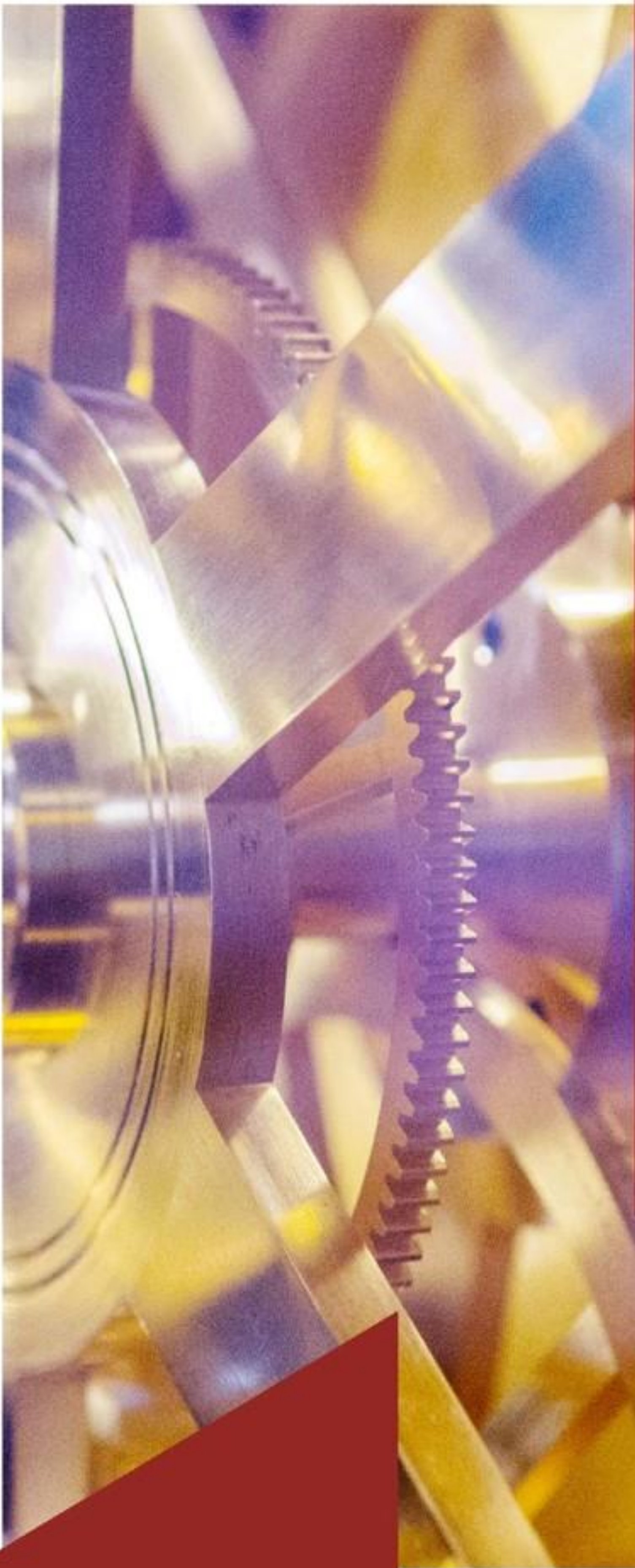

Stochastic analyses of adequacy

Renewable energy and system adequacy in South Africa

Ea Energy Analyses

Eskom

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Contents

1. Introduction

The project “Strategy about System Adequacy and Reserve Margin with Increasing Levels of Variable Generation” assesses the effects of increasing levels of penetration of renewables on the system adequacy and reserve margins of the South African grid. It is supported by the South African-Danish program for renewable energy.

The project is led by Ea Energy Analyses and supported by the Danish Technical University, EOH EnerWeb, Danish Energy Agency, as well as the Danish TSO, Energinet.dk (in an advisory capacity).

This report documents the Stochastic Analysis and System Adequacy study – and explores scenarios for the South African power system assessing how system adequacy and the need for reserves may develop in the future, addressing the geographical distribution of the renewables, the load, and the transmission grid. It also provides input to the analysis of costs of ensuring system adequacy.

Thoughout the project we have collaborated closely with the Steering Comittee and the User Group. SANEDI, DoE and Eskom have been represented in these groups. Detailed data about the South African system has been supplied by Eskom for use in this project.

Training in the use of the SisyfosR model has been part of the project. The institutions involved in the project can continue using the SisyfosR model free of charge after the completion of the project.

In this project, the use of stochastic analyses has been demonstrated. Extensive data collection has taken place, and the current study has been based on the best available information. In order to further refine the analysis, however, continued work with the model could include further improvements of the input data.

Mikael Togeby

2. Executive summary

The reliability of electricity supply in South Africa is far from the desired level. In periods since 2005 it has been necessary to curtail demand to secure the stability of the overall supply. Many critical parameters contribute to the crisis, including lack of adequate investment in new generation and low level of availability of the existing fleet of generators[1].

Electricity systems must be in balance at all times: Generation must be equal to demand – in each hour and each second. If generation is not adequate, demand must be curtailed – or system blackout is a distinct possibility. Reserves are used to maintain a stable system, also after loss of individual elements like power stations or transmission lines. Traditionally, static methods have been used to allocate reserves, e.g. the N-1 criteria that dictates that the system should always be able to survive a sudden loss of the largest or most critical unit or a certain excess capacity e.g. 20%.

This perspective will always remain relevant. Sudden loss of elements happens and the system security should not be threatened by this. Strategic or economic consideration can indicate whether it should be N-1 or N-2 (one or two independent failures) and what timespan is required before the system must again be able to withstand a new failure.

In this study a stochastic method of analysing system adequacy has been used. Stochastic methods can improve the N-1 method, since failure of all units is considered. The strengths of stochastic methods are multiple:

- The results are in real security of supply units, e.g. energy not served (ENS). This can be compared to a security of supply criterion (e.g. max 20 GWh ENS per year or 1 hour per year) or used to find "an economically optimal level of ENS". Different future systems can be simulated, e.g. with different levels of plant availability or different levels of renewable energy penetration etc.
- The complex nature of a given system can be represented, e.g. the actual set-up with the individual power plants and the layout of the transmission grid, as well as the actual availability of the different elements. Especially new power sources with varying generation, like wind and solar, can be included in the analyses and their contribution to security of supply investigated.

[1] See: Wilson et al (2006), MAPS (2014), Trollip (2014), South Africa Government (2015)

Stochastic methods can be complex and demanding with respect to computational power resources. The model employed in this study, SisyfosR, simplifies some aspects of power system modelling (e.g. unit commitment and merit-order dispatch), while delivering superior performance in terms of ease of use as well as speed of model run-time. It should though be noted that the simplifications indicated do not affect the model's ability to calculate ENS.

The system adequacy model SisyfosR has been populated with detailed data about the South African electricity system. Information about all power plants and a detailed representation of the transmission grid has been entered into the model. Hourly demand profiles for each node in the transmission grid have been used, as well as hourly node-specific generation profiles for wind and solar power (time series of 8,760 hours for each profile). Energy Not Served (ENS) has been calculated for 2014, 2020 and 2025 for a selected number of alternative scenarios.

The SisyfosR model has an MS Excel interface and can be run on a server or a regular personal computer.

Scenarios

In the current study, a number of scenarios have been investigated in the SisyfosR model. All results are based on 1 000 annual, i.e. 8 760-hour, model runs for each scenario. A 'Reference' case representing year 2014 has been simulated in order to provide a validation for the model, as well as a within-model benchmark for the future scenarios. For year 2014, the SisyforR-modelled ENS of 655 GWh compares relatively well to the real-life reported ENS of 512 GWh.

Simulations are also made for years 2020 and 2025, respectively. In order to account for the uncertainty regarding future developments, a number of key parameter variations are explored:

- Demand (Low 1% p.a., Moderate 2% p.a., High 3% p.a.)
- Plant outage levels (on average: Low 8%, High 13%, Very High 17%)
- Renewable energy development pathways (All RE, Half RE, Half_Half[2] RE)

[2] Scenarios where only half of the planned RE expansion takes place, whereas the other half (in expected power generation equivalent) is substituted through conventional generation capacity

The results of all of the scenarios explored in the current study are presented in Table 1.

		Demand: Low			Demand: Moderate			Demand: High		
		Outage level								
Year	*RE development*	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**
2014	*Actual*			655						
2020	*Half_Half RE*	9	9	9	19	42	293	136	1 636	5 435
2020	*All RE*	9	9	9	19	55	355	174	1 746	5 440
2020	*Half RE*	9	9	9	19	83	569	256	2 636	7 776
2025	*Half_Half RE*	9	9	9	16	16	16	47	344	1 389
2025	*All RE*	9	9	9	16	16	17	66	493	1 699
2025	*Half RE*	9	9	9	16	16	21	104	926	3 134

Table 1: Annual average ENS for all SisyfosR modelled scenarios across 1000 runs per scenario. Unit: GWh per annum

The SisyfosR scenario analysis suggests that the demand projections are a critical factor with regard to the resulting modelled system adequacy, as expressed by the average annual Energy Not Served (ENS). E.g. with the current generation fleet expansion plans materializing on schedule and the demand growth continuing at a rate of 1% per annum (Demand: Low), the system adequacy should be able to reach satisfactory levels, even in the absence of improvement in the existing generation fleet availability rates. Should the demand growth rate reaches 2% per annum throughout the projection period (Demand: Moderate), the modelling results suggest that system adequacy outcomes would be more dependent on the developments in other key factors, e.g. the availability rates of the existing generation fleet and realization of the RE development plans (the factors tested), especially towards 2020. Finally, if the demand development reaches the levels as projected by IRP 2010 (i.e. demand growth rate reaches 3.1% per annum throughout the projection period; Demand: High scenarios), the modelled outcomes in terms of average annual ENS reach critical levels even under the assumption of most favourable outcomes in terms of other key factors.

In addition, the impact of potential alternative futures with regard to the RE expansion development have been explored in the current analysis. The 'Half RE' scenario compared to the 'All RE' shows that a delay in the RE expansion will result in severe implications for system adequacy if demand is high. Similar effects can be observed in the case of 2020 with moderate demand and outage levels above low.

The ‘Half_Half RE’ scenarios investigate the possibility of half of the planned RE expansion taking place, whereas the other half (in expected power generation equivalent) being substituted through conventional generation capacity, i.e. coal- and gas-fired. There are only slight differences in the resulting modelled ENS between the ‘Half_Half RE’ and ‘All RE’ scenarios. The direction of the differences (i.e. higher resulting ENS for ‘Half_Half RE’ scenarios compared to ‘All RE’ scenarios) indicates that dispatchable capacity does provide higher contribution to security of supply; the absolute scale of difference (i.e. fairly slight) would though indicate that also RE generation can contribute very significantly to system adequacy. Finally, it can be observed that the difference in the modelled ENS is almost negligible in the most critical system condition scenarios (i.e. high demand and high outage rate), which is fairly intuitive considering that in critical situations any additional power generation capacity can likely help alleviate the pressure. It should be noted, however, that these results are subject to the underlying assumptions (e.g. expression of expected RE generation into conventional generation capacity and its allocation in the transmission system, as well as the specific RE generation profiles).

Economically optimal ENS

Energy-not-served is seen as a sign of failure in the power system. However, some solutions to avoid ENS can be too expensive. In a simplified set-up, the economically optimal ENS has been computed in this study. The inputs used are a (defined) price on ENS and a price for adding new generation capacity.

With 2014 as test case it is found that it would have been optimal to have additional firm capacity in South Africa of 3 500 MW. This result is influenced by the fact that 2014 was a year with high outage rates on many power plants.

The analysis supports the idea of having a goal for ENS. In the IRP 20 GWh is described as the maximum acceptable level of ENS. This seem to be in line with the analyses of optimal amount of ENS – all results have values between 10 and 20 GWh after optimal investment in new generation capacity. To reduce ENS below these value would lead to generation capacity that is used less than 16 hours per year.

3. Method

The reliability of a synchronous electricity system can be divided into *adequacy* and *security*. System adequacy is fulfilled when sufficient generation and transmission capacities exist to serve all electricity demand. Security describes the system's ability to withstand sudden failures, e.g. sudden loss of transmission lines or major power plants.

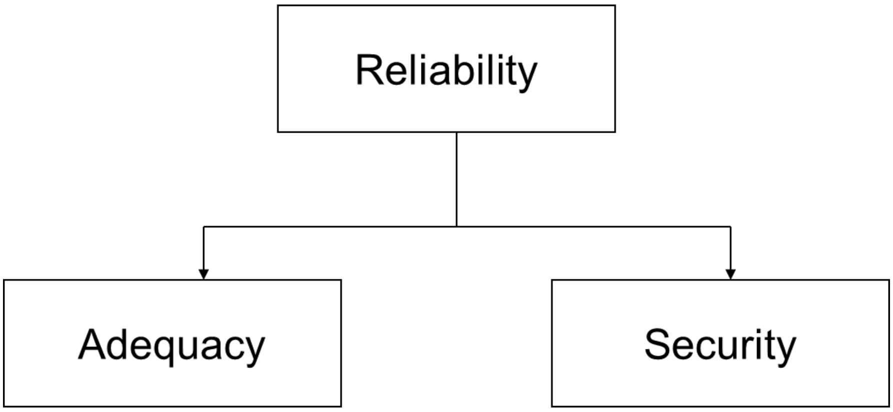

Figure 1. The reliability of an electricity system depends on its adequacy and its security.

The SisyfosR model focusses on system adequacy. *Will the available units (plants and transmission) be able to supply all demand?*

Security can be studied in other models, e.g. PSS/E or PowerFactory, where the system's ability to withstand failures can be computed. This includes studies of voltage, power flow and dynamic properties of the system.

SisyfosR model

SisyfosR is a simulation model for investigation of power system adequacy. It is suitable for analyses of long-term security of supply in the power system (generation and transmission), e.g. in relation to the system adequacy implications brought about by increasing wind power penetration, decommissioning of existing plants, or possible improvements to power system adequacy arising from new investments in generation plants or transmission lines.

The SisyfosR model applies a numerical approach based on the Monte Carlo principle (with a large number of runs with random outcome of unplanned outage). The outcome of a Monte Carlo simulation is the probability distribution of the expected values of reliability indices.

The high-voltage network is included in the modelling, and the model evaluates whether it is the network or the production capacity that is the key cause of power system adequacy issues.

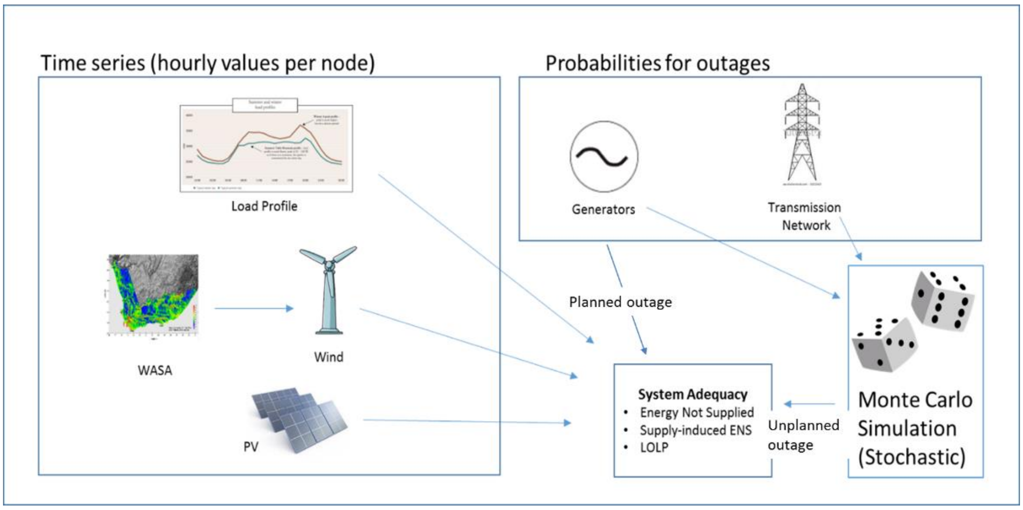

Figure 2. Outline of the computation in SisyfosR. Also hydro plants and pumped hydro may be represented by time series due to their limited / time-specific generation.

The model uses stochastic methods of power generation and grid outages to determine Energy Not Supplied (ENS). ENS is computed per hour and per node across many runs. Results can be aggregated to yearly values or presented in graphs. Median results as well as percentiles and minimum and maximum values across all runs are computed. ENS can be expressed in MWh or in percentage as ENS divided by the total demand.

Key inputs to the model are:

- Generation: Capacity (MW) and planned and unplanned outage (%)
  - Wind, solar and pumped hydro are represented by hourly variation profiles for a year
- Lines: Capacity (MW) and unplanned outage (%). It is the typical, actual transfer capacity that should be used. Practical operation may dictate that this can be smaller than the technical line rating.
- Demand: Hourly demand per node for a year

The SisyfosR model is based on the SISYFOS model developed by the Danish Energy Agency. The rights of the current model are shared between the Danish Energy Agency and Ea Energy Analysis.

Limitations of the model

The model does not include any economic dispatch. The focus is on *adequacy*, i.e. whether it is possible to cover all load (at any costs). The model is not concerned with *security*, i.e. if the operation is in a way that the system can survive a sudden loss of elements.

The SisyfosR model does not fully support chronological / consequential representation of events. The model considers 8,760 “cases” per year (i.e. each representing one hour of the year) – each with a random assignment of outage for each unit. As such, features like e.g. unit commitment or duration of a specific failure are not represented in the model analyses by default. However, representation of chronological and simultaneous timelines can be done through application of time series profiles in the model (e.g. availability and operational limitations of hydro and pumped storage plants, planned maintenance schedules per unit over the year etc.)

A simple example

A simple test case is supplied together with the model. In the example, three nodes exist: Demand is constant 1,000 MW in one node and the electricity can be supplied by one of the two plants each with 1,000 MW capacity. The grid is connecting the three nodes and all lines have 2,000 MW capacity. Plants and lines have 10% probability of not being in service (unplanned outage).

This system can tolerate any N-1 error without interrupting demand. Several combinations of N-2 errors will result in ENS, e.g. loss of both power plants (G1 and G2) or loss of two lines (T1 and T2). See Figure 3.

This example is so small that it is possible to compute the ENS exactly. Seen over a long period of time this system has ENS of 2.15% of the demand.

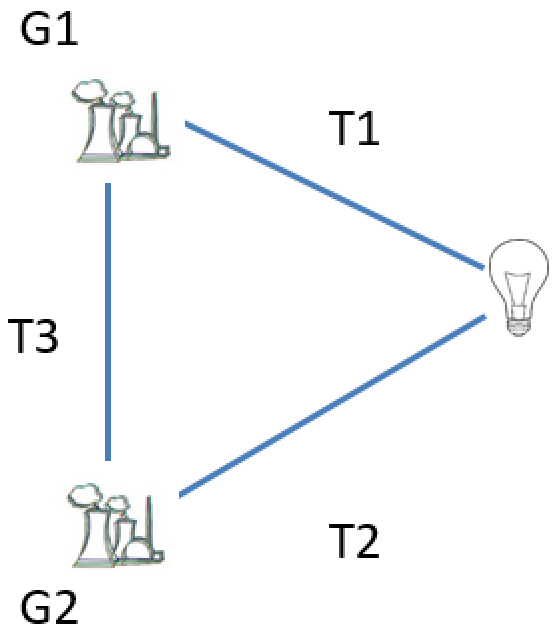

Figure 3. Illustration of the simple example.

Table 2 show the result of the model. The median result gives the correct theoretical value.

	ENS (MWh/yr)	ENS (%)
Max	243.000	2,77%
75 percentage	197.000	2,25%
50 percentage	188.000	2,15%
25 percentage	163.000	1,86%
Min	140.000	1,60%

Table 2. Results based on 1,000 runs. The median result (50%) is the main result. The other rows indicate the variation across the 1,000 runs.

The user decides on the number of runs that the model should execute. In one run the model evaluates all hours of one year (8,760 hours). In Figure 4 the development of the result (median value) is described as a function of the number of runs. The model needs more than 50 runs to get a stable result below 0.5% from the correct value and more than 850 runs to make the result be within 0.1% from the correct value.

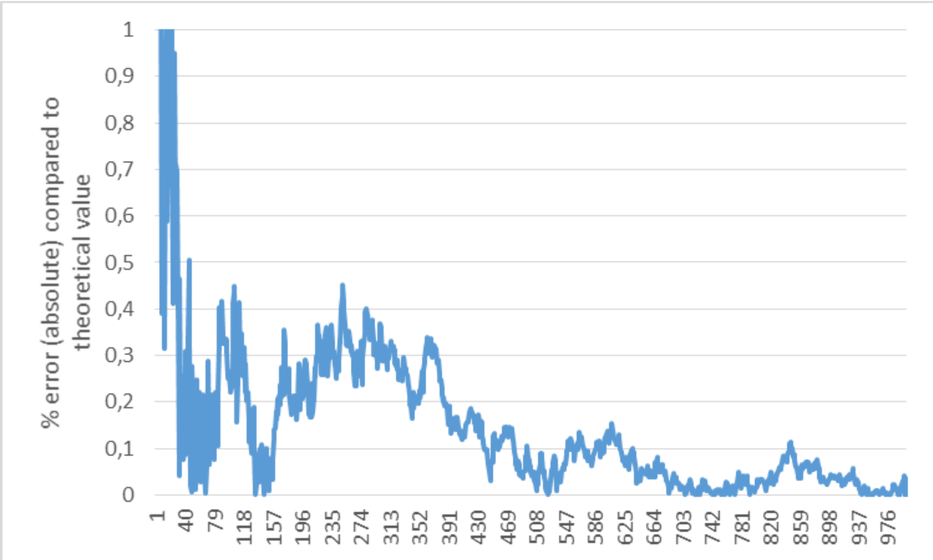

Figure 4. The SisyfosR result accuracy compared to the theoretical result. Results from a test with 1,000 runs.

Thus, the statistical error can be reduced by executing many runs. However, in real-life situations, other sources of error due to simplification of the problem or lack of information are usually of larger importance. Therefore, it is recommended to balance the time spent on execution with the quality of input data. With excellent input data it is relevant to minimise the statistical error by using many runs. When comparing different scenarios, e.g. two runs with one parameter changed, it is relevant to keep the statistical error lower than the studied impact.

Method

The SisyfosR model calculates key indicators of power system adequacy:

- Energy Not Supplied (ENS): all unserved energy demand (e.g. due to missing supply or missing grid capacity)
- Supply-induced ENS: energy not supplied due to missing supply, i.e. generation and import capacity (in order to be able to discriminate between supply and grid adequacy impacts)
- Loss-of-Load probability (LOLP): The probability that an instance of unserved energy occurs in the system, expressed in hours/year (i.e. number of hours with ENS incidents divided by the number of hours in the year, i.e. 8760) or in percentage points.

The necessary number of simulations to calculate ENS and LOLP depends on how "reliable" the power system is. Typically, 100 to 1,000 runs, equal to 876,000 to 8,760,000 individual tests, is a relevant number of runs.

The simulation procedure is as follows:

- Compute the plan for the planned outage (or load an external plan). The computed plan will allocate the planned outage per unit – based on the hourly surplus capacity (generation capacity minus demand). See Figure 5.
- Calculate available power for all power plants and transmission by random process ("Monte Carlo") based on outage rates.
- Determine demand load for all nodes based on historical time series, possibly scaled to a projected future consumption level.
- Determinate the available power from wind and solar. Input per node from CorWind used in WP2.
- Calculate a generation and transmission solution, which supplies all power demand if possible, or as much as possible.
- If production is less than consumption, calculate the corresponding contribution to the ENS.

Each generator has two probabilities of being out of service: A planned and an unplanned probability. For transmission lines only an unplanned outage factor is used.

The plan for planned outage will allocate most of the planned outage to summer (November – February) when the demand is low. Dependent on the amount of planned outage the stress on the system tend to be the same all year round. This fact is a strong argument for investigating all hours of the year – and not only to focus on peak hours. See Figure 5.

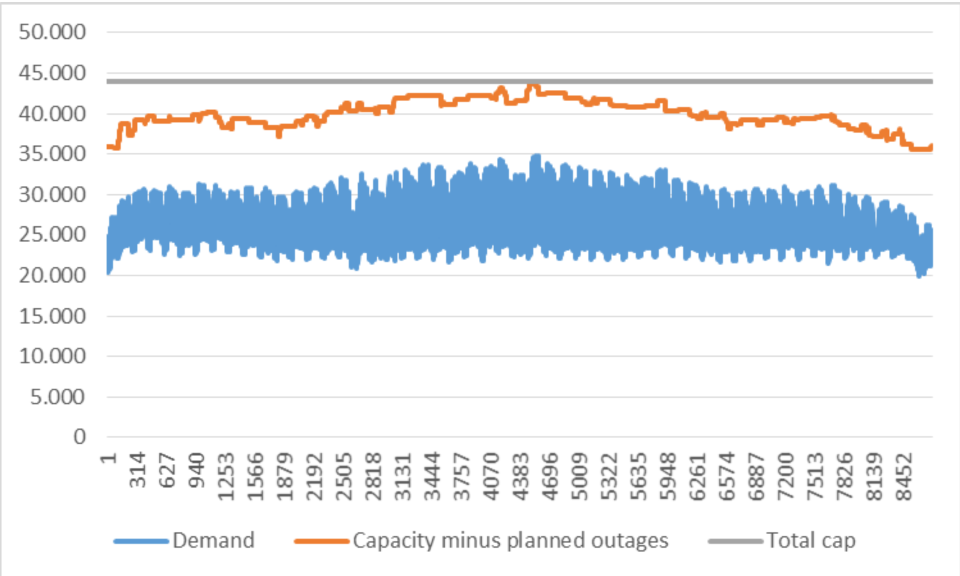

Figure 5. Example of model based allocation of planned outage.

By default (and throughout this study) all unplanned outage is considered as independent. However, the model has a feature where *common failures* can be defined. A group of elements can share a probability of outage. This can be units of a power plant sharing some elements or transmission lines sharing some elements – or a combination of both.

The method used and the mathematical equations are described in the SisyfosR manual (Ea Energy Analyses and Danish Energy Agency, 2016).

Other examples of use of Sisyfos

The Sisyfos model has been used in a number of studies. The Danish Energy Agency uses the Sisyfos model in the Danish system adequacy investigations, and e.g. in 2014 an analysis of the transmission grid functionality was carried out (Agency, 2014) using the Sisyfos model. Surplus and deficits of capacity to obtain a predefined level of security in different regions for future years was estimated in this study. For the long term, six different scenarios were set up and investigated.

Ea Energy Analyses (2014) has applied the Sisyfos model to investigate the level of system adequacy in Lithuania. Scenario analysis was used to investigate the trade-off between RE-development and additional investments in dispatchable generation capacity. Fully functional model of Lithuania in Sisyfos was then transferred to the Lithuanian National Control Commission for Prices and Energy upon completion of the project.

Generally, the application of simulation models is becoming more prevalent within system adequacy studies. A simulation model similar to SisyfosR has also been used to estimate the adequacy of the entire European network (ENTSO-E, 2016).

4. Data

This section of the report provides an overview of the input data used in the model, focusing on demand, generation and outage data.

Demand

The following data sources for the demand in South Africa have been used in this study:

- Node-specific hourly load data for 2014
- Net Sentout (NSO) hourly data for 2014
- Interruptible Operating Services (IOS) hourly data for 2014, estimated by the National Control Center (NCC)

All this data has been obtained from Eskom and match the Eskom generation. Demand satisfied from generation of independent producers is not represented in this data. Therefore, the hourly node demand is scaled to match total demand in South Africa.

Annual demand for year 2014

The node-specific hourly demand is scaled so as to correspond to the total system NSO demand data hour by hour, thereby incorporating any underlived demand. The modelled annual demand for 2014 for South Africa equals to 234 TWh.

IRP 2010 demand projections for 2020 and 2025

In order to obtain a 'representative hourly load profile' for South Africa, the 2014 IOS hourly data has been added back to the 2014 NSO hourly data to account for the 'suppressed demand'. Thereafter the node-specific hourly demand is scaled so as to correspond to the total system (NSO + IOS) demand data hour by hour. Finally, the obtained hourly load profile is then scaled to the 2020 and 2025 annual demand levels, respectively.

The annual demand projections for 2020 and 2025 have been derived from the IRP 2010. As illustrated by Table 3, IRP 2010 projects a very steep demand growth trajectory towards 2020 and 2025 – and projected a much higher annual demand level for 2014 (than was actually realized).

	2014	2020	2025
Historical demand (NSO)	234 TWh	-	-
IRP 2010 demand (SO Moderate)		356 TWh	404 TWh

Table 3. The demand values used in the simulations.

Figure 6 illustrates the discrepancy between the realized and the projected electricity demand development over time.

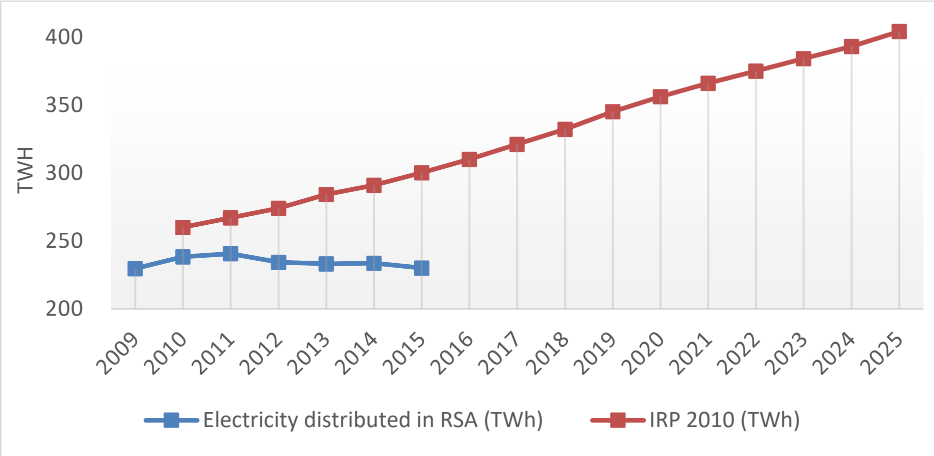

Figure 6: Realized vs. Projected electricity demand in South Africa. Sources: (Statistics South Africa, 2014), (Department of Energy of South Africa, 2011), (Statistics South Africa, 2016)

Due to the widening gap between the realized and the IRP 2010-projected electricity demand development, a number of alternative demand projection scenarios for 2020 and 2025 have been investigated in this study (please see Scenarios section of this report).

Nodal demand profiles 2020 and 2025

The hourly node-specific load profiles for the existing nodes from the 2014 reference case are maintained for the 2020 and 2025 scenarios. New nodes are assigned an 'average' nodal demand profile (weighted average based on the hourly nodal load profiles from 2014), which are then scaled to correspond to the peak load projections per node for the respective year provided by Eskom[3]. The resulting hourly node-specific load profiles for 2020 and 2025 are then scaled to correspond to the projected annual demand levels, respectively[4].

Table 4 provides an overview of the peak load as projected by different sources vis-à-vis the peak load as obtained from the demand profile represented in the SisyfosR model. The level of peak demand extracted from the modelled demand profile in SisyfosR (scaled to correspond to the annual 2020 and 2025 demand projections from IRP 2010) is broadly consistent with the peak demand projections as per IRP 2010, with a slight upwards tendency.

[3] Based on the data from 2015 TD – 2020 CF Post Peak Rev 2
[4] This is done in order to ensure consistency across the nodes with regard to the annual demand level. Further scaling the demand in the new nodes (beyond their projected peak load levels) could, however, overestimate their respective shares of the total demand.

	IRP 2010	PSS/E study projected peak load data[5]	SisyfosR modelled peak*
2014	43 436 MW		45 451 MW
2020	52 719 MW	40 923 MW	55 643 MW
2025	60 150 MW	42 264 MW	63 256 MW

Table 4. Comparison of the peak demand data derived from IRP 2010, the PSS/E analysis results, and the SisyfosR modelled data (Based on the adjusted and scaled demand profile as described in the Demand section).*

Generation

Information per individual generation plant has been used to represent the existing generation fleet in South Africa. The generation plants and their respective capacities for the 2014 modelled system are presented in Table 5.

Plant type / Name	Capacity (MW)	Plant type / Name	Capacity (MW)
Coal	**35,940**	**Hydro**	**2,100**
Arnot	2,220	Cahorra Bassa	1,500
Camden	1,520	Gariep	360
Duvha	3,480	Vanderkloof	240
Grootvlei	1,080	**Oil**	**2,460**
Hendrina	1,900	Acacia	180
Kendal	3,840	Ankerlig	1,350
Komati	900	Gourikwa	750
Kriel	2,880	Port_Rex	180
Lethabo	3,540	**Nuclear**	**1,860**
Majuba	3,840	Koeberg	1,860
Matimba	3,720	**Wind**	**457**
Matla	3,480	Cookhouse (Poseidon)	135
Tutuka	3,540	Dorper (Delphi)	97
Storage	**1,400**	Hopefield (Aurora)	65
Drakensberg	1,000	Jeffreys Bay (Grassridge)	134
Palmiet	400	VanStaden (Grassridge)	26

Table 5. Generation capacity 2014.

The number of units per plant have been represented in the model, with an assumption of the same unit size within one plant (in real life, the unit sizes within a plant can vary).

Only Cahorra Bassa out of the non-Eskom generation plants has been represented due to lack of information on the other plants. According to IRP 2010 (2013 update) the additional non-Eskom generation in the system amounts to

[5] Based on the data from 2015 TD – 2020 CF Post Peak Rev 2

1 830 MW – and it is not represented in the SisyfosR model in the current study.

The expansion of generation capacity towards 2025 is shown in Table 6.

Generation type (MW)	2014	2020	2025
Coal	35,940	45,596	45,626
Oil	2,460	2,460	2,460
Hydro	2,100	2,000	4,563
Nuclear	1,860	1,860	6,660
Pumped storage	1,400	2,732	2,732
CCGT		474	711
OCGT		1,029	2,643
Wind	457	3,846	7,446
Solar PV		2,697	4,897
CSP		700	1,200
Other		79	79
Total Capacity (MW)	**44,217**	**63,472**	**79,016**

Table 6. Generation expansion based on the data from 2015 TD – 2020 CF Post Peak Rev 2.

More detailed representation of the generation expansion as modelled in SisyfosR is presented in Appendix I: Generation Expansion Plan.

Decommissioning

Decommissioning schedule of the existing generation fleet has been based on the capacity development plan data provided by Eskom[6]. Camden and Komati plants are being gradually decommissioned towards 2025.

Wind power

Detailed generation profiles for each node with wind capacity have been computed. By use of the program CorWind metrological meso-scale data has been converted to node-specific and capacity-specific time series. Data development is documented in a separate report.

Due to the size of the country, a strong smoothing of the electricity generated by wind power takes place, see Figure 7 and Figure 8.

[6] "TDP 2017 – 2026 Assumptions Paper – gen details Rev 3": Conventional Generation Schedule for the Period 2017 to 2026

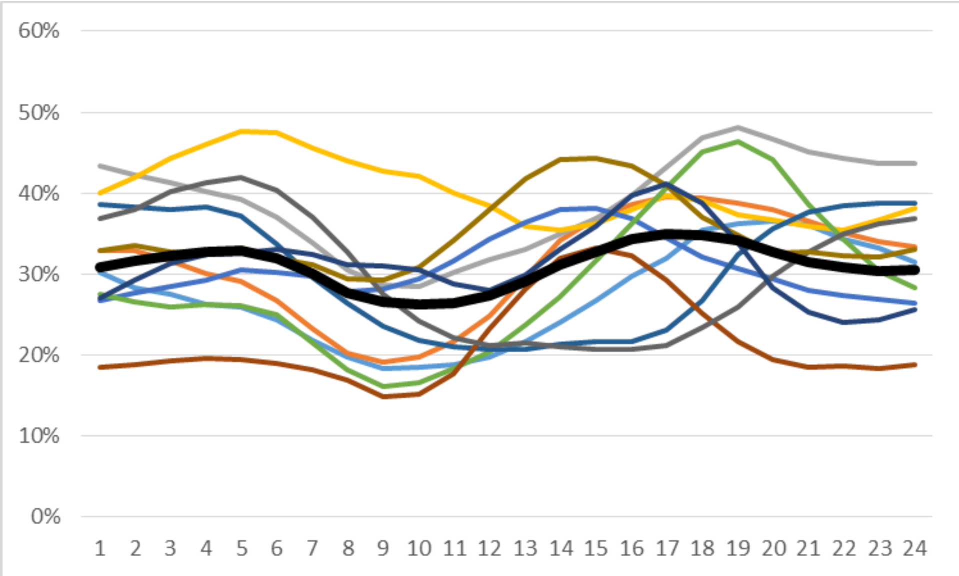

Figure 7. Yearly average wind generation across the hour of the day. Percentage of installed capacity. The black thick line is capacity-weighted average. The other lines are node-specific data.

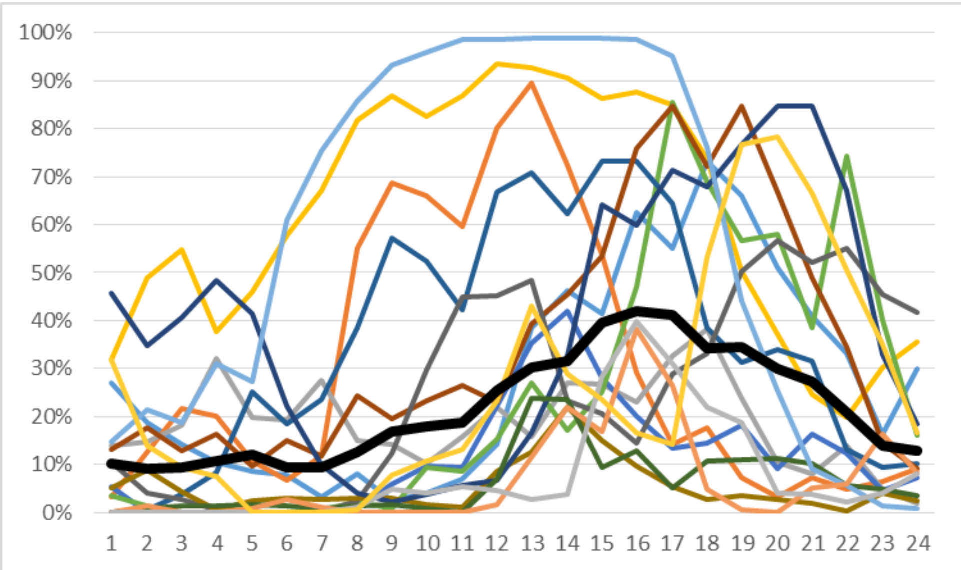

Figure 8. Example of wind generation a specific day (1 January). The black thick line is the capacity-weighted average. The other lines are node-specific data.

Solar

Data for PV generation time series has been developed per node in the transmission grid. Documentation of the data development is presented in a separate report.

Solar generations in illustrated in Figure 9 and Figure 10. The variation between areas is much smaller than for wind.

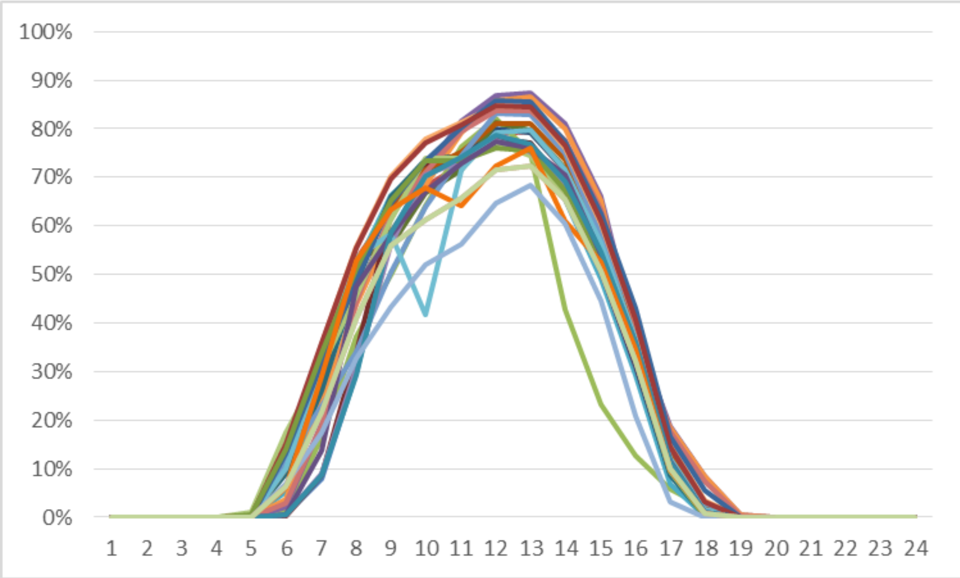

Figure 9. Examples of solar profiles for a specific day: 1 January. 27 nodes with PV capacity in 2020.

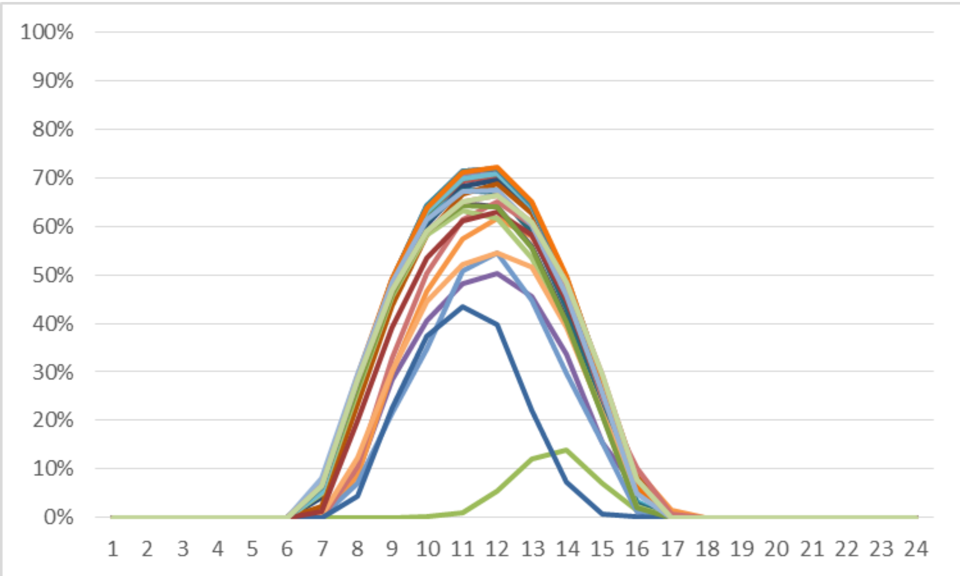

Figure 10. Examples of solar profiles for a specific day: 1 July. 27 nodes with PV capacity in 2020.

Hydro and pumped storage

The generation from hydro plants is limited by the inflow of water. In the study hydro plants with storage are represented with full capacity availability during 7:00 – 11:00 and 15:00 – 19:00 time periods each day for the two units Gariep and Vanderkloof. Cahora Bassa has a base load (flat profile) 1500 MW in 2014 and 1400 MW for 2020 and 2025.

The pumped storage plants Drakensberg and Palmiet are represented as charging at night on weekdays and all day on weekends; and being available for generation during daytime on weekdays. In the model the pumped storage is represented to be available at full capacity from 7:00 to 22:00 on workdays.

No availability profiles have been assigned to the future hydro plants Import Hydro 1 and 2. The prospective Ingula hydro plant has been assigned the pumped storage availability profile.

Hydro plant	Modelled capacity available (MW)			Availability profile
	2014	**2020**	**2025**	
Cahora Bassa	1500	1400	1400	Flat
Gariep	360	360	360	7:00 – 11:00 and 15:00 – 19:00 daily
Vanderkloof	240	240	240	7:00 – 11:00 and 15:00 – 19:00 daily
Drakensberg	1000	1000	1000	7:00 – 22:00 on work-days
Palmiet	400	400	400	7:00 – 22:00 on work-days
Ingula		1332	1332	7:00 – 22:00 on work-days
Import Hydro 1 (4 x 570)			2280	Flat
Import Hydro 2			283	Flat

Table 7: Overview of the hydro and pumped storage representation in SisyfosR

Demand response

Demand response could be modelled as a one or more power plants. Demand response has not been explicitly represented in the model in the current analysis. This is due to the complex nature of demand response representation (and the uncertainty associated with making future projections thereof), and the fact that SisyfosR currently does not employ chronological / sequential representation of events. Most demand responders act by moving the power demand to later hours. In the interpretation of the modelling results in terms of Energy Not Served (ENS) it should, however, be noted that in real-life operation, a share of the ENS instances registered could in fact have been alleviated via activation of demand response.

Outage data

Existing generation fleet

Statistics on outage are central for system adequacy studies. Hourly data on outage has been received for a number of power plants for the period from

January 1998 to September 2014. In total 20 plants with 112 units are included in the statistics (more than 15.000.000 data entries).

It has not been possible to acquire outage information for the plants Cahorra Bassa, Kriel, and Port Rex. The outage rates for these plants are calculated as the average of the actual outage rates of plants of the same type in the fleet (e.g. the outage rate of Cahorra Bassa is based on the average between outage rates of Gariep and Vanderkloof).

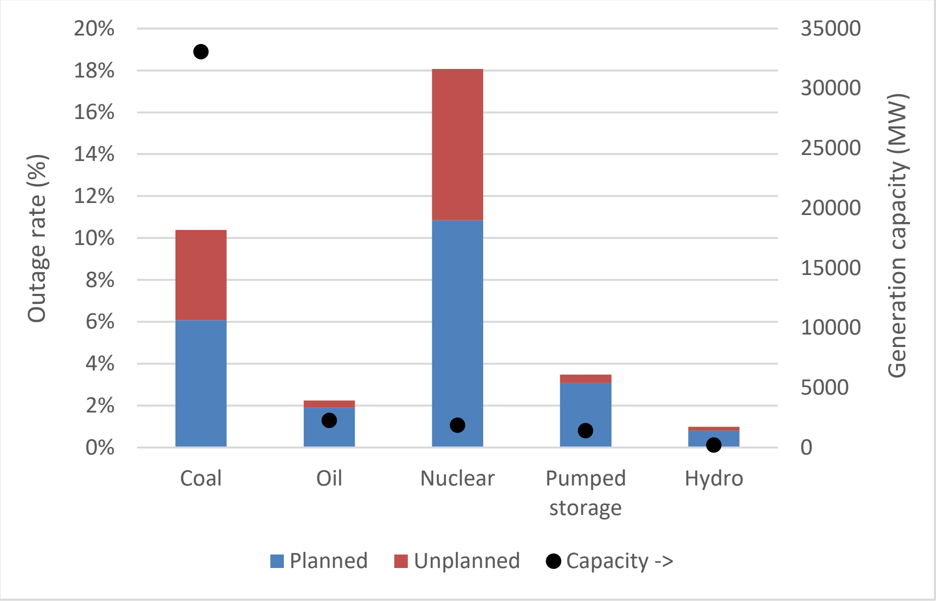

Figure 11. Average outage rates, 1998-2014, capacity-weighted. The total generation capacity per fuel type is shown on the right axis

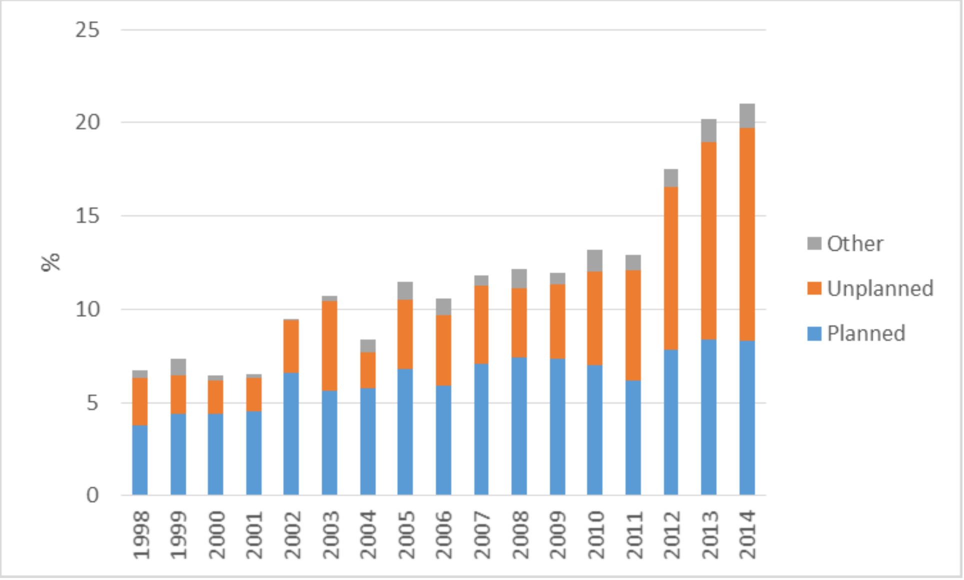

Figure 12. Outage statistics 1998-2014, capacity-weighted

For the existing generation fleet, outage data has been used per station (average across units). For stations without statistical information, average values for all other stations of the same type have been used.

All units within a plant have been assigned the same (plant average) outage probabilities. In the modelling process, however, the units are treated as separate entities. I.e. the units can experience outage independently in the model.

New generation plants

For new generation plants, the standard planned and unplanned maintenance values from the IRP 2010 have been used to represent the planned and unplanned outage rates, respectively, as summarized in Table 8.

Plant type	Planned maintenance	Unplanned maintenance
Coal	4.8%	3.7%
Hydro	0.8%	0.2%
Storage	5.0%	1.0%
Nuclear	6.0%	2.0%
CCGT	6.9%	4.6%
OCGT	6.9%	4.6%
Other	4.0%	6.0%

Table 8: Planned and unplanned maintenance assumptions for new generation plants based on IRP 2010

Transmission

The transmission grid has been represented in a considerable level of detail, incorporating the projected power system development plans towards 2020 and 2025. The number of nodes represented in the modelling of each scenario year has been provided in Table 9.

Modelled year	Number of nodes represented
2014	167
2020	205
2025	248

Table 9: Number of nodes represented in the model in each scenario year

Each transmission line is described with a capacity. Estimating the relevant capacity data can be a challenge, since, while all lines have a technical capacity (thermal capacity), this value may for many lines be bigger than the practical maximum loading of the line. N-1 considerations (that the loss of any line should not overload other lines) as well as considerations for voltage and reactive effect can significantly reduce the practical loading of a line. As an example the line *Alpha-Beta* connection has a technical capacity of 14,000 MW, but in practical operation it is not loaded with more than 4,000 MW.

For this study, the operational line capacities have been provided by Eskom transmission experts – but have not been adjusted to correspond to the practical loading limits[7]. I.e. this study has employed the current and projected technical capacities of the transmission lines.

No statistical information about outage of transmission lines has been received. Instead, a standard value of 0.35% outage is used to represent the unplanned outage rate[8], as per the dimensioning value used in IRP 2010. The real-life outage values may be lower. Planned transmission outages have not been modelled. This may to some extent underestimate the modelled ENS.

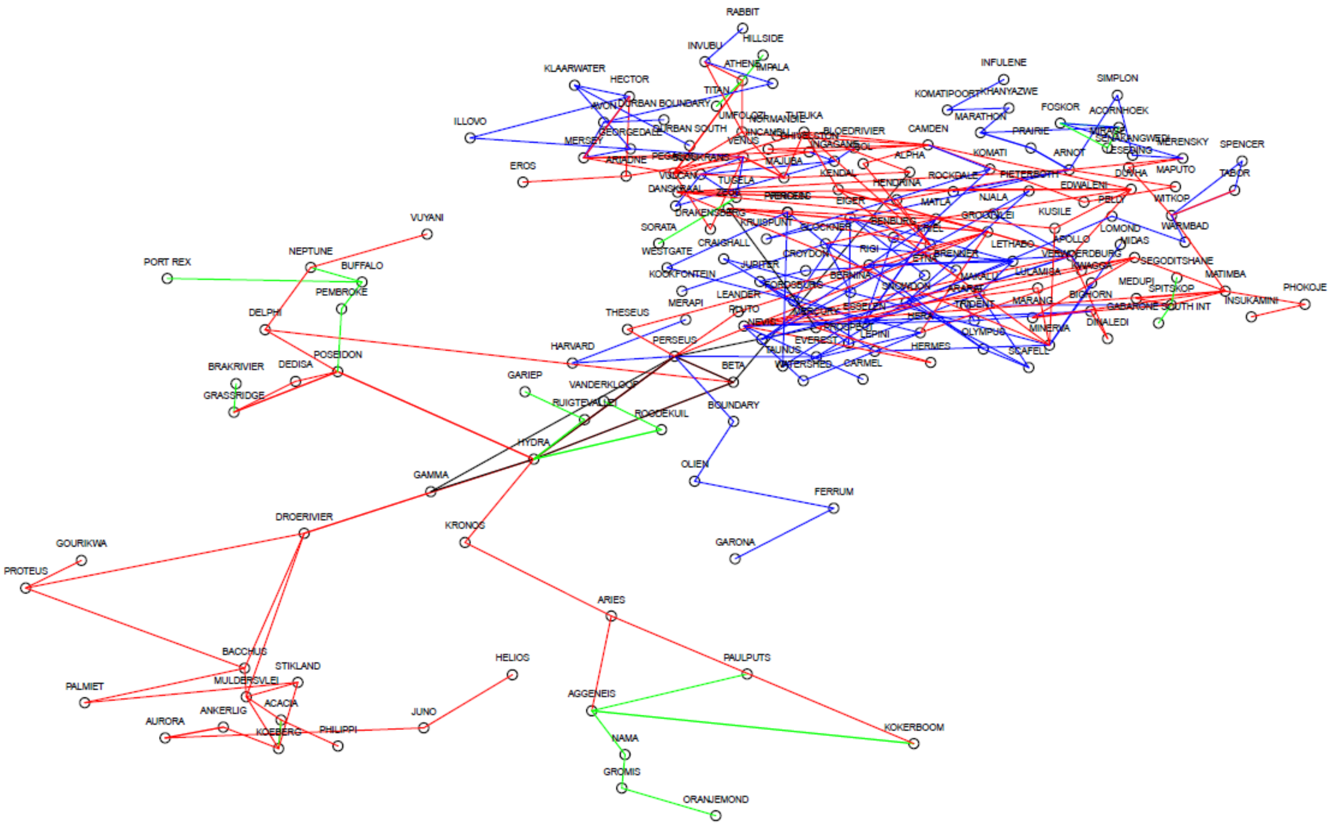

Figure 13. Simplified representation of the transmission grid. 2014.

[7] With the exception of the ALPHA – BETA line, where the practical limit of 4 000 MW has been implemented

[8] Planned outage rate has been disregarded for transmission, as the information provided by Eskom transmission representatives suggest negligible operation interruptions arising from transmission maintenance

5. Scenarios

The SisyfosR model has been used in two different tasks within the framework of the current study. In the first task, the economic optimal level of reserves is analysed. In the second task, several parameter variations are done for 2020 and 2025 to describe the ENS in alternative futures.

In all scenarios it is assumed that 1,000 MW of available-at-all-times reserve generation capacity is required to cover N-1 errors (sudden loss of the largest unit). This capacity is excluded from the model. The capacity reduction is implemented by reducing all generators (excluding wind, solar and pumped hydro) proportionally. The background is that in practice curtailment of load will start when the remaining capacity is in the order of 1,000 MW. Many practical operational issues influence the concrete operational procedure. The 1,000 MW is used as an indicative volume.

Relationship between outage and reserves

Any electricity system will need generation capacity to cover peak demand and have a surplus to enable realisation of the planned maintenance of power plants. Also, any system must have reserves to make the system secure: To withstand sudden loss of major elements. Also capacity is needed to off-set unplanned outage. A number of different scenarios has been computed and for each a duration curve of ENS will be established. From the duration curve an optimal level of reserves (to cope with unplanned outage) will be computed.

Input to the optimal level is a price parameter describing the cost of ENS (the 'harm done' by curtailment) and the cost of having reserves (mainly, capacity costs).

Alternative futures

Simulation are made for 2014, 2020 and 2025. The future is uncertain and many central parameters cannot easily be defined.

- Demand
- Plant outage levels

For the purpose of the study we also vary the amount of renewable energy.

Demand

The official prognoses for the electricity demand are from IRP 2010. However, this prognosis is based on a higher economic growth that what has been realised in the past 10 years. Three scenarios are therefore defined:

- IRP 2010 SO Moderate: average growth: 3.1 % p.a. in the 2014-2025 period ("High")
- IRP 2013 SO Low: average growth: 2 % p.a. in the 2014-2025 period ("Moderate")
- Low growth: average growth 1% p.a. in the 2014-2025 period ("Low")

The demand projection scenarios are presented in Table 10 below.

Year / TWh per annum	IRP 2010 (SO Moderate)	IRP 2013 (SO Low)	Low growth
2014	291*	271*	235
2020	356	316	250
2025	404	339	262

Table 10: Expected annual electricity demand scenarios (TWh).
**) Prognosis levels. Only the historical level (i.e. 235 TWh per annum, i.e. Low growth) is used in the 2014 scenario*

By varying the demand, the capacity balance is changed (generation surplus). The scenarios with lower demand can therefore also be seen as examples indicating the impact of extra investment in generation.

The total demand is scaled to match demand from IRP 2010 and IRP 2013 SO Low scenario, respectively. It should be noted that the resulting peak of this scaling is higher that the corresponding peak from the two reports. The difference is about 2,000-3,000 MW or 5-6%. The only exception being IRP 2013 SO Low for 2025. Table 11 provides an overview of the peak demand projections derived from different sources.

	From data reports			Calculated from SisyfosR data		
	IRP 2010	IRP 2013 SO Low	PSS/E study[9]	IRP 2010	IRP 2013 SO Low	Low growth
2014	43 436	40 210		45 451	42 513	36 747
2020	52 719	48 154	40 923	55 643	49 423	39 007
2025	60 150	54 596	42 264	63 256	53 031	40 997

Table 11: Comparison of the peak demand data derived from IRP 2010, IRP 2013, the PSS/E analysis results, and the SisyfosR modelled data.

Outage

[9] Based on the data from 2015 TD – 2020 CF Post Peak Rev 2

Outage data from different time periods has been used in the scenarios, in order to represent the different potential states of the fleet availability in the future:

- 1998-2009 ("Low" on average 8%)
- 2010-2014 ("High" on average 13%)
- 2014 ("Very High" on average 17%)

Renewable energy

The IRP describes the expected expansion of renewable energy. To illustrate the impact of increased RES generation on ENS, this expansion is varied. This is done by testing the following cases relating to RE development:

- All RE expansion as planned ("All")
- Half of the planned RE expansion in a given period on top of the existing capacity[10], no additional capacity to compensate for the reduction ("Half")
- Half of the planned RE expansion in a given period on top of the existing capacity[11], and the other half (in expected power generation equivalent) is substituted through conventional generation capacity, i.e. coal- and gas-fired ("Half_Half")

Table 12 presents the RE capacity and expected generation differences vis-à-vis 'All RE' scenarios, as well as the resulting conventional generation capacity values added in the 'Half_Half' scenarios.

Year	RE capacity reduction (MW)	RE generation reduction* (GWh)	Conventional generation FLH assumption**	Additional conventional capacity (MW)
2020	3,393	7,998	7,752	**1,032**
2025	6,543	14,949	7,752	**1,928**

Table 12: RE capacity and expected generation differences in the 'Half_Half RE' scenarios vis-à-vis 'All RE' scenarios, and the conventional generation capacity added in the 'Half_Half' scenarios in 2020 and 2025, respectively, based on power generation equivalence terms.
** Based on the expected wind, solar PV and CSP generation*
*** Based of newly built thermal plant availability assumption of 88.5% (source: IRP).*

The additional capacity has been proportionally distributed (on capacity basis) across the planned coal- and natural gas-fired units in the system post 2020. Table 13 provides an overview of the additional conventional capacity distribution across individual plants in the 'Half_Half RE' scenarios (the capacities of

[10] E.g. 'Half' scenario for 2025 will fully include the existing RE capacity from 2014, but only half the RE capacity developments from 2014 to 2025

[11] E.g. 'Half_Half' scenario for 2025 will fully include the existing RE capacity from 2014, but only half the RE capacity developments from 2014 to 2025. The 'missing' RE capacity compared to the 'All RE' scenario (in expected power generation terms) is compensated by conventional capacity (in expected power generation equivalence terms)

other conventional generation plants are not changed in the 'Half_Half RE' scenarios vis-à-vis other scenarios).

Plant name	Plant type	2020 Default capacity (MW)	2025 Default capacity (MW)	2020 'Half_Half RE' scenario capacity (MW)	2025 'Half_Half RE' scenario capacity (MW)
Medupi	Coal	4,428	4,428	4,837	4,988
Kusile	Coal	4,428	4,428	4,837	4,988
Dedisa	OCGT	294	294	321	331
Avon	OCGT	735	735	803	828
Khanyisa	Coal	400	400	437	451
Masa	Coal	-	1,000	-	1,126
Kriel	Coal	400	400	437	451
Masa	Coal	-	1,250	-	1,408
Dedisa	CCGT	474	711	518	801
Dedisa	OCGT	-	1,614	-	1,818

Table 13: Additional conventional capacity distribution across the power plants in the 2020 and 2025 'Half_Half RE' scenarios, respectively

Scenarios analysed

Table 14 provides an overview of all of the scenarios tested in the study.

Parameter / Year	2014	2020	2025
Demand	Actual	High Moderate Low	High Moderate Low
Plant outage*	Actual (Very High)	Very High High Low	Very High High Low
Renewable energy	Actual	All Half Half_Half	All Half Half_Half
Number of scenarios	1	27	27

Table 14. Overview of the scenarios tested in the study.
** Only applies to the existing units. All new units are assigned outage rates as per IRP 2010.*

6. Energy not served

This section of the report presents the results of the SisyfosR modelled scenarios. The results of each scenario modelled in the current analysis have been based on a sequence of 1 000 annual runs (i.e. 1 000 stochastic simulations of each year represented by 8 760 hours).

2014 Reference

The South African power system as of year 2014 has been represented using the actual measured demand data, the node-specific load profiles and the actual planned maintenance schedule of the existing generation fleet. Figure 14 illustrates the capacity surplus situation (only accounting for the planned outages) in the South African power system in 2014 as represented in SisyfosR.

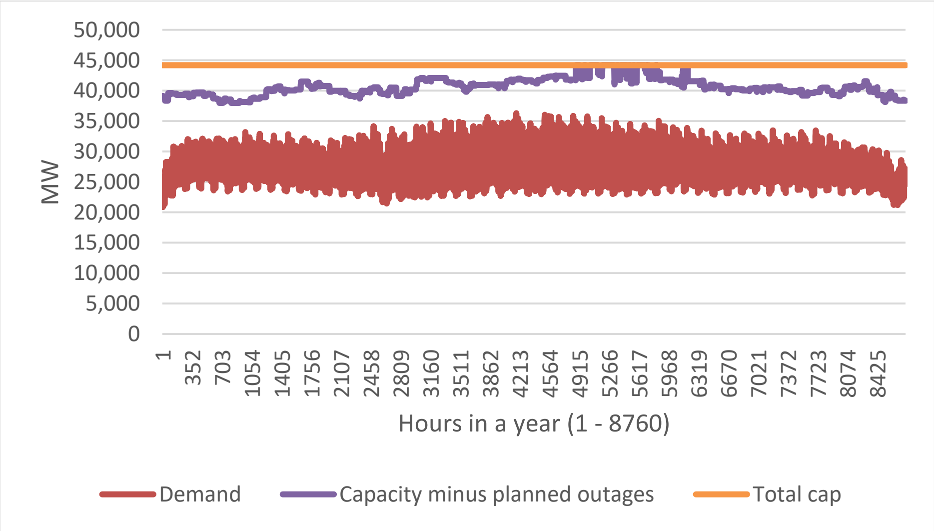

Figure 14: Demand, total generation capacity and capacity minus planned outages for the SisyfosR modelled year 2014

Using the above as inputs, the unplanned outages on generation units and transmission lines have been stochastically simulated in the SisyfosR model. Figure 15 presents the modelled distribution of demand and ENS over the hours of the day.

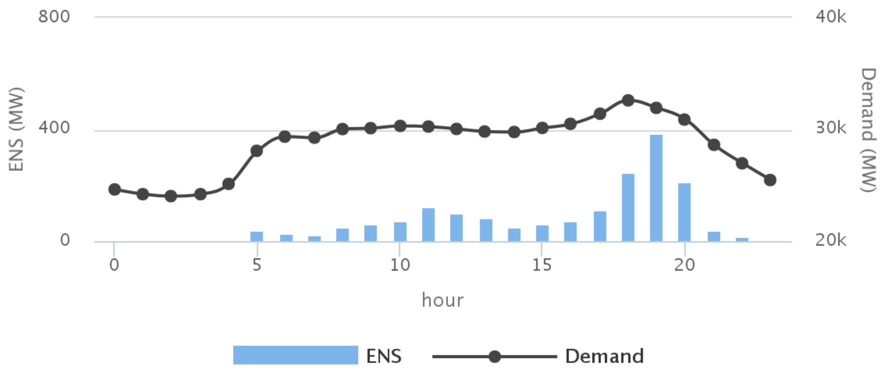

Figure 15: Average demand and ENS over the 24 hours of the day in the SisyfosR modelled year 2014 across 1000 runs

In line with expectations, the ENS instances are on average higher at times of the day exhibiting higher overall demand, and vice versa. However, as illustrated by Figure 16, the highest frequency of ENS instances is not to be found during hours with the highest demand; it is in fact the load levels of 30 000 – 32 000 MW that exhibit the highest frequencies of ENS instances in the modelled results of the 2014 system.

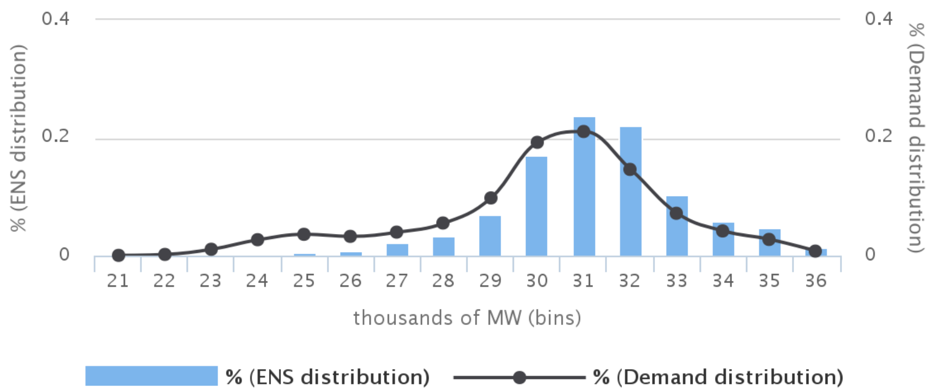

Figure 16: ENS distribution per demand ranges (bins) for the SisyfosR modelled year 2014 over 1000 runs

Figure 17 illustrates the duration curve of the ENS instances representing the minimum, median and maximum of the 1 000 runs modelled in SisyfosR.

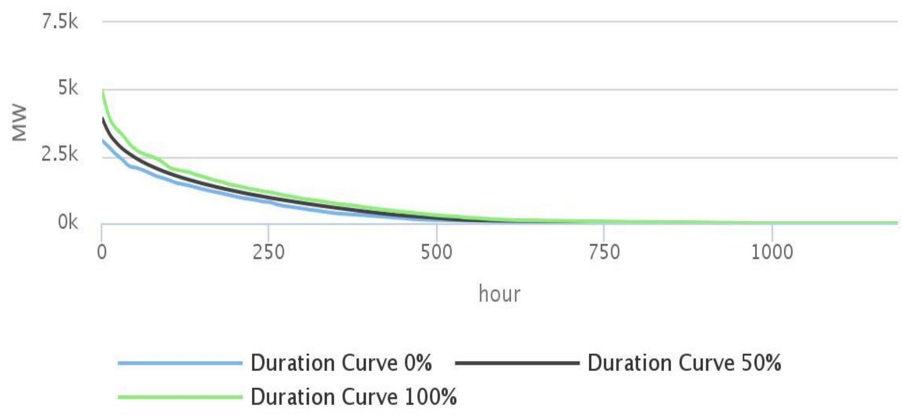

Figure 17: Duration curves of ENS representing the minimum, median and maximum of the 1000 runs in SisyfosR for modelled year 2014

Figure 18 presents the capacity surplus histogram in relation to the number of instances and ENS incidents, as well as the average ENS across the 1 000 runs in SisyfosR. As the graph illustrates, the vast majority of ENS takes place at times of capacity deficit (the remaining ENS instances being attributable to grid issues).

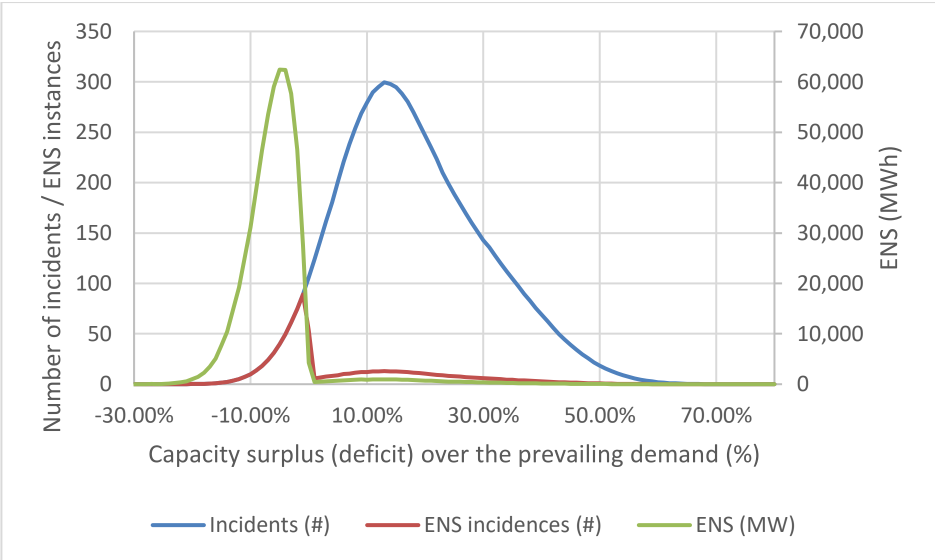

Figure 18: Histogram of average number of Incidents and ENS instances, as well as average ENS, over capacity surplus bins over the prevailing demand across the 1000 runs in SisyfosR for modelled year 2014

Figure 19 presents an ENS density map for the modelled year 2014. It should be noted, however, that the node-specific results arising from the SisyfosR modelled simulations should be interpreted with caution as SisyfosR does not apply economic dispatch in its ENS allocation algorythm, and a given annual ENS result could yield a number of different ENS allocations per nodes.

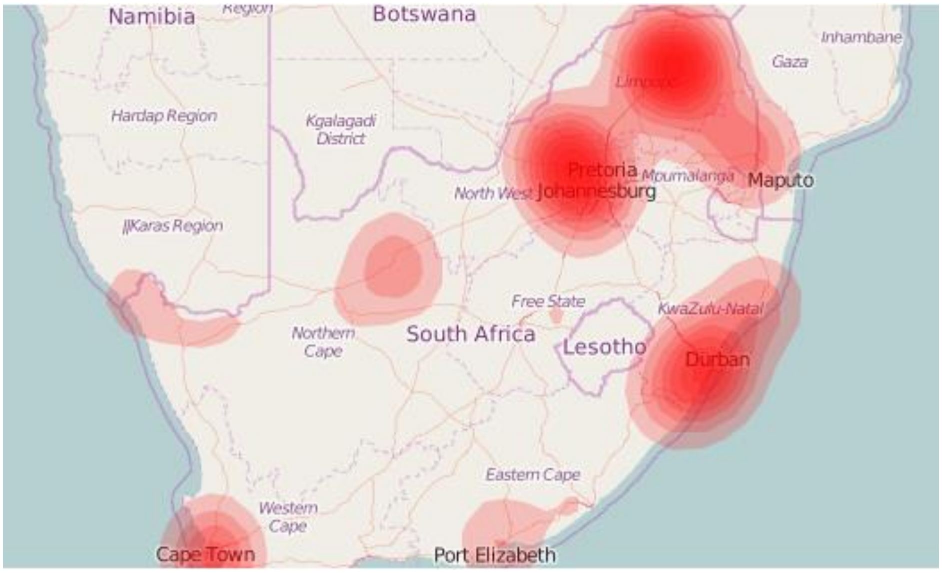

Figure 19: ENS density map for SisyfosR modelled year 2014 over 1000 runs

The results in terms of Energy Not Served (ENS), ENS due to missing capacity, ENS as a share of the total annual demand and Loss-of-Load Probability (LOLP) are presented in Table 15.

	ENS (GWh/y)	Share of capacity-induced ENS	ENS as % of annual demand	LOLP* (%)
Average	655	94%	0,28%	10,4%
Max	747	93%	0,32%	11,4%
75 percentile	674	93%	0,29%	10,6%
50 percentile	654	94%	0,28%	10,4%
25 percentile	597	94%	0,25%	9,8%
Min	566	94%	0,24%	9,5%

Table 15: ENS, capacity-induced ENS, share of ENS of the annual demand and LOLP results for the SisyfosR modelled year 2014 across 1000 runs
** Loss of Load Probability (LOLP): The probability that an instance of unserved energy occurs in the system, expressed in number of hours with ENS incidents divided by the number of hours in the year, i.e. 8760*

As can be seen from the results, the ENS instances in the modelled 2014 case are almost exclusively related to missing capacity (94% of all instances), which is in line with the overall assessment of the ENS causes in South Africa in 2014 (reported to be solely attributed to capacity shortage).

The total annual ENS in the modelled South African system for 2014 (average of 655 GWh) slightly exceeds the actual reported ENS of 512 GWh. There could be several reasons for this, including the missing non-Eskom generation in the model[12] (apart from Cahora Bassa), the provision for the 1000 MW available-at-all-times generation capacity buffer (i.e. reduction of the total generation capacity by 1000 MW) and the fact that there might be alternative possible power flow re-routing options beyond the high-voltage transmission grid represented (which might be possible in real life through lower voltage lines). More importantly, the demand response capabilities have not yet been represented in the model, meaning that a fraction of the modelled ENS in reality could have been alleviated by activating the demand response. (On the other hand, implementation of planned transmission outage might somewhat increase the modelled ENS.) Further data input and model assumption improvements could yield a result more closely resembling the actual reported level of ENS.

Though not perfectly matching the realized ENS in 2014, the modelled ENS for 2014 can be a useful benchmark for the alternative scenarios tested, investigating the prospective impact of different development pathways for key parameters towards 2020 and 2025 on a like-for-like basis.

2020 and 2025 scenario results

Table 16 provides an overview of the results of all of the scenarios investigated in the SisyfosR model, expressed in terms of average Energy Not Served (ENS) in GWh per annum across 1 000 model runs for each scenario.

		Demand: Low			Demand: Moderate			Demand: High		
		Outage level								
Year	*RE development*	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**
2014	*Actual*			655						
2020	*Half_Half RE*	9	9	9	19	42	293	136	1 636	5 435
2020	*All RE*	9	9	9	19	55	355	174	1 746	5 440
2020	*Half RE*	9	9	9	19	83	569	256	2 636	7 776
2025	*Half_Half RE*	9	9	9	16	16	16	47	344	1 389
2025	*All RE*	9	9	9	16	16	17	66	493	1 699
2025	*Half RE*	9	9	9	16	16	21	104	926	3 134

Table 16: Annual average ENS for all SisyfosR modelled scenarios across 1000 runs per scenario. Unit: GWh per annum

[12] In case non-Eskom generation units were to be represented in the model, alignment between the generation and demand data should be ensured. The extent to which the demand supplied by the non-Eskom generators is represented in the current demand data might be limited.

The 'Low Demand' (1% annual growth rate) scenarios all show a very small amount of ENS regardless of the other parameter variations, well below the adequacy metric of Unserved Energy of 20 GWh per annum indicated in the IRP 2010 (2013 update). The system has enough spare capacity even if plant outage and RE generation capacity developments are less than satisfactory.

The 'Moderate Demand' (2 % annual growth rate) scenarios are all below the 20 GWh metric in 2025, except for the Half RE and High outage case, which is only slightly exceeding the limit (21 GWh). 2020 is more critical, and the resulting system adequacy is more dependent on the other parameter variations. Particularly the outages levels affect the resulting level of ENS. Only low outage levels result in acceptable modelled values of ENS. For higher levels of outages, the modelled ENS is exceeding the threshold. Here the impact of delayed RE-development ('Half RE') also shows, resulting in significantly higher ENS.

The 'High Demand' (3.1 % annual growth rate) scenarios all result in critical ENS levels, with 2020 being more stressed than 2025. The results also suggest that the outage level variations have a higher impact than the RE-development pathways tested. In the scenarios featuring the generation plant outage levels consistent with those observed in 2014 ('Very High'), the modelling results suggest extreme levels of ENS.

The 'Half_Half RE' scenarios investigate the possibility of half of the planned RE expansion taking place, whereas the other half (in expected power generation equivalent) being substituted through conventional generation capacity, i.e. coal- and gas-fired. There are only slight differences in the resulting modelled ENS between the 'Half_Half RE' and 'All RE' scenarios. The direction of the differences (i.e. higher resulting ENS for 'Half_Half RE' scenarios compared to 'All RE' scenarios) does indicate that dispatchable capacity provides higher contribution to security of supply; the absolute scale of difference (i.e. fairly slight) would though indicate that also RE generation can contribute very significantly to system adequacy. Finally, it can be observed that the difference in the modelled ENS is almost negligible in the most critical system condition scenarios (i.e. high demand and high outage rate), which is fairly intuitive considering that in critical situations any additional power generation capacity can likely help alleviate the pressure. It should be noted, however, that these results are subject to the underlying assumptions (e.g. expression of expected

RE generation into conventional generation capacity and its allocation in the transmission system, as well as the specific RE generation profiles).

Table 17 presents the share of capacity shortage-induced ENS instances as a fraction of all ENS outages across all of the modelled scenarios, 1 000 runs per each scenario.

		Demand: Low			Demand: Moderate			Demand: High		
		Outage level								
Year	*RE development*	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**
2014	*Actual*			96%						
2020	*Half_Half RE*	-	-	0%	0%	56%	94%	79%	98%	100%
2020	*All RE*	-	-	0%	1%	67%	95%	84%	99%	100%
2020	*Half RE*	-	-	0%	1%	78%	97%	89%	99%	100%
2025	*Half_Half RE*	-	-	-	-	0%	0%	6%	36%	45%
2025	*All RE*	-	-	-	-	0%	1%	13%	41%	49%
2025	*Half RE*	-	-	-	-	0%	3%	20%	45%	52%

Table 17: Share of capacity-induced instances of ENS for all SisyfosR modelled scenarios across 1000 runs per scenario. "-" implies no capacity-induced ENS occurrences registered.

The generation capacity-induced instances of ENS are non-existent or negligible in scenarios with low demand growth assumptions. Here the unplanned transmission outages result in a minimum level of ENS at 9 GWh per annum, see Table 16. As the demand projection assumptions increase, the minimum ENS level rises to 16 GWh. It is worth noticing that in some instances when the demand is high (e.g. 2020, high outage rate, half RE), the minimum level of ENS due to grid alone (1% of 2 636 GWh) is above the acceptable level of 20 GWh per annum.

When ENS is above the acceptable level, it is mostly due to insufficient generation capacity. 2014 demonstrates a very high share of capacity-induced ENS; this share is only comparable to the most pessimistic of the future scenarios tested. That is, in the cases for 2020 with high demand growth assumptions and / or very high level of outages.

Table 18 presents the modelled annual average ENS per scenario expressed as a fraction of the respective annual demand.

		Demand: Low			Demand: Moderate			Demand: High		
		Outage level								
Year	*RE develop-ment*	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**	**Low**	**High**	**Very High**
2014	*Actual*			0.279%						
2020	*Half_Half RE*	0.004%	0.004%	0.004%	0.006%	0.013%	0.093%	0.038%	0.460%	1.528%
2020	*All RE*	0.004%	0.004%	0.004%	0.006%	0.018%	0.112%	0.049%	0.491%	1.529%
2020	*Half RE*	0.004%	0.004%	0.004%	0.006%	0.026%	0.180%	0.072%	0.741%	2.186%
2025	*Half_Half RE*	0.003%	0.003%	0.003%	0.005%	0.005%	0.005%	0.012%	0.085%	0.343%
2025	*All RE*	0.003%	0.003%	0.003%	0.005%	0.005%	0.005%	0.016%	0.122%	0.420%
2025	*Half RE*	0.003%	0.003%	0.003%	0.005%	0.005%	0.006%	0.026%	0.229%	0.775%

Table 18: Average annual ENS expressed as a fraction of respective annual demand (%) for all SisyfosR modelled scenarios across 1000 runs per scenario

Though some of the cases tested result in truly extreme absolute levels of ENS, when regarded relative to total national demand, the fractions are still very minor. In most cases ENS only amounts to less than half of 0,01% of the national demand. In the most severe case, the ratio of ENS to the demand exceeds that of the 2014 case scenario by 10 times.

Figure 20 provides a graphical representation of the results of all of the scenarios investigated in the SisyfosR model, expressed in terms of average Energy Not Served (ENS) in GWh per annum across 1 000 model runs for each scenario.

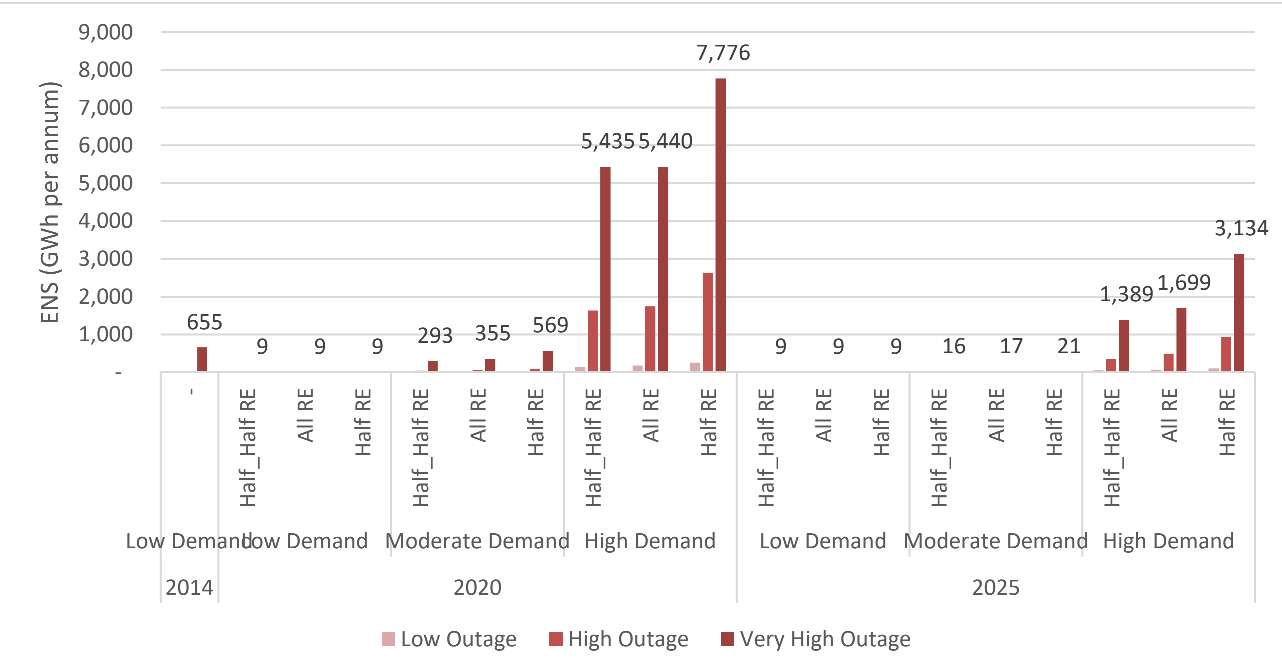

Figure 20: Annual average ENS for all SisyfosR modelled scenarios across 1000 runs per scenario.

Economically optimal amount of ENS

Methods, like N-1 or 'peak demand + 20%', can point out an amount of reserves needed – but cannot describe the expected amount of ENS. In this section we will demonstrate how the probabilistic method (in principle) can be used to find an economically optimal amount of ENS. We say *in principle,* because some of the input parameters may be difficult to obtain in practice (e.g. the value of ENS).

In this exercise it is assumed that the cost of ENS is US $ 6,000 per MWh. This is 25% more than the 75,000 R/MWh that is used in the IRP. It is difficult to find the correct value of ENS. Households and industry may have different values[13]. The used value indicates that ENS should be avoided, as it is in the order of 100 times higher than the average generation costs.

Furthermore, it is assumed that additional peak generation capacity can be established at US$ 95,000 per MW/year. This is meant to illustrate the costs of a single cycle gas turbine. With these values it is not economical to invest in extra generation capacity, if the marginal capacity is used less than 16 hours per year.

2014 is used as an example. The total available capacity is 44,217 MW (including 457 MW wind power). The peak demand is 36,997 MW, so the total capacity is 7,200 MW about the peak demand (29%). It is possible to plan planned outage and still have surplus capacity in all hours. However, unplanned outage results in situations with ENS.

SisyfosR is used to compute a duration curve for the ENS, see Figure 21.

[13] A study about costs of ENS in Denmark indicated a cost of 4,000 to 6,000 $/MWh for households and agriculture and 20,000 to 50,000 $/MWh for trade and industry. Damvad (2015).

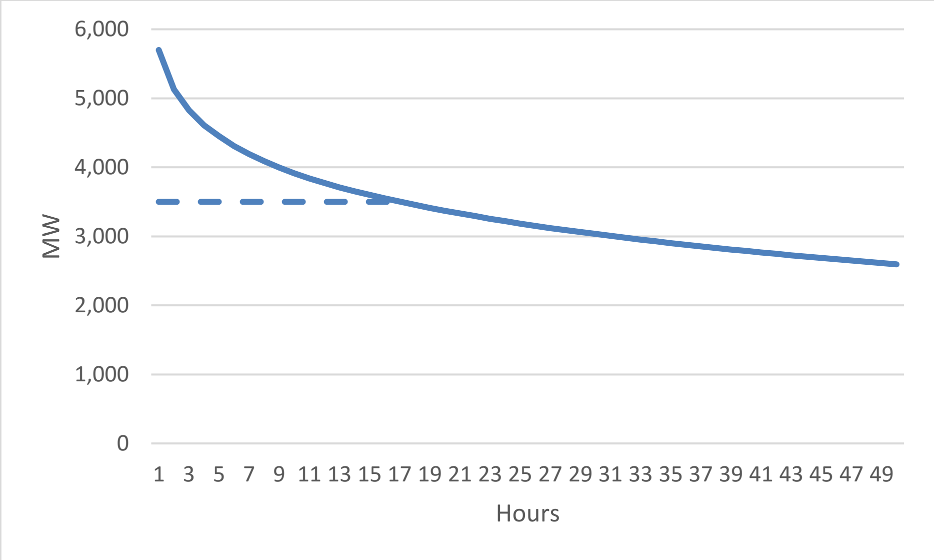

Figure 21. Duration curve for ENS. Data for 2014, with 1,000 MW capacity reserved for N-1 incidences. Assuming additional 3,750 MW, the area below the dashed line will be avoided as ENS, However, the area above the line will still be ENS.

In the results from 2014 (with actual unplanned outage frequency and optimal planned outage, and 1,000 MW reserved for N-1 incidences) the ENS is 655 GWh. The hour with the highest ENS has ENS of 5,700 MW, in total 914 hours have some ENS (LOLP = 10.4 % of all hours). The ENS corresponds to 0.28% of the total demand. Practically all (94%) ENS is generation capacity-induced.

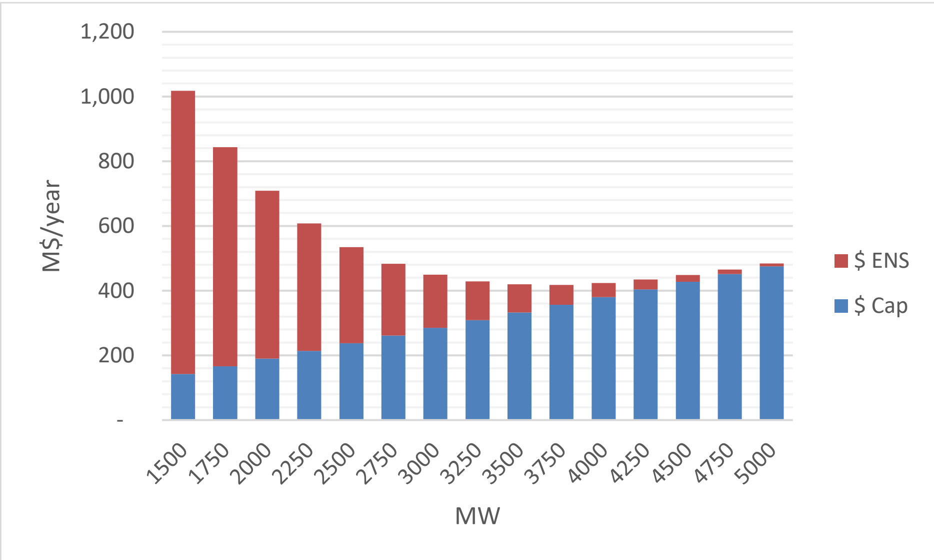

Figure 22. Total cost for ENS (red) and new capacity investment (blue). Minimum total costs can be found at 3,750 MW of new capacity.

The optimal amount of extra capacity is 3,500 MW. This would significantly reduce the amount of ENS. There will be 11 GWh ENS after adding the capacity.

However, adding capacity beyond the 3,500 MW would increase the total costs. The marginal capacity would have less than 16 hours of run time per year.

For the future, more capacity can be added, or investments can be done to reduce the outage frequency of the existing plants. An economic analysis can show what is cheapest. It is also possible to increase the planned outage. Since planned outage is less harmful than unplanned outage, this can be a good idea – depending on the possible reduction of the unplanned outage.

7. Discussion

The power system adequacy in South Africa in 2014 was deemed highly problematic, yielding reported ENS of 512 GWh. This compares reasonably well to the SisyfosR modelled average annual ENS for 2014 of 655 GWh, taking into account that e.g. demand response capabilities were not represented in the model in the current study. As such, a proportion of the modelled ENS in 2014 would have in reality been alleviated by the activation of demand response.

As the SisyfosR scenario analysis suggests, the demand projections are a critical factor with regard to the resulting system adequacy, as expressed by the average annual Energy Not Served (ENS). Across all of the 'Low Demand' 2020 and 2025 scenarios, the resulting average annual ENS are within the 9 GWh range, well below the adequacy metric of Unserved Energy of 20 GWh per annum indicated in the IRP 2010 (2013 update). I.e. with the current generation fleet expansion plans materializing on schedule and the demand growth continuing at a rate of 1% per annum, the system adequacy should be able to reach satisfactory levels, even in the absence of improvement in the existing generation fleet availability rates.

In the scenarios where the demand growth rate reaches 2% per annum throughout the projection period, i.e. 'Moderate Demand', the modelling results suggest that system adequacy outcomes would be more dependent on the developments in other key factors, e.g. the availability rates of the existing generation fleet and realization of the RE development plans (the factors tested), especially towards 2020. For instance, with significant improvements in generation fleet maintenance ('Low Outage level') the modelled average annual ENS level meets the adequacy metric of 20 GWh per annum in 2020. If the generation outage situation is high (matching the one realised in 2010-2014 'High Outage level'), but RE development is realised, then ENS reaches 55 GWh in 2020. If, in addition, the RE development plans do not fully materialize / are delayed (and no conventional generation is built to compensate for this, i.e. 'Half_Half_RE development'), the corresponding modelled ENS level reaches 83 GWh in 2020.

Finally, if the demand development reaches the levels as projected by IRP 2010 (i.e. demand growth rate reaches 3.1% per annum throughout the projection period), the modelled outcomes in terms of average annual ENS reach critical levels even under the assumption of most favourable outcomes in terms of other key factors.

Last but not least, the impact of potential alternative futures with regard to the RE expansion development have been explored in the current analysis. The ‘Half_Half RE’ scenarios investigate the possibility of half of the planned RE expansion taking place, whereas the other half (in expected power generation equivalent) being substituted through conventional generation capacity, i.e. coal- and gas-fired. There are only slight differences in the resulting modelled ENS between the ‘Half_Half RE’ and ‘All RE’ scenarios. The direction of the differences (i.e. higher resulting ENS for ‘Half_Half RE’ scenarios compared to ‘All RE’ scenarios) does indicate that dispatchable capacity provides higher contribution to security of supply; the absolute scale of difference (i.e. fairly slight) would though indicate that also RE generation can contribute very significantly to system adequacy. Finally, it can be observed that the difference in the modelled ENS is almost negligible in the most critical system condition scenarios (i.e. high demand and high outage rate), which is fairly intuitive considering that in critical situations any additional power generation capacity can likely help alleviate the pressure. It should be noted, however, that these results are subject to the underlying assumptions (e.g. expression of expected RE generation into conventional generation capacity and its allocation in the transmission system, as well as the specific RE generation profiles).

8. Further development

The SisyfosR model and the complete data set is handed over to the Steering Committee for the project (including Eskom, DoE, Sanedi). During the current project, the model has been populated with a number of high quality and detailed data inputs (e.g. demand per node and outage data per unit etc.). However, some input data could still be improved. This includes more accurate demand forecasts and typical transfer capacities for the individual transmission lines.

More years

In this study 2014 has been used as the basis for the analyses. Demand data as well as wind and solar data has been used as the basis for the calculations. For 2020 and 2025 demand projections, scaled values of 2014 load profiles' data have been used. For wind and solar production time series, meteorological year 2014 has been used (CorWind power time series simulation model is then applied to simulate real and forecasted wind power for 2014, 2020 and 2025, based on the projected wind power capacity and location). The volume of energy not served (ENS) is highly dependent of the occurrence of challenging combinations of demand and renewable energy generation and outage of generation. The most challenging combinations may be rare – and by using several (e.g. three) years for the input data for demand, wind and solar a better representation of the rare situations can be achieved. This can also act as a sensitivity analyses.

Common failures

In the present study all probabilities for outage have been assumed to be independent. However, it is possible to use *common failure* functionality to represent the probability of one failure affecting two or more elements.

It has been tested if all units on a station have a common probability of failure. This was found not to be the case. However, many other combinations exist, e.g. two specific units may have a common failure. This could be further studied in future projects.

Data refinement

Implementation of the demand response capabilities would prospectively yield a result more accurately matching of actual realized ENS in South Africa in 2014. Also, the transmission line capacity values used in the current study have been based on technical capacities. Using the practical loading limit values would be an improvement. In addition, a representation of non-Eskom generation plants (along with their corresponding demand data) would also improve the accuracy of the analysis. Finally, implementing a prospective availability profile for the future hydro plants (e.g. Import Hydro 1 and 2), if relevant, could contribute to more representative results.

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Appendix I: Generation Expansion Plan

Generation type (MW)	2014	2020	2025
Coal	**35,940**	**45,596**	**45,626**
Arnot	2,220	2,220	2,220
Camden	1,520	1,520	-
Coal_IPP1_Khanyisa	-	400	400
Coal_IPP1_Kusile	-	4,428	4,428
Coal_IPP1_Medupi	-	4,428	4,428
Coal_IPP2_Kriel	-	400	400
Coal_IPP3_Masa	-	-	1,000
Coal_IPP4_Masa	-	-	1,250
Duvha	3,480	3,480	3,480
Grootvlei	1,080	1,080	1,080
Hendrina	1,900	1,900	1,900
Kendal	3,840	3,840	3,840
Komati	900	900	200
Kriel	2,880	2,880	2,880
Lethabo	3,540	3,540	3,540
Majuba	3,840	3,840	3,840
Matimba	3,720	3,720	3,720
Matla	3,480	3,480	3,480
Tutuka	3,540	3,540	3,540
Oil	**2,460**	**2,460**	**2,460**
Acacia	180	180	180
Ankerlig	1,350	1,350	1,350
Gourikwa	750	750	750
Port_Rex	180	180	180
Hydro	**2,100**	**2,000**	**4,563**
Cahorra	1,500	1,400	1,400
Gariep	360	360	360
Import Hydro	-	-	2,563
Vanderkloof	240	240	240
Nuclear	**1,860**	**1,860**	**6,660**
Koeberg	1,860	1,860	1,860
Nuclear_Thyspunt	-	-	4,800
Pumped storage	**1,400**	**2,732**	**2,732**
Drakensberg	1,000	1,000	1,000
Palmiet	400	400	400
Hydro_IPP1_Ingula	-	1,332	1,332

Generation type (MW)	2014	2020	2025
Solar PV	**-**	**2,697**	**4,897**
PV_Aggeneis	-	140	240
PV_Aries	-	110	210
PV_Aurora	-	89	89
PV_Bacchus	-	36	36
PV_Bighorn	-	7	7
PV_Boundary	-	228	328
PV_Ferrum	-	224	424
PV_Garona	-	9	9
PV_Harvard	-	64	64
PV_Helios	-	75	75
PV_Hydra	-	317	517
PV_Juno	-	9	9
PV_Kappa	-	-	200
PV_Kronos	-	225	225
PV_Lomond	-	50	50
PV_Matimba	-	60	60
PV_Mercury	-	68	68
PV_Mookodi	-	75	475
PV_Nama	-	-	200
PV_Olien	-	139	139
PV_Paulputs	-	185	185
PV_Perseus	-	60	60
PV_Ruigtevallei	-	70	70
PV_Tabor	-	28	328
PV_Theseus	-	100	100
PV_Upington	-	225	525
PV_Watershed	-	75	75
PV_Witkop	-	30	130
CSP	**-**	**700**	**1,200**
CSP_Boundary	-	100	100
CSP_Ferrum	-	100	200
CSP_Garona	-	100	100
CSP_Olien	-	100	100
CSP_Paulputs	-	200	200
CSP_Upington	-	100	500
Other	**-**	**79**	**79**
Oth_Etna	-	18	18
Oth_Impala	-	17	17
Oth_Marathon	-	25	25
Oth_Paulputs	-	10	10
Oth_Tugela	-	9	9

Generation type (MW)	2014	2020	2025
OCGT	**-**	**1,029**	**2,643**
OCGT_Dedisa	-	-	1,614
OCGT_IPP1_Avon	-	735	735
OCGT_IPP1_Dedisa	-	294	294
CCGT	**-**	**474**	**711**
CCGT_Dedisa	-	474	711
Wind	**457**	**3,846**	**7,446**
Wind_Aggeneis	-	137	237
Wind_Aries	-	-	100
Wind_Aurora	65	256	256
Wind_Bacchus	-	58	58
Wind_Delphi	97	197	597
Wind_Droerivier	-	100	400
Wind_Grassridge	160	642	642
Wind_Gromis	-	-	200
Wind_Helios	-	276	276
Wind_Hydra	-	387	1,187
Wind_Juno	-	100	100
Wind_Kappa	-	108	708
Wind_Komsberg_RE	-	419	619
Wind_Kronos	-	238	238
Wind_Muldersvlei	-	135	135
Wind_Nama	-	-	200
Wind_Pembroke	-	53	353
Wind_Poseidon	135	740	940
Wind_Thyspunt	-	-	200
Total Capacity (MW)	**44,217**	**63,472**	**79,016**