Analysis of new international interconnectors to the South African power system

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Summary and key findings

There are abundant hydropower resources to the north of South Africa. Mozambique, Zambia and DR Congo have ambitions of developing major power generating projects and connecting these projects to South Africa.

This report looks at the following options:

- The Zambia option would connect 600 MW hydropower with a 600 MW interconnector.
- The DR Congo option is assumed to be a 2,500 MW interconnector as 2,500 MW of hydro may be contracted from the Grand Inga project.
- The Mozambique option is a 3,100 MW transmission expansion for hydro and coal generators to supply South Africa from Mozambique.

The analysis aims at determining the relative value for the South African power system of connecting to each expansion programme by comparing four scenarios - a base case and three hydro scenarios that represent each project. The costs of satisfying electricity demand in South Africa in the base case and in each scenario provides the basis for determining attractiveness of the investments.

The Balmorel model is used in the analysis. Balmorel is an economic/technical partial equilibrium model that simulates the power system. The model optimises the production at existing and planned production units.

Scenario results

The key results of the scenario analyses are:

- Imported hydropower results in significant reductions in coal powered generation.
- The annual savings range from ZAR 1.1 billion in the Zambia scenario to about ZAR 6 billion in the Mozambique and DR Congo scenarios.
- These savings can justify a total investment of approximately ZAR 13 billion in the Zambia project and approximately ZAR 70 billion in the Mozambican and DR Congo projects. Actual investment costs should be further investigated to determine feasibility of the hydro scenarios.
- Imports from hydropower can save up to 9 % of CO_2-emissions compared to the base case.
- The investigated interconnection projects are connected in the North of the country and will not necessitate major reinforcements of the South African internal grid.

Conclusions and perspectives

Increased hydropower imports into the South African power system can reduce the cost of meeting electricity demand. If CO_2 taxes come into effect the benefit of hydro imports are increased.

The analyses are made under the assumption of identical composition of the generation capacity in the South African power system, and therefore the derived benefit is a direct result of avoided variable costs – mainly fuel. The integration of imported hydropower also has the potential to postpone investments in new generating capacity in South Africa thereby resulting in significant additional economic benefits.

The present analysis considers the three interconnection projects individually. The benefits are calculated as an assessment of the value to the South African System. Ideally, however, an integrated and coordinated approach to developing interconnectors and generation expansion programmes in the region should be adopted. Thereby, the combination and benefits for the entire region could be determined to provide a more clear roadmap for the future development of the regional power system.

Introduction

Cooperation between South Africa and Denmark

The Department of Energy and the Danish Energy Agency are partners in strengthening decision-making capacity through mutual cooperation and the exchange of experiences between entities in these organisations.

At a meeting between representatives of the Department of Energy and the Danish Energy Agency at IRENA in 2014, a preliminary analysis of transmission expansion projects connecting South Africa to hydropower resources in neighbouring states was discussed. This discussion was inspired by the proposed African Clean Energy Corridor.

This report provides a thorough analysis of the implication of large-scale hydropower imports for the South African power system. The report is sponsored by the Danish Energy Agency and has been carried out with assistance from Ea Energy Analyses. The analysis is based on data provided by The Department of Energy and ESKOM as well as publicly available information.

Potential for connecting to abundant hydro resources in the north

There are abundant hydro resources to the north of South Africa. Hydropower projects in Mozambique and Zambia are identified in the draft revised Integrated Resource Plan (IRP) as a potential source of clean energy for South Africa as is the Grand Inga project in the Democratic Republic of Congo (DRC). Many of the proposed hydropower projects in Southern Africa have similar timelines for development and investments in these projects are largely reliant on connecting to the South African power system for making them financially viable.

Model based analysis

The integration of large amounts of hydropower in the South African power system will change the way the system is operated and influence the total costs associated with satisfying demand for electricity. This analysis aims to determine the comparative value of each interconnector in isolation by determining reductions in the total variable cost of supply that can be attributed to each interconnector. This is done using model-based power system scenarios based on least-cost dispatch.

Decision-making tool

The modelling tool developed for the project can be used to assist the Department of Energy analyse the comparative value of other electricity infrastructure investments and the effect they will have on the South African power system as well as simulate investments in new generating capacity and reinforcements of transmission within South Africa e.g. in the IRP. This could contribute to strengthening the decision-making process and provide the basis for determining whether proposed investments and associated costs are beneficial for South African consumers.

The South African power system

Most power stations in South Africa are owned and operated by Eskom, which accounts for approximately 95% of all the electricity produced in South Africa.

Eskom relies on coal-fired power stations to produce approximately 90% of its electricity. The majority of coal deposits used for power generation are found in the north-east of the country, in eastern and south-eastern Gauteng and in the northern Free State. These coal power plants are located near the mines, whereas some of the main load centres (e.g. Port Elizabeth and Cape Town) are located in the south and south-west. South Africa has developed a strong transmission network to feed geographically dispersed load centres from highly concentrated power production areas.

Development of renewable energy

In recent years several projects were created with focus on utilizing renewable energy resources in South Africa. In 2009 the government began exploring feed-in tariffs for renewable energy, but these were later rejected in favour of competitive tenders. The Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) was created to further the development of renewable energy, reduce the environmental impact of electricity generation and help ensure the continued uninterrupted supply of electricity. The REIPPPP has through several bid rounds paved the way for RE deployment and continues to do so. By April 2015 the Department of Energy had procured 4,116 MW of renewable generation capacity with more bid programmes to follow.

International cooperation

South Africa has had electrical connections to neighbouring states for many years and has supplied a large part of these countries' demand for electricity. South Africa has also imported hydro power from Mozambique for many years and the two countries electricity systems are closely linked. Increased cooperation through initiatives such as the Southern African Power Pool (SAPP) provides a forum for the further development of an interconnected system in the southern African region that can connect the large demand areas in South Africa with the large hydro resources in the northern and central parts of southern Africa.

Overall challenges in the power system

Power demand is expected to increase significantly over the coming years in the region and in South Africa. Timely investments in production capacity as well as development of the transmission and distribution network is therefore crucial for the South African power system to be able to deliver a high level of security supply.

Due to the large share of coal power, the South African power system has high CO_2 emissions per kWh relative to other power systems. A challenge for the coming years is to address climate concerns whilst still satisfying the increasing power demand in South Africa.

Methodology and scenarios

Power system scenarios are designed to represent a coherent and consistent description of a plausible future based on the interaction of key economic parameters. They are a tool for approaching uncertainties by illustrating the effect of policy and regulation on the functioning of the power system providing foresight for decision-makers.

Model based analysis can help assist and analyse effects on possible future projects and scenarios. Building models to represent the complex nature of the existing and future power system provide the opportunity for predicting the effects of building new generation or transmission capacity, analysing environmental effects and helping identify economically and environmentally sustainable options for meeting future demand.

Aim of scenario analysis

Accessing large hydropower resources in neighbouring countries may provide South Africa with a source of clean, affordable electricity, whilst contributing to regional development and increased cooperation. The aim of this analysis is to determine the relative value of interconnectors to DRC, Mozambique and Zambia respectively and how import of hydropower from northern neighbours may influence existing infrastructure in the South African power system and how the power system is managed.

Model based analysis

The scenario analysis was carried out using a model-based approach. The electricity market model, Balmorel performed an economic optimisation of generation dispatch using a simplified representation of the grid.

The figure below shows the structure of the model of the South African power system and how the system is divided into electrical regions connected by transmission lines. The assumed capacity of these lines is also shown. The electricity demand and generation capacity of power production units is defined in each region.

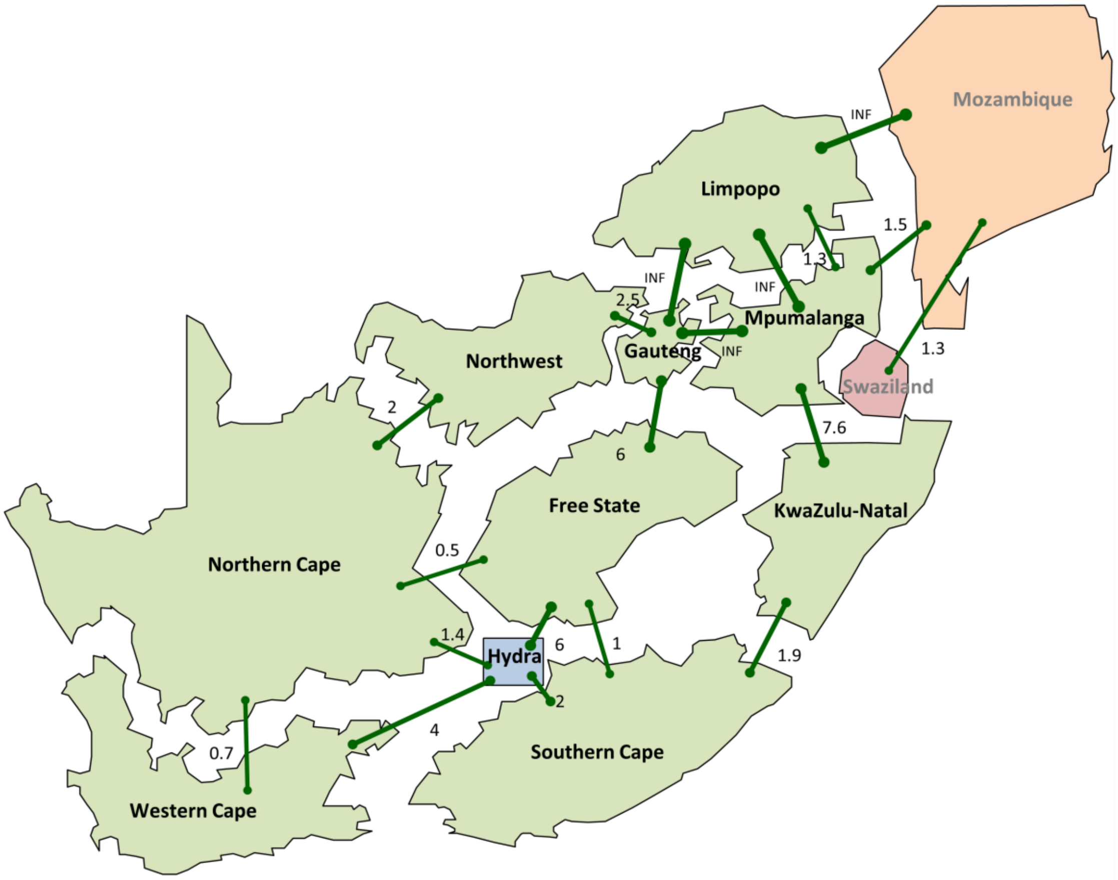

Figure 1: Visualisation of the South African power system in the Balmorel modelling tool for the year 2025.Figure shows each province in the power system as well as the hydra station and Swaziland and the southern part of Mozambique. Numbers refer to kMW transmission capacity and INF means infinite transmission capacity. Transmission capacity can be the same in each direction of a line but this is not necessarily so.

Determining the value of interconnector projects

When determining the value of an infrastructure project it is important to compare results with the correct alternative. This is the situation that would have occurred if not for the project under consideration. This provides information on the costs of satisfying demand without, for example, interconnectors to regional hydropower as well as information on whether the interconnectors can provide the functionality required of them to satisfy demand.

Market studies using modelling tools such as Balmorel are used to highlight market conditions and structural rather than incidental bottlenecks. They take constraints such as flexibility and availability of thermal units, hydro conditions, wind and solar profiles, load profiles, fuel costs, etc. into account.

Social welfare economics

As interconnectors are considered a common good owned and operated on behalf of the state the profitability of interconnector projects is assessed using social welfare economics rather than focusing on corporate profits. This means, it is not only the financial performance of the transmission company that is considered, but also the costs and benefits of other agents in the South African economy with particular focus on consumers and producers of electricity. Indirect effects on employment and GDP are not considered in this analysis.

Scenarios

Four scenarios were developed to illustrate the relative value of the three transmission corridors that can access hydropower resources in southern Africa. The year 2025 was chosen for assessing the value of the interconnectors as it represents a realistic time horizon for the commissioning of international transmission lines.

The reference scenario forms a reference point when performing other scenario simulations. Thus, the effects of alternative scenarios can be found by comparing results to those of the reference scenarios.

The detailed assumptions and data used in the scenarios are described in a separate chapter on assumptions in this report.

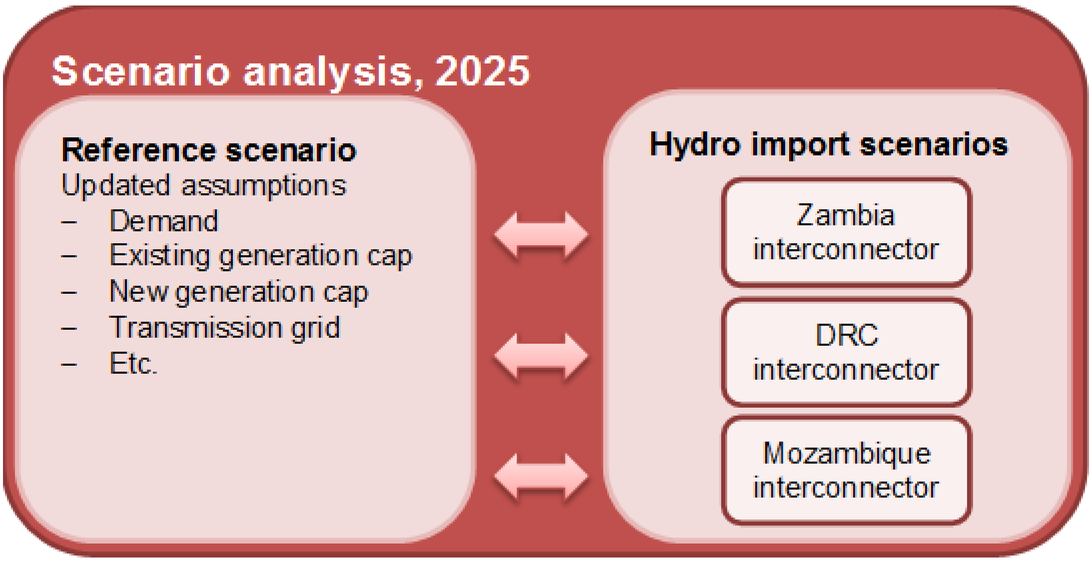

Figure 2: Scenario analysis of the three international interconnectors.

Reference scenario

The reference scenario is built around data from the “Integrated Resource Plan for Electricity – Update Report 2013” (IRP 2013) and the “Transmission development plan 2015-2024” published by Eskom in Oktober 2014 (TDP). The reference scenario includes no new electricity supply from neighbouring countries except for those that already exist or are in the process of being commissioned.

In both the reference scenarios and the hydro scenario power plant data and fuel prices are sourced from the IRP 2013.

Demand forecasts and existing and committed generation capacity are derived from TDP with the exception of the acceleration of investments in renewables announced by the minister in April 2015 (REIPPPP). This provides consistency with existing policy and planning processes in South Africa. The reference scenario represents a best estimate of the development of the South African power system. Using the Balmorel model a simulation of the year 2025 is performed to simulate supply and demand of electricity on an hourly basis.

Hydro import scenarios

Each hydro import scenario represents an interconnector from the South African power system to a hydro power plant. Three hydropower projects were chosen to analyse the effects of importing electricity based on hydro power. The scenarios are the same as the reference scenario except for the addition of interconnectors to hydro power plants in DRC, Mozambique and Zambia respectively. Balmorel model simulations of each hydro scenario are used to analyse the effects of importing hydropower by comparing variable costs of supply in each scenario with those of the reference scenario. This indicates the costs and benefits associated with imported hydropower and whether it can displace more expensive generation like coal, gas or diesel fired units.

Zambia scenario

The Zambia interconnector scenario connects the South African system with a 600 MW hydropower plant. The hydro plant in Zambia is assumed to have a load factor of 66 %.

Grand Inga scenario

The DRC interconnector scenario connects to the Grand Inga hydro plant. It is assumed that South Africa will contract 2,500 MW of hydro generation from the Grand Inga 3 project. Therefore, in this scenario a 2,500 MW line to the 4,800 MW Grand Inga 3 plant is built – the so-called “Eastern corridor”. The current plan for Grand Inga 3 is that it will be commissioned by 2022. The transmission line between South Africa and Zambia would probably constitute a part of the Eastern corridor if this were to be constructed.

Mozambique scenario

The Mozambique interconnector scenario represents building a transmission line to supply generation from Cahorra Basa North Bank (1,245 MW) and Mphanda Nkuwa (1,500 MW) hydropower plants as well as the Benga Moatize coal fired plant (550 MW). The additional transmission line connecting these plants to the South African system is assumed to be a 3,100 MW connection into Mozal from which a 1,500 MW line to the South African system already exists. If the 3,100 MW line were to be constructed, then it is assumed this would help supply the Southern Mozambique and Mozal regions. Thus in this scenario an additional 1.8 TWh demand is added corresponding to half of Mozambique's demand. The rest is assumed to be satisfied by other Mozambican generation.

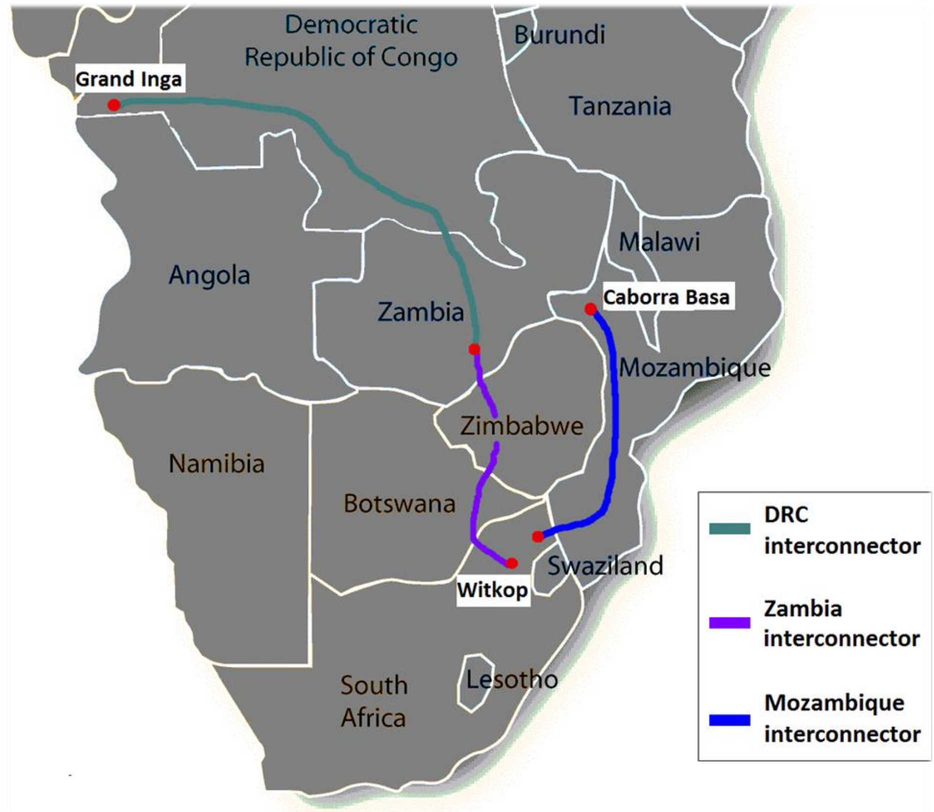

Figure 3: Geographic overview of the interconnectors for the hydro import scenarios.

Value of interconnectors

The value of the interconnectors represents the avoided costs associated with the introduction of hydropower to the South African power system. Avoided short-term marginal costs consist of mainly of fuel costs, variable operation and maintenance cost, cost of demand side measures and possibly costs related to the emissions of CO_2.

The avoided costs are determined by simulating least cost dispatch of available generation required to satisfy demand over the course of a year, in this case 2025.

Investment costs in transmission and the building of the hydropower plants are not included in least-cost dispatch simulations as the merit order is based on the short-term marginal cost of generation. This is the most efficient methodology for dispatching power plants in the power system.

Least cost dispatch simulations determine the reduction in total cost of supply that can be attributed to electricity sourced from the addition of hydropower to the power system when compared to the reference scenario. This represents the avoided costs associated with the investment, but should not be seen as an indicative tariff for electricity from hydro resources. Tariffs should preferably be based on project investment costs, a reasonable return on investments and avoided long-term marginal costs of generation.

The reduction in total costs can then be used to calculate whether the net present value of the investment in hydro capacity and transmission is socio-economically favourable based on annual savings in the short term marginal cost of supply over the technical lifetime of the transmission line, the capital investment in infrastructure and the socio-economic discount rate.

Displacement of investments in generation capacity in South Africa

Calculating the avoided long-term marginal costs of generation accrued due to sourcing regional hydropower is reliant on policy on whether regional power supplies are considered sufficiently reliable to displace investments in power plants in South Africa seen from a security of supply perspective. This issue is not addressed in the report.

Main results and conclusions

Power generation in 2025

The figure below shows power generation in the South African system for the reference scenario (Base Case) compared to the generation in the current power system (2013). The figure shows that power generation will increase significantly due to increasing demand. Power generation from coal increases towards 2025, but the share of coal in the overall generation mix decreases as greater diversification in the generation mix is introduced. This is due to the expected increases in nuclear power and renewable energy respectively. Production from diesel and natural gas plays a marginal role in the 2025 model results. This is a consequence of the planned power production capacity expansion with coal, renewable energy and nuclear power, which is sufficient to satisfy increasing demand.

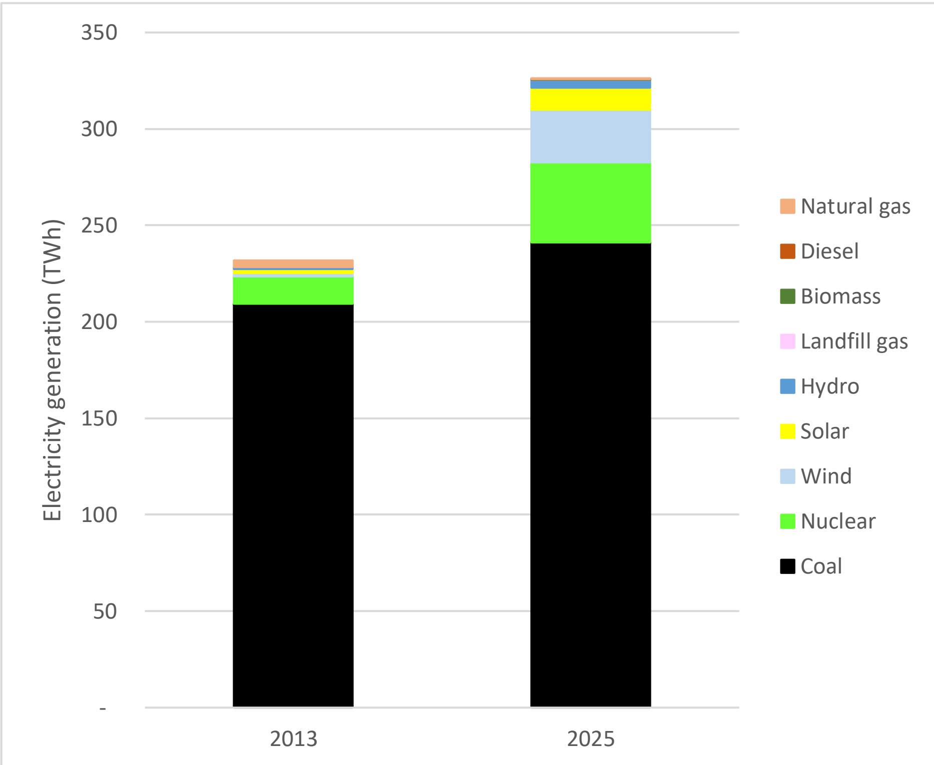

Figure 4: Total annual South African electricity generation in 2013 (historical) and 2025 (model run) given in TWh for the Base Case.

Consequences for the South African system of the three hydro scenarios

The graph below shows power generation in South Africa across the modelled scenarios. Power generation from South African generators is reduced in the three scenarios when power is imported from the hydro power plants north of the country.

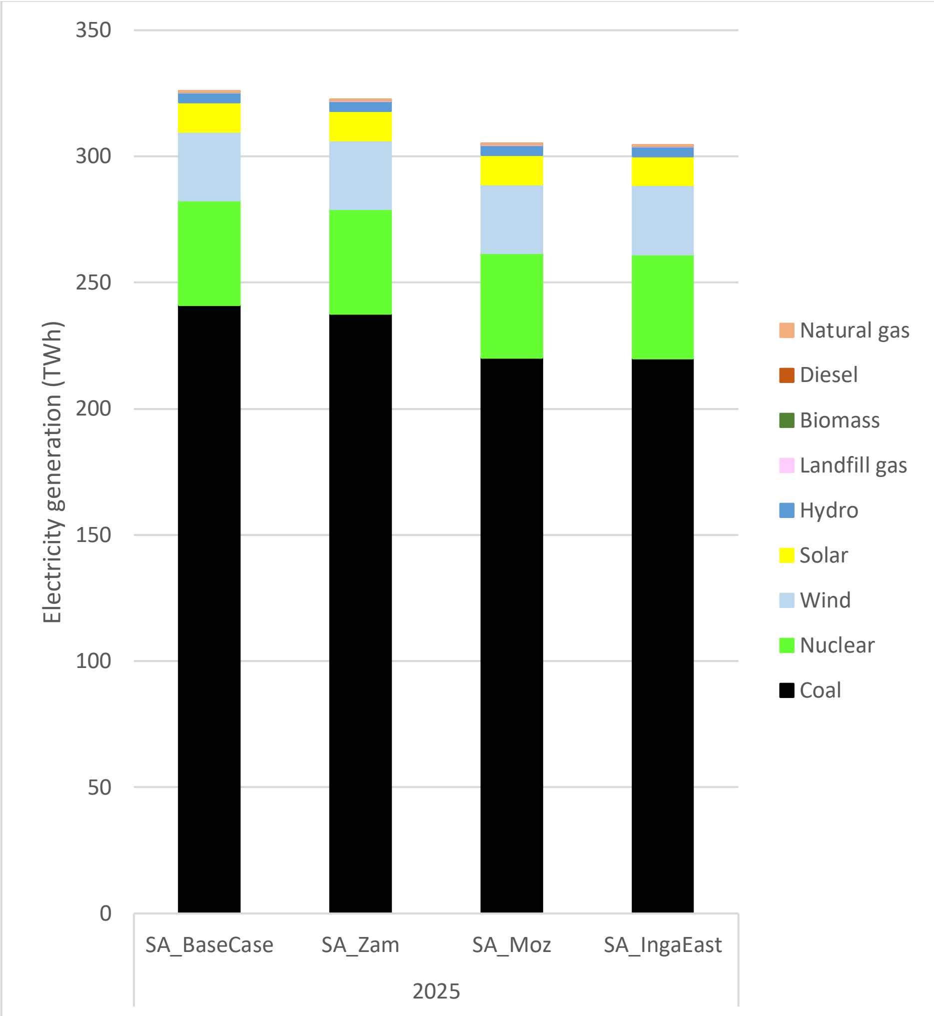

Figure 5: Total annual South African electricity generation in 2025 given in TWh for the Base Case and the three interconnector scenarios.

The table below shows that imported hydropower mainly displaces coal-fired generation. Power generation from wind, solar and nuclear has very low marginal costs and is therefore unaffected by hydropower imports.

Electricity generation SA (TWh)		Difference to Base Case		
	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Coal	241.2	-3.5	-20.9	-21.3
Nuclear	41.4	-	-	-
Wind	27.2	-	-	-
Solar	11.5	-	-	-
Hydro	4.1	0.1	0.0	-0.1
Landfill gas	0.1	-	-	-
Biomass	0.1	-	-	-
Diesel	0.0	-	-	-
Natural gas	0.0	-	-	-
Total	**325.8**	**-3.5**	**-20.9**	**-21.4**

Table 1: Total annual South African electricity generation in 2025 given in TWh for the Base Case and the displaced generation in South Africa for Zambia, Mozambique and Grand Inga interconnectors given in TWh.

Economic consequences for the system

The import of hydropower reduces variable costs and start-up costs for some power plants. The table below shows the total saved costs in the system distributed by category of expenditure. In total, the new interconnectors will reduce variable costs of meeting demand by between R 1,149 mil. and R 6,341 mil annually.

Total costs (mill. ZAR)		Difference to BaseCase		
	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Fuel Cost	49,448	-956	-4,991	-5,101
Variable O&M	7,898	-128	-1,012	-1,030
Start-up costs	1,089	-64	-166	-202
DSM costs	448	-1	11	-6
Total costs	**58,883**	**-1,149**	**-6,162**	**-6,341**
Maximum investment		**12,935**	**69,370**	**71,386**

Table 2: Total costs in terms of fuel, variable O&M and DSM costs in mill. ZAR in 2025 and cost savings compared to the Base Case for each of the three scenarios. The maximum investment is calculated using a lifetime of 30 years and an interest rate of 8 % (real).

The cost savings of imported hydro power should be compared to the investment cost of hydro power plants, transmission lines etc.. However, the investment costs have not been evaluated in this project. Using the results for reduced costs seen above a maximum investment cost can be estimated.

The maximum investment cost is the highest investment that can be allowed to make the scenario economically feasible with a required rate of return. Assuming a technical lifetime of 30 years and an interest rate of 8 % (real) the maximum investment that will be economically viable is determined for each of the hydro import scenarios. The results indicate that with the estimated savings in variable costs, a total investment of up to R 13 bn. is economically viable in the Zambia scenario whereas an investment of up to R 70 bn. could be economically viable in the Mozambique and DRC scenarios. Investments include those in transmission infrastructure and part of the hydropower plants needed for import to South Africa.

Including consequences on the necessary investments in thermal capacity could increase the value of hydro scenarios

The analysis only includes the reduction of variable costs in the system. The model results indicate that imported hydropower can displace or delay the need for new investments in generation capacity in South Africa.

For this project it has not been possible to find credible investment figures for the three transmission and hydro scenarios. This would be a necessary next step to evaluate the feasibility of the projects.

Zambia and Grand Inga projects are linked

The interconnector to Zambia forms part of the Eastern corridor of the Grand Inga interconnector. Therefore, if the Zambia interconnector was to be built the costs of connecting further on to Grand Inga would in fact be smaller.

Development of CO_2-emissions

The table below shows the development of the CO_2-emissions in the Base Case and the reduction in the three hydro import scenarios. The import of hydropower can save up to 9 % of the CO_2-emissions from the South African power system, mainly because of the reduction in coal consumption.

CO_2 emissions (mill. ton)		**Difference to BaseCase**		
	SA_BaseCase	**SA_Zam**	**SA_Moz**	**SA_IngaEast**
Coal	237	-3.5	-19.9	-20.3
Diesel	0.02	-	-	-
Total	**237**	**-3.5**	**-19.9**	**-20.3**
Value (CO_2 price 120 ZAR/ton)		**-420**	**-2,388**	**-2,436**

Table 3: CO_2 emission in megaton for the South African power system in 2025 for the Base Case and the emission savings compared to the Base Case in each of the three scenarios.

To illustrate a possible monetary value of the CO_2-reductions a calculation example with a CO_2-price of R 120/t[1] is shown in the table above. If CO_2 has a cost at this level the value of reducing CO_2 will lead to a cost reduction that corresponds to 35-40 % of the total variable cost reduction indicated earlier.

Value of increasing interconnector capacity internally in South Africa

The Balmorel model is also capable of evaluating the need for strengthening the transmission system inside South Africa.

In the figure below, the marginal values of transmission lines are shown for the Base Case scenario (given in kR/MW). The marginal value is an expression of the economic value to the system if one extra MW of transmissions capacity is built and can thus be seen as the sum of all price differences between to areas over one year. Note that this is only the value of the first additional MW of transmission line and system value per MW would probably decrease for further expansions. The figure indicates the bottlenecks in the system.

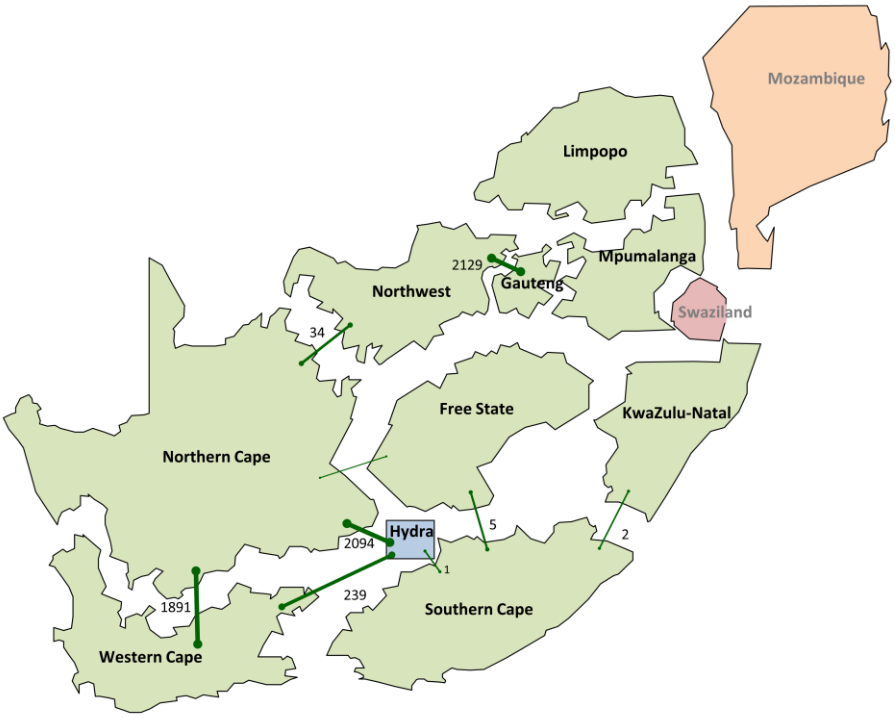

Figure 6: Marginal value of transmission lines (kZAR/MW) in the Base case.

[1] This CO2-price has earlier been suggested by the South African government. The department of National Treasury published the “Carbon Tax Policy Paper” in May 2013 which describes the proposed carbon tax. The tax, originally proposed to start 1 January 2015 has since been delayed to start 1st January 2016. The tax is planned to be phased in over a period of time. (http://www.thecarbonreport.co.za/the-proposed-south-african -carbon-tax/)

It is noticeable how most congestion exists in the southern and western parts of South Africa. All interconnector scenarios connect hydropower to the north but because of high cohesiveness in the northern regions no or limited bottlenecks are seen here. Following this, the difference in the marginal values is quite small when comparing the Base case to the three scenarios. The model results show that introducing imported hydropower does not necessarily call for reinforcements in the national transmission grid. However, reinforcements could benefit the system either way.

Conclusion

A detailed representation of the South African system has been set up in the power system model Balmorel. Three transmission and hydro scenarios (Zambia, Mozambique and Inga East) have been analyzed and compared to a base case for 2025. The model results show that:

- Establishment of the new interconnectors and hydro power projects will increase imports of power and thereby reduce power production in South Africa by 3.5, 20.9 and 21.3 TWh respectively. The import of hydro power mainly displaces power production from coal.
- The import in the three scenarios reduces annual variable costs in the South African system by R 1.1, R 6.2 and R 6.3 bn. respectively. This is mainly due to savings in fuel costs and variable O&M costs.
- Based on annual savings in variable costs investments of up to R 12.9, R 69.4 and R 71.4 bn. respectively could be economically viable using a lifetime of 30 years and an interest rate of 8 % (real).
- The investments in interconnectors and import of hydropower will significantly reduce CO_2-emissions in South Africa due to the reduction of power production from coal. In 2025 CO_2-emmissions can be reduced by up to 9 %. If the reduction in CO_2-emissions is set to a monetary value of R 120 /t variable costs in the power system could further reduced by 35-40 %, thereby increasing the value of the investments significantly.

In a broader view the analysis also has the following conclusions and perspectives:

- The integration of hydro power imports into the South African power system has the potential to reduce the overall cost of meeting electricity demand.

- The integration of imported hydropower has the potential to post-pone or even reduce the need for investments in new generating capacity in South Africa thereby resulting in significant savings over and above those described in this analysis.
- Introduction of CO_2 taxes will further improve the business case of the hydro scenarios compared to the base case.
- An integrated and coordinated approach to developing interconnectors to generation expansion programmes in the region should be adopted as this could reduce overall investment costs.
- Stronger transmission lines to hydropower in the north could also improve security of supply in South Africa by further diversifying supply options.
- This analysis has been based on one central set of assumptions for development of demand and generation. However, the development of the future power system is uncertain and sensitivity analyses could be applied to investigate the value of hydro and transmission projects in different future scenarios thereby, contributing to a more robust power system planning.

Detailed results of the scenario analysis

Power generation in the Base Case

The figure below shows the power generation in the South African System for the Base Case compared to the generation in the current power system (2013). The figure shows that power generation will increase significantly due to the increasing demand. Power production from coal increases but the share of coal production in the overall production mix decreases. This is because of the assumptions on increase in nuclear power capacity and renewable energy (wind and solar). Production from diesel and natural gas is marginal in the 2025 model results.

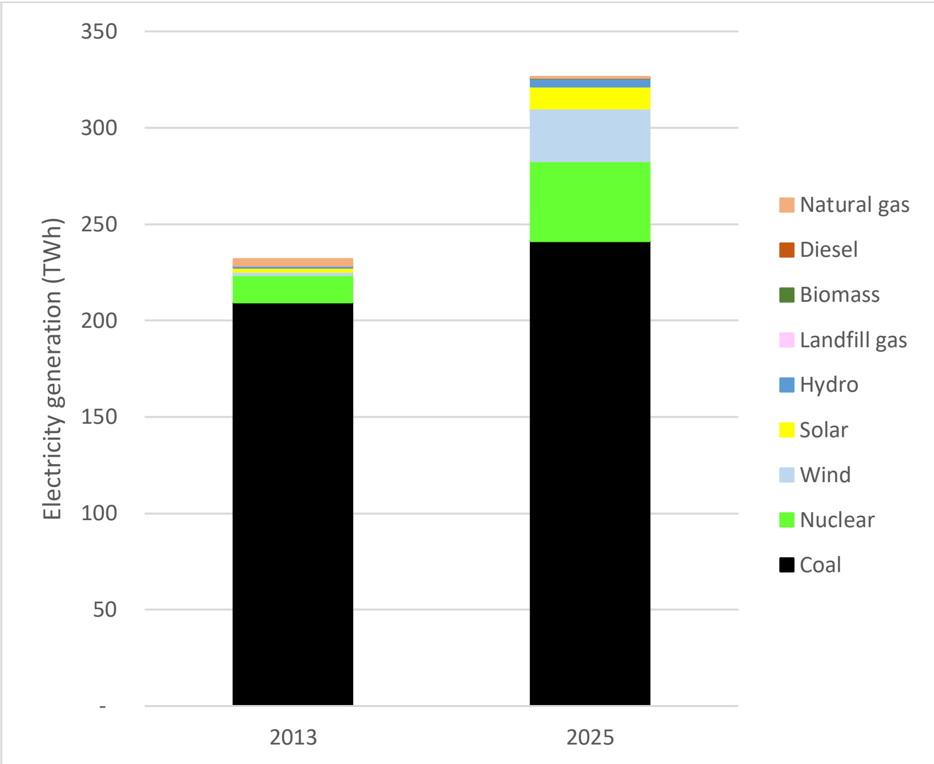

Figure 7: Total annual South African electricity generation in 2013 (historical) and 2025 (model run) for the Base Case given in TWh.

Figure 8 shows the power generation on the main power production units in the system.

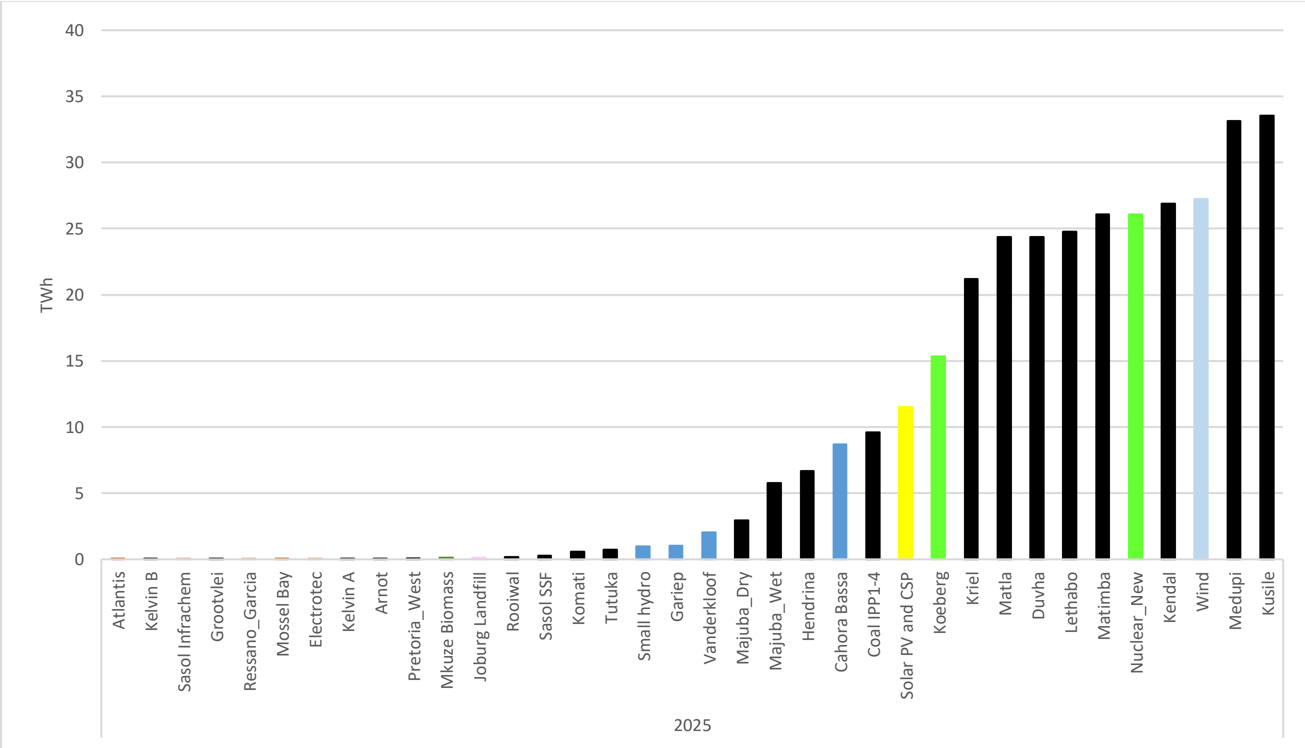

Figure 8: Annual electricity generation by units in 2025 given in TWh for the Base Case.

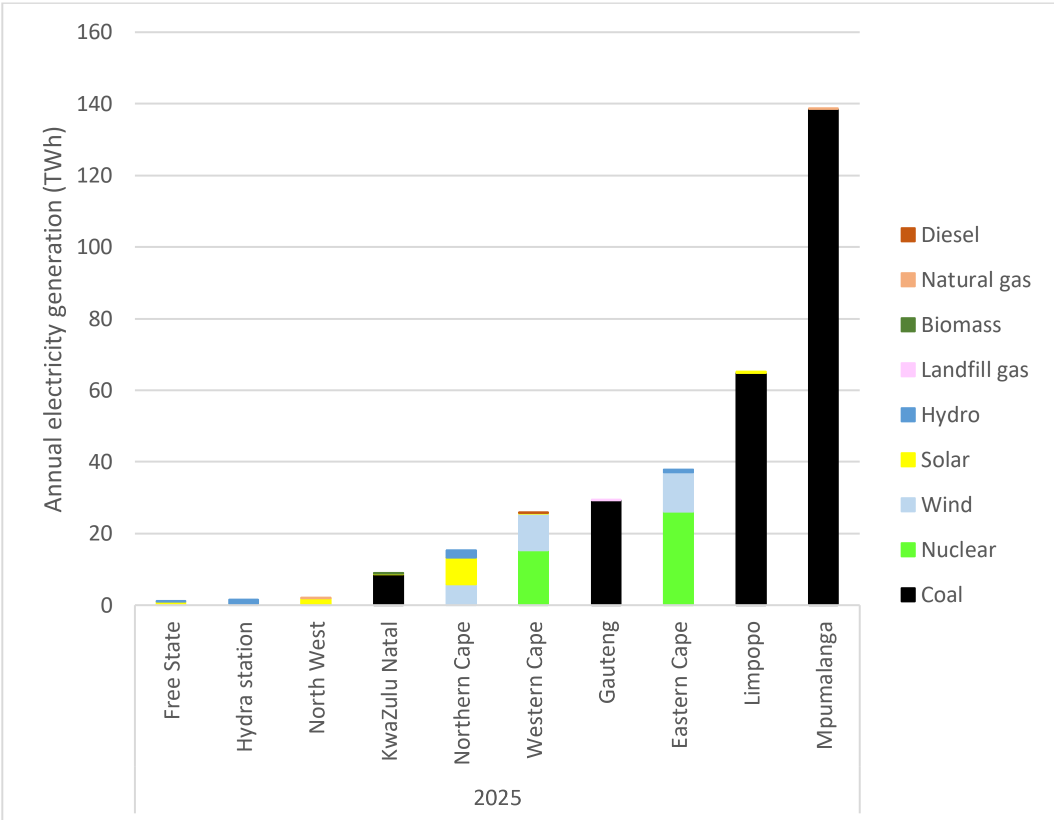

Figure 9 below shows the geographic distribution of the power production.

Most of the coal production is situated in the north-east of the country and Limpopo, whilst nuclear production is in the Eastern Cape and Western Cape where most of the wind capacity is also located. Solar development is mainly in Northern Cape.

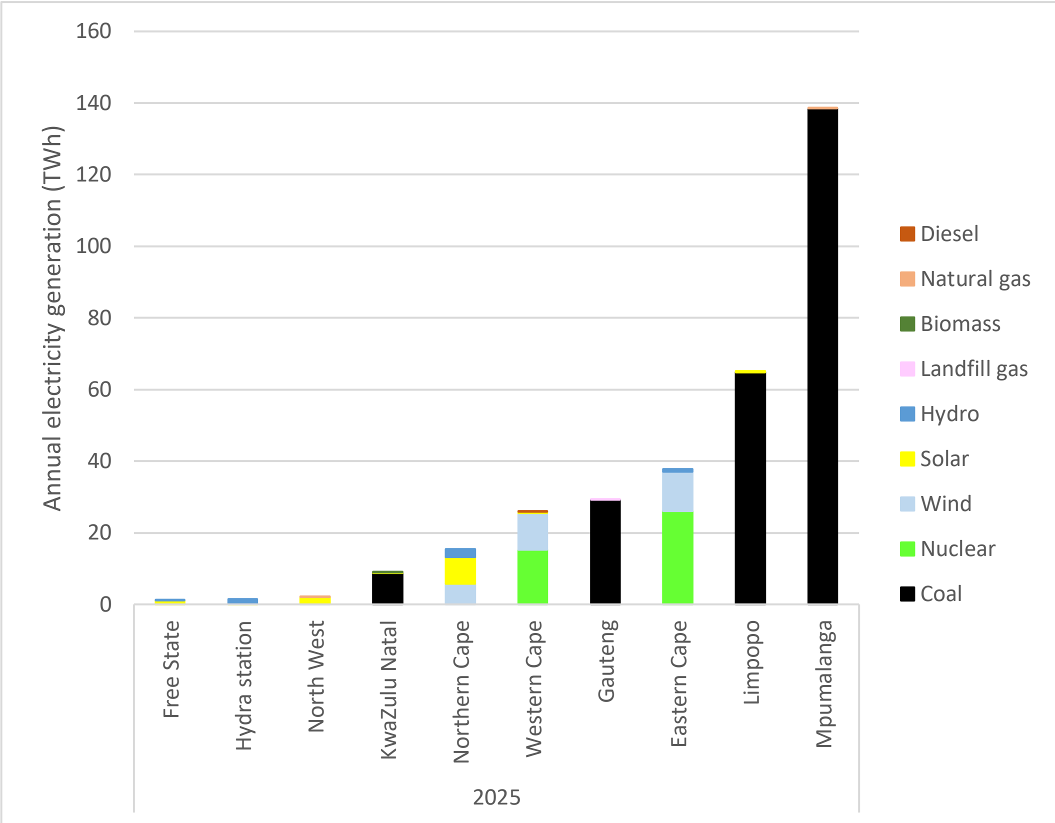

Figure 9: Annual electricity generation by regions in 2025 given in TWh for the Base Case.

Merit order of existing generation capacity

In Figure 10 the merit order of nuclear and fossil fuel-fired power plants in 2025 are shown. The merit order demonstrates the short-run marginal costs in terms of the variable costs and fuel costs. It is seen that the fuel costs have great impact on the merit order, especially for OCGT since diesel prices are high in relation to coal prices. Coal-fired power plants have different coal prices due to different long-term supply contracts with various suppliers and different levels of efficiency depending on age and technology choice.

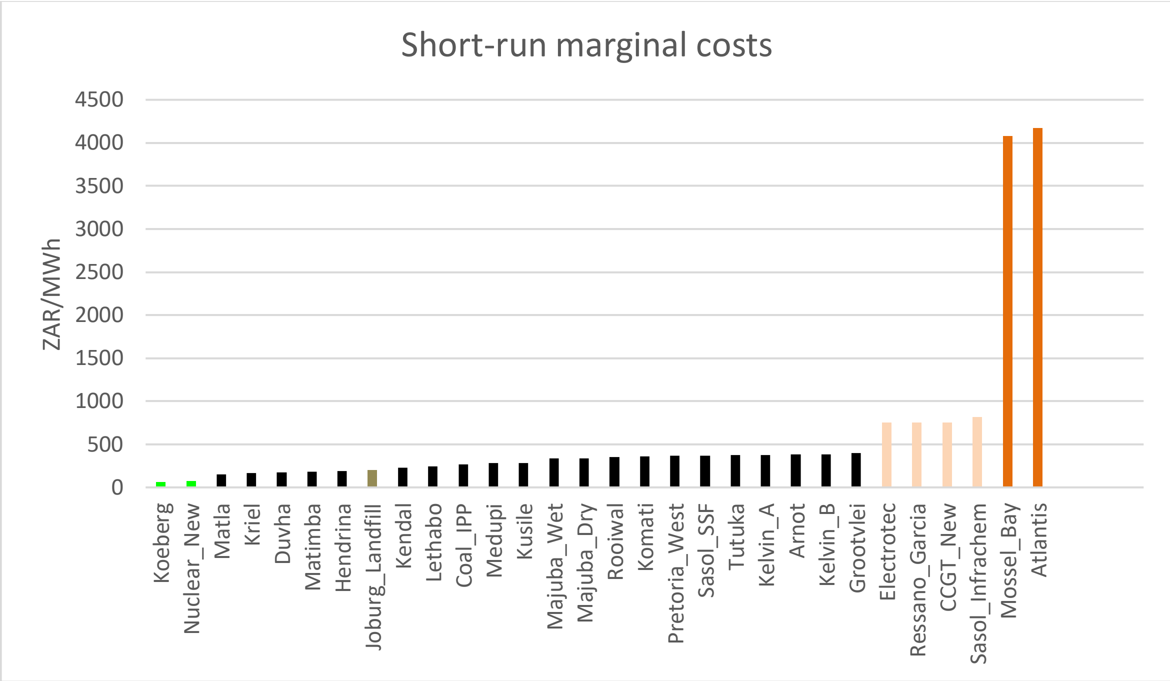

Figure 10: Merit order of nuclear power and fossil fuel-fired power stations in the Base Case scenario in 2025. "Coal_IPP" represents the short-run marginal cost of each IPP coal plant as these are asummed to be the same.

Power generation in the three interconnector scenarios

The figure below shows the power generation in South Africa across the modelled scenarios. South African power generation is reduced in the three scenarios when power is imported from the hydro power plants North of the country.

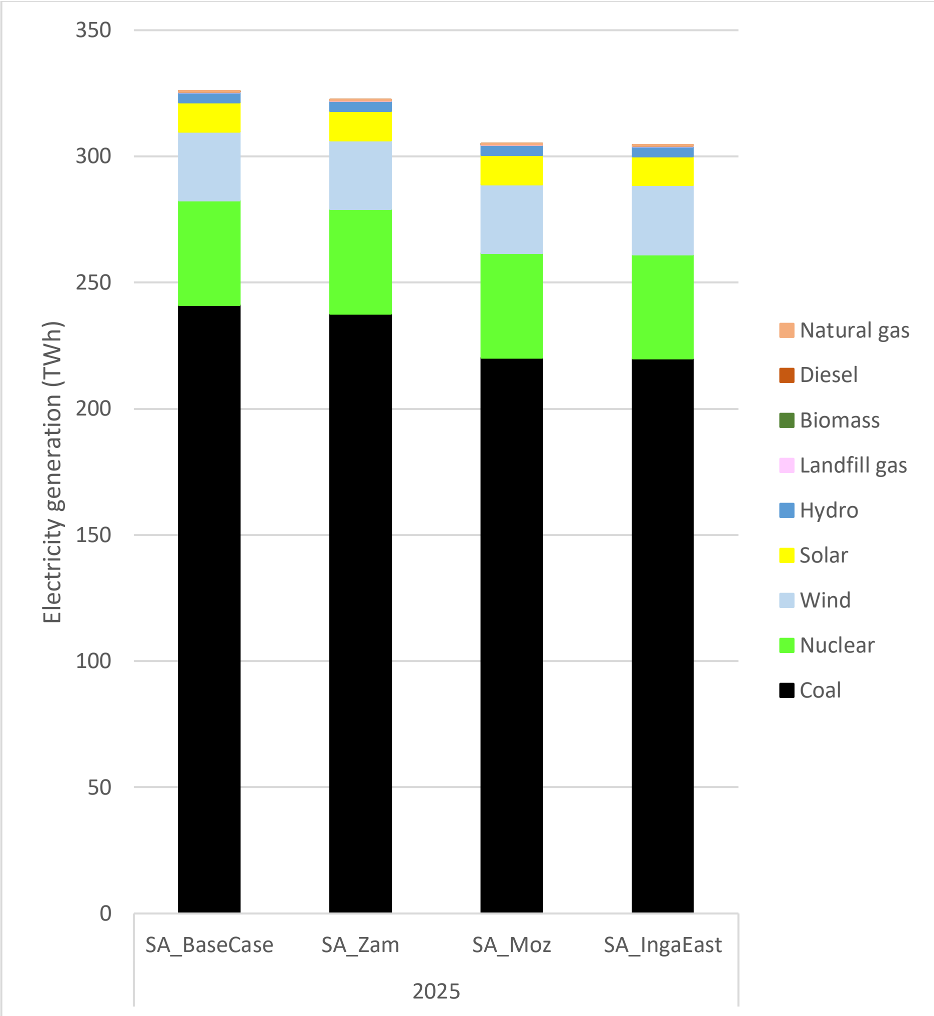

Figure 11: Total annual South African electricity generation in 2025 given in TWh for the Base Case and the three interconnector scenarios.

The table below shows what type of power generation is replaced by the imported power. It is mainly coal generation that is reduced in South Africa. Power generation from wind, solar and nuclear has very low marginal costs and the power production from these sources is therefore unaffected by the import of hydro power from the North. Instead, the more expensive production from coal is reduced.

Electricity generation SA (TWh)		Difference to Base Case		
	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Coal	241.2	-3.5	-20.9	-21.3
Nuclear	41.4	-	-	-
Wind	27.2	-	-	-
Solar	11.5	-	-	-
Hydro	4.1	0.1	0.0	-0.1
Landfill gas	0.1	-	-	-
Biomass	0.1	-	-	-
Diesel	0.0	-	-	-
Natural gas	0.0	-	-	-
Total	**325.8**	**-3.5**	**-20.9**	**-21.4**

Table 4: Total annual South African electricity generation in 2025 for the Base Case and the displaced generation in South Africa for Zambia, Mozambique and Grand Inga interconnectors given in TWh.

In the table below the increase in hydro generation in Zambia, Mozambique and DRC is compared to the reduction in generation in South Africa. The two numbers almost match but the increase in demand also plays a minor role.

Non SA generation (TWh)	SA_Zam	SA_Moz	SA_IngaEast
Hydro	3.5	22.9	21.5
Additional demand	-	*1,9*	-
Displaced gen. SA	-3.5	-20.9	-21.4
Displaced DSM	-0.001	-0.007	-0.010

Table 5: Non South African electricity generation, additional demand, displaced electricity generation and displaced demand side measures in the three scenarios for 2025 in TWh.

Economic results

The import of hydro from the North displaces generation in South Africa and thus saves variable costs on the power plants. The table below shows the saved costs in the system. It can be seen that the new interconnectors will save between 1,148 mio. ZAR and 6,335 mio. ZAR in variable costs for the South African power system.

Total costs (mio ZAR)		Difference to Base Case		
	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Fuel Cost	49,448	-956	-4,991	-5,10
Variable O&M	7,898	-128	-1,012	-1,03
Start-up costs	1,089	-64	-166	-20
Total	**58,435**	**-1,148**	**-6,169**	**-6,333**

Table 6: Total cost given as the fuel and variable O&M costs for the Base Case and the cost savings for the three scenarios in the South African system.

The average value of the displaced generation is between 288 ZAR/MWh and 332 ZAR/MWh. This corresponds well with the marginal costs for coal production shown earlier in Figure 10.

Value of displaced generation	SA_Zam	SA_Moz	SA_IngaEast
Displaced generation (TWh)	3.5	23.0	21.5
Average value (ZAR/MWh)	332	303	288

Table 7: Displaced electricity generation in TWh and average value of displaced generation given in ZAR/MWh for 2025 for the three scenarios.

In addition to the saved variable costs on power production units the three interconnector scenarios give room to a higher demand.

DSM	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Demand response (GWh)	288.7	287.8	282.4	280.0
Demand response costs (mio. ZAR)	448.0	447.4	459.1	442.4
Reduced DSM cost compared to BaseCase (mio. ZAR)		**-0.6**	**11.1**	**-5.7**

Table 8: Total demand side measures (DSM) in TWh and corresponding costs.

Demand response costs increase in the Mozambique interconnector case. This is due to the fact that the price of demand response in Mozal 1 & 2 are low. Therefore, when the system is in need of demand response, meaning shortage of supply, this is where it is cheapest and will be the best place to cut out, if transmission capacity allows power to flow. The flow of hydro generation from Mozambique into South Africa occupies the transmission lines and the demand response is then moved to another region with higher cost of DSM which causes a higher cost of demand response.

Total costs (mill. ZAR)		Difference to BaseCase		
	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Fuel Cost	49,448	-956	-4,991	-5,101
Variable O&M	7,898	-128	-1,012	-1,030
Start-up costs	1,089	-64	-166	-202
DSM costs	448	-1	11	-6
Total costs	**58,883**	**-1,149**	**-6,162**	**-6,341**

Table 9: Total costs in terms of fuel, variable O&M and DSM costs in mill. ZAR in 2025 and cost savings compared to the Base Case for each of the three scenarios.

The saved costs in the system should be compared to the costs of implementing the new interconnectors. Using a lifetime of 30 years and an interest rate of 8 % (real) the maximum investment allowed has been calculated. The results indicate that with the estimated savings in variable costs, a total investment of up to 13 bill. ZAR is acceptable in the Zambia case whereas up to a 70 bill. ZAR investment can be acceptable in the Mozambique and DRC cases. This investment would include both the investments in transmission lines as well as the investments in part of the hydro power plants that is needed for import to South Africa.

CO_2-emissions for the South African power system

The table below shows the development of the CO_2-emissions in the Base Case and the reduction in the three hydro import scenarios. The import of hydropower from the North can save up to 9 % of the CO_2-emissions from the South African power system, mainly because of the reduction of the use of coal.

CO_2 emissions (mill. ton)		Difference to BaseCase		
	SA_BaseCase	SA_Zam	SA_Moz	SA_IngaEast
Coal	237	-3.5	-19.9	-20.3
Diesel	0.02	-	-	-
Total	**237**	**-3.5**	**-19.9**	**-20.3**
Value (CO_2 price 120 ZAR/ton)		**-420**	**-2,388**	**-2,436**

Table 10: CO_2 emission in megaton for the South African power system in 2025 for the Base Case and the emission savings compared to the Base Case in each of the three scenarios.

To illustrate a possible monetary value of the CO_2-reductions a calculation example with a CO_2-price of 120 ZAR/ton[2] is shown in the table above. If CO_2 has a cost at this level the value of reducing CO_2 will lead to a cost reduction that corresponds to 35-40 % of the total variable cost reduction indicated earlier.

Marginal value of new interconnectors

The figure below shows the marginal value of new interconnectors in the South African power system.

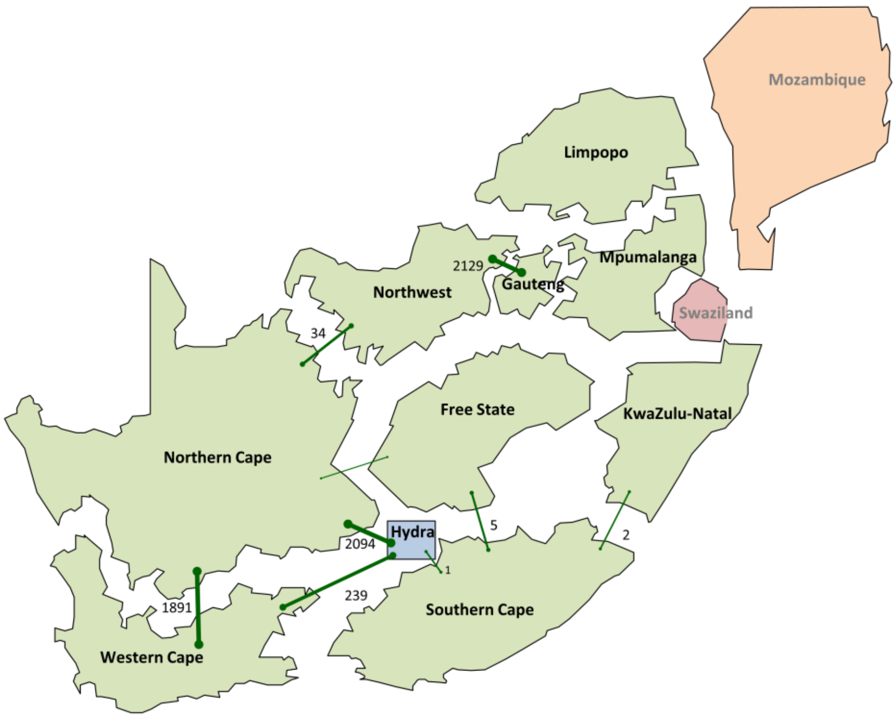

Figure 12: Marginal value of transmission lines (kZAR/MW) in the Base Case.

In the tables below the marginal values of transmission lines are shown for the Base Case and the three interconnector scenarios (given in ZAR/MW). The marginal value is an expression of the economic value to the system if one extra MW of transmissions capacity was available and can thus be seen as the sum of all power price differences between to areas over the simulation period. Note that this is only the value of the first additional MW of transmission

[2] This CO2-price has earlier been suggested by the South African government. The department of National Treasury published the "Carbon Tax Policy Paper" in May 2013 which describes the proposed carbon tax. The tax, originally proposed to start 1 January 2015 has since been delayed to start 1st January 2016. The tax is planned to be phased in over a period of time. (http://www.thecarbonreport.co.za/the-proposed-south-african -carbon-tax/)

line and system value per MW would probably decrease for further expansions. The tables indicate the bottlenecks in the system (can also be seen in the figure above).

It is noticeable how most congestion exists in the South and West part of South Africa. All interconnector scenarios connect hydro power to the North but because of high cohesiveness in the Northern regions no or limited bottlenecks are seen here. Following this, the difference in the marginal values are quite small when comparing the Base Case to the three scenarios. The model results show that introducing import of hydro power to the South African system does not necessarily call for reinforcements in the national transmission grid. However, reinforcements could benefit the system either way. These results are based on the assumed transmission capacity presented in Table 12. Thus, these results are sensitive to the future development the transmission grid.

Basecase interconnector	Nothern Cape	North West	Western Cape	Free State	KwaZulu Natal	Mpumalanga	Hydra	Eastern Cape
Hydra	2094261	0	239393	0	0	944	0	5
Gauteng	0	2129364	0	0	0	0	0	0
Western Cape	1871706	0	0	0	0	0	0	0
Nothern Cape	0	33865	19022	101	0	0	5	0
Eastern Cape	0	0	0	4735	2305	0	888	0
Free State	0	0	0	0	0	918	0	0
Mpumalanga	0	0	0	0	0	0	299	0
KwaZulu Natal	0	0	0	0	0	0	0	2

Zambia interconnector	Nothern Cape	North West	Western Cape	Free State	KwaZulu Natal	Mpumalanga	Hydra	Eastern Cape
Hydra	2098451	0	239962	0	0	943	0	6
Gauteng	0	2133616	0	0	0	0	0	0
Western Cape	1875483	0	0	0	0	0	0	0
Nothern Cape	0	33981	19169	103	0	0	5	0
Eastern Cape	0	0	0	4701	2314	0	880	0
Free State	0	0	0	0	0	917	0	0
Mpumalanga	0	0	0	0	0	0	291	0
KwaZulu Natal	0	0	0	0	0	0	0	2

Mozambique interconnector	Nothern Cape	North West	Western Cape	Free State	KwaZulu Natal	Mpumalanga	Hydra	Eastern Cape
Hydra	2111591	0	241984	0	0	944	0	4
Gauteng	0	2146562	0	0	0	0	0	0
Western Cape	1887011	0	0	0	0	0	0	0
Nothern Cape	0	33830	19525	100	0	0	5	0
Eastern Cape	0	0	0	4538	2208	0	808	0
Free State	0	0	0	0	0	918	0	0
Mpumalanga	0	0	0	0	0	0	283	0
KwaZulu Natal	0	0	0	0	0	0	0	2

Grand Inga interconnector	Nothern Cape	North West	Western Cape	Free State	KwaZulu Natal	Mpumalanga	Hydra	Eastern Cape
Hydra	2113637	0	242203	0	0	943	0	5
Gauteng	0	2149225	0	0	0	0	0	0
Western Cape	1888821	0	0	0	0	0	0	0
Nothern Cape	0	34441	19526	98	0	0	5	0
Eastern Cape	0	0	0	4533	2200	0	817	0
Free State	0	0	0	0	0	917	0	0
Mpumalanga	0	0	0	0	0	0	286	0
KwaZulu Natal	0	0	0	0	0	0	0	2

Table 11: Marginal value of transmission lines in 2025 given in ZAR/MW for the Base Case and the three interconnector scenarios

Model assumptions for the South African power system

Model of the South African power system

The South African power system has been modelled in Balmorel based on Eskom's seven regional grids and the areas within these regions. The map in shows how the power system is constructed in the model.

The connection lines between regions indicate a transmission constraint in the model. The magnitude of transmission capacity is demonstrated by the width of the arrows. Transmission flow can be the same in each direction of an arrow but this is not necessarily so, see Table 12 for actual transmission constraints. It is not possible to have constraints between areas in Balmorel, only between regions, so bottlenecks within a region are not represented but could be by divided a regional grid into 2 or more model regions. A region, Hydra, has been created to represent the constraint along the Cape corridor at the Hydra transformer station.

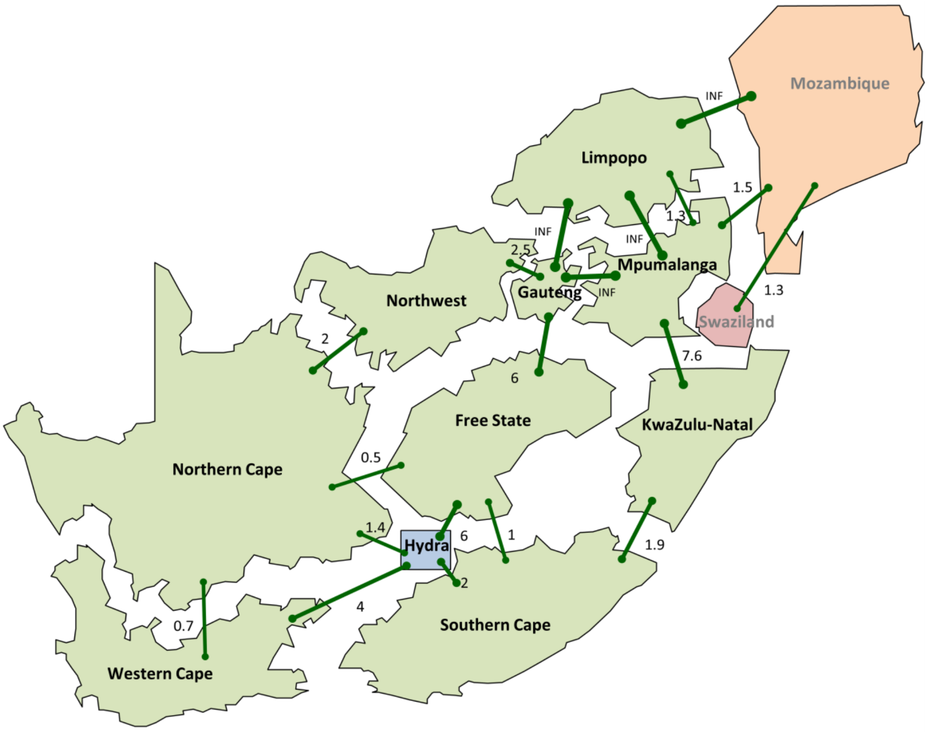

Figure 13: Visualisation of the South African power system in the Balmorel modelling tool.

Transmission constraints

Including transmission constraints is important when determining the value of new interconnectors to surrounding countries as well as the value of displaced generation in the power system. The presence of new generation capacity in the coastal regions provides an alternative to transmitting electricity from generation centres in the North and East of the country to the large coastal demand centres in the Western and Eastern Cape. This can also help determine the value of additional investments in transmission infrastructure. Only the 400 kV and 765 kV transmission systems are considered and only constraints over the most important bottlenecks were included for the purpose of this study. New investments in transmission capacity which are expected to be completed by 2016 are included in the model.

The transmission constraints in the model are listed in Table 12 below. No transmission limitations between the Central, North Eastern and Northern grids are included in the model as these areas have very strong transmission grids due to the high level of demand and generation in these grid areas.

Table 12: Transmission constraints in MW included in the power model

Grid (MW)	Gauteng	KwaZulu-Natal	Limpopo	Mpumalanga	Free state	E. Cape	W. Cape	N. Cape	Hydra	North West
Gauteng	-	-	INF	INF	6,000	-	-	-	-	1,000
KwaZulu-Natal	-	-	-	7,600	-	1,900	-	-	-	-
Limpopo	INF	-	-	-	-	-	-	-	-	INF
Mpumalanga	INF	7,600	-	-	-	-	-	-	2,000	-
Free state	-	-	-	1,000	-	-	-	-	4,000	-
E. Cape	-	1,900	-	-	1,000	-	-	-	2,000	-
W. Cape	-	-	-	-	-	-	-	1,000	4,000	-
N. Cape	-	-	-	-	485	-	725	-	1,400	600
Hydra	-	-	-	2,000	6,000	1,000	3,175	1,125	-	-
North West	1,000	-	-	-	-	-	-	600	-	-

INF – no limitation on transmission capacity

Mozambique and Namibia

In the model there is one interconnector directly to Mozambique from South Africa and one that doglegs through Swaziland and on to Mozambique. Demand in Mozambique is limited to Mozal aluminium smelter in the model. This is due to Mozal providing interruptible demand and the low residual demand in Southern Mozambique. Gas-fired power stations in Southern Mozambique are included in the model. This constitutes 490 MW of gas-fired generation from Ressano Gargia (140 MW), Electrotec (250 MW) and Gigawatt (100 MW). These plants will be able to handle approximately one third of the Mozal peak demand. The average hourly demand is 950 MW or 8.3 TWh annually.

The Cahora Bassa hydro plant in Mozambique is modelled as four units of 375 MW each with an availability of 67 %. The availability factor is taken from the SNAPP model and confirmed by sources in Eskom. This results in imports from Cahorra Bassa of approximately 7 TWh in 2025. No restrictions are placed on the DC connection between Cahora Bassa and South Africa in the model.

Exports to Namibia amount to approximately 1.5 TWh in all scenarios. There is no interconnector to Namibia in the model. Namibia's demand is aggregated in the Western grid as is the 45 MW of interruptible demand provided by the Skorpion zinc mine.

Load forecast

The overall demand for electricity in South Africa is expected to increase steadily according to the TDP. The annual electricity demand for each region is found by extrapolating the 2014 demand with the grid area peak demand projections. The rate of increase varies from grid area to grid area. The model aggregates demand data from hourly readings from all transmission level substations in each grid area from 1 January 2009 to 31 December 2010 and then applies the expected percentage increase in demand in each area as described in TDP. This results in an hourly demand forecast for each grid area. The total nominal demand in South Africa in 2025 in the model is 347 TWh. Together with Mozambique and Swaziland the model must satisfy a total nominal demand of 356 TWh. This demand is distributed between the regions in the model as shown in Figure 14 below.

Net demand refers to the energy demand at the point of consumption. More energy must be generated to meet the demand as grid losses and consumption for pumped storage must also be taken into account. Electricity consumed by pump storage is modelled as a generation loss rather than an end user demand.

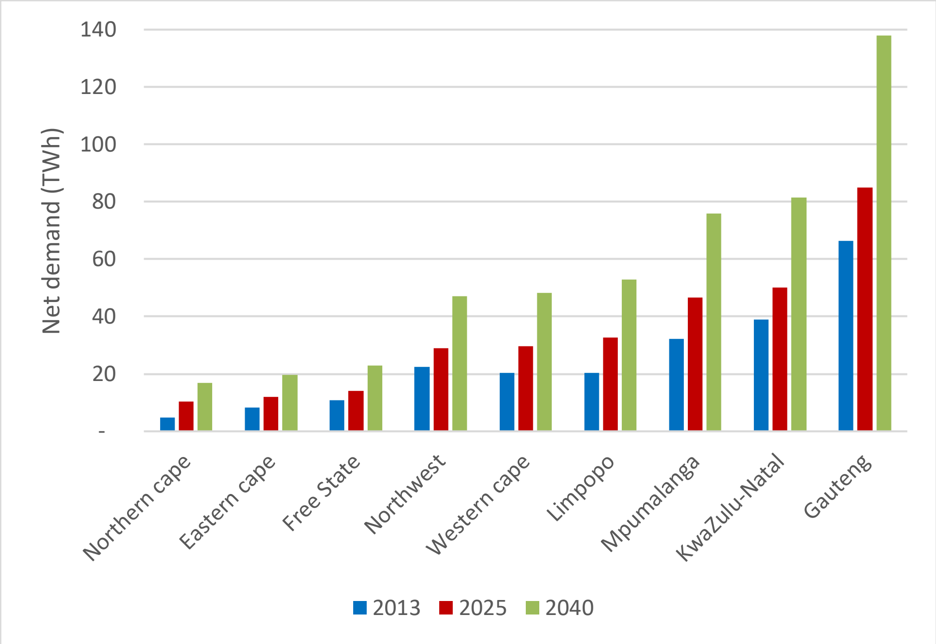

Figure 14: Net demand (TWh) in the regions in 2013, 2025 and 2040.

Demand Side Measures

The model includes price responsive interruptible demand or demand side measures (DSM) and the option of delaying consumption in industry through DRAPP. Data on interruptible demand and "Demand Response Aggregation Pilot Programme" (DRAPP) originates from "Third National Integrated Resource Plan for South Africa" (NIRP 3) and the Energy Research Centre at the University of Cape Town (ERC) respectively.

Interruptible demand can be disconnected when the marginal cost of electricity exceeds the price for interrupting the load; however, each interruptible demand market participant can at most be disconnected 1% of the time over a year, but no longer than for 2 hours at a time at any one time. There is a total of 1,945 MW of interruptible demand in the model.

An additional 990 MW of load reduction is included in the model under DRAPP. This is an action of last resort for the system operator as the marginal cost for activating load reduction in the model is high as shown in Table 7 below. In the model 200 MW of load reduction through DRAPP is positioned in the Southern grid whilst the remainder is positioned in the central grid in due to the concentration of industry in this area.

Unit	Unit size	Units	Availability	Mar. cost, ZAR/MWh
BHP Bayside	300 MW	1	1 %	182
BHP Hillside	400 MW	2	1 %	180
Mozal 1 & 2	400 MW	2	1 %	81
Skorpion	45 MW	1	1 %	176
Total	*1,945 MW*	-	-	-
SA_C	510 MW	1	1 %	1067
SA_C & SA_E	480 MW	1	1 %	800
Total DRAPP	*990 MW*	-	-	-
Total demand response	**2,935 MW**			

Table 13: Interruptible demand and load reduction included in the model

In order to ensure the supply-demand balance in the model in 2025 additional DSM is added. In each region 600 MW is added at a disrupt price of 5000 ZAR/MWh. Adding additional DSM to the model at an expensive price of ZAR 5000 insures that the DSM is the last possible option to ensure the supply-demand balance. However, this price will directly dictate the economic results of reducing DSM in the scenarios. One reason for the need of additional DSM is that some peak demands in the model based on historical profiles is larger than that assumed in the TDP. Another reason is that it is preferable to fulfil the supply-demand balance in a deterministic model like the Balmorel model with makes for a more robust model solution.

Generation capacity

In the Balmorel model, individual power stations or types of power stations (aggregated groups) are represented by different technical and economic parameters, e.g.

- Technology type
- Type of fuel
- Capacity
- Efficiency
- Desulphurisation
- NO_x emission coefficient
- Variable production costs
- Fixed annual production costs
- Investment costs

Information on the available generation capacity in South Africa in 2016 is taken from NIRP 3, Eskom's Annual Report 2012/13, information on Eskom's power plants on their website, the IRP 2010 technology catalogue “Power Generation Technology Data for Integrated Resource Plan of South Africa” and the IRP 2013 update “Integrated Resource Plan for Electricity” (South African Department of Energy, 2013).

NIRP 3 provided data on the generation efficiency of most existing Eskom and non-Eskom power plants, planned and unplanned outages, fuel costs, fixed costs and variable costs. Data on the newer OCGT power stations, Ankerlig and Gourikwa was obtained from the data on Eskom’s homepage. The new peakers, Devon and Avon, are assumed to have the same generation specifications as Eskom’s OCGT power plants. Medupi and Kusile are assumed to have the same specifications as indicated in the IRP 2010 technology catalogue for their technology types.

Commissioning of Medupi and Kusile

The commissioning of Medupi and Kusile power stations has been repeatedly delayed. The commissioning of the two power plants has been included in the model with the following timeframe.

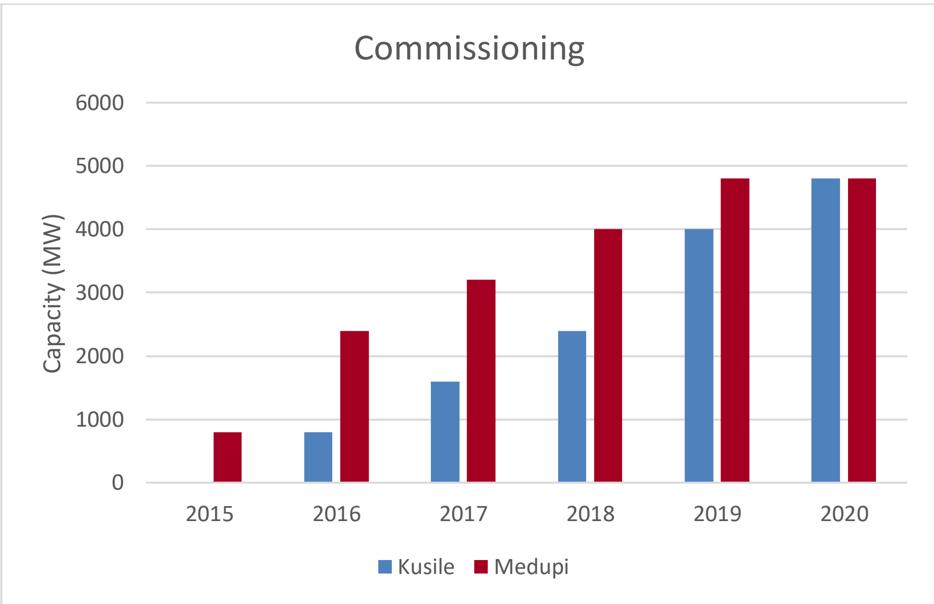

Figure 15: Cumulative commissioning of generation capacity from Medupi and Kusile power plants in the model

Generation capacity

Generation plants are divided into units and positioned in the grid area where they are situated geographically. This positions them in relation to the transmission grid and demand providing a better simulation of transmission restraints in the power system.

The model is updated based on the IRP 2013. This includes capacities for all existing generation units. New generation capacity is based on the TDP and plans for the first four bid programmes of REIPPPP along with additional bid programmes.

Existing capacity

The existing capacity used in the Balmorel model is updated based on table 16, p. 59 of the IRP 2013. This produced the following capacity for the existing generation as of 2015:

South African generation capacity 2015			
	(MW)		(MW)
Eskom generation	**53139**	**Non-Eskom generation**	**3856**
Camden	1520	Cahorra Bassa	1500
Grootvlei	1080	Pretoria West	90
Komati	900	Rooiwal	180
Arnot	2220	Sasol_Infrachem	150
Hendrina	1900	Sasol_SSF	500
Kriel	2880	Steenbras	180
Duvha	3480	Kelvin A	75
Matla	3480	Kelvin B	153
Kendal	3840	Umtata falls 1	6
Lethabo	3540	Umtata falls 2	17
Matimba	3720	Avon OCGT	670
Tutuka	3540	Dedisa OCGT	335
Majuba Wet	1990		
Majuba Dry	1850		
Koeberg*	2128		
Gariep	360		
VanderKloof	240		
Colleywobbles	70		
Drakensberg	1000		
Palmiet	400		
Acacia	57		
Port Rex	180		
Atlastis	1350		
Mossel bay	750		
Medupi	4800		
Kusile	4800		
Ingula	1332		

Table 14: Generation capacity in South Africa in 2015.
**Koeberg is increased from 1860MW to 2128MW based on TDP information on the Thermal Power Uprate Project and the Steam Generator Replacement Project.*

Furthermore, solar power and wind power is included in the model. The first four rounds of the REIPPPP are included as well as an additional 6300MW of RE (EngNews, 2015). In 2015 the solar and wind power is constituted by:

- 1050 MW Solar PV
- 200 MW CSP
- 1305 MW Wind (including Sere, Klipheuwel and Darling).

New capacity

Towards 2025 additional capacity is added:

- 7,386 MW Wind
- 4,560 MW Solar PV
- 500 MW CSP
- 3,468 MW nuclear power (Koeberg increase and 3,200MW new at Thyspunt)
- 2,750 MW coal fired (Coal IPP1-4 in Witbank and Lephale)
- 1,005 MW diesel fuelled (Avon and Dedisa)
- 19 MW small hydro (Neusberg, Stortemelk and Kruisvallei)
- 18 MW landfill gas

The model can provide the option of investing in new generation capacity. However, in this study new capacity is handled exogenously dictated by the REIPPPP and TDP. This provides data for the amount of new generation in different generation types.

The deployment of new capacity is sensitive to geographical location as bottlenecks in the existing transmission grid might influence the value of generation. No information on the placement of the additional 6,300 MW RE were available. However, in collaboration with Eskom Transmission a placement was found. Eskom Transmission has performed a transmission network study in new placement of generation along with the necessary transmission line expansions. Based on this the new capacity was fitted into the Balmorel model. Placement and capacity for new generation can be seen in Figure 16 and Table 15.

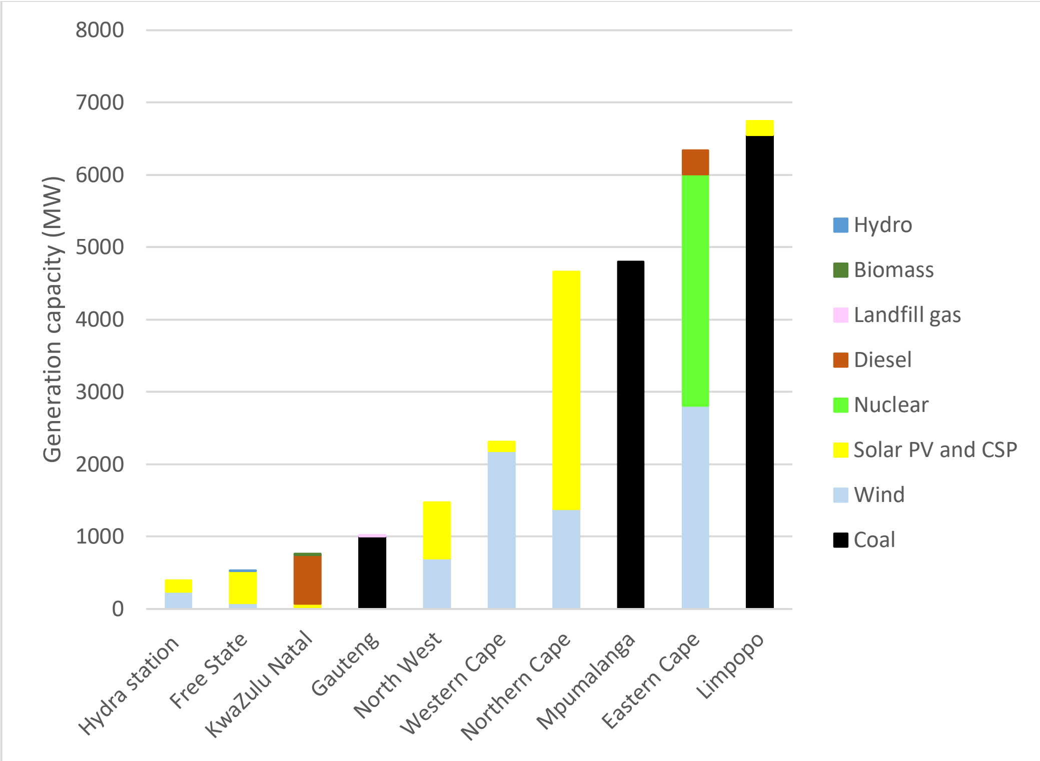

Figure 16: Distribution of new SA generation capacity in the model shown in MW. Including the REIPPPP

(MW)	Coal	Wind	Solar PV and CSP	Nuclear	Diesel	Landfill gas	Biomass	Hydro	Region total
Hydra station		235	162						**397**
Free State		79	447					5	**531**
KwaZulu Natal			75		670		16		**761**
Gauteng	1000					18			**1018**
North West		700	771						**1471**
Western Cape		2180	134						**2314**
Northern Cape		1385	3278						**4663**
Mpumalanga	4800								**4800**
Eastern Cape		2807		3200	335				**6342**
Limpopo	6550		193						**6743**
Fuel total	**12350**	**7386**	**5060**	**3200**	**1005**	**18**	**16**	**5**	**29040**

Table 15: Distribution of new SA generation capacity in the model shown in MW. Including the REIPPPP

Decommissioning

Many of the existing power plants in South Africa are beginning to reach their technical lifetime. Some maybe given lifetime extensions while others are decommissioned. In the TDP a decommissioning plan is given. Based on this the Balmorel model was updated with the corresponding lifetimes of each generation unit. The plants who will undergo a decommissioning is Arnot, Camden and Hendrina resulting in 3,600 MW capacity reduction.

Power plant outages

The model distributes planned outages for each unit of each power station according to the yearly demand profile and availability of other generation units in the power system. As such more planned outages will occur at times of the year where demand is low. Unplanned outages are also included in the model stochastically. They occur randomly based on outage data from NIRP 3 and ERC. The model compensates for unplanned outages using the least cost option available. This is sometimes interruptible demand.

Unit commitment

Unit commitment is utilized in the model. Each power station is divided into the subunits of which it is comprised of. This allows for planned outages to be implemented at the unit level rather than the entire power plant being removed from generation at one time in the model. The model also includes generalized unit commitment data on minimum load and start-up costs for all thermal power plants. Such, it is possible for the model to start a number of units within a plant and the start-up cost will be paid for the number of units which are started. Adding unit commitment functionality to model simulations helps produce a more nuanced image of dispatch regulation in the scenarios with imported hydro power and produce a more real-lifelike solution.

Solar resources

Solar resources are taken from the EC project "Photovoltaic Geographical Information System". The project provides a map-based inventory of solar energy resource and assessment of the electricity generation from photovoltaic systems in Europe and Africa. Solar data was available in the form of average production every hour over a day in each month of the year.

Solar data was acquired from PVGIS for Namaqualand, Northern Cape, North West, Gauteng, Eastern Cape, Karoo and Limpopo. The results showed that there are different seasonal solar generation profiles in different areas of South Africa. There are areas with higher capacity factors in the summer months and areas with higher capacity factors in the winter months. There are higher annual capacity factors in areas with the summer profile, but the higher levels of generation in winter for areas on the Highveld and Lowveld may give greater value to solar power in these areas. They are also closer to the largest demand centres in the country. There may be advantages for the power system in ensuring that solar capacity is dispersed in both the summer and the winter profile areas in order to ensure generation from solar resources when the electricity is most needed. Three examples of solar capacity factor profiles are shown in Figure 17 below.

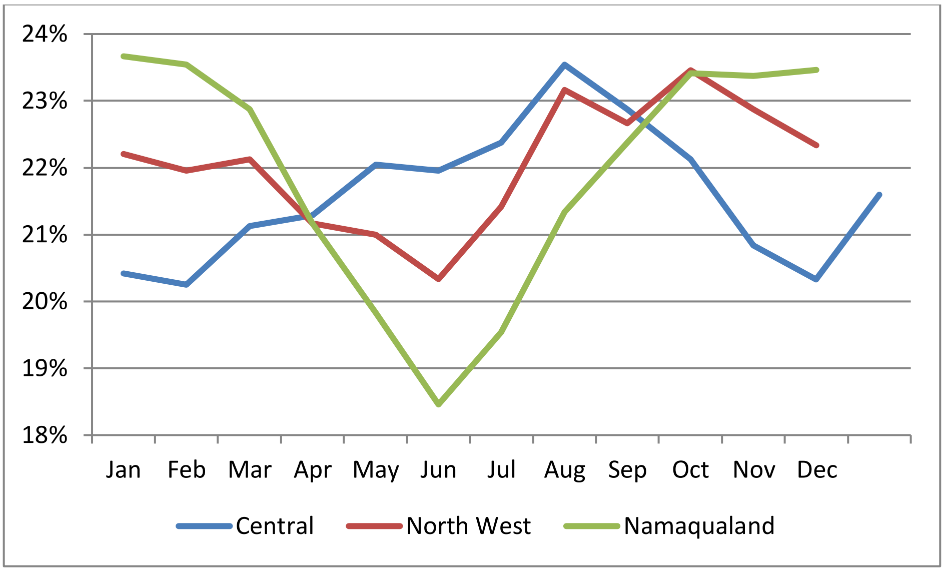

Figure 17: Forecast of monthly average capacity factor for solar PV in North West, Central (Free State) and Namaqualand (Northern Cape) grid region.

Solar generation

The same resource data has been used for CSP as for solar PV. For the purpose of this study it is assumed that only CSP without storage will be constructed. CSP generation capacity is dispersed in the model as shown in Table 16. Total PV generation capacity is assumed to reach 4.560 MW in 2025. The distribution of this can be seen in Figure 16 and Table 15.

Project	MW	Grid area	Grid region
REIPPPP CSP	200	Namaqualand	Northern Cape
Bokpoort	50	Kimberley	North West
KaXu Solar One	100	Namaqualand	Northern Cape
Khi Solar One	50	Kimberley	North West
Xina Solar One*	100	Namaqualand	Northern Cape

*Table 16: Deployment of CSP generation capacity in the RE scenario. *Xina Solar One is commissioned in 2017.*

Wind resource and generation

The wind resource and generation is based on data from WASA. Hourly readings from wind measuring masts are publically available on the WASA homepage. These have been included in the model along with a power curve for a standard model turbine reflective of the wind turbine models available on the South African market and results in different full load hours for wind turbines in different areas and different wind profiles for each area.

Grid area	Full Load Hours
East London	2.617
Karoo	3.477
Port Elisabeth	3.307
Peninsula	2.442
Southern Cape	3.976
West Coast	3.119

Table 17: Full load hours for wind turbines in each grid area in the model

The overall variability of wind power generation in the system is reduced in the updated model as there are profiles for each grid area based on data from WASA. There is very limited correlation of wind power production in the three areas shown in Figure 18 even though each region has only one point at which wind speed measurements have been taken resulting in greater variability within each region than can be expected in reality.

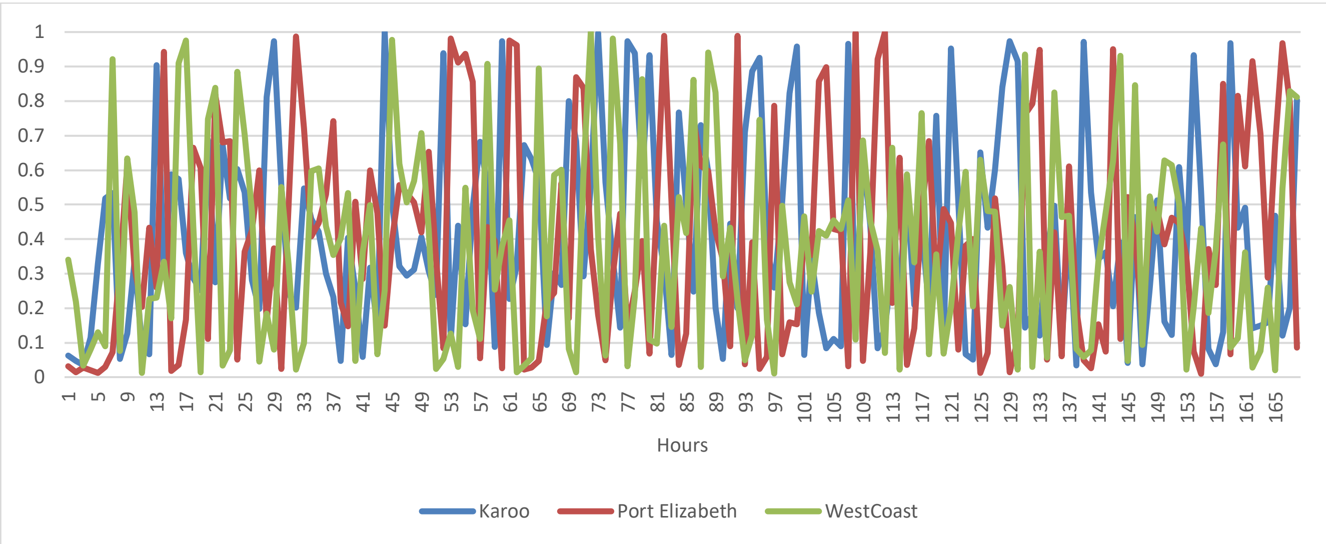

Figure 18: Wind power generation in three grid areas as a fraction of total installed wind capacity in the region for one week in the model

Other renewables

Small hydro has been allocated in the REIPPPP. Only 14 MW have been awarded to date. In Table 17 the total deployment of hydropower in the system is seen.

Project	MW	Grid area	Grid region
Existing Hydro	**2.212**		
Stortemelk*	4	Bloemfontein	Free State
Neusberg*	10	Namaqualand	Northern Cape
Gariep 1 – 4	360	Hydra	Hydra
Van Der Kloof 1 & 2	240	Karoo	Northern Cape
Umtata Falls 1 & 2	23	East London	Eastern Cape
Collywobbles	70	East London	Eastern Cape
Kruisvallei	5	Welkom	Free State
Cahora Bassa 1 – 4	1.500	Moz CB	Moz CB

*Table 18: Deployment of hydro in the model. *Stortemelk and Neusberg are assumed to be commissioned by 2015.*

One biomass (Mkuze), one landfill (Johannesburg) but no biogas projects has been identified as preferred bidders in the REIPPPP to date. The allocation for these technologies is also very limited totalling only 34 MW.

Technology catalogue for new generation

The table below shows the technology data and costs applied in this analysis for new electricity generation technologies. The costs of RE technologies are based on the reported costs in relation to the renewable energy programme by the Department of Energy. Nuclear, coal and natural gas technology costs are based on the IRP2013. Note that investment costs are ignored in this study. It was chosen to let future generation capacity be dictated by the TDP and cost of establishing new generation are the same across all scenarios. Thus, this study does not focus on the total costs of investing in new generation capacity but the value of interconnectors feeding into the described power system. As such, the results do not include potential investment savings of new generation capacity displaced by hydro import.

		Fuel efficiency	Fixed O&M ZAR12/MW$_{el}$	Variable O&M ZAR12/MWh$_{el}$
OnshoreWind	Wind turbine	1	0,497	0,0
CSP	Concentrated solar power	1	0,574	0,0
SolarPV	Solar voltaic	1	0,574	0,0
Nuclear	Nuclear power	0,33	0,532	29,5
Coal	Coal power	0,37	0,552	51,2
OCGT	Open cycle gas turbine	0,30	0,078	0,2
CCGT	Combined cycle gas turbine	0,48	0,163	0,7

Table 19: Data for new generation capacity.

Fuel prices

The coal prices in the model are based on the price found in the IPR 2013 providing an average of R21.3/GJ. The coal price paid by each power station was calculated based on information from NIRP 3 and hereby divided to the individual coal fired power plants. Medupi and Kusile are considered to have fuel costs equal to the average R21.3/GJ. Natural gas price is found in the IRP 2013 to be R74/GJ in 2013 and projected using the IEA World Energy Outlook 2013.

Diesel is bought on the international market and the costs in the model are based on price prognoses from the New Policies scenario in the IEA World Energy Outlook 2013. In 2025 the diesel price is R342/GJ. Figure 19 below shows the fuel prices used in the model for power stations in the model in year 2025.

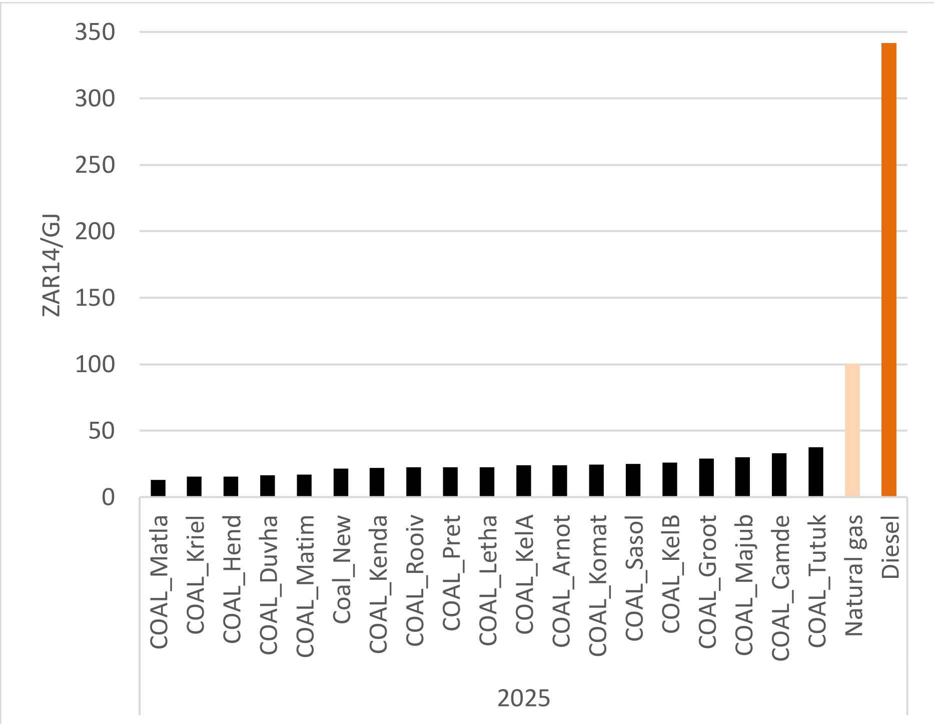

Figure 19: Fuel prices used in the Balmorel model

The Balmorel model

Building the model

The analysis was carried out using the Balmorel model, which is an economic/technical partial equilibrium model that simulates the power system and market. The model optimises the production at existing and planned production units (chosen by the user). It can also allow new investments in generation capacity and transmission capacity to be made in scenarios. Investments are chosen by the model on a cost minimising basis. However, model runs performed in this study does not include endogenous investments by the model.

In order to simulate the economic dispatch of generation capacity as realistically as possible the model considers the most important transmission constraints in the power system. This is done by specifying geographically distinct entities in the model divided into countries, regions and areas. Each country is constituted by one or more regions while each region contains zero or more areas. Any area may only be included in one region, and any region may only be included in one country. Figure 20 below illustrates how the model is built up using the geographical entities in Balmorel.

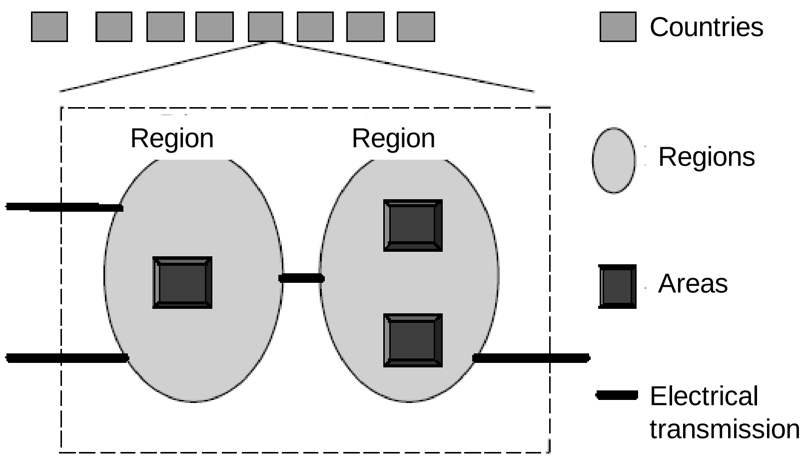

Figure 20: The geographical entities used in the model of the South African power system.

Electricity balances are given on a regional basis. In each region an electricity balance must be fulfilled in the model either by generation, the transmission of electricity into or out of the region or a combination of generation and transmission. When using transmission for exchange of electricity between regions transmission constraints, losses and costs are included. This is the motivation for the concept of regions and allows the model to determine the value of placing infrastructure investments in different regions of a power system as well as the different costs associated with generation and consuming electricity in different regions in the same country. A number of regions constitute a country.

A country does not have any generation or consumption apart from that which follows as the sum of the regions in the country. However, a number of characteristics may be identical for all entities in a country (e.g. generation units, demands, prices and taxes). A country is constituted of more than one region when required to represent constraints in the electricity transmission system within the country that limit the ability of generation capacity in one region to supply another region with electricity.

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