MEDIUM-TERM SYSTEM ADEQUACY OUTLOOK 2020

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Generation System Adequacy for the Republic of South Africa

30 October 2020

IMPORTANT NOTICE

While the System Operator has taken all reasonable care in the collection and analysis of data available, the System Operator is not responsible for any loss that may be attributed to the use of this information. The changing environment in the South African energy industry means continually changing data that might not have been included in the modelling of this study.

The study is not intended to be used as a plan, but rather to explore how possible different futures might test the adequacy of a generation system. Prior to taking business decisions, interested parties are advised to seek separate and independent opinion in relation to the matters covered by this report and should not rely solely on data and information contained here. Information in this document does not amount to a recommendation in respect of any possible investment.

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List of abbreviations

Term	Definition
DMRE	Department of Mineral Resources and Energy
EAF	Energy availability factor
FOR	Forced outage rate
IPP	Independent power producer
IRP	Integrated Resource Plan
MES	Minimum emission standards
MTSAO	Medium term system adequacy outlook
NERSA	National Energy Regulator of South Africa
OCGT	Open-cycle gas turbine
OCLF	Other capability load factor
PCLF	Planned capability load factor
PV	Solar photovoltaic
REIPP	Renewable energy independent power producer
SSEG	Small-scale embedded generation
SO	System Operator
UCLF	Unplanned capability load factor

1. INTRODUCTION

The South African Grid Code (NERSA, 2014) requires the System Operator (SO) to publish a review called the Medium-Term System Adequacy Outlook (MTSAO) on or before 30 October of each year of the adequacy of the integrated power system to meet the medium-term (five-year future) requirements of electricity consumers.

In preparing the MTSAO, the SO considers the latest information provided by Eskom generators, independent power producers, other non-Eskom generators, the national transmission company, transmission network service providers, and distributors, such as:

- possible scenarios for growth in the demand of electricity consumers;
- possible scenarios for growth in generation available to meet that demand;
- committed projects for additional generation;
- demand management programmes; and
- reasonable assumptions about imports and exports, and any other information that the SO may reasonably deem appropriate.

The MTSAO measures the capability of the generation system to meet the expected country demand, within component ratings and voltage limits, while taking into account the planned and unplanned outages and operating constraints. The expected demand includes the country’s demand plus exports, whereas the supply to meet the demand is all the generation resources licensed by NERSA plus imports, demand-side management resources, and rooftop PV. This study provides a statement of the South African power generation adequacy for the calendar years of 2021 to 2025. The adequacy needed to transport and distribute electricity does not form part of the MTSAO.

2. METHODOLOGY

2.1 Adequacy metrics

The metrics used to assess the system’s adequacy of the MTSAO 2020 are shown in Table 1 below. These metrics were chosen after the load-shedding experience in the year 2008, to reflect allowable risk of supply shortages to avoid the unreasonably high cost associated with reducing this risk to a negligible level. The adequacy metrics provide information about the capacity and energy adequacy of the generation system to meet expected demand. The system is deemed adequate if all three of the system adequacy metrics are met.

Table 1: System adequacy metrics

Adequacy metric	Threshold	Details
Unserved energy	< 20 GWh per annum	The amount of energy in a year that cannot be supplied due to system supply shortages.
OCGT capacity factor	< 6% per annum	The combined capacity factor of the OCGT plant in operation in a year.
Baseload stations – capacity factor	< 50% per annum	The capacity factor of a contingency coal-fired baseload station in a year.

2.1.1 Capacity adequacy

Unserved energy and OCGT capacity factor metrics look primarily at the capacity adequacy. Capacity-type contingencies are typically unexpected load increases or coincident unplanned failure of a number of generating units. These short-duration-type events (typically hours) occur when there is just sufficient total plant capacity to supply the load during high-demand hours under the expected supply-and-demand situation. The plant then has insufficient capacity reserve to cater for a capacity-type contingency should it occur. The capacity shortfall would, in this case, result in unserved energy for a few hours. Capacity inadequacy will be flagged when the threshold of any one of these metrics is exceeded. The likelihood that the system will be unable to meet the load during a capacity-type contingency then becomes unacceptably high.

2.1.2 Energy adequacy

The capacity factor of the expensive baseload station looks primarily at the energy adequacy. Energy-type contingency is the occurrence of a significantly higher-than-forecast load growth or the loss of a large source of supply for a prolonged period (weeks/months). The system may be deemed energy inadequate when there is just sufficient baseload plant to supply the load on a continuous basis under the expected supply-and-demand situation. All baseload plant will, therefore, operate at high capacity factors, resulting in a shortage of energy reserve to cater for an energy-type contingency should it occur. When all baseload plant is operating at high capacity factors, the energy shortfall would then require baseload-type generation from a peaking plant (mostly OCGTs). This may not be financially sustainable or even possible from a fuel-supply perspective. Energy inadequacy will be flagged when the capacity factors become high, meaning that the system response to an energy-type contingency may not be sustainable.

2.2 **Modelling framework**

The MTSAO assesses system risks using a Monte Carlo simulation technique to balance generation resources with expected demand. The assessment is conducted with PLEXOS® Simulation Software, based on an hourly unit commitment and economic dispatch problem that does an optimisation under uncertainties of the load, renewable generation production (particularly wind and solar), and plant outages based on historical data. The simulation results are tested against the three adequacy metrics of Table 1 above. Should any of the adequacy metrics not be met, additional capacity is added as per the iterative process shown in Figure 1 until all the adequacy metrics have been met. The capacity options added to get to an adequate system are quantified per year and classified as baseload, mid-merit, or peaking capacity in MW, depending on the capacity factor required by the system for this resource.

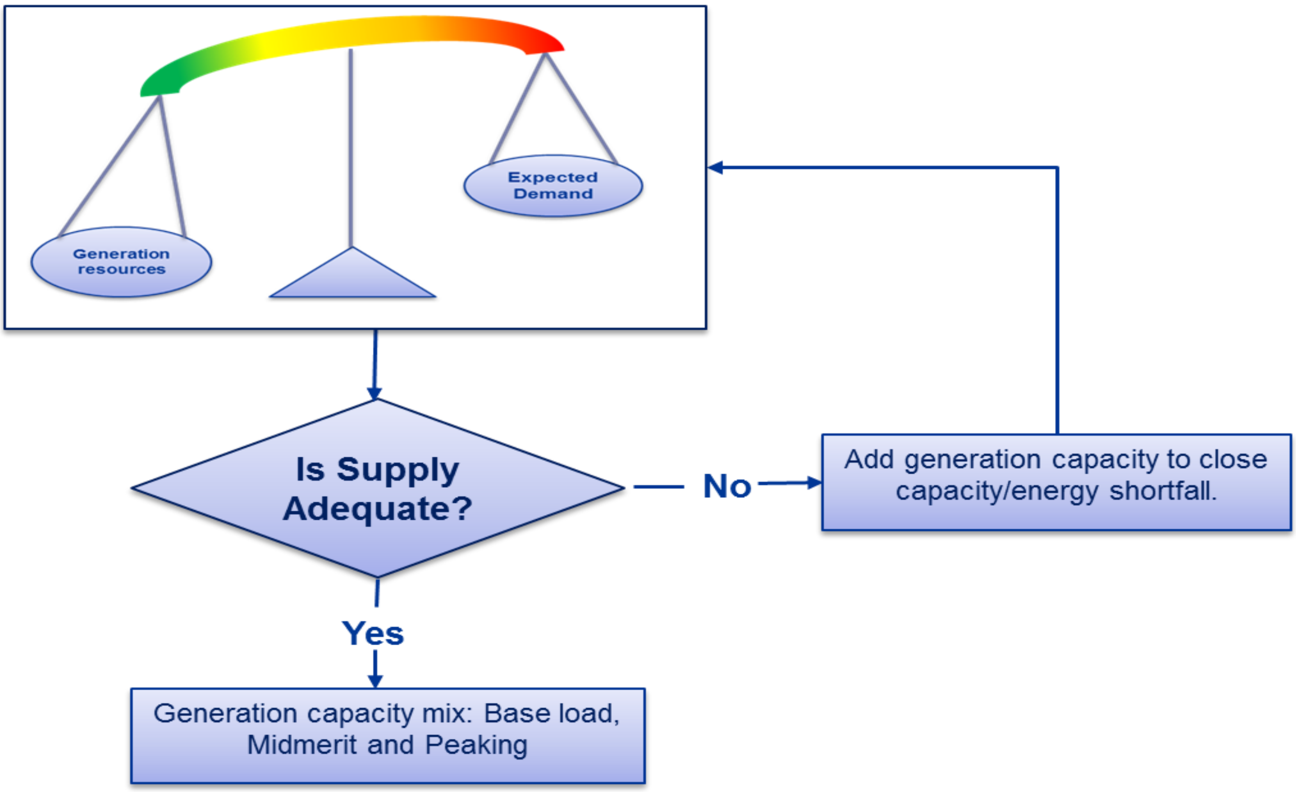

Figure 1: MTSAO methodology

3. KEY ASSUMPTIONS

This section describes the input assumptions used in the MTSAO 2020. The assumptions are split into demand-side assumptions and supply-side assumptions. The assumptions with the largest impact on system adequacy are the energy forecast, existing and committed RSA generation capacity, and the plant performance of the Eskom fleet. Details of the key assumptions are discussed below.

3.1 Demand forecast

The energy demand forecasts used for this MTSAO 2020 study are depicted in Figure 2 below. The two energy demand forecasts studied were the moderate and the low demand scenarios. Two methodologies differentiated by the key assumptions were used in compiling these two forecast scenarios, as detailed below.

The moderate demand scenario, with an average annual growth rate of 0,85%, was computed using GDP input from the IHS Market Regional eXplorer (ReX) update of the first quarter of 2020. The GDP forecasts contraction of -3,5% on the South African economy for the year 2020 due to the impact COVID-19 has on the economy, followed by a positive GDP growth from 2021 resulting in growth in sent out.

The low energy demand scenario, with an average annual growth rate of -0,06%, is in line with the Eskom historical customer consumption and assumes less favourable economic conditions due to COVID-19 lockdown. The negative growth in this scenario is due to the assumption that the country will be in a continuous recession for the MTSAO period similar to what was declared by Moody's for the year 2019.

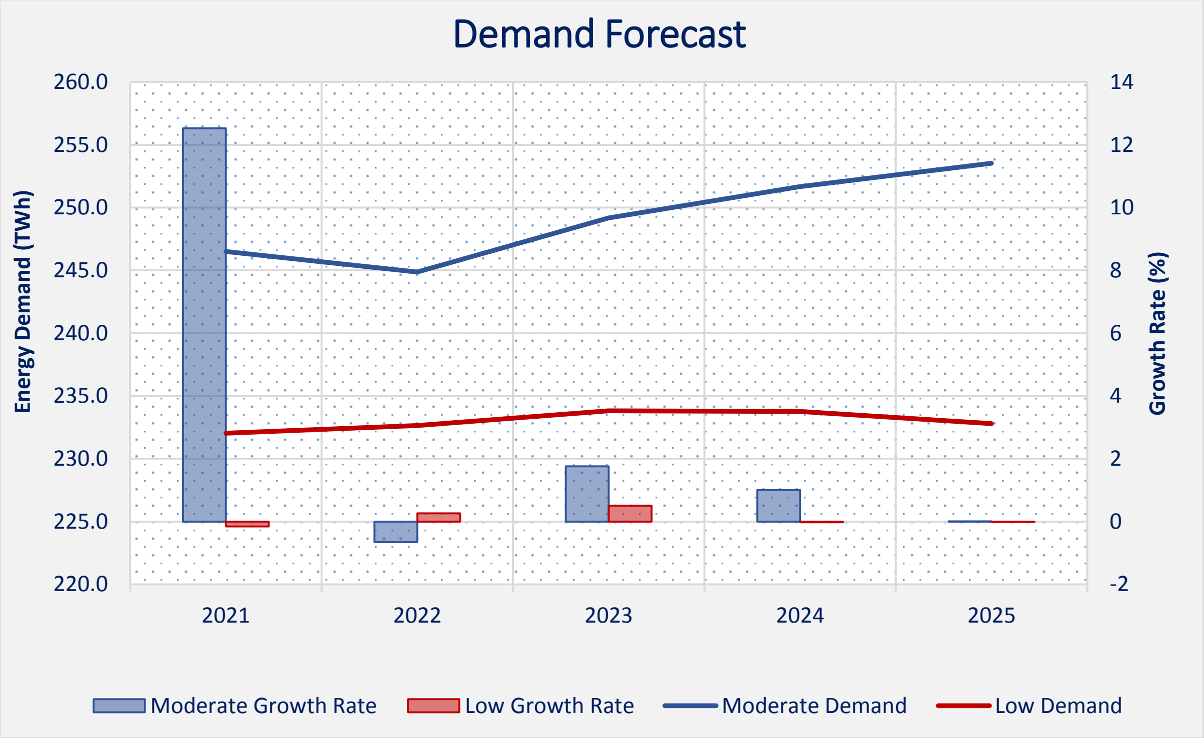

Figure 2: Energy forecast and actuals

Demand is then statistically modelled to cater for the probability of load variability within the hourly median.

3.2 Eskom's existing and committed supply resources

3.2.1 Eskom's committed build schedule

The cumulative capacity from Medupi and Kusile units follows the P80 forecasted commercial operation dates for all the remaining units and is depicted in Figure 3 below. All Kusile units are expected to be in commercial operation in 2024 and the remaining Medupi unit in 2021.

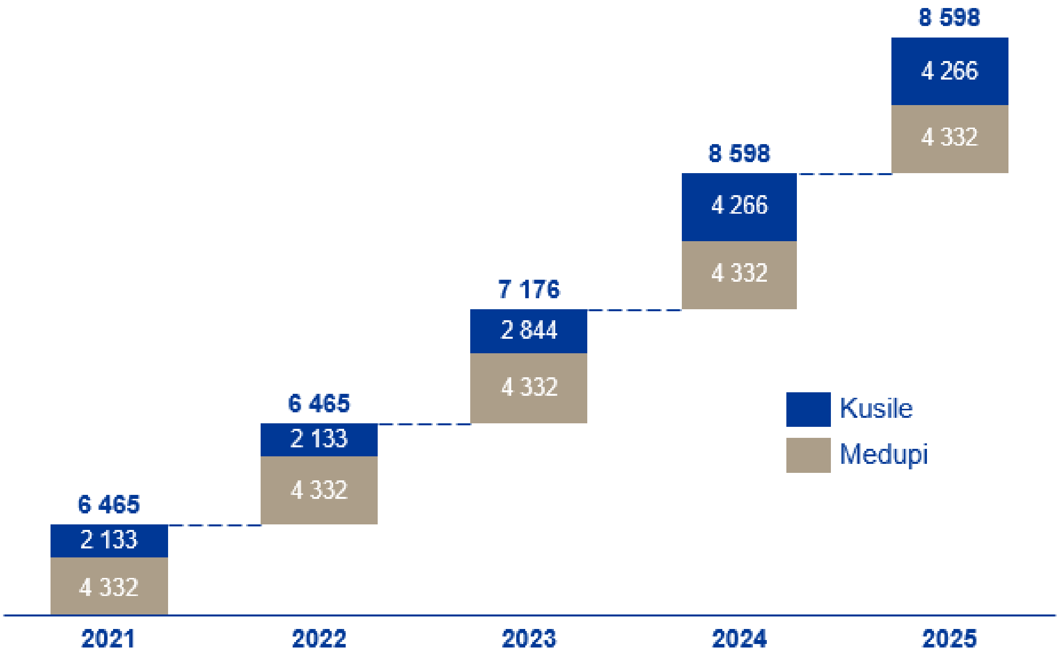

Figure 3: New build cumulative capacity (MW)

3.2.2 Eskom fleet shutdown

The study assumed capacity reductions as Eskom's coal-fired units reached the end of their 50-year life in alignment with the IRP 2019 (IRP, 2019). These reductions will result in the shutdown of a single unit at Arnot in 2021 and all Camden units by 2024. Duvha Unit 3 was assumed to be unavailable throughout the study horizon; its capacity was netted from the total capacity sent out.

The study, furthermore, assumed that units at Hendrina, Komati, and Grootvlei would be shut down when they reached their turbine dead-stop dates and it was no longer economical to carry out the maintenance required in terms of the Occupational Health and Safety Act to keep them in service. The capacity reduction due to 50-year-life and turbine dead stop shutdowns is depicted in Figure 4 below.

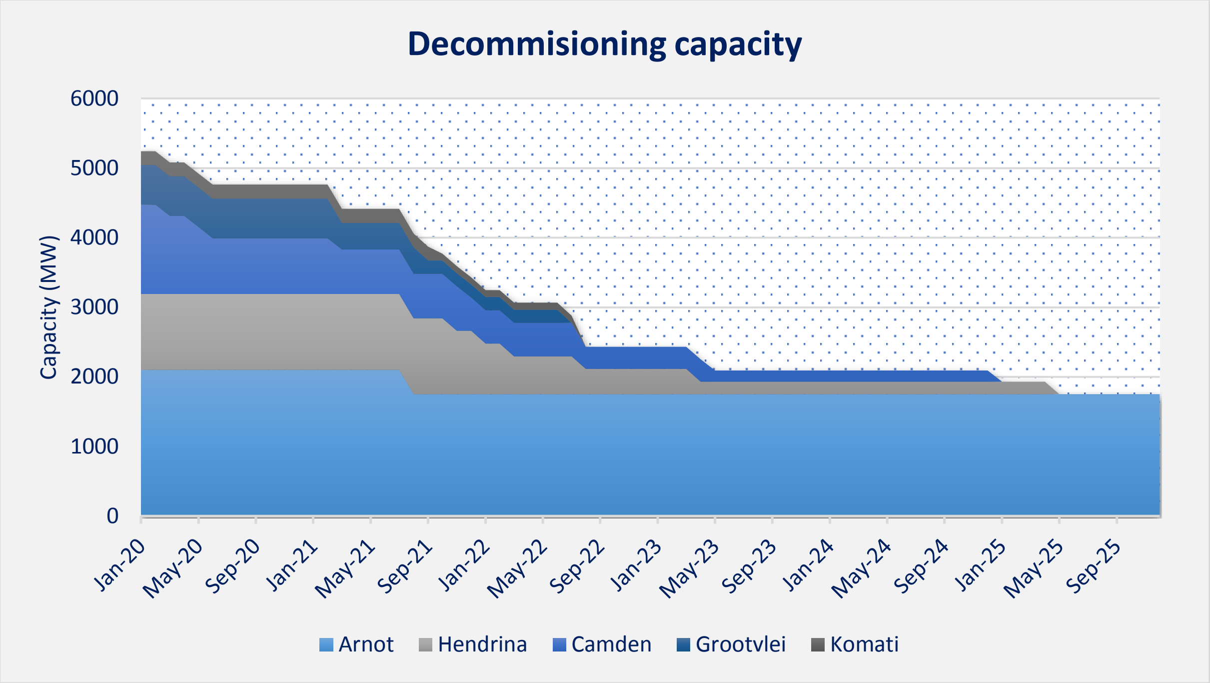

Figure 4: Shutdown of Eskom coal-fired station units

3.2.3 Eskom's existing and committed sent-out capacity

The total Eskom installed capacity consists of coal, nuclear, pumped storage, diesel, hydro, and wind, as shown in Figure 5 below. This capacity takes into account the assumed timing of the commissioning of new build stations and the shutting down of some units from older stations.

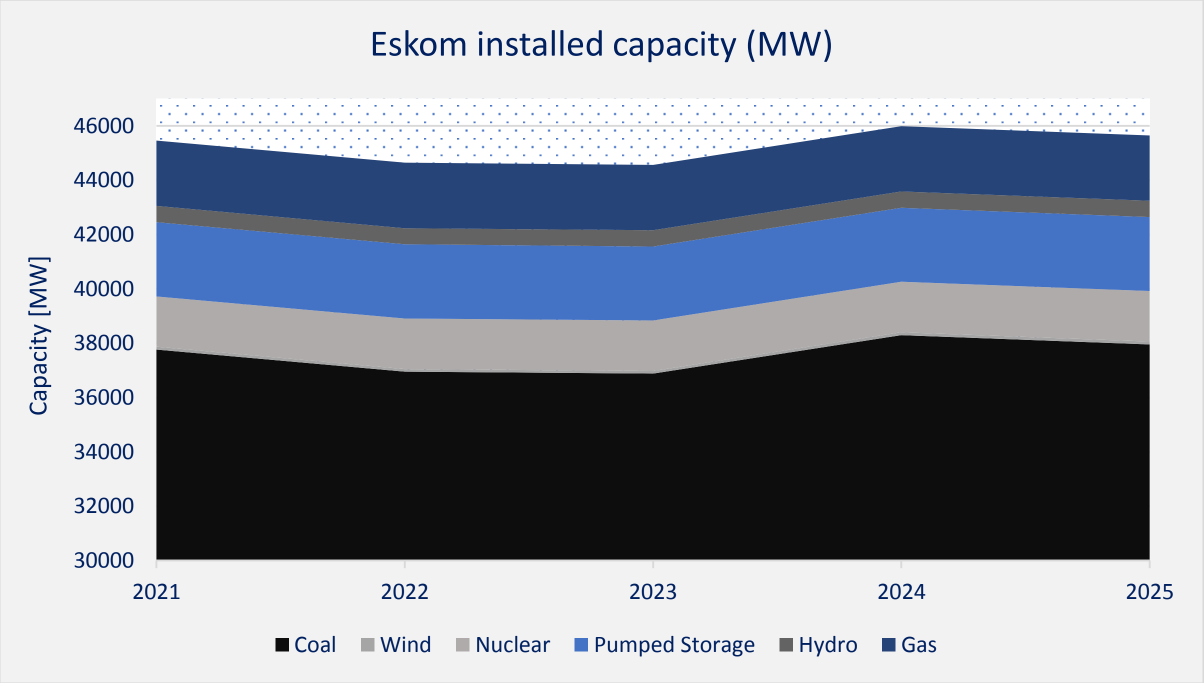

Figure 5: Eskom installed capacity (MW)

3.2.4 Eskom plant performance

Planned outages

The study assumed an annual average of 10% planned capability loss factor (PCLF) for all the plant performance scenarios considered. This PCLF incorporates the retrofit outages required at the power stations to comply with the minimum emission standards (MES).

Forced outages

The forced outage rate (FOR) includes both the unplanned capability loss factor (UCLF) and other capability loss factor (OCLF). Forced outages are modelled as independent events, and the generator forced outage rate is expressed as a percentage that is set as the expected level of unplanned outages that result in partial or complete loss of generating capability for a certain period of time. An annual rate of forced outages is defined for all plant and simulated by random occurrences of outages within the probabilistic Monte Carlo scheme. Since the occurrence of forced outages is not predetermined, it is a useful tool for testing the resilience of a power system against sudden unscheduled unavailability of generation resources.

Partial load losses

Since load losses are categorised as capacity on forced outage in plant performance reporting, an explicit modelling of the pattern of partial load losses improves the assessment of system adequacy. Historical data of partial load losses from 2014 to May 2020 was used to predict the pattern of partial load losses used in the study horizon. The partial load losses were discounted in the unplanned outages of both plant performance scenarios.

Energy availability factor

The plant performance scenarios considered in this study are illustrated in Figure 6, namely, high EAF (~74%) and low EAF (~65%). Both plant performance scenarios assume the same PCLF of 10%. The difference between the high and low EAF scenarios is the forced outage rate; the high EAF scenario has an average FOR of 17%, while the low EAF scenario has an average FOR of 25%. The Generation historical plant availability has continued to decrease in the past years, reaching 67% in financial year 2020. This necessitated the inclusion of the low EAF in the MTSAO study, which has followed a similar declining trend.

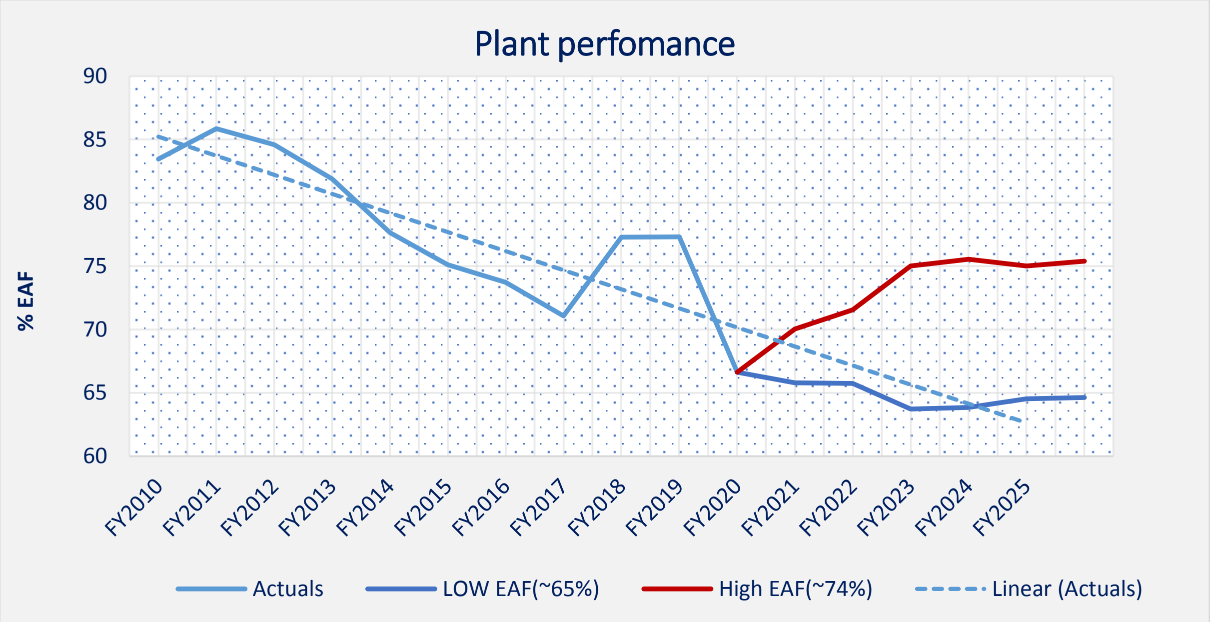

Figure 6: Eskom fleet energy availability factor

3.3 Renewables from independent power producers

All contracted build REIPPP capacity, from Bid Window 1 to Bid Window 4, was considered as committed in the study and is shown in Figure 7 below, with consideration of COVID-19 project delays.

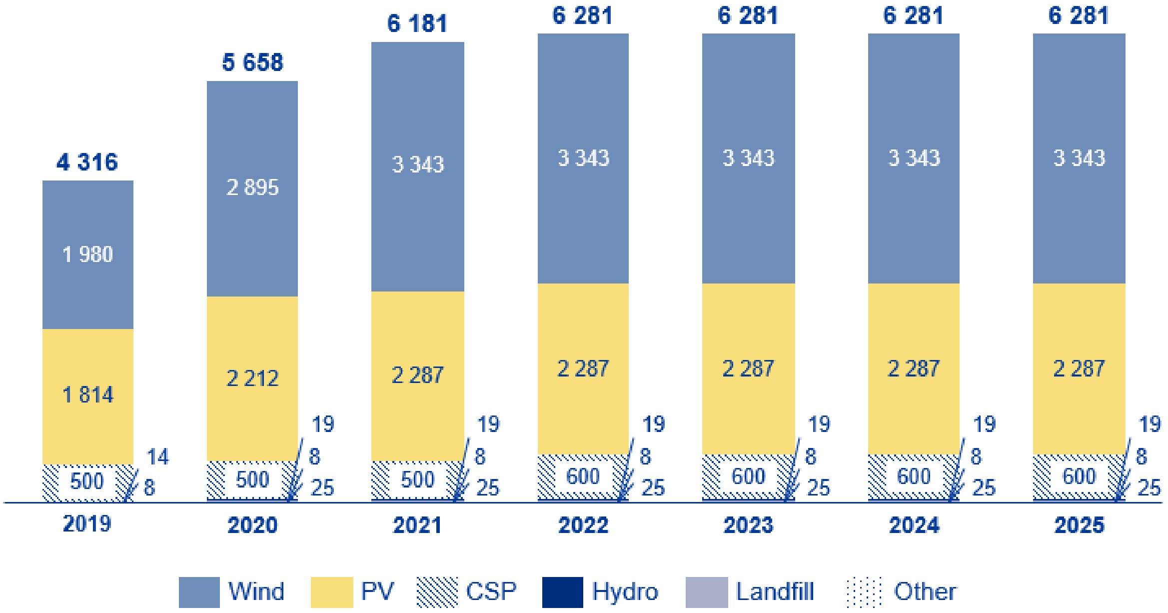

Figure 7: REIPPP cumulative capacity (MW)

Wind and solar PV plants were modelled as stochastic objects based on historical actuals. An aggregated regional profile was used for installations with a shorter operation period as well as for future installations.

3.4 **Existing non-Eskom installed capacity**

Installed sent-out capacity of non-Eskom generation in South Africa is shown in Figure 8 below. The DMRE IPP peaking plants at Dedisa and Avon were included in the total for gas, and the hydro includes Cahora Bassa. The energy produced by the non-Eskom plant, excluding Cahora Bassa and DMRE Peakers, was limited to 11,3 TWh per annum throughout the study horizon. Any reduction in this production would negatively affect the system adequacy outlook. The study assumed that non-Eskom generators not contracted to Eskom would continue generating for own use. Due to the unavailability of data on non-Eskom plant performance, the MTSAO modelled typical plant performance based on plant of similar size and age.

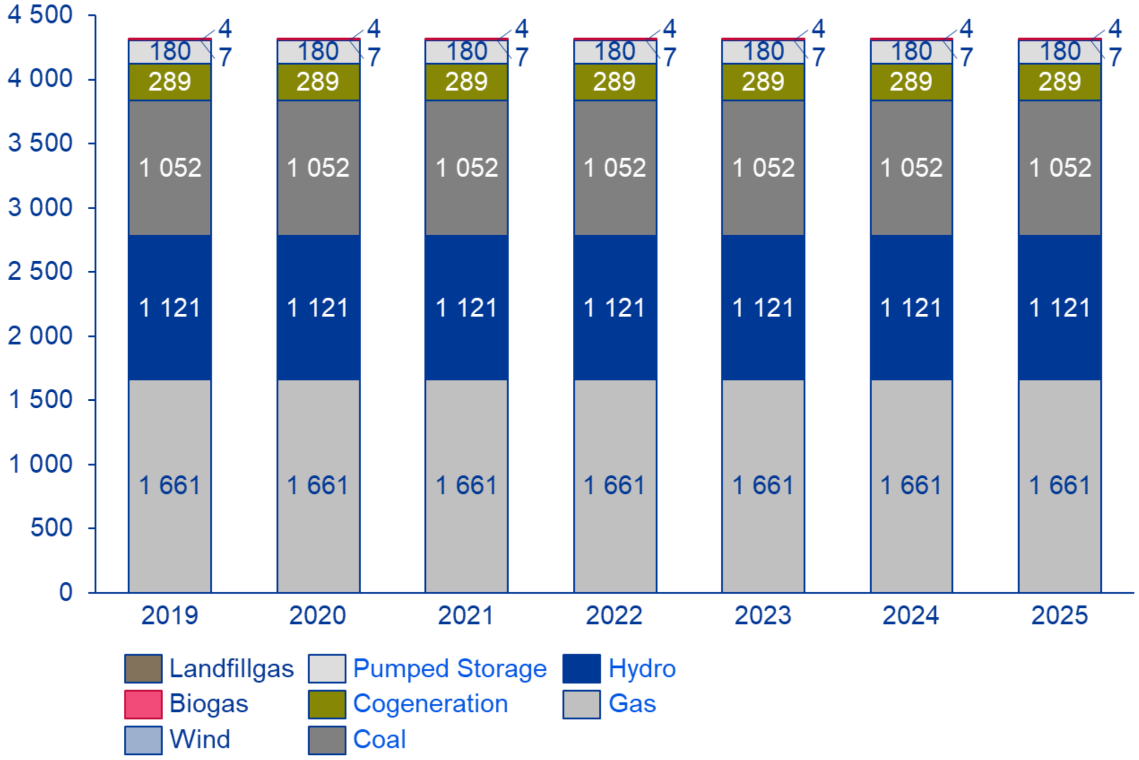

Figure 8: Non-Eskom capacity (MW)

3.5 **Small- scale embedded generation (SSEG)**

SSEG installations are not yet licensed by NERSA, and hence, there is no data of the existing installed capacity. Current indications are that this capacity has been growing due to increasing electricity prices and load shedding. Various publications (AREP, 2019) and (AREP, 2019) have been used to derive a reasonable estimate of currently installed capacity, particularly rooftop PV. Estimates for future installations are based on the IRP 2019 gazette (IRP, 2019) that makes provision for other types of embedded generation. The estimated capacity is shown in Figure 9 below.

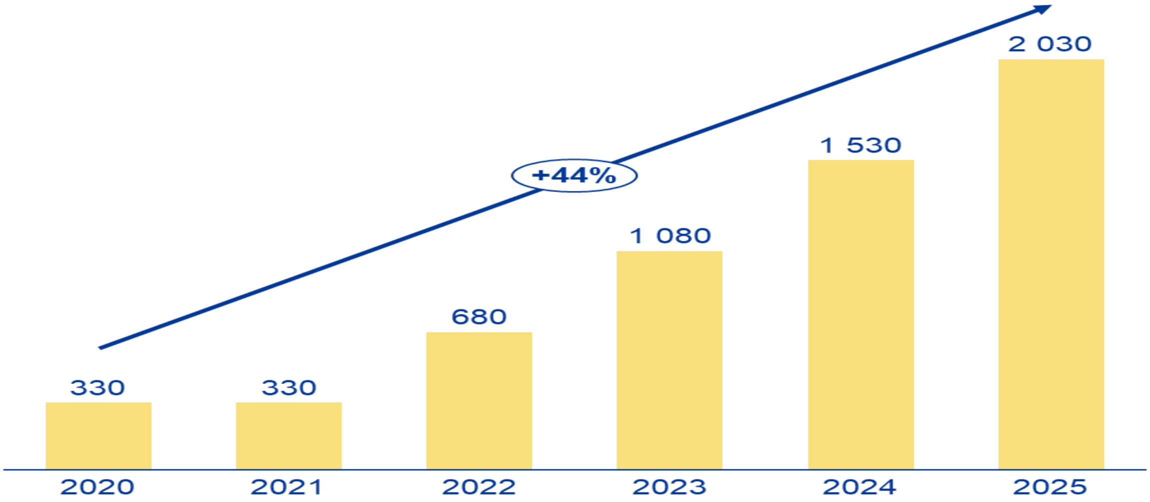

Figure 9: Estimated SSEG capacity (MW)

3.6 Reserves requirements

Reserves are used to balance the system when unexpected events occur, such as customer demand fluctuations, changes in the availability of supply capacity, and generation variations from intermittent plant. The reserve requirements used in the study are depicted in Table 2 below (SO, 2019).

Table 2: Reserves requirements for summer and winter (MW)

Type	Period	2020/21	2021/22	2022/23	2023/24	2024/25
Instantaneous	Peak	650	650	650	650	650
	Off-peak	850	850	850	850	850
Regulating	Peak/Off-peak	500	500	500	500	500
Ten-minute	Peak	1 050	1 050	1 050	1 050	1 050
	Off-peak	850	850	850	850	850
Supplemental reserve	Peak/Off-peak	300	300	300	300	300
Operating	Peak/Off-peak	2 200	2 200	2 200	2 200	2 200
Emergency	Peak/Off-peak	1 600	1 600	1 600	1 600	1 600

Operating reserves, which require activation within a short period of time, are used to deal with disturbances on the system as well as energy shortages. Under normal circumstances, these are provided by power stations already contracted to do so, typically coal and/or pumped-storage generating units. However, not all contracted stations are able to provide the required reserves.

Emergency reserves are provided by instantaneous loads and/or peaking generating capacity. Their operation is similar to operating reserves, but is dispatched as a measure of last resort due to their high overall cost to the system. The study assumed that instantaneous loads whose contracts expired during the study period would be renewed and available to the power system. Although not ideal, emergency reserves are, at times, dispatched in place of operating reserves due to shortages.

Supplemental reserves are generating units or demand-side load that can be called on hours ahead to complement emergency reserves. The study assumed that these would be available to the power system only in financial year 2021, for which they were contracted.

4. STUDY CASES

The studied scenarios were selected to cater for the unpredictable nature of the South African integrated power system. The energy demand forecast and the Eskom plant performance were identified as the most sensitive assumptions; as such, combinations of these assumptions form the base-case scenarios, as shown in Figure 10 below.

Assumptions that are common to all scenarios are the 50-year life of plant for Eskom power stations, with shutdowns at turbine shutdown dates of some coal-fired stations, commercial operation dates for Eskom's new build plants, non-Eskom installed capacity, and contracted REIPP capacity and timing.

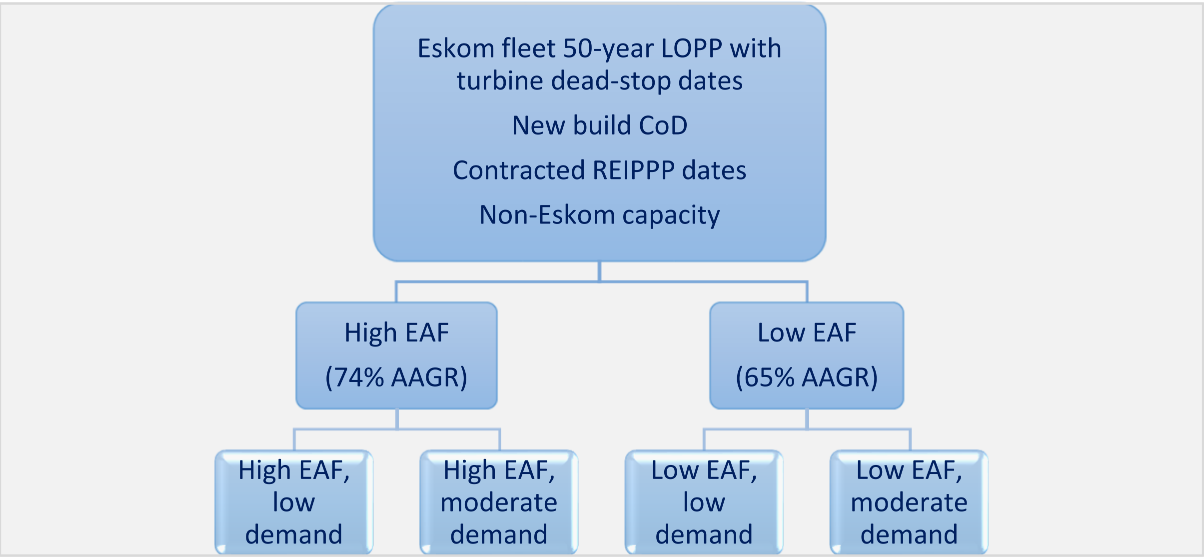

Figure 10: MTSAO study scenarios

5. RESULTS

The base-case results of the MTSAO 2020 were categorised into high EAF and low EAF scenarios. The results were assessed against the following adequacy metrics thresholds:

- Contingency baseload capacity factor < 50%
- OCGT capacity factor < 6%
- Unserved energy < 20 GWh

5.1 High EAF scenarios

The outcomes of the high EAF scenario for the contingency baseload capacity factor, OCGT capacity factor, and unserved energy for both the moderate and the low energy demand forecasts are depicted in Figure 11, Figure 12, and Figure 13, respectively. The red dotted line shows the threshold for each adequacy metric.

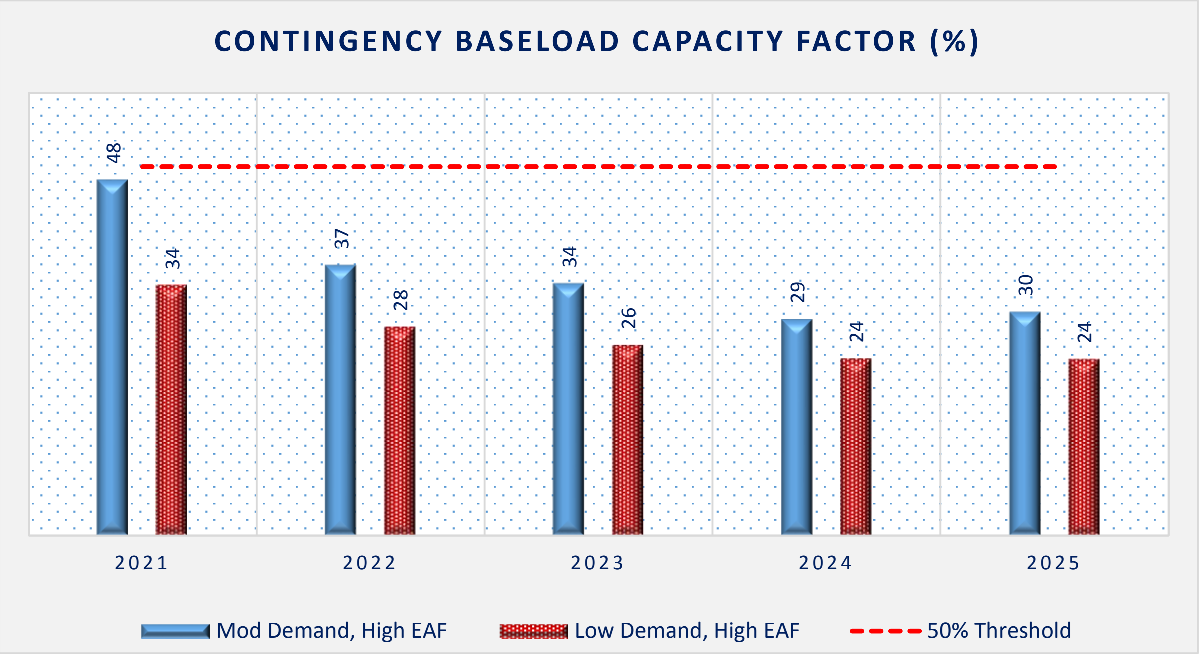

Figure 11: High EAF contingency baseload capacity factor

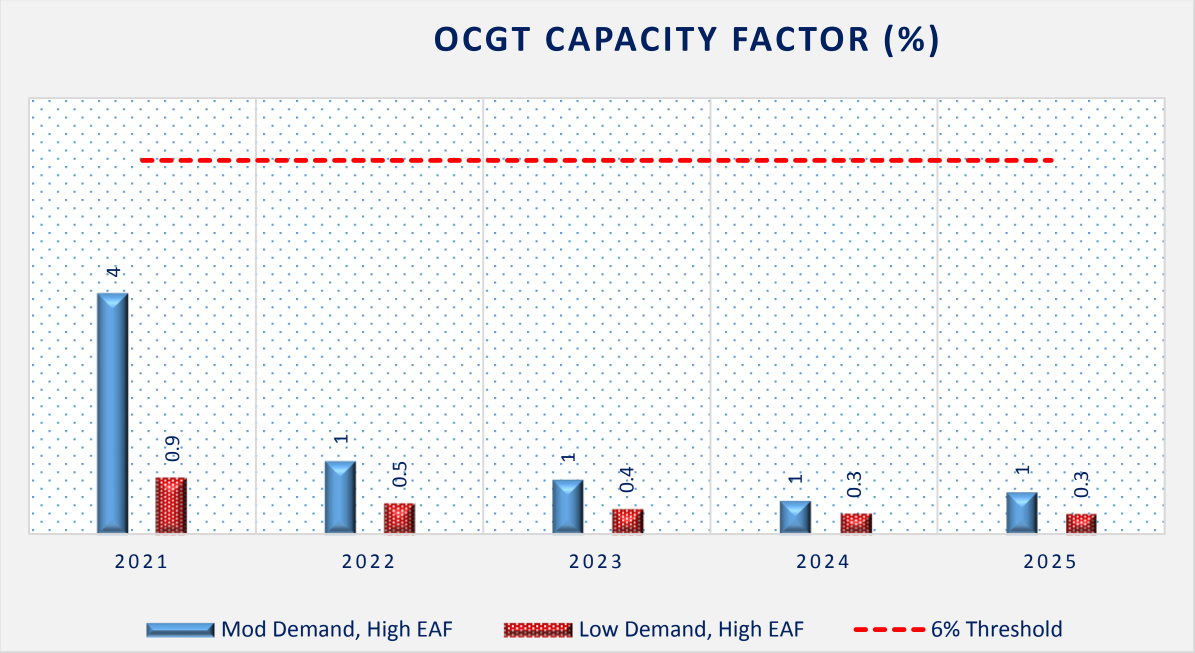

Figure 12: High EAF OCGT capacity factor

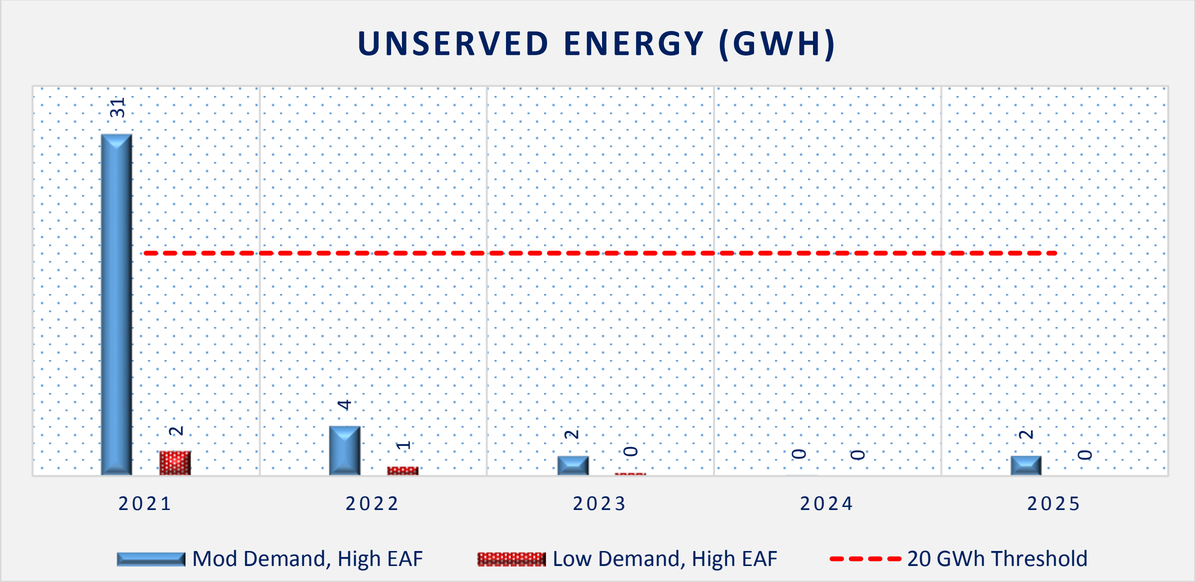

Figure 13: High EAF unserved energy

The results show that the power system is adequate for the high EAF throughout the study horizon for the low energy demand forecast. Furthermore, the system is adequate for the moderate energy demand forecast, with the exception of year 2021, where the unserved energy threshold is violated. However, this violation can be managed operationally by the System Operator.

5.2 Low EAF scenarios

The low EAF scenario results for the contingency baseload capacity factor, OCGT capacity factor, and unserved energy are depicted in Figure 14, Figure 15, and Figure 16, respectively, for both the moderate and the low energy demand forecasts. The red dotted line shows the threshold for each adequacy metric.

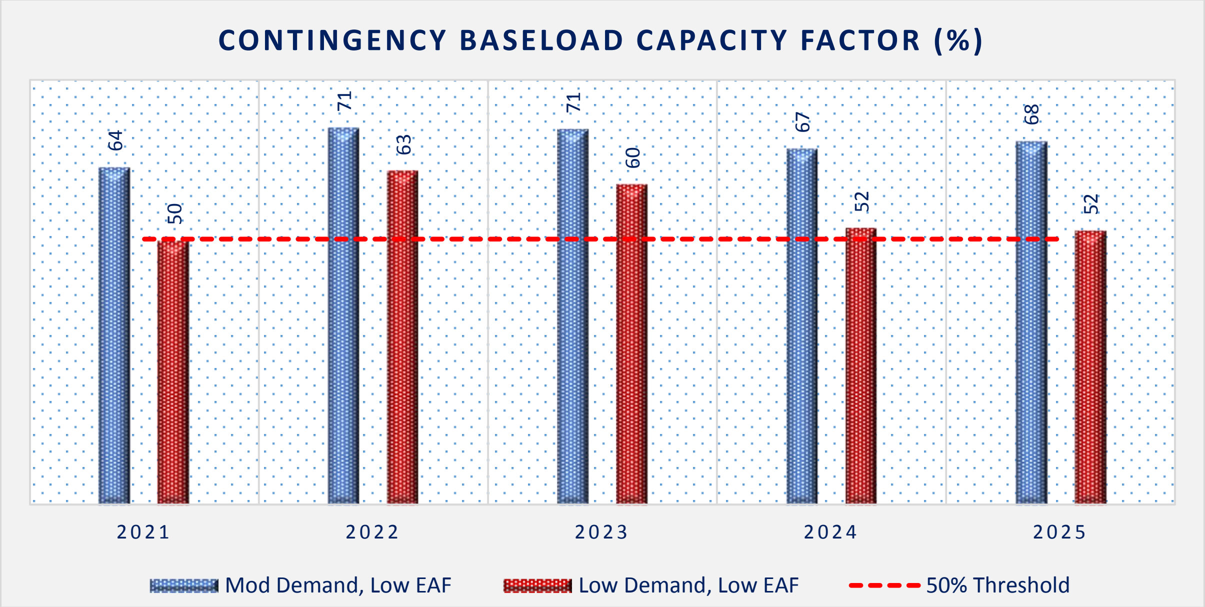

Figure 14: Low EAF contingency baseload capacity factor

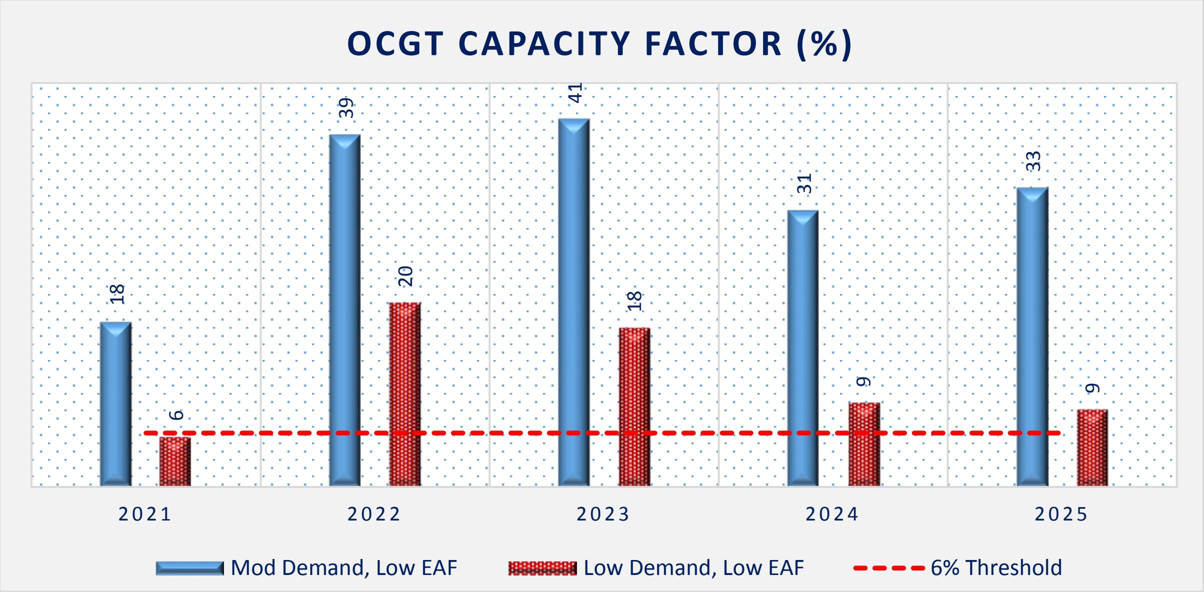

Figure 15: Low EAF OCGT capacity factor

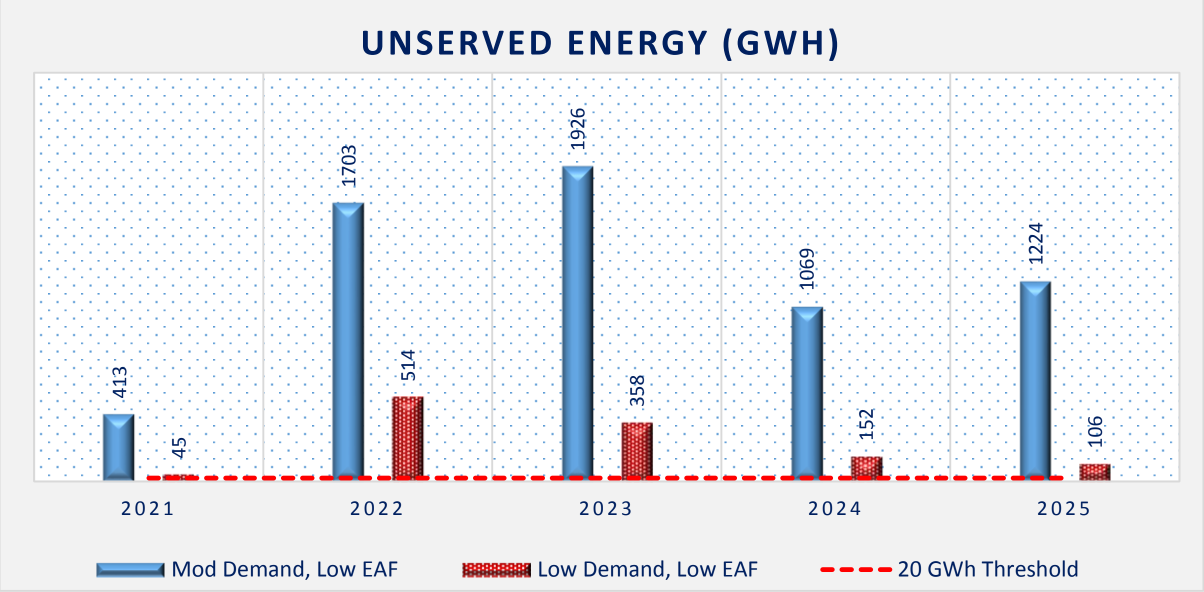

Figure 16: Low EAF unserved energy

The integrated power system is inadequate throughout the study horizon for both low and moderate energy demand forecasts.

5.3 **Required capacity**

The study determined that only baseload capacity was required to restore the power system to adequacy for both low and moderate demand with low EAF. The violations of the low EAF and low demand scenario in 2021, 2024 and 2025 are marginal and can be managed operationally by the System Operator. The results are depicted below in Table 3.

Table 3: Capacity required for closing gap

Year	2021	2022	2023	2024	2025
Low EAF, moderate demand	2 000	4 000	4 000	3 200	3 400
Low EAF, low demand	-	1 500	1 000	-	-

The following section introduces possible initiatives that may be used to close the identified gaps in the system.

6. SENSITIVITY ANALYSIS: OPTIONS

Additional capacity identified to restore the power system to adequacy for both the low and moderate demand with low EAF scenarios is detailed below.

6.1 IRP 2019 cumulative capacity

The promulgated IRP 2019 (IRP, 2019) indicates the build programme of various technologies from 2022. However, it is envisaged that the request for proposals documents for Bid Window 5 will be issued to the market in December 2020. The estimated procurement process could take 18 months, including the expected time allowed for bid submission of 6 months, 4 months for evaluation, which includes the governance processes for the preferred bidder decision, and 8 months for approvals (which includes Eskom Board approval, PFMA approvals, and NERSA cost recovery approvals), as well as licensing of preferred bidders, GSFA signature, and conclusion of project financing agreements. This means that, at best, legal close would occur in June 2022, leading to project and network construction, which, on average, would require 15 months for PV and 21 months for wind.

Thus, the bulk of the IRP capacity would be commissioned by 2024. As a results, this study delayed the gazetted capacity implementation by two years (with the exception of the battery capacity) in order to reflect the realistic timelines as shown in Figure 17 below.

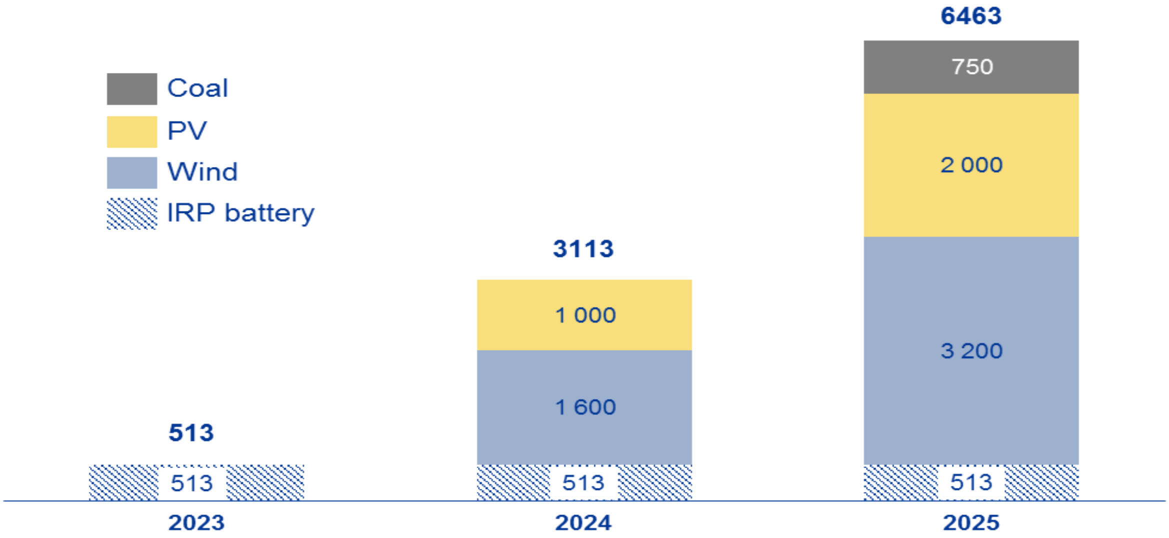

Figure 17: IRP installed cumulative capacity (MW)

6.2 **Risk Mitigation Power Purchase Programme**

The DMRE issued a request for proposals (RFP) in respect of the design of a Risk Mitigation Power Purchase Programme (RFIRMPPP, 2019)[1], as indicated by the promulgated IRP 2019, through an open-ended allocation for the period 2019 to 2022. NERSA concurred (NERSA, 2020) with the DMRE to procure 2 000 MW from a range of energy source technologies in accordance with the short-term risk mitigation capacity allocated in the IRP 2019. The procurement programme will target connection to the grid for the new generation capacity as soon as reasonably possible, but by no later than June 2022. Although the RFP states that procured capacity should be available daily between the time of 05:00 and 21:30, the details of the type of technology are not confirmed. The study assumed dispatchable capacity with at least 75% load factor.

The DMRE stated that this procurement programme would not displace other longer-term procurement programmes, including the much-anticipated fifth BW round of the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP).

6.3 **Extended shutdown dates**

This sensitivity assumed that the capacity of Grootvlei and Hendrina operational units due for shutdown as per the turbine dead-stop dates as well as Arnot and Camden units due for shutdown according to the 50-year technical life of plant would be extended up to end of 2025. The study assumed that the generating units at these stations would maintain the current performance. This capacity is additional to Figure 4 and is depicted in Figure 18 below.

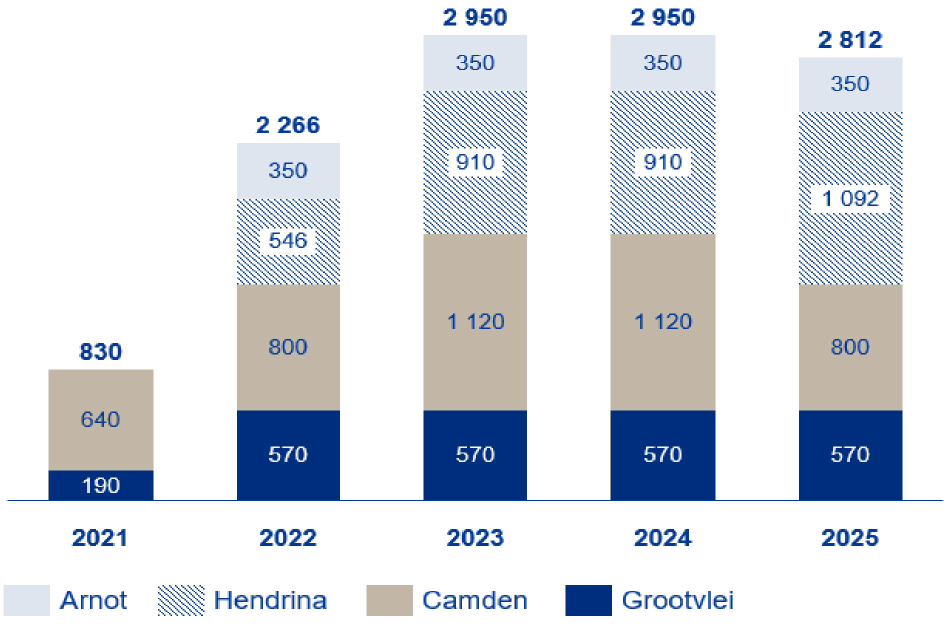

Figure 18: Delayed shutdown capacity (MW)

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[1] RFP documentation only available for tender purposes, at a cost.

7. SENSITIVITY ANALYSIS: RESULTS

The sensitivities were performed for both the low and moderate demand with low EAF scenarios as defined.

- **Sensitivity 1:** Adds IRP 2019 cumulative capacity effective from year 2023.
- **Sensitivity 2:** Adds the Risk Mitigation Power Purchase Programme capacity effective from year 2021.
- **Sensitivity 3:** Adds both the IRP 2019 cumulative capacity from year 2023 and the Risk Mitigation Power Purchase Programme capacity from 2021.
- **Sensitivity 4:** Adds both the Risk Mitigation Power Purchase Programme and IRP capacity, with extension of shutdown dates.

7.1 Moderate demand and low EAF scenario

The results of the adequacy metrics for the sensitivity studies on the moderate demand, low EAF scenario are presented in Figure 19, Figure 20, and Figure 21 below.

Addition of the IRP capacity does not restore the system to adequacy, more so in the early years of the study horizon where no new capacity is expected. However, significant improvements of the system adequacy are observed in 2025 when new baseload capacity is commissioned.

Addition of the Risk Mitigation Power Purchase Programme yields more improvement on the unserved energy violations compared to Sensitivity 1. Extension of shutdown dates in addition yields further improvements, but does not restore the system to adequacy.

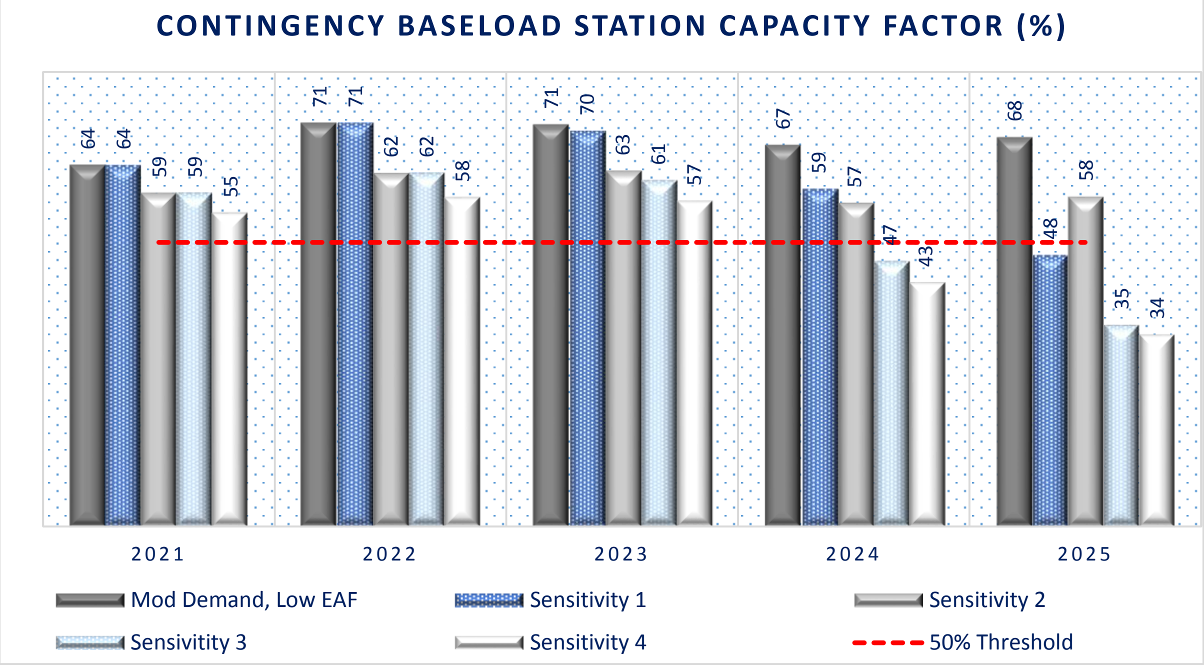

Figure 19: Moderate Demand & Low EAF Sensitivities: Contingency baseload capacity factor

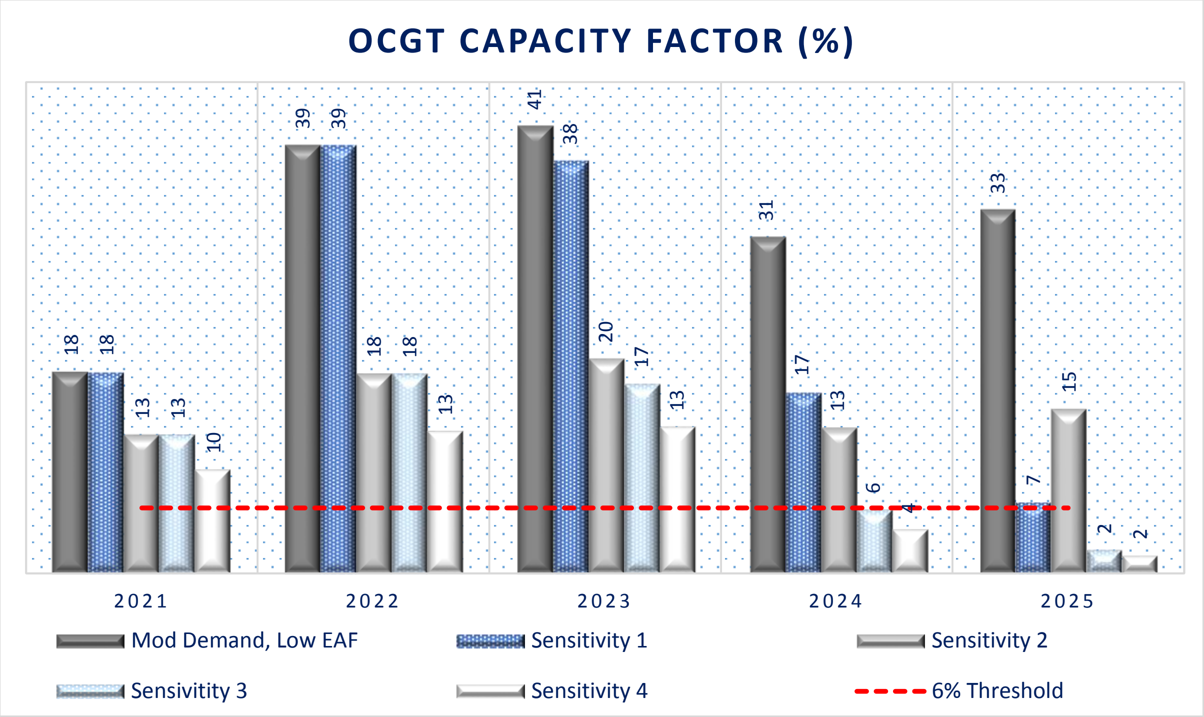

Figure 20: Moderate Demand & Low EAF Sensitivities: OCGT utilization

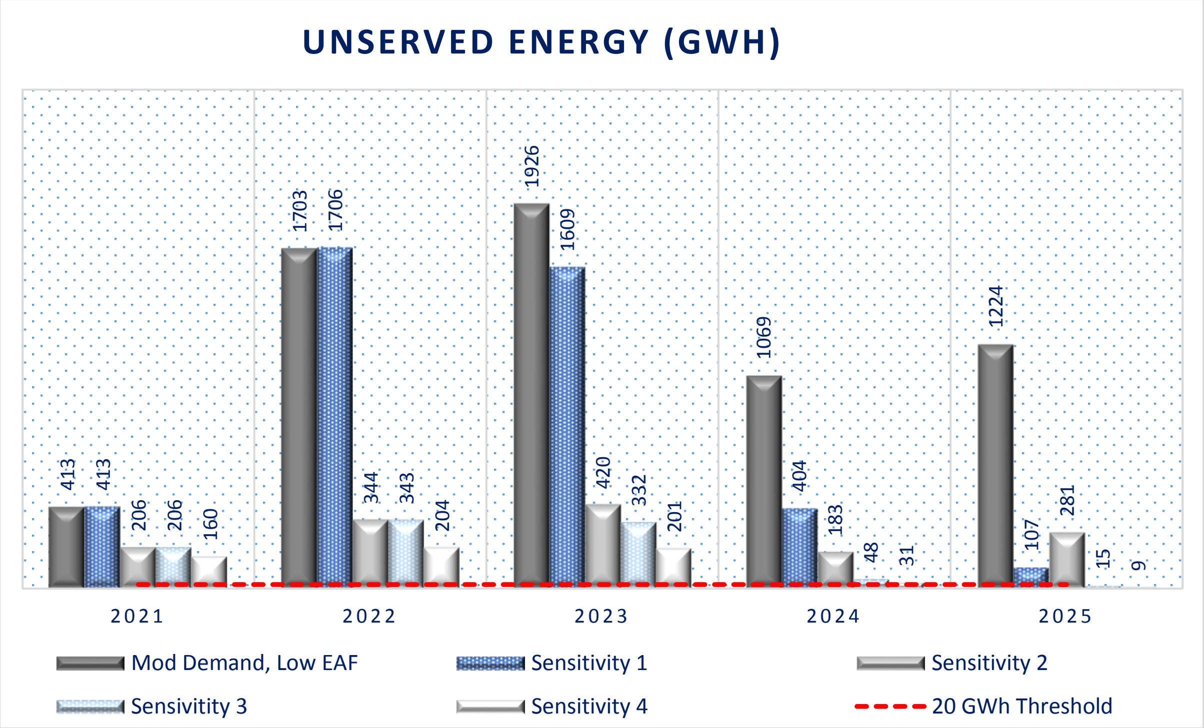

Figure 21: Moderate Demand & Low EAF Sensitivities: Unserved energy

7.2 Low demand and low EAF scenario

The results of the adequacy metrics for the sensitivity studies performed on the low demand, low EAF scenario are presented in Figure 22, Figure 23, and Figure 24 below.

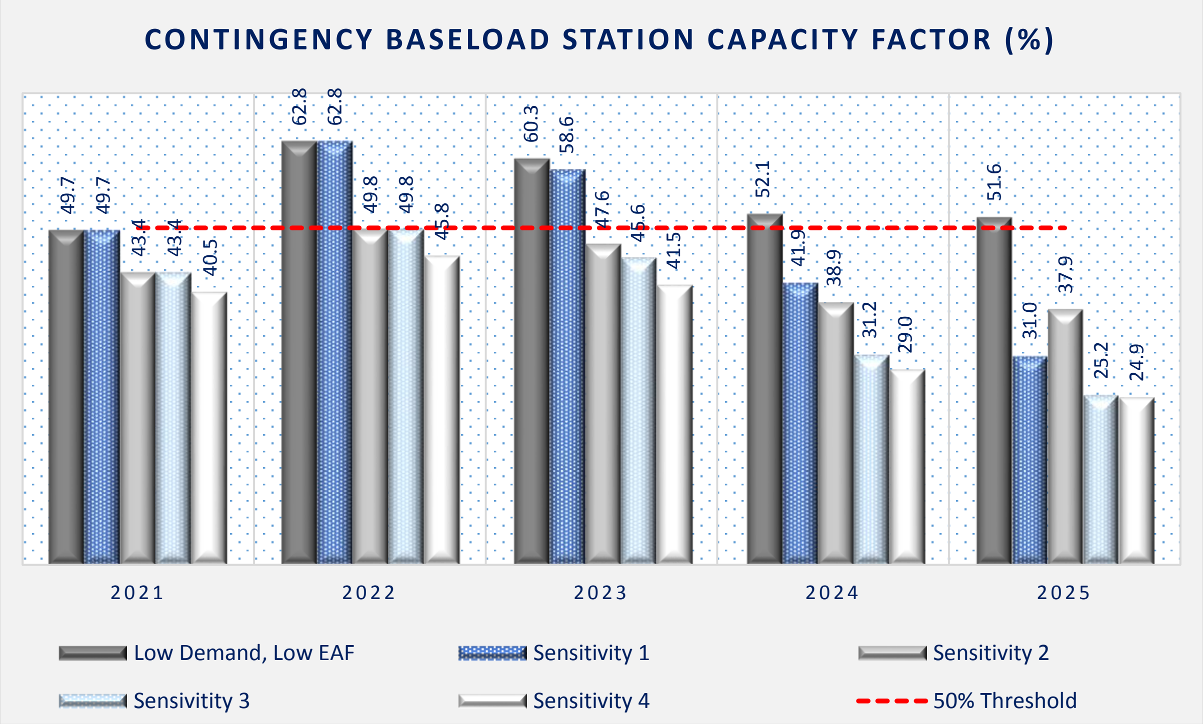

Figure 22: Low Demand & Low EAF Sensitivities: Contingency baseload capacity factor

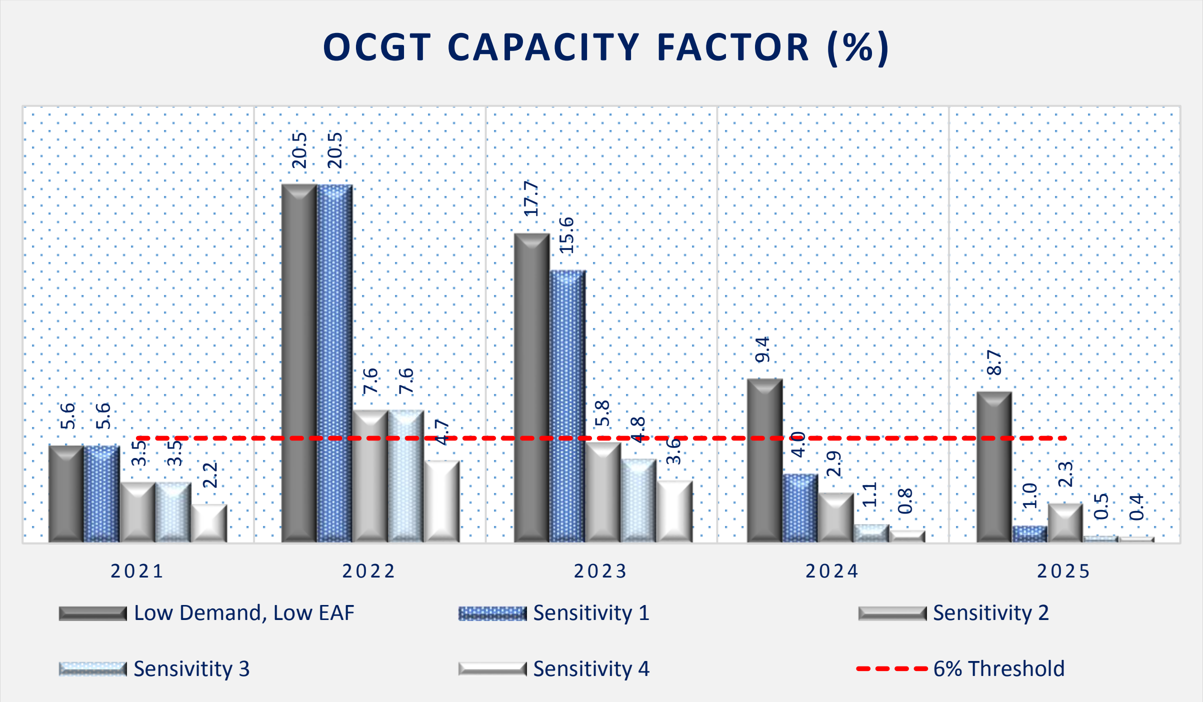

Figure 23: Low Demand & Low EAF Sensitivities: OCGT utilization

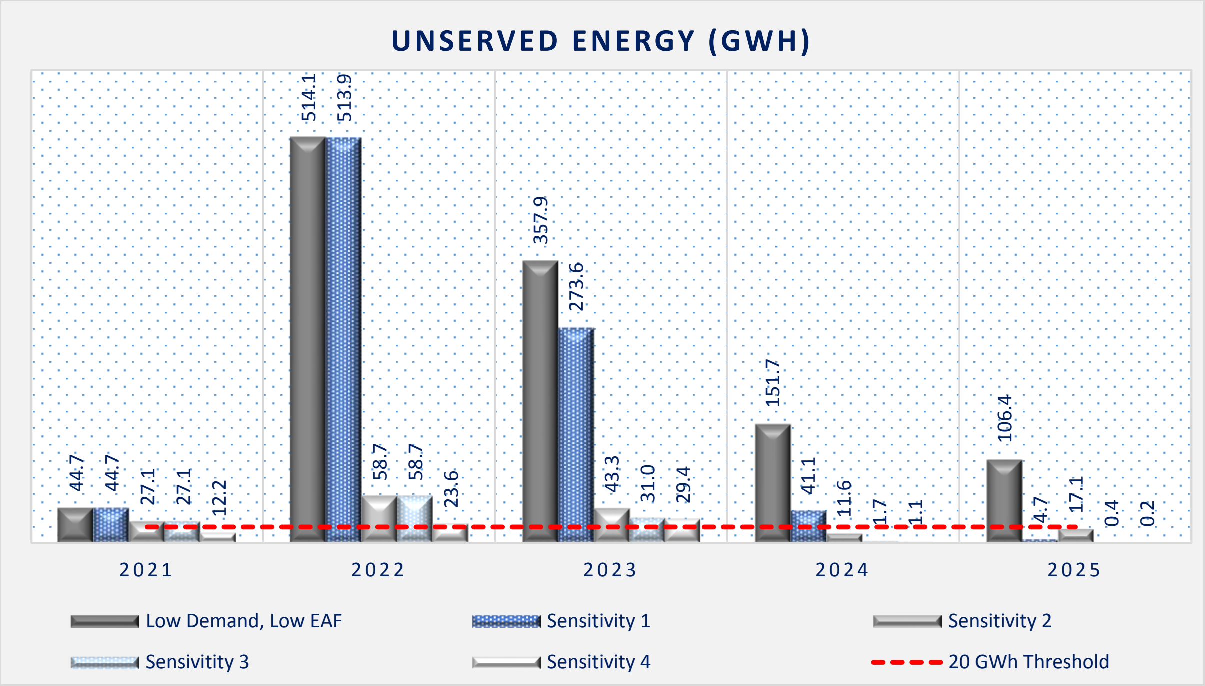

Figure 24: Low Demand & Low EAF Sensitivities: Unserved energy

Addition of the Risk Mitigation Power Purchase Programme, IRP capacity, and extension of the shutdown dates restores the power system to adequacy with minor violations on the unserved energy metric, which can be controlled operationally.

8. POSSIBLE RISKS TO SYSTEM ADEQUACY

The risks to the integrated power system identified by the MTSAO 2020 are similar to those reported in the MTSAO 2019. Progress on risk mitigation and control is provided.

- Shutdown of Eskom and non-Eskom generating units with no immediate replacement of the lost capacity puts system adequacy at risk. Possible mitigation and control measures include extension of the shutdown dates, allowing time for the possible implementation of the IRP capacity from 2023. Furthermore, the Risk Mitigation Power Purchase Programme has been put in place to provide some relief to the power system.
- Poor performance of Eskom coal fleet due to equipment breakdowns poses a risk to security of supply. The breakdowns are mainly a result of irregular maintenance of some of the Eskom coal fleet. Eskom has initiated a Generation Reliability Maintenance Recovery Programme to address the deep refurbishment and maintenance requirements, thus improving the EAF.
- The trend of increasing partial load losses has been observed by the System Operator over the past years. Although the pattern of these partial load losses could be highly unpredictable, an effort has been made to model them in the study using the historical data to predict their pattern in the study horizon.

- Non-compliance with air quality requirements remains a risk that might have an impact on the available generation capacity. The plant performance used in this MTSAO study assumed inclusion of retrofit projects required for Eskom power stations to comply with minimum emission standards required by the National Environmental Management: Air Quality Act 39 of 2004. However, there is still a residual risk related to the adequacy of the planned outage durations that cater for the execution of projects. These outages might require more time than already planned for further reducing available generation.
- The delays in commissioning and poor performance of Eskom new build stations have contributed to the constrained power system over the past years. The delays in commissioning the REIPPP Bid Window 4 capacity puts an additional strain on the system. However, progress in bringing these plants to commercial operation is monitored continuously, and the realistic commercial operation dates were used in the study.

9. CONCLUSION

Based on the recent trend in terms of the decline in Eskom plant performance and reduction in demand, the most likely scenario studied is that with low EAF and low demand. However, the address by President Cyril Ramaphosa to the Joint Sitting of Parliament on “South Africa’s Economic Reconstruction and Recovery Plan” on 15 October 2020 suggests that the moderate demand forecast could be realised.

Given that the low EAF with the moderate demand is identified as the worst-case scenario based on the magnitudes of the adequacy metrics violations, it is evident that aspirations of growth in demand in the short to medium term hinge on increasing plant performance to an average of 74%. Other options to allow for the higher growth while maintaining system adequacy, include a combination of IRP capacity, procurement of risk mitigation power, and extension of the shutdown dates.

MTSAO 2019 illustrated the positive impact that timeously commissioning capacity from Medupi and Kusile had on power system adequacy. The subsequent delay in commercial operation (from June 2022 in MTSAO 2019 to May 2024 in MTSAO 2020) of the new build units worsens the situation in an already constrained system, even with reduction in the demand forecast. Fast-tracking commercial operation of this baseload capacity will unlock growth potential sooner than determined in this report, particularly if coupled with EAF recovery initiatives.

10. SYSTEM OPERATOR STATISTICS

This section monitors and reports actual system reliability indices that are affected by the adequacy of a power system. The data reported is year to date as at 30 September 2020.

10.1 OCGT utilisation

Usage of the open-cycle gas turbine (OCGT) capacity factor includes Ankerlig (1 327 MW), Gourikwa (740 MW), and the DMRE OCGTs at Dedisa (335 MW) and Avon (670 MW). The actual system OCGT capacity factor is depicted in Figure 25 below, showing an average of 7,95% up to 30 September 2020.

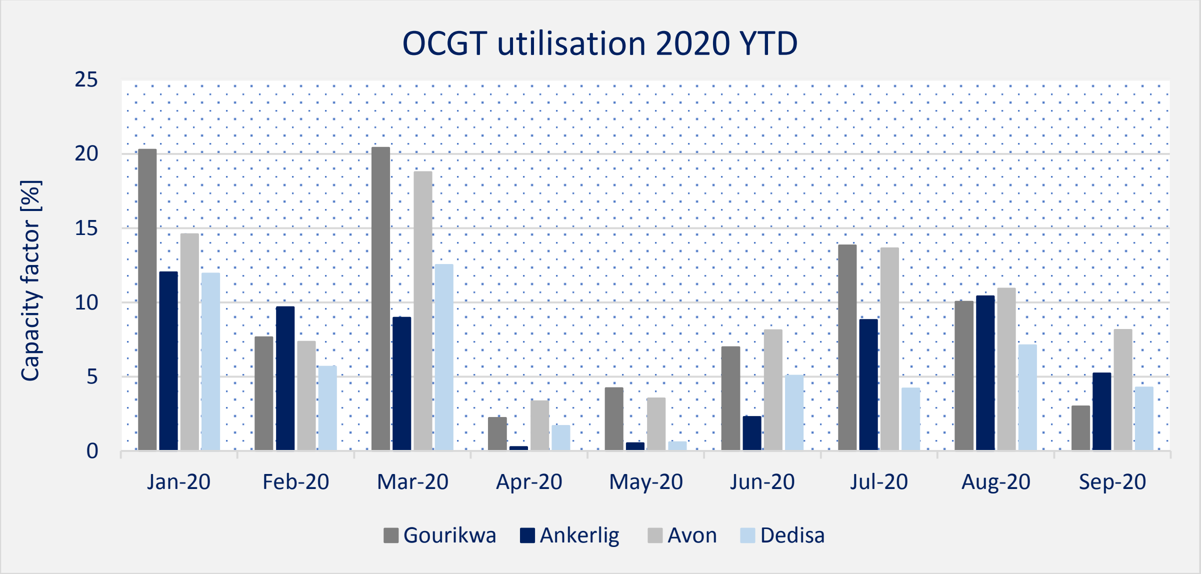

Figure 25: Actual OCGT utilisation 2020 YTD

10.2 Performance of reserves

Paragraph 9 of the South African Grid Code: Version 9 stipulates the type (instantaneous and regulating reserves) and capacity in MW required to restore system frequency to acceptable levels, depending on the drop in the level of frequency.

Frequency incidents are correlated to performance of reserve deployment. Given the identified risk of reserve shortages due to underperformance of Eskom stations contracted to provide reserves, monitoring this index is critical in alerting the System Operator to an increasing trend in frequency incidents.

The actual incidents in Figure 26 below show that the number of incidents of frequency falling within the 49,5 < f < 49,7 band has, during the same period of January to September, decreased from a total of 848 in 2019 to 379 incidents in 2020, linked primarily to fewer sudden generator trips in 2020.

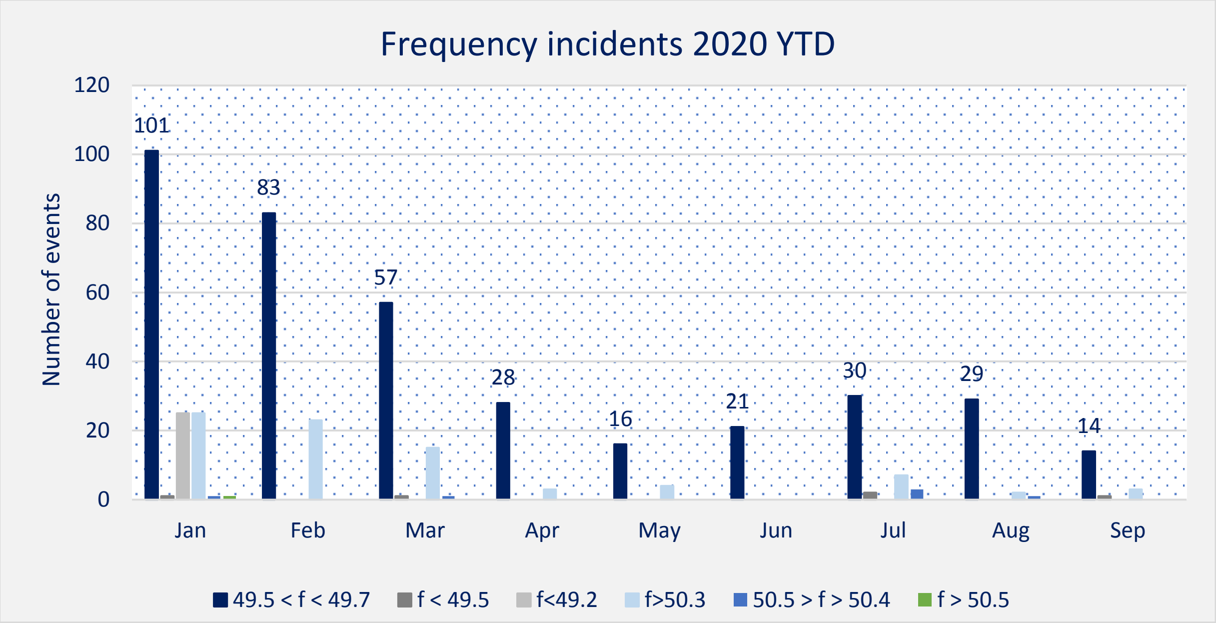

Figure 26: Actual frequency incidents 2020 YTD

10.3 **Unserved energy**

The System Operator has recorded energy not supplied due to emergency load reduction as 1.2 TWh for the current year; this is in comparison to 1.0 TWh for the full year 2019.

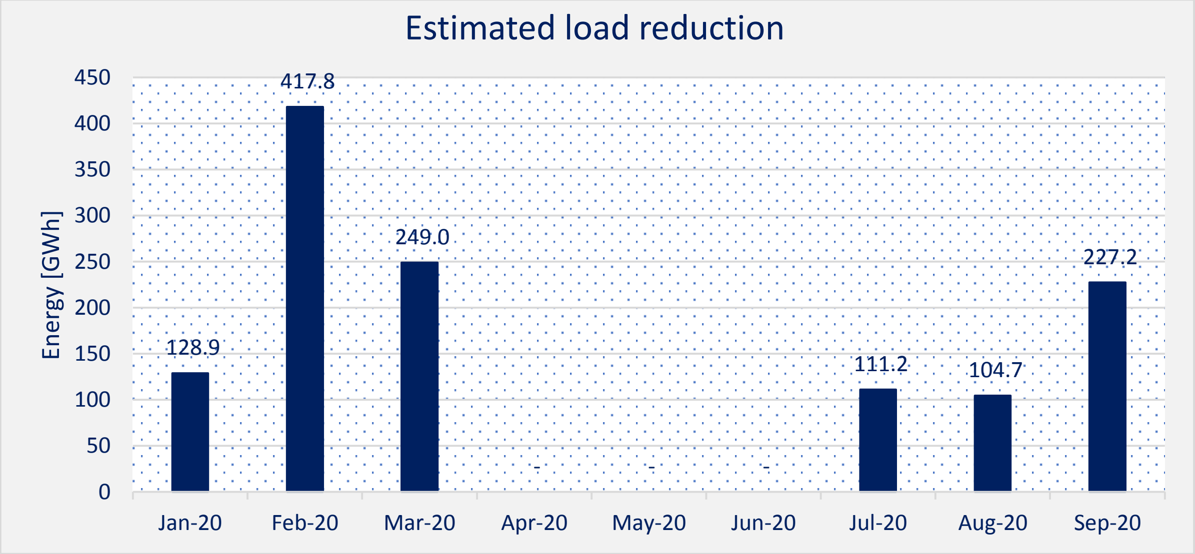

Figure 27: Estimated manual load reduction

The values include load shedding and load curtailment (also referred to as manual load reduction), but exclude interruption of supply (IOS). IOS refers to all contracted and mandatory demand reductions to maintain system frequency and security of supply within acceptable bands.

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