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.

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List of acronyms

AMD	Acid Mine Drainage
ATR	Autothermal Reforming
CCGT	Closed-Cycle Gas Turbine
CSP	Concentrated Solar Power
CTL	Coal-to-Liquids
FGD	Flue Gas Desulphurisation
FT	Fischer-Trospch
GTL	Gas-to-Liquids
IRP	Integrated Resource Plan
IEP	Integrated Energy Plan
m^3	Cubic metre
OCGT	Open-Cycle Gas Turbine
OM	Operations and Maintenance
PF	Pulverised Fuel
POX	Partial Oxidation
PJ	PetaJoule
REIPPP	Renewable Energy Independent Power Producer Programme
RES	Reference Energy System
REWS	Reference Energy-Water System
RO	Reverse Osmosis (Desalination)
SACRM	South African Coal Road Map
SATIM-W	South African TIMES Water-Energy model
SR	Steam Reforming
Tcf	Tera cubic feet
TDS	Total Dissolved Solids
UF	Ultra-Filtration

URV	Unit Reference Value
UWC	Unit Water Cost
WMA	Water Management Area
WRC	Water Research Commission
WSR	Water Supply Region
WTP	Water Treatment Plant
ZAR	South African Rand
ZLED	Zero Liquid Effluent Discharge

1 Introduction

In common with many developing countries, South Africa faces a convergence of 'wicked problems' that include energy supply, water supply, food security, massive and growing unemployment and other problems associated with rapid urbanisation (Adams,1992;CSIR,2010;Davies,2012;Taylor,2012).

It is clear that many of these problems are linked and interact and this presents technical professionals and decision makers with great difficulties in finding solutions. The linkage between energy and water has been widely publicised and the term water-energy nexus has found widespread common currency. This nexus is a critical sub-set of our nexus of wicked problems to study because solutions for the rest of these issues rely heavily on both. In each case we are dealing with single commodities, strongly linked through their supply chains that can be analysed by similar methodologies.

Indeed, the problems of supplying these two commodities are perhaps far more tractable to technical analysis than others more beset by the issues arising from human co-existence. Modelling in particular, offers the potential to provide useful support to decision makers and planners of infrastructure looking to ensure security of supply. Attempts to integrate energy and water in planning have a relatively long history in South Africa, mostly arising from water security concerns. The country's first foray into dry-cooling for coal thermal power plants occurred in the late 1960s with two indirect dry-cooled units added to the Grootvlei power plant to investigate dry-cooling as an alternative to wet-cooled systems (Lennon,2011). As a result, to date, approximately 30% of existing coal thermal power plants are of dry-cooled design with the commissioning of the new Medupi and Kusile powerplants increasing the dry-cooled portfolio to almost half the stock. 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).

Degraded water sources have a direct detrimental effect not only on aquatic ecosystems, but have a far wider impact on the environment and economy as more energy-intensive, predominantly electricity dependent, treatment is required to remediate raw water for productive use. This has the effect of both increasing energy consumption for water utilisation and its subsequent cost. Electricity derived from mined coal further accelerates the pollution-treatment cycle most notably from the contamination of water sources from acidic leachate - commonly referred to as Acid Mine Drainage (AMD) - from mined coal fields with concomitant long term economic and environmental ramifications.

The expansion of water services infrastructure to meet growing demand in a future of increasing environmental and energy constraints requires the consideration of alternative water supply and treatment options as the capacity of the present system is reached. A framework for integrated water-energy analysis as presented in this document is to be implemented as the South Africa TIMES-Water (SATIM-W) model, providing a tool that offers insight into the trade-offs that exist when accounting for the linkages between water and energy systems as part of cost-effective sustainable planning.

2 Scope and Objectives of Task 2: Phase 1

The scope of Task 2 of the Thirsty Energy South Africa Project has as its main objective "The development of a "water smart" SATIM model. SATIM is a national energy system model built using the TIMES[1] platform by the Energy Research Centre (ERC). TIMES is a partial equilibrium linear optimisation model capable of representing the whole energy system, including its economic costs and its emissions. The proposal recognised that the challenge will be to take account of the different cost of water in different parts of the country as represented by the cost curves derived in Task 1, as is outlined in the sub-tasks below.

This task involves the following changes to the SATIM model:

Task 2a: Incorporate incremental water supply cost in SATIM

- Allocate major supply technologies to different water management areas (WMA): existing and new.
- Include power plants, oil refineries, coal-to-Liquids (CTL) and gas-to-Liquids (GTL) plants, coal mines, shale gas fields and uranium mines and enrichment facilities.
- Ensure once through versus closed cooling systems properly reflect current ESKOM stations.
- Represent coal washing water use impacts, differentiating between export and power plant coal, ensuring that water consumption is net and includes re-use in mines.
- Reflect the requirements of Flue Gas De-sulphurisation (FGD) on water consumption (as a special pipeline had to be constructed to Lephalale to account for Medupi's increased water demand for FGD).
- Reflect the distance of plants from river/dam sources for estimating added reticulation costs of water.

Task 2b: Revise water factors (L/kwh) for different power generation technologies

- Add seasonal variation of water for hydro-plants.
- Add wet-cooling technologies to new coal and solar thermal technologies available.
- After checking efficiencies of dry and wet cooled existing plants introduce values for new plants.

2.1 Additional Considerations since the Initial Proposal

In the course of the project, water quality has also been raised as an issue on the basis that it is a significant cost component of water supply and that it has been deteriorating and secondly can be significantly different for different water supply schemes implemented in the same WMA.

[1] http://iea-etsap.org/web/Times.asp

2.2 Specific objectives of this document

The overall objective of the exercise undertaken to prepare this document is to develop a detailed methodology to reflect the cost of water to the energy supply sector in the existing South Africa TIMES (SATIM) energy model. The following specific objectives were defined to achieve this:

- List the key assumptions incorporated into the methodology;
- Describe in detail how the water cost curves developed in Task 1 will be implemented;
- For all relevant sub-systems where water is to be incorporated in SATIM develop Reference Energy-Water System (REWS) diagrams detailing this implementation and showing the additional technologies to be added to the model and how they fit in the energy supply chains represented in the model, and
- For all relevant sub-systems where water is to be incorporated in SATIM describe how the REWS diagram will be parameterised in the TIMES model, presenting alternatives if appropriate and explaining which approach is favoured and why; in particular, detail the methodology for tackling the critical spatial aspect of water supply to power plants and other supply technologies.

2.3 The South African TIMES model (SATIM) and its current representation of water

In its current form, SATIM is a single region national representation of energy commodity flows, energy transformation technologies and the incurred costs. For example, the extraction, transmission and distribution of gas and coal their transformation to electricity, the transmission and distribution of that electricity and the use of that electricity by end-use technologies to supply energy services are represented by technologies linked by commodities and characterised by associated efficiencies, costs, plant life and other techno-economic parameters.. Technologies are further organised by sector (e.g. the Power Sector) and type (e.g. large existing coal plants). Currently SATIM is configured for two modes of representing the national energy system. In a simplified representation, electricity supply, referred to as the Power Sector, is modelled with an aggregated national demand for electricity. In the more detailed full sector configuration, attention is paid to the growth in demand for electricity and other commodities at the subsector level as is shown schematically in (e.g. electricity demand by the Pulp and Paper sub-sector in Industry). Referring to Figure 1, the Power Sector is divided into three main sections: Generation;

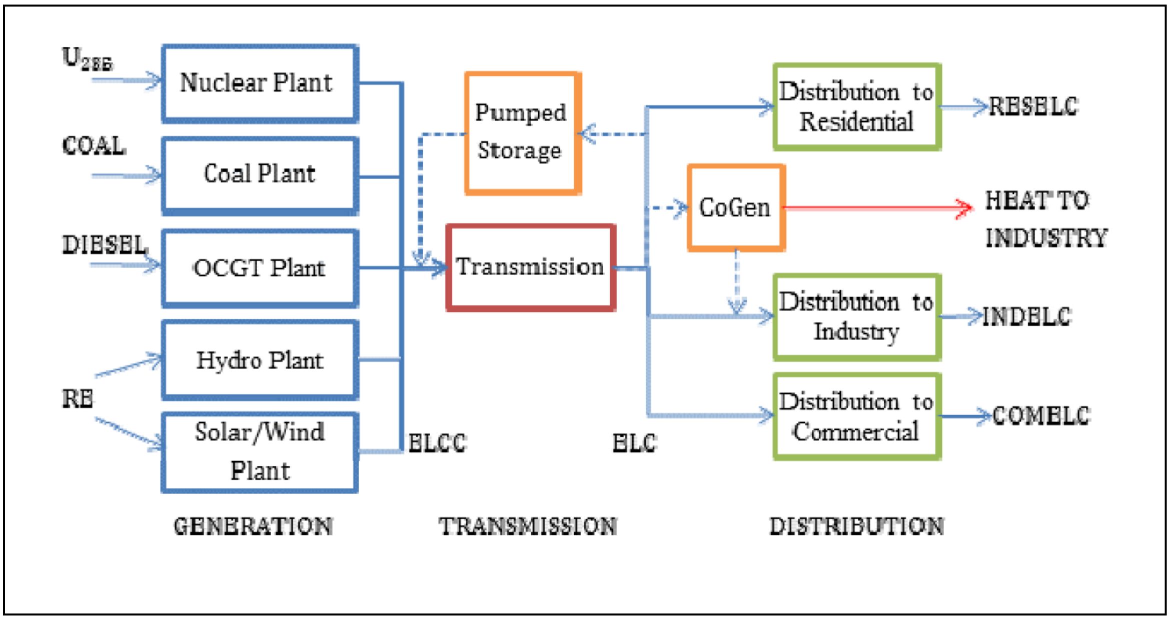

Figure 1 Simplified representation of the power sector in SATIM

Transmission; and Distribution. Electricity is dispatched via a central transmission system that in turn links to distribution nodes for each sector. In the Power Sector configuration, distribution costs and losses are also aggregated. The cost of transmission is therefore uniform for the system while that of distribution can be sector dependent.

In SATIM commodity supply is described by the Supply Sector and includes technologies and processes such as, imports, crude oil refineries and indigenous resource extractive such as coal mining.

The modelling of water consumption and of its transformation within SATIM had received little attention. At present only water consumption by the Power Sector is represented by including the water use intensity of power plants. The implementation did not consider regional disparities in water supply and costs and does not include auxiliary water usage by non-electricity generation technologies such as coal mining. In SATIM water is currently modelled as an accounting flow from the system similar to emissions such as CO_2. The existing representation of a wet-cooled power station is shown in Figure 2. The activity consumes low grade thermal coal (PWRCLE) and produces electricity at the plant gate (ELCC) requiring transmission. The figure depicts the consumptive water flow from the system (PWRWAT) and the environmental levy (PWRENV). The levy, currently set at ZAR 2c/kWh, applies to non-renewable energy sources and contributes to the national Demand Side Management programme.

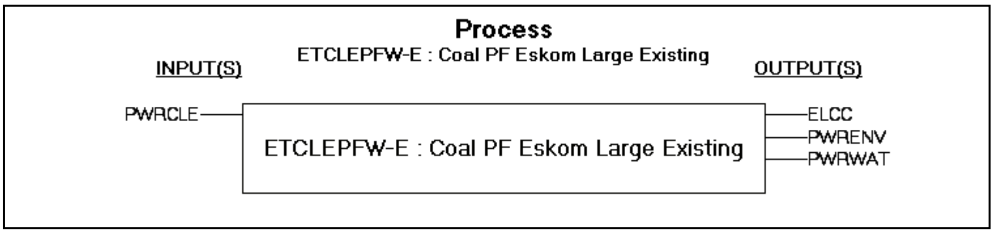

FIGURE 2: SATIM REPRESENTATION OF AN EXISTING WET-COOLED POWER PLANT.

Incorporating a regional cost and quality for water allows the model to examine potential trade-offs within the Power Sector by fully accounting for the cost of electricity generation associated with water consumption arising from:

- Fuel extraction and processing, for instance coal washing;
- 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 plant;
- 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 methodology for SATIM-W, will represent these activities so that the model is responsive to the regional cost and availability of water.

3 Spatial Characterisation of Water Supply in SA and its Representation in SATIM-W

At present South Africa's water resources management is overseen by the Department of Water Affairs. WMAs are administrative water resources regions established by the Department to decentralise administration of water resources at the catchment level. The boundaries of WMAs do not necessarily align with provincial borders or catchment basins as is illustrated in Figure 3. It is envisioned that each WMA be managed by a local Catchment Management Agency (CMA). Nineteen WMA exist but due to the difficulties of establishing and administering the 19 CMA required, it has been proposed that the existing 19 WMA be consolidated into 9 WMA administrations. The Upper Vaal would then be combined with the Middle and Lower into the Vaal WMA, for example.

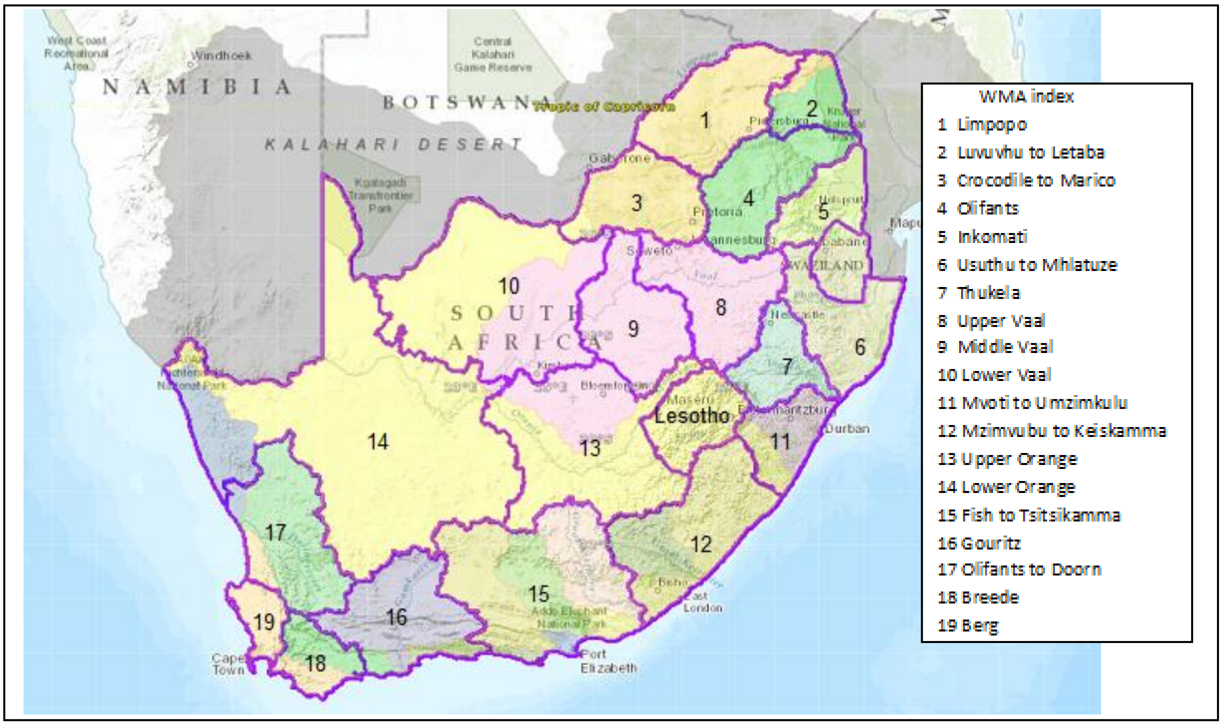

FIGURE 3: EXISTING 19 WMA CONTRASTED WITH CATCHMENT BASINS (SHADED).

(SOUTH AFRICA. DEPARTMENT OF WATER AFFAIRS,2012)

In contrast, water supply infrastructure is highly localised and distinct from WMA representing the civil engineering undertaken to implement water supply systems that cater for multiple users across economic sectors. The supply systems are typically comprised of multiple approaches to water supply and delivery that may span WMA. Schemes are discrete projects, for example an inter-basin transfer, for providing additional water to a water supply system. The term 'Water Supply Region' (WSR) as introduced in Task 1 is therefore used in this study to refer to a region of interest that is supplied with water from an integrated water supply network.

Thus a WSR is serviced by an integrated water supply network or system which may span WMAs and is composed of multiple schemes each of which contributes to the total supply system. For example, the Western Cape Water Supply System supplies water to urban, rural and agricultural users in the Berg and Breede WMA, while 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 systems, as described in Task 1.

4 Projecting Growth in Demand for Energy and Water

Forecasting demand for both energy and water presents a challenge because these primary needs are managed by separate national departments and different techniques are utilised. The Department of Energy (DOE) which is responsible for the development and growth of the energy supply sector oversees the Integrated Resource Plan (IRP) (DOE, 2011). The IRP is South Africa's cornerstone strategy for expanding the electricity generation sector and relies on expectations of the country's Gross Domestic Product (GDP) as a key determinant. Typically, forecasts for energy demand in South Africa are based on an expected national account of future economic growth. Although provincial demand and supply analyses are researched to assess future investment requirements for growth in the transmission and distribution network, the analyses is not as yet applied to the IRP, and thus there is no regard for regional variations in sectorial demand when planning future generation capacity expansion (Booysen & Dekenah, 2013; Eskom,2012).

Water resources are managed by the Department of Water Affairs (DWA) which periodically conducts strategic supply and demand reconciliation assessments. The reconciliation studies determine the necessary supply and demand management options available to cater for forecasted growth in demand. 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 yield of regional water supply systems are independently assessed as the distribution of water consumers varies and is a key driver of demand. For example, as highlighted in Task 1, in the Lephalale region (Limpopo WMA) where the Waterberg coal deposits occur, the demand for water is driven by the energy supply sector which accounts for 40% of the existing water withdrawals and which may grow to 75% by the year 2030 if further developments in coal-based energy supply are pursued. Of these volumes approximately 20% and 40% of the total are directly attributed to electricity generation and are consumptive requirements as the national power utility Eskom operates a Zero Liquid Effluent Discharge (ZLED) policy. This is in contrast to the national water balance where the electricity sector accounts for approximately 2% of total water withdrawals (SOUTH AFRICA. DEPARTMENT OF WATER AFFAIRS,2012).

Thus while electricity planning utilises national level 'top-down' macro-economic drivers, water planners conduct regional 'bottom-up' assessments that use a combination of regional economic, population (including provincial migration) and sector specific growth drivers (e.g. coal-to-liquids refineries in the Lephalale region). Furthermore, a regional disaggregation of electricity demand may not coincide with the boundaries for regional water supply.

The water requirements for the non-energy sectors have been aggregated in Phase 1 of the South African Thirsty Energy case study. Therefore care is needed when applying macroeconomic indicators in a 'top-down' approach to project both the demand for energy and water as this would distort regional water requirements. For Phase 1, future water demands for the Non-energy Sector are determined by their base or reference year sectorial shares for each region as reported in Task 1 and adjusted according to the national sectorial growth assumptions for energy demand. This is further elaborated in section 14 which introduces the scenarios modelled and the assumptions for forecasting growth. Elasticities and opportunity costs for each sector are not considered in Phase 1.

5 Incorporating the Marginal Cost Curves for Water Supply in SATIM-W

In Task 1, regions of interest for current and future energy supply sector development were defined, as WSRs. Marginal water cost curves were then calculated to estimate the cost of supply and delivery of water to these regions where competition for water resources are likely to be experienced with further growth.

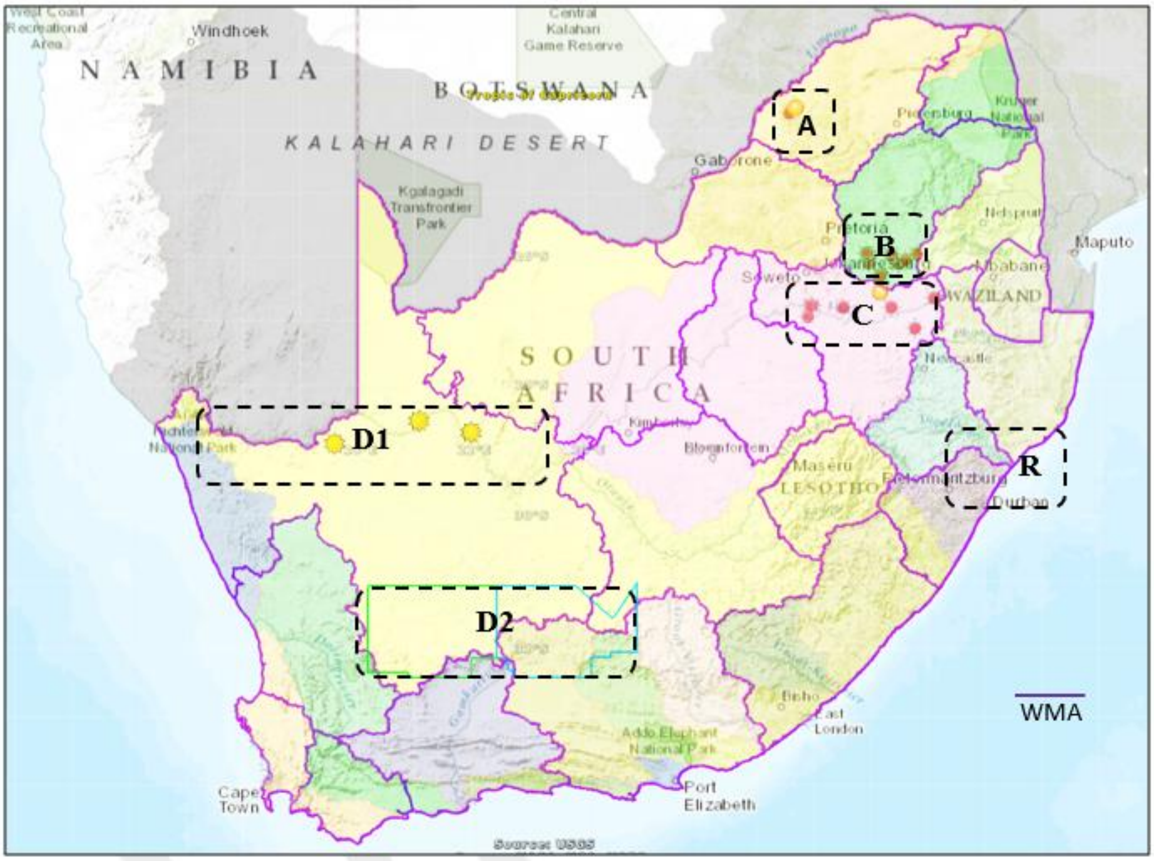

FIGURE 4: WATER SUPPLY REGIONS OF INTEREST PROPOSED FOR SATIM-W WITH THE ASSOCIATED WMA.

Figure 4 displays the WSR previously identified and their spatial relationship to the WMA. In the figure, WSRs are differentiated from WMA by the cost of supply and delivery to a particular region within a WMA.

Region 'R,' which is assumed to be in the vicinity of the Richard's Bay Terminal (RBT), has been included as a likely site for the option of coastal coal-fired thermal power stations. In this scenario the WMA in which such activity occurs is not considered for water supply as it is assumed that the bulk of process water withdrawn would be seawater. The RBT is the country's primary coal export corridor and is therefore deemed the most plausible location. Table 1 lists the technologies and activities represented in SATIM-W WMAs for Task 1 WSR.

TABLE 1: TECHNOLOGIES TO BE REPRESENTED IN SATIM-W FOR PHASE 1IMPLEMENTION BY WATER SUPPLY SYSTEM.

WSR	WMA	Country Region	Activity
A	Limpopo	Lephalale	• Open-cast coal mining • Coal thermal power plants with FGD option • Coal-to-Liquids refineries
B	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

In SATIM-W the cooling systems for thermal power plants may be either closed-cycle wet-cooled or direct dry-cooled. The model is free to choose the cooling type, except for open-cycle wet-cooled plants which are restricted to the coastal region, as part of determining the least-cost energy-water integrated system.

6 Representing the Regional Future Costs of Water in SATIM-W

In order to capture the impact of the cost of extraction, transmission and distribution of water in the model, it is necessary to spatially disaggregate the technologies and processes that utilise water to reflect the differing cost of water supply options in different locations.

In the previous incarnation of SATIM power plants were represented in aggregate by technology type (e.g. PF Coal, Nuclear, CCGT, etc.), capacity and vintage (i.e. new or existing). Coal power plants which currently comprise the larger share of generation capacity in the country are categorised as listed in Table 2 along with the representative raw water use intensity. Since the power plants are aggregated, the water use intensities are also aggregated by means of a weighted (by capacity) average.

The small existing coal power plants are typically municipal plants with a plant unit size of usually less than 100 MW and are of closed-cycle wet cooled design. The largest plant in this category is the somewhat larger Hendrina plant operated by Eskom which consists of ten units with a combined capacity of 1,900 MW. The analysis focuses on Eskom's generation portfolio as the small municipal plants account for ca. 1% of existing capacity and will dilute further when the new coal plants are commissioned.

TABLE 2: THE REPRESENTATION OF COAL POWER PLANTS IN SATIM WITH AVERAGE WATER USE INTENSITIES.

Plant Category	Net Capacity (MW)[1]	Weighted raw water consumption (l/MWh)[2]
Existing small (*Eskom*)	5400	2481
Existing IPP small (*Municipal*)	450	2565[3]
Existing large wet-cooled (*Eskom*)	21150	1992
Existing large dry-cooled (*Eskom*)	9390	128
New supercritical dry-cooled (*Eskom*)	4334	229

[1] As of the year 2014; [2](Downes,2011) [3]Value taken from Eskom's Camden plant which is typical of the design and vintage of these plants

The remaining stock of larger plants comprises a mix of dry-cooled and closed-cycle wet-cooled plants. At present all wet cooled plants are of closed cycle design. 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 ca. 30% 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. As in the case of the Kusile and Medupi plants, all new power plants are considered to be of supercritical design (Eskom, 2011).To facilitate the spatial variation in the cost of water it is necessary to further divide the above categories by WSR as regions in SATIM-W. This applies to all water consumers in the model such as mining, refineries, other generation technologies and synthetic fuel plants which would compete for regional water resources.

Table 3 lists the current and commissioned stock of Eskom's coal power plants according to the water supply region defined in Task 1 along with their water use intensities, capacity and SATIM category as in Table 2 . The relevant data is obtained from Eskom and is presented in Appendix B.

TABLE 3: THE INDIVIDUAL ESKOM COAL PLANTS AS AGGREGATED IN SATIM AND BY WATER SUPPLY REGION.

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. Referring to Appendix B 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)

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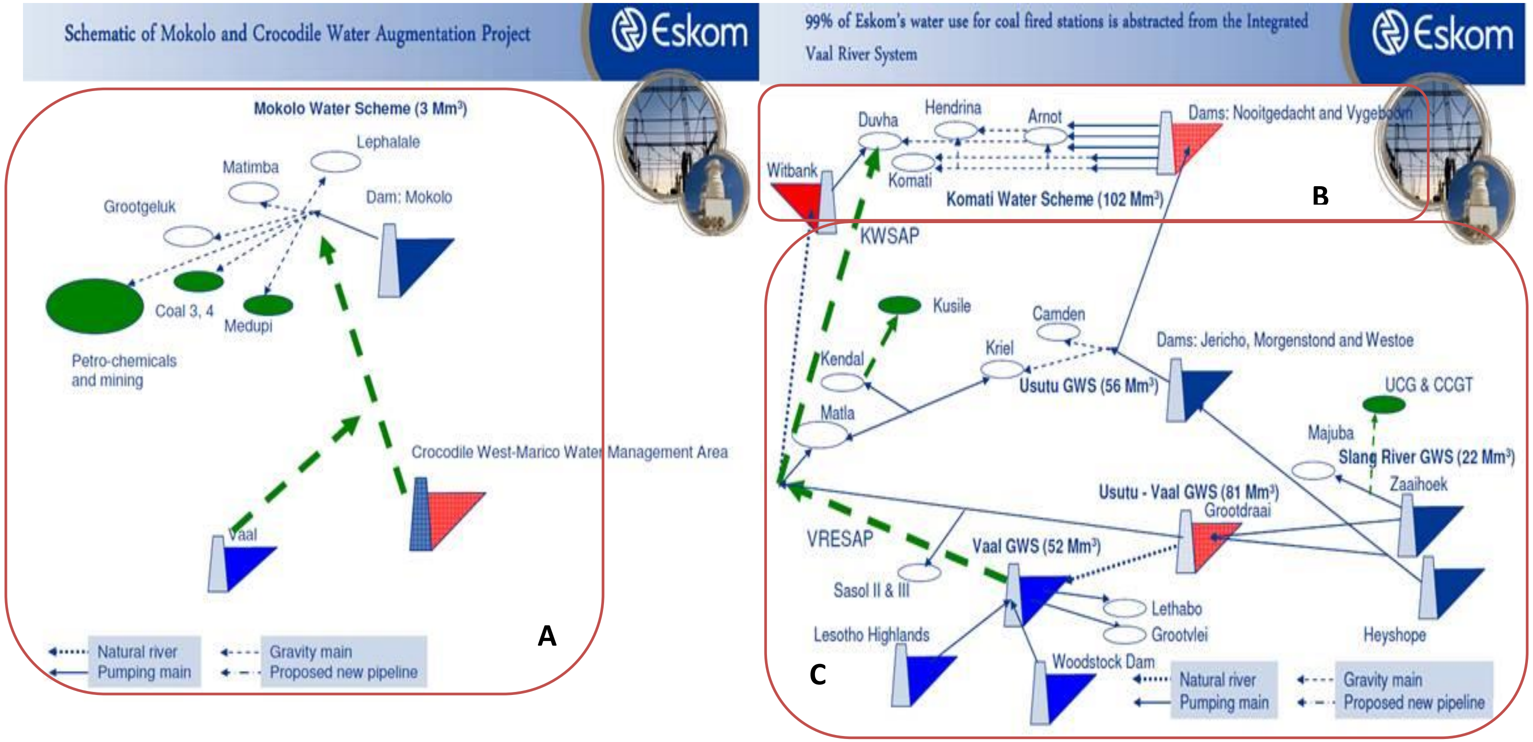
Power plants were attributed to WSR according to the map of the existing supply network, as shown below in Figure 5.



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

FIGURE 5: WATER SUPPLY NETWORK FOR POWER PLANTS IN WATER SUPPLY REGIONS A TO C.

It is evident from Table 3 that the current SATIM implementation cannot capture the heterogeneous spatial distribution of plants by water supply region and cooling design. Therefore in order to examine the water-energy relationship for the energy supply sector, SATIM-W requires the power plant categories to be further divided by incorporating additional attributes for the water supply region and cooling design. The additional attributes are incorporated as follows:

- The **cooling design** is attributed by the raw water usage factor for the plant.
- The **WSR** is attributed by mapping regional water commodities to associated regional technologies as indicated in Table 1, as opposed to a single water commodity as currently modelled in SATIM.

An example of changes required to naming conventions in SATIM-W: the case for an existing large PF coal power plant.

The current designation for a large existing coal power plant is given as: **ETCLEPF-E**. The water requirements as described earlier are incorporated in the TIMES model for the appropriate plant type. The concatenated codes that describe the technology are as follows: 'ET' = Electricity generation Technology; 'CLE' = Low Calorific value coal; 'PF' = Pulverised Fuel. The hyphenated '-E' refers to existing technologies where 'N' would refer to new.

In SATIM-W the above technology is further described with the cooling-design and regional identifier. Thus, for the example, the adjusted technology name becomes ETCLEPF[i]-[j]-E where i and j identifies the cooling design and region respectively. Thus for Region C, the technology code is adjusted to **ETCLEPFW-C-E** where the code 'W' identifies the cooling design as closed-cycled wet-cooled. The technology code **ETCLESCO-R-N** would describe a new coal-fired plant that is: supercritical; cooled via open-cycle wet-cooled design and located in Region R.

6.1 The impact of temperature

The net output from a thermal power plant is determined by its net efficiency and its ability to dissipate the heat load generated. The efficiency of thermal power plants is governed by the heat rate of the plant which determines the heat load to be dissipated (El-Wakil,1985). The ambient temperature is an important factor as it influences the heat transfer.

Of issue is the application of an annual average water use intensity value to power plants built in different climatic zones. Currently the cold interior climate average would be utilised by default. In the absence of climate specific data and to better reflect the water consumption of a wet-cooled thermal plant in the hot interior, the cooling water usage is adjusted according to the rate of change derived by Zhai and Rubin (2010) for coal-fired plants as illustrated in Figure 6.

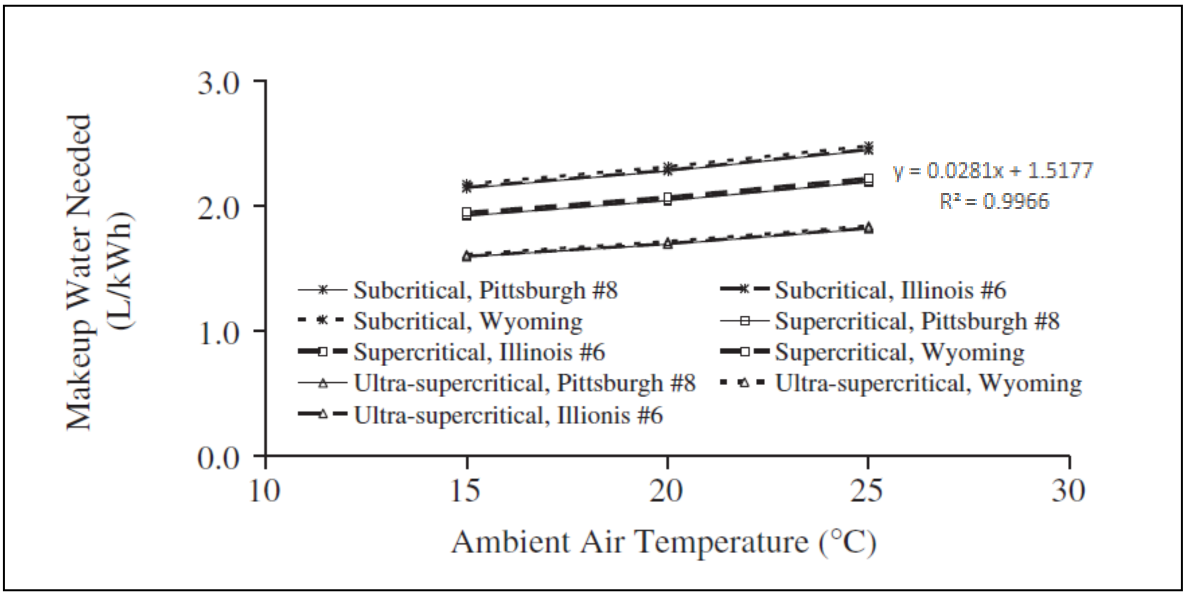


FIGURE 6: THE MODELLED EFFECT OF AMBIENT TEMPERATURE ON WATER USAGE FOR A WET-COOLED COAL POWER PLANT. ZHAI AND RUBIN (2010)

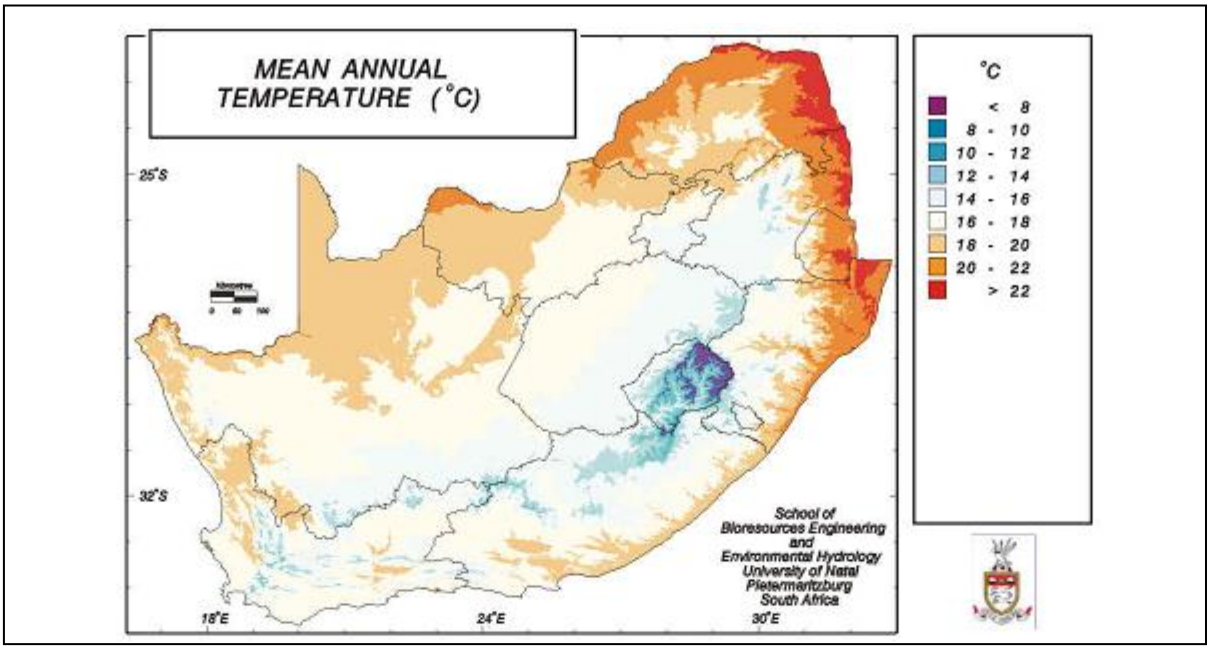


FIGURE 7: MEAN ANNUAL TEMPERATURES FOR SOUTH AFRICA.

(THE SOUTH AFRICAN ATLAS OF AGROHYDROLOGY AND CLIMATOLOGY, 2001)

For simplicity, the climatic zones attributed to the power stations are those defined in the South African National Standard for Energy Efficiency in Buildings 204 (2008) which divides the country into 6 climatic zones. Regional annual mean temperatures are provided by the South African Atlas of Agrohydrology and Climatology (Schulze et al., 2001) as illustrated in

Figure 7. With reference to Figure 6 and

Figure 7 a wet-cooled PF coal power plant is assumed to increase its cooling water consumption by 9% on average if located in the Lephalale area for an average 6^{o}C change in annual temperature.

6.1.1 Seasonal variation in water use

The Lethabo plant located in the Vaal water supply area is reported to have a water use rate of 1.7 to 1.9 L/kWh which is dependent on prevailing environmental conditions (de Bod,2012). An annual average value of 1.86 L/kWh was reported for the year 2014 (Appendix B), which is consistent with the plant's historical average (de Bod,2012).

In SATIM-W water consumption is annualised using the average value of water intensity because, at present, only annual water intensity values are available. Water demand across the economic sectors varies seasonally and often increased competition for water occurs during the drier typically warmer months for which water availability is lower. With monthly data, the impact of a seasonal variation in water-use intensity may be further investigated at a later stage.

7 Costing Water in SATIM-W

In SATIM-W, the consumption of water is included as an additional consumption commodity defined as an ancillary or feedstock commodity for a process - similar to the requirement for coking coal in the Iron and Steel subsector or the requirement for feedstock natural gas for the Fischer- Tropsch process for synthetic fuel production.

In this study, the cost of water to a consumer can be considered to have three components: the supply; delivery (transmission and distribution) and treatment required for its application. The treatment of effluent for discharge is not considered although this does not as yet apply to power plants due to the current ZLED practice. The necessary treatment and cost incurred further relates to the water quality of the supply system. A scheme for each supply system may have distinctive attributes for each component and it may therefore be necessary to separate the relevant costs. Where applicable however the supply and delivery components are combined for simplicity. This is valid where both components are common to all users of a given supply system. Utilising the results from Task 1, the marginal cost of water delivered per scheme for a given regional supply system is implemented as:

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

The capital, fixed OM and variable OM components are as provided in Task 1 and give the base cost of implementing a scheme and its delivery.

The energy cost of conveyance is proportional to the energy intensity of a particular scheme's supply mechanism as highlighted in Figure 8 which is reproduced from Task 1. The figure contrasts the sensitivity of scheme options such as desalination and regional transfers to electricity costs as compared to schemes that largely exploit gravity.

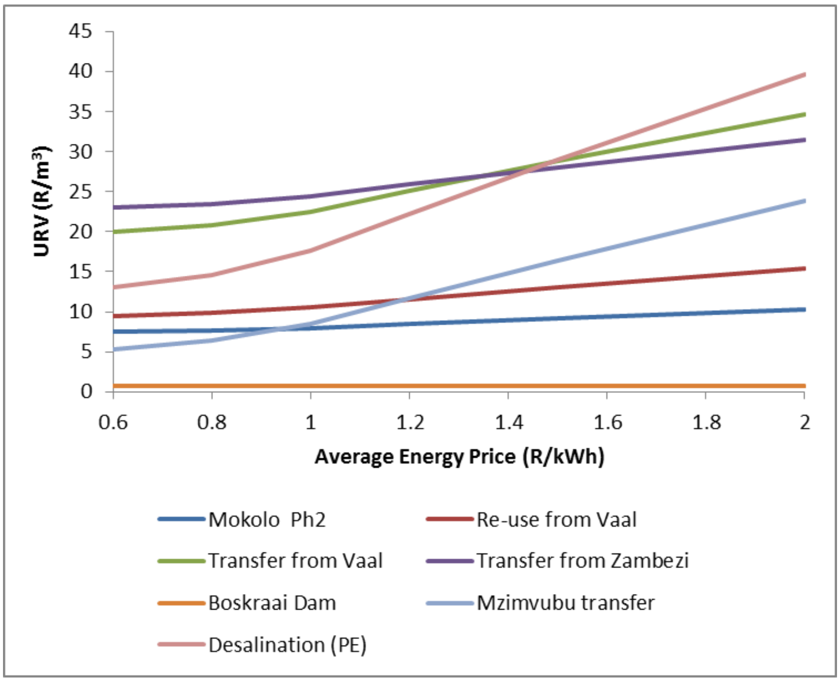


FIGURE 8: SENSITIVITY OF FUTURE WATER SUPPLY SCHEME COSTS TO CHANGES IN THE ENERGY PRICE.

Electricity prices are determined endogenously in SATIM and therefore the energy cost attributed to a scheme is better expressed in terms of the energy intensity of water supply (i.e. kWh/m^3). Thus in SATIM-W schemes requiring electricity, whether for conveyance, or production as in desalination, are represented as requiring additional electricity demands. For shale gas water supply the option of water delivery via road freight requires the substitution of electricity demand for diesel consumption as a technology input commodity.

Current investment and OM costs for power plants assumed in national energy system models including the SATIM and IRP already include the necessary water treatment infrastructure associated with prevailing water quality of the current supply system (Goyns,2013). Therefore to represent the potential additional costs for the treatment of water incurred due to deterioration in regional water quality with the introduction of new schemes, it is proposed that only the relative change in regional water quality is modelled. This will account for the existing cost structure and allows for the additional cost of water treatment to be included for a change in water quality relative to the Reference case.

Water treatment in the model is interpreted as the additional cost for the transformation of bulk water for process use. Where applicable this would include:

- Primary treatment - clarification via coagulation and flocculation, where consumption would include the makeup water for cooling towers in wet-cooled power stations and coal washing at coal mines, and
- Secondary treatment - production of demineralised water, primarily for boiler recharge or make-up volumes.

Additional treatment costs would include effluent management where applicable. As an end-use consideration, this is further outlined in the sections discussing the processes or activities modelled in SATIM-W. This includes, for example, water management for coal and shale gas mining which are discussed in Sections 10 and 11.

The cost of treatment for bulk water can be represented in two ways as shown below, where **Scheme Marginal Treatment Cost equals:**

Var_OM (R/m^3) (simplified form) or:

Capital + Fixed_OM (as %Capital) + Var_OM (kWh/m^3)

The two distinct water treatment types refer to two water commodities that are required by consumers:

- Basic quality or Primary treated water, and
- High Quality (HQ) demineralised water for boiler feed water make-up.

In SATIM-W, for the Power Sector, primary water would then refer to the cooling water requirements while HQ water refers to the boiler circuit water.

Primary treated water has a relatively low energy intensity of production at ~ 6 kWh/1000m^3 (Ras,2011) such that a standard simplified cost of R2/m^3 can be applied in the model. The energy intensity of desalination by reverse osmosis (RO) for demineralised water production is higher (2 to 3 kWh/m^3) and depends on the Total Dissolved Solids (TDS) range of feed water (e.g. low or high salinity brackish waters). Therefore to reflect the impact of lesser quality water and energy prices on the cost of HQ water it was decided to model the two water types separately.

Is should be noted that existing and commissioned plants have a mix of Ion-Exchange (IX) and RO technologies for demineralised water production. For example, according to Eskom data the new Medupi plant located in the Limpopo WMA relies on Ultra-Filtration and Reverse Osmosis (UF-RO) with Electro-Deionisation (EDI) for final polishing. The new Kusile plant located in the Olifants WMA relies on IX. The energy intensity and usage of feedstock chemicals for IX exhibits a wider variation than the UF-RO process for changes in TDS which as highlighted in the Eskom Medupi Water Treatment Plant (WTP) analysis, see Figure 9. The figure displays the total cost for the two treatment options for changes in TDS (mg/L) for different feed water options. The options range from the existing Mokolo river system (92.8 mg/L) to the Crocodile River supply scheme (447 mg/L) and a 50% mix of both.

REWS diagrams for each water supply region identified in Task 1 are detailed in Appendix A depicting the regional energy technologies and activities listed in Table 1. Descriptions are colour coded in green and TIMES process and commodity names are in black. The supply system for region D differs from the generic format due to the different modes of delivery. This effectively creates sub-regional water supply systems owing to the combination of delivery modes and water sources (i.e. surface and ground water).

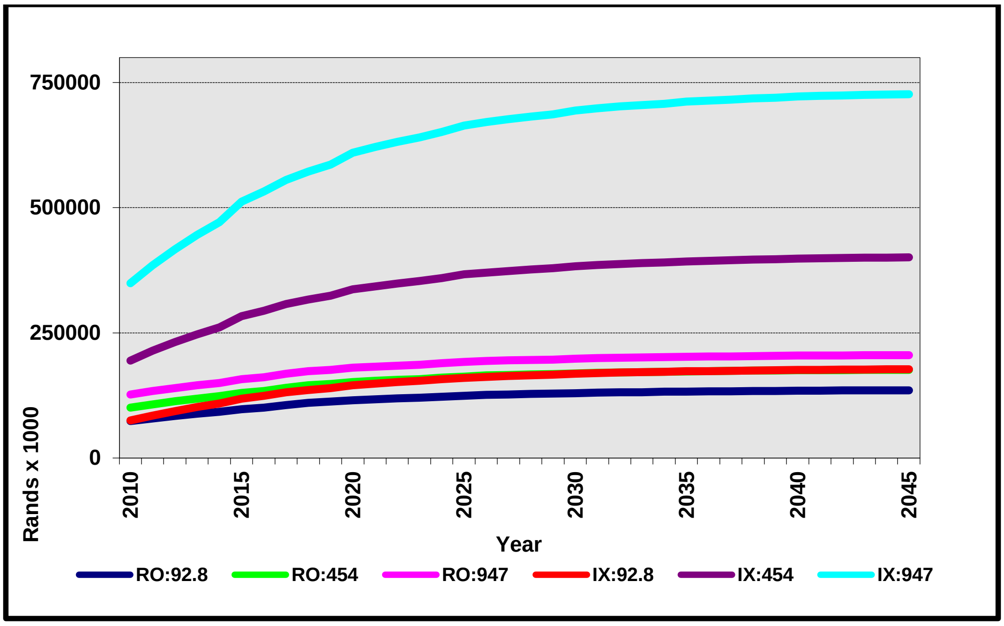


FIGURE 9: LIFE-CYCLE COST COMPARISON FOR RO AND IX TECHNOLOGIES AGAINST TDS CONCENTRATION (MG/L) FOR THE MEDUPI WTP. (ESKOM,2008)

7.1 Water quality and treatment costs

In the model 'water quality' refers to the TDS of the water supply and the TDS of the regional supply system is taken as the reference water quality. The reference quality can vary by region but plants or mines built or commissioned in a region would have the costs incorporated for regional reference water quality. New schemes that are commissioned to augment regional supply may require pre-treatment by the consumer if the TDS of the scheme is above the operational design of the existing water treatment facilities. It is proposed that this be represented by a pre-treatment technology in SATIM-W which would include investment and operational costs.

Additional schemes are then ranked as equivalent to the reference scheme or less. The concentration of TDS is supply specific and the sensitivity to the level of TDS is use specific. For example, the operating pressure of boilers has a direct dependence on feed water quality with low pressure boilers more tolerant to higher TDS concentrations (Lenntech,2014). The method used represents an average discrete marginal cost across uses with an explicit representation of electricity as a driver of cost for the production of high quality water. In this manner a direct account of TDS variation is abstracted by considering a relative departure from the reference.

Thus in SATIM-W a water supply system for a region is implemented in the generic form shown in Figure 10. To account for the embedded costs of a WTP for a process (e.g. mining, power plants and refineries), the HQ water treatment process as depicted in the schematic has no associated costs in the base year.

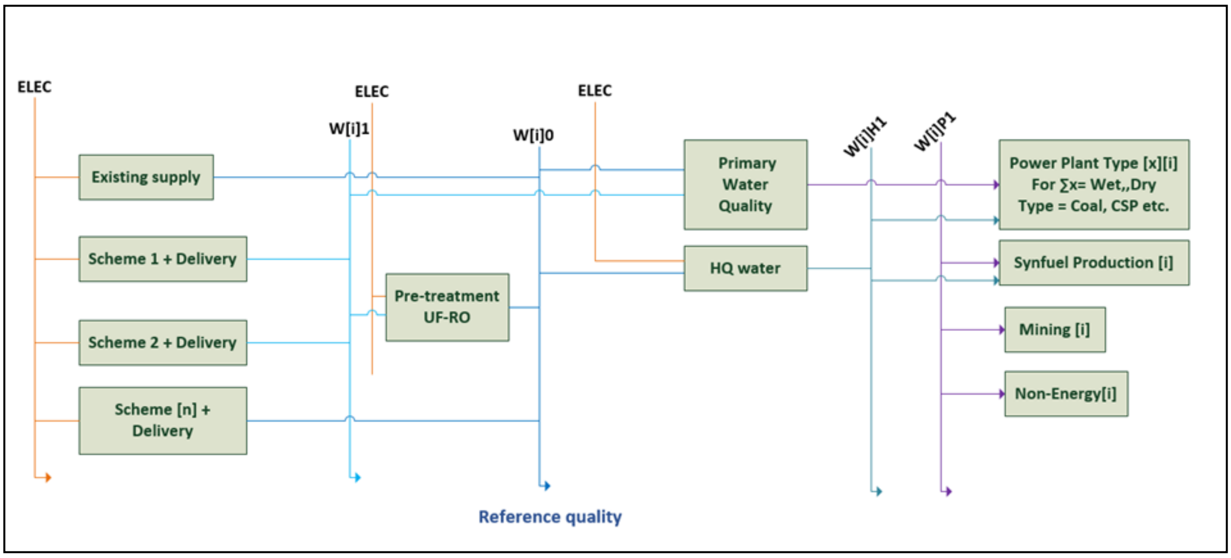


FIGURE 10: DEPICTION OF A GENERIC WATER SUPPLY SYSTEM IN SATIM-W.

At present it only acts as a conduit for HQ water and would be populated when the water components are separated from the gross plant costs. Only pre-treatment via UF-RO, as shown in the figure for water quality that departs from the reference level, has investment and operational costs included. This approach has the advantage that current or commissioned costs associated with either IX or RO for the WTP are aggregated into total plant capital and OM costs and only pre-treatment of water for a departure from reference water quality is considered.

Only one category below the reference is represented (level 1 or W[i]1). Schemes with level 1 type water would require pre-treatment for HQ end-use. The effect is to introduce a discrete marginal cost for water types with primary water usage incurring a lower cost and having a wider tolerance range. The tolerance range for primary water is depicted in Figure 10, as a blending technology with the flexibility to choose from the given water types. This manner of implementation accounts for the case where the blending of raw water from the different schemes may occur and the increased cost associated with higher level treatment is only applied to that volume of water treated for HQ use.

Referring to Figure 10, in the model, all schemes produce two types of water:

1) Reference, and
2) Non ideal category 1 or 'worse.'

Two scheme commodities are chosen for model simplicity, although additional commodities can be included if warranted. Uses which have different sensitivities to water quality are either restricted to certain commodities or have no restrictions. It is proposed that this be accomplished in SATIM-W via 'blending' technologies that have flexible shares of water commodity types. The blending technologies allow the direct use of a range of water types without the further pre-treatment shown in Figure 10. To attribute the appropriate water quality commodity to a scheme, further investigation of the water quality for each scheme is thus required. The complete list of water types (or commodities) for a supply system is given in Table 4.

TABLE 4 WATER PARAMETER AND COMMODITY TYPES IN SATIM-W.

Water parameter	Commodity type	Description
W[i]0[1]	Scheme supply	Existing Reference Water Quality
W[i]1	Scheme supply	Worse Water Quality
W[i]H1	System supply	High quality demineralised water
W[i]P1	System supply	Primary treated water for general use
W[i]P0	System supply	Raw water supply. Includes agricultural use for example. This is not implemented in Phase 1 as non-energy demands are aggregated

[1]WATER SUPPLY REGION 'A' WOULD HAVE WA0 AS THE REFERENCE EXISTING QUALITY FOR EXAMPLE.

As suggested in Task 1, it is proposed that the likely scenario of water quality deterioration in the reference supply be addressed via the escalation of treatment costs for a case of increasing TDS levels in the supply system. The approach borrows from the DWA study on water quality impacts in the Vaal catchment for different sectorial users and an Eskom case study examining the cost of demineralised water production from alternate water sources for the direct-dry cooled Medupi power plant (South Africa. Department of Water Affairs and Forestry,2009). In this regard, treatment costs are extrapolated from the reference values and applied uniformly to all water supply options including the existing supply. Water quality modelling in this study is thus conducted as an exogenous model determinant. For example, referring to Figure 10, for the case of deteriorating water quality the base or existing supply would be adjusted to produce category 1 (or W[i]1) water. Subsequent schemes would be adjusted accordingly – that is schemes producing reference quality water or W[i]0 would provide the lesser W[i]1 water where applicable. For example, seawater desalination would be excluded.

This consideration of water quality is particularly relevant to the power sector which requires the production of energy intensive demineralised water for the boiler systems. Using the dry-cooled Matimba and wet-cooled Lethabo plants as examples, table 5 gives the basic unit cost and total cost to the plants for three grades of water, assuming that secondary treatment is via the UF-RO route. The unit cost of secondary treatment is taken from the Medupi WTP analysis which is based on the Lethabo desalination plant that is used to treat mine decant for reuse. Figure 11 displays the costs for double the price of electricity. We note that the total cost is dependent on the sensitivity of secondary treatment to both the TDS concentration and electricity price. The doubling of electricity prices increases the total estimated water cost by 3% for Lethabo and 8% for Matimba respectively for all TDS concentration scenarios.

TABLE 5: THE COST OF PRIMARY AND SECONDARY TREATMENT FOR SELECTED POWER PLANTS.

Electricity Price		Water use	Lethabo	Matimba
47c/kWh (Industrial)		I_{raw} (l/kWh)	1.86	0.12
		I_{demin} (l/kWh)	0.076	0.02
TDS	Primary treatment cost	Secondary treatment cost	Total cost	Total cost
(mg/L)	R/m3	R/m3	R/m3	R/m3
92.8	2	6.74	2.28	3.12
454	2	8.83	2.36	3.47
947	2	10.54	2.43	3.76

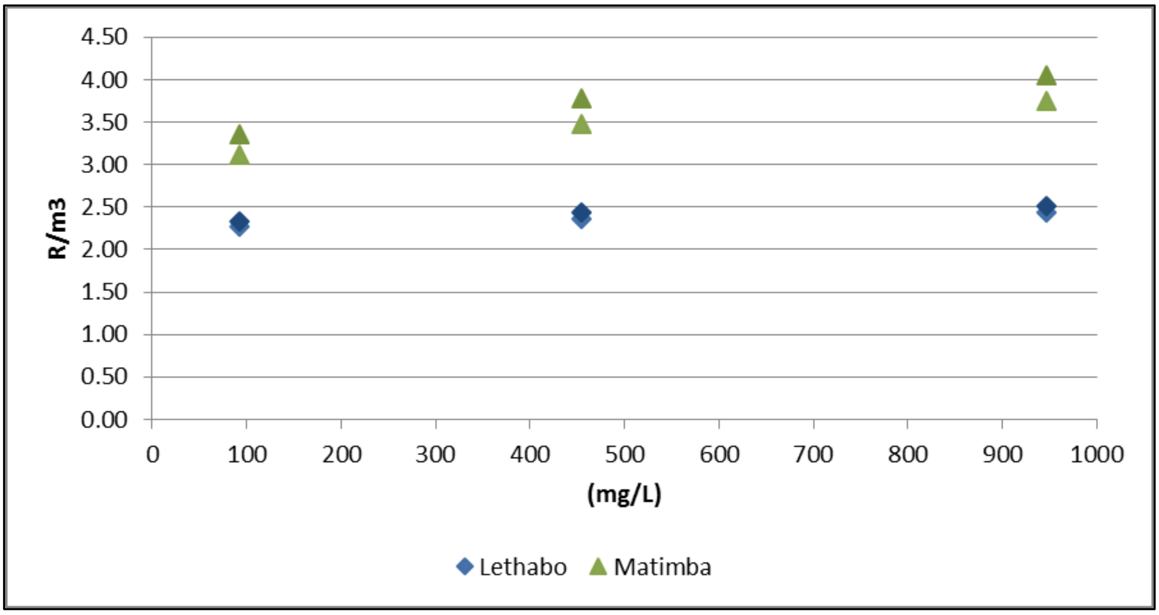


FIGURE 11: THE TOTAL COST OF WATER TREATMENT FOR SELECTED POWER PLANTS AGAINST TDS LEVEL AND AT TWICE THE NOMINAL ELECTRICITY PRICE.

The above analysis is simplified to reflect the impact of secondary treatment to the total cost and ignores the increase in primary water cost as a result of increased TDS levels. This would impact wet-cooled power plants as the cooling water withdrawal may either:

1) Increase to maintain reference TDS levels (i.e. the cycles of concentration for cooling water would decrease as the TDS levels of the feed water increases), or
2) Require desalination pre-treatment to maintain existing water usage rates.

In SATIM-W the default case for water quality pre-treatment is the desalination option as was discussed earlier.

8 Thermal Power Plant Costs and Water Use

The water use intensities for generation for future build (e.g. CCGT, CSP) are informed by the Electric Power Research Institute (EPRI) report *Power Generation Technology Data for the IRP of South Africa* (EPRI,2012). Appendix C reproduces the reference cost data and water consumption factors reported by EPRI for new build options in the IRP which is duplicated in the existing SATIM representation of the power sector.

The EPRI data is specific to Eskom's build policy. That is cost and water use intensity estimates are only provided for new dry-cooled thermal power plants. To include wet-cooled plants in the modelling, data from the USA is applied. The direct application of cost data would ignore local nuances such as the cost of labour and materials. In the interim, generic factors are used for different cooling designs. These are elaborated in the relevant sections below where such scaling is required in the absence of local data.

8.1 Existing power plants

Figure 12 displays the water use intensities for the individual coal plants with dry-cooling systems in place while Figure 13 displays data for wet-cooled plants. The water use intensities for both for raw and demineralised (demin) water production are displayed along with the mean values which are weighted by plant capacity. Included in Figure 13 is the median value for demineralised water which displayed the only significant deviation influenced by the Hendrina plant. The values for demineralised water use for the direct-dry cooled Matimba plant is 33% of the mean. The large deviation for Matimba may relate to the difference in cooling design. Kendal is an indirect dry-cooled plant while three of Majuba's units are wet-cooled. It also difficult to explain the large difference in the intensities for raw and demineralised water production for Matimba without knowledge of the plant's specific water balance. The most likely non-cooling process use would be for ash handling. These plants employ dry ash handling which reduces process water requirements.

From Figure 12, it is better to model the Majuba plant as two distinct plants as is at present the case in SATIM; using the water-use intensity data of Matimba as similar dry-cooled systems are in place. The mean values for raw and demineralised water usage would otherwise be unrepresentative of the dry-cooled plants. The 3,840 MW Kendal plant uses indirect dry-cooling and would require to be modelled as a distinct category.

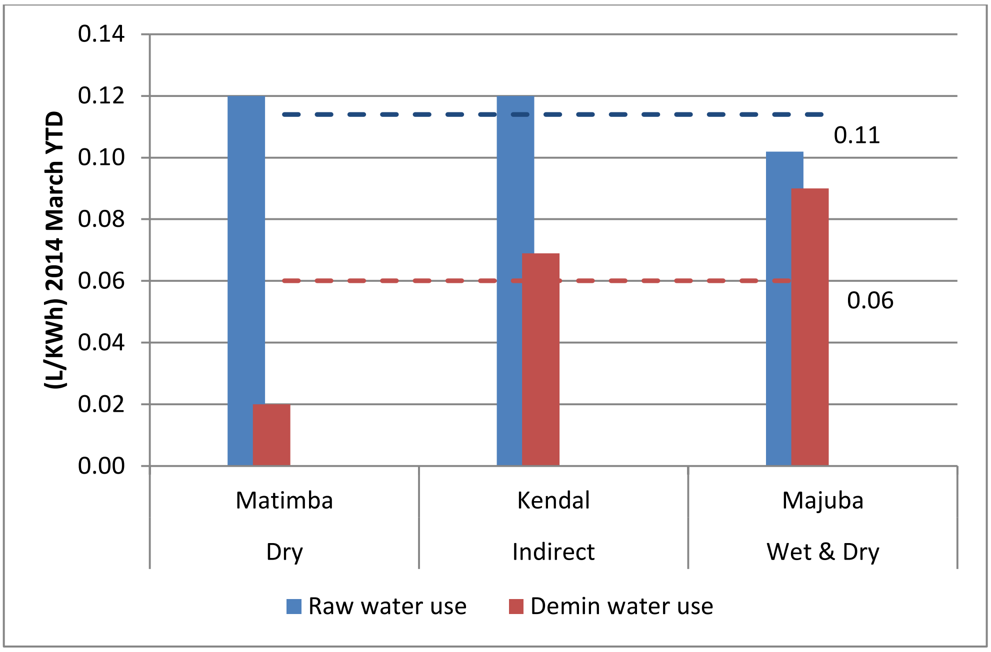


FIGURE 12: WATER USE INTENSITY VALUES FOR ESKOM PLANTS WITH DRY-COOLING.

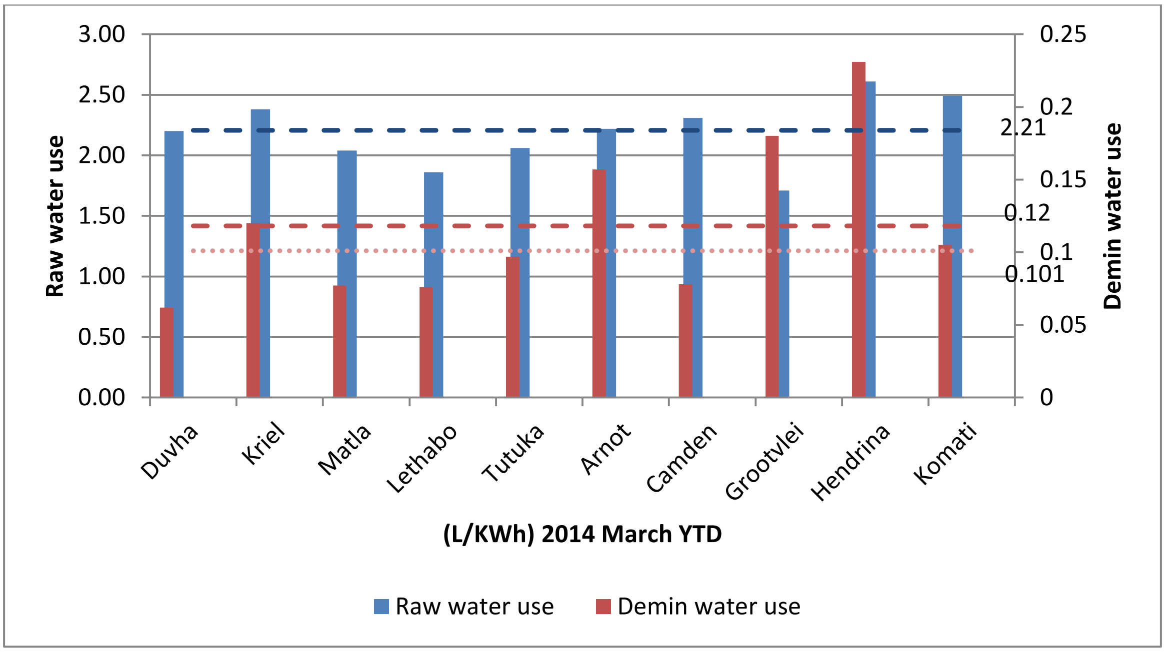


FIGURE 13: WATER USE INTENSITY VALUES FOR ESKOM PLANTS WITH CLOSED CYCLE WET-COOLING.

Since all wet-cooled plants are located in a similar climatic zone the weighted average value for raw water usage is used for a 'typical' wet-cooled plant, while the median value for demineralised water production is used to minimise the skewing effect of the Hendrina plant. The values for the Matimba plant are used to estimate the value for a 'typical' dry-cooled plant. Eskom practices a Zero Liquid Effluent Discharge (ZLED) policy and therefore these values are taken to represent consumptive use.

The marginal cost of water as calculated in Task 1 refers to the cost associated with volumes withdrawn from the regional integrated supply system. Other water sources are also utilised by

Eskom and these sources include mine decant, storm water and effluent recycling and reuse. In addition to being an electricity utility, Eskom functions as a water service provider producing potable water for district supply. Referring to Table 6, the contribution of these alternative sources is minor. Furthermore the extended use of mine decant is targeted as an augmentation option for the wider system (South Africa. Department of Water Affairs,2010b). Therefore, with Lethabo power station as an example, the error introduced by costing water from regional integrated supply system is considered minor.

TABLE 6: THE WATER BALANCE FOR THE LETHABO POWER STATION (2010). (DE BOD,2012)

Input Data	Unit	Value
Station load factor	%	81
Units sent out	MWh	23574920
Thermal efficiency	%	34.77
Coal Burnt	tonnes	16715509
% Ash in coal	%	38.7
Vaal water received	ML	4127.40
Mine water received	ML	824.78
Rainfall (actual)	mm	760.5
Potable to third parties	ML	518.68
Sewage water recovered to CCW	ML	45.00
Water to ash dump	ML	841.60
Water to fly ash conditioners	ML	430.47
Water to bottom ash quenching	ML	1096.48
Fly ash to ash resources	tonnes	1193841
Water to ash dump dust suppression	ML	600

8.2 Coastal coal plants and wet-cooled coal generation in the hot interior

The present cooling categories of new build coal plants are that of wet and direct-dry cooled and the model is unrestricted in choice of plant by climatic zone via the water cost curves. To include the efficiency change of wet-cooled coal power plants, the efficiency de-rating applied to the dry-cooled Medupi is effectively reversed and a 2% efficiency gain applied. This factor is corroborated in the study by Zhai and Rubin (2010) who compared the performance of wet and dry cooled pulverised coal power plants. The relative cost for the two cooling designs are given below in Table 7. They report a similar variation in relative costs for Supercritical and Ultra-supercritical designs.

TABLE 7: THE COMPARATIVE COST AND PERFORMANCE OF A SUB-CRITICAL COAL POWER PLANT WITH EITHER A WET OR DIRECT DRY-COOLED DESIGN (US$2007). (ZHAI & RUBIN, 2010)

Performance and cost measures	PC plant with a wet cooling system	PC plant with a dry cooling system
Gross power output (MW)	593.3	600.7
Net plant efficiency, HHV (%)	36.1	34.6
Tower evaporation loss (tonnes/h)	1012	0
Tower blowdown (tonnes/h)	337	0
Tower drift loss (tonnes/h)	0.6	0
Total cooling system makeup water (tonnes/MWh)	2.46	0
Number of air cooled condenser cells		63
Cooling system total capital requirement ($/kW)	90.4	224.4
Cooling system levelized annual cost ($/MWh)	3.9	7.2
Plant total capital requirement ($/kW)	1788	1940
Plant revenue requirement (COE) ($/MWh)	69.1	73.1

While cooling systems costs for a dry-cooled plant can range from 3 to 6 times that of wet-cooled designs depending on the configuration and climate (Electric Power Research Institute,2007a;Electric Power Research Institute,2007b;Mielke, Anadon & Narayanamurti, 2010), Table 7 suggests an 8% reduction in total capital costs for wet-cooled plants relative to direct-dry although other studies have estimated the capital cost difference to be of the order of 12% (Mielke, Anadon & Narayanamurti, 2010).Therefore a 10% reduction in capital costs (including fixed OM) is applied for new wet-cooled supercritical power-plants. For wet-cooled power plants, a similar factor is applied to open-cycle power plants as total capital costs are reported to be similar to that of closed-cycled design as illustrated in Figure 14.

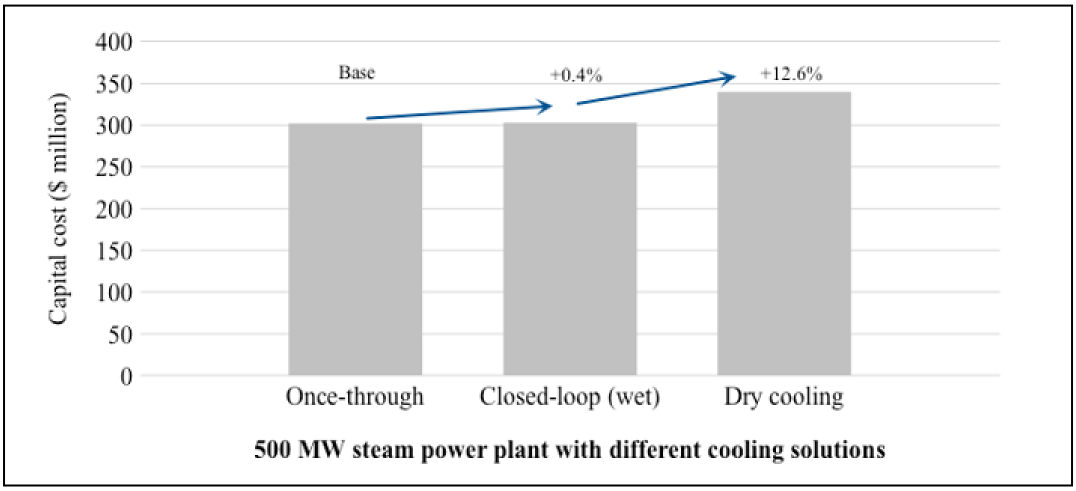


FIGURE 14: THE RELATIVE CHANGE IN TOTAL CAPITAL REQUIRED FOR A HYPOTHETICAL THERMAL POWER PLANT WITH A DIFFERENT COOLING SYSTEM DESIGN (MIELKE ET AL., 2010).

Water usage for coastal power plants in SATIM-W is not considered as seawater is used for cooling and any potential FGD fitment. The relatively small freshwater requirement for boiler makeup is not considered to impact water supply for the RBT area. This would most likely be sourced at the plant from cooling water effluent via Reverse Osmosis (RO) desalination or purchased from local municipalities.

The associated gain in net efficiency for a migration to open-cycle (referred to as once-through) wet-cooled thermal power plants is estimated at 1.5 % which results from a combination of a reduction in the heat rate and parasitic power load (Electric Power Research Institute,2007a).

8.3 Non-coal generation

8.3.1 Concentrating Solar Power (CSP)

The Renewable Energy Independent Power Producer Programme (REIPPP) aims to reduce the country's dependence on coal with an allocation of renewable energy generation of up to 19 GW in capacity by 2030 as shown in Figure 15. 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 not yet operational. The 200 MW of CSP committed build comprises three plants shown in the Northern Cape comprising: 150 MW of parabolic trough (KaXu); 50 MW central receiver (Khi) and 50MW of parabolic trough (Bokpoort).

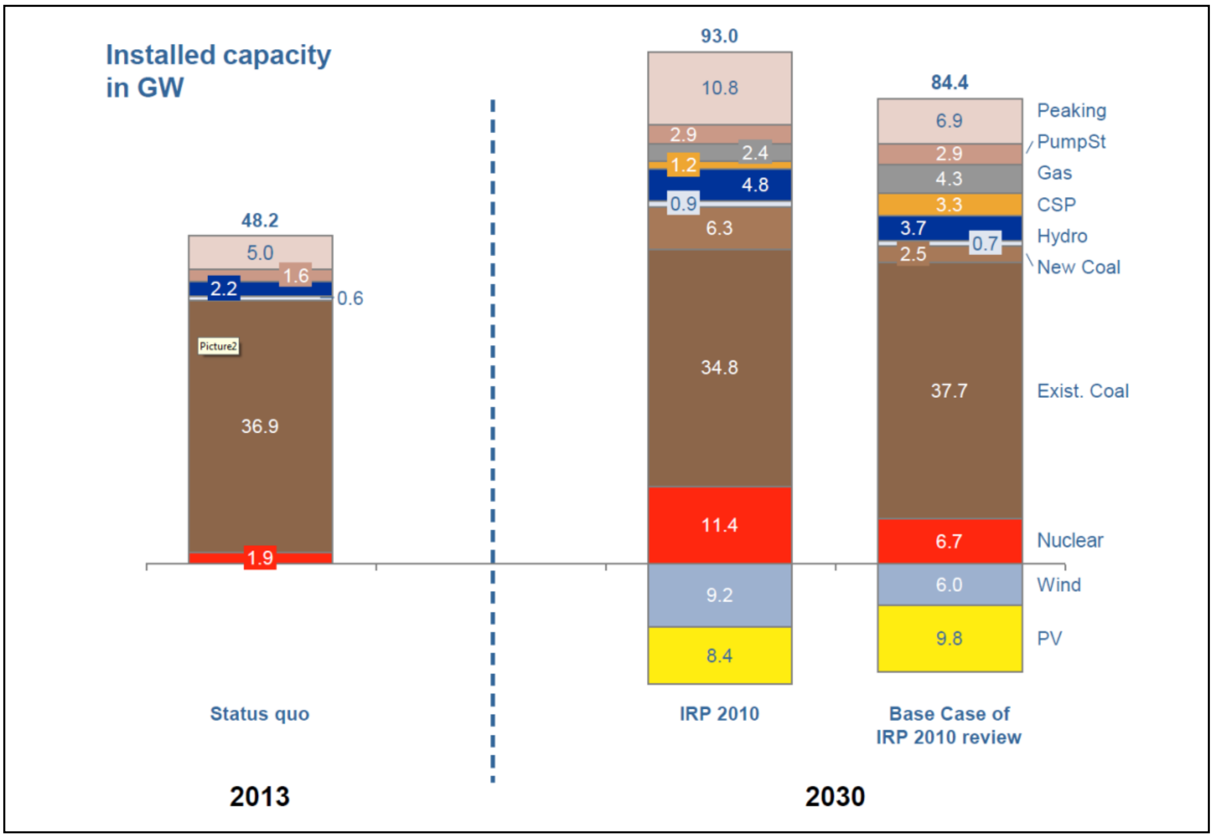


FIGURE 15: THE GENERATION MIX FOR THE BASE SCENARIO OF 84 GW OF CAPACITY BY 2030 STIPULATED IN THE INTEGRATED RESOURCE PLAN. (SOUTH AFRICA. DEPARTMENT OF ENERGY,2013)

(Fluri, 2009) has indicated that the Northern Cape, where the three plants are under construction, offers the highest capacity of utility scale CSP generation with a total capacity on the order of 500 GW available for electricity generation. For a scenario with high nuclear costs, the revised IRP projects a maximum of close to 40 GW of CSP capacity by 2045.

The two CSP categories that are represented in the model are:

1) Central Receivers, and
2) Parabolic Trough.

The model is allowed to optimise with a choice of wet or dry cooled design, and by storage capacity. Storage capacity of 3 and 9 hours is included for both Central Receiver and Parabolic Trough plants with no storage as an additional option for Parabolic Trough plants only.

With regard to CSP plants commissioned in the Northern Cape, Abengoa reports that natural draft dry-cooling systems are employed (Adarve,2014). As such, the main water consumption activity is that for mirror washing with secondary treatment for boiler makeup fluid minor component.

Boiler feed water requirements are estimated at 20% of the total raw water requirements which is taken from Figure 16 that estimates the water consumption for the 125 MW parabolic trough plant in Upington. The boiler feed water requirement is similar to that quoted by Eskom for the direct dry-cooled plant Matimba for which the value is 16.7%. Therefore a similar estimate is applied for the boiler feed water requirements for CSP central receivers.

Figure 16 includes a description of the water treatment and management for the plant as well. It is presumed that the remaining 75,000 m^3 of water is allocated for auxiliary use.

Description	Approximate annual use (m^3/year)
Raw water consumption	300,000
Mirror washing	80,000
Boiler makeup	60,000
Evaporation ponds discard stream	85,000

» Makeup water for the steam generator
» Water for mirror washing
» Service water
» Potable water
» Fire protection water

In order to reduce the overall water consumption and the requisite sizing of the evaporation ponds, service water will first be used as makeup. Water conditioning chemicals may be fed into the makeup water to minimise corrosion and to inhibit mineral scale formation. The blow down from the circulating water will be continually treated by lime-softening clarification and filtration processes and then delivered to a clear well where the water will be treated by reverse osmosis prior to being used for other plant requirements. Prior to the reverse osmosis process, ion-exchange softeners will be used to remove any dissolved hardness minerals that remain after the clarifier. The discard brine stream will be delivered to the evaporation ponds.

FIGURE 16: THE ESTIMATED WATER CONSUMPTION FOR A 125 MW DIRECT DRY-COOLED PLANT IN UPINGTON. (SAVANNAH ENVIRONMENTAL,2013)

Poullikkas et al. (2013) investigated the performance and costs of CSP generation utilising different cooling designs for plants located in the USA and Spain. Table 8, Table 9 and Table 10 lists the indicative performance and cost parameters they estimate.

TABLE 8: WATER CONSUMPTION BY CSP TECHNOLOGY. (POULLIKKAS,2013)

Technology	Water consumption (lt/MWh)		
	Direct dry cooling ACC system	Circulating evaporative WCC system	Hybrid ACC/ WCC system
CSP parabolic trough plant	303	3,030	378-1,703
CSP solar tower plant	340	1,890-2,840	340- 945
CSP Fresnel plant	n/a	3,785	n/a

TABLE 9: THE RELATIVE EFFICIENCY OF CSP TECHNOLOGIES BY COOLING DESIGN COMPARED TO WET-COOLED CLOSED-CYCLE PLANTS. (POULLIKKAS ET AL., 2013)

Technology	Efficiency reduction (%)		
	Direct dry cooling ACC system	Circulating evaporative WCC system	Hybrid ACC/ WCC system
CSP parabolic trough plant	4.5-5	Base case	1-4
CSP solar tower plant	1-3	Base case	1-3
CSP Fresnel plant	n/a	Base case	n/a

TABLE 10: THE RELATIVE CAPITAL OF CSP TECHNOLOGIES BY COOLING DESIGN COMPARED TO WET-COOLED CLOSED-CYCLE PLANTS. (POULLIKKAS ET AL., 2013)

Technology	Capital cost increase (%)		
	Direct dry cooling ACC system	Circulating evaporative WCC system	Hybrid ACC/ WCC system
CSP parabolic trough plant	4-5	Base case*	2-3
CSP solar tower plant	4-5	Base case*	2-3
CSP Fresnel plant	n/a	Base case*	n/a

*Capital costs for WCC system include cooling equipment, boiler feed water pumps, and HTF pumps

The water consumption estimates for the dry-cooled designs compare favourably with those reported by EPRI for Eskom in Appendix C, so the EPRI values are used instead. The change in capital cost and efficiency are based on the average values given in Table 9 and Table 10. Since dry-cooled CSP plants are the default case, the EPRI estimates are adjusted to reflect wet-cooled plant costs.

At present hybrid-cooled design are not included in the modelling to facilitate a comparison of the impact of the cost of water consumption for the two extremes of water consumption design.

8.3.2 Gas generation

The cost and water consumption for gas generation is taken from the data in Appendix C. Referring to

Figure 7, all indigenous gas generation that utilises the water supply systems identified in Task 1 is assumed to operate under similar climatic conditions. This climatic zone encompasses the region where shale gas extraction is presumed to occur and where the majority of the existing coal power plants are located (i.e. Central Basin). Coastal located plants are excluded with respect to water requirements as they are presumed to utilise seawater. In any regard, since water consumption for this generation category is low compared to dry-cooled coal power plants, no further adjustment is made to the data.

The two plants categories that are represented in the model are:

1) Open-Cycle Gas Turbine (OCGT), and
2) Combined-Cycle Gas Turbine (CCGT).

Existing OCGT plants are operated with diesel fuel but the SATIM includes gas-fired plants as a competing technology. There are no existing CCGT plants in South Africa at present.

8.3.3 Domestic Hydropower

To be completed.

Domestic hydropower represents a minor component to the generation portfolio and this remains the case for future generation options (Energy Research Centre,2013).

9 Flue Gas Desulphurisation

To date, no South African coal power plant has Flue Gas Desulphurisation (FGD) technology installed. Power plant emissions controls have instead focussed 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 such as sulphur dioxide (SO_2). The legislative amendments relevant to coal thermal power plants are summarised in Table 11.

TABLE 11: AIR EMISSION STANDARDS APPLICABLE TO ELECTRICITY GENERATION IN SOUTH AFRICA.

(SOUTH AFRICA. DEPARTMENT OF ENVIRONMENTAL AFFAIRS,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}Kelvin 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 are expected to comply with the new regulations by the year 2015 and meet the emission standard for new plants by 2020. Eskom has however sought to postpone the application of the standard to the majority of its coal fleet (South Africa,2014). SATIM-W therefore includes the fitment of FGD technology to thermal power plants to evaluate the competiveness of air emissions compliance of coal power plants with regard to their relative water use. The FGD option is applicable to new and existing large coal plants.

The removal of SO_2 can be accomplished through two categories of FGD process routes. These are:

1) Wet Process, and
2) Dry/Semi-dry Process

The wet and dry FGD routes are further subdivided by technology type as illustrated in Figure 17.

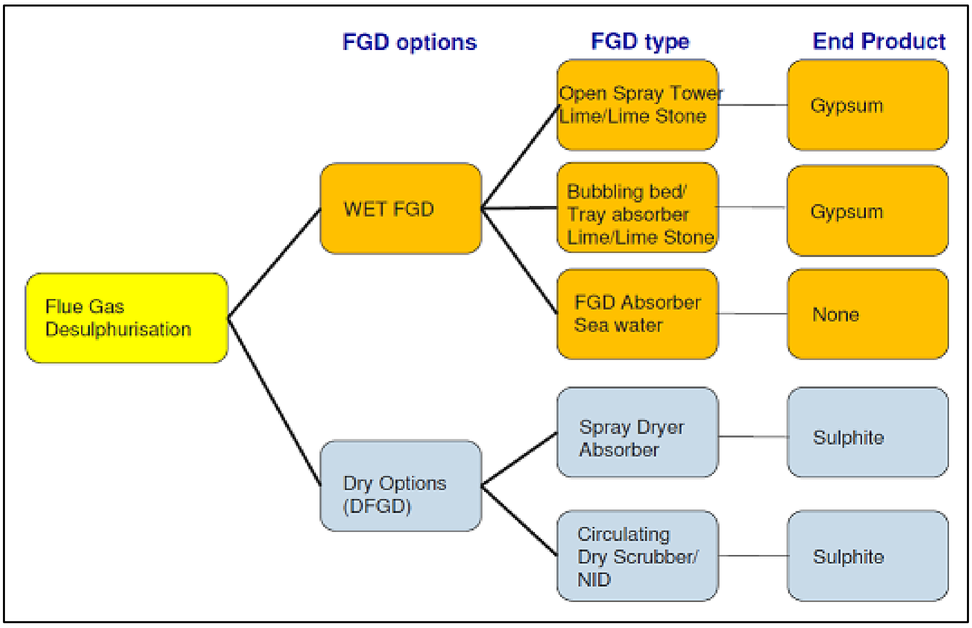


FIGURE 17: FGD PROCESS ROUTES AND TECHNOLOGIES. (JOHANSSON,2012)

Water is the chief promoter of the chemical reaction to precipitate SO_2 from the flue gas and the main difference between dry and wet FGD systems is essentially the composition of the reagent utilised which determines the delivery mechanism and reaction environment. Dry systems use hydrous lime or calcium hydroxide, $Ca(OH)_2$, which is created from the exothermic reaction of calcium oxide, Ca0, with water. The sorbent is then delivered to the flue gas reaction chamber to precipitate SO_2 as Calcium Sulphite which requires disposal as solid waste. The process is depicted in Figure 18.

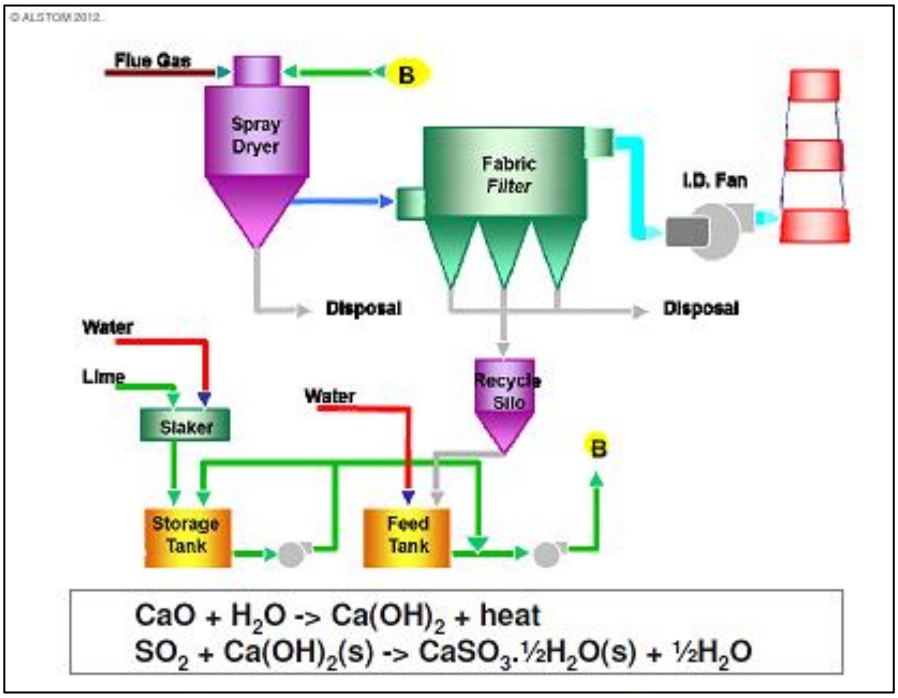


FIGURE 18: SCHEMATIC OF A DRY FGD SYSTEM. (JOHANSSON,2012)

In contrast the wet-limestone process delivers a water-based calcium carbonate, $CaCO_3$, or limestone slurry to the reaction chamber to precipitate SO_2 as calcium sulphate, $CaSO_4{\bullet}2H_2O$, or gypsum and CO_2 as by-products. The gypsum obtained is saleable as a construction commodity. The process is depicted in Figure 19.

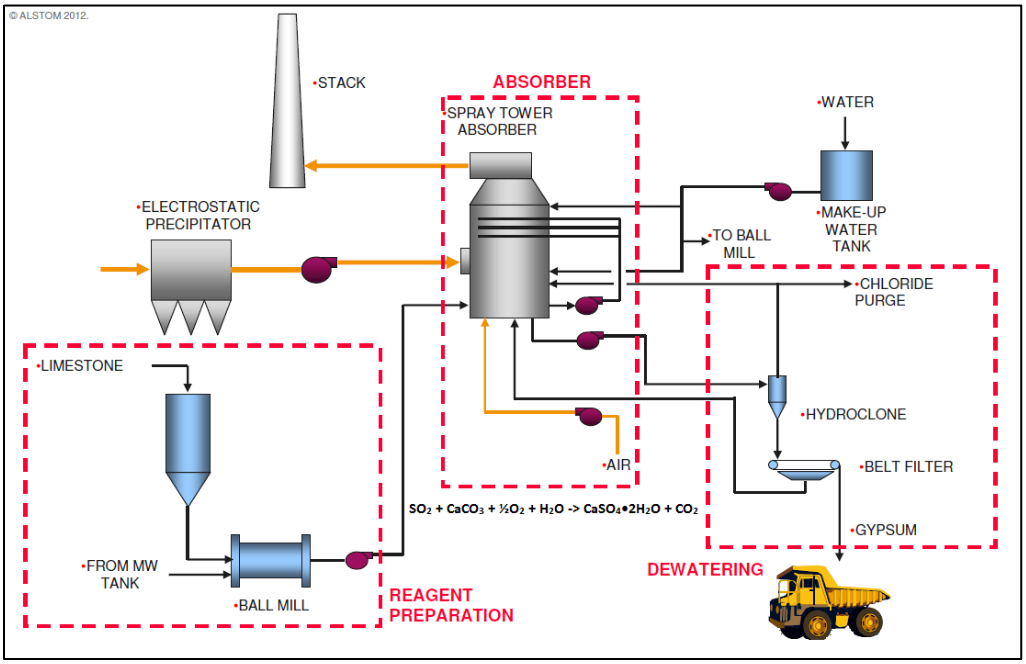


FIGURE 19: SCHEMATIC OF A WET FGD SYSTEM. (JOHANSSON,2012)

A variant of the wet FGD process uses seawater as the reagent which relies on the alkalinity of seawater to absorb the SO_2. No by-product results from the process and the chemical composition of the discharged seawater is relatively unaltered as indicated in Table 12. The process of FGD with sea water is illustrated in Figure 20.

TABLE 12: FGD SEAWATER DISCHARGE QUALITY. (ALSTOM,2013)

	UNIT	INLET SEAWATER	DISCHARGE
WATER QUALITY MEETS REQUIREMENTS			
pH		7 – 8	6 ~ 7
Sulfate	mg/l	2,700	2,785
Temperature	°C	T	T + 1.5 ~ 2
Salinity	‰	33.5	33.5
Suspended solids	mg/l	SS	<(SS + 1.0)
OXYGEN BALANCE CONTROLLED			
COD	MgO_2/l	0	<2.5 – 5.0
DO	%	50 – 100	70 – 90

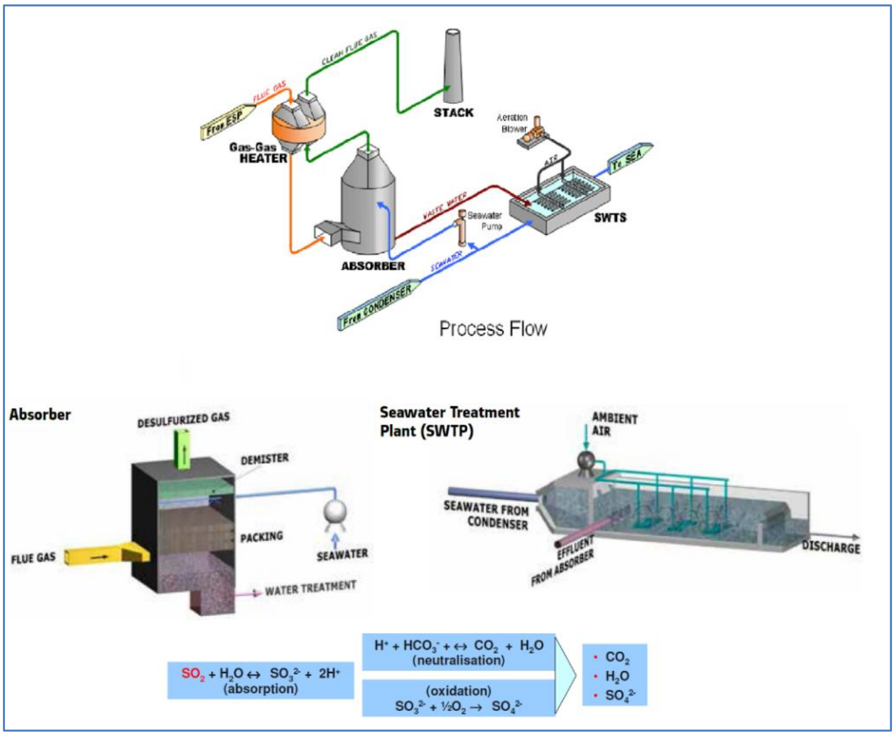


FIGURE 20: FGD BY SEAWATER REACTION. (ALSTOM, 2013)

The comparative performance of the three types of FGD introduced is summarised in Table 13.

TABLE 13: COMPARATIVE COST AND PERFORMANCE OF FGD OPTIONS. (JOHANSSON,2012)

© ALSTOM 2012

	Dry FGD	Seawater FGD	Limestone WFGD
Absorber	NID or SDA	Packed Tower	Spray Tower
First Installation	1980	1968	1968
Features	• Low investment cost • Dry by-product • Small footprint • Multi-pollutant control	• No reagent • No by-product	• High efficiency spray zone • Low cost reagent • By-product flexibility
Reagent	Lime	Seawater	Limestone
By-product	Landfill	Seawater	Marketable gypsum or landfill
Sulfur	<4.5 % (NID)	<1.5 %	<6 %
Removal Efficiency	-98 % (NID)	-98 %	-99 %
Capital Cost	0.7X	0.8X	X
Power Consumption (inc. booster fans)	0.7 %	0.7-1.5 %	1.0-2.0 %
Aborbent Cost	€80/ton	€0/ton	€20/ton
By-product Cost	€5-10/ton	€0/ton	€5-10/ton – disposal (€5/ton) – sale

Dry FGD systems have lower capital costs but incur higher maintenance costs because of the more expensive reagent and necessary waste disposal. Singleton (2010) identifies Eskom's preference for wet FGD systems which represents about 80% of the market because of the lower lifecycle costs.

The analysis in SATIM-W is therefore restricted to the wet FGD process for all coal power plants. The exception applies to the coastal build case for which the seawater FGD option is chosen. The EPRI data for the IRP suggests that the wet FGD option imposes a water consumption penalty of 0.2 l/kWh and a net efficiency penalty of 0.4% which is lower than the indicative value given in Table 13. In addition the FGD option increases the capital cost by R4053/kW (2012). Table 14 provides approximate costs for the FGD option.

TABLE 14: ESTIMATED COST DIFFERENTIAL FOR A NEW PF COAL PLANT (6X750 MW) IN SOUTH AFRICA WITH WET (LIMESTONE) FGD. (EPRI,2012)

	Price change	USD equivalent (2012)
Total Overnight Cost (ZAR/kW)	4053	495
Fixed O&M (ZAR/kW-yr)	185	23
Variable O&M (ZAR/MWh)	13	1.6

The cost schedule estimated by Black & Veatch for 600 MW plant is given in Table 15, which includes the replacement of the existing stack to accommodate the FGD system. The retrofit cost estimates for the USA are cheaper than that for the South African new build case.

TABLE 15: COST SCHEDULE FOR A POWER PLANT (606 MW) WITH WET FGD RETROFIT TECHNOLOGY. (BLACK & VEATCH,2012)

Year	Retrofit Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)
2008	371	–	–	–
2010	360	3.71	23.2	36
2015	360	3.71	23.2	36
2020	360	3.71	23.2	36
2025	360	3.71	23.2	36
2030	360	3.71	23.2	36
2035	360	3.71	23.2	36
2040	360	3.71	23.2	36
2045	360	3.71	23.2	36
2050	360	3.71	23.2	36

The local price differential is therefore preferred for retrofit costing as well. However due to design restrictions when considering retrofits in contrast to an optimised integrated design for new plants a conservative retrofit difficulty factor of 1.1 is applied to the South African data and used for implementing retrofits to the existing stock in SATIM-W.

For the seawater FGD option, capital costs are adjusted as indicated in Table 13 with a nominal fixed OM cost of 3% the capital cost. This figure is representative of the estimates for the fixed OM of wet-cooling systems (Bailey 2010). No additional water consumption is attributed to the seawater FGD option.

Of importance is the dependency of the OM costs to the sulphur content of the coal as this determines the rate of sorbent material use. A national average value of 1% is assumed (Prévost,2014).

The IRP update (2013) states that:

'beyond the return to service stations the coal-fired power stations are all expected to be decommissioned at the end of 50 year plant life. The ***IRP2010 Update however considered refurbishment options for the life of these power stations to be extended by another ten years****, providing a mechanism to defer new capital expenditure and contain electricity price increases'.*

The IRP also notes that the cost of FGD retrofit to the older existing and less efficient fleet provides additional motivation for the life extension beyond their planned decommissioning without the FGD option. Therefore existing large plants that undergo FGD retrofits in SATIM-W have their decommissioned schedule deferred by ten years.

10 Coal Mining

The known coal deposits for the country are shown in Figure 21. The two main coal mining regions are distinguished by the deposits occurring in the Waterberg and those of the Central Basin represented by the cluster from Springs-Witbank to Klipriver and Vryheid.

FIGURE 21: COAL FIELDS AND COLLIERIES OF SOUTH AFRICA. (STEYN,2009)

The estimated reserves, listed in Table 16 identifies the Central Basin as the primary coal supply hub containing 69% of the country's coal stock with the Waterberg accounting for a fifth. The deposits are mainly bituminous thermal coal.

TABLE 16: ESTIMATED COAL RESERVES BY COAL FIELD.(PRÉVOST,2014)

COALFIELDS	RESERVES 2013 (Mt)	%
HIGHVELD	9 271.4	28.8
WITBANK	7 965.3	24.8
WATERBERG	6 635.5	20.6
ERMELO	4 356.3	13.5
VRG.-SASOLBURG	1 647.0	5.1
SOUTH RAND	715.5	2.2
UTRECHT	539.7	1.7
KLIPRIVIER	521.3	1.6
SOUTPANSBERG	256.5	0.8
KANGWANE	145.6	0.5
VRYHEID	98.3	0.3
NONGOMA	3.7	0.01
TOTAL	32 156.1	100

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 22. 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.

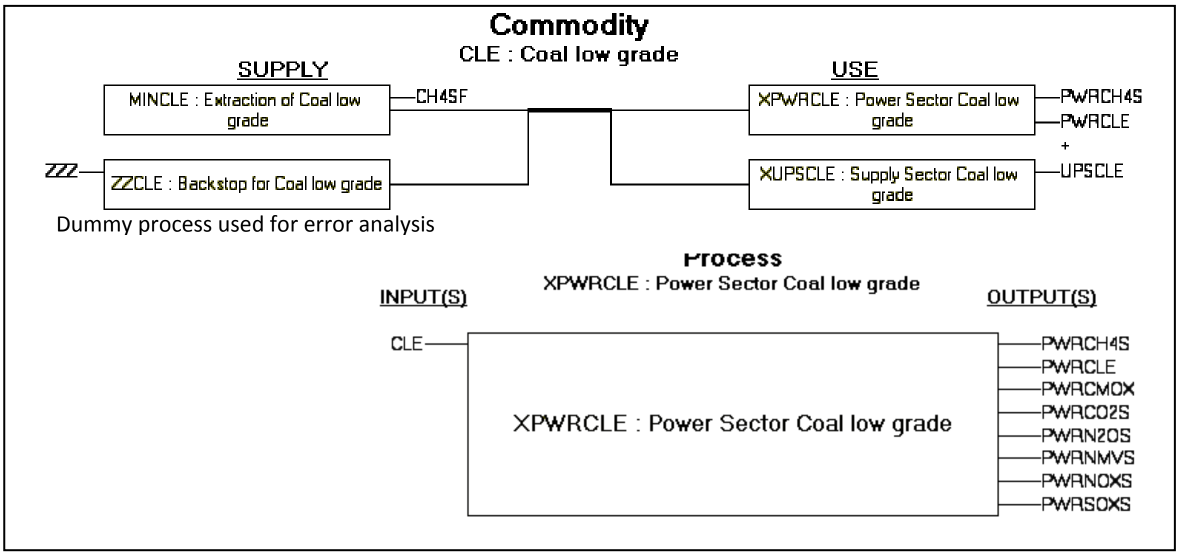


FIGURE 22: COAL SUPPLY TO THE POWER SECTOR AS IMPLEMENTED IN SATIM.

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.

Table 17 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 20 MJ/kg is obtained by weighting plant capacity and efficiency.

TABLE 17: ESTIMATED CALORIC VALUES FOR COAL POWER PLANTS. (THE GREEN HOUSE,2013)

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

The South African Coal Road Map (SACRM) examined possible future scenarios for coal supply until the year 2040 (The Green House,2013). In its scenario analysis, the report includes the supply of Waterberg coal to the Central Basin in the event of a shortfall of coal stock in the region. This scenario accounts for a business as usual coal-oriented electricity supply system with no carbon restrictions. The IRP states that such a scenario would naturally entail higher coal prices in the Mpumalanga region mainly due to the additional distribution costs incurred. The SACRM study estimated that a constrained supply system could emerge from the year 2025 onwards due to a combination of increased exports and reduced reserves. The extent of the rail distribution system is shown in Figure 23. The figure displays the main link from the Mpumalanga region to the Richards Bay Terminal (RBT) and the line from the Waterberg to both destinations. Included are the estimated capital costs for the expansion of the system.

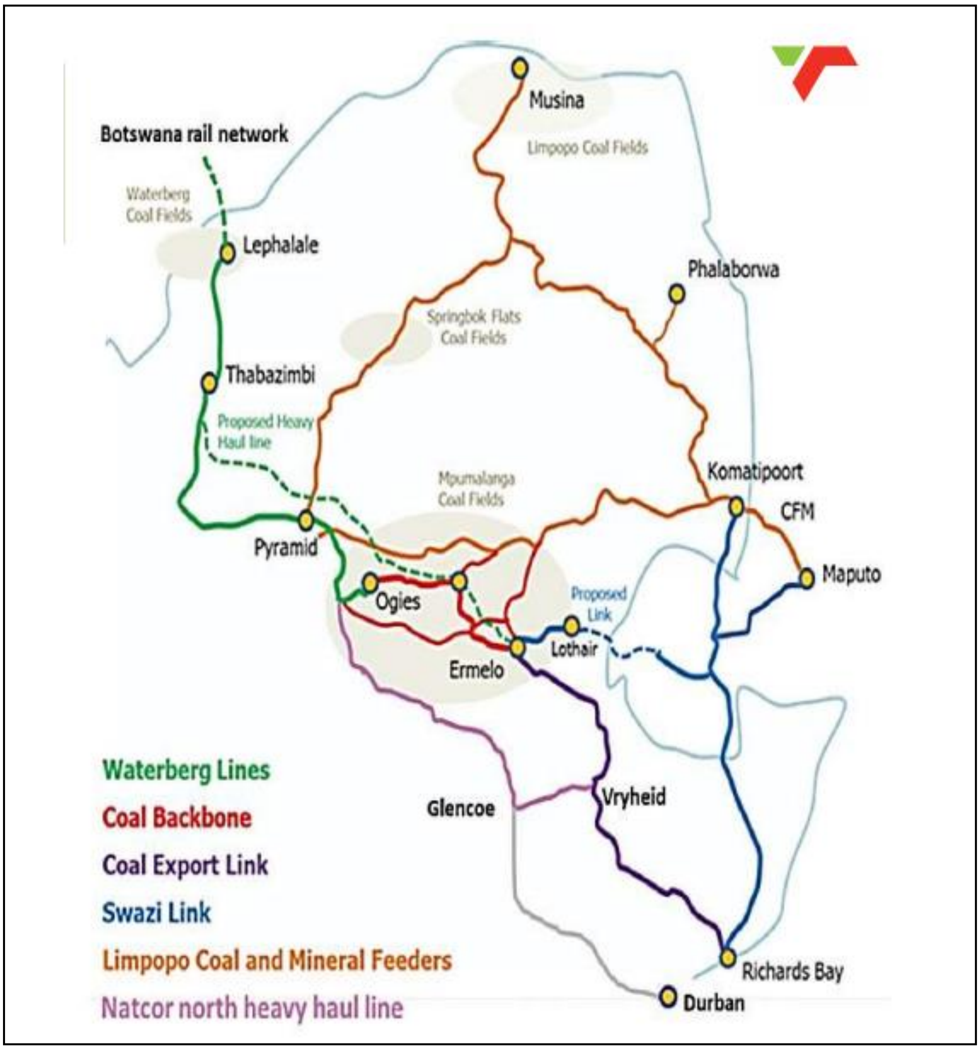


FIGURE 23: THE PRIMARY COAL RAIL DISTRIBUTION NETWORK IN SOUTH AFRICA. (TRANSNET,2013)

To implement SATIM-W, coal mining is regionalised according to each relevant water supply region and a distribution network included facilitating the scenarios discussed. That is the supply of coal from:

1) the Waterberg (Region A) to Mpumalanga (Regions B and C), and
2) Mpumalanga to the coastal region in the vicinity of the Richard's Bay Terminal (Region R).

A schematic of the implementation required in SATIM-W is shown in Figure 28. The figure also shows the water treatment option that is discussed in section 10.1.

In reality the extent of coal reserves are uncertain. At present there is no limit on coal extraction in SATIM. To consider strained local supplies an exogenous cap is required and would require an initial unconstrained supply model run to estimate a limit in the vicinity of the year 2030. The imposed limit would apply to the annual consumption of coal for energy supply and be modelled as a scenario.

Regional distribution costs are taken from the SACRM (2013) study as shown in Table 18. 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 18: RAIL DISTRIBUTION COSTS FOR THE SUPPLY OF COAL. (THE GREEN HOUSE,2013)

Destination	Transport cost (Rands/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)

10.1 Water demand and management

The generic water balance for coal mines in South Africa provides the main source of information for the use and disposal of water for coal mining (Pulles, Boer & Nel, 2001). The main uses are for domestic (potable) needs and coal washing (beneficiation). The volumes of water purchased vary by mine as some mines have excess volumes due to dewatering activities (e.g. the extraction of groundwater). The analysis for the SACRM limited the volumes to that purchased externally and a similar approach is adopted. Purchased volumes account for about 45% of the mines total water requirements. Only purchased volumes which vary regionally, as noted in Table 19, are used to calculate the washing factor as this represents the cost of water to coal mines. The calculated coal washing water intensity would therefore be lower than is actually observed.

TABLE 19: ESTIMATED VOLUME OF WATER PURCHASED BY COLLIERIES. (THE GREEN HOUSE,2013)

Mine type	Value applied
Central Basin underground (mine only)	25
Central Basin opencast (mine only)	50
Central Basin combined or unknown	40
Central Basin wash plant only	85
Waterberg mine and wash plant	65

Values quoted for Ml/Mt of processed coal.

From the above table the Waterberg value is applied for region A, while the Central Basin mean value of 50 ML/Mt is used for regions B and C. It is also assumed that collieries are able to utilise purchased raw water with no further treatment.

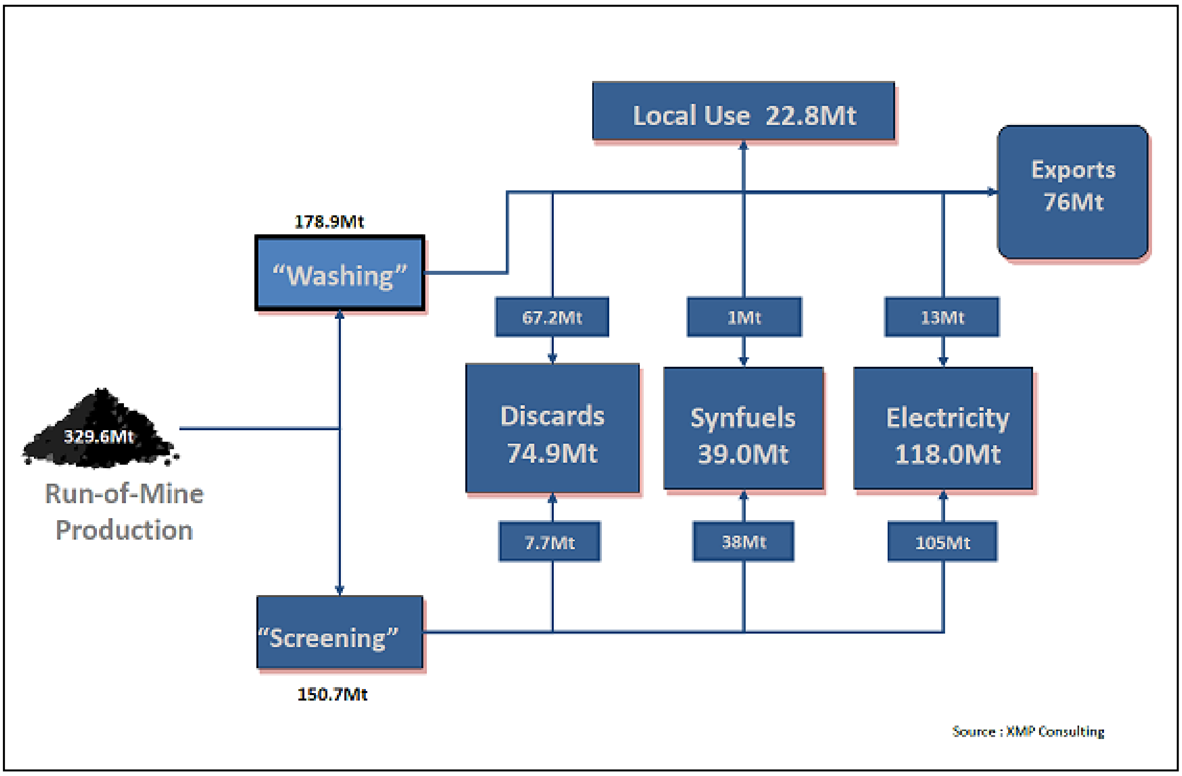


FIGURE 24: THE DISTRIBUTION OF WASHED AND SCREENED RAW COAL FOR SOUTH AFRICA. (PRÉVOST,2014)

According to Pulles et al. (2001) about 25% of water used for washing is discharged as effluent. In addition, as some mines have excess water, dewatering and management of decant is necessary to mitigate the impact of Acid Mine Drainage (AMD) seepage into groundwater bodies and spillage into the surface water system. An example is illustrated in Figure 25 which details water levels for an opencast coal mine in the Upper Olifants area during and after mining activity has ceased. An increase in the water level is noted as dewatering operations stop increasing the risk of AMD contamination of the environment.

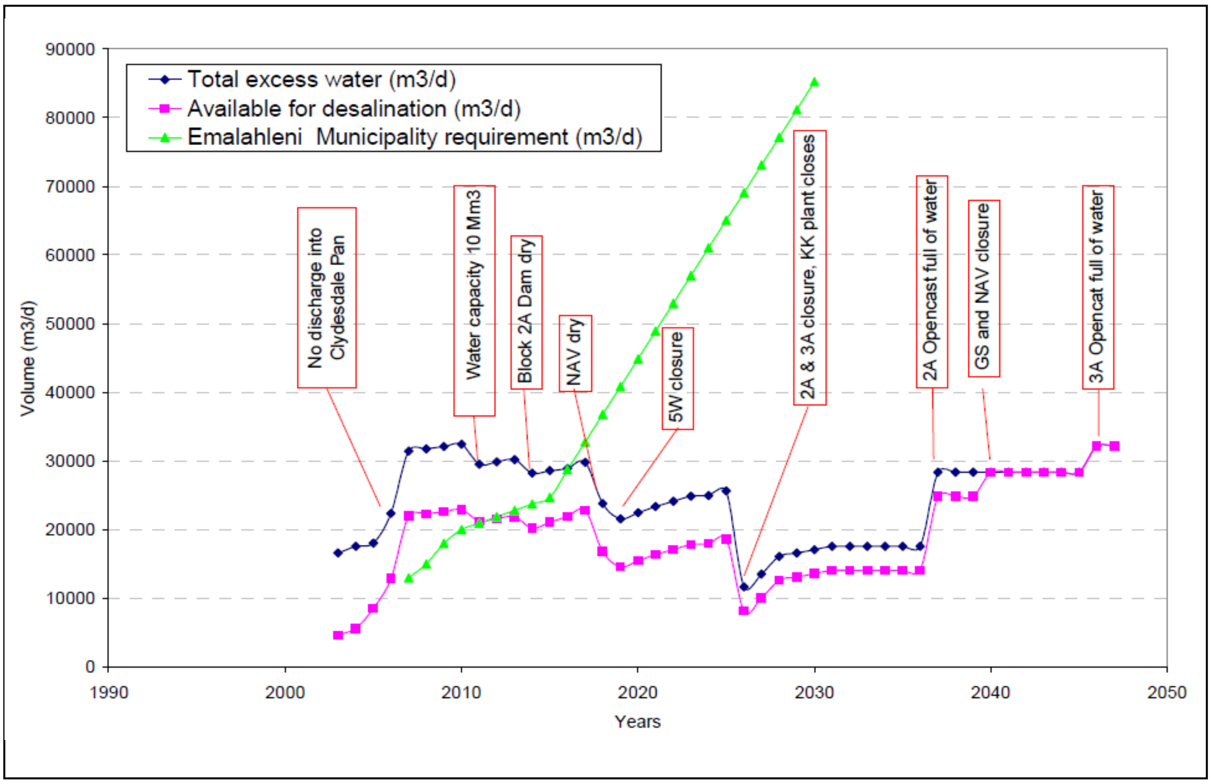


FIGURE 25: HISTORICAL AND PROJECTED DECANT FOR AN OPEN CAST COLLIERY IN THE OLIFANTS WMA. (GUNTHER & MEY, 2008)

Dewatering solutions are reactive requiring constant monitoring of water levels and pumping. Pumping requirements are likely to increase with time as water levels accumulate, increasing the demand for electricity and the susceptibility to AMD spillage without active management and adequate pump-station maintenance.

AMD treatment: a case study of the eMalahleni Water Reclamation Plant (WRP)

The example depicted in figure x explored the option of treating mine water for potable water supply to the nearby eMalahleni Municipality from four nearby mines. The eMalahleni WRP located in the Olifants WMA has been operational since 2007 and produces 25 ML/day at an investment cost of about R600 million. A It is planned to expand the capacity of the WRP to 50 ML/day for a total investment of R1.4 billion. The increased capacity allows the plant to accept mine water from additional mines including the defunct Middelburg Steam and Station mines (Golder Associates,2010).

The core treatment comprises Neutralisation and Clarification followed by Ultra-filtration and Reverse Osmosis as shown in Figure 26. A by-product of the process solid waste is Gypsum.

The energy consumption of the process is reported as 2.5 kWh/l of product with a typical feed water TDS concentration of 5000 mg/L.

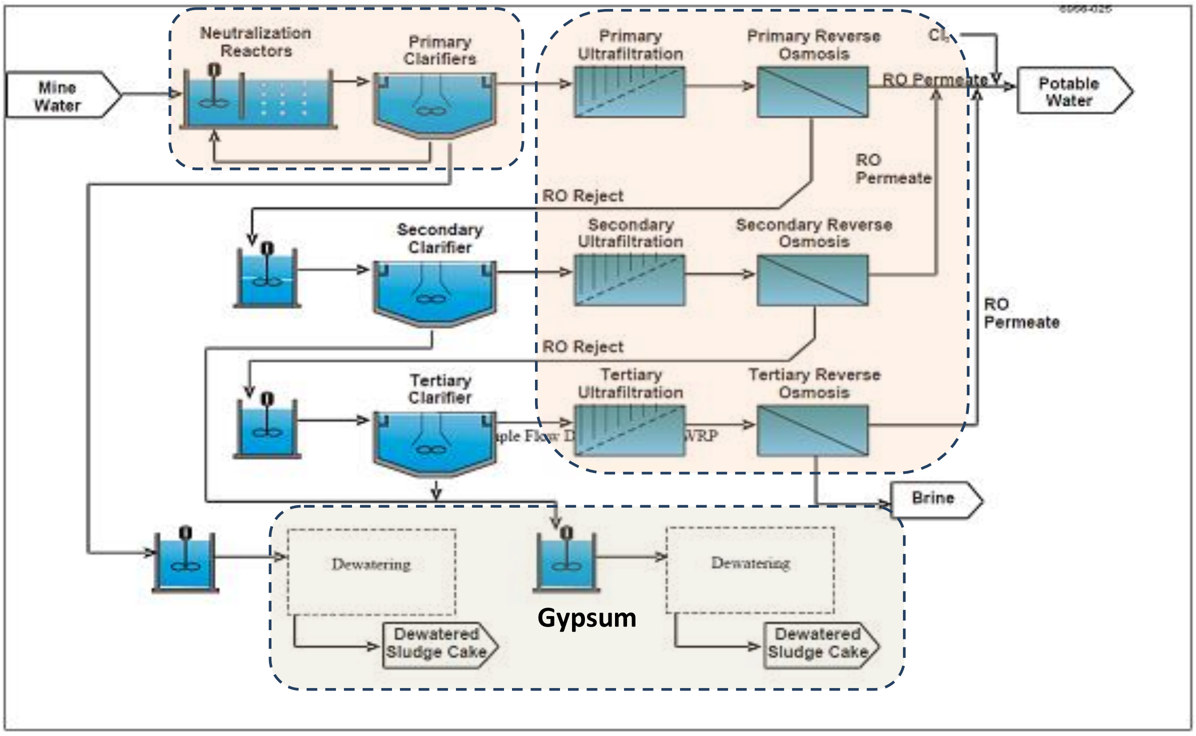


FIGURE 26: THE PROCESS FLOW FOR THE EMALAHLINI WATER RECLAMATION PLANT. (HUTTON ET AL.,2009)

(McCarthy,2011) states that AMD is largely prevalent in the Olifants WMA (Region B) where water quality has deteriorated to the extent that Eskom utilises inter-basin transfers instead. He further notes that mining in the Vaal catchment (Region C) is at present less prone to AMD due to deeper mining activity and active water management.

Figure 27 highlights the concentration of AMD due to coal mining in the Olifants river catchment. The Department of Water Affairs has issued guidelines for mining industries that transfers responsibility for the remediation of waste waters to the mine on the basis of a 'Polluter Pays' principle.

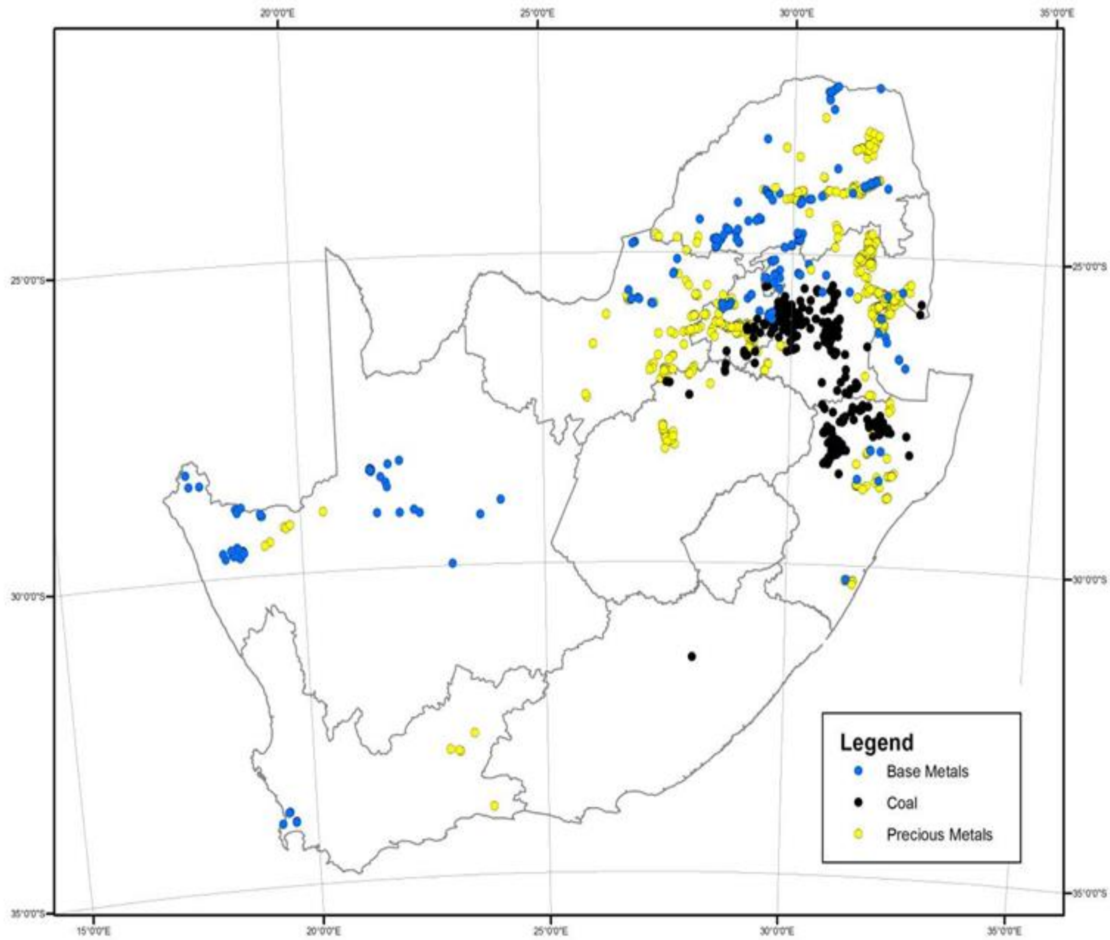


FIGURE 27: POTENTIAL SOURCES OF ACID MINE DRAINAGE IN SOUTH AFRICA FROM MINING ACTIVITY. (SOUTH AFRICA. DEPARTMENT OF WATER AFFAIRS,2010A)

To address the issue the Lebalelo Water User Association initiated a study assessing the feasibility of processing mine water in the Olifants WMA. The Olifants River Project 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 20. The costs are indicative of the treatment required for 146.5 ML/day (53 Mm^3/a).

TABLE 20: 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/m³)	Capex (R million)	Opex (R/year)	Opex R/m³)	Charge (R/year)	Charge (R/m³)
New Largo WRP	6.0	R151 600 000.00	R27 747 300.00	12.7	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 20 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 21.

TABLE 21: COSTS FOR COAL MINE WATER TREATMENT IN SATIM-W.

Investment cost R(x1000)/Mm3	Fixed OM R(x1000)/year	Variable OM
60 842	9 742	3 kWh/m³

As previously noted, mine decant volumes do not necessarily correlate with the volumes of water required for coal washing. Although it may include coal washing slurry, it remains a problem after mining activity has ceased. To attribute the cost of mine water to mining activity, the volume of AMD treated over the production life of a region is estimated. To estimate the volume of AMD treated per tonne of coal mined, the production of a region is averaged over a one hundred year life based on the regional reserves stated in Table 16.

In order implement the above approach the effluent volumes treated per unit of mined coal is estimated. A first order estimate is arrived at by factoring the annual treatment of effluent volumes of 53 Mm^3/annum (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 20 year treatment plant life, using a discount rate of 8%, the cost amounts to about R5.4/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 & 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.

McGeorge (2014) estimates an escalation of coal mine decommissioning costs from R4 billion to R20 - R25 billion if AMD remediation is included. He quotes a value of R80/t of coal mine for complete environmental compliance. The previous value of 5.4 R/t refers only to the remediation cost of mine water while the R80/t figure is for the entire disposal of the mine and should be encapsulated in the mining investment cost rather. For consistency this would need to apply to mining activities such as shale gas and uranium extraction. This requires further investigation and the same water pollution value is being used in the interim.

10.2 Coal mining sub-model REWS diagram

The REWS diagram for the implementation of coal mining in SATIM-W as proposed above is introduced in Figure 28.

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.

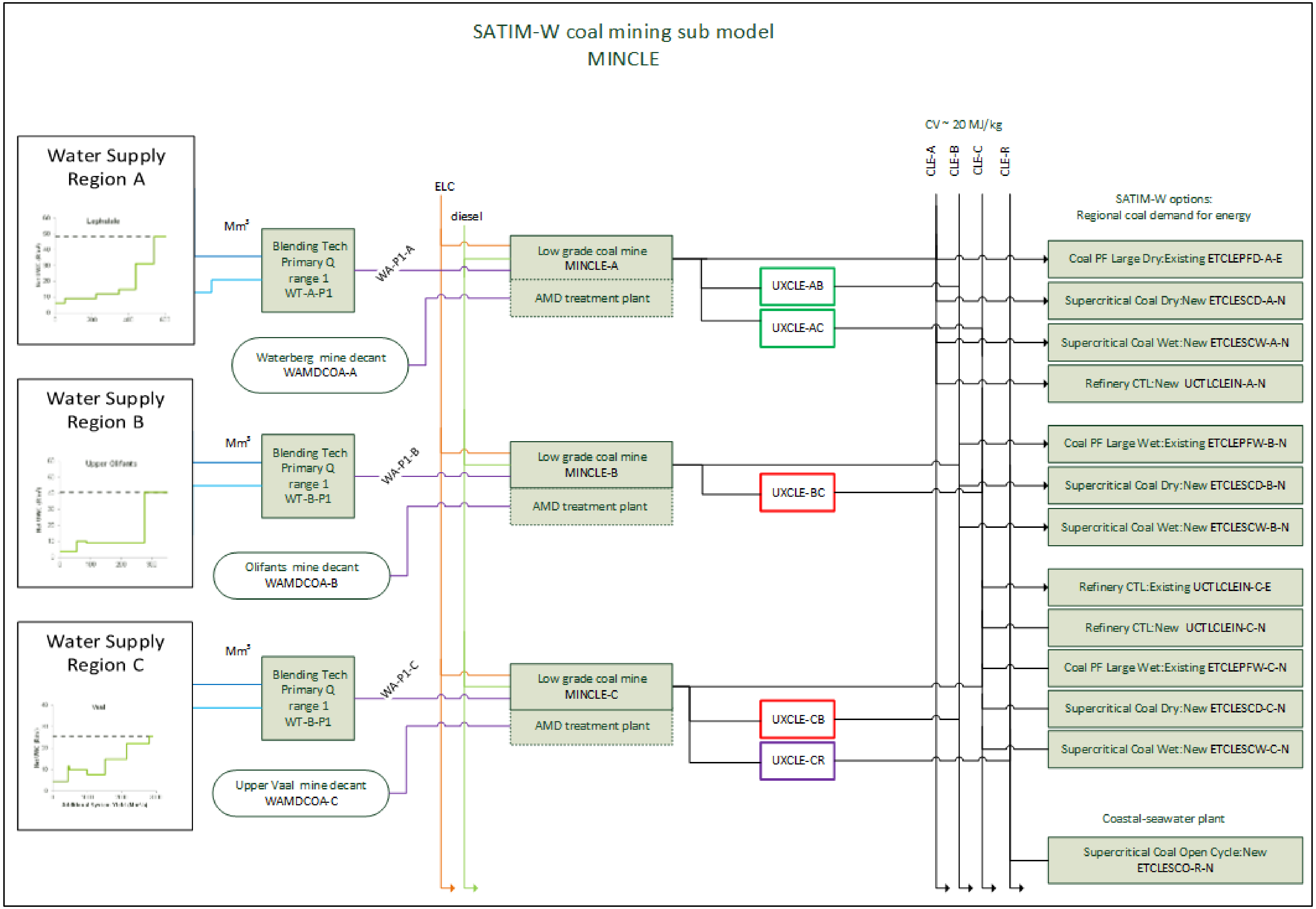


FIGURE 28: THE IMPLEMENTATION OF COAL MINING (MINCLE) LINKED TO REGIONAL WATER SUPPLY SYSTEMS IN SATIM-W.

11 Shale Gas Mining

In 1965 the South African government agency Soekor undertook exploratory drilling to assess the country's onshore oil and gas resources. Exploration of the 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). The extent of recoverable shale gas reserves in the country's Karoo region was previously estimated at 485 Tcf, but has since been revised to 30 Tcf (South African Oil & Gas Alliance,2014). Therefore this study limits shale gas extraction to 30 Tcf.

The Power sector has been identified as a potential strategic consumer of shale gas should mining proceed. With regard to existing and future generation technologies in SATIM-W, OCGT and CCGT plants can utilise gas. SATIM-W distinguishes several gas commodities. For example the model includes the inland import of regional gas from Mozambique and coastal imported LNG. This analysis focuses rather on the potential exploitation of indigenous shale gas in the energy sector in the context of a possible water-energy trade-off. The revised IRP suggests up to 70 GW of gas based capacity by 2050 could be possible in its 'Big Gas' scenario. This projection includes conventional gas from Mozambique and imported LNG.

The SATIM-W implementation of shale gas is based on the recent (yet to be published) Energy Research Centre (ERC) study of gas utilisation in South Africa. The sub-model Power Sector RES diagram for shale gas mining (MINGIH) is displayed below in Figure 29, while Figure 30 depicts shale gas distribution with the other gas commodities in the model. The RES diagrams depict 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 30 also displays the distribution of gas to non-energy sectors as the national gas utilisation study assessed the full sector potential for gas demand and supply. In Phase 1, the SATIM-W implementation restricts shale gas utilisation to the Power Sector.

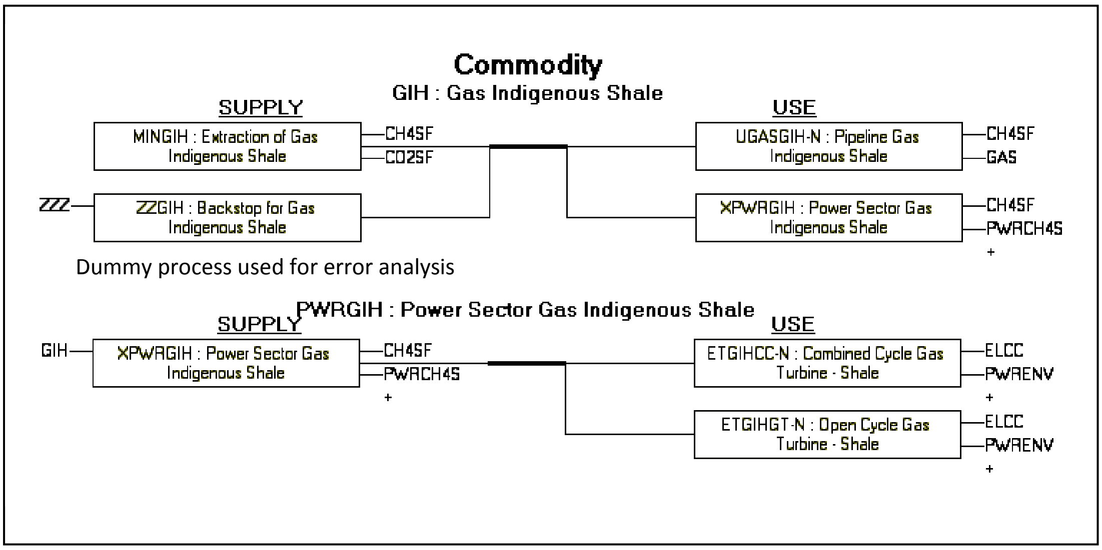


FIGURE 29: SHALE GAS EXTRACTION AND COLLOCATED GENERATION IN SATIM.

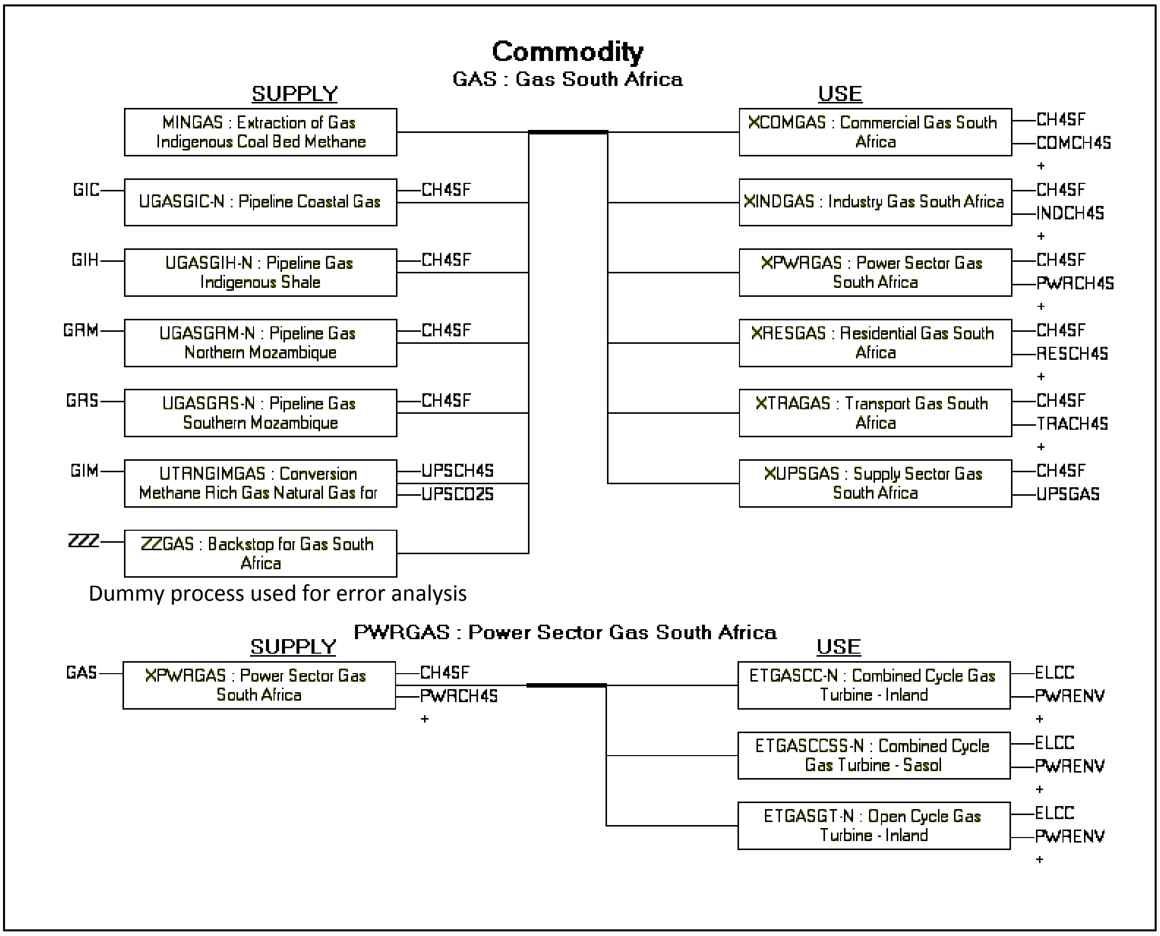


FIGURE 30: SHALE GAS EXTRACTION INLAND GENERATION BY THE POWER SECTOR IN SATIM.

11.1 Water and shale gas extraction

Figure 31 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.

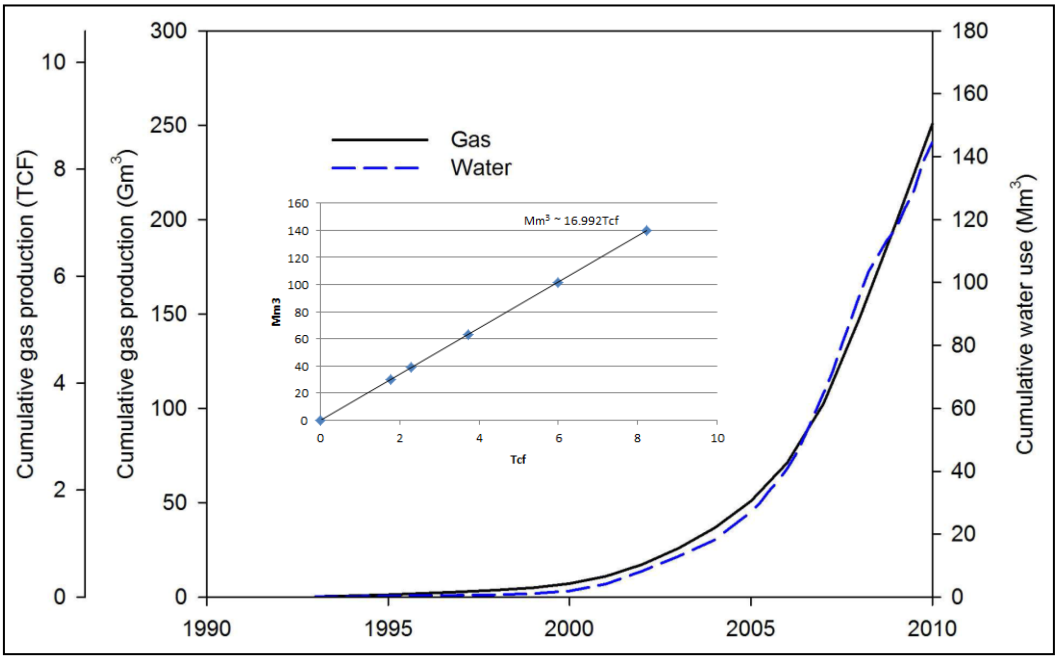


FIGURE 31: CUMULATIVE GAS PRODUCTION AND WATER USE FOR THE BARNETT SHALE FORMATION, TEXAS, USA. (NICOT & SCANLON, 2012)

Figure 32 highlights the very different nature of water usage for shale gas mining compared to coal mining. Whereas for coal mining water use and processing occurs beyond production, shale gas mining has an intensive but short water use period over the production life of the mine. Water use is most intensive during well development, although Figure 31 indicates that wells require periodic fracturing to extend their productive life.

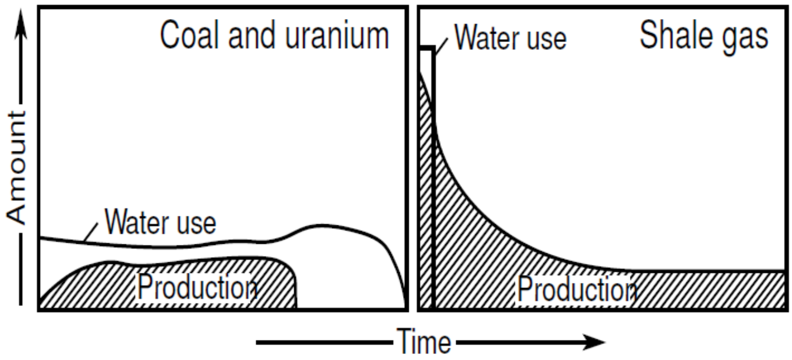


FIGURE 32: PATTERN OF WATER USAGE FOR COAL MINING AND THAT FOR SHALE GAS.
(NICOT & SCANLON, 2012)

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. The water withdrawn for a total extraction of 30 Tcf is then approximately 510 Mm^3, which is about 1.5 times the total volume of freshwater abstracted by the City of Cape Town for the year 2010. 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 33.

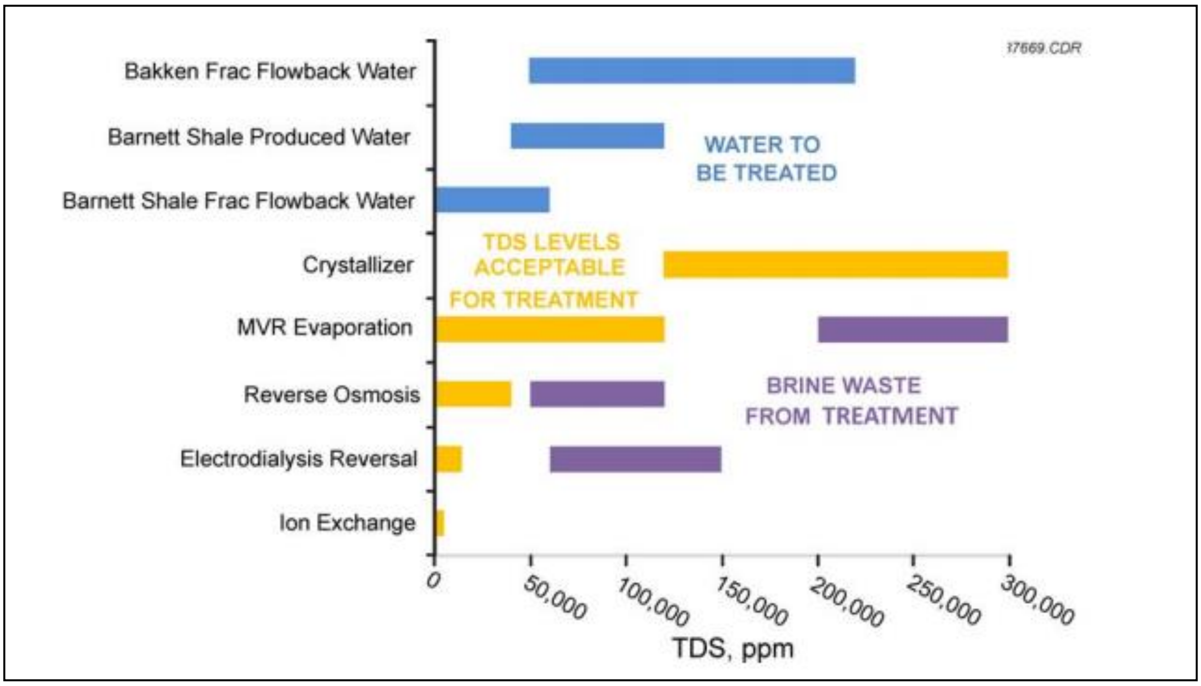


FIGURE 33: TREATMENT PROCESSES FOR RETURN FLOWS WITH INDICATIVE TDS LEVELS OF BRINE PRODUCT. (STEPAN ET AL.,2010)

In the USA deep well-injection is the preferred option of disposal followed by evaporation and burial the next common (Colorado School of Mines, 2009). Deep well-injection is unlikely in South Africa due to the lack of suitable sites and evaporation and disposal of the sludge may have to be opted for treatment of effluent. Robart (2012) considered alternative wastewater management regimes for the Eagle Ford shale region in the USA. The reference treatment regime was considered the standard US industry practice of truck transportation of source water, the collection and transport of returned flows for offsite disposal via deep well injection. His analysis shows that the treatment process selected has different cost components that affect the lifecycle treatment costs. Two alternative processes were included for comparison to the reference case. They consisted of a central or district wastewater processing facility and mobile onsite processing units.

Figure 34 displays the results for the lifecycle costs for the scenarios while Figure 35 displays the difference in capital cost. Over a 20 year production life, the district facility found to be the most cost effective, followed by mobile onsite processing units.

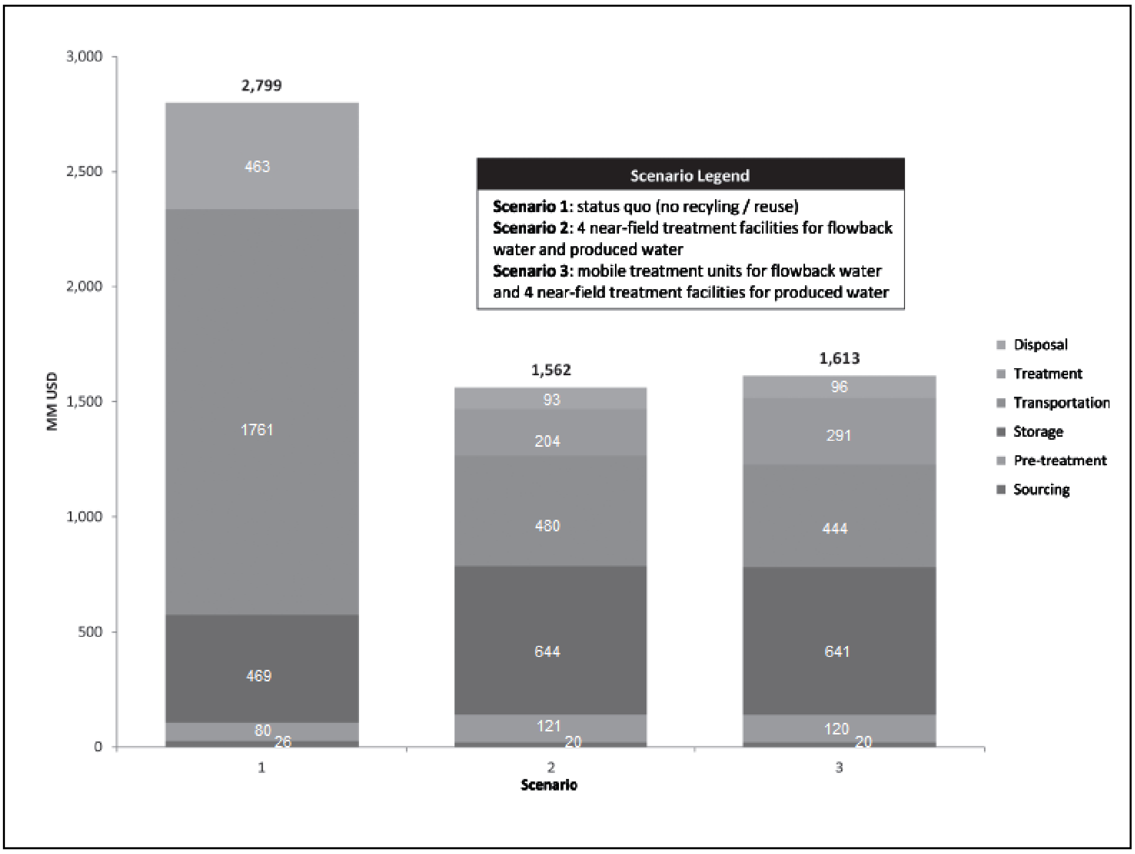


FIGURE 34: NET PRESENT VALUE OF SELECTED WASTE WATER MANAGEMENT REGIMES FOR THE EAGLE FORD REGION (USA) FOR THE PERIOD 2011-2030. (ROBART,2012)

For the site considered, the highest costs are incurred for the standard practice and is largely due to transportation costs which amounted to US$1,761 million. The cost for either district or mobile treatment facilities appear similar.

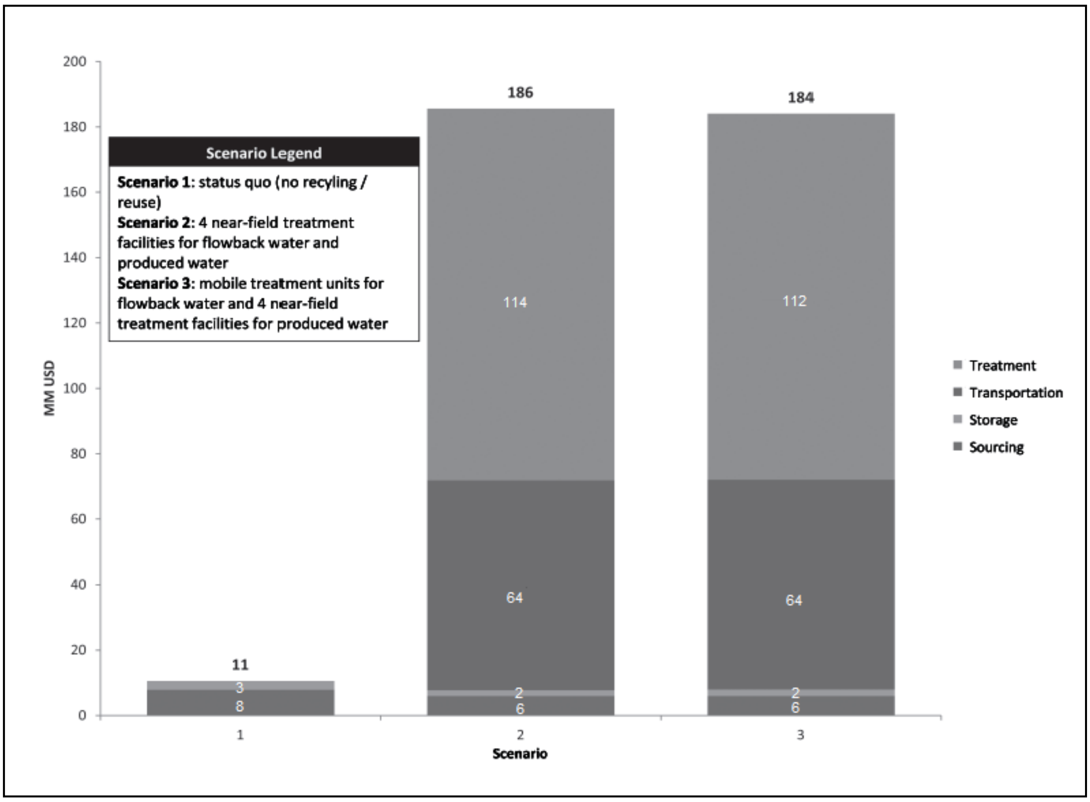


FIGURE 35: NET PRESENT VALUE OF CAPITAL OUTLAY FOR SELECTED WASTE WATER MANAGEMENT REGIMES FOR THE EAGLE FORD REGION (USA) FOR THE PERIOD 2011-2030. (ROBART, 2012)

In light of increasing competition for water resources, return flows are more commonly being recycled for reuse as fracturing fluid. The analysis for this study is restricted ZLED water use by industry in accordance with the DWA's advocacy of such a policy. Therefore 40% of water withdrawn is presumed to be recycled with disposal in the form of evaporation and crystallisation. The treatment of wastewater for discharge is further presumed to occur at district processing facilities with delivery via truck transport. In Task 1 the delivery cost of raw water to the shale gas region was estimated and this value is applied for the transport of effluent for offsite processing.

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/L.

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

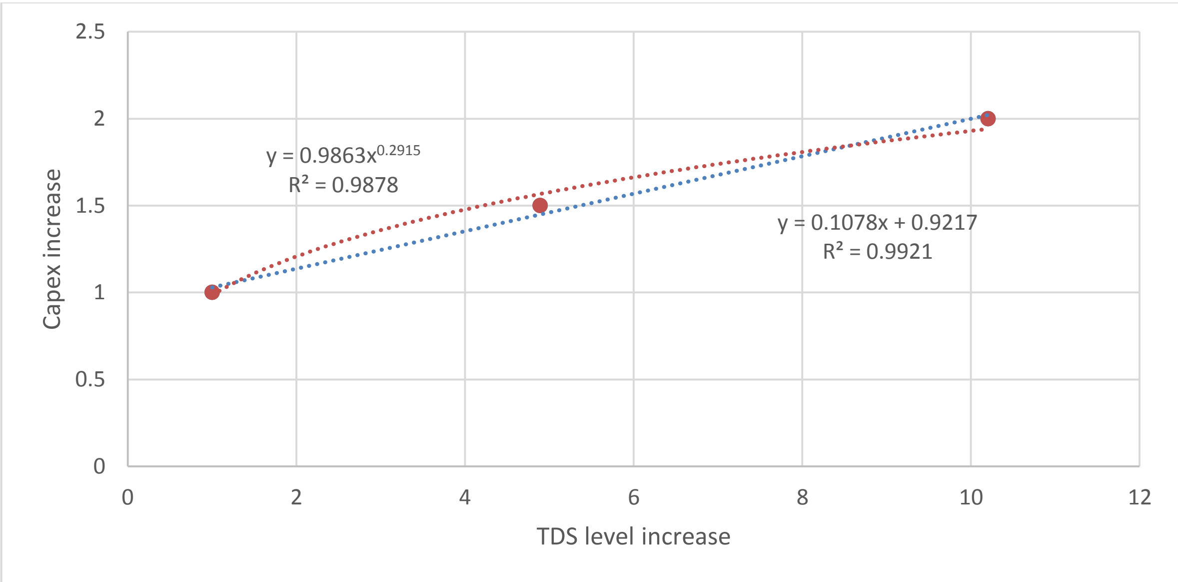


FIGURE 36: THE RELATIVE COST OF ADDITIONAL WTP CAPITAL FOR A CHANGE IN TDS CONCENTRATION. (SOUTH AFRICA. DEPARTMENT OF WATER AFFAIRS AND FORESTRY, 2009)

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 21 to yield the values given in Table 22. 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 22: COSTS FOR SHALE GAS MINING WASTE WATER TREATMENT IN SATIM-W.

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

The REWS diagram for the implementation of shale gas mining in SATIM-W as proposed above is shown in Figure 37. 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.

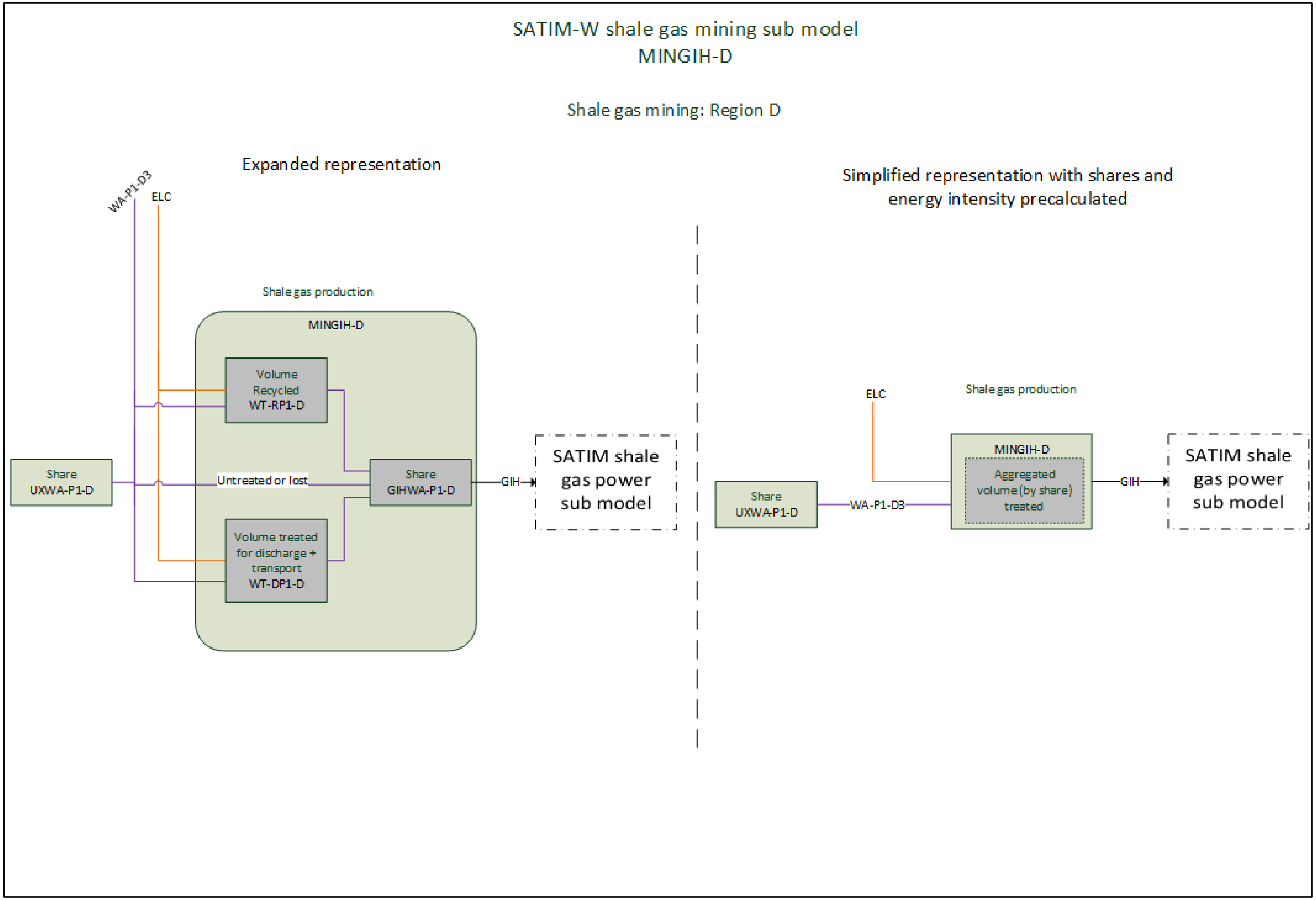


FIGURE 37: THE IMPLEMENTATION OF SHALE GAS MINING (MINGIH).

12 Uranium Mining

In South Africa uranium is extracted in tandem with gold where it is encountered. 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 AMD. The impact of gold and uranium mining on the quality of water resources requires further study to quantify the relative contribution of uranium extraction as reported mining activity data is aggregated.

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. In Phase 1, the water requirements of uranium mining is therefore grouped with gold mining in the non-energy category in SATIM-W.

13 Liquid Fuels Supply Sector

Petroleum refining (refining crude oil, natural gas and coal[2]) is a complex process which has numerous discrete processing units operating in close interaction. The numerous processing units produce a range of energy and non-energy products and they also have unique energy requirements in the form of ancillary energy services. In SATIM-W, the existing refineries are regrouped into 4 technologies as follows:

- Crude Oil Coastal (Sapref, Enref, Chevref);
- Crude Oil Inland (Natref);
- Gas-to-Liquids (GTL) (PetroSA), and
- Coal-to-Liquids (CTL) (SASOL-Secunda).

Of the coastal refineries, the Chevref (Chevron Refinery) is located in the Berg (19) WMA while the remaining two refineries are located in the Mvoti to Umzimkulu (11) WMA. The coastal crude oil refineries are not further considered as these are not linked to the water supply regions identified as being of interest for Phase 1. A detailed parameterisation of the refinery technologies in SATIM-W is presented in Appendix D.

13.1 Synthetic fuel production

Synthetic fuel in South Africa is derived via the Fischer-Trospch (FT) process with either coal or natural gas as feedstock. The process requires the conversion of the feedstock material to syngas (H_2 + CO_2) which forms the basic reaction compounds from which long chain hydrocarbons are obtained. The use of coal requires an additional gasification stage to produce syngas. This is achieved by reacting coal in a low oxygen environment with steam at high temperature. The initial combustion reaction with oxygen provides the heat for the steam reformation of the reduced coal (char) into syngas. The reformation of gas is similarly achieved by the reaction with steam. The chemical reaction for syngas production from either coal or gas is shown below with

[2] South African liquid supply industry uses coal, gas and crude oil as their feedstock

Figure 38 illustrating the process route to the final product. With gas reforming, excess hydrogen is reacted with CO_2, producing water as a by-product.

Coal reforming:

$C + 1/2O_2 \rightarrow CO$
$C + O_2 - CO_2 \rightarrow CO_2$
$C + H_2O \rightarrow H_2 + CO$

Gas reforming:

$CH_4 + H_2O \rightarrow CO + 3H_2$
$H_2 + CO2 \rightarrow CO + H_2O$

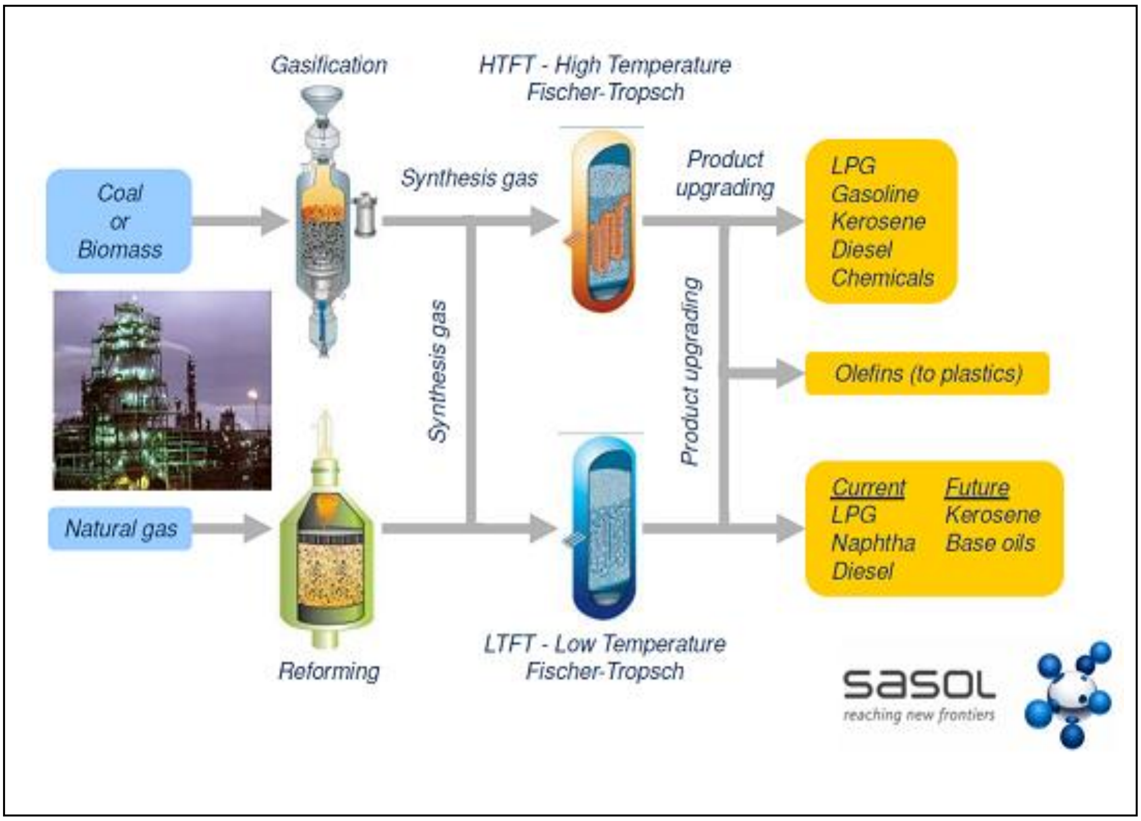


FIGURE 38: THE PROCESS ROUTE FOR SYNTHETIC FUEL PRODUCTION FROM EITHER GAS OR COAL. (SASOL,2013)

The choice of high temperature or low temperature FT determines the product slate, where the low temperature route favours diesel production.

There are three major thermochemical reforming techniques used to produce syngas from hydrocarbon fuels:

1) steam reforming (SR);
2) partial oxidation (POX), and
3) autothermal reforming (ATR)

(Zahedi nezhad, Rowshanzamir & Eikani, 2009).

ATR combines partial oxidation and steam reforming. ATR is a stand-alone process, in which the entire hydrocarbon conversion is completed in one reactor.

The reformation process route for both GTL and CTL technologies in South Africa that of Auto-Thermal Reformation.

13.1.1Coal-to-Liquids (CTL) refineries

South Africa's first CTL plant, referred to as SASOL 1, was fully operational in the mid-1950s and was commissioned to exploit the vast coal deposits discovered. In the wake of the 1973 oil crisis SASOL 2 was commissioned, followed by SASOL 3 in 1983 with rising crude oil prices. The evolution of the CTL plants production is depicted in Figure 39.

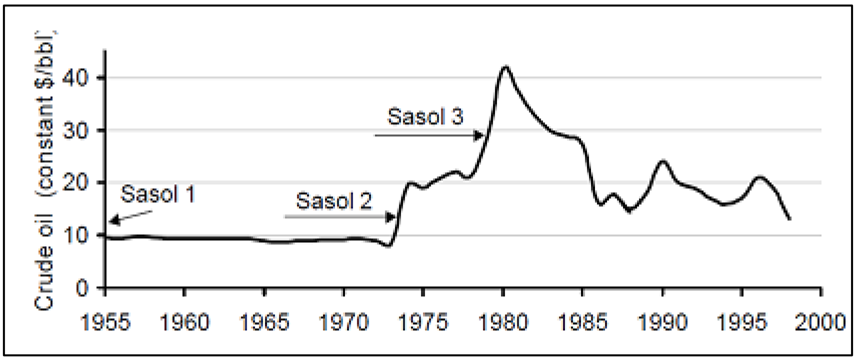


FIGURE 39: THE OPERATION OF SOUTH AFRICA'S CTL PLANTS AGAINST THE PRICE OF CRUDE OIL. (GIBSON,2007)

Located in Sasolburg, 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.

Located in Secunda, in the Upper Vaal WMA (Region C), Sasol 2 and 3 is the country's sole CTL plant. The Secunda plant predominantly uses coal feedstock but is 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.

The water requirements for CTL refineries are taken from the Water Research Commission's (WRC) Water and Wastewater Management in the Oil Refining and Re-refining Industry (2005) survey which is listed in Table 23.

TABLE 23: AVERAGE WATER REQUIREMENTS FOR THE SECUNDA CTL REFINERY. (PEARCE & WHYTE,2005)

Average Water requirement per tonne of feedstock (m^3/t)	Use of water (%)		
	Boilers (steam generation)	Cooling	Other
2.9	41.4	47.2	11.4

The implementation of CTL refineries in SATIM-W is shown in Figure 40. As depicted in the figure, the refinery boilers are modelled separately. The onsite generation capacity at Secunda amounts to approximately 800 MW. This component of the Sasol complex is modelled in the Power Sector and personal communication with Sasol reports that 23% of steam produced is required for power. The data from Table 23 is therefore adjusted with a lower value of 0.92 m^3/t (coal) applied as the boiler feedwater requirement to CTL refineries for the Fischer-Tropsch process. Therefore the Sasol figure is used for the high quality water requirement for CTL while the remainder is taken to be primary treated water.

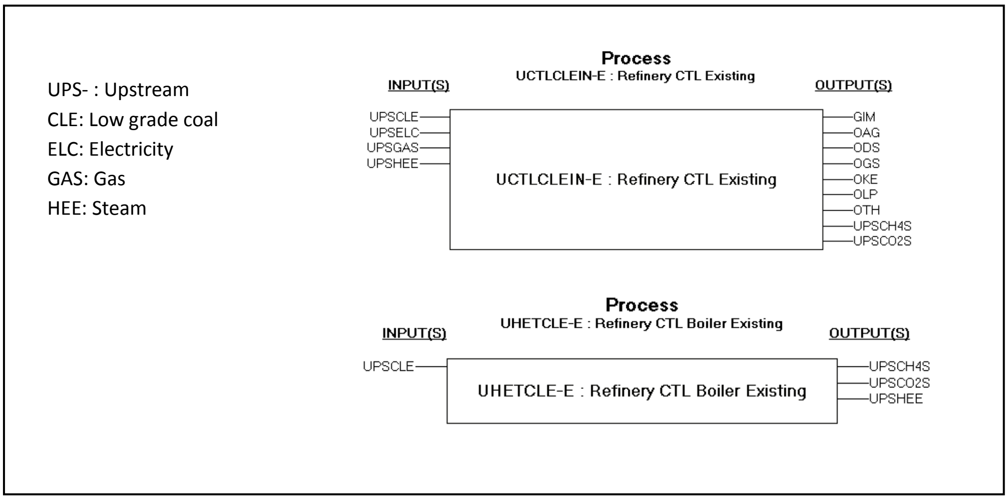


FIGURE 40: CTL REFINERIES (EXISTING AND NEW) AS REPRESENTED IN SATIM-W.

13.1.2 Gas-to-Liquids (GTL) refineries

In 2006 the GTL production capacity in South Africa was approximately 45,000 barrels per day or approximately 60 PJ per annum. By 2011 production had decreased to around 45 PJ/a due to declining indigenous gas production. The existing GTL plant is situated on the coast and is not further considered. New inland GTL plants are assumed to employ the LTFT process route for increased diesel production (Shaw,2012). Figure 41 depicts the representation of GTL plants in SATIM-W.

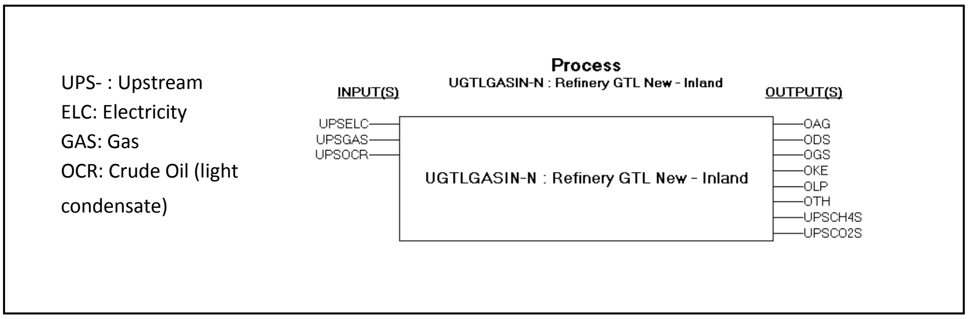


FIGURE 41: GTL REFINERIES (EXISTING AND NEW) AS REPRESENTED IN SATIM-W

(Martinez et al.,2014) investigated the water-energy requirements of the three aforementioned reforming process routes for GTL conversion and noted that the ATR method is a net producer of water with a greater output of water per unit volume of product as shown in Table 24. Furthermore they conclude that with direct recycling (i.e. use of the discharge as feed water) the water requirements for the ATR route are nil. The comparative water needs for the reforming methods are included in Table 24. The nil requirements are corroborated by Shaw (2012) who only specifies seawater requirements (15 m^3/ton of product) for power generation for new coastal located plants in South Africa. As such, the GTL plants in SATIM-W have nil water requirements as their power requirements are modelled in the Power Sector as is done for the CTL plants.

TABLE 24: WATER BALANCE FOR GTL PRODUCTION BY REFORMING PROCESS ROUTE. (MARTINEZ ET AL., 2014)

	ATR	POX	SR
WATER BALANCE FOR GTL PRODUCTION BY REFORMING ROUTE			
Water produced (m^3) per liquid product (m^3)	0.329	0.197	0.841
Water feed (m^3) per liquid product (m^3)	0.151	0.019	1.006
MINIMUM WATER REQUIREMENTS AFTER DIRECT RECYCLE			
Fresh water	0	0	0.841
Discharge	0.151	0.019	1.006

TABLE 25: COMPOSITION OF WATER RESULTING FROM THE FT SYNTHESIS. (MARTINEZ ET AL., 2014)

Component	% wt.
Water	98.88
Non-acid oxygenated hydrocarbons	1
Acidic oxygenated hydrocarbons	0.09
Other hydrocarbons	0.02
Inorganic components	0.01

13.1.3Inland crude oil refineries

Crude oil refineries represent a fraction of water consumption in SATIM-W as they are located along the coast and new refineries are likely to be similarly located. The existing inland Natref refinery is included as it is located in the Upper Vaal WMA and therefore linked to Region C for its water requirements. Figure 42 depicts the representation of crude oil refineries in SATIM-W. The refinery's water requirements, per tonne of crude oil feedstock, are listed in

Table 26 which is derived from the WRC (2005) survey.

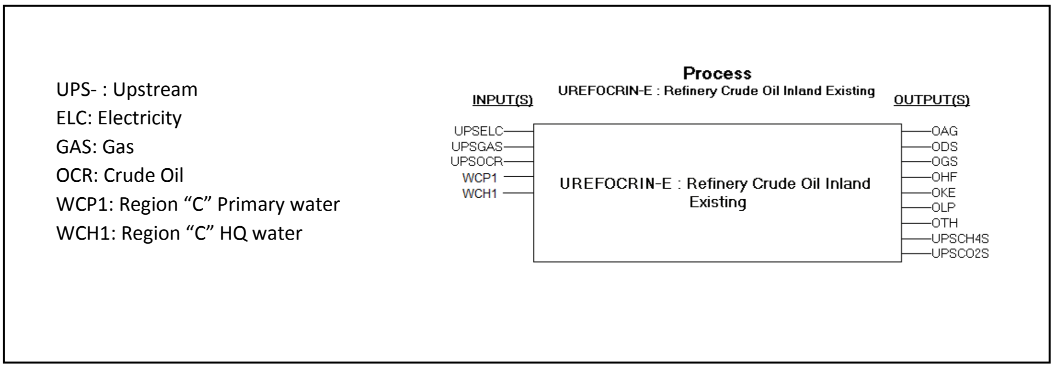


FIGURE 42: THE EXISTING INLAND CRUDE OIL REFINERY AS REPRESENTED IN SATIM-W.

TABLE 26: AVERAGE WATER REQUIREMENTS FOR CRUDE OIL REFINERIES IN SOUTH AFRICA. (PEARCE & WHYTE, 2005)

Average Water requirement per tonne of feedstock (m^3/t)	Use of water (%)		
	Boilers (steam generation)	Cooling	Other
0.57	52.6	32.3	15.1

14 Scenarios for Phase 1: energy supply sector analysis (*draft*)

The five themes that encompass the water-energy modelling framework are illustrated in Figure 43.

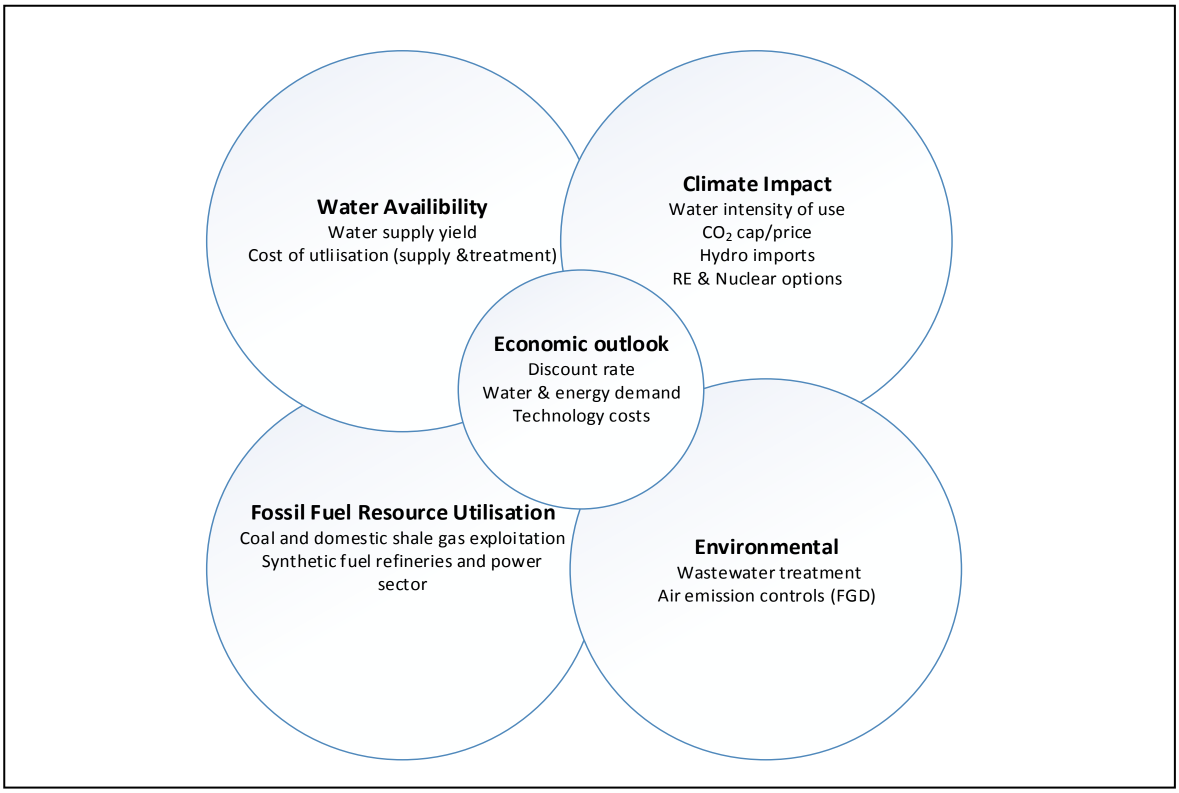


FIGURE 43: THE SCENARIO THEMES ADOPTED FOR THE MODEL RESULTS.

These themes explore the interaction of the various factors that would influence planning decisions in the energy supply sector from a water and energy perspective.

The various external interacting factors or elements which are considered to impact the uncertainty of the model outcomes are listed in Table 27.. Table 28 lists potential policy options which are candidates for assessment using SATIM-W.

Of these scenario elements, draft scenario cases are created. Certain elements are combined to give a composite scenario variable. For example, the Environmental Compliance variable encapsulates options that would be implemented if environmental regulations were enforced. These include air emissions standards and wastewater treatment. The scenario parameters are further described below.

TABLE 27: EXTERNAL FACTORS THAT IMPACT MODELLING OUTCOMES.

External Factors	Dependencies
Electricity demand	• GDP • Population • Income • Household electrification • Electricity use intensity (Transport- EV's, etc)
Regional water demand	• GDP • Population • Income • Water-use intensity (Climate: cooling water demand, CTL growth)
Regional water yield and cost	• Construction time and capital expenditure • Climate
Regional water quality	• Population • Sectorial water management (e.g. Industry, Mining, Agriculture, Residential)
Gas supply and cost	• Recoverable reserves, water availability and cost (supply and treatment) • Decommissioning cost
Coal supply and cost	• Recoverable reserves, water availability and cost (supply and treatment) • Decommissioning cost

TABLE 28: POLICY OPTIONS THAT IMPACT MODELLING OUTCOMES.

Policy Options	Dependencies
Hydro import capacity	• Climate • Cost
CO2 cap	
CO2 tax	
Air emissions (FGD) FGD to existing plant with >10 yrs life remaining (extension of retrofitted plant life)	• Legislation • Cost • Plant retirement
Waste water treatment (mining) Treatment of liquid effluent suitable for environmental discharge.	Mining Sector growth?
Dry-cooling retrofits For existing >10 yrs life remaining (extension of retrofitted plant life)	• Plant retirement profile • Cost

14.1 Scenario variables

Water and electricity demand: The impact of economic growth on both water and energy demand is considered. At this stage existing sectorial water-use intensities are projected with economic growth forecasts. In Phase 2 further consideration will be given to sectorial demand. The residential sector, for example, accounts for nearly a third of national water demand according to the National Water Resources Strategy 2 (2012) and may act as a stressor on the supply regime considering the migration to formal housing from the informal sector which at present is serviced via standpipes that inherently curtail demand.

The cost of water: The cost of water as provided by the cost curves obtained in Task 1 is incorporated to analyse the impact of pricing water on the generation portfolio compared to the case where the cost of water is not considered. An increase in cost would consider the impact of investment cost uncertainty for future supply schemes.

Climate change: The uncertainty of the yield of a water supply scheme as well as a likely increase in water-use intensity from consumers if a region is projected to experience a decrease in precipitation and elevated temperatures. This may apply to the Agricultural, Residential and Power sectors (i.e. impact on cooling water approach for wet-cooled plant).

A "No-Hydro" import case accounts for a decline in hydro-electricity imports due to regional climate change. The analysis from Task 1 (Section 4.4) summarises two climate change scenarios: Wet; and Dry. The results are reproduced in Table 29. The potential change in supply and demand for these scenarios are applied to the reference case.

TABLE 29: CHANGE IN THE AVERAGE ANNUAL WATER DEMAND AND SUPPLY FOR FUTURE ENERGY PRODUCTION.

WMA		Water Supply		Annual Demands	
	SATIM-W WSR	Wet	Dry	Wet	Dry
1 Limpopo	A	9.5%	-2.0%	2.8%	8.9%
4 Olifants	B	7.1%	-0.5%	4.4%	11.4%
6 Usutu to Mhlatuze		6.4%	4.0%	3.3%	8.8%
8 Upper Vaal	C	1.5%	0.4%	4.5%	13.0%
14 Lower Orange	D	4.9%	2.8%	3.8%	6.7%

CO_2 cap or price: The final results of the ERC National Gas Utilisation study (currently underway) should better inform our decision as to which presents the more interesting option.

- The application of a CO2 cap of 275 Mt/a for the Power Sector (Phase1) or a 14 Gt cap by 2050 for a full sector analysis (Phase 2).

- The application of a CO2 tax. Based on the analysis of the current ERC National Gas Utilisation Study, two price regimes of R100/t and R300/t are considered.

Environmental compliance: Considers regulatory compliance in the power and extractive sectors for effluent discharge. This comprises:

- Retrofitting of FGD controls to existing candidate coal plants, where wet (limestone) FGD and seawater FGD is considered, and
- Investment in waste water treatment infrastructure for mining activity.

Shale gas mining: The development of an indigenous unconventional gas supply and its impact on:

- Water allocation/supply, and
- Investment in gas-fired power plants.

A high water cost is considered with this option due the limited existing supply in the region of interest for shale gas extraction.

The cost of low carbon technologies: The uncertainty of investment costs for energy supply alternatives to coal based generation.

Increased water treatment costs due to poorer raw water quality: The additional cost of water treatment relative to the reference water quality cost.

Improved water-use efficiency (Phase 2): A decoupling of water demand from economic growth as the economy/country becomes water-use efficient. For example, municipalities actively pursue and maintain water conservation and water demand management reducing residential demand. Industrial water-use intensities decline where applicable as zero-liquid-discharge practice is adopted.

14.2 Scenarios

The scenario variables identified are combined to form scenarios (or cases). These scenarios form the basis for the interrogation of the water-energy model developed to highlight possible trade-offs for future investment in the Energy sector. Table 30 summarises the scenarios formulated for the modelling in Phase 1. Table 31 lists the scenarios and the scenario variables for the defined model runs.

TABLE 30 SCENARIO SUMMARY

Index	Scenario or Case	Description
1	**Reference (Ref)**	The SATIM-W Power Sector configuration is run with default assumptions similar to the SATIM configuration with the cost of water not considered
2	**Water Supply Cost**: Reference with the cost of water.	• The SATIM-W Power Sector configuration is run with the default assumptions incorporating the cost of water. • The reference case is that of a business as usual demand for energy and water with GDP growth (i.e. water and energy use intensities are constant).
3	**Climate Change**: Water Supply Cost with Climate Change	• Water supply cost curves and water demands adjusted as reflected in Table 29. • The cooling water demand and efficiencies of power plants are adjusted by region if significant. • Includes "No-Hydro" imports. (for drying scenario or both?)
4	**High Economic Growth**: Climate Impact with growth in demand	• Explores the case of increased economic growth and its effect on energy and water demand. • The reference case is that of a business as usual demand for energy and water with GDP growth (i.e. water and energy use intensities are constant).
5	**Local Environmental Best Practice**: High Economic Growth with local environmental best practice	• As with Scenario 4 but with local environmental best practice. • Wet Flue Gas Desulphurisation technology fitted to all new coal power plants, and retrofitted to candidate existing coal power plants. • Coal mining includes waste water treatment.
6	**Shale Gas**: Environmental Compliance with shale gas mining	• Similar to scenario 5 but includes shale gas mining. Shale gas mining includes water treatment as with coal mining.
7	**Increased Water Supply Cost**: Shale Gas with increased investment cost of water supply schemes	• The impact of investment cost uncertainty for future supply schemes.
8	**Low Carbon Technologies Increased Cost**: Increased Water Supply Cost with low carbon technology options	• The sensitivity of the model results to an increase in cost for low carbon options are examined. The options include imported hydropower, renewable energy and nuclear power)

TABLE 31: THE PROPOSED SCENARIO MODELLING MATRIX FOR SATIM-W

Case	Description	CO_2 cap/price	The cost of water	Climate change	Water and electricity demand	Environmental compliance	Shale gas mining	The cost of low carbon technologies (Imported Hydro, RE costs, Nuclear Costs)
1	Reference	NO	NO water Costs	No Impacts	Reference	SATIM base: No	No Shale	SATIM base
1.1	CO2 price/constraint level 1	1	NO water Costs	No Impacts	Reference	SATIM base: No	No Shale	SATIM base
1.2	CO2 price/constraint level 2	2	NO water Costs	No Impacts	Reference	SATIM base: No	No Shale	SATIM base
2	Water Supply Cost	NO	Base	No Impacts	Reference	SATIM base: No	No Shale	SATIM base
2.1	CO2 price/constraint level 1	1	Base	No Impacts	Reference	SATIM base: No	No Shale	SATIM base
2.2	CO2 price/constraint level 2	2	Base	No Impacts	Reference	SATIM base: No	No Shale	SATIM base
3	Climate Change	NO	Base	Climate Impacts	Reference	SATIM base: No	No Shale	SATIM base
3.1	CO2 price/constraint level 1	1	Base	Climate I	Reference	SATIM base: No	No Shale	SATIM base
3.2	CO2 price/constraint level 2	2	Base	Climate I	Reference	SATIM base: No	No Shale	SATIM base
4	High Economic Growth	NO	Base	Climate I	HIGH	SATIM base: No	No Shale	SATIM base
4.1	CO2 price/constraint level 1	1	Base	Climate I	HIGH	SATIM base: No	No Shale	SATIM base
4.2	CO2 price/constraint level 2	2	Base	Climate I	HIGH	SATIM base: No	No Shale	SATIM base
5	Local Environmental Best Practice	NO	Base	Climate I	HIGH	YES	No Shale	SATIM base
5.1	CO2 price/constraint level 1	1	Base	Climate Impacts	HIGH	YES	No Shale	SATIM base
5.2	CO2 price/constraint level 2	2	Base	Climate Impacts	HIGH	YES	No Shale	SATIM base
6	Shale gas	NO	Base	Climate Impacts	HIGH	YES	With Shale	SATIM base
6.1	CO2 price/constraint level 1	1	Base	Climate Impacts	HIGH	YES	With Shale	SATIM base
6.2	CO2 price/constraint level 2	2	Base	Climate Impacts	HIGH	YES	With Shale	SATIM base
7	Increased Water Supply Costs	NO	HIGH	Climate Impacts	HIGH	YES	With Shale	SATIM base
7.1	CO2 price/constraint level 1	1	HIGH	Climate Impacts	HIGH	YES	With Shale	SATIM base
7.2	CO2 price/constraint level 2	2	HIGH	Climate Impacts	HIGH	YES	With Shale	SATIM base
8	Low Carbon Tech. Increased Cost	NO	HIGH	Climate Impacts	HIGH	YES	With Shale	High
8.1	CO2 price/constraint level 1	1	HIGH	Climate Impacts	HIGH	YES	With Shale	High
8.2	CO2 price/constraint level 2	2	HIGH	Climate Impacts	HIGH	YES	With Shale	High
	Reserve Scenario Variables							
	Increased Water treatment costs due to poorer raw water quality							
	Water Demand Management. Reduction in water demand from lower water-use intensities across sectors (Phase 2)							

This is the reference demand in the DWA study excluding water for energy. We require GDP assumptions to agree with energy demand projections.

Impact on both supply curve and water-use intensity of Power and other sectors. Require Aurecon input if significantly different.

Requires a high demand projection (excl. water for energy) for water with accompanying GDP growth assumption. (This could be done simply by applying the reference sectoral intensities to higher sector growth).

Higher costs - using upper limits of cost estimates/higher discount rates. Require Aurecon input.

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