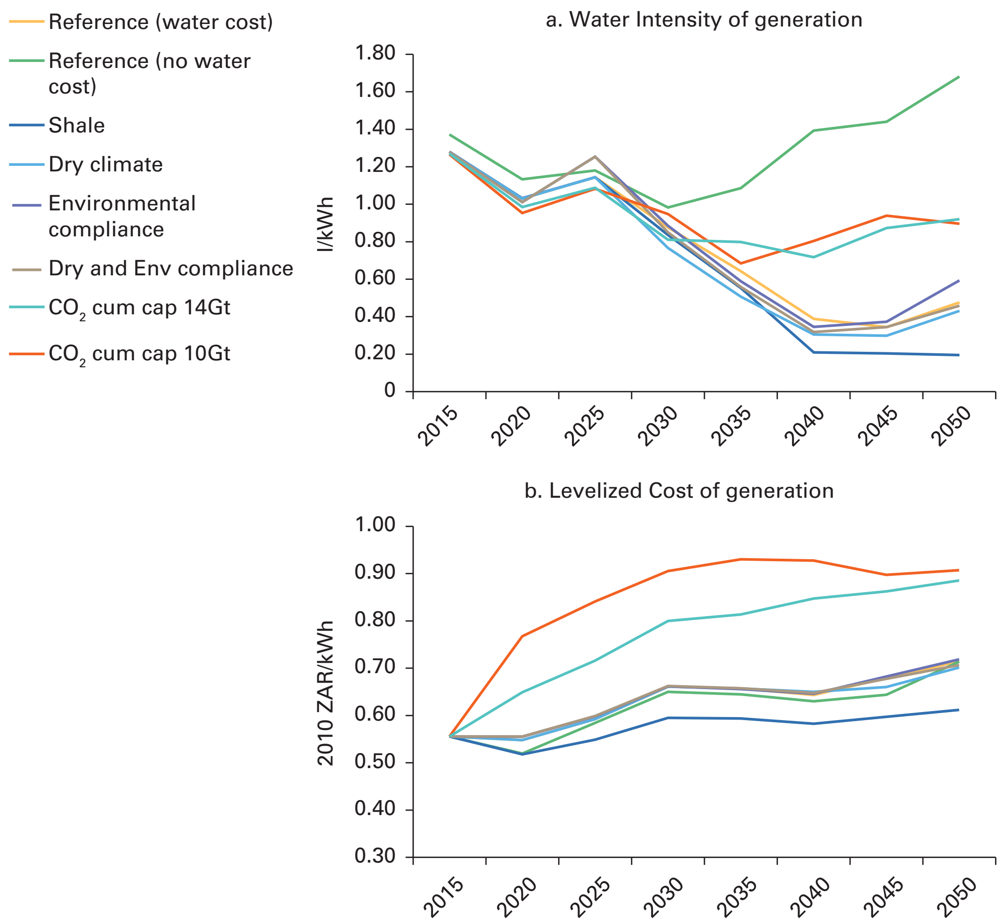
The main differences in the Shale Gas scenario, as compared with the Reference scenario, is the reduced investment in wind generation, with no further CSP commissioned beyond committed capacity. The preliminary assessment suggests that a scenario of shale gas availability with an extraction cost of 55 ZAR (2010)/GJ lowers the cost of electricity generation by approximately 10 percent in 2030, when electricity generation from shale gas appears with 5 GW of capacity. A potential of 30 GW of capacity appears in 2040, which provides 50 percent of electricity supply. The estimated reserves are fully exploited by 2040, with annual shale gas consumption for power in the order of 1,700 PJ/year. In response to growing demand, the share of supply declines to 35 percent in 2050 as new dry-cooled coal plants in the Waterberg are selected as the next preferred economic alternative. The addition of new coal plants result in a lower utilization of the gas plants, which go from a 90 percent to a 75 percent capacity factor. This is potentially due to the increased competition for shale gas by the other economic sectors such as transport and industry, where gas consumption displays an increasing trend. Shale gas consumption is primarily for electricity generation, which consumes 50 percent of available gas in 2030 and increases to 80 percent in 2040, thereafter declining to 70 percent of total shale gas consumption in 2050.

A comprehensive consideration of water management for shale gas extraction was not possible for this analysis, so the results are preliminary. It is noted, though, that the water intensity of the Shale Gas scenario exhibits a sharp decline, departing from the Reference in 2030, to approach 0.2 l/kWh for the national average. The decline in water intensity is monotonic over the period, with the rate of change approximately 0.2 l/kWh as a result of the new dry-cooled coal plants.

Water Intensity

Both Carbon Cap scenarios result in higher water intensities than the Reference (figure E.10). The Carbon Cap scenarios limit the ability of the model to reduce water intensity of generation below ~0.9 l/kWh. For the 10 Gt CO_2 Cap, the earlier investment in 10 GW of CSP capacity in 2030 (compared to the Reference case of 2050) results in an increase in water intensity of 10 percent. The inclusion of nuclear power in the 10 Gt CO_2 Cap case mitigates a further increase in water intensity, causing the water intensity to approach the Reference value of 0.64 l/kWh in 2035. The increase in water intensity attributed to the investment in wet-cooled CSP is offset by the large expansion of capacity in solar photovoltaics (PV) in the late term (2040–50). Almost 50 percent (25 GW) of the 55 GW of total capacity appears during this period for both Carbon Cap scenarios.

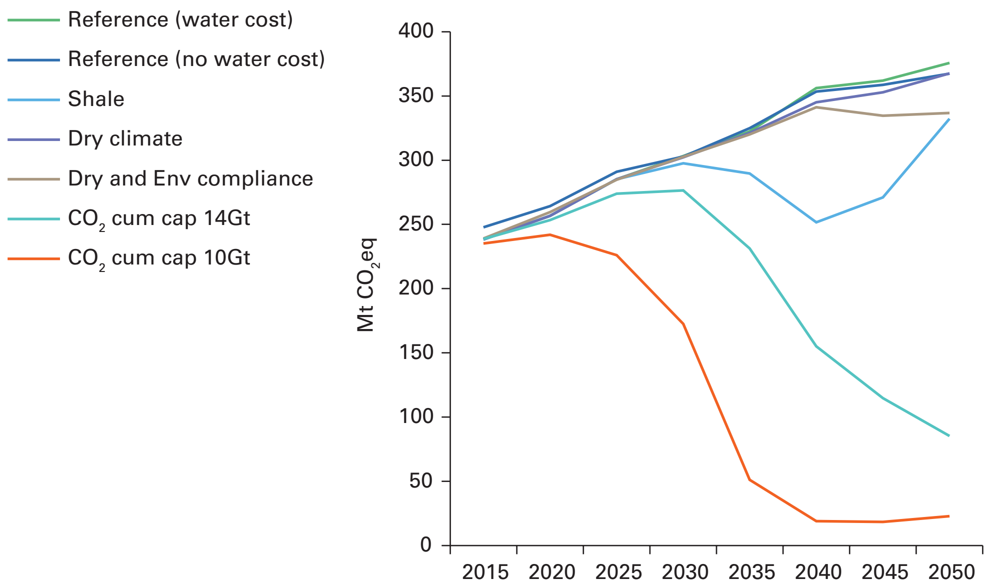
Figure E.10 Cost of Electricity Generation and Water Use Intensity



CO_2 Emissions

The effect of the Carbon Cap scenarios is also evident in the GHG emissions over time (figure E.11). The 14 Gt CO_2 cap prevents further CTL expansion, and the plant is fully utilized until its scheduled decommissioning in 2040. Emissions from the power sector exhibit the advocated Peak-Plateau-Decline trajectory, with emissions peaking at approximately 275 Mt CO_2eq by 2030. For the 10 Gt CO_2 cap, emissions from both the refineries and the power sectors plummet after 2020.

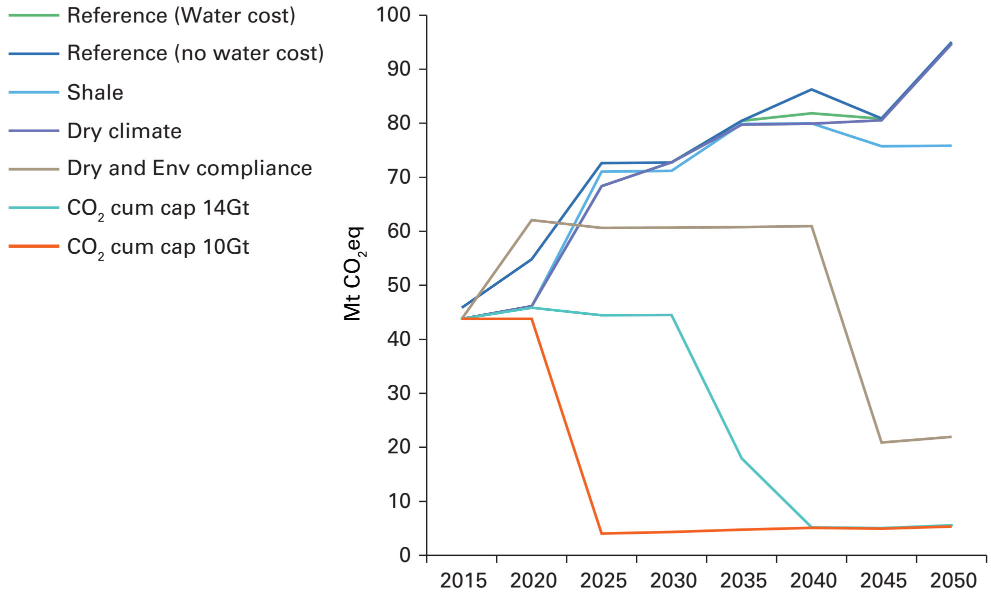
Figure E.11 GHG Emissions for the Power Sector



Emissions from the Shale Gas scenario depart from the Reference in 2030 with the onset of shale gas utilization for power. Emissions are reduced by 30 percent (250 Mt CO_2eq) compared to the Reference case of 356 Mt CO_2eq in 2040. However, if the estimated reserve of 40 Tcf is fully allocated by 2040, a resort to economical coal for electricity supply erodes the emissions savings to 12 percent of the Reference (375 Mt CO_2eq). Within the refineries sector, reduced demand for liquid fuels owing to the introduction of gas-combustion vehicles reduces further investment in CTL from 2045 with a concomitant decrease in emissions of 20 percent by 2050 as compared to the Reference case (95 Mt CO_2eq).

Although the Dry Climate scenario has little effect on the Reference emissions baseline for both sectors, the Dry Climate + Environmental Compliance scenario has interesting implications for CTL refineries (see figure E.12). The Environmental Compliance scenario causes an earlier investment in new CTL capacity in the Waterberg than in the Reference case. This is most likely a model decision that deems it cost-effective to offset the future cost of environmental compliance in the prevailing five years. The stricter 10 Gt CO_2 cap causes existing CTL plants to retire ahead of schedule by 20 years, which slashes the emissions from refineries, with crude oil refineries emitting the remaining ~3 Mt CO_2-equivalent.

Figure E.12 GHG Emissions for the Liquid Fuels Sector



Appendix F

Regional Water Supply Systems in SATIM-W

To establish the Reference Energy Water System (REWS) for South African TIMES model "water smart" (SATIM-W) it is necessary to adopt a naming convention scheme that enables the user to easily recognize the nature and role of each of the components such as. To accomplish this, the REWS component names are assembled from the acronym components listed below.

Regional water supply region (WSR) identifiers:

A: Limpopo water management agency (WMA) (Waterberg)

B: Olifants WMA (Central Basin)

C: Upper Vaal WMA (Central Basin)

D: Orange WMA (Northern Cape/Karoo)

K: Karoo aquifer system

R: Area in the vicinity of the Richards Bay Coal Export Terminal

WMIN: Water supply system

Ux: Delivery (transmission) of water

UPS: Upstream water delivery

WT: Water treatment technology

WAx: Scheme water commodity

where *x* designates water-quality subcategory

Px: Primary/raw water (e.g., coal washing) where *x* designates the water-quality subcategory ($x = 0, 1$)

Hx: High-quality water (e.g., boiler feedwater) where *x* designates the water-quality subcategory ($x = 1$)

Note: While the model features only one subcategory ($x = 1$) is implemented in, the approach permits additional categories.

Example naming structure:

<u>WA-P1-D</u>: Volume of primary water quality—i.e., generic boiler feedwater (1), delivered to a process or technology in region D.

<u>UPSWA-H1-D</u>: Volume of high quality water with no associated delivery cost in region D.

<u>U1WA-H1-D:</u> Cost for a specific mode of delivery (e.g., by pipeline) attributed to the water commodity in region D.

Note: Region D has different delivery modes for the technologies represented and this results in a sub-regional water supply system that is differentiated by an additional regional index. The subregional supply systems are labeled D1 and D2. The remaining regions combine supply and delivery costs, a move that simplifies the implementation and naming conventions adopted.

Regional Water Supply Systems and Individual Schemes

Each regional water supply system is distinguished by an appended region code. Where possible, the supply and delivery (transmission) costs as elaborated in Task 1 are combined to simplify implementation.

In region D, the different delivery costs for the shale gas and concentrated solar power (CSP) sectors rendered this impossible. Delivery is modeled as a distinct component, as explained below.

- Shale gas may bring additional development of the energy sector in the region, possibly including gas-to-liquids (GTL), open-cycle gas turbine (OCGT), and combined-cycle gas turbine (CCGT) technologies. Because CSP technologies are located in the North Cape, delivery costs for shale-gas mining include all these technologies, assuming they would be co-located.
- The REWS for region D is more complex than for other regions because of the multiple delivery options. This is especially true for shale-gas mining, which has three delivery routes: bulk pipeline, truck, and piped onsite groundwater. In the model this is represented as modal shares, which can vary over time. For example, truck delivery would most likely dominate the initial development phase of shale gas sector, with a bulk pipeline potentially reducing the requirement for vehicular transport as the sector matures and additional energy-supply-sector technologies emerge, such as gas-fired electricity generation and/or GTL production.
- For the above reasons, as depicted in the REWS diagram for Region D, the water supplied to consumers is split into subregional systems: D1, CSP region; and D2, shale gas energy technologies (such as GTL and CCGT) and shale gas mining.
- Each scheme has a commodity attribute water quality with the existing supply system set as the reference (level 0).

Parameterization of Water Supply Technologies

The model parameters for implementing the regional water supply systems in SATIM-W are summarized below in table F.1. For the treatment technologies, a simplified expression is given as an alternative should levelized costs be preferred. This may occur if a treatment cost is relatively small and would apply to primary treatment. As previously discussed, Region D requires the delivery component to be separated.

Some schemes have construction lead times. For example, this applies to the case of the use of acid mine drainage (AMD) as an interim option should the cheaper Vaal-Usutu scheme be unavailable when the DWA water demand forecast need for additional supply. The construction lead times are mostly derived from the Department of Water Affairs (DWA) study of the marginal cost of water for future supply options and modified where more recent data exists (DWA 2010a).

Table F.1 SATIM-W Parameters Characterizing a Water Supply Scheme

TIMES Parameters	Scheme Supply and Delivery	Treatment
Time-varying parameters		
NCAP_COST	Capital (ZAR/Mm^3)	Capital (ZAR/Mm^3/year)
NCAP_FOM	Fixed OM (ZAR)	Fixed OM (ZAR)
PRC_ACTFLO	Energy commodity Electricity or diesel (kWh/m^3) or (L/m^3)	Energy commodity Electricity (kWh/m^3)
ACT_COST[a]	In SATIM-W included as a FOM cost	n/year
ACT_BND	Yield (Mm^3)	n/year
Time invariant parameters		
TOP-IN (commodity input)	Electricity or diesel	Electricity
TOP-OUT (commodity output)	W[i]1 (Mm^3)	W[i]H1 (Mm^3)
Commodity usage	Simplified alternative for primary treatment	
FLO_COST	n/year	Unit water cost (ZAR/Mm^3)

a. Variable costs are combined with FOM costs to ensure that the model is committed to a particular scheme once selected. This is necessary due the varying construction time of individual water supply projects (schemes) and the demands that may occur.

Water Supply Costs

The costs for the regional water-supply schemes are summarized in table F.2. For Region D, costs are shown for the supply and delivery modes. Figures F.1–F.4 display the individual regional REWS representation in SATIM-W.

Table F.2 The Costs for Regional Water-Supply Schemes

Scheme	Region ID	Scheme Yield (Mm³/year) 2010	Energy Requirement	Capital Cost	Annual O&M Cost
			(kWh/m³)	(R x 10⁶)	(R x 10⁶)
Waterberg, existing	A0	25			
Mokolo pipeline (Phase 1)	A1	29	1	1,759	5
Mokolo-Crocodile River Transfer (Phase 2) pipeline[a]	A2	75	1	8,174	22
Reuse and transfer from the Vaal	A3	126	1	1,216	3
Transfer from Vaal River	A4	90	1	2,562	7
Transfer from Zambezi River	A5	100	2	14,469	38
Desalination of seawater	A6	100	14	20,896	55
Upper Olifants, existing	B0	400			
Vaal Eskom transfer[c]	B0-UX	230			
Olifants Dam	B1	55	0	1,241	3
Use of acid mine drainage (AMD)	B2	31	2	1,637	4
Transfer from Vaal River	B3	190	1	4,281	11
Transfer from Zambezi River	B4	95	4	18,553	49
Desalination of seawater	B5	100	14	14,210	38
Upper Vaal, existing	C0	3523			
LHWP-II[d] (Polihali Dam)	C1	437	0	11,947	32
Use AMD	C2	38	3	1,820	5
Thukela-Vaal transfer	C3	522	3	21,976	58
Orange-Vaal transfer	C4	289	2	15,671	42
Mzimvubu transfer scheme	C5	631	4	41,568	110
Transfer from Zambezi	C6	650	4	52,254	138

(continued)

Table F.2 The Costs for Regional Water-Supply Schemes *(continued)*

Scheme	Region ID	Scheme Yield (Mm³/year) 2010	Energy Requirement (kWh/m³)	Capital Cost (R x 10⁶)	Annual O&M Cost (R x 10⁶)
Desalination of seawater	C7	100	14	7,831	21
Orange, existing	D0	4131			
Boskraai Dam (55 percent)[b]	D1	515	0	2,678	7
Boskraai Dam (full yield)[b]	D2	422	0	3,286	9
Mzimvubu-Kraai transfer	D3	165	5	4,370	12
Desalination of seawater	D4	100	14	11,175	30
Hydraulic fracturing—groundwater	DK0	1	4	2.6	0.01

Source: DWA 2010a.
Note: Annual supply from aquifer arbitrarily set at 1 Mm³/year. Groundwater usage requires further study for appropriate inclusion. Seawater desalination was chosen as the ultimate supply scheme. The transfer from the Zambezi River, the alternative, posed water security concerns. Road transport diesel consumption was estimated at 2MJ/ton-km with a calorific value of diesel given as 35.94 MJ/L and a load factor of 50 percent. The costs for pumping and road transport are estimates and their actual value will depend on the demand for water in the model as electricity and diesel consumption are explicitly modeled as input commodities in terms of kWh/m³ and Liters/m³ of water delivered (although in TIMES the native units are petajoules/Mm³).
a. DWS 2015.
b. DWA 2013.
c. Aggregate representation.
d. Lesotho Highlands Water Project Phase 2.

Figure F.1 The SATIM-W Water Supply System for Region A (Lephalale, Waterberg, Limpopo WMA)

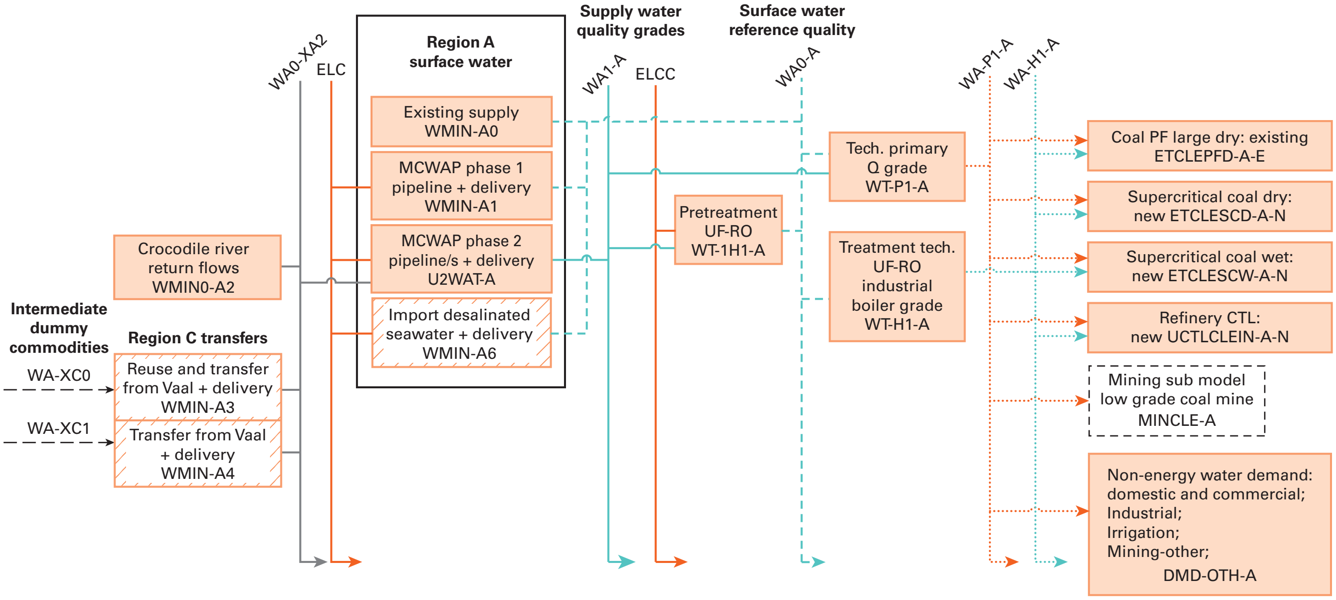


Figure F.2 The SATIM-W Water Supply System for Region B (Upper Olifants WMA)

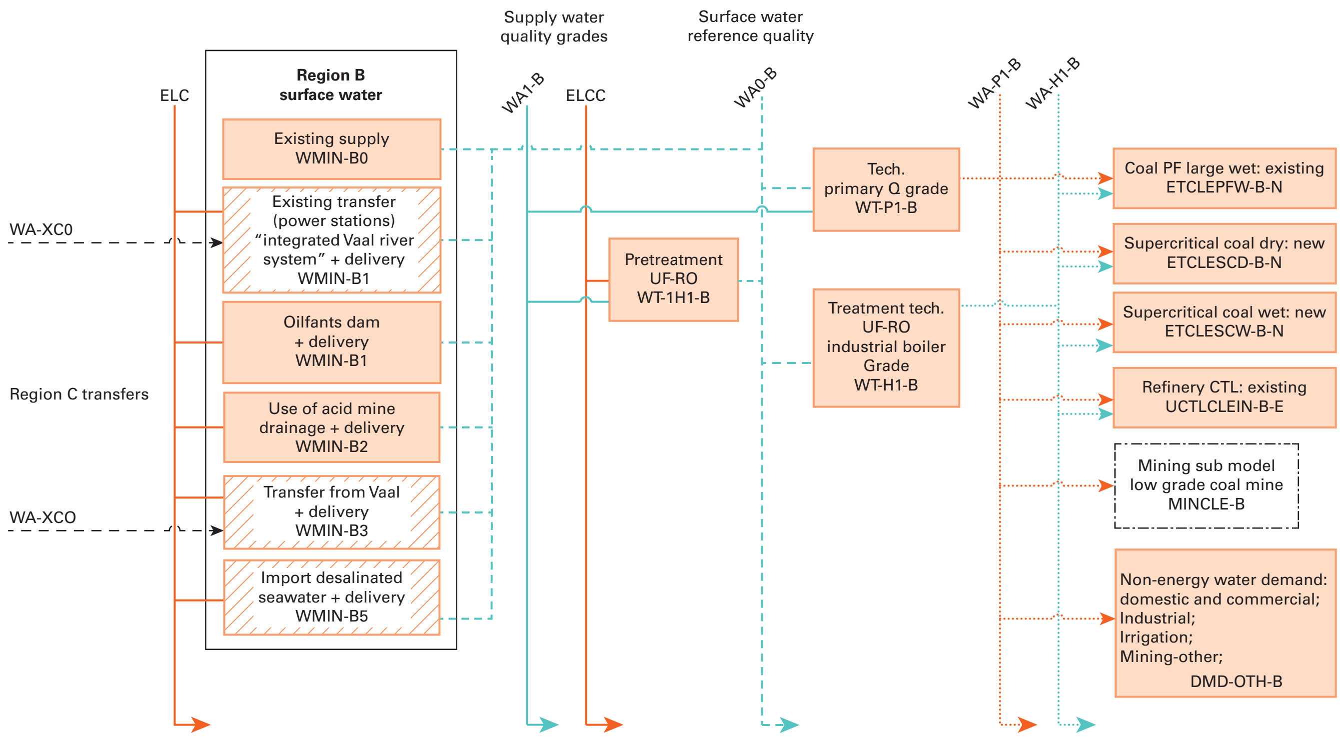


Figure F.3 The SATIM-W Water Supply System for Region C (Upper Vaal WMA)

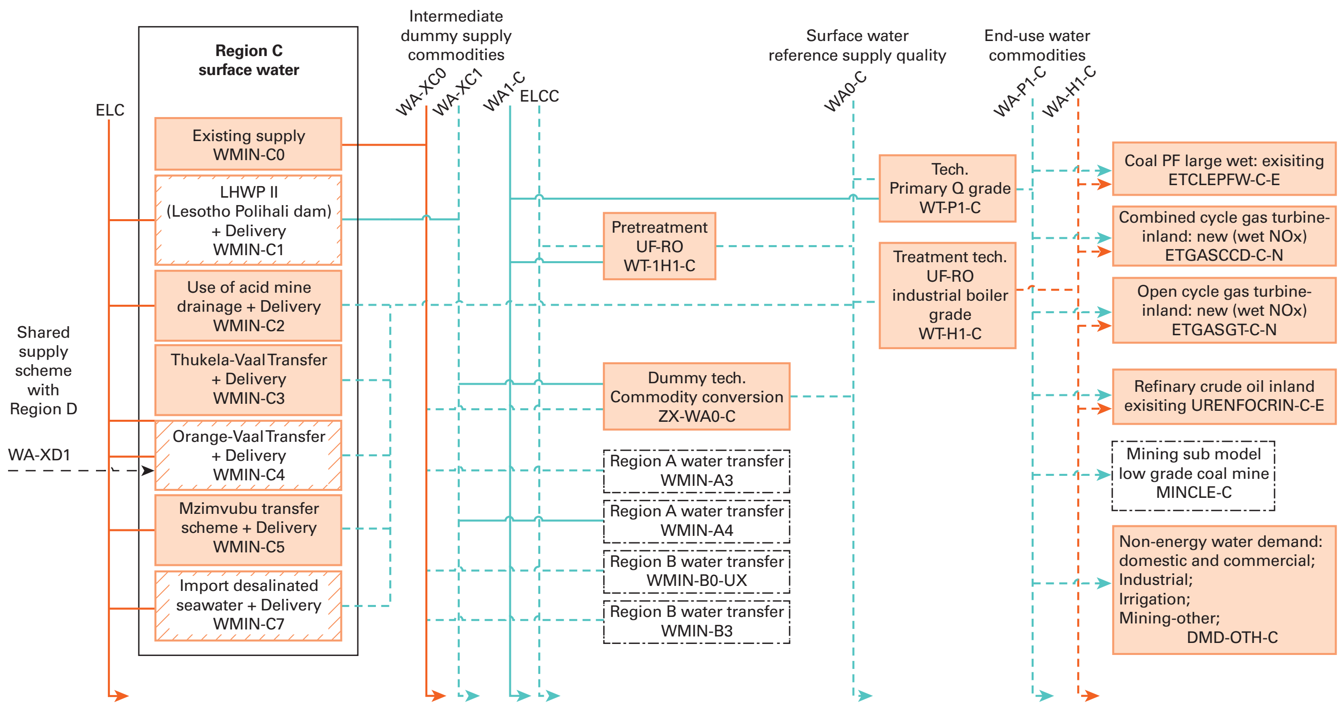
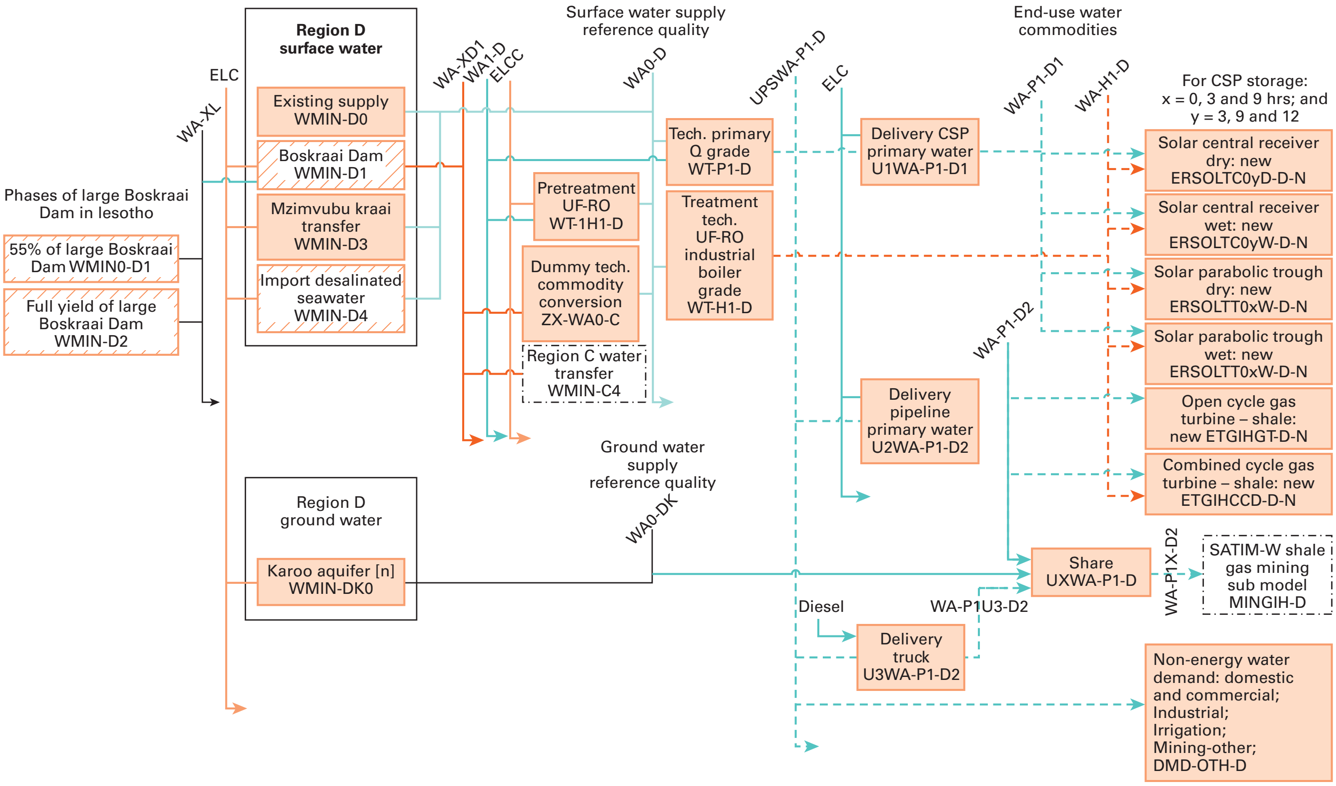


Figure F.4 The SATIM-W Water Supply System for Region D (Orange River WMA)



Appendix G

Data and Sources

Power Plants

Table G.1

Existing and Committed Eskom Coal Plants as Aggregated in SATIM, by Water Supply Region

Plant	SATIM Category	Net Capacity	Cooling Type	Raw Water Use (l/kWh)	Boiler Water Use (l/kWh)	WSR	Interior Climate Zone[d]
Matimba	Large dry existing	3,690	Direct dry (ACC)	0.12	0.02	A	Hot
Medupi	Supercritical new	4,334	Direct dry (ACC)	0.12[c]	0.02[c]	A	Hot
Kendal	Large dry existing	3,840	Indirect dry	0.12	0.07	B	Cold
Duvha	Large existing	3,450	Wet closed cycle	2.2	0.062	B	Cold
Kriel	Large existing	2,850	Wet closed cycle	2.38	0.12	B	Cold
Matla	Large existing	3,450	Wet closed cycle	2.04	0.077	B	Cold
Arnot	Large existing	2,232	Wet closed cycle	2.22	0.157	B	Cold
Hendrina	Small existing	1,865	Wet closed cycle	2.61	0.231	B	Cold
Komati	Small existing	906	Wet closed cycle	2.49	0.105	B	Cold
Kusile	Supercritical new	4,267	Direct dry (ACC)	0.12[c]	0.02[c]	B	Cold
Camden	Small existing	1,440	Wet closed cycle	2.31	0.078	C	Cold
Majuba wet[a]	Large existing	1,980	3 units: Wet-cooled	1.86	0.076	C	Cold
Majuba dry	Large dry existing	1,840	3 units: Direct dry (ACC)	0.12	0.02	C	Cold
Lethabo	Large existing	3,558	Wet closed cycle	1.86	0.076	C	Cold
Tutuka	Large existing	3,510	Wet closed cycle	2.06	0.097	C	Cold
Grootvlei[b]	Small existing	1,130	Wet/dry	1.71	0.18	C	Cold

Source: Eskom 2014.
Note: WSR = water supply region.
a. From Lethabo: similar wet-cooled system apparent.
b. Four units, wet closed cycle, and two units: indirect dry system with spray condenser and dry-cooling tower (implemented during initial experimentation with dry cooling ca. 1960s).
c. Estimated from Matimba.
d. According to the South African National Standard 204 (2008).

Table G.2 Cost and Performance Summary for Pulverized Coal Without FGD

Technology	1 x 750 MW, No FGD	2 x 750 MW, No FGD	6 x 750 MW, No FGD
Heat Rate, kJ/kWh			
Average Annual	9,707	9,707	9,707
100% Load	9,664	9,664	9,664
75% Load	9,844	9,844	9,844
50% Load	10,371	10,371	10,371
25% Load	12,524	12,524	12,524
Net Plant Efficiency, %	37.1	37.1	37.1
Plant Load Factor			
Typical Capacity Factor	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%
Water Usage			
Per Unit of Energy, L/MWh	33.4	33.4	33.4
Sorbent (Limestone) Usage			
Per Unit of Energy, kg/MWh	0	0	0
Air Emissions, kg/MWh			
CO_2	930.2	930.2	930.2
SO_x	9.03	0.90	9.03
NO_x	1.91	1.91	1.91
Particulates	0.13	0.13	0.13
Solid Wastes, kg/MWh			
FGD solids	0.0	0.0	0.0
Fly ash	166.2	166.2	166.2
Bottom ash	3.3	3.3	3.3
Rated Capacity, MW Gross	804	1,608	4,824
Rated Capacity, MW Net	750	1,500	4,500

(continued)

Table G.2 Cost and Performance Summary for Pulverized Coal Without FGD *(continued)*

Technology	1 x 750 MW, No FGD	2 x 750 MW, No FGD	6 x 750 MW, No FGD
Plant Cost Estimates (January 2012)			
Total Overnight Cost, ZAR/kW	20,176	19,114	17,519
Lead-times and Project Schedule, years	4	5	9
Single Unit Expense Schedule, % of TPC per year	10, 25, 45, 20	10, 25, 45, 20	10, 25, 45, 20
Full Project Expense Schedule, % of TPC per year[a]	10, 25, 45, 20	5, 18, 35, 32[a], 10	2, 6, 13, 17*, 17, 16, 15, 11, 3
Fuel Cost Estimates			
First Year (ZAR/GJ)	15.4	15.4	15.4
Expected Escalation (beyond inflation)	0%	0%	0%
Fuel Energy Content, HHV, kJ/kg	17,850	17,850	17,850
O&M Cost Estimates			
Fixed O&M, ZAR/kW-yr	433	409	367
Variable O&M, ZAR/MWh	38.2	38.2	38.2
Availability Estimates			
Equivalent Availability	91.7	91.7	91.7
Maintenance	4.8	4.8	4.8
Unplanned Outages	3.7	3.7	3.7
Performance Estimates			
Economic Life, years	30	30	30

Source: EPRI 2012.
Note: a. Commissioning year of first unit.

Table G.3 Technology Costs Reported in the Revised Integrated Resource Plan, 2012

	Pulverised Coal, with FGD	Pulverised Coal, with CCS	Fluidised Bed Combustion (Coal) with FGD	Fluidised Bed Combustion (Coal) with CCS	IGCC	IGCC, with CCS	Nuclear (Single Unit)	Nuclear Fleet
Rated capacity, net (MW)	4,500 (6 x 750)	4,500 (6 x 750)	250	250	1,288 (644 x 2)	1,288 (644 x 2)	1,600	9,600 (6 x 1,600)
Life of programme	30	30	30	30	30	30	60	60
Typical load factor (%)	85	85	85	85	85	85	92	92
Overnight capital costs (R/kW)	21,572	40,845	21,440	40,165	29,282	39,079	46,841	44,010
Lead time	9	9	4	4	5	5	6	16
Phasing in capital spent (% per year)[a]	2, 6, 13, 17[a], 17, 16, 15, 11, 3	2, 6, 13, 17[a], 17, 16, 15, 11, 3	10, 25, 45, 20	10, 25, 45, 20	5, 18, 35, 32[a], 10	5, 18, 35, 32[a], 10	15, 15, 25, 25, 10, 10	3, 3, 7, 7, 8, 8[a], 8, 8, 8, 8, 8, 8, 6, 6, 2, 2
Adjusted overnight capital costs, accounting for capex phasing (R/kW) and discount rate	25,772	48,789	23,661	44,325	32,340	43,160	58,036	59,226
Fixed O&M (R/kW/a)	552	923	543	902	794	951	532	532
Variable O&M (R/MWh)	51.2	81.4	110.8	149.1	42.5	65.4	29.5	29.5
Variable Fuel costs (R/GJ)	17.5	17.5	8.75	8.75	17.5	17.5	6.8	6.8
Fuel Energy Content, HHV, kJ/kg	17,850	17,850	17,850	17,850	17,850	17,850	3.9×10^9	3.9×10^9
Heat Rate, KJ/kWh, avg	9,812	14,106	10,081	15,425	9,758	12,541	10,762	10,762
Equivalent Avail	91.7	91.7	90.4	90.4	85.7	85.7	94.1	94.1
Maintenance	4.8	4.8	5.7	5.7	4.7	4.7	3	3
Unplanned outages	3.7	3.7	4.1	4.1	10.1	10.1	3	3
Water usage (l/MWh)	231	320	33	43	256.7	1,027	-	-
Sorbent usage (kg/MWh)	15.8	22.8	38	59	0	0		

(continued)

Table G.3 Technology Costs Reported in the Revised Integrated Resource Plan, 2012 *(continued)*

	Pulverised Coal, with FGD	Pulverised Coal, with CCS	Fluidised Bed Combustion (Coal) with FGD	Fluidised Bed Combustion (Coal) with CCS	IGCC	IGCC, with CCS	Nuclear (Single Unit)	Nuclear Fleet
CO_2 emissions (kg/MWh)	947.3	136.2	978	150	930	120		
SO_x emissions (kg/MWh)	0.46	0.66	0.47	0.72	0.18	0.23		
NO_x emissions (kg/MWh)	1.94	0.42	1.39	2.13	0.01	0.01		
Hg (kg/MWh)								
Particulates (kg/MWh)	0.13	0.18	0.13	0.2	0.04	0.05		
Fly ash (kg/MWh)	168	241.5	172.6	264.1				
Bottom ash (kg/MWh)	3.3	4.8	3.4	5.2				
FGD solids (kg/MWh)	25.2	36.2	61.1	93.4				
Levelized Cost								
Adjusted Capital (R/MWh)	287.10	543.51	263.58	493.78	360.27	480.80	524.14	534.89
O&M (R/MWh)	125.33	205.36	183.73	270.24	149.13	193.12	95.51	95.51
Fuel (R/MWh)	171.71	246.86	88.21	134.97	170.77	219.47	73.18	73.18
Total (R/MWh)	584.14	995.72	535.52	898.99	680.17	893.39	692.83	703.58

Source: EPRI 2012.
Note: a. Commissioning year of 1st unit. CCS = carbon capture and storage; FGD = flue gas desulphurization; GIH = gas indigenous shale; IGCC = integrated gasification combined cycle.

Table G.4 Technology Costs Reported in the Revised Integrated Resource Plan, 2012

	OCGT	CCGT	CCGT with CCS	Wind	CSP, Parabolic trough, 3 hrs	CSP, Parabolic trough, 6 hrs	CSP, Parabolic trough, 9 hrs	CSP, Central receiver, 3 hrs	CSP, Central receiver, 6 hrs	CSP, Central receiver, 9 hrs	PV, crystalline silicon, Fixed Tilt
Rated capacity, net (MW)	115	711	591	100 (50 x 2)	125	125	125	125	125	125	10
Life of programme	30	30	30	20	30	30	30	30	30	30	25
Typical load factor (%)	10	50	50	30	30.90	36.90	42.80	31.80	40.00	46.80	19.40
Overnight capital costs (R/kW)	4,357	6,406	13,223	15,394	40,438	51,090	61,176	37,577	44,866	51,604	28,910
Lead time	2	3	3	4	4	4	4	4	4	4	2
Phasing in capital spent (% per year)[a]	90, 10	40, 50, 10	40, 50, 10	5, 5, 10, 80	10, 25, 45, 20	10, 25, 45, 20	10, 25, 45, 20	10, 25, 45, 20	10, 25, 45, 20	10, 25, 45, 20	10, 90
Adjusted overnight capital costs, accounting for capex phasing (R/kW) and discount rate	4,671	7,089	14,632	15,945	44,626	56,381	67,512	41,469	49,513	56,949	29,141
Fixed O&M (R/kW/a)	78	163	292	310	582	599	616	537	555	573	208
Variable O&M (R/MWh)	0.2	0.7	0.7	0	1.9	2	2	0	0	0	0
Variable Fuel costs (R/GJ)	92	92	92	0							
Fuel Energy Content, HHV, kJ/kg	39.3	39.3	39.3	0							
Heat Rate, kJ/kWh, avg	11,926	7,487	9,010	0							
Equivalent Avail	88.8	88.8	88.8	94-97	95	95	95	92	92	92	95
Maintenance	6.9	6.9	6.9	6							5
Unplanned outages	4.6	4.6	4.6								
Water usage, l/MWh	19.8	12.7	19.2		299	304	308	310	302	300	

(continued)

Table G.4 Technology Costs Reported in the Revised Integrated Resource Plan, 2012 *(continued)*

	OCGT	CCGT	CCGT with CCS	Wind	CSP, Parabolic trough, 3 hrs	CSP, Parabolic trough, 6 hrs	CSP, Parabolic trough, 9 hrs	CSP, Central receiver, 3 hrs	CSP, Central receiver, 6 hrs	CSP, Central receiver, 9 hrs	PV, crystalline silicon, Fixed Tilt
Sorbent usage, kg/MWh											
$C0_2$ emissions (kg/MWh)	618	388	47								
SO_x emissions (kg/MWh)	0	0	0								
NO_x emissions (kg/MWh)	0.27	0 29	0.35								
Hg (kg/MWh)											
Particulates (kg/MWh)											
Fly ash (kg/MWh)											
Bottom ash (kg/MWh)											
FGD solids (kg/MWh)											
Levelized Cost											
Adjusted Capital (R/MWh)	442.29	134.25	277.10	575.93	1367.51	1446.80	1493.62	1234.81	1172.09	1152.24	1498.70
O&M (R/MWh)	89.24	37.91	67.37	117.96	216.91	187.31	166.30	192.77	158.39	139.77	122.39
Fuel (R/MWh)	1097.19	688.80	828.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total (R/MWh)	1628.73	860.97	1173.39	693.89	1584.42	1634.11	1659.92	1427.58	1330.48	1292.01	1621.09

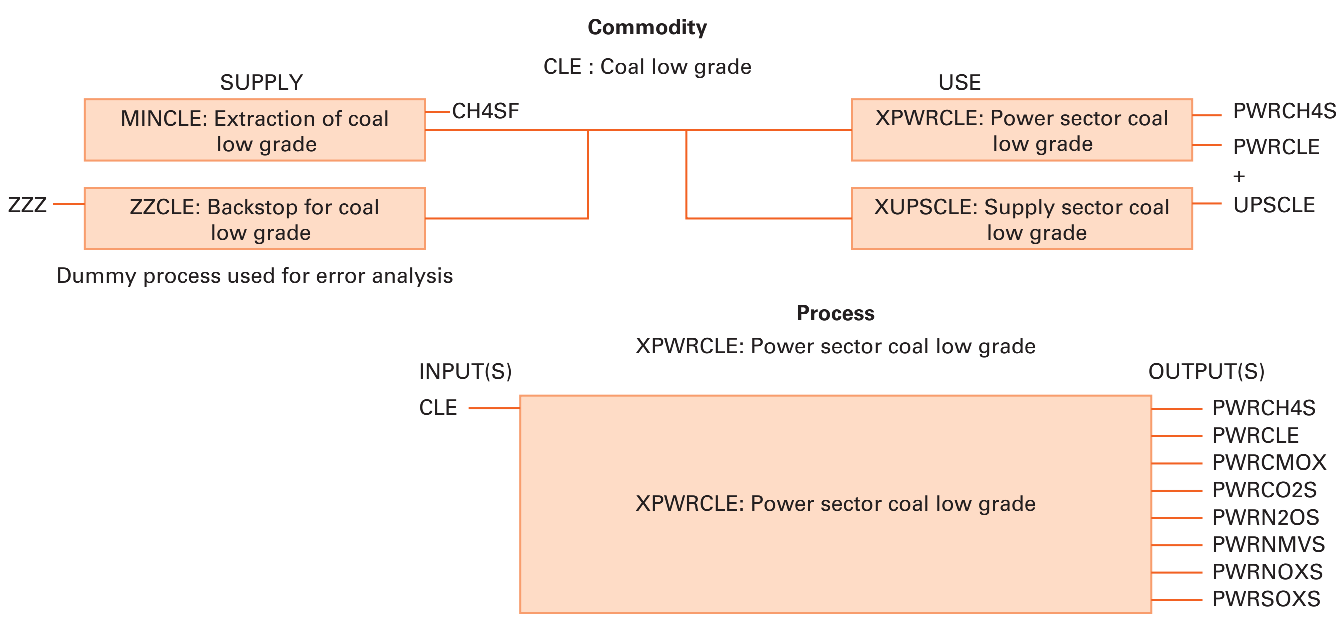
Source: EPRI 2012.
Note: a. Commissioning year of 1st unit

Coal Mines

With the exception of the Majuba plant, all coal-fired plants are linked to a coal mine which supplies the plants via a run-of-mine design, the majority of which are conveyor systems. In the aggregated representation, coal supply to the power sector incurs no distribution cost (see figure G.1). Also shown in the figure are the associated fugitive emissions and additional upstream supply. In South African TIMES model (SATIM), commodity demand for coal-mining activity is captured in the mining subsector under industry while supply and distribution are implemented in the supply sector. Work is underway, however, to place coal mining—both opencast and underground—in the supply sector.

SATIM-W conforms to the current SATIM representation of coal commodities, which define three calorific grades of coal—high, low, and discard. Current power-generation technologies rely on low-grade coal. Future Fluidized Bed Combustion technologies will however use discard coal. Table G.5 lists the calorific value design range of the fleet of plants built for low-grade coal. An average calorific value of 21 MJ/kg is obtained for low-grade coal by weighting plant capacity and efficiency.

Figure G.1 Coal Supply to the Power Sector as Implemented in SATIM



Note: PWRCH4S = power sector methane South Africa; PWRCMOX = power sector carbon monoxide South Africa; PWRCO2S = power sector carbon dioxide South Africa; PWRNMVS = power sector non-methane volatile organic compounds South Africa; PWRN2OS = power sector nitrous oxide South Africa; PWRNOXS = power sector nitrogen gases South Africa; PWRSOXS= power sector sulphur gases South Africa; UPSCLE = supply sector coal low grade.

Table G.5 Estimated Caloric Values for Coal Power Plants

Power Station	Value Applied
Arnot	22–24 MJ/kg
Camden	
Tutuka	
Non-Eskom	
Kriel	20–22 MJ/kg
Duvha	
Grootvle	
Hendrina	
Komati	
Majuba	
Matla	
Kendal	18–20 MJ/kg
Matimba	
Medupi	
Kusile	
Sasol 1 (Sasolburg)	
Sasol 2 & 3 (Secunda)	
Lethabo	16–18 MJ/kg

Source: Green House 2013.

Regional distribution costs are taken from the South African Coal Road Map (SACRM) study, as shown in table G.6. For the coastal coal build option, additional distribution cost is required for transport beyond the Richards Bay Terminal (RBT). The cost for intraregional coal distribution within the Central Basin is used as an estimate.

Estimates of water consumption for coal mining are given in table G.7.

Table G.8 lists, in energy units, the estimated consumption of energy commodities by coal mines per unit of coal produced. The values are estimated from data obtained from the annual reports of large coal mines (Exxaro 2013; Anglo American 2007).

Table G.6 Rail Distribution Costs for the Supply of Coal

Destination	Transport Cost (ZAR/ton)
Waterberg to Richards Bay Coal Terminal (RBT)	258, rising to 308 in 2015 to account for the cost of building a new rail line from Waterberg
Mpumalanga to RBT	126,150[a]
Waterberg to Central Basin/Vereeniging	132,158[a]
Within Central Basin	30[b]

Source: Green House 2013.
a. Adjusted to reflect increased cost for expanding rail capacity.
b. Truck transport estimate (McGeorge 2014).

Table G.7 Freshwater Consumption Estimated for Coal Mining (M^3/ton)

Water Usage (Estimated Purchased Volumes of Freshwater)	SACRM (2013)	Buermann (1982)	Golder and Associates (2013)
Region	m^3/t	m^3/t	m^3/t
Waterberg (A)	0.065	0.2002	0.2730
Central Basin (B and C)	0.05		
	Mm^3/PJ	Mm^3/PJ	Mm^3/PJ
A[a]	0.0031	0.0094	0.0129
B/C[a]	0.0024	0.0073	0.0099[b]

Source: Golder and Associates analysis for the Exxaro mine in the Waterberg (Region A).
a. Calculated for an average CV of 21 MJ/kg.
b. Derived from SACRM data.

Table G.8 Coal Mining Feedstock Commodities

Commodity	Transport Cost (PJ/PJ)
Electricity	0.0025
Diesel	0.0023

Coal Mine Wastewater Treatment

In order to attribute a cost of treating water for environmental discharge in SATIM-W, data from *The Olifants River Project* was used to assess the feasibility of processing mine water in the Olifants water management area (WMA). It examined a number of collieries with respect to two water-treatment scenarios: (1) treat and discharge, and (2) treat and supply to towns (Golder and Associates 2012). The costs of the first option for selected collieries are summarized in table G.9. The costs are indicative of the treatment required for 146.5 ML/day (53 Mm^3/a).

In SATIM-W, Option 1, which is the lower cost option, is chosen as the Reference case for coal mining environmental best practice. The costs are indicative for Region B in SATIM-W, but are applied to Regions A and C as well. The costs in table G.9 are adjusted to reflect the new capacity required, and therefore only the capital costs for new plants are used. The effect is to increase the unit cost of treating effluent. The adjusted costs required for implementation in SATIM-W are given in table G.10.

The volumes of mine decant do not necessarily correlate with the amounts required for coal washing; aside from coal-washing slurry, totals may include water pumped out after mining has ceased. To mitigate acid mine drainage (AMD) after the mining has ceased, mine operators are required to remove any remaining water via pumping. This cost is attributed to mining activity, so the volume of acid mine drainage (AMD) treated over the production life of a region is estimated per ton of mined coal. This volume assumes an average lifetime of 100 years of mining, which includes removal of excess water via pumping. Regional coal reserves are estimated from Prevost (2014).

A first-order estimate is achieved by factoring the annual treatment of effluent at 53 Mm^3/annum (The Olifants River Project) needed to extract 20,000 Mt of coal over a 100-year production life for the Central Basin. The Highveld coalfields (ca. 30 percent of reserves) are estimated to have a storage or residual volume of 653 Mm^3 of mine water produced by past and future mining activity (Golder and Associates 2012). The residual volume represents the accumulated mine water in existing and abandoned mines. An estimate of 1,300 Mm^3 (double the existing volume) for the

Table G.9 Olifants River Project: Cost Summary for Managing Colliery Effluent

Mine Water Reclamation Plant	Flow	Reclamation Plants			Discharge Pumpstations and Pipelines			Water Resource Charge	
	Ml/day	Capex (R million)	Opex (R/year)	Opex (R/m³)	Capex (R million)	Opex (R/year)	Opex (R/m³)	Charge (R/year)	Charge (R/m³)
New Largo WRP	6.0	R151 600 000.00	R27 747 300.00	12.7	R7 894 129.50	R294 400.87	0.13	R438 000.00	R0.20
Kriel WRP	14.0	R287 500 000.00	R47 829 600.00	9.4	R27 762 106.50	R686 935.37	0.13	R1 022 000.00	R0.20
Matla WRP	12.0	R257 700 000.00	R43 143 000.00	9.9	R33 864 241.50	R588 801.75	0.13	R876 000.00	R0.20
Xstrata WRP	15.0	R302 000 000.00	R50 151 000.00	9.2	R49 609 332.00	R736 002.18	0.13	R1 095 000.00	R0.20
Emalahleni WRP – Module 1	25.0		R73 547 500.00	8.1		R1 226 670.31	0.13	R1 825 000.00	R0.20
Emalahleni WRP – Module 2	25.0	R422 300 000.00	R73 547 500.00	8.1	R38 914 287.00	R1 226 670.31	0.13	R1 825 000.00	R0.20
Middelburg WRP	15.0	R302 000 000.00	R50 370 000.00	9.2	R28 922 814.00	R736 002.18	0.13	R1 095 000.00	R0.20
Mafube WRP	16.0	R316 200 000.00	R52 384 800.00	9.0	R32 276 268.00	R785 69.00	0.13	R1 168 000.00	R0.20
Optimum WRP	15.0		R38 325 000.00	7.0	R28 524 402.00	R736 002.18	0.13	R1 095 000.00	R0.20
Optimum Eikeboom WRP	3.5	R103 200 000.00	R20 503 875.00	16.1	R3 319 833.00	R171 733.84	0.13	R255 500.00	R0.20

Source: Golder and Associates 2012.

Table G.10 Water-Treatment Costs for Coal Mines in SATIM-W

Investment Cost ZAR(x1000)/Mm³	Fixed OM ZAR(x1000)/year	Variable OM (kWh/m³)
60,842	9,742	3

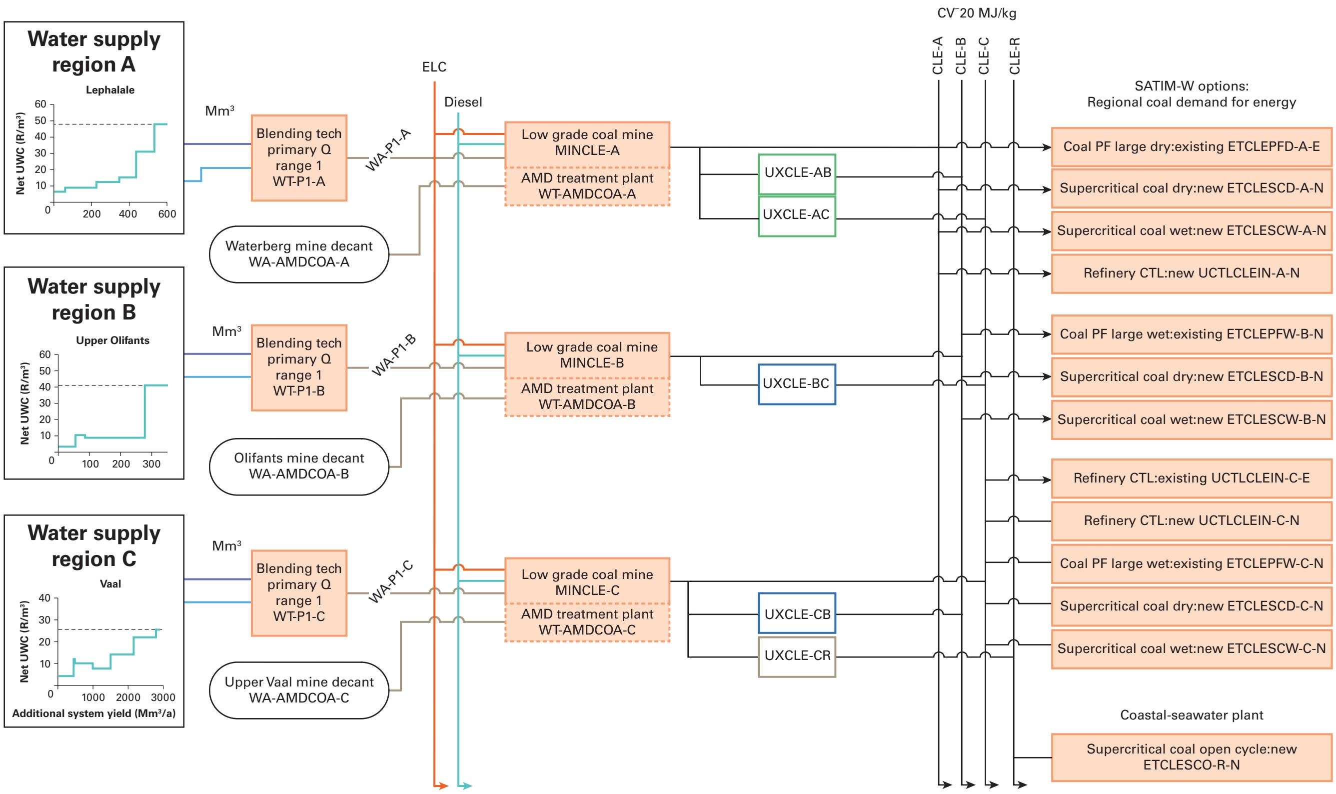
Central Basin is used. This gives a factor of 0.33 liters of effluent treated per kg of coal mined (or 0.33 Mm³/Mt); this factor is applied to the three coal mining regions in SATIM-W. The sensitivity to the residual volume gives a range of -10 percent to +30 percent for the factor.

For a 20-year treatment plant life, using a discount rate of 8 percent, the cost amounts to about 6 (ZAR)/t of coal mined. For a weighted average calorific value of 20 MJ/kg and a net efficiency of 33 percent for electricity generation, this equates to a cost of 3c/kWh of electricity to address water pollution. This base cost would vary with the price of electricity, energy intensity of treatment, and increasing volumes of effluent being treated. The modeling framework allows these factors to be considered. Nkambule and Blignaut (2012) attribute an externality cost of coal mining and transport in South Africa in the range of 20.24 c/kWh and 39.3 c/kWh. Their analysis attributes less than 1 percent of the cost to water pollution, with the opportunity cost of water dominating the price.

A Coal Mining Submodel: The Reference Energy-Water System (REWS)

See below for a simplified REWS diagram for coal mining in SATIM W. The water needs for coal mining is taken to be of basic quality. As with power plants, coal mines are disaggregated by regional water supply systems. Coal is delivered to power plants is via regional distribution. Region A contains the Waterberg deposits; Regions B and C cover the Central Basin. The distribution technologies are color-coded in the REWS to show similar costs. Also included is the rail link to the Richards Bay Export Terminal (RBT). A coastal-build scenario near the RBT is selected as the most likely given the area's existing high-capacity transport infrastructure. As the cost for transport to RBT from either B or C is similar, only transport from either region is necessary in the model. In the REWS, Region C is chosen. As shown in figure G.2, the REWS diagram and selected for SATIM-W is the inclusion of the cost of a water treatment facility for discharge mine water.

Figure G.2 Coal Mining Linked to Regional Water Supply Systems, SATIM-W

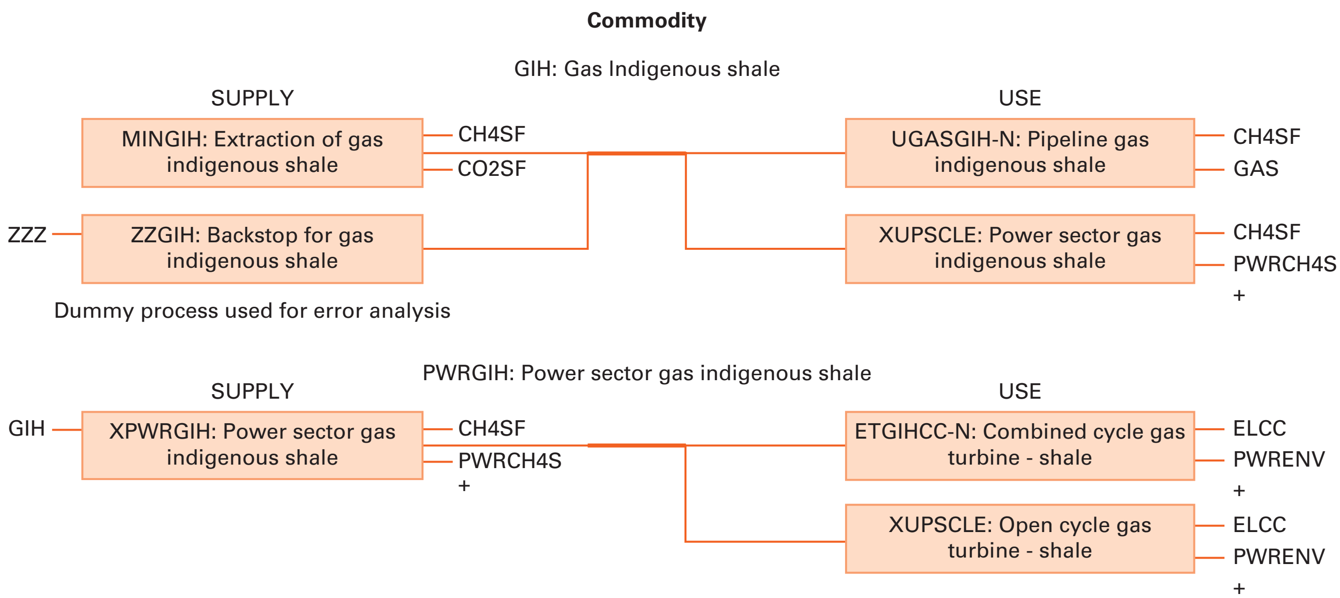


Note: Refer to Appendix F "Regional Supply Water Systems in SATIM-W" for naming conventions. CTL = coal-to-liquids.

Shale Gas Extraction

Figure G.3 depicts the two forms of shale gas utilization in the model: (1) in the vicinity of extraction; and (2) inland in the Mpumalanga region where the majority of coal-fired plants are located. Generation co-located with shale gas mining incurs only distribution costs while inland generation incurs both transmission and distribution costs. The figure depicts the fugitive emissions associated with extraction (MINGIH) and distribution (XPWRGIH) as well as the existing 2c/kWh fossil fuel levy (PWRENV). Also shown are the open- and combined-cycle gas turbine (OCGT and CCGT) gas plant technologies.

Figure G.3 Shale Gas Extraction and Co-Located Generation in SATIM



Water and Shale Gas Extraction

Figure G.4 displays the cumulative gas produced, and the volumes of water required, for the Barnett shale production region in Texas. The chart indicates a strong correlation between total gas production and water use. Although the Karoo region is geologically similar to the Barnett region, a Soekor exploration found dolomite dykes (Vermeulen 2012); these present a challenge as they might act as conduits for fracking fluid and gas to migrate into shallow aquifers.

To obtain an average or levelized water-withdrawal rate for the extraction of shale gas, this analysis used the estimated total volume of water withdrawn for a given production life for the Karoo region. Assuming that 1 Tcf ~ 1000 PJ, the water intensity required for shale gas extraction in the Karoo is estimated at 17,000 m^3/PJ. The local geology and other factors (such as water quality and extraction methodology) will influence water intensity, and so that this value is subject to refinement.

Aside from the quantity of water required, the chemical composition of the volume of returned fracturing fluid might be a source of water pollution (Royal Academy of Engineering 2012). Vengosh and others (2014) reported of number environmental breaches caused by shale gas extraction in Pennsylvania therefore recommend that the industry adopt a zero liquid effluent discharge (ZLED) policy due to the potential