MERIDIAN ECONOMICS
NAVIGATING COMPLEXITY

RESOLVING THE POWER CRISIS PART B: AN ACHIEVABLE GAME PLAN TO END LOAD SHEDDING

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All errors remain those of the authors.

EXECUTIVE SUMMARY

The outlook for South Africa's escalating load shedding problem is significantly worse than generally recognised, but insights from the empirical evidence demonstrate that practical pathways exist to contain and then resolve load shedding and kickstart the country's green industrialisation and decarbonisation ambitions. Unprecedented interventions are required.

Load shedding in 2021 was the worst on record with 2022 fast becoming as bad or worse. As the reliability of the existing fleet of generators continues to decline and delays with procuring and connecting new capacity to the grid continue to mount, South Africa now faces the very real prospect of a return to level 6 or even level 8 load shedding in the foreseeable future[1]. If the average annual coal plant energy availability factor (EAF) reduces from the current levels of approximately 56%, to below 50% our modelling shows a widening generation capacity shortfall of between 5 000 MW and 7 000 MW (up to stage 7 load shedding), in the absence of drastic interventions. This situation is arguably the central manifestation of South Africa's economic crisis, and a pathway to resolving it, its greatest economic opportunity.

Given the political imperative to do so it is not surprising that the message from policy makers is that plans are well under way to resolve load shedding and it appears that most stakeholders assume that it is just a matter of time before current efforts bear fruit. The inescapable finding from this investigation, is that this is unfortunately not yet the case, and that in too many plausible scenarios load shedding and power shortages will continue indefinitely. Furthermore, it appears that South Africa does not have a single government entity with the overall responsibility of ensuring that a coherent plan is in place to resolve load shedding, safeguarding that the necessary suite of interventions by different players is co-ordinated, and indeed being delivered; and monitoring progress to provide regular feedback and strategy adjustment.

The purpose of this report is two-fold. It is to demonstrate to policy makers, regulators, and key stakeholders: (a) how insistence on poorly conceived measures and regulatory rules has the direct effect of worsening the load shedding crisis by obstructing and delaying interventions that could reduce it; and (b) that by applying a laser focus to implementing a coherent set of strategically identified policy levers government can establish a high level of confidence that the problem will be resolved in a reasonable period of time.

The objectives of this report are therefore to:

1. demonstrate that the goal of containing, reducing and then resolving load shedding is eminently achievable;
2. demonstrate that the probability that this will be achieved with the current set of policy and procurement measures is unacceptably low;
3. demonstrate the nature and extent of a suite of interventions that will establish a credible expectation that load shedding will be resolved in a reasonable period of time (by mapping out a potential resource plan and game plan for implementing it); and
4. by considering the policy and institutional causes behind the current delays in

[1] It is not hyperbole to suggest that sustained levels 6 – 8 load shedding will provide the fertile ground for even greater social unrest than what South Africa experienced in July 2021. This level of sustained load shedding or partial grid failure will have cascading effects, rapidly disrupting critical services such as water supplies, sewerage pumping and processing, fuel supplies, cell phone networks, internet connections, ATMs and payment systems, retail stores, food supplies and medical services.

resolving load shedding, demonstrate the types of urgent institutional changes and policy reforms that are required to solve the problem.

This report is the second of a two-part series. In Part A[2] of this series we laid an empirical foundation for the evaluation of feasible strategies to resolve load shedding by analysing Eskom's data from 2021. In that report we quantified the impact that additional generation capacity would have had on load shedding if it were already operational in 2021. To perform this "what if" test we focussed on the shortest lead-time and cheapest sources of generation – wind and solar. Confirmed by two separate modelling methods, the results are startling – an additional 5 000 MW of wind and solar capacity (the approximate capacity of two IPP[3] Office REIPPPP[4] bidding rounds) would have allowed Eskom to eliminate 96.5% of load shedding in 2021. The extra renewable energy and capacity would have allowed more optimal use of the coal plant, the pumped storage assets, and the Open Cycle Gas Turbine (OCGT) peakers, reducing the amount of diesel burnt by 70% - 80%. The remaining small fraction of load shedding could have been eliminated by a modest expansion of Eskom's ILS[5] demand response programme or other aggregated Demand Response interventions, and 2 000 MW of one-hour batteries. Such a solution would not only have put paid to load shedding in 2021 but also have resulted in a net annual saving to Eskom of at least R2.5 Bn.

This outcome is counterintuitive. Rather than increasing system risk as many observers expect, the analysis based on the empirical data shows unequivocally that adding variable renewable generators to the existing distressed South African power system will result in a disproportionate *reduction* in load shedding, and an *increase* in system reliability. The addition of renewable energy to the system not only addresses load shedding at times when power is generated. It spawns a virtuous cycle that unlocks *existing* OCGT and pumped storage generation capacity that is currently hobbled by empty diesel tanks and unreplenished reservoirs, whilst breathing life into the gasping coal plant maintenance programme. This insight is critical for mapping the way forward and avoiding expensive pitfalls and delays in doing so.

Due to a range of political, institutional, rent seeking and corruption related factors, South Africa has now seen a delay of seven years since a concluded IPP Office procurement round has resulted in new capacity being connected to the grid. This despite ongoing load shedding over this period that, according to our 2021 analysis, would have been almost entirely avoided had the REIPPPP process not stalled in 2016. These results show the devastating impact of the delays and how avoidable the current load shedding crisis has been. But, the results also demonstrate, in principle, that by taking adequate steps, solutions to resolving load shedding within the foreseeable future are within reach.

In contrast to conducting an *ex post* analysis on historical data, developing a forward looking plan to resolve it is a more complex task – even over the short to medium term – due to the uncertainty associated with, and

[2] Meridian Economics, 2022. Resolving the Power Crisis Part A: Insights from 2021 – SA's Worst Load Shedding Year So Far.

[3] Independent Power Producer

[4] Renewable Energy Independent Power Producer Procurement Programme

[5] ILS - Interruptible Load Shed. This is consumer load(s) that can be contractually interrupted without notice or reduced by remote control or on innostruction from Eskom National Control

continued evolution of the key drivers behind load shedding. The analysis presented in this report covers the period up to 2026. Our first step was to analyse the nature of the problem, based on current trends and the interventions already being implemented to connect new generation capacity onto the grid (the remaining Kusile units and IPP Office procurements up to BW6) in order to identify any remaining supply gaps – we term this the Base Case. Thereafter we developed a near optimised suite of additional resources that will have to be deployed to close the gap that remains – a Risk Adjusted Resource Plan – which we explain in more detail below.

For the Base Case we had to consider many factors that determine the level of load shedding, such as how demand changes, the availability and eventual shut down of Eskom power stations, the timing and capacity of new generators connected to the grid (both Eskom and existing IPP Office procurement rounds and distribute generators), etc.

While there are a limited number of plausible scenarios where load shedding is resolved under the Base Case, this requires a decreasing demand trajectory and no further decline in the coal fleet performance. In the more likely scenarios, load shedding in 2023 will see up to a 4-fold increase compared to 2021; up to 5-fold in 2024, 4-fold in 2025 and up to 10-fold in 2026 all when compared to 2021 – South Africa's worst year on record. In other words, in the absence of further urgent and drastic interventions load shedding is likely to increase substantially in the coming years.[6]

Some of the key current challenges that contribute to this negative outlook are:

- The well-known decline in the reliability and availability of Eskom's power stations – especially its coal plant. This trend is likely to continue for as long as the constraints on the power system make it impossible to take out plant for long enough to do adequate maintenance, and for as long as Eskom's financial situation constrains its ability to fund this maintenance (other challenges such as a shortage of skilled personnel and poor staff morale will also have to be resolved). See Figure 6 below. It appears unlikely that the EAF decline can be contained to less than 2% per year as long as there is not adequate space to take plant out for maintenance.
- Growth in electricity demand from 2020 levels in a post Covid 19 environment. Annual demand in 2020 dropped significantly to 220.6 TWh, as the economy slowed. Load shedding could have been substantially higher in 2020 and 2021 if demand had remained closer to 2019 levels of 232.5 TWh. As the economy reopened fully, demand in 2021 increased to 227.2 TWh, and further growth could be expected for demand to reach pre-Covid19 levels.[7]
- The fact that the aggressively priced bids for the RMIPPPP[8] and REIPPPP BW5 projects were prepared before the series of commodity price, equipment, and logistic costs escalations (reported as 40% increases and more in some cases) that resulted from the Covid19 pandemic

[6] *Due to the fact that little information is available about the emerging 100MW embedded generation market we have excluded any wind, solar and storage capacity from this market segment from the Base Case for analytical purposes. The Risk Adjusted Resource Plan (discussed below) relies heavily on this market segment. This provides a clear dilieation of the distributed generation capacity that has to be realised to resolve load shedding.*

[7] *Our assumptions about coal plant EAF decline and economic growth for the Base Case are potentially a bit optimistic with respect to load shedding, while the exclusion of the 100MW distributed generation segment from this case probably under reports what is likely to be available in this scenario.*

[8] *Risk Mitigation Independent Power Producer Procurement Programme*

and the Russian invasion of the Ukraine. Developers are generally unable to fix these project costs by the time they submit their bids and projects are thus exposed to the risks of these costs escalating due to external factors. The current input cost escalations are unprecedented in the history of competitive power procurements globally[9]. Our conclusion from numerous interviews and broader research is that there is a high probability that the many of the RMIPPPP renewables projects (1 850 MW) and REIPPPP BW5 projects (2 585 MW) will fail without further intervention.

- The high likelihood that the DTIC[10] and IPP Office's poorly conceived and often unimplementable position on local content conditions for the procurement will cause many of the urgently needed RMIPPPP and BW5 projects to be delayed and ultimately fail, while the upcoming BW6 projects could also be affected. It is especially the insistence on unrealistic local content requirements for photovoltaic (PV) modules for which very little compliant local production capacity exists that causes the immediate crisis (currently modules make up approximately 30% of a large solar project's total costs). There are two problems: Firstly, the total volume of compliant modules required from the local market are simply unobtainable in time for these projects to deliver on schedule. This creates substantial risks that projects will not be able to come online before the long-stop date for commercial operation which exposes them to the risk that their Power Purchase Agreement (PPA) could be cancelled. Developers will simply not be able to obtain finance and proceed with the projects for as long this risk remains significant.
  However, a further problem relates to the large input cost increases that occurred after bids were submitted for the RMIPPPP and BW5. Unimplementable or expensive local content requirements (it costs 18% – 30% more for locally produced modules) will simply further undermine the financial viability of these projects that might already be "under the water" and fatally increase the probably that they will not be financed and built. The delays of the parties to come to a common understanding of the facts has postponed the conclusion of the commercial agreements. While it appears that policy makers are not aware of the impact of their actions, this problem is now directly exacerbating load shedding, which will of course result in much greater damage to the South African economy than any benefit that could possibly be achieved by these uninformed policy measures.
- The high likelihood that the gas-based RMIPPPP projects will be substantially delayed or fail due to the poor procurement design, their complexity, excessive pricing, and exposure to ongoing litigation.
- The fact that the design of the RMIPPPP (contracted offtake at a predefined hourly dispatch profile) will make much less energy and storage capacity available to the system than what would be possible with the actual hardware that will be built. The pricing for the projects will have to cover their full costs, but the way the procurement was specified means that

[9] *Globally, the costs of renewable energy and storage projects has increased substantially, while the costs of coal and gas power has increased even more.*

[10] *Department of Trade, Industry and Competition*

much of the potential value from the projects will be wasted (through curtailed energy and underutilised batteries) – thereby drastically reducing value for money and directly exacerbating load shedding.

Any credible plan to resolve load shedding cannot be based on 'best case' scenarios, it needs to respond effectively to most of the plausible downside scenarios outlined above. Furthermore, the plan cannot be based on the same centralised "all eggs in one basket"-type approach that created the problem in the first place. The challenge is so large and complex that no single player will be able to solve it alone. The focus of Government's intervention should be on mobilising thousands of economic actors throughout the economy to take the necessary steps to bring new capacity online urgently. This must be achieved by opening doors, removing policy obstacles and red tape, and creating powerful incentives for delivering the right outcomes. The solution must be diversified, contain contingency and avoid "single points of failure"[11]. Furthermore, there is no time to start from scratch – to deliver expedited capacity we must work with what we have. This means, for instance, exploiting opportunities with the existing IPP Office procurement rounds, existing IPP projects, the 100 MW and 1 MW market segments, Eskom and municipal procurements, etc.

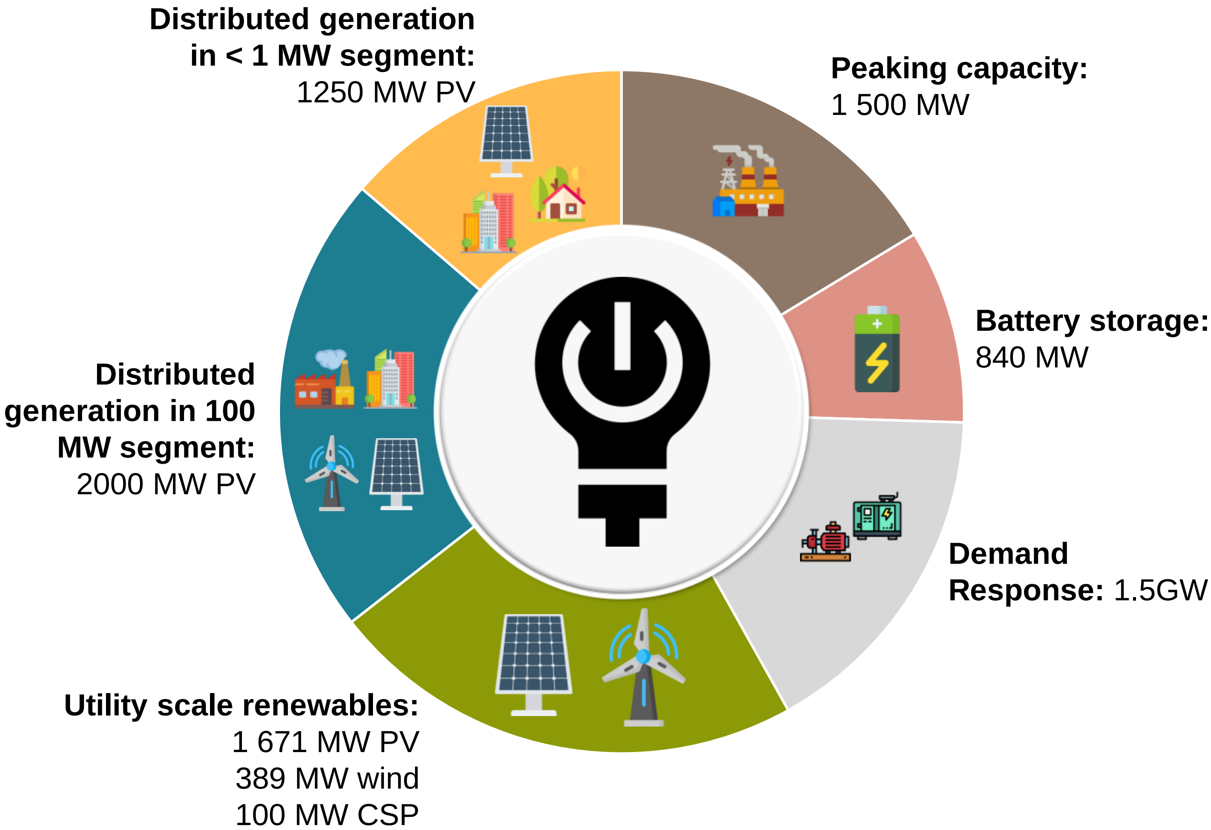
We analysed numerous resource expansion scenarios designed to resolve load shedding. From this we developed an ambitious Risk Adjusted Resource Plan (Table 6) that also contains a modest amount of contingency to hedge against the high probability that not all aspects of a plan will be delivered in time. The Plan is built on the following main components (in addition to Eskom's efforts to improve the reliability of their plant):

1. A substantial increase in the likelihood that projects from existing IPP Office procurement rounds (RMIPPPP, and REIPPPP BW5) can close and then minimise further PPA signature delays;
2. Maximised benefits that can be obtained from REIPPPP BW6 by more than doubling its size, removing project size limits, and strengthening incentives for earlier connection (and therefore early energy);
3. Drastically increased incentives to expedite the ramp-up in renewables build in the <1 MW and 100 MW market categories to the maximum rates that can be achieved;
4. Utilisation of the potentially large opportunity to obtain additional energy from the multitude of existing and new projects (big and small) that are distributed throughout the grid;
5. Urgent installation of additional thermal peaking capacity and expanded diesel storage at existing peakers;
6. Procurement of a large amount of Demand Response (DR) capacity from DR aggregators and a large amount of additional battery storage.

Together this suite of resource increases can practically eliminate load shedding by 2024 with full security of supply reached by 2025.

[11] *For these reasons it becomes evident that a strategy that relies on 'big gas' (gas-to-power infrastructure that is operated at high capacity factors and utilises large gas volumes) will be an economically costly mistake that will be unlikely to resolve load shedding in time. See Appendix 4 for more detail on this issue.*

Figure 1: Risk Adjusted Resource Plan: New capacity connected to the grid to resolve load shedding by the beginning of 2024



See Table 6 on page 12 for further details on the additional system resources required to resolve load shedding with the Risk Adjusted Resource Plan.

Ensuring the Risk Adjusted Resource Plan is delivered on time will be a substantial challenge. In practice the outcomes can be achieved by a "game plan" consisting of the following measures:

1. Eliminate or drastically reduce local content requirements on PV modules;
2. Fix RMIPPPP design flaws to enable all the projects with PV, wind and storage to proceed and the entire project energy and capacity to be made available to Eskom;
3. Implement across the board price increases for BW5 projects to compensate for large cost escalations;
4. Accelerate uptake in the distributed generation market by implementing further licence exemptions, net feed-in tariffs and further tax incentives;
5. Expand REIPPPP BW6 and launch it in time with stronger incentives for early energy;
6. Expedite the procurement of additional peaking capacity, demand response capacity and battery storage;
7. Urgently implement Eskom's Just Energy Transition (JET) renewable energy Public-Private Partnership (PPP) projects;
8. Clarify and unlock the opportunity for Municipalities to rapidly procure new capacity;
9. Bolster the Eskom grid connection process;

10. Fix significant institutional problems at the IPP Office and NERSA[12]; and implement the first phases of the multi-market model (even before passing the founding legislation);
11. Expedite additional amendments to Schedule 2 of the Electricity Regulation Act (ERA) and issue new Ministerial announcements / determinations;
12. Establish a dedicated well-resourced power crisis implementation unit inside the Presidency to drive and monitor the implementation of these measures.

This game plan to resolve load shedding consists of a combination of interdependent measures which, if all implemented, will result in a high probability that load shedding will practically be eliminated by 2024. Implementing these measures will require the cooperation of different players – including some who do not always appreciate the negative impact of their current positions or behaviour on the ability of the power system to resolve load shedding. As with the 100 MW reform, substantial "arm twisting" will be required.

Failure to implement a suite of measures similar to the game plan set out here will lead to ongoing load shedding up to and after 2025 when an increasing number of Eskom's coal-fired power stations will reach the end of their operating life. This will have further severe consequences. In addition to the economic cost of ongoing power shortages, any prospect that South Africa will not be able to retire these older stations, due to power shortages, will drastically undermine the country's ability to finalise the negotiations for the USD 8.5 Bn Just Energy Transition Partnership (JETP) climate finance negotiated at COP26[13], because its primary objective is the earlier closure of coal plant. The success of the JETP agreement framework is thus critically dependant on the urgent resolution of load shedding by means of a renewables-heavy strategy similar to the game plan set out above. Its first focus should be to support this outcome.

These proposals are focused on resolving load shedding in the short-term. Whilst beyond the scope of this study, large scale expansion of the transmission and distribution grid capacity to ensure that low-cost generation capacity can be connected to grid in the medium term and customers be supplied reliably remains a critical objective.

As can be seen from the recommendations above, the responsibility to implement the required measures are spread between different public sector players (DMRE[14], NERSA, DTIC, Eskom, etc.) – it does not just lie with Eskom – especially once the limits to what can be achieved with the coal plant are understood. Players that have "line responsibility" for delivering measures to resolve load shedding have strong incentives to underreport the extent to which they are not achieving their objectives. In recent years this situation has caused an information asymmetry problem whereby the full extent of the problem (delays with implementing adequate measures to resolve load shedding) and its implications was not being recognised in time by policy makers and stakeholders. It will therefore be critical that a neutral party within Government, such as the Presidency, takes the lead in setting out the elements of the game plan that must be implemented, and in driving its implementation as proposed above. Successful execution of this role will require a full-time dedicated team with some of the best technical, financial and legal skills

[12] *National Energy Regulator of South Africa*

[13] *Conference of the Parties (COP) 26 was held in Glasgow in November 2021*

[14] *Department of Mineral Resources and Energy*

available to South Africa to design and drive this process in consultation with key stakeholders. It will probably have to consist of senior public sector officials and private sector experts. A substantial budget will have to be made available on an emergency basis.

Implementing these reforms will require political will at a scale that has not yet been demonstrated in dealing with South Africa's power crisis. We believe that expending the necessary political capital will be worthwhile, because in considering the options open to South Africa we arrived at the conclusion that no other strategy is likely to have a better chance of resolving load shedding faster, at a lower cost and with less unintended consequences than one based on the approach proposed here (the Risk Adjusted Resource Plan and the Game Plan for implementing it).

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Bn	Billion
BW	Bid Window
CF	Capacity Factor
COP	Conference of the Parties
DFFE	Department of Forestry, Fisheries and the Environment
DMRE	Department of Mineral Resources and Energy
DPE	Department of Public Enterprises
DTIC	Department of Trade, Industry and Competition
EAF	Energy Availability Factor
FY	Financial Year
Gt	Gigatonnes
GW	Gigawatt
GWh	Gigawatt-hour
ICE	Internal Combustion Engine
ILS	Interruptible Load Shed
IPP	Independent Power Producer
IPPO	Independent Power Producer Office
IRP	Integrated Resource Plan
JETP	Just Energy Transition Partnership
kW	Kilowatt
kWh	Kilowatt-hour
Ml	Million litres
Mt	Megatonnes
MW	Megawatt
NERSA	National Energy Regulator of South Africa
NT	National Treasury
OCGT	Open Cycle Gas Turbine
PS	Pumped Storage
PV	Photovoltaic
t	Tonne
TDP	Transmission Development Plan

TWh	Terawatt-hour
RFP	Request for Proposal
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme

1 INTRODUCTION

Load shedding in 2021 was the worst on record with 2022 fast becoming as bad, or worse. As the reliability of the existing fleet of generators continues to decline and delays with procuring and connecting new capacity to the grid continue to mount, South Africa now faces the very real prospect of a return to level 6 or even level 8 load shedding in the foreseeable future[15]. If the average annual coal plant energy availability factor (EAF) reduces from the current levels of approximately 56%, to below 50% our modelling shows a widening generation capacity shortfall of between 5 000 MW and 7 000 MW (up to stage 7 load shedding), in the absence of drastic interventions. This situation is arguably the central manifestation of South Africa's economic crisis, and a pathway to resolving it, its greatest economic opportunity.

Given the political imperative to do so it is not surprising that the message from policy makers is that plans are well under way to resolve load shedding and it appears that most stakeholders assume that it is just a matter of time before current efforts bear fruit. The inescapable finding from this investigation, is that this is unfortunately not yet the case, and that in too many plausible scenarios load shedding and power shortages will continue indefinitely. Furthermore, it appears that South Africa does not have a single government entity with the overall responsibility of ensuring that a coherent plan is in place to resolve load shedding, safeguarding that the necessary suite of interventions by different players is co-ordinated, and indeed being delivered; and monitoring progress to provide regular feedback and strategy adjustment.

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4. by considering the policy and institutional causes behind the current delays in resolving load shedding, demonstrate the types of urgent institutional changes and policy reforms that are required to solve the problem.

This report is the second of a two-part series. In Part A[16] of this series we laid an empirical

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This outcome is counterintuitive. Rather than increasing system risk as many observers expect, the analysis based on the empirical data shows unequivocally that adding variable renewable generators to the existing distressed South African power system will result in a disproportionate *reduction* in load shedding, and an *increase* in system reliability. The addition of renewable energy to the system not only addresses load shedding at times when power is generated. It spawns a virtuous cycle that unlocks *existing* OCGT and pumped storage generation capacity that is currently hobbled by empty diesel tanks and unreplenished reservoirs, whilst breathing life into the gasping coal plant maintenance programme. This insight is critical for mapping the way forward and avoiding expensive pitfalls and delays in doing so.

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In contrast to conducting an *ex post* analysis on historical data, developing a forward looking plan to resolve it is a more complex task – even over the short to medium term – due to the uncertainty associated with, and continued evolution of the key drivers behind load shedding. Our analysis covers the period up to 2026. Our first step was to analyse the nature of the problem, based on current trends and the interventions already being implemented to connect new generation capacity onto the grid (the outstanding Kusile units and IPP Office procurements up to BW6) – we term this the Base Case. Thereafter we

[17] *Independent Power Producer*

[18] *Renewable Energy Independent Power Producer Procurement Programme*

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developed a near optimised suite of additional resources that will have to be deployed to close the gap that remains – a Risk Adjusted Resource Plan – which we explain in more detail below.

For the Base Case we had to consider many factors that determine the level of load shedding. Some of the key current challenges that contribute to this negative outlook are:

- The well-known decline in the reliability and availability of Eskom's power stations – especially its coal plant. This trend is likely to continue for as long as the constraints on the power system make it impossible to take out plant for long enough to do adequate maintenance, and for as long as Eskom's financial situation constrains its ability to fund this maintenance (other challenges such as a shortage of skilled personnel and poor staff morale will also have to be resolved). See Figure 6 below. It appears unlikely that the EAF decline can be contained to less than 2% per year as long as there is not adequate space to take plant out for maintenance.
- Growth in electricity demand from 2020 levels in a post Covid 19 environment. Annual demand in 2020 dropped significantly to 220.6 TWh, as the economy slowed. Load shedding could have been substantially higher in 2020 and 2021 if demand had remained closer to 2019 levels of 232.5 TWh. As the economy reopened fully, demand in 2021 increased to 227.2 TWh, and further growth could be expected for demand to reach pre-Covid19 levels.
- The fact that the aggressively priced bids for the RMIPPPP[20] and REIPPPP BW5 projects were prepared before the series of commodity price and logistic costs escalations (reported as 40% and more in some cases) that resulted from the Covid 19 pandemic and the Russian invasion of the Ukraine. This situation is unprecedented in the history of competitive power procurements globally[21]. Our conclusion from numerous interviews and broader research is that there is a high probability that the many of the RMIPPPP renewables projects (1 850 MW) and REIPPPP BW5 projects (2 585 MW) will fail without further intervention.
- The high likelihood that the DTIC[22] and IPP Office's poorly conceived and often unimplementable position on local content conditions for the procurement will cause many of the urgently needed RMIPPPP and BW5 projects to be delayed and ultimately fail, while the upcoming BW6 projects could also be affected. It is especially the insistence on unrealistic local content requirements for photovoltaic (PV) modules for which very little compliant local production capacity exists that causes the immediate crisis (currently modules make up approximately 30% of a large solar project's total costs). There are two problems: Firstly, the total volume of compliant modules required from the local market are simply unobtainable in time for these projects to deliver on schedule. This creates substantial risks that projects will not be able to come online before the long-stop date for commercial operation which exposes them to the risk that their Power Purchase Agreement (PPA) could be cancelled. Developers will simply not

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[22] Department of Trade, Industry and Competition

be able to obtain finance and proceed with the projects for as long this risk remains significant.

However, a further problem relates to the large input cost increases that occurred after bids were submitted for the RMIPPPP and BW5. Unimplementable or expensive local content requirements (it costs 18% – 30% more for locally produced modules) will simply further undermine the financial viability of these projects that might already be "under the water" and fatally increase the probably that they will not be financed and built. The delays of the parties to come to a common understanding of the facts has postponed the conclusion of the commercial agreements. While it appears that policy makers are not aware of the impact of their actions, this problem is now directly exacerbating load shedding, which will off course result in much greater damage to the South African economy than any benefit that could possibly be achieved by these uninformed policy measures.

- The high likelihood that the gas-based RMIPPPP projects will be substantially delayed or fail due to the poor procurement design, their complexity, excessive pricing, and exposure to ongoing litigation.
- The fact that the design of the RMIPPPP (contracted offtake at a predefined hourly dispatch profile) will make much less energy and storage capacity available to the system than what would be possible with the actual hardware that will be built. The pricing for the projects will have to cover their full costs, but the way the procurement was specified means that much of the potential value from the projects will be wasted (through curtailed energy and underutilised batteries) – thereby drastically reducing value for money and directly exacerbating load shedding.

2 CURRENTLY EXPECTED LOAD SHEDDING: THE BASE CASE

2.1 OVERVIEW

We start by analysing a Base Case, constructed from current assumptions about electricity demand, trends in the availability of Eskom's coal and other power stations, the capacity expansion processes already under way and the retirement dates for end-of-life coal plant. This Base Case reflects the expected outcomes based on the policy and other interventions that are currently in place. The detailed assumptions are set out in Appendix 1. Over the analysis horizon, new capacity is expected to come online from the RMIPPPP and REIPPPP BW3.5-BW6, as well as three new units at Kusile, whilst capacity retires at Camden, Arnot and Kriel.

Due to the financial and local content difficulties faced by BW5 and RMIPPPP projects we have made assumptions about further delays to this capacity and the percentage of projects that will proceed. Table 1 provides an overview of the expected timelines for projects to reach financial close in the Base Case. An analysis of past wind and solar PV projects from the REIPPPP was conducted to estimate the time between a project reaching financial close and generation capacity entering commercial operation.

Table 1: Base Case - expected timelines for financial close

Project	Type	Projects closable	Expected capacity	RFP issuance	Award	Expected close	Projects delayed	Last close
BW5	Solar PV	50%	475 MW	12/04/2021	31/10/2021	30/09/2022	100%	31/01/2023
	Wind	70%	1 120 MW				40%	30/11/2022
BW6	Solar PV	100%	1 000 MW	06/04/2022	31/10/2022	31/05/2023	0%	31/05/2023
	Wind	100%	1 600 MW				0%	31/05/2023
RMIPPPP	Hybrid	19%	375 MW	24/08/2020	18/03/2021	31/08/2022	100%	31/01/2023

This Base Case is premised upon the closing of 50% of BW5 solar PV and 70% wind projects, due to local content issues and recent technology cost increases. Due to its complexity, excessive pricing, and ongoing litigation it will be prudent to assume that gas-based RMIPPPP projects will not be connected to the grid during our analysis horizon – up to 2026. The remaining RMIPPPP projects include solar PV, wind, battery storage and peaking plants. We also assume that not all non-gas projects will close, and that only 375 MW of firm capacity will be available to the grid. To date, only the Scatec projects with a combined total of 150 MW have signed a PPA with the DMRE. Under the current structure of the programme these plants must be dispatchable to Eskom between the hours of 05:00 to 21:30. In the Base Case, the RMIPPPP is represented as a dispatchable generator and not as distinct solar PV, wind, battery storage and peaking capacity.[23]

Battery energy storage is also expected to be added to the grid as part of the Eskom Distributed Battery Energy Storage Project, funded by the World Bank. Further REIPPPP bid windows after BW6 are not included in the modelling as these are likely to come online after the time horizon of our analysis.

Due to the fact that little information is available about the emerging 100MW embedded generation market we have excluded any wind, solar and storage capacity from this market segment from the Base Case for analytical purposes. The Risk Adjusted Resource Plan (discussed below) relies heavily on this market segment. This provides a clear delineation of the magnitude of the 100MW market segment capacity that has to be realised to resolve load shedding.

Post 2023, decommissioning of units at Arnot, Camden, and Kriel will decrease the available coal capacity. A summary of the annual changes in capacity of each technology in the Base Case (assuming no further interventions) is presented in Table 2.

[23] *However, as pointed out above, for the renewables based RMIPPPP projects to be able to guarantee the dispatchable capacity that they have been awarded they have to build much larger capacity (mostly) PV or wind plant – in some cases up to three times more. Under the current procurement arrangements even though it is paying for it, Eskom will not receive a significant portion of the power generated by these projects of benefit fully from their additional storage capacity.*

Table 2: Base Case - expected changes in installed generation capacity (MW) between 2022 and 2026

Technology		Installed Capacity Dec 2021	Changes in capacity each year by 31 Dec (MW)					
			2022	2023	2024	2025	2026	Total 2022-2026
Coal	Kusile		+720	+720	+720	-	-	+2 160
	Decommissioning		-	-	-356	-370	-1 326	- 2 052
	Total	39 456	+720	+720	+364	-370	-1 326	+108
Solar PV	BW4		+75					+75
	BW5		-	-	+375	+100	-	+475
	BW6		-	-	+500	+400	+100	+1 000
	Total	2 212	+75	-	+875	+500	+100	+1 550
Solar PV (distributed)	< 1MW		+250	+250	+250	+250	+250	+1 250
	100 MW		-	-	-	-	-	-
	Total	Unknown	+250	+250	+250	+250	+250	+1 250
Wind	BW4		+279	-	-	-	-	+279
	BW5		-	+50	+470	+520	+80	+1 120
	BW6		-	-	+200	+800	+600	+1 600
	Total	3 023	+279	+50	+670	+1 320	+680	+2 999
Wind (distributed)	100 MW		-	-	-	-	-	-
	Total	-	-	-	-	-	-	-
CSP	BW3.5		-	+100	-	-	-	+100
	Total	500	-	+100	-	-	-	+100
RMIPPPP dispatchable	RMIPPPP		-	-	+375	-	-	+375
	Total	-	-	-	+375	-	-	+375
Battery storage 4h	World Bank			+200	+160	-	-	+360
	Total	-	-	+200	+160	-	-	+360
Other RE	Total	22	+24	-	-	-	-	+24
Total generation changes			+ 1348	+1 320	+2 694	+1 700	-296	+6 766

Assumptions:
50% of BW5 solar PV reach financial close
70% of BW5 wind reach financial close
100% of BW6 solar PV and wind reach financial close
375 MW of firm capacity from RMIPPPP reach financial close (not reported as separate solar PV, wind, storage, and peaking capacity)
<1MW solar PV market grows at up to 250 MW per annum (MW/a)
Existing installed capacity of distributed solar PV generation at the end of 2021 is unknown, but it is implicitly included in the modelling already, since it reduces the residual demand profile that is used
Assumed overall diesel storage expanded from 27 Ml to 50 Ml by 2023

2.2 LOAD SHEDDING RISK FOR THE BASE CASE

We used a power system model to simulate how the system operator will dispatch the available resources over the 8 760 hours in each year to minimise or eliminate load shedding. The modelling that was conducted to determine the levels of unserved energy (a measure of load shedding) is described in Appendix 1. Having carefully calibrated this model to actual operational data from Eskom for 2021, it provides a good representation of how Eskom is likely to operate the energy system in the future under the different scenarios investigated.

The system dispatch modelling results under the Base Case are summarised in Table 3.

Table 3 indicates the level of load shedding[24] for different combinations of coal plant availability (energy availability factor – EAF) and electricity demand growth scenarios. Results highlighted in light or dark red indicate levels of load shedding that exceed 2021 levels. The results highlight the growing risk of increasing levels of load shedding over the coming years. Load shedding is only avoided in the case where there is no further demand growth and no further deterioration of the coal fleet performance. Constraining demand growth implies limiting the potential for economic recovery, whilst a stable coal EAF is improbable given the historical trend and a greater than 2% decrease in 2022 to date (YTD).[25] Any delays to the commercial operation of Kusile Unit 5 and Unit 6, combined with delays in the Koeberg steam generator replacements will further exacerbate load shedding in 2023 to catastrophic levels exceeding three times those experienced in 2021[26].

Table 3: Base Case - implied load shedding

Scenarios / EAF decline / Demand Growth	2023			2024			2025			2026		
	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.
Demand +1% p.a.												
Demand 0% p.a.												
Demand -1% p.a.												

Resolved or negligible
Up to 2021 levels
Exceeding 2021 levels and up to 3x 2021
Catastrophic levels exceeding 3x 2021

The use of the diesel-fired peaker plant is also a good indication of the degree to which the power system is constrained. In 2021 the average capacity factor of the Eskom OCGT plants was 12%, which is more than double the typical values of less than 5% in a stable power system. Table 4 presents the capacity factor of the peaking plants under the analysed demand and coal EAF scenarios, illustrating that load shedding will be accompanied by the requirement to run existing OCGT plant at unacceptably high capacity factors of between 15% and 20%. With a crude oil price exceeding $100/barrel, the cost to operate diesel fired peaking plant exceeds R5/kWh, implying an annual cost of R20 Bn to R30 Bn for diesel fuel alone.

[24] The corresponding levels of unserved energy are to be found in the Appendix 1. Table 11

[25] Our assumptions about coal plant EAF decline and economic growth for the Base Case are potentially a bit optimistic with respect to load shedding, while the exclusion of the 100MW distributed generation segment from the Base Case probably under reports what is likely to be available in this scenario.

[26] The corresponding levels of unserved energy considering Kusile and Koeberg delays are to be found in the Appendix 1: Table 12

Table 4: Base Case - annual diesel consumption (Ml) for peaking plants (OCGT/ICE[27])

Scenarios / EAF decline / Demand Growth	2023 EAF -2% p.a.	2023 EAF -1% p.a.	2023 EAF 0% p.a.	2024 EAF -2% p.a.	2024 EAF -1% p.a.	2024 EAF 0% p.a.	2025 EAF -2% p.a.	2025 EAF -1% p.a.	2025 EAF 0% p.a.	2026 EAF -2% p.a.	2026 EAF -1% p.a.	2026 EAF 0% p.a.
Demand +1 p.a.	1 113	726	431	1 472	832	351	1 113	439	153	1 113	805	262
Demand 0% p.a.	857	504	301	1 178	488	127	587	234	25	1 113	339	47
Demand -1% p.a.	742	432	266	767	278	51	355	79	7	598	140	8

Load shedding

- Resolved or negligible
- Up to 2021 levels
- Exceeding 2021 levels and up to 3x 2021
- Catastrophic levels exceeding 3x 2021

2.3 CONCLUSIONS FROM THE BASE CASE

Based on the modelling conducted, there are only a limited number of scenarios where load shedding is substantially lower than 2021 levels (primarily due to negative demand growth). In the more likely scenarios, where the coal EAF continues to decline and demand remains flat or increasing, load shedding is likely to increase substantially in the coming years, unless further urgent and drastic interventions are made.

[27] *Internal Combustion Engine*

3 RESOLVING LOAD SHEDDING: THE SOLUTION CASE

3.1 OVERVIEW

The aim of the Solution Case is to demonstrate a capacity expansion plan that will be sufficient to resolve load shedding by 2024/25. We know from previous analyses[28,29,30,31,32,33] that the most economic system to rapidly reduce and then eliminate load shedding *in the short term* contains a combination of the following:

- New wind and solar generation capacity;
- Containment of a further reduction in the availability of the existing coal generation capacity (load shedding probability is highly sensitive to plant availability);
- Additional battery storage capacity;
- Additional fuel storage capacity; and
- Additional thermal peaking and aggregated demand response capacity.

The Solution Case can be viewed as a combination of interventions under three primary categories, as described below:

Utility scale interventions (RMIPPPP and REIPPPP)

- Substantially increase the likelihood that projects from existing IPP Office procurement rounds (RMIPPPP, and REIPPPP BW5) can close and then minimise further PPA signature delays;
- Drastically maximise the capacity that can be obtained from REIPPPP BW6 by more than doubling its size, removing project size limits and strengthening incentives for earlier connection.
- Renegotiate RMIPPPP contracts to gain access to the full energy and capacity of the installed generation and storage assets.
- Ensure there are no further delays to the commissioning of Kusile Units 5 and 6, nor the Koeberg steam turbine replacements.

Distributed generation interventions (<1 MW and 100 MW markets)

- Increase the incentives to expedite the ramp up the renewables build in the <1 MW and 100 MW market categories to the maximum rates that can be achieved.
- Extend the licencing threshold to 1000 MW and remove it for Traders.
- Exploit the large opportunity to obtain additional energy from the multitude of existing and new projects (big and small) that are distributed throughout the grid.

Battery storage, thermal peaker and demand response interventions

- Urgently install additional OCGT/ICE[34] peaker capacity and expand diesel storage at existing peakers.

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[28] *Meridian Economics, 2020. "Resolving the Power Crisis Part A: Insights from 2021 – SA's Worst Load Shedding Year So Far."*

[29] *Marquard et al., 2021. "South Africa's NDC targets for 2025 and 2030 – further analysis to support the consideration of more ambitious NDC targets."*

[30] *National Business Initiative, 2021. "Decarbonising South Africa's power system."*

[31] *Mallinson, 2021. "A systems approach to the South African electricity-supply crisis: unpacking the results of the Risk Mitigation Independent Power Producers Procurement Programme."*

[32] *Meridian Economics, 2020. "A Vital Ambition: Determining the cost of additional CO_2 mitigation in the South African power sector."*

CSIR, 2020. "Setting up for the 2020s: Addressing South Africa's electricity crisis and getting ready for the next decade… and now Covid-19."

[33] *Mccall et al., 2019. "Least-cost integrated resource planning and cost-optimal climate change mitigation policy: Alternatives for the South African electricity system."*

[34] *Internal Combustion Engines (ICE) may likely be preferable to OCGTs as they operate well at altitude and the coast, they are more modular and can therefore be added incrementally and easily moved from one place to another, their operational efficiency is higher than that of OCGTs and they also have a greater operating range – i.e. they can meet requirements for peaking (high power output for short period) as well as more mid-merit type (medium output for longer period) requirements if needed, their ramp rates and start up times are higher and faster than that of OCGTs. These qualities do mean that ICEs have higher maintenance costs, but this has the benefit of providing more localised jobs.*

- Procure a large amount of Demand Response (DR) capacity from DR aggregators and install a significant amount of battery storage.

We assume that it is prudent to plan for at least 1% per year growth in demand from 2022 to 2026, to allow space for economic growth – if demand does not grow such a plan will provide an added and much needed level of reserve margin, which itself will have the effect of stimulating power demand. The demand growth figure is *before* taking account of the supply provided by distributed generation – in other words the demand will be supplied from the national grid (Eskom provided power) and electricity that is self-supplied. As the levels of distributed generation increase, the residual demand that must be supplied by Eskom could remain flat or even decrease.

3.2 SOLUTION CASE

This solution is premised upon the closing of 80% of BW5 solar PV and wind projects, gaining access to the full capacity of RMIPPPP projects and radically increasing the size of BW6 to 3 GW of solar PV and 4 GW of wind. Table 5 provides an overview of the expected timelines for projects to reach financial close in the Solution Case. As described previously, due to their complexity, excessive pricing, and ongoing litigation, gas-based RMIPPPP projects are not included in the analysis horizon up to 2026.

Table 5: Solution Case - improved timelines for REIPPPP and RMIPPPP projects to reach financial close

Project	Type	Projects closable	Expected capacity	RFP issuance	Award	Expected close	Projects delayed	Last close
BW5	Solar PV	80%	775 MW	12/04/2021	31/10/2021	30/09/2022	0%	30/07/2022
	Wind	80%	1 280 MW					
BW6	Solar PV	100%	3 000 MW	06/04/2022	31/10/2022	31/05/2023	0%	31/05/2023
	Wind	100%	4 000 MW					
RMIPPPP	Solar PV	87%	1 471 MW	24/08/2020	18/03/2021	31/08/2022	63%	31/12/2022
	Wind	100%	160 MW				100%	31/12/2022
	Battery	100%	640 MW				65%	31/12/2022
	Gas/diesel dispatchable	10%	153 MW				100%	31/12/2022

Leaving aside the contingency peaker capacity proposed in the Risk Adjusted Resource Plan, Table 6 shows the total changes in installed capacity required for the Solution Case to resolve load shedding by 2024/25.

Table 6: Risk Adjusted Resource Plan - changes in installed capacity (MW) of generators between 2022 and 2026, including risk contingency

Technology		Installed Capacity Dec 2021	Changes in capacity each year by 31 Dec (MW)					
			2022	2023	2024	2025	2026	Total 2022-2026
Coal	Kusile		+720	+720	+720	-	-	+2 160
	Decommissioning		-	-	-356	-370	-1326	- 2 052
	Total	39 456	+720	+720	+364	-370	-1326	+108
Solar PV	BW4		+75	-	-	-	-	+75
	BW5		-	+125	+575	+75	-	+775
	BW6		-	-	+2 000	+900	+100	+3 000
	RMIPPPP		-	+1471	-	-	-	+ 1 471
	Total	2 212	+75	1 596	+2 575	+975	+100	+5 321
Solar PV (distributed)	< 1MW		+500	+750	+750	+750	+750	+3 500
	100 MW		+500	+1 500	+1 500	+1 500	+1 500	+6 500
	Total	Unknown	+1 000	+2 250	+2 250	+2 250	+2 250	+10 000
Wind	BW4		+279	-	-	-	-	+279
	BW5		-	+110	+530	+580	+60	+1 280
	BW6		-	-	+1 100	+1 700	+1 200	+4 000
	RMIPPPP		-	-	+58	+80	+21	+159
	Total	3 023	+279	+110	+1 688	+2 360	+1 281	+5 718
Wind (distributed)	100 MW		-	-	+200	+400	+400	+1 000
	Total	-	-	-	+200	+400	+400	+1 000
CSP	BW3.5		-	+100	-	-	-	+100
	Total	500	-	+100	-	-	-	+100
Peaking	BW (contingency)		-	+1338	-	-	-	+1 338
	RMIPPPP		-	+153	-	-	-	+153
	Total	3 056	-	+1491	-	-	-	+1 491
Battery storage 1h	BW		-	-	+1000	-	-	+1 000
	Total	-	-	-	+1000	-	-	+1 000
Battery storage 4h	World Bank			+200	+160	-	-	+360
	RMIPPPP			+640	-	-	-	+640
	Total	-	-	+840	+160	-	-	+1 000
Demand response	Aggregator		-	+1 500	-	-	-	+1 500
	Total	-	-	+1 500	-	-	-	+1 500
Other RE	Total	22	+24	-	-	-	-	+24
Total generation changes			+2 098	+ 8 607	+8 237	+5 615	+2 705	+ 27 262

Assumptions:

80% of BW5 solar PV reach financial close
80% of BW5 wind reach financial close
100% of BW6 solar PV and wind reach financial close
BW6 is increased to 3 GW of solar PV and 4 GW of wind
RMIPPPP capacity of 1471 MW of solar PV, 160 MW of wind, 640 MW of 4h battery storage and 153 MW of peaking is available to the system
1500 MW of demand response capable of 0.5 TWh/a is added
< 1 MW solar PV market grows at up to 750 MW/a
1 MW-100 MW solar PV market grows at 1500 MW/a, and wind grows at 400 MW/a from 2025 onwards
Overall diesel storage capacity is increased to 100 Ml from existing 27 Ml
1350 MW of thermal peaking capacity (preferably ICE) installed as contingency for risk of delays in implementing the Solution Case

The extent to which the current trajectory is inadequate to solve load shedding is evidenced by the large difference in installed capacities between the Solution Case which does resolve load shedding and the Base Case which does not. This is better illustrated by the charts in Figure 2 which compare the capacity likely to be installed each year under the Base Case versus what is necessary in the Solution Case.

Given the urgency to resolve load shedding, solar PV forms a key part of the overall solution due to the shorter project development timeframes and scalability, which allows for additional capacity to be added to the grid faster than for wind projects. The largest increase in capacity of 11 000 MW is required under distributed generation, which is predominantly from solar PV within the 100 MW segment. Overall, the capacity expansion needed will require a high level of ambition to deliver.

Figure 2: Comparison of the capacity added between the Base Case and the Solution Case (excludes additional peaking plant contingency)

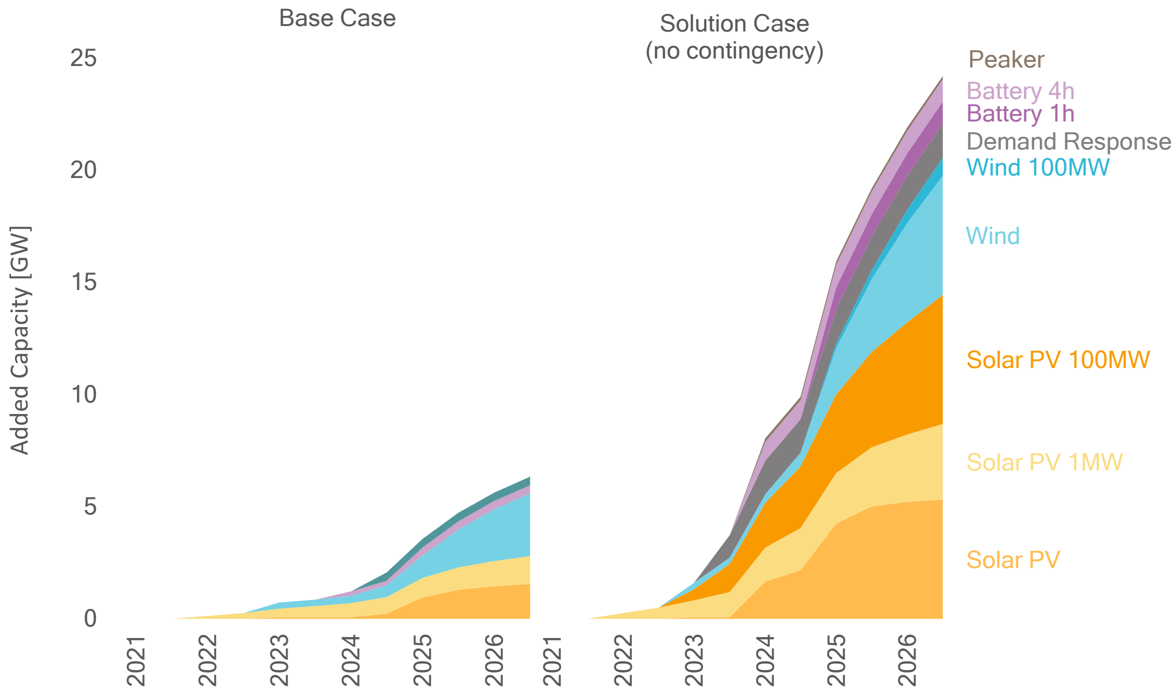
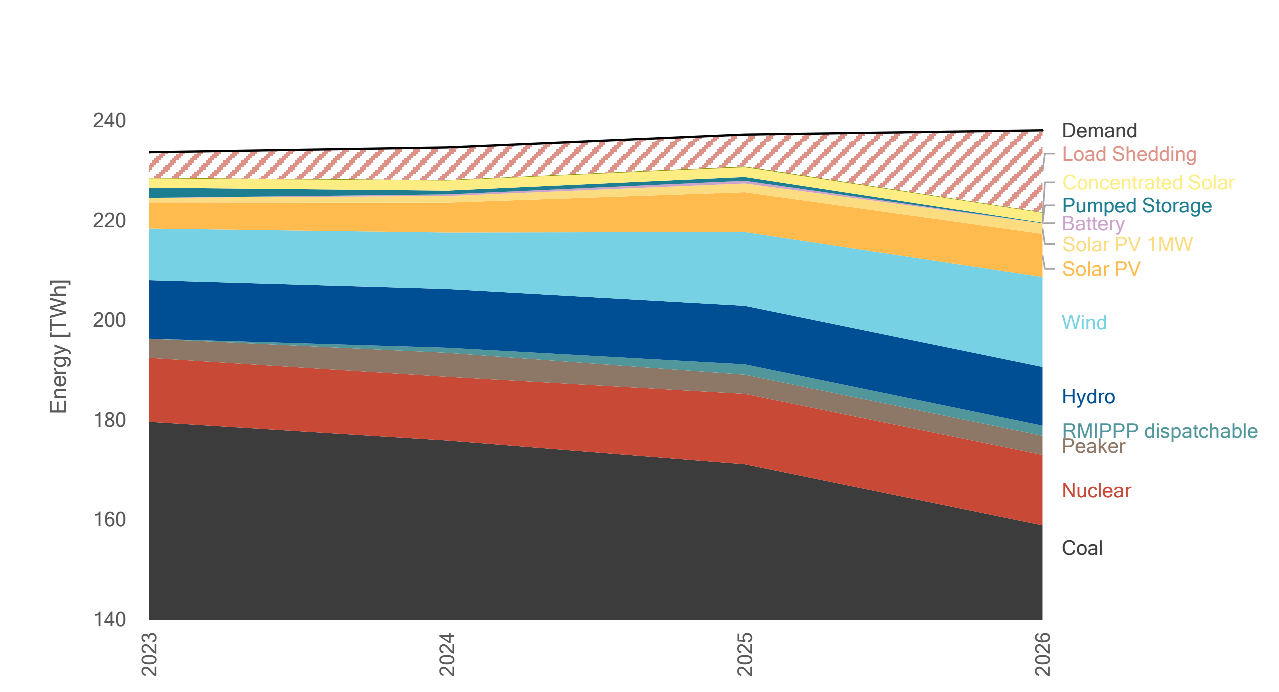
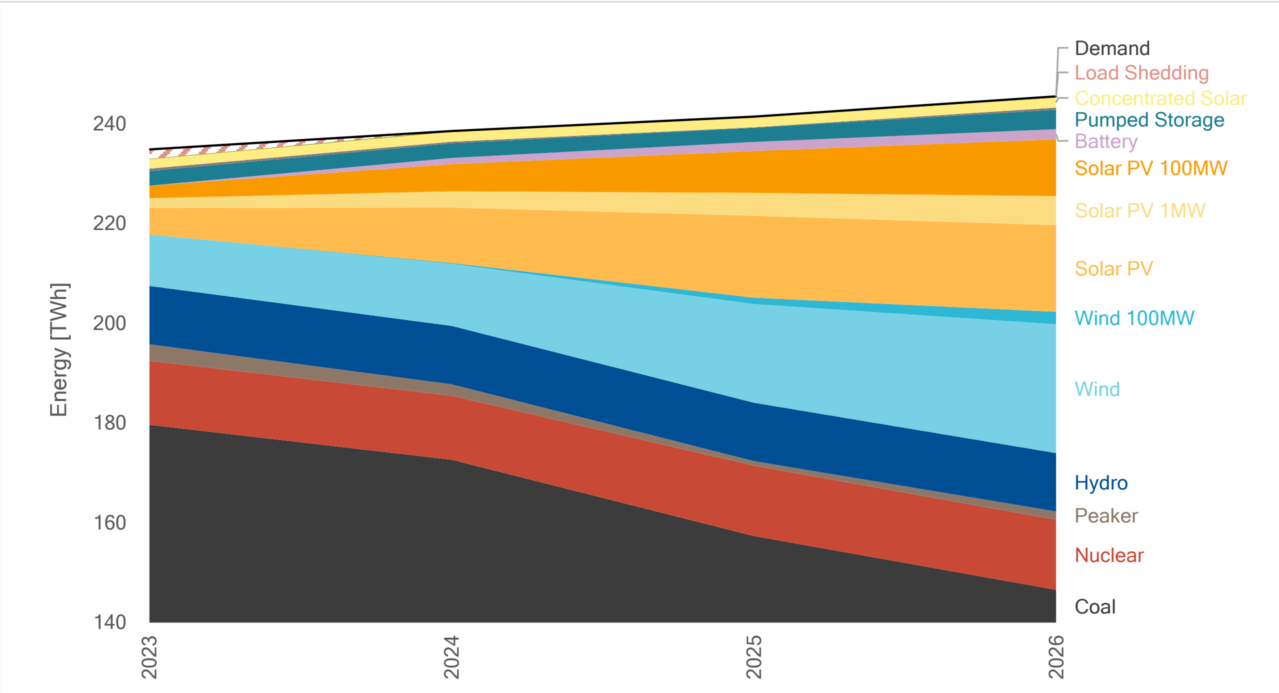


Figure 3 below illustrates that the energy in the Base Case (top chart) is insufficient to close the supply gap over the period from 2022 to 2026. The significant load shedding that will occur in the Base Case scenario is eliminated in the Solution Case from 2024, with lower coal usage required (allowing necessary maintenance to be done) and lower use of the thermal peaking plant.

Figure 3: Supply gap evolution under the Base Case (above) and Solution Case (below) for 1%p.a. demand growth and EAF decline of -2%p.a





Although the capacity expansion illustrated in Figure 4 under the Solution Case is adequate to resolve load shedding by 2024, it relies on every part of the Solution Case being implemented within the exceptionally challenging timelines of Table 6. Should any of the capacity fail to come online when required as shown ("execution risk"), the risk of further load shedding will materialise. It will therefore be prudent for any plan to include some contingency capacity as a risk adjustment measure to augment the solution. For practical purposes we therefore propose a Risk-Adjusted Plan based on the Solution

Case, by adding a further 1 350 MW of thermal peaking capacity by 2024 and increasing the overall levels of diesel storage to 100 Ml to mitigate the risk of recurring load shedding in 2024. These are no-regret options given the valuable additional load shedding "insurance" provided and the fact that this peaking capacity and fuel storage will in any case be required later in the decade. The additional thermal peaking capacity and diesel storage does not mean that diesel consumption will be excessive – in this scenario it is still expected to be 683 Ml in 2024 (74% of 2021 levels) and then to decline thereafter.

The efficacy of the Risk-Adjusted Plan is illustrated in Figure 4 under a scenario in which delay risk materialises resulting in the expanded BW6 only achieving 2 GW of solar PV and 3.2 GW of wind, whilst we also reduce the achieved growth rate of distributed solar PV generation in the 100 MW and <1 MW segments. Without the additional thermal peaking capacity for contingency purposes, the Solution Case is vulnerable to delays in implementation (execution risk) specifically in the short term to 2024. In the delay scenario, the Solution Case alone would be inadequate to end load shedding by 2024, but the addition of the thermal peaking capacity would mitigate for this eventuality.

Figure 4: The benefit of augmenting the Solution Case with contingency thermal peaking capacity to hedge against execution risk

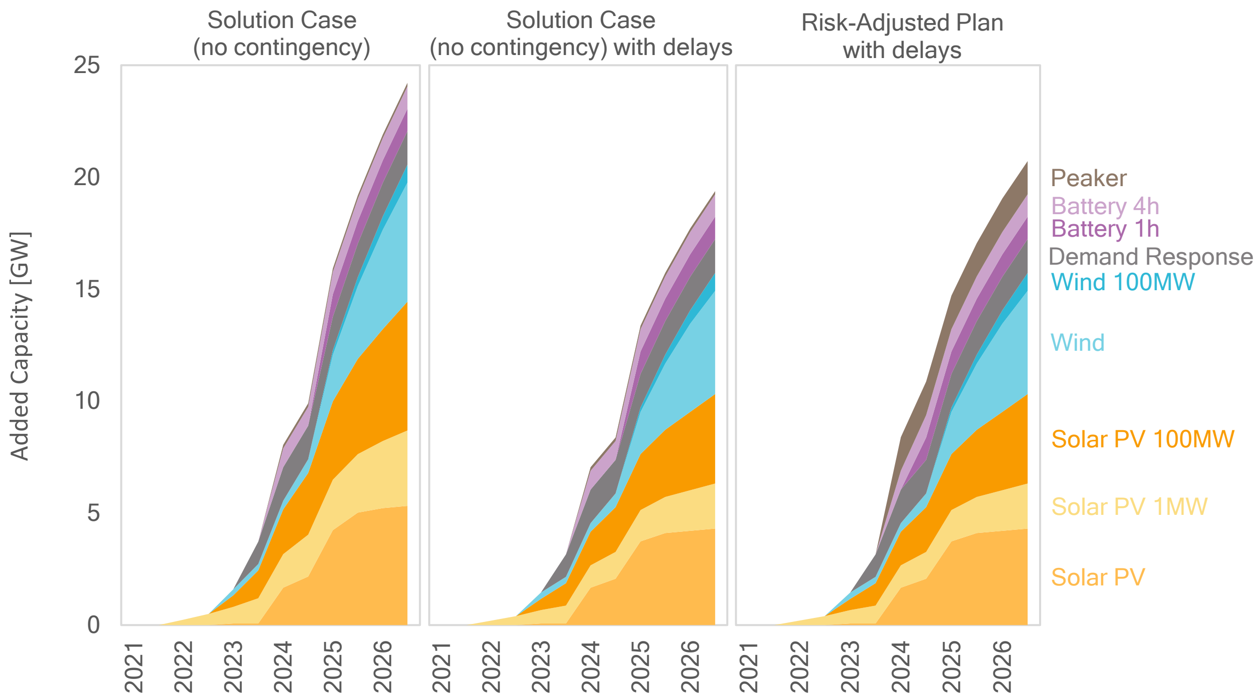


Table 7 illustrates the impact on load shedding achieved by implementing the Solution Case, with the further reduction of load shedding risk achieved by augmenting the Solution Case with the additional thermal peaking capacity as per the Risk-Adjusted Plan. By following the Risk-Adjusted Plan it is evident from the table that even if some delays materialise in elements of the Solution Case the risk of load shedding in 2024 and 2025 is reduced to negligible levels.

Table 7: Load shedding under different scenarios with a 1% p.a. growth in demand

Scenarios	EAF decline	2023			2024			2025			2026		
		EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.
Base (for reference)													
Solution Case implemented on time - no delay risk materialises													
Solution Case only													
Delay risk materialises													
Solution Case only													
Risk Adjusted Plan													

Resolved or negligible
Up to 2021 levels
Exceeding 2021 levels and up to 3x 2021
Catastrophic levels exceeding 3x 2021

Table 8 below shows that the unacceptably high thermal peaking plant fuel usage attendant to the Base Case are reduced substantially by implementing the Solution Case. As can be seen, the addition of contingency thermal peaking plant does not result in greater use of peaking assets than in the Base Case - even if delay risk materialises (the colours coding still shows the degree of load shedding, not diesel usage).

Table 8: Annual diesel consumption (Ml) for peaking plants (OCGT/ICE) in the Solution Case and Risk Adjusted Plan with a 1% p.a. growth in demand

Scenarios / Demand Growth (EAF decline)	2023			2024			2025			2026		
	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.
Base (for reference)	1 113	726	431	1 472	832	351	1 113	439	153	1 113	805	262
Solution Case implemented on time - no delay risk materialises												
Solution Case	955	556	342	665	217	56	267	48	7	470	101	15
Delay risk materialises												
Solution Case	1 113	594	364	809	303	70	367	73	9	703	166	19
Risk Adjusted Plan	1 113	594	364	899	323	74	435	77	9	833	182	19

Load shedding
- Resolved or negligible
- Up to 2021 levels
- Exceeding 2021 levels and up to 3x 2021
- Catastrophic levels exceeding 3x 2021

3.3 GRID CAPACITY TO ABSORB ADDITIONAL GENERATION

Table 9 below provides an estimate of the grid capacity that will be required for the additional generation capacity that is proposed to resolve load shedding under the Risk-Adjusted Resource Plan. All REIPPPP and RMIPPPP projects are assumed to be connected to the transmission grid, whilst distributed generation that is connected behind the meter is excluded from the transmission grid requirements. It is assumed that 100% of distributed generation less than 1 MW and 30% of 100 MW solar PV generation is connected behind-the-meter. The remaining distributed generation is assumed to be wheeled through the grid. The total estimated grid requirement is 4.3 GW up to the end of 2023 and 18.2 GW up to the end of 2026.

The Eskom Generation Capacity Connection Assessment (GCCA) provides an overview of the "potential capacity available on the Eskom transmission network to facilitate the connection of generation projects." The GCCA indicates that within the 11 supply areas within the Eskom transmission network there is potential to install 32.4 GW of new generation capacity above all bid windows up to BW5 and including the RMIPPPP.

Although there is currently sufficient grid capacity to absorb the proposed generation capacity in the Risk Adjusted Resource Plan, the GCCA-2024 capacity by supply (Figure 5) indicates that there are currently grid bottlenecks in the Northern Cape, Western

Cape[35]. Hydra Cluster and Eastern Cape. Therefore, more projects will need to be located in provinces without grid bottlenecks, which will could have a lower solar resource than the Northern Cape and a lower wind resource than the Western and Eastern Cape. Although this may increase the cost of such projects it is unlikely to be material in respect of the broader plan.

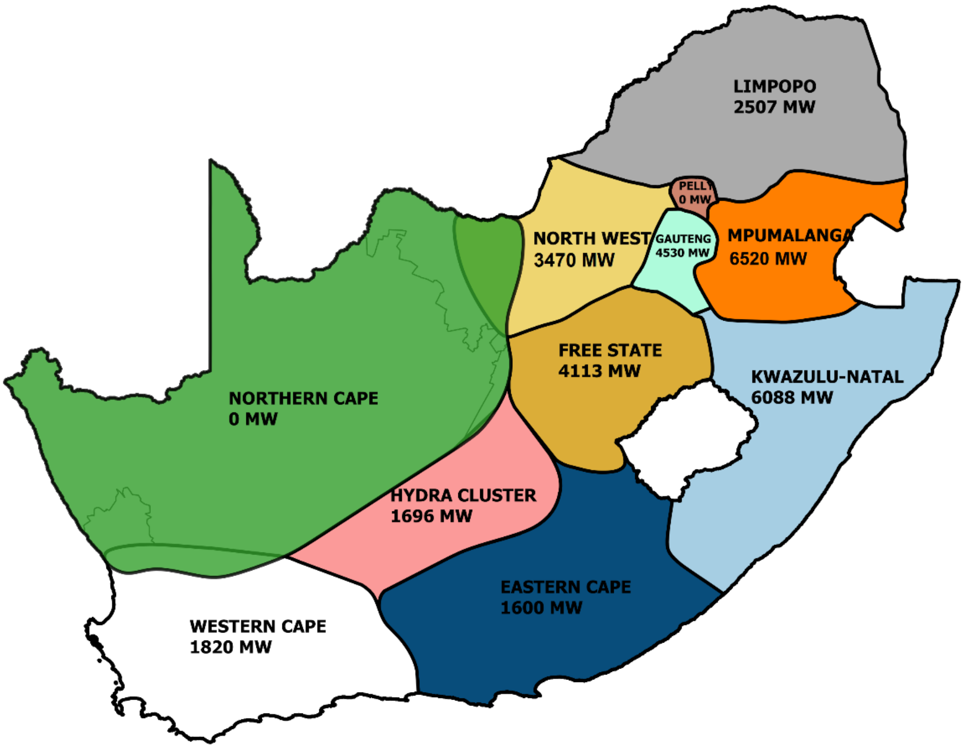
Table 9: Estimate of grid capacity requirements (MW) for the Risk Adjusted Plan (additional to 2021)

Generator	Risk Adjusted Plan Transmission connected		Eskom Transmission Development Plan	
Year end	**2023**	**2026**	**2023**	**2026**
Solar PV utility	1 671	5 321	1 869	3 869
Solar PV distributed 100MW	600	4 550		
CSP utility	100	100	100	100
Wind utility	389	5 718	2 125	6 925
Wind distributed 100MW	-	1 000		
Peaker utility	1 491	1 491	1 776	2 434
Total	**4 251**	**18 180**	**5 870**	**13 328**

The proposed grid connected capacity of the Risk Adjusted Resource Plan will consume 56% of the current available capacity. Therefore, it will be critical to increase the planned targets for increasing the transmission grid capacity. The Eskom Transmission Development Plan (TDP) outlines the current plans for expansion of the transmission infrastructure up to 2031. The latest TDP highlights the need to substantially strengthen the upstream network to enable generation in the Northern Cape supply area. The current TDP is based on the generation capacity expansion from the outdated Integrated Resource Plan (IRP2019). Figure 4: The benefit of augmenting the Solution Case with contingency thermal peaking capacity to hedge against execution risk shows that the additional wind capacity that is proposed in the Risk-Adjusted Resource Plan is already catered for in the TDP, however, the levels of grid connected solar PV capacity required is significantly higher than allowed for in the plan. Therefore, the TDP clearly requires an urgent update.

[35] *See Eskom (2022) "Transmission Generation Connection Capacity Assessment of the 2024 Transmission Network."*

Figure 5: Eskom's GCCA-2024 showing the generation connection capacity available within each supply area



3.4 CONCLUSIONS FROM THE SOLUTION CASE

Load shedding can mostly be eliminated by 2024 provided that successful interventions can be implemented on an emergency basis to secure a suite of capacity expansions required as demonstrated by the Risk Adjusted Resource Plan. In order to mitigate the risk that some of the required capacity is delayed, the additional contingency of installing 1 350 MW of thermal peaking plant is a prudent augmentation of the Solution Case and together constitute a reasonable Risk Adjusted Resource Plan to address load shedding.

Given the present circumstances the targets are necessarily highly ambitious, however our analysis shows that without concrete measures designed to deliver an outcome of this nature load shedding is unlikely to be resolved within a reasonable timeframe.

4 A GAME PLAN TO RESOLVE LOAD SHEDDING

In this section we discuss a coherent suite of practical interventions that, working together, is designed to contain, reduce and then eliminate load shedding in accordance with the Risk Adjusted Resource Plan outlined in section 3. The plan is out of necessity highly ambitious. Without a realistic game plan and substantial political will to deliver it, it is unlikely that load shedding will be resolved soon.

Given the urgency of presenting the findings of this study the proposals are necessarily of a high-level nature and will benefit from further investigation and revisions by key stakeholders.

In the remainder of this section we set out a range of proposed (sometimes drastic) implementation measures – a "game plan" – designed to end load shedding. While there could be many variations of a workable suite of interventions the objectives will most likely not be achieved without a range of interventions as broad and drastic as envisaged here. For any game plan to have a reasonable chance of success, it must (a) avoid over-reliance on any one or two measures (the "all eggs in one basket" problem); but must (b) instead rely on a well-diversified set of players and strategies to deliver the additional capacity and energy, with some level of contingency.[36]

4.1 ELIMINATE OR DRASTICALLY REDUCE LOCAL CONTENT REQUIREMENTS ON PV MODULES

For the reasons set out above (section 3.1) the current local content requirements pose a critical risk to the closure of most of the solar PV RMIPPPP and REIPPPP BW5 projects. These projects are of critical importance for resolving load shedding urgently and it will be devastating for the efforts to do so if the issue is not resolved immediately. The economic cost will be orders of magnitude larger than any marginal increase in local content that might be achievable.

The IPP Office has imposed the local content obligations under direction of the DTIC. The problem with the way in which it was designed is that it appears that no proper study was done to investigate the opportunity cost, benefits and therefore trade-offs involved – despite the fact that South Africa is facing a load shedding disaster. In the absence of this information it might well appear to the officials and politicians involved that obtaining greater local content in the PV value chain by means of these measures is a free lunch – i.e. it does not impose any economic costs. The reality might be very different. By contributing to the failure of these critical projects, the measures will extend load shedding, or at best increase the cost of electricity, which is likely to cause much greater economic damage and deindustrialisation downstream than the very modest benefits from PV panel localisation. Given that South Africa has absolutely no competitive advantage in manufacturing PV panels, that all the raw materials must be imported and that, to be competitive, the

[36] Other factors that also impact critically on the reliability of power supply are beyond the scope of this study. These include the increasing failure of the distribution networks – also in most of the key Metro areas where a large part of the productive economy is located – and the need to implement large scale expansion of the Transmission grid (briefly discussed in section 3.3 above).

process will have to be highly automated, there appears to be no economic rationale for imposing more load shedding on South Africans and "taxing" them to subsidise the establishment of local panel manufacturers.

Given the critical importance of avoiding a load shedding disaster, and the absence of a sound economic argument in its favour, we simply recommend that the local content requirement for PV panels for the RMIPPPP and BW5 be scrapped in its entirety.[37]

A comprehensive study of the numerous problems with the local content programme is beyond the scope of this report. Global supply chains for energy related hardware are currently subject to unprecedented supply shocks and cost escalations. This comes at a time when South Africa urgently needs to scale up its build programme to resolve load shedding and then replace retiring coal plant.

As recommended below a much larger REIPPPP BW6 will be a critical part of the plan but will unfortunately be delivered before the current global supply chain problems have been resolved. At the time of writing, the bid submission date is 11 August 2022. Given the short time frames and its large scale, it is of critical importance to avoid further cost increases and delays due to unrealistic and unjustified local content requirements for BW6 as well.[38]

These proposed changes will be challenging under South Africa's procurement legislation, and might well upset bidders who were not successful. However, given the severely negative social and economic impact the country now faces there are likely to be legal mechanisms available to allow the necessary changes to be made should the political will exist. While our initial consultations suggest that this will be possible, the details are beyond the scope of this study.

For procurement beyond BW6, localisation policy needs a complete rethink. Localisation strategy should be based on empirical reality, not wishful thinking or ideological insistence. It should focus on South Africa's competitive advantages, and it should be based on an explicit understanding of the trade-off between higher inputs costs due to localisation, and its negative impact on industrial and broader economic activity down the value chain. There is no point in shining the light on a small part of a bigger, interconnected, highly complex economic system, to impose drastic regulatory interventions, while the damage to the larger economic system is much larger than any modest gain that can be made. To the extent that local content requirements are preferred (over positive incentives), we recommend that it be designed as part of a multi-year plan allowing for a gradual phase-in and achievable targets.

4.2 FIX DESIGN FLAWS TO ENABLE ALL THE PROJECTS WITH PV, WIND AND STORAGE TO PROCEED

There are two primary problems with the RMIPPPP renewables projects that, if not resolved, will significantly reduce their contribution towards resolving load shedding.

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[37] On 2 June 2022, Scatec was the first RMIPPPP project to sign their Eskom PPA and other commercial agreements with Government. They have two months from this date to reach financial close – financing for the project has therefore not yet been secured. Scatec's strategy puts them in front of the queue for any panels that can be manufactured by local suppliers – thereby reducing their supply risk under the local content requirements. Scatec bid prices were also the highest of the preferred RMIPPP bidders and the very aggressive bids received for the subsequent BW5, Scatec's RMIPPPP pricing thus probably puts them near the top of the ranking of RMIPPPP and BW5 projects that are likely to reach financial close.

[38] All developers will be demanding hundreds of MW of compliant PV panels from the nearly non-existent local manufacturing industry creating massive supply bottle necks and escalating prices.

The first is that projects will fail to obtain financing in time and either completely fail or not be built according to the envisaged time frames due to stalled and protracted negotiations with government about changes required to the procurement rules to enable the projects to proceed. The second relates to fundamental RMIPPPP procurement design flaws that drastically reduce the energy and capacity contribution that will be delivered to the grid compared to that which is possible from the plant that will be installed.

The renewables-related RMIPPPP projects[39] consists of 1 471 MW of solar PV, 160 MW of wind, 640 MW of batteries, and 153 MW of thermal peaking capacity. However, under the RMIPPPP procurement rules only 375 MW of this capacity will be made available on a dispatchable basis between 05:00 and 21:30 each day. In some projects more than 40% of the energy produced will currently be wasted[40]. This current arrangement is reflected in the Base Case assumptions and contributes to the load shedding expected in this case. The Solution Case and proposed Risk Adjusted Resource Plan requires that all renewables-based RMIPPPP projects reach financial close in time, and that they are relieved of their specific dispatch profile requirements, but instead have to offer all energy produced to the system and that their battery storage and peaking plants can be fully dispatched by the System Operator.

Project developers already have powerful incentives to make projects proceed and succeed. This includes the possible loss of their bid bonds, the large sunk investments in development costs, the potential loss of scarce grid connection rights, loss of a well-advanced opportunity to undertake a viable project investment, potential reputational damage and the personal loss for the key personnel involved that have spent most of their waking hours over the last year and a half to develop these highly challenging hybrid projects.

Resolving the local content problems related to PV panels is unlikely to be enough to ensure that all the renewable RMIPPPP projects proceed. Without further interventions a significant portion of the RMIPPPP renewables-based projects is likely to fail. This will be severely damaging for the prospects of expediting the resolution of load shedding. A combination of one or more of the following interventions is likely to enable all these projects to proceed and maximise their contribution to eliminating load shedding:

- Remove the local content requirements on solar PV modules for the RMIPPPP.
- Remove the 15-hour qualification test. A number of the renewables projects have to install large and expensive diesel generators just to pass the 15-hour qualification test at project completion. Under the current dispatch regime, these generators are not expected to be used thereafter and will therefore not add any system value in practice. In some cases, this can add up to approximately R1 Bn to the project cost but deliver no tangible system benefit. Furthermore, locating this peaking plant in renewable generation areas where grid capacity is scarce means that they mostly will not be available to be used as peaking plant – should the regime be changed to allow this. Removing the 15-hour qualification

[39] *We assume that the gas-based RMIPPPP projects will not be available on the short-term to resolve load shedding due to the practical and legal problems experience by their project developers.*

[40] *Mallinson, C., 2021. Briefing note: A systems approach to the South African electricity-supply crisis: Unpacking the results of the Risk Mitigation Independent Power Producers Programme (RMI4P).*

test is a no regret, quick and easy way to improve the viability of the projects.

- Allow projects to sell or provide their excess energy back to Eskom or some other buyer at any time of day (this could be on a negotiated basis, or on a positive net metering / billing basis as proposed in section 4.4.1.6 below). If a feasible deal might be struck where the excess power is provided for free in return for the removal of the local content requirement on PV panels and the 15-hour qualification test.
- Allow projects to sell early energy to Eskom before full capacity operations. This could compensate them to procure parallel construction teams from their EPC contractors.
- Allow battery charging from the grid at any time at the applicable time-of-use tariffs.
- A more optimal outcome from the power system perspective will be to relieve them of their dispatch requirement, and then allow the batteries to be dispatched by the System Operator. Consideration will have to be given to whether this will impact on the pricing arrangements.

Given that the RMIPPPP hybrid projects differ with respect to the combination of technologies used they will not all benefit equally from each of these interventions. Careful design will be required. In principle the aim should be to maximise the additional benefits from the projects by making concessions to the procurement rules as outlined above, while restoring viable returns for the projects, and not increasing the total payments from Eskom.

Finalising these adjustments will be a complex task requiring substantial skills and time to finalise. It will not be possible to delay the project commercial and financing agreements to allow for this process, and still construct them in time to provide critical load shedding relief by 2024. The strategy should be to do what is necessary to allow the projects to proceed immediately – even if that means not achieving all the state's objectives – while keeping the option open to continuing with negotiating further revisions while the projects are being constructed. Fortunately, the state has significant bargaining power on the basis of the contract clauses which currently do not allow the RMIPPPP projects to sell their surplus power to any other party.

The procurement changes required will most likely have to be approved by National Treasury. Consideration should also be given to whether any RMIPPPP renewable energy bidders who did not achieve preferred bidder status could obstruct the process by litigating. The existing litigation related to some of the gas-based RMIPPPP projects might well result in a reluctance by the government officials to pursue the types of solutions outlined here. However, given the large contribution that these projects can make to eliminating load shedding expeditiously and the overwhelming public interest in doing so, it will be worth retaining the best legal advice to find an appropriate solution in terms of South Africa's procurement law.

4.3 IMPLEMENT ACROSS THE BOARD PRICE INCREASES FOR BW5 PROJECTS TO COMPENSATE FOR LARGE COST ESCALATIONS

The successful completion of BW5 projects will be critical for any plan to resolve load shedding by 2024. According to the IPP Office the commercial agreements (including PPAs) are expected to be signed in a staged manner between the end of July and the end of September 2022. Due to the exceptionally low average prices bid for the BW5 projects and the subsequent unprecedented increases in logistics and equipment costs (which are not fixed at the time of bidding), it is likely that a substantial number of the projects will be delayed or never reach financial close because they are unable to secure the necessary finance. This will be a problem even if the local content requirements for PV panels are removed (as discussed above). From a public interest point of view this situation is unacceptable as it will prolong load shedding.

The simplest, fastest and cheapest route to securing all of these projects is to offer them a pro-rata increase in their prices bid to compensate for the increased costs. The main challenge here is that reliable information about the extent of the cost increases is not yet available. We propose the following strategy to address this:

1. Urgently announce the intention to implement such an adjustment (making the objective clear – that is to compensate for the increases in the cost of capital equipment and logistics) well before the target date for the commercial agreements from end July to September. This will provide a strong incentive for projects to sign the commercial agreements and start committing expenditure on long-lead time project development costs.
2. Ensure that the details of adjustment mechanism is announced well before the staggered financial close dates (usually two months after commercial close). We can see two options for price discovery and implementation of the adjustment:
   a. Immediately appoint independent experts to conduct a study and recommend a price increase percentage.
   b. Wait for the submission of the BW6 bids. Use this information to select the best qualifying projects to make up the equivalent capacity of BW6 projects that could have been awarded for BW5. The percentage difference in the average cost of the representative BW6 projects compared to that of the actual BW5 projects can be used to adjust the individual prices for BW5. This does not have to be an exact science but should be executed in such a way as to provide a fair reflection of the price discovery offered by the competitive bidding in BW6, which will reflect the information available in the market about the cost increases.

We have a strong preference for option b: using BW6 prices for price discovery to apply to BW5 adjustments. Short lead-time expert studies without the benefit of competitive bidding is unlikely to provide useful information. It should be possible to publish the price increase percentage offered to BW5 bidders in the first week of September 2022 – in time for all the projects to reach financial close and proceed.

4.4 ACCELERATE DISTRIBUTED GENERATION UPTAKE

Because of the vast number of projects involved, and the vast scale of additional human and financial resources that can be mobilised to install new generation capacity, putting in place interventions to drastically accelerate the roll-out of distributed generation[41] holds the largest potential upside for a game plan to resolve load shedding

[41] *For the South African context, we use the term "distributed generation" to refer to all generation projects, both large or small, that are not the result of formal procurement processes by the IPP Office, Eskom or municipalities.*

urgently.[42] The recent increase in the licence-exemption threshold for generation projects from 1 MW to 100 MW has spurred momentum in the distributed generation space, but further revisions are required to mobilise capacity at the scale required to contribute to ending load shedding.

4.4.1 EXPAND LICENCE EXEMPTIONS

4.4.1.1 Revise the NERSA method for determining compliance with the licencing threshold

NERSA currently insists that any battery capacity on a site should be added to the PV or wind generation capacity when calculating compliance with the 100 MW licence-exemption threshold. This substantially reduces the incentive to build larger generation plant or alternatively disincentivises the installation of batteries. These outcomes are counterproductive when trying to encourage maximum investment to resolve load shedding.

Leaving aside the question of whether the retrieval of electricity from a storage facility constitutes the "generation" of electricity, NERSA's view also appears to be irrational and serves no public purpose. Section 7(1)(a) of the Electricity Regulation Act states that a licence will be required to "operate any generation, transmission, or distribution facility". The singular, "facility" is used. Clearly a battery installation is of a completely different technological nature and has a very different functional role to that of a generation plant (say PV, wind or peakers) and thus constitutes a separate facility. In practice batteries are in effect more closely associated with managing network limitations and providing fast system operator support (i.e. "transmission") than with the operation of "generation".

Given the public interest in doing so and the absence of any obvious legal impediments, we recommend that NERSA be urgently requested to simply clarify that batteries will be viewed as separate facilities for the purposes of calculating compliance with the licence-exemption limit.

4.4.1.2 Revise the 100 MW limit to 1000 MW

Due to economies of scale the optimal size for new wind and solar project development is now often far more than 100 MW. Further cost reductions are possible from larger projects. Furthermore, several existing large electricity consumers, and potential new investors in green hydrogen production (although this falls largely outside of the scope of this report), urgently need to procure green electricity from facilities much larger than 100 MW. The 100 MW threshold has been arbitrarily determined, and still delays and complicates acceleration of renewable energy construction in South Africa and the development of a large green hydrogen industry.

It is very difficult to develop projects larger than 100 MW for private of takers for the following reasons. To accept a Budget Quote for a grid connection Eskom needs the project to have a NERSA generation license. To obtain a generation licence, developers need to have a signed PPA *and* a ministerial deviation that states that the project is exempt from having to comply with the IRP (this means that every single distributed generation project larger than 100 MW for the private offtake market currently has to be approved independently by the Minister of Mineral Resources and Energy, and then NERSA). Off-takers are not going to sign up

[42] *Some industry experts estimate, based on customs data, that distributed generation PV investments are in the region of 1000 MW per year. (source: Wido Schnabel, personal communication, 28 May 2022).*

for PPAs for projects where the grid is not secured and if they do not know if a ministerial deviation will be approved. This leaves developers with the absurdity of a circular dependency (or "red tape hell") which generally just means that they give up trying to develop larger projects.

In order to solve these problems and given that no obvious economic rationale remains for retaining the 100 MW threshold it should be changed to at least 1000 MW or simply be removed.

4.4.1.3 *Exempt traders from licencing - require them to register instead.*

The existence of viable and competing traders will play a critical role in derisking distributed generation project investments. Traders provide off-take diversification opportunities and potentially make it easier for new developers who do not yet have a diversified customer base (or balance sheet) to enter the market. Traders currently need to be licenced, which can take years to achieve. In February 2022, ENpower Trading became the second private electricity trading company in South Africa to be granted a trading licence by NERSA, and the first to be awarded such a licence in over 12 years.[43]

Given the important role that traders can play to facilitate the distributed generation market, and the fact that there is no net benefit to require traders to be licenced, we recommend that traders be exempt from the need for NERSA licencing and be required to register with NERSA instead, by means of regulations promulgated to amend Schedule 2 of the Electricity Regulation Act.

4.4.1.4 *Reform tariff rules to leverage significant additional energy*

There are two important tariff related opportunities to achieve widely distributed and cumulatively significant responses to reduce load shedding. The first is to delay the rebalancing of tariff structures between energy and fixed charges; and the second (closely related) the implementation of a feed in / net metering tariff by Eskom (and municipalities). Both opportunities arise because of the current severe energy and capacity shortages on the power system.

As demonstrated in Part A of this two part-series, Eskom's diesel-fired OCGTs are often working around the clock to avoid load shedding and charge the pumped storage dams – not just at peak times. This demonstrates that additional power at any time of the day can be used to relieve pressure on the diesel-fired OCGTs and pumped storage assets, thereby reducing diesel burn and ensuring that the dams and diesel tanks are full when they are needed. Also, as explained in Part A, the current role of the pumped storage assets in providing near instantaneous operating reserves to avoid an uncontrolled grid failure severely limits their ability to utilise their vast energy storage capacity to reduce load shedding. This is because of the severe energy shortage on the system which creates the risk that they cannot be recharged in time.

Despite this obvious need for additional energy and capacity, currently renewable generators often have to curtail production when, due to favourable circumstances, they could generate more than the capacity they have been contracted for – even at times when OCGTs are running.

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[43] *See Crown (2022): https://www.crown.co.za/latest-news/electricity-control-latest-news/20302-landmark-licensing-of-private-electricity-trader*

Tariff related measures should be designed to avoid unintended consequences over both the short and longer term. Because the marginal economics of power supply will (hopefully) change over this time horizon the tariff should be adjusted accordingly. In the short-term, tariffs should reflect the fact that the power system is severely energy constrained, and that additional energy will also free up generation capacity (greater use of pumped storage assets, full diesel tanks at the OCGTs, headroom to take out coal plant and maintain them to be more reliable). In other words, consumers of energy should get the correct pricing signal about the value that the energy that they consume would otherwise have had for the power system (the opportunity cost).[44] Over the longer term, in an unconstrained system, additional energy will not release additional capacity and will then be of lower value. Tariff related strategies should be designed to address the urgent imperatives of the short-term but then adjust to the changing economics over the longer-term.

Tariffs are a condition of licence in terms of section 14 of the Electricity Regulation Act. In terms of section 16(1) any affected party may apply to NERSA for a change in any licensee's licence conditions, with or without the licensee' s agreement.

4.4.1.5 Delay tariff rebalancing until load shedding is resolved

Under the Eskom wheeling tariff arrangements customers of wheeled power from embedded generators (say in the 100 MW or 1 MW market segments) still must pay all the fixed charges associated with their grid connection – it is just the metered energy part of the Eskom or municipal supply that will be replaced by the energy generated by their embedded generator. Customers contemplating investments in *onsite* grid connected embedded generation are essentially in the same position. Customers that invest in more energy efficient equipment will also only save on the energy component of their tariff.

When it comes to the question of whether embedded generation projects will be viable and can be financed, much will rest on the Eskom or municipal energy charge that they will displace. Eskom's current argument is that the energy charge includes the cost of the back-up generation capacity ("energy capacity") that it provides and that Eskom is unfairly losing out if their energy charge is displaced by that of an embedded generator. Eskom has therefore concluded that the Megaflex, wheeling and other tariffs should be rebalanced to shift the "back-up generation cost recovery" onto the fixed charges thereby reducing the energy charge. This will reduce the saving that can be realised by a customer from an embedded generation investment. Eskom's tariff restructuring application is currently before NERSA.

While this economic reasoning might sound intuitively appealing under normal circumstances, it is flawed under conditions of power shortages and load shedding for the following reasons:

- Eskom is currently unable to provide generation backup. As demonstrated in the Part A report, Eskom is not able to provide backup generation under the current circumstances – it often must institute load shedding.
- Currently, any additional energy converts into additional backup generation capacity. As we further demonstrate in the same report, the severe energy shortage

[44] *Section 15(1)(c) of the Electricity Regulation Act puts this succinctly: "[approved] prices, charges and tariffs… must give end users proper information regarding the costs that their consumption imposes on the licensee's business"*

on the system has the effect that when they must be used to avoid load shedding the OCGT peakers or the pumped storage assets are not available because they have run out of diesel or sufficiently stored pumped water. Typically, the peakers are utilised around the clock – not just at peak hours. This means that additional energy provided at any time of day will displace diesel burn, reduce pumped storage discharging – including the efficiency losses – thereby enabling these important peaking generation capacity resources to be more available for other periods when they are still required. Thus, due to the leveraged recovery that results from adding any additional energy to the system (the virtuous cycle), additional energy also brings capacity benefits by reducing diesel burn and pump-storage discharging. This enables these generators to provide backup generation capacity when it is still needed (which will now be much less frequently).[45]

A figure of up to 20% reduction of energy charges has been mentioned, which will drastically reduce the incentive to invest in embedded generation – especially for PV projects. For as long as load shedding or the risk of load shedding continues it will be counterproductive to rebalance variable energy towards fixed capacity charges as it does not reflect the current economic reality (opportunity cost) on the system and will make it harder to get distributed generation projects to cross the financing hurdle, resulting in fewer generation projects being connected to the grid.

Eskom's application for numerous adjustments to its tariff structure was submitted to NERSA in August 2020, but the process has not yet been finalised. Eskom expects to implement the tariffs in 2023. Eskom and NERSA should be requested to delay the aspect of this application that relates to rebalancing "energy capacity" charges for the reasons set out above. NERSA should not allow Eskom and Metros to rebalance the active energy charges in their tariffs until such time as load shedding has been resolved and large customers have access to the, yet to be launched, multi-market mechanisms (in particular, the balancing market) that will provide for appropriate price discovery of back-up capacity.

4.4.1.6 Implement net-metered feed-in tariffs and auctions for incremental energy

The energy accounting rules relating to Eskom's and some municipal feed-in (FIT)[46] / net billing and wheeling tariffs are not designed appropriately for South Africa's electricity crisis. In essence the rules typically only allow a customer with a grid connected, behind the meter generator to net off their energy consumption to a neutral position, either over a calendar month, or over a year. The same rules apply for wheeling customers. They cannot be compensated for any additional energy provided to the grid. Energy tariff levels are also too low in some cases.

An important opportunity exists to rapidly mop up existing surplus energy available on the power system (or energy that could rapidly be made available) and to incentivise a wide range of projects currently in development to

[45] *The purpose of backup-generation capacity is similar to taking out insurance: it should be available but be used as little as possible. The cost of the "insurance" is the capital and fixed cost of maintaining the plan to ensure that it is available to generate if called upon. Over time, when the energy shortage on the system and load shedding has been resolved, it would make sense (all things being equal) to rebalance the fixed cost of efficiently procured back-up capacity onto fixed charges.*

[46] *In principle feed-in tariffs are not the most efficient way to procure energy, and South Africa rightly opted for a reverse auction design for its normal centralised IPP Office procurements. However, a standard FIT has the benefit of being a simple, fast and highly effective way of incentivising the provision of large volumes of distributed generation to the grid and is therefore an appropriate strategy for the current power crisis.*

increase their capacity to sell the excess power to the grid.[47]

An offering that pays up to the current value of new power on the grid, with a pathway that slopes down over time to follow Eskom's actual incremental cost of energy (including fixed and variable maintenance costs) will create the correct and powerful incentives to obtain surplus power currently available and increase the size of projects currently under development. This additional power will not need additional grid connections, environmental approvals, wheeling arrangements, registration or licencing - it would all have happened anyway or would already be in place. Some projects might need to amend regulatory approvals, but this will be a much faster process.

The recent experience of countries such as Vietnam[48], or even Australia[49], demonstrate that embedded generation incentivised by feed-in tariffs, if implemented rapidly, can potentially make a large and rapid contribution to resolving load shedding. This strategy is likely to also play an important role in the portfolio of levers that are required in South Africa to resolve load shedding urgently.

It appears that both Eskom and the municipalities that have implemented net-metered tariffs have been of the view that there are legal impediments to paying a customer for the net export of energy over a specified period. We are of the view that it is unlikely that any legal issues are insurmountable – especially in circumstances of a power emergency where it can be shown that the alternative to allowing net feed-in tariffs will simply be more or extend load shedding. Section 217 (1) of the Constitution, under the heading "Procurement", states that:

> *When an organ of state in the national, provincial or local sphere of government, or any other institution identified in national legislation, contracts for goods or services, it must do so in accordance with a system which is fair, equitable, transparent, competitive and cost-effective.*

Whether the procurement system is "competitive and cost-effective" is essentially an economic question that will not just depend on whether economic agents were competing on price to provide the services.[50] If transaction costs and real-world complexity of such a system will result in unaffordable delays in procuring economically and socially critical services the system will not be cost-effective (it might have realised a competitive cost, but by "missing the boat" will not deliver the required "effect" and will therefore not be cost-effective). The question will thus have to be answered in terms of whether the system will be able to acquire the necessary resources (incremental embedded generation in this case) cheaper than the alternatives available (i.e. more expensive coal or peaking power, taking into account potential greater grid losses, and assuming

[47] *A central question for the developers of every single embedded generation project relates to the optimal sizing of the plant. Due to the variability of renewable energy investors face a trade-off between building larger plant, thereby securing more electricity for more of the time (both within the diurnal cycle and over longer time periods), on the one hand, but then encountering periods (with high winds or solar insolation) when they are unable to utilise all the electricity, on the other hand. The more investors can benefit from the power they cannot themselves consume, the more they will be incentivised to increase the size of the projects (that are in any case being built) and deliver more benefits to the power system as a whole. In many cases existing projects also already have the ability to provide additional energy to the grid, or could rapidly do so with incremental generation capacity expansion while using existing grid connection capacity.*

[48] See: https://www.economist.com/asia/2022/06/02/vietnam-is-leading-the-transition-to-clean-energy-in-south-east-asia

[49] See the Rule determination by the Australian Energy Market Commission on 12 August (2021): Access, pricing and incentive arrangements for distributed energy resources,

[50] *The argument set out here is specific to the power shortage circumstances described here. We remain of the view that it is the economically and legally correct policy to procure power in terms of a system where suppliers compete on price.*

that other procurements are already "maxed out"); and whether it is more likely to acquire it in time compared to the alternative options – assuming there are any remaining. Any impediments in the normal procurement legislation (PFMA[51], MFMA[52], etc.) could most likely be dealt with by exemptions issued by the Minister of Finance.[53]

The purpose of net-metered feed-in tariffs as argued here is not for it to replace South Africa's other mechanisms for centralised power procurement, but rather to exploit opportunities to obtain additional energy: either from existing REIPPPP or RMIPPPP projects, or embedded generation installations that are built primarily for third party or "own use". We thus propose the following options for implementation:

1. For larger potential generators, run **quarterly auctions for surplus energy** in each of the three time-of-use tariff categories[54] with Eskom as the buyer. No government guarantees should be provided and there should be no obligation on the procurer to buy any power. The terms should be that of the normal Eskom net billing / wheeling tariff, but revised to allow for net positive exports and pricing determined in the auction. The term of the agreements should be at least 15 years, or what is offered in the auction, whichever is the lesser. Together these terms will make it unlikely that any new projects will be bid into this auction – it will only be viable for incremental energy from projects that are already near viable or already built.

   There should be no limits on projects that can participate. The actual volume of energy procured for each auction should depend on the volume bid, pricing and timing of supply. Further work will be required to ensure appropriate auction design. This no-regret approach and rapid repeats of the procurement process will enable subsequent rounds to benefit from learning and rapidly improve market credibility. By removing the need for government guarantees for this energy this process will let the market optimise how to diversify risk over individual PPA offtake customers and Eskom and could develop into a model for removing government guarantees on procured power.

   It should be possible to run the first round by October 2022.
2. Implement **net-metered feed-in tariffs** for Eskom and municipal customers by simply removing the rule that customers must be in a neutral position over a specified period (either a calendar month or a year). This will allow these customers to sell all surplus energy to their utility at the active energy charge applicable in each time of use period (if applicable). As explained above, over time, as load shedding is resolved the relevant energy charges for all tariffs (consumption and generation) must be rebalanced to continue providing the correct pricing signal for energy. This option could initially be an alternative to option 1 – it will be faster to implement – or only be made available to

[51] *Public Finance Management Act*

[52] *Municipal Finance Management Act*

[53] *Nothing in section 34 of the Electricity Regulation Act setting out the powers of the Minister to make determinations on the procurement of new generation capacity, or the Electricity Regulations on New Generation Capacity, appear to prohibit the implementation of net-metered feed-in tariffs by public entities such as Eskom on municipal distributors. Essentially the point is that the procurement of new generation capacity by a public entity does not require a "section 34" ministerial determination but can be required by such a determination.*

[54] *Peak, Standard, Off-Peak*

smaller generators / customers alongside option 1 being used for larger customers.[55]

This option can be submitted to NERSA in September 2022 for approval by the end of November 2022.

4.4.2 IMPLEMENT MORE POWERFUL TAX INCENTIVES FOR SMALLER SCALE PROJECTS.

From the analysis presented in Section 3.2 it is clear that rapid upscaling of investment in the 1 MW and 100 MW unlicenced market segment will be critical to deliver the desired growth in generation capacity to solve load shedding. Sections 12B and 12U of the Income Tax Act (58 of 1962) already provides for generous capital allowances ("tax write-offs") for renewable energy – especially for PV projects not exceeding 1 MW. Capital cost allowances are offset against taxable revenue and therefore provide a tax saving associated with the investment in the relevant asset. The capital allowances associated with renewable energy reduce the net effective cost of the projects and therefore the price or tariff at which the power must be sold to make the investment financially viable.[56] This in turn increases the likelihood that more projects will be built, faster.

While a feed-in tariff can go some way to incentivise smaller grid-connected projects, it will take time to nudge all South Africa's municipalities to implement appropriate tariffs. Projects also need to be able to export to the grid to benefit. A tax incentive provides a critical complementary intervention as it will benefit all distributed generation opportunities in the economy, including the many opportunities that are in local authority areas and might not benefit from adequate net metering tariffs soon – due to the delays experienced with implementing tariff reforms in municipal areas.

Given the large public benefits associated with the rapid connection of distributed generators, it might well make sense to revisit the existing tax incentive with the view to increase it. Given the economic emergency we are in and the broad benefits (including positive externalities) that embedded generation brings (less load shedding; investments; enterprise development; high labour intensity; energy decarbonisation - climate de-risking) it is likely that there is a strong case to drastically increase the tax incentive.

The system is already in place and it would be fast and efficient to implement any change to it. This could potentially be achieved by increasing the first year allowance to something between 200 - 300% of the cost for the smaller segment (below 1 MW) for the next 2 years, whereafter it can be scaled back again if load shedding is being resolved. The intervention is likely to fund itself in greater tax revenues in time. It is also a good candidate to benefit from the increase in tax revenues resulting from the commodities price increases. It would also be an ideal candidate to be supported by the $8.5 Bn concessional JETP funding - some of which is likely to come to Treasury for purposes such as this.

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[55] *A more limited alternative to feed-in tariffs (should it be legally difficult to implement) will be to change Eskom's wheeling and net metering rules to allow surplus energy in any time of use category to be accounted for in the other time of use categories, adjusted by the inverse ratio of the respective energy tariffs. In this way the energy accounting rules will be adjusted to maximise the energy that can be credited to the generator before it ends-up in a net positive position.*

[56] *For photovoltaic solar energy projects not exceeding 1 MW companies can deduct the full capital cost in the first year of expenditure. For other renewable energy projects (wind, solar, CSP, hydro and biomass) the capital allowance is spread over three years on a 50%/30%/20% basis. A good summary of the incentive is provided by Cliffe Dekker Hofmeyr, (2021): https://www.cliffedekkerhofmeyr.com/en/news/publications/2021/Tax/Tax-Alert-24-June-2021-Giving-the-green-light-opportunities-for-renewable-energy-capex-following-increased-embedded-electricity-generation-limit.html*

In order to provide National Treasury (NT) with a leading indicator of progress (and to know when to scale it down again) - if the NERSA registration process is not being resolved - NT can run a simple web-based pre-registration process as a requirement to claim the allowances later when the capital expenditure has been completed.

The idea would be that NT could announce the intervention in the October mid-term review and implement it in the Budget next year.

4.5 EXPAND REIPPPP BW6 AND LAUNCH IT IN TIME

As described in Section 3.2, REIPPPP BW6 provides a critical opportunity to increase the capacity of utility scale solar PV and wind plants that will come online before an increasing capacity of coal plant is retired from 2026 onwards. At the time of writing the bid submission date was 11 August 2022. Our Risk Adjusted Resource Plan recommends that solar PV capacity is increased from 1 GW to 3 GW and wind from 1.6 GW to 4 GW for BW6.

Currently project sizes are limited to 75 MW for solar PV projects and 140 MW for wind projects. As is evident from the sizing of the bids received for both the RMIPPPP and BW5 developers are generally able and incentivised to develop larger projects. Give the overwhelming response that are typically received for bid rounds there is ample space to more than double allowable project sizes to benefit from greater economies of scale and faster generation expansion.[57]

We further propose that substantial financial incentives are provided to encourage earlier commissioning. This could be implemented as an enhanced version of the "early energy" rates that have been offered in previous bid rounds. In our modelling we assume that this approach will expedite 1 GW of the solar PV and 500 MW of wind capacity.

The expansion of BW6 in line with capacity additions necessary for the Risk Adjusted Plan will require an additional section 34(1) determination for new generation capacity by the Minister of Mineral Resources and Energy For more detail on what this may entail, see section 4.11.

It might be prudent to delay the bid closure date by a few weeks after announcing the increase in allowable project size. The increase in the total procurement size can be announced after bid submission and the finalisation of the updated ministerial determination – which can run in parallel with the bidding process.

4.6 EXPEDITE THERMAL PEAKING CAPACITY, DEMAND RESPONSE AND STORAGE PROCUREMENT

The Risk Adjusted Resource Plan requires a significant amount of addition dispatchable peaking and storage resources. This includes the need to procure a total additional 1 491 MW[58] of dispatchable thermal peaking plant to be online by 2024 and to significantly increase the overall diesel storage capacity across the peaking sites to 100 Ml to avoid fuel tanks running dry as they currently do.

Given the scarce transmission capacity in other areas, the thermal peakers (ICEs or OCGTs) should probably be located in KwaZulu-Natal. This capacity can potentially

[57] *These proposals need to be seen in the context of the fact that – after catching up – South Africa needs to be building between 5 – 9 GW of renewables a year (depending to what extent the country pursues green hydrogen opportunities) until such time as we achieve a non-emitting power system.*

[58] *This includes the 153 MW currently expected from the RMIPPP renewables projects – see Table 9 above.*

be spread between Richards' Bay and a site on or close to the refineries in Durban / eThekwini where there is existing fuel import, storage and grid capacity. Given the need for rapid capacity expansion and a premium on fast response generators consideration should be given to the use of ICEs which have the benefit of modular expansion and faster start-up times (approximately two minutes to full load), and equal or better fuel efficiency than OCGTs.

During the second half of 2024, when Koeberg Unit 1 will be out for refuelling greater use will have to be made of the thermal peakers. Eskom will have to plan to put in place improved logistical arrangements to enable the adequate resupply of the peakers to avoid them running out of fuel during this period. Consideration should also be given to the cash flow requirements to pay for this short-term increase in fuel demand.

There are likely to be opportunities beyond road transport and local storage to improve the logistics of fuel supply to Ankerlig – the largest OCGT in the country. The crude oil petroleum pipeline between the Saldanha SFF storage facility and the Astron refinery in Cape Town runs right past Ankerlig[59] Astron is also connected by pipeline to the Burgan Cape Terminals fuel loading and storage facility in the Cape Town harbour. It is potentially possible to rapidly connect Ankerlig[60] to import terminals at the ports and the Burgan, Astron, and even the 7 billion litre SFF storage facility in Saldanha[61]

The Risk Adjusted Resource Plan also requires an additional 1 500 MW of demand response resources to be available to the system operator by the beginning of 2024. Essentially demand response means this means that customers are contracted to reduce their demand on instruction by the System Operator. We estimate that there is likely to be more than enough capacity available in South Africa provide this amount, but that it will be a substantial challenge to procure and set it up in time.

We foresee that, depending on the exact requirements, demand resources can be procured for the following categories as provided for by the South African Grid code:

- 10 Minute Reserves
- Supplemental Reserve
- Emergency Reserve.

Given the energy intensity of the South African economy, and the years of load shedding that has prepared customers to implement load reductions[62] we expect there to be a ready market for demand response providers with much "low handing fruit". Demand response will not be required for many hours per year. Customers will be able to implement it by turning off non-essential processes, delaying production, or running their diesel back-up generators, etc.

We foresee that the fastest way to procure this will be for the System Operator to go out on an emergency competitive tender to procure the services from at least two large providers for a number of years, with the option of providing the services into the capacity or balancing market when established. Demand response services can become available to the System Operator on an incremental basis from mid-

[59] *It is possible to transport diesel in a crude oil pipeline – Transnet has regularly done this in their crude oil pipeline between Durban and Sasolburg when required.*

[60] *The question of whether it is economically viable or possible to use LNG (natural gas) to fire Ankerlig is discussed in a separate Meridian paper. See Meridian Economics (forthcoming) report on the role of gas in the South African power sector.*

[61] *A part of the SFF crude storage facility will have to be converted to store diesel.*

[62] *Large customers are not subjected to load shedding, but are requested to implement load reductions during periods of load shedding.*

2023 with the full capacity available by January 2024.

The Risk Adjusted Resource Plan also assumes that the 640 MW of 4hr batteries constructed for the RMIPPPP will be made available for dispatch by the System Operator (i.e. that the RMIPPPP dispatch requirements will be removed – see section 4.24.2 above). It further requires that the intended IPP Office battery procurement plans be extended from 513 MW to a 1 000 MW for commissioning by 2024. The value of the batteries for the system can be further enhanced by locating them behind transmission constraints close to points where renewable energy is generated in order to increase the renewable energy that can be evacuated.

Given the central role that all these system resources play in maintaining grid stability it will be preferable that they are either procured by the System Operator on in close collaboration with it.

4.7 IMPLEMENT ESKOM JET RENEWABLE ENERGY PPP PROJECTS

Eskom is pursuing several Public Private Partnership (PPP) power procurement projects at its older power stations where there is ample grid capacity available as part of its Just Energy Transition (JET) initiative. This can be a valuable addition to the generation capacity required. Given the poorer solar resource in these areas it is critical that projects be procured on a competitive basis to keep costs down. If the electricity from these projects can be wheeled over the grid and sold directly to a portfolio of end-customers the need for further (highly limited) government guarantees can be avoided for these projects. It appears that Eskom does not need section 34 ministerial determinations for these projects.

4.8 CONFIRM THAT MUNICIPALITIES DO NOT NEED MINISTERIAL PERMISSION TO PROCURE ELECTRICITY

There appears to be no impediment in current legislation prohibiting municipalities procuring electricity from an independent power producer (IPP) in terms of a PPA. The normal procurement legislation will apply.

On 16 October 2020, the Minister of Mineral Resources and Energy issued an amendment to the Electricity Regulations on New Generation Capacity[63]. This amendment provides for municipalities to buy or procure "new generation capacity" – which appears to apply to circumstances where municipalities want to procure the assets. DMRE and the Minister of Mineral Resources and Energy appear to be of the view that Regulation 5 of the New Generation Capacity Regulations oblige municipalities to obtain Ministerial approval for any additional capacity (or electricity by means of a PPA) they intend to buy or procure and to demonstrate that it is 'in accordance with the Integrated Resource Plan' – regardless of the size of the project. Municipalities have raised concerns that such an obligation – if it does indeed exist (currently the single biggest legal obstacle to their procurement of additional capacity) affects them unfairly compared to other market players.

Rather than wait years for this matter to be resolved by litigation it would be much more effective if the minister could either withdraw the amendment to section 5 of the New

[63] *DMRE, 2020a. Electricity Regulation Act, 2006: Amendment of Electricity Regulations on New Generation Capacity, 2011. Available:* https://www.gov.za/sites/default/files/gcis_document/202010/43810gon1093.pdf

Generation Capacity Regulations that has created the problem or confirm in a statement that his view is that ministerial permission is not required (and withdraw from any litigation on this matter).

4.9 BOLSTER THE ESKOM GRID CONNECTION PROCESS

At the time of writing project developers are experiencing significant delays in obtaining Cost Estimate letters and Budget Quotes from Eskom for the provision of grid connections for generation projects. This has in turn contributed to delays in the IPP Office procurement rounds and the development of projects in the sub 100 MW market. We understand that these challenges are receiving attention from Eskom.

As a public entity it is important that Eskom is required to provide full transparency on the number of applications received and the time they are taking to process and that any further steps are being taken as necessary to expedite this process. Grid capacity that is reserved for RMIPPPP projects that are based on gas generation in the Western Cape (Karpowership SA Saldhana) and the Eastern Cape (Karpowership SA Coega and Mulilo Total Coega) should be released for renewable energy generation if these projects are unable to reach financial close.

The Eskom TDP is based on the growth of generation planned in the IRP2019, which is insufficient to avoid load shedding in most plausible scenarios. Therefore, the TDP should be updated with increased generation capacities connection requirements. Grid strengthening in the Northern, Western and Eastern Cape is critical to allow for more renewable projects in high wind and solar resources regions.

4.10 FIX AND ESTABLISH KEY INSTITUTIONS

Ultimately South Africa's power crisis is self-inflicted – the result of institutional and policy failure. Putting in place a game plan to resolve it, even over the short-term, will require key institutional challenges to be addressed. A detailed analysis of many institutional and regulatory challenges in the power sector is beyond the scope of this report. We briefly highlight key areas that will require urgent attention to deliver a viable game plan to sustainably resolve load shedding.

4.10.1 FIX THE IPP OFFICE

Objectively it is clear that the IPP Office has suffered a large loss of skills and capacity both in terms of permanent employees and the world-class advisors that it could rely on. The effects of this are clear from the ongoing and multiple delays now experienced in its procurement programmes and its struggles to put together a viable RMIPPPP. These delays will have the effect of extending load shedding. While critically important, a detailed analysis of the causes behind the problems is beyond the scope of this study. Suffice it to say that factors such as its funding, governance (the role of the DBSA[64] and the close political control by the DMRE), etc. should receive attention.

Numerous elements of the game plan proposed here will require support and execution by the IPP Office. In order to do this, it will have to rapidly retain critical advisory capacity to bolster its capacity. Steps are also required to ensure that it has the budget available and that any additional procurement

[64] *Development Bank of Southern Africa*

processes required can be expedited without any political interference.

4.10.2 FIX NERSA PERFORMANCE AND PRACTICES

It is of great concern that the entity that should be leading the charge to resolve load shedding and achieve the objects of the Electricity Regulation Act, has at times been more of an a hinderance to solving, than a solution to South Africa's power crisis. For instance, it has taken immense pressure from stakeholders and the Presidency to persuade NERSA to remove the need to present a signed PPA to register projects. For those projects that require it the procedures to apply for a licence are often prohibitively cumbersome.

A longer-term solution will have to consider factors such as: the need for an appeals mechanism; resolving the conflict of interest inherent in requiring it to report to the policy Ministry; removing the political influence over the appointment process for regulators by providing a more transparent and objective mechanism; commissioning an independent empirical study comparing the skills available in the regulator to those that it requires, etc.

On the short-term NERSA should be required to provide much greater and up to date transparency on its performance. It should report regularly on how it has improved the registration and licencing processes, and details about how the processing of applications for both is proceeding. In general NERSA should also be asked to demonstrate the measures it is taking so support the achievement of Risk Adjusted Resource Plan to end load shedding.

4.10.3 ESTABLISH THE DAY AHEAD AND BALANCING MARKET.

The establishment of the multi-market mechanisms as envisaged in the Electricity Regulation Amendment Bill (published on 10 February 2022) will be an important mechanism to further diversify risk exposure of power system investments and allow surplus power to be sold. The market mechanisms can be introduced in stages as Eskom already has the infrastructure set up internally. With Eskom's own power stations bidding into the market, it can be opened up in stages to external participants – even before the legislative measures are finalised.

4.11 EXPEDITE ADDITIONAL SCHEDULE 2 AMENDMENTS AND MINISTERIAL DETERMINATIONS

The suite of interventions outlined in this report will necessarily require some key amendments to the existing regulations as well as Ministerial responsibilities to issue announcements and determinations with haste. These include:

Amendments to Schedule 2 of the ERA

- Exempt all storage facilities from licensing – storage facilities should be added to the list of licence-exempt plant categories if it is not already exempt (i.e. it is not a "generator").
- Specify in Schedule 2 that traders are only required to be registered with NERSA – not licenced.
- Extend the current licence-exemption threshold for grid-connected projects from 100 MW to 1 000 MW.

Ministerial announcements / determinations

- Immediately issue another Ministerial Determination for the procurement of capacity at least in line with that required by the Risk Adjusted Resource Plan, but preferably for the remainder of the capacity contained in Table 5 of the IRP.

The current Ministerial determination[65] for new generation capacity calls for 6 800 MW of renewable energy capacity to be procured up to 2024 – this is the determination under which Rounds 5 and 6 of the REIPPPP have been issued. The additional capacity under an expanded BW6 plus what we assume will realistically be able to come online from BW5 will total around 9 055 MW of new capacity. This means that an additional Ministerial determination for *at least* 2 255 MW of renewable energy will be required for the Risk Adjusted Resource Plan (6 800 MW + 2 225 MW = 9 055 MW). Given the urgency of resolving the current power crisis, and the fact that additional determinations will need to be made in line with the prevailing IRP in future anyway – an efficient strategy may be to make a determination for all of the remaining capacity allocated to renewable energy in the IRP to 2030 up front, a total of 13 600 MW[66].

- The Minister should either withdraw the amendment to Regulation 5 of the Electricity Regulations on New Generation Capacity which has created confusion around whether municipalities are required to gain Ministerial approval to buy or procure new capacity – or should confirm in a statement that Ministerial approval is not required.

If, in order to implement the above set of regulatory amendments and determinations swiftly, it is necessary to pass an Emergency Bill, this should be done. It will be important to clarify exactly what will be in included in the Bill to ensure the desired outcome of rapid implementation across the relevant regulatory processes – expert legal advice will need to be sought in the drafting of such a Bill.

4.12 ESTABLISH A DEDICATED WELL-RESOURCED POWER CRISIS IMPLEMENTATION UNIT INSIDE THE PRESIDENCY

As can be seen from the recommendations above, the responsibility for implementing the required measures are spread between different public sector players (DMRE, NERSA, DPE[67], Eskom DTIC, National Treasury, DFFE, etc) – it does not just lie with Eskom – especially once the limits to what can be achieved with the coal plant are understood. This creates too many opportunities for bureaucrats and politicians to pass the buck when questions are asked about the impact of their actions (or lack of actions). Players that have "line responsibility" for delivering measures to resolve load shedding have strong incentives to underreport the extent to which they are not achieving their objectives. In recent years this situation has caused an information asymmetry problem whereby the full extent of the problem (delays with implementing measures to resolve load shedding) and its implications was not being recognised in time by policy makers and stakeholders.

It will therefore be critical that a single neutral overarching entity in government takes the lead in setting out the elements of the game plan that must be implemented, and in driving its implementation as proposed above. The natural place for this role is in the Presidency.

[65] *DMRE, 2020b. Determination under Section 34(1) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006). 25 September 2020. Available: https://www.gov.za/sites/default/files/gcis_document/202009/43734gon1015s.pdf*

[66] *The IRP2019 allocates a total of 6 000 MW of solar PV and 14 400 MW of wind up to 2030. 6 800 MW has already been determined for and therefore is available for procurement, meaning that there is a remaining 13 600 MW which needs to be determined for before procurement processes can commence.*

[67] *Department of Public Enterprises*

Successful execution of this role will require a full-time dedicated team with some of the best technical, financial and legal skills available to South Africa to design and drive this process in consultation with key stakeholders. It will probably have to consist of senior public sector officials and private sector experts. A substantial budget will have to be made available on an emergency basis.

5 CONCLUSIONS

This study demonstrated the large resource expansion that will be required to resolve load shedding expeditiously. We have developed a Risk Adjusted Resource Plan that contains a reasonable amount of redundancy to allow for the fact that not all aspects of the plan will necessarily be delivered on time. We advocate for the adoption of a different strategy to that used on the past which relied on "silver bullets" in the form of mega projects. This approach puts all the "eggs in one basket" with too much reliance on a single point of failure (a single utility, a single procurement process, a single set of infrastructure, etc.). A better alternative is to devise a strategy that mobilises the wide diversity of human, institutional, market, capital, natural, grid and other resources available to South Africa to solve the problem. With this approach it does not matter if some aspects fail –in totality it will succeed because thousands of actors will be working to achieve a common objective. The proposed game plan sets out a wide-ranging suite of reforms and other interventions that will be required to achieve this outcome rapidly.

Several of these interventions might appear to be objectionable to some – such as increasing prices across the board for an IPP Office bid round. However, when considering these proposals, it is critical to consider the correct counterfactual: more and longer load shedding including its economic and social consequences. While on closer inspection some of these proposals might turn out not to be viable, due to practical or legal considerations, should they be discarded, other measures with the equivalent impact on resolving load shedding rapidly will have to be put in their place – there is no "free lunch".

These proposals are focused on resolving load shedding in the short-term. While beyond the scope of this study, large scale expansion of the transmission and distribution grid capacity to ensure that low-cost generation capacity can continue being connected to grid in the medium term, and customers be supplied reliably, remains a critical objective.

Implementing these reforms will require political will at a scale that has not yet been demonstrated in dealing with South Africa's power crisis. In considering the options open to South Africa we have arrived at the conclusion that no other strategy is likely to have a better chance of resolving load shedding faster and with less unintended consequences than one based on the approach adopted here.

6 REFERENCE LIST

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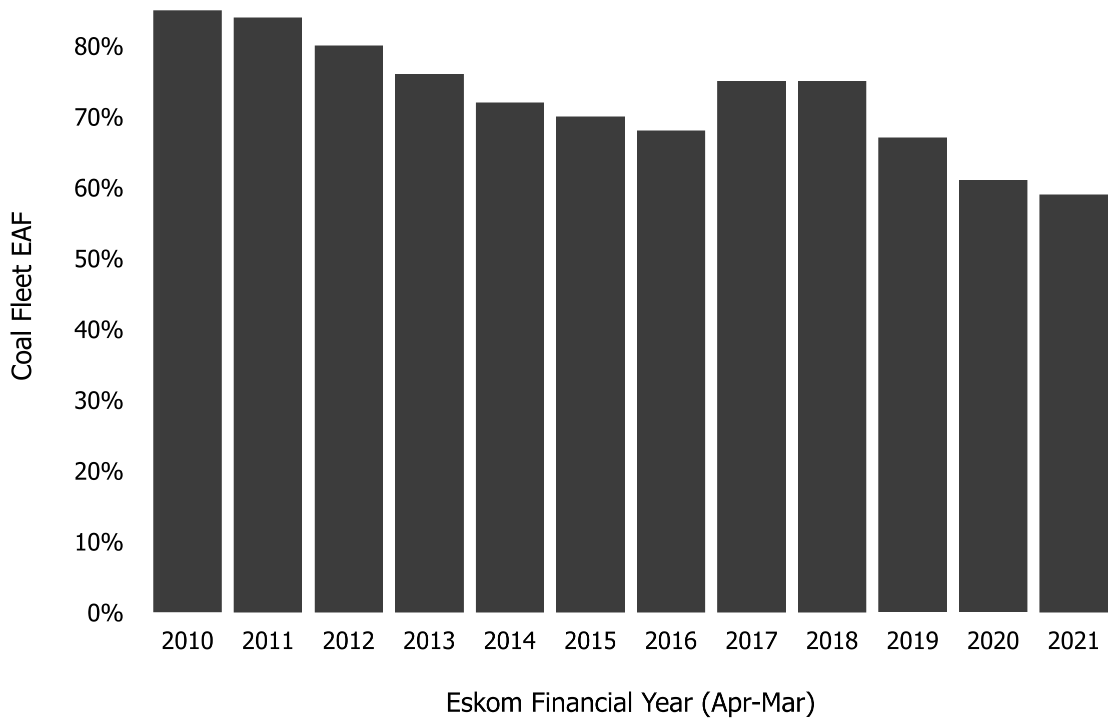
APPENDIX 1: ASSUMPTIONS AND METHODOLOGY

Here we present our modelling approach, including the main assumptions that were implemented in terms of the projected coal fleet EAF and demand profiles, as well as the availability of Koeberg due to extended outages for the replacement of the steam generators. We then explain the approach adopted for the system dispatch modelling.

6.1 COAL FLEET EAF PROFILE

Eskom currently reports on the hourly planned and unplanned outages related to its entire generation fleet, including coal, nuclear, and peaking stations. Due to the high availability of peaking plants, the coal fleet EAF (coal EAF) is generally lower than the overall fleet EAF. Unfortunately, the Eskom data portal does not currently provide outage data for the coal fleet in isolation. However, Eskom does provide annual averages of coal EAF for each financial year (April-March). Figure 6 shows the continued decline in coal EAF over the past decade, decreasing from 85% in FY2010 to below 60% in FY2021.

Figure 6: Average annual coal EAF according to Eskom Financial years



The average EAF masks the intra-day and seasonal variations in coal EAF. Therefore, in this work the historical hourly coal EAF was calculated from the overall Eskom EAF by estimating and removing the outages for non-coal generators. A comparison between the overall EAF and the calculated coal EAF is presented in Figure 7 for 2021. To verify the accuracy of this calculated coal EAF profile, the annual average was compared to the data provide by Eskom in their System Status and Outlook Briefing presentation for FY2019 to FY2022. As shown in Table 10, there is good agreement between the current approach and the Eskom data.

Figure 7: Comparison between the Eskom total fleet EAF and the calculated coal EAF

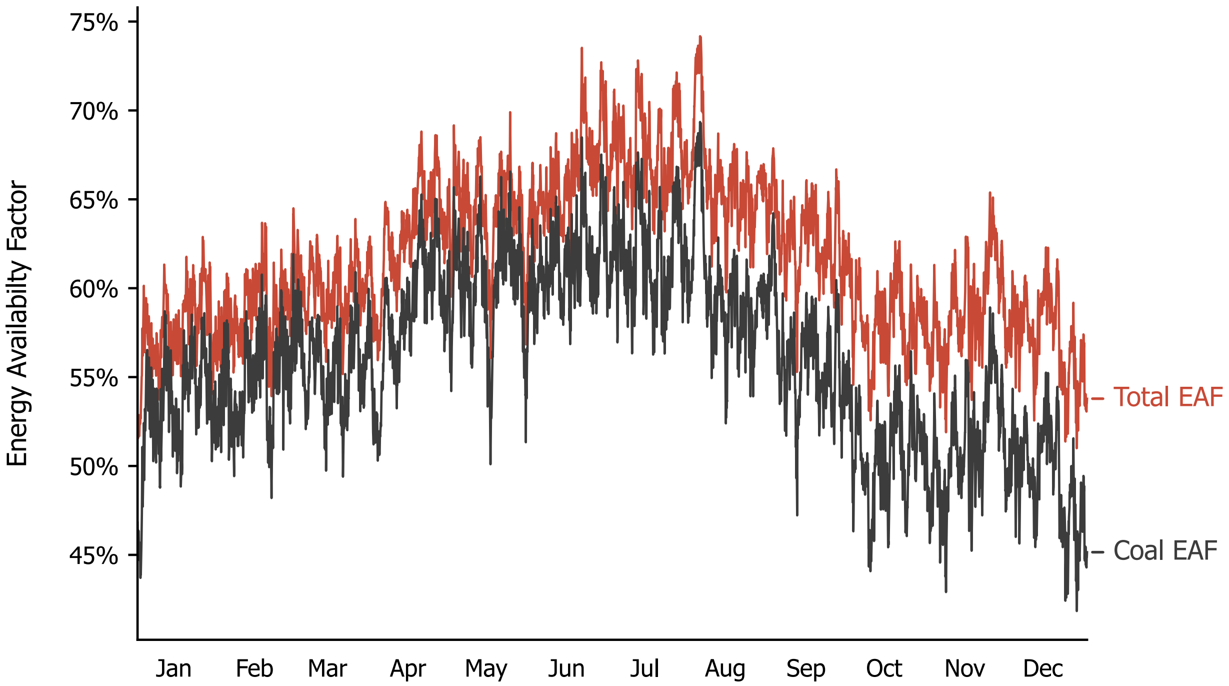
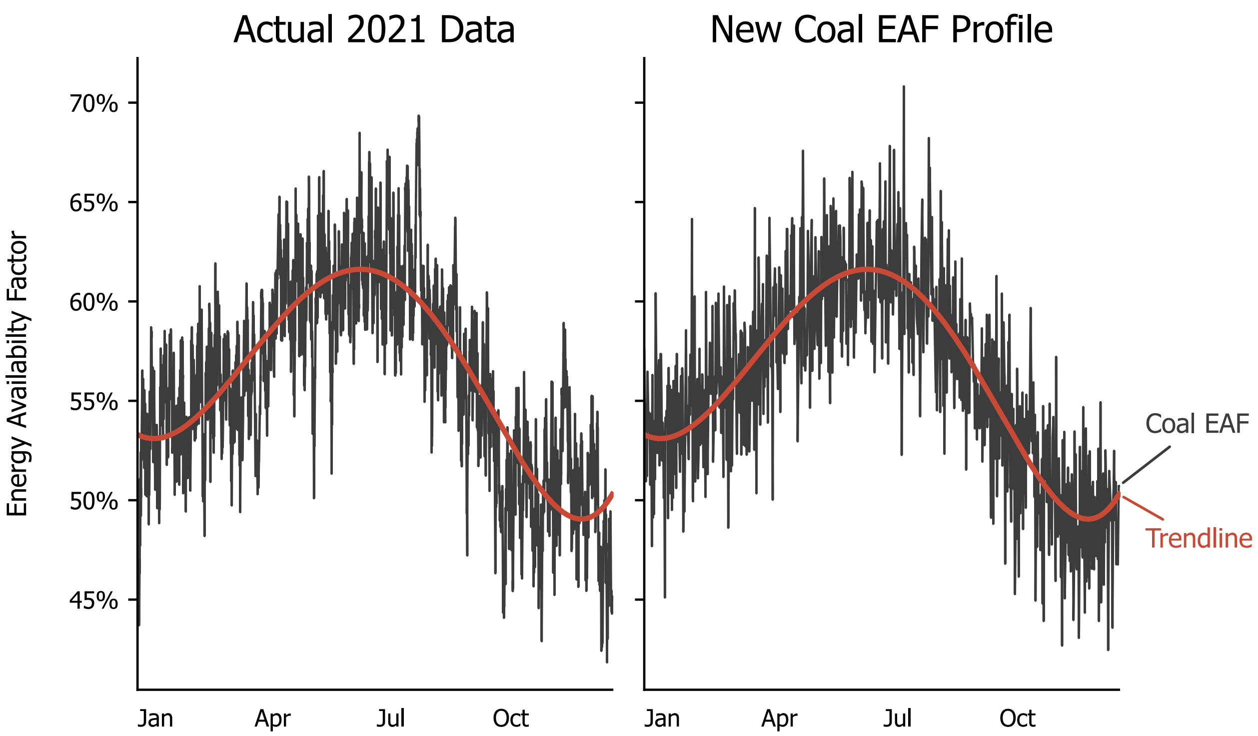


Table 10: Comparison of calculated annual average coal EAF to Eskom actual data

Eskom Financial Year	Eskom coal EAF	Calculated coal EAF
FY2019	67%	66.6%
FY2020	61%	62.1%
FY2021	59%	59.8%
FY2022 (up to Nov 2021)	60%	59.2%

Two approaches were followed in projecting the coal EAF into future years between 2023 and 2026. In the first approach the calculated coal EAF profile from 2021 was assumed for future years, but it was scaled by the projected annual EAF trend (either flat or decreasing). Part of the risk of using both the 2021 hourly demand profile and coal EAF profile, is the potential for coincidental events such as a surge demand coupled with a sudden EAF drop that will be propagated into future years. Therefore, a second coal EAF profile was created based on statistically representative variations around the trendline coal EAF profile from 2021. This allows a decoupling of the exact 2021 coal EAF and load profiles, whilst keeping the EAF variations within the same standard deviation as the original data.

Figure 8: Comparison of the two approaches utilised to develop the coal EAF profile



6.2 ANNUAL AVERAGE COAL EAF

The calculated coal EAF in calendar years is presented in Figure 9 below. Projections based on historical data indicate that the annual average coal EAF is tracking to drop below 50% before 2026. This is particularly catastrophic when viewed through the lens of current energy planning policy (IRP2019), which assumed that the coal EAF would have already recovered to above 70% by now. IRP2019 also plans for the addition of 750 MW of coal capacity in 2023 and 2027, which are unlikely to reach financial close. Therefore, despite new capacity coming online over the next 2-3 years, the capacity gap will continue to widen, unless urgent action is taken. In terms of annual coal EAF projections a total of 3 profiles are included in this work, ranging from a 0%-2% per year decreases. The slight increase in coal EAF in 2025 is incorporated to represent the return to service of Medupi Unit 4.

6.3 DEMAND PROFILE

The hourly demand profile for this work is based on the RSA Contracted Demand[68] data from Eskom for 2021. This data was then scaled for future years, according to the trajectories presented in Figure 9. A total of 3 different demand trajectories from 2021-2026 were considered, which included (1) a no growth trajectory, (2) a +1% per year growth from the end of 2021, and (3) flat demand growth in 2022, followed by a -1% per year reduction in demand up to 2026.

[68] *RSA contracted demand excludes the pumping energy required for the pumped hydro storage systems, as well as energy losses associated with synchronous condenser operation (friction losses). Therefore, the sum of total energy production will always exceed demand.*

Figure 9: Historical data and projected annual average coal EAF for different scenarios up to 2026 (calendar labels represent year-end)

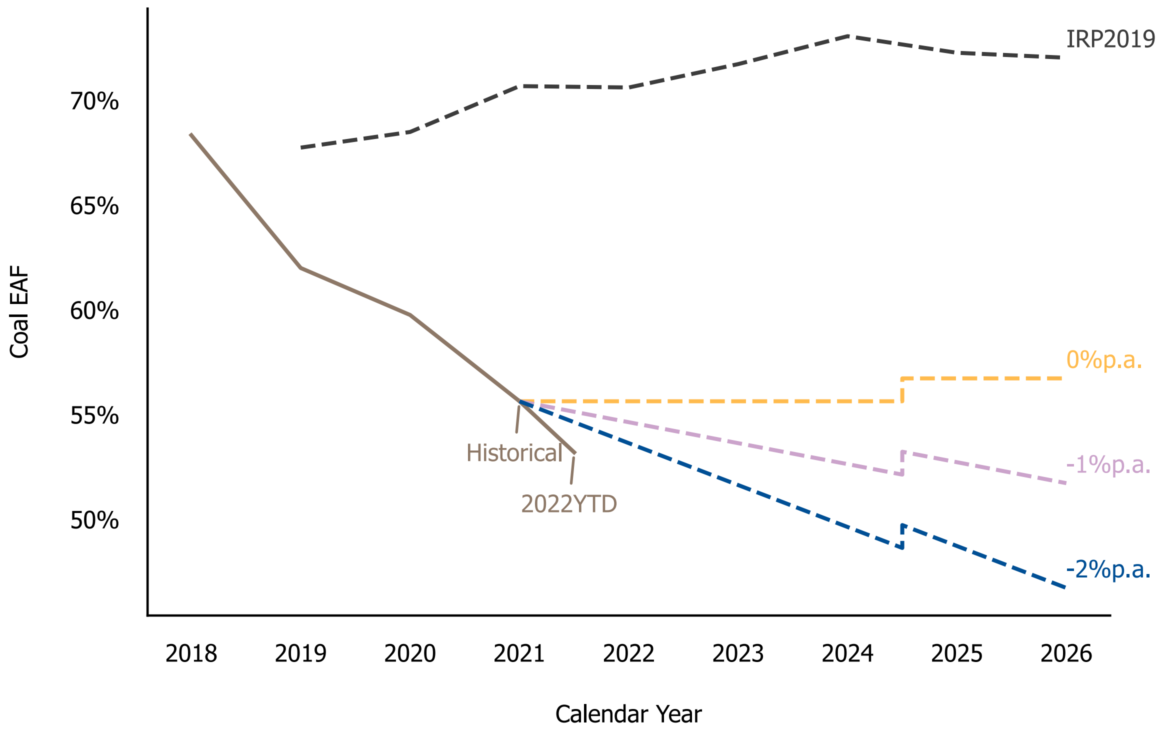
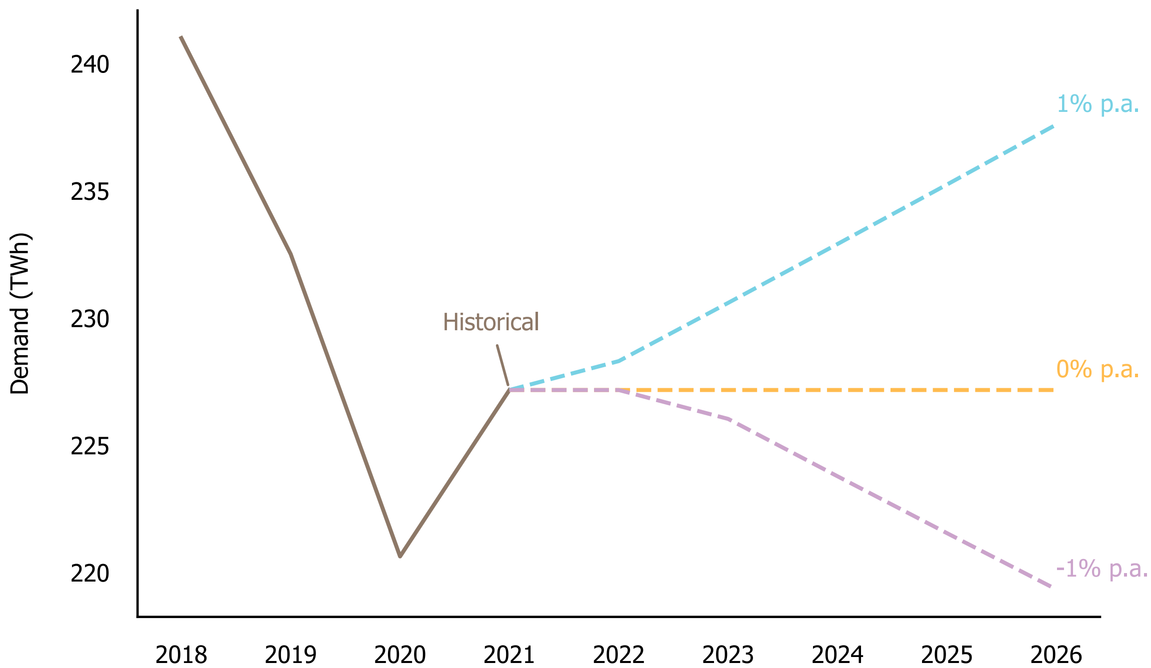


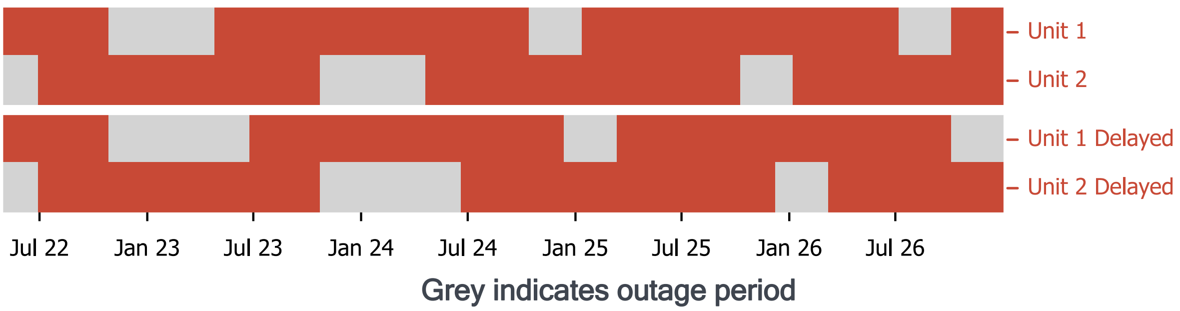
Figure 10: Historical data and projected annual demand for different scenarios up to 2026



6.4 KOEBERG AVAILABILITY

As part of a scheduled maintenance and plant modernisation programme at the Koeberg Nuclear Power Station, both units will experience prolonged outages of 155 days in order to complete their routine refuelling outage as well as to complete the replacement of each unit's three steam generators. The steam generator replacement for Unit 2 was initially set to commence in January 2022 along with the routine maintenance, however the project has been delayed and rescheduled for the end of 2023. Unit 2 is currently completing its routine 18-month refuelling outage, which is set to be completed by the end of July 2022. Unit 1 will commence its refuelling outage and steam generator replacement as per originally scheduled from October 2022. Figure 11Figure 11 illustrates the scheduled outage assumptions used in the modelling, including a scenario in which the outages are delayed for a further two months.

Figure 11: Scheduled outages for Koeberg Unit 1 and Unit 2 assumed in the modelling



6.5 SYSTEM DISPATCH MODELLING

We used dedicated system dispatch modelling software[69] to determine if the installed capacity of generation and storage in a scenario is sufficient to meet demand projections. For each scenario, the system dispatch model runs a chronological simulation through every hour of the 8760 hours per year for every year of the period from 2022 to 2026. The simulation replicates how a system operator would dispatch the various resources at their disposal in order to maintain a secure supply of power in each hour or minimise the incidence of load shedding if there are insufficient resources available. Having carefully calibrated this model to actual operational data from Eskom for 2021, it provides a good representation of how Eskom is likely to operate the power system in the future under the different scenarios investigated.

We set the detail of the system model at the same level that Eskom has adopted in the publication of hourly system data – i.e. different technology types are treated as aggregate generation sources. For example, coal is not modelled at the level of each individual unit or station but is modelled as the total capacity of coal with appropriate adjustment for how much of the capacity is available based on the EAF modelling. Likewise, all solar PV facilities are modelled as a single generator, similarly for wind and other technologies.

A diagram of the dispatch model showing storage and generators is presented in Figure 12, with example dispatch profiles shown in

[69] *We are using the PyPSA platform (https://pypsa.org/)*

Figure 13 and Figure 14. Modelling is based on a single node for the supply/demand energy balance, and therefore non-linear power flow through the transmission and distribution network is not considered – i.e. we did not explicitly model the grid constraints relying on Eskom's GCCA publication to test scenarios for grid compatibility. Because individual plants within a technology type are modelled as an aggregated generator, a full unit commitment is not currently included in the modelling. The modelling of system dispatch is done on an hourly basis and takes account of the relevant real-world constraints on operation of the different technology types:

- Ramping constraints are applied to the overall coal fleet (limited to below 2.5 GW/h*) based on what was achievable in 2021. As is well known, the ramping ability of the coal is severely compromised at present due to the state of many of the units and is a fraction of the typical 30% per hour nameplate ability.
- Pumped hydro storage charge and discharge rates are constrained to those achieved in the 2021 data. The three pumped storage reservoirs are modelled as a single storage unit that is constrained to never drop below 50% of total storage dam levels in any hour of the simulation[70].
- The diesel availability required to run the OCGTs is based on a model of aggregated available storage at the four OCGT sites and allows for the replenishment of diesel at an appropriate hourly rate, much slower than the rate at which diesel is burned under full load conditions. An average diesel refill rate of 127 kl/h is used in the modelling, which was determined by considering the actual 2021 OCGT operational data and calibrating the refill rate until the capacity factor of the OCGT plants matched. In the Solution Case, the diesel refill rate in Q4 of 2024 is increased to 250 kl/h, to allow a higher capacity factor on the OCGTs when a unit from Koeberg is out for refuelling.
- Reserve constraints are included in the model to capture the capacity that Eskom must allocate towards providing instantaneous, regulating and 10-minute reserves. Reserve requirements that are included in the model consist of 1 GW for fast acting reserves (typically battery and pumped hydro storage) and 2.2 GW for total reserves (typically battery, pumped hydro storage, and peaking).
- The installed capacity of each generator is updated semi-annually to capture addition of capacity across each year.
- Unserved energy is calculated in the model when generation is insufficient to meet demand.

[70] *The three pumped hydro storage schemes in South Africa have a combined energy storage capacity in the order of 57 GWh. However, these assets are not currently utilised to their full potential, as often generating capacity must be kept in reserve to provide a fast response to frequency drops. Battery energy storage with a 1C rating (1h storage) is ideally positioned to provide fast acting reserves and therefore allow for better utilisation of the pumped hydro storage.*

Figure 12: Diagram of dispatch model

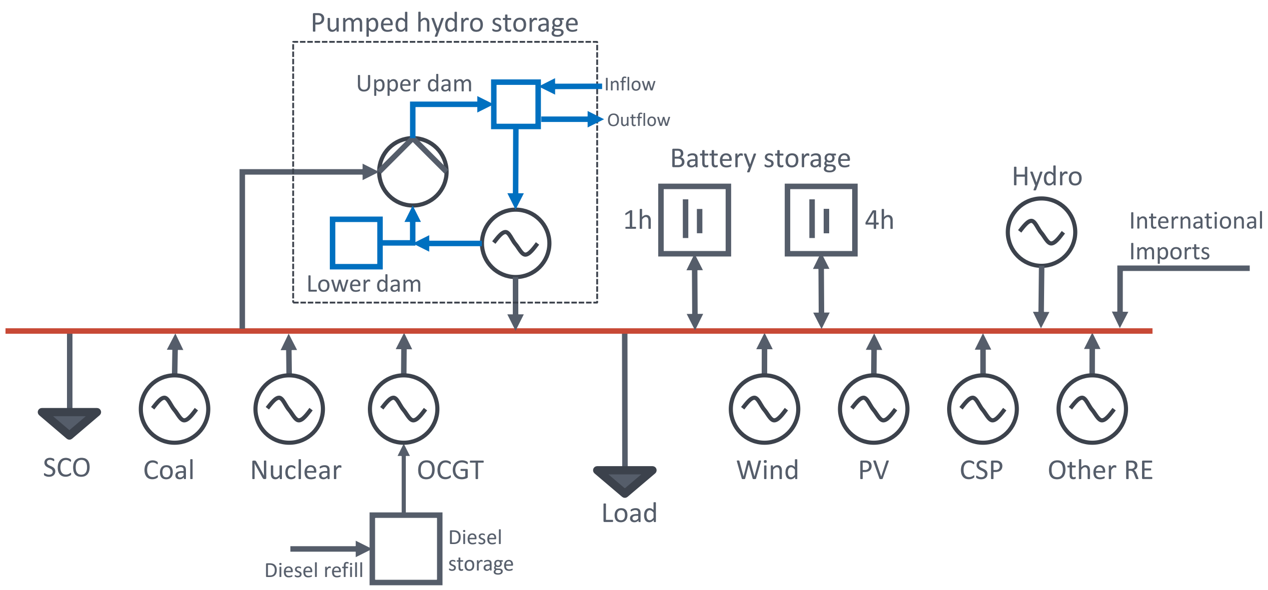


Figure 13: Example dispatch for the Base Case (October 2025)

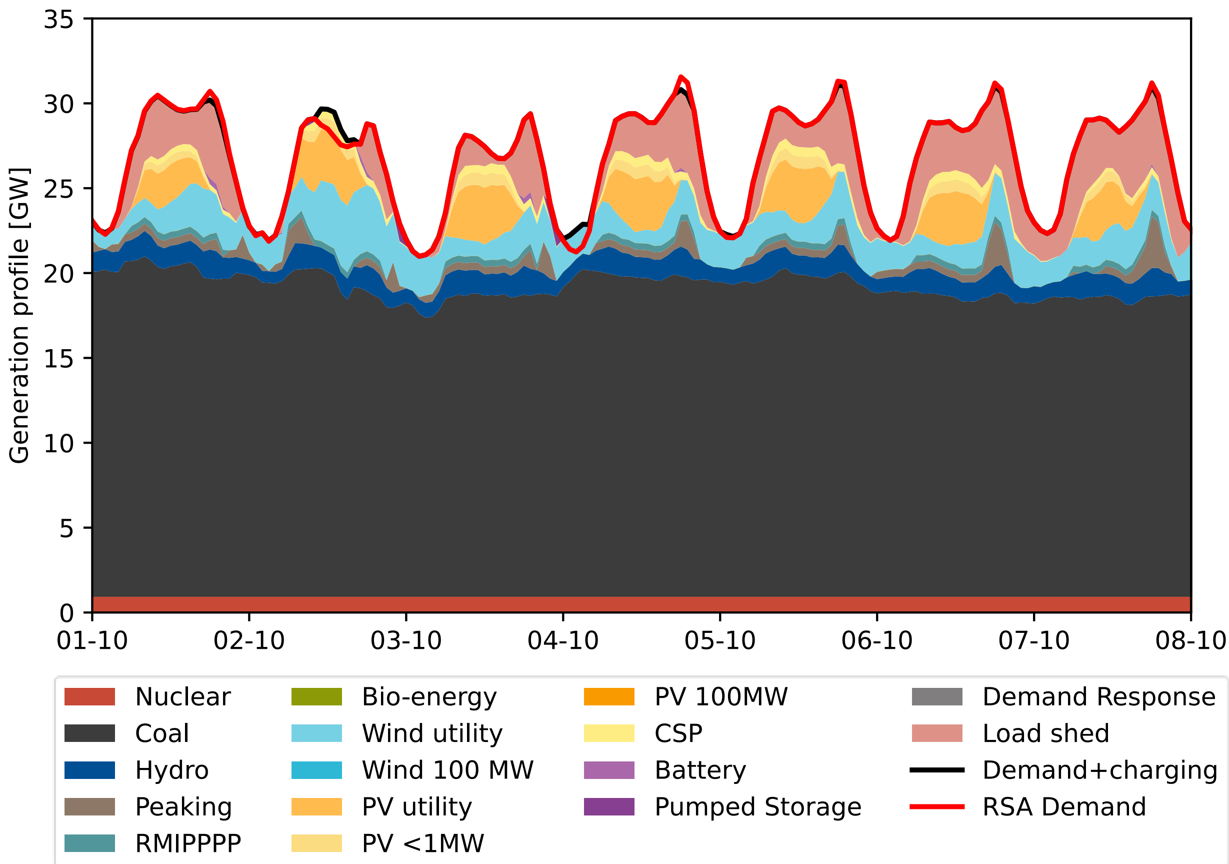
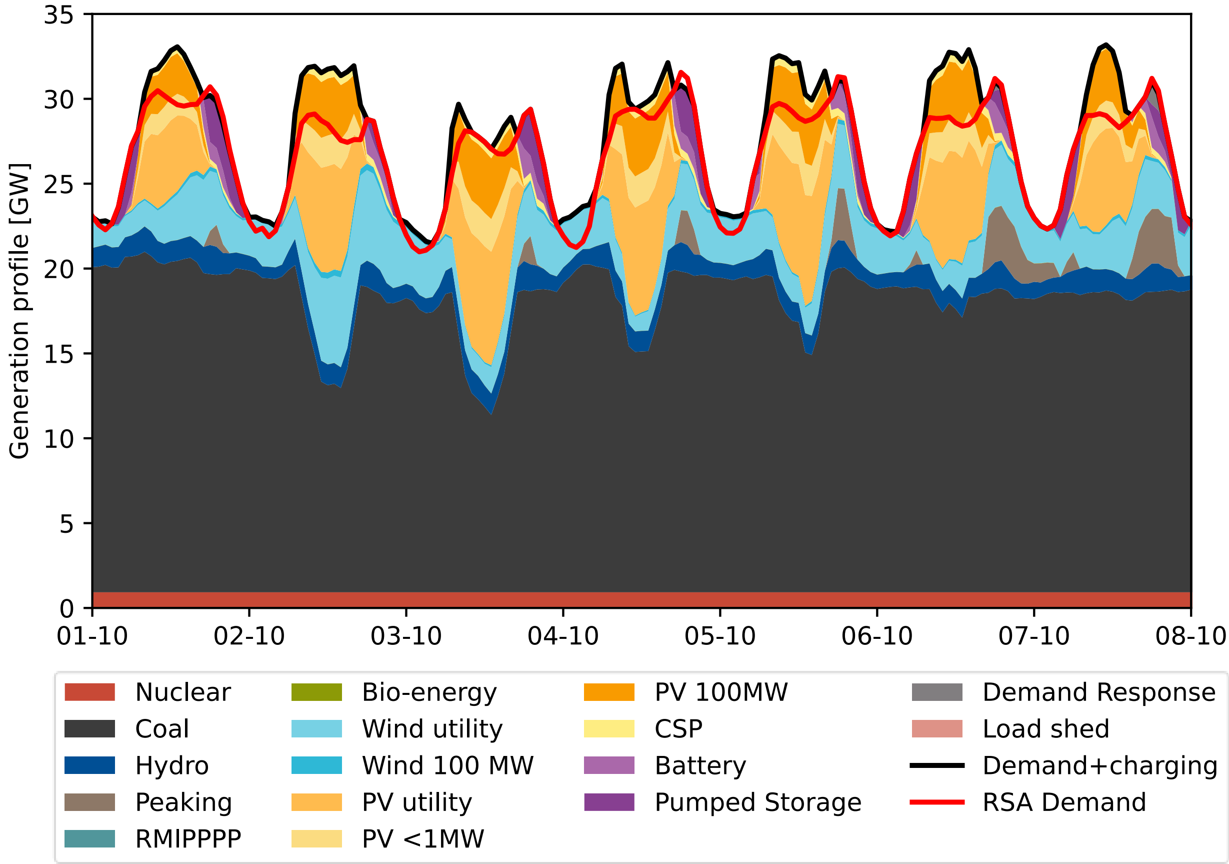


Figure 14: Example dispatch for the Solution Case (October 2025)



* Eskom's stated coal plant ramping flexibility is around 25-35% of the nameplate capacity of each coal plant. The 2.5 GW/h ramp rate estimate used in this analysis is a fraction of this value (around 6% of nameplate capacity or 12% of operational capacity given the EAF) – which recognises that current operational issues at many of Eskom's coal plants render them less capable of ramping. Despite it being a conservative estimate, there may still be concerns that the coal fleet is unable to ramp at 2.5 GW/h. Recognising this, we performed a sensitivity test by running the model with a ramping specification of 1.25 GW/h and it made little difference to load shedding (less than 0.1 TWh). The only difference a lower ramp rate may make is to the overall cost, i.e. at times when the coal plant is unable to ramp down when variable resources such as solar are generating large amounts of power, the solar power will be curtailed. Noting that we would already be in a much better position than we are currently as supply would be exceeding demand. But this also assumes that Eskom or the Market Operator (MO) would watch the power go to waste. Eskom or the MO could easily create a new tariff category for mid-day power at a low price (e.g. 30c/kWh) which would incentivise private investment in batteries, so that the demand side would respond to absorb the additional power and provide it at a later time[71]. Furthermore, if the inflexibility of the coal fleet is an impediment to a rollout of renewables, this presents an opportunity for South Africa's JETP funding to be used to replace the most inflexible coal units with a renewables plus storage alternative, even if it is slightly more expensive.

[71] *See more on this in the following article: https://www.miningweekly.com/article/hillside-aluminium-could-get-green-003ckwhr-lifeline-by-2030-mallinson-2022-01-18/rep_id:3650*

APPENDIX 2: UNSERVED ENERGY TABLES

Table 11: Load shedding (TWh) under the Base Case with no delays to Kusile or Koeberg

Scenarios / EAF decline / Demand Growth	2023			2024			2025			2026		
		EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.
Demand +1 p.a.	5.1	2.0	0.9	6.2	1.1	0.1	6.4	1.2	0.0	16.4	2.6	0.2
Demand 0% p.a.	2.4	1.2	0.4	1.5	0.2	0.0	1.8	0.1	0.0	5.7	0.6	0.0
Demand -1% p.a.	1.9	0.9	0.2	0.8	0.0	0.0	0.7	0.0	0.0	1.6	0.0	0.0

Table 12: Load shedding (TWh) under the Base Case with delays to Kusile or Koeberg

Scenarios / EAF decline / Demand Growth	2023			2024			2025			2026		
	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.
Demand +1 p.a.	7.8	2.8	1.4	7.7	0.9	0.1	5.7	0.6	0.0	17.1	2.6	0.2
Demand 0% p.a.	4.1	1.7	0.7	2.0	0.1	0.0	1.1	0.0	0.0	6.3	0.6	0.0
Demand -1% p.a.	2.7	1.3	0.5	0.6	0.0	0.0	0.3	0.0	0.0	1.6	0.0	0.0

Table 13: Load shedding (TWh) under the Solution Case and Risk Adjusted Plan with a 1% p.a. growth in demand

Scenarios / EAF decline	2023			2024			2025			2026		
	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.	EAF -2% p.a.	EAF -1% p.a.	EAF 0% p.a.
Base (for reference)	5.1	2.0	0.9	6.2	1.1	0.1	6.4	1.2	0	16.4	2.6	0.2
Solution Case implemented on time - no delay risk materialises												
Solution Case Only	1.9	0.6	0.1	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0
Delay risk materialises												
Solution Case Only	2.3	0.9	0.1	0.3	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0
Risk Adjusted Plan	2.3	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0

APPENDIX 3: SENSITIVITY OF UNSERVED ENERGY TO COAL EAF PROFILE AND WEATHER DATA

A sensitivity analysis was conducted to determine how the levels of unserved energy vary in the model as a function of the year from which the weather data is taken, as well as the hourly coal EAF profile within a year (2021 hourly vs recreated profile, see Page 42). The analysis in this section is focussed on a load growth of 1% per year and the scenario for coal EAF of -2% per year. Table 14 presents the sensitivity analysis for the Solution Case (without implementation delays), while Table 15 presents the results for the Risk Adjusted Resource Plan. Naturally when the system is most constrained the levels of unserved energy have a higher degree of variation with statistical variations in weather and coal EAF data. Overall, the results and the associated conclusion about the severity of load shedding are relatively consistent across the different sensitivities that were analysed.

Table 14: Sensitivity of predicted levels of unserved energy (TWh) to weather data and EAF profile for the Solution Case

Scenarios	2023			2024			2025			2026	
Weather data / EAF profile	2021 actual	EAF fitted curve		2021 actual	EAF fitted curve		2021 actual	EAF fitted curve		2021 actual	EAF fitted curve
Weather 2019	2.22	2.24		0.05	0.06		0.01	0.02		0.05	0.07
Weather 2020	2.10	2.17		0.08	0.07		0.02	0.03		0.08	0.08
Weather 2021	1.88	2.14		0.04	0.06		0.01	0.02		0.03	0.06

Table 15: Sensitivity of predicted levels of unserved energy (TWh) to weather data and EAF profile for the Risk Adjusted Plan with lower renewables

Scenarios	2023			2024			2025			2026	
Weather data / EAF profile	2021 actual	EAF fitted curve		2021 actual	EAF fitted curve		2021 actual	EAF fitted curve		2021 actual	EAF fitted curve
Weather 2019	2.63	2.64		0.09	0.00		0.00	0.00		0.85	0.64
Weather 2020	2.58	2.65		0.18	0.01		0.01	0.01		1.10	0.48
Weather 2021	2.31	2.56		0.00	0.01		0.00	0.00		0.34	0.18

APPENDIX 4: WHY 'BIG GAS' IS NOT THE SOLUTION TO LOAD SHEDDING

There are a number of reasons why gas (and 'big gas'[72] in particular) is not the solution to load shedding, and would comprise a 'single point of failure' type of decision which South Africa can ill afford.

1. **Gas-to-power plants are unnecessary to end load shedding.** Multiple system modelling studies show that load shedding can be ended by building a combination of renewables, storage and some thermal peaking plant capacity. Gas *could* be used to fire the thermal peaking plant capacity but so could diesel – and importantly the amount of fuel used is small as the plants are run infrequently to meet short-term fluctuations in demand.
2. **Constructing gas-to-power plants takes longer than renewables.** A new "big gas" solution will be slower to implement than a solution that makes use of the existing renewables procurement processes already under way and large-scale distributed generation. Liquified Natural Gas (LNG) via Matola is only due to come online by 2025. Additionally, ROMPCO pipeline capacity limitations would limit the mid-merit capacity[73] that could be brought online at Komati or other inland location in the near term without further capacity expansion. An LNG solution at Richards Bay would be a greenfields project requiring 2-3 years to implement. The development of any domestic gas opportunities would take at least as long, if not longer.
3. **Mega-Project Risk.** A new "big gas" solution would involve yet another large centrally controlled procurement process. Effectively another mega project with many single point of failure risks – any execution failures, litigation for example, or just normal procurement delays would threaten or hold up the entire capacity. This option should be compared to the fundamentally different proposal to recruit thousands of economic agents in South Africa to address the problem, by largely making use of existing, far advanced IPP Office procurements, and the distributed generation market.
4. **Gas is a more expensive solution.** System modelling studies consistently show that the use of gas-fired plant in a mid-merit or baseload role is far more expensive than the combination of renewables, storage and peaking capacity.
5. **Emissions from large-scale gas solution are much greater than the viable alternative.** Emissions from a large-scale gas solution are about seven-fold greater than emissions from an alternative renewables plus thermal peaking solution that would provide the same value to the power system and the same efficacy in arresting load shedding.
6. **JETP funding could be placed in jeopardy by a swing to 'big gas' in power** given that a renewables plus thermal peaking alternative to large-scale gas is both cheaper and generates a fraction of the emissions. $8.5Bn in concessional funding and grants is on the table but "SA's $8.5bn energy package is intended only for renewables", donors say. One of the key funders stated recently that "further investments in fossil-fuel based power would also be inconsistent with the country's commitment to limit emissions to between 350-million tonnes and 420-

[72] *By 'big gas' we refer to gas-to-power plants that are operated at high capacity factors and utilise large gas volumes, for example, Combined Cycle Gas Turbines*

[73] *Mid-merit plants generally operate at capacity factors of around 50%.*

million tonnes of carbon dioxide equivalent — a reduction of between 20% and 33% — by 2030", according to John Morton, the US Treasury's climate counsellor

7. **Lock-in.** The only possible motivation for large-scale gas use could be that a short-term emergency period justifies its use in the absence of the ability to build renewables fast enough (although we show this is not required). However even if it were possible to implement a gas solution timeously, it is highly unlikely that a gas supply agreement (GSA) to fire any mid-merit (or even peaking) plant with gas could be secured for a short time horizon. These will likely be at least 10yr-20yr contracts, with take-or-pay commitments. This will lock South Africa into costly emitting power for a decade or two. Large-scale gas power generation in South Africa is already sub-economic compared to the alternative of renewables and peaking use.
8. **Gas is not necessarily better than diesel**. The power system requirement is for a peaking function, not a mid-merit function. Peaking plant could be fuelled by diesel or gas. At the quantities required for peaking it is not clear that gas would be cheaper than diesel. When accounting for fugitive emissions from the gas supply chain it is also not clear that gas would have lower emissions than diesel.