RESOLVING THE POWER CRISIS PART A: INSIGHTS FROM 2021 - SA'S WORST LOAD SHEDDING YEAR SO FAR

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All errors remain those of the authors.

EXECUTIVE SUMMARY

Empirical evidence demonstrates that an additional 5 GW of renewable capacity would have essentially solved load shedding in 2021 whilst enabling better and more efficient operation of our power system – all at a cost saving to Eskom.

Load shedding in 2021 was the worst on record spanning 1 165 hours with a total of 1.8 TWh of energy unserved – uncomfortably close to one percent of total electricity demand. The broader economic cost due to daily disruptions is difficult to quantify but includes lost production, lost investments, deindustrialisation, greater unemployment and declining livelihoods. 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 7 load shedding in the foreseeable future[1]. This situation is arguably the central manifestation of South Africa's economic crisis, and a pathway to resolving it, our greatest economic opportunity.

This report is the first of a two-part series exploring a feasible strategy to resolve load shedding and aims to provide a proper empirical basis for the development of such a strategy. For this report, we utilise Eskom's actual data to investigate the impact that additional generation capacity would have had on load shedding if it had been operational last year, focussing on the shortest lead-time and cheapest sources of power generation – wind and solar.

Confirmed by two separate modelling platforms, the results are startling – an additional 5 GW of wind and solar (the approximate capacity of two REIPPPP[2] bidding rounds) in the same proportion as the currently installed capacity, would have allowed Eskom to eliminate 96.5% of load shedding in 2021. Further to this, the additional wind and solar capacity would have reduced the amount of diesel burnt in the open cycle gas turbine (OCGT) peakers by more than 70%, simply by generating power at the time that these were running. More optimal use of Eskom's pumped storage assets, enabled by the additional energy on the system could have created further diesel savings – exceeding 80% in all. We find that the remaining fraction (3.5%) of load shedding could have been eliminated by a modest expansion of Eskom's ILS[3] demand response programme or other aggregated Demand Response intervention, and the very last few hours by 2 GW of one-hour batteries.

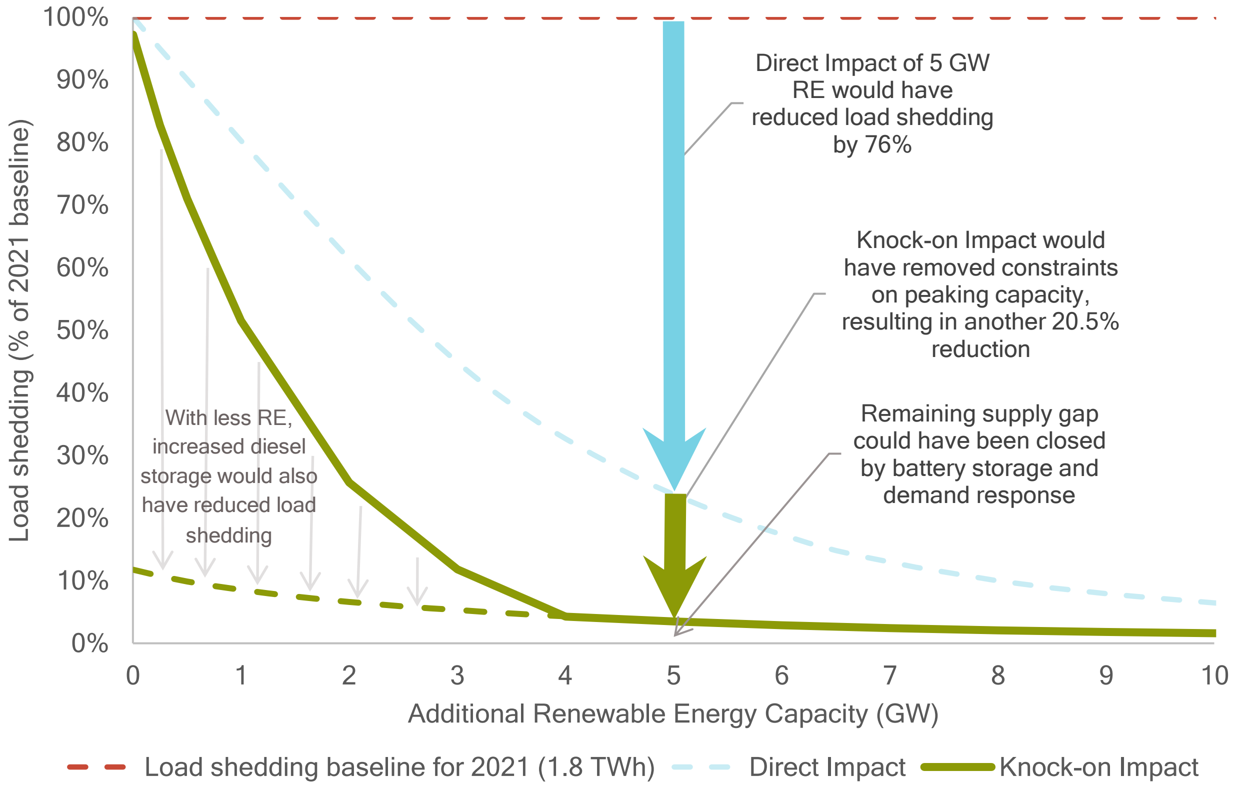
This outcome is counterintuitive. Rather than increasing system risk as many observers expect, the analysis based on the empirical data shows unequivocally that adding variable renewable generators to the existing distressed South African power system will result in a disproportionate *reduction* in load shedding and *increase* in system reliability. This insight is critical for mapping the way forward and avoiding expensive pitfalls and delays in doing so.

[1] It is not hyperbole to suggest that sustained levels 6 – 7 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.

[2] Renewable Energy Independent Power Producer Procurement Programme

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

Figure 1: Summary of results: 5 GW Additional renewables would have reduced load shedding by 96.5% in 2021



Analysis of the cost impact of adding 5 GW of renewable energy capacity to the system is equally surprising. Based on Eskom's 2020/21 Financial Year[4] dispatch cost of OCGTs (R3.04/kWh) and coal power (R0.42/kWh)[5] and assuming renewables prices around R0.68/kWh[6], the additional 5 GW of wind and solar would have created a net annual saving of R2.5Bn for Eskom. This takes no account of the economic benefit of avoiding load shedding but is merely the net cash saving to Eskom driven primarily by reduction in the quantity of diesel burned. The saving is after provision for a hypothetical R6.08/kWh incentive for participating customers to reduce load under a demand response programme (this equates to a 100% premium over the cost of running existing OCGTs), and the cost of 2 GW of batteries.

The analysis in this report demonstrates how avoidable the current load shedding crisis has been, and how cost-effectively it can be resolved based on hard evidence from the actual 2021 data. Insights from this analysis also demonstrate that by taking adequate steps (starting immediately), solutions to resolving load shedding are within reach.

[4] Eskom, 2021. "Integrated Report – 31 March 2021" (Eskom, 2021)

[5] This cost is likely to be understated as it only reflects fuel costs, excludes the escalating cost of maintaining and refurbishing coal-fired power stations, and is the average across all stations. In reality the most expensive coal will be displaced first generating far greater cost savings.

[6] An estimated value for the price of additional renewable capacity had it been installed in annual increments under an uninterrupted REIPPPP procurement process since 2016.

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Bn	Billion
BW	Bid Window
CF	Capacity Factor
c/kWh	Cents per kilowatt-hour
CO_2	Carbon Dioxide
DMRE	Department of Mineral Resources and Energy
EAF	Energy Availability Factor
FY	Financial Year
Gt	Gigatonnes
GW	Gigawatt
GWh	Gigawatt-hour
ILS	Interruptible Load Shed
IPP	Independent Power Producer
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	Kilowatt-hour
Ml	Million litres
MLR	Manual Load Reduction
Mt	Megatonnes
MW	Megawatt
NERSA	National Energy Regulator of South Africa
OCGT	Open Cycle Gas Turbine
PS	Pumped Storage
t	Tonne
TWh	Terawatt-hour

RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
R/kWh	Rands per kilowatt-hour
RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme

1 INTRODUCTION

The South African economy has been plagued by a power supply deficit intermittently since 2007, with 2021 delivering SA's record number of 'load shedding' hours – 1 165 of the year's 8 760 hours. Load shedding refers to the planned interruption of power supply to certain parts of the national electricity grid to reduce strain on the power system. Load shedding 'stages' are announced prospectively by Eskom's National Control Centre and reflect the system operator's forecast of the extent to which demand will exceed supply for the coming hours. Each stage corresponds to the need for demand to be reduced by roughly 1 000 MW.

The primary drivers of load shedding are the poor availability of Eskom's coal fleet, and lack of progress in procuring and connecting new generation capacity to the national grid to fill a growing power supply gap. Eskom has repeatedly stated that any significant improvements in the Energy Availability Factor (EAF) of its coal fleet – a measure of how often plants can be online and generating power – is very unlikely[7] and relying on improved coal plant performance to resolve or reduce load shedding is thus a dangerous strategy.

It is now abundantly clear that the only way to resolve load shedding is by adding new generation capacity to the system as fast as possible. South Africa's Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) was making progress in this direction through the procurement of additional generating capacity, until it was stalled in 2016. The REIPPPP has recently begun moving again albeit slowly, with the award of 2 583 MW[8] in Bid Window (BW) 5 and procurement of an additional 2 600 MW under way in BW6.

In this report we analyse what the impact would have been on load shedding last year if there had been more generation capacity on the system. We consider a range of additional generation capacities, but focus on an amount of 5 GW – a reasonable assumption for what would have been on the system had the REIPPPP continued running after 2016[9]. The outcomes of the analysis inform the next report[10] in this two-part series which aims to develop a practical game plan to resolve load shedding, within the context of current realities and developments in the power sector.

This report begins in section 2 with an explanation of how the current energy deficit results in a capacity shortfall that gives rise to load shedding. In section 3 we quantify the impact that additional renewables would have had on addressing this problem in 2021, and in section 4 the further minimal measures required to have eliminated load shedding altogether in that year. In section 5 we calculate the cost to Eskom in 2021 had there been 5 GW of additional renewable capacity and other resources online to end load shedding and in section 6 assess the emissions impact of this additional generation. Section 7 contains the conclusions.

[7] This conclusion was repeatedly emphasised in its most recent "System Status and Outlook Briefing" released 11 May 2022.

[8] As announced by the Minister of Mineral Resources and Energy on 28 October 2021 (DMRE, 2021)

[9] By 2015, three separate Ministerial Determinations were made for new renewable capacity totaling 13 225 MW, most of which was to be awarded under the REIPPPP. 6 322 MW of capacity was awarded under BW1-4 (IPP Office, 2021). This left 6 308 MW of capacity to still be bid into the REIPPPP were it to have continued after BW4 in 2015. No timelines were stipulated for new bid windows after BW4. Assuming that we continued to conduct one BW per year, that each BW would have awarded 1 500 MW–2 000 MW of capacity and that projects reached commercial operation roughly 2 years after financial close (i.e. projects bid in 2016, 2017 and 2018 would have reached commercial operation), it is reasonable to assume that 4 500 MW–6 000 MW would have been online by the beginning of 2021.

[10] Meridian Economics, 2022. Resolving the Power Crisis Part B: An Achievable Game Plan to End Load Shedding.

2 THE VICIOUS CYCLE - ENERGY DEFICIT HOBBLES CAPACITY

Eskom's primary weapons for plugging short term gaps between generation and demand are its pumped storage facilities[11] and OCGTs[12], with a maximum of 2 739 MW and 3 056 MW available respectively in 2021. However, a set of intertwining factors in the current state of the power system means that these important 'peaking'[13] assets cannot properly be utilised in the fight against load shedding.

For pumped storage assets to be useful at any time, they must be sufficiently charged with water in the upper reservoirs, and for OCGTs to be able to generate power they must of course have diesel in their onsite tanks. However, both these fundamental requirements need a system that can generate power in excess of its immediate demands for enough hours of the day to replenish the storage of water in the upper reservoirs without burning diesel in order to pump it there (apart from being extremely expensive, diesel is burned much faster than it can be replenished whenever OCGTs are running). Unfortunately, at present the system is frequently unable to do this – evidence that it is short of *energy*, i.e. lacks the ability to generate sufficient electricity in total over a period of time (measured in kWh, MWh, GWh, etc). The system is additionally short of *capacity*, i.e. at times it is unable to meet the maximum or 'peak' power demand on the system on a short-term basis, for example when everyone arrives back home from work and switches on their appliances. Capacity is a measure of the instantaneous ability to generate power measured in kW, MW, GW etc.

In this section we demonstrate how the current shortage of energy results in a sterilisation of available capacity, which in turn through the cycling of the pumped storage assets results in a further shortage of energy – a classic vicious cycle.

2.1 CONSTRAINTS ON THE USE OF PEAKING ASSETS

The overall lack of available *energy* means that the system operator is seldom able to pump enough water to the upper dams of the pumped storage assets in order to fully replenish them[14], and unreliable coal generation with unpredictable outages necessitates highly conservative operating rules on how often and to what level the dams can be discharged. The system operator is rightfully nervous of a nasty surprise loss of thermal capacity that would jeopardise the next replenishment cycle of the dams, or result in unmeetable demand if too much water is discharged. This means that often some or all of the pumped storage generation capacity, although available (even after accounting for short-term reserve requirements) with water in the upper dam, is unable to run when needed to avoid load shedding[15].

[11] The pumped storage facilities are configurations of two water reservoirs (dams) at different elevations. During times of high demand, water is released from the upper dam to the lower dam, during which it passes through a turbine and generates power. During times of low energy demand, the water is pumped back to the upper dam, drawing electricity from the grid.

[12] Open Cycle Gas Turbines (OCGTs) are fast-acting combustion turbines that compress air and heat it using gaseous fuel, and then run the expanding air through a generator rotor to produce electricity (Thurber & Verheijen, 2022)

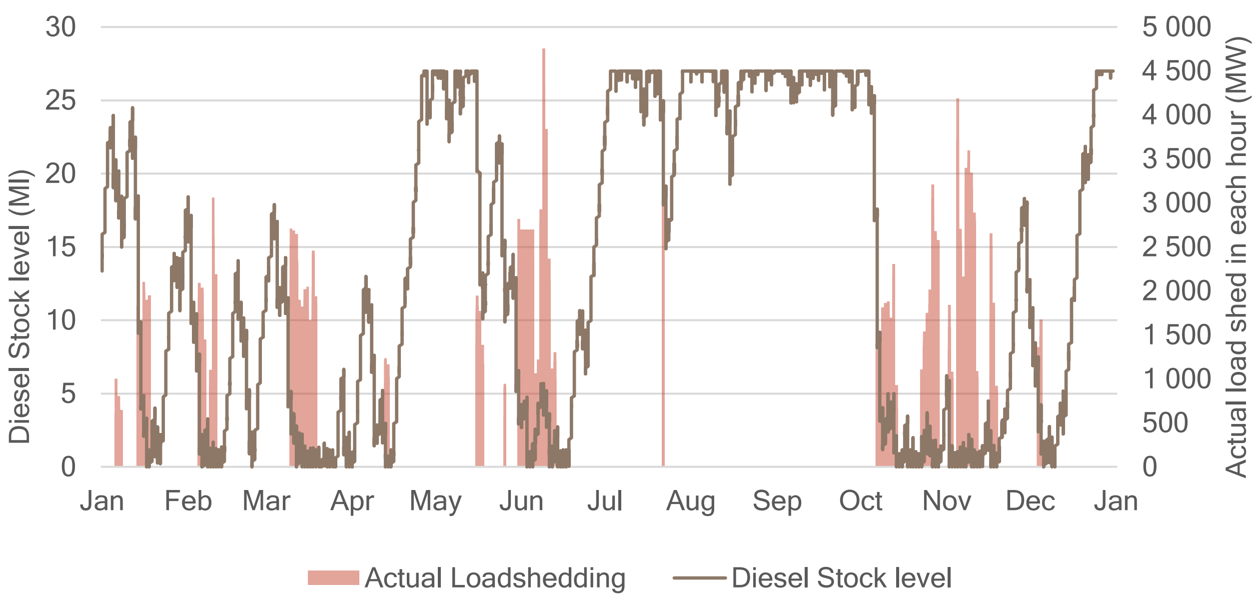
[13] Peaking plants are fast-acting plants that are used to cater for quick changes in power demand.

[14] This issue is outlined in detail in the following article by Creamer (2022): https://www.engineeringnews.co.za/article/eskom-admits-to-energy-rather-than-capacity-constraint-as-it-sheds-load-to-replenish-pumped-storage-dams-2022-02-02

[15] Of course some capacity may also be offline for maintenance but the pumped storage and OCGT assets are among *Eskom's most reliable and available* generators.

The lack of available energy from coal or other generators also means that the OCGTs are often run more frequently than their design role of meeting occasional peak demand incidents[16]. The overuse of the OCGTs means that they burn excessive quantities of diesel at great cost, but more importantly this also results in diesel tanks running dry at the OCGT sites. A lack of stored diesel at OCGT sites, or a rationing of what is stored, frequently results in an inability to run some or all of the available OCGT capacity when it is needed to stave off load shedding. Figure 2 illustrates the relationship between this stock-out problem and load shedding – it is a simulation of on-site diesel stock levels for 2021 based on aggregate OCGT usage per hour[17]. Diesel stocks for much of the year were unable to recover to full capacity before subsequent periods of need quickly drained them, resulting in load shedding, such as in October and November 2021.

Figure 2: Simulated diesel fuel stock levels for 2021



The lack of sufficient energy (and fuel storage) on the system thus converts into a lack of available generation *capacity* of both pumped storage and OCGT assets – i.e. there is a reduction in the number of MW that is sufficiently 'stocked' or 'charged' in order for it to be available to the system. But this induced reduction of capacity, itself further exacerbates the paucity of energy. In attempting to keep sufficient capacity available, the pumped storage assets are cycled frequently in order to ensure their availability to meet both morning and evening peaks if required. This would not be an issue if there was sufficient energy in between peaks to replenish the upper reservoirs, but there is not. The need to frequently cycle the pumped storage wastes the precious energy the system does have due to pumping cycle losses (only 75% of the energy going into pumped storage is recovered), further reducing the already insufficient energy available to meet demand.

[16] OCGTs are designed to run with capacity factors around 5%, not the 12% usage of FY2021 (Eskom, 2021)

[17] Our results were calibrated such that the resultant ability to run OCGTs with zero additional renewables (i.e. the simulation of the 2021 actual history) matched *Eskom's actual* OCGT capacity factor of 12% with 1.8 TWh total load shed as closely as possible. The simulation uses Eskom plus Independent Power Producer (IPP) aggregate OCGT usage and assumes total diesel storage of 27 Million litres (Ml).

The burden of generating power to keep cycling the pumped storage falls frequently on the OCGT generators, there being no other generation capacity available to do this[18]. Recharging the pumped storage with OCGT-generated power adds an extra *third* to the fuel quantity burned due to the pumping cycle losses[19], hastening the emptying of diesel storage tanks and thus increasing the times when OCGT capacity is unavailable, all because of an original shortage of energy.

2.2 THE ENERGY TRAP

Just like being in a Debt Trap – where more money is borrowed to service existing debt obligations, creating a larger debt burden in the future – Eskom is stuck in an Energy Deficit Trap. Current constraints on the system mean it has to effectively 'borrow' energy from the future (e.g. diesel stocks for OCGTs or water levels in pumped storage reservoirs) in order to meet demand on a particular day, but without being able to adequately replenish these reserves for the next day, ultimately leaving the system more constrained and less capable to meet demand than it was before. Load shedding is the safety valve that has to keep stepping in to relieve this spiral.

In addition to being short of energy and generating capacity, Eskom is also chronically short of cash. Adverse regulatory decisions, the toll of state capture and unsustainable debt have left the utility struggling to make ends meet on a frequent basis. State bailouts are specifically earmarked for debt relief, in other words they cannot be used for diesel purchase, and the regulatory process seldom compensates Eskom adequately for diesel costs. This is especially so when diesel burned exceeds budgeted amounts (caused typically by unforeseen failures in the coal fleet) as is increasingly the case with OCGT usage being required to replenish the pumped storage, burning a wasteful third more diesel in the process. The lack of both diesel storage and cash to pay for the fuel thus has the perverse effect of forcing the rationing of OCGT usage, which saves R3.04/kWh[20] in diesel costs whilst imposing a load shedding cost on the economy (consumers) of at least R10.28/kWh[21].

Cash and energy shortages also create a similar "Maintenance Trap" where neither sufficient cash to do maintenance, nor enough additional energy to take plants offline allow for adequate maintenance to be conducted. But delaying maintenance procedures only creates a bigger problem down the line due to the compounding negative effects of postponing essential work – creating further failures and greater costs to rectify.

Although currently trapped in a vicious cycle[22], escaping this condition is in principle simple by addressing the genesis of the problem – a shortage of energy on the system. In this report we quantify the extent to which additional renewable energy could have broken the vicious cycle in 2021 and what other measures would have been required to have eliminated load shedding completely in that year.

[18] Nearly 20% of load shedding hours in 2021 were necessary in order to refill the pumped storage whilst running OCGTs. Reservoirs were being charged in more than 55% of load shedding hours.

[19] If only 75% of the energy is recovered, then to get 1 kWh out requires 1.33 kWh to go in – see Box 1.

[20] Weighted average OCGT fuel cost for FY2021. IPP OCGT fuel cost R3.58/kWh, Eskom OCGT fuel cost R2.78/kWh.

[21] Estimate from Nova Economics study by Walsh, Theron & Reeders (2021). Updated from reported 2020 price of R9.53 to 2022 prices based on historical inflation rates published by StatsSA.

[22] The vicious cycle issues are captured eloquently in these recent articles:

https://www.engineeringnews.co.za/article/diesel-supply-and-pricing-again-under-the-spotlight-as-eskom-intensifies-cuts-to-preserve-reserves-2022-03-09/rep_id:4136

https://www.engineeringnews.co.za/article/steeply-rising-diesel-prices-may-increase-load-shedding-risk-as-eskom-warns-of-difficulties-in-absorbing-costs-2022-03-08

3 QUANTIFYING LOAD SHEDDING REDUCTION FROM ADDITIONAL RENEWABLE ENERGY

Multiple power system modelling studies of the last few years have confirmed that the most economic candidates for new generation capacity in South Africa for the foreseeable future are wind and solar.[23,24,25,26] These modelling studies have used powerful system modelling software to conduct multi-year simulations of the current and future power system using projections of demand, costs and generator performance. Whilst some form of forecasting is essential for adequate power system planning, we know that the reality that unfolds will be different from these forecasts – increasingly so for periods far into the future. Modelling simulations must also simplify the future in order to make the model tractable, and in general most modelling is based on meeting demand for a reduced sample of hours from each future year.

A useful alternative approach, particularly for the near-term challenge of testing interventions to resolve load shedding, is to use actual system data from the recent past as an evaluation platform. Eskom has increased transparency on its system performance data and detailed power system information is now available on an hourly basis for the last five years[27]. This includes hourly generation from all sources, installed capacity, hourly demand and actual load shed in every hour when load shedding was in place. Using this real-world data to conduct analyses has immense value as it is by nature robust (it actually occurred), and provides a rigorous framework for exploring what might have happened if a particular intervention had been put in place during that year.

In this report, using Eskom's hourly data from 2021[28], we specifically investigate: how would load shedding have been impacted in 2021 by more renewable capacity on the system?

3.1 METHODOLOGY

South Africa's renewables portfolio at the start of 2021 consisted of 2 495 MW of wind and 2 107 MW of solar PV, which had grown by year end to 3 023 MW and 2 212 MW respectively[29]. This average mix of 4 856 MW installed capacity produced 13.4 TWh of energy in 2021 (just 6% of all generation), realising an average capacity factor[30] of 31.57%. For this analysis, we made the simple assumption that any new renewable energy capacity would have been added to the system in the same proportions of wind and solar as the existing portfolio[31], and would have had the same hourly generation profile.

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

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

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

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

[27] https://www.eskom.co.za/dataportal/

[28] Data from 1 Jan 2021 – 31 Dec 2021, 8 760 hours for the full year

[29] For simplicity we only considered wind and solar resources

[30] Capacity factor a measure of how often a power plant runs over a specific period of time (the number of hours in a year, for example). Capacity Factor is expressed as a percentage and is calculated by taking the actual power produced by a plant during a time period and dividing it by the theoretical power output of the plant were it to be running constantly during that period.

[31] Our modelling thus assumes that each new MW of renewables added would have produced 2.76 GWh over the course of the year (where 2.76 GWh = 13 400 GWh/4 856)

We used Eskom's data on the actual load shed[32] in each hour and assumed that, had additional energy been available to the grid to exceed the load shed in any hour, load shedding would have been entirely avoided for that hour[33]. In an hour where the additional energy from renewables was *less* than the load shed in that hour, the load shedding total for that hour would be reduced by the amount of additional energy available.

The primary metric we used to assess the impact of additional renewables on load shedding was the sum of remaining load shedding over the year – i.e. the sum of the load shed over all 8 760 hours in the year – after subtracting the additional energy that would have been generated by the renewables in the load shedding hours. The actual load shed in 2021 was 1 775 GWh. The percentage load shedding reductions quoted in this document are referenced against this figure.

We conducted this analysis using two separate platforms – a spreadsheet model and a dedicated system modelling software tool[34] to more accurately simulate hourly dispatch. The comparison of outcomes from the different platforms was used to verify the findings and confirm the credibility of results. The spreadsheet analysis is simple and provides an intuitive basis for demonstrating the 'direct impact' of additional renewable energy, and the extent to which this energy reduces diesel usage and cycling of the pumped storage facilities. The more sophisticated system dispatch model is necessary to realistically assess constraints on the further 'knock-on' impact on load shedding reduction that could be gained by using the OCGT and pumped storage assets to most optimally use the additional energy on the system. This provides a more realistic view on how the system would actually be run by the system operator, yielding more realistic estimates for what it would have cost to do so.

3.1.1 THE 'DIRECT IMPACT' OF ADDITIONAL RENEWABLE ENERGY

We quantified the impact of additional renewable generation for capacities spanning the range from 250 MW to 10 GW. In the short-term context of the next two to three years, the prospect of commissioning anything more than 10 GW is probably unrealistic given current grid constraints and lead times, and did not warrant modelling. For each level of additional renewable capacity, we calculated the hourly additional generation that would have been available for each of the 8 760 hours of the year, and allocated it in each hour as follows:

1. If there was load shedding in an hour, the additional generation from renewable capacity was used to offset the amount of load shed in that hour,
2. If the renewable energy generation *exceeded* the load shed in the hour, the net remaining energy was used to offset generation from OCGTs in that hour (if any) – resulting in a saving of the corresponding diesel cost and emissions

[32] *Eskom discloses load shed in its data as "Manual Load* Reduction*" or MLR* – it is an estimation of the demand that has been reduced due to load shedding under the national load shedding schedule and/or curtailment. Whilst the MLR in any hour is lower than the load shedding stage number multiplied by 1 000 MW we have used MLR as a measure of actual load shed to be representative of the true extent of the problem.

[33] This assumes that the system operator would have been able to rely on forecasts of renewable generation for the hour in question – which is not an unreasonable assumption given a geographically diverse renewables portfolio and the accurate weather forecasting now available – and thereby determine that load shedding is not necessary. Hourly generation from renewable resources is known to a high degree of accuracy at least 24 hours in advance, allowing an adequately capacitated power system to prepare alternative generation to supplement any shortfall between supply and demand.

[34] See Appendix 8.2

and leaving the matching quantity of diesel in the tank for later use,

3. If there was still additional renewable energy remaining in the hour, it was used to offset any power generated from the pumped storage facilities in that hour – thereby leaving water in the upper dams of the pumped storage assets for later use (see Box 1. for a detailed explanation of the benefits of doing this).
4. Further additional renewable energy generation in any hour was assumed to offset coal power, reducing the need to burn coal with associated cost and emission reductions.

We refer to these as the Direct Impacts of additional renewables.

3.1.2 THE 'KNOCK-ON IMPACT' ON GENERATION CAPACITY

The direct impact of additional renewables results in a reduction in load shedding, but importantly also results in significant reduction in diesel usage (diesel tank levels remain much higher) and generation from the pumped storage assets (upper reservoirs remain fuller for more of the time). What this means is that diesel-fired OCGTs can increasingly be run when they are *actually* required (to meet sudden changes in demand) because diesel tanks are less often empty at critical times, and the pumped storage can run (and run for longer) when needed. These are the knock-on impacts from having additional energy on the system. With sufficient additional renewable capacity, it is possible to break the vicious cycle described in section 2, freeing the peaking capacity from its current considerable constraints.

In our simple spreadsheet model, we assumed that 5 GW or more of additional renewable capacity would sufficiently save diesel and obviate unnecessary pumped storage generation such that these assets could then have been used at full capacity[35] to fight any load shedding not already offset by the direct impact of the additional renewable energy. However, this assumption needed verifying in the context of the actual available diesel storage capacity, a realistic filling and emptying cycle of the pumped storage, and the manner in which a rational system operator would have dispatched these assets given the additional renewable energy on the system. We addressed these issues (and more) with the proper system dispatch model, and did indeed verify that 5 GW of additional renewables would have been sufficient to break the vicious cycle in 2021 and free up the peaking capacity to perform without constraint.

The full Knock-on Impact analysis conducted using the system dispatch model accounted for the following:

- **Modelling the actual diesel tank storage levels at OCGTs**[36]. We modelled aggregate storage across the four OCGT sites, assuming storage volume and replenishment rates calibrated against the actual 2021 OCGT usage. The model kept hourly track of diesel tank levels in our revised simulations ensuring that OCGT dispatch could only occur if sufficient fuel was available at that time in the year. We also tested the impact that additional diesel storage would have had at the OCGT sites – increasing diesel tank volumes is an easy, cost-effective way to

[35] Subject to reserve margin requirements

[36] Modelling diesel storage constraints is confounded by a lack of publicly available information (such as about the full extent of existing usable storage at Gourikwa/PetroSA and the Independent Power Producer (IPP) OCGT sites) and about some practical realities related to the ordering and scheduling of shipments that are difficult to simulate. The use of diesel follows an unpredictable pattern depending on power system demands, and market supply constraints which vary with the volume of diesel required at any one time and which is compounded by a six-week lead time in the scheduling of vessels for delivery.

ensure OCGTs are always available when required.

- **Simulating OCGT and pumped storage re-dispatch with additional energy on the system.** Subject to Eskom's operating reserve requirements[37] which constrain usage of the entire OCGT and pumped storage assets in any hour, we simulated the cost-effective dispatch of OCGT and pumped storage assets based on minimising diesel burn. The dispatch simulation included an hourly recalculation of pumped storage dam levels, restricting charge and discharge rates to those actually achieved in 2021, and conservatively never allowing dam levels in any hour to drop below the actual 2021 dam levels for the corresponding hour. Thus, any assumption on increased pumped storage generation in any hour only made use of additional water stored by virtue of previous avoided discharge. In reality the system operator would (and will in future) be able to relax some operating procedures with more energy on the system and make more use of the full discharge potential from the dams.
- **Simulating generation by the coal fleet.** To verify whether the excess renewable energy could reasonably have resulted in less coal burned we modelled a conservative re-dispatch of the coal fleet. We assumed that the coal fleet as a whole would never run harder in any hour than it ran for that corresponding hour in 2021. We also accounted for the constrained ability of the coal to ramp up and down to absorb additional renewable energy into the system – the maximum ramp rate allowed at any time was constrained to be lower than the maximum achieved in 2021. The ability for coal ramping to absorb renewables affects only the cost saving analysis – if coal could not have ramped down then renewables would have been curtailed in that hour. However, our coal cost saving assumptions are so conservative (see 8.4.1.3) that this would likely not impact our cost findings at all.

3.2 RESULTS

In summary, we found that an additional 5 GW of renewable capacity on the system in 2021 would have reduced load shedding by 96.5% (76% from the direct impact of additional generation closing the gap between supply and demand in load shedding hours, plus a further 20.5% from the knock-on impact that would have allowed OCGT and pumped storage assets to operate at all times when required). In the sections that follow, we unpack the analysis step-by-step which leads to this astounding overall result.

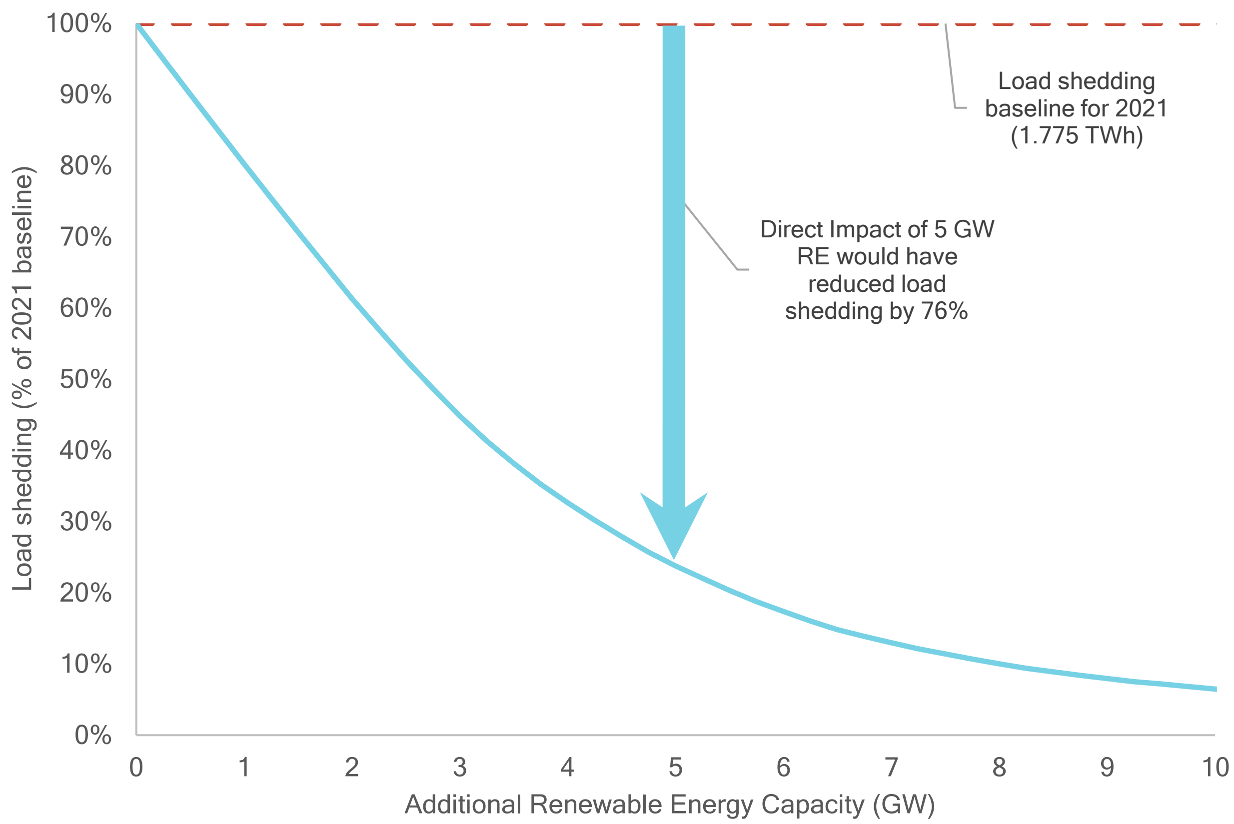
3.2.1 THE DIRECT IMPACT – HUGE REDUCTION IN LOAD SHEDDING AND DIESEL BURN

Figure 3 demonstrates what the Direct Impact would have been on load shedding in 2021 had additional renewable capacity been available to the system. It shows that 2.5 GW (equivalent to a single REIPPPP bid window[38]) would have almost halved the amount of load shedding, and 5 GW would have avoided more than three quarters of it. An hourly analysis shows that on direct impact alone, 5 GW of renewable capacity would have completely eliminated the need for load shedding in more than half of the 1 165 hours in which load shedding occurred in 2021, whilst reducing the severity in every other load shedding hour.

[37] We assumed 2 200 MW of the 5 795 MW sum of OCGT and pumped storage capacity had to be kept in reserve at all times. Of this, we assumed 1 000 MW would need to come from the pumped storage in order to meet the instantaneous and regulating reserve requirements.

[38] In March 2021, the DMRE relaunched the REIPPPP after more than a 5-year hiatus in procurement. In October 2021, twenty-five preferred bidders were announced with capacity from the projects totalling 2 583 MW.

Figure 3: Load shedding reduction achieved by the Direct Impact of adding renewables to the system



This result is counter intuitive. Load shedding occurs unpredictably and is caused predominantly by multiple generation failures of aging coal plant. Such failures happen without warning requiring swift action from the system operator to start generation from the pumped storage or fire up the OCGTs in order to avoid having to shed load. How is it that renewable energy which is often viewed as "variable", "unreliable", "non-dispatchable"[39] and subject to "the sun shining or the wind blowing" have such a dramatic impact on reducing load shedding?[40]

Figure 4 provides some insight by illustrating the hourly distribution of load shedding (the red bars) – this is the aggregate amount of energy shed at different times of day in 2021. Whilst somewhat more of the load shedding did indeed occur around conventional 'peak' hours of 18h00 to 21h00, the vast majority of load shedding was evenly spread across all hours of the day. The green bars of Figure 4 illustrate the hourly profile of power that would have been generated by an additional 5 GW of wind and solar. Whilst the majority of the energy is generated in the daylight hours, substantial power is also generated at night due to the diversified portfolio of wind and solar resources. It is evident that 5 GW of additional renewables would have generated significant quantities of power during times in

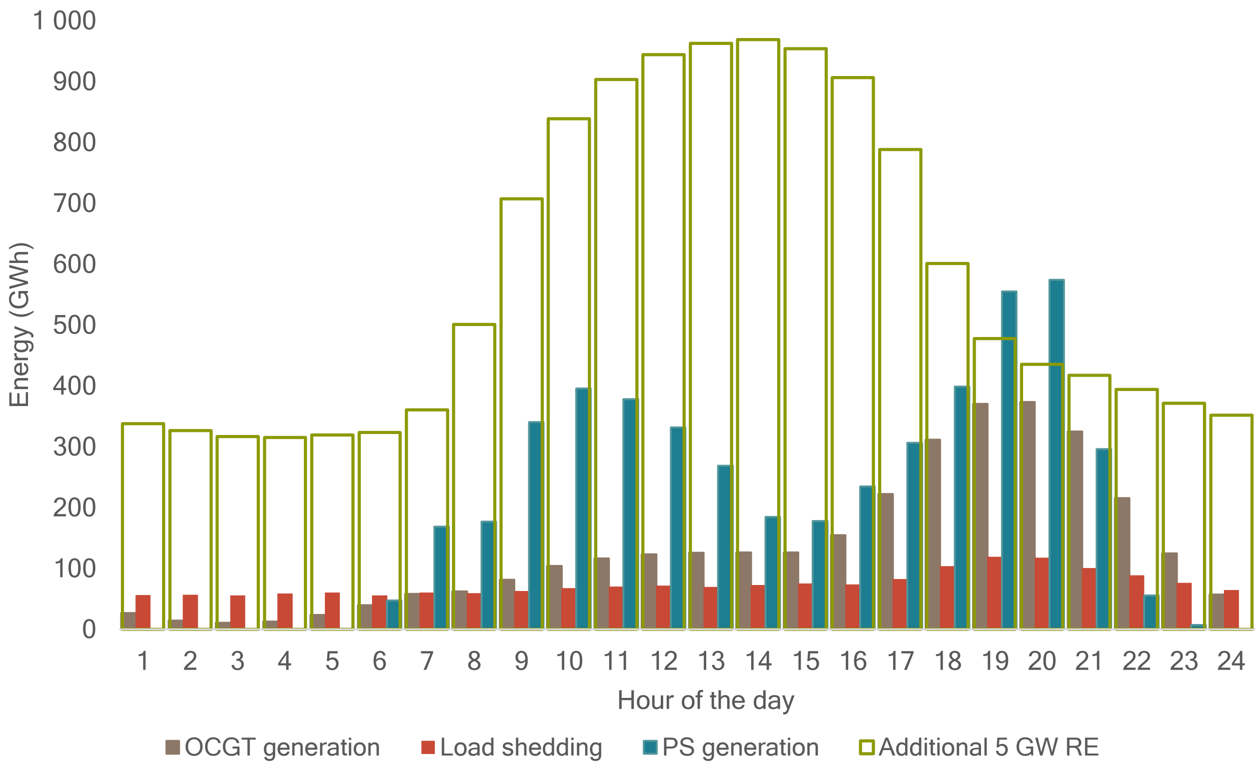
[39] "Dispatchable" generation can be switched on and off (and turned up and down) by the system operator to balance supply and demand *whilst "non-dispatchable" generation increases* and decreases due to exogenous factors (e.g. variations in wind / solar resource) (Junge et al., 2022)

[40] The terms variable, unreliable and unpredictable are often interchangeably applied to renewable energy. The latter two are misnomers and more aptly apply to the current state of the coal fleet. Hourly generation from renewable resources is known to a high degree of accuracy at least 24 hours in advance, allowing an adequately capacitated power system to prepare alternative generation to supplement any shortfall between supply and demand.

which load shedding occurred. Had this power been available, it would have effectively stopped load shedding before it started in many of those hours and reduced the overall severity over the year by 76% (as shown in Figure 3).

Figure 4: Hourly occurrence of actual load shedding, OCGT and Pumped Storage (PS) generation in 2021, overlayed with contribution of 5 GW additional renewables

2021 hourly distribution of load shedding (red), OCGT generation (brown), PS generation (blue). Green bars show the hourly distribution of power that would have been generated from 5 GW of additional renewables.

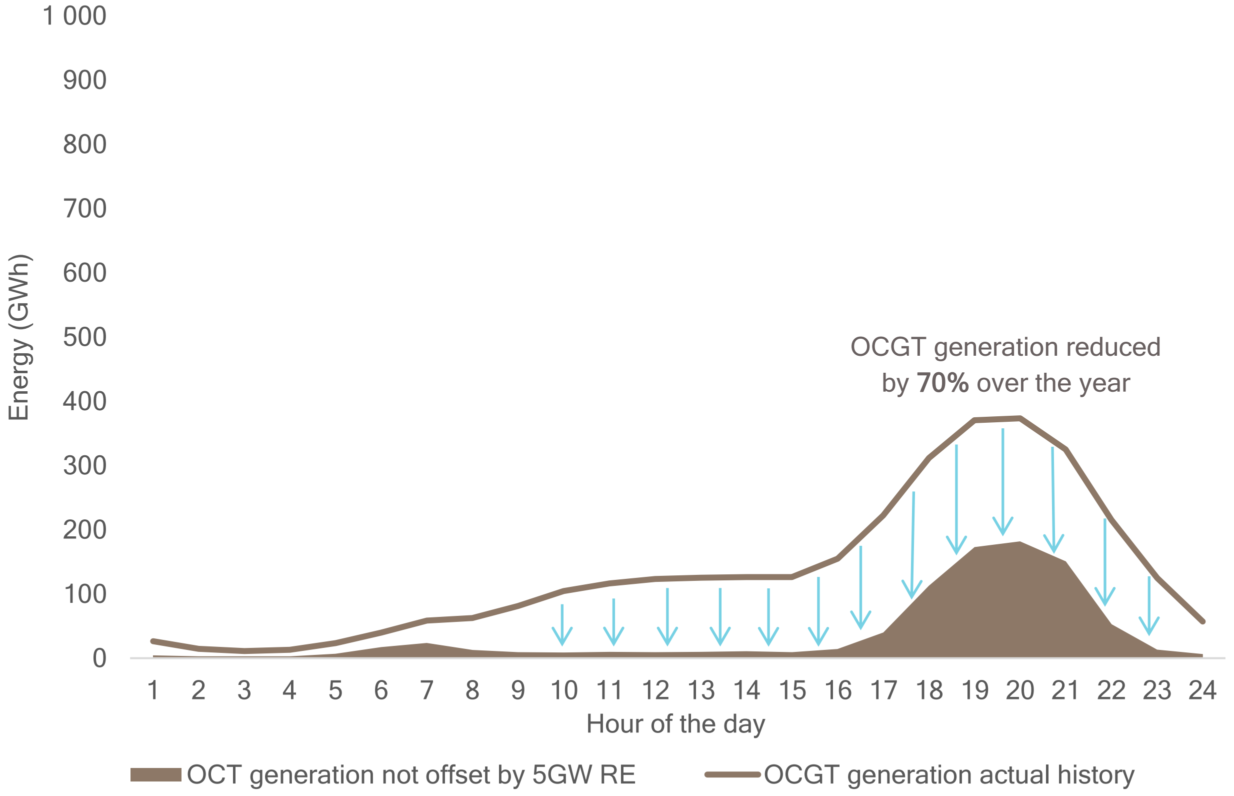


The 76% reduction in load shedding is however just the beginning of the Direct Impact benefits that an additional 5 GW of renewables would have had.

In addition to the renewables and load shedding hourly profile, Figure 4 also shows the hourly distribution of OCGT generation (brown bars) and pumped storage generation (blue bars) during 2021. Based on these histograms one would expect many hours of the year in which the renewable energy would have offset some or all of the diesel burned by OCGTs, and the need to discharge some or all of the water from the pumped storage facilities to generate power. This is indeed the case as evidenced by Figure 5 and Figure 6, which illustrate the dramatic reduction in both pumped storage and OCGT generation offset by the additional energy left over after offsetting load shedding. More than 70% of the diesel burned in 2021 would not have been required based on the direct offset impact from an additional 5 GW of renewable capacity. More than 60% of the energy generated by the pumped storage facilities would not have needed to cycle through them in the first place, adding a further third of this energy to the grid by avoiding the pumping cycle losses (see Box 1.). Figure 7 illustrates the reduction in capacity factor[41] of OCGTs and pumped storage generators for the full range of additional renewable capacity contemplated in our study based on the direct impact of the additional energy.

Avoiding unnecessary discharge from the pumped storage dams has further benefits in respect of security of supply, as the pumped storage assets are more fully charged for more of the time. An additional 5 GW of renewables would have increased the average available stored energy by more than 10% (see Figure 8), *just by offsetting pumped storage generation* and leaving water in the upper dams for later use – this is before any re-dispatch of the pumped storage is considered.

Figure 5: OCGT generation from 2021 showing actual and remainder after offset by 5 GW of additional renewables



[41] Reduction in capacity factor is directly proportional to the reduction in energy generated by each asset.

Figure 6: Pumped storage generation from 2021 showing actual and remainder after offset by 5 GW of additional renewables

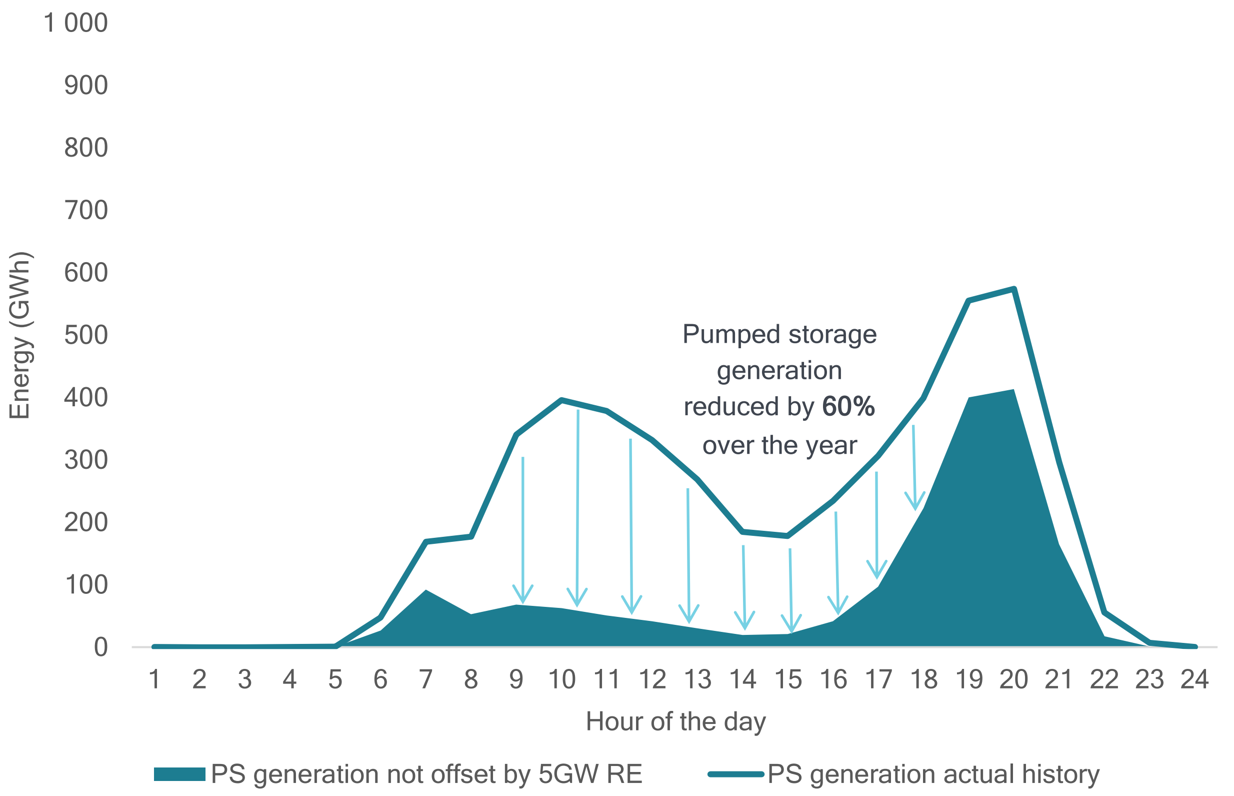


Figure 7: Reduction in the Capacity Factor of OCGT and pumped storage achieved by the Direct Impact of adding renewable energy to the system

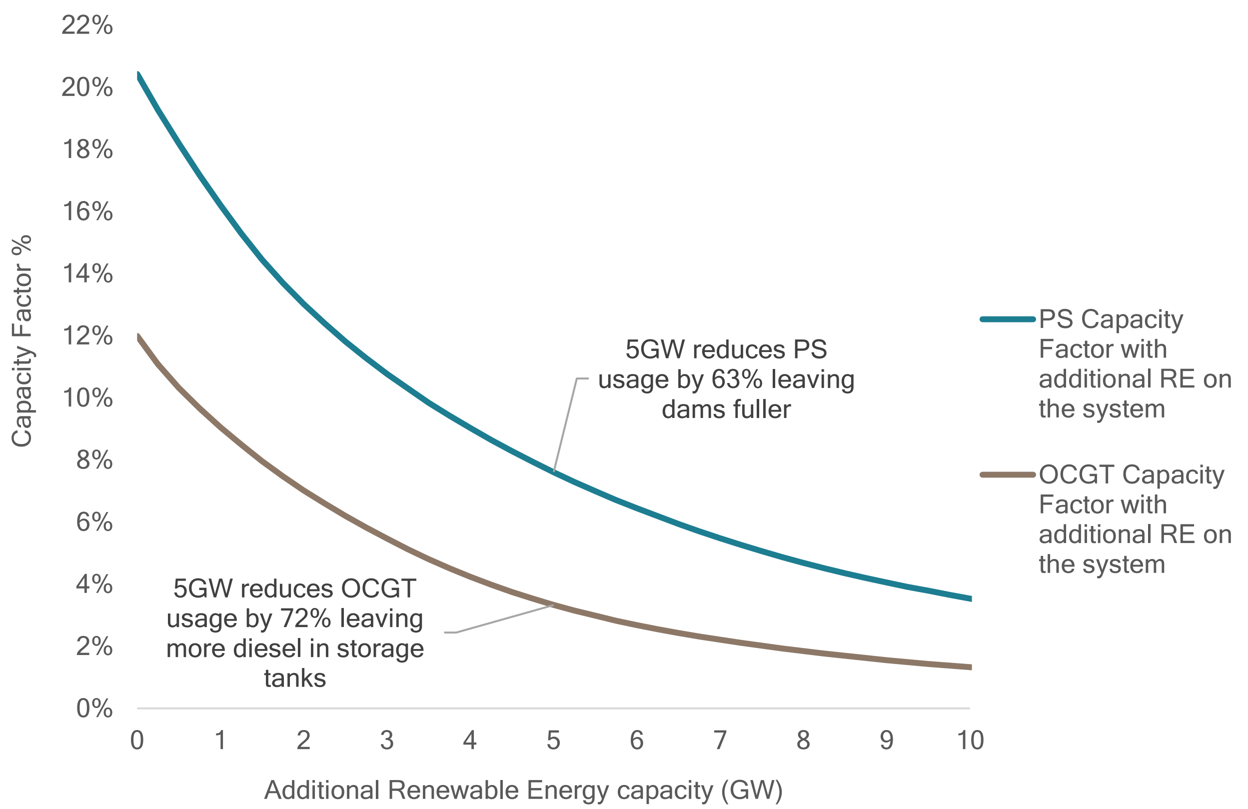
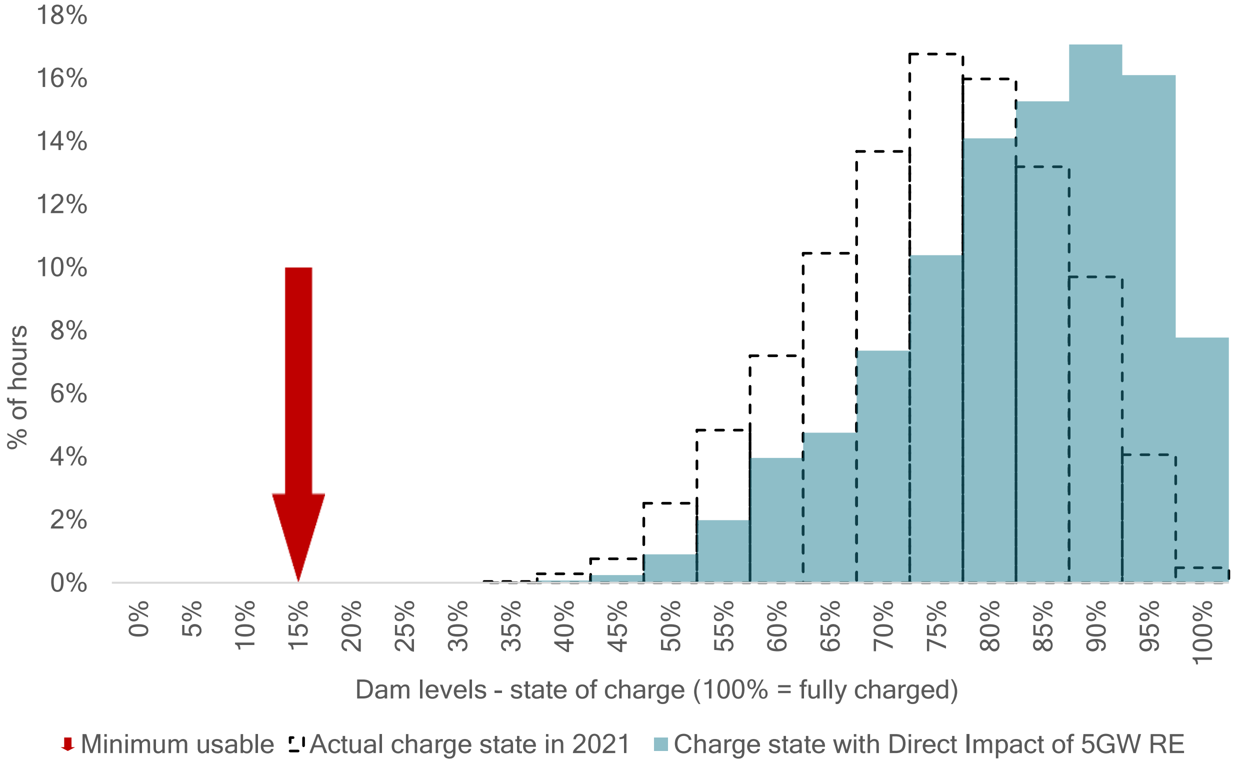


Figure 8: Histogram showing distribution of pumped storage state of charge if 5 GW of additional renewables had been available in 2021

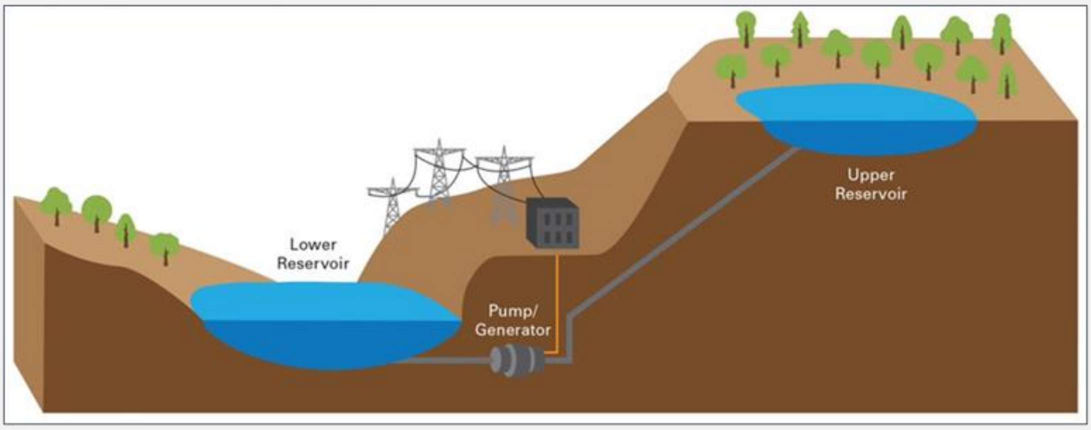


Box 1. The system value of pumped storage assets and the benefit of fully charged dams

The pumped storage facilities are configurations of two water reservoirs (dams) at different elevations and generate power as water flows from the upper to the lower dam, discharging through a turbine. The pumped storage facilities are essentially large batteries and leaving water in the upper dams (i.e. not discharging the "battery") has two distinct advantages:

1. The state of charge of the pumped storage battery is kept at a higher level which significantly enhances the system's ability to provide secure supply. Pumped storage is one of Eskom's first lines of defence in the fight against load shedding as it can be dispatched almost instantaneously in the event of unexpected generation failures. Having the batteries fully charged for more of the time means there is more in the tank to address these eventualities, and to deal with longer-term energy shortfalls. This reduces the need for Eskom to burn expensive diesel in the OCGTs – which are the next line of defence when the pumped storage runs out of water or has insufficient generation capacity to deal with a shortfall.
2. **Leaving the water in the upper dam for later use saves the energy required to pump that water back up in a subsequent hour**. This results in a 'release' of the energy that would have been needed to fill the dam in the next cycle (e.g. during the night-time hours that the water would have had to be pumped back up). However, there is a further significant bonus to this. The round-trip efficiency of pumped storage facilities – a measure of the amount of electricity which can be retrieved after it has been stored –is approximately 75%. This means that every kWh generated when water flows out of the dam, required one third more (25%/75% = 1/3) energy to be generated in the first place. Conversely, every 1 kWh of additional renewable energy that displaces power generated from the pumped storage, results in 1.33kWh of energy being 'released' to the system.

The pumped storage facilities are a tremendously valuable resource, but require a system with plenty of cheap, reliable, predictable energy to function optimally – none of which South Africa has at the moment. The current state of affairs which requires constant cycling of the pumped storage to ensure that its generation capacity is always available results in too much of the precious energy we do have, being lost through the pumped storage round trip efficiency losses. The good news is that turning this around by adding any new energy to the system invokes a virtuous cycle of disproportionate benefits, breaking the current shackles on both pumped storage and OCGT assets.



Depiction of pumped storage asset configuration *(Encyclopédie de l'énergie, 2021)*

Figure 9 illustrates the extent to which additional renewables would extract greater utility from the existing pumped storage assets. These assets are in effect just long-duration batteries and are significantly under-utilised in the current system, but provide great opportunity to support an increasing penetration of renewables. Figure 9 illustrates only the direct impact of 5 GW of additional renewable capacity – i.e. it is not based on an optimal re-dispatch of the pumped storage but merely shows the effect of offsetting pumped storage generation with surplus renewable energy (after offsetting load shedding and OCGT) at the time it is generated. In Figure 9, the dark green shaded profile illustrates the same hourly distribution of energy generated by 5 GW renewables in the year as in Figure 4. The profile illustrated by the black line indicates the *net hourly impact* of this additional energy in the system, when surplus energy is utilised to avoid having to discharge the pumped storage to generate power. As explained in Box 1. , avoided discharge from the pumped storage means that a large portion of energy is 'released' at the time when the next replenishment cycle would have been – i.e. this energy does not need to be used to pump water into the upper dams (it is already there).

This 'released' energy thus becomes available to the system, as demonstrated by the sharp hike in the profile of the black line from 21h00 to 7h00. Because this energy is no longer subject to the pumping cycle losses, more is 'released' than would have ultimately been discharged from the pumped storage – the net result is a *bonus* of energy to the system. Thus, 5 GW of additional renewables would have generated a total of 13.83 TWh in 2021, but would have *added 14.83 TWh to the power system*, the difference of 1 TWh is the saving by avoiding pumping cycle losses and comes at zero cost.

Figure 9: Net impact of 5 GW of additional renewables – illustrating energy 'released' by the avoided discharge from pumped storage (PS) assets

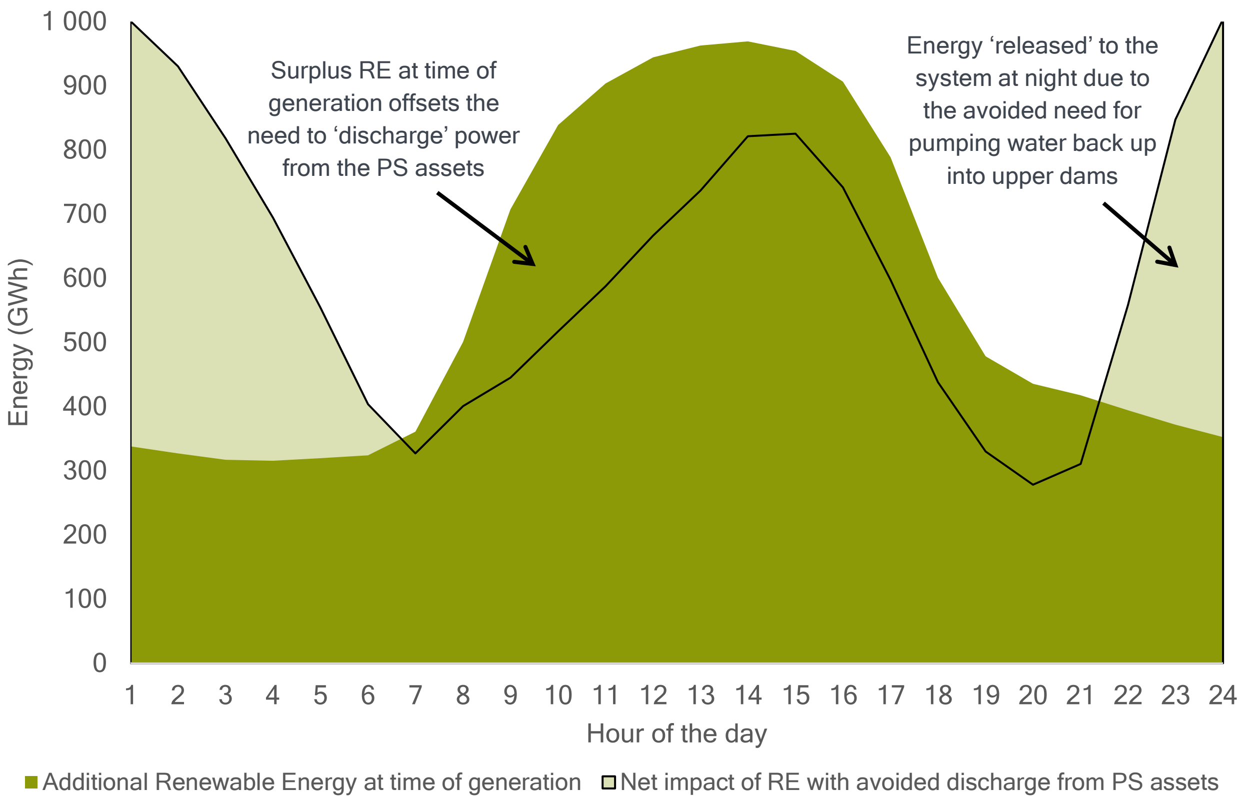


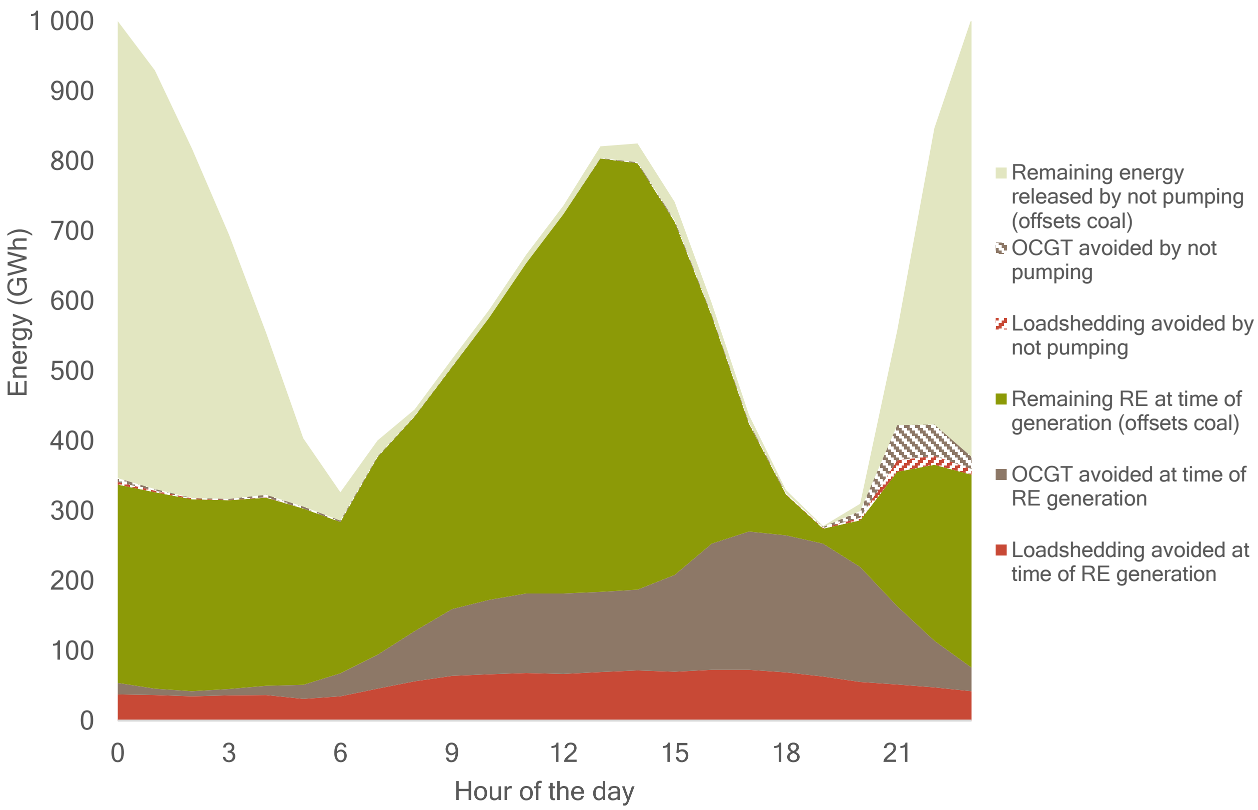
Figure 10 then shows on an hourly basis how the net 14.83 TWh contribution from 5 GW would have been put to use in the power system for the 2021 year.

At the bottom of the figure, we see the amount of load shedding that would have been reduced in each hour just by having additional renewable energy available on the system during that hour (red shading) and the amount of generation by diesel-fired OCGTs which would have been avoided (brown shading) by having renewable energy available during that hour, after offsetting the load shedding.

The dark green area is the renewable energy at time of generation that is available after offsetting load shedding and OCGTs – this would replace coal-fired power. The light green shaded area at the top of the figure is the energy that is 'released' (as described in Figure 9), purely because the energy is not needed to pump water back into the upper dams (i.e. recharge the pumped storage). This also offsets coal-fired electricity which would have been used to recharge the pumped storage assets.

The small brown patterned area illustrates the further amount of OCGT generation that is also avoided through the energy 'released' to the system at night. Finally, the small red patterned area demonstrates the further amount of load shedding that would also be offset by the energy 'released' by avoided pumping.

Figure 10: Attribution of the hourly distribution of total annual net generation from 5 GW of additional renewables



It is important to bear in mind that the above results only indicate the Direct Impact of the additional renewable energy on load shedding i.e. the load shedding avoided at time of renewable generation plus the small additional load shedding avoided by energy 'released' through obviated pumping.

There is a further, substantial 'knock-on' reduction in load shedding that would have been made possible by the additional renewable energy through releasing the constraints on the OCGT and pumped storage facilities.

3.2.2 THE KNOCK-ON IMPACT - AN IMMENSE IMPROVEMENT IN PEAKING ASSET PERFORMANCE

The previous section demonstrates that in addition to avoiding 76% of load shedding, 5 GW of additional renewable capacity would have saved more than 70% of the diesel burned in 2021, reducing the OCGT capacity factor from 12% to 3.3%. A similar reduction in the generation from pumped storage assets would have seen that capacity factor fall from more than 20% to under 8%. With the resulting full diesel tanks and dams at the system operator's disposal, how could the OCGT and pumped storage generators have better been deployed to address the remaining hours of load shedding?

3.2.2.1 From Vicious Cycle to Virtuous Cycle

A naïve calculation based on the simple spreadsheet model showed a further 20.5% could be addressed by unhindered use of OCGTs (this would have raised the capacity factor from 3.3% to 4.7% by burning some of the saved fuel) and a negligible increase in pumped storage discharge cycling (still under 8%). However, a rational system operator would have used the well-replenished pumped storage more and the expensive OCGTs less in order to address the remaining hours. Indeed, the system dispatch modelling confirmed that more optimal peaking asset use could have addressed the same further 20.5% of load shedding, but without burning any more diesel by incurring a very small increase in pumped storage capacity factor (to 8.4%).

The results of the system dispatch modelling demonstrate that adding anything more than 4 GW of renewable capacity to the system would have been sufficient to break the vicious cycle described in section 2. The additional renewable energy would have initiated a virtuous cycle of savings in both diesel and pumped storage use that would have resulted in fuller tanks and dams allowing unhindered use of the peaking assets to address both the energy and capacity causes of load shedding.

Figure 11 shows how the 'Knock-on Impact' attendant to the addition of renewable generation capacity would have further reduced load shedding in 2021, virtually eliminating it for capacities greater than 4 GW. If 5 GW of additional renewables had been available load shedding would have been reduced by 96.5%.

Figure 11 also highlights the constraint placed on the system by the current insufficient diesel storage, but this should be seen as an easy opportunity to contribute to the solution[42]. Diesel storage is relatively cheap and quick to build and will benefit the system into the future as renewable penetration grows[43]. Section 8.1 in the Appendix illustrates in more detail the impact of increasing onsite diesel storage capacity.

The reduced load shedding would likely have spawned a host of secondary system benefits that would have in turn further reduced its incidence and impact although these are not factored into the analysis:

- 5 GW of additional renewable capacity would have resulted in coal-generated energy reducing by about 10 TWh, this is the equivalent annual production from 2 160 MW[44] of coal capacity (the entire installed capacity of Kusile in 2021) or four average-sized[45] coal units. This would have provided a large increase in the "space" for significantly more maintenance to have been done on the coal fleet, thus increasing the EAF and likely further reducing the need for load shedding. 2 160 MW of capacity is equivalent to more than 40% of the average PCLF[46] for 2021 of 5 021 MW. In other words, the equivalent coal capacity idled over the year as a result of the additional renewable energy would have been 40% of the capacity (across all generation sources) planned to be taken out for maintenance through the year. Of course, this does not mean that 40% more maintenance could have been done due to the timing of the additional energy, but it is a useful gauge of the scale of the relief that renewables would provide to the coal fleet. We have not quantified the extent of this impact in the numbers, making our full estimates of load shedding reduction from

[42] See Figure 15 in the Appendix

[43] As renewable penetration increases, the power system will move from having to deal with the unpredictable events presented by unreliable coal plant, to less frequent more predictable but potentially longer duration events caused by occasional adverse weather conditions (a coincidence of less wind and less sunshine throughout the areas where renewables are located). Provided sufficient renewables are added in conjunction with new diesel storage, the diesel actually burned will reduce precipitously even if all the financial constraints on its use are lifted – it will simply be unnecessary to burn it very often.

[44] based on the 2021 coal capacity factor of 53.4%

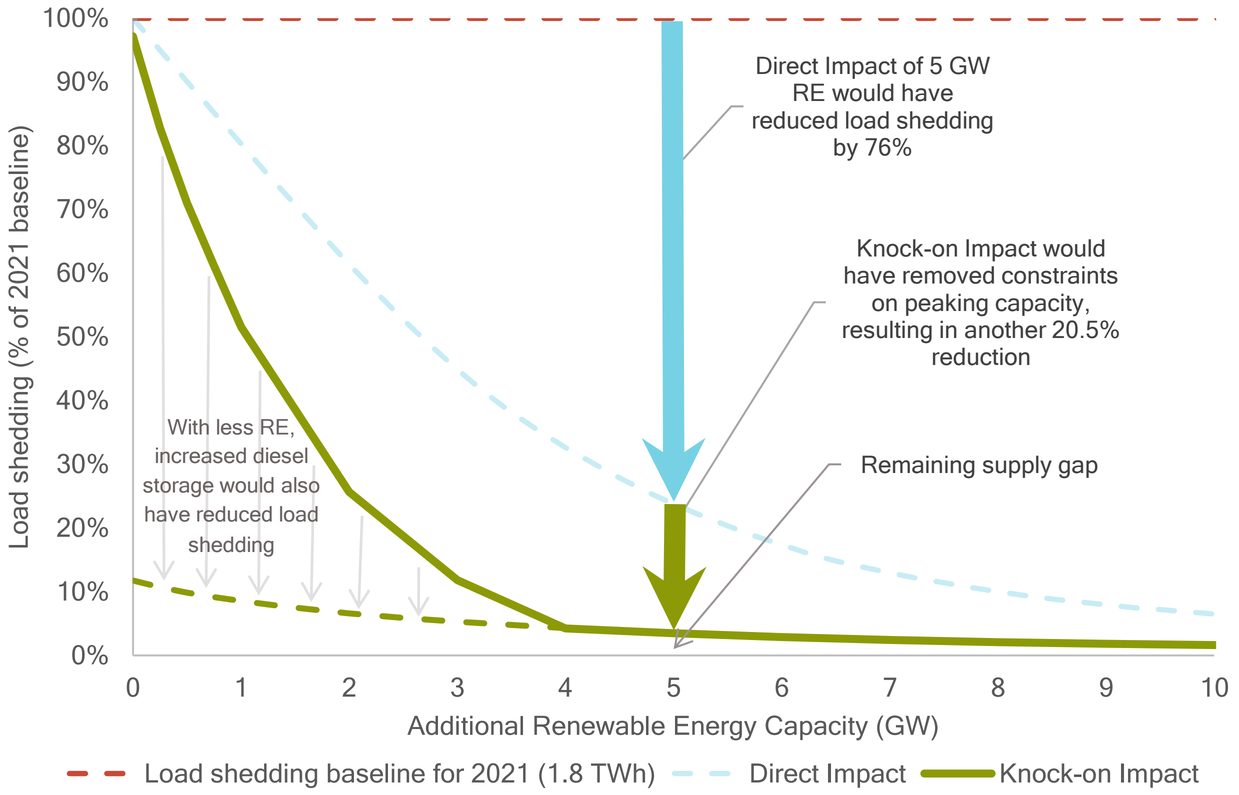
[45] Eskom had 80 coal units in use across 15 stations as at September 2021 with capacities ranging from 114 MW to 720 MW, average size 493 MW

[46] Planned Capability Loss Factor

additional renewables highly conservative in this regard.

- The significant collateral damage to distribution infrastructure caused by constant switching on and off would have been largely eliminated by 5 GW of additional renewables.

Figure 11: Summary of results: 5 GW Additional renewables would have reduced load shedding by 96.5% in 2021

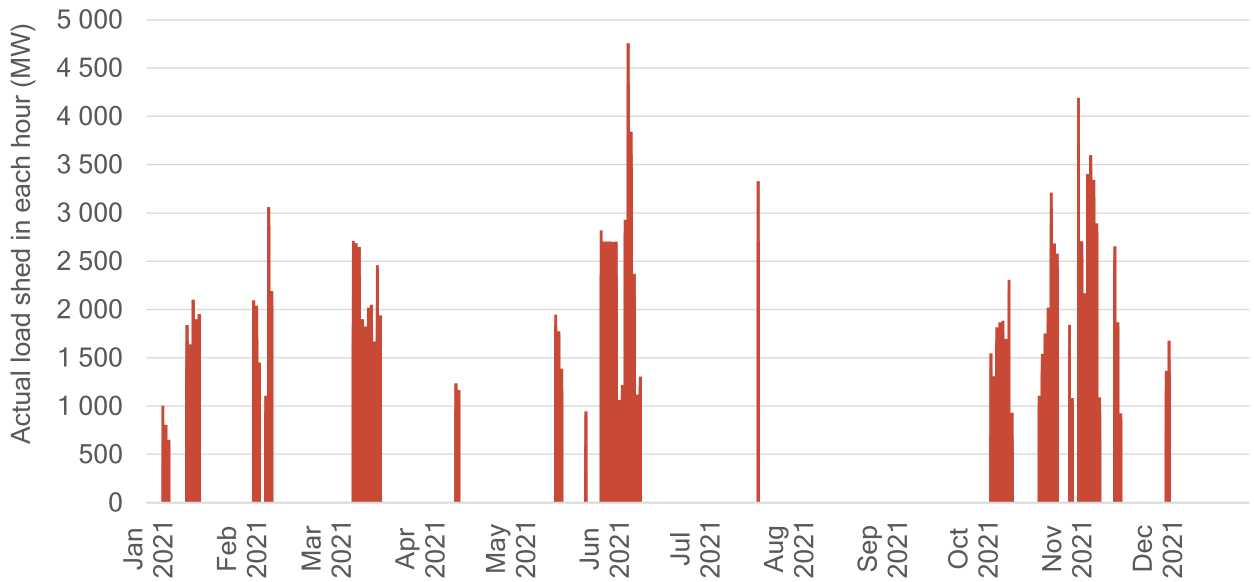


4 CLOSING THE GAP THAT RENEWABLES CANNOT

It is incontrovertibly clear from the previous section that adding renewables to the power system would dramatically reduce load shedding from the first new MW of added capacity. But even with large amounts of renewable capacity, there would still be a few remaining hours of load shedding (~3.5% of the overall TWh shed with 5 GW of additional renewables). What does this remainder of the problem look like and how could it be addressed in the power system? To answer this, we needed a few extra tools to understand the nature of the gap that renewables cannot solve – the load-duration curve is one of them.

Load shedding occurred throughout the year in 2021, scattered among the 8 760 hours as shown in Figure 12.

Figure 12: Hourly load shed in 2021

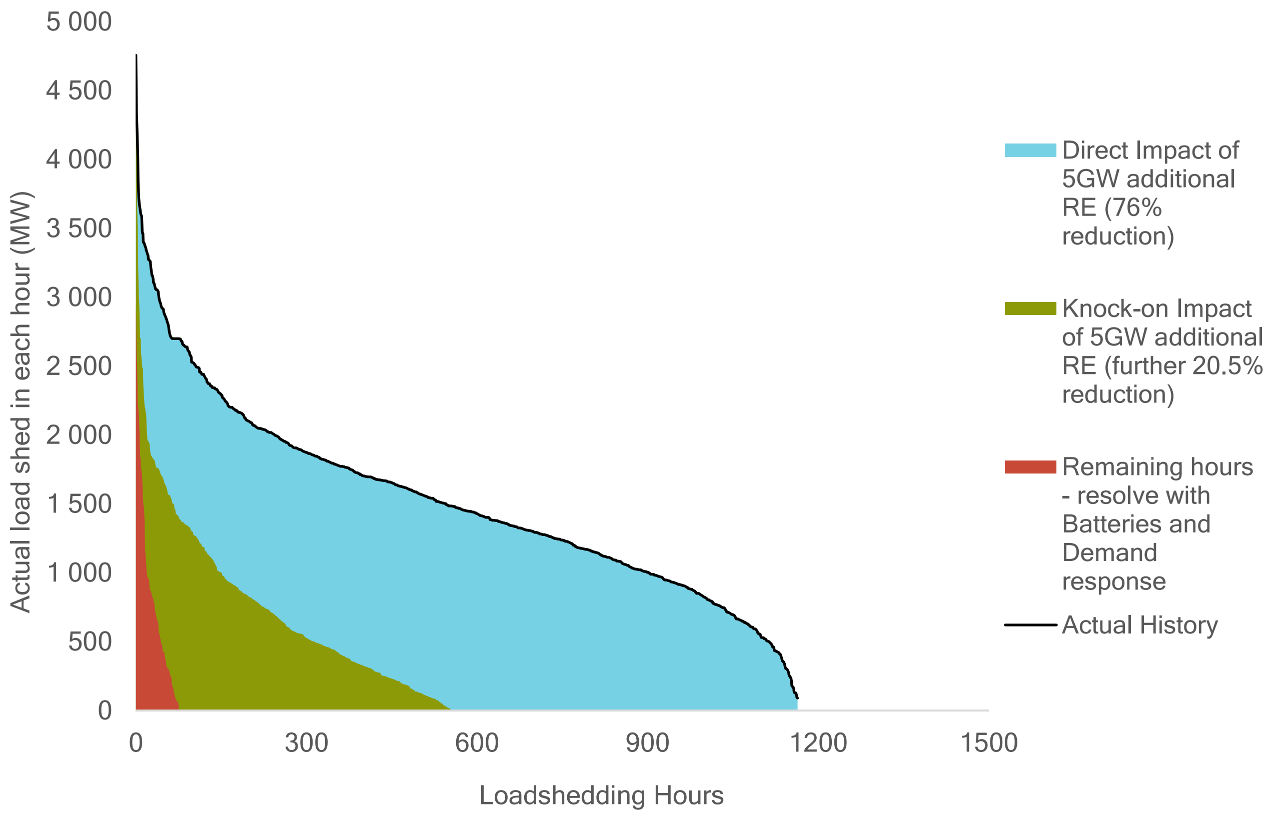


Looking at the chronological occurrence however makes it difficult to gauge the extent of the problem – how many hours were there when more than 4 000 MW was shed for example? This kind of question becomes very important in understanding the interventions needed to close the final supply gap – do we need something that provides an additional 2 000 MW say for just a few hours, or for many hours?

A load-duration curve in this context takes all the hours from the year, and sorts them in order of the amount of load shed in each hour – it is just a graphical depiction of the sorted list of load shedding hours from worst (on the left) to least severity (on the right). The black line in Figure 13 is the load shedding duration curve for 2021, illustrating the 1 165 hours of load shedding in which the amount shed in each hour ranged from 100 MW to 4 700 MW. The blue shaded area shows how this load shedding curve would have shrunk with the Direct Impact of 5 GW of additional renewables, whilst the green shaded area shows the further Knock-on Impact which enables the peaking assets to be used more optimally. The red shaded area shows the remaining hours that would not have been addressed through simple addition of renewable energy.

The addition of 5 GW of renewables would have reduced the load shedding problem from 1 165 hours to 79 hours – a massive reduction in both the scale and severity of the problem. Most of the remaining hours (59 of 79) would have seen less than 1 000 MW of load shed (i.e. stage 1-2), but 20 hours would have remained exceeding 1 000 MW of which 10 hours would have required up to 3 000 MW to be shed (i.e. stage 2-4).

Figure 13: The load-duration curve of load shedding in 2021 accounting for the full benefit of 5 GW of additional renewables



4.1 RESOLVING THE LAST REMAINING HOURS

Cost-effectively addressing such a small number of hours in which demand exceeds supply is best achieved without building any new generation capacity. We investigated the cost and efficacy of two interventions: the introduction and/or expansion of a demand response programme, and the installation of additional battery storage.

Without building any further physical infrastructure it would have been possible to address most of the remaining hours through the extension of Eskom's existing demand response programme. Demand response programmes are based on an agreement between Eskom and participating customers and require customers to reduce their load by a certain percentage on instruction by Eskom at any time. In return, customers are provided financial compensation.

Eskom's existing Interruptible Load Shed (ILS) programme allowed it to address short term demand spikes of up to 842 MW[47] covering 218 hours in 2021, with the total energy reduction over the year summing to 57 GWh. By signing up another 1 000 MW of demand to a similar programme aggregated

[47] This capacity figure is calculated on the ILS energy provided (saved) within the hourly time slots that the data is provided by Eskom. In reality the demand offset provided is likely to be quite a bit higher, but for a period of less than an hour.

across large industrial customers, load shedding in 2021 could have been reduced to just 20 hours. Participating customers would be incentivised through a compensatory tariff adjustment – we assumed that customers would be paid per kWh of reduced load at twice the cost of dispatching the OCGTs.

The 20 remaining unaddressed load shedding hours would have consisted of about 10 hours each of stage 1-2 and stage 2-3 events. The dispatch modelling confirms that these remaining few hours could easily have been resolved with 2 000 MW of 1hr battery storage.

5 WHAT IT WOULD HAVE COST - LESS THAN NOTHING!

The economic cost of load shedding is notoriously difficult to quantify and debate on the exact GDP[48] impact to the economy is lively and ongoing. In this cost analysis we steer clear of that debate and focus purely on the annual cash cost impact to Eskom and thereby the price of electricity that would have accompanied the intervention of renewables, demand response and batteries in preventing load shedding in 2021.

5.1 REALISTIC COST ASSESSED WITH SYSTEM DISPATCH MODEL

In order to assess the cost impact properly, we used the system dispatch model to simulate how a reasonable system operator would have dispatched the power system in 2021 if they had additionally had access to 5 GW of renewables, 1 GW of demand response and 2 GW of 1-hour batteries. As expected, the additional energy from the renewables plus the capacity from the demand response and batteries would have allowed load shedding to be completely eliminated with even less use of the OCGTs than contemplated in section 3.2.2 – some 80% less[49] than the actual use in 2021. The knock-on impact analysis of section 3.2.2 only considered the additional benefit to the system of 5 GW of renewables and did not include the addition of demand response and batteries.

The system dispatch model shows that with an additional 5 GW of renewables, 1 GW of demand response and 2 GW of 1-hour batteries at their disposal the system operator would have been able to provide an adequate supply of power in 2021 with no load shedding. This could have been achieved with the 13.8 TWh of additional renewable energy whilst saving 2.7 TWh of diesel-fired OCGT generation (83% reduction) and 9.98 TWh of coal-fired generation (5.4% reduction). The extension of the demand response programme would have required participating customers to provide load reduction totalling 0.01 TWh of energy over the course of the year – amounting to a 10% extension of the 57 GWh load reduction extracted from the existing ILS programme in 2021.

5.2 COST CONSIDERATIONS

We considered four separate annual cost/savings elements of the intervention:

1. **Energy costs and savings** – the cost to purchase 5 GW of additional renewable capacity and the savings occasioned by reduced diesel and coal burn,
2. **Additional sales** – solving load shedding would have meant that Eskom could have sold the power that instead it could not deliver to customers, resulting in additional revenue to Eskom,
3. **Demand response** – an extension of the ILS programme would require negotiated pricing in favour of participating customers, which would come at a cost to Eskom,
4. **Batteries** – the capital cost of batteries is taken into account on the basis that it would be recovered over the life of the batteries at a constant annual amount in real terms.

We conducted the analysis in two separate framings as follows:

a) The retrospective case in which we consider all costs based on Eskom's FY21

[48] Gross Domestic Product

[49] The simulated dispatch required OCGTs to run with just a 2% capacity factor

results, and with renewables priced as if they had been procured and installed in an uninterrupted REIPPPP ongoing from 2016.

b) The prospective case in which we conduct a sensitivity analysis on the major driving variables of renewables costs and the price of diesel. This allows us to consider the cost implications in the current world where renewables that will be deployed will not be at legacy REIPPPP prices from delayed rounds but at closing prices from BW5, BW6 and the RMIPPPP, and diesel subject to the geopolitical pricing risks that manifested in the last year.

Our detailed cost assumptions are to be found in the appendix section 8.4.

5.3 RETROSPECTIVE VIEW - THE COST OF ENDING LOAD SHEDDING IN 2021 BASED ON ESKOM'S FY21 ACTUALS

Table 1 shows the full analysis of the costs associated with an additional 5 GW of renewables having been online in 2021. For this analysis we have used a renewable cost consistent with prices that would likely have been achieved had the REIPPPP process continued and annual capacity had been installed steadily from 2018. The 5 GW of renewables would have generated 13.8 TWh of additional energy costing R9.4 Bn. However, this cost would have been almost entirely offset by the R8.2 Bn saving in required diesel burn due to both the direct offset of renewable energy at the time the OCGTs were running, the further benefit of charged and usable pumped storage, and further reduction from the use of the additional batteries. Renewable energy would have also reduced coal generation by nearly 10 TWh saving a further R4.2 Bn in coal costs. The net energy savings would have achieved a cost reduction for the year of R3 Bn. The cost of eliminating the last few hours of load shedding would have been achieved with just over R2 Bn consisting primarily of the capital recovery cost of 2 GW of battery storage. With the elimination of load shedding, Eskom would have been able to sell the energy that it could not serve to customers at the average sales price generating a further R1.65 Bn. All added together, the net cost impact had an additional 5 GW of renewables been online in 2021 would have been a reduction of R2.5 Bn in Eskom's costs for the year. This saving if passed through to the tariff (along with the additional sales possible) would have resulted in a 2.2 c/kWh reduction in the sale price of electricity, based on the FY21 sales volumes and revenue.

Table 1: Cost impact for 2021 had 5 GW of additional renewable capacity been available

Energy Costs and savings		TWh		R/kWh	Annual Costs (Savings)	
Cost of RE		13.83	@	0.68	9.40	R'Bn
Saving Diesel OCGT Cost	*-83%*	-2.70	@	3.04	(8.20)	R'Bn
Saving Coal cost	*-5.4%*	-9.98	@	0.42	(4.19)	R'Bn
Net Energy Cost (Saving)					(2.99)	R'Bn
Cost of further interventions						
1/ Demand Response						
Extend ILS by 1GW @ 100% premium over OCGT cost		0.01	@	6.08	0.03	R'Bn
2/ Batteries						
2GW @ R7500/kW						
15 years at 8.3% real						
Annual capital cost					1.78	R'Bn
Ops and Maintenance					0.30	R'Bn
Sale of formerly unserved power						
Loadshedding avoided (includes system losses)		1.77				
System losses (11.78%)		-0.21				
Increased Sales create net saving		1.57	@	-1.06	(1.65)	R'Bn
Net Cost (Saving) to completely eliminate loadshedding 100%					**(2.53)**	**R'Bn**
Net impact on average sale price of electricity					**-2.2**	**c/kWh**

5.4 PROSPECTIVE VIEW - COST OF ENDING LOAD SHEDDING AT CURRENT ENERGY PRICES FOR A YEAR SIMILAR TO 2021

In the current reality the price of diesel has almost doubled since FY21 and the renewables that are and will be procured will not be at historic prices from the 2016 – 2021 period, but will be based on prices achieved (and closed) under BW5, BW6 and the RMIPPPP. By conducting a sensitivity analysis across the likely range of diesel and renewables prices we are able to tabulate the more realistic annual savings impact that would be achieved by an intervention consisting of 5 GW of additional renewables, 2 GW of batteries and a 1 GW demand response programme. Table 2 and Table 3 show the result of this analysis and demonstrate emphatically that the implementation of such an intervention whilst ending load shedding would also save Eskom likely in excess of R10 Bn per year at current fuel prices (where OCGT costs are currently in excess of R5.50/kWh[50]). The green shaded cells in Table 2 indicate a cost saving for Eskom, and in Table 3 indicate a saving on the tariff for consumers. For all credible renewable energy prices and diesel costs the intervention would come at no cost or at a saving to Eskom. Based on the FY21 sales revenue and volumes the likely savings would amount to a reduction of at least 5 c/kWh when expressed in terms of a tariff impact.

[50] See Figure 16 in the Appendix for more detail.

Table 2: Net annual cost (saving) to have completely eliminated load shedding under different renewable and diesel price assumptions

Includes 5 GW additional renewables, 2 GW batteries and 1 GW DR. Cost (saving) expressed in R'Bn.

<- RE cost R/kWh ->	<- OCGT Diesel cost R/kWh -> 2.50	3.00	3.50	4.00	5.00	6.00
0.50	(3.57)	(4.91)	(6.25)	(7.60)	(10.28)	(12.97)
0.55	(2.87)	(4.22)	(5.56)	(6.91)	(9.59)	(12.28)
0.60	(2.18)	(3.53)	(4.87)	(6.21)	(8.90)	(11.59)
0.65	(1.49)	(2.83)	(4.18)	(5.52)	(8.21)	(10.90)
0.70	(0.80)	(2.14)	(3.49)	(4.83)	(7.52)	(10.21)
0.75	(0.11)	(1.45)	(2.80)	(4.14)	(6.83)	(9.52)
0.80	0.58	(0.76)	(2.10)	(3.45)	(6.14)	(8.82)
0.85	1.27	(0.07)	(1.41)	(2.76)	(5.44)	(8.13)
0.90	1.97	0.62	(0.72)	(2.07)	(4.75)	(7.44)

Table 3: Impact 5 GW of additional renewable capacity would have on the average sale price of electricity under different renewable and diesel price assumptions

c/kWh change to Eskom sale price of electricity

<- RE cost R/kWh ->	<- OCGT Diesel cost R/kWh -> 2.50	3.00	3.50	4.00	5.00	6.00
0.50	-2.7	-3.4	-4.1	-4.8	-6.2	-7.6
0.55	-2.3	-3.0	-3.7	-4.4	-5.8	-7.2
0.60	-2.0	-2.7	-3.4	-4.1	-5.5	-6.8
0.65	-1.6	-2.3	-3.0	-3.7	-5.1	-6.5
0.70	-1.3	-2.0	-2.7	-3.4	-4.7	-6.1
0.75	-0.9	-1.6	-2.3	-3.0	-4.4	-5.8
0.80	-0.6	-1.2	-1.9	-2.6	-4.0	-5.4
0.85	-0.2	-0.9	-1.6	-2.3	-3.7	-5.1
0.90	0.2	-0.5	-1.2	-1.9	-3.3	-4.7

6 EMISSIONS IMPACT

Adding 5 GW of renewables with the support of demand response and batteries would not only put paid to load shedding, save significant sums of money, but also have a material impact on Eskom's annual emissions. This is primarily due to the resultant reduction in coal burn required, as well as the reduced emissions from lower utilisation of the OCGT and associated diesel burn. Table 4 shows the breakdown of the 13.6 Mt annual saving in carbon dioxide-equivalent (CO_2e) emissions that would be achieved. For context, Eskom's emissions for FY21 were 206.8 Mt – the saving would thus result in an approximate 6.6% decrease in this figure.

Table 4: CO_2e Emission reduction achieved by additional 5 GW of renewables, 1 GW demand response, 2 GW batteries

Fuel	Avoided energy *(TWh)*	Carbon intensity *(kgCO₂e/kWh)*	Emissions saving *(Mt per annum)*
Diesel Burn	-2.70	0.856	-2.31
Coal Burn	-9.98	1.136	-11.34
			-13.6

7 CONCLUSIONS

The detailed analysis of the power system data from 2021 conclusively reveals the following:

1. Load shedding is eminently solvable and would have been virtually eliminated in 2021 had there been more renewables on the system. 5 GW of additional renewables (well within what could have feasibly been installed by 2021 under an uninterrupted REIPPPP programme) would have put paid to 96.5% of load shedding.
2. Adding wind and solar generation capacity to the current power system reduces the system risk in contrast to a pervasive narrative that variable renewable generation makes it more difficult to meet demand. In 2021 additional wind and solar capacity would, in addition to reducing load shedding, have resulted in a 70%-80% reduction in the requirement to run OCGTs whilst materially increasing the average available energy stored in the pumped storage facilities. Adding renewable capacity not only addresses load shedding at the time the wind and solar assets generate power, but the additional energy available at other times allows the OCGT and pumped storage peaking assets to be operated fully when necessary. Both diesel and water storage levels have time to recover between periods when they are required, removing the choke this currently places on the use of OCGTs and the pumped storage respectively.
3. 5 GW of additional renewables would have generated more energy than was required to end load shedding based on the 2021 demand. The additional energy would have decreased the generation requirement from the coal fleet by about 10 TWh (about 6% reduction in coal burned). In addition to the cost saving, this reduction in use would have allowed for significantly more maintenance to be achieved on the coal fleet (10 TWh is the equivalent generation from about 2 GW of coal capacity), increasing the system's EAF.

4. Additional interventions to eliminate the remaining 3.5% of load shedding not resolved by 5 GW of renewables are easy and quick to implement – a 1 GW demand response programme and the installation of 2 GW of one-hour batteries could reasonably be achieved within 12 months.
5. The savings realised by reduced diesel (R8.2 Bn) and coal (R4.2 Bn) usage, more than cover the cost of the 5 GW of renewables (R9.4 Bn), allowing sufficient saving to cover the additional annual cost of a demand response programme plus 2 GW of batteries (together about R2.2 Bn). Without load shedding, Eskom's ability to sell the electricity it could not serve in 2021 would have resulted in further revenue of R1.65 Bn. Taken in aggregate, the solution to load shedding consisting of 5 GW of renewables, 1 GW of demand response and 2 GW of batteries would have conservatively resulted in a net saving of more than R2.5 Bn in 2021.
6. Ending load shedding based on the 2021 data does not require the use of any additional fossil fuel generation. On the contrary, the deployment of 5 GW of renewables would have resulted in a reduction in fossil fuel generation by 12.7 TWh, creating a reduction of 13.6 Mt in CO_2e emissions.

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APPENDIX

8.1 EXISTING PEAKING CAPACITY

Table 5: Existing OCGT facilities

OCGT facility	*Plant Capacity (MW)*
Ankerlig	1 323
Gourikwa	735
Avon	670
Dedisa	335
Acacia	*
Port Rex	*
	3 063

*The Acacia and Port Rex facilities are used for reserve purposes only and will retire in the period to 2030

Table 6: Existing pumped storage facilities

Pumped Storage facility	*Plant Capacity (MW)*	*Storage Capacity (MWh)*
Ingula	1 324	19 353
Drakensberg	1 000	25 500
Palmiet	400	11 740
	2 724	

8.2 SYSTEM DISPATCH MODELLING ASSUMPTIONS AND DETAILS

We used dedicated system dispatch modelling software[51] to determine the load shedding impact of scenarios of additional renewables and where appropriate additional demand response and battery capacity added to the power system. For each scenario, the system dispatch model runs a chronological simulation through every hour of the 8760 hours of 2021. The simulation replicates how the system operator would have dispatched the entire power system resources (including the additional capacity) at their disposal in that hour in order to maintain a secure supply of power or to minimise the incidence of load shedding if resources were insufficient. We carefully calibrated this model to the actual operational data from Eskom for 2021, ensuring that it recreated the same outcomes achieved by the system operator in the absence of the additional resources.

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. Likewise, all solar PV facilities are modelled as a single generator, similarly for wind and other technologies.

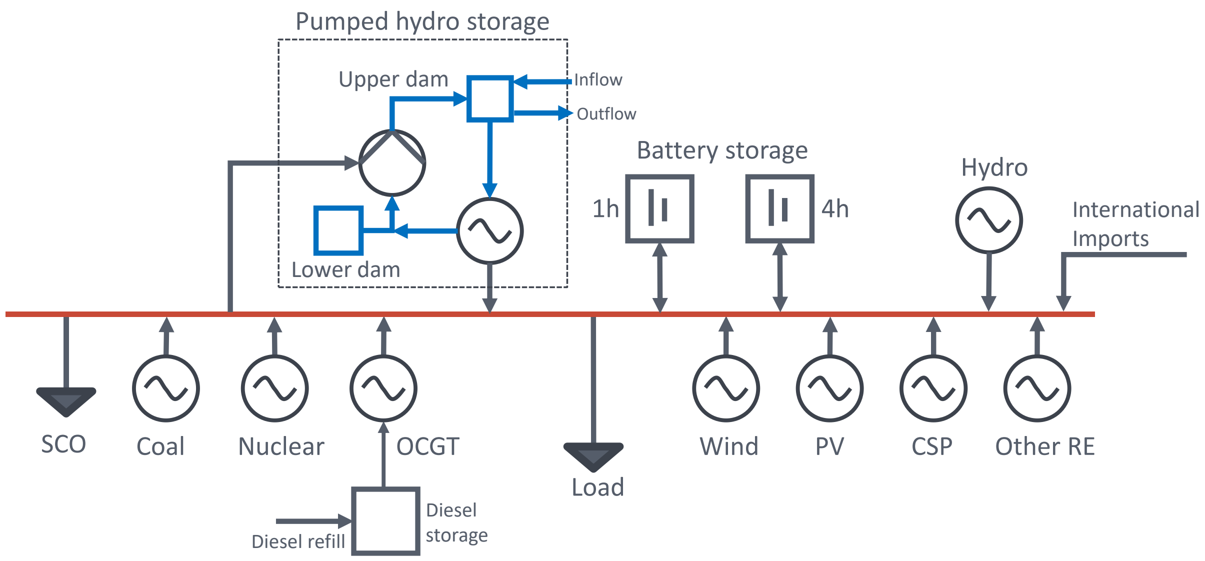
A diagram of the dispatch model showing storage and generators is presented in Figure 14. Modelling is based on a single node for the supply/demand energy balance i.e. we did not explicitly model the grid constraints. Because individual plants within a technology type are modelled as an aggregated generator, a full unit commitment is not included in the modelling. However, 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. We additionally applied some further conservative assumptions on how the coal and pumped storage assets could have been operated differently if additional renewable generation had been available. Constraints and assumptions applied in the simulated re-dispatch of the power system for 2021 are as follows:

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

- Coal capacity
    - We constrained coal generation in every hour such that it could not exceed what was achieved in that hour in the actual history.
    - A ramping constraint of 2.5 GW/h was applied in every hour, this being the maximum ramp rate achieved in 2021.
- Pumped storage
    - Maximum hourly 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 in every hour to never drop below the total stored in that hour in 2021[52]. This is a highly conservative assumption as additional energy would certainly allow for reservoir levels to fall lower than they were kept at for 2021.
- OCGTs and diesel storage
    - Diesel availability required to run the OCGTs is based on a model of aggregated available storage at the four OCGT sites (assumed to total 27 Ml) 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. This value was determined by considering the 2021 generation data and calibrating the refill rate until the capacity factor of the OCGT plants matched that of the actual data i.e. we calibrated the modelling of diesel storage and replenishment to match the extent of load shedding that appeared in the data to be as a result of diesel stock-out in 2021.
- Reserves
    - Constraints are included in the model to capture the reserve capacity that Eskom must hold out of production 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 storage) and 2.2 GW for total reserves (typically battery, pumped storage, OCGTs).
    - Unserved energy is calculated in the model when generation is insufficient to meet demand – the sum of unserved energy over the year is compared against the actual value of 1 775 GWh experienced in 2021

[52] 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.

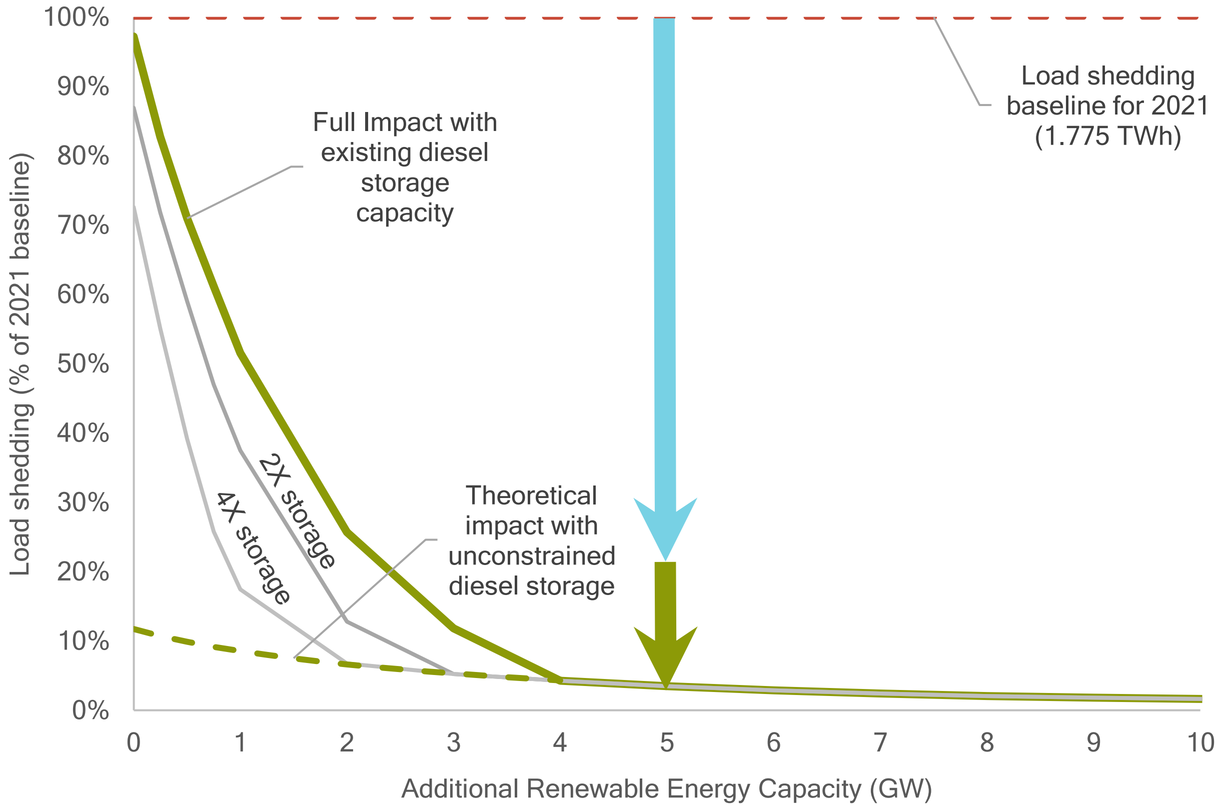
Figure 14: Diagram of dispatch model



8.3 IMPACT OF IMPROVED DIESEL STORAGE CAPACITY

Figure 15 illustrates the impact of increasing the level of onsite diesel storage capacity from the 2021 baseline of roughly 27 Ml. It is clear that improving onsite diesel storage could have significantly reduce load shedding particularly at lower levels of renewable energy penetration. Figure 15 demonstrates that if we had doubled our diesel storage in 2021 and added only 1 GW of renewable capacity to the system, load shedding could have been reduced by 60% (a 10-15% greater reduction than if our diesel storage capacity remained at 2021 levels).

Figure 15: Impact of increasing diesel storage capacity on load shedding reduction at lower levels of additional renewable capacity



8.4 ASSUMPTIONS FOR COST IMPACT ANALYSIS

8.4.1 ENERGY COST ASSUMPTIONS

8.4.1.1 Renewables

Our renewables pricing assumptions for the retrospective case attempt to construct a reasonable estimate of what the bid prices post 2016 would have been for REIPPPP power had the programme continued and capacity been installed each year accordingly. Our starting point is the 62 c/kWh bid in the BW4 expedited round. These prices were bid in 2015 with the pricing being as at April 2016. The associated capacity was never built but is indicative of the pricing for power that would have come online two years after these projects would have closed i.e. in 2018. Assuming these prices were fully inflation-indexed the power online from the 2016 bid rounds, hitting the grid from 2018 would have cost 75 c/kWh by 2021. The other data point we use is the bid pricing from Round 5 averaging 50 c/kWh. Although there may be some doubt regarding how many of these projects will close at 50 c/kWh, the threats to financial close manifest largely after the bidding process was complete. This means it is still reasonable to use the bid prices in 2021 as the end point of an assumed trajectory of how historic bid window prices might have declined during the years since 2016. The power from BW5 projects will largely come online in 2023 and as shown in Table 7, we linearly interpolated between the BW4 expedited and BW5 prices to obtain estimates for the price of renewable power that would have come online each year from 2018. Assuming a constant annual build rate, the average price of the accumulated portfolio over the four years from 2018 to 2021 is 68 c/kWh – this is our assumed price that Eskom would have been paying for additional renewable energy in 2021 had the REIPPPP not stalled.

Table 7: Assumed prices at which REIPPPP power would have been contracted if the programme had not stalled in 2016

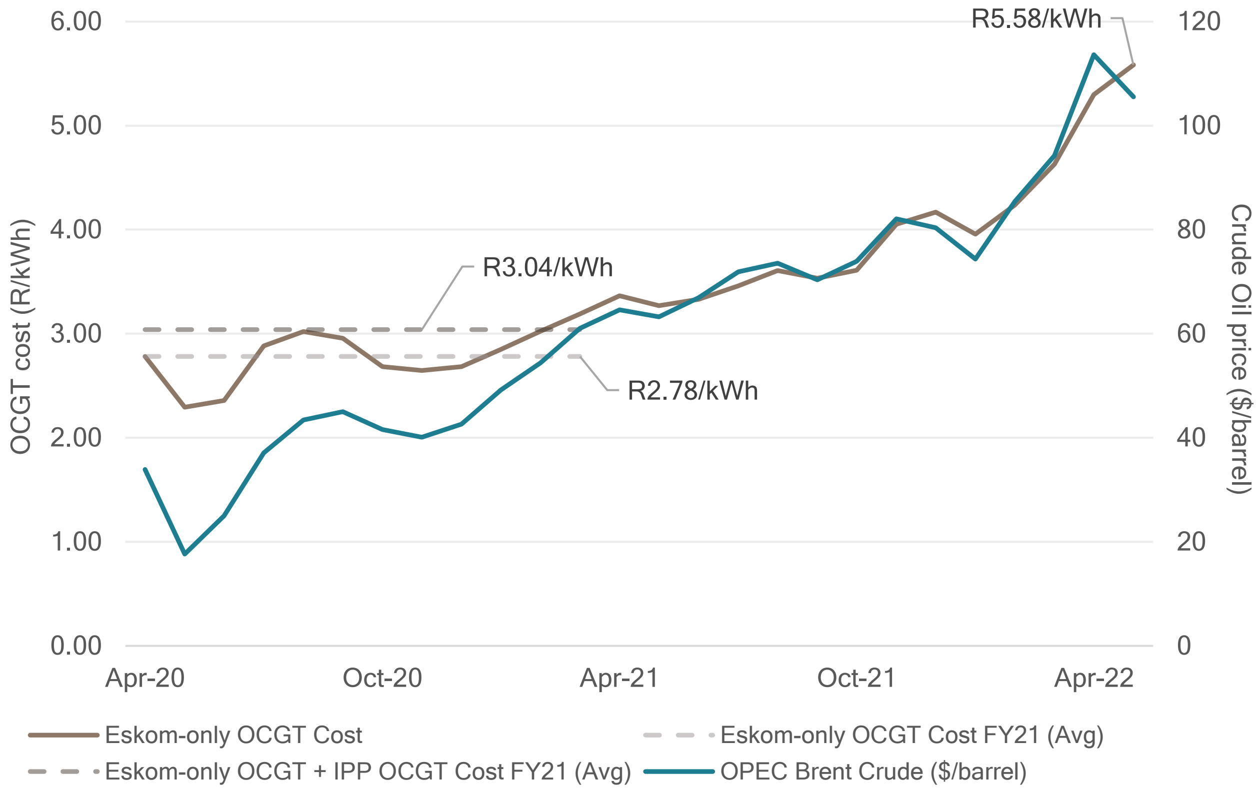
	Year of first power	Real 2021 c/kWh	
BW4 Expedited	2018	75	Average
	2019	70	67.5 c/kWh
	2020	65	
	2021	60	
	2022	55	
BW5	2023	50	

For purposes of the prospective view, we consider renewable prices in the range from 50 c/kWh to 90 c/kWh.

8.4.1.2 OCGT dispatch cost

The average dispatch cost of OCGT power in FY21 was R3.04/kWh – this includes power from Eskom's OCGTs at R2.78/kWh and R3.58/kWh from the IPP OCGTs. Although presumably the system operator would favour the use of Eskom's facilities due to the cost difference, we have assumed conservatively that any saved OCGT generation would only accrue financial savings at the average rate of R3.04/kWh for our retrospective analysis of 2021. This is extremely conservative considering the rise in diesel cost since close of the financial year in March 2021 on the back of increases in the dollar price of crude as shown in Figure 16. For the prospective analysis we have considered diesel costs for the OCGTs from R2.50/kWh up to R6.00/kWh. The dispatch cost of Eskom's own OCGTs has already exceeded R5.50/kWh and the IPP OCGTs presumably much higher than this. Without better understanding how much of the IPP OCGT dispatch cost is linked to the fuel price we are unable to ascertain their further impact on the overall dispatch cost, but crude prices in excess of $100/barrel and 15.00 R/$ or weaker will clearly result in OCGT costs of at least the R5.00/kWh – R6.00/kWh range.

Figure 16: Cost of running diesel-fired OCGTs (left) versus Crude Oil price (right)[53]



8.4.1.3 Coal dispatch cost

Where we have assumed that additional renewable energy displaces/avoids the need to burn coal we have assumed a cost saving of R0.42/kWh as the average primary energy cost of coal generation disclose din the FY21 integrated report. This does assume that coal capacity could have been ramped down in order to save the coal that would have been burned (we accounted for ramp rates as explained in 3.1) and that take-or-pay contracts would not have hindered Eskom's ability to bank these savings. Although these assumptions may seem unconservative, use of the primary energy cost of R0.42/kWh is extremely conservative for a number of reasons. Firstly, this is the cost for the financial year ending March 2021 – we have used this cost for our analysis of the calendar year from 1 Jan to 31 Dec 2021. Secondly it is the average primary energy cost across the coal fleet. This means that on a weighted basis half of the coal burned is higher than this figure – some of it by a considerable amount, and in reality, the system operator would save the most expensive coal first of course subject to the ability to reduce generation from the most expensive coal stations as required. Thirdly, the R0.42/kWh does not include direct savings in variable costs occasioned by reducing coal burn, and nor does it include the indirect savings that would result from avoided unplanned failures of the generators that would result from reductions in their use.

[53] OCGT costs based on Diesel Basic Fuel Price, current SA fuel tax levy, plus additional infrastructure costs. Average FY21 cost for Eskom-only OCGTs (R2.78/kWh), and cost for Eskom OCGTs plus IPPs (R3.04/kWh) depicted as dotted lines. OPEC Brent Crude *price plotted on right hand axis. Note that we have conservatively used Eskom's FY21 cost of running OCGTs (Eskom + IPPs) for* the modelling period in this study (Jan 2021-Dec 2021).

Fourthly, recent statements[54] by Eskom's CEO suggest that the dispatch cost of coal is much higher than this – approximately twice that of renewable energy. In short, the use of R0.42/kWh is an extremely conservative saving for every kWh of coal generation offset by additional energy being available.

We nevertheless use this figure for both the retrospective and prospective analyses.

8.4.2 DEMAND RESPONSE

We have assumed that customers participating in an extended demand response programme would be remunerated at twice the cost of running OCGTs per kWh, so effectively a cost to Eskom of R6.08/kWh for the retrospective analysis of 2021. For the prospective analysis the range is R5.00/kWh – R12.00/kWh. In reality the tariff may be structured in a different manner than a direct price per kWh curtailed, we however assume the net effect of the cost to be the same as if it were applied as a direct saving to the customer per kWh reduced on demand.

8.4.3 BATTERIES

Batteries are assumed to provide one hour storage and costing is based on:

Capital: $500/kW

R/$: 15.00

Lifetime: 15 years

Annual Operating cost: 2% of capital cost

8.4.4 AVERAGE SALES PRICE

Our assumption on the price at which Eskom could have sold the unserved energy from 2021 if it had been able to serve it is based on the average sales price calculated from the electricity revenue and sales figures disclosed in the FY21 integrated report and is R1.06/kWh[55]. This conservatively includes the accounting reductions for unrecoverable funds (the gross average sales price as R1.11/kWh).

[54] See McLeod (2022) *"South Africa has no choice* but to pivot *to renewables: De Reuyter." Tech Central. Available:* https://techcentral.co.za/south-africa-has-no-choice-but-to-pivot-to-renewables-de-ruyter/211630/

[55] R1.06/kWh = R202.6Bn /191.85TWh