WORLD BANK THIRSTY ENERGY CASE STUDY – SOUTH AFRICA

ENERGY RESEARCH CENTRE
University of Cape Town

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Acronyms

AMD	Acid Mine Drainage
BAU	Business-as-usual
Bn	Billion
CCGT	Combined Cycle Gas Turbine
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 Desulphurization
GTL	Gas-to-Liquids
GHG	Greenhouse Gas
IAM	Integrated Assessment Model
IBT	Inter-Basin Transfers
IEP	Integrated Energy Plan
IRP	Integrated Resource Plan
LNG	Liquefied Natural Gas
LTAS	Long Term Adaptation Scenarios
mm	millimetre
Mt	Million tons
MWSC	Marginal Water Supply Cost (curve)
NO_x	Nitrogen Oxides
NREL	National Renewables Energy Laboratory
OCGT	Open Cycle Gas Turbine
OM	Operating and Maintenance (cost)
PPD	Peak-Plateau-Decline (of emissions)
PV	Photovoltaics (solar)

PWTC	Primary water treatment costs
R	South African Rand
RE	Renewable Energy
REIPPP	Renewable Energy Independent Power Producer Programme
SO_x	Sulphur Oxides
SWTC	Secondary water treatment costs
TRMC	Total Regional Marginal Cost (of water)
UCE	Un-Constrained Emissions (scenario)
UNFCCC	United Nations Framework Convention on Climate Change
UWC	Unit Water Cost
VRES	Vaal River Eastern Subsystem
WDMC	Waste Discharge Mitigation Charges
WEC	World Energy Council
WSA	Water Supply Area
WSR	Water Supply Region
WRMC	Water Resources Management Charges
WSDC	Water Supply Delivery Costs
WSEC	Water Supply Energy Costs
WSSIC	Water Supply Scheme Infrastructure Costs
ZLED	Zero Liquid Effluent Discharge

Executive Summary

Both water and energy are crucial for life and are entwined such that the utilisation of one resource is dependent on the availability of the other. The sustainable supply of services from these two interdependent resources constitutes a set of integrated challenges commonly referred to as the water-energy nexus. South Africa is a water stressed country experiencing an electricity supply crisis with experts warning of a future water supply crisis, such that the water-energy nexus is particularly relevant in this country at this time.

The World Bank has embarked on a global initiative called 'Thirsty Energy' to assist countries in tackling water energy management challenges in an integrated manner, rather than the traditional "silo" approach starting with the energy sector as an entry point. A primary aim is to demonstrate the importance of combined energy and water management approaches and practical methodologies that can be applied to evidence-based operational tools.

South Africa has established long term infrastructure planning processes for the supply of energy and water in the public domain, both of which have historically taken into account the cost and scarcity of the other, though to varying degrees. The dominant South African utility, ESKOM, has a Zero Liquid Effluent Discharge (ZLED) Policy, for example, and has significant historical investment in dry cooling for thermal plants as well as a policy of dry cooling for all future plants. South Africa is therefore

uniquely placed as a useful case study for the Thirsty Energy Program for the purposes of developing and demonstrating methodologies for integrated planning tools.

Thirsty Energy identified the South African TIMES model (SATIM), a public domain energy systems model developed by the University of Cape Town's Energy Research Centre (ERC), as a suitable base model which could be adapted to an integrated water-energy planning tool. SATIM is a national energy system model built using the TIMES modelling platform. TIMES is a partial equilibrium linear optimisation framework capable of representing the entire energy system, including its economic costs and its emissions. The proposed Thirsty Energy Case Study, documented in this report, involved the development of a water-energy SATIM model (SATIM-W), in which options for bulk water infrastructure and alternative sources (e.g., desalination) are integrated within the model. The wealth of water planning datasets and cost curves available from the Department of Water and Sanitation publications on its Water Resources Yield Model and supported by local water modelling experts serve as the main data source for this purpose. A regional water infrastructure plan therefore emerges in concert with a least-cost energy supply plan as the model optimises under constraints taking into consideration water requirements for energy, and vice versa.

By highlighting key interactions of the water-energy relationship for energy supply, it is believed that the analysis of this initial Thirsty Energy Case Study provides a tool which better informs strategic water and energy supply planning. Preliminary results relating to questions of concern for South Africa in the context of water for energy supply are summarised below.

1. **The current practice of commissioning dry-cooled coal power plants appears economically justified.**

When full consideration is given to water supply costs, dry-cooling is the preferred cooling option for commissioning new coal plants in the Waterberg which is the preferential region of expanding coal based electricity generation. New dry-cooled capacity of approximately 40 GW is commissioned by 2050 and includes the replacement of the existing stock of 37 GW which are mostly retired by then.

In the absence of water supply costs wet-cooled plants are the default choice due to their lower investment costs and higher net generation efficiencies.

2. **Stricter environmental controls reduces investment in coal-based energy supply.**

Air emissions regulations requiring Flue Gas Desulphurisation (FGD) is a major dis-incentive for new CTL plants due to the cost of complying with stricter air emissions controls. As a result of a reduction in new CTL capacity, the requirement for new water supply schemes in the Waterberg is also deferred.

3. **Requiring existing power stations to retrofit FGD has little impact on regional water supply schemes. Non-energy water requirements are the main drivers of investment in the regions where the bulk of existing coal power plants are located.**

Future water supply schemes that are commissioned for the Business-As-Usual (BAU) case appear sufficient to also meet the air emissions regulations requiring FGD retrofits for power plants in the Upper Vaal and Olifants regions.

4. **The quality of water transfers to the Waterberg is a limiting factor in the future expansion of the energy sector for the region.**

The extent to which new power plants and Coal-to-Liquids (CTL) production occurs in the Waterberg is shown to be affected by the cost treating imported water of lower quality compared to the existing local supply.

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 %) compared to the BAU case by 2050. The reduction is largely substituted by increased investment in Renewable Energy (RE) capacity, in approximately equal share between Solar Thermal and Solar PV (distributed and centralised). An additional 9 GW of RE capacity is required along with a further 2 GW of Combined-Cycle Gas Turbine (CCGT) power plants.

Similarly, a reduction of 20 % (approximately 100 PJ/a or 60k bbl/d) in new CTL capacity occurs by 2050 when the imported water quality s costed.

5. **The cost of water supply is not the primary driver for shale gas production. Although regional (surface) water supply costs could potentially double, shale gas remains attractive for electricity supply.**

The growth of shale gas utilisation for power generation occurs at a similar rate when accounting for water supply costs. Thus, the cost of water does not appear to alter the decision to invest in shale gas for power, based upon the current assumptions which exclude the cost of treating return-flow effluent.

An arbitrary limit of on-site groundwater usage of 1 Mm^3/a and a reliance on trucking for surface water supply for shale-gas recovery in the early stages of development for the sector, results in a relatively expensive water supply cost. The initial high cost of water supply suggests that the construction of a water supply pipeline in 2030 would be economical by reducing the cost of supply by ~95%. The lower cost of water supply would accelerate shale gas development in the region.

However, it is important to note that in this preliminary analysis the potential costs of:

1) treatment and disposal of flow-back effluent; and
2) a detailed analysis of the distribution or delivery costs of water supply

are not fully reflected in the current model. When these considerations are fully incorporated and modelled, the water-energy implications for shale gas extraction and utilisation may vary from the results reflected in this analysis.

6. **Policies limiting carbon emissions may result in stranded water-energy infrastructure.**

When considering a 14 Gt and 10 Gt cumulative carbon cap for energy emissions by 2050 we explore the risk to investment in energy and water supply options in the near term. For the analysis, we note that no new investment in CTL capacity occurs for a policy of limiting CO_2eq emissions. Furthermore, with an emissions cap, the life of the existing CTL facility is shortened by 20 years with a more restrictive cap of 10 Gt compared to the 5 year early decommissioning phase for the 14Gt limit.

A 10 Gt limit results in a reliance on importation of refined petroleum products for which 80% of existing CTL production is substituted by 2025. The remainder coming from increased production in the existing refineries. Although a 14 Gt limit allows the existing CTL facility to operate at full capacity in 2025, there still is an increase in finished petroleum product imports owing to a lack of investment in new CTL capacity in the Waterberg.

In contrast, the existing and committed-build coal power plants are less at risk under the 14 Gt limit as these coal assets remain operational for their entire production life with no new plants commissioned.

A 10 Gt limit would however reduce the operating life of the committed-build plants by at least 15 years with decommissioning occurring by 2035. In addition, the 10 Gt limit would shift electricity production from the Waterberg to the Orange River region where CSP technology would be the primary substitute.

In addition to the risk to coal derived energy supply infrastructure, investment for related water supply infrastructure to the Waterberg is also at risk for both CO_2eq limits considered. An increase in supply cost in 2035 in the Waterberg would occur due to the growth in demand from the non-energy sectors requiring investment which had been deferred due to idle capacity.

7. **Current Climate Change modelling suggests that the influence of climate has a minimal impact on future energy supply planning. Regional water supply disparities are mitigated by the reliance on a national integrated water supply network.**

Climate Change as a driver of investment in energy supply is seen to largely manifest under a combination of a projected change in regional climate and a policy limiting carbon emissions rather than being solely influenced by climatic changes. This results from the integrated water supply network which enables the transfer of water from high rainfall regions (e.g. Lesotho) and of urban return flows (e.g. Johannesburg) to water scarce regions such as the Waterberg.

The impact of increased water demand resulting from a warmer and drier from 2030, would trigger further investment in water infrastructure which would causes the average cost of water supply to increase. The rise in cost is significant enough, to shift investment in CSP from predominately wet-cooled technology in the BAU case to dry cooling for additional CSP capacity from 2045 onwards.

The results demonstrate the value of the SATIM-W model as an integrated assessment tool that can better inform decision makers of the potential costs, benefits and risks of alternative policies and technology choices under a range of possible futures conditions. Employing an integrated approach that looks systematically at the development of both water and energy sectors can potentially help avoid such oversights.

It is envisioned that the initial phase of the modelling and analysis presented in the case study will be, in future, further developed. The main areas identified to expand the water-energy focus are summarised below.

- Harmonising growth assumptions driving non-energy water demands and energy demands, which currently come from two different modelling frameworks that are only broadly internally consistent.

- Incorporating a more detailed disaggregated representation of non-energy water consumption in order to examine water reallocation schemes and the impact of water-use efficiency.

- Linkage with an economic model to enable a more holistic assessment of economy-wide effects of changes to, for example, labour costs, income levels and industrial activity.

- Incorporating water supply linkages to a variety of biofuel feedstocks.

- Exploring approaches to incorporating the externality costs of energy supply such as, for example, the societal impacts from air and water pollution.

I. Why the Water-Energy Nexus and Why Now?

Water is "*a finite, vulnerable and essential resource, essential to sustain life, development and the environment*" (Ludwig et al. 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." (Walt Patterson, 2007)

I.1 The Critical Path of the Global Water-Energy Nexus

Both water and energy are crucial for life and are entwined such that the utilisation of each resource is dependent on the availability of the other. 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 this paramount challenge, the World Bank has embarked on the Thirsty Energy initiative designed to bring leading practitioners in the field of water and energy in key developing countries together to demonstrate advanced approaches to integrated water-energy planning, the merits arising from such new methods, and the policy relevance of the resulting analysis. The impetus for this program is readily illustrated by some compelling real world examples of the growing interdependence of water-energy issues.

In many regions, the energy required to meet water supply needs are significant and are growing. In the USA, the State of California receives 30% of its water supply from ground water sources and the electricity demand for ground water pumping during the drier summer period is greater than the energy demanded by the remaining water conveyance systems combined (Bennett and Park, 2010). In northern India, unsustainable ground water abstraction by farmers relying on heavily subsidised electricity is resulting in both increased electricity demand and water scarcity as the water table is lowered and ground water is pumped from greater depths (IAEA, 2009). In the Middle East and North Africa, sea water desalination is already an important supply of potable water, and is derived from relatively energy intensive processes (Cooley, 2011), and use of desalination technology is expanding to other regions. In China, large scale conveyance of water is required from the country's water abundant south to meet the demand in the drier energy intensive north (DUT, 2004).

In addition, weather and climate change are affecting energy production. An illustration of this in the United States is the Brown's Ferry Nuclear Power Plant on the Tennessee River , which is one of the 70 out of 118 reactors in the United States with once through cooling, often experiences warm river flows, such that the temperature of the water at the plant's cooling intakes approaches or exceeds the Alabama water quality criterion of 30^{o}C (US DoE, 2006; NRC, 2012) necessitating plant shutdown. In 2010, the resulting reduced availability of the Brown's Ferry plant cost Tennessee Valley Authority customers $50 million (Ingram et al, 2013). The Brown's Ferry, Sequoyah and Vermont Yankee nuclear plant's cooling systems have been augmented with supplementary cooling towers to reduce outlet temperatures in the summer months (NRC, 2012) at a further cost to customers.

In 2012, the 880 MW reactor at the Millstone nuclear plant in Waterford, Connecticut was shut down because the water in Long Island Sound at intake rose to a temperature of 24.8^{o}C exceeding the 23.8^{o}C stipulated under the reactor's safety rules as a result of the warmest summer temperatures since commissioning in 1970 (The New York Times, 2012). Ultimately the costs of water constraints on power are passed to the consumer as shown by McDermott and Nilsen (2012) who showed that in Germany "electricity price is significantly impacted by both a change in river temperatures and the relative abundance of river water".

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 entire Marathwada region which caused the Khadka dam supplying the plant to 'almost dry up' (NDTV India, 2013).

Furthermore, in many parts of the world, water availability is becoming more constrained through the combined effects of increasing demands, deteriorating water quality, and climate change. This presents a significant threat to future energy production (WEC, 2010). Similarly, ever increasing water demand requires investment in more energy intensive technologies such as Inter-Basin Transfers (IBT), desalination and rehabilitation and re-use of waste water (Hussey and Pittock, 2012). This will add additional energy demands to an already energy constrained world. 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 leading to increased water supply shortages.

This networked system of resource supply trade-offs is referred to as the Water-Energy Nexus. The interconnected nature of energy and water supply infrastructure naturally suggests the need for taking an integrated approach to optimal strategic water-energy resource planning. The mutual dependencies between water and energy supply are shown graphically below in Figure 1.

In addition, energy and water are critical aspects of any economy, and yet despite their strong interdependence, the two sectors are often managed independently (Hussey and Pittock, 2012). Developing an integrated approach to modelling the water-energy nexus is critical to supporting the development of effective national policies and regulations to ensure continued economic development and growth in a sustainable way (Bazilian et al, 2011; Rodriguez et al, 2013).

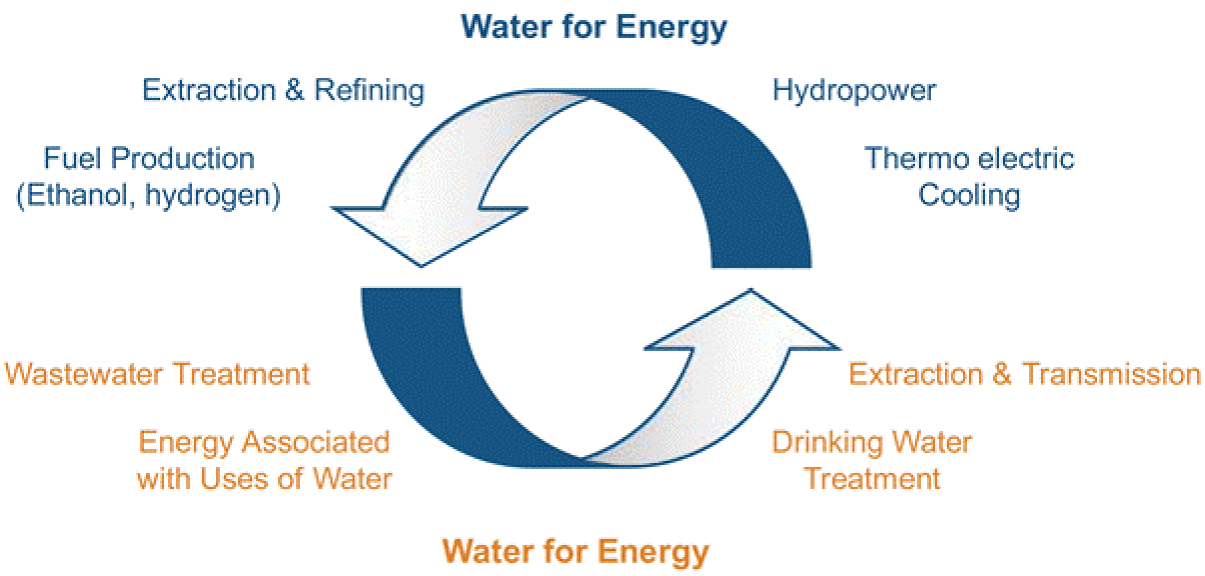


Figure 1: The Water-Energy Nexus (Source: WEC, 2010)

To help address the energy-water nexus challenge, the World Bank has initiated the 'Thirsty Energy' program which aims to assist countries to tackle water energy management and planning in an integrated manner rather than the traditional "silo" approach. With the energy sector as the entry point, a primary aim is 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 future water and energy planning requires the inclusion of water costs and constraints in energy system models, and energy consideration into water supply models; leading towards a single integrated model of the water-energy nexus to support future policy and planning. As a first important step, the World Bank has chosen South Africa as the initial Thirsty Energy Case Study.

I.2 The Rationale for a South Africa Case Study

Like much of the developing world, South Africa is a country struggling to achieve an ambitious development agenda in an unsustainably resource and emissions intensive manner and with aging infrastructure (Coetzer, 2012; Gaunt, 2010). The electricity supply capacity crisis of 2007/8 led to power shortages with a direct impact on economic growth (Eberhard, 2008). The electricity supply shortages currently experienced will most likely have similar economic consequences (NERSA, 2015b). The dilemma of planning for economic growth in an energy constrained environment is further exacerbated by the future prospect of a lack of adequate water supply. 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). And now increasingly the uncertainties introduced by global climate change further complicate preparing for tomorrow's water and energy needs. Thus, to ensure that the country's growth aspirations remain viable, prudent coordinated planning for future energy and water supply and use is essential.

The water demands for electricity generation are well documented for Eskom, the dominant South African utility (Eskom, 2008; SEI, 2012). Accordingly, South Africa's Integrated Resource Plan (IRP) includes water availability as a criterion to assess power generation alternatives. For example, in the country's northern Waterberg region, the consideration of water scarcity was key in the decision to construct only dry-cooled coal power plants going forward. Conversely, the consumption of water requires energy, and as the demand for water is often dislocated from the source, requiring pumping, sometimes over great distances, and often treatment before the water is put to productive use.

South Africa has established long term infrastructure planning processes for the supply of both resources in the public domain under the auspices of the Department of Energy and Department of Water and Sanitation, respectively. The planning of both resources has taken into account cost and scarcity of the other to various degrees, but to date integrated modelling of the bulk supply infrastructure of both systems has not been undertaken. For example, Eskom has a Zero Liquid Effluent Discharge (ZLED) policy and has significant historical investment in dry-cooling for thermal plants and a policy of dry-cooling for all future plants. South Africa is therefore uniquely placed as the initial case study country for the Thirsty Energy program to develop and demonstrate an advanced integrated water-energy planning tool.

Thirsty Energy identified the South African TIMES model (SATIM), a public domain energy systems model developed by the University of Cape Town's Energy Research Centre (ERC), as a suitable base model which could be adapted to an integrated water-energy planning tool. SATIM 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 (IEA-ETSAP), an international community operating under an IEA implementing agreement that uses long term energy scenarios to analyse energy and environmental problems (IEA, 2011, IEA, 2015, Giannakidis et al., 2015). TIMES is a partial equilibrium linear optimisation model capable of representing the 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 for all technologies embodied in the system, including economic costs. The proposed Thirsty Energy Case Study involved the development of a "water smart" SATIM model (SATIM-W) where water supply and bulk infrastructure options are represented along the lines of the energy infrastructure, based upon the wealth of water planning datasets and cost curves available from Department of Water Affairs and Sanitation (formerly Water Affairs and Forestry) publications and supported by local water modelling experts. As a result, SATIM-W produces a regionally-based national water infrastructure expansion plan as part of the model optimizing for the least-cost evolution of the integrated water-energy system subject to constraints, with water required for energy explicitly costed and vice versa.

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 a separate report "Modelling the Water Energy Nexus in South Africa Task 1 Report: Development of Regional Marginal Water Supply Cost Curves" (Aurecon, 2014). The detailed methodology of actual integration into SATIM, including the water demands of energy infrastructure, is detailed in a report, "Task 2: Phase 1 Development of the "water smart" SATIM-W model - Modelling the water-energy nexus in South Africa: development of a national water-energy system model with emphasis on the Power Sector." (ERC 2014). This document summarises some of this background, but focusses presenting the results of investigating key policy questions in the power sector using the integrated water-energy SATIM-W model.

II. Water and South Africa

II.1 Water Supply in South Africa

South Africa's water resources management is overseen by the Department of Water and Sanitation (DWS) formerly Water Affairs and Forestry (DWAF). Water Management Areas (WMA) are administrative water resources regions established by the DWS to decentralise administration of water resources at the catchment level. The boundaries of WMA do not necessarily align with provincial borders or catchment basins (Figure 2). Currently, nineteen WMA exist, but these will soon be consolidated into nine WMA. For example, the Upper Vaal will be combined with the Middle and Lower into the Vaal WMA (DWAF, 2012).

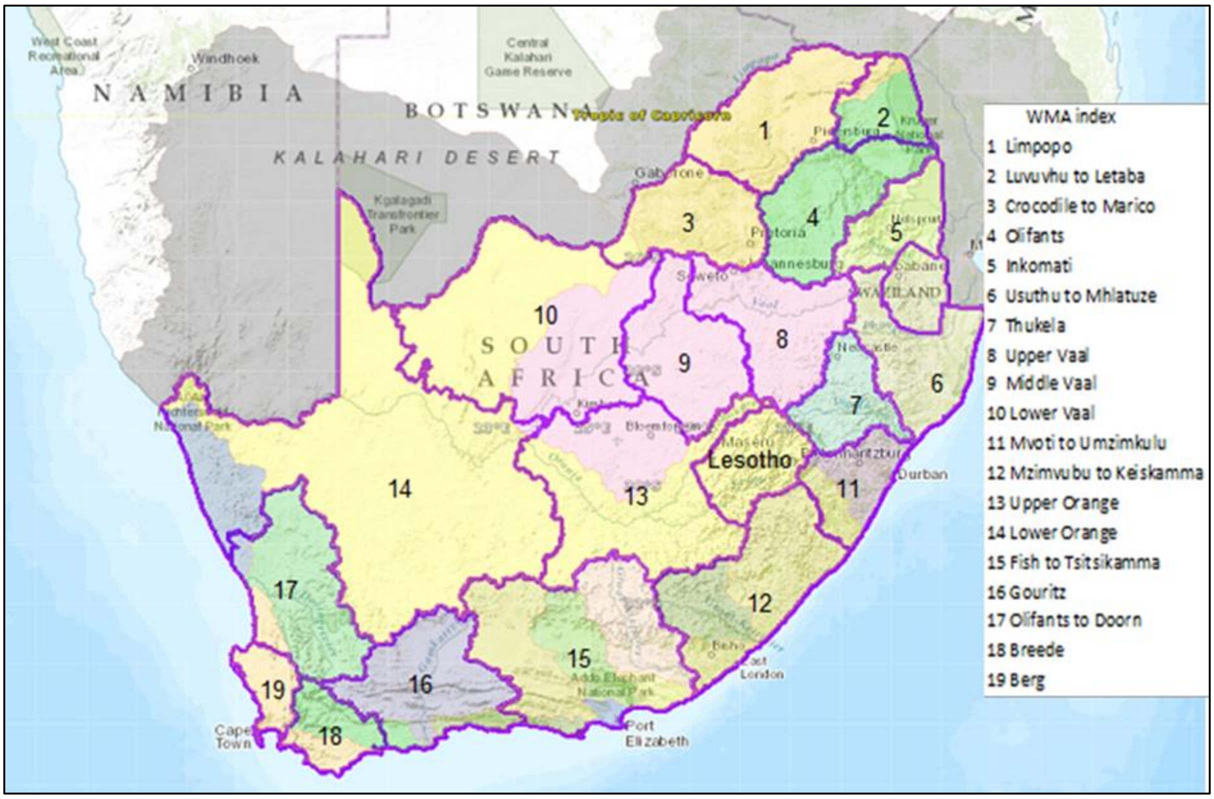


Figure 2: WMA Contrasted with Catchment Basins (shaded)[1]

Water resources are managed by the DWS in conjunction with municipalities. The DWS periodically conducts strategic supply and demand reconciliation assessments using forecasted growth in demand and constraints in supply to determine available management options. Similar to the national transmission and distribution of electricity, inter-basin water transfers mitigate regional supply constraints. However, due to the highly spatial variation in local water supply and demand, the yields of regional water supply systems are assessed independently.

The distribution of water consumers varies, and is a key driver of demand. For example, in the Waterberg (Lephalale) district municipality in Limpopo province where the Waterberg coal deposits occur, the demand for water is dominated by the dry-cooled Matimba coal-fired power station (7.3 million m^3 p.a.) and the Grootgeluk coal mine (9.9 million m^3 p.a.) supplying it which together account

[1] Adapted from DWAF (2012)

for approximately 40% of the existing water withdrawals. Energy sector withdrawals may grow to 75% by the year 2030 if further developments in coal-based energy supply are pursued (Aurecon 2014, van Vuuren 2006). The approximately 20% of withdrawals directly attributed to electricity generation are consumptive requirements as the national power utility Eskom operates a ZLED policy. This is in contrast to the national water balance where the electricity sector accounts for approximately 2% of total water withdrawals (DWAF, 2012).

Water supply infrastructure is highly localised and distinct within each WMA. It includes the civil engineering undertaken to implement water supply systems that cater to multiple users across economic sectors. The supply systems are typically comprised of multiple schemes that may span multiple WMA. Schemes are an amalgamation of discrete projects, such as an inter-basin transfer for providing additional water to a water supply system. Thus, a specific region is serviced by an integrated water supply network or system, which may span more than one WMA and may be comprised of multiple schemes, each of which contributes to the total supply system. Therefore, the term Water Supply Region (WSR) is used in this study to refer to a region of interest that is supplied with water from an integrated water supply network. For example, the Vaal River Eastern Subsystem (VRES), which is a subsystem of the integrated Vaal River system, supplies water to users in the Upper Vaal, Olifants and, in future, to the Limpopo WMA. An example of the distinction between WMA and WSR is that shale gas mining and concentrated solar power (CSP) generation may occur in the same WMA but incur different water costs because they will likely be supplied by different WSR systems.

II.2 Water Demand in South Africa

South Africa is a water-scarce country (annual freshwater availability is less than 1,700 m^3 per capita), with limited average rainfall of about 450 mm/year and unevenly distributed 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 highly variable, erratic, and seasonal.

In addition, most of South Africa's key economic centres, including the urban and industrial centre of Gauteng and key mining areas and power stations, are located in areas of low water availability far from major water sources where local demands exceed local supply. South Africa, however, has had a very proactive approach to water supply, which has resulted in a highly developed and integrated water supply system of large dams and many inter-basin transfers to balance supply and demand as shown in Figure 3. The blue bars in the figure indicate the resource in each WMA, the green bars indicate the total demand, and the red bars indicate the resource development potential. The blue arrows show the major IBT schemes, including transfers for power generation and international exports. Given this, it is no surprise that South Africa has the most registered dams in Africa, and the eighth highest number of registered large dams globally (ICOLD, 2015).

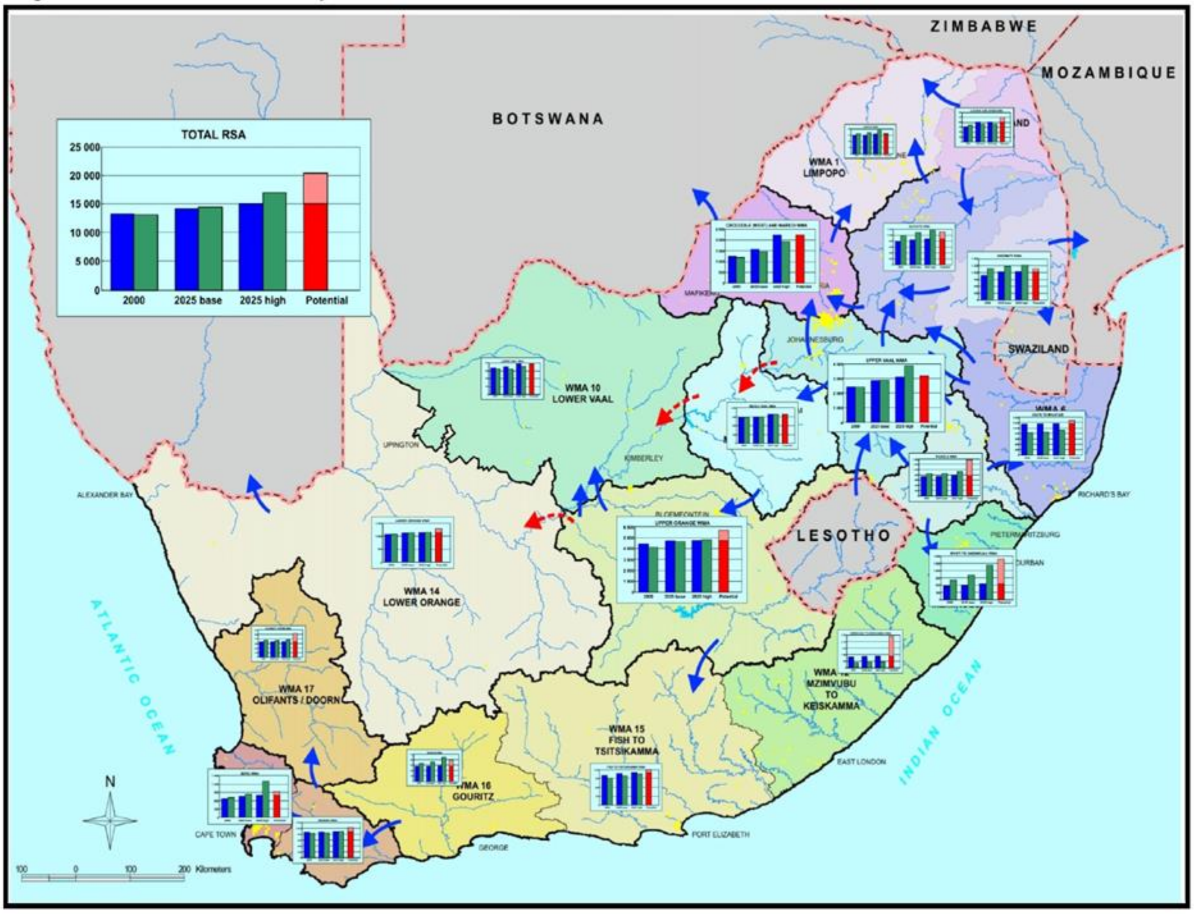


Figure 3: Water Resource Availability vs Demand showing Major Inter Basin Transfers (Source: DWAF, 2008)[2]

A summary of the recent and planned near term power station developments in South Africa are shown in Table 1. This table illustrates the likely future key priority areas for the water-energy nexus as regards electricity generation. Additionally, given that many of Eskom's existing coal-fired power stations are supplied with water from the Integrated Vaal and the Upper Olifants systems the key regional demands to understand from a water-electricity perspective are:

- Upper Olifants;
- Integrated Vaal System;
- Waterberg (Lephalale) area - Crocodile West/Mokolo System, and
- Orange River System.

[2] The blue bars indicate the available resource in each WMA, while the green bars indicate the total demand and the red bars indicate the resource development potential. The blue arrows indicate the major IBT schemes including transfers for power generation and international exports.

Table 1: 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	4800	Limpopo	Mokolo Dam and Crocodile West
	Kusile (Eskom)	Delmas (Central Basin)	2020	4800	Olifants	Upper Komati and Vaal Systems
	4+ IPP Projects of max. 600MW each[2]	Central Basin or Waterberg[4]	2021	2500	Olifants or Limpopo	Upper Komati and Vaal Systems
Concentrated Solar Power (CSP)	REIPPP - 8 Projects [3]	88% NC, 12% FS[1]	From 2015 onwards	700	Lower Orange	Lower Orange
Wind	REIPPP - 36 Projects[3]	44% EC, 26% NC, 18% WC, 8% KZN, 5% FS[1]	From 2013 onwards	3461	Various	Various
Solar PV	REIPPP - 45 Projects[3]	63% NC, 12% NW, 6% WC, 5% EC, 5% FS, 5% LM, 4% MP[1]	From 2013 onwards	2315	Mostly Lower Orange	Mostly Lower Orange

1: EC – Eastern Cape; WC – Western Cape; NC – Northern Cape; NW – North West; FS – Free State; MP – Mpumalanga; LM – Limpopo; KZN – Kwazulu-Natal; The % indicates the share of total capacity of that technology in the region

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

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

4:A total of 7 projects have applied for the first stage of environmental approval of which all but one application located in the Umtshezi Municipal area in Kwazulu-Natal (not yet approved), are in the Central Basin (Emalahleni & Delmas) or Waterberg (Lephalale) coal producing areas. A total of 2510 MW capacity of the 4660 MW of project applications has passed environmental approval. The proposed Central Basin plants are Fluidised Bed Combustion (FBC) plants using discard coal (Burton J, 2015, Engineering News, 2015)

Assessing emerging sites for generation capacity was a key consideration in developing the 'water-smart' SATIM-W model because the energy-only version of the model was not regionally disaggregated. The locations for new generation shown in Table 1 arise because the resources for thermal power and to a lesser extent PV are regionally concentrated with future coal reserves within the Olifants and Limpopo WMAs and the best solar resource mostly in the Lower Orange WMA. Wind in contrast has seen far more dispersed projects awarded in South Africa's Renewable Energy Independent Power Procurement Process (IREIPPP), however wind power is a very marginal consumer of water so not a big a concern in this regard.

The regional water demands of the four regional supply systems identified as critical above are discussed in detail in Appendix A, which includes estimates of future demand. Essentially though, energy sector demands are significantly less than domestic and industrial in the Vaal System and irrigation demands in the Orange System, but more dominant in the Olifants and potentially, the Waterberg systems.

The water requirements for the non-energy sectors have been aggregated in SATIM-W in this first phase of the study. To undertake the analysis, future water demands for the non-energy sectors were determined by regression analysis of historical usage and midterm forecasts, as discussed in detail in the supporting "Task 2" report (ERC, 2014). Caution is however needed when regressing against macroeconomic indicators in a 'top-down' approach to project both the demand for energy and water as this could distort regional water requirements. This is definitely an area for future work as the Case Study results show the role of non-energy demands can be highly variable. The water usage of the energy supply sectors was excluded from the non-energy demand forecasts developed for input to SATIM-W, as these are 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.

III. 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, combined with public concerns in common with many countries over the environment and the safety of nuclear power, have made energy supply a contested policy arena as the country struggles to weigh up the many options for future supply, under immense pressure to grow the economy and alleviate developmental problems of unemployment, poverty and inequality. Strategic energy supply planning in South Africa is highly centralised with planning processes 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 have seen vigorous public participation and have also brought a lot of information into the public domain about the unfolding energy landscape and how policy decisions are being made and trade-offs considered. This section summarises some of this background to the developing energy system to contextualise the policy environment in which models like SATIM-W can be applied.

III.1 Energy Supply in South Africa

III.1.1 Resource Supply

At present the engine of South Africa's economy is coal, which accounts for nearly 70% of primary energy supply, is an important international export at 75 Mt/annum, and provides 92% of electricity generation (IEA, 2014; DoE, 2006). In addition, around 16% 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), placing them approximately as the world's sixth-largest (SACRM, 2013) with a reserve/production ratio of more than 200 years.

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

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 during the period 1965 to 1975, which saw a total of 24 boreholes developed and shale gas deposits discovered (Vermeulen, 2012). These deposits were not economically viable in the era of conventional drilling technology and no further exploration or development was undertaken. Exploration has recently been resumed to assess the potential for extraction by hydraulic fracturing (fracking) and is in the initial stages, although hampered by protracted negotiations between government and industry over the terms of rights. Published speculations on estimates of reserves, in the absence of conclusive exploration data, cover the very broad range of 17 – 485 trillion cubic feet (US EIA, 2013; SAPA, 2014; SAOGA, 2014). Shale gas production requires large amounts of water, and 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).

In South Africa, uranium is extracted in tandem with gold and copper where it is encountered (World Nuclear Association, 2015). The quality of the uranium ores is generally low, although cheaply extractable and beneficiation has been sporadic depending on the price on the world market. Eskom rather procures its supply of enriched uranium, to fuel its single nuclear power plant Koeberg, from the international market (IAEA, 2010). 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 K, Cukrowska E & MCCarthy TS, 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.

III.1.2 Electricity Sector

Electricity supply is dominated by the state owned utility Eskom, which also functions as the system operator and owns and operates the transmission and distribution networks outside of that owned and managed by the large metropoles. Eskom operates 27 power stations with a total nominal capacity of 41.9GW, of which 85% 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 the legislated planning processes of the IEP and IRP and augmented by wide ranging ministerial powers which include the scope to make 'determinations' as to the future generation mix. Eskom retails directly to consumers and municipal distributors and more recently, as a monopsonistic retailer, obliged to purchase from a growing pool of independent power producers (IPP).

The granting of independent power generation licenses by public procurement process has become a feature of electricity policy with three rounds of the Renewable Energy Independent Power Producer Program (REIPPP) awarded, a 4th in process and projects from Rounds 1 and 2 already generating electricity (see Table 1 above). Procurement processes with predefined capacity targets for independent fossil-fuelled and controversially, nuclear capacity, are also underway with nuclear vendor offerings having been reviewed by the Department of Energy (GCIS, 2015) and the first respondents to the DOE's coal IPP request for proposals having passed the environmental approval stage (see Table 1 above).

The 2010 Integrated Resource Plan is South Africa's current official generation capacity procurement policy. This takes the form of the 'Policy Adjusted Scenario' (which is based on the results of modelling using a similar least-cost optimisation 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 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 (SAIIA 2013, World Nuclear Association 2010). 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 with the National Energy Regulator (NERSA) in the process of drafting the regulatory rules for Small-Scale Embedded Generation (NERSA, 2015a), the Small-scale Embedded Generation Programme (SSEG) of the City of Cape Town now buying power fed to the grid, with total rooftop PV capacity in South Africa having increased from 10 to over 30 MW in the year prior to March 2015 (Donnelly, 2015).

On average in South Africa, 1 kWh of electricity consumes about 1.4 litres of water (Eskom, 2011), a water intensity which is within the range of the world average of 1.2 – 1.5 litres/kWh as reported by the UN (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 around 1.7 litres/kWh, as reported by the National Renewables Energy Laboratory (NREL) for subcritical coal power plants cooled by wet recirculating cooling (Macknick et al, 2011). The detailed water consumption and other key metrics for existing power stations are presented in Appendix G.2.1.

III.1.2.1 Coal-fired Power Plants

The country's stock of large coal-fired power plants utilize 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% 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% 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).

III.1.2.2 Renewable Energy Plants

The country possesses considerable solar energy resource potential in the arid north as well as favourable wind resources along its coastline (Hagemann, 2008; Fluri, 2009), and the commissioning of utility-scale concentrating solar-thermal power (CSP), solar-photovoltaics (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). Thus the challenge for solar power and CSP in particular is no different in South Africa being that the best locations are generally far from sources of sufficient water and transmission infrastructure. For a scenario with high nuclear costs, the as yet unapproved IRP 2013 update (DoE, 2013) projected a maximum CSP capacity of close to 40 GW by 2045.

The Renewable Energy Independent Power Producer Programme (REIPPP) aims to reduce the country's dependence on coal with an allocation to renewable energy generation of up to 19 GW in capacity 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 iteration of the programme'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 committed build comprises three plants in the Northern Cape including: 150 MW of parabolic trough (KaXu); 50 MW central receiver (Khi) and 50MW of parabolic trough (Bokpoort).

III.1.2.3 Gas-fired Plants

The power sector has been identified as a potential strategic consumer of gas in the future 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 (OCGT) and combined cycle gas turbine (CCGT) plants are considered. Several different sources of gas are possible, including the inland import of regional gas from Mozambique, coastal imported liquefied natural gas (LNG), and indigenous shale gas should mining proceed. The recent, but yet to be approved, IRP Update in its 'Big Gas' scenario suggests 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).

III.1.2.4 Nuclear Plants

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 2 pressurised water reactors. Due 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, in Phase 1, 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.

III.1.3 Liquid Fuels Refining

Liquid fuel production in South Africa involves 6 domestic refineries, 4 conventional and 2 synthetic (synfuel) as follows:

- 3 Coastal Conventional Crude Oil Refineries: Sapref, Enref, Chevref;
- 1 Inland Conventional Crude Oil Refinery: Natref;
- 1 Coastal Synthetic Gas-to-Liquids (GTL) Refinery: PetroSA (reduced gas supply has necessitated supplementary light crude distillate feedstock), and
- 1 Inland Synthetic Coal-to-Liquids (CTL) Refinery: SASOL-Secunda.

The coastal crude refineries are grouped together in SATIM-W having similar product slates and operating inputs. The inland crude refinery has a more diesel and kerosene heavy product slate, and the two synthetic refineries a gasoline heavy slate, thus they are characterized separately in SATIM-W. Synthetic fuel refining includes numerous discrete chemical processing units operating in close interaction requiring both ancillary energy and water services resulting in an energy, water and emissions intensive product, particularly for CTL. However, no South African refinery uses once through cooling and a Water Research Commission study found that this means oil refining in South Africa is, on average, relatively water efficient in global terms (Pearce K & Whyte D, 2005), although the synthetic refineries are considerably more water intensive. Table 2 below shows the relative production and water intensity of South African liquid fuels refineries.

Table 2: Relative Output and Water Intensity of South African Liquid Fuels Refineries

Refinery Name	Location	Typical Feedstock Intake (toe/month)	Typical Annual Production (TJ)	SWI[1](m3/toe intake)	SWI (m3/TJ product out)	SWI Excluding wastewater Recycling (m3/TJ product out)
SAPREF	Durban	668 000	330 000	0.59	14	9[2]
ENREF[4]	Durban	412 500	204 000	0.51 - 0.67	13 - 17	-
CHEVREF[4]	Cape Town	389 500	192 000	0.51 - 0.67	13 - 17	1.3 - 5.3[3]
Natref[4]	Sasolburg	341 000	203 000	0.6	12	-
PetroSA GTL[4]	Mossel Bay	154 000	58 000	2.9	92	-
Sasol CTL[5]	Secunda	655 000	236 000	8.6	394	-

1: SWI – Specific Water Intake

2: Assumes 1900 Ml of 4750 Ml total annual water consumption is reclaimed water from waste water treatment facility (SAPREF, 2011)

3: SA Crude refinery range from (Pearce K & Whyte D, 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)

4: SWI estimated from (Pearce K & Whyte D, 2005)

5: SWI assumes 255 Ml/day intake to SASOL Secunda (DWAF, 2009)

South Africa's first CTL plant, referred to as SASOL 1, was fully operational in the mid-1950s. In the wake of the 1973 oil crisis, SASOL 2 was commissioned, 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 therefore not represented in the SATIM-W supply sector, but rather included in the Industry sector. Sasol 2 and Sasol 3 in Secunda are the country's remaining CTL plants. The Secunda plants predominantly use coal feedstock, but are supplemented with natural gas, although the share of gas is limited by plant design. In 2006, the total CTL production capacity in South Africa was approximately 125,000 barrels of oil equivalent per day, or roughly 246 PJ per annum. Of the total output, 93% is used for liquid fuels. Although located in Secunda, in the Upper Vaal WMA (Region C), water supply for the CTL refineries are actually sourced from the Upper Olifants water supply system.

In 2006, the GTL production capacity in South Africa from the PetroSA plant located in Mossel Bay was approximately 45,000 barrels per day or around 60 PJ per annum. By 2011, production had decreased to around 45 PJ/a due to declining indigenous gas production. The PetroSA refinery is situated at on the coast and is supplied with reaction and cooling water from the Wolwedans Dam, discharging treated liquid 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).

III.1.4 Air Emissions Arising from the 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. In 2010, national Greenhouse Gas (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% to the total, while coal-to-liquids (CTL) synfuel production contributed 5% (DEA, 2013c). The release of CO_2 due to the spontaneous combustion of discarded coal stores, and methane (CH_4) released during coal extraction, add another 1% to the national GHG inventory (Cook, 2013). In terms of CO_2 from fuel combustion alone, these emissions made South Africa the 18th highest emitter worldwide in 2010 (IEA, 2012). South Africa's per capita fuel combustion CO_2 emissions of 6.94 tons/capita placed lower at 40th in the world in 2010 with the United States and Australia emitting over 17 tons/capita by comparison (IEA, 2012). South Africa was however the 15th most carbon intensive economy in the world, emitting 0.73 kg CO_2/US$(2005) GDP PPP compared to a global average of 0.4. This reflects the continued dominance of exports by energy-intensive sectors, in particular mining and metals processing. The coal intensive energy supply furthermore results in comparative high emissions of particulate matter (PM), oxides of nitrogen (NO_x), oxides of sulphur (SO_x - predominately SO_2) although South African coal on average exhibits relatively low sulphur content (< 1% wt.).

III.2 Energy Demand in South Africa and its Drivers

Energy demand forecasts rely heavily on assumed projections of GDP growth, 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, with for instance metals processing being high and the services sector low, and so understanding an economy's evolving structure is important to understanding future energy demand. The handling of this for SATIM-W is discussed in more detail in Section V.1 below but important concepts are firstly that energy demand is exogenous to the model such that the model essentially solves for a least cost energy plan to meet an exogenous demand, and secondly, that this demand is expressed as a demand for an useful energy service like tons of cement, passenger km of travel or lumens of light rather than for final energy.

South Africa is an upper middle-income developing country with a gross domestic product (GDP) per capita of R73,715 per person (US$5,941 at current exchange rate of 0.08 US$/ZAR). There is a modern urban economy, with an advanced service sector and an energy-intensive industrial base reliant on large domestic mineral resources, co-existing with large-scale poverty. Annual average growth from 2003 to 2008 was 4.6% per year, until 2008 when the global financial crisis negatively impacted economic growth in a large portion of the world, including South Africa. GDP growth has averaged 1.9% since 2008, a value significantly below the development goals set out in the National Development Plan – 2030, which specifies 5% per year (NDP, 2012). Projections of growth for beyond 2014 have continuously been revised downwards (currently at 2.1 % for 2015; IMF WEO, 2015), which is typically attributed to continued labour unrest and low global commodities prices, as well as slow growth in key trading partners and power shortages.

Throughout the twentieth century the South African economy shifted from a primarily rural, agricultural economy, to an urban, industrial economy. 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 towards an economy dominated by the tertiary sector, which has increased from 57% of GDP in 1984 to 70% of GDP today (Altieri K. et al., 2015)

The Integrated Resource Plan Update (DOE, 2013) for South Africa assumes GDP growth rates that range from 2.9 to 5.4%, which results in a range of annual average electricity demand increases of 1.3 to 2.8%, depending on energy efficiency assumptions. Currently, electricity demand exceeds supply in South Africa, which results in planned load shedding in order to meet demand, which obviously negatively impacts economic growth. The commissioning of Medupi and Kusile, two new coal-fired power stations, over the next few years will provide sufficient capacity to reduce load shedding.

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% (Merven et al., 2015). From a sectoral perspective, the agricultural sector is unlikely to grow, partially due to water shortages. Mining activities, which dominate the secondary sector, face strong pressure from unions and uncertain government policies as well as global price fluxuation. However, as discussed below, the potential for shale gas exploration and development could result in a boost to the secondary sector. The less energy-intensive tertiary sector is quite large for a middle-income country of South Africa's size, and therefore SATIM-W's useful energy demand projections assume that it will likely remain roughly 70% of total GDP.

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[3] (NDP) identifies rapid urbanization as a major challenge: South Africa will need to make provision for 8 million new urban residents by 2030 (NPC 2011b). Population growth, used in SATIM as a driver for a number of energy services including passenger transport and household demand, is based upon recently developed country-specific probabilistic population projections from the United Nations Population Division (Raftery et al., 2012).

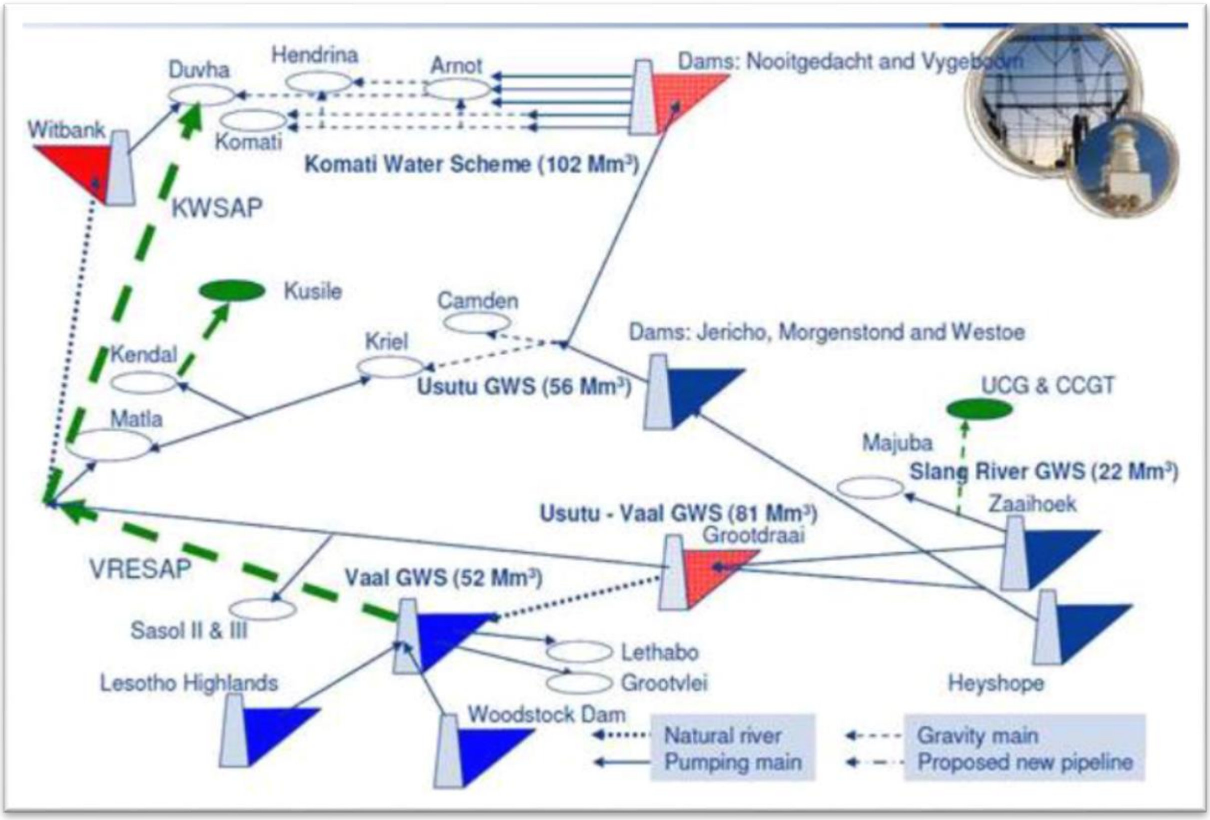
IV. Water-Energy Challenges Facing South Africa's Energy Sector

This study involved integrating the representation of the water into an energy systems model to better reflect the interdependent nature of the nexus. The water challenges facing the energy system were therefore of primary interest. This section outlines some of these emerging water-energy nexus stress points in the energy system.

[3]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 the elimination of poverty and a reduction of inequality by 2030.

IV.1.1 Water Consumption for Energy

Although power generation accounts directly for only about 2% of the total water demand of the country (DWA, 2013), it contributes about 15% to GDP and provides around 250,000 jobs (GCIS, 2011). Power generation is also considered to be a key strategic industry, thereby requiring a very high level of assurance of supply and high water quality. As a result, many of the large IBTs in the country have been 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, depicting the water supply to Eskom stations from the integrated Vaal River system.



Red dam icons indicate water transfers from another WMA. VRESAP = Vaal River Eastern Subsystem Augmentation Project, KWSAP = Komati Water Scheme Augmentation Project.

Figure 4: System Schematic of Eskom Power Stations supplied from the Integrated Vaal River System (Source: Eskom)

These IBTs not only ensure a reliable supply of water, but in many cases they are also necessary to provide water of sufficient quality. The locally available water supply in the areas of the power stations are often naturally hard or of poor quality due to the high level of mining and industrial activity in the region.

Air emissions control technologies that mitigate SO_x generally increase a power plant's water consumption significantly. This may also apply to NO_x control systems if steam injection is opted for rather than low temperature combustion technologies. 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 (PM), Sulphur Dioxide (SO_2) and oxides of nitrogen (NO_x), with compliance deadlines in 2015 at moderate levels for all existing plants and stricter levels for plants that were licensed after 2010, with all plants having to meet the stricter levels by 2020 (Government of South Africa, 2013). Currently local coal-fired power plants, for example, do not as yet control flue gas emissions, other than for particulate matter with levels of their control varying (Eskom 2009, Eskom 2012). Of the new capacity under construction, the Kusile plant will employ wet flue gas desulphurization while Medupi will be retrofitted with this technology which will be fully operational 6 years after commissioning (Eskom 2012, Eskom 2014). The IRP of 2010 assumed all new coal capacity to be fitted with FDG which suggests this is firm policy for coal capacity beyond Medupi and Kusile (DoE 2011). Existing plants, given low sulphur levels in the low ash coal used, all meet the 2015 compliance levels for SO_2 but would require retrofit of FGD to meet the 2020 compliance levels (Eskom 2009, Eskom 2012, Eskom 2014). Eskom has however long argued that high capital cost, long outage times estimated at 120 – 150 days, limestone sorbent supply constraints and water scarcity militate against FGD retrofit (Eskom, 2009), and applications for a 5 year postponement of SO_2 regulations were granted to all affected Eskom plants by the Department of Environmental Affairs in February 2015 (Mdluli TN 2015), so it remains unclear if any fleet retro-fit of FGD will take place.

The extraction and utilisation of energy commodities requires water. For example, coal extraction, in addition to typical mining uses such as dust suppression, requires water for coal beneficiation. Referred to as coal-washing, the calorific value of the product is improved by the reduction of 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. The electricity for pumping is required beyond the coal extraction life of a mine to prevent the potential formation of acid-mine leachate commonly referred to as acid mine drainage (AMD). To date, a number of mines have commissioned water treatment plants for either the safe discharge of mine effluent or the supply of potable water to neighbouring municipalities. The Department of Water and Sanitation requires all mines to include a water management plan, and although many mines are non-compliant a more stringent legal environment is expected see mine water treatment as a mandatory practice in a similar fashion to the regulations gazetted for air quality emissions.

Historically, cheap high-ash and low calorific-value coal for electricity has been supplied directly to ‘mine-mouth’ plants via conveyor from adjacent mines keeping electricity production costs relatively low. However as existing mines approach their production limits, new mining activity, exploiting less economical coal deposits, will be required to cater for future growth in domestic electricity demand. The remaining economical reserves have been identified in the Waterberg region located north of the existing mining-industrial complex and new generation plants located here would all require investment in transmission and distribution infrastructure as well as water supply infrastructure. The extent of water supply infrastructure investment is contingent on growth in coal-derived energy supply for both domestic and export markets.

At the same time, existing water supply systems are at or approaching their capacity with 97% of existing water supply systems allocated. Agriculture consumes 60% of water withdrawals (South Africa. DWAF 2004). As shown in Figure 5, the national water allocation masks regional disparities in water supply. Also, a national summary does not reflect regional sectorial composition. For example, in the northern Limpopo (Waterberg) region where vast new coal deposits are located, energy supply activity accounts for close to half the water withdrawals and may grow to be the dominant regional water consumer should coal-based energy supply expand; whereas in the populous industrial heartland of the Vaal region, the energy sector is an almost insignificant consumer on a relative basis accounting for less than one percent of withdrawals.

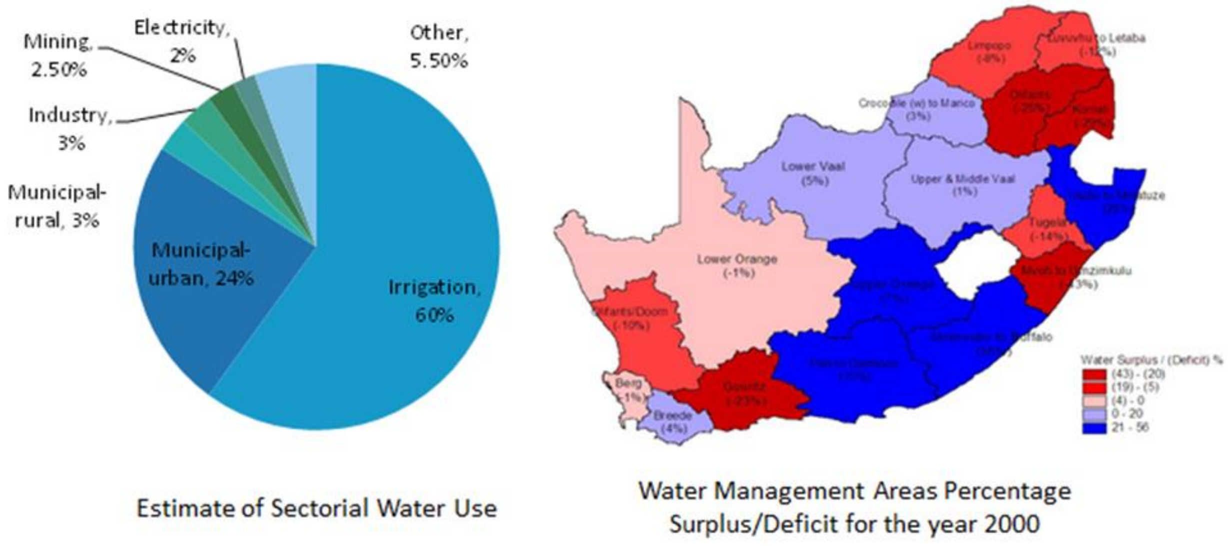


Figure 5: National Water Allocation by Sector and Region

Shortfalls in regional water supply are compensated for by the construction, existing and planned, of large scale water transfers. Figure 6 highlights the water-energy dependency of an interconnected energy and water supply scheme. Electricity, as indicated in the figure, is a critical commodity sustaining the energy matrix via the intricate network of pump-stations in operation.

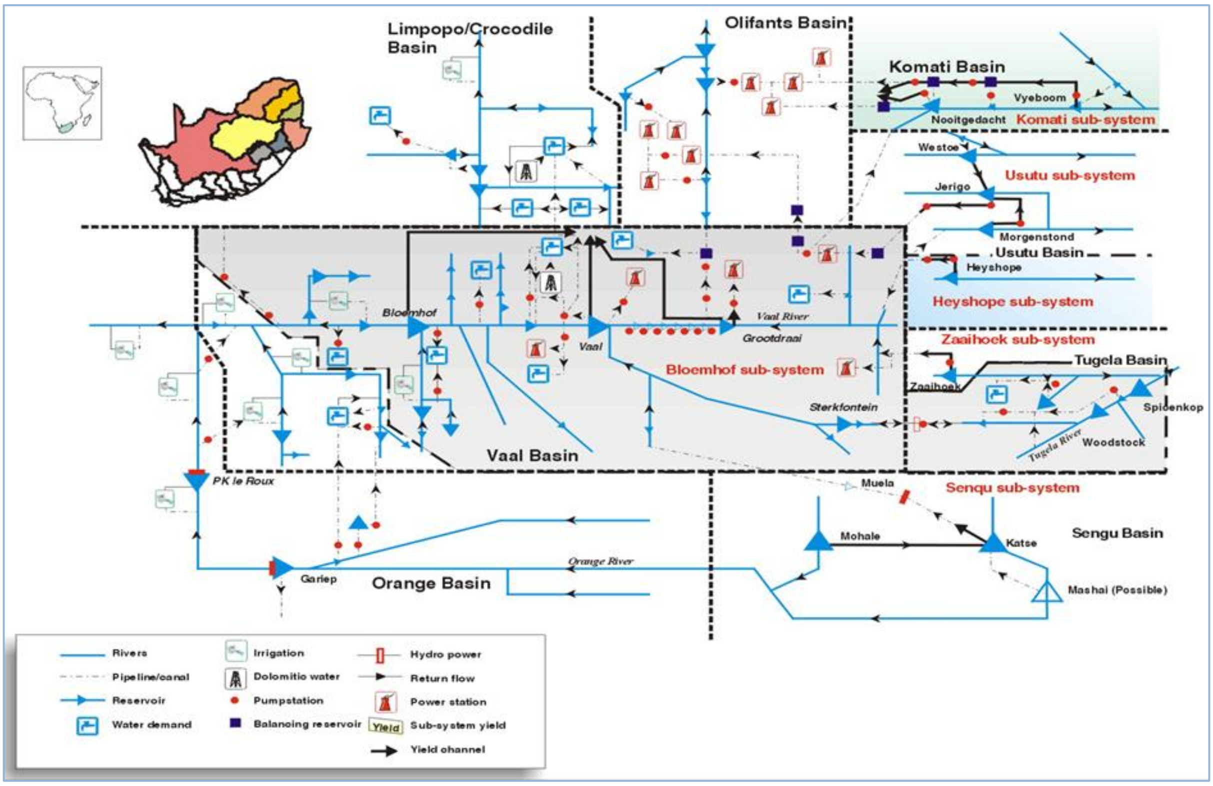


Figure 6: Power Sector Reliance on Water (DWAF, 2006)

In light of the dependency of power generation on a complex water distribution network, the practice of Zero Liquid Effluent Discharge (ZLED) has been adopted, encouraging new coal plants to turn to dry-cooling. Investigated since the late 1960s, to date, approximately 30% or 9,700 MW of existing coal power plants are of dry-cooled design with the commissioning of the new direct-dry-cooled Medupi and Kusile power plants increasing the dry-cooled portfolio to almost half the stock. Dry-cooled plants are reported to be on average 10% more capital intensive and 2% less efficient, and therefore more coal intensive with higher atmospheric pollutant loads (EPRI,2007a; EPRI,2007b; Mielke, Anadon & Narayanamurti, 2010). Thus the benefit of reduced water consumption at a dry-cooled power plant is contrasted with a shift in environmental burden.

All this leads to the requirement of properly reflecting the infrastructure decisions embodied in the water-energy nexus at the appropriate regional resolution needed to capture the discrete water supply and transfer schemes that will be necessary according to power plant location decisions. 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 energy sector investments decisions are made.

IV.1.2 Water Quality Impacts

In addition to the actual volumes of water available, attention has increasingly been directed to the quality of water available which impacts its utility value. The Council for Scientific and Industrial Research (CSIR) has stated 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,2010). Poor water quality impacts power stations by increasing the need for extra water purification on site. At Duvha Power station a diversion pipeline was constructed to bypass the polluted areas of the Olifants river system at a cost of R1.5 Bn. Desalination plants can increase water costs by R10 to R20 per mega litre (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. With deteriorating water quality additionally effluent would need to be managed on, otherwise potentially moving towards violation of ZLED license conditions.

Degraded water sources not only have a direct detrimental effect on aquatic ecosystems, but require more treatment to remediate affected water for productive use. This has the effect of increasing energy consumption for water utilisation and thereby its cost. In response to concerns along these lines expressed by stakeholders at a review workshop the impact of poor water quality was examined by means of a sensitivity analysis that assumes increased water costs in areas where it is known that there is a high risk of water quality degradation, as discussed in Section IV.

IV.1.3 Future Climate Change Impacts

Sub-Saharan Africa is considered to be one of the more vulnerable regions to climate change, and while there is a general agreement that temperatures will continue to increase, there is still much uncertainty about the potential impact on precipitation (Schulze, 2011). The prevailing consensus is that there is likely to be drying in the western part of the country, particularly in the south-western Cape, but the eastern parts of the country are more likely to experience increasing precipitation, although with some potential for seasonal shifts (DEA, 2013a).

Thus in South Africa, while climate change might or might not impact the availability of water for power plant cooling and other demands, it will almost definitely impact the efficiency of cooling through increased temperatures, which could perversely increase the relative benefits of wet cooled power stations over dry cooled power stations. Increasing temperatures will also likely lead to higher demands from other competing water use sectors, agriculture for irrigation in particular. Increasing temperatures and changing streamflow dynamics could also negatively impact water quality, which is already a concern for power stations and other water users in South Africa, requiring in some cases additional water use 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 (LTAS) flagship research program of the Department of Environmental Affairs (DEA, 2013a), discussed in more detail in Appendix B. The results of this study, in particular the range of potential impacts of climate change on the average annual water supply for each WMA, and the impact on the average annual runoff for different catchments, were used to construct a climate change scenario, discussed in more detail in Appendix B. An important result from the LTAS study was the observation that the national water supply system of South Africa, which is the result of many years of pro-active water resources planning to deal with a high level of natural variability and is highly integrated as a result of all the IBTs, appears to provide a high level of resilience to future climate change, although potentially at a cost in terms of increased pumping rates and potential negative impacts on environmental flow requirements (DEA, 2013a, Cullis et al. 2014, Cullis et al. 2015, DEA, 2015). However, the potential impacts of climate change on the water-energy nexus will need ongoing investigation to assess adaptation options specifically for the power sector.

V. Integrating Water and Energy Planning

V.1 The SATIM Energy Model

In its previous form, SATIM was a single-region national representation of energy commodity flows. The multitude of energy transformation technologies, their alternatives and the incurred cost for the delivery of commodities to consumers were represented. For example, the extraction, transmission and distribution of gas and coal for their transformation to electricity; the transmission and distribution of electricity; and the consumption of electricity by end-use technologies to supply energy services such as lighting or motive power. Technologies are linked by commodities and characterised by techno-economic parameters such as activity efficiency, capital and operational costs, plant life, etc. Technologies are further organised by sector (e.g., the Power Sector, households, transportation) and type (e.g., large existing coal plants, lights, vehicles respectively). SATIM is a detailed full sector configuration of the supply and demand components of the national energy system. Attention is paid to the growth in demand for electricity and other commodities at the subsector level (e.g., electricity and biomass demand by the Pulp and Paper sub-sector in Industry). Referring to Figure 7, the Power Sector is divided into three main sections: Generation; Transmission; and Distribution. Electricity is dispatched via a central transmission system that in turn links to distribution nodes for each sector,

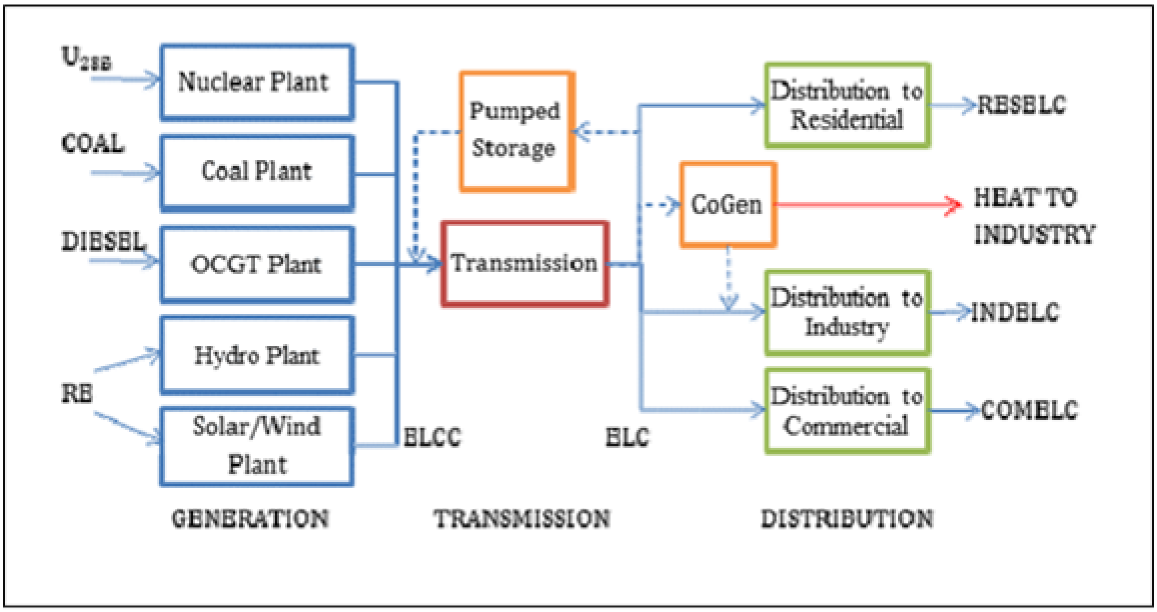


Figure 7: Simplified Representation of the Power Sector in SATIM

In SATIM, commodity supply is described by the Supply sector, which includes technologies and processes such as imports, crude-oil and synthetic-oil refineries and indigenous resource extraction (e.g., coal mining).

Growth in demand for energy services in South Africa is assumed to be driven broadly by overall GDP growth, the relative contribution of primary, secondary, and tertiary sectors to that growth, and population. For example the Residential sector representation divides households into electrified and non-electrified households and low, middle and high income households within those two categories. Demand for energy services within a category is assumed proportional to the population in that category, with GDP growth determining the per capita income and thus demand. In SATIM demand for useful energy services is imposed exogenously, with the model then determining how to meet these indicators of economic and demographic development in the country, at least-cost.

As the model solves for future years, demand for electricity and other forms of energy is determined in order to configure the optimal development pathway. To accomplish this SATIM solves for the least cost chain of supply extending from primary energy, through supply side transformation (e.g., electricity generation and refining), to transmission and distribution to reach the demand devices delivering the energy services needed to drive the economy and meet household needs. It is this feature that makes the model tractable to incorporating the representation of water infrastructure as a component of the energy system supply chain for integrated planning purposes

V.2 The Beginnings of the SATIM-W Water-Energy Model

Until now, the modelling of water consumption and of its transformation within SATIM had received little attention. Previously, the water consumption of the Power sector was represented by including the estimated water use intensity of power plants. The implementation was relatively crude and did not consider regional disparities in water supply and costs, nor the auxiliary water usage by non-electricity generation technologies such as coal mining nor treatment requirements, and therefore did not capture important aspects of the water-energy nexus.

In order to remedy this shortcoming, individual water supply options, include major investments in dams and transfer projects and water supply energy needs, were incorporated into the SATIM-W model so as to capture the water-energy interplay. Incorporating a regional cost and quality for water allows the model to examine potential trade-offs within the Supply sector arising from:

- Fuel extraction and processing (e.g. coal washing and shale gas extraction);
- The consumption and treatment of water for the cooling and steam circuits in thermal plants;
- Cleaning and other water services required by all types of power plants;
- The possible 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; and
- Meeting air quality emissions standards, with end of pipe technologies, like Flue Gas Desulphurisation (FGD), that require water.

The updated model, SATIM-W, allows these activities to be represented so that the model is responsive to the regional cost and availability of water and energy supply, connected to a single national demand-side representation.

V.3 Aligning the Water-Energy Nexus in SATIM-W

The spatial dislocation between water and energy supply options, and the fact that some energy technologies may be located in areas with easier and cheaper access to water, are good reasons for representing the water supply picture in SATIM-W with appropriate regional detail. This includes the need to transfer water over large distances to supply power stations which can result in significant additional costs for water, and thereby energy supply. These costs vary between regions depending on water availability, competing demands from other sectors, treatment requirements and the financing levels incurred by the utility on existing bulk supply infrastructure.

With increasing demands over time, these costs are also likely to increase as existing water supply options are exhausted and more expensive options are required. The costs of these future schemes will vary in different locations, potentially resulting in very different costs for water in the future that may influence the choice of optimal future energy supply options. In addition, there are significant externality costs in terms of potential water quality impacts and ecological risk, particularly in dry regions. While these are important considerations, there are many challenges associated with incorporating these costs in an assessment of the water-energy nexus.

One of the factors that motivated a South Africa case study was that industrialisation in a water scarce environment has resulted in a strong legacy of water engineering, planning and modelling, with crucial information available in reports published by the Department of Water Affairs and Sanitation (DWS). The depiction of the future water infrastructure schemes has drawn extensively from a DWS report that has estimated the ultimate marginal cost for water supply for different regions of South Africa (DWAF 2010a), developing regional water supply cost curves for water supply as a function of total demand. After review and modification, these were integrated into the energy supply chains represented in SATIM-W as the costs of the different options, thus solving for an optimal future water-energy supply mix that accounts for a realistic future cost of water supply, as reflected by the current plans and knowledge of local practitioners. The details of the development of the water supply cost curves and an explanation of the thinking and assumptions behind them, their limitations and the impact of external factors like climate change are discussed in detail in the supporting report for “Task 1” of this study (Aurecon 2014).

The first step in developing SATIM-W was to determine the appropriate level of spatial disaggregation required to explore water supply cost impacts and interdependencies on the energy supply side. As discussed in Section II.2 and depicted in Table 1 above, the regional spread of recent and committed power generation projects and their proximate water supply systems show four systems of interest. A fifth region was added to give the model the option of railing coal to the coast and using seawater for cooling future coal fired capacity should fresh water costs make this viable. Thus five water supply regions (WSR), corresponding to major water supply systems like the Integrated Vaal System, were identified as being sufficient to cover the likely spatial spread of fresh water intensive energy supply infrastructure over the model time horizon of 2050. These regions for which separate water supply costs were developed and integrated into the SATIM-W are shown below in Figure 8 supported by Table 3, which lists the energy supply activities in the indicated regions.

Existing and future coastal crude oil refineries water needs 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 above in Section III.1.3 (SAPREF 2011, CHEVRON 2015, Pearce K & Whyte D, 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, the crude fed Natref located in the Upper-Vaal WMA (Region C in Figure 8) and the SASOL Coal-to-Liquids plant located in the Upper-Olifants WMA (Region B in Figure 8) are included in SATIM-W. A detailed parameterisation of the refinery technologies in SATIM-W is presented in Appendix G.2.4.

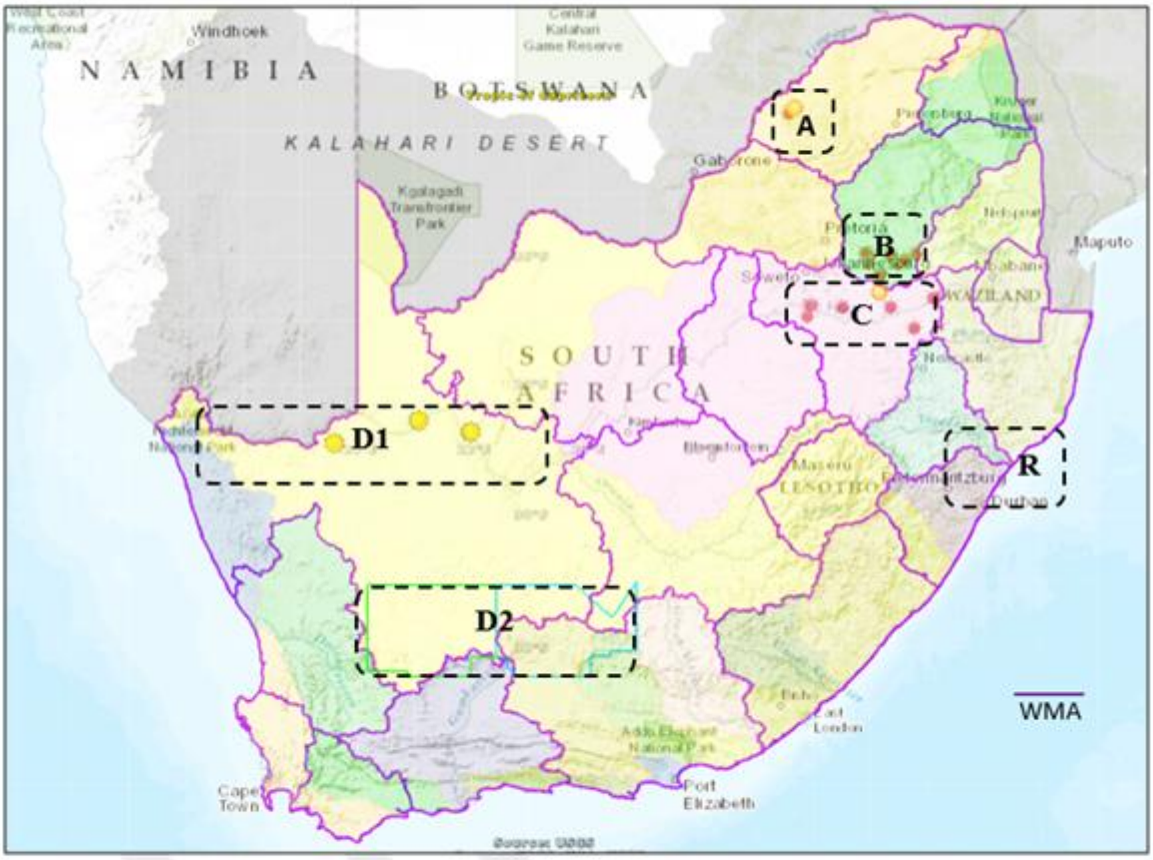


Figure 8: Water Supply Regions in SATIM-W and Associated WMA

Table 3: Technologies for Water Supply Schemes 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	Upper Olifants	Mpumalanga, Witbank	• Open-cast & underground coal mining • Coal thermal power plants with FGD option.
C	Upper Vaal	Mpumalanga, Secunda	• Open-cast & underground coal mining • Coal thermal power plants with FDG option • Coal-to-Liquids refineries • Inland gas thermal power plants • Inland Gas-to-Liquids refineries
D1	Lower Orange	Northern Cape, Upington	• Concentrated Solar Thermal Power Plants (CSP)
D2	Lower/Upper Orange	Northern Cape, Karoo	• Shale gas mining • Gas thermal power plants • Inland gas-to-liquids refineries
R	n/a	Richards Bay Terminal	• Coastal open-cycle coal power plants with seawater cooling and seawater FGD option

V.4 Regional Water Supply Cost Curves

The cost of water supply for energy is determined from three separate infrastructure components: the supply; delivery (transmission and distribution); and treatment requirements as presented here:

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

The capital, fixed and variable operating and maintenance (OM) components are calculated separately for each water supply region (WSR) as part of determining the regional marginal water supply cost (MWSC) that takes into account the current and potential water supply options that have been identified for each region (DWA, 2010). The costs for delivery of water to power plants is based upon estimates for deploying and managing water supply and transfer schemes, and as such do not capture final details (and associated costs) that can only be determined when a specific site is identified. This is also true for fracking and CSP where the exact locations and method of water delivery have not been determined.

The MWSC is developed according to the *Revised Water Pricing Strategy for Raw Water* (DWA, 2012) by using data provided in the analysis of the ultimate marginal cost of water supply in South Africa (DWA, 2010). Where possible these costs have been updated with more recent cost estimates for specific schemes and regions (Aurecon, 2011; DWA, 2009; Coleman et al, 2007; DWA, 2010; DWA, 2014). These studies were also used to update the energy and non-energy demands in each WMA.

The MWSC is determined in R/m^3 on an annual basis according to the basic equation given below:

$$MWSC = WRMC + WSSIC + WDMC + WSDC + WSEC + PWTC + SWTC$$

Where the individual components making up the MWSC are described below:

- WRMC = Water resources management charges, which cover the charges required to manage water resources within the designated WMA;
- WSSIC = Water supply scheme infrastructure costs, which cover the development and use of bulk water supply infrastructure including the cost of planning and design, capital loan repayment, operations and maintenance, energy, and annual depreciation;
- WDMC = Waste Discharge Mitigation Charges, which cover the charge for discharge of water containing waste into a water resource or onto land;
- WSDC = Water supply delivery costs, which include the capital and O&M costs for transporting water from the nearest bulk water source to the location of a power generation plant or mine;
- WSEC = Water supply energy costs, which includes the cost for pumping water either as part of the raw water supply scheme or included in the delivery cost to the power station or mine and is a function of the average cost for electricity in South Africa, and
- PWTC and SWTC = 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.

The estimated infrastructure costs for the bulk supply of water for various schemes identified by the Department of Water Affairs and Sanitation (DWAS) are presented in Table 4. This includes the estimated unit water cost for water supply infrastructure to four regions critical for future power generation, see Table 5. What is interesting to note is the relative high cost of pumping from the Orange River to a CSP plant (R 4.07/m^3) compared to gravity pipelines from the Lephalale River based infrastructure to prospective new coal power plants (R0.39/m^3). This contrasts with the order of magnitude higher cost of future planned bulk water supply infrastructure incurred for lower yields in the Waterberg (Lephalale) region, emphasising the sometimes extreme regional disparities in the cost of water supply. Also evident is how the water supply cost can rise steeply with the deployment of discrete schemes that need to be implemented in order to meet the total water supply requirements.

Table 4: Estimated UWC for Planned Bulk Water Supply Infrastructure

Water Supply Region	Scheme Description	ID	Scheme Yield (2010) (M.m³/a)	Energy Requirement (kWh/m³)	Capital Cost ($R10^6$)	Annual O&M Cost ($R10^6$)	CUC* ($R10^6$)	ADC$ ($R10^6$)	OMC ($R10^6$)	EC# ($R10^6$)	UWC (R/m³/a)	Net UWC (R/m3/a)	Note
Waterberg (Lephalale)	Existing	A0	25									0.60%	
	Mokolo Phase 1	A1	29	0.85	1759	4.7	224	13	5	12	8.9	8.89	
	Mokolo-Crocodile Phase 2	A2	75	0.8	8174	21.7	1042	61	22	30	15.4	15.40	
	Reuse and transfer from Vaal	A3	126	0.87	1216	3.2	155	9	3	55	1.8	10.98	1
	Transfer from Vaal	A4	90	1	2562	6.8	327	19	7	45	4.4	13.64	1
	Desalination of seawater	A6	100	13.82	20896	55.4	2664	157	55	691	36	33.67	2
Upper Olifants	Existing	B0	400									1.42%	5
	Vaal eskom transfer	B0-X	230									1.42%	5
	Olifants Dam	B1	55	0	1241	3.3	158	9	3	0	3.1	3.11	
	Use of acid mine drainage	B2	31	2.2	1637	4.3	209	12	4	34	8.4	6.37	2
	Transfer from Vaal River	B3	190	1.07	4281	11.3	546	32	11	102	3.6	8.06	3
	Desalination of seawater	B5	100	13.82	14210	37.7	1812	107	38	691	26	24.47	3
Upper Vaal	Existing	C0	3523									0.44%	
	LHWP II (Polihali Dam)	C1	437	0	11947	31.7	1523	90	32	0	3.8	3.76	4
	Use of AMD	C2	38	2.51	1820	4.8	232	14	5	48	7.8	5.85	2
	Thukela-Vaal Transfer	C3	522	3.35	21976	58.2	2802	165	58	874	7.5	7.47	
	Orange-Vaal transfer Boskraai Dam (55%)	C4	289	1.99	15671	41.5	1998	118	42	287	8.5	8.47	
	Mzimvubu transfer scheme	C5	631	4.38	41568	110.2	5300	312	110	1382	11.3	11.26	
	Desalination of seawater	C7	100	13.6	7831	20.8	998	59	21	680	18	15.58	2
Lower Orange	Existing	D0	4131									0.17%	
	Boskraai Dam (55%)	D1	515	0	2678	7.1	341	20	7	0	0.7	0.72	
	Boskraai Dam (full yield)	D2	422	0	3286	8.7	419	25	9	0	1.1	1.07	
	Mzimvubu kraai Transfer	D3	165	5.26	4370	11.6	557	33	12	434	6.3	6.28	
	Desalination of seawater	D4	100	14.1	11175	29.6	1425	84	30	705	22	22.43	

Notes:

* Annual capital loan repayment over a period of 25 years at 12% interest

$ Assumes 30% depreciation portion and an average lifetime of 40 years

Based on R0.50 /kWh electricity cost.

% Reflects tariff

Prices in 2010 ZAR

1 Requires additional cost of transfer to Lephalale

2 Excludes R2/m³ water treatment cost

3 Additional cost of water from LHWPII

4 Excludes cost for hydropower station

5 Generation-weighted average cost of water to power stations applied

Table 5: Estimated UWC for Delivery of Water from Major Supply Schemes to Power Plants

Region	Description of Final Delivery from Bulk water scheme to power plant	ID	Annual Supply ($M.m^3$)	Capital Cost ($R \times 10^6$)	O & M Cost ($R \times 10^6/a$)	Energy Requirement (kWh/m^3)	Fuel Cost ($R10^6$)	CUC* ($R10^6$)	ADC[$] ($R10^6$)	OMC ($R10^6$)	EC[#] ($R10^6$)	UWC ($R/m^3/a$)
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	2656.5	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 AMD - 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	3165.2	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	8173.8	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

*Annual capital loan repayment over a period of 25 years at 12% interest

[$]Assumes 30% depreciation portion and an average lifetime of 40 years

[#]Using R0.50 /kWh electricity cost.

Prices in 2010 ZAR

V.5 Incorporating the Cost of Water into SATIM-W

The impact of increasing demand on the regional water supply is shown in Figure 9, in the form of Unit Water Supply Costs (UWSC) curves. These 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 water resources areas considered in this study.

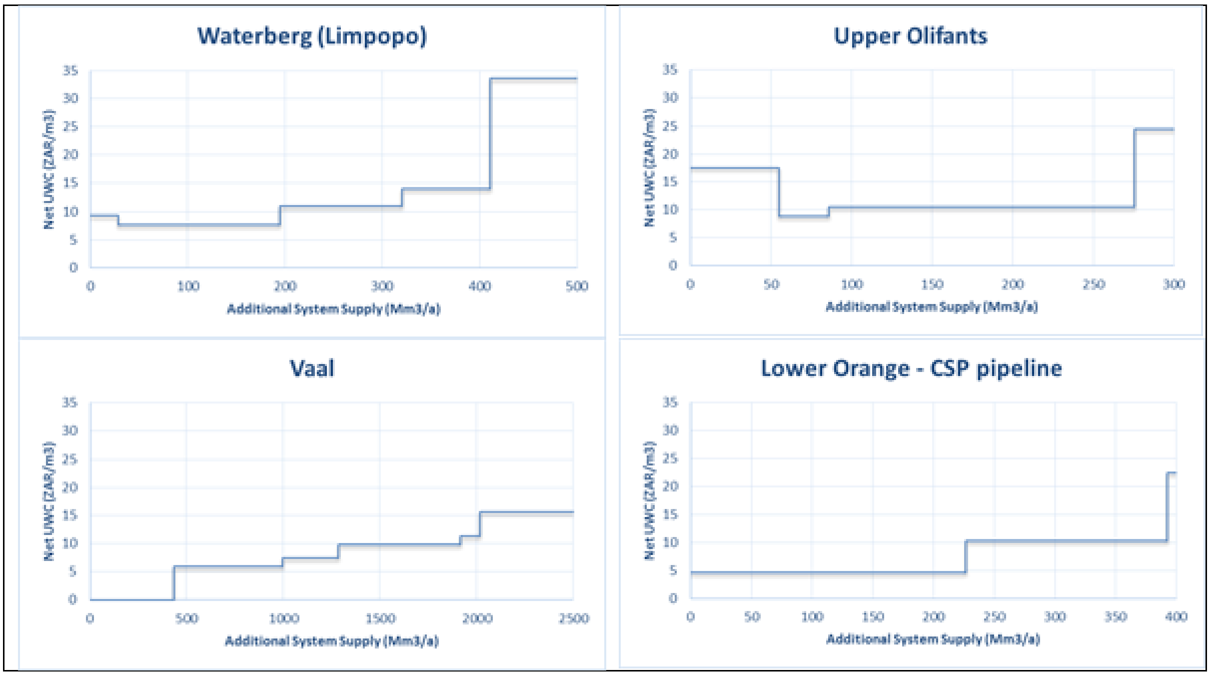


Figure 9: Unit Water Supply Cost in Key Water Resources Areas

The above figure illustrates estimated costs based on fixed assumptions about the price of energy (i.e., electricity and diesel) required for the treatment and transport of water and the implementation timeline of specific supply schemes. A refinement to the incorporation of the UWSC supply curves is the direct representation of the infrastructure costs for supply and delivery as done in SATIM-W. This approach allows for a scenario-specific dynamic cost curve formulation to be represented since the price of energy supply is endogenously determined and water supply schemes are commissioned as necessitated to meet the requirements of the energy system and the exogenous (fixed) non-energy demand. A further refinement in SATIM-W is the direct representation of inter-regional water transfers by linking specific regional supply schemes.

The commissioning of schemes are predicated within a national energy supply system. In this manner the investment choice 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 across the entire planning horizon.

Figure 10 illustrates the general method of representing a water supply region in SATIM-W, where each scheme, water pre/post-treatment process and water consuming energy processes are individually depicted, along with the required energy (electricity) inputs required to deliver the needed water.

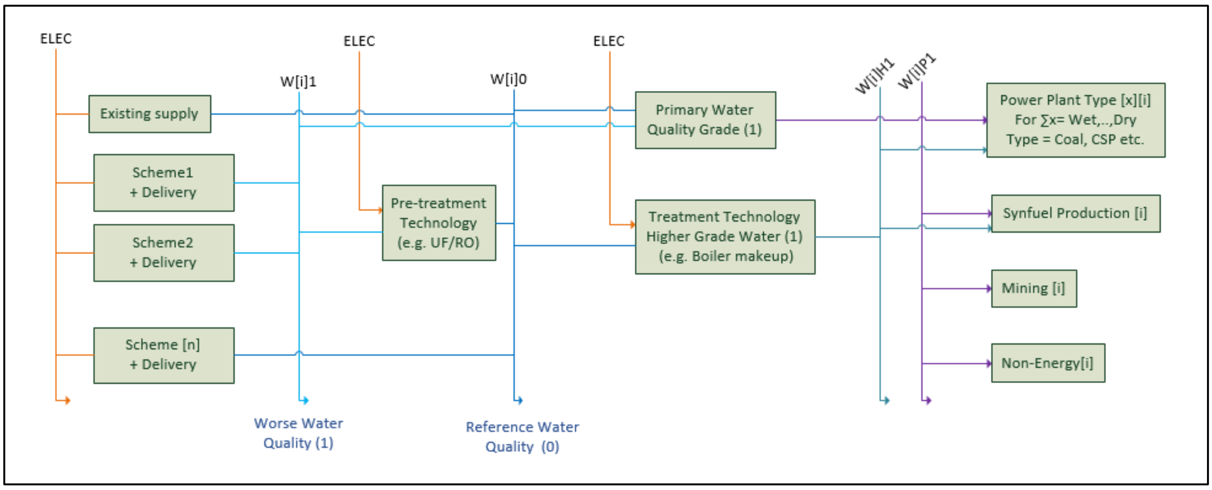


Figure 10: A Generic Water Supply System in SATIM-W

VI. Exploration of South Africa's Water-Energy Planning Challenges

Regional water supply is incorporated into SATIM-W as an additional economic and risk factor to future energy and water investment decisions, as discussed in Section V. This section summarizes the analysis of the future evolution of the integrated South Africa water-energy system by examining the impact of particular development issues confronting the country. The suite of scenarios presented in the next section combine to provide important insights into these pressing policy questions. The results of the scenarios themselves are presented in detail in Appendix D.

VI.1 Scenario Development

The primary value of integrated water-energy planning is to support the decision-making process through the exploration of scenarios that simulate the impact of possible policies and technology choices of significance to the country. SATIM-W provides a particularly powerful platform for exploring the impact of possible futures on the planning of infrastructure in the nexus. In this Case Study six (6) scenarios, shown below in Table 6, were developed which capture the main areas of investment uncertainty in water and energy supply. The process by which these scenarios were developed, based upon themes such as the availability of economically viable shale gas and the future impacts of climate change on water supply and demand, is discussed in detail in Appendix C. The analysis of these scenarios showcase how SATIM-W can be used to advise the energy sector policy formulation and decision-making process, and its inter-dependency with that of water infrastructure planning.

Table 6: South African Water-Energy Case Study Scenarios

Scenario Name	Description
Reference (BAU)	The Reference SATIM-W scenario, which assumes a continuation of status quo planning, but includes the cost of water supply.
Shale	Shale-gas extraction occurs in the Orange River region. At total of 40 Tcf of gas is estimated to be recoverable.
Dry Climate	Regional water supplies and the non-energy water demands in the reference scenario are adjusted to reflect the possible effects of future climate change, affecting the unit water supply cost of regional schemes (Table C-1).

WaterQ	Water quality of transfers from Regions B and C to Region A is lower than local supplies, requiring additional treatment costs for demineralised application (e.g. make-up water for boilers).
Env. Compliance	This scenario entails: • Retrofitting existing coal power plants with wet-FGD. • Fitting existing and new CTL refineries with semi-dry CFB-FGD technology. • Operating all CCGTs with wet NOx control in accordance with EPRI data submitted to Eskom. • Including the increased costs to coal mines associated with the treatment of water discharged to the environment. • Includes the WaterQ scenario
Dry & Environmental Compliance	• A dry climate with environmental compliance scenario. The scenario represents a water stress case with elevated water demands across sectors and increased costs associated with water usage. • Includes the WaterQ scenario
CO_2 Cum Cap 14GT	The imposition of a carbon budget limiting cumulative national GHG emissions to 14Gt by 2050.
CO_2 Cum Cap 10GT	The imposition of a carbon budget limiting cumulative national GHG emissions to 10Gt by 2050.

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.

VI.2 What are the key features of the Reference (BAU) scenario

The SATIM-W business-as-usual (BAU) or Reference scenario (referred to as Reference (BAU)) is the modelled 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 time horizon. It serves as the point of comparison against which the costs and benefits of the alternate scenarios will be evaluated.

The evolution of the South Africa electricity generation mix between 2010 and 2050 is shown in Figure 11. The 2010 mix is almost 90% coal based with a variety of renewable, nuclear, natural gas, and oil technologies filling out the remainder. By 2050, the share of coal based power reduces to 59% while the balance is comprised of concentrating solar, solar PV, wind and hydropower technologies comprises 25%. Imported electricity grows from 3.4% to 8.2%, while nuclear shrinks from 5% to less than 1%.

The absence of new nuclear generating capacity is driven by the preference for new coal plants and the 50 GW of new RE capacity, incentivised by the Renewable Energy Independent Power Producer Programme (REIPPP). By 2050, the portfolio of supply technologies comprises 42 GW of new supercritical coal, 9 GW of wind, 30 GW of utility and distributed solar PV, and 10 GW of CSP with storage. A further 3 GW of Fluidised Bed Combustion (FBC) generation which utilises discard-coal is also included.

Apart from the different cooling design preferences, the generation mix for both cases are similar: the share of renewable energy (RE) generation remains low, contributing only 10% to generation until 2040. This share is comprised of wind and solar PV technology in approximately equal shares. Solar thermal technology (CSP) with storage appears later, between 2045 and 2050, with a rapid capacity expansion totalling 10 GW, based upon assumed continued global learning reducing the cost of CSP over time. The 'Other' generation category is primarily imported electricity (8%).

The absence of new nuclear generated electricity is also evident in both scenarios, driven by the preference for coal plants and 50 GW of new RE capacity, incentivized by the Renewable Energy Independent Power Producer Programme (REIPPP). In 2050, the portfolio of supply technologies comprises 42 GW of new coal, 9 GW of wind, 30 GW of utility and distributed solar PV, and 10 GW of CSP with storage. As shown in Figure 12 below the RE portfolio generates nearly 30% of all electricity by 2050, with solar PV and CSP each contributing approximately 10%, domestic and imported hydro 5% and wind energy 4%.

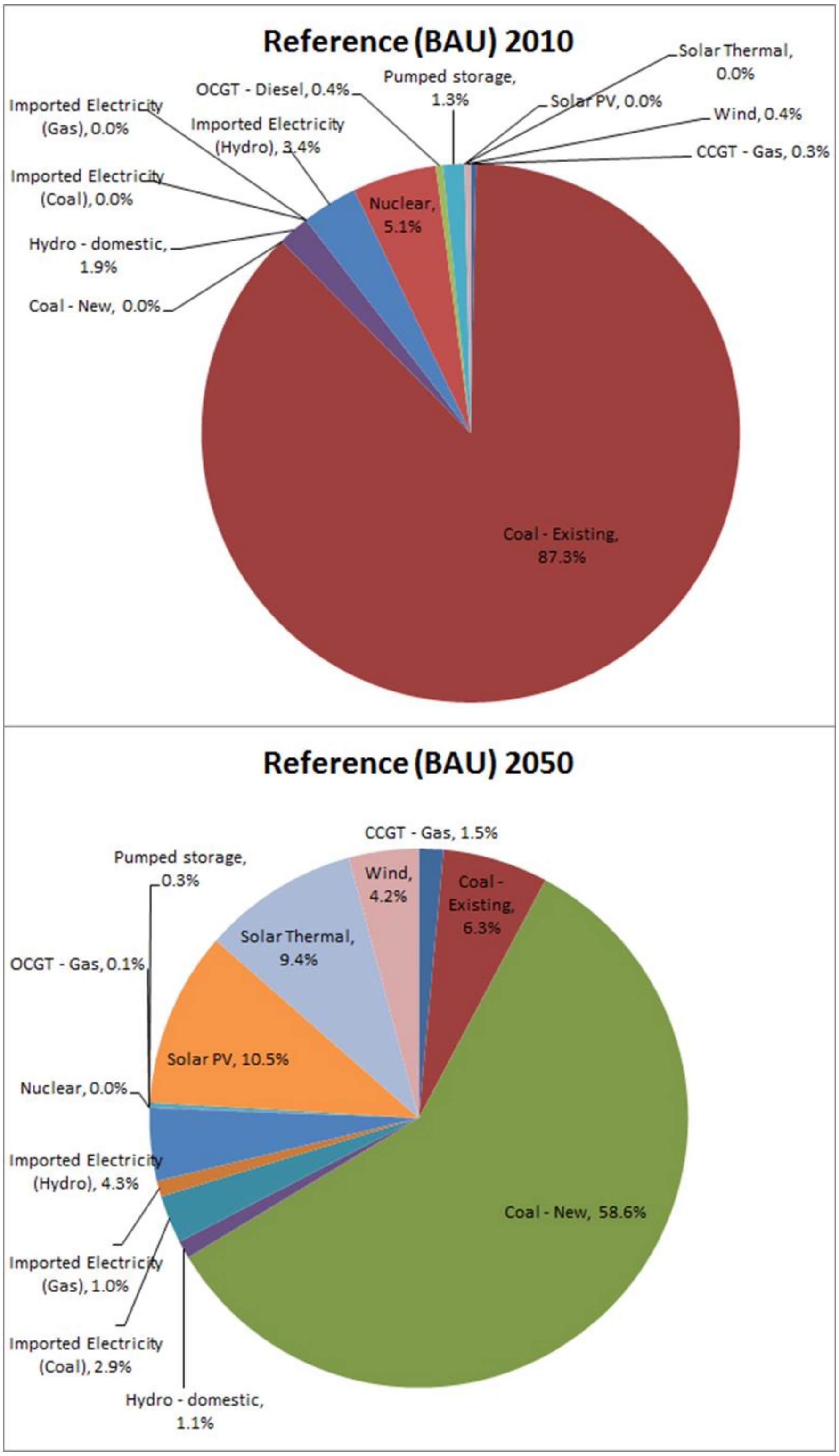
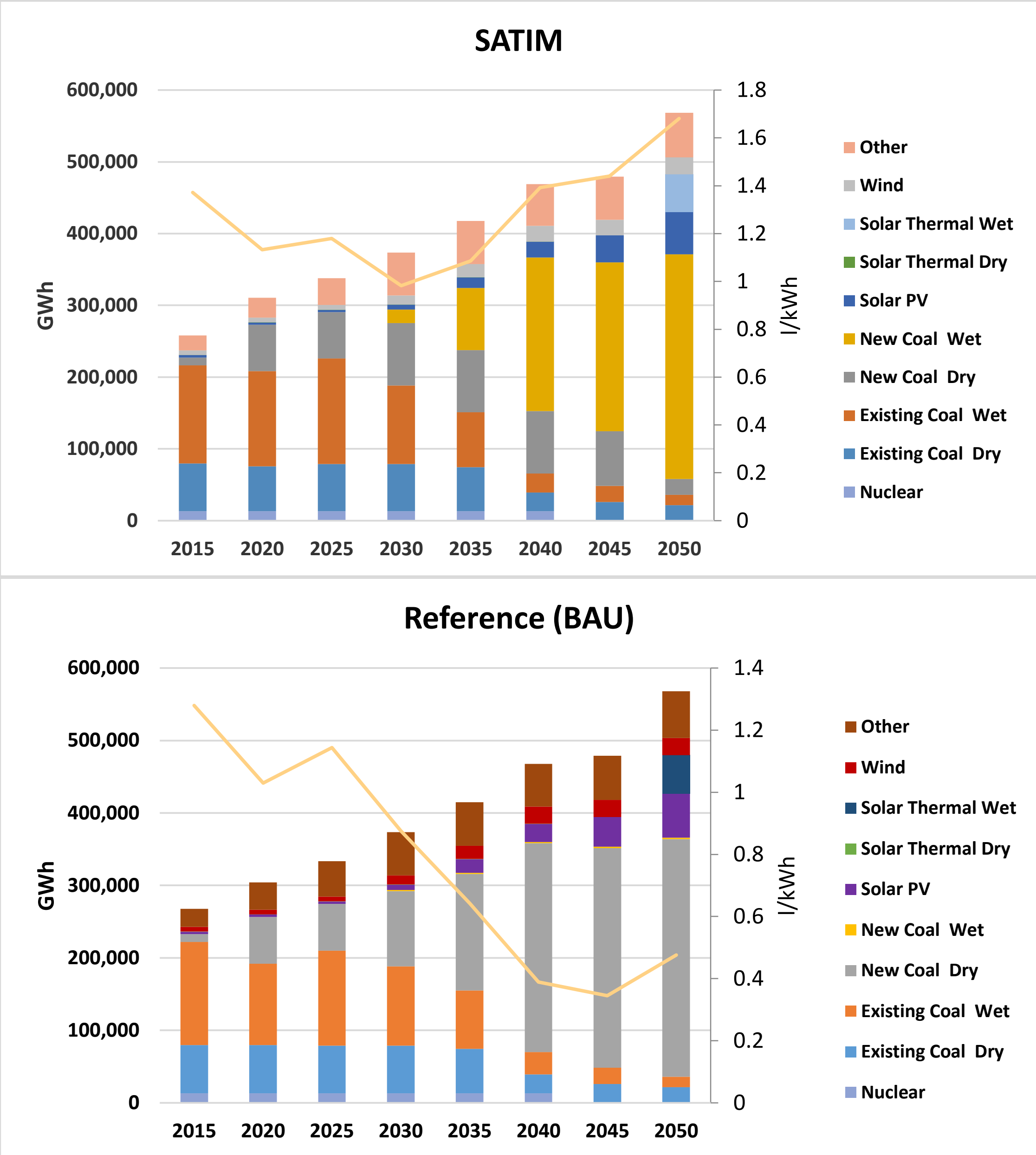


Figure 11: Comparison of Generation Share by Technology for 2010 and 2050 for BAU Scenario

VI.3 Is the Current Dry-Cooling Coal Policy Economically Justified?

Due to water security concerns, the country's first foray into dry-cooling for coal thermal power plants occurred in the late 1960s, and dry-cooling for new coal thermal plants is ESKOM current policy. As a result, approximately 30% of existing coal thermal power plants are currently of dry-cooled design, and the commissioning of two plants already under construction will soon increase the dry-cooled portfolio to almost half the stock.

In the SATIM case shown in the top of Figure 12, water supply costs and constraints are not factored into planning, and a clear preference is seen for new wet-cooled coal power plants[4] due to their higher operating efficiencies and lower capital costs. However, when full consideration is given to the water, as in the Reference scenario, there is an all-out shift to dry cooling (see Figure 12 bottom), which reinforces the economics of ESKOM's decision to employ dry cooling for new coal power plants.



[4] It is important to note that in South Africa all inland wet-cooled power plants are of recirculating closed-cycle design and operate with zero liquid effluent discharge (ZLED) such that water withdrawals are consumptive. Therefore, it is assumed in the modelling analysis that new wet-cooled power plants situated inland adhere to a similar design and ZLED practice.

Figure 12: Electricity Supply by Generation Technology with Water Intensity (plot)

Interestingly, wet-cooled CSP with storage is the preferred solar thermal technology which is counter-intuitive given that this technology is being located in the arid Northern Cape, as discussed above in Section III.1.2. This comes about because wet-cooled CSP generation is cheaper and more efficient than dry-cooled CSP given that water is available and cheap for the Orange River Supply System where non-energy demands are very large in comparison to those of wet-cooled CSP capacity by 2050, despite this capacity growth. This is discussed in detail in Appendix D - see Figure 41 for a comparison of regional water costs. This result could raise an interesting dialogue with water planners given that their contingency planning may involve any number of options not considered here including transfers from the Orange to other water systems to relieve pressure on those systems increasing water scarcity and cost. Alternatively, it may be attractive in a national water planning context to transfer water demand by the electricity sector to the Orange system where CSP capacity, which under several scenarios, especially the low carbon scenarios, has the potential to be far larger than in the Reference (BAU) case.

The top of Figure 12 also shows that In the SATIM (no water costs) case, 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 of 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 (BAU) scenario, the preference for dry-cooled technology leads to a dramatic decline in water-intensity as the dry-cooled design replaces the retiring wet-cooled stock. This modal shift to dry-cooled technology is primarily driven by the availability of relatively cheaper coal in the water-scarce Waterberg region. Expensive water transfer investments would be required to support building wet-cooled coal power plants in the Waterberg region. Therefore, when water costs are taken into account, the most cost-effective option is new dry-cooled power plants that utilise cheap coal in the Waterberg.

Figure 13 shows the water consumption for the SATIM (No water) and Reference (BAU) scenarios, where the differences are primarily due to the cooling technology choices for coal-fired power plants. However, in both cases there is a notable sharp increase in water consumption in 2050 due to the commissioning of wet-cooled CSP plants. Approximately 110 Mm^3/year of water would be required to support 10 GW of wet-cooled CSP capacity, providing about 10% of electricity supply. In the Reference (BAU) case, this accounts for 45% of all water consumption for electricity generation in 2050. This is in addition to the 41 GW of new dry-cooled coal capacity built in the Waterberg, which consumes approximately 103 Mm^3/year of water by 2050, or 40% of total freshwater requirements for electricity generation.

The increase in the water intensity for generation in the arid Orange River region by 2050 is the result of a relative low cost of water supply when compared to the Waterberg region. The magnitude of water required for wet-cooled CSP which is estimated at 250 Mm^3 in 2050 is however dwarfed by the demands of the non-energy sectors which totals 4,200 Mm^3 (Figure 39 in Appendix D). Electricity generation in this region would consume only 3% of total water requirements in 2050.

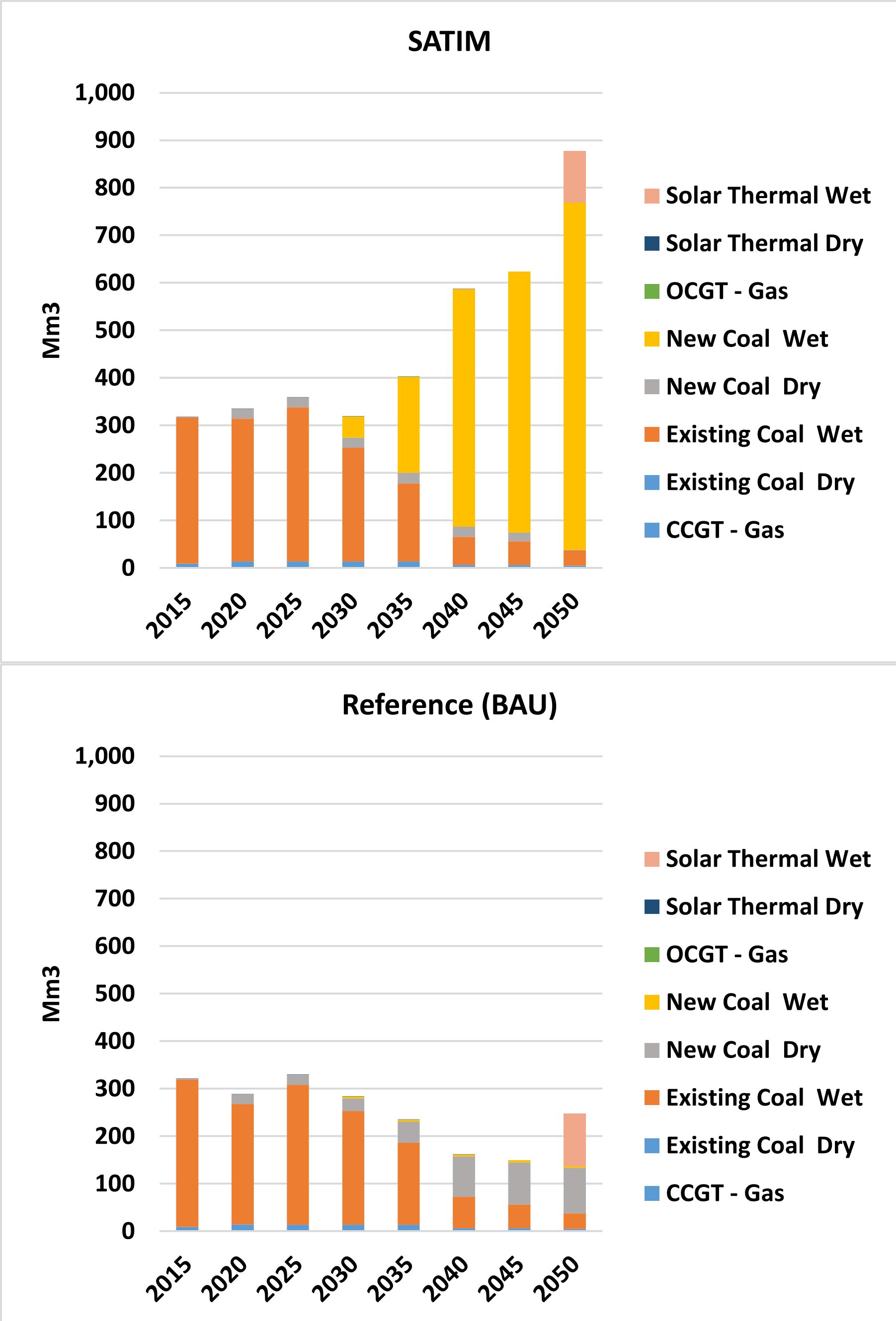


Figure 13. Water Consumption by Generation Technology

Table 7 summarizes the key cumulative metrics (2010 to 2050) from the two scenarios discussed above. 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 61% lower (almost 7000 Mm^3) in the Reference (BAU) case. Interestingly, this does not result in significantly higher power plant investment costs. Also, the Reference (BAU) produces slightly less CO_2 emissions because it generates 1.3% less electricity with coal and 2% more with RE technologies.

Table 7: Summary Metrics for Reference (BAU) and SATIM Cases

Scenario	Units	Reference (BAU)	SATIM	% change
System Cost	2010 MZAR (x1000)	7,646	7,586	-1%
Expenditure - Supply	2010 MZAR (x1000)	10,292	10,305	0%
Primary Energy	PJ	271,328	272,963	1%
Final Energy	PJ	137,619	137,692	0%
Power Sector CO2 Emissions	Mt	12,242	12,293	0%
Power Plant Builds	GW	134	131	-2%
Power Plant Investment Difference	2010 MZAR (x1000)	2,722	2,686	-1%
Water to Power Plants	Mm3	11,093	17,910	61%

VI.4 How do stricter environmental controls impact coal investments in the Waterberg?

Economical coal deposits in the Waterberg is 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 and the Dry and Environmental Compliance scenarios, require environmental control technologies, specifically Flue Gas Desulphurisation (FGD), be installed for existing coal power plants and all CTL plants. This impacts the operating efficiency and water intensity of both types of plants, which is particularly critical in the Waterberg. Although the Reference (BAU) scenario grows CTL plants to a capacity of over 500 PJ per year, the Environmental Compliance scenario limits the capacity to 100 PJ/year.

The Dry and Environmental Compliance scenario includes the added pressure of climate change effects, and also limits the buildout of CTL plants to 100 PJ/year. This is in contract to the Dry Climate scenario alone, which has a CTL build-out similar to the Reference BAU scenario.

The Dry and Environmental Compliance scenario was also run with an assumption that the quality of transferred water was significantly degraded (WaterQ). In this scenario, the transferred water requires treatment before use. The result was a small reduction in CTL capacity compared to the Reference (BAU) case.

Clearly, the Environmental Compliance scenario leads to a dramatic reduction in CTL capacity (Figure 14). The Dry Climate case alone has little impact on new CTL capacity, largely because of the limited impact of climate change on bulk water supply.

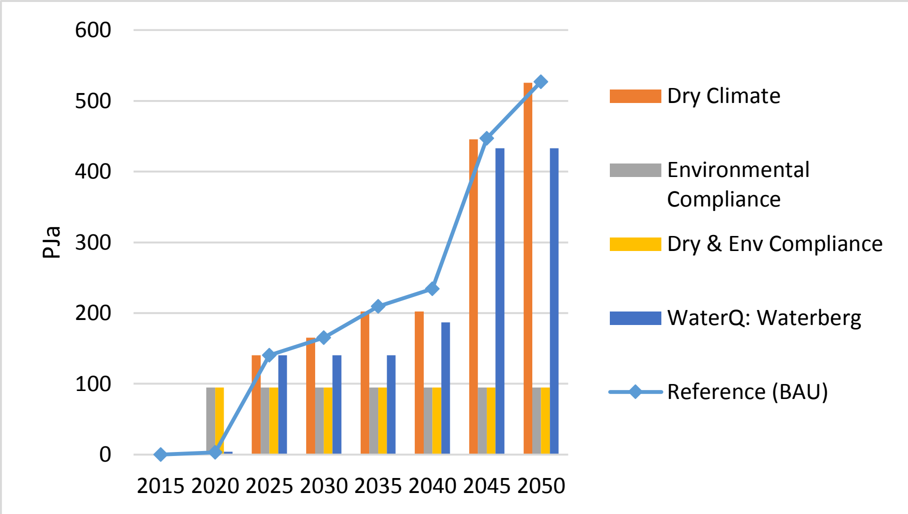


Figure 14: New CTL Capacity

The lack of new CTL capacity under the Dry and Environmental Compliance scenario reduces the requirement for new water supply schemes in the Waterberg as compared to the Reference and WaterQ scenarios (Figure 15).

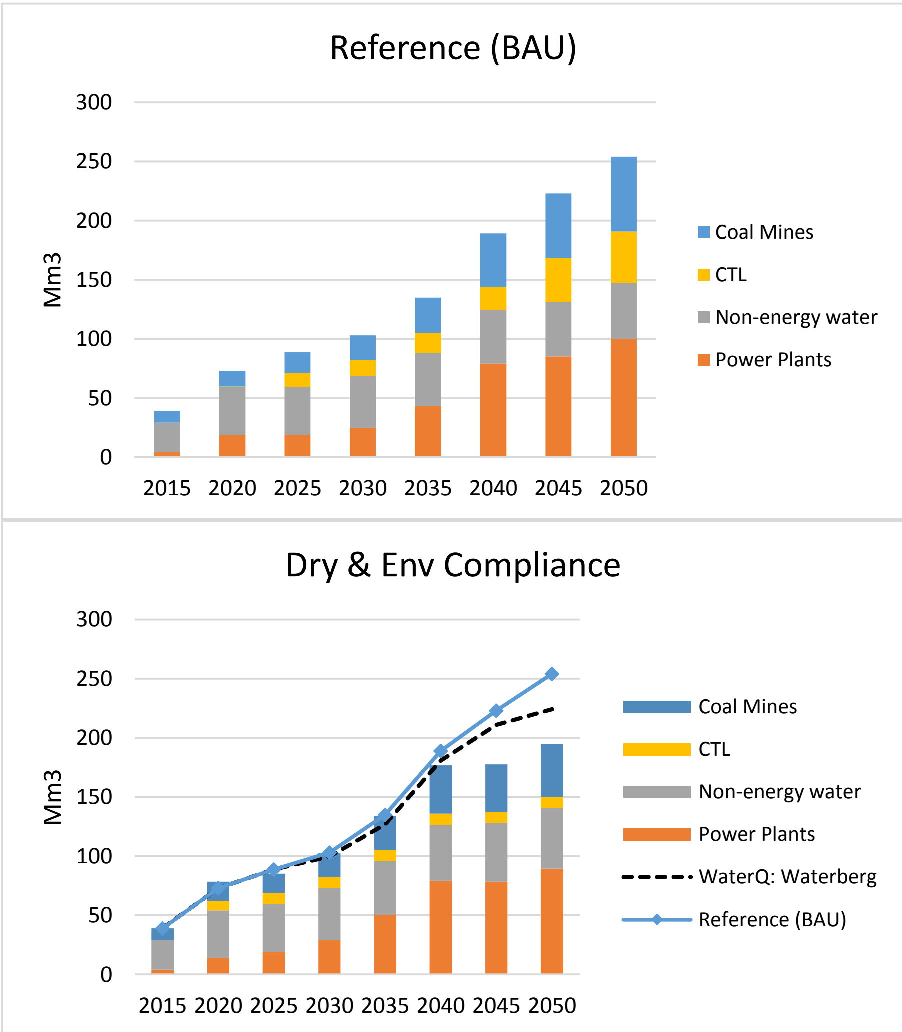


Figure 15: Water Demand in the Waterberg under Reference and Dry & Env Compliance Cases

The WaterQ scenario, impacts new coal power plant capacity in the Waterberg (Figure 16) in a similar fashion to new CTL (Figure 14). The main water consumption of the direct- dry-cooled plants is that of demineralised water for boiler make-up and therefore the cost of supply is sensitive to water quality. The increased cost of treatment begins to decrease the new coal plant capacity from 2040 and results in a decrease of ~7 GW from the Reference. The reduction in new Waterberg coal capacity is largely substituted by RE capacity in approximately equal share between Solar PV and CSP (wet-cooled).

Figure 16 also shows that when the Environmental Compliance with WaterQ scenario is combined with the Dry Climate scenario, the decline in new coal capacity is less. The effect of the Dry Climate scenario is early retirement of wet-cooled coal capacity in the Olifants and Upper Vaal regions due to increased water demands by the non-energy sectors, and this results in an additional 2 GW of dry-cooled coal capacity in the Waterberg in 2050 relative to Environmental Compliance scenario alone.

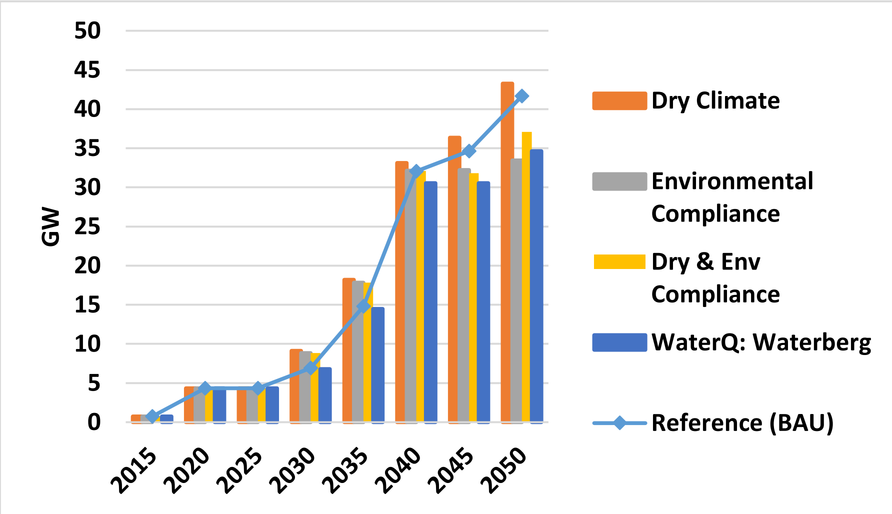


Figure 16: New Coal Capacity in the Waterberg (Note that the Env. Compliance cases includes the WaterQ scenario as outlined in Table 6)

Table 8 summarises the key cumulative metrics (2010 to 2050) from the scenarios discussed above.

Table 8: Summary Metrics for Dry Climate Case (DRY), Environmental Compliance Case (ENV)

Scenario	Units	Reference (BAU)	DRY	% change	ENV	% change	DRY & ENV	% change
Discounted System Cost	2010 MZAR (x1000)	7,646	7,651	0%	7,706	1%	7,707	1%
Expenditure - Supply	2010 MZAR (x1000)	10,292	10,265	0%	10,494	2%	10,491	2%
Primary Energy	PJ	271,328	270,009	0%	263,463	-3%	263,394	-3%

Final Energy	PJ	137,619	137,625	0%	137,598	0%	137,582	0%
Power Sector CO2 Emissions	Mt	12,242	12,111	-1%	12,004	-2%	11,991	-2%
Power Plant Builds	GW	134	130	-3%	131	-2%	131	-2%
Power Plant Investment Difference	2010 MZAR (x1000)	2,722	2,864	5%	2,818	4%	2,821	4%
Water to Power Plants	Mm3	11,093	10,421	-6%	11,158	1%	10,898	-2%

VI.5 What is the Investment impact of requiring power stations to retrofit FGD?

The regional lump sum investment cost for water supply is displayed in Figure 17. Investments in FGD retrofits which occur in the Environmental Compliance scenario are also commissioned in the Reference scenario and appear sufficient for that scenario as well.

The Dry Climate scenario increases water investments in the Upper Vaal and Orange regions in response to non-energy sectors water demands. Therefore, the requirement for FDG does not impact water sector investments.

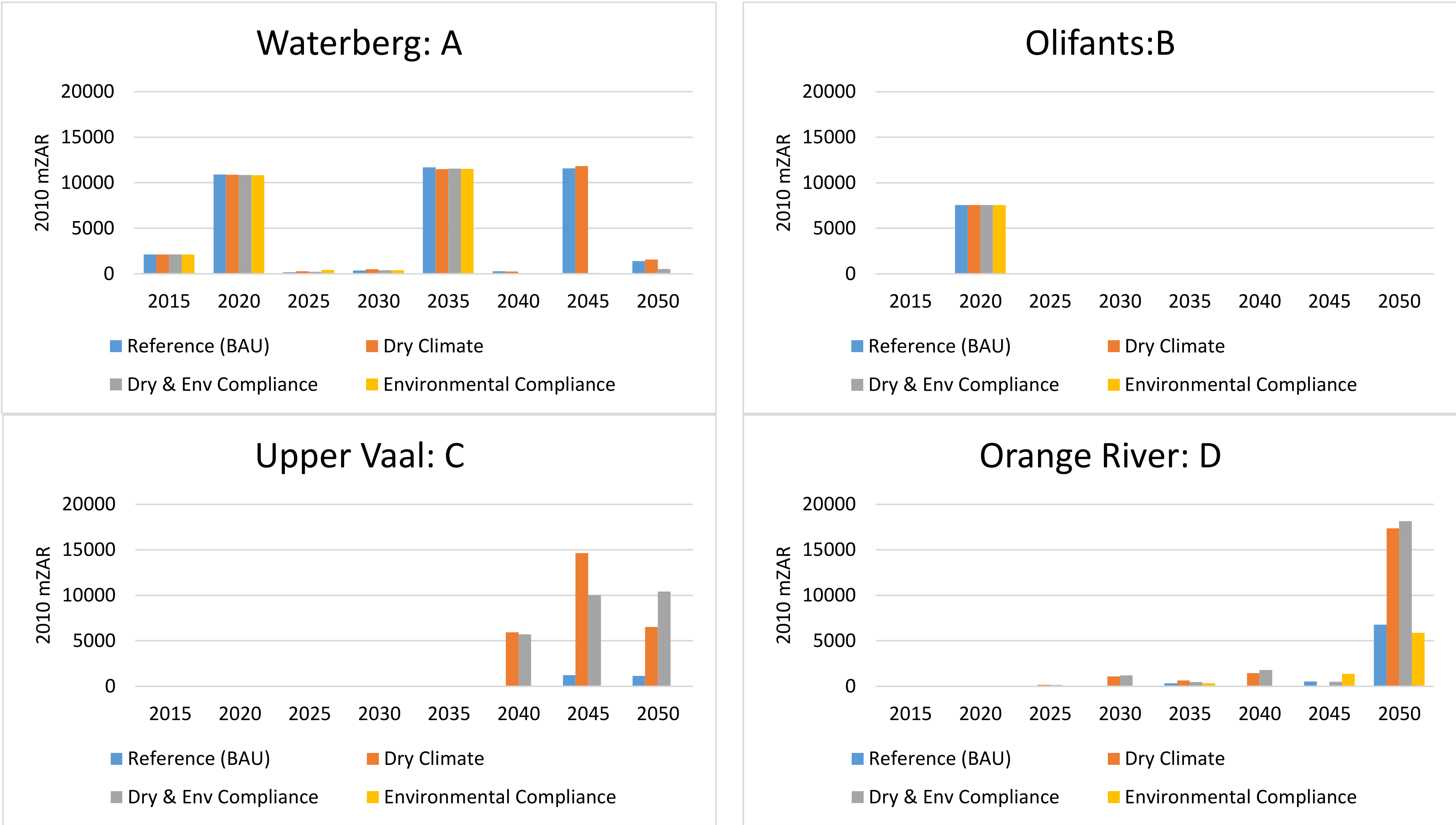


Figure 17: Lump sum investment in new water supply infrastructure

VI.6 How does the cost of water impact shale gas production?

As shown in Figure 18, the Shale Gas scenario significantly increases power generation from natural gas compared to the Reference (BAU). Figure 19 shows that the growth of shale gas utilisation for power generation occurs at a similar rate for the Shale Gas and Shale Gas with No Water Cost scenarios. The slight increase in capacity that occurs for shale gas power plants when water is costed suggests that more shale gas would be utilised for electricity production with a water supply pipeline in place than consumed for other purposes (e.g. supplied to Industry) This preliminary result indicates that the cost of water does not alter the decision to invest in shale gas for power generation. However, SATIM-W does not currently model the cost of treating return-flow effluent.

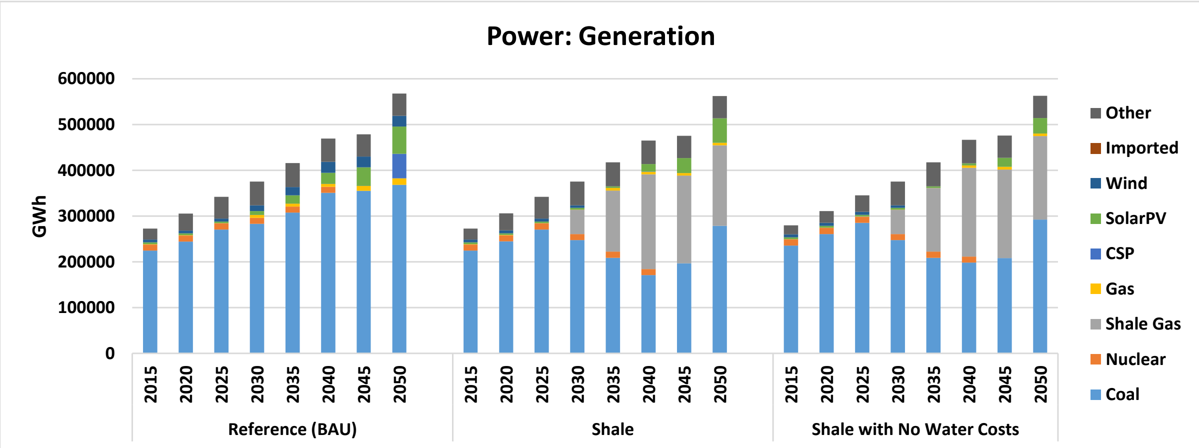


Figure 18: Electricity Supply Portfolio with Shale Gas

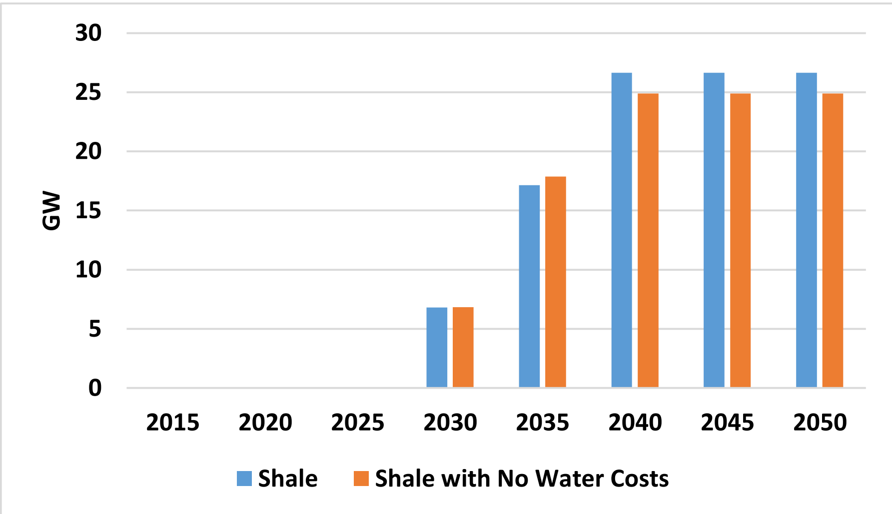


Figure 19: New Shale-Gas Plant Capacity Additions with Shale Gas Availability

Figure 20 shows that in the Shale Gas scenario, there is an initial reliance on groundwater (~ 1 Mm^3/year) and trucking (~300 km per roundtrip) for water delivery in the absence of a pipeline, which results in a relatively expensive water supply cost. The construction of a water supply pipeline in 2030 dramatically lowers cost of water and accelerates shale gas development in the region. However, it is important to note that the costs of treatment and disposal of flow-back effluent from shale gas exploration and extraction; and detailed distribution or delivery costs of water supply are not fully reflected in the current analysis. When these considerations are fully incorporated and modelled, the water-energy implications for shale gas extraction and utilisation may vary from the results reflected in this analysis. The treatment of these waste-water streams is an improvement planned for Phase 2.

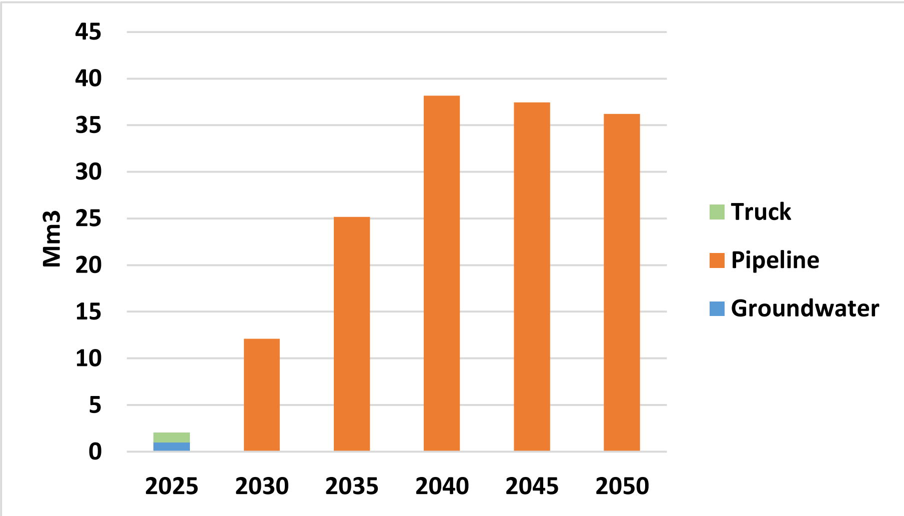


Figure 20: Water Supply by Mode for Shale Gas Sector (Power and Mining)

Table 9: Summary Metrics for Shale Gas Case

Scenario	Unit	Reference (BAU)	Shale Gas	% change
System Cost	2010 MZAR (x1000)	7,646	7,597	-1%
Expenditure - Supply	2010 MZAR (x1000)	10,292	10,789	5%
Primary Energy	PJ	271,328	266,866	-2%
Final Energy	PJ	137,619	137,938	0%
Power Sector CO2 Emissions	Mt	12,242	11,143	-9%
Power Plant Builds	GW	134	118	-12%
Power Plant Investment Difference	2010 MZAR (x1000)	2,722	1,946	-29%
Water to Power Plants	Mm3	11,093	9,841	-11%

VI.7 In a carbon constrained world, what is the likelihood of stranded assets?

A system-wide carbon constraint in the form of a cumulative cap was used in SATIM-W to help identify the most cost-effective path to mitigating energy sector CO_2 emissions in response to international climate change obligations and national policy. These have typically been applied at two levels: 14 Gt CO_2 equivalent by 2050, which is broadly in line with the current 'Peak, Plateau and Decline' policy (Altieri et al 2015), and 10 Gt CO_2 equivalent, which would be a more aggressive policy that might be followed if South Africa's trading partners mitigated aggressively and applied pressure to limit embedded emissions in their exports. These scenarios highlight the potential impact of these policies on energy sector investments and the potential for stranded assets as a consequence. In both scenarios, there is no new investment in CTL capacity and operation of the existing CTL plants is impacted, as illustrated in Figure 21. The 14 Gt CO_2 Cap case reduces production at the plant to zero by 2040, which 5 years earlier than in the Reference case. If a 10 Gt CO_2 Cap is implemented, production at the plant is completely halted by 2025, a full 20 years prior to the scheduled decommissioning date.

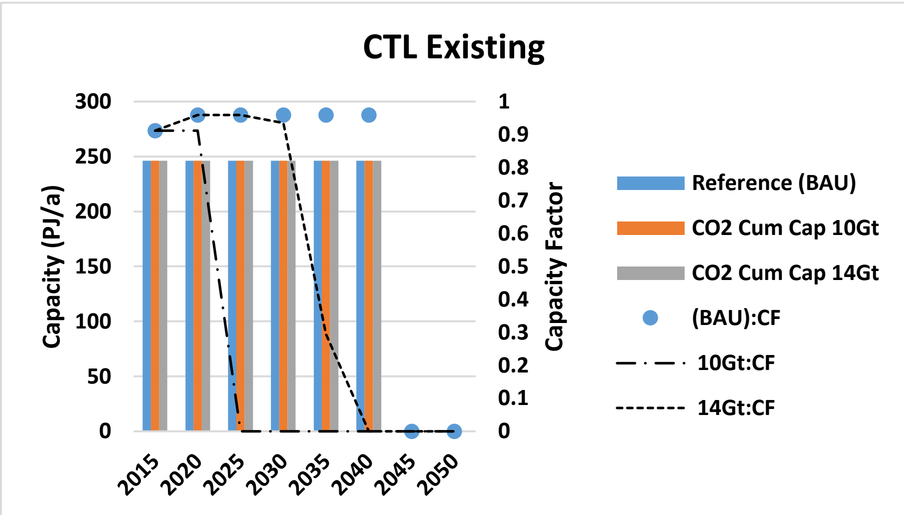


Figure 21: CTL Utilisation under Carbon Constraints

The reduction in CTL capacity is substituted by an increased reliance on imported petroleum products (Figure 22) and crude-oil (Figure 23).

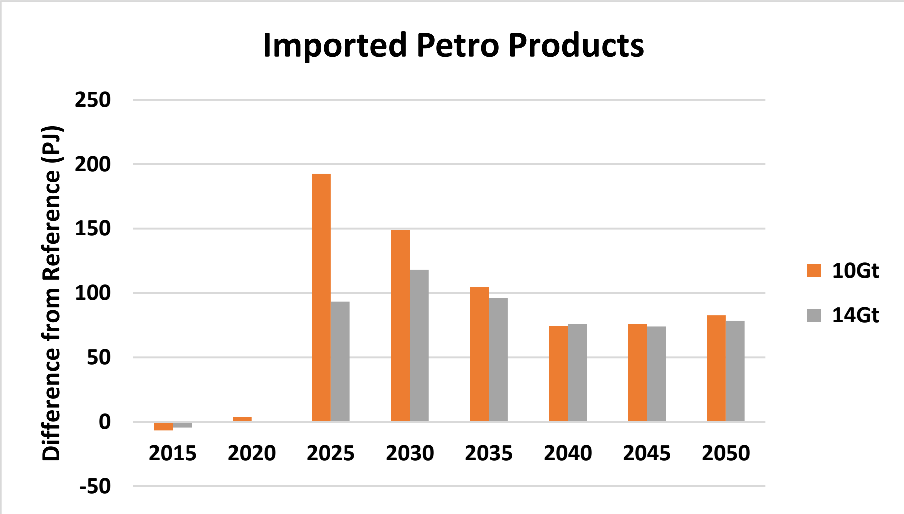


Figure 22: Imported Petroleum Products under Carbon Constraints - Difference from Reference (BAU)

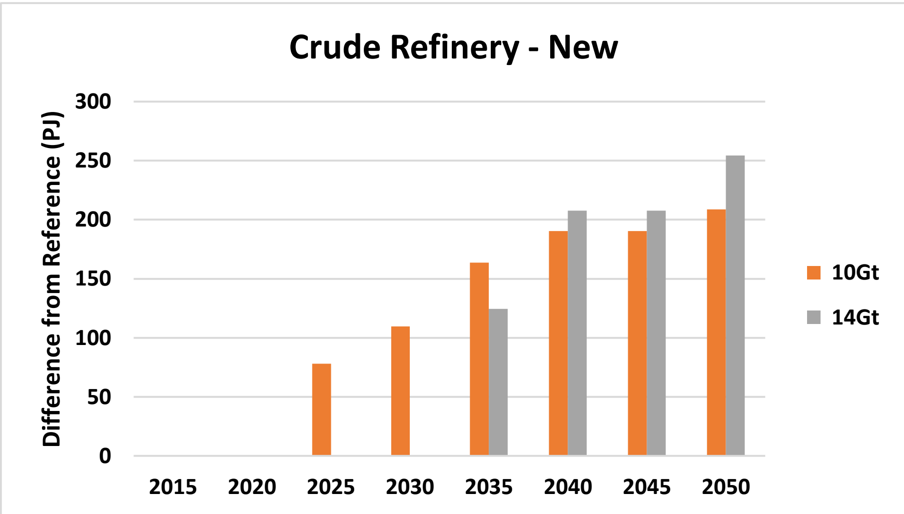


Figure 23: Crude Oil Production under Carbon Constraints - Difference from Reference (BAU)

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

In contrast to the vulnerable CTL facilities which have very high CO_2 emissions per unit output, the existing and committed coal power plants are less at risk under the 14 Gt CO_2 Cap scenario and remain operational for their entire technical life, as shown in Figure 24, although their utilisation is highly variable from 2040 onwards for the 14 Gt CO_2 Cap scenario. By 2045, existing plants in the Central Basin total 4 GW or only 4% of total capacity of (93 GW) comprising in roughly equal shares both wet and dry-cooled plants. The wet-cooled plants are effectively mothballed and generate very little and as such the capacity factor of the residual coal fleet increases in 2050 once these reach the end of life and the 1.22 GW of dry-cooled coal plant or ~1% of total capacity remains operational.

In contrast, there is indeed a risk of significant stranded coal assets under the 10 Gt CO_2 constraint, which requires early retirement of the existing coal 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 (Upper Vaal and Olifants) is similar to that of the Reference in 2025, a 30% decrease in electricity production occurs. Thereafter, the stock is retired by 2035 with idle capacity of 2 GW in 2050 for both Carbon Cap scenarios. In contrast, the Reference scenario selects life extension for 2GW of existing stock with ~4 GW of capacity remaining at the end of the planning horizon.

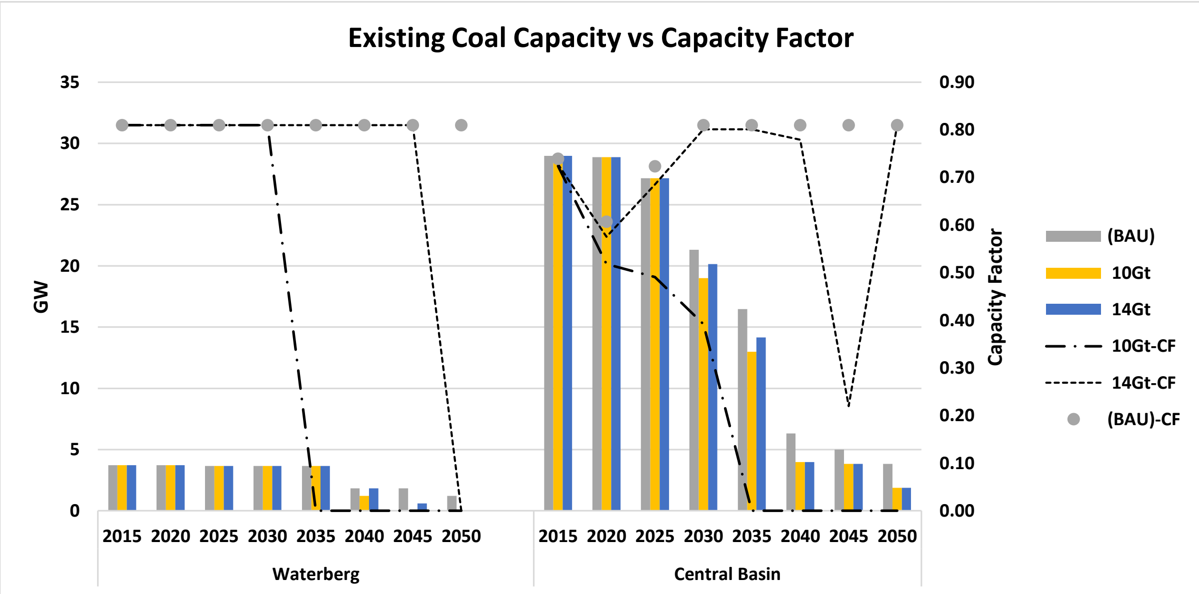


Figure 24: Existing Coal Capacity with Production Factors

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 25). The regional coal price is a likely factor in the preferential early retirement of plants in the Olifants as Waterberg coal is more economical. In both scenarios 3 GW of new Fluidised Bed Combustion (FBC) plants are built and operate over the planning period.

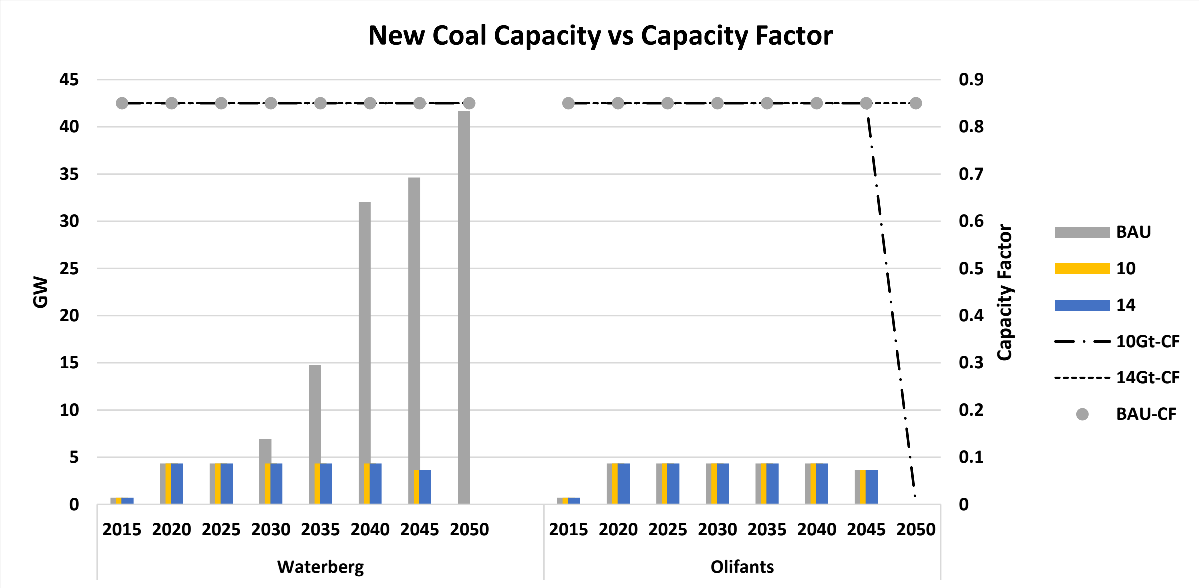
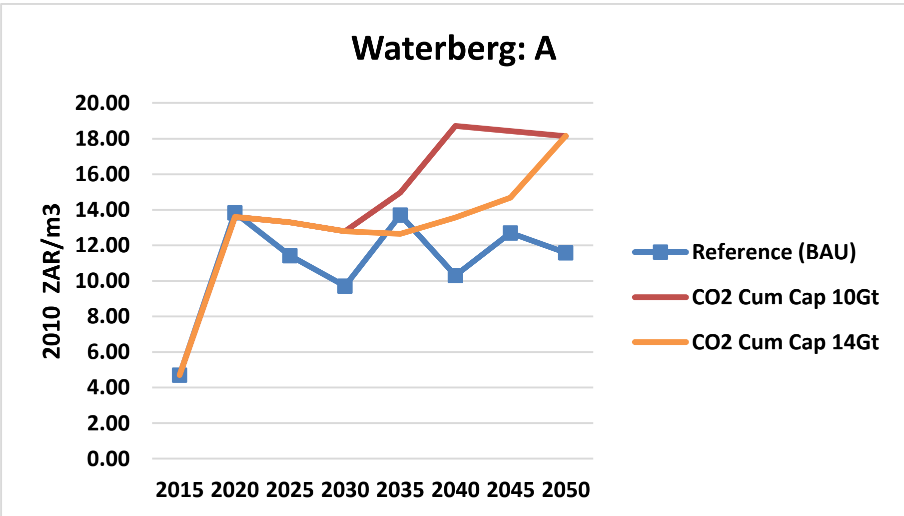


Figure 25: New Coal Capacity with Production Factors

Figure 26 suggests that water supply infrastructure for the Waterberg is also at risk of being under-utilised if CO_2 mitigation policy is carried through and possibly intensified given that the cost of water supply increases markedly after 2030 for the 10 Gt Cap scenario and after 2040 for the 14 Gt scenario because of the early closure of coal-fired capacity. This effectively increases costs for the remaining users as the supply system is being under-utilised. Conversely, the cost of water in the Olifants for the CO_2 cap scenarios decreases relative to the Reference Case with the stricter 10 Gt CO_2 cap also reducing costs relative to the 14 Gt cap in both cases due to the early retirement of the older wet-cooled existing plants.



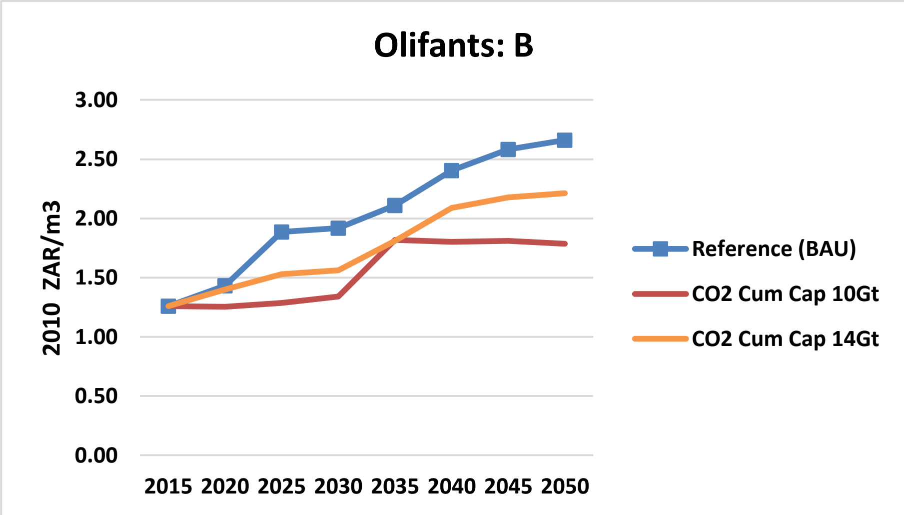


Figure 26: Water Supply Costs in Coal Rich Regions

The summary metrics for the 2 carbon cap scenarios relative to the Reference Case are shown below. Notable are the large increases in power plant investments for the 14 Gt scenario (26%) and double for the 10 Gt scenario. These are very muted in the system cost differences which aggregate and discount all supply and demand side costs. There are significant increases in water consumption by power plants reflecting the shift to wet-cooled solar thermal in the Orange River Region where water is relatively cheaper although as we see in the next section, when the stresses of a climate change and shale gas mining in the region are factored in, the model shifts to less water intensive dry-cooled CSP.

Table 10: Summary Metrics for 10 Gt and 14 Gt Cumulative Carbon Cap Cases

Scenario	Units	Reference (BAU)	CO2 Cum Cap 14 Gt	% change	CO2 Cum Cap 10 Gt	% change
Discounted System Cost	2010 MZAR (x1000)	7,646	7,690	1%	7,865	3%
Expenditure - Supply	2010 MZAR (x1000)	10,292	10,397	1%	9,788	-5%
Primary Energy	PJ	271,328	232,447	-14%	214,162	-21%
Final Energy	PJ	137,619	136,870	-1%	135,996	-1%
Power Sector CO2 Emissions	Mt	12,242	9,000	-26%	6,035	-51%
Power Plant Builds	GW	134	170	27%	189	41%
Power Plant Investment Difference	2010 MZAR (x1000)	2,722	3,430	26%	5,456	100%
Water to Power Plants	Mm3	11,093	12,785	15%	13,097	18%

VI.8 How do the potential effects of climate change alter investment decisions in the power sector?

The impacts of Climate Change are examined utilizing results of cases including the Dry Climate scenario, in which the water supply and demand curves are adjusted for the different water management areas as specified in Table C-1 (Appendix C) to simulate the possible effects of climate change as they are currently understood. This section explores whether these cases impact new investments in coal-fired generation in the Waterberg region and solar thermal investments in the Orange River region.

VI.8.1 The Impact on Investment in Coal-Fired Power Generation

As shown in Figure 27, in the Dry Climate scenario the life of some of the existing dry and (older and less efficient) wet cooled coal power plants are not extended as they are in the Reference scenario. These plants, as well as the 800 MW of new wet-cooled plants are instead replaced by new dry-cooled plants. This is primarily influenced by the competition for water from the non-energy sectors, which increases by an average of 11% from 2030 to 2050 in the Central Basin, where the existing plants are located. In the CO_2 constrained scenarios, there is almost no new investment in coal-fired generation and so there is no significant impact of a Dry Climate on investment in coal-fired power generation.

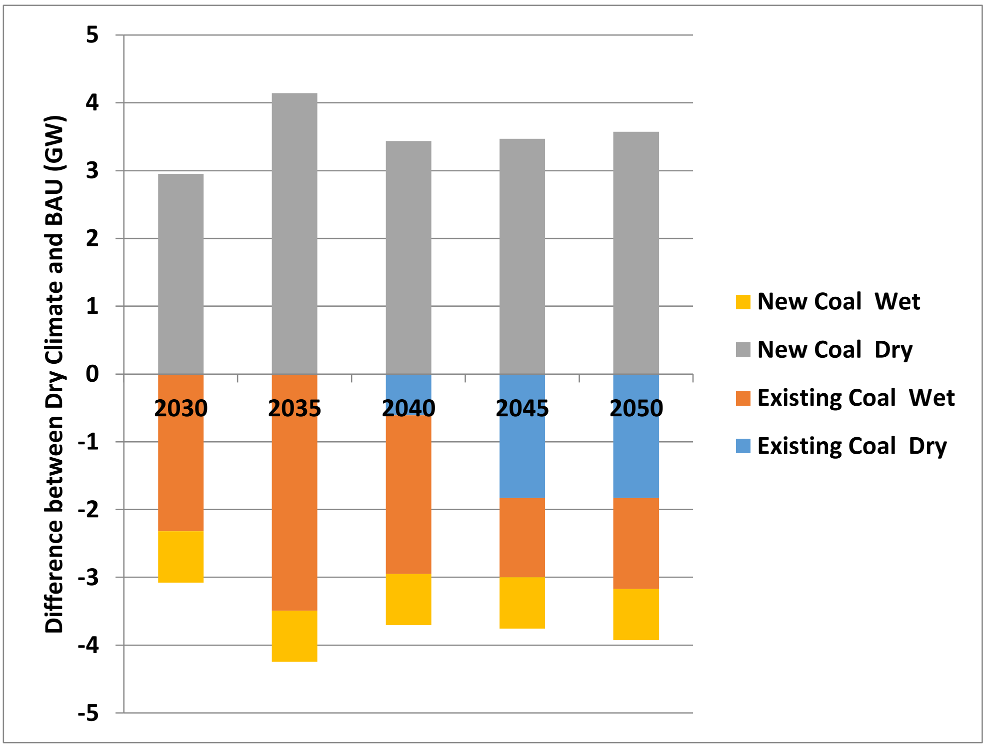


Figure 27: Difference in Installed Capacity between Dry Climate and Reference (BAU) Scenarios[5]

[5] The bars under the x-axis essentially show the capacity in the reference case that is substituted. In the case of existing capacity therefore this implies that it is retired before end of life and replaced by dry-cooled capacity. Note that this difference in capacity composition is for around 4GW – about 10% of today's installed capacity and about 3% of that in 2050.

VI.8.2 The Impact on Investment in Solar Thermal Power Generation

As shown in Figure 28, dry-cooled CSP capacity appears under the combined 14 Gt CO_2 Cap and Dry Climate scenarios, with and without shale gas. Although shown to appear only later in the planning horizon (2045-2050), dry-cooling CSP plants may be prudent as a pre-emptive risk management strategy in an uncertain climate and policy future.

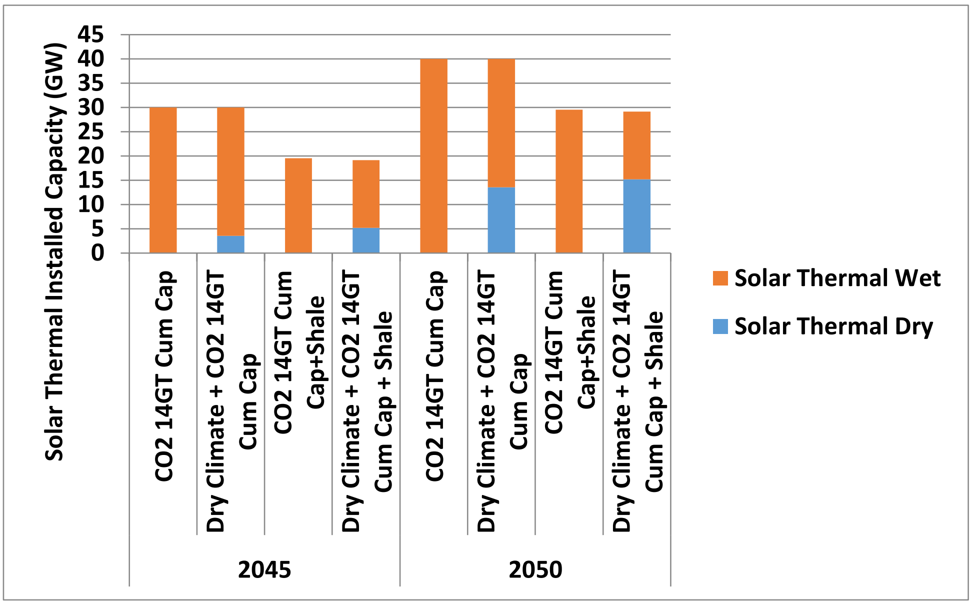


Figure 28: Impact of Dry Climate on Solar Thermal Installed Capacity

The increased demand from the non-energy sectors under a Dry Climate scenario causes a degree of regional water stress in the Orange River region, which is slightly exacerbated by the advent of shale gas extraction, as shown in Figure 29. The increased demand triggers further investment in water infrastructure, which causes the average water costs to go up significantly enough, as shown in Figure 30, to move some of the investment in CSP to dry cooled technology.

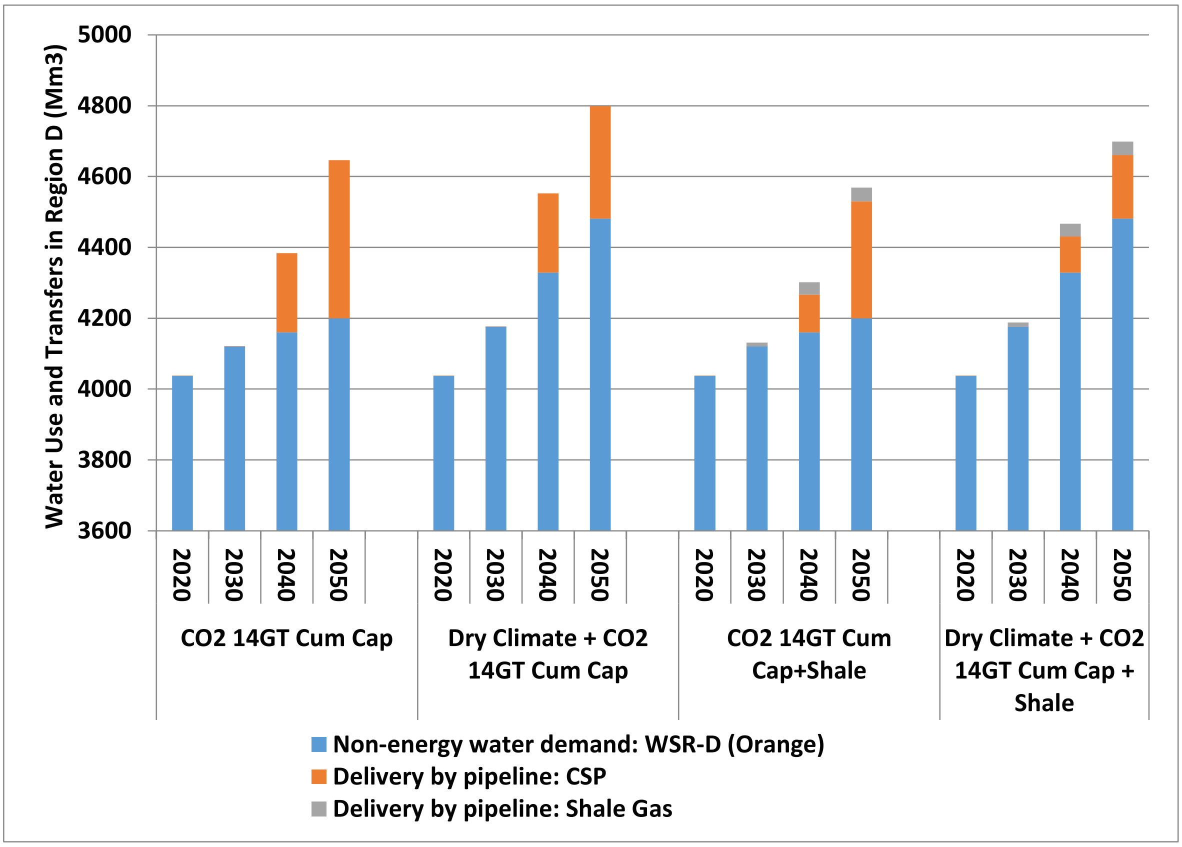


Figure 29: Water Use and Transfers for the Orange River WMA (Region D)[6]

[6] Note that the non-energy water demands (blue bars) are higher when the 'Dry Climate' case is included

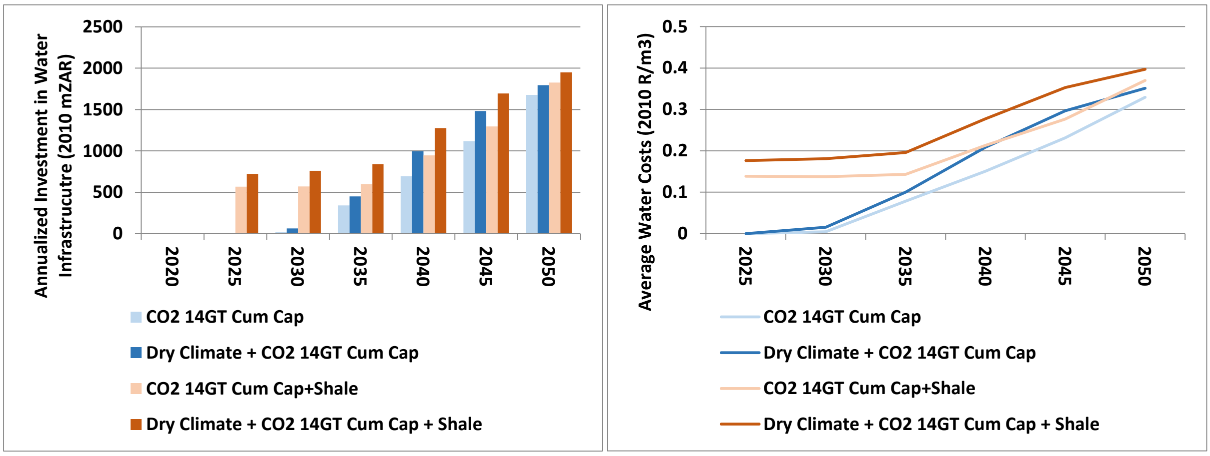


Figure 30: Annualised investment in water infrastructure in Orange Basin and the impact on the average cost of water

The summary metrics for the 14 Gt Cap case under the effects of climate change ('Dry' case) show a small reduction in the increased water intensity from the shift to CSP based production in the Orange River region caused by the cap. Essentially the water supply system appears to be resilient to the effects of climate change on water supply and demand as currently understood although there are changes to the cost optimal mix of wet and dry cooling coal and CSP technologies on the energy supply side in response to increased water costs.

Table 11: Summary Metrics for the Combined Scenarios for the Dry, Shale and 14 Gt Carbon Cap (C14Gt) Cases

Scenario	Units	Reference (BAU)	Dry & C14Gt	% change	Shale & C14Gt	% change	Shale & Dry & C14Gt	% change
System Cost	2010 MZAR (x1000)	7,646	7,691	1%	7,635	0%	7,636	0%
Expenditure - Supply	2010 MZAR (x1000)	10,292	10,394	1%	10,783	5%	10,804	5%
Primary Energy	PJ	271,328	232,434	-14%	232,656	-14%	232,601	-14%
Final Energy	PJ	137,619	136,859	-1%	136,991	0%	137,015	0%
Power Sector CO2 Emissions	Mt	12,242	8,994	-27%	8,924	-27%	8,938	-27%
Power Plant Builds	GW	134	170	27%	157	18%	158	18%
Power Plant Investment Difference	2010 MZAR (x1000)	2,722	3,430	26%	2,667	-2%	2,653	-3%
Water to Power Plants	Mm3	11,093	12,485	13%	10,387	-6%	9,938	-10%

VII. Conclusions

The World Bank's Thirsty Energy initiative is designed to assist countries in tackling water-energy management challenges in an integrated manner, rather than the traditional "silo" approach. This case study report demonstrates the importance of combined energy and water management approaches and practical methodologies that can be applied to energy sector planning tools.

The planned options for future bulk water supply to the energy sector were explicitly represented with their costs and availability in an updated version of the South Africa TIMES model, SATIM-W. For the first time, the full cost of water supply has been assessed in an energy supply expansion plan. The scenarios used to exercise the model addressed the main drivers of investment uncertainty in water and energy supply that are of key importance to South Africa, such as the availability of economically viable shale gas and the future impacts of climate change These scenarios serve to showcase how SATIM-W can be used to advise the energy sector policy formulation and decision-making process of the impacts of integrated water and water planning.

VII.1 Main Findings

The main findings of this initial Thirsty Energy case study provide important insights into priority investment decisions and policy recommendations, as well as provide identification of potential vulnerabilities (e.g., conditions that could result in stranded water or energy assets). As highlighted in the executive summary, the integrated water-energy analysis demonstrates that:

- **A critical attribute of SATIM-W is the ability to represent the water needs of the energy sector by region, and the ability to understand which water infrastructure will be needed for the energy sector *when* and *where.*** In South Africa, given that virtually all water is allocated, any future demand for water in the energy sector will require new water infrastructure. However, it can take up to 10 years (or more) to have that infrastructure approved and ready. Therefore, integrated long term planning of water and energy is crucial in South Africa. The SATIM-W model is a valuable tool to help with this integrated planning and to ensure timely investments and delivery of water supply and treatment infrastructure for the energy sector.

- Once the full costs of water supply are incorporated into the energy model, it chooses dry cooling for most coal power plants, which means **that dry cooling makes economic sense in South Africa** even if dry cooling decreases the efficiency of the power plant, and this result confirms the decisions by ESKOM to use dry cooling.

- **Water for power in South Africa is supported by major inter-basin transfers.** Even though the amount of water consumed nationally by the energy sector is a small percentage of the total, it has already changed the regional water picture in South Africa, and in one region (the Waterberg) energy consumes over 40% of all water demand.

- Not including the costs of water in the model, results in the build of wet-cooled coal-fired power plants with more than a **60% increase in water consumption for power generation.** **T**he generation mix for both cases is similar, with renewable energy (RE) generation contribution less than 10% until 2040, and no new nuclear power generation**.**

- The **requirements for flue gas desulphurization (FDG) systems at new coal facilities** in the Environmental Compliance and the Dry and Environmental Compliance scenarios dramatically reduces the investment in Coal-to-Liquid (CTL) plants, as capacity declines by 75% in 2050 as compared to the Reference case. In addition, it leads to an 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.

- A **requirement for existing coal power plants to retrofit with FDG systems** leads to the early retirement of 6 GW of capacity with over 5 GW of solar PV and 1.2 GW of concentrating solar with storage.

- The development of **Shale gas resources significantly increases power generation from natural gas** compared to the Reference (BAU). However, the cost of water as currently incorporated does not appear to alter the decision to invest in shale gas for power generation. The model also shows the preference for shale gas generation over that of wind and CSP, as neither option is considered when shale gas is utilized.

- Possible **CO2 Cap scenarios reduce coal consumption and increases renewables**, wind, solar PV and concentrating solar with storage using wet cooling. These scenarios also defer any new investment tin CTL plants. In the combined CO2 Cap and Dry Climate scenario, the concentrating solar with storage shifts to dry cooling.

- The **CO2 Cap scenarios also have the potential to lead to stranded coal assets.** The 14 Gt CO2 Cap case reduces production at the existing CTL plant from 96% to 30% by 2035, with the plant decommissioned 5 years earlier than in the Reference case. In the 10 Gt CO2 Cap scenario, production at the plant is completely halted by 2025, 20 years prior to the scheduled decommissioning date. The existing and committed coal power plants are less at risk under the 14 Gt CO2 Cap scenario and remain operational for their entire production life. In contrast, the 10 Gt CO2 Cap scenario leads to the early retirement of the existing coal plants and shifts electricity production from the Waterberg to the Orange River region. the The stock of existing coal plants is retired by 2035 with idle capacity of 2 GW in 2050 for both Carbon Cap scenarios.

- The **CO2 Cap scenarios impact the cost of water supply differently in each region water basins.** The coal power plants in the Olifants appear most at risk under the 10 Gt CO2 cap scenario, as they cease production earlier than plants located in the Waterberg. Therefore, the cost of water in the Olifants decreases. However, the cost of water in the Waterberg region increases water demand is maintained by new Fluidised Bed Combustion (FBC) plants that are built to replace the retiring plants.

- The **impact of climate change (leading to a Dry Climate) is to move forward investment**. Earlier investments in Solar PV, increases its capacity in 2050 by 1 GW. Approximately 2 GW of new coal capacity are added earlier in the Waterberg, offset by 3 GW of existing coal capacity retired by 2050.

- In general, because of its highly integrated water system, **South Africa's water resources seem to be quite resilient to climate change impacts**.

These findings from the SATIM-W model results highlight the insights such models can provide to inform decision makers of the potential costs, benefits and risks of alternative policies and technology choices under a range of possible futures conditions. In particular, these results demonstrate the potential of identifying major infrastructure investments that could become stranded down the road. Using an integrated tool, such as SATIM-W, which looks systematically at the development of both sectors, can potentially avoid such stranded infrastructure investments.

VII.2 Next Steps

The SATIM-W model and this analysis are an important 1st step that highlights the essential need to take an integrated approach to energy-water planning. The main follow-on areas to improve the model and further expand the coverage and insights include:

- Incorporating wastewater streams, treatment plants and other related infrastructure;
- Incorporating aspects of non-energy water consumption to be able to examine water reallocation schemes;
- Linkage with an economic model to enable the impact of the water-energy nexus trade-offs on the economy as a whole including the impacts on jobs, investment and affordability;
- For both the above perhaps regionalizing the energy demands as well;
- Harmonizing growth assumptions driving non-energy water demands and energy demands, which currently come from two different modelling frameworks that are only broadly internally consistent.
- Developing water linkages to a variety of biofuel feedstocks.
- Exploring approaches to incorporating the externality costs of power production including health and environmental impacts.

Whether it is economical to retire the existing stock or mandate the FGD instead is not answerable in the model's current form, and is being considered as another model refinement for the future. Other pertinent issues related to the cost of FGD that require future attention include:

- the costs and constraint for FGD feedstock (e.g., lime) and disposal; and
- the reduction in plant availability during FGD fitment.

Dry FGD systems have lower capital costs but higher maintenance costs due to the more expensive reagent and necessary waste disposal. Singleton (2010) identified that there is a local preference for wet FGD systems because of lower lifecycle costs. Therefore, the FDG control technology representation in SATIM-W is presently restricted to the wet FGD process for all coal power plants. Next would be to evaluate both dry and wet FGD systems and their impacts.

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Appendix A: Water Demand in South Africa

A.1 Upper Olifants

The estimated current water requirements in the Olifants catchment show that the water resources of the Olifants River system are close to being fully utilised (Table A- 1). The future water balance shows a deficit for the whole system by 2030 (Table A- 2). A major contributor to this deficit is the implementation of the ecological reserve, provisionally phased in during 2020 to 2025, which will reduce the water available for abstraction by about 200 Mm^3 per year. Power generation accounts for 23% of the current demand in the catchment. Despite plans for additional power generation capacity in the catchment, Eskom does not anticipate a significant increase in the total water demand as the planned new power stations will be dry cooled and will replace the existing wet-cooled power stations. After about 2025, it is anticipated that there might even be a gradual decrease in the total water demand for power generation in the catchment.

Table A- 1: Olifants System Water Requirements 2010 (Aurecon, 2011)

Management Zone	Irrigation (Mm^3/a)	Domestic & 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	1047

Table A- 2: Olifants Water Balance 2030 (Aurecon, 2011)

Management Zone	Total Water Resource (Mm^3/a)	Water Requirement (Mm^3/a)	EWR[1] (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	1047	1092	200	-245

[1]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 in addition to the existing IBTs. The feasible augmentation options include:

- Olifants River Dam: Construction of a dam in the middle Olifants close to Rooipoort;

- Ekurhuleni Effluent: It is possible to pump treated effluent from the East Rand, where the water would need to be treated to meet acceptable phosphate levels for discharge into the Olifants;

- Acid mine drainage 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;

- Import from Vaal Dam: Water could be transferred from the Vaal River System to the upper Olifants, where the infrastructure required includes a pipeline and pump station;

- Desalination of seawater: Although technically feasible it is likely to be prohibitively expensive, and

- Transfer of Zambezi water: 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 use of Ekurhuleni effluent and water imported from Vaal Dam would mean that the Vaal River augmentation would be expedited. The removal of alien invasive plants and the prevention of illegal irrigation could increase the water yield in the Upper Olifants by 16.1 Mm^3/a.

A.2 Integrated Vaal System

The supply area of the Integrated Vaal River System extends beyond the catchment boundaries of the Vaal River (Figure 31). It supplies around 12 million people with water (mainly in Gauteng), Eskom's power-stations and Sasol's petro-chemical plants in Mpumalanga, and various mines in the North-West and Free State. Additionally, the system will supply water to the developments on the Waterberg coal-fields near the town of Lephalale in the Limpopo WMA (DWA, 2009).

Figure 31: Location of the Olifants System (Source: DWA, 2009)

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 has been estimated at 228 Mm^3/a (Aurecon, 2011).

Table A- 3: Integrated Vaal System Power Station Water Abstractions (Eskom, 2012)

Catchment	Power station	Water Supply (Mm^3)
Komati	Arnot, Hendrina, Komati, Duvha	94
Usutu	Camden, Kriel, Matla	51
Usutu-Vaal	Duvha, Kriel, Tutuka, Matla, Kendel	88
Vaal	Lethabo, Grootvlei	52

The water quality in Grootdraai Dam and Vaal Dam is influenced by the water quality of the transfers from Lesotho, Thukela, Zaaihoek and the Usutu transfer schemes. The water quality of the transfers is currently of an acceptable quality. There is a concern that in the future the quality of the water in Grootdraai Dam will deteriorate due to acid mine drainage (AMD) water from closed mines and that the salinity will increase from the Vaal Barrage to Bloemhof Dam due to urbanisation and mine discharges (DWA, 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 LHWP to maintain an acceptable water quality standard.

To meet the increasing water demand driven primarily 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. The current and future water requirements for Vaal systems are presented in Table A- 4 (Coleman et al., 2007).

Table A- 4: Vaal System Water Requirements

Major User Group	Annual Water Requirement (Mm^3/a)				
	2010	2015	2020	2025	2030
Rand Water	1338	1417	1481	1568	1666
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

As the system is already over allocated, additional augmentation options are required to meet future water demands for the integrated Vaal River system. The feasible augmentation 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;
- Lesotho Highland Water Project (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.

A.3 Lephalale (Waterberg) area – Crocodile West/Mokolo System

The development of the Waterberg coalfield west of Lephalale, the construction of several coal-fired power stations and the establishment of other industrial users such as Sasol will dramatically increase water demand in the area. The expected growth in demand up to 2030 for the Lephalale area is presented in Table A- 5. Currently power generation uses only about 4.3 Mm^3/ a or 18 % of the total demand. But 2030 it is expected that the water demands from Eskom's power stations will increase to 79 Mm^3/a with an additional 20 Mm^3/a required for coal mining and 15 Mm^3/a required for independent power producers (IPP). This is a total 113 Mm^3/a, or 54 % of the future demand.

Table A- 5: Lephalale System Water Requirements

Major User Group	Annual Water Requirement (Mm^3/a)									
	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
Exxaro 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	6	6	8	10	12	14	15	20	21	22
Sub-Total	13	14	19	32	40	53	85	161	194	198

Irrigation	10	10	10	10	10	10	10	10	10	10
Total#	23	24	29	42	51	64	95	172	205	208

#Values may differ due to rounding errors.

The available water resources in the area are already over allocated. The future demand will be met initially from the underutilised Mokolo Dam and then via transfers from the Crocodile West catchments.

The current water use plan for the area states that water from the Crocodile River will be transferred to the Waterberg coalfields to meet the demand growth. This water will primarily consist of the growing return flows from the northern urban and industrial areas of Gauteng (DWA, 2010). However, the impacts on the Reserve and flows to the Limpopo must be considered as the Crocodile West reconciliation strategy study shows that this return flow may not be sufficient (DWA, 2010).

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;
- Reuse of effluent from the Vaal catchment;
- Transfer from Vaal system: from Vaal Dam;
- Transfer from the Zambezi, and
- Desalination of seawater.

A.4 Orange River System

The Orange River System has a catchment area of approximately 0.9 million km^2 and flows in a westerly direction from Lesotho to the Atlantic Ocean (Figure 32). There is a west-east rainfall gradient in the orange catchment with MAPs in some areas of the Northern Cape being below 100 mm per annum near to the Atlantic coast where as some part of the Orange catchment in Lesotho have MAPs in excess of 1,200 mm per annum (Schulze, 2006). The natural runoff for the Orange River basin has been estimate at 11,600 Mm^3/a. The current day runoff that is discharged at the river mouth has been estimated at 5,500 Mm^3/a.

Figure 32: The Orange River System (Source: DWA)

In terms of energy and water demand, the growth areas in the Lower Orange catchment will be from concentrated solar power (CSP) and potentially the recovery of shale gas. The water requirements for the Orange River are summarised in Table A- 6.

Table A- 6: Orange River System Water Requirements

Major User Group	Annual Water Requirement (Mm^3/a)			
	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 requirement	615	615	615	615
Operating requirements	180	180	180	180
River Mouth Environmental requirement	288	288	288	288

The source of the water required for hydraulic fracturing to recover the extensive shale gas deposits in the Karoo has yet to be determined. There are, however, very few surface water sources available in the area with many towns already experiencing sever water shortages. The nearest large surface water supply option is from the Orange River or one of its tributaries. 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.

The increase in irrigation and industrial water usage in the Orange River catchment has led to deterioration in water quality. The water quality is also dependent on the source of the water i.e., 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 (DWA, 2009).

Currently the water balance of the Orange River system reflects a slight surplus (DWA, 2010). 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: Future Climate Change Impacts

Sub-Saharan Africa is considered to be one of the more vulnerable regions in the world to climate change, and while there is a general agreement that temperatures will continue to increase, there is still significant uncertainty about the potential impact on precipitation. A recent review of existing climate models identified four possible future scenarios as part of the Long Term Adaptation Scenarios (LTAS) flagship research program of the Department of Environmental Affairs (DEA, 2013a):

- **Warmer (<3˚ C above 1961-2000)** and wetter with greater frequency of extreme rainfall;
- **Warmer (<3˚ C above 1961-2000)** and drier with an increase in the frequency of drought events and somewhat greater frequency of extreme rainfall events.;
- **Hotter (>3˚ C above 1961-2000)** and wetter with substantially greater frequency of extreme rainfall events, and
- **Hotter (<3˚ C above 1961-2000)** and drier with a substantial increase in the frequency of drought events and somewhat greater frequency of extreme rainfall events.

The LTAS study concluded that while there was a general consensus on the fact that temperatures would continue to increase into the future, the level of increase would be dependent on the outcomes from global mitigation efforts. Under a business-as-usual scenario South Africa would likely experience a much "hotter" future with an average increase in temperature greater than 3˚C by the end of the century. If, however, there was improved global co-operation on climate change and a significant reduction in GHG emissions then South Africa would like face only a "warmer" future. For both scenarios, the potential impacts would apply for all regions of the country, but with inland areas likely to experience greater increases than coastal zones and the mountains.

Under both the "hotter" and "warmer" futures there was still much uncertainty about the possible impact on precipitation, although it was generally agreed that the variability would increase under both scenarios, but more so under the "hotter" scenario. Unlike temperature, precipitation impacts would vary quite significantly for different regions of the country.

B.1 Water Supply

As part of the LTAS study, the potential biophysical impacts of a range of possible climate futures was analysed using a rainfall runoff model at quaternary scale, as well as a water resources yield model configured at secondary catchment scale for the whole of South Africa, including all the major water supply infrastructure, dams and inter-basin transfer systems (DEA, 2014). These national water models were used to investigate the potential impacts of climate change on future water supply to the urban, industry and agriculture sectors in each WMA, and they were used to contribute to an Integrated Assessment Model (IAM) assessing the potential economic impacts of climate change at a national scale and at the level of individual WMAs. A key result from this study was the observation that the national water supply system of South Africa, which has been planned to deal with a high level of natural variability and is highly integrated as a result of all the IBTs, appears to provide a high level of resilience to future climate change, although potentially at a cost in terms of increased pumping rates and potential negative impacts on environmental flow requirements (DEA, 2013a).

The range of potential impacts of climate change on the average annual water supply for each of the nineteen WMAs is shown in Figure 33, which is based on the results of the LTAS study (DEA, 2014).

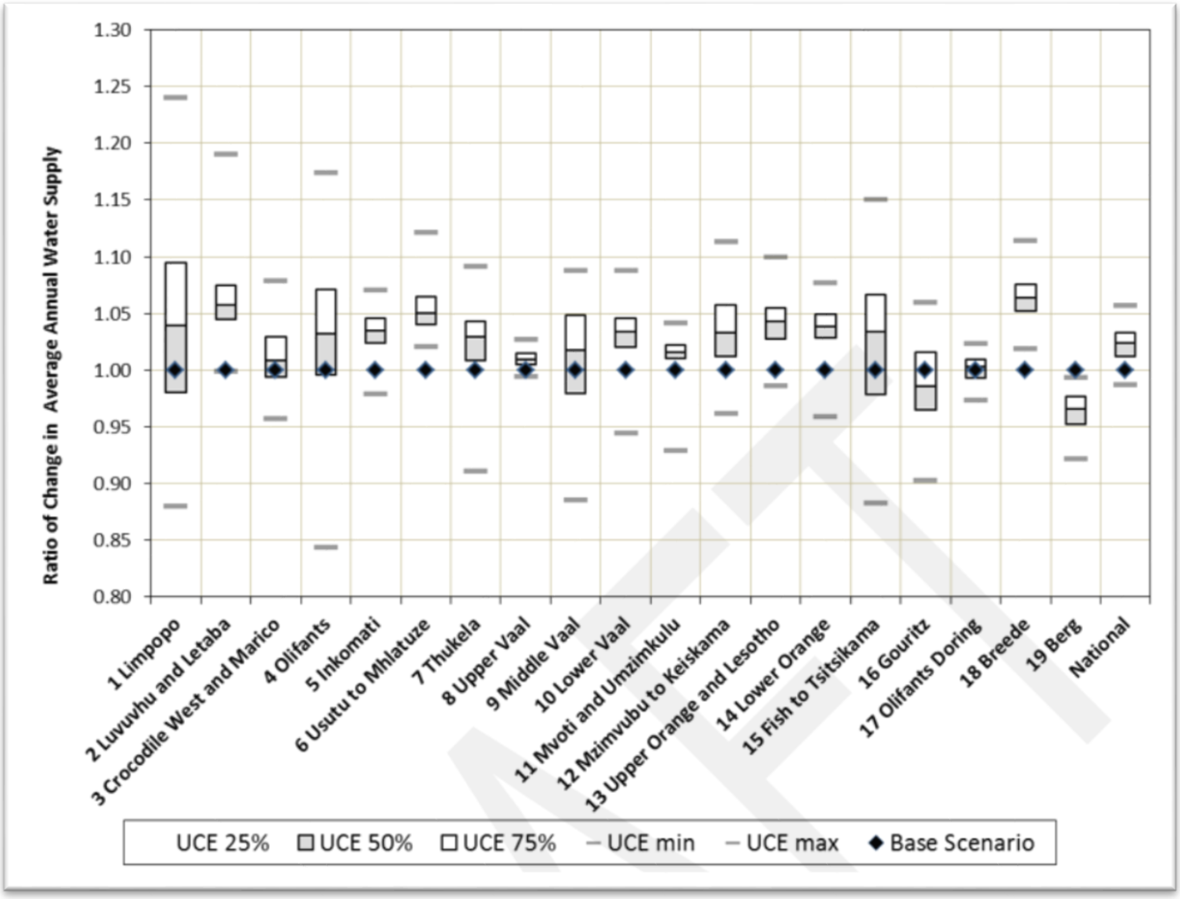

Figure 33: Impacts of Climate Change on Average Annual Water Supply by WMA

Figure 33 shows the ratio of change in the average annual water supply, from 2040 to 2050 for each WMA, as well as 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 a slight increase in the total water supply to the country (+2.3%) by 2050, but with a wide range of possible impacts on individual WMAs. For example, all model scenarios show a likely reduction in the average annual water supply to Cape Town, which is located in 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. This is one of the primary reasons why the results of the economic model found only limited impact of climate change 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 scale. This analysis required substantial simplification of the existing water supply infrastructure as well as other local impacts on precipitation, catchment runoff and water supply. The analysis was also based on time series simulations and determined in terms of the potential impact on the average annual supply, and did not consider particular impacts during critical periods or the potential for increased frequency of droughts and extreme events. More specific results in selected WMAs or catchments would require more detailed water supply models, as well as stochastic analysis of alternative base line and future scenarios to determine the potential

B.2 Coal Power Stations

Future coal-fired power stations are likely to be located in catchments A (Limpopo), B (Olifants) and C (Vaal), which show a median impact of around zero change or a small increase in the average annual runoff by 2050, but with a wide range of possibilities. Future CSP plants will be located in the Orange River basin (D), which has a median impact of a 5% reduction in catchment runoff, but also with a wide range of potential impacts with up to as much as 50% reduction in some areas.

B.3 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 of increasing temperatures under all future climate scenarios will result in an almost certain increase in evaporation and associated irrigation demands in all regions of the country.

The average median impact across secondary catchments is 6.4 ± 1.9 % for the UCE scenario. While some very wet scenarios show a small reduction in future irrigation demands in the Limpopo (A), Olifants (B), Vaal (C) and Orange (D) catchments, other very dry scenarios show possible increases in average annual irrigation demand of up to 25%.

B.4 Hydropower Potential

Hydropower is currently not a major contributor to energy production in South Africa. There is potential for reduced hydropower production at existing power stations, but there is also potential for increased hydropower potential in South Africa through the retrofitting of existing dams in certain areas of the country likely to experience increasing precipitation and runoff (DEA, 2014). This 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.

The primary impact of climate change, in terms of water supply to the power stations, will be a potential reduction in the availability of water and an increase in the relative cost of water given the likely increases from other users, particularly agriculture. However, the 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 sources due to climate change, this will most likely result in earlier than planned implementation of alternative, and more expensive, water supply augmentation options, as well as increasing the unit cost of these schemes as they will deliver less water at the same price.

B.5 Catchment Runoff

Regional climate modelling of possible climate futures to assess the potential impact on the average annual runoff for different catchments across the country is summarised in Figure 34. The results are for the UCE scenario in the period 2040 to 2050 for secondary catchments, which are indicated by the horizontal axis. The results show a reduction in streamflow for the western half of the country (D to K) and in particular the south Western Cape catchments (F, G and H) where all the climate models show a reduction in streamflow. In contrast there are some very large potential increases in runoff for the east coast (Q to W) which could result in increased flooding risks.

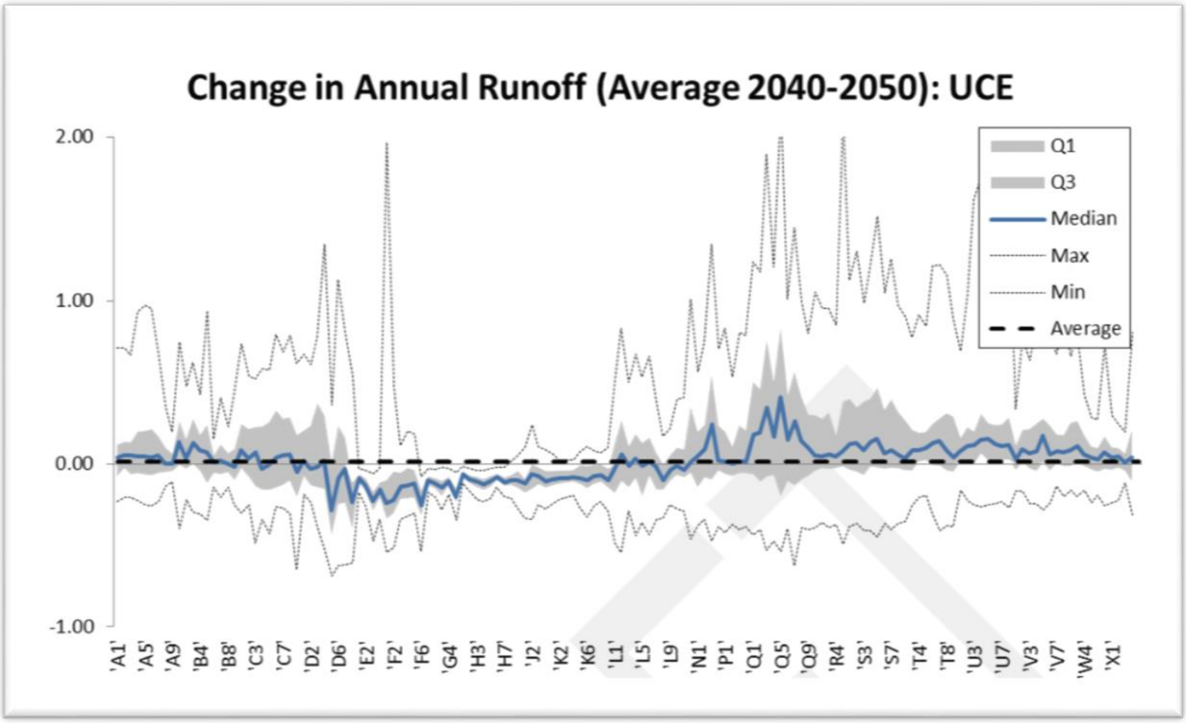

Figure 34: Impacts of Climate Change on Runoff by Catchment

B.6 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 SATIM-W model as follows:

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

Figure 35 illustrates the resultant regional water demands as included in SATIM-W for the non-energy sectors. The impact of Climate Change on water demand is discussed in *Appendix C: Scenario Development and Key Assumptions*.

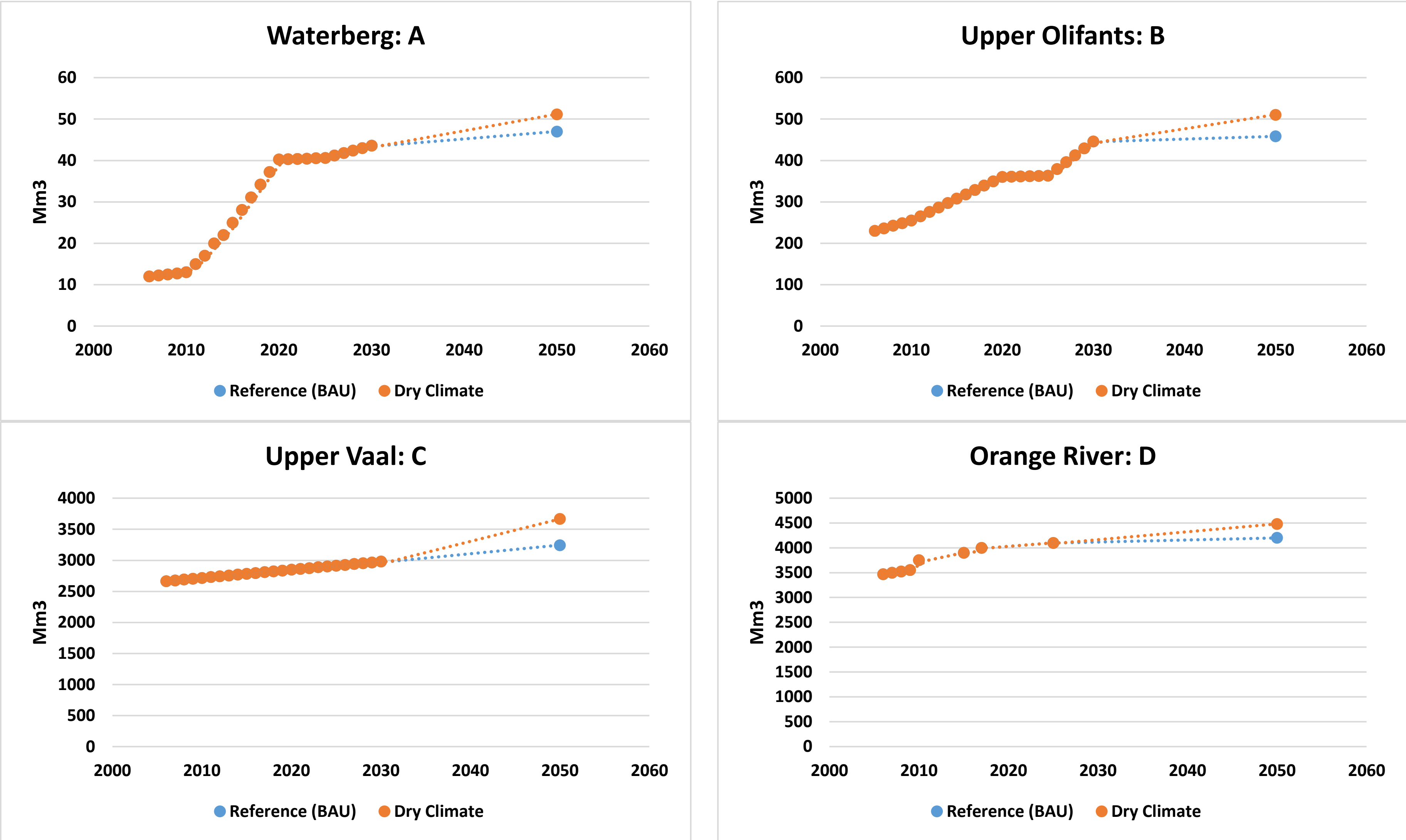

Figure 35: Regional Water Demands for the Aggregated Non-energy Sectors

Appendix C: Scenario Development and Key Assumptions

The SATIM-W model was used to examine the choice of future energy supply technologies in a water constrained landscape. Figure 36 illustrates the interconnected dimensions that impact on key policy decisions in the water-energy sector. In this section the policy and investment strategy scenarios are used to gain insights into key issues confronting the South Africa energy sector going forward. The results of these scenarios are compared to the Reference (BAU) scenario results to evaluate the costs and benefits of different policy options, and weigh the impact of uncertainty on the outcomes.

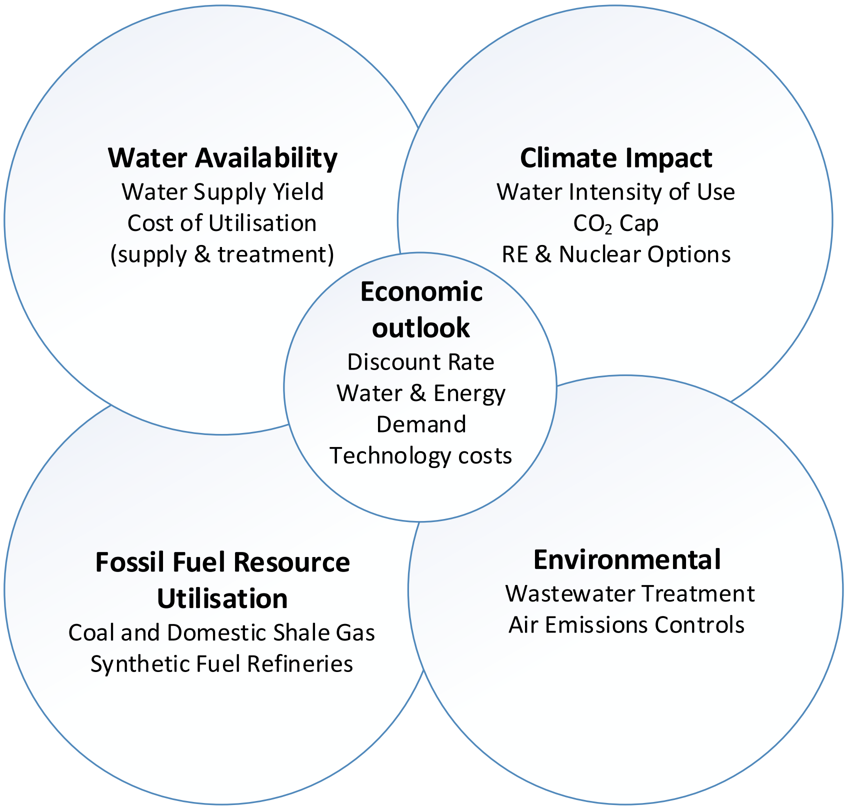

Figure 36: Scenario Themes Exploring the Water-Energy Nexus

In this Case Study, these policy themes have been collated into five cases, which highlight the main drivers of investment uncertainty in water and energy supply. The scenarios which were developed to frame the South African water-energy dialogue for each of these themes are summarized in Table 6.

Greenhouse Gas Mitigation. South Africa has committed to a "Peak-Plateau-Decline" (PPD) emissions pathway (See Figure 37) as the country's Intended Nationally Determined Contribution (INDC) for the United Nations Framework Convention on Climate Change (UNFCCC) Conference of Parties in December 2015. This commitment was modelled as the imposition of carbon budgets limiting cumulative national 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.

Figure 37: "Peak-Plateau-Decline" (PPD) Emissions Trajectory for South Africa (Source: NBI)

Climate Impact on Water Availability. Climate change is a stressor to regional water supply and demand, and Table C- 1 summarises the climate change impacts on water supply and demand that are modelled for the four regions of interest utilizing the 0.25% estimates from the LTAS study. A sensitivity was done for the water stress scenario to help identify possible risks or necessary alternative decisions relative to the energy sector. In the model, the change in supply and demand as outlined below is applied from 2030.

Table C- 1: Climate Impacts on Water Supply and Demand in 2050 (Source: WBTE-SA Task 1 Report)

WMA	SATIM-W WSR	DRY Climate Case	
		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%

Shale Gas Exploitation. The potential for shale gas to contribute to primary energy supply to enhance energy security and diversification is explored in this scenario. While as yet not comprehensively surveyed, the extent of recoverable shale gas reserves in the country's Karoo region have been 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 L, 2015). Therefore, this study limits shale gas extraction to 40 Tcf.

Environmental Compliance. Recent legislative amendments requiring stricter air emissions controls, along with best practice water management for coal mines, are explored in this scenario. At present, water management best-practice is restricted 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 instead focused on the reduction of particulate matter in the flue stack (Singleton, 2010). However, recent legislative amendments to improve local air quality include stipulations to control the emission of combustion by-products. Of particular concern is the emission of sulphur dioxide (SO_2) due the high concentration in flue gas and its deleterious environmental and public health impacts.

The legislative amendments relevant to coal thermal power plants are summarised in Table C- 2.

Table C- 2: Air Emission Standards Applicable to Electricity Generation in South Africa (DEA, 2013)

National Environmental Management: Air Quality Act (No. 39 of 2004)		
Solid fuels combustion installations used primarily for steam raising or electricity generation[1]		
	mg/Nm^3 under normal conditions of 10% O_2 , 273^O K and 101.3 kPa	
	Existing Plant	New Plant
Particulate matter (PM)	100	50
Sulphur dioxide (SO_2)	3500	500
Oxides of nitrogen (NO_x)	1100	750

[1]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.

Existing power plants were expected to comply with the new regulations by 2015 and to meet the emission standard for new plants by 2020. However, postponement of the application of the standard to the majority of the existing coal fleet has been petitioned (South Africa, 2014). The model includes FGD for new power stations, and the Environmental Compliance scenario (ENV) applies the minimum emissions standards (MES) to existing power plants. To date, none of the existing plants have FGD systems, and in light the retrofit delay, the ENV case is only applied in 2025.

In addition to the cost and water requirements of FGD, the Environmental Compliance scenario 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 restricted to water transfer to the Waterberg (Region A) and is based on the Eskom analysis of water from the Crocodile River for demineralised water production (Eskom, 2008). Furthermore, water quality remains constant over the planning period.

The question of whether available water resources are a limiting factor to future energy supply choices in South Africa depends very much 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.

C.1 Key Assumptions

Exogenous growth expectations over the planning period are shown in Figure 38 and assume a national average GDP growth rate of 3.1% 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[7], is expected to grow four-fold.

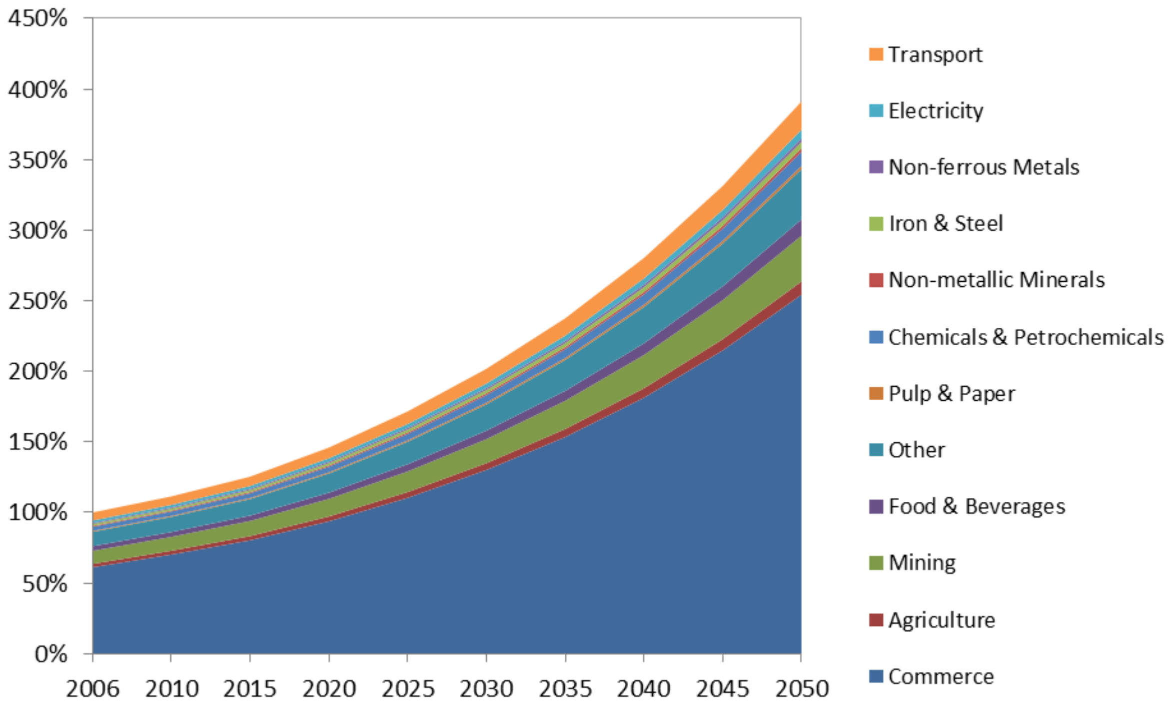

Figure 38: GDP Growth Assumptions by Sector

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

Table C- 3 lists the prices in the model for primary commodities.

Table C- 3: Primary Commodity Prices in SATIM-W (2010 ZAR)

Commodity Prices	Units	2015	2030	2050
Coal Region A (existing)	ZAR/t[1]	126	176	176
Coal Region A (new)	ZAR/t[1]	-	360	360
Coal Region B/C (existing-1)[#]	ZAR/t[1]	179	248	248
Coal Region B/C (existing-2)[%]	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

[#]Tier1: Eskom product only; [%]Tier2: Dual product mine linked to Eskom; [1]Assuming a calorific value of 21 MJ/kg;

[7] 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.

Appendix D: Detailed Modelling Results

As can be seen in Figure 39, with the exception of the Waterberg, the demand for water from the non-energy sectors is the main driver of new water supply infrastructure. The comparative demands of the energy supply sectors are especially dwarfed by the demand for water in the Orange River 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 dominates in the region, accounting for approximately 50% of the total water requirement, while domestic and industrial demand use 30% 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 CTL facility, and a migration of coal mining to the Waterberg from the period 2030-2035 as less-economic coal deposits are abandoned in the Olifants and Upper Vaal in favour of Waterberg coal.

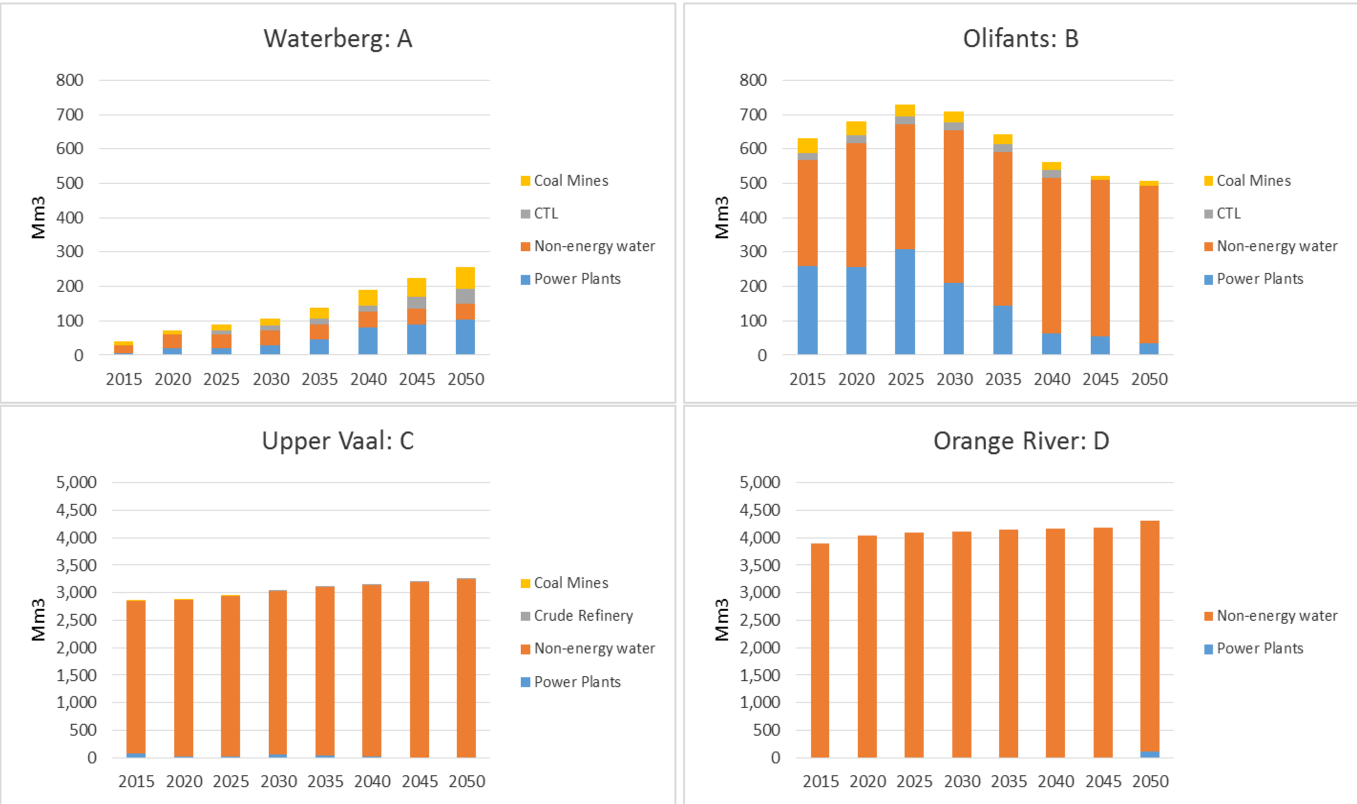

Figure 39: Regional Water Demands by Supply Sector

The water requirements in the Upper Vaal for energy supply are less than 1% of the total. There are two existing coal plants in this region and they retire between 2040 and 2045. In addition, the country's sole inland crude-oil refinery, which operates throughout the period, consumes 0.65 Mm^3/a or 0.02% of the total water demand in 2050.

As discussed above, 10 GW of wet-cooled CSP capacity are added by 2050, which is located in the Orange River region. The additional CSP capacity, with a preference for wet-cooled technology, accounts for less than 3% of the total regional water supply.

In contrast, more than 80% of future water supply to the Waterberg is attributed to the energy supply sector. Power generation directly accounts for 40% of this total. New CTL plants in the region would consume close to 20% of the water supply, while coal mines, assumed to practice wet-beneficiation, would total 25%. A sharp escalation in water demand in the Waterberg is experienced due to continued demand for coal and the preference for new coal plants to be built in this region. The magnitude of water demand is curtailed, as previously discussed, by the preference for dry-cooled coal power plants. This reduces the total water supply requirements for the region to a potential maximum of 260 Mm3/a by 2050.

The contrast between the Waterberg and other regions in the annual investment expenditure required for bulk water supply is shown in the left portion of Figure 40. The regional expenditure for water supply infrastructure to reconcile projected demand is concentrated in the Waterberg. The right portion of Figure 40 provides a breakdown of the water conveyance infrastructure required in the Waterberg for water transfers to this arid and water scarce region. The additional supply options are facilitated by the interconnected regional system.

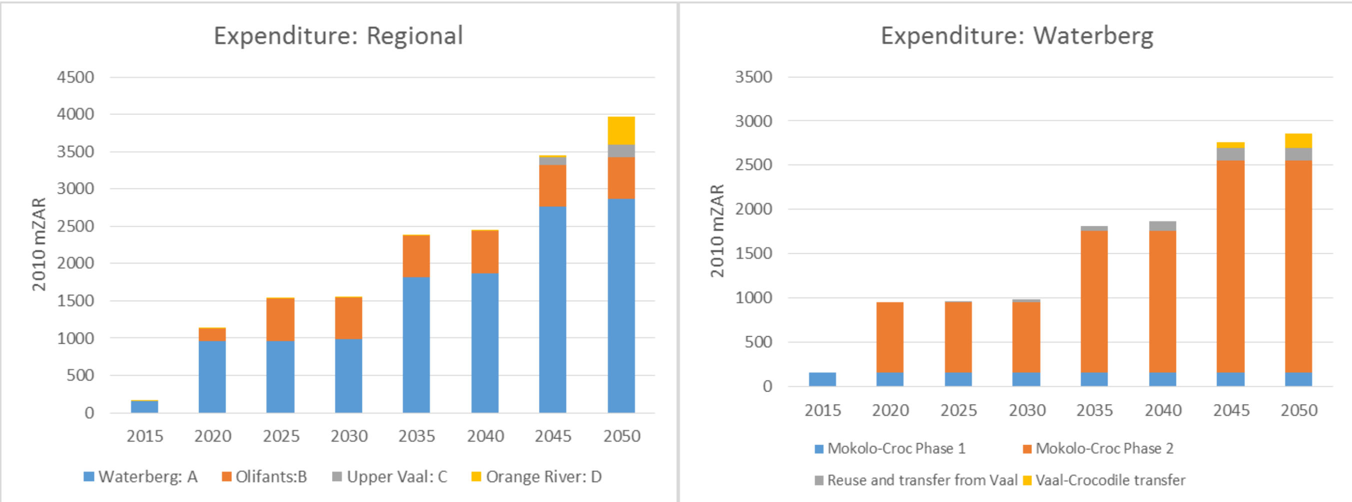

Figure 40: Annual Investment in Water Supply Infrastructure

The lack of natural causeways in the vicinity of the Waterberg requires substantial investment in supply pipelines for inter-regional water transfers. This is evident in the relative sizes of the Phase-1 and Phase-2 supply schemes (Figure 40). 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 utilise the existing local supply system. The additional investment required to establish the supply options, such as the transfer of return flows from the City of Johannesburg (i.e., reuse and transfer from Vaal), represent a much smaller expenditure.

This series of investments in water supply infrastructure will lead to a future of increased water supply costs. The Waterberg is the region where the cost of water can be expected to escalate dramatically should further growth in coal supply proceed unabated. Figure 41 shows the annualised average unit cost of water supply in each region, and these costs can be compared to the expenditure shown in the left side of Figure 40. For the Waterberg region, the peaks observed for the average water supply cost are due to the lump sum investment in pipelines for water transfers to the region. 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 water supply cost decreases with an increase in water volumes transferred until the existing supply capacity is reached, necessitating new investment for continued exploitation of coal in the Waterberg.

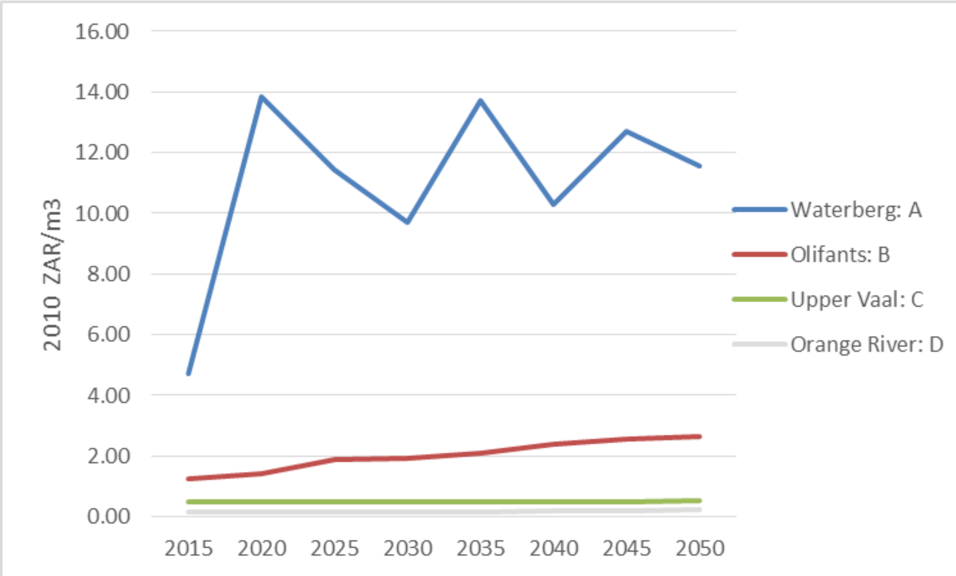

Figure 41. Average Regional Water Supply Costs

In contrast, the average supply cost for the other regions are not expected to experience a similar escalation (Figure 41). Non-energy demand is responsible for the rise in water supply cost to the Olifants. The resultant expenditure is due to additional water transfers from the Vaal River system with interim usage of treated acid mine drainage near 2020. The option of an additional dam in the Olifants is avoided. The average cost of water in the Olifants effectively doubles over the 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 modelled, but represented by regional categories.

The Orange River region, with regard to water supply, is essentially an agricultural region. Due to the incremental demand for water in this region, the supply cost increases by approximately 40% through to 2050, from a base of 17c/m^3 to 25c/m^3. The increase occurs from 2045 and is due to the increase in demand for wet-cooled CSP in this region.

In the Waterberg, the average supply cost of R4.70/m^3 in 2015 assumes a fully operational Phase-1 implementation. The cost is an approximate 700% 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 is warranted when comparing the supply cost to the supply tariff, as the cost would not necessarily reflect the actual price paid via the tariff. The water supply tariff is usually structured on a 20 year cost recovery, after which a return-on-assets component is reflected. Furthermore, tariffs differ by consumer 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 is related to energy supply. Agriculture and domestic consumers reliant on the local supply system would be subject to a lower supply 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 currently the water demand from the non-energy sectors are included in aggregate, and modelled without consideration of sectoral water reallocation or demand reduction interventions. A refinement of the model incorporating the disaggregation of water demand from the non-energy sectors may therefore result in deferment of investment in regional water supply infrastructure as water-use efficiency and value-added usage improves. However, since investment in the Waterberg is dominated by the requirement for the conveyance infrastructure and water demand is primarily for energy supply, it is doubtful whether such further consideration would significantly affect investment requirements in this region.

D.1 Carbon Cap Scenarios

Carbon policies look to limit total cumulative emissions over the planning horizon, in line with the nation's UNFCCC INDC and share in a future where the global warming level rises no more than 2^{o}C.

In all regions except the Upper Vaal, water supply costs rise over time when a carbon cap is applied (Figure 42The Carbon Cap scenarios (green and orange) reduce hydrocarbon fuel utilization (i.e., coal, gas, and crude-oil from refineries), which results in the under-utilisation of existing water conveyance infrastructure in the Waterberg, which results in a marked increase in the unit supply cost of water. The more carbon restrictive scenario (10 Gt CO_2 Cap) results in existing and newly commissioned coal plants being effectively mothballed, and this dramatically reduces 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 produce a decrease in water costs as the existing coal plants are retired early. As previously discussed, the increasing trend in the average cost of water in the Olifants region is due to the increasing demand for water 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 due 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 water supply cost region, with the maximum cost of bulk water supply approaching 50 c/m^3.

In the Carbon Cap scenarios, earlier investment in the RE 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 % in the near-term (2015-2025), and by 40 % to 70 % in the latter period (2020-2035), 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% above that of the Reference cost of 70c (2010) /kWh in 2050.

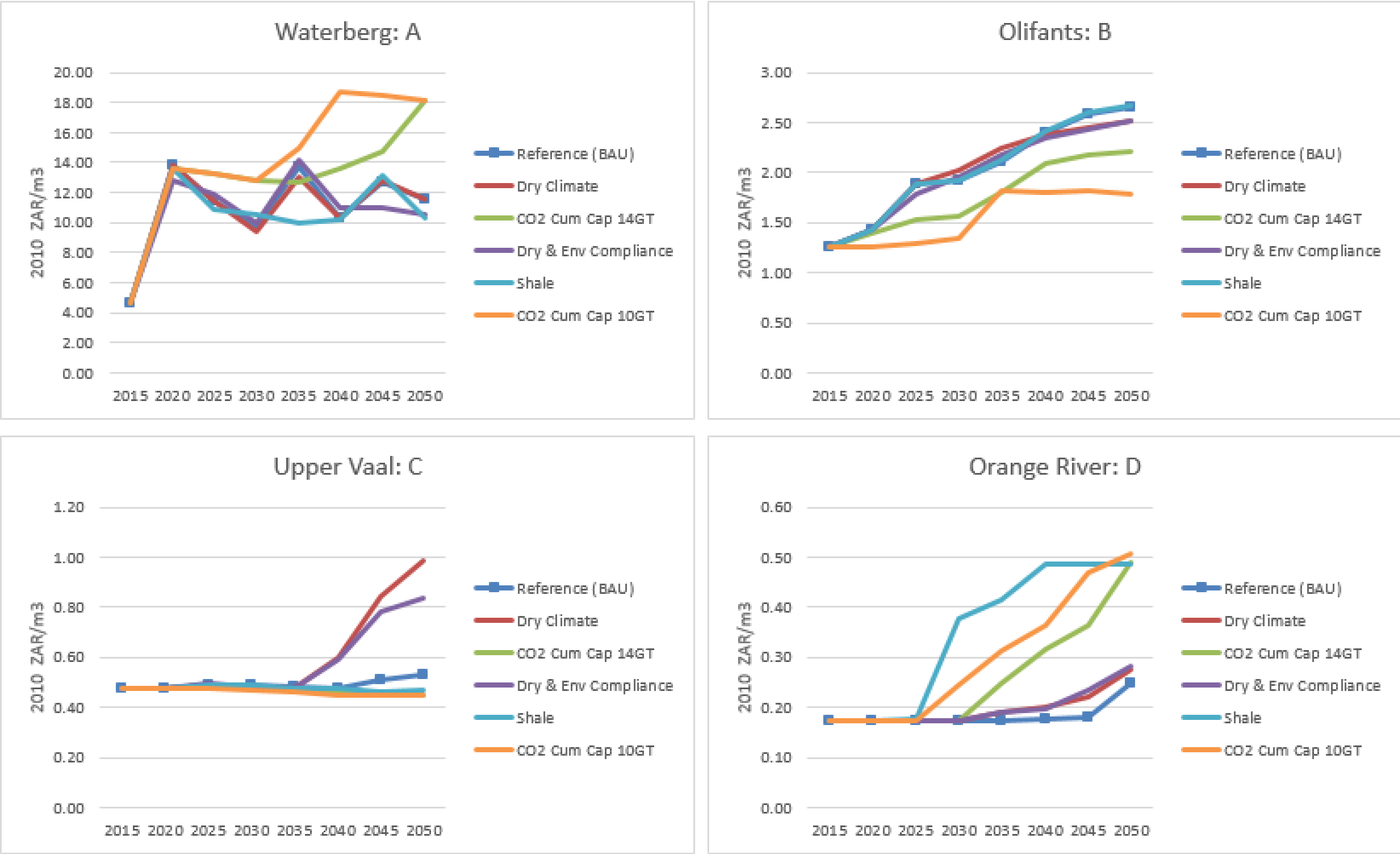

Figure 42: The Projected Regional Average Cost of Water Supply

D.2 The Dry and Environmental Compliance Scenario

The Dry and Environmental Compliance scenario, which represents the extreme water stress scenario, is mostly impacted by the Environmental Compliance and to a lesser extent the potentially climate-induced changes to water supply and demand. Figure 43 highlights the similar, cost optimal, power plant portfolio when comparing the Reference case to that of the Dry Climate case.

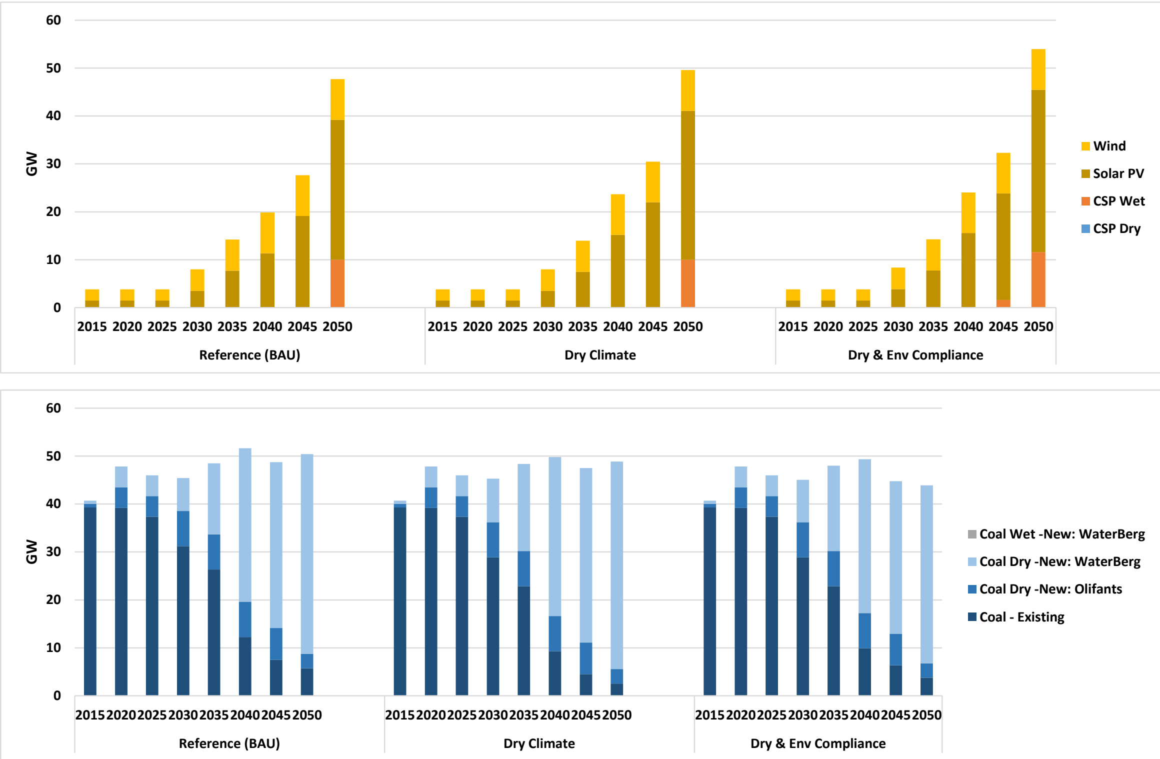

Figure 43: Comparison of Generation Capacity for Coal and RE Portfolio

Model results for the regional impact of Climate Change on water demand suggests 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 44).

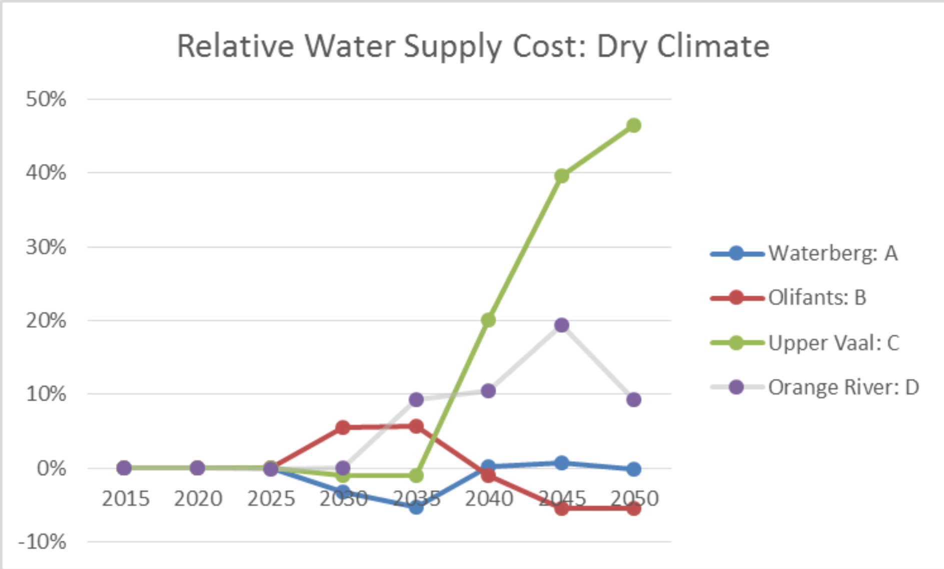

Figure 44: The Relative Cost of Water Supply Compared to the Refernce(BAU) Case

The slight decrease in water cost observed in the Waterberg is due to the early retirement of the older wet-cooled coal plants under a "warmer and drier" (Dry) climate in the Olifants and Upper Vaal with the resultant migration to new dry-cooled coal plants in the Waterberg. Approximately 2 GW of additional plant is added to the Waterberg with 3 GW of existing plant retired early by 2050. The decrease in cost reflects the increased utilisation 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 VI.4). The increased cost of treatment associated with demineralised water production for boilers further reduces the attractiveness of coal-based energy supply (Section VI.4). In addition, FGD technology on new CTL plants which are not considered in the Reference scenario is also included. The FGD technology, unlike the 'wet' based process for power plants CTL[8], is presumed to be of semi-dry Circulating Fluidised Bed design due to concerns over space restrictions for the existing plants (SRK, 2014).

Furthermore as previously stated (Section VI.1), there are also additional water treatment costs as inter-region transfers are presumed to be of lower quality. The lower quality water requires pre-treatment for demineralised use as boiler make-up fluid and for process use (i.e., stream generation

[8] It should be noted that the current model represents the cost of FGD as an annualised 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 in 2020 than in the Reference. This artefact 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.

for the Fischer-Tropsch process). The associated cost increase for treated water is equal to the marginal cost of water treatment for demineralised use for water transferred from the Crocodile River (Eskom, 2008). [9]

Requiring existing coal plants be retrofitted with FGD technology results in an earlier retirement profile for the existing coal power plants, which reduces the regional water demand, thus deferring investment in new water supply (Refer to Section D.2.1). The added cost of FGD retrofits makes the existing wet-cooled power plants less economically attractive compared to the Reference scenario, where life extension of these plants is seen.

[9] It should be noted that water consumers are supplied with equal priority by the model. 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 utilised 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.

D.2.1 What is the Investment impact of requiring power stations to retrofit FGD?

To date, no South African coal power plant has Flue Gas Desulphurisation (FGD) technology installed. However, as noted in the previous section, recent legislative amendments to improve local air quality include stipulations to control the emission of combustion by-products. Dry FGD systems have lower capital costs but higher maintenance costs due to the more expensive reagent and necessary waste disposal. Singleton (2010) identified that there is a local preference for wet FGD systems because of lower lifecycle costs. Therefore, the FDG control technology representation in 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 FDG retrofits, and if not, when could water be available?
- Will the additional demand significantly affect regional water cost?
- What will be the effect of retrofits on electricity price?

In considering the above questions, it is useful to start by examining the retirement profile of existing coal capacity when the minimum emissions standards are applied (Environmental Compliance) and under changing climate (Dry Climate) (Figure 45, 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 to the Reference case – approximately 2 GW by 2050 (Figure 45, 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.

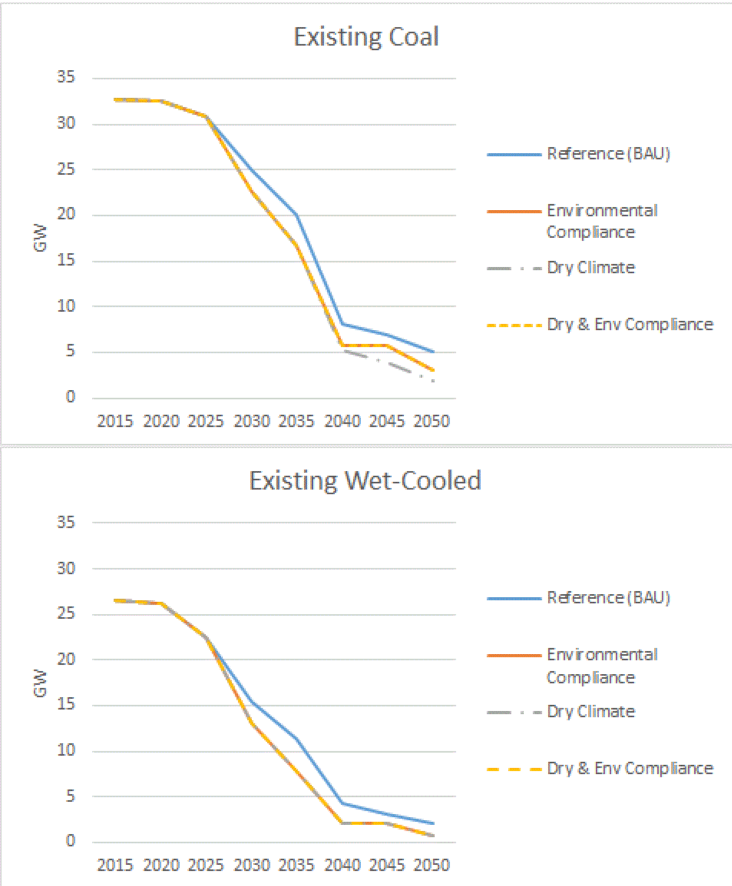

Figure 45: Existing Coal Capacity Retirement Profile

The regional lump sum investment cost for water supply is displayed in Figure 46. Investments are largely influenced by the Dry Climate case and the FGD retrofits which occur in 2025. The near term water supply requirement in the Olifants are catered for with treated local acid mine drainage 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. This is evident in Figure 46 where investment in water supply infrastructure in the Upper Vaal is delayed as a result.

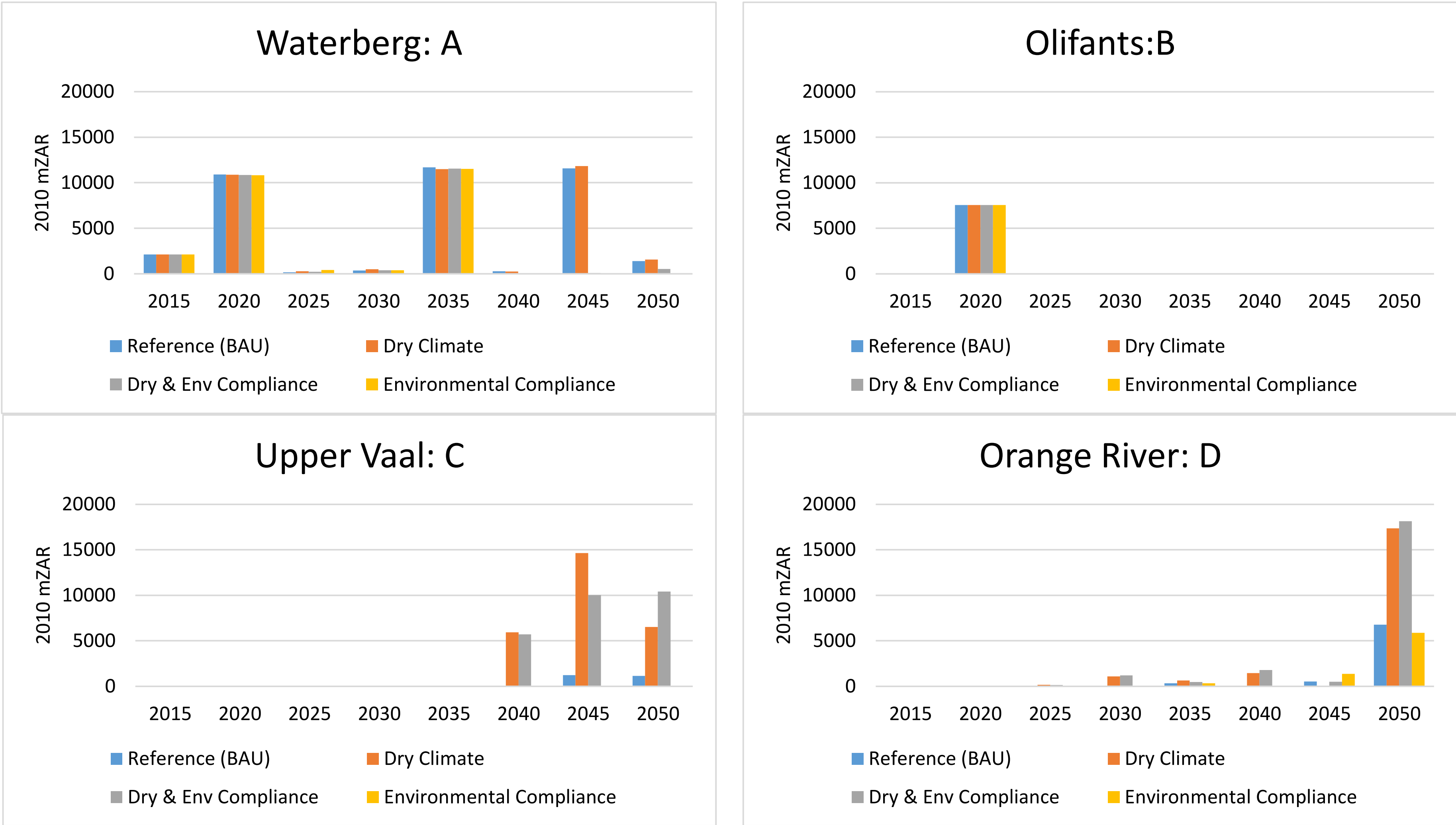

Figure 46: Lump sum investment in new water supply infrastructure

Figure 47 summarises the key water and energy performance indicators. As expected, an increase in the water intensity of generation occurs in 2025 due to the FGD retrofits. The value of 1.25 l/kWh is 10% higher than the Reference 1.14 l/kWh. However, due to the earlier retirement of the existing stock the water intensity decreases by a similar amount by 2040.

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% from the Reference value of 0.48 l/kWh to 0.6 l/kWh during this period (2045-2050).

The cost of electricity remains stable relative to the Reference when considering the effect of the Environmental Compliance case (Figure 47, right panel) with no discernible deviation. The deviation observed for the Dry Climate case amounts to 3% less than Reference, 0.68 - 0.72 ZAR/kWh during 2045 -2050. This reduction is attributed to the increase in new coal capacity of 2 GW in the Waterberg.

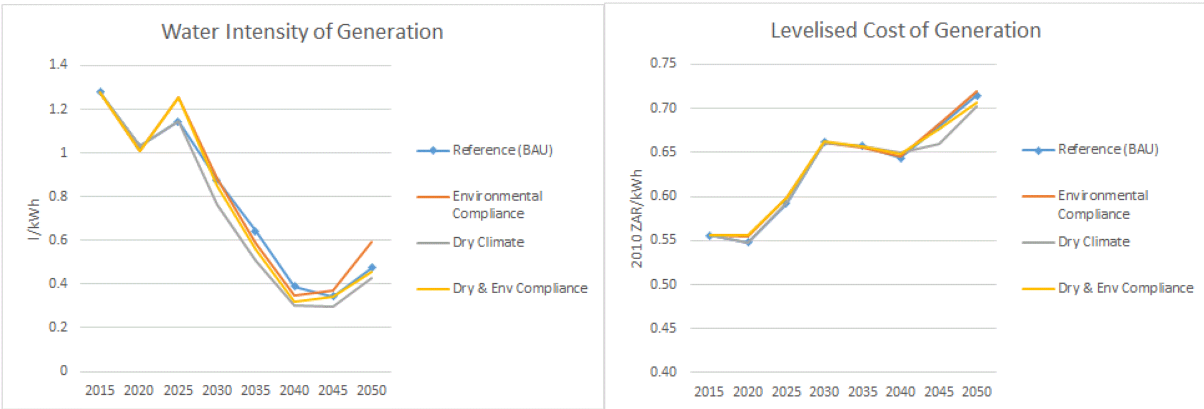

Figure 47: Water and Energy Performance Indicators

Table D- 1: Summary Metrics for Dry Climate Case (DRY), Environmental Compliance Case (ENV)

Scenario	Units	Reference (BAU)	DRY	% change	ENV	% change	DRY & ENV	% change
Discounted System Cost	2010 MZAR (x1000)	7,646	7,651	0%	7,706	1%	7,707	1%
Expenditure - Supply	2010 MZAR (x1000)	10,292	10,265	0%	10,494	2%	10,491	2%
Primary Energy	PJ	271,328	270,009	0%	263,463	-3%	263,394	-3%
Final Energy	PJ	137,619	137,625	0%	137,598	0%	137,582	0%
Power Sector CO2 Emissions	Mt	12,242	12,111	-1%	12,004	-2%	11,991	-2%

Power Plant Builds	GW	134	130	-3%	131	-2%	131	-2%
Power Plant Investment Difference	2010 MZAR (x1000)	2,722	2,864	5%	2,818	4%	2,821	4%
Water to Power Plants	Mm3	11,093	10,421	-6%	11,158	1%	10,898	-2%

D.4 Shale Gas Scenario

Shale gas has the potential to increase energy security (by reducing imports) and enhancing diversification and lowering GHG emissions (by displacing coal). The question is at what cost, needing how much (more) water, and how much of those benefits it realizes.

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 reduces the water supply investment required in the Waterberg, and defers new investment until the latter period (2040-2050) as new coal power capacity is postponed.

The main differences in the Shale Gas scenarios, as compared to 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% 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% 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/a. In response to growing demand, the share of supply declines to 35% 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 utilisation of the gas plants, which go from a 90% to a 75% 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% of available gas in 2030 and increases to 80% in 2040, thereafter declining to 70% 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 current 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 with higher water consumption factors.

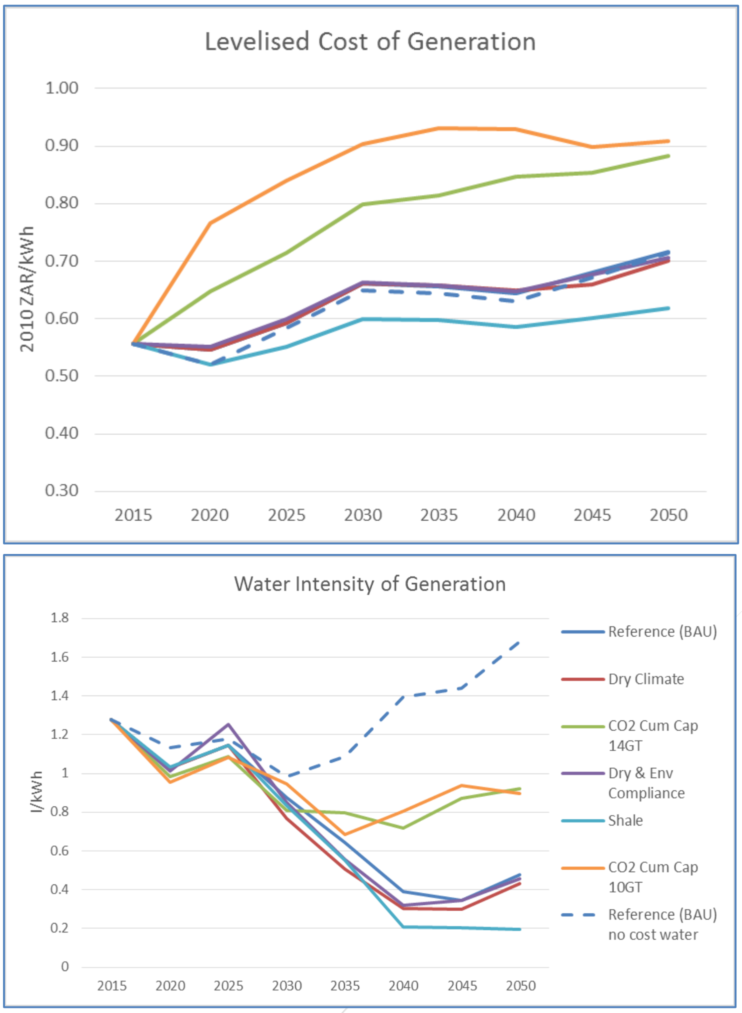

Figure 48: Cost of Electricity Generation and Water Use Intensity

D.5 Water Intensity

Both Carbon Cap scenarios result in higher water intensities than the Reference (See Figure 48). 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%. 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 PV in the late term (2040-2050). Almost 50% (25 GW) of the 55 GW of total capacity appears during this period for both Carbon Cap scenarios.

D.6 CO2 Emissions

The effect of the Carbon Cap scenarios are also evident in the GHG emissions over time (See Figure 49). The 14 Gt CO_2 Cap case prevents further CTL expansion, with the existing plant fully utilised until its scheduled decommissioning date 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 case, emissions from both the refineries and the power sectors decline sharply from 2020.

Emissions from the Shale Gas scenario depart from the Reference in 2030 with the onset of shale gas utilisation for power. Emissions are reduced by 30% (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% of the Reference (375 Mt CO_2eq). Within the refineries sector, reduced demand for liquid fuels due to the introduction of gas-combustion vehicles reduces further investment in CTL from 2045 with a concomitant decrease in emissions of 20% 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 & Environmental Compliance scenario has somewhat interesting implications for CTL refineries (See Figure 26b). 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 which deems it cost effective to offset the future cost of environmental compliance in the prevailing 5 years. The stricter 10 Gt CO_2 Cap causes existing CTL plants to retire ahead of schedule by 20 years, which results in a sharp decline in emissions from refineries, with crude oil refineries emitting the remaining ~ 3 Mt CO_2-eq.

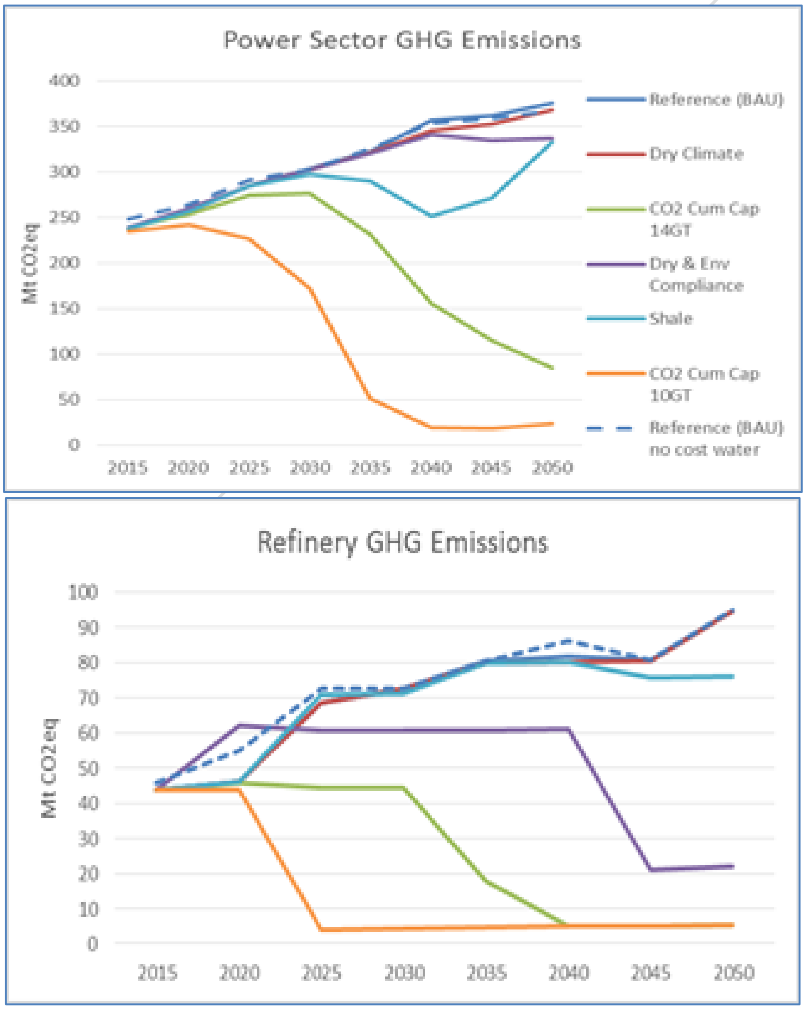

Figure 49: GHG Emissions for the Power and Liquid Fuels Sectors

Appendix E: Modelling Energy

Appendix F: Regional Water Supply Systems in SATIM-W

To establish the Reference Energy Water System (REWS) for SATIM-W it is necessary to adopt a naming convention scheme that enables the user to easily recognise the nature and role of each of the components. To accomplish this the REWS component names are assembled from the acronym components listed below.

Regional WSR identifiers:

A: Limpopo 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 of 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 only one subcategory (x=1) is implemented in the model the approach allows for the flexibility to include additional categories.

Example naming structure:

WA-P1-D: the volume of primary quality water, i.e. generic boiler feedwater (1), delivered to a process or technology in region D.

UPSWA-H1-D: the volume of high quality water with no associated delivery cost in region D.

U1WA-H1-D: the 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 sub-regional supply systems are labelled D1 and D2. The remaining regions have supply and delivery costs combined which simplifies the implementation and naming conventions adopted.

F.1 Regional water supply systems and individual schemes

Each regional water supply system is distinguished by an appended region code. The nomenclature is adopted from the naming conventions introduced in Task 1. Where possible the supply and delivery (transmission) costs as elaborated in Task 1 are combined to simplify the overall model implementation.

For region D this was not possible as different delivery costs are given for the shale gas and CSP sectors. Therefore delivery is modelled as a distinct component, as explained below.

- It is likely that additional gas related energy sector development in the region would occur with shale-gas mining. As shown in the RES diagrams, this may include GTL, OCGT and CCGT technologies. Since CSP technologies are located in the North Cape, delivery costs given for shale-gas mining are include for these technologies as it is assumed that they would be collocated.

- The RES for region D is more complex than the other regions because of the multiple delivery options. This is especially the case for shale-gas mining which has three delivery routes: bulk pipeline, truck; and onsite groundwater use. In the model this is represented as modal shares which can vary in time. For example, delivery by truck would most likely be the main delivery route in 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 RES diagram for Region D, the water supplied to consumers is split into sub regional systems: D1 (CSP region), D2 (shale gas energy technologies such as GTL and CCGT) and (shale-gas mining).

- Each scheme has a water quality commodity attribute with the existing supply system set as the reference (level 0).

F.2 Parameterisation of Water Supply Technologies

The model parameters for implementing the regional water supply systems in SATIM-W are summarised below in Table F- 1. For the treatment technologies, the simplified expression is included as an alternative should a levelised cost be preferred for certain cases. 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.

Table F- 1: SATIM-W Parameters Characterising a Water Supply Scheme

TIMES parameters	Scheme Supply & Delivery	Treatment
Time varying parameters		
NCAP_COST	Capital (ZAR/Mm^3)	Capital (ZAR/Mm^3/annum)
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[1]	In SATIM-W included as a FOM cost	n/a
ACT_BND	Yield (Mm^3)	n/a
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/a	Unit Water Cost (ZAR/Mm^3)

[1]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.

Note that some schemes have construction lead times. For example, this applies to the case of the use of Acid Mine Drainage as an interim option should the cheaper Vaal–Usutu scheme be unavailable at such a time when the DWA water demand forecast requires additional supply for the Vaal region. The construction lead times are mostly derived from the DWA study of the marginal cost of water for future supply options and modified where more recent data exists (DWA, 2010).

F.3 Water Supply Costs

The costs for the regional the water supply schemes (as derived from Task 1) are summarised in Table F- 2. For Region D, the supply and delivery costs are shown for the different modes of supply and delivery.

Figure 50 to Figure 53 displays the individual regional REWS representation in SATIM-W.

Table F- 2: Cost Data for Regional Water Supply Schemes (DWA, 2010)

Scheme Description	Region ID	Scheme Yield	Energy Requirement	Capital Cost	Annual O&M Cost

		(Mm^3/a) 2010	(kWh/m^3)	(R x 10^6)	(R x 10^6)
Waterberg - Existing	A0	25			
Mokolo pipeline (Phase-1)	A1	29	1	1759	5
Mokolo-Crocodile River Transfer (Phase-2) pipeline[1]	A2	75	1	8174	22
Reuse and Transfer from the Vaal	A3	126	1	1216	3
Transfer from Vaal River	A4	90	1	2562	7
Transfer from Zambezi River	A5	100	2	14469	38
Desalination of Seawater	A6	100	14	20896	55
Upper Olifants - Existing	B0	400			
Vaal Eskom Transfer[3]	B0-UX	230			
Olifants Dam	B1	55	0	1241	3
Use of Acid Mine Drainage	B2	31	2	1637	4
Transfer from Vaal River	B3	190	1	4281	11
Transfer from Zambezi River	B4	95	4	18553	49
Desalination of Seawater	B5	100	14	14210	38
Upper Vaal -Existing	C0	3523			
LHWP-II[4] (Polihali Dam)	C1	437	0	11947	32
Use of Acid Mine Drainage	C2	38	3	1820	5
Thukela-Vaal Transfer	C3	522	3	21976	58
Orange-Vaal transfer	C4	289	2	15671	42
Mzimvubu Transfer Scheme	C5	631	4	41568	110
Transfer from Zambezi	C6	650	4	52254	138
Desalination of Seawater	C7	100	14	7831	21
Orange - Existing	D0	4131			
Boskraai Dam (55%)[2]	D1	515	0	2678	7
Boskraai Dam (full yield)[2]	D2	422	0	3286	9
Mzimvubu-Kraai Transfer	D3	165	5	4370	12
Desalination of Seawater	D4	100	14	11175	30
Hydraulic fracturing - groundwater	DK0	1	4	2.6	0.01

[1](DWS, 2015); [2](DWA, 2013); [3]Aggregate representation; [4]Lesotho Highlands Water Project-Phase 2

Note:

- Annual supply from aquifer arbitrarily set at 1 Mm^3/a. Groundwater usage require further study for appropriate inclusion.

- Seawater desalination was chosen as the ultimate scheme supply. The alternate option of a transfer from the Zambezi River was not included due to potential water security concerns.
- Road transport diesel consumption was estimated at 2MJ/tonne-km with a calorific value of diesel given as 35.94 MJ/L and a load factor of 50%.
- 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 modelled as input commodities in terms of kWh/m^3 and $Litres/m^3$ of water delivered (although in TIMES the native units are $PetaJoules/Mm^3$).

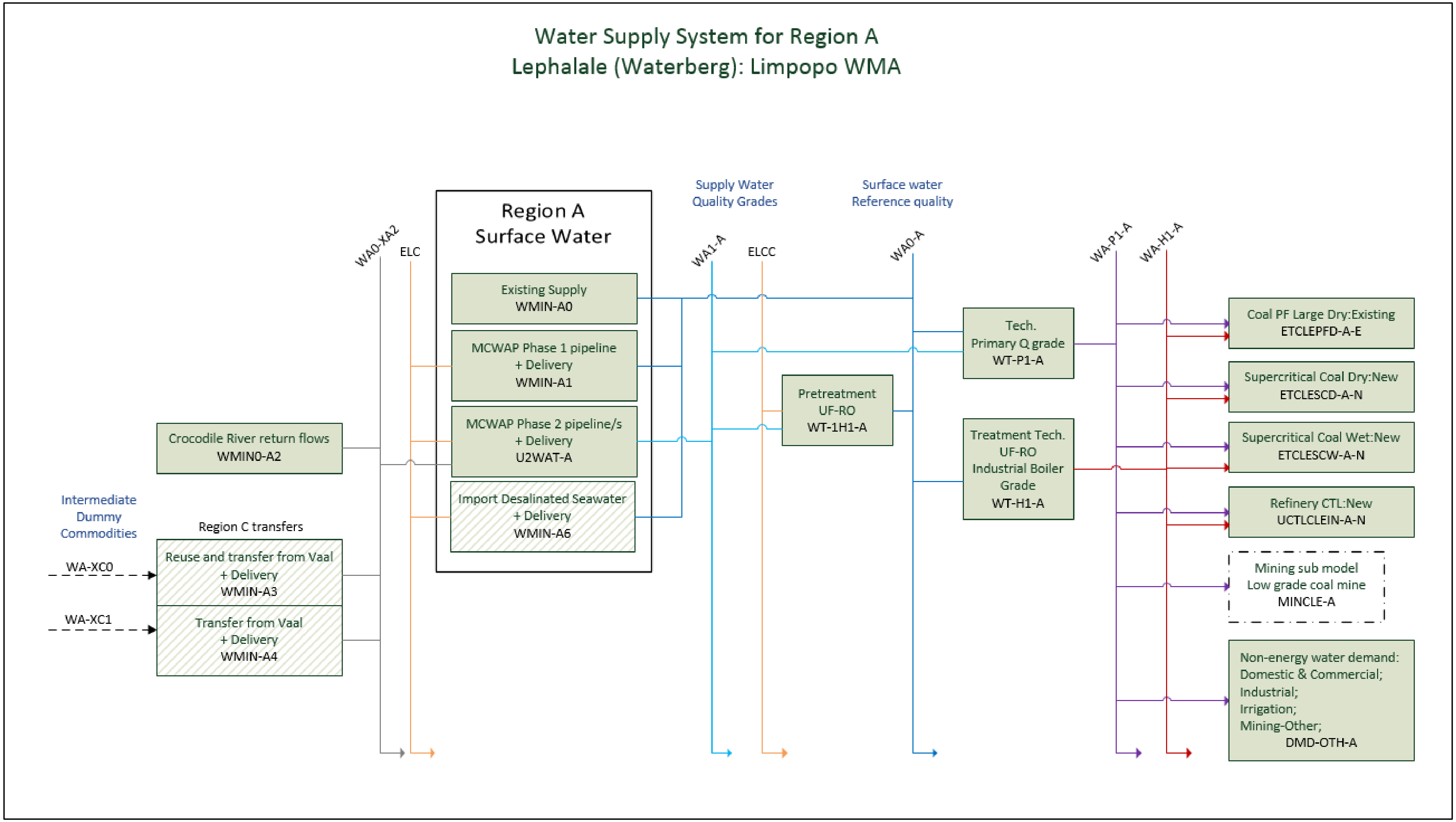

Figure 50: The SATIM-W water supply system for Region A

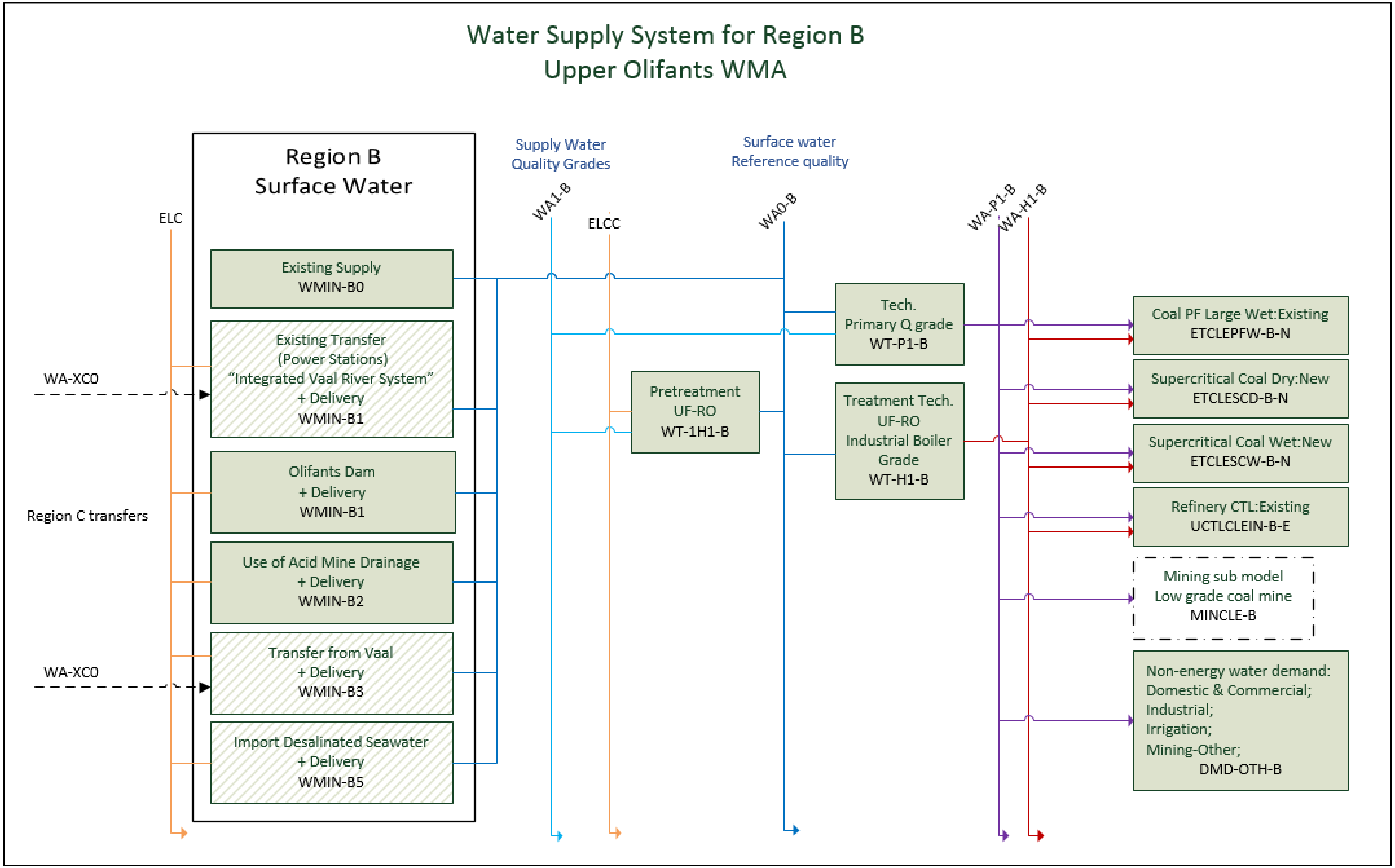

Figure 51: The SATIM-W water supply system for Region B

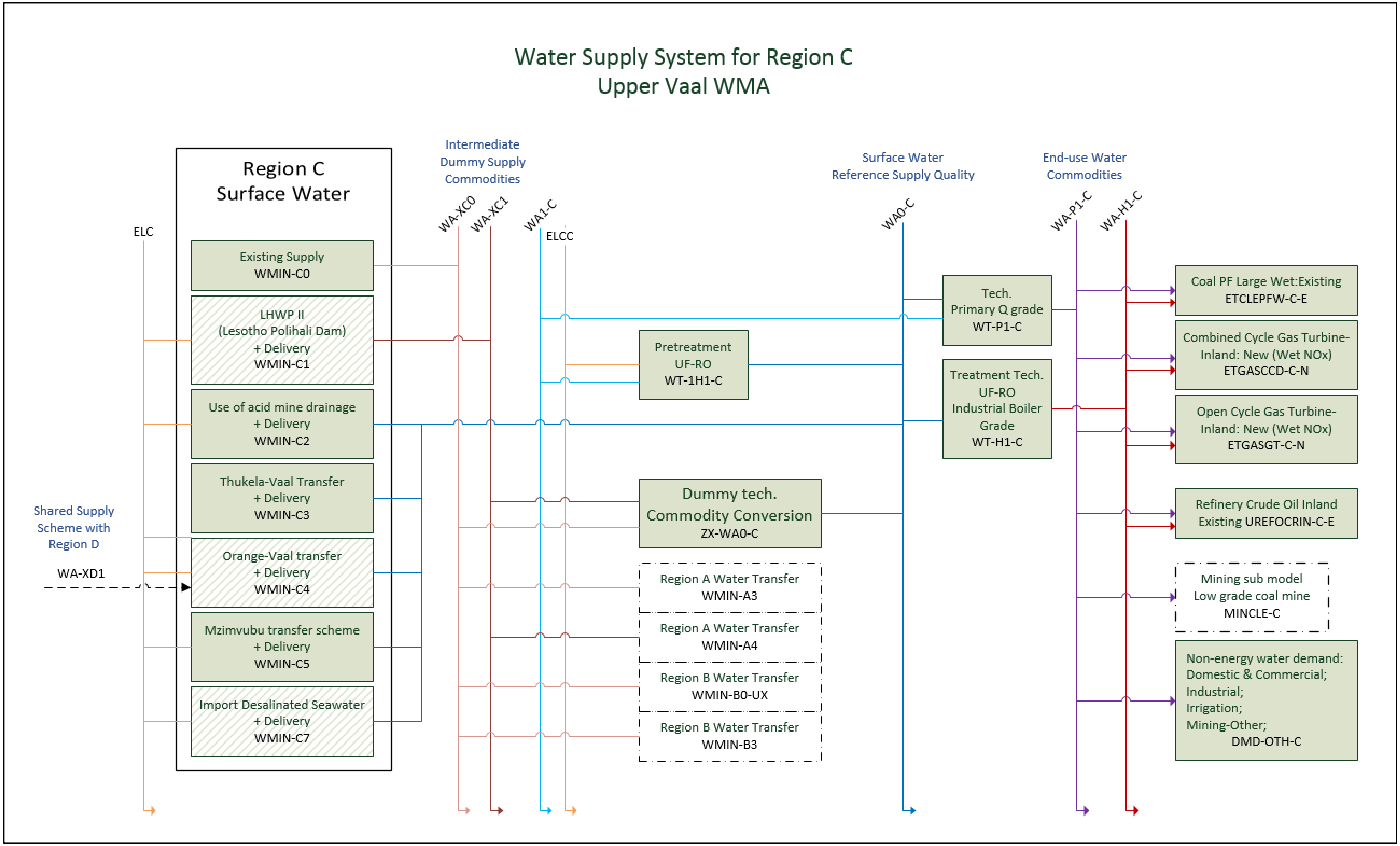

Figure 52: The SATIM-W water supply system for Region C

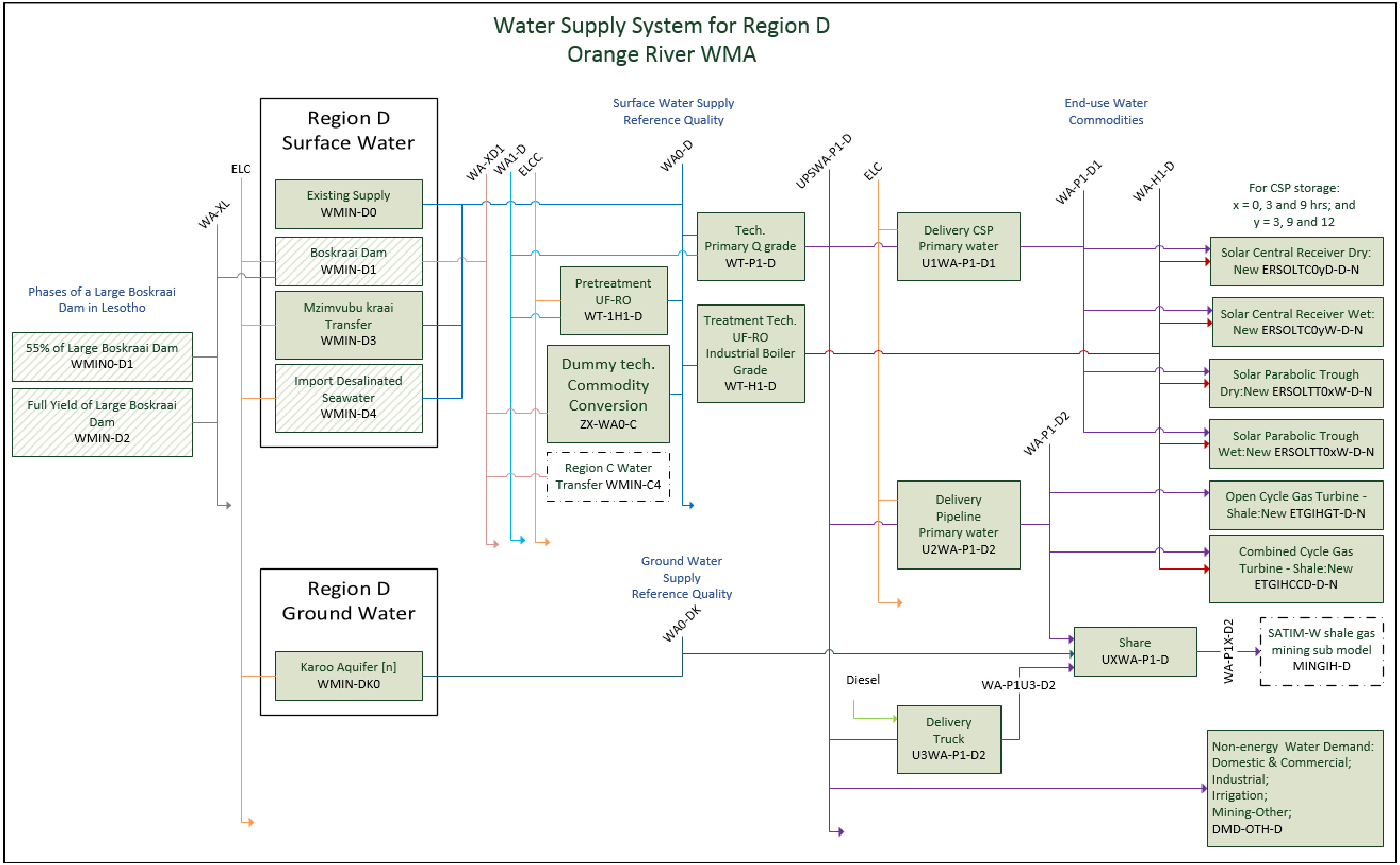

Figure 53: The SATIM-W water supply system for Region D

Appendix G: Data and Sources

G.1 Water System data

Text to come...

G.2 Power Plants

Table G- 1: The Existing and Committed Individual Eskom Coal Plants as Aggregated in SATIM and by Water Supply Region (Eskom, 2014)

Plant	SATIM Category	Net Capacity	Cooling Type	Raw water use (l/kWh)	Boiler water use (l/kWh)	WSR	Climatic Zone[4]
Matimba	Large Dry Existing	3690	Direct Dry (ACC)	0.12	0.02	A	Hot interior
Medupi	Supercritical New	4334	Direct Dry (ACC)	0.12[3]	0.02[3]	A	Hot interior
Kendal	Large Dry Existing	3840	Indirect-dry	0.12	0.07	B	Cold interior
Duvha	Large Existing	3450	Wet closed cycle	2.2	0.062	B	Cold interior
Kriel	Large Existing	2850	Wet closed cycle	2.38	0.12	B	Cold interior
Matla	Large Existing	3450	Wet closed cycle	2.04	0.077	B	Cold interior
Arnot	Large Existing	2232	Wet closed cycle	2.22	0.157	B	Cold interior
Hendrina	Small Existing	1865	Wet closed cycle	2.61	0.231	B	Cold interior
Komati	Small Existing	906	Wet closed cycle	2.49	0.105	B	Cold interior
Kusile	Supercritical New	4267	Direct Dry (ACC)	0.12[3]	0.02[3]	B	Cold interior
Camden	Small existing	1440	Wet closed cycle	2.31	0.078	C	Cold interior
Majuba Wet[1]	Large Existing	1980	3 units: Wet cooled	1.86	0.076	C	Cold interior
Majuba Dry	Large Dry Existing	1840	3 units: Direct Dry (ACC)	0.12	0.02	C	Cold interior
Lethabo	Large Existing	3558	Wet closed cycle	1.86	0.076	C	Cold interior
Tutuka	Large Existing	3510	Wet closed cycle	2.06	0.097	C	Cold interior
Grootvlei[2]	Small Existing	1130	Wet/Dry	1.71	0.18	C	Cold interior

[1] From Lethabo: similar wet cooled system apparent; [2] 4 units: wet closed cycle; and 2 units: indirect dry system with spray condenser and dry cooling tower (implemented during initial experimentation with dry-cooling during ca.1960s); [3]Estimated from Matimba; [4]According to the South African National Standard 204 (2008).

Table G- 2: Cost and Performance Summary for Pulverised Coal without FGD (EPRI, 2012)

Technology	1x750 MW, No FGD	2x750 MW, No FGD	6x750 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
SOx	9.03	0.90	9.03
NOx	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

Technology	1x750 MW, No FGD	2x750 MW, No FGD	6x750 MW, No FGD
Rated Capacity, MW Gross	804	1,608	4,824
Rated Capacity, MW Net	750	1,500	4,500
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 (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 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

Table G- 3: Technology costs reported in the revised Integrated Resource Plan (2012) (After EPRI, 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)	4500 (6 x 750)	4500 (6 x 750)	250	250	1288 (644 x 2)	1288 (644 x 2)	1600	9600 (6 X 1600)
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)	21572	40845	21440	40165	29282	39079	46841	44010
Lead time	9	9	4	4	5	5	6	16
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	5%, 18%, 35%, 32%*, 10%	15%, 15%, 25%, 25%, 10%, 10%	3%, 3%, 7%, 7%, 8%, 8%*, 8%, 8%, 8%, 8%, 8%, 8%, 6%, 6%, 2%, 2%
Adjusted overnight capital costs, accounting for capex phasing (R/kW) and discount rate	25772	48789	23661	44325	32340	43160	58036	59226
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	17850	17850	17850	17850	17850	17850	3.9×10^9	3.9×10^9
Heat Rate, kJ/kWh, avg	9812	14106	10081	15425	9758	12541	10762	10762
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	1027	-	-
Sorbent usage, kg/MWh	15.8	22.8	38	59	0	0		
CO2 emissions (kg/MWh)	947.3	136.2	978	150	930	120		
SOx emissions (kg/MWh)	0.46	0.66	0.47	0.72	0.18	0.23		
NOx 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				
Levelised 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

Table G- 4: Technology costs reported in the revised Integrated Resource Plan (2012) (After EPRI, 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)	4357	6406	13223	15394	40438	51090	61176	37577	44866	51604	28910
Lead time	2	3	3	4	4	4	4	4	4	4	2
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	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	4671	7089	14632	15945	44626	56381	67512	41469	49513	56949	29141
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	11926	7487	9010	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	
Sorbent usage, kg/MWh											
CO2 emissions (kg/MWh)	618	388	47								
SOx emissions (kg/MWh)	0	0	0								
NOx 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)											
Levelised 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

G.3 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. As such no distribution cost is incurred for coal supply to the Power sector in the current aggregated representation as depicted in Figure 54. Also shown in the figure are the associated fugitive emissions and additional upstream supply. In SATIM, commodity demand for coal mining activity is captured in the Industrial sub-sector 'Mining' while supply and distribution is implemented in the Supply sector. Work is underway though to fully encapsulated coal mining - both opencast and underground - within the Supply sector.

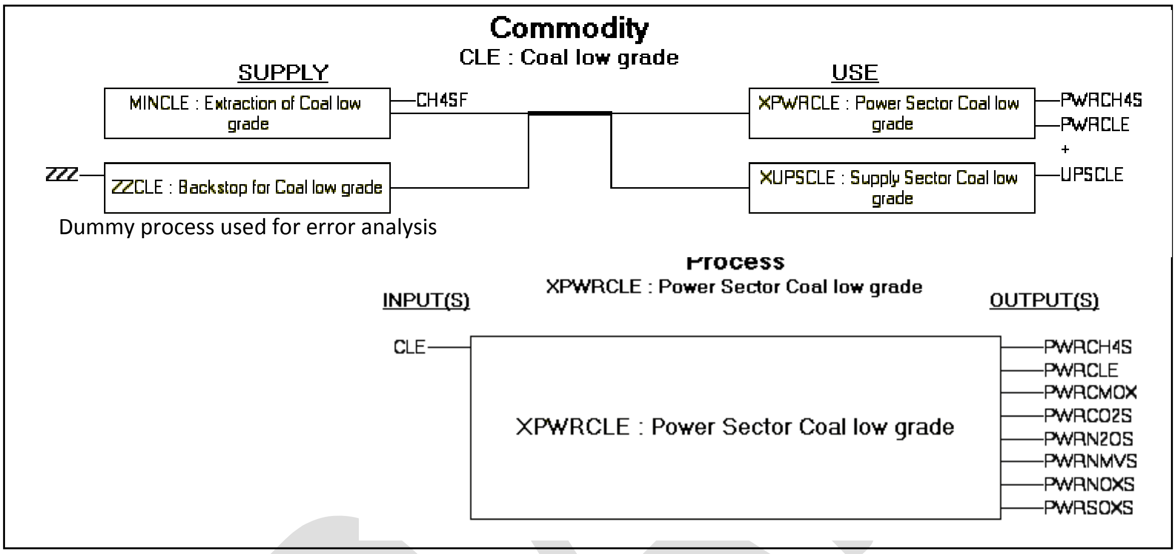

Figure 54: Coal supply to the power sector as implemented in SATIM.

SATIM-W conforms to the current SATIM representation of coal commodities. Three calorific grades of coal are defined, namely: High; Low and Discard. All current power generation technologies utilise the low grade coal. Future Fluidised Bed Combustion technologies will however use discard coal. Table G- 5 lists the calorific value design range of the coal plant fleet for the low grade coal category. For low grade coal a weighted average calorific value of 21 MJ/kg is obtained by weighting plant capacity and efficiency.

Table G- 5: Estimated caloric values for coal power plants. (The Green House, 2013)

<table>
<tr><th>Power station</th><th>Value applied</th></tr>
<tr><td>Arnot</td><td rowspan="4">22 – 24 MJ/kg</td></tr>
<tr><td>Camden</td></tr>
<tr><td>Tutuka</td></tr>
<tr><td>Non-Eskom</td></tr>
<tr><td>Kriel</td><td rowspan="7">20 – 22 MJ/kg</td></tr>
<tr><td>Duvha</td></tr>
<tr><td>Grootvlei</td></tr>
<tr><td>Hendrina</td></tr>
<tr><td>Komati</td></tr>
<tr><td>Majuba</td></tr>
<tr><td>Matla</td></tr>
<tr><td>Kendal</td><td rowspan="6">18 – 20 MJ/kg</td></tr>
<tr><td>Matimba</td></tr>
<tr><td>Medupi</td></tr>
<tr><td>Kusile</td></tr>
<tr><td>Sasol 1 (Sasolburg)</td></tr>
<tr><td>Sasol 2 & 3 (Secunda)</td></tr>
<tr><td>Lethabo</td><td>16 – 18 MJ/kg</td></tr>
</table>

Regional distribution costs are taken from the South African Coal Road Map (SACRM) study as shown in Table G- 6 (The Green House, 2013). For the coastal coal build option, an additional distribution cost is required for transport beyond the RBT. The intra-regional cost for coal distribution within the Central basin is used as an estimate.

Table G- 6: Rail distribution costs for the supply of coal. (The Green House, 2013)

Destination	Transport cost (ZAR/tonne)
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 the Waterberg
Mpumalanga to RBT	126, 150[1]
Waterberg to Central Basin/Vereeniging	132, 158[1]
Within Central Basin	30[2]

[1] Adjusted to reflect increased cost for rail capacity expansion; [2] truck transport estimate (McGeorge,2014)

Water consumption estimates for coal mining are presented in Table G- 7. The detailed analysis conducted by Golder and Associates for the Exxaro mine in the Waterberg (Region A) is used in the model.

Table G- 7: Freshwater Consumption Estimated for Coal Mining (m^3/tonne)

Water Usage (estimated purchased volumes of freshwater)	SACRM (2013)	Buermann (1982)	Golder & 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[1]	0.0031	0.0094	0.0129
B/C[1]	0.0024	0.0073	0.0099[2]

[1]Calculated for an average CV of 21 MJ/kg; [2]Derived from SACRM data;

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 published annual reports of large coal mines (Exxaro, 2013; Anglo Coal, 2007).

Table G- 8: Coal Mining Feedstock Energy Commodities

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

G3.1 Coal Mine Waste Water Treatment

In order to attribute a cost of treating water for environmental discharge in SATIM-W, data from *The Olifants River Project* is used. *The Olifants River Project* assessed the feasibility of processing mine water in the Olifants WMA and examined a number of collieries in the region for two water treatment scenarios: 1) Treat and Discharge, or 2) Treat and Supply to Towns (Golder Associates, 2012). For the selected collieries, the costs associated with Option 1 is summarised in Table G- 9. The costs are indicative of the treatment required for 146.5 ML/day (53 Mm^3/a).

Table G- 9: Olifants River Project: cost summary for the management of colliery effluent (Golder Associates, 2012)

Project Option 1 - Treat and discharge

Mine Water Reclamation Plant	Flow	Reclamation Plants			Discharge pumpstations and pipelines			Water resource charge	
	Mℓ/day	Capex (R million)	Opex (R/year)	Opex (R/m^3)	Capex (R million)	Opex (R/year)	Opex R/m^3	Charge (R/year)	Charge (R/m^3)
New Largo WRP	6.0	R151 600 000.00	R27 747 300.00	12.7	R 7 894 129.50	R 294 400.87	0.13	R 438 000.00	R0.20
Kriel WRP	14.0	R287 500 000.00	R47 829 600.00	9.4	R27 762 106.50	R 686 935.37	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	R 588 801.75	0.13	R 876 000.00	R0.20
Xstrata WRP	15.0	R302 000 000.00	R50 151 000.00	9.2	R49 609 332.00	R 736 002.18	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	R 736 002.18	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	R 785 69.00	0.13	R1 168 000.00	R0.20
Optimum WRP	15.0		R38 325 000.00	7.0	R28 524 402.00	R 736 002.18	0.13	R1 095 000.00	R0.20
Optimum Eikeboom WRP	3.5	R103 200 000.00	R20 503 875.00	16.1	R 3 319 833.00	R 171 733.84	0.13	R 255 500.00	R0.20

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 effluent treated. The adjusted costs required for implementation in SATIM-W are given in Table G- 10.

Table G- 10: Costs for coal mine water treatment in SATIM-W

Investment cost ZAR(x1000)/Mm^3	Fixed OM ZAR(x1000)/year	Variable OM (kWh/m^3)
60,842	9,742	3

Mine decant volumes do not necessarily correlate with the volumes of water required for coal washing as, aside from coal washing slurry, it may include pumped mine water which remains a problem after mining activity has ceased. To mitigate the formation of Acid Mine Drainage (AMD), the removal of mine water after mining activity has ceased is required. To attribute the cost of mine water to mining activity, the volume of AMD treated over the production life of a region, per tonne of mined coal, is therefore estimated. This volume is based on an assumed average operating lifetime of 100 years of mining activity which includes excess water removal via pumping. Regional coal reserves are estimated from Prevost (2014).

A first order estimate is arrived at by factoring the annual treatment of effluent volumes of 53 Mm^3/annum (*The Olifants River Project*) to extract 20,000 Mt of coal over a 100 year production life for the Central Basin. It is estimated that the Highveld coal-fields (ca. 30% of reserves) has a storage or residual volume of 653 Mm^3 of mine water for past and future mining activity (Golder Associates,2012). The residual volume represents the accumulated volume of mine water in existing and abandoned mines. An estimate of 1300 Mm^3 (double the existing volume) for the Central Basin is used. This gives a factor of 0.33 litres of effluent treated per kg of coal mined (or 0.33 Mm^3/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% to +30% for the factor.

For a 20 year treatment plant life, using a discount rate of 8%, 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% for electricity generation this equates to a cost of 3c/kWh of electricity to address water pollution. This estimate represents a base cost which would vary with the price of electricity, energy intensity of treatment and increasing volumes of effluent treated. The modelling framework allows these factors to be considered. Nkambule and Blignaut (2012) attribute an externality cost in the range of 20.24 c/kWh and 39.3 c/kWh to coal mining and transport in South Africa. Their analysis attributes less than 1% of the cost to water pollution, with the opportunity cost of water dominating the price.

G3.2 Coal mining sub-model REWS diagram

A simplified representative Reference Energy-Water System diagram for the implementation of coal mining in SATIM-W as proposed above is introduced in Figure 55.

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 for delivery to power plants is via regional distribution. Region A represents the Waterberg deposits while regions B and C together represent the Central Basin. The distribution technologies are coloured-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 in the vicinity of the RBT is selected as the most likely locale given the 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 n the model. In the RES, region C is chosen.

As shown in the REWS diagram and selected for SATIM-W is the inclusion of the cost of a water treatment facility for discharge mine water.

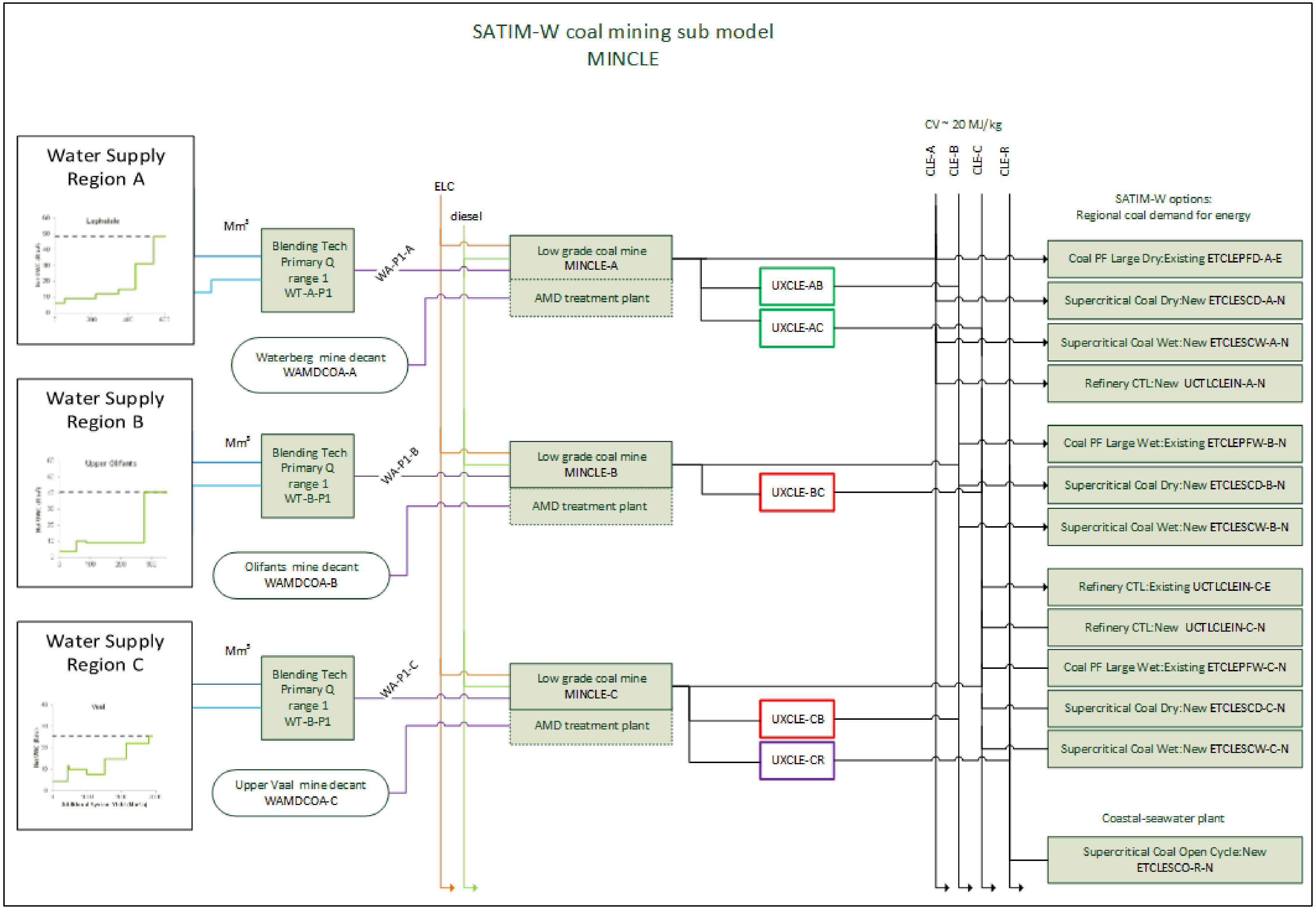

Figure 55: Simplified Representation of Coal Mining Linked to Regional Water Supply Systems in SATIM-W

G.4 Shale Gas Extraction

Figure 56 depicts the two forms of shale gas utilisation 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 collocated with shale gas mining only incurs 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 OCGT and CCGT gas plant technologies.

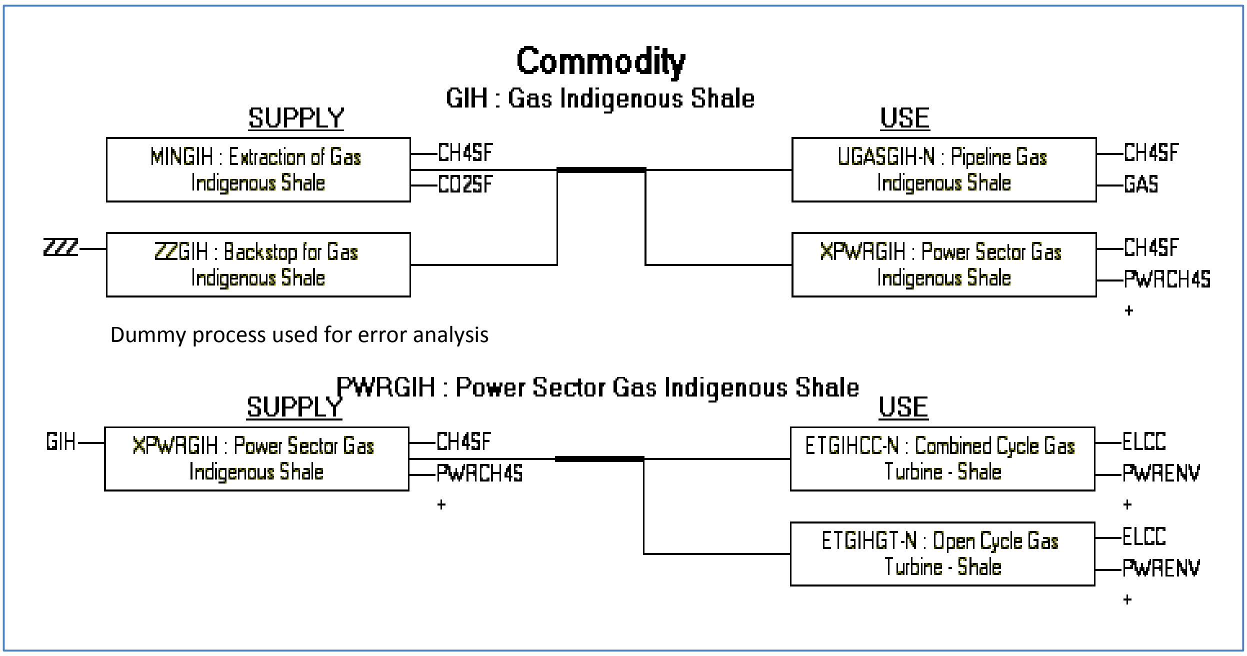

Figure 56: Shale Gas Extraction and Collocated Generation in SATIM.

G4.1 Water and shale gas extraction

Figure 57 displays the cumulative gas produced and corresponding volumes of water required for the Barnett shale production region for Texas (USA). The chart indicates a strong correlation between total gas production and water use. The Barnett shale region is the third largest producing region in the USA and is one of the shale gas regions that is similar in geological composition to the Karoo region where Soekor exploration took place, although differentiated by the occurrence of dolomite dykes (Vermeulen, 2012). The dolomite dykes present a challenge as they may act as conduits for uncontrolled migration of fracturing fluid and gas to shallow aquifers.

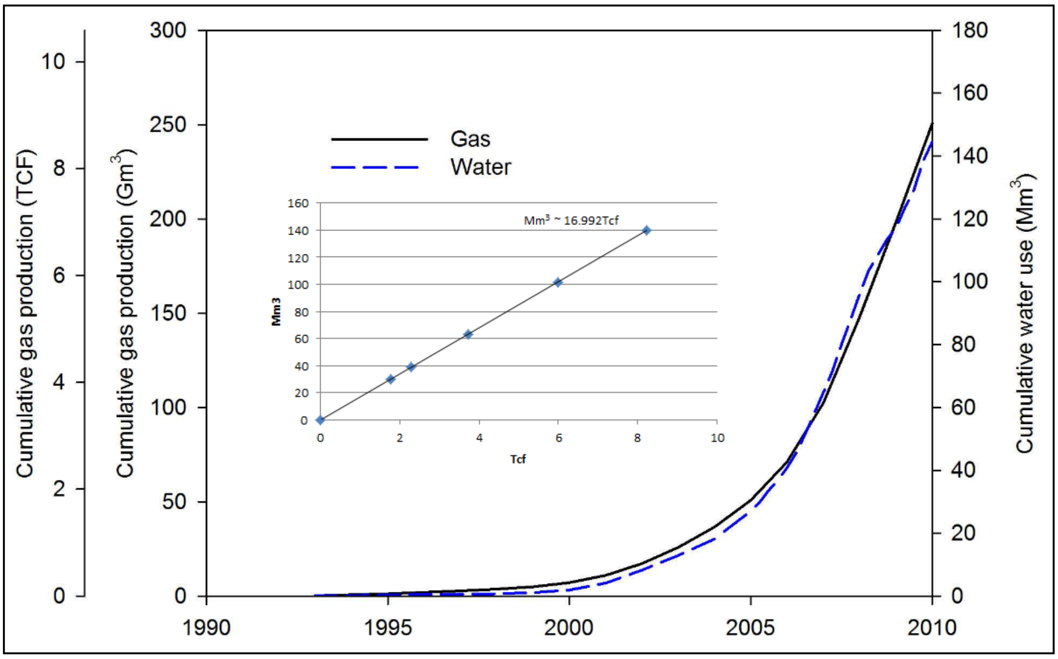

Figure 57: Cumulative gas production and water use for the Barnett shale formation, Texas, USA (Nicot & Scanlon, 2012)

To obtain an average or levelised water withdrawal rate for shale gas extraction, the estimated total volume of water withdrawn for a given production life for the Karoo region is used. Assuming that 1 Tcf ~ 1000 PJ, the water use intensity of shale gas extraction in the Karoo is estimated at 17,000 m^3/PJ. It is acknowledged that water use intensity of extraction will be influenced by the local geology and this value is subject to refinement.

Aside from the quantity of water required, the chemical composition of the volume of returned fracturing fluid has been identified as a potential source of water pollution (The Royal Academy of Engineering, 2012). Vengosh et al. (2014) reported of number environmental breaches due to shale gas extraction in Pennsylvania (USA) and therefore recommend that a Zero Liquid Effluent Discharge (ZLED) policy be adopted for the industry due to the potential impacts on water resources. For a ZLED policy, the volume of return flow determines the required treatment processing capacity. The extremes of the ranges reported are 8-15% (Shaffer et al., 2013) and 25-75% (The Royal Academy of Engineering, 2012). To calculate costs associated with waste water treatment, a return flow of 40% is presumed. The treatment of waste water generally depends on its TDS value although local geology influences the necessary treatment process as additional toxic contaminants (e.g. radium, barium & strontium) may be present (Vengosh et al., 2014). Return flows with lower TDS levels ranging from brackish to sea water equivalent can be processed primarily via reverse osmosis. Higher TDS levels approaching 180 000 mg/L require evaporation and crystallisation processes as indicated in Figure 58.

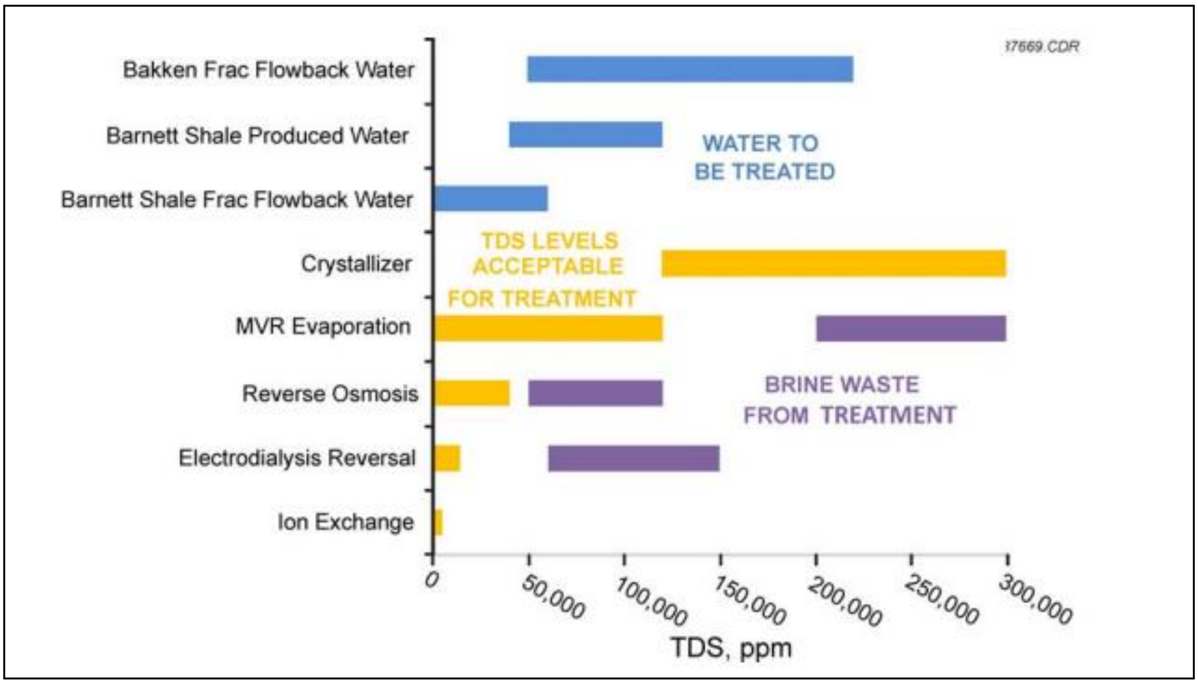

Figure 58: Treatment processes for return flows with indicative TDS levels of brine product (Stepan et al., 2010)

The Karoo Groundwater Atlas Volume 2 states that:

As the target shale gas horizons are located between c.1 700 m to 1 900 m it is unlikely that highly saline groundwater or brine will be encountered during gas well drilling. This is supported by the fact that SOEKOR well KL1/65, …, produced groundwater with a Total Dissolved Solids (TDS) of 1 390 mg/L from a depth of 1 006 m (van Tonder et al., 2013).

If the above statement is taken as guideline and return flows are at worse of brackish quality (i.e. TDS < 15,000 mg/L), one can suppose that similar costs would be incurred for that of AMD treatment for the collieries as was discussed for coal mining. The TDS concentration of the coal mine effluent is reported to be in the range of 1,000 -5,000 mg/lL.

Thus for shale gas mining, SATIM-W implements onsite water recycling which occurs by basic or primary treatment at a nominal cost of R2/m3. Offsite treatment of effluent for discharge is presumed with distribution by truck. The offsite treatment is implemented as for coal mining effluent treatment and similar costs are applied with adjustment for the increase in TDS concentration. The adjustment factor is obtained from DWA's Vaal river water quality impact study. The increase in capital expenditure for water treatment estimated by Sasol - South Africa's largest petrochemical and synthetic fuel producer - for an increase in TDS concentration is shown in

Figure 59. The relationship, albeit only for three data points, seems adequately described either by a power or linear interpolation.

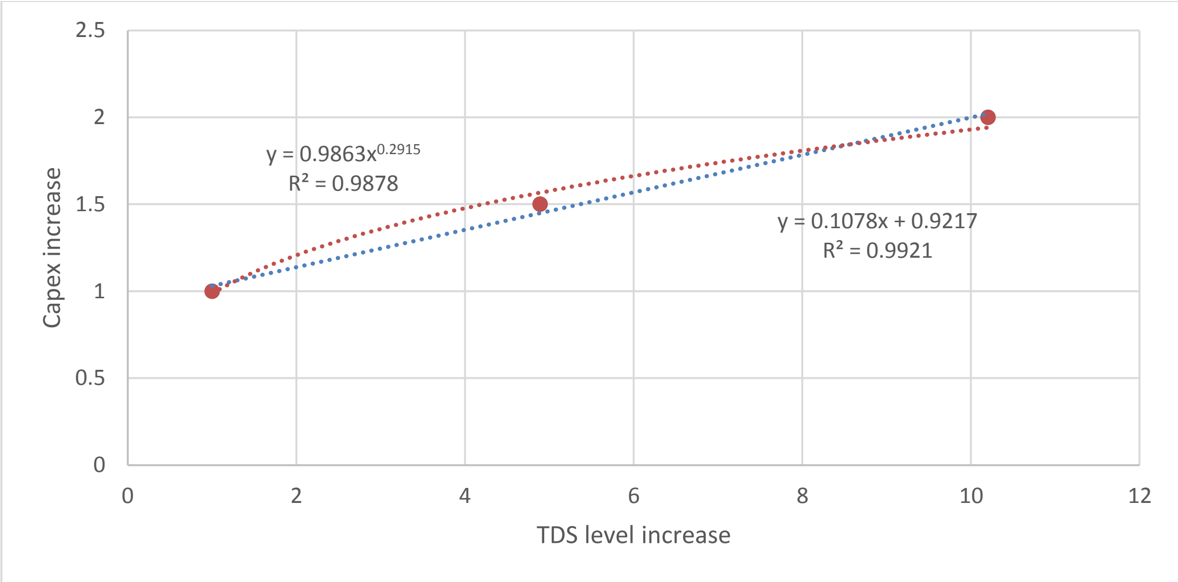

Figure 59: The relative cost of additional WTP capital for a change in TDS concentration (DAWF, 2009)

For a change in TDS from 5,000 mg/l to 15,000 mg/l, a capital increase of approximately 1.3 is derived and applied to the data in Table G- 10 to yield the values given in Table G- 11. The energy intensity of treatment is kept constant as this value is typical for systems treating highly saline water - seawater desalination via RO ranges from 3.5 kWh/m^3 to 4.5 kWh/m^3 (Vince et al., 2008).

Table G- 11: Costs for shale gas mining waste water treatment in SATIM-W

Investment cost R(x1000)/Mm^3	Fixed OM R(x1000)/year	Variable OM (kWh/m^3)
79,207	12,683	3

The REWS diagram for the implementation of shale gas mining in SATIM-W as proposed above is shown in Figure 60. The water needs for shale-gas mining is taking to be of basic quality. Two methods are shown for incorporating the cost of water management for shale-gas mining. The expanded form has a direct representation of the treatment costs for the three types water use associated with gas extraction. The three types are:

1) Water losses, that is water that leaves the system, which includes non-return flows from well fracturing operations;
2) The fraction of recovered fracturing fluid that is recycled (i.e. treated onsite for reuse), and
3) The fraction of recovered fracturing fluid that is transported offsite to be treated for discharge or reuse.

In the simplified method as chosen for the model, the costs and relative share of volumes of water recycled and treated for discharge as shown in the expanded form is modelled in aggregate with the separate costs combined.

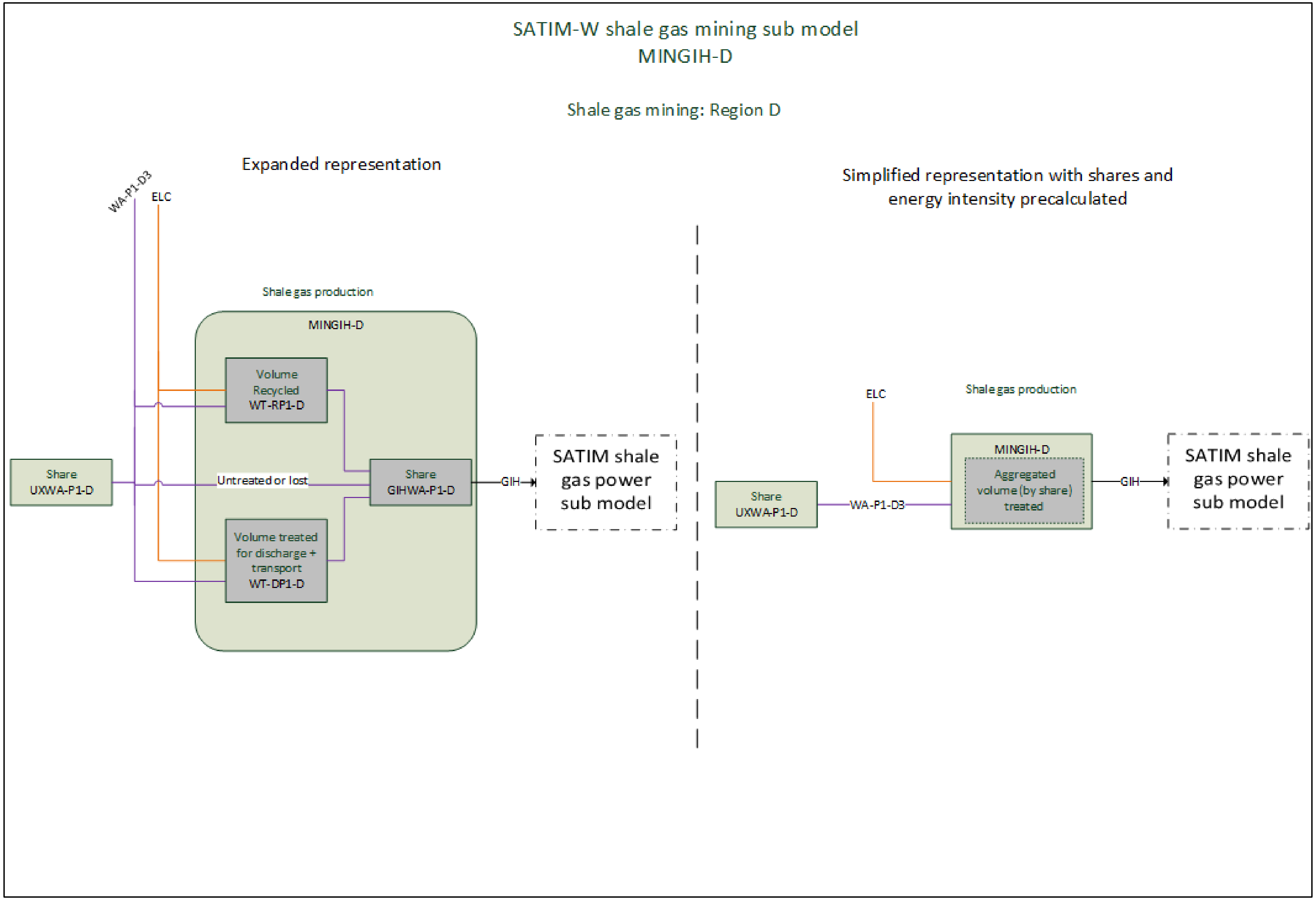

Figure 60: The Proposed Implementation of Shale Gas Mining (MINGIH)

G.5 Refinery Technologies

G.5.1 Crude Oil Refineries

This sector supplies liquid fuels such as diesel and gasoline to the South African economy. Conventionally these products would be derived from crude oil but South Africa has a large so-called synthetic fuel industry that produces liquid fuels from gas and coal feedstocks. This industry, which includes a Coal-to-Liquids (CTL) and a Gas-to-Liquids (GTL) refinery complicates the modelling of this sector somewhat because these plants add a number of input commodities to the energy chain.

The refinery slate data for existing crude oil refineries are derived from Lloyd (2001) which is now quite an old study but the only large scale changes to South Africa's refineries since then has been the increase in capacity of Enref in 2003 from 100,000 barrels/day to 125,000 barrels/day. Table G- 12 lists the output commodities from refineries in SATIM and Table G- 13 describes the relative share of each commodity.

Table G- 12: SATIM Refinery Outputs

Commodity	SATIM code
Aviation Gasoline	OAG
Diesel Oil	ODS
Gasoline	OGS
Methane Rich Gas	GIM
Kerosene	OLK
Liquified Petroleum Gas	OLP
Other Oil-derived Products	OTH

Table G- 13: Assumed Upper Bounds on Output Commodity Shares for Refinery Technologies

Output Product	Crude Coastal Existing	Crude Inland Existing	GTL Existing	GTL New	CTL Existing	CTL New	Crude New
Av Gasoline	0%	0%	0%	0%	0%	0%	0%
Diesel	33%	39%	6%	29%	24%	73%	36%
Gasoline	29%	32%	53%	50%	54%	24%	36%
HFO	23%	4%	0%	0%	0%	0%	0%
Kerosene	11%	21%	11%	12%	4%	0%	20%
LPG	2%	0%	8%	4%	1%	4%	3%
Other	2%	4%	18%	5%	7%	0%	5%
Methane Rich Gas	0%	0%	0%	0%	8%	0%	0%
TOTAL	100%	100%	100%	100%	100%	100%	100%

Table G- 14 presents a summary of the assumptions regarding refinery technology characteristics and costs as used in SATIM currently.

Table G- 14: Summary of Refinery Technology Characteristics

		Existing Technologies				New Technologies		
	Units	**Sasol CTL**	**Inland Crude Existing**	**Coastal Crude Existing**	**PetroSA GTL**	**New GTL[1]**	**New CTL[2]**	**New Crude[3]**
Capacity	bbl/day	150 000	108 000	405 000	45 000			
Capacity in terms of outputs	PJ/annum	246	212	874	59			
Overall Efficiency	%	44%	93%	95%	70%	73%	49%	97%
Availability	%	96%	96%	96%	96%	96%	96%	96%
Plant Life	Yrs					50	50	50
Running Costs per unit of output	mR/PJ	30	11	11	25	14.25	30	11
Investment Cost[3]	mR/[PJ/annum]	0	0	0	0	130	305	66
CO_2 emissions	(kt/PJ)	119	6.9	2.9	28	28	119	6.2
CH_4 emissions	(kt/PJ)	1.5	0.00	0.00	0.0045	0.0045	1.49	0.00

1: Based on the Integrated Energy Plan Technical Report (DoE,2013) 2: Based on data for the proposed Mthombo project; 3: Based on data for proposed Mafutha project

G.5.2 CTL technology

In brief, the CTL refinery is characterised as described below.

1. Required for constraints on output shares:
   - The product slate is derived from Lloyd (2001), and
   - The Methane Rich Gas output is determined from Sasol's financial statements as published in the "Analyst Book Dec 2006" (SASOL, 2007).

2. Required for constraints on input shares:
   - The total coal use by SASOL is determined from SASOL's financial statements as published in the "Analyst Book Dec 2006" (SASOL, 2007);
   - The coal for material use for the base year (feedstock excl. steam generation) is published in the Sasol Sustainability Report (2009) expressed in kton dry ash free (DAF);
   - The dry ash free (DAF) coal to run of mine coal (ROM) ratio used to convert this number is 0.65 as per personal communication with Sasol;
   - The total coal for energy use (TJ) is published in the Sasol Sustainability report 2009 (SASOL, 2009), and
   - The Energy content of steam used in the Sasol process of 2,627 MJ/ton comes from a personal communication with SASOL.

G.5.3 Modelling the supply of ancillary steam input services to refineries

Refineries have various commodity inputs which can include crude oil, coal, gas, methane rich refinery gas and steam, all of which complicates costing the energy chain. Steam is modelled as an ancillary input service to the refinery by creating boiler technologies that output steam with an energy commodity as an input.

The modelling of steam as an ancillary input service allows the model to potentially optimise the most cost effective fuel (coal vs gas) and technology (e.g. existing vs new and more efficient boiler vs CHP) to provide the steam needed for process heat, as well as for feedstock in CTL plants. This latter use is much greater per unit of refinery output than process heat requirements. Steam is also consumed by crude refineries and GTL plants but further data is required for the characterization and therefore this consumption is not currently reflected in SATIM. The steam consumption of crude and GTL refineries is however significantly lower and so the absence of this detail is assumed to not have a very significant impact on the overall results. While the framework for optimising refinery steam production is in place, the current version of SATIM-W has only two technologies implemented (Table G- 15).

Table G- 15: Current Refinery Steam Boiler Technologies Replicated from SATIM

Boiler Technology	Input Commodity	Output Commodity	Efficiency
Refinery CTL Boiler Existing	Coal Existing	Steam Existing	72%
Refinery CTL Boiler New	Coal New	Steam New	77%

Appendix X: Potential Future Improvements and Areas of Further Investigation

Link to an economy-wide (CGE) model to realize a comprehensive national energy-water-economy-environment planning framework

Water

- Harmonise sectorial water and energy demands;
- Disaggregate the non-energy water sectors to explore reallocation schemes demand elasticities to cost, water-use efficiency and DSM interventions;
- Water-energy cost for other energy supply sectors: hydrogen, uranium mining and processing;
- Impact of water treatment of return flows for shale gas extraction;
- Impact of regional water quality;
- Incorporate the temporal (intra annual) variation in water supply and demand.

Energy

- Add costs for expansion of the transmission lines from remote solar sites;
- Introduce load balancing requirements as the share of renewables grows;
- Include biofuels regions.