Eskom

Generation Licensee (Gx)

Multi-Year Price Determination (MYPD) 5 Revenue Application for FY2023 – FY2025

Submission to NERSA

June 2021

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1.1 Context of Generation Generating environment

Generation is operating an ageing Generation fleet, notwithstanding the new power stations under construction. More than half of the stations and more than half of the coal-fired stations will be over 40 years old by the start of the MYPD5 period. Due to various constraints, most notably inadequate capacity and financial limitations, the mid-life refurbishment and enhancement projects that are required to maintain and improve technical performance as plants age, have generally not been implemented. Together with high utilisation that places higher than expected wear and tear on components and systems, in particular since 2008, this has contributed to a steady decline in generating plant availability over the past decade. Due to a combination of performance improvements, additional capacity (both Generation and IPPs), as well as stagnant demand, the rapid decline in availability post 2010 was arrested and availability improved to 78% in FY2018. The constraints, particularly financial, however, remain and this, together with the phenomenon of the ageing fleet, has contributed to the current availability of approximately 64% EAF. Generation's medium term aspiration to achieve and sustain 72% availability for its Generation fleet, by reversing the overall trend, remains a challenge.

1.2 Revenue requirement summary

TABLE 1: GENERATION MYPD5 REVENUE REQUIREMENT

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		1 002 173	981 823	963 840	963 719	956 211
WACC %	ROA	X	-1.99%	0.69%	0.87%	1.65%	3.04%
Returns			(19 953)	6 794	8 414	15 853	29 021
Primary energy	PE	+	79 615	78 791	84 156	85 447	91 192
International purchases	PE	+	4 589	4 878	5 157	5 466	5 794
IPPs	PE	+	70 019	85 321	101 807	124 128	133 616
Environmental levy	L&T	+	6 610	6 243	5 906	5 451	5 362
Carbon tax	L&T	+	2 714	10 121	10 099	9 680	10 052
Arrear debt	E	+	-	-	-	-	-
Operating costs	E	+	37 667	32 673	34 399	37 373	37 406
Research and Development	R&D	+	-	-	-	-	-
Depreciation	D	+	54 231	56 502	59 537	56 475	56 874
MYPD5 Allowable revenue			**235 491**	**281 322**	**309 476**	**339 873**	**369 316**
Add: Approved RCA's for liquidation	RCA		10 848	-	-	-	-
MYPD5 Allowable revenue including RCAs	R'm		**246 339**	**281 322**	**309 476**	**339 873**	**369 316**

NB: Research and development included in operating costs

Table 1, above, summarises the revenue requirement for the Generation licensee in accordance with the MYPD methodology with a proviso that the return on assets is not applied for as in the methodology, but is gradually phased over the MYPD5 period.

1.3 Return on assets

The ERA and the Electricity Pricing Policy require the recovery of efficient costs and earning a fair return on revalued asset valuations. In accordance with the MYPD methodology, Generation is allowed to earn a return on the Regulatory Asset Base (RAB) as well as on relevant capital works that are under construction.

The RAB valuation was undertaken by an independent entity that has international experience in the realm of asset valuation for large infrastructure companies. As required by the MYPD methodology, the determination of the regulatory asset base value is based on the costs to replace these assets (i.e. Modern Equivalent Assets Valuation (MEAV)) and adjusted for the remaining life and any relevant forms of obsolescence. This valuation has been undertaken in accordance with the guidelines and requirements of the International Valuation Standards. The MYPD5 RAB values are based on this asset valuation.

TABLE 2: GENERATION MYPD5 RETURN ON ASSETS

Return on Assets (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Closing RAB (R'm)	1 002 173	981 823	963 840	963 719	956 211
Real pre-tax WACC %	7.1%	7.1%	7.1%	7.1%	7.1%
Cost Reflective RoA (R'm)	71 154	69 709	68 433	68 424	67 891
RoA Applied for RoA %	-1.99%	0.69%	0.87%	1.65%	3.04%
RoA Applied for (R'm)	**(19 953)**	**6 794**	**8 414**	**15 853**	**29 021**

As summarised in Table 2, the RAB value decreases over the MYPD5 period as the fleet ages. In order to contain the impact of the overall Generation revenue requirement, a phasing-in of the return on assets was included, also as reflected in Table 2 above. This is to a contribution towards minimising the impact of the price increase on the consumer.

1.4 Primary energy

The total primary energy is inclusive of international purchases, carbon tax, environmental levy, IPPs and Eskom primary energy. The CAGR in the three year application experiences a growth of 13%. When comparing the simple growth in the costs related to IPPs, the costs has almost tripled from FY2021 to FY2025 (simple growth of 185%). These increases are due to a substantial increase in the volume of energy secured from mainly renewable energy from IPPs. The introduction of carbon tax liability during the FY2023, a simple growth of 39% is seen from FY2023 to FY2025. The Eskom primary energy CAGR over the three year period is 5.37%

1.5 Operating expenditure

Generation's Turnaround Strategy, which amongst other objectives, aims to address the financial challenges faced by Generation in the short to medium term. Reducing the cost base is one of the initiatives undertaken in the aim to address the financial challenges, which encapsulates cost reductions in all aspects of the business, including Opex.

Generation's operating costs forecast is prudent and efficient as reflected in the comparison with international norms. The compound average growth rate (CAGR) for the period FY2023 to FY2025 for Generation operating costs including corporate overheads is -4.4%, which is negative and below inflation.

The CAGR for the period FY2023 to FY2025 for Generation manpower costs is 3.8%, which is below inflation.

The CAGR for the period FY2023 to FY2025 for Generation maintenance costs is -0.4%, which is below inflation.

The CAGR for the period FY2023 to FY2025 for Generation Other Opex is -22.2%, which demonstrates Generation's commitment to reducing controllable costs.

1.6 Environmental compliance

The environmental clause in the Bill of Rights sets the context for environmental protection, providing for an environment which is not harmful to health and well-being and for ecological sustainable development. The National Environmental Act and several Strategic Environmental Management Acts (SEMA's) give effect to the environmental right in the Constitution. The development of environmental legislation has resulted in new and more stringent requirements which Generation is obligated to respond to in order to continue operating its power stations. Given the nature of Generation's activities these requirements are far reaching, they affect all the divisions and subsidiaries in some manner, including air quality, protection of the natural environment and biodiversity, water use and preventing pollution of water resources, general and hazardous waste management, the utilisation of ash and licensing processes. These legislative requirements are enforced through licences and permits. They lead to operational and capital expenses.

To retain the licence to continue to operate, these expenses must be allowed for in the tariff, preferably in a manner which separates non-negotiable statutory requirements from refurbishment and maintenance expenses.

2 Structure of the Generation Licensee

The role of the Generation Licensee is to manage the full generation value chain from the construction of new generation plant, through to the production of electricity products to the national grid. This includes the sourcing of primary energy, lifecycle management (which incorporates routine and regular maintenance activities as well as major refurbishment and performance improvement projects), production planning, outage planning, engineering services and the operation of the power stations to provide not only the energy to serve daily requirements and capacity to meet the peaks but also ancillary services to assist the grid operator in maintaining grid security.

The Generation Licensee includes the Generation Division which operates and maintains the power stations, but also houses Primary Energy which sources primary energy for the stations and Technology, which provides technology services to the stations. The various departments that deal with IPPs, Renewables and International purchases also form part of the Generation Licence. The Group Capital Division is responsible for the execution of capital projects. This includes the new build stations, currently Medupi and Kusile, as well as all major capital projects at the existing stations. In addition there are a number of centralised service and strategic functions that provide services to the various Licensees. These include, but are not limited to, Finance, Human Resources, Commercial, Security, Stakeholder Management, and Sustainability which is responsible for both Environmental and Safety Management. The costs of these centralised services are allocated to the Generation Licensee based on various allocation criteria.

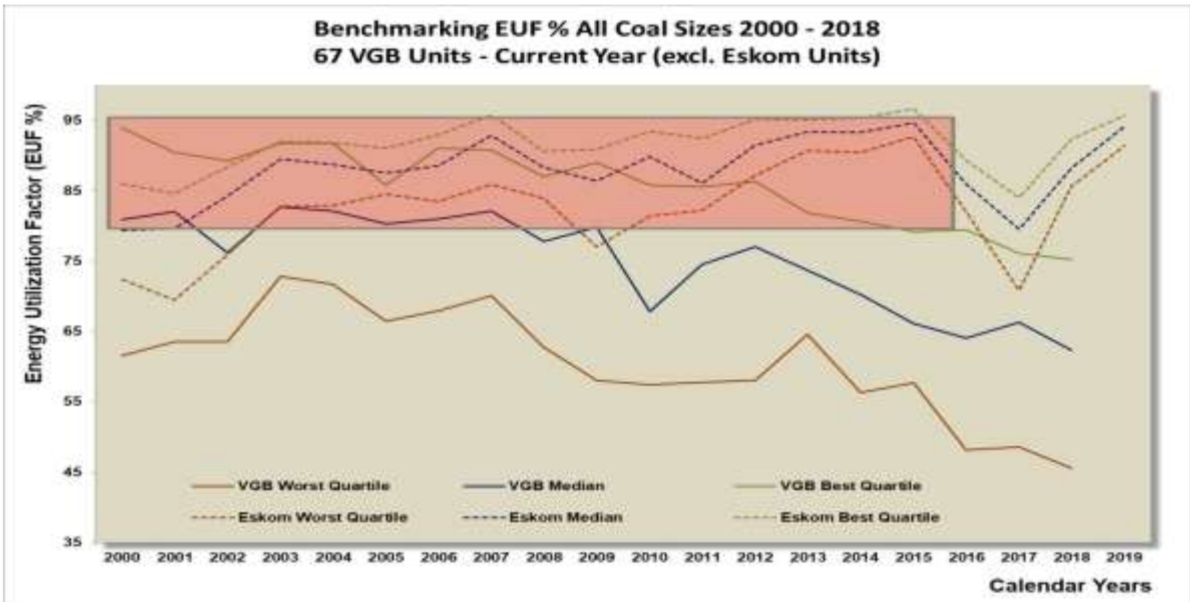
3 Context of the Gx operating environment

3.1 Environment

The responsibility to balance the supply with the demand of electricity and to ensure adequate capacity lies with the Minister of Mineral Resources and Energy. The Integrated Resource Planning process lays out the requirements in terms of necessary capacity per technology to ensure that sufficient energy is made available in the country whilst balancing the various other priorities such as least cost and environmental considerations. In the short-term, however, Generation is cognisant of the negative impact of electricity shortages on the country's economy and does everything reasonable to ensure adequacy of supply. In the past, this has led to actions that may have had a long-term negative impact of the health of Generation's generating fleet.

The performance of Generation's generating fleet is below aspiration. Although there are many contributing and aggravating factors, the root cause of this performance is the government's decision in the 1990's that Generation would not build any more power stations. This led to the late start of the build programme and severe capacity constraints. This required that that the existing plant had to be run exceptionally hard to meet the demand, accelerating the wear and tear on the ageing units. The graph below illustrates how Generation's coal-fired units were, for a period of about 15 years, run at an Energy Utilisation Factor (EUF) far higher than the international benchmark; and in the "red zone". In particular, for four years from 2012, Generation's lowest quartile was "run harder" than the top quartile of the benchmark stations.

FIGURE 1: UTILISATION OF GENERATION'S COAL FLEET VERSUS INTERNATIONAL BENCHMARK



At the same time, the financial and capacity constraints meant that Generation was not able to implement most of the "mid-life refurbishments" that are required in order to maintain and improve the performance of the stations as they age.

Although one expects performance challenges in newly commissioned stations, the performance of Medupi and Kusile as well as the pump-storage station, Ingula, is below aspiration. Once again, a major contributor, if not the root cause, is the capacity constraints due to the late start to the build programme. This resulted in a condensed design phase to accelerate the programme. Allied to the exceptionally long period, and related loss of skills and institutional knowledge, from the previous build programme where the design was executed in the 1980s, this contributed to the design faults that have resulted in an unacceptably high level of plant failures. These are being addressed with plant and procedure modifications and an improvement in performance is anticipated.

As previously noted, there are numerous contributing factors to the performance of Generation's generation fleet, the root cause goes back to the late 1990's. Generation needed to make decisions on building new power stations by 1999 at the latest to meet demand by 2007 but, as apologised for by former President Thabo Mbeki, was not allowed to do so. This meant that the final investment decision could only be taken in December 2006 – too late. This was later exacerbated by delays in the construction of Medupi and Kusile due to lack of sufficient time for undertaking a thorough design phase. It should also be noted that one of the key reasons for the delays was an accelerated design period as a result of the late decision and the subsequent over-optimistic expectations on delivery dates.

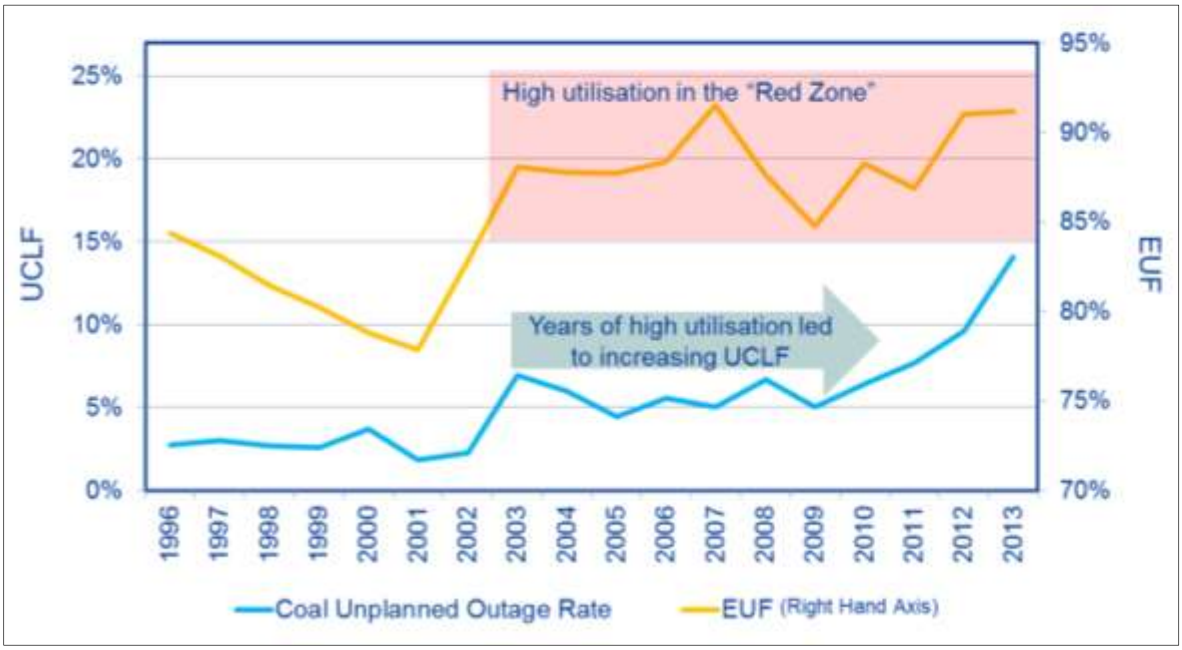
This all led to inadequate capacity to meet demand whilst leaving inadequate maintenance space to perform an ideal level of preventative maintenance, particularly mid-life refurbishments. As a power station reaches 25 to 30 years of operation, major systems and components need to be refurbished, replaced or upgraded to maintain and improve the performance of the stations. Allied to this, in the early 2000s, a requirement to reduce costs which meant that capital expenditure was constrained and this also impacted on mid-life refurbishments, even when there was space to perform the maintenance.

The performance of Eskom's Generation fleet continued to perform well up to 2012 with an availability of over 80%. However, Generation was operating in a constrained environment and had a *de facto* obligation to meet national electricity demand, particularly in the lead up to and during the 2010 World Cup. This required Generation to both defer maintenance and run the plant very hard when it was available. This obviously had a negative impact on the health of the stations and thus their availability due to increased unplanned breakdowns. The decline in plant availability from 2013 meant that even less capacity was available to meet demand and thus required the available plant to run even harder resulting in a "vicious circle".

This situation was not sustainable and in subsequent years, planned maintenance levels and spend were increased despite the fact that this resulted in load shedding. This was essential but only possible because the Shareholder removed the KLO requirement from the Shareholder Compact from 1 April 2013. This increase in maintenance was the major contributor to the improvement in plant availability in FY2017 and FY2018. This improvement was, unfortunately, short-lived and availability started to decline again from late 2017. The reasons for this latest decline are many, complex and varied. The historical sub-optimal mid-life refurbishments and hard running of an ageing fleet (more than half – including Medupi and Kusile – over 40 years) still has the highest impact on plant failures, but shortages of experienced skills and staff morale, driven by consistent under-recovery through the tariff and current uncertainty are also amongst the contributing factors.

The figure below illustrates how the generation fleet was operating at exceptionally high level, between 85 and 95%, utilisation (EUF) since 2003. Higher utilisation leads to additional stress on components and thus to increasing breakdowns but only after a delay. This is evident from the increasing unplanned unavailability (UCLF) from 2010.

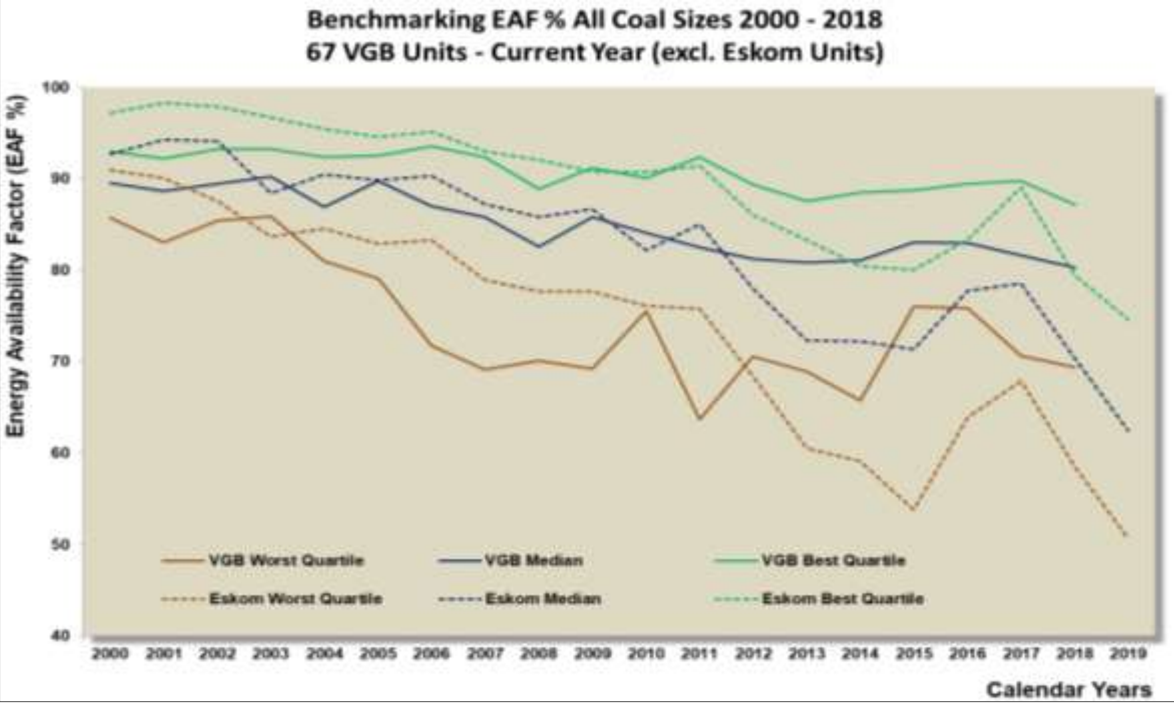
FIGURE 2: HISTORICAL COAL FLEET UCLF AND EUF - 1996 TO 2013



This trend of high utilisation has continued and even the lowest quartile stations have, in general, been running harder, at a higher utilisation, than the VGB benchmark.

Even without this exceptionally high utilisation, the ageing of the fleet, on its own, would lead to increased unavailability, particularly when not all the ideal mid-life refurbishments could be carried out due to financial and capacity constraints. This trend of a decreasing availability as a fleet ages can also be seen in the performance of the VGB benchmark fleet.

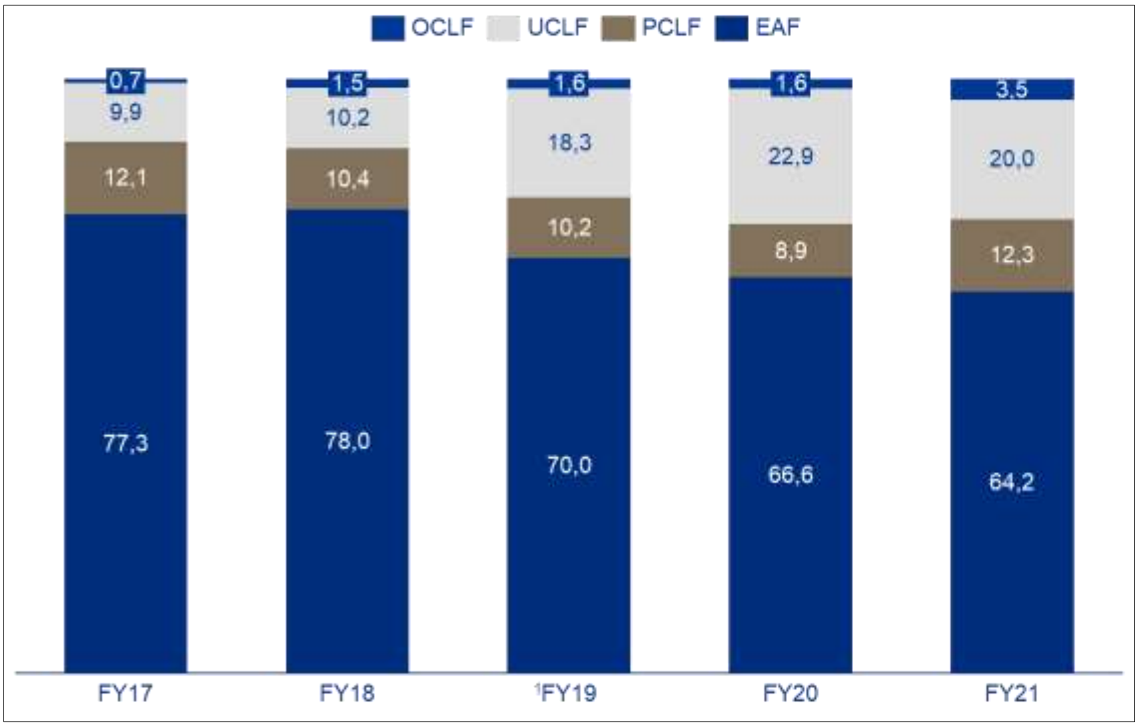
FIGURE 3: GENERATION'S COAL FLEET AVAILABILITY VS THAT OF THE VGB BENCHMARK



3.2 Generation technical performance parameters

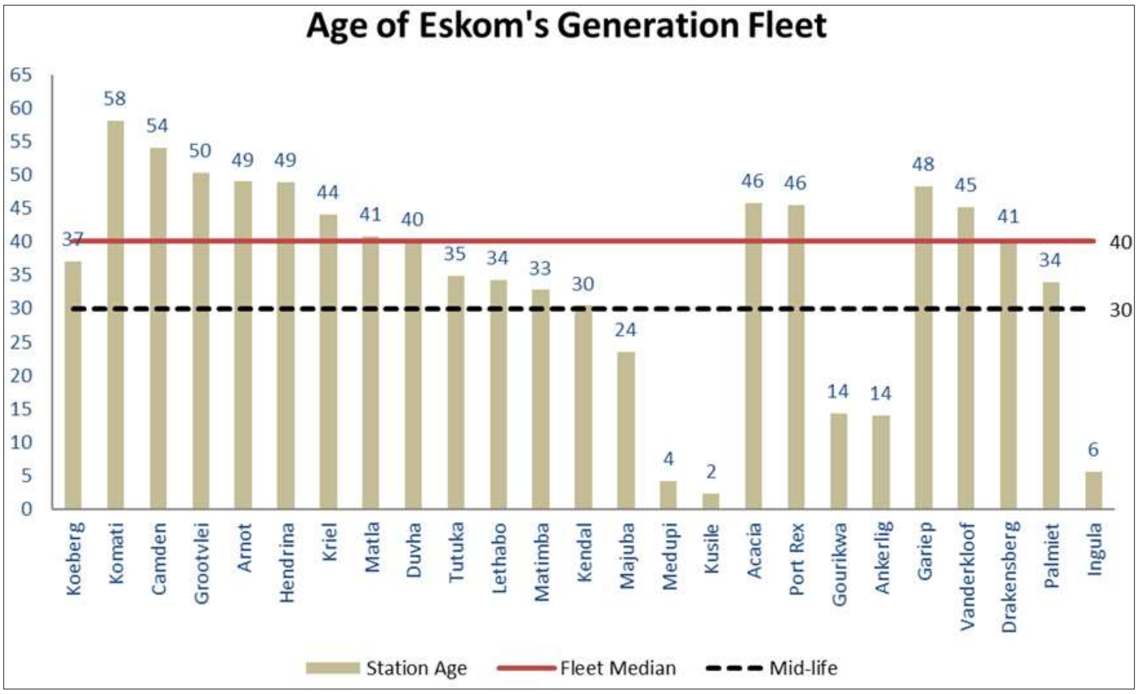
Generation's availability – energy availability factor (EAF) has declined significantly from a high of 78.0% in 2017/18 to 64.2% in 2020/21. Generation's aspiration is to drive availability (EAF) to and to maintain 72%. PCLF refers to planned capability loss factor, UCLF refers to unplanned capability loss factor and OCLF refers to other capability loss factor where the cause of the energy loss is outside of plant management control.

FIGURE 4: PERFORMANCE OF GENERATION'S FLEET



Generation operates an ageing Generation fleet, notwithstanding the new stations under construction. More than half of the stations and more than half of the coal-fired stations will be over 40 years old by the beginning of the MYPD5 period.

FIGURE 5: AGE OF GENERATION'S FLEET AT 1 APRIL 2022



Due to various constraints, most notably inadequate capacity and financial limitations, the mid-life refurbishment and enhancement projects that are required to maintain and improve performance as plants age have generally not been implemented. Together with high utilisation, which places higher than expected wear and tear on components and systems, in particular since 2008, this has contributed to a steady decline in generating plant availability over the past 2 decades. In addition, Medupi and Kusile have not yet been completed and their commercial units are still in the first phase of the “bath-tub” curve, where reliability is expected to be lower as “teething” problems reduce availability.

Due to a combination of performance improvements, additional capacity, Generation and IPP, as well as stagnant demand, the rapid decline in availability post 2010 has been arrested and availability improved to 78% by 2017/18. The constraints, particularly financial, however, remain and this, together with the phenomenon of the ageing fleet, has contributed to the current availability of approximately 64% EAF. Generation’s medium term aspiration to achieve and sustain 72% availability for its Generation fleet by reversing the overall trend remains a challenge.

TABLE 3: ASSUMED GENERATION EAF

Generation Technical performance (%)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Energy Availability Factor (EAF)	66.4	65.1	70.0	72.0	72.0	72.0	72.0	72.0

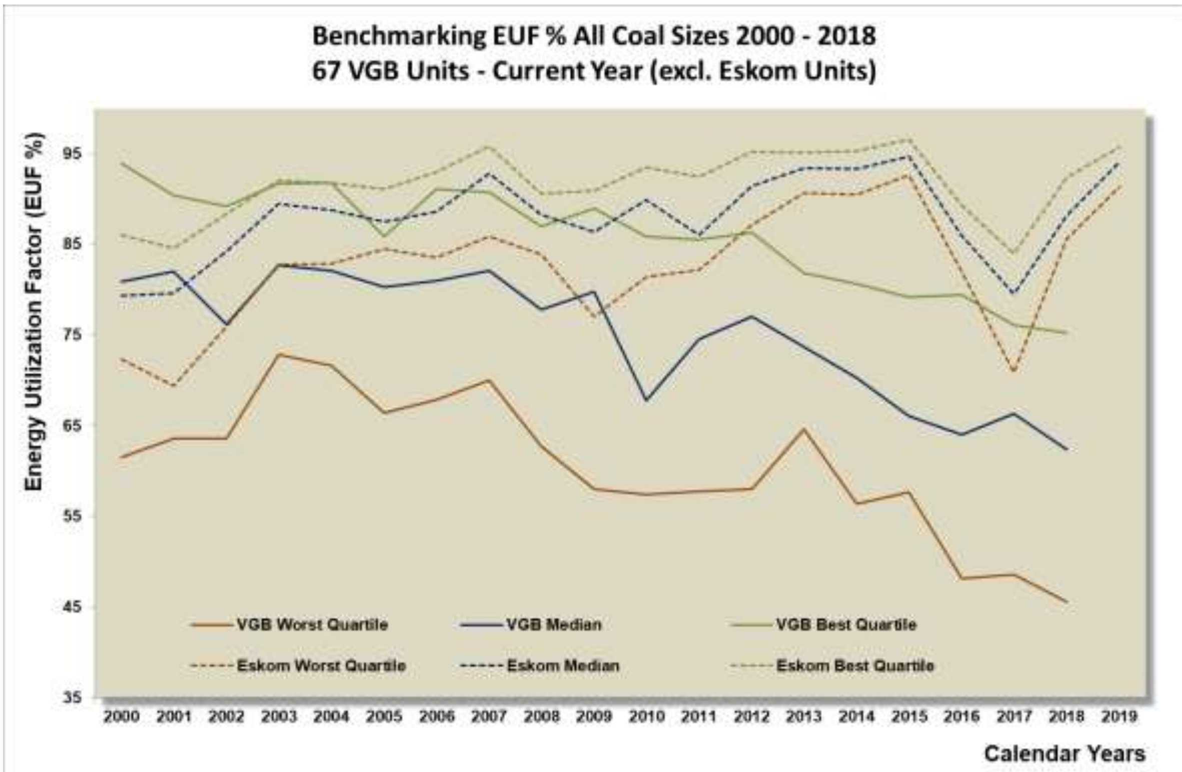
In addition, the stations that are not expected to be required according to the Production Plan will not be decommissioned but will instead be placed in reserve storage. This will allow them to be operational within a year should the assumptions in the Production Plant not be borne out in reality. These uncertainties include Generation’s plant performance, variations in demand, IPP capacity (which is dependent on the IRP and the implementation thereof) and new build timelines. This strategy will allow for some savings as it is assumed that there will be no Capex expenditure on these stations and only minimal Opex for essential services, whilst maintaining flexibility. In effect, these stations will provide risk mitigation against changes to the environment in which Generation operates.

3.3 Plant performance benchmarks

Generation benchmarks its generating plant technical performance against similar stations using the VGB PowerTech (VGB), of which Generation is a member. The latest available data from VGB is for the 2016 calendar year. Note that Generation data is also in calendar years.

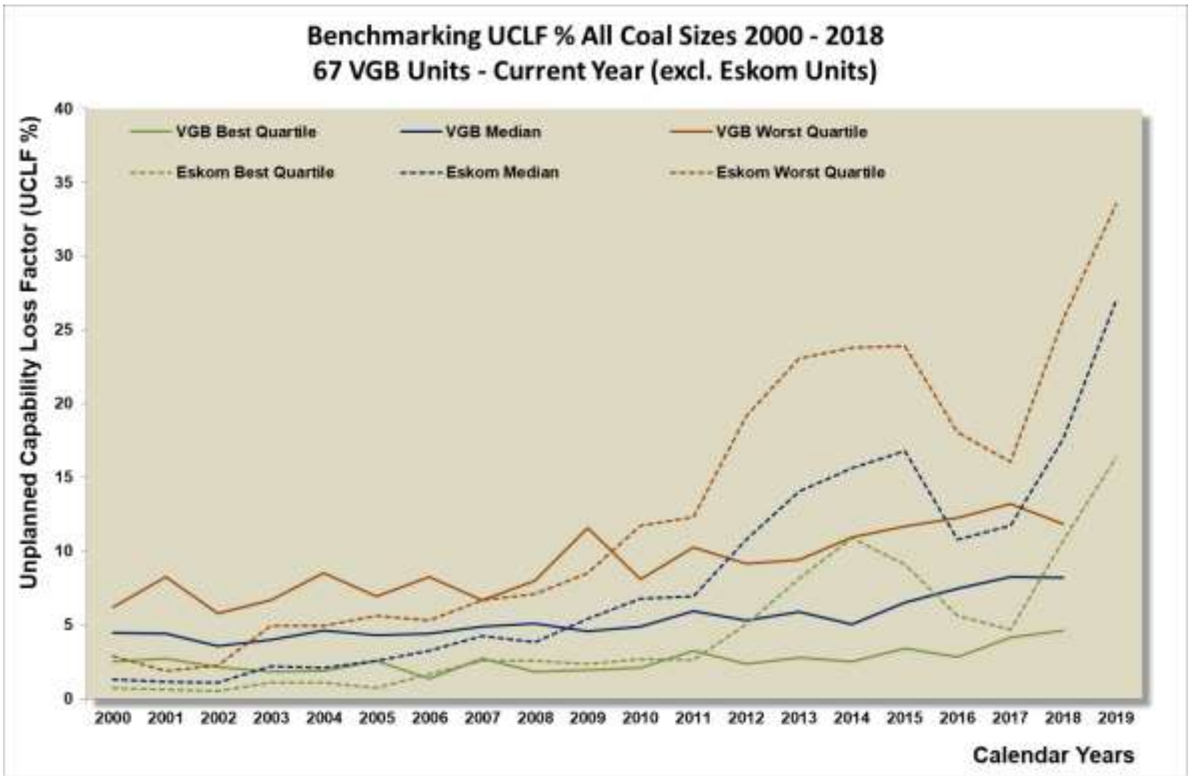
For more than the last 10 years, Generation's fleet has been running at higher utilisation (EUF) than the VGB benchmark. In addition, until recently the availability of Generation's plant was higher than the benchmark. This is indicative of the constrained environment in which Generation was operating and is a contributor to the recent reduced availability due to additional stress on an ageing fleet.

FIGURE 6: EUF BENCHMARKING



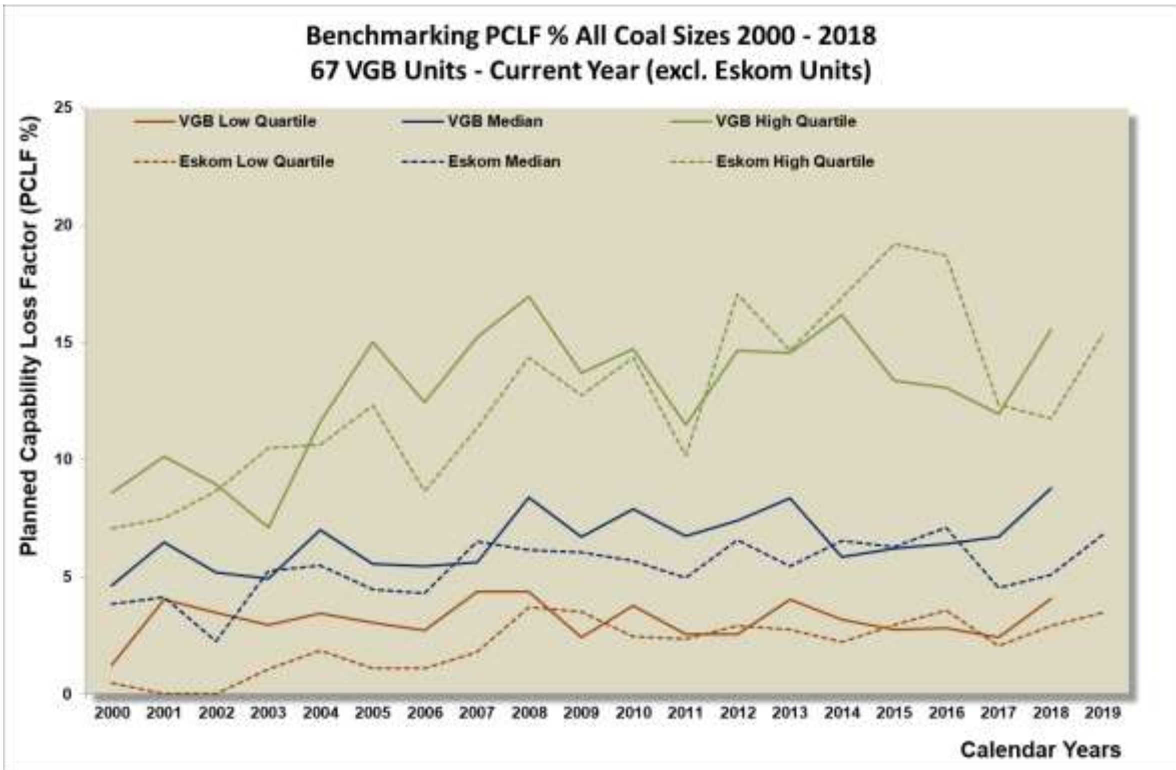
EUF measures "how hard" the units are being run and thus is an indicator of the wear on systems and components. From the figure above, it can be seen that Generation coal units have been consistently run harder than the coal units of the other VGB members. In particular, since 2012, even Generation's lowest quartile stations have mostly been running at a higher utilisation than the VGB highest quartile.

FIGURE 7: UNPLANNED CAPABILITY LOSS FACTOR (UCLF) BENCHMARKING



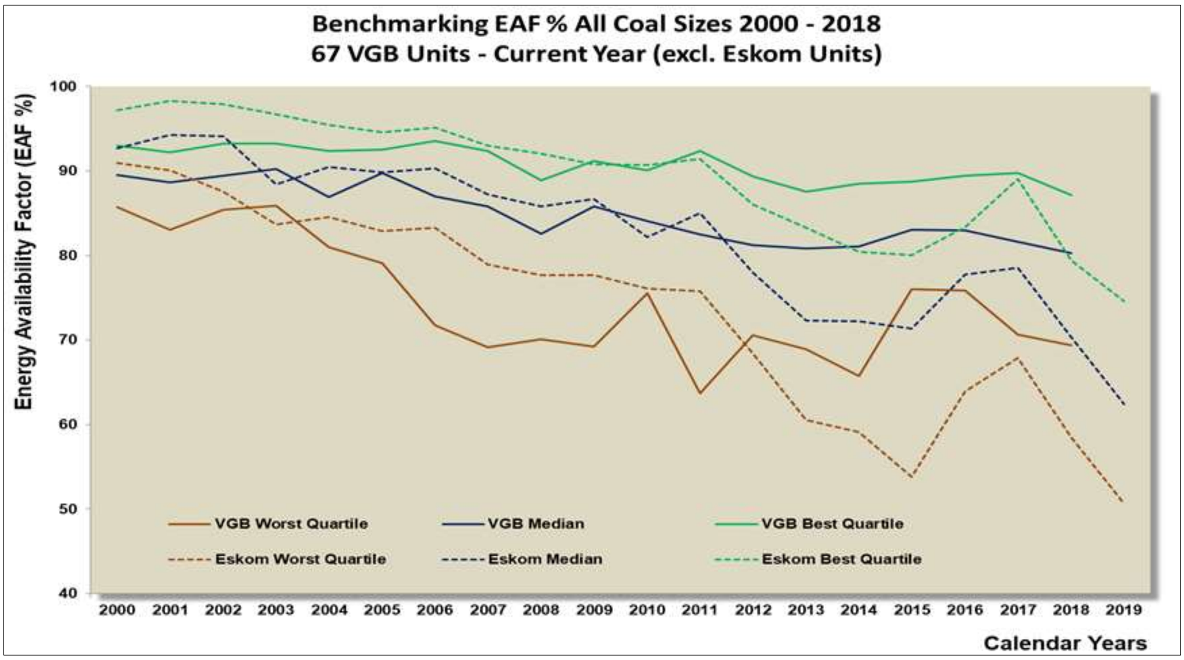
Until 2010, Generation's UCLF performance was in line with the VGB benchmark but deteriorated significantly from 2011 to 2015. Despite the improvement in 2016 and 2017, Generation's UCLF has deteriorated and is now significantly worse than that of the benchmark.

FIGURE 8: PLANNED CAPABILITY LOSS FACTOR (PCLF) BENCHMARKING



Until 2011, planned maintenance was consistently under the benchmark. Since then, PCLF was increased significantly, particularly on those stations most in need, as can be seen by the top Quartile being higher than the VGB top Quartile. Generation's planned maintenance was lower during this time due to the constrained capacity where planned maintenance could not be ideally undertaken.

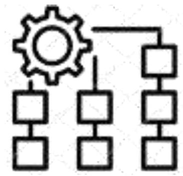
FIGURE 9: ENERGY AVAILABILITY FACTOR (EAF) BENCHMARKING



In recent years (since 2011), the availability of Generation's coal fleet has dropped below that of the benchmark, notwithstanding the improvement in 2017 and 2018. The general trend, for both Generation and the VGB benchmark units is that of reducing availability. This is consistent with the expectation due to a generally ageing fleet. Generation's EAF has deteriorated significantly in recent years.

4 Production Planning

4.1 Production Planning Objective



The main objective of Production Planning is to ensure optimal output from available power stations to reliably meet the system demand at least cost, while recognising Generation, primary energy and any other technical constraints. The key principle for Production Planning is for the merit order dispatch to be maintained within known constraints. Constraints may include emissions, coal shortages/surplus, water shortages and any other technical constraints.

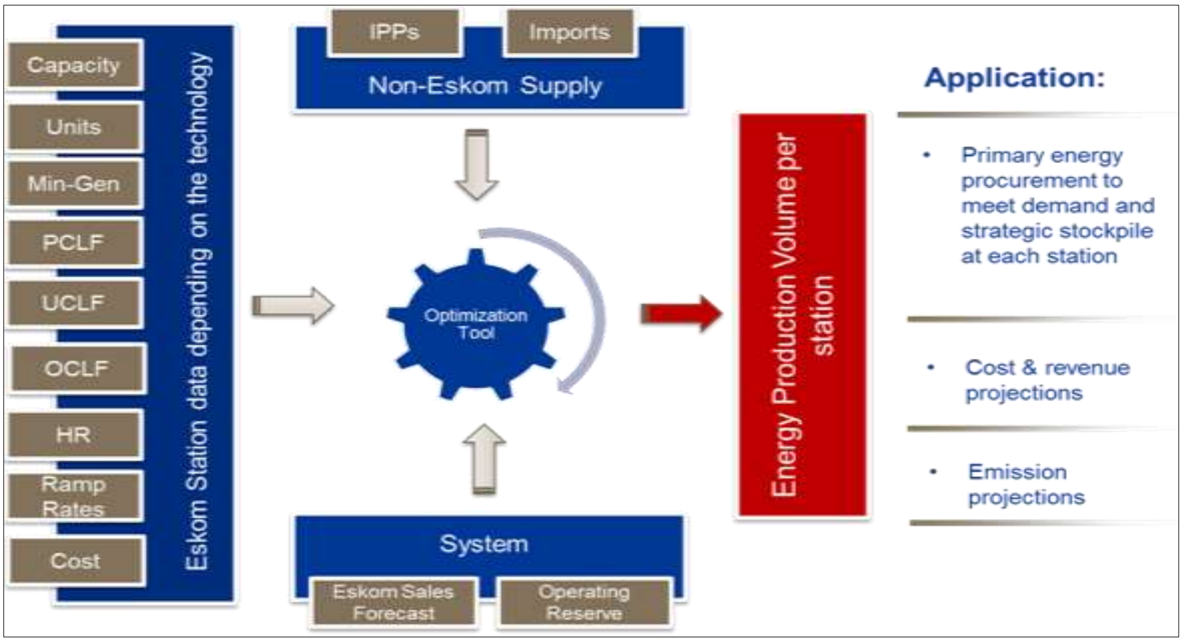
Merit order dispatch is achieved by deriving the merit order from the primary energy costs (mainly coal and diesel cost) as well as power station burn rates (station efficiency and coal quality) resulting in an energy cost (R/MWh) ranking per station from the cheapest to the most expensive. Coal and diesel costs are the major contributors to the variable cost of electricity production, and on its own, results in an accurate relative merit order and optimum dispatch.

The Production Plan outcome provides the expected production level at each station which is the basis of the Primary Energy (i.e. Coal, Water, Sorbent, Nuclear, OCGT, Start-up Fuel, Water Treatment, Coal Handling and Environmental Levy) cost projections.

4.2 Production Planning Process

The Production Plan is optimised using a simulation tool called the Plexos Simulation Tool. Plexos is a simulation tool that uses data handling, mathematical programming and stochastic optimisation techniques to provide analytical framework for power market analysis. It is able to optimally dispatch generating units based on user defined constraints and respecting technical limits. This modelling tool determines the optimal dispatch of generating resources within given system constraints to meet the power demand from a single period to daily, weekly, monthly or annual timeframes.

FIGURE 10: OVERALL PRODUCTION PLANNING PROCESS



The process for Production Planning is depicted in the figure above. The inputs to the optimisation tool include hourly demand forecast, planned and unplanned maintenance, ramp rates, variable cost (coal and diesel cost), capacity, number of units per station, minimum generation, operating reserve requirements, commercial operations date for Generation new build, import capacity, IPPs and all other parameters required for modelling the system.

Generators are dispatched from the lowest variable cost to the most expensive generator in the system. Nuclear power station (Koeberg) is a must run station and it is always dispatched to its maximum capacity available. The cycle efficiency of a pumped storage scheme (Drakensberg, Palmiet and Ingula), system costs (based on pumping requirements) and the historical generating patterns of existing schemes determine their generation pattern hence they are given minimum load factors. They are modelled such that their top reservoirs must be full at the beginning of every week.

Gariep and Vanderkloof generate as per agreement between Department of Water Affairs and Generation Peaking department. The full capacity of these stations is thus not always available in all hours; they can only be dispatched for an agreed number of hours per day. The OCGTs are not fuel constrained but restricted by their availability, position in the merit order and also by the approved assumption on utilisation. Generation OCGTs are an emergency supply and are therefore constrained to produce at least 1% load factor per annum to cater for any unforeseen event occurring on the system.

Coal fired power stations are modelled as per their technical parameters which include; number of units, units' end of plant life, minimum generation levels, ramp rates, energy cost, availability and other characteristics required by the tool. Dispatch of power stations will be based on their energy cost. Expensive stations are expected to produce less if the system is not constrained.

Non-Generation generators (Imports and IPPs) are modelled as contracted to Generation. Renewable IPPs are modelled using their hourly profiles for each technology to meet projected monthly/annual energy. Imports and IPPs are forced in the model to dispatch first and the remainder of the energy is met by Generation generators.

4.3 Production Planning Assumptions

The plan was developed based on a 50-year life of plant plan for all coal fired power stations for planning purposes. It must be noted that the useful life of the power station is not determined by age but also by factors such as economic viability and strategic considerations. The main assumptions include:

4.3.1 Generation Capacity

Generation currently operates 46 366 MW (nominal capacity) of commercial fleet (excluding 100 MW of Sere), of which 38 773 MW is coal-fired. The rest is made up of 1 860 MW nuclear, 2 409 MW of gas turbines, 600 MW hydro and 2 724 MW pumped storage. The table below shows the Generation power stations total installed and nominal capacities.

TABLE 4: GENERATION EXISTING CAPACITY

Power station capacities as at 29 March 2021

The difference between installed and nominal capacity reflects auxiliary power consumption and reduced capacity caused by the age of plant.

Name of station	Location	Years commissioned - first to last unit	Number and installed capacity of generator sets MW	Total installed capacity MW	Total nominal capacity MW
Generation Group power stations					
Base-load stations					
Coal-fired (15)				43 256	38 773
Arnot [2]	Middelburg	Sep 1971 to Aug 1975	6x370	2 220	2 100
Camden [1, 2]	Ermelo	Mar 2005 to Jun 2008	3x200; 1x196; 2x195; 1x190; 1x185	1 561	1 481
Duvha [8]	Emalahleni	Aug 1980 to Feb 1984	5x600	3 000	2 875
Grootvlei [1,7]	Balfour	Apr 2008 to Mar 2011	4x200; 2x190	1 180	570
Hendrina [2,6,7]	Middelburg	May 1970 to Dec 1976	6x200; 2x195; 1x170	1 760	1 135
Kendal [3]	Emalahleni	Oct 1988 to Dec 1992	6x686	4 116	3 840
Komati [1,7]	Middelburg	Mar 2009 to Oct 2013	4x100; 4x125; 1x90	990	114
Kriel	Bethal	May 1976 to Mar 1979	6x500	3 000	2 850
Lethabo	Vereeniging	Dec 1985 to Dec 1990	6x618	3 708	3 558
Majuba [3]	Volksrust	Apr 1996 to Apr 2001	3x657; 3x713	4 110	3 843
Matimba [3]	Lephalale	Dec 1987 to Oct 1991	6x665	3 990	3 690
Matla	Bethal	Sep 1979 to Jul 1983	6x600	3 600	3 450
Tutuka	Standerton	Jun 1985 to Jun 1990	6x609	3 654	3 510
Kusile [3]	Ogies	Aug 2017 to	3x799	2 397	2 160
Medupi [3]	Lephalale	Aug 2015 to	5x794	3 970	3 597
Nuclear (1)					
Koeberg	Cape Town	Jul 1984 to Nov 1985	2x970	1 940	1 860

TABLE 5: GENERATION EXISTING CAPACITY (CONTINUED)

Peaking stations					
Gas/liquid fuel turbine stations (4)				2 426	2 409
Acacia	Cape Town	May 1976 to Jul 1976	3x57	171	171
Ankerlig	Atlantis	Mar 2007 to Mar 2009	4x149.2; 5x148.3	1 338	1 327
Gourikwa	Mossel Bay	Jul 2007 to Nov 2008	5x149.2	746	740
Port Rex	East London	Sep 1976 to Oct 1976	3x57	171	171
Pumped storage schemes (3) [4]				2 732	2 724
Drakensberg	Bergville	Jun 1981 to Apr 1982	4x250	1 000	1 000
Palmiet	Grabouw	Apr 1988 to May 1988	2x200	400	400
Ingula	Ladysmith	June 2016 to Feb 2017	4x333	1 332	1 324
Hydroelectric stations (2) [5]				600	600
Gariep	Norvalspont	Sep 1971 to Mar 1976	4x90	360	360
Vanderkloof	Petrusville	Jan 1977 to Feb 1977	2x120	240	240
Total Generation Group power station capacities (25)				50 954	46 366

1. Former moth-balled power stations that have been returned to service. The original commissioning dates were:
   Komati was originally commissioned between Nov 1961 and Mar 1966.
   Camden was originally commissioned between Aug 1967 and Sep 1969.
   Grootvlei was originally commissioned between Jun 1969 and Nov 1977.
2. Due to technical constraints, some coal-fired units at these stations have been de-rated.
3. Dry-cooled unit specifications based on design back-pressure and ambient air temperature.
4. Pumped storage facilities are net users of electricity. Water is pumped during off-peak periods so that electricity can be generated during peak periods.
6. Hendrina unit 3 is under extended inoperability
7. Due to financial constraints, some units at these stations have been placed in reserve storage and their capacity removed from the nominal base.
8. Duvha Unit 3 Recovery Project has been cancelled

This takes into account the units that have been shut down and placed in either extended inoperability or reserve storage. These comprise; 1 unit at Duvha, 3 units at Grootvlei, 4 units at Hendrina and 8 units at Komati.

The rationale for removal of these units is based on techno-economic constraints. Some generating plant units need refurbishment which is uneconomical as it will not improve the efficiency of these stations. Other units require an immediate investment on repairs and General Overhauls (GO) to continue to operate. However, no resources have been allocated given the capital constraints. Also, long lead times for the spares dictate that some of these units will only be brought back to service closer to the their shutdown dates based on 50 year Life of Plant Plan (LOPP).

Coal stations are assumed to be shut down in line with their 50 year life assumption unless a dead stop date has been determined. A dead stop date is where the unit requires significant intervestions, especially requireing a large Capex input, before it can continue to operate.

TABLE 6: DEAD STOP DATES

	Hendrina		Arnot		Camden		Grootvlei	
Dead Stop Dates	HD04	31-Aug-26	AN01	17-Sep-27	CD03	22-Mar-25	GV02	21-Mar-26
	HD05	30-Nov-26			CD06	08-May-25	GV01	16-Aug-26
	HD10	31-Dec-27			CD04	06-June-25	GV03	02-Jul-27
	HD02	16-Dec-25			CD02	20-Mar-26	**Komati**	
	HD07	31-Dec-28			CD01	10-Nov-26	KM09	09-Aug-22
	HD06	17-Jul-25			CD07	28-Jul-27		
					CD08	08-May-28		
					CD05	19-Dec-29		

In addition, for Hendrina, Camden and Grootvlei, it is assumed that the remaining units at these stations will not operate beyond December 2025.

Peaking and Koeberg units are assumed to be decommissioning at 60 year life of plant plan except Acacia & Port Rex which are assumed to shut down between May and October 2026.

4.3.2 Generation new build capacity assumptions

Generation new build dates assumed in the production plan inputs are based on latest forecast of commercial operational dates for Medupi and Kusile. The table below shows the commercial operation dates for Medupi and Kusile that were used as inputs in the Production Plan.

TABLE 7: GENERATION NEW BUILD CAPACITY

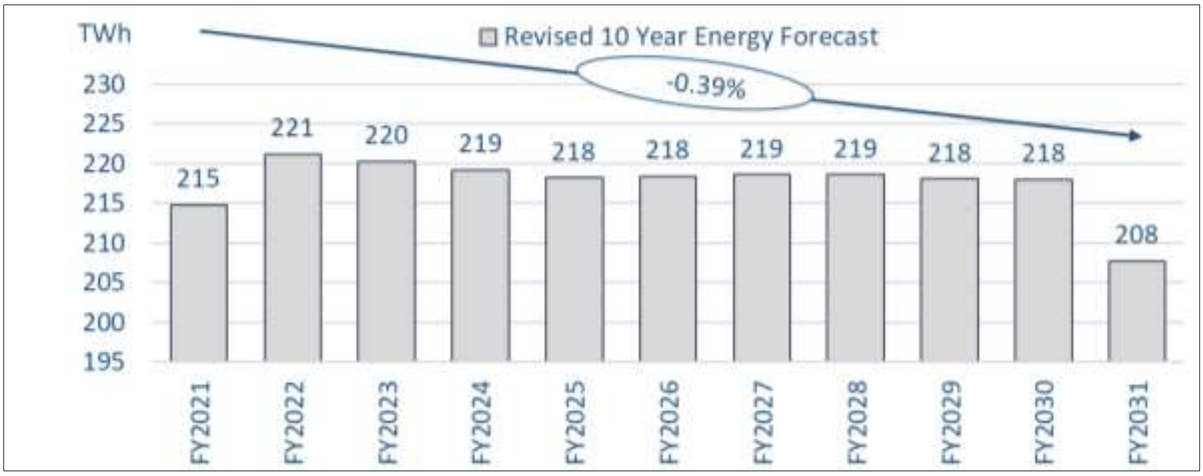
Station	Unit	Assumed CO Date
Medupi	1	April 21
Kusile	2	Jan 21
Kusile	3	Mar 21
Kusile	4	Jan 23
Kusile	5	Dec 23
Kusile	6	May 24

4.3.3 Energy forecast assumptions

As included in the Distribution Licensee submission, the energy forecast is robustly undertaken within Generation. For production planning purposes, the source of the energy forecast is the Energy Wheel Diagram. The forecast provides an indication of the energy sales from International exports, Distribution and Transmission national sales per month and/or annum. Distribution and Transmission line losses are added to these sales to arrive at the total energy forecast for a month or year.

The production planning model requires an hourly demand forecast for each of the years being studied. The hourly demand forecast is developed from the Energy Wheel Diagram's monthly or annual energies and the IRP hourly profile as a reference of hourly demands. The hourly demands of the reference profile are scaled until the given monthly or annual energy figures are satisfied. The peak demands for each of the years of the study period are also the result of this scaling process. The figure below, shows net energy forecast.

FIGURE 11: ENERGY FORECAST AS PER WHEEL DIAGRAMME



4.3.4 Non-Generation supply assumptions

Non-Generation supply includes Independent Power Producers and International imports. The International imports consist of mainly Cahora Bassa. The IPP initiatives are included up to Bid Window 8 which includes coal, gas programme, risk mitigation programme, short term and munics and battery storage up to 2031. Generation generators supply the balance after imports and IPPs have been utilised.

TABLE 8: INTERNATIONAL IMPORTS AND INDEPENDENT POWER PRODUCERS (GWH)

Electricity output (GWh)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
IPPs	14 179	20 262	36 485	45 063	52 936	64 960	67 286
Imports (purchase and wheeling)	11 126	10 545	10 545	10 573	10 545	10 545	10 545
TOTAL	**25 305**	**30 808**	**47 031**	**55 637**	**63 481**	**75 505**	**77 831**

4.3.5 Generation Plant Performance

Plant Performance Indicator assumptions data determine the availability of the generating plant, its technical performance and the constraints within which the available plant will be operated. These data include unplanned capability loss factor (UCLF) estimates, other capability loss factor (OCLF) estimates, planned capability loss factor (PCLF) and any other specified technical constraints. The Generation Plant Performance is assumed to remain at 72% Energy Availability Factor (EAF) for the MYPD5 period as indicated in the table below.

TABLE 9: GENERATION TECHNICAL PERFORMANCE

Generation Technical performance (%)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Energy Utilisation Factor (EUF)	79.0	74.0	68.1	62.4	58.9	55.3	52.8	53.7
Energy Availability Factor (EAF)	66.4	65.1	70.0	72.0	72.0	72.0	72.0	72.0
Planned Capacity Loss Factor (PCLF)	8.9	12.7	10.5	10.5	10.5	10.5	10.5	10.5
Unplanned Capacity Loss Factor (UCLF)	22.9	18.7	18.0	16.0	16.0	16.0	16.0	16.0
Other Capacity Loss Factor (OCLF)	1.6	3.5	1.5	1.5	1.5	1.5	1.5	1.5
Gross Load Factor (GLF)	52.6	48.2	47.6	44.9	42.4	39.8	38.0	38.7

Note: FY2021 values are as at October 2020 when production plan was run

It must be noted that the plan assumes a low Other Capability Loss Factor (OCLF) as this is based on assuming that there are adequate coal stock piles at the power stations so as to deal with supplier shortfalls, strikes, weather conditions, etc.

4.1 OCGT usage

Generation and IPP OCGTs are optimised but constrained to a minimum load factor of 1% per annum.

4.2 Approval and monitoring of Production Plan

The draft Production Plan from the optimisation process is submitted for approval through the governance process, following which it is implemented. The Energy Wheel Diagramme is then updated to reflect the final Production Plan.

The actual performance versus the assumption in the plan is monitored during the year of operation. Actual versus assumed production variances are investigated and reasons for the variances are reported to the relevant stakeholders. The power stations' actual production performance is monitored and reported on a monthly basis. The year-end plan is revised on a quarterly basis for the months ahead. In managing the system, Generation, Transmission and the other relevant role-players meet once a week to look at the week ahead risks to production and devise mitigations accordingly.

The Production Plan for the remaining months of the year is revised quarterly due to a revised energy forecast. During the quarterly revisions, changes in forecast volume of energy imports, plant technical indicators, coal issues related to fuel delivery and stockpile days, and nuclear Production Plans are considered. The Production Plan may be revised outside quarterly intervals due to major events on the system.

The coal stockpile levels are closely monitored in order to identify supply risks. The aim is to ensure that optimum stockpile levels are maintained. Minimum, target and maximum stockpile days are determined for each coal power station. Power stations are required to ensure that their targeted stockpile levels are maintained and any deviation must be reported, together with mitigation plans to bring the stockpile levels back to the target level.

4.3 Production Plan Outcome

With the above assumptions, the Production Plan shows that there will be operational excess capacity as from FY2023. As a result of operational excess capacity, expensive stations will start ramping down to zero production as they are no longer required to meet the demand. Since the system dynamics can change at any time, the excess capacity status can change due to changes in the assumptions made. As a result of the excess capacity, some high production-cost power stations (based on primary energy merit order ranking) are not expected to be utilised to meet demand: Grootvlei and Komati from April 2022, Kriel UG, Camden and Hendrina from April 2023, and Arnot from April 2025. Also based on the current assumptions, OCGTs are not required by the system, so, as a result, both IPP and Generation OCGTs are kept at 1% load factor per annum for the entire planning cycle.

Not utilising certain units/stations to manage operational excess capacity and the system should be an operational decision based on system health and security, Scheduling and Dispatch Rules (SDR), grid stability and technical capability of units at that particular period. SDR stipulates that "*System Operator shall Schedule and Dispatch generation and demand-side resources to least cost whilst maintaining prescribed system security*". SDR further states that the "*generator should take into account all prevailing constraints, technical and/or economical*". The Table below shows the detailed production per technology for the MYPD5 period.

TABLE 10: ENERGY PRODUCTION PER PLANT MIX (GWH)

Electricity output (GWh)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Power sent out by Eskom stations, GWh (net)	214 968	198 694	196 945	180 345	170 227	161 379	148 895	146 510
Coal-fired stations (incl. Pre-Commissioning), GWh (net)	*194 357*	*180 955*	*178 986*	*169 217*	*163 197*	*153 232*	*139 836*	*131 529*
Virtual Power station, GWh (net)	-	*953*	-	*(7 973)*	*(12 775)*	*(10 487)*	*(9 896)*	*(5 039)*
Hydroelectric stations, GWh (net)	*688*	*761*	*573*	*573*	*573*	*573*	*573*	*573*
Pumped storage stations, GWh (net)	*5 060*	*5 128*	*5 012*	*5 443*	*5 081*	*5 075*	*4 573*	*4 376*
Gas turbine stations, GWh (net)	*1 328*	*777*	*211*	*211*	*211*	*211*	*211*	*192*
Wind energy, GWh (net)	*283*	*306*	*313*	*312*	*308*	*307*	*304*	*311*
Nuclear power station, GWh (net)	*13 252*	*9 813*	*11 850*	*12 562*	*13 631*	*12 468*	*13 295*	*14 566*
IPP purchases, GWh	11 958	14 179	20 262	36 485	45 063	52 936	64 960	67 286
Wheeling, GWh	2 491	2 197	2 088	2 088	2 093	2 088	2 088	2 088
Energy imports from SADC countries, GWh	8 568	8 928	8 457	8 457	8 481	8 457	8 457	8 457
Total Gross Production , GWh	**237 985**	**223 998**	**227 753**	**227 376**	**225 864**	**224 860**	**224 400**	**224 342**
Less Pumping	6 629	6 856	6 545	7 110	6 636	6 628	5 967	5 714
Total Net Production , GWh	**231 356**	**217 142**	**221 208**	**220 266**	**219 228**	**218 232**	**218 433**	**218 628**

4.4 Conclusion on the production plan

As can be observed by the results in the table above, the Generation energy sent-out drops from 214 968 GWh (FY2020) to 146 510 GWh in FY2027, whilst Generation market share decreases from 90% to 65% in the same period. The IPPs' market share will increase from 6% in FY2021 to 30% in FY2027. As the plant availability stabilises and new capacity is added into the grid, energy growth remains stagnant and plant utilisation will drop. The Energy Utilisation Factor (EUF) for coal fired power stations drops from 77% in FY2022 to 57% in FY2027, whereas EUF for Generation system drops from 68% in FY2022 to 54% in FY2027.

4.5 "Stress test" on Production Planning

The Production Plan used for this application is based on a plant availability of 72% which is Generation's aspiration. However, current availability, as per the Q3 projection for FY2021 is an EAF of 65.11%, and current financial and system constraints make improvement a challenge. Availability of the Generation fleet is one of many assumptions in the Production Plan. Others include the energy forecast and changes in the Generation and IPP new build programmes.

Due to uncertainties in these Production Planning assumptions, a risk impact assessment on the system was conducted. The assumptions for this assessment include higher sales, and an EAF that increases from 65% in FY2022 to 69.5% in FY2031, and a delay in non-Generation new capacity increases. These can be seen in the tables below. All other assumptions remain the same as for this submission.

TABLE 11: STRESS TEST ENERGY FORECAST AND PLANT PERFORMANCE ASSUMPTIONS

Stress Test	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
MYPD5 Forecast (GWh)	221	220	219	218	218	219	219	218	218	208
Stress Test Forecast (GWh)	228	226	225	223	223	223	224	224	224	214
Variance	7	6	6	5	5	4	5	6	6	6
EAF (%)	65.0%	65.5%	66.0%	66.5%	67.0%	67.5%	68.0%	68.5%	69.0%	69.5%

The Risk Mitigation Programme, the IPP Gas Programme and the Coal IPP and some REIPP projects are assumed to be delayed. For the purpose of this stress tests, with regards to the REIPP projects for wind, PV and CSP, different assumptions are made on commercial operational dates. For any renewable capacity to be commissioned in the application period, it is assumed that any capacity will be commissioned a year later than used as a basis for the production plan.

TABLE 12: NON-GENERATION CAPACITY ASSUMPTIONS

Non-Eskom capacity	MYPD 5 Date	Stress Test Date	Delay
Risk Mitigation Programme	Dec-21	Jun-22	6 Months
IPP Gas Programme	Apr-24	Apr-26	2 Years
Coal IPP	Apr-25	Apr-28	3 Years

Note: Coal IPP is outside of MYPD5 period but is included in the 10-year Production Plan.

Based on the stress test assumptions, OCGTs will be required for the first 2 years (FY2022 and FY2023) of the planning horizon whereas with the application assumptions, OCGTs were not required more than 1% for the full period. However, beyond FY2023 OCGTs would not be required by the system, as a result both IPP and Generation OCGTs are kept at 1% load factor per annum for the entire planning cycle. This is because the model instead uses stations/units that were not required in the application scenario to run for longer as these are cheaper than the OCGTs. Thus Komati would be required until September 2022, Grootvlei until December 2022, Camden until April 2024, Arnot and Kriel UG until April 2028, and Kriel OC until April 2030.

This means that although the base Production Plan for this application shows that some of the older and more expensive units or stations will not be required to produce electricity to meet demand, these units or stations cannot be decommissioned at this time as they will be required should any of the risks taken into account in the “stress test” materialise. These units or stations will thus instead be shut down and placed in reserve storage. This submission assumes that there will be opportunities for further efficiencies at these stations due to no Capex and minimal Opex spend for essential services so that the units could return to service within a year should they be required. Effectively, these units or stations will be a risk mitigation or insurance policy for possible changes to the environment in which Generation operates. Updated information, if applicable, will be provided during the consultation phase, prior to the revenue decision being made.

4.6 Energy losses

The nature of transporting electricity from generator to the end-users involves losses in energy volumes (electrical or technical losses) that reduce the amount of electricity volumes available for sale to end-customers. In addition, other energy losses may occur due to non-metered usage related to electricity theft (non-technical losses). The representation of the measure for the levels of the combined total technical and non-technical losses is by way of loss factors. As required by the MYPD methodology, the updated Generation loss factors calculated as per the Tariff grid code are included.

Energy loss is an inherent risk in the electricity business and utilities globally are addressing this issue. Energy losses are incurred when energy is transferred from the suppliers to the customers through the network. This energy lost, is approximately equal to the difference between the energy supplied and the energy consumed.

- Transmission losses are determined by the difference between energy injected onto the transmission grid and energy off-take at main transmission substations (MTS) and interconnection points.
- Distribution losses are determined by the difference between energy purchased (measured at main transmission substations) and energy sold to all Distribution customers.

Energy loss has a direct effect and increases generation requirements (both capacity and energy volumes) and thus primary energy costs.

4.7 Virtual “Negative” Power Station

The concept of a virtual station was introduced in response to risks relating to actual vs. planned station availability, coal procurement and fuel burn costing. The benefit of using the virtual station is to facilitate both the planning for sufficient coal procurement at station level as well as more accurate burn costing at system level.

In preparing the system production plan each station's maximum possible availability (EAF) is used in conjunction with the station's merit order, with the high merit order stations assumed to produce annual electricity on the basis of its maximum possible availability. Using each station's respective maximum possible availability would, however, result in an artificially high overall system EAF which will be difficult to achieve in practice. The virtual station allows the system average EAF to be lower than the sum of each station's maximum possible EAF by assigning a negative availability and output to the virtual station, with the shortfall in output compensated for from the lower-merit-order stations. As the system's required output is determined from the sales plan, total planned production does not change due to the virtual station.

The virtual station is used to provide for swings in burn to more expensive stations. Individual station coal burn and supply is planned on a least cost basis on the upper boundary of individual plant technical performance i.e. on the assumption of the maximum amount of coal that might be consumed in a year at each power station. Collectively these respective upper boundaries result in an overstated assumption of electricity production from the base load coal stations, compared to the expected coal fleet's system performance. The overstatement of output results in an understatement of required electricity production from mid- and low-merit-order coal stations as well as from gas and other stations, with the risk of inadequate fuel supply to such stations. In addition, it results in in understatement of total fuel cost due to the assumed lower production from the low-merit-order power stations. Any actual inability on the part of a high-merit order station to burn as planned will result in that burn being shifted to stations with available capacity. These stations will obviously be the more expensive stations – the stations where the least burn was initially planned.

A virtual station is thus introduced in the production plan as a negative energy output. This has the consequence of causing the planned output from the lower-merit-order power stations to increase, which ensures that adequate fuel supply is planned for those stations. It also ensures a more accurate fuel cost by virtue of the "negative energy output" from the high-merit-order stations which is deducted from fuel cost, being less than the planned fuel cost for the production from the lower order stations.

The virtual station then caters both for the increase in total burn cost because of this shift, as well as for adequate fuel supply at the lower-merit-order power stations. In terms of stock values this is reflected as a slight increase in the planned value of total stockpile especially at the high order stations, although in practice the fuel supply volume is managed in accordance with plant performance thus avoiding stockpile levels which exceed the accepted range.

The benefit of using the virtual station is to facilitate both the planning for sufficient coal procurement at station level as well as more accurate burn costing at system level. This concept was further extended to Other Primary Energy such as Water Treatment and Start-up gas and oil.

As Matla is the power station performing the closest to the fleet average for coal fired power stations, all the parameters for the Virtual Power Station were based on Matla.

5 Primary Energy

5.1 Summary

IPPs experience an upward contribution trend towards allowable revenue over the three application years. The contributions to the total allowable revenue for each financial year increases from 25%, to 25% to 28% over the application period. This corresponds to R70bn, R85bn and R102bn for the three years respectively. Thus, from the FY2024, the revenue related to IPPs will exceed that of Eskom's primary energy.

The contribution of **environmental levy and carbon tax** combined, increases from 3% to 5% and drops to 4% in each year of the application respectively. This shows the impact of the introduction of carbon tax liability from January 2023. From January 2023, when the carbon tax liability is implemented, the contribution of environmental levy and carbon tax accounts for over 8.5c/kWh.

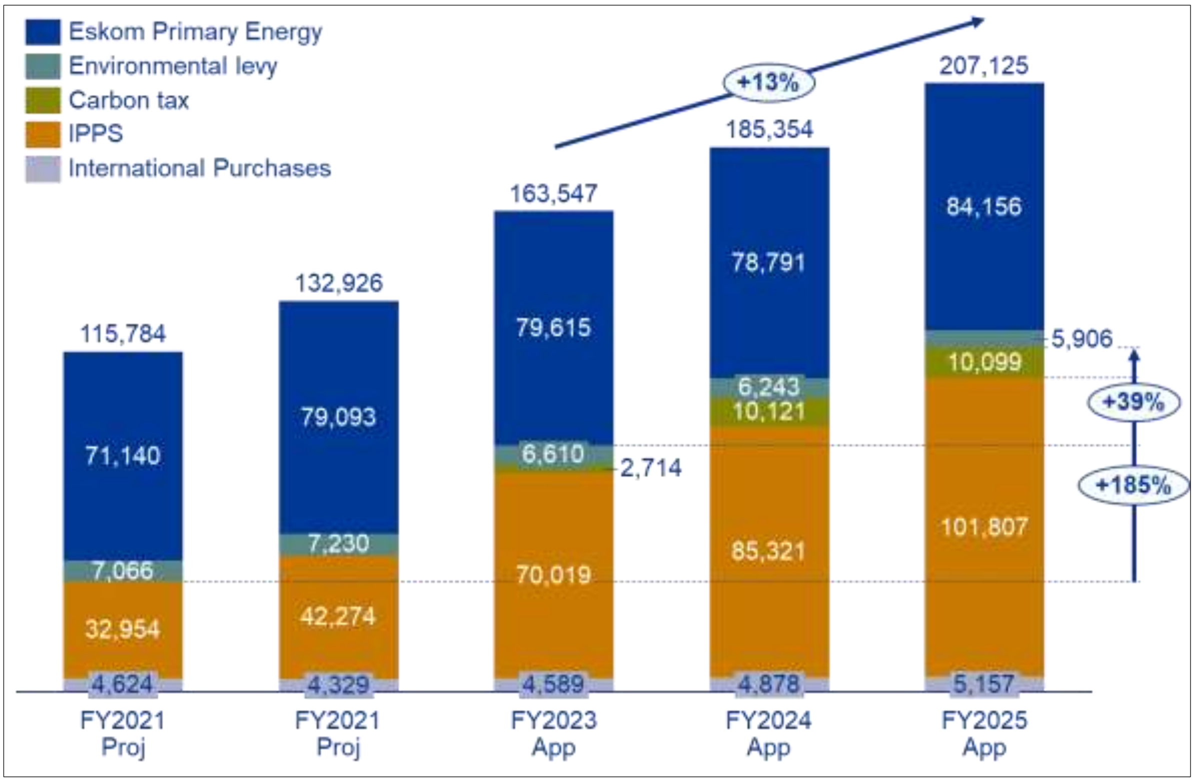
Collectively for IPPs, environmental levy and carbon tax contribution to allowable revenue increases from 28% to 30% to 32% over the application period. These are defined as items of the revenue that Eskom includes in the revenue application – but has no control over. They could be defined as externally influenced.

The costs associated with most Eskom related primary energy elements have remained relatively static from the MYPD4 period to the MYPD5 period. The increase in the coal price rate (average R/ton) is less than 10%, when costs of logistics are included.

TABLE 13: TOTAL PRIMARY ENERGY COSTS

Primary energy costs (R'm)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Coal usage	57 589	57 093	67 326	66 975	66 252	70 691	71 190	76 060
Water usage	2 278	2 291	2 768	3 047	3 341	3 681	3 924	4 397
Fuel and water procurement service	188	199	247	288	313	335	347	368
Coal handling	2 018	2 122	2 354	2 480	2 399	2 564	2 724	2 810
Water treatment	484	553	613	590	621	646	692	760
Sorbent usage	59	238	233	279	372	508	461	418
Gas and oil (coal fired start-up)	3 960	3 039	3 508	3 712	3 039	3 151	3 306	3 484
Total coal	**66 576**	**65 535**	**77 050**	**77 371**	**76 337**	**81 576**	**82 644**	**88 297**
Nuclear	844	666	749	839	957	989	1 111	1 191
Coal and gas (Gas-fired)	7	10	9	10	10	10	10	10
OCGT fuel cost	4 303	4 601	867	936	1 009	1 086	1 169	1 160
Demand reponse	295	295	339	381	399	416	435	455
Demand response - power alert		33	78	78	78	78	78	78
Power buy back	76	-	-	-	-	-	-	-
Total Eskom generation	**72 101**	**71 140**	**79 093**	**79 615**	**78 791**	**84 156**	**85 447**	**91 192**
Environmental levy	7 613	7 066	7 230	6 610	6 243	5 906	5 451	5 362
Carbon tax		-	-	2 714	10 121	10 099	9 680	10 052
Independent Power Producers (IPPs)	29 693	32 954	42 274	70 019	85 321	101 807	124 128	133 616
International Purchases (SAE)	4 704	4 624	4 329	4 589	4 878	5 157	5 466	5 794
Total primary energy	**114 111**	**115 783**	**132 926**	**163 547**	**185 353**	**207 126**	**230 171**	**246 016**

FIGURE 12: PRIMARY ENERGY TRENDS



Note: trends shown are average increases per year which are not the same as CAGR.

The total primary energy costs are captured in the figure above. The total primary energy is inclusive of international purchases, carbon tax, environmental levy, IPPs and Eskom primary energy. The CAGR in the three year application experiences a growth of 13%. When comparing the simple growth in the costs related to IPPs, the costs has almost tripled from FY2021 to FY2025 (simple growth of 185%). These increases are due to a substantial increase in the volume of energy secured from mainly renewable energy from IPPs. The total energy secured from IPPs increases from a projection of 20TWh in FY2022 to approximately 53TWh by FY2025. Of this total, renewable energy accounts for an increase of approximately 18TWh (Projected for FY2022) to 41 TWh (application for FY2025). The non-renewable sources of IPPs energy increases from a projection of 0.8TWh in FY2022 to approximately 12TWh by FY2025. This is mainly due to the risk mitigation programme. The introduction of carbon tax liability during the FY2023, a simple growth of 39% is seen from FY2023 to FY2025. Due to the inclusion of these significant increases in IPPs and carbon tax, the overall CAGR is 13% over the three year period. As a comparison, the Eskom primary energy CAGR over the three year period is 5.37%

5.2 Coal and Water Overview

Generation procures coal, water and Sorbent and other primary energy for its power stations. The environment within which it does so is dynamic, having become more so since the SARS-COVID 19 pandemic.

While Generation is a regulated entity, the coal market is unregulated, so Generation competes with local and global buyers on price and supply. Although South Africa has abundant coal resources, coal in close proximity to the power stations is in dwindling supply. Large mines located adjacent to some of the power stations are old and require significant expenditure to extend the lifespans.

Where coal is procured from sources which do not have a conveyor to the power station stock yard, the coal must be transported by road and/or rail, instead of being moved over short distances on conveyor. This adds complexity and cost to the value chain. Historically, Generation purchased as much as 130 Mt of coal per annum. Coal is procured on three types of contracts: Cost Plus, Long Term Fixed Price, and Short/Medium Term.

More recently, the volumes of coal purchased have been reducing, and this application forecasts that this trend will continue for the MYPD5 period.

The forecast decrease in volumes from FY2021 manifests in the lower volumes from the Fixed Price (FP) and Short and Medium Term (STMT) contracts. This may be attributed to the following:

- The decrease in offtake by Matimba and Medupi Power Stations from the Grootegeluk mine as a result of lower demand and full stockpiles.
- The decrease in demand from STMT coal supply agreements (CSA)s as Camden, Grootvlei, Hendrina and Komati Power Stations wind down generation.
- The decrease in demand from STMT CSAs because Kusile Power Station is generating at levels lower than expected.
- There is an increase in the cost of coal purchased because of: the inclusion of take or pay payments coal from Grootegeluk mine for Matimba and Medupi Power Stations.
- The inclusion of take or pay payments from certain STMT CSAs for the reasons stated above.

Generation has seen the cost of water increase significantly over the past years. This is due to new water infrastructure, increasing tariffs and new power stations. Water tariffs are legislated, so Generation cannot negotiate lower tariffs. The primary supplier of water to

Generation is the Department of Water & Sanitation (DWS). The water schemes are interconnected so water may be pumped between schemes to supplement supply. Pumping costs add to the cost of water. Generation's water consumption reduces from approximately 276 to approximately 163 million cubic meters (Mm^3) of water per annum from FY2021 to FY2027.

Generation's sense of corporate responsibility and increasingly stringent environmental requirements motivated the introduction of flue gas desulphurisation (FGD) processes at the new power stations, Medupi and Kusile. While FGD is in use at Kusile, it is not expected to be introduced at Medupi Power Station during this MYPD5 period. Sorbent is used to reduce Sulphur emissions. This process requires additional water consumption. There is an increase in the cost associated with the Sorbent procurement and logistics, as well as the water.

5.3 Primary Energy Market Overview

This section summarises the trends and market forces impacting the Primary Energy business and the key elements of the Generation coal strategy to exploit and mitigate said trends and market forces.

5.3.1 Overview of the Primary Energy Business Environment

Within the Generation licensee, the Primary Energy function's mandate is to safely and sustainably identify, develop, source, procure and deliver the necessary amounts of primary energy (coal, water, Sorbent and biomass) of the required quality for Generation's power stations, at the right time and at optimal cost.

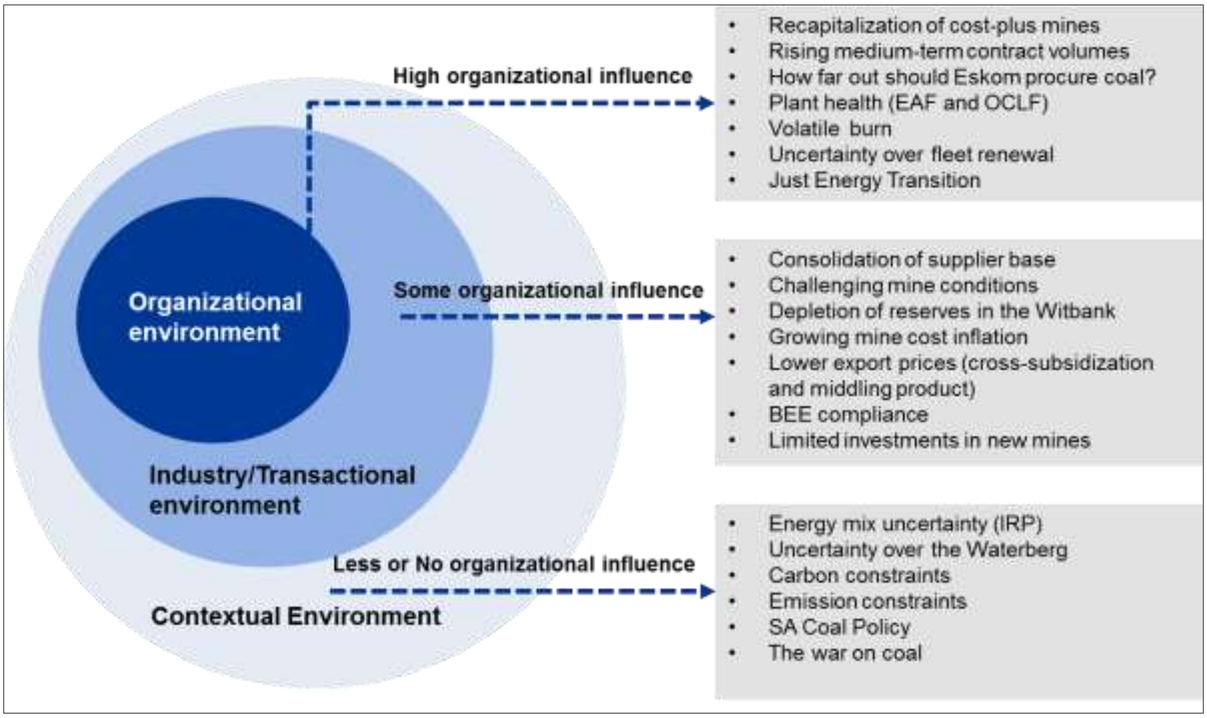
Generation has entered into three types of coal contracts, namely long-term, medium-term and short-term contracts. These mines are based primarily in the Mpumalanga province of South Africa due to the high concentration of power stations in the region.

Key responsibilities and activities are to secure future primary energy requirements and associated logistics by working with relevant stakeholders and government departments at a national level to ensure that adequate resources (coal, water and Sorbent) are available and accessible for power generation. The division's accountability covers a range of functional areas extending from the source of fuel to delivery and stockpiling at the power stations:

FIGURE 13: PRIMARY ENERGY VALUE CHAIN

Within each of these functional areas lies an array of factors, over which Generation has varying degrees of influence.

FIGURE 14: CHALLENGES FACING GENERATION'S PRIMARY ENERGY FUNCTION



The division is, thus, exposed to various factors that have had, and will continue to have implications for costs and security of primary energy supply to Generation. Some of these factors above are discussed below.

5.3.2 Impact of economic uncertainty on the long term growth trend

Generation's coal supply strategy is impacted by the electricity demand forecast. This, in turn, is based on the forecast for economic growth in South Africa. After the high growth and consequent high electricity demand of 2003 – 2008, the subsequent global economic meltdown resulted in a sharp decline in electricity demand. Recent forecasts are that South Africa will experience very little economic growth. This is reflected in the flat gross electricity generation forecast for the MYPD5 period. Generation can base its electricity, and coal, demand forecast on this scenario, but continued economic uncertainty will impact on the accuracy of electricity demand forecasts, reduce the accuracy of primary energy forecasts, and increase the risk of under- or over-supply of primary energy.

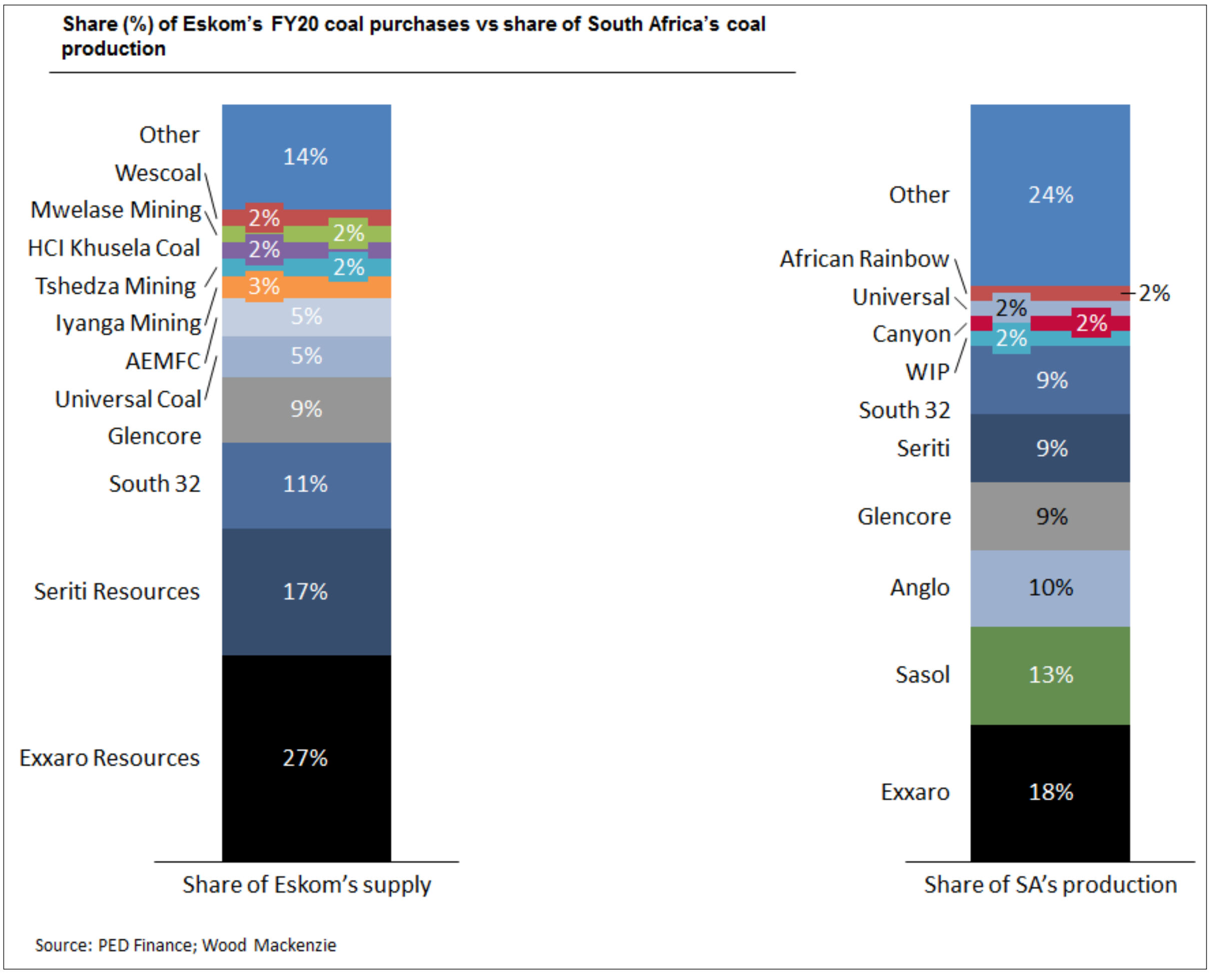
5.3.2.1 Implications:

- Continued uncertainty and economic instability increases the risk of over or under contracting of coal supply, which necessitates the requirement for Generation to increase the volume flexibility in the portfolio of coal contracts. However, this flexibility will bear a cost.
- Continued uncertainty will also increase the risk associated with cost projections as many of the coal supply agreements are linked to external indices or cost drivers.

5.3.3 Changing the coal industry structure

Perhaps, because of both the economic and political environment, where South Africa previously saw the emergence of more junior and BEE miners in the coal sector, the current cyclical downturn has resulted in a dearth of new mines. The previously hopeful new players provided Generation with a larger supplier base. The figure illustrates that approximately 70% of the South African coal market is dominated by six suppliers.

FIGURE 15: PRIMARY COAL SUPPLIERS FY2020



5.3.3.1 Implications:

- Funding for coal projects is a major challenge, more so for smaller miners
- There is a lack of large scale investment into the coal mining industry. This will create a supply shortage in the future.
- The slowdown in global and local economic growth, and the resultant decrease in export demand and pricing, increases the risk of marginal mines facing liquidity challenges. This increases Generation's supply risk.
- The increase in export demand for a RB3 product (lower export specification product) has removed the availability of the Generation quality middlings coal product that was previously available to Generation.

5.3.4 Mines have an alternative market

Existing mines are taking advantage of the high export coal prices. Many investment decisions which were made at the height of the last commodity boom are now on line. However, these mines are targeting the more lucrative export market and not the domestic market. The relatively weak exchange rate also provides an incentive to earn revenue from exports. Facilitating these exports, and reducing the coal available to Generation, are traders with export allocations at the RBCT. These traders are willing and able to buy up coal from small miners, paying cash on delivery.

Although China tried to reduce thermal coal's share of the generation mix in order to raise environmental standards in the country, the lack of alternative power and heating supplies are expected to result in this policy being relaxed in the colder months. If the country does not increase its coal production, it will have to import coal. While India is expected to become self-sufficient in producing its own coal, the country is still reporting a shortage.

Major companies such as Seriti and Exxaro have stated that there will be no further greenfield investments in new coal mines. Generation will, therefore, contend with a reduced supply, from reduced investments, as well as displaced export coal, which will push prices up.

The demand for lower quality coal is reflected in the fact that the bulk of coal exported out of Richard's Bay is now the 5 500 kcal coal instead of 6 000 kcal, and that coal of 4 800 kcal is also being exported. These are qualities used by Generation's power stations.

5.3.4.1 Implications:

- The uncertainty makes planning for coal purchases very challenging. There could be significant variations between plans and actual events and costs.

- Because of the uncertainty, there is a lag in new projects.
- Coal allocated for Generation is being diverted to the export
- Suppliers are demanding higher base prices when negotiating new contracts.
- There are other markets for coal that used to be exclusively for Generation's use. Historically, export prices cross-subsidised Generation's middling product. Now the middling product is being exported to India.

5.3.5 Deteriorating resource/reserve base

The mines in the Mpumalanga basin are entering a phase where the cost of coal is driven upwards by factors such as deteriorating coal quality, increased occurrence of geological disturbances, thinner coal seams, depleting reserves in the currently accessible reserve blocks, high investments to access the remaining new small reserve blocks and longer 'on-mine' transport distances. These factors increase coal handling, maintenance and labour costs and reduce productivity, while increasing the need for costly beneficiation of the coal. The majority of Generation's current long term coal supply sources have been in operation in excess of 20 years and, as some of the oldest operating mines in South Africa, are directly impacted by these increased costs. Managing the quality and quantity of Generation's coal supply is becoming more challenging.

5.3.5.1 Implications:

- The costs of establishing and operating new mines will be significantly higher than in the past, due also to the more geological complexity, thinner and deeper coal seams and which will translate into higher coal prices for Generation.
- Substantial investment will be required to open new, more marginal coal reserve blocks (with limited life as the large blocks have been mined) to maintain coal supplies.
- The calorific value of coal is reducing. There will be an increased need for beneficiation of certain resources to meet power station coal quality parameters, further increasing costs.

5.3.6 Increased transport distances between mines and power stations

The procurement of coal from sources, which are great distances from the power stations means that this coal must be transported by road or rail.

5.3.6.1 Implications:

- Coal resources and reserves away from an existing Power Station is likely to incur additional logistics cost to deliver that coal to the Power Station which will result in an increase in the coal cost.
- The logistics strategy must consider the interests of transporters, those of Generation and the public regarding cost and road safety.

5.3.7 Increasing environmental pressure

Generation's coal-focused generation mix requires significant volumes of water, a scarce and important resource in South Africa. The opening of new coal mines to supply both Generation and the export market is expected to place pressure on the already strained environment and on water catchments. Existing and new environmental legislation is expected to be more stringent than past standards, and the requirements are likely to result in a decrease in productivity levels and/or an increase in costs.

5.3.7.1 Implications:

- New emissions standards for power stations will necessitate higher coal quality specifications, which could, potentially, increase the cost of coal.
- Similarly, any more stringent environmental legislation will increase the mine environmental, rehabilitation and closure costs, leading to higher overall prices charged to Generation.

5.3.8 Constraints on water supplies

Generation is a strategic user of water, consuming approximately 2% of the total annual use of the country, which is equivalent to the consumption of the City of Cape Town. As the South African economy grows, there will be an increased demand for scarce water supplies.

5.3.8.1 Implications:

- Increased demand will require significant investment in new water schemes, the cost of which must ultimately be recovered from both current and future users, including Generation.
- There is a need for significant investment in infrastructure to supply water to the Waterberg area, which will increase water costs and tariffs in that region.
- There is a possibility that the DWA might re-price the water tariffs to reflect water scarcity in the country.

- The DWS can include more water tariff components to fund infrastructure, administration and initiatives through the revision of the National Water Pricing Strategy
- The possibility exists that additional costs may be incurred if the effects of the current drought in certain parts of the country are prolonged. These costs have not been included in this application.

5.3.9 Supply constraints in key mining inputs

As the world's economic recovery and political stability in many regions remain uncertain, commodity prices will also fluctuate. This uncertainty is compounded by labour unrest in the mining industry in South Africa that could result in mine closures and higher prices of commodities. There is speculation that falling sea borne thermal coal prices, together with poorer quality Indian domestic coal, could provide support to coal imports. While the price of coal from Generation's existing contracts is not impacted significantly by export prices, increased exports of RB3 type coal does affect the coal that is available for Generation in the South African market.

5.3.9.1 Implications:

- Continued real increases in domestic mining input and labour costs will impact all of Generation's coal contracts as industry wide input cost changes are ultimately passed through to Generation, since they are deemed to be beyond the control of the coal suppliers.
- Lower volumes of RB3 (Generation quality) coal available to Generation in the South African market.

5.3.10 Key elements of PED strategy to exploit and mitigate trends and market forces

5.3.10.1 Generation Coal Strategy

In 2018, Primary Energy costs and security of coal supply were identified as one of the major focus areas for Generation in order to ensure business sustainability. Primary Energy Division (PED) has developed a Long Term Coal Strategy to address these focus areas.

Generation's Long-Term Coal Strategy has been revised to revert Generation's coal supply to dedicated long term coal contracts for the life of the stations, with preference for conveyor delivered coal.

(i) There are four main levers which will support the strategy objectives:

- Investing into cost-plus mines for the life of the reserve to ensure a sustainable price path for coal stations.
- Engaging the market for long term contracts (>10 years, for the remaining life of power stations) to send a market signal for investments in untapped reserves (preferably close to power stations).
- Ensure that Generation contracts, procures and delivers coal quality as required by the station. Provide assurance that the contracted coal is delivered to the station
- Strive to move coal as economically as possible, leaning to more tied colliery model delivering coal by conveyor. Rail and road transportation come second and third.

Generation will also review its operating model for a holistic approach in implementing the strategy.

(ii) The follow items are critical to the success of the Coal Strategy:

- Generation tariff to be reflective of the market price/cost of coal.
- Availability of capital funding for investing into existing cost plus mines.
- The availability & access to highly skilled resources to ensure implementation and realisation of the strategy (commodity sourcing specialists, contract negotiators and contract lawyers).
- (External to Generation) Policy and legislation certainty, which will encourage investment in new coal mines.
- Power stations to ensure there are measurement meters in place to measure coal quality delivered at stations.

Generation's coal supply faces 4 main challenges and the strategy aims to address it through the following levers:

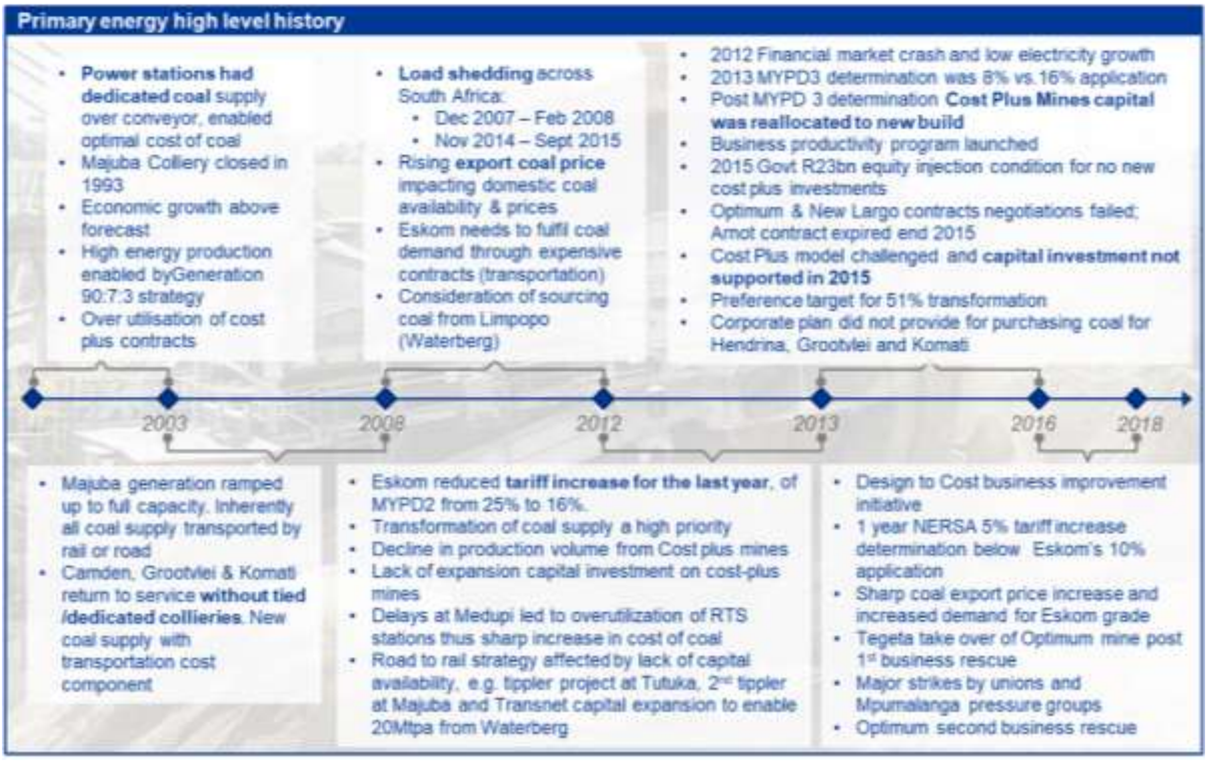
FIGURE 16: MAIN CHALLENGES IN COAL SUPPLY AND LEVERS TO ADDRESS

Objectives	Challenge	Impact	Levers to address challenges
The optimal cost of coal • Contribute to the lowest cost per MWh sent-out for Eskom by delivering **end-to-end cost** of (Opex and Capex) coal efficiency	1 **No new mining investment** and current mining rights not executed	Interrupts the volumes of coal mined	• Trigger new mines through expression of long term contracts (>10years)
	2 Rising **coal market price and mining costs** increase	Interrupts the volumes of coal contracted and supplied	• Cost plus investment • Production optimisation of cost plus mines • Long term contracts which hedge against price fluctuations and limits expensive logistics options
Security of coal supply • Meet **volume requirements** and safety margin on high confidence scenario with flexibility to increase	3 **Coal supply shortfall** at several power stations with contracts coming to an end	Interrupts the amount of coal stockpiled and burnt	• Cost plus contract extensions • Investment in Cost Plus mines • Long term contracting to unlock large unmined reserves (manage competition with coal exporters)
Transformation in coal procurement • Support Eskom's **socio-economic policy** objectives	4 Increased pressure and **violent protests** from local communities for localisation of Eskom procurement	Interrupts the volumes of coal transported and therefore stockpiles run low	• Transformation opportunities to be shared with stakeholders • Prioritize conveyor coal (manage road and rail supply interruption)

Historically Generation power stations were built on mouth of the dedicated colliery whereby coal was supplied over conveyor, the model changed in the last decade and a half.

The timeline below illustrates a high-level history of coal supply and the associated changes in the landscape, which has affected the cost of primary energy in Generation:

FIGURE 17: HISTORY OF COAL SUPPLY



For a very similar/lower energy output historically, Generation is producing a similar output with a much more expensive coal supply mix mainly due to the following:

- The use of expensive power stations (with no tied colliery) and a steady decrease in cost plus mine production due to a lack of investment has led to an increase in procurement on medium term contracts with additional transport cost. It is important to note that on average 30% coal costs relate to the transporting of coal when Generation purchases coal from a non-tied mine i.e. medium term contracts.
- FY2020 – 44% Medium term volume (~50Mt) contributes 54% of the coal costs. Thus, Medium term contracts remains the most expensive coal contracts
- The reduced production from the cost plus mines (volumes) and the associated inflationary fixed cost escalations at these cost plus mines results in a higher unit cost of coal. (i.e. the fixed costs remain the same with reduced volumes)

On average, 25 - 30% of coal costs relate to the transporting of coal when Generation purchases coal from a non-tied mine (Short/Medium term contracts).

There are four main levers PED will utilise to ensure the sustainable coal cost:

FIGURE 18: FOUR MAIN LEVERS TO ENSURE SUSTAINABLE COAL

Lever	Description
Long term fixed price contracts	Apply a variety of contracting and technical levers to improve overall TCO[1] (across coal price, transport, handling, and quality) Long term contracting for remainder of power stations life will through open tender per station: • Reduce price path fluctuations (Medupi, Matimba are examples) • Trigger new investments into mining resources
Cost plus contracts	Increase value from Eskom's current contracts through improved volumes with predictable cost trajectory: • Cost plus investment to get mine back to "contractual" levels • Business case to consider the best option between Eskom and mining house capital funding • Cost plus contracts extension for the entire reserved and production optimisation
Increasing bargaining and negotiation power	Operating structure review around increasing the flexibility and relevance of contracting procedure Power Station specific open tender to build a catalogue of suppliers Improve the negotiation capability of PED by implementing one of the following: • Contracting in commodity procurement experts and negotiators for long term negotiations • Building capability by recruiting own commodity experts from the market • Dedicated contract lawyers
Long term coal contracting	Approval to communicate Eskom coal requirements in the following platforms: • Conferences • Mining related publications • Hosting supplier engagement forums • Enter into talks with investors for mine investment with guaranteed off takes, to ensure correct ramp up periods post open tender per power station

5.4 Key assumptions underlying the sourcing plans and cost forecasts

The key assumptions underlying the primary energy sourcing plans and cost forecasts are detailed below. Changes in one or a combination of these assumptions will result in changes to the forecast costs.

5.4.1 Demand for coal

The demand for coal is based on a particular Production Plan for a 10 year period FY2022-FY2031.

5.4.2 Coal sources and volumes

- Dedicated (Cost Plus) mines, produce at expected levels, which are largely below contractual volumes
- Multi-product (Fixed Price) mines produce at expected levels.
- Kriel and Matla CSAs will be extended.
- Capex will be available immediately for investment in cost plus mines.
- Any shortfalls will be sourced from smaller operating mines, most of which are already supplying Generation.

5.4.3 Coal costs and price escalations

- Cost Plus mines costs increase at different percentages, but the average annual increase for the contract type is 6%.
- Fixed Price mine costs have been escalated in accordance with the terms of the contracts using Generation's parameters. The average annual increase for this contract type is 9%.
- A modelled index has been used for future escalations for contracts that are still to be negotiated. The average annual increase for this contract type is 9%.
- Prices from medium term contracts have been based on existing contractual delivered cost. The average annual increase for this contract type is 9%.

5.4.4 Logistics

- All coal to Majuba planned on rail.
- The free carrier agreement (FCA) road transport contracts expire in October 2021. It is assumed that any new contracts will also be subject to the existing rates model.
- The rail services contract with Transnet expires in 2023. It is assumed that a new contract will retain the same terms and conditions.

5.4.5 Parameters used in forecasts

The forecast cost of coal ultimately depends on a forecast demand for electricity and on expected coal volumes and costs from cost plus, long term fixed price and short/medium term sources, as well as the various costs associated with the value chain, e.g. logistics costs. Generation has made certain assumptions with regard to these variables. Generation has based these assumptions on the information available at the time this application was complied. Changes to these assumptions will result in changes to the costs and volumes.

5.5 Key drivers affecting the coal cost forecasts

Among the various factors affecting coal costs, a few have particular relevance for Generation.

5.5.1 Uncertain energy plans

The delay in confirming the Integrated Resource Plan (IRP) requirements, together with IPP generation, has resulted in Generation's production plan being compiled under great uncertainty. The production plan, in turn, impacts the coal procurement requirements. Changes in the production plan can result in significant changes in coal procurement and burn cost.

5.5.2 Logistics

Transport costs depend on the distances over which coal is transported, the transport mode and the transport rate.

5.5.3 Cost plus mine production

Lower production levels at cost plus mines have resulted in a higher unit cost at the respective mines. Limited historical capex investments, together with ageing mines, has compounded production challenges and increased costs. These contracts are largely still more beneficial to Generation than an alternate supply as they have a transport advantage over any other supply.

5.5.4 Mining costs

- The input costs into coal mining are increasing at rates higher than inflation.
- The natural geology is also contributing to increasing coal mining costs.

5.5.5 Stricter Environmental Legislation

- Stricter mine closure and rehabilitation requirements.
- Stricter legislation regarding water management and disposal.
- Stricter emissions legislation and application thereof.

5.5.6 Water

- The Department of Water Affairs under spent on maintenance and refurbishment on bulk water infrastructure over the years. This has resulted in a backlog of maintenance and refurbishment that is required to be planned and implemented in the forthcoming years to ensure plant reliability and availability.
- The development and implementation of new water infrastructure, as the Mokolo Crocodile West Augmentation Project (MCWAP2) required for water to the Waterberg, will increase the cost of water.
- Water costs are regulated in line with the prevailing National Water Pricing Strategy. A new draft Water Pricing Strategy has been issued. Water tariffs could change once the draft Pricing Strategy is finalised. Water cost increases are primarily driven by increasing water demands of the new build, which require new water infrastructure and therefore higher capital tariffs to repay off the financing debt.

5.5.7 Sorbent

- The coal-fired power stations where Flue Gas Desulphurisation is planned are geographically remote from viable sorbent sources; hence logistics and the final delivered cost will contribute to the selection of the most cost effective option.
- Estimated pricing escalations are assumed to be driven by producer price index (PPI).
- Greenfield sources will require capital investment in rail infrastructure and as such will require a return. However, Generation is looking for other sources of sorbent to reduce dependence on a single source.

These drivers have the potential to increase or decrease coal costs significantly. Generation has limited control over them, but has attempted to limit the impact thereof by taking into account the existing circumstances around them and using the best available information to forecast the impact of these factors on costs and volumes.

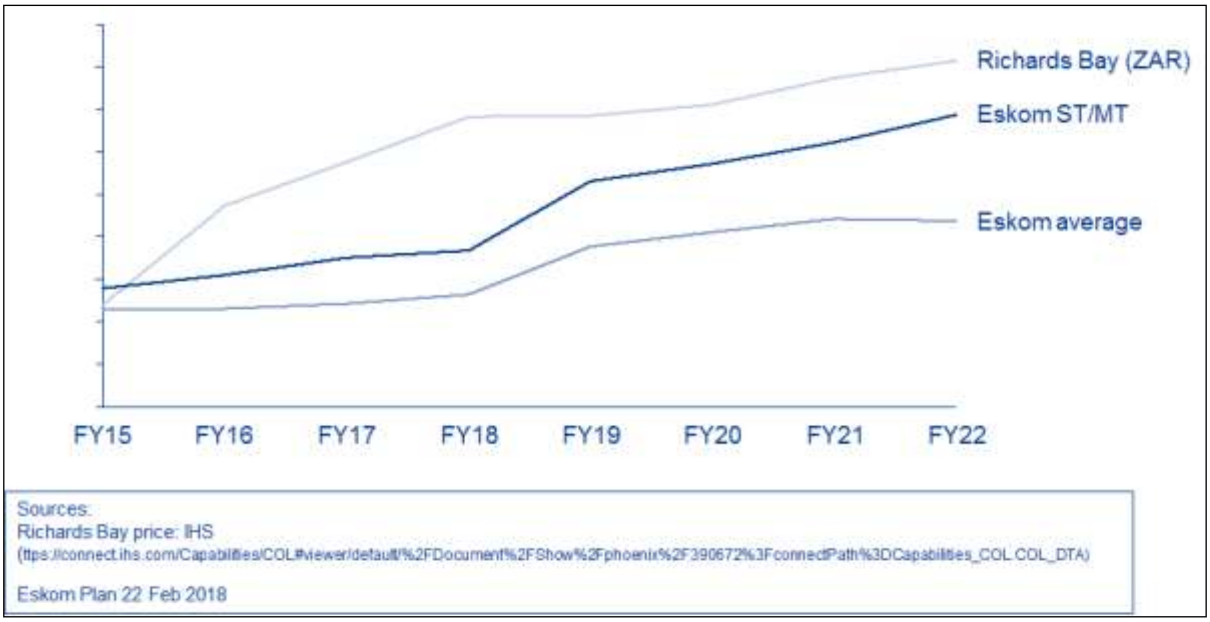
5.5.8 Key Opportunities and Challenges

- The South African coal market requires substantial investment and recapitalisation to meet both domestic and export coal requirements. The current economic environment is not conducive to investment.
- Generation’s current financial position creates a difficult environment for Generation to raise capital for further investment in maintaining existing cost-plus coal mining operations.
- Funding within the coal environment remains a substantial challenge of new and established miners.

5.6 Coal Benchmarking

This section compares the volumes and prices of coal supplied to the domestic market (primarily Generation) with that exported. The graph below reflects the trend in the average Generation price per tonne compared with the price out of Richards Bay (converted at the average ZAR/$ for the year). The purpose of the graph is to indicate that the average export prices far exceed the average prices Generation pays and that this gap is expected to remain. This provides suppliers with leverage during price negotiations. It also provides an incentive for mines that export and supply to Generation to prioritise exports at the expense of Generation.

FIGURE 19: AVERAGE FOT STEAM COAL PRICES(R/T)



5.7 Governance

Governance issues in coal procurement have been in the media recently. Generation's Board has embarked on a process of addressing the findings and recommendations from various reports. Generation's delegation of authority specifies who may authorise transactions/ expenditure and the financial limits applicable to each delegee.

In the Primary Energy Department (PED), procurement of goods and services follows the Generation commercial process. Once it is approved, the mining houses will place the contracts with the suppliers.

If an investment or expenditure is approved, it must then go through the tender governance process which includes mandating a specific person who will manage the contract.

Modifications to existing contracts must be approved by National Treasury if the value exceeds:

- 15% or R15m on contracts for goods or services
- 20% or R20m on contracts for infrastructure projects

The processes that must be followed when procuring coal, the purpose of which is to reduce the risk of irregular expenditure, financial loss and reputational damage to Generation.

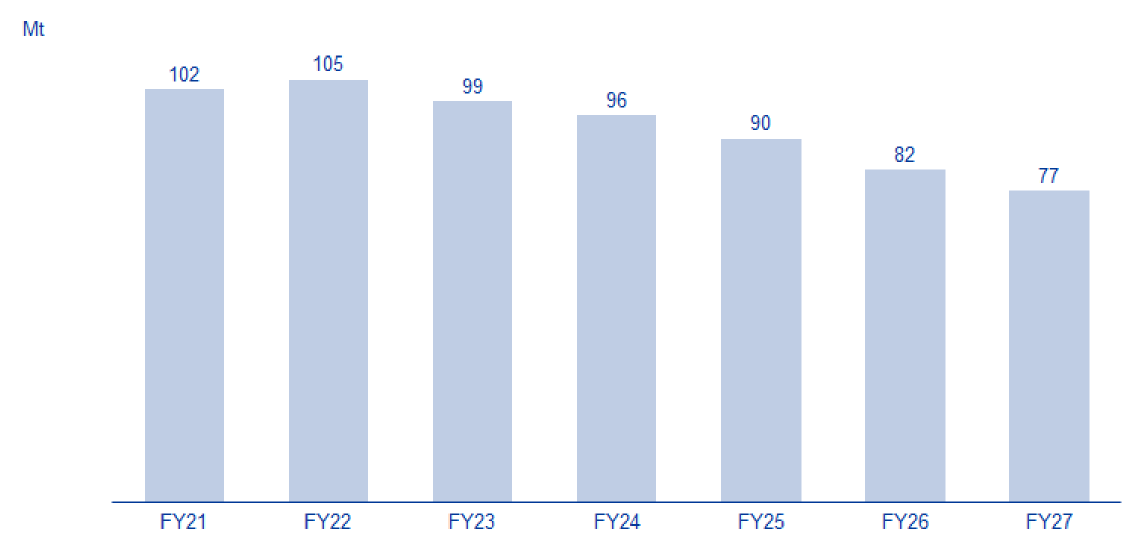
5.8 Summary of total forecast volumes and cost

The following section details the coal volumes required to meet Generation's forecast electricity generation and the related costs.

5.8.1 Coal Volumes

The volume of coal to be purchased is a function of the opening stock, the coal forecast to be burnt and the closing stock required as per Generation's coal stock policy. The coal to be burnt is determined from the generation production forecast, in which power stations are scheduled according to cost, fuel availability and maintenance plans. These volumes are determined for each power station. Generation's projected coal burn decreases from FY2021 to FY2027 as a result of a lower average burn rate and declining coal fired electricity generation.

FIGURE 20: COAL BURN PROJECTIONS (MT)



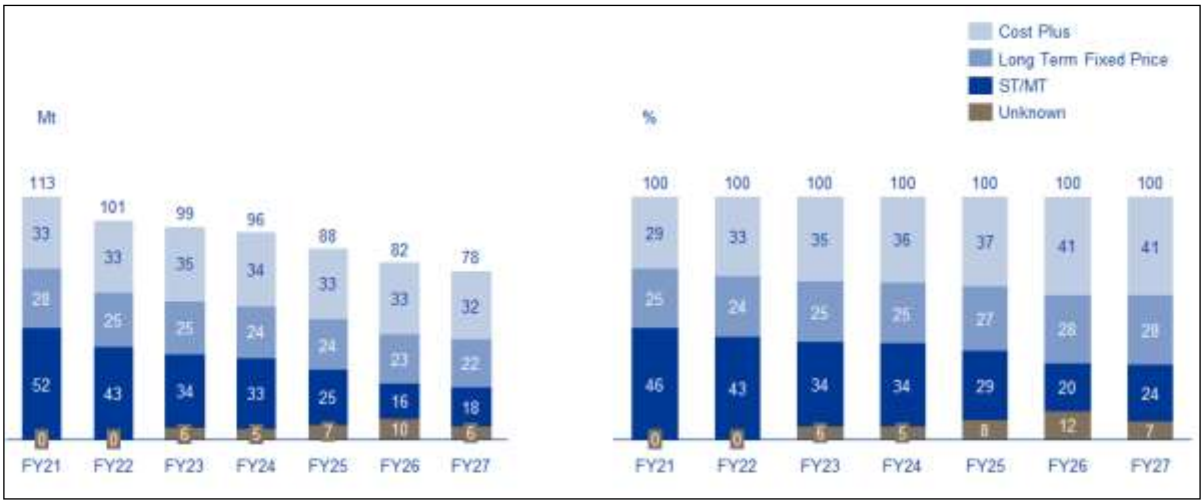
Coal USO (TWh)	176	178	159	146	142	130	126
Avg burn (kg/KWh)	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Avg CV (MJ/kg)	19.36	19.24	19.08	18.91	18.84	18.70	18.69

5.8.2 Forecast Coal Supply to meet Coal Burn

Generation prefers to contract for coal on long term contracts. The presumption is that this provides Generation with assurance of supply at a lower cost because the supplier is able to depreciate certain fixed costs over a longer revenue stream. Sometimes, for various reasons, it is not possible to contract for all of Generation's coal requirements on long term contracts. However, contracts of a shorter duration and a percentage of uncontracted coal allow for flexibility should there be a change in overall demand or should there be a need to change the mix of supply. It is prudent to have a portfolio of coal supply agreements that allows flexibility to meet changing electricity demand patterns.

In FY2021, approximately 54% of coal was procured on long term contracts. These are historical contracts with original durations of 40 years, which were designed to match the life of the associated power station(s). Although the volumes (Mt) decrease from FY2021 to FY2027, the proportion of coal from these long term contracts is envisaged to increase over the period. By FY2027, approximately 69% is forecast to be purchased from long term contracts. This is partly because of the overall decline in coal required, which has resulted in lower volumes STMT contracts. It is also because contractual volumes from the fixed price contracts could not be taken because it is forecast that stockpiles will be full.

FIGURE 21: COAL PROCURED CATEGORISED BY CONTRACT TYPE



The total volume of coal procured to meet the burn requirement in FY2021 is 113 Mt. In FY2025, it is 88 Mt and by FY2027 it is lower still at 78 Mt. As electricity production from coal fired stations declines, the volume of coal that Generation needs to procure is also forecast to decline.

5.8.2.1 Cost Plus Mines

The volumes from the cost-plus mines are maintained at an average of 33 Mt p.a. This is enabled by the extension of the Kriel CSA as well as the assumption that Generation will invest in the cost plus mines as required when such investment is shows financial benefit for Generation.

The table below shows the actual production compared to the contractual production from these mines for the FY2023 to FY2025 period.

TABLE 14: COST PLUS MINES FORECAST AND CONTRACTUAL SUPPLY (MTONS)

Volumes (Mt)	FY2023		FY2024		FY2025		Over/(under)
	Forecast	Contractual	Forecast	Contractual	Forecast	Contractual	Supply
Kriel	3.68	4.00	3.97	4.00	4.13	4.00	(0.22)
Lethabo	13.91	17.80	13.24	17.80	12.62	17.80	(13.63)
Tutuka	4.00	5.10	4.00	5.10	2.99	5.10	(4.31)
Matla	6.64	10.07	6.64	10.07	6.64	10.07	(10.28)
Kendal	6.30	13.30	6.30	13.30	6.30	13.30	(21.00)
Total	**34.53**	**50.27**	**34.15**	**50.27**	**32.69**	**50.27**	**(49.43)**

Production levels from the cost plus mines over the FY2023 – FY2025 period are expected to be below contractual volumes. The reasons are discussed below.

(i) Khutala (Kendal):

KSA – Investment to access additional reserves has been historically delayed. Consequently, production from Khutala has been below contractual volumes. This plan includes funding for equipment replacement and access to some of the underground areas, but investment in significant lifex projects has not been included. Consequently, production remains at around 6. Mt p.a.

(ii) Kriel:

The cost-plus contract for Kriel expired in 2019. Generation is in the process of finalising an extension to this contract. An interim contract is in place on the same terms and conditions as the previous contract, with the understanding that the new terms and conditions will apply retrospectively to January 2020. Investment in the mine was delayed but applications are expected to resume once the new contract is signed.

(iii) New Vaal (Lethabo):

New Vaal's production is constrained by the stockyard capacity and lower electricity generation at Lethabo Power Station. The low quality of the coal and geographical location prevents it from being burnt at another power station. Generation is investigating possibility of beneficiating the excess coal at Lethabo for use at other power stations. There are a number of uncertainties. It is expected that, if this is possible, costs would be incurred for the beneficiation and the transport to other stations. There would also be some yield loss and Generation would need to manage the discard coal.

(iv) New Denmark (Tutuka):

New Denmark requires significant capex to open a new mining area - the North shaft. (This was a previously opened area which was closed during the era of excess electricity supply). This is going to be a challenging area to mine from a geological perspective, but is still expected to produce coal at a lower cost than can be bought in. This project is required to limit the decline in production volumes from the mine. It was expected that this project would have been complete by FY2023, but funding constraints have resulted in delays. The project is expected to be largely complete by FY2024, with some equipment replacement thereafter.

(v) Matla:

Together with Kriel, Matla mine's historical production also significantly exceeded contractual levels. Safety concerns at mine 1 resulted in production from that mine being stopped in 2015. The mine 1 shaft was planned to be relocated, but the project approval was delayed. In 2018, the short-wall sections at mines 2 and 3 were also closed. Production subsequently declined to as low as 5.6 Mt p.a. in FY2021. Capex has been included in this application for a short-wall for mine 2 and for the mine 1 shaft relocation. Production is expected to improve to 7 Mt p.a. by FY2026.

5.8.2.2 Long Term Fixed Price Mines

Generation had four long term fixed price contracts. The contract for coal to Hendrina Power Station expired in 2018. Three of these contracts were historical long term contracts that suppled coal to Matimba, Duvha and Hendrina Power Stations. A more recent addition has been the contract with Exxaro to supply coal to Medupi Power Station. The following table indicates the forecast volume from these contracts:

TABLE 15: LONG TERM FIXED PRICE CONTRACTS SUPPLY (MTONS)

Long term Fixed Price contract - volumes (Mt)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Duvha (MMS)	5.24	2.65	-	-	-	-	-	-
Matimba (Grootgeluk)	14.26	13.73	12.80	12.80	12.20	11.60	11.40	10.66
Medupi (Grootegeluk)	9.96	11.30	12.00	11.95	11.64	11.93	11.52	11.34
Total	**29.45**	**27.68**	**24.80**	**24.75**	**23.84**	**23.53**	**22.92**	**22.01**

- The contract with Optimum colliery for Hendrina Power Station expired at the end of 2018. Therefore, coal for Hendrina is assumed to be procured on ST/MT contracts.

- The contract for coal for Duvha Power Station is being renegotiated as South32 claimed hardship and would have placed the mine in business rescue had Generation not been open to renegotiating the price. Generation and South32 have agreed to conclude a new short term contract (FY2022 – FY2025), under which South32 will supply 30 Mt to Duvha Power Station. This has been included under the STMT contracts.

- Matimba Power Station has a contract with Exxaro for 13 - 14 Mt Mt p.a. Depending on the electricity demand and how Matimba is scheduled to run, excess coal is stored on the station's stockpile. When stockyard capacity is reached, the take or pay payments need to be made. This plan makes provision for such a payment from FY2022. Matimba's stockyard reaches capacity because of lower burn requirements.

- Lower burn requirements at Medupi Power Station has also resulted in the station not being able to accept all its contractual coal. Because the stockyard is expected to be at capacity, provision has been made for take or pay payments from FY2022.
- It is difficult to move coal from Matimba and Medupi in the Waterberg to power stations in Mpumalanga because of logistical constraints. However, this plan makes provision for costs to move at least some of the coal to Mpumalanga in an attempt to reduce the take or pay penalties.

5.8.2.3 Medium Term and uncontracted coal:

Coal is contracted on medium term contracts to fill the gap between long term contracts and the coal requirement. The table below indicates the volumes of such coal and the related power stations.

TABLE 16: SHORT/MEDIUM TERM CONTRACTED AND UNCONTRACTED SUPPLY (MTONS)

S/M Term Volumes (Mt)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Arnot	6.37	5.92	4.20	3.94	3.58	2.61	-	-
Kriel	-	4.00	2.39	3.22	-	-	-	-
Lethabo	-	-	-	-	-	-	-	-
Tutuka	5.00	3.68	0.74	1.22	1.30	-	0.07	0.02
Matla	5.92	4.63	2.96	1.74	2.14	1.29	0.64	-
Hendrina	3.30	2.33	2.61	1.64	-	-	-	-
Duvha	2.24	3.50	5.22	5.35	5.23	4.66	3.67	3.45
Kendal	4.06	3.75	4.79	4.72	4.51	2.98	2.97	2.72
Majuba	12.67	12.67	9.15	7.68	9.41	8.30	8.44	8.28
Matimba	-	-	-	-	-	-	-	-
Camden	3.25	2.25	3.13	1.21	-	-		-
Komati	0.87	0.43	0.19	-	-	-	-	-
Grootvlei	1.71	1.70	1.83	-	-	-	-	-
Medupi	-	-	-	-	-	-	-	-
Kusile	4.77	6.83	5.88	8.69	11.75	12.25	10.04	9.64
Total	**50.16**	**51.68**	**43.08**	**39.41**	**37.91**	**32.08**	**25.82**	**24.11**

Procurement of coal from medium term (MT) contracts declines significantly from FY2021 as production from coal fired stations declines. Arnot Power Station receives its coal from MT contracts since the cost plus contract expired at the end of 2015. Majuba, Komati, Grootvlei and Kusile Power Stations do not have dedicated mines. These stations still forecast for all their coal from medium term contracts. The Optimum contract for Hendrina Power Station ended in December 2018, so this coal requirement is being met by the ST/MT market. The long term New Largo contract with Seriti Coal for Kusile Power Station did not materialise as expected, so coal for Kusile is also currently from medium term contracts.

Included in the MT and uncontracted volumes above are the following uncontracted / unknown volumes.

TABLE 17: UNCONTRACTED COAL REQUIREMENT (MTONS)

Volumes (Mt)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Uncontracted & Unknown	-	-	-	5.54	5.01	6.86	9.70	5.75

These uncontracted volumes range between 13 – 21% of the STMT coal annual requirements. This coal is costed at a slightly higher price than contracted STMT coal on the assumption that these sources are likely to be further away and that Generation would have contracted for the cheaper coal first.

Generation prefers to contract for coal on long term contracts. This provides security of supply for Generation and an assured offtake of coal for the supplier, which should result in a lower cost for Generation. Unfortunately, because of the lack of economic growth, electricity demand is declining and it has become necessary to redistribute some of the coal which was contracted on ST/MT contracts, mainly for Kusile Power Station between power stations. This was done where possible. However, there is still coal which may not be taken under these contracts. The coal quality requirements at Kusile are relatively low, so this coal cannot be reallocated to all power stations. Generation has therefore provided for take or pay payments from FY2022.

5.9 Costs

5.9.1 Coal Burn Cost

This section explains what the coal burn cost is and how it is derived. The coal burn figure is derived from the coal purchases cost. Therefore, the reasons for variances in the coal burn will be similar to the reasons for the variances in the coal purchase costs. These are discussed in more detail further on in this section. The changes in the coal burn figures over the FY2021 – FY2027 period are made up of efficiency, mix, volume and price variances. The change has been analysed per annum in the table below. The table indicates the absolute and percentage annual increase in burn in nominal values. This increase is then allocated between price, volume and other (efficiency and mix) variances.

Between FY2021 and FY2025, the burn cost increases by R12.82bn. The price variance is the largest variance. It is a negative variance of R30.55bn. It is offset by a positive volume variance of R15.61bn and other smaller positive variances of R2.12bn.

TABLE 18: ANALYSIS OF ANNUAL COAL BURN VARIANCES (R'BN)

Analysis of Coal burn variance	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Total burn (R'bn)	57.87	67.33	66.98	66.25	70.69	71.19	76.06
YoY Increase/(decrease) %		16%	-1%	-1%	7%	1%	7%
Annual increase/(decrease) in burn cost		**9.46**	**(0.35)**	**(0.73)**	**4.44**	**0.50**	**4.87**
Price variance		8.98	7.25	5.41	8.90	6.15	7.19
Volume variance		0.89	(7.88)	(6.71)	(1.91)	(5.38)	(1.93)
Other variances		(0.41)	0.28	0.57	(2.56)	(0.27)	(0.38)

- Other variances comprise the efficiency and mix variances. Efficiency refers to the rate at which power stations consume coal to generate a unit of electricity. There is a small improvement in the CV and a small positive efficiency variance. The mix variance refers to the manner in which power stations are utilised. There are a number of reasons why one power station may generate more than another. Some of these are planned maintenance, the cost of generation at a power station, fuel availability, minimum generation requirements and grid stability and efficiency.

- From FY2021 to FY2022, there is a negative volume variance in line with the increase in coal fired generation. Thereafter, the volume of coal burnt decreases in line with the decrease in electricity generation.

The biggest portion of the increase is related to the price. A detailed explanation on the price per contract type is provided in Sections 5.9.4 to 5.9.6.

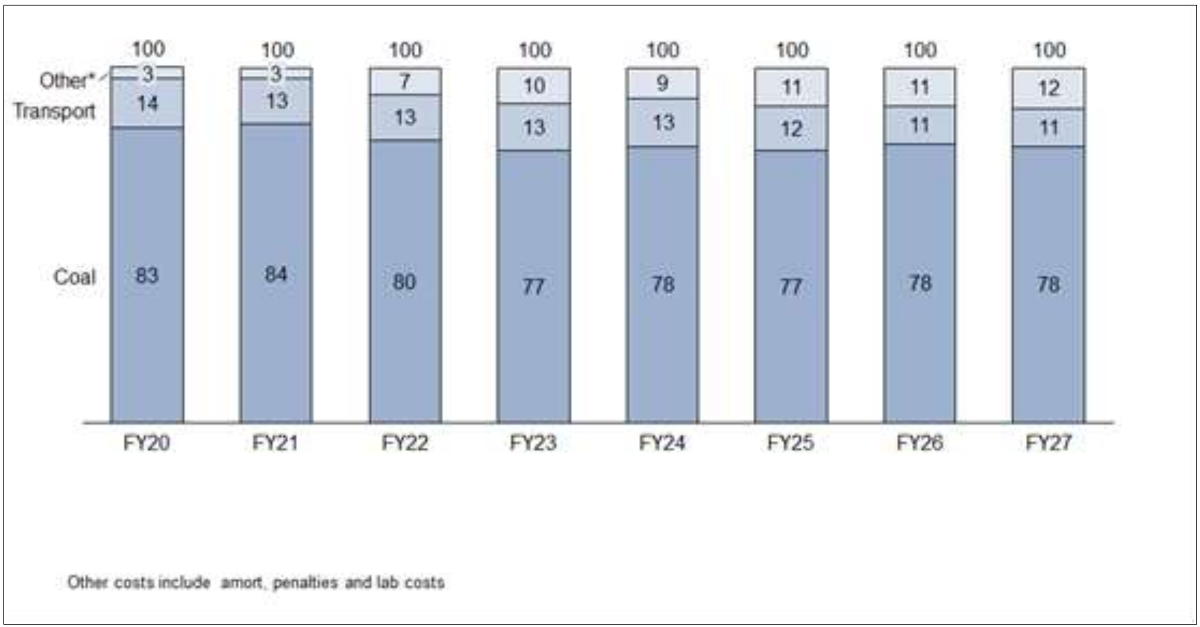
5.9.2 Annual coal purchases costs

The average annual growth in total coal purchases costs over FY2023 – FY2025 is 4%. Over the same period, between 60 and 65% of the coal is purchased on the cost plus and fixed price long term contracts, with corresponding purchases costs of between 52 and 55% from these long term contracts. It is Generation's policy to secure long term contracts with mines close to power stations and source only the coal shortfall from sources further away.

5.9.3 Forecast average coal cost

The average R/t delivered cost will be affected by the transport solutions that are introduced over the period and by the volume of medium term coal, as this coal is typically transported over longer distances than the long term cost plus and long term fixed price coal. The mode of transport is by road and/or rail, which is more expensive than conveyor. The average annual increase over FY2023 – FY2025 is 10%, as per the graph below. Included in this is a provision for take or pay payments and the cost of moving excess coal from Medupi to Mpumalanga.

FIGURE 22: PERCENTAGE OF COAL, TRANSPORT AND OTHER COSTS IN THE AVERAGE DELIVERED R/TON COAL COST

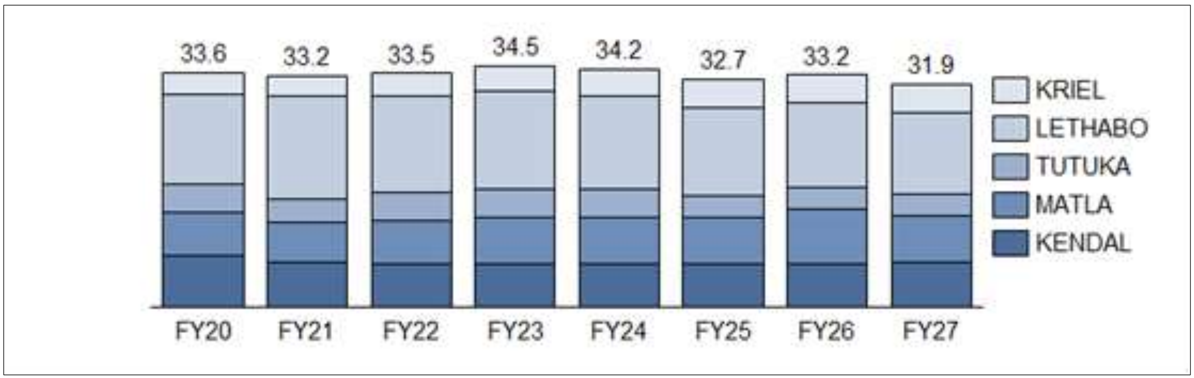


The bulk of the cost of a ton of coal delivered to a power station is the ex-mine cost of the coal. Over the FY2023 – FY2025 period, this is around 78% of the cost. Transport as a percentage of delivered coal cost is around 13%. Other costs, such as take or pay payments and laboratory fees, comprise the balance. Over FY2023 – FY2025, the increase in the unit cost of cost plus coal is 6%, long term fixed price coal is 9 – 10% and medium term coal is 9%.

5.9.4 Forecast costs from existing cost plus contracts (dedicated mines)

Generation is liable for all of the costs incurred by the cost plus mines. A significant part of these costs, e.g. labour, administration, overheads, is fixed in the short to medium term. Therefore, the costs incurred may not always correlate with tons produced. A decrease in production will result in an increase in the R/ton cost, while higher production will result in a lower R/ton cost.

FIGURE 23: FORECAST SUPPLY FROM COST PLUS CONTRACTS



The figure above reflects the decrease in production in FY2025 and again in FY2027. Production levels have been maintained at Kriel and Matla, primarily from accessing additional reserves. Production was curtailed at New Vaal because of decreasing electricity demand and full stockpiles. Total cost increases have been maintained at 6%, but because of the decrease in volumes the R/t average has increased at 11%.

5.9.4.1 Re-investment in mines:

The purpose of reinvesting in mines is to maintain production at the mines to meet burn requirements. As the mines are older than 20 years, some of the main equipment will have to be replaced due to age/wear or obsolete technology. Furthermore, prior to 2011, several of these mines produced beyond contractual volumes, thus further increasing wear of the equipment.

- **Investments to access new reserves and to increase life of mines**: The power stations' lives were extended from 40 to 50 years. The mine plans had to be adjusted to enable coal supply over this extended period. In addition, the life of mines was adversely impacted by the increased coal burn requirements beyond contractual limits in the past few years. Due to this and due to unexpected geological conditions, current reserve blocks were becoming depleted earlier than forecast. To maintain supply and to extend the mines' lives, new underground access shafts or opencast pits will have to be developed. Hence, further investment is required in order to ensure that the life of mine meets the extended life of the power stations. This is expanded on further in the section on Future Fuel.

5.9.5 Forecast costs from existing fixed base/indexed contracts (multi-product mines)

There were three long term fixed price contracts that supplied coal to Generation in FY2021:

- Middleburg Mine Services (MMS): Supplies coal to Duvha Power Station
- Exxaro Grootegeluk: Supplies coal to Matimba Power Station
- Exxaro Grootegeluk: Supplies coal to Medupi Power Station

The MMS coal supply agreement was initially a cost plus type agreement. It was changed to a long term fixed price agreement to enable the mine to sell coal to other mainly export parties (developing the coal export market at that stage) and to provide Generation with a low cost product that is subsidised with the profits of the export product. This resulted in coal from these contracts being among the cheapest in Generation's portfolio. This was only possible because the mines received a "free" Cost Plus mine to export coal. The current/existing Cost Plus mine reserves do not have export quality coal or sufficient reserves for such a deal to potentially take place. Entering into new long term fixed price contracts now will almost certainly not yield the same benefits to Generation.

The MMS contract with South32 is being renegotiated because South32 claimed hardship and was going to put the mine into business rescue. Generation is concluding a four-year contract (FY2022 – FY2025) for coal for Duvha Power Station from South32. This coal is reflected under the STMT sources. This coal will cost more than the coal did under the previous contract, but it is still cheaper than the next best alternative, which would be to buy in coal from further away and transport it by road, rail or a combination of the two.

The increase in the R/ton cost from long term fixed price contracts is dictated by the terms of the contracts. The average R/ton increase from these long term fixed price contracts in FY2023 – FY2025 is 9%. This increase is higher than forecast PPI because the Matimba and Medupi annual escalation is based on the prior year's actual coal costs and not linked to PPI. Historically, actual escalation has been higher than PPI.

From FY2022, take or pay payments have been included for Matimba and Medupi coal that cannot be received by the power stations because of lower burn and stockpile capacity being reached. After including the take or pay payments and the cost of moving coal from Medupi to Mpumalanga, the effective annual increase is higher than the 9%.

All coal from Long Term Fixed Price contracts is transported by conveyor to the power stations and priced on a delivered cost basis.

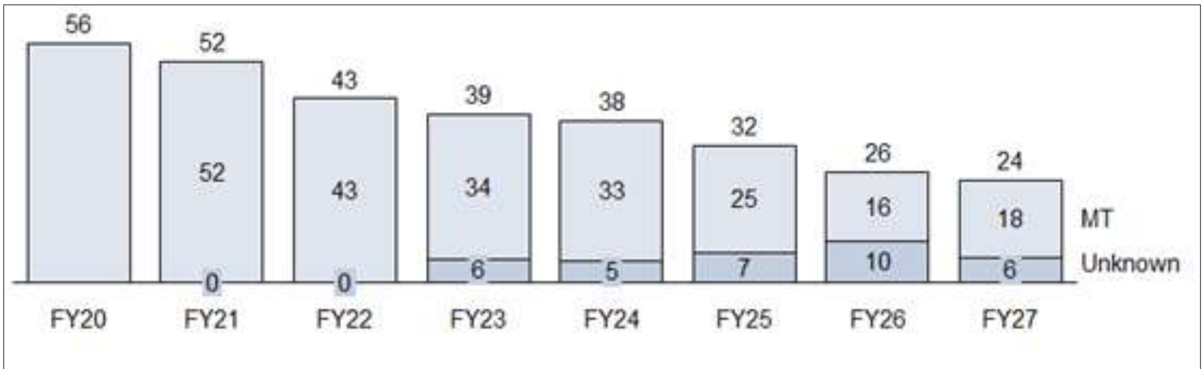
FIGURE 24: FORECAST SUPPLY FROM FIXED BASE/INDEXED CONTRACTS

5.9.6 Forecast costs from medium term sources

The costs of new medium term coal contracts are projected to be on par with the existing medium term contracts. The average annual R/ton increase is 9%. However, the following must be noted:

- From FY2023, a portion of this coal is labelled as 'unknown', i.e. the coal is required as per the production plan, but the source is unknown, as yet. This adds to the uncertainty regarding the mode of transport. This uncertainty has been mitigated by an increase in the planned price of this coal.
- The assumption is that all unknown coal for Majuba, Tutuka, Camden, Arnot and Grootvlei can be sourced close enough to existing rail sidings – there will be no extension of infrastructure for these power stations. Coal will be transported by rail or a combination of road and rail.

FIGURE 25: FORECAST SUPPLY FROM MEDIUM TERM SOURCES



In summary, the primary reason for the increase in the coal burn cost is the purchase cost of coal and the costs to get the coal to the power stations. The coal burn cost is a function of the coal purchases cost. Therefore, increases in the coal purchases price will result in increases in the coal burn price. Increases in the coal purchases price are a combination of increases in prices from cost plus, long term fixed price and short/medium term coal. The purchases price variance on the cost plus contracts is partly a result of the lower production and partly because of the increase in mining costs. The reasons for the lower production are largely lack of investment and the difficult mining conditions as the mines age. These mines are all well beyond their half year lives. The challenging geological conditions are not unique to the cost plus mines. It is for this reason that so many of South Africa's gold and platinum mines close. They are not profitable unless the market prices of these metals are high enough to offset the increasing costs. Generation is fortunate that the cost plus arrangement has largely fixed the return to the mining houses, resulting in this coal still being cheaper than many other sources. Generation is expecting to resume investment in the cost plus mines as and when funding is secured. The cost increases in long term fixed price and existing short/medium term coal are as per contractual conditions. The cost increases in coal from new contracts depend on the circumstances at the time of negotiation. As has been explained under the sections on the market overview and cost drivers, there are a number of external factors which impact price, but over which Generation has little control. Generation has, however, revised its coal strategy to mitigate this impact to the extent possible.

5.9.7 Logistics

This section explains how coal is transported from a source, which is usually a mine, to a power station. It also explains what factors drive the cost of transporting coal.

5.9.7.1 Forecast logistics modes and costs for medium and long term sources of coal

Generation transports coal by one of three modes or a combination of these modes:

- Conveyor – this is the mode used for coal from collieries located close to the power station receiving the coal. It is the cheapest mode.

- Rail – Transnet Freight Rail provides the rolling stock. Coal is railed from the supplier to the power station, if the supplier and the power station have the infrastructure. Alternatively, coal may be transported from a supplier to a rail siding by truck, and then railed to a power station. If the power station does not have rail infrastructure either, coal may be transported by truck to a siding, then railed to another siding closer to the power station, and again loaded onto a truck for the final leg to the power station. The more complex the transport arrangement, the more expensive the transport cost is likely to be.

- Road – Coal is trucked to its destination when conveyor and rail are not possible.

Rail is preferred over longer distances. However, only Majuba and Tutuka Power Stations have the infrastructure for coal to be railed to the station. Majuba uses a sophisticated tippler system whilst the other stations use a containerised solution. Grootvlei and Camden Power Stations are located close to rail sidings, so coal is railed to the siding and then trucked to the station. Rail has historically generally been cheaper than road for a system that delivers coal from the mine directly to a power station. However, should a rail option not be cheaper than road, coal will be transported by road. Rail has also proven to be safer than road. So, where it is possible, Generation strives to maximise volumes on rail. The organisation is also investigating the feasibility of establishing infrastructure to accommodate alternative modes of transport, e.g. rail infrastructure where a station cannot accommodate the volumes of truck deliveries. Currently, Transnet is the only provider of freight rail. The organisation determines the tariff, which varies with the type of service required, e.g. open top wagons are cheaper than closed containers. The setting of the tariffs is not a transparent process, making Generation a price taker. Tariffs are escalated annually in accordance with a basket of published indices agreed to by Generation and Transnet. This increase has been higher than general inflation over the past five years.

Transnet is currently negotiating with potential service providers to lease and operate Transnet rail sidings. Sidings rates are, consequently, not yet available. Eskom has used historical costs in this application.

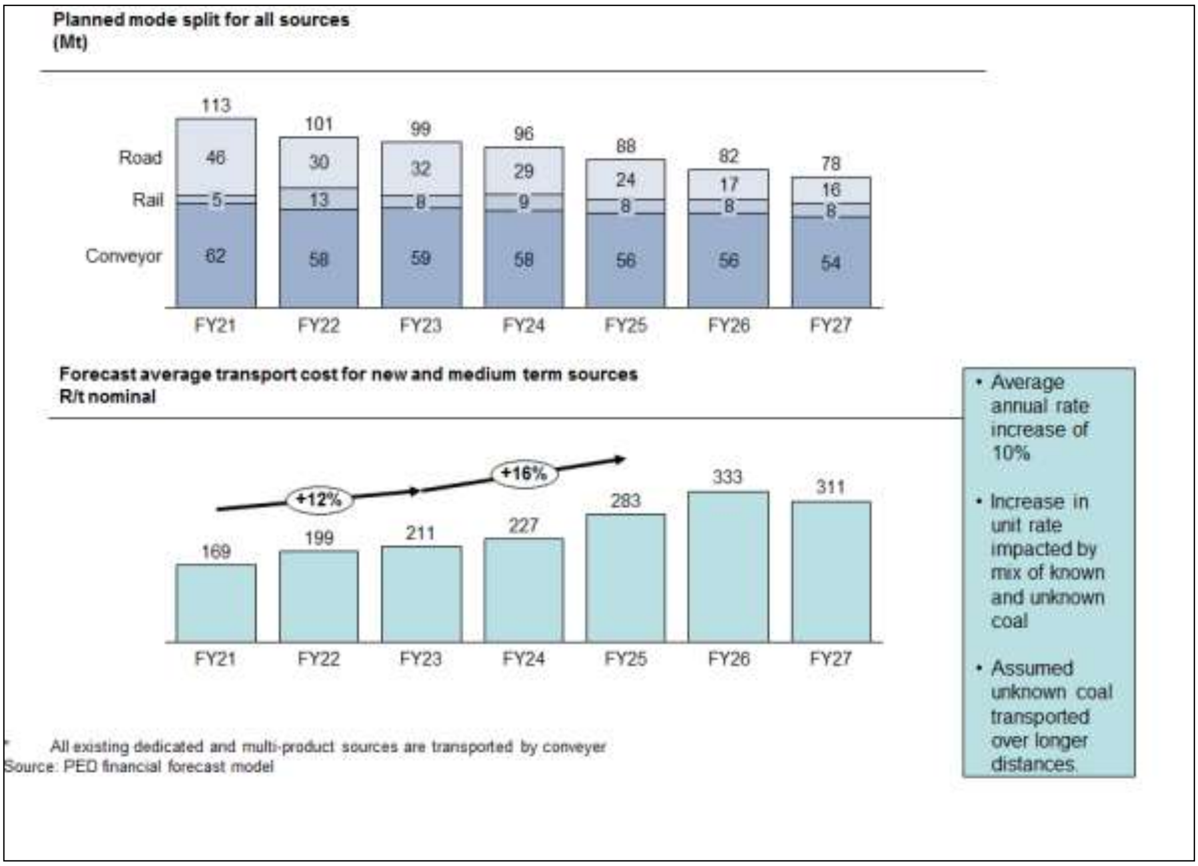
The volume on rail decreases from 12.7 Mt in FY2022 to 8.3 Mt in FY2025. While some new coal purchases will be on rail, unknown sources are assumed to be on road. Most of the smaller sources will not have links to the rail system.

Transport on road is managed using two types of contracts:

- Delivered – the cost of coal includes the cost of transport. The coal supplier is accountable for the transport. The transporter contracts with the mine.
- Free Carrier (FCA) – Generation pays the coal supplier for the coal only. Generation then allocates the route to one of the transporters contracted to Generation.

The figure below indicates the average R/t cost of transport for the FY2021 – FY2027 period and the volumes per transport mode.

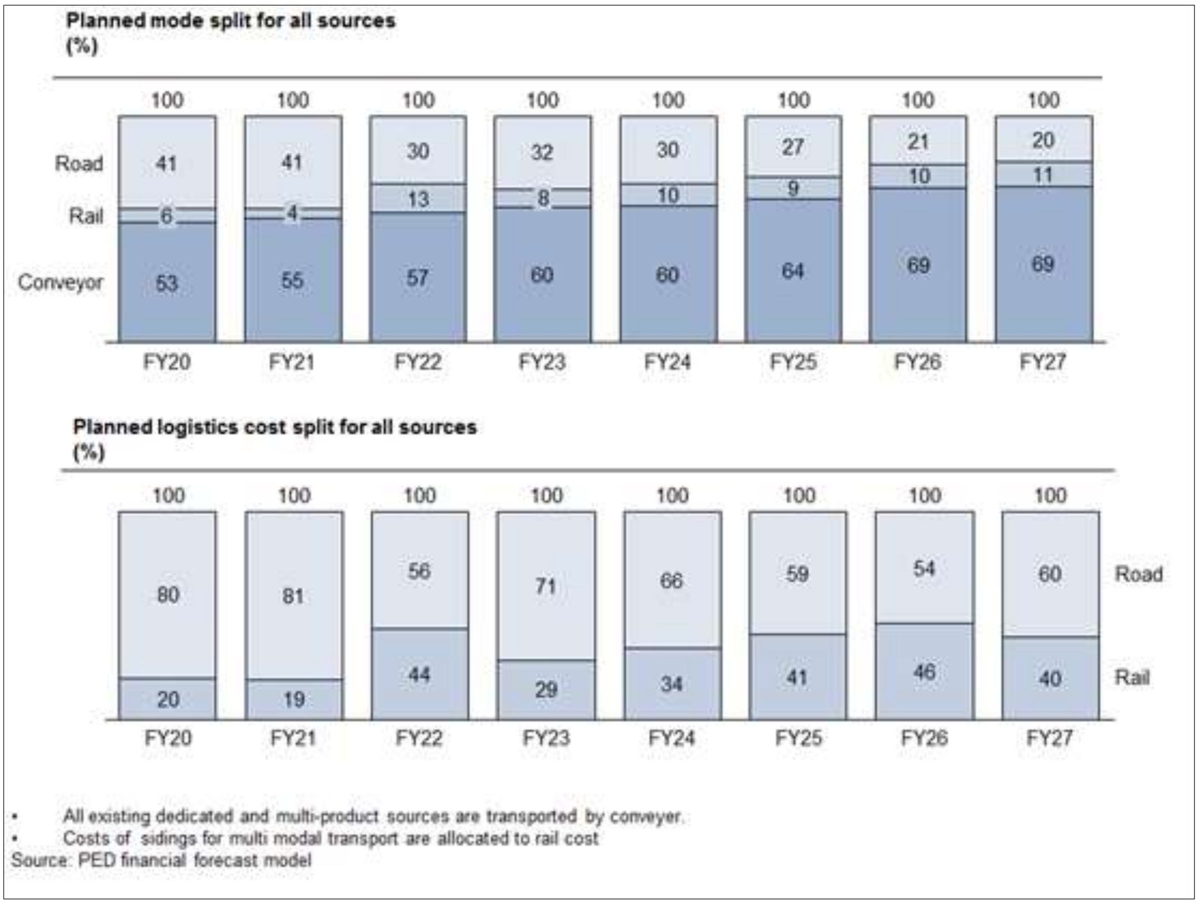
FIGURE 26: FORECAST LOGISTICS MODES AND COSTS FOR LONG AND MEDIUM TERM SOURCES



The average annual cost of getting a tonne of coal from the source to the power station increases by 16% p.a. over the FY2023 – FY2025 period. Coal transported by rail will often include a road component because there may not be a rail link from the source to the power station. Additionally, there may not be a rail line to the power station, so the last leg from the siding to the power station stock yard will be on road. Therefore, there is not always a clear correlation between increases or decreases in volumes on rail and the cost. In some instances, the multi-mode trip may be more expensive than a direct road trip, but rail is preferred because the reduced time on the road translates into fewer possibilities for road accidents.

Generation would prefer to have all of its coal on conveyor or rail, but conveyor is only feasible where the mine is close to the power station. A rail link is only an option where the volumes make it economically feasible. Like Generation, Transnet must allocate its capital where it will yield the best returns. The figure below indicates that, although total volumes purchased decline over the period, there is a small increase in volumes transported by conveyor and rail, and in general, there is a corresponding decline in the proportion of money spent on road transport.

FIGURE 27: FORECAST LOGISTICS PERCENTAGES PER MODE FOR LONG AND MEDIUM TERM SOURCES



Conveyor is the cheapest mode of transport. However, it is only feasible where the mine is located close to the power station. Because the cost plus and long term fixed price mines, which are linked by conveyor to the power stations, are experiencing the challenges already elaborated on under the sections on coal volumes and costs, it is necessary to procure coal from other sources further away. This coal must be transported by road and/or rail, depending on the access to rail sidings and the infrastructure at the power stations. While Generation would like to move this coal on rail rather than road, these physical constraints make this impossible. Both Generation and Transnet Freight Rail are constantly discussing adding rail capacity. This does require large capital investment, and is likely to have an impact on cost. Rail will also not necessarily prove cheaper because Transnet's pricing is not regulated. The increase in the cost of coal on road is managed by the pricing and escalation terms in the transport contracts. Generation has managed to reduce these rates in the past, but there are real cost increases which transporters face, e.g. fuel, maintenance and labour.

5.9.8 Stock management over the MYPD Period

It is sometimes the case that coal contracted is not supplied. Although contracts contain remedies for this possibility, the immediate impact on Generation is the risk of a power station running out of coal. Generation has put in place measures to prevent this, such as interrogating the life of mine plans at short/medium term suppliers and reviewing the coal supply agreements to include more stringent punitive measures for under delivery, if possible. In addition, each power station maintains a stockpile as a mitigation measure. This section explains how closing stock is calculated and what stock levels are expected at each of the power stations.

Generation calculates the closing stock of coal (cost and volume) as follows:

(Opening stock [Cost and Volume] + Purchases [Cost and Volume]) – Burn [Cost and Volume]

An example is provided in the table below. *Note that the values and volumes are only examples for illustration purposes and not actual values*.

TABLE 19: EXAMPLE OF A COAL STOCK CALCULATION

Example of coal stock calculation	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening stock:							
Mtons	34.91	45.40	42.21	41.78	41.88	40.24	40.07
Rands (bn)	16.82	12.95	11.04	11.51	12.69	13.55	15.06
R/ton	481.96	285.22	261.66	275.37	302.96	336.75	375.90
PLUS							
Purchases:							
Mtons	112.57	101.37	98.69	95.91	88.29	81.98	77.97
Rands (bn)	25.24	25.45	27.75	30.21	31.15	32.39	34.51
R/ton	224.20	251.10	281.24	314.99	352.78	395.12	442.53
MINUS							
Burn:							
Mtons	102.07	104.57	99.11	95.81	89.94	82.14	77.12
Rands (bn)	29.11	27.36	27.29	29.03	30.29	30.88	32.38
R/ton	285.22	261.66	275.37	302.96	336.75	375.90	419.91
IS EQUAL TO							
Closing stock:							
Mtons	45.40	42.21	41.78	41.88	40.24	40.07	40.93
Rands (bn)	12.95	11.04	11.51	12.69	13.55	15.06	17.19
R/ton	285.22	261.66	275.37	302.96	336.75	375.90	419.91

The stock days in the table below reflects that closing stock level in FY2021 was 96 days. Thereafter, forecast stock levels decrease slightly to 79 days in FY2025.

TABLE 20: FORECAST COAL STOCK DAYS

Coal stock days	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application	Post Application
Arnot	26	46	46	41	36	13	16	20
Kriel	40	47	27	64	68	79	71	51
Lethabo	89	108	97	97	97	97	97	97
Tutuka	58	42	42	42	42	42	42	42
Hendrina	35	19	19	22	22	22	33	-
Matla	41	69	63	41	45	49	57	48
Duvha	61	29	35	35	35	35	39	42
Kendal	53	73	68	71	66	31	21	50
Majuba	41	103	77	50	52	54	53	51
Matimba	51	80	65	65	66	66	69	66
Camden	24	3	3	2	2	2	3	-
Grootvlei	36	-1	9	9	9	9	12	-
Komati	10	42	18	42	-	-	-	-
Medupi	418	416	400	397	395	395	395	395
Kusile	40	71	41	40	31	23	21	33
TOTAL (weighted avg.)	**81**	**96**	**87**	**86**	**84**	**79**	**81**	**89**
TOTAL (weighted avg. excl. Medupi & Kusile)	**50**	**65**	**56**	**54**	**55**	**50**	**52**	**58**

The relatively high stock levels are because of increasing levels of stock at Lethabo and Medupi Power Stations. It is economically more viable to build up more stock.

- Lethabo's burn is limited because of emissions constraints. The mine is a cost plus mine, so it does not make sense to limit production. The option to use this coal at other power stations is being investigated.

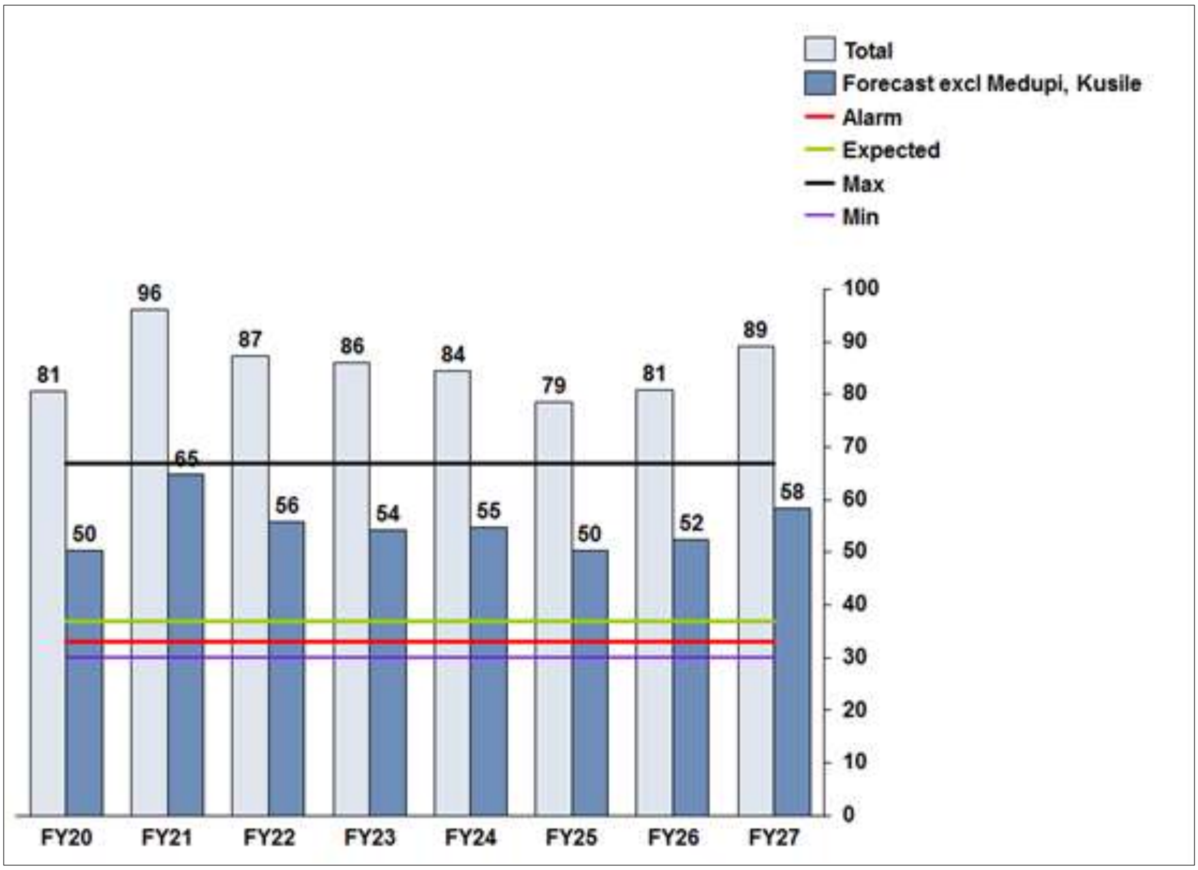
- Medupi has a coal contract with Exxaro that includes a take or pay clause. Because the power station is not generating as was planned when the contract was negotiated, Generation is taking the stockpiling as much coal as is possible, and is also moving some of the excess coal from Medupi to stations in Mpumalanga, where possible.

- The delay in commissioning of Kusile units results in stock initially also being high at that station.

- Although Grootvlei and Komati Power Stations expect to stop production in FY2023 and Camden, Hendrina and Kriel (U1 – U3) in FY2024, there is still some stock at these stations, in case it is required.

The graph below illustrates what happens to the stock days if the stock for Medupi and Kusile Power Stations is removed. Then system stock days fall well below maximum levels, but within minimum levels.

FIGURE 28: FORECAST SYSTEM COAL STOCK DAYS



Generation is considering the following measures to bring and maintain stock days at expected levels:

- Investigate alternative storage facilities at stations that need it.
- Automate the system to track energy (GJ's) and dates to trigger notifications of contract expiration dates.
- Modify coal supply agreements to minimise coal volumes, where feasible.
- Reallocate excess stock to stations that have the capacity to receive and stock it.

The table below, reflects the stock volumes of the coal stations.

TABLE 21: FORECAST COAL STOCK VOLUMES (KTONS)

Coal stock volumes (ktons)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Arnot	604	1 054	1 056	944	834	305	305	305
Kriel	1 258	1 506	877	2 033	2 174	2 510	2 259	1 403
Lethabo	4 217	4 958	4 442	4 446	4 449	4 452	4 468	4 480
Tutuka	2 177	2 332	1 967	2 026	2 086	2 130	2 241	2 306
Hendrina	613	261	252	303	303	303	303	303
Matla	1 553	2 559	2 304	1 505	1 640	1 800	2 084	1 773
Duvha	1 817	945	1 134	1 136	1 137	1 139	1 248	1 352
Kendal	2 465	3 606	3 371	3 485	3 290	1 548	1 049	2 501
Majuba	1 684	4 075	3 037	2 009	2 091	2 153	2 129	2 051
Matimba	2 130	3 369	2 747	2 748	2 795	2 801	2 912	2 795
Camden	403	51	42	29	29	29	29	29
Grootvlei	242	-5	67	67	67	67	67	67
Komati	45	104	25	25	25	25	25	25
Medupi	15 057	16 286	16 835	16 941	16 849	16 854	16 865	16 880
Kusile	643	1 545	1 031	1 067	1 096	1 104	1 071	1 641
TOTAL	**34 910**	**42 647**	**39 186**	**38 764**	**38 865**	**37 218**	**37 055**	**37 910**
TOTAL excl. Medupi, Kusile	**19 209**	**24 816**	**21 321**	**20 757**	**20 920**	**19 260**	**19 118**	**19 388**

It is necessary to hold stock in order to manage changes in supply and demand. As with most risk mitigation measures, the cost one is willing to pay depends on the risk level one is willing to accept. Generation is the primary supplier of electricity in South Africa. The cost of not being able to generate far exceeds the cost of stockpiling coal. Nevertheless, Generation is very mindful of the cost to the consumer and attempts to manage coal stock levels to minimise this cost while reducing the risk of stockouts. In certain circumstances, such as at Medupi Power Station, stock levels do exceed optimal levels. However, these are specific instances, rather than the norm.

5.9.9 Future Fuel Expenditure

This section deals solely with the capital expenditure related to the acquisition of future fuel. The motivations for this expenditure and any associated operating expenditure are included in the section below, which details costs per power station. Future fuel capital expenditure (capex) has a direct cash implication in the year that it is incurred. However, the effect on the bottom line is through the amortisation of the capex over the determined period. Some Capex is non-negotiable, e.g. Capex related to safety and environmental matters. Other Capex may be to replace equipment or to optimise production.

Future Fuel at Generation comprises investment in water related projects on the Komati Water Scheme and in coal projects at the cost plus mines. Expenditure on assets/projects which will yield benefits over more than one year is classified as future fuel and amortised over the life of that asset or project. The process is as follows for water related projects on the Komati Water Scheme:

- The results of performance and condition monitoring, as well as original equipment manufacturer (OEM) plant specifications, will determine what work needs to be done on the scheme. Pre-feasibility and feasibility studies will be conducted to narrow the field of options. Thereafter, a motivation will be prepared to obtain approval for the execution of the selected option. The motivation will include a cost benefit analysis of the proposed project. The motivation is subjected to Generation's governance process. If it is approved, the commercial process is then followed to procure the required services and/or equipment.

- For coal related projects, the cost plus mines submit a motivation for the asset or project to the mining houses internal governance structures. If it is approved, the motivation is submitted to Generation. The proposed expenditure is evaluated in terms of the cost and benefits to Generation and is taken through the Generation governance process. If it is approved, the mine is notified of the approval and of the value that has been approved. The mining house then proceeds with the procurement or construction of the project. The mine invoices Generation monthly as expenditure is incurred. If the project is longer than nine months, it incurs interest during construction (IDC) until it is completed and brought into operation. These costs are captured in an asset under construction account until the project is completed and brought into operation. The cost of the project is then transferred into the future fuel account and amortised over the useful life of the asset/project/contract. The amortisation of future fuel is taken to inventory and is charged to the income statement as the coal is consumed.

TABLE 22: FUTURE FUEL BALANCES (R'M)

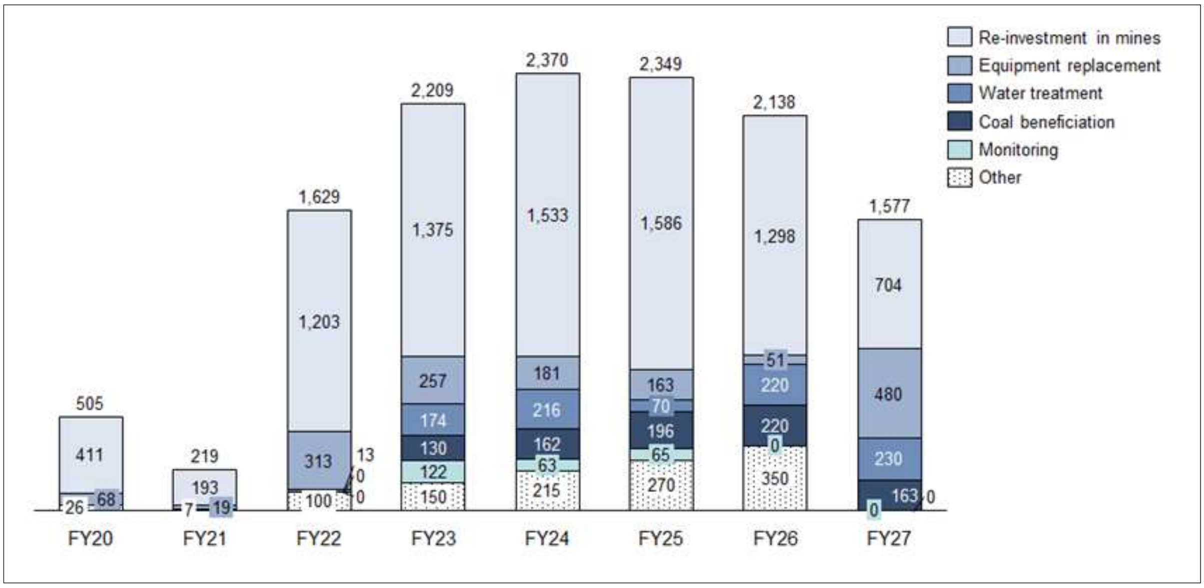
Future Fuel (R'm)	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Coal, Water & Mine Closure	4 614	5 345	5 351	5 143	4 782	4 152

If Capex is not spent on the cost plus mines, the impact in the year is typically the difference between the cost of procuring coal on the ST/MT market and the cost if the cost plus mine produces that coal. This difference is closer to the cost of the ST/MT coal because most of the costs incurred on cost plus mines are fixed, so will be incurred anyway. The actual cost will be dependent on the power station and where the coal is sourced from. The average cost of coal from the cost plus mines in FY2023 is R633/t while the forecast average cost for unknown coal is R1 108/t. The impact of not investing in the cost plus mines is usually also felt in subsequent years, e.g. not investing in a new shaft could result in the mining plan changing, new sections having to be opened or the mining method changing. To reduce the risk of this cost being incurred, it is advisable to invest in future fuel where the business case justifies doing so.

Investment in the cost plus mines is strategic to Generation's savings and improvement initiatives. The coal costs included in this plan rely largely on the cost plus mines receiving the funding necessary to maintain or increase production, thus limiting the need to procure coal on ST/MT contracts.

The largest component of the future fuel capex is the reinvestment in the cost plus mines, as reflected below.

FIGURE 29: COAL FUTURE FUEL CAPEX SPEND (R'M)



Approximately 65% of capex for FY2023 – FY2025 is expected to be for reinvestment in the cost plus mines. Financial analysis has shown that it is still cheaper to invest in these mines than it is to buy in coal from other sources for the related power stations.

New Denmark Colliery: Capex is included to complete Block 950, including ventilation shafts

Kriel: Funding is included to complete the development of Block F and to purchase land for future mining of the opencast mini pits.

Khutala: A number of projects, including the purchase of land, are in progress to access additional reserves for Kendal Power Station. Production from the KSA Lite project is already underway. Funding is included for the North East Extension and Block A West to access to access 2 seam reserves.

Matla: Matla Colliery has two large projects - A new shaft at mine 1, which will enable mining to resume at mine 1 and should reduce the volumes of ST/MT purchases. Approval of this project has previously been delayed at the DPE, resulting in Exxaro having to obtain a new cost for the project cost. This added to the delay in starting, but the project has now begun. The plan also assumes that the short-wall equipment replacement project for mine 1, which is a necessary part of the new shaft, will start in FY2022. There is also funding for the relocation of the plant workshop and the ventilation shaft at mine 3 included from FY2022.

Because of their age, the mines are also re-equipping to maintain production. From FY2023 – FY2025, around 9% of capex is forecast for equipment. In addition, funding is included for relocating the plant workshop at Matla, and water treatment projects at Arnot, Kriel and New Denmark to comply with legislation. Two projects to monitor coal quality are also included in the FY2023 – FY2025 period.

Future Fuel also comprises the investment in water infrastructure on the Komati Water Scheme because this scheme belongs to Generation. This plan comprises the expected timing and cost of Future Fuel expenditure. In actual mode, each investment will be prioritised in the year according to funding available for Generation as a whole and for each project. The biggest projects are the Kilbarchan water treatment plant (An old mine is discharging water, which Generation is legally bound to treat and manage) and the Komati Water Scheme security project. Both these projects have legal implications if they are not done. The cost and timing of these projects are illustrated below.

TABLE 23: WATER CAPEX SPEND (R‘M)

Water capex spend (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Motors	23.79	1.20	-	-	-	-	-	-
Water - Security Fence Upgrade & Camera Installation at KWS Sites	-	-	-	-	-	-	-	184.80
Water - New Bio Water Treatment Plant	-	-	-	-	-	-	15.90	106.00
Water Flow Meters	-	-	19.08	15.90	-	-	-	-
KWS SCADA Upgrade	-	-	42.40	5.30	-	-	-	-
Total	**23.79**	**1.20**	**61.48**	**21.20**	**-**	**-**	**15.90**	**290.80**

The effect on the cost of coal purchases or production may only be evident in the years after the expenditure is incurred. The benefit may not be a direct decrease in the cost of coal, but instead it may be a flatter coal cost curve because coal did not have to be procured on short/medium term contracts. The benefit of a security upgrade is a secure supply of water because equipment and pipelines are not vandalised or stripped for parts to be sold. In short, while the impact of capital expenditure on the coal mines or on the Komati Water Scheme is not always immediately obvious in the cost of coal and water, it is vital to secure coal and water supplies to the power stations so that they may continue to generate electricity for the country.

5.10 Water

This section explains the challenges and assumptions that underlie this forecast. It also details how and where Generation obtains the water needed to produce electricity and the components of the costs of this water.

Generation receives raw water from the DWS and Rand Water. This water is then treated for its intended use for human consumption or for the plant. The power stations cannot function without water for cooling the plant and producing steam for the turbines.

5.10.1 Water Assumptions

- The water volumes are determined using the production plan.
- The new power stations (Medupi and Kusile) use flue gas desulphurisation (FGD) at 0.45 litres per units sent out (l/USO).
- Mokolo Crocodile West Augmentation Project (MCWAP) 2 will be completed by 2026 to support the growing water demands in the Waterberg Area. No emergency projects will be required for drought – (as we noted that the Mokolo Dam level dropped to 40% in 2020 and violated Generation's assurance of water supply)
- The Department of Water and Sanitation (DWS) has a backlog of maintenance, which will also result in an increase in the water tariff as well as actual costs related to Operations and Maintenance. The DWS expects to have a maintenance contract placed by August 2021.
- Tariffs for Medupi and Matimba comprise of MCWAP1 until FY2026, thereafter a system tariff (combining MCWAP1 and MCWAP2) will be applied. Tariffs are calculated on total cost of infrastructure divided by allocation in the resource and payable on a take or pay basis, over the duration of the loans.
- The costs for water don't include any potential additional sourcing and drought mitigation efforts should any of the systems run into a deficit.
- The Vaal River Tariff (VRT) is increased above inflation annually to cater for the development of Lesotho Highlands Water Project (LHWP) Phase 2 currently being developed as well as above inflation adjustments on the electricity tariffs. The LHWP2 project has commenced and is likely to be completed in 2026 / 2027. The VRT increases will become more as the project progresses and possibility be higher than inflation.

- All current water supply and operations and maintenance related contracts will be renegotiated with the same terms and conditions.

5.10.2 Key drivers affecting the water cost forecast

There are also some costs which are not volume related (operating and maintenance costs, Inter-basin transfers, security related activities, catchment management fees, take or pay capital unit charges for new augmentation etc). Over the FY2022 – FY2027 period, the total volume of water consumed decreases, but the total cost of water is expected to increase due to:

- increase in existing tariffs
- introduction of additional tariffs based on the proposed National Water Pricing Strategy (NWPS) such as the demand management levies and waste discharge charges
- Development of additional water augmentation schemes to meet increase water demand will require significant investment (Lesotho Highlands Water Project Phase 2 (LHWP2) and the Mokolo Crocodile West Augmentation Project Phase 2a (MCWAP2), the cost of which must ultimately be recovered from both current and future users, including Generation. Both the MCWAP2 and LHWP2 are expected to be commissioned by FY2027. Recent new water infrastructure includes augmentation to the Vaal River Eastern Subsystem (VRESAP), Komati (KWSAP) and Mokolo water schemes. (MCWAP Phase 1). The DWS National Water Pricing Strategy allows DWS to implement these projects "off budget" and to recover associated costs via a tariff. The MCWAP1, VRESAP and KWSAP costs are recovered on a take or pay pricing basis.

Generation is a strategic user of water, consuming approximately 2% of the total annual use of the country. As the total demand for water increases (a combination of all user demands), existing water systems have come into deficit. As Generation is a user within these systems the following are impacts to its water costs:

- There is a possibility that the DWS might re-price the water tariffs to reflect water scarcity in the country, which will be reflected in the revised National Water Pricing Strategy
- Generation pays for the water it consumes through a series of water tariffs. These are legislated, so Generation has no control over what they are. Historically, water costs have been very low as a percentage of the Generation operating costs. The main reason for this is that the water infrastructure assets (Generation's and that of DWS) were constructed several years ago and are almost completely depreciated. As new infrastructure and water

charges have been introduced, the demand for water and the cost have increased. Furthermore, the cost increases as the distances over which water needs to be transferred increase and as new tariffs are introduced into legislation.

The water financial plan comprises the following cost elements:

- Water cost, including cost of new water infrastructure
- Electricity
- Operations and maintenance
- Amortisation and capital spend

5.10.3 Major Water Schemes and Contracts

Generation's power stations receive water supply from various schemes and through various contracts.

TABLE 24: SCHEMES AND POWER STATIONS

Scheme	Power Stations Supplied	Water Tariff Components
Vaal River Eastern Sub System (VRESS)		
Komati Water Scheme	*Duvha (approx. 50%), Komati, Hendrina, Arnot & Kusile*	*Catchment Management Fee (CMF); Water Research Commission (WRC); VRESSAP & KWSAP*
Usutu Water Scheme	*Kriel (approx.40%) & Camden*	*Return on Assets (ROA); CMF; WRC; VRESSAP; Operations & Maintenance (O&M)*
Usutu-Vaal Water Scheme	*Tutuka, Matla, Kendal, Kusile, Kriel, (approx. 60%), Duvha (approx. 50%), Matla, Kendal, Tutuka & Kusile*	*ROA; CMF; WRC; VRESSAP; VRT; O&M*
Slang	*Majuba*	*CMF; WRC; VRT; VRESSAP*
Vaal	Lethabo, Grootvlei	ROA; CMF; WRC; VRT
Mokol	Matimba & Medupi Power Stations	Contract with Exxaro

The Vaal River Eastern Sub System Augmentation Project (VRESSAP) supports the entire VRESS. Hence, all the power stations currently on the VRESS scheme bear the additional cost of VRESSAP.

The Komati Water Scheme Augmentation Project (KWSAP) was commissioned to support the demand for water on the Komati Water Scheme. Therefore, all power stations supplied from or to be supplied from (e.g. Kusile Power Station) the Komati Water Scheme, attract this tariff.

The first phase of the Mokolo Crocodile West Augmentation Project (MCWAP1) was commissioned in 2015 and provides water to Medupi Power Station. The second phase of this project is expected to be commissioned in 2027. Generation and other users will be levied with a system tariff (MCWAP1 and 2). The water for Mokolo system augmentation is sourced from return flows from the Vaal River System.

5.10.4 Drivers of Water Cost

(i) Current Water Tariff

The components of the current water tariff are:

- Capital Unit Charge (CUC) which comprises a return on assets and (ROA) depreciation
- Water Research Commission (WRC)
- Catchment Management Fee (CMF)
- Operating and maintenance cost (O&M)

The National Water Pricing Strategy will be revised as part as part of the National Water Resources Strategy Revision and this may result in increases water tariffs.

(ii) Illegal abstractions

Unlawful and unaccounted water usage results in higher water tariffs payable by billed consumers. Furthermore, this will also trigger further augmentation schemes to meet demand, and thus increase water tariffs.

(iii) Current Water Demands

Electricity is a pass through cost to Generation on the Vaal River Eastern Sub-System (VRESS) and is increasing much higher than inflation. Demand also initiates water transfers to provide 99.5% assurance to Generation (via Operating Rules), which thus requires water from expensive schemes. Should the water come from the Vaal, then the Vaal River Tariff becomes applicable.

5.10.5 Raw Water Usage & Cost

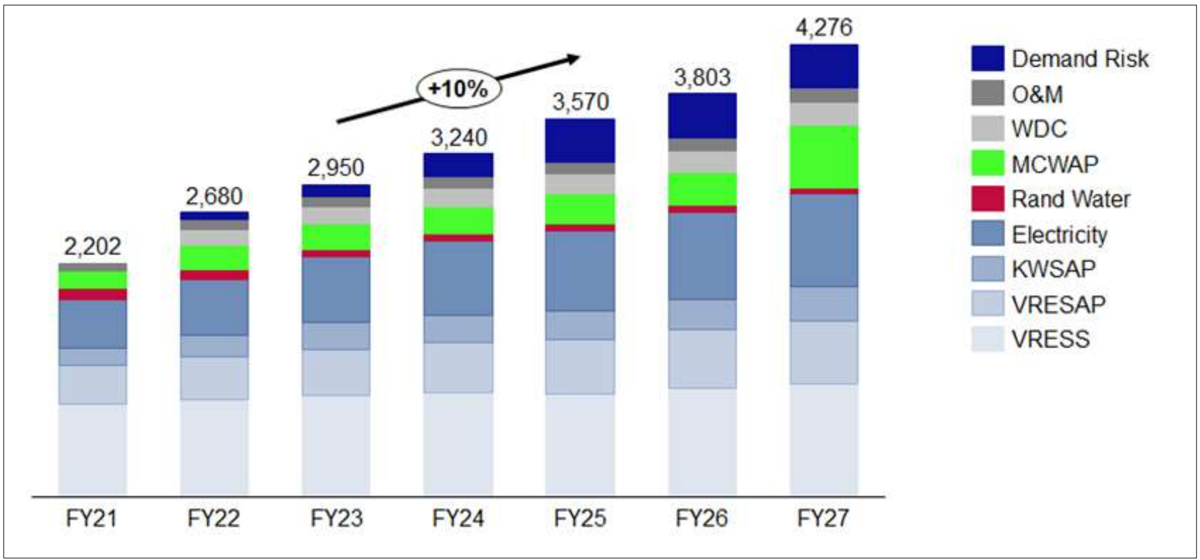
The power station performance targets are based on a regression model and a water balance model of each power station. This is then used to ascertain the quantum of water each power station will use in each period of the anticipated plans. The 50th percentile line of the power station performance is used as the basis for determining the amount of water that would be used by the power station. Any anticipated change at the power station that may impact on water use is accounted for as well. This is aggregated on a scheme by scheme basis and submitted to DWS bi-annually in April and October of each year. In forecasting the water use at each power station, cognisance is taken of the water quality and the points where the water will be sourced, based on the most recent dam operating rules that are available from DWS.

The table and figure below, illustrate Generation's forecast water costs and a breakdown of the elements of water costs for coal stations respectively, for the period under review.

TABLE 25: GENERATION RAW WATER COSTS (EXISTING AND NEW INFRASTRUCTURE)

Water costs (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Coal Stations	2 202	2 680	2 950	3 240	3 570	3 803	4 276
Koeberg	6	5	8	6	7	8	8
Peaking	79	81	87	93	101	111	111
Renew	1	2	2	2	2	2	2
Renewables	3	1	-	-	-	-	-
Total	**2 291**	**2 769**	**3 047**	**3 341**	**3 680**	**3 924**	**4 397**

FIGURE 30: TOTAL COAL STATION RAW WATER COSTS (EXISTING AND NEW INFRASTRUCTURE)

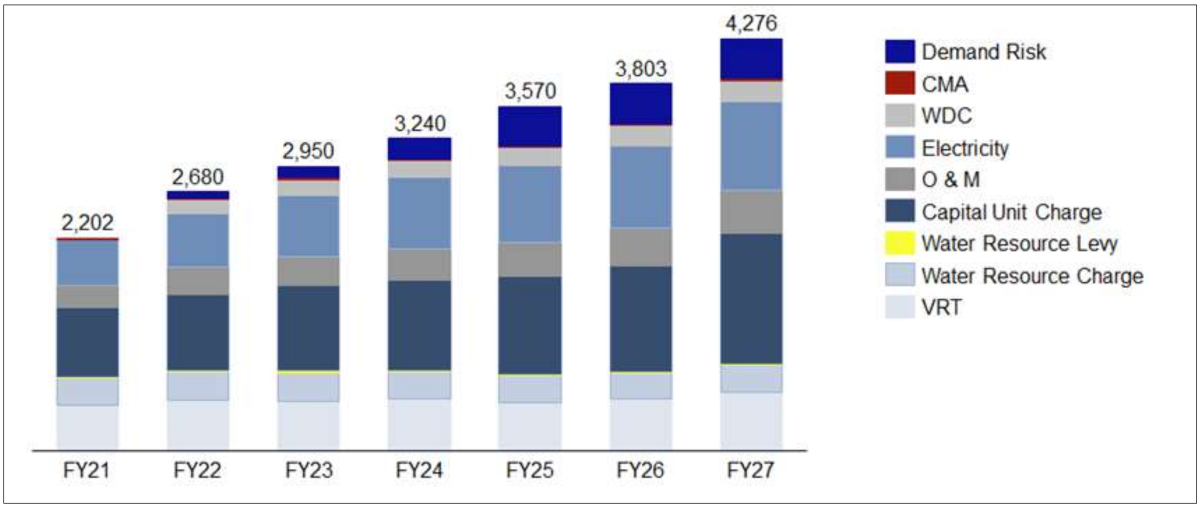


The impact of each scheme on cost is indicated in the figure above. The total cost of water is based on the energy to be generated, the water usage at the power stations (l/USO) and the cost of water (R/Ml). Therefore, the cost of water is equal to the energy sent out x l/USO X R/Ml, plus other none volume related costs. The forecast to the end of FY2021 is R 2.3bn. The year on year increase post FY2021 is about 10%, which caters for a potential Waste Discharge Charge (WDC) and potential water demand changes due to the variations on the planned production at each station. FY2027 includes the MCWAP 2 capital unit charges.

The uncertainty that has the potential for the biggest increase in the cost of water is the introduction of the new water pricing strategy. This should already have been implemented, but the DWS has not done so.

The cost components for the existing schemes, which form part of the total raw water costs, are depicted below. The Vaal River Tariff (VRT), capital charges (CUC) and electricity comprise the larger components of total cost (between 65 – 70%) on existing water supplies. These are volume based tariffs and the increase in water consumption in FY19 results in a corresponding increase in cost. In subsequent years, the increase in consumption at Kusile power Station attracts these tariffs.

FIGURE 31: COMPONENTS OF COAL STATION WATER COSTS



The cost of water comprises legislated costs, pumping costs, amortisation of infrastructure and operating and maintenance costs:

- *The Vaal River Tariff (VRT), Water Research Levy and Water Resource Charge* are legislated tariffs. The tariffs are determined by the DWS. These costs are incurred per million litres (Ml) consumed.

- The Water Research Commission Levy (WRCL) is a tariff applicable to all water users in the country. The only distinction is between irrigation and other uses. At present, the tariff is charged on the actual consumption of the user. DWS may, in future, charge the tariff on registered use instead of actual use because of fluctuations in consumption. The money generated from this charge is paid over to the Water Research Commission by DWS.

- Water Resource Management Charge is a tariff set for a specific catchment area. The tariff applies to all the users and is applied on the registered use of a user and not on the actual volume used. The money generated from this charge is paid over to the Catchment Management Agency. The country is divided into 19 catchment areas.

- The Vaal River tariff (VRT) is a tariff applicable to all water users in the Vaal Catchment. At present, the tariff is charged on the actual consumption of the user. A portion of the money generated, approximately 83%, from this charge is paid over to the Trans Caledon Tunnel Authority (TCTA) by DWS. The DWS infrastructure associated with the scheme includes the following dams and their transfer infrastructure, the Thukela Scheme, Sterkfontein Dam, Heyshope Dam, Zaaihoek Dam, Grootdraai Dam, Vaal Dam and the Lesotho Highlands Transfer Scheme.

- In times of water shortages in the Usutu-Vaal Scheme, water is transferred from the Heyshope Dam to augment the supply. Such transfers attract the Vaal River Tariff, increasing the cost of this water. The DWS models indicate that the Usutu and Usutu-Vaal systems need to be augmented with water from the Vaal system.

- *Capital Unit Charges (CUC):* The Water Pricing Strategy requires Generation to pay a capital unit charge (CUC) which consists of a depreciation charge and an ROA charge. A depreciation charge is calculated based on the current replacement cost of the water infrastructure. The current ROA levy is 4% of the asset value. The pricing strategy makes provision for the revaluation of the assets and the original aim was to execute such a revaluation at 5-year intervals. The revaluations of the assets required that the tariff increases annually by PPI plus 10%. The CUC is also a legislated tariff. In FY16, CUC on MCWAP started being incurred.

- *Operating and maintenance cost (O&M):* These costs vary depending on the specific contract Generation has with the supplier. Generation owns the Komati Scheme and has a contract with Rotek/Roshcon, a subsidiary of Generation, to perform the maintenance. Generation pays the actual operations and maintenance on the Usutu, Usutu-Vaal, Mokolo and Slang Schemes. The costs range from salaries, fuel and vehicle hire to the maintenance of the offices and accommodation for the staff. It is also a requirement in terms of the contract for DWS to submit budgets to Generation. Generation uses these budgets to plan its own costs.

- *Electricity:* The cost that DWS incurs is a “pass through” to Generation. The electricity cost is affected by the forecast electricity consumption. The electricity demand is based on the pumping requirements to support the power station water demands and water transfers from various catchments to prevent dams from failing (*i.e.* to prevent dam levels from falling so low that water cannot be released to power stations). DWS runs models to balance the inter-basin transfer of water. Due to the limitations of the transfer infrastructure and the uncertainty of climate conditions the lead time required to transfer water is very long. The base date for the DWS model is 01 May and the dam levels on that date are used in determining the operating rule. Transfer volumes increase in “dry or drought’ years.

5.10.6 Future Water Demand and Infrastructure

The Integrated Resource Plan (IRP) forecasts new generating capacity. The new infrastructure is developed by DWS via their “off budget” funding mechanism, as described in the DWS National Pricing Strategy. The strategy allows for DWS to recover monies to redeem the loan repayments and operational cost.

The IRP illustrates the timing and technology of choice, thereby prescribing the related water use. Changes in how and where electricity will be generated also impacts the capital expenditure required. The DWS is responsible for capital expenditure for the Usutu, Usutu-Vaal and Vaal. Generation owns the Komati Water Scheme and is responsible for all capital expenditure costs. The capital expenditure for this scheme over the FY2023 – FY2025 period is indicated in section 6.5 on Future Fuel below.

5.10.7 Water Risks

(i) Water Quality

The deteriorating water quality poses a major risk to Generation. The power stations will have to construct appropriate treatment plants and use chemical technologies to manage deteriorating water quality. The problem is further compounded by the management of the hazardous waste generated by the intake of “poor quality” water.

(ii) Waste Discharge Charge System

The DWS’s pricing strategy focuses mainly on water use in terms of volumes abstracted or stored and not on the discharge or disposal of waste or water containing waste or the associated effects. The waste discharge charge system, which will form a vital component of the pricing strategy, will address the latter by introducing financial and economic instruments, designed to internalise costs associated with waste, to encourage the reduction in waste and to minimise the detrimental effects on water resources. The DWS has not determined a mechanism and tariff for this charge, so Generation has allowed for the waste discharge charge in this budget, but it is mere guestimate.

(iii) Drought or Infrastructure failure risk

The budget allows for the normal inter-basin water transfer required by DWS in its hydrological model. The model is fairly robust in forecasting one year. However beyond a year, water transfer in drought conditions cannot be fully determined. No allowance/provisions have been made for either additional water transfers or water infrastructure that may be needed to mitigate the effects of drought. During drought conditions the water resource quality deteriorates which further exacerbates the water management problem at the power stations.

(iv) Water Supply Infrastructure failure risk

Power stations are planned to receive water from better quality sources, however during infrastructure failures some power stations will be expected to move to alternate water sources. These sources will attract additional tariffs and is also of poorer quality. Kriel, Kendal, Kusile and Duvha as such power stations. To cater for this risk, some allowance has been made in the demand variation.

(v) Project Cost Variance on New Water Infrastructure

The second phase of MCWAP has been delayed to FY2026/27. In the interim, Medupi Power Station will utilise the water for flue gas desulphurisation from its current water allocation within the Mokolo system. The second phase will increase the water supply to Medupi for the flue gas desulphurisation process and create a redundant water supply for both Medupi and Matimba power stations to ensure a 99.5% assurance of water supply. The DWS will also supply water to Lephalale Municipality and other mines in the area.

A cost risk exists regarding new water infrastructure. Currently, Generation pays a tariff based on the actual cost of the infrastructure. The Trans-Caledon Tunnel Authority (TCTA) has provided budget estimates. Any increases outside the budgets provided by TCTA are not allowed for in this submission.

The cost of water to Generation is largely outside of the control of Generation. As part of being environmentally responsible, Generation puts in place measures to monitor and manage water consumption. However, power stations do use water for people and plant. If electricity generation changes (output volume or mix of power stations), water needs to be supplemented from other schemes, when the DWS introduces new tariffs or new infrastructure is required, the total cost of water is impacted.

(vi) Production Plan Variations

A major cost driver for water is the total production mix within the fleet of power stations. This plan is based on the October 2020 production and deviations from the plan (extending the life of wet cooled stations, delays on newer dry cooled stations etc) results in a water demand variance and ultimately a change to the projection. Some demand variation is included in the projection for, demand variation, drought and minor local catchment failures.

(vii) Tariff increases

- Vaal River Transfer (VRT)
  The VRT is escalated by 9% year on year in the budget. With more electricity needed in the water systems and further infrastructure VRT increases maybe beyond these assumptions.
- Additional tariffs
  There is a possibility that the DWS might re-price the water tariffs to reflect water scarcity in the country, which will be reflected in the revised National Water Pricing Strategy. This budget attempts to cater for one element of the new tariffs which the waste discharge charge.

5.11 Sorbent

This section explains what Generation uses Sorbent for, what it is likely to cost and why.

Sorbent is required for the flue gas desulphurisation (FGD) technology at Medupi and Kusile Power Stations. The sources identified for this commodity are located in the Northern Cape. The Sorbent is railed from the Northern Cape to Gauteng. Then, because of a lack of rail infrastructure, it is trucked to the powers stations. This process increases the delivered cost of Sorbent significantly.

The use of Sorbent also increases the water requirements at each of the above mentioned power stations. The primary energy water volumes and cost include water for FGD at Kusile, based on a requirement of 0.45 litres per unit of energy sent out.

For this submission, the following assumptions have been made with regards to Sorbent:

5.11.1 Quantities required:

The Sorbent volume requirements per station for each year are based on the GWh energy sent out per station. Although Medupi power station has already started generating, it will only be retro fitted with FGD at a later stage. The use of FGD at Medupi Power Station has been delayed because of technical challenges at the station, so there is no Sorbent consumption at Medupi in the MYPD5 application. Kusile Power Station will have all six units fitted with FGD when they are commissioned.

TABLE 26: ENERGY SENT OUT FOR STATIONS WITH FGD

Energy sent out - FGD stations (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Medupi	-	-	-	-	-	-	-	-
Kusile	3 041	8 002	10 662	11 818	15 124	19 687	16 789	15 123
Total	**3 041**	**8 002**	**10 662**	**11 818**	**15 124**	**19 687**	**16 789**	**15 123**

The estimated purchases of Sorbent are shown in the table below.

TABLE 27: VOLUME OF SORBENT REQUIRED

Sorbent Volumes (kTons)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Kusile	142	176	235	260	333	433	369	333
Total	**142**	**176**	**235**	**260**	**333**	**433**	**369**	**333**

5.11.2 The cost of Sorbent:

5.11.2.1 Key drivers affecting the cost of Sorbent

- The coal-fired power stations where Flue Gas Desulphurisation is planned are geographically remote from viable Sorbent sources; hence logistics and the final delivered cost will contribute to the selection of the most cost effective option.
- Estimated pricing escalations are assumed to be driven by PPI.
- Greenfield sources will require capital investment in rail infrastructure and as such will require a return

5.11.2.2 Cost assumptions:

- The cost of Sorbent for Kusile is R139/ton FCA in FY2022. This is based on the existing contract.
- The cost of transport for Kusile is R809/ton in FY2022. This is the cost of the rail and road elements.

5.11.2.3 Cost escalations:

The Sorbent price and the transport cost have been escalated by PPI as per Generation's parameters.

TABLE 28: FORECAST PURCHASES COST OF SORBENT (R'M NOMINAL)

Sorbent Purchase costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Limestone	18	23	33	38	52	72	65	62
Transport	103	134	190	223	303	418	378	360
Total	**121**	**158**	**222**	**261**	**355**	**489**	**442**	**422**

The purchases costs above translate into consumption costs as follows:

TABLE 29: FORECAST CONSUMPTION COST OF SORBENT (R'M NOMINAL)

Consumption cost of sorbent (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Costs (R 'm)	57	155	219	258	350	485	438	418
Volumes (kt)	71	176	235	260	333	433	369	333

The decision to implement flue gas desulphurisation plant at Medupi and Kusile Power Stations is in line with environmental requirements to reduce emissions globally. There is a cost to implementing these measures. The long distance over which the Sorbent needs to be transported adds to this cost. Generation is investigating options to reduce this cost, such as alternative sources of Sorbent which may be closer to the power stations, as well as railing the product from the Northern Cape to Mpumulanga instead of Gauteng to reduce the distance on road. At this stage, the source with the capacity to supply the volumes required is the mine in the Northern Cape. Therefore, the costs have been based on this information.

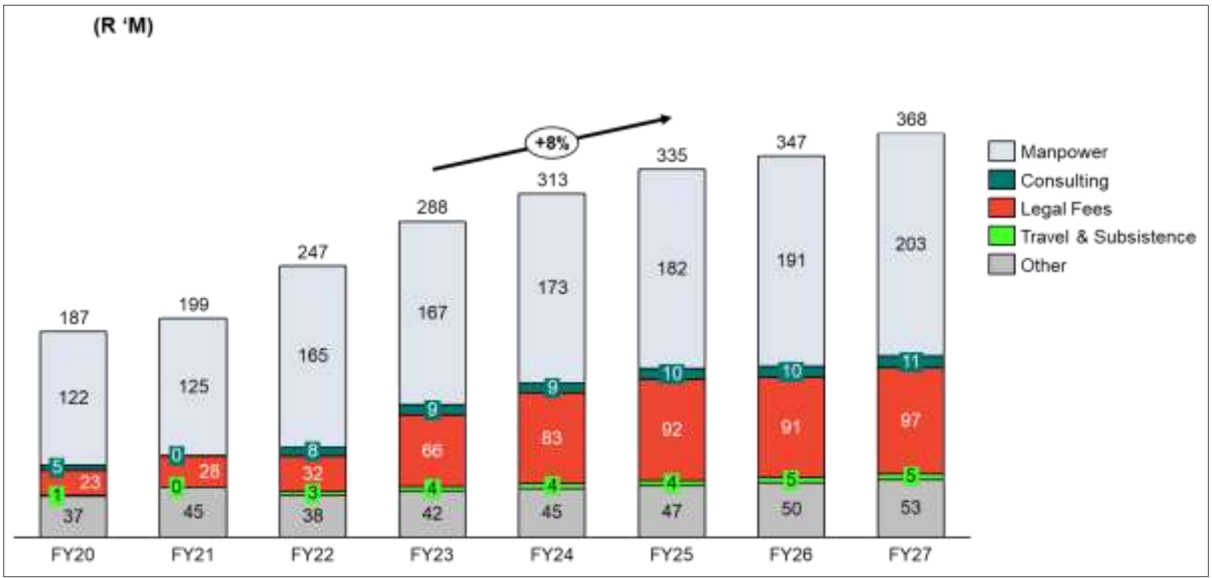
5.11.3 Sorbent handling costs

Sorbent is required at Kusile for the flu gas desulphurisation (FGD). Sorbent handling costs account for about 6% of total Sorbent usage costs. Sorbent handling costs remain flat in the MYPD5 period with CAGR of 3.9% which is below inflation.

5.12 Fuel Procurement Costs

These costs are incurred to operate the Primary Energy function. Apart from the provision for decommissioning and rehabilitating mines, the rest of these costs consist of manpower related costs. Manpower includes sourcing, technical, environmental and operational staff, essential for managing the procurement and supply of coal from source to destination. These costs are not included in Generation's operating expenditure, but are shown separately as Fuel Procurement Costs.

FIGURE 32: PRIMARY ENERGY FUNCTION SPEND



Total costs increase by 8% over the period. Other costs include operating and administration costs, such as insurance premiums and subscriptions to databases.

Although there are vacancies which will be filled during the period, over the FY2021 – FY2027 period manpower costs have been increased by only 5%. Legal fees increase substantially as Generation expects to need this service for primarily coal related matters. Other costs form a relatively small part of the departmental costs.

5.13 Independent power producers (IPPs)

The Government policy in accordance with the Integrated Resource Plan of 2019, is to significantly increase the contribution of energy sourced from Independent Power Producers. In addition to further acceleration energy from renewable sources, the risk mitigation plan for dispatchable energy as well as contribution from gas technology are envisaged to be introduced in the MYPD5 period. All of this energy will be sourced from independent power producers in accordance with determinations made by the DMRE Minister and concurred to by NERSA. The DMRE Minister is exercising his role in ensuring that the supply demand balance is achieved. Certain requirements of the IRP will not be met in the DMRE procurement process. Thus the IPP projections, as approved by the relevant Government Departments, has factored this into the projections included in this MYPD5 application. The acceleration in the Government's IPP programme directly impacts the price increases being applied for. Despite the decrease over time in the cost of certain technologies the overall cost of IPPs to the consumer increases significantly. This is due to the comparatively higher price of each technology in the earlier bid windows, being locked into the power purchase agreements signed at that time, The significant increase in the quantum of energy from IPPs, mainly renewable technology as well as the introduction of new technologies such as gas and other dispatchable technologies.

In accordance with the sections 3.1.4(e) of the Government Support Framework Agreement (GSFA), Generation is required to consult with and seeks approval from the Department of Mineral Resources and Energy (DMRE) together with the Department of Public Enterprises (DPE) and National Treasury with regards to the proposed amounts for IPP purchase costs and payment obligations to be included in the MYPD5 application for the period from FY2023 to FY2025.

Generation has undertaken this process. Generation has received feedback from all three relevant Government Departments, that all concur with the projections on IPP projects to be included in Generation's MYPD5 revenue application.

TABLE 30: ASSUMED COSTS FOR IPP ENERGY

IPP Costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Eskom short term programmes	**-**	**553**	**2 378**	**2 520**	**2 013**	**-**	**-**	**-**
MTPPP	-	-	-	-	-	-	-	-
Short term (incl Munic)	-	553	2 378	2 520	2 013	-	-	-
WEPS	-	-	-	-	-	-	-	-
Section 34 programmes (non RE)	**4 883**	**3 545**	**4 129**	**21 874**	**27 082**	**37 189**	**49 078**	**51 925**
DoE Peaking- Capital costs	1 631	2 053	1 738	1 780	1 829	1 871	1 920	1 973
DoE Peaking- Other costs	3 252	1 492	746	756	768	776	788	800
Risk Mitigation Programme	-	-	1 645	18 364	22 702	23 999	25 439	26 965
Gas programme	-	-	-	-	-	8 659	9 178	9 729
Baseload Coal	-	-	-	-	-	-	9 755	10 341
Storage	-	-	-	974	1 783	1 884	1 997	2 117
Renewable IPP	**24 807**	**28 771**	**35 498**	**45 339**	**55 923**	**64 297**	**74 709**	**81 330**
Renewable IPPs Round 1	10 611	11 131	12 281	13 000	13 817	14 546	15 361	16 238
Renewable IPPs Round 2	6 097	6 416	6 814	7 118	7 410	7 764	8 106	8 487
Renewable IPPs Round 3	6 705	7 543	7 925	8 364	8 802	9 312	9 848	10 399
Renewable IPPs Round 3.5	1 330	1 596	1 876	1 987	4 007	4 271	4 581	4 848
Renewable IPPs Round 4	65	1 345	3 506	4 497	4 773	5 038	5 333	5 645
Renewable IPPs Round 4+	-	740	3 097	4 056	4 303	4 539	4 801	5 079
Renewable IPPs Round 5	-	-	-	6 271	7 131	7 522	7 957	8 417
Renewable IPPs Round 6	-	-	-	-	5 600	7 539	7 975	8 436
Renewable IPPs Round 7	-	-	-	-	-	3 322	5 690	6 031
Renewable IPPs Round 8	-	-	-	-	-	-	4 583	7 251
Small-scale renewable - committ	-	-	-	-	30	390	416	439
Small-scale renewable - new	-	-	-	48	51	54	57	60
Solar Park Round 1	-	-	-	-	-	-	-	-
Total IPP energy costs	**29 690**	**32 869**	**42 005**	**69 733**	**85 018**	**101 486**	**123 787**	**133 255**
Network pass through	-	85	270	286	303	321	340	361
Total IPP costs	**29 690**	**32 954**	**42 274**	**70 019**	**85 321**	**101 807**	**124 128**	**133 616**

Notes:

FY2020 excludes the provision of R3m

FY2021 to FY2022 reflects projections

FY2023 to FY2025 reflect the MYPD5 application

TABLE 31: ASSUMED ENERGY FROM IPPS

IPP Energy (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Eskom short term programmes	**-**	**389**	**1 577**	**1 577**	**1 188**	**-**	**-**	**-**
MTPPP	-	-	-	-	-	-	-	-
Short term (incl Munic)	-	389	1 577	1 577	1 188	-	-	-
WEPS	-	-	-	-	-	-	-	-
Section 34 programmes (non RE)	**711**	**412**	**803**	**7 566**	**8 779**	**12 259**	**17 187**	**17 187**
DoE Peaking	711	412	88	88	88	88	88	88
Risk Mitigation Programme	-	-	715	7 532	8 784	8 760	8 760	8 760
Gas programme	-	-	-	-	-	3 504	3 504	3 504
Baseload Coal	-	-	-	-	-	-	4 928	4 928
Storage	-	-	-	- 54	- 93	- 93	- 93	- 93
Renewable IPP	**11 247**	**13 378**	**17 883**	**27 342**	**35 096**	**40 677**	**47 773**	**50 099**
Renewable IPPs Round 1	3 653	3 607	3 800	3 797	3 806	3 785	3 775	3 768
Renewable IPPs Round 2	2 971	2 977	3 056	3 052	3 046	3 039	3 031	3 026
Renewable IPPs Round 3	4 243	4 455	4 545	4 540	4 539	4 529	4 527	4 523
Renewable IPPs Round 3.5	308	351	401	400	892	885	895	894
Renewable IPPs Round 4	71	1 277	3 267	4 074	4 081	4 064	4 059	4 054
Renewable IPPs Round 4+	-	709	2 814	3 507	3 511	3 495	3 488	3 482
Renewable IPPs Round 5	-	-	-	7 916	8 485	8 444	8 427	8 410
Renewable IPPs Round 6	-	-	-	-	6 664	8 464	8 447	8 429
Renewable IPPs Round 7	-	-	-	-	-	3 729	6 026	6 026
Renewable IPPs Round 8	-	-	-	-	-	-	4 854	7 245
Small-scale renewable - committed	-	-	-	-	15	186	186	185
Small-scale renewable - new	-	-	-	56	57	56	56	56
Solar Park Round 1	-	-	-	-	-	-	-	-
Total IPP	**11 958**	**14 179**	**20 262**	**36 485**	**45 063**	**52 936**	**64 960**	**67 286**

5.13.1 Assumptions related to local IPP purchases

Consumer Price Index inflation is assumed at 6% p.a.

5.13.1.1 Section 34 Procurement

a) Renewable Energy IPP Programme

- All prices are indexed to the assumed inflation, except for certain bid window (BW) 2 and BW 3 options that are only partially indexed

- Bid Windows 1 through 4 included as per the energy expectations in the power purchase agreement (PPA) and prices as per PPA

- The expected renewable capacity under the IRP (and supported by the Ministerial Determination of 2020) is 6 800 MW for the years 2022-24. This is split between three bid windows (Bid Window 5 of 1000 MW PV and 1600 MW Wind; Bid Window 6 of 1000 MW PV and 1600 MW wind; and Bid Window 7 of 1600 MW Wind).

- The expected commercial operation dates for projects under Bid Windows 5 to 7 have been provided by the DMRE through the GSFA consultation process. The load factor for Wind in these programmes is expected at 43% and PV at 28%, with the cost for Wind and PV both assumed as R0.62/kWh in 2017 rands.

b) Peaker programme

The two IPP Peaker power stations are commercially operating. These are assumed to be operating at 1% load factor and expected costs split between the "fixed" capital component and variable energy component.

c) Risk Mitigation programme

The RMPPP is expected to realise an additional 2000 MW, with expected commissioning occurring in three tranches (as per input from the IPP Office) of:

- 250 MW by 30 December 2021;
- 600 MW by 30 January 2022; and
- 1150 MW by 30 June 2022.

The expected load factor is 50% for the full capacity and an expected cost of R2.17/kWh in 2020 rands, escalating at CPI.

d) Gas programme

The 1000 MW gas capacity procured under a specific gas programme is expected 1 April 2024, at a load factor of 40% and cost of R1.72/kWh.

e) Section 34 – Baseload Coal programme

It is expected that the 750 MW capacity to be procured under the Baseload Coal programme would only come into operation after the MYPD5 period.

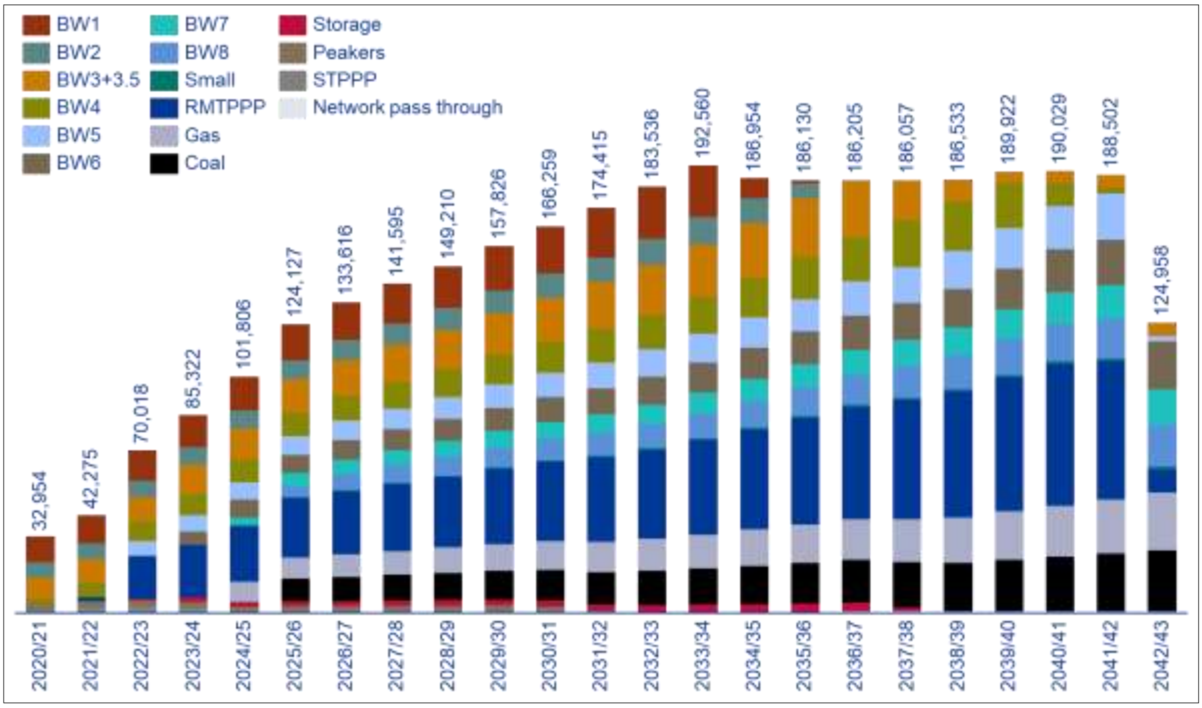
f) Section 34 – Storage

The IRP provides for 513 MW of battery storage. It is expected this will operate from September 2022 with 4 hours storage capability, 89% cycle efficiency and one cycle per day for the duration of the contract. This means that each day will see 4.5 hours of charging and 4 hours of generation, thus daily net consumption is 256 MWh, and annual net consumption is 93 GWh. The energy payment to the storage facility is expected to set to counter balance the energy charge (e.g. a fixed charge of 30c/kWh for 4.5 hours of charging is offset by a payment of 33.7c/kWh for 4 hours of output). Thus the costs reflected are for the fixed costs of the generator (annualised capacity costs and fixed operating and maintenance). The expected cost for this is based on R2.79m per MW per year (itself based on assumed capital cost of $300/kWh installed for a 4 hour system, and annual fixed O&M of $15/kW/year, with a foreign exchange rate of R18/USD).

5.13.1.2 Generation programmes

Generation has applied to NERSA for cost recovery approval for short term additional capacity contracts awarded in tenders during FY2021. The expected start of the new capacity was 1 January 2021 (since delayed by cost recovery approvals) with 300 MW at an average load factor of 60%. These contracts are expected to be three years, expiring on 31 December 2023. The cost is expected at R1.42/kWh in 2020 Rands, escalating at CPI.

FIGURE 33 : SUMMARY OF IPP COSTS OVER LIFE OF CONTRACTS (RM)



The figure above reflects the nominal cost of IPP contracts over the life of the contracts for each of the bid windows from Bid window 1 to Bid Window 8, as well as the non-renewable Section 34 programmes (Gas, Risk Mitigation, Coal and Storage). It is assumed that subsequent bid windows will be awarded to IPPs. All of the contracts have annual increases included in the contracts. The nominal costs associated with these IPP projects peak at R194bn in FY2034. It should be noted that despite the decrease in many IPP technologies (e.g. solar), the total IPP costs continue to increase for more than 10 years. This is due to significant increased energy sourced from IPPs, the continual escalation, further technologies being introduced. Thus the trend seen in the MYPD5 period is likely to continue. The impact of any further bid programmes is not included. The drop in the 2043 year is due to many present bid programmes coming to an end. Any further subsequent programmes that are as yet unknown will provide a different trajectory in the later years.

5.13.1.3 International Purchases

Electricity supply from neighbouring countries is mainly driven by imports from Cahorra Bassa (HCB) with expected supply of approximately 1200~1400MW. This source has been and will continue to be subject to fluctuations due to network constraints, drought conditions affecting the level of the dam and thus reducing supply by around 500MW in certain instances and availability of HCBs 5th generator on a non-firm basis. The forecasts remain fairly consistent at around 10.5 TWh.

TABLE 32: INTERNATIONAL PURCHASES

International Purchases (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
International Purchases	4 704	4 624	4 329	4 589	4 878	5 157	5 466	5 794

5.14 Ancillary Services and Demand Reduction Programmes

In terms of the MYPD Methodology, the Transmission System Operator should submit the methodology and models for calculating costs of the Ancillary Services (AS) and Demand Reduction (DR) programmes for consideration by the Energy Regulator. This motivation is therefore included in the Transmission licensee revenue application (section 3.3 of the Transmission licensee revenue application).

Eskom’s revenue requirement for Ancillary Services and Demand Reduction initiatives is summarised in the table below. Note that only Power Alert and demand response are included in the Primary Energy portion of Generation’s revenue requirements. The cost of the other ancillary services provided by Generation, such as Reserves, Reactive Power and Voltage, Black start and Islanding and Demand Response are built into the operating costs of Generation.

TABLE 33: ANCILLARY SERVICES AND DEMAND REDUCTION PROGRAMMES (R’M)

Transmission Ancillary Services (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Reserves Total	333	321	369	895	937	979	1 164	1 218
Eskom Generation	*22*	*26*	*30*	*40*	*42*	*44*	*47*	*49*
Eskom BESF	-	-	-	*59*	*62*	*65*	*68*	*71*
IPP's and External BESF	-	-	-	*415*	*434*	*453*	*615*	*643*
Demand Response	*311*	*295*	*339*	*381*	*399*	*416*	*435*	*455*
Reactive Power and Voltage	169	185	199	112	121	131	142	153
Black Start & Islanding	41	45	52	53	55	55	56	59
Constrained Generation	0	2	12	-	-	-	-	-
Power Alert	-	33	78	78	78	78	78	78
Total	**543**	**586**	**710**	**1 138**	**1 191**	**1 243**	**1 440**	**1 508**

5.14.1 Ancillary services

The extent of the AS services and the manner in which they are to be provided is defined in the South African Grid Code. The ancillary services currently defined include:

- Reserves (Generation, IPPs & Demand Response),
- Black Start and Islanding,
- Energy Imbalance (Constrained Generation) as well as
- Reactive Power and Voltage Control.

The reliability of the power system has been compromised in recent years due to a lack of sufficient reserves. To help remedy this during the MYPD5 window, the System Operator has:

- Increased the quantity of reserves required from Demand Response providers;
- Implemented a performance based costing methodology for emergency reserves;
- Made provision for the procurement of additional reserves from IPP's and BESF at cost reflective rates.

This has resulted in a significant increase in the reserves revenue requirement for MYPD5.

5.14.1.1 Power Alert Programme

The System Operator (SO) is responsible for the reliability and security of the South African national electricity grid by monitoring, controlling and operating it in a safe, economical and reliable manner. One of the Demand Reduction Programmes available to the System Operator during system emergencies is the Power Alert Programme.

Power Alert is a voluntary residential demand reduction project broadcast on selected television channels, during the evening peak period (between 17:00 and 21:00). Historically Power Alert was successful and delivered between 150 and 350 MW peak demand savings, linked to seasonality. This programme predominantly saw support from the residential segment which forms a large portion of Generation's weekday peak consumption.

The Power Alert is typically scheduled and dispatched by the SO before Generation's emergency reserves are implemented. By placing Power Alert in this merit order, Power Alert is a cost-saving tool (economic dispatch) as it reduces the need to use Generation's peaking stations (gas turbines).

5.15 Nuclear Fuel

5.15.1 Nuclear Fuel procurement

Nuclear Fuel procurement comprises the acquisition of uranium, conversion, enrichment and the fabrication of the fuel assemblies for Nuclear Fuel. Long-term contracts are established to ensure security of supply as well as availability of nuclear fuel at the appropriate time and within the prescribed quality standards. The table below shows the expenditure on acquiring the Nuclear Future Fuel which is held in Inventory until such time as it is placed into the reactor and burnt.

TABLE 34: NUCLEAR FUTURE FUEL PROCUREMENT COSTS (NOMINAL R'M)

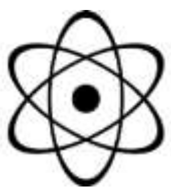
Nuclear Future Fuel Procurement costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Fuel Purchases	739	1 155	601	971	787	1 426	893	1 165
Delivery of Fuel Assemblies	108	104	-	120	60	60	60	120

The fuel manufacturing process is approximately eighteen months with contractual progress payments throughout the fuel manufacturing cycle. As indicated above, this results in the above cashflows being different from the burn in Primary Energy of the fuel. Fuel Procurement volumes will fluctuate as they follow the delivery requirements for Koeberg. Fuel is required to be delivered approximately six months prior to each refuelling outage.

All the Nuclear Fuel expenditure is incurred in foreign currency and Cashflow Hedge Accounting is applied to the purchases. The Cashflow Hedge Accounting requires a Basis Adjustment to the price of the delivered fuel.

5.15.2 Assumptions

Nuclear Fuel costs mainly comprise four categories, being Uranium, Uranium Conversion, Uranium Enrichment and Fuel Assembly manufacturing. The cost contribution per category depends on market prices and the ruling exchange rates. As per the latest available Term-market prices, the respective apportionment of the total cost is:



48% Uranium

8% Uranium Conversion

22% Uranium Enrichment

22% Fuel Assembly manufacturing

Nuclear Fuel purchases are based on the following forward-looking nuclear fuel price assumptions:

TABLE 35: NUCLEAR FUEL PRICING AND INFLATION ASSUMPTIONS (NOMINAL R'M)

Nuclear Fuel Plannng Assumptions	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Ave Fuel Assembly Price	9.42	9.81	0.00	13.00	13.11	13.62	13.70	15.29

The above nuclear fuel assembly prices are the average prices of the fuel assemblies delivered to Koeberg during that financial year.

The cost of the delivered nuclear fuel is expensed as part of Koeberg's primary energy costs over the period that the assemblies remains in the reactor, which is normally approximately 54 months. Thus there is not a direct correlation between when the nuclear fuel procurement costs incurred and when it is expensed as primary energy costs.

TABLE 36: NUCLEAR FUTURE FUEL

Nuclear Future Fuel (R'm)	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening Balances	**227**	**828**	**211**	**211**	**865**	**937**
Add:						
Purchases	601	1 001	810	1 444	897	1 169
Cashflow Hedge Basis Adjustment	-	(30)	(23)	(18)	(5)	(3)
Less:						
Transfers to Nuclear Inventory	-	(1 588)	(787)	(772)	(821)	(1 835)
Closing Balance	**828**	**211**	**211**	**865**	**937**	**267**

TABLE 37: NUCLEAR FUEL INVENTORY

Nuclear Fuel Inventory (R'm)	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening Balances	**2 612**	**1 954**	**2 924**	**2 840**	**2 782**	**2 673**
Add:						
Transfers from Future fuel	**-**	**1 588**	**787**	**772**	**821**	**1 835**
Less:						
Fuel Burnt	(591)	(660)	(788)	(794)	(873)	(997)
Fuel Written Off	(54)	(29)	(68)	-	(104)	(70)
Spent Fuel Management:						
Increase in Decomissioning Asset	91	187	103	83	160	82
Depreciation of Decom Asset	(105)	(115)	(118)	(119)	(113)	(111)
Closing Balance	**1 954**	**2 924**	**2 840**	**2 782**	**2 673**	**3 412**

5.15.3 Nuclear fuel usage and costs

Koeberg Power Station consists of two reactors requiring each a loading of the reactor core of 157 fuel assemblies to achieve an even energy output as one third of the fuel assemblies are replaced at each refuelling cycle. These fuel assemblies remain in the reactor core and are typically "burnt" over a period of approximately 54 months depending on the Production Plan and the refuelling strategies. The costs of the fresh fuel assemblies are amortised over the anticipated burn period and are reflected in Primary Energy costs.

Factors influencing Koeberg's primary energy (nuclear fuel) costs include:

5.15.3.1 Nuclear Fuel Price

Nuclear fuel procurement comprises mainly of four distinct phases, being procurement of uranium, conversion of the uranium into the gas UF6, enrichment of the U-235 isotopes to the required level, and the fabrication and delivery of the fuel assemblies. All these activities are undertaken internationally and are subject to market price and foreign exchange fluctuations. Generation has contracts that cover 100% of Koeberg's demand until the end of 2017 with procurement currently in progress to acquire uranium, conversion and enrichment services for the period up until 2028. For the fuel assembly fabrication phase, Generation recently concluded contracts for the supply of fabricated assemblies up until 2022 with an option to extend to 2026.

The pricing formula for the fuel fabrication is 100% a base escalated price. For the rest, being the uranium, uranium conversion and uranium enrichment, a mix of price conditions have been agreed to being a mix between base escalated and market related prices, a mix between term and spot market prices and/or a reset of the base price to market during the contract period.

These prices are stated in the international functional currency of USD and are translated into ZAR at the rates provided by Generation Treasury.

5.15.3.2 Koeberg Production Plan

Koeberg has the lowest cost of Primary Energy per MWh produced in the Generation fleet and is therefore run as a base-load station. Its Production Plan is influenced by its need for refuelling every eighteen months as well as it Maintenance regime which requires it to replace and modify its plant components. The MYPD5 application is based on version 72 of the Koeberg Production Plan which covers the full period of the application.

The fuel is burnt over a period of three reload cycles of approximately eighteen months each, being a total of 54 months, however based on the energy requirements some fuel assemblies may be changed and replaced with fresh fuel after only two cycles. This partially burnt assemblies are then expensed fully and removed from the reactor.

5.15.3.3 Spent Fuel Management Costs

The costs associated with the management, including the disposal of the Spent Fuel Assemblies generated by Koeberg is quantified from extensive studies which is incorporated into the Reference Technical Plan and reflected into a Spent Fuel Management Provision. The costs in raising the liability to safely and responsibly manage the spent fuel is amortised over the burn period of the fuel in the reactor core. The Spent Fuel Reference Technical Plan, which is based on extensive consulting studies, is revised every three years or when deemed necessary.

TABLE 38: KOEBERG PRIMARY ENERGY COSTS (NOMINAL R'M)

Primary Energy - Nuclear Fuel Costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Fuel Burnt	716	550	591	660	788	794	873	997
Fuel Written Off	37	21	26	51	38	44	111	70
Depreciation of Decom Asset	88	94	106	115	118	119	113	111
Nuclear Other	3	2	27	13	13	31	14	13
Total	**844**	**667**	**750**	**839**	**957**	**988**	**1 111**	**1 191**

The costs above represent the following:

5.15.3.4 Unit 1 and Unit 2 "Fuel burnt"

These costs represent the fuel burnt as per the Rev 72 of the Koeberg Production Plan which is developed by Koeberg Power Station in conjunction with the Generation-wide Production Plan. The fuel assemblies loaded are expected to be burnt over a period of three cycles which equates to approximately 54 months.

5.15.3.5 Depreciation of Decommissioned Asset: Spent Fuel Backend Costs

All the costs required to manage the Spent Fuel must be allocated to period of production from which the benefits of burning the fuel is derived. Hence the costs relating to the long-term storage and disposal of the fuel is expensed over the period for which the fuel is burnt. This represents the variable costs of burning the fuel as should the fuel not be irradiated the costs would be avoided. The above charge to the income statement is credited to Spent Fuel Provision thereby ensuring that the obligation for managing the Spent Fuel is correctly reflected on the balance sheet.

The Spent Fuel assemblies are stored in the Spent Fuel Pools at Koeberg Power Station, however, given that Koeberg is over 32 years in use, the pools are reaching their capacity. The station has commenced acquiring Spent Fuel Casks which will allow the spent fuel to be removed from the pools and stored in dual-purpose, storage and transport casks. With each fresh reload of fuel into the reactor core the displaced spent fuel from the core will require older and cooler spent fuel to be removed from the pool. Hence the cashflow expenditure relating to the Spent Fuel Provision is being incurred now and will continue through to the end of life of the station. Unlike the Plant Decommissioning expenditure which is mainly incurred at the end of life of the station, the spent fuel decommissioning expenditure is a current and ongoing cost.

5.15.3.6 Nuclear Other and Nuclear Fuel Write-offs

These costs represent the write-off of partially burnt fuel. Partially burnt fuel arises when due to energy requirements not all fuel assemblies can be fully burnt over the 54 months. The Reactor Fuel Engineering section calculates the energy requirements from the fuel so as to ensure sufficient energy for the full duration of each cycle.

5.16 OCGT fuel burn

5.16.1 Introduction to OCGT fuel

The purpose of this section is to provide information on how OCGTs are utilised to indicate their prudent usage considering the dynamics of the system. The focus is on the operational aspects of their usage. From a planning perspective, the OCGTs are considered together with the other available supply and demand options as peaking stations for use during peak hours which provides space for essential maintenance at base-load stations as well as for emergencies as a last resort before load reductions during extreme events.

The load factor for OCGTs during the forecasting period was assumed to be 1% as this is the minimum constraint imposed in the production plan, which translates to 211 GWh per annum. However, this is based on the assumptions made when developing the production plan. Should the reality turn out to be different from the assumptions, then the OCGT usage could be higher than the assumed. The only possible mitigations against OCGT usage higher than the assumptions are increased dispatchable capacity (from either Generation of other generators) and improving the reliability and predictability of the Generation fleet. The latter is an integrated part of the Stabilise Operations leg Generation’s Turnaround Plan and includes the 9 Point Plan and the Reliability Maintenance Recovery Programme.

The fuel used is mainly diesel (Ankerlig and Gourikwa). The price of the diesel is subject to the international USD price of Brent crude oil and the ZAR/USD exchange rate. The official Generation economic parameters for the forecasting period were used in the calculations of the fuel costs. The diesel used by Generation is subject to a wholesale discount and a fuel rebate as determined by the Minister of Finance.

5.16.2 OCGT Specifications

Ankerlig and Gourikwa are heavy duty industrial gas turbines (Siemens) and can be used over a wide variety of loading regimes from peaking to base load. Acacia and Port Rex are based on jet engine technology. Ankerlig and Gourikwa were constructed to assist with the demand supply balance predicted from the early 2000s because of their shorter (2-3 years) construction times. Originally, the business case for the OCGTs was based on a load factor of 6%.

5.16.3 OCGT utilisation plan

When making a decision to run the OCGTs, all available resources are considered, for the current day as well as the next few days. Possible restrictions on Generation generation include the dam levels at the pump storage stations (Ingula, Palmiet and Drakensberg) and the availability of water at the other hydro stations (Gariep and Vanderkloof) which is managed by the Dept. of Water Affairs. OCGTs are used only once available base, mid merit and hydro-generation have been utilised or planned to be utilised over peak, and once load reduction through the Virtual Power Station (VPS) (see Section 4.7 for details on the VPS) and other demand response options have been dispatched. These have limited energy reduction opportunity and they are normally planned to be utilised over peak. Emergency reserves are then considered. These include Emergency Level 1, Interruptible Load Shedding (ILS) and the OCGT generation.

When the system is constrained, OCGTs are used to meet the remaining load when all other available generation is on line. In winter this is typically for a few hours over evening peak due to the peaky load profile. However, in summer this may be for many hours per day due to the significantly flatter load profile. During the day, fewer units will be required than over evening peak. OCGTs typically take about 20-30 minutes to come on line and cannot all be brought on simultaneously. The number of units expected to be required for evening peak are brought on load prior to the sharp evening pick up to ensure they are on load on time and prevent running at low frequencies. If the load does not materialise as expected there may appear to be extra machines on load but it is necessary that the machines are ready to support the load and the expected “peak in the peak”.

If large amounts of generation are lost it is essential to have this quick response available to the System Operator. Hence the utilising of OCGTs is done to meet total system demand; they may also be used to manage power transfer to the Cape. This may become an issue during Koeberg single or zero unit operation, as well as during certain transmission outages.

TABLE 39: OCGT ASSUMPTIONS

OCGT Assumptions	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Total OCGT Fuel burn cost (Rm)	4 303	4 601	867	936	1 009	1 086	1 169	1 160
Total OCGT Production (GWh)	1 328	777	211	211	211	211	211	189

5.16.4 OCGT fuel costs

The price of the mix of gas fired stations was at the ruling rate of 5 February 2020. The price was then escalated with inflation parameters of 5.4 and 6% thereafter. There are monthly storage fees included for the fuel tanks where diesel stock are kept off site for Ankerlig and Gourikwa as well as provision made for any possible demurrage fees that might occur.

TABLE 40: BASE FUEL PRICES

Prices at 5 February 2020	Rands
Port Rex Kerosene	5.58
Acacia Jet A1	11.42
Gourikwa	14.03
Ankerlig	14.03

TABLE 41: STORAGE AND DEMURRAGE FEES

Storage & demurrage fees (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Demurrage fees	13	14	15	16	17	18	19	20
Gourikwa storage	11	37	34	36	39	41	43	46
Ankerlig Storage fees	35	38	47	50	53	56	59	67
Total	**59**	**90**	**96**	**102**	**108**	**115**	**121**	**132**

TABLE 42: STATION FUEL PRICES CALCULATIONS

Fuel Prices (R/litre)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Acacia ruling price	11.42	12.04	12.69	13.45	14.25	15.11	16.02
Assumed fuel inflation	5.4%	5.4%	6.0%	6.0%	6.0%	6.0%	6.0%
Forecasted price Jet A1	12.04	12.69	13.45	14.25	15.11	16.02	16.98
Port Rex ruling price	8.58	9.04	9.53	10.10	10.70	11.35	12.03
Assumed fuel inflation	5.4%	5.4%	6.0%	6.0%	6.0%	6.0%	6.0%
Port Rex ruling price	9.04	9.53	10.10	10.70	11.35	12.03	12.75
Ankerlig & Gourikwa ruling price	14.03	14.79	15.59	16.52	17.51	18.56	19.68
Assumed fuel inflation	5.4%	5.4%	6.0%	6.0%	6.0%	6.0%	6.0%
Forecasted price diesel	14.79	15.59	16.52	17.51	18.56	19.68	20.86

The forecasted use of the OCGTs power stations reflects an estimated production of 211GWh per annum at an average of 18GWh per month. OCGTs require approximately 320 litres of diesel fuel to generate 1 MWh of electricity. The assumed load factor for FY2022 - FY2027 is an average of 1.05%.

From a costing perspective Generation currently receives a wholesale discount of about 30 cents per litre and a diesel rebate of R3.85 per litre on diesel volumes burnt for energy production at Ankerlig. At Gourikwa, the wholesale discount is 27 cents per litre and a diesel rebate of R3.85 per litre. Both these benefits are used to reduce to overall price paid per litre.

Understandably if either the rebate or wholesale discount changes over the next 5 years, the differences would need to be addressed.

5.17 Coal handling

5.17.1 Introduction to coal handling

Coal handling refers to all the activities that are necessary to get the coal to the boiler once it has been delivered to the power station.

The cost elements are fuel/diesel for white/yellow plants, strategic stock pile maintenance, coal reclamation, labour & machinery such as bobcats, bulldozers, rollers, tippers, etc. (vehicles which are known as yellow and white plant). Refer to the table below for the split of the costs. Cost for the MYPD5 period are R7 444m.

Coal handling cost elements:

- Labour costs depend on how many people, what they do. Contractor labour inflation assumptions are contained in the level service agreement (SLA) of each station and are negotiated centrally for the whole Generation fleet of stations to obtain better rates.
- White plant includes LDV (Leyland DAF Vans) used to transport spares and tools. In addition, buses are used to transport employees on-site and home-work-home.
- Yellow plant entails machinery such as bull dozers for moving coal between piles, front end loaders pushing coal onto piles and for loading coal into mobile feeders, dump trucks for moving to coal to various and difficult areas. Some other machinery includes, tipper trucks, motor graders, water trucks etc.
- Fuel and diesel for yellow and white plants.

TABLE 43: COAL HANDLING COSTS

Coal handling assumptions (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Labour (60%)	1211	1273	1412	1488	1439	1539	1634	1686
White & Yellow (25%)	504	531	588	620	600	641	681	703
Fuel (15%)	303	318	353	372	360	385	409	422
Total	**2018**	**2122**	**2354**	**2480**	**2399**	**2564**	**2724**	**2810**

5.17.2 Coal Handling Costs over the MYPD5 Period

Inflation related increases are experienced at most power stations.

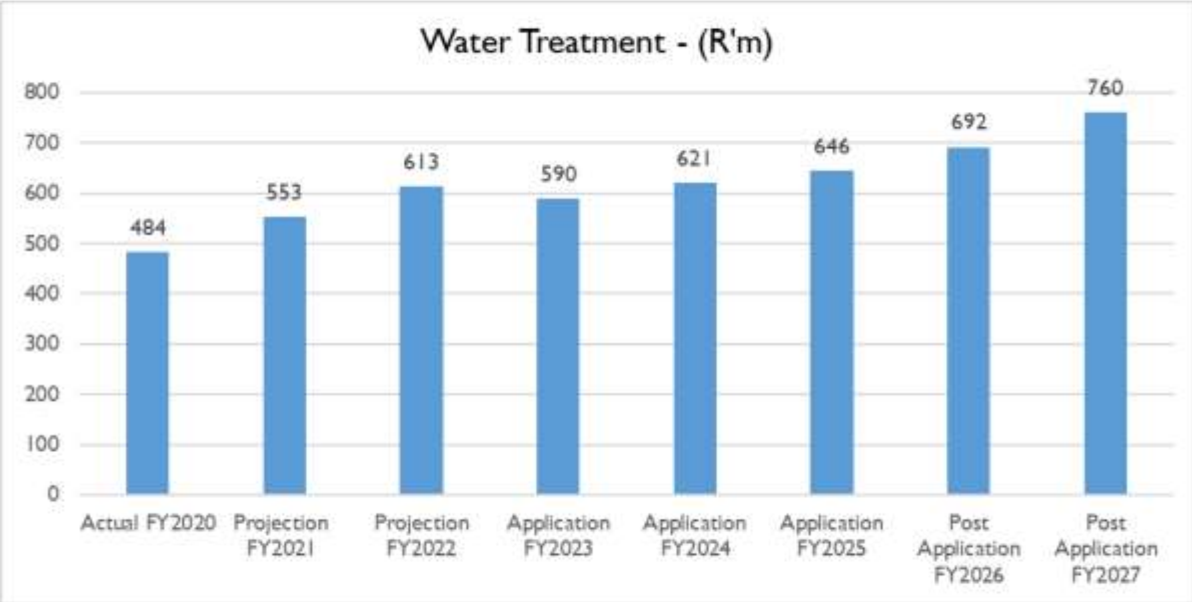
Coal handling costs have a CAGR of 1.7% for the MYPD5 period (FY2023 – FY2025), which is a well below inflation.

5.18 Water treatment

The quality of water from the various sources impacts on the water treatment costs. The main drivers of water treatment costs are the cost of the chemicals used to treat the water including the purchase of materials such as ion exchange resins, membranes, and other and small instruments written-off on purchase.

The figure below demonstrates the Water Treatment trend.

FIGURE 34: WATER TREATMENT COSTS



Water treatment costs have a CAGR of 0.3% for the MYPD5 period (FY2023 – FY2025), which is significantly below inflation.

5.19 Start-up gas & oil

Gas and oil (coal-fired start-up) costs are incurred when purchasing the heavy fuel oil used for start-up and shut down of a coal-fired power station and stabilises the boiler flame on occasion e.g. when operated at low load. The start-up fuel is also used during emergencies to prevent the flame from extinguishing, for example during unit trips or if the coal supply is interrupted or unstable.

There are three different purposes for the fuel oil plant installed at Eskom's power stations, namely boiler start-up, mill start-up and coal firing support.

Each power station's fuel oil plant will need an offloading and storage plant, fuel oil preparation and pumping station as well as the oil burners and associated pipework installed at the boilers.

Eskom uses a variety of different fuel oil plant designs. This condition exists due to the era when the Power Stations were designed, different OEMs and the recommended technology at the time. Consequently, different Power Stations have different designs, although many are fairly similar to one another. Similarly, the fuel oil type used at each station may be different and Eskom stations use three different grades of fuel oil.

The oil burners are located either within the coal burners or adjacent to the coal burners, depending on boiler design. The location of the oil burners allows for easy ignition of the coal flame as well as being able to provide for heating of the boiler during a boiler start-up.

To ensure safe operation, the oil burners are designed to deliver an energy input which is between 8% and 20% of the associated coal burner energy input. To achieve this, a typical 600MW power station would have an oil burner that could provide an energy input of between 7 MW and 12 MW. To provide this energy, the fuel oil flow rate would be between 600 kg/h and 1028 kg/h. At Eskom's power stations, similar philosophies are applicable and due to the size differences, oil burner sizes range from 350 kg/h to 1900 kg/h.

For a 600 MW boiler, the following approximate fuel oil consumption could be expected.

a) Start-up:

- Cold (when the unit has been shut down for an extended period, which varies from plant to plant) – 100 tons. If testing is required, this value could increase substantially.
- Hot (only shut down for a short time – this also varies from plant to plant) – 50 tons.

b) Mill changes (start-up or shutdown of a mill):

- 1.5 tons per activity.

c) Combustion support to ensure that there is sufficient combustion in the boiler during operation:

- This can vary substantially and depends on the length of time that the support is required. Different power station designs may influence the frequency of need for this support.
- Reasons for combustion support include:
  - Poor combustion which could include coal outside of design requirements.
  - Soot blowing activities.
  - Ash removal activities.
  - Low load operation.

- Boiler disturbances.

All power stations receive their fuel oil via road tankers from the suppliers. The offloading plant consists of pumps that draw the fuel oil from the road tankers via a flexible hose, associated pipework, strainers and flow meter, and deliver the fuel oil to storage tanks. For the lighter grade 1 and 2 fuel oils, no heating system is provided, whereas for the grade 3 fuel oils, a heating system is located within the storage tank at the tank outlet. The heating system for grade 3 fuels is needed to allow for the fuels viscosity to be controlled at a value that allows for proper handling of the fuel.

Start-up gas and oil prices are very difficult to predict because fuel oil and gas prices are difficult to forecast accurately as they are extremely volatile. The key reasons for this is that the fuel oil price is dependent mainly on the Rand/Dollar exchange rate. The international Dollar price of crude oil fluctuates on a daily basis, hence it is difficult to predict.

The tale below that shows assumptions for the two factors that influence the cost for the start-up gas & oil - unit prices (linked to Rand/Dollar exchange rate) and quantities (litres of diesel and gas (kg). The latter are influenced by production requirements at the stations. In FY2023, there is a reduction of about 18 million litres, yet there is a cost increase of R153m, because of the price increase per litre from R7.46 to R8.07. From the above one can appreciate why prices are volatile because of exchange rate fluctuations and how they can influence the costs.

TABLE 44: GENERATION START-UP FUEL

Generation start-up fuel (R'm)	Units	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Total Start-up fuel oil	MLitres	547	476	438	419	379	382	385	393
Average Cost R/Litre	R/L	7.24	6.39	8.01	8.86	8.02	8.25	8.58	8.86
Total Cost	**R'm**	**3 960**	**3 039**	**3 508**	**3 712**	**3 039**	**3 151**	**3 306**	**3 484**

The figure below indicates the trend in start-up gas & oil over the MYPD5 period. In FY2023, the increase in costs is influenced by estimated fuel price increases while the volumes are reducing mainly due to a drop of 18 676218 litres because of stations (Camden, Grootvlei and Hendrina) in reserve storage. This is off-set by the increase in volumes of 6.7m from Kusile Power station that will have an additional unit in commercial operation.

The decrease in cost in FY2024 is explained by the reductions in volumes (41 million litres) from Camden, Hendrina and Grootvlei as they are ramping down. Overall, this reduction in volumes has resulted in cost decrease of R620m from these stations. Overall, this is a 17% decrease from FY2023. The slight increase from FY2024 to FY2025 is caused by a slight increase of 2 million litres in volumes, but because of the price increase from R8.02 to R8.25, the overall cost has increased by R112m. This is a 4% increase, which is below inflation.

FIGURE 35: START-UP GAS AND OIL COSTS

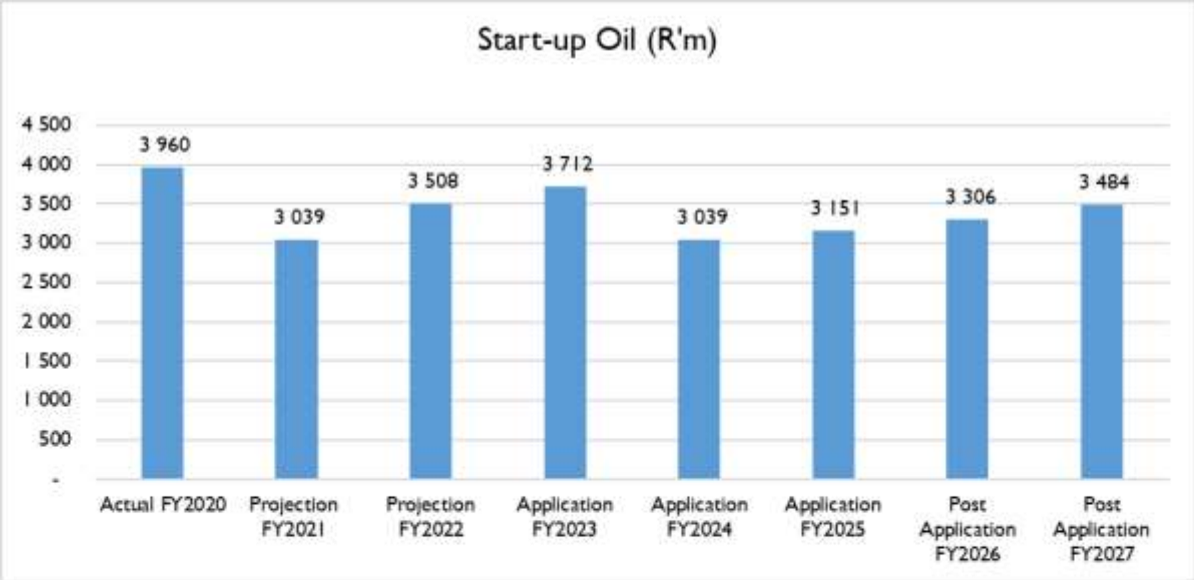


FIGURE 36: START-UP GAS AND OIL VOLUMES

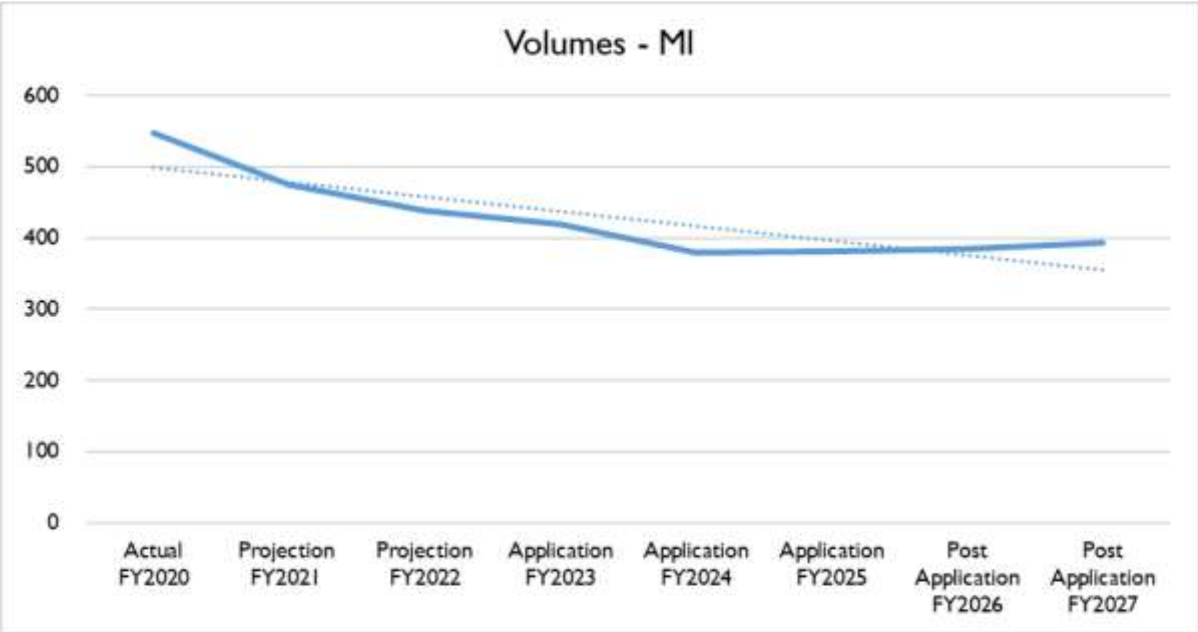


FIGURE 37: START-UP GAS AND OIL RAND/LITRE

As previously noted, the fuel oil and gas prices are difficult to forecast accurately as they are very volatile. The key reasons for this are that the fuel oil price is dependent on mainly the Rand/Dollar exchange rate and the international dollar price of crude oil on a daily basis and it is therefore difficult to predict. Despite this fact, Generation has demonstrated efforts to reduce costs by ramping down on old power stations that consume higher volumes and thus result in high start-up gas and oil cost. The volumes are on the downward trend and price fluctuations are the ones that cause slight increases in the cost. The overall trend (FY2020 to FY2027) shows a decrease in volumes but an unfortunate forecasted price increases, this will in a resulting in a higher cost. This is demonstrated by the figures above – refer to Volumes that reduced from 547ML (FY2020) to 393ML (FY2027) resulting in a reduction of 173 108ML of oil. This is 39% reduction in volumes and demonstrates efficiency. Generation, unfortunately cannot import raw materials or exchange rates for that matter as we are price takers. The same trend applies for the MYPD5 period i.e. FY2023 to FY2025, where volumes are assumed to drop from 419ML to 382ML, a reduction of 37ML of oil. This is a 9% reduction demonstrating efforts to remain efficient.

5.19.1 Conclusion on Start-up Gas and Oil

Start-up Gas and Oil costs have a CAGR of -7.20% for the MYPD5 period i.e. (FY2023 to FY2025), which is a negative growth in cost. If the Virtual Station (see Section 4.7) is excluded, the CAGR is -6.6% which is still a significant negative trend.

5.20 Environmental levy

5.20.1 Introduction

The Customs and Excise Act, 1964 promulgated in July 2009 that the generation of electricity from Non- Renewable generators is liable to pay an Environmental Levy. The Government Gazette No 32309 dated 01 July 2012 set the rate at 3.5 c/kWh on the generated volume. All Generation generators with the exclusion of Hydro and Pumped Storage Power Stations were registered and licenced as manufacturing warehouses as required by legislation.

5.20.2 Process

According to the Act, the owner of the “Manufacturing Warehouse” is accountable for the compliance to the Act. In Generation’s case it is the Power Station Manager of each Power Station. With twenty different sites liable for the payment of the Environmental Levy it is necessary to manage, consolidate and plan on a centralised basis to ensure full compliance from all participants. Each Power Station has procedures in place which govern this process. The Act requires the appointment of a Responsible Person. Power Station Managers are required to appoint a Production Manager and a Financial Manager in writing as Responsible for full compliance to all aspects of the process.

5.20.3 Planning

The first principle of this application is that it must be fully aligned with the official approved Generation sales volumes. The Generation Production Plan is the only source that could be used as a prudent source of the volume applicable which is liable for the payment of the Environmental Levy. The Production Plan takes cognisance of all supply requirements such as imports and IPP supply and then on a least cost methodology allocate supply to Generation generators to meet the Generation sales predictions.

Power Station volumes as expressed in the Production Plan are measured at the bus bar of each Power Station where it is exported onto the Transmission grid. The common terminology used for energy at this point is “Energy Sent Out” (ESO).

Since the Act imposes the Environmental Levy on generated volumes as measured at the generator of the Power Station one needs to derive the difference between generated energy and sent out. This difference in volume is the energy consumed by the Power Station (also known as auxiliary consumption) which is not available to be exported onto the grid.

This auxiliary volume is expressed as a percentage of sent out energy known as the Aux % of a Power Station and ultimately added to the sent out energy as expressed in the Production Plan. The result is the gross generated volume on which the Levy is calculated and which is fully aligned with the overall Generation approved sales plan.

The auxiliary consumption of the Power Station is for unit auxiliary equipment, common plant such as lighting and lifts, and outside plant such as conveyer systems, admin buildings, laboratories, stores, security, and water and ash plants.

The Aux % for each Power Station is different and fluctuates from hour to hour. Auxiliary equipment differs between generators. There is little direct short-term correlation between Aux % and energy sent out at a Power Station. The Auxiliary consumption on common plant does not reduce linearly when the production from one or more of the units reduces or stops due to planned or unplanned events. This variability will therefore mostly result in variances between a Power Station's estimated Auxiliary consumption and the actual volumes consumed.

The Aux % used in this submission is aligned to the FY2020 and FY2019 actuals. The system Aux % should not be seen as a constant. Variances in individual Power Station Aux %, as well as variances in ratio of production between Power Stations and between renewable / non-renewable sources will result in Levy cost variances.

TABLE 45: ENVIRONMENTAL LEVY CALCULATIONS

Environmental Levy	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Acacia	0	1	0	0	0	0	0	0
Ankerlig	809	529	126	128	128	128	128	115
Gourikwa	519	391	85	83	83	83	83	77
Port Rex	0	1	0	0	0	0	0	0
Koeberg	13 252	10 804	11 850	12 562	13 631	12 468	13 295	14 566
Kusile	3 041	8 002	10 662	11 818	15 124	19 687	16 789	15 123
Medupi	15 675	17 543	21 996	23 278	23 073	23 443	22 633	22 274
Duvha	10 649	11 375	8 712	9 263	9 050	8 060	6 161	5 790
Kendal	17 187	14 342	17 124	16 502	16 416	16 448	15 915	13 684
Lethabo	18 888	21 179	21 682	20 939	19 928	18 994	18 308	17 647
Majuba	22 089	19 516	19 225	16 273	17 431	15 405	15 817	15 614
Matimba	26 704	22 982	22 789	21 732	20 636	19 687	19 167	18 302
Matla	19 888	17 038	16 956	16 708	16 274	14 682	14 670	12 784
Tutuka	12 130	10 728	8 297	8 296	8 420	4 739	4 841	4 768
Arnot	10 713	9 582	7 492	7 229	6 595	5 601	0	0
Camden	5 847	4 453	5 480	2 140	0	0	0	0
Grootvlei	2 478	2 825	2 636	0	0	0	0	0
Hendrina	4 785	4 209	4 253	2 583	0	0	0	0
Komati	1 581	617	431	0	0	0	0	0
Kriel 1_3 (UG)	6 740	5 015	4 780	3 882	0	0	0	0
Kriel 4_6 (OC)	7 212	6 322	5 954	5 969	5 835	5 775	5 534	5 542
Kusile Pre-Comm	0	0	0	2 605	4 417	711	0	0
Medupi Pre-Comm	0	0	0	0	0	0	0	0
Virtual Station	0	0	0	-7 973	-12 775	-10 487	-9 896	-5 039
Total Non-Renewable energy sent out	200 187	187 454	190 529	174 017	164 264	155 423	143 446	141 249
Add: Auxilliary volumes (GWh) [b] =	17 333	14 419	16 031	14 834	14 100	13 333	12 283	11 942
Generating volumes [c] = [a + b]	**217 519**	**201 873**	**206 560**	**188 850**	**178 364**	**168 756**	**155 729**	**153 191**
Rate in c/kWh [d]	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Generation levy cost (Rm) [e] =	**7 613**	**7 066**	**7 230**	**6 610**	**6 243**	**5 906**	**5 451**	**5 362**
Average Effective Aux % = [b] /[a]	8.66%	7.69%	8.41%	8.52%	8.58%	8.58%	8.56%	8.45%

Notes:

- **Station specific Aux % were considered in calculating the Environmental Levy Amount.**
- **No increase in the Environmental Levy Rate of 3.5 c/kWh is assumed during the MYPD5 period.**
- **Matla's Aux % was used as a proxy for the Virtual Station (See Section 4.7).**
- **Environmental Levy on pre-commissioned energy expensed in Income Statement from FY2023 onwards in alignment with relevant accounting standards.**

5.21 Carbon Tax

The carbon tax has been introduced by National Treasury, in addition to the existing environmental levy on the generation of electricity from non-renewable resources.

TABLE 46: CARBON TAX LIABILITY CALCULATION FOR GENERATION

Carbon dioxide emissions*	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Acacia	0	1	0	0	0	0	0	0
Ankerlig**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gourikwa**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Port Rex	0	1	0	0	0	0	0	0
Kusile	3 987	8 002	10 662	11 818	15 124	19 687	16 789	15 123
Medupi	10 600	16 193	20 302	21 485	21 296	21 638	20 890	20 559
Duvha	7 355	12 706	9 731	10 347	10 109	9 003	6 882	6 467
Kendal	11 551	16 852	20 120	19 389	19 289	19 327	18 700	16 079
Lethabo	10 570	22 852	23 395	22 593	21 502	20 494	19 755	19 042
Majuba	17 703	24 473	24 108	20 406	21 858	19 318	19 835	19 580
Matimba	14 565	22 844	22 652	21 602	20 512	19 569	19 052	18 192
Matla	14 446	20 190	20 093	19 799	19 284	17 398	17 384	15 149
Tutuka	9 193	13 163	10 180	10 179	10 332	5 814	5 940	5 851
Arnot	7 077	12 418	9 709	9 369	8 548	7 258	0	0
Camden	4 530	6 128	7 540	2 945	0	0	0	0
Grootvlei	1 874	4 080	3 806	0	0	0	0	0
Hendrina	3 683	5 805	5 865	3 562	0	0	0	0
Komati	1 084	849	594	0	0	0	0	0
Kriel 1_3 (UG)	10 189	6 148	5 860	4 760	0	0	0	0
Kriel 4_6 (OC)	0	7 751	7 299	7 318	7 153	7 080	6 785	6 795
Kusile Pre-Comm	0	2 351	0	2 605	4 417	711	0	0
Medupi Pre-Comm	0	1 736	478	0	0	0	0	0
Virtual Station (coal fired average 1.2 tonnes CO_2/MWh)	0	0	0	-9 607	-15 394	-12 637	-11 925	-6 071
Total qualifying carbon dioxide (CO_2) emissions (kilotonnes)	128 408	204 542	202 396	178 570	164 029	154 661	140 087	136 765
Multiply: tax-free allowances*** (60% for category 1A1a)	89 719	122 725	121 438	107 142	98 417	92 797	84 052	82 059
Net emission equivalent [c] = [a] - [b]	**38 689**	**81 817**	**80 958**	**71 428**	**65 612**	**61 864**	**56 035**	**54 706**
Carbon tax rate in R/tonneCO_2eq [d]*****	120	127	134	144	152	161	170	181
Carbon tax rate in R/tonneCO_2eq [e]*****	127	134	144	152	161	170	181	192
Gross carbon tax levy liability (Rm) **[f] = [[0.75 x [c] x [d]] + [0.25 x [c] x [e]]]/1000**	**4 642 730**	**10 534**	**11 051**	**10 428**	**10 121**	**10 099**	**9 680**	**10 052**
Additional deductions to "generators of electricity from fossil-fuels" [g]	Environmental levy paid; Renewable premium calculated on REIPPPP volumes			0 from 1 January 2023 (last 3 months of the FY)				0
Net carbon tax levy liability after deductions (Rm) **[h] = [f] - [g]**	**0**	**0**	**0**	**2 714**	**10 121**	**10 099**	**9 680**	**10 052**

*** Station-specific emission factors (tonnes CO2/MWh sent out) were utilised (excluding additional greenhouse gases of nitrous oxide (N2O) and methane (CH4) which are reported to the Department of Environment, Forestry and Fisheries and which also incur the "carbon" tax. The addition of these gases adds roughly 0.5% to the gross CO2eq emissions. Comprehensive station-specific emission factors are being developed for future use.**

**** Ankerlig and Gourikwa utilise diesel. Greenhouse gas emissions for diesel are taxed at source (i.e. included in the fuel costs).**

***** Currently category 1A1a emissions have a 60% basic tax-free threshold. Additional allowances for carbon budgets (5%) and trade (4.87%) may or may not be accessible to Generation in future years as the regulations for carbon budgets will only be gazetted after the Climate Change Bill is enacted.**

******* Tax rate increases from R120/tonneCO2eq in 2019 by CPI+2% per annum until 31 December 2022 and then it increases at CPI per annum thereafter.**

******* The tax liability in a financial year will attract two different rates (emissions from 1 April to 31 December will be at one rate and emissions from 1 January to 31 March will be at another rate) hence when applying the calculations to the FY volumes, the two rates are applied to three quarters and then the remaining quarter (0.75 and 0.25).**

5.21.1 Activities subject to the tax

The Carbon Tax Act, no 15 of 2019 came into effect from 1 June 2019. This Act provides for the imposition of a tax on the greenhouse gas emissions of a company (expressed in carbon dioxide equivalents (CO2eq)) and matters connected therewith.

There is a popular misconception that Generation is exempt from the tax which is not true. A taxpayer is liable "if that person conducts an activity in the Republic resulting in greenhouse gas emissions above the threshold determined by matching the activity listed in the column ''Activity/Sector'' in Schedule 2 of the act, with the number in the corresponding line of the column ''Threshold'' of that table. Generation currently conducts two activities listed in Schedule 2 where the corresponding threshold is exceeded. These activities are 1A1a (Main Activity Electricity and Heat Production) and 1A3a (Domestic Aviation). It has also been proposed in the Budget Review 2021; that an additional category (2G1b) for "use of electrical equipment" should be added effective 1 January 2021.

5.21.2 Emissions data

The tax base should be the sum of emissions over the preceding calendar year - determined either according to a reporting methodology approved by the Department of Forestry, Fisheries and Environment (DFFE) or determined in accordance with the formulas and input values provided for in the act. Since 2017, Generation already reports greenhouse gas emissions to DFFE using an approved "Tier 3" methodology, as required by the National Greenhouse Gas Reporting Regulations of 3 April 2017 (notice no 40762). However, the DFFE has recently published Technical Guidelines for the Validation and Verification of Greenhouse Gas Emissions. Should there be any question as to the veracity or validity of Generation's reported GHG emissions to DFFE, the South African Revenue Service will require Generation to submit the tax declaration using default emission (Tier 1) factors listed in Schedule 1 of the Carbon Tax Act instead. Using the default emission factors would result in higher reportable emissions.

5.21.3 Tax rate

The tax rate was introduced at R120/tonne CO_{2eq} but the act specifies that the tax must escalate at CPI+2% during phase 1 of the tax (i.e. for 2020, 2021 and 2022) and then at CPI thereafter. For 2021, the Budget Review indicated that the carbon tax rate is now R134/ tonne CO_{2eq}.

5.21.4 Allowances

- Schedule 2 of the Carbon Tax Act also lists the categories and maximum percentages of "tax-free allowances" that tax payers may claim against each type of activity. These are listed in the table below for the three activities for which Generation is currently liable. While the table indicates that emissions from category 1A1a are able to receive a maximum of 90% total "tax-free" allowances, not all of these allowances are accessible.

- According to the published trade-exposure regulations (GG no. 43451), under the Standard Industrial Classification (SIC) code of 411, the production, distribution and collection of electricity qualifies for only 4.87%.

- According to the published performance allowance regulations (GG no. 43452), there is no performance benchmark provided for the electricity sector or the domestic aviation sector and therefore no allowance can be claimed.

- The carbon budget allowance is expected to be phased out after 31 December 2022 (Budget Review 2021) and may also become inaccessible from 1 January 2021 as the pilot carbon budgets negotiated with DFFE expire on 31 December 2020, depending on the interim budget process and when the draft Climate Change bill and associated regulations (for mandatory carbon budgets) will be finalised.

- Lastly, the offset allowance requires that an entity purchase offset credits up to a maximum of 10%. Generation does not expect to purchase offsets during phase 1 of the carbon tax and **future purchases would only be undertaken if such expenditure was considered prudent** (i.e. if the cost of the purchases was equal to or less than the amount of carbon tax avoided).

TABLE 47: TAX-FREE ALLOWANCE CATEGORIES

IPCC code/ Emissions category	Basic tax-free allowance for fossil fuel combustion emissions %	Basic tax-free allowance for process emissions %	Fugitive emissions allowance %	Trade exposure allowance %	Performance allowance %	Carbon budget allowance %	Offset allowance %	Maximum total allowances %
1A1a	*60 – can be claimed*	*0*	*0*	*10 – 4.87% can be claimed for now*	*5 – no benchmark published, cannot be claimed*	*5 – can be claimed currently but the pilot carbon budgets allocated by DEFF expire on 31 December 2020*	*10 – requires an entity to purchase carbon offsets, up to a maximum of 10%*	*90 – however, only 60% (the basic allowance) can be assured at this time*
1A3a	*75 – can be claimed*	*0*	*0*	*0*	*5 – no benchmark published, cannot be claimed*	*5 – was not included in Eskom's pilot carbon budget and cannot be claimed*	*10 – requires an entity to purchase carbon offsets, up to a maximum of 10%*	*95 – however, only 75% (the basic allowance) can be assured at this time*
2G1b	*n/a*	*60 – calculation for process emissions to be checked for applicability*	*0*	*10 – gazette for trade exposure to be checked for applicability*	*5 – no benchmark published, cannot be claimed*	*5 – was not included in Eskom's pilot carbon budget and cannot be claimed*	*10 – requires an entity to purchase carbon offsets, up to a maximum of 10%*	*90 – however, applicability of various allowances to be confirmed given this is a new addition*

5.21.5 Additional deductions during Phase 1 (ends 31 December 2022)

The Carbon Tax Act allows Generation (as a "generator of electricity from fossil-fuels") to make two extra deductions from the carbon tax liability during "phase 1" of the carbon tax. These deductions are only allowed until 31 December 2022. The first deduction is equivalent to the renewable energy premium that has been paid in a tax period. This is calculated based on the renewable energy purchases in each category, multiplied by the gazette premium. The second deduction is equivalent to the amount equal to the environmental levy that has been paid in a tax period. For the first carbon tax declaration (October 2020), these two deductions have been sufficient to nullify the carbon tax liability. From 1 January 2023, when these deductions fall away, the full carbon tax liability is expected to be passed through.

5.21.6 Opportunities to reduce Generation's greenhouse gas emissions

Coal-fired power stations produce greenhouse gases as a by-product of the coal combustion process. Unlike the local air pollutants (Sulphur dioxide, nitrogen oxides and particulate matter), **there is currently no commercially-viable technology to capture carbon (either to store or for re-use) from large coal-fired power stations**. Hence, electricity sector greenhouse gas emissions are closely tied to electricity production from coal (and to a lesser extent gas) fired power stations. As the single largest contributor to South Africa's greenhouse gas emissions, achieving a national peak, plateau and decline scenario for the country is largely dependent on rapid decarbonisation of the electricity sector. Using 50-year end-of-life dates for Generation's coal-fired power stations, the most recent Integrated Resource Plan (2019) projected that 10 500 MW of plant would be decommissioned by 2030. Lower carbon options would be built to meet increasing demand (average annual growth rate of 1.21% to

2030), such that the share of coal-fired electricity production was expected to decline from around 81% currently to around 63% in 2030 with carbon dioxide (CO_2) emissions declining to around 215 Mtpa. It should be noted that **even with the absolute reduction of greenhouse gas emissions, a carbon tax will still be payable** given that the tax-free allowances are percentage-based.

5.21.7 Carbon tax/Carbon budget alignment

The carbon tax is one instrument that has been implemented to try and encourage a reduction in greenhouse gas emissions by providing a pricing signal to consumers. The Department of Environment, Forestry and Fisheries have also piloted another instrument in the form of a carbon budget. A carbon budget essentially provides a greenhouse gas emissions allocation to an emitter. The allocation rules for future carbon budgets are expected to be laid out in regulations and takes into consideration (amongst others) historical emissions, opportunities to reduce emissions in future and South Africa's international commitments. National Treasury and the Department of Environment, Forestry and Fisheries have committed to align these two instruments with a view to reducing the burden of compliance on industry and ensuring the efficacy of the instruments to reduce emissions. The format for this alignment has not yet been finalised. It is possible that the carbon budget could be used in a two-tier process that triggers an even higher carbon tax.

5.21.8 Phase 2 of the Carbon Tax (from 1 January 2023)

As it stands, the carbon tax liability arising in January 2023 is expected to result in an amount as reflected above.

5.21.9 Opportunities for reviewing the tax

National Treasury has made a commitment to review the carbon tax design after a minimum of 3 years of implementation (from June 2022). The scope of this review is yet to be determined – it may be limited to the tax rate only, or the number and size of the tax-free allowances. It is considered that such a review must take account of the actual national greenhouse gas emissions (in relation to South Africa's international commitment under the Paris Agreement) as well as the socio-economic impacts of the tax. There are opportunities to alleviate the socio-economic impacts while preserving the emissions reduction incentive. For example, in the carbon tax/budget alignment, the carbon budget could be annualised and used to substitute for the basic tax-free allowance. Alternatively, the deductions allowed to "generators of electricity from fossil fuels" could be extended into Phase 2 of the tax, given that the renewable energy power purchase agreements are 20-year agreements.

6 Operating Costs (Opex)

6.1 Introduction to Operating Expenditure

The Generation Licensee Operating Costs include Generation and Southern African Energy (SAE), which is responsible for the imports. Operating costs or Operational Expenditure (Opex) comprises three categories, namely Manpower, Maintenance and Other Opex. Also considered are Other Income and a pro-rata portion of Corporate Overheads. The compound average growth rate (CAGR) for Generation Operating Costs, including Corporate Overheads, for the period FY2023-FY2025, is -4.3%. This is a negative growth and far below inflation.

In order to meet its obligation to supply electricity, Generation must exercise due care in the operations and maintenance of its generation fleet. Based on the recent, current and projected trends of load growth, reserve margin, load factors, technical performance, forced outage rates and historical maintenance costs, the ages of the plants in service, future maintenance activities and costs can be planned.

The aim of this section of the document is to provide an overview of the operating costs projections required to support the Production Plan. Motivations and the explanations for the cost levels and the annual movements are provided. Included in the section are descriptions of the planning processes used to manage and thereby forecast Manpower, Maintenance and Other operating expenditure.

6.2 Key drivers of operating costs

6.2.1 Capacity expansion

Generation is still in the process of commissioning two new coal power stations. The last unit at Medupi and the remaining three units at Kusile are expected to be commissioned before the end of the MYPD5 period. Therefore, one can expect Generation's operating costs to increase by more than inflation over the period of the application.

6.2.2 Reserve storage stations

According to the Production Plan, at an overall assumed Generation fleet EAF of 72%, four and a half coal stations can be placed into reserve storage, as they will not be needed to produce electricity to meet the demand. The stations are Hendrina, Grootvlei, Komati, Camden and half of Kriel (UG). The "stress test" scenario which increases the current EAF up to 66.5% showed, however, that only 3 stations (Grootvlei, Komati and Camden) would not be required by the end of the MYPD5 period and should EAF be even less than the "stress test" assumptions, then all the stations could be required up to 2025. Therefore, at this stage, it is premature to decommission these stations and a decommissioning decision has not yet been made. Generation has, however, reduced the operating costs at these stations over the planning period to reflect a reduction in activities during a period of reserve storage.

6.2.3 Ageing fleet and high UCLF impact on maintenance costs

The existing operational fleet of power stations is now on average about 32 years old and more than half of the coal-fired fleet will be older than 40 years by the start of the MYPD5 period. Thus, a real increase in maintenance costs on this ageing fleet over their remaining life is expected due to additional maintenance activities and mid-life refurbishments on many power plants.

6.2.4 Insurance costs

An upward trend for the period FY2023-FY2025 in insurance costs is expected. This is typical for a generation fleet that has experienced high levels of unplanned outages that resulted in an increase in insurance premiums from a very low base. In addition, more assets will be under insurance, as the new units of Medupi and Kusile are commissioned.

6.2.5 Once-off abnormal items

There is only one once-of abnormal item that should be disregarded from the base when comparing MYPD5 application costs to historical costs.

6.2.5.1 Koeberg Decommissioning cost in FY2023-FY2025

The decommissioning provision of Koeberg has reduced the cost by R9.2bn. The adjustment is for the extension of Koeberg life expectancy from 40 to 60 years.

6.3 Summary of operating costs

TABLE 48: OVERALL SUMMARY OF OPERATING COSTS (EXCLUDING SAE)

Total Generation Operating Costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Manpower	10 283	10 887	11 291	10 968	11 367	11 813	11 643	11 501
Maintenance	9 958	11 327	13 602	14 029	13 233	13 910	13 223	13 155
Other Opex	8 279	8 608	7 128	8 687	3 951	5 261	8 781	8 846
Corporate Overheads	2 363	2 685	4 709	4 594	4 775	4 103	4 223	4 396
Other Income	(541)	(1640)	(397)	(427)	(449)	(470)	(308)	(308)
Total Generation Opex exc O/H	**30 342**	**31 868**	**36 333**	**37 851**	**32 877**	**34 617**	**37 562**	**37 590**
Corporate Overheads: portion excluded from revenue requirement			(266)	(245)	(270)	(289)	(272)	(272)
Total Generation Opex	**30 342**	**31 868**	**36 067**	**37 606**	**32 607**	**34 328**	**37 290**	**37 318**

TABLE 49: SAE OPERATING COSTS (R'M)

Operating costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses	27	26	27	33	36	41	46	49
Impairment loss	0	8	-	-	-	-	-	-
Other Operating expenses	1	6	9	8	10	10	11	11
Corporate Overheads	1	-	22	20	20	21	27	27
Total	**29**	**40**	**58**	**61**	**66**	**72**	**84**	**87**

The analysis below focuses on all other aspects of the Generation business except SAE.

The compound average growth rate (CAGR) for the period FY2023 to FY2025 for Generation operating costs including corporate overheads is -4.4%, while excluding corporate overhead for the same period is -4.2%, both of which are negative and below inflation.

The CAGR for the period FY2023 to FY2025 for Generation manpower costs is 3.8%, which is below inflation.

The compound annual growth rate (CAGR) for the period FY2023 to FY2025 for Generation maintenance costs, including Koeberg, is -0.425% which is way below inflation for the necessary costs to be incurred. The compound annual growth rate (CAGR) for the same period excluding Koeberg's maintenance cost, is -1.83%. This demonstrates that the cost of maintenance has remained flat for the MYPD5 period, proving Generation remained committed to do more with less (prudent).

The CAGR, for Other Opex, excluding Koeberg Decommissioning Provision for the period FY2023 to FY2025 is 3.9%. CAGR for the Total Net Other Opex for the same period is -22.7%. If both decommissioning and environmental costs are included, the CAGR is -24.5%. The above shows that the costs, in real terms, are coming down.

6.4 Manpower

6.4.1 Generation's Turnaround Strategy

Manpower costs fall under the ambit of Generation's Turnaround Strategy, which amongst other objectives, aims to address the financial challenges faced by Generation in the short to medium term. Reducing the cost base is one of the initiatives undertaken in the aim to address the financial challenges, which encapsulates Headcount and Employee Benefit cost reductions.

It should also be noted that the Functional and Legal Separation of Eskom into three legal entities also forms part of the Turnaround Strategy and has a direct impact on Generation's headcount.

As part Generation's organisational restructuring and Divisionalisation process, employees in service and support functions were re-linked back to line functions. The aim of this process was to:

- Strengthen operations and maximise decision making;
- Improve levels of accountability at the right levels of business;
- Improve operational and financial efficiencies;
- Maximise execution of strategy; and
- Improve productivity and value delivery - shortest sustainable lead time.

Employees from Technology, Risk and Sustainability, Procurement, Finance, Security, Environmental Management, Safety, Quality, Properties, and Human Resources – Generation Academy of Learning, were relinked to Generation; commenced in FY2019 and concluded in FY2021.

6.4.2 Generation Licensee Headcount

Manpower costs are predominantly driven by headcount numbers.

The headcount numbers of Generation for the MYPD5 period are as follows:

TABLE 50: GENERATION HEADCOUNT (EXCLUDING SAE)

Headcount Number	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Generation Licence Total Headcount	13 620	13 076	13 042	12 724	12 427	10 654	10 654
Y-o-Y Movement		-4.0%	-0.3%	-2.4%	-2.3%	-14.3%	0.0%

As alluded to previously, these reductions is based on a short to medium term strategy to reduce Generation's cost base. This is aimed to be achieved through normal attrition, supported by limited recruitment (up to 15% of attrition) and voluntary separation packages (as and when funding is available).

6.4.2.1 Comparison with International Norms

Generation's own further research, based on published US Government data, indicates that the ratio of generation plant capacity per employee for US coal power stations is around 3.38MW per employee.

Over the MYPD5 period, Generation's coal fleet ranges between 3.84MW per employee and 4.03MW per employee. This compares favourably to US coal power stations, to the extent that it could be viewed as a bit aggressive from Generation (in terms of headcount targets) in order to support the strategy of reducing its cost base.

6.4.2.2 Risks Associated with Headcount Reductions Norms

In pursuit of headcount reduction, the following risks have been identified that will require management thereof:

- **Negative impact on Generation operations:**

Following the loss of other critical skills through normal attrition and non-replacement thereof, there are certain vacancies that remain critical without which the operations within the generation business have been negatively impacted.

- **Unintended loss of core and critical skills:**

The headcount reduction, if not properly managed, could result in the loss of critical skills that should in fact be retained.

- **Increased Costs:**

Loss of core skills and expertise may negatively impact on operations which could result in higher costs.

- **Unachieved Employment Equity Targets:**

Unrealistic employment equity targets that are pushed without consideration of headcount targets and current core and critical resources requirements.

- **Low Employee Morale:**

Pursuit of headcount reduction resulting in the non-replacement of critical positions may lead to employees assuming multiple roles and conflicting work demands may cause low staff morale and fatigue.

6.4.2.3 Conclusion on Headcount Numbers

Generation's headcount numbers are in line with World norms, if not erring on the side of being a bit aggressive due to financial constraints. It should also be borne in mind that overly aggressive headcount reductions poses operational and financial risks to the Generation business which need to be managed.

6.4.2 Employee Benefits Costs

The aforementioned headcount numbers result in the following Employee Benefits costs:

TABLE 51: GENERATION EMPLOYEE BENEFIT COSTS (EXCLUDING SAE)

Employee Benefit Costs (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Generation Licence Total Employee Benefit Costs	10 887	11 291	10 968	11 367	11 813	11 643	11 501
Y-o-Y Movement		3.7%	-2.9%	3.6%	3.9%	-1.4%	-1.2%

The movement in EB costs from FY2021 to FY2027 represents a Compound Annual Growth Rate (CAGR) of 0.9% and over the MYPD5 period CAGR is 3.8% which is below CPI.

This is primarily attributable to a targeted headcount reduction.

Employee expenses are inclusive of cost to company remuneration and other employee related expenditures such as the skills levy, workman's compensation contributions, training, professional fees, overtime, contingency travel costs as well as labour recoveries for capital projects. The employee benefit costs for staff working on capital projects are directly allocated to the respective projects (capitalised) and recovered over the life of the capital asset through amortisation when the asset is depreciated. These costs are therefore excluded from the Employee expenses costs.

The need for fundamental operational changes is recognised in order to provide affordable, sustainable electricity supply to all South Africans. Efficiency opportunities have also been pursued to ensure that the headcount increase is contained utilising natural attrition and voluntary separation options to drive internal efficiencies, increase productivity and lower operating costs.

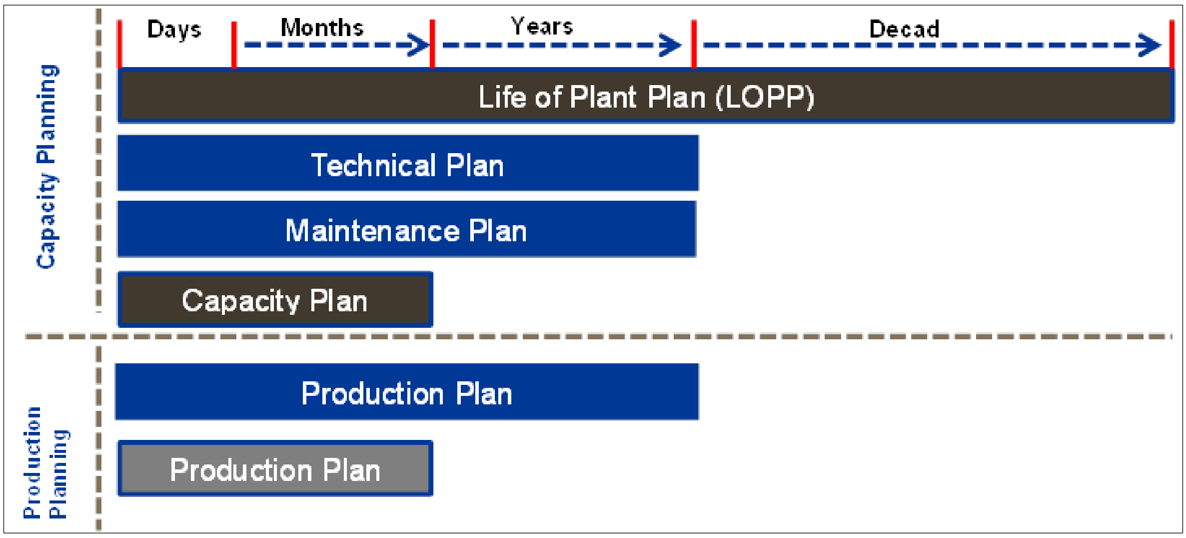
6.5 Maintenance cost

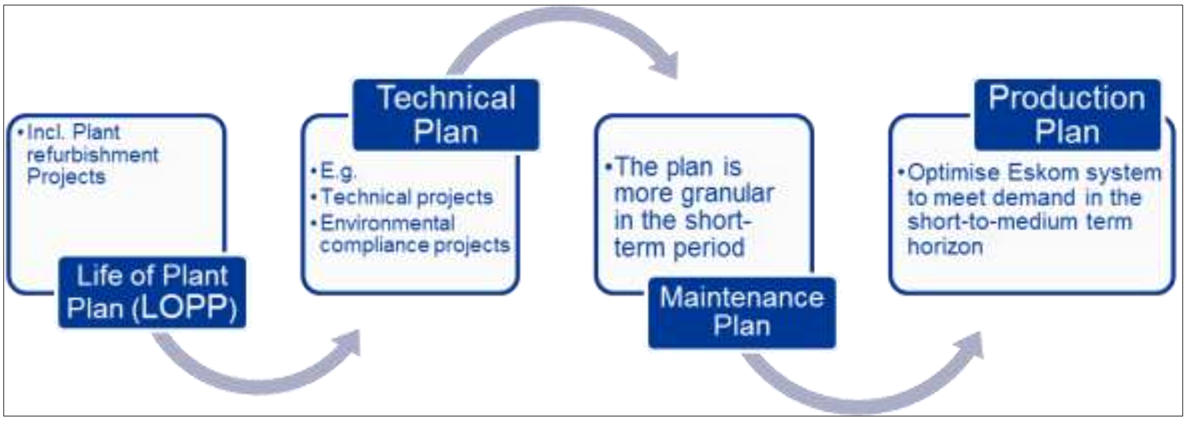
6.5.1 Introduction

Generation applies asset management principles which include planning on how to ensure the optimal operating and maintenance of the existing fleet for the duration of its economic life, including inputs such as primary energy and major refurbishments. Planning for the operating and maintenance of the fleet can be separated into Maintenance Planning and Production Planning.

Maintenance Planning is informed by what maintenance needs to be performed, in terms of replacement/refurbishment of components of the assets as well as the routine outage maintenance activities. The Life of Plant Plan (LOPP), details these major maintenance and refurbishment projects that are required over the life of the plant. The Technical Plan is a more refined extract of the LOPP over a shorter period and the Maintenance Plan is a listing of the outages required to implement the LOPP and Technical Plans. The Capacity Plan then takes a detailed view of the first year of the Maintenance Plan to ensure that all required outages are scheduled whilst ensuring there is adequate capacity available to meet demand. Production Planning describes how the required energy demand is to be met on an hourly basis whilst maintaining least-cost dispatch within known constraints.

FIGURE 38: MAINTENANCE PLANNING OVERVIEW





The LOPP is a plan of major maintenance and refurbishment interventions that are required over the full life of the station. Generation uses a plant-aged assumption for long term planning including the Generation expansion, financial and Life of Plant Plans (LOPP), however, the actual life is not determined by age but the economic viability. Currently, 50 years for the coal fleet is used for planning purposes.

The LOPP is based on a codified preventive maintenance strategy for each power station. This prescribes what maintenance interventions are required at what periodicity as well as the standard maintenance activities required.

Stations have specific requirements with respect to the numerous cyclical maintenance interventions required on a power plant. However, generic rules exist:

- General Overhaul (GO): Every 10 – 12 years plant shutdown to do inspection and repair of turbine & generator.
- Mini GO: Every 5 - 6 years inspection of low pressure turbines, and statutory pressure test.
- Interim Repair (IR): 18 – 36 monthly plant is shutdown to inspect and repair the boiler components.
- Boiler Inspection (IN): Between IR's an inspection is carried out to review condition of the boiler and scope the next outage.

Opportunity maintenance frequently leads to the above schedule being modified which gives rise to adaptions of the sequence, but every effort is made to recover the sequence to ensure plant safety and operability.

Maintenance activities are prioritisation by scheduling outages according to the following priority:

- Immediate safety risk as per Emergency Response Action Plan (ERAP) inclusive of any emerging technical threat which is deemed to pose immediate and significant personnel or plant risk.
- Statutory such as pressure tests.
- Licence to operate' risks such as major contraventions of legislation.
- Philosophy/Reliability scope is included in the outages based on the durations available.

Maintenance costs are primarily a function of the amount of maintenance and the cost of each maintenance activity. The amount of maintenance is influenced by factors such as capacity added to or removed from the system, the age of plant and maintenance activities are determined by the maintenance planning process.

The compound annual growth rate (CAGR) for the MYPD period FY2023 to FY2025 for Generation maintenance costs is -1.83%, which is negative growth and below inflation. This is mainly due to the reduction in maintenance costs at the reserve storage stations, partially offset by increased maintenance costs at Medupi and Kusile as new units are brought into commercial operation and extra ordinary extended outages with PCLF of 130 and 180 days, LTO (Long-term outages) modifications of 90 days at Koeberg in order to extend its life expectancy from 40 to 60 years, which will add maintenance costs to the Generation fleet base during the MYPD5 period.

6.5.2 Key drivers of maintenance costs

The aging of Generation fleet assets and the recent load-shedding incidents require an intervention to fix and maintain the Generating Plants. Some of the key maintenance activities are highlighted below

In FY2023-FY2025, maintenance costs are driven by Koeberg which is assumed to spend R5 153m cumulatively over the three year period. In FY2023 Koeberg will spend R1 705m due to extended outage of as a result of SGR (Steam Generator Replacement) - with scope of 130 PCLF impact. In FY2024, the station will spend R1 416m on an outage with a 90 days' PCLF impact catering for the LTO (Long-term Planned Outage) modifications and in FY2025, the station will spend R2 032m due to a longer outage for the implementation of the balance of the LTO and SALTO (Safety Assessments for Long-term Outage) with 140 PCLF impact coupled with it being a 10 yearly outage.

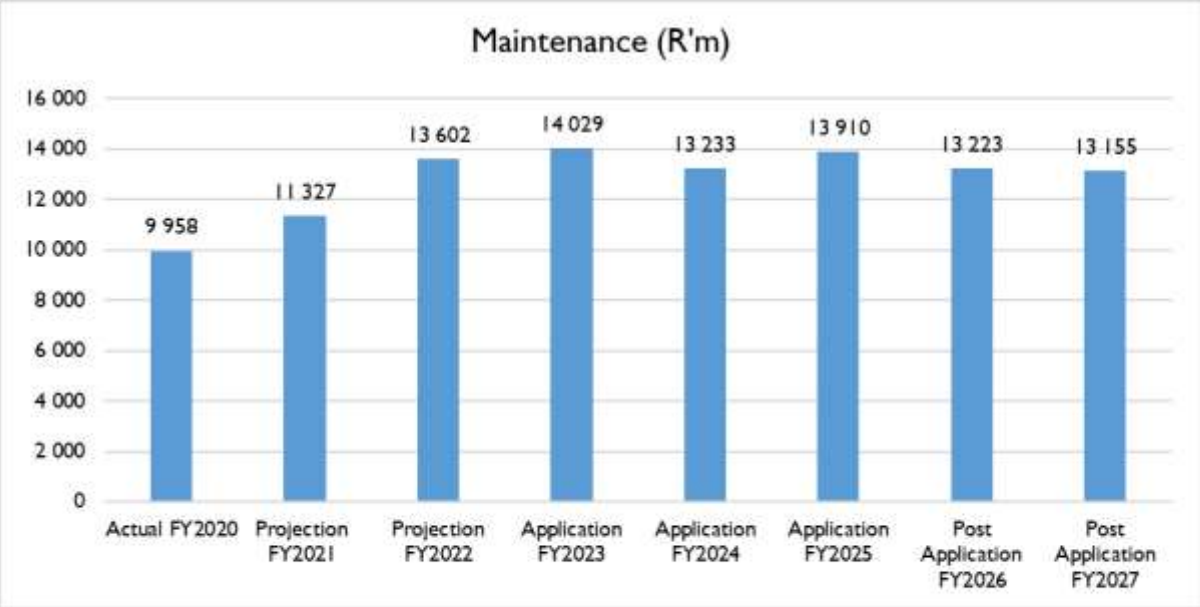
All these activities are reflected in the high maintenance cost of R5 153m in the MYPD5 period which is a 13% contribution of the total fleet. These outages and modifications are necessary costs to be incurred in order to increase Koeberg's life expectancy from 40 to 60 years. The life extension of Koeberg has been established as a viable option for the availability of baseload capacity.

The rest of the fleet will feature as follows for FY2023-FY2025:

- Hendrina will require R2 719m in the same period mainly because for the past 3 years, there was not any capital invested nor any maintenance philosophy as the station was ear-marked for early shut-down. However, it has been established that it is viable from a country point of view to invest in maintenance to allow for further operation of this plant. The projected amount is to run the required 6 units to work towards an energy availability (EAF) of 72%. The amount will be for both routine maintenance and scheduled outage activities based on station outage philosophy.
- Lethabo is projected to require R3 334m i.e. R2 048m on routine maintenance where the main contributor is mechanical maintenance (R1 700m). In addition there are scheduled outages for MO (Mini – General Overhaul) & IR (Interim Repair) to the value of R1 286m based on station outage philosophy.
- Medupi is projected to require R3 306m i.e. R1 591m on routine maintenance where the main contributor is mechanical maintenance (R1 236m). In addition there are scheduled outages for MO & IR to the value of R1 1719m based on station outage philosophy.

- Duvha is projected to require R3 027m i.e. R1 495m on routine maintenance where the main contributor are common plant, turbine, electrical & mechanical maintenance. In addition there are scheduled outages for MO & IR to the value of R1 020m based on station outage philosophy.
- Matla is projected to require R2 885m i.e. R2 083m on routine maintenance where the main contributors are common plant, turbine, electrical & mechanical maintenance. In addition there are scheduled outages for MO & IR to the value of R802m based on station outage philosophy.

FIGURE 39: MAINTENANCE COST



These interventions are necessary to comply with statutory requirements and at the same time to improve plant health and performance, so as to continue to provide electricity to the millions of South Africans.

As discussed above, Koeberg is the biggest contributor to maintenance costs over the MYPD5 period. The table below shows the impact of Koeberg on Generation's overall maintenance costs.

TABLE 52: IMPACT OF KOEBERG ON MAINTENANCE COSTS

Generation Maintenance (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Total Generation Maintenance	11 327	13 602	14 029	13 233	13 910	13 223	13 155
Koeberg Maintenance	(991)	(1429)	(1705)	(1416)	(2032)	(1514)	(888)
Total Maintenance excl. Koeberg	**10 336**	**12 173**	**12 324**	**11 817**	**11 878**	**11 708**	**12 267**

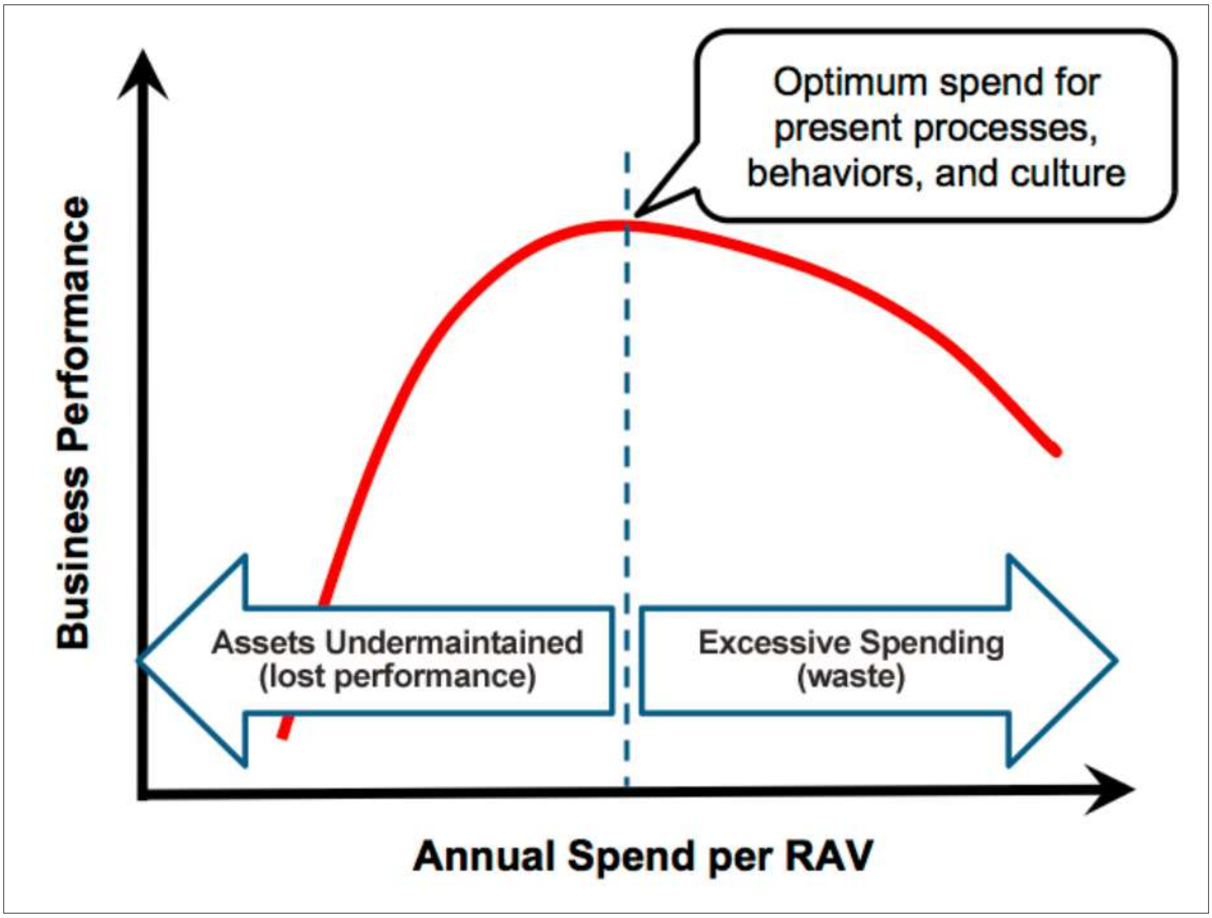
The compound annual growth rate (CAGR) for the period FY2023 to FY2025 for Generation maintenance costs, including Koeberg, is -0.4% which is below inflation. When excluding Koeberg's costs, the CAGR for the same period is -1.8%. This demonstrates that the cost of maintenance is reducing for the MYPD5 period, proving Generation remains committed to doing more with less (prudent) despite insurmountable challenges is facing such as aging infrastructure of its fleet, load-shedding etc. to deliver electricity to the millions of South Africans.

6.5.3 Maintenance Cost Benchmarking

Generation undertook to measure it's Maintenance Costs (Opex and Capex) relative to the Replacement Cost (i.e. the present cost to replace the asset if it were removed tomorrow) of its fleet as valued by external consultant's as part of its RAB valuation.

This is a widely used International approach of measuring the efficiency of a utility's maintenance spend. Research indicates that in general the optimum percentage ranges between 1.75% and 2.5% (the lower the percentage, the more efficient the spend is deemed to be).

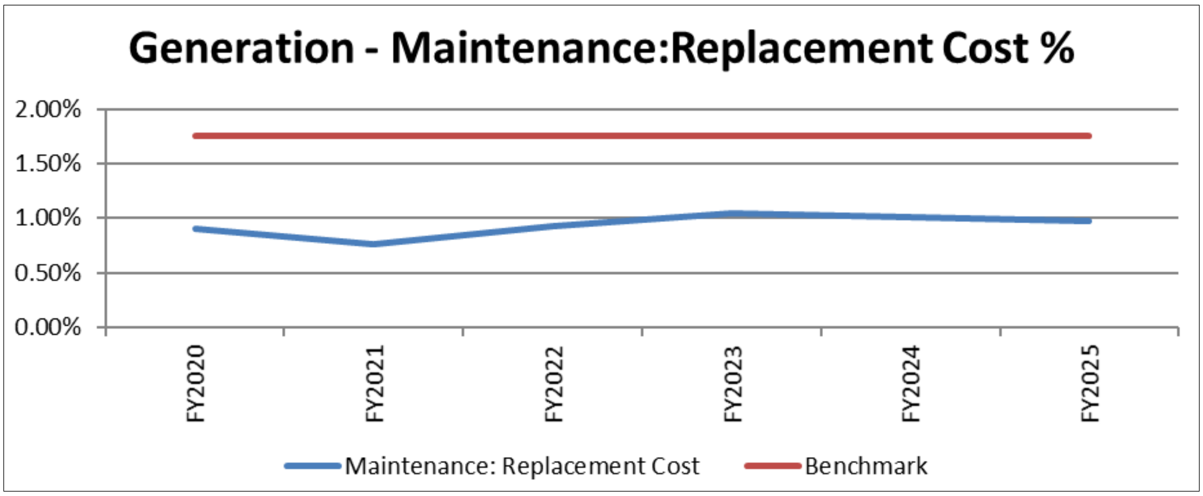
FIGURE 40: ANNUAL SPEND PER RAV



***RAV: Replacement Asset Value which is synonymous with Replacement Cost**

How does Generation compare relative to this benchmark?

FIGURE 41: GENERATION MAINTENANCE REPLACEMENT COST %



Using the lower spectrum of the optimum range as a benchmark, **Generation's maintenance spend is consistently lower than this optimum**, ranging between 0.76% and 1.04% in the period FY2020 to FY2025.

This benchmark serves to further highlight the reasonability of Generation's Maintenance spend.

6.5.4 Conclusion on maintenance costs

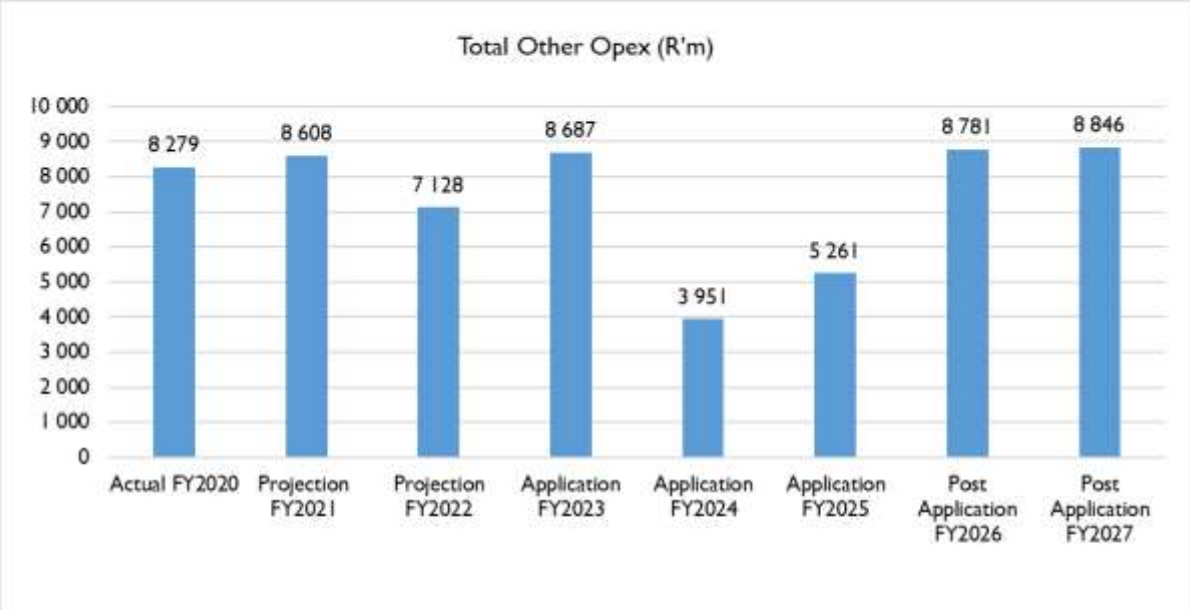
The compound annual growth rate (CAGR) for the period FY2023 to FY2025 for Generation maintenance costs is 1.25%, which is below inflation. These cost are necessary and prudent.

6.6 Other Opex

The cost category "Other Opex" contains all the operating costs that are not classified as either manpower or maintenance costs. It includes the following operating costs: internal electricity usage, rates and taxes, insurance, and decommissioning provisions, amongst others.

Most of these costs are inflationary related. The figure below reflects the trend for the seven years inclusive of the MYPD5 period.

FIGURE 42: GENERATION OTHER OPEX (EXCLUDING SAE) – R'M



The breakdown of Other Opex is shown in the table below.

TABLE 53: OTHER OPEX CATEGORIES

Total Generation Other Opex (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Contractor costs	3 847	2 208	2 805	2 918	2 872	2 907	2 121
Decommissioning expenses	183	127	269	(4939)	(3618)	(31)	160
Environmental expenses	61	286	983	911	474	148	76
Internal electricity revenue consumption	718	754	894	1 021	1 110	1 210	1 332
Materials expense	849	805	794	846	884	838	879
Net insurance expense	3 066	2 808	3 019	3 192	3 378	3 539	3 607
Office and site operation costs	1 236	1 372	1 421	1 287	1 407	1 488	1 308
Operating lease, consulting &travel	598	854	788	703	659	559	552
Other general expenses	378	366	315	226	206	207	243
Recovery postings	(820)	(893)	(1493)	(1737)	(1857)	(1920)	(1259)
Secondary account capitalisations	(1508)	(1558)	(1106)	(476)	(253)	(164)	(172)
Total Generation Other Opex	**8 608**	**7 128**	**8 687**	**3 951**	**5 261**	**8 781**	**8 846**

Adjusting for abnormal items shows a normalised trend:

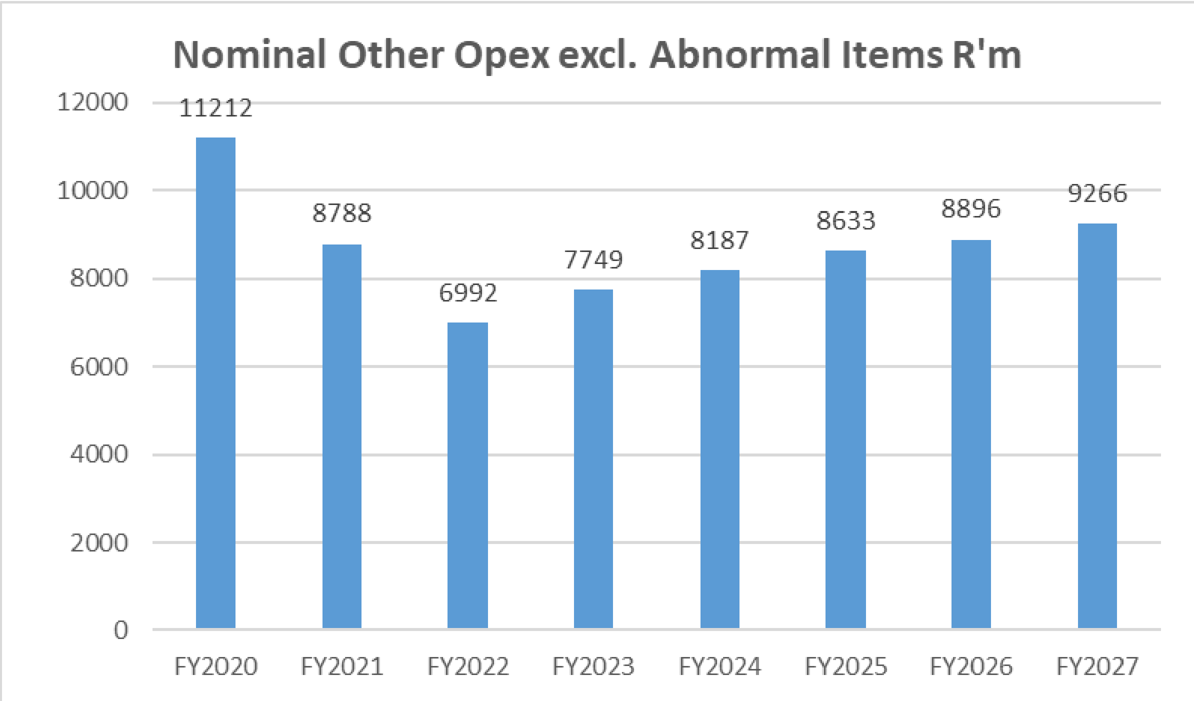
TABLE 54: OTHER OPEX ADJUSTED FOR PROVISIONS AND AIR QUALITY OFF-SET PROJECTS

Total Generation Other Opex (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Other Opex	**8 279**	**8 608**	**7 128**	**8 687**	**3 951**	**5 261**	**8 781**	**8 846**
Koeberg Decomm Provision	1 798	60	-	-	5216	3904	191	420
Camden Decomm Provision	1 135	121	-	(134)	(134)	(134)	-	-
Air Quality Project phase 1 to 3	-	-	(136)	(804)	(846)	(398)	(76)	-
Total Other Opex excl. Abnormal Items	**11 212**	**8 788**	**6 992**	**7 749**	**8 187**	**8 633**	**8 896**	**9 266**

The table above demonstrates the impact of the two abnormal items during the MYPD5 period. These are; **Decommissioning Provision**, especially for Koeberg (R9.1bn) and **Environmental** (Air Quality Project phase 1 to 3) costs (R2.0bn).

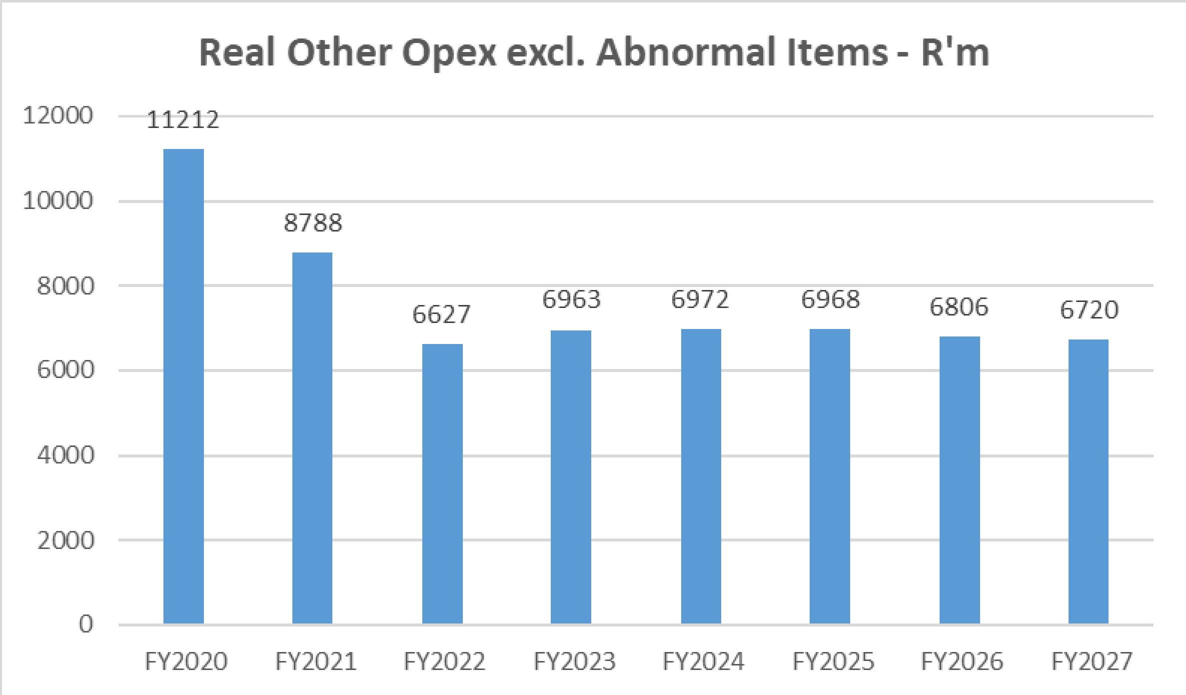
The decommissioning provision for Koeberg has the effect of abnormally reducing the net Other Opex over the MYPD5 period. Adding it back normalises the Other Opex and makes trending more meaningful. The adjustment is for the extension of Koeberg life expectancy from 40 to 60 years. The figure below, reflects other Opex excluding Koeberg Decommissioning and environmental costs. Similarly, the Environmental costs related to Air Quality Off-set projects would distort Other Opex trends if not excluded.

FIGURE 43: NOMINAL OTHER OPEX EXCLUDING ABNORMAL ITEMS –R'M



In real terms the Other Opex trend, when excluding abnormal items, is relatively flat over the MYPD5 period and decreases post MYPD5. The figure below, also illustrates how the normalised real Other Opex spend has decreased significantly since FY2020 and FY2021.

FIGURE 44: REAL OTHER OPEX EXCLUDING ABNORMAL ITEMS – R'M



After decommissioning and insurance premiums the third biggest spend comes from production plant service cost, these are contracts that are non-maintenance related, such contracts includes ROTEK contracts for field service (at Medupi), station cleaning contracts, office cleaning contracts, catering contracts, resident engineering contracts, Ash Dump management contracts etc. The increases in the MYPD5 period are less than inflation.

6.6.1 Insurance Premiums

Insurance premiums are the second biggest cost after Koeberg decommissioning costs contributing R9.6bn in the MYPD5 period. The Generation fleet is insured by Escap SOC LTD, which is the Generation captive insurer. The insurance premiums are costs incurred to insure Generation fleet in case of any eventuality so that the assets can be repaired, reinstated or replaced at a replacement value. Insurance premiums are based on the market asset value of the fleet. The compound annual growth rate (CAGR) for the period FY2023 to FY2025 for Generation's insurance premiums is 5.78%, which is below an inflationary increase.

6.6.2 Air Quality Off-set Environmental Projects

Generation is required to implement air quality offset projects as a condition of the approved Minimum Emission Standards postponements, and a condition of all Highveld power stations' Atmospheric Emission Licences. Air quality offsets are designed to reduce human exposure to harmful levels of air pollution by reducing emissions from local sources, like domestic coal burning and waste burning. The non-compliance with the environmental legislation will cost

Generation even more and the cost will be unfairly be borne by the customers. The projects have a significant impact on other Opex and thus should be disclosed separately as shown in the table above. The total cost is R2.3bn and for the MYPD5 period it's estimated at R2.0bn. This part is reflected under the section to be expensed. These costs are also discussed under ***environmental costs*** section.

Since air quality offsets have not been tested at scale yet, Generation is proposing a phased approach to air quality offset implementation:

Phase 1 (2021-2023): *Lead implementations* at one Generation-impacted community per district municipality. The logistics required to implement offsets on the scale of a whole settlement will be tested. Housing insulation and LPG devices will be distributed in KwaZamokuhle (next to Hendrina) and Ezamokuhle (next to Amersfoort), and interventions to reduce waste burning will be rolled out in Sharpeville.

Phases 2&3 (2023-2027): *Full implementation*. Once the interventions have been refined, they will be rolled out simultaneously for at least one community per power station.

Around 40 000 households will receive cleaner energy and/or insulation, and many more will be indirectly affected through community interventions. The successful implementation of air quality offsets promises to meaningfully improve the air quality of the air breathed by thousands of people, and should improve the health and create employment opportunities for many.

The compound annual growth rate (CAGR), for Other Opex (CAGR), excluding Koeberg Decommissioning Provision for the period FY2023 to FY2025 for Generation's Other Opex is 3.9%. CAGR for the Total Net Other Opex for the same period is -22.7%. If both decommissioning and environmental costs are included, the CAGR is -24.5%. The above simply proves the real cost are coming down. The figure above, showed that the real other Opex cost excluding decommissioning and environmental costs. This graph shows the trend is actually coming down, not even flat, further demonstrating that Generation remains efficient and prudent in future spending.

6.7 International Trader Operating Costs

6.7.1 Operating Costs

International Trader (SAE) is an electricity trader in the Southern African Development Community (SADC) and acts as Eskom's interface in the region.

International Trader operations include the following:

- Manage the cross–border trading portfolio (electricity imports and exports) both long-term and short-term including the Southern African Power Pool (SAPP) Markets with the aim of ensuring Eskom's position is protected and maximised and all associated risks are appropriately treated.
- Provide professional one-stop primary relationship management with trading partners and other role players.
- Actively participate in SAPP related regional activities to contribute to the creation of an environment conducive to achievement of Eskom's strategic intent in the region.
- Assist in increasing exports by identifying and developing the interconnectors required to reach potential markets.

Operating costs include employee costs and other expenses and are shown in the table below.

TABLE 55: SAE OPERATING COSTS (R'M)

Operating costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses	27	26	27	33	36	41	46	49
Impairment loss	0	8	-	-	-	-	-	-
Other Operating expenses	1	6	9	8	10	10	11	11
Corporate Overheads	1	-	22	20	20	21	27	27
Total	**29**	**40**	**58**	**61**	**66**	**72**	**84**	**87**

6.7.2 Employee Expenses

Employee expenses are inclusive of cost to company remuneration and other employee related expenditures such as the skills levy, workman's compensation contributions and training as well as professional fees. The projected growth in staff complement is primarily to replace the resources lost due to employee natural attrition in recent years. International Trader was unable to replace lost resources due to Eskom's moratorium on external recruitment.

Furthermore, International Trader will be require more resources to provide new services to the growing energy trading industry in the SAPP area.

The table below, provides a summary of employee expenses and headcount.

TABLE 56: SAE EMPLOYEE EXPENSES AND HEADCOUNT

Employee expenses & headcount	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses (R'm)	27	26	27	33	36	41	46	49
Number of Employees	22	21	24	28	30	33	35	35

Eskom's general approach to remuneration and benefits is designed to attract and retain skilled, high-performing employees. This is done by providing market-related remuneration structures, benefits and conditions of service, within the guidelines set by the shareholder in order to remain competitive

6.7.3 Other Operating Costs

Other operating costs are defined in the table below.

TABLE 57: SAE OTHER OPERATING EXPENSES (R'M)

Other Operating expenses (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Travel and subsistence expenses	1	3	4	4	4	4	4	4
Subcriptions	-	2	3	3	3	3	3	3
Legal Fees	-	0	2	1	2	2	3	3
Other expenses	0	1	1	1	1	1	1	1
Total	**1**	**6**	**9**	**8**	**10**	**10**	**11**	**11**

6.7.3.1 Travel and Subsistence expenses:

Travel expenses include both the local and international business travels undertaken by employees for operational purposes. The travel and related expense budget was determined based on standard SAPP meetings, anticipated regional meetings with trading partners and relationship building engagements.

6.7.3.2 Subscription costs:

This relates to annual SAPP membership fees, which allows Eskom to operate within the SAPP markets.

6.7.3.3 Legal Fees:

Legal costs are required to cater for contract establishment, advising on legal disputes and arbitrations with trading partners.

6.7.3.4 Other sundry expenses:

Other sundry expenses are inclusive of insurance premiums, sponsorships, telecommunication, stationery as well as other office expenses.

6.7.4 Corporate Overheads

Corporate overheads charges are costs that cannot be allocated directly to a specific line division because the service provided is an overall support to the various divisions in delivering core business activities. These costs are in the table below.

Direct overheads are allocated to the business units by using the most appropriate cost driver that is specific to the service being provided. The following services are charged as direct overheads. This includes IM charge, real estate as well as finance and HR shared services.

Indirect overhead costs cannot be apportioned to a specific division using a distinctive cost driver and are shared amongst the three licensees in proportion to employee complement, asset values as well as other operating costs and primary energy costs. The increase in indirect overhead costs is due to the new allocation method which uses primary energy costs (i.e. cross border energy purchases) as one of the three cost allocation factors.

TABLE 58: SAE CORPORATE OVERHEADS (R'M)

Corporate Overheads (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Direct Corporate Overheads	-	3	3	3	3	3	3
Indirect Corporate Overheads	-	19	17	17	17	24	24
Total	**-**	**22**	**20**	**20**	**21**	**27**	**27**

6.8 Other Income

Other income consists of the following categories: Insurance income, operating lease income, sale of scrap and sundry income which forms part of the above.

Other income is difficult to forecast with any degree of accuracy. The forecast for the next few years was done based on historical trends and is shown in the table below.

TABLE 59: GENERATION OTHER INCOME (EXCLUDING SAE) - R'M

Other Income (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Other Income	(541)	(1640)	(397)	(427)	(449)	(470)	(308)	(308)

6.9 Opex Benchmarking

It is acknowledged that comparison to operational cost benchmarks is not always simple nor an exact science due to complexity in the status of various power plants. Sources of benchmark data may vary significantly from Generation plant in terms of equipment, age, maintenance philosophy and overall condition of plant.

However, certain comparisons have been undertaken for Generation's coal power plants. They give an indication of level of cost comparatively to other similar utilities. This analysis could improve confidence in own costs or stimulate investigation if own costs do not compare favourably.

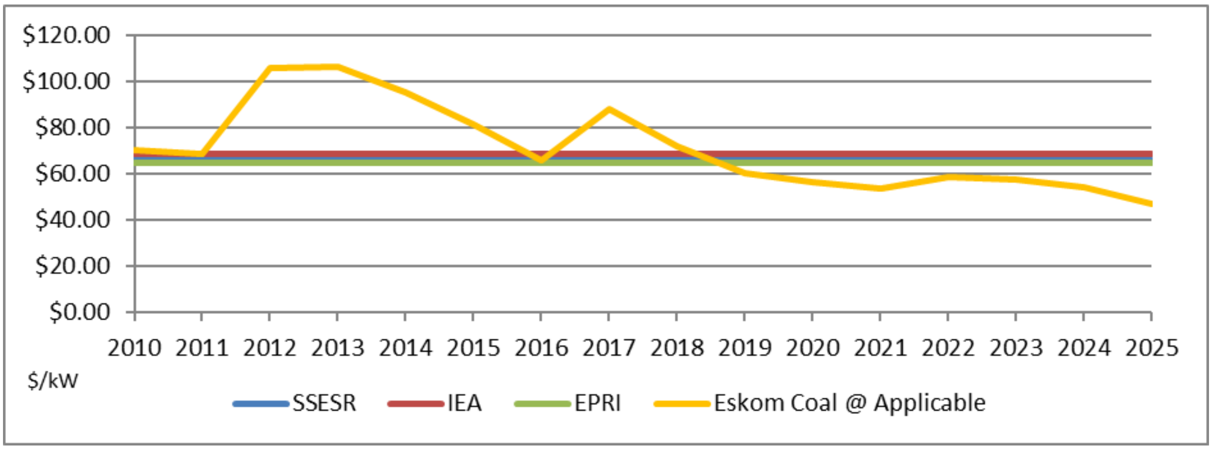
Generation has compared its operational performance against three international benchmarks with a **2020 base year comparison**:

TABLE 60: BENCHMARK O&M COSTS

	Total O&M $/kW
SSESR	66.02
IEA	68.49
EPRI	64.99

NB: Note that for purposes of this comparison, Generation includes Outage Capex as part of O&M.

FIGURE 45: BENCHMARK COMPARED TO REAL $/KW (COAL ONLY)



One should take into consideration that the benchmarks are skewed in that it considers lifecycle costs, which smooth the benchmark, whereas we are comparing to Generation power station annual costs, the bulk of which are in mid-life cycle requiring higher mid-life refurbishment costs and as well as maintenance backlog costs. In addition, more expensive maintenance interventions were performed at the Return to Service stations and Hendrina where the units are smaller with a higher impact from a $/KW perspective than spend on the conventional 600MW units. The high utilisation of the Generation power stations over a number of years has placed unusually high stress on plant systems and components which would also increase operating and maintenance costs.

Bearing this in mind one would **expect the Generation costs to be higher than the benchmark**.

However Generation is consistently below all three of the International Benchmarks over the MYPD5 period (and prior years) which emphasises the reasonability of Generation's Opex. The reduction in spend at the stations that will be placed in reserve storage, will contribute to a lower R/kW. However the bulk of the Generation fleet consists of mid-life stations which will necessitate increased maintenance costs.

It is Generation's intent to keep the Opex within international benchmarks, unless there is a strategic intent to increase maintenance to improve technical performance due to aging plant.

6.10 Conclusion on Opex

As was motivated in detail above, Generation's operating costs forecast is prudent and efficient. The benchmarking exercise proves that Generation's operating costs are lower than international norms.

7 RAB, Return and Depreciation

7.1 Regulated asset base (RAB)

The Regulatory Asset Base (RAB) is defined as assets of the regulated business that is used or usable in the production of the regulatory services. The MYPD methodology specifies that the RAB of the regulated business operations must only include assets necessary for the provision of regulated services based on the net depreciated value (residual value) of allowable fixed assets necessary to allow the utility reasonable return to be financially viable and sustainable while preventing unreasonable price volatility and excessive sustainability.

The RAB forms the basis for the determination of the regulatory depreciation and return on the RAB provides the regulatory mechanisms under which capital investment costs are recovered on a cost reflective basis over the course of its regulatory economic life. Hence capital expenditure is not a separate cost item in the revenue regulatory formula.

In this revenue application, Generation is required to apply for the following:

- Depreciation on the commissioned assets, in accordance with the method prescribed by the MYPD methodology. Depreciation is calculated on revalued assets as at 31 March 2020, assets commissioned since 31 March 2020 and asset purchases.
- Return on assets is calculated on all assets including work under construction and working capital, at a rate determined by NERSA.

The relevant aspects of the allowed revenue, in terms of the MYPD methodology considered here are highlighted in the formula below:

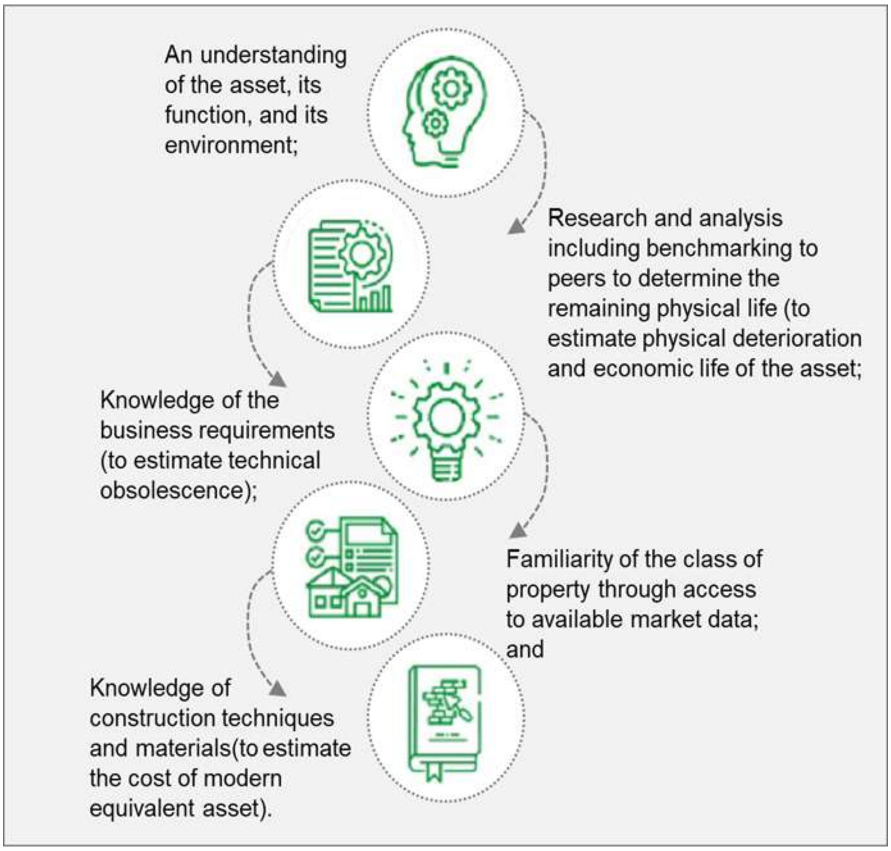
$$AR=(RAB\times WACC)+E+PE+D+R\&D+IDM\pm SQI+L\&T\pm RCA$$

The ERA and the Electricity Pricing Policy (EPP) requires the recovery of efficient costs and earning a fair return on capital. The EPP and the MYPD methodology require that assets are valued at its Modern Equivalent Asset Value (MEAV). In accordance with the MYPD methodology, Generation has undertaken a revaluation of all completed assets used in the generation, transmission and distribution of energy as at 31 March 2020. It should be noted that the process followed requires an **independent assessment** of the value of the RAB. Generation's actual capital expenditure is not considered when this RAB valuation is undertaken. It is viable benchmarks, for the depreciated replacement costs that are considered in arriving at the valuation of RAB as at 31 March 2020.

The RAB valuation was undertaken by an independent entity that has international experience in the realm of asset valuation for large infrastructure companies. As required by the MYPD methodology, the determination of the regulatory asset base value is based on the costs to replace these assets (i.e. Modern Equivalent Assets Valuation (MEAV)) and adjusted for the remaining life and any relevant forms of obsolescence. This valuation has been undertaken in accordance with the guidelines and requirements of the International Valuation Standards. The basis of the valuation was the Generation fixed asset registers and comparisons were made with market data for actual construction cost of similar assets. This valuation exercise included site visits where samples of the physical assets were performed. The site visits had to be minimised due to the restrictions of the Covid pandemic.

In determining the depreciated replacement cost, the independent consultants ensured that the following key elements were considered.

FIGURE 46: KEY ELEMENTS IN DETERMINING DEPRECIATED REPLACEMENT COST

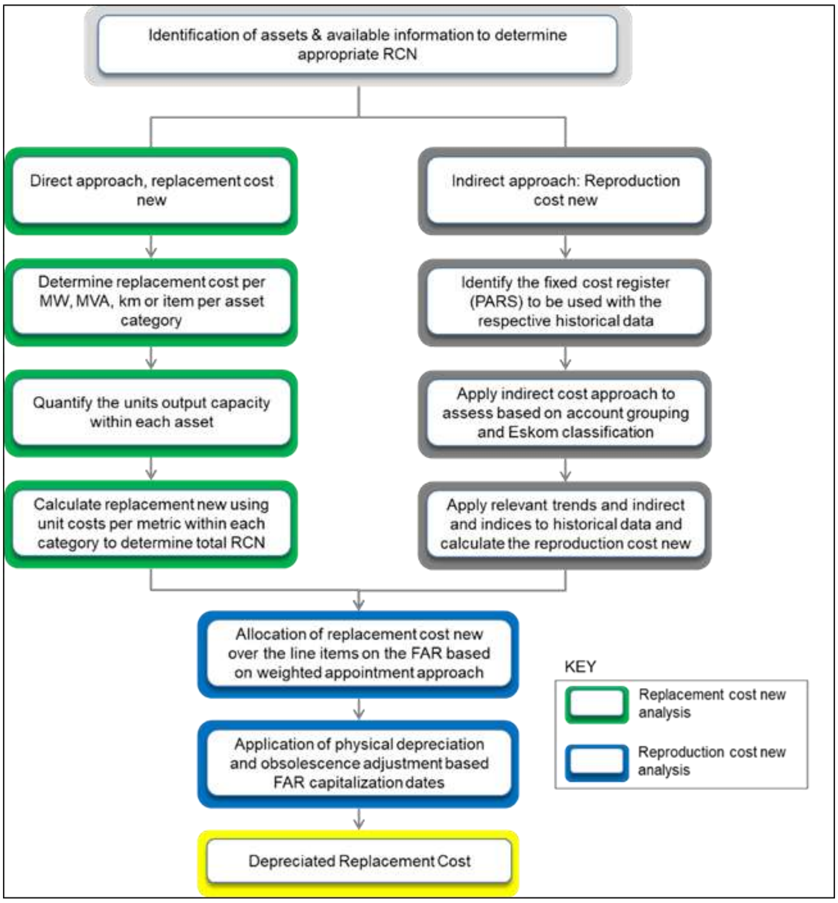


The International Valuation Standards Charter defines a Modern Equivalent Asset as *"An asset which provides similar function and equivalent utility to the asset being valued, but which is of a current design and constructed or made using current materials and techniques."*

The MEAV approach is synonymous with the Cost Approach or Depreciated Replacement Cost approach. The DRC was determined through the application of the cost approach methodology, which is a recognised approach for the valuation of specialist assets which are not regularly traded. The cost approach methodology includes the identification of the estimated new replacement cost of assets, which is then adjusted to reflect physical and functional obsolescence.

The cost approach is summarised in the figure below

FIGURE 47: COST APPROACH FOR VALUATION OF EXISTING ASSETS



7.1.1 Depreciated Replacement Cost of Generation's generation assets

The Generation assets have been valued based on a Depreciated Replacement Cost (DRC) method. The DRC method is a form of cost approach that is defined as:

"The current cost of replacing an asset with its modern equivalent asset less deductions for physical deterioration and all relevant forms of obsolescence and optimisation."

The DRC method is based on the economic theory of substitution and it involves comparing the assets being valued with another. However, DRC is normally used in situations where there is no directly comparable alternative. The comparison, has to be made with a hypothetical substitute, also described as the modern equivalent asset (MEA).

The underlying theory is that the potential buyer in the exchange would not pay any more to acquire the asset being valued than the cost of acquiring an equivalent new one. The technique involves assessing all the costs of providing a modern equivalent asset using pricing at the valuation date.

In order to assess the price that the potential buyer would bid for the actual subject asset, valuation depreciation adjustments have to be made to the MEA to reflect the differences between it and the subject assets.

These differences can reflect obsolescence factors such as the physical condition, the remaining economic life, the comparative running costs and the comparative efficiency and functionality of the actual subject assets.

The asset values in the Regulatory Asset Base are therefore not shown at the new cost to replace them but at their depreciated replacement cost. For example, if it costs R1bn to replace an asset at the end of March 2020 which has two years remaining life out of a total useful life of 25 years, the depreciated replacement cost at the end of March 2020 would be R80m (i.e. R1bn x 2/25). This valuation forms the basis of the RAB application as shown in the table below.

TABLE 61: REGULATORY ASSET BASE (RAB) SUMMARY

Regulatory asset base (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	375 490	339 640	723 171	677 641	633 995	592 490	552 973
Assets Transferred to Commercial Operations	281 222	323 486	150 581	196 543	225 300	231 723	250 302
Work Under Construction (WUC)	4 346	(48761)	90 422	74 362	62 017	88 661	99 163
Net Working Capital	34 765	41 727	37 383	32 656	41 860	50 155	53 060
Assets Purchases	804	779	617	621	668	691	713
Assets funded upfront by customers	-	-	-	-	-	-	-
Closing RAB	**696 626**	**656 871**	**1 002 173**	**981 823**	**963 840**	**963 719**	**956 211**

7.1.2 Assets (including WUC) components

In accordance with the MYPD methodology, the regulatory asset base is comprised of the following:

- Depreciated replacement cost assets: these are assets as per the March 2020 asset valuation. The valuation includes assets already in use in the generation, transmission and distribution of electricity as at 31 March 2020. All other assets in construction are not included in the valuation but rather in the WUC.

- Assets transferred to commercial operations: This refers to generation, distribution and transmission assets transferred into Commercial Operation subsequent to the 2020 asset valuation. Once commissioned, these assets are then depreciated by dividing the cost of the asset over the number of years that the asset is to be used for i.e. the useful life of the asset.

- Work under construction (WUC): In accordance with the MYPD methodology, for assets that constitute the ‘creation of additional capacity’, the capital project expenditures or WUC values (excluding IDC) incurred prior to the assets being placed in Commercial Operation (CO) are included in the RAB and earn a rate of return.

- Net working capital: This includes trade and other receivables, inventory and future fuel less trade and other payables.

- Asset purchases: all movable items that are purchased and ready to be used are included in this category eg. Equipment and vehicles, production equipment etc

7.1.3 Depreciated replacement costs

The extract of the DRC from the valuation report is shown in the table below. The valuation report excludes interest during construction (IDC) due to the overnight cost being used to determine the MEAV. Overnight cost is defined as the cost of a construction project if no interest is incurred during construction as if the project was completed overnight.

TABLE 62: EXTRACT FROM INDEPENDENT VALUATION REPORT

	Cap Cost	NBV	NBV in Scope	Final RCN	Physical Depreciation	Technical Obsolescence	DRC
Generation (Gx)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)
Generation Plant	496.399	382.771	382.771	2,139,774	(1,156,162)	(28.132)	955.474
Land and Building							
Land (Gx) (1000)	521	521	-	-	-	-	N/A
Building (Gx) (4000)	3.500	2.359	-	-	-	-	N/A

The Capital Cost (Cap Cost), Net Book Value (NBV), and Net Book Value in Scope (NBV in Scope) was in accordance with the Eskom’s fixed asset registers (FARs). The Modern Equivalent Asset Value (MEAV) was determined using the Overnight Cost methodology and assigned the costs on a “like for like” basis based on the nature of the subject assets to arrive at the Final Replacement Cost New (RCN). The Final RCN was adjusted for physical depreciation as per the age profile of the assets. The Final RCN less Physical Depreciation was then adjusted for Technical Obsolescence based on the performance of the assets in comparison to a defined performance standard, to arrive at the Depreciated Replacement Cost. The Depreciated Replacement Cost being “the current cost of replacing an asset with its modern equivalent asset less deductions for physical deterioration and all relevant forms of obsolescence and optimisation.

7.2 Work under construction (WUC)

In terms of the MYPD methodology the criteria for inclusion of WUC into the RAB is for those assets that are for the creation of additional generation, transmission and distribution capacity and are defined as follows:

- **Expansion** – this is capital expenditure to create additional capacity to meet the future anticipated energy demand forecast.
- **Upgrade** – this is capital expenditure incurred to ensure that the current and future energy demand forecast is met.
- **Replacement** – this is capital expenditure to replace assets that have reached the end of their useful life in order to continue meeting the current demand.
- **Environmental legislative requirements** – this is capital expenditure incurred to ensure that the licensing condition is maintained thereby continuing to meet the current energy demand forecast.

A WUC in essence refers to the capital expenditure being undertaken and meets the criteria referred to above for inclusion in the RAB. In terms of the MYPD methodology, the WUC balance is required to earn a return on assets but is not depreciated until assets are transferred to Commercial Operation (CO). Only upon CO do these assets incur depreciation costs.

7.3 Depreciation

The depreciation is the cost of usage over the life of the asset. This is generally a proxy for the recovery of the capital portion of the debt incurred.

As is required by the MYPD methodology, the annual depreciation allowance is determined by dividing the cost of the asset by the estimated useful life of that asset. The table below reflects the revenue related to depreciation for the MYPD5 period.

TABLE 63: DEPRECIATION

Depreciation (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	47 615	45 530	43 646	41 505	39 517
Assets Transferred to Commercial Operations	6 461	10 817	15 724	14 797	17 178
Assets Purchases	154	155	167	173	178
Assets funded upfront by customers	-	-	-	-	-
Total	**54 231**	**56 502**	**59 537**	**56 475**	**56 874**

Depreciation on assets as per the FY2020 valuation is computed by dividing the depreciated value of the assets over the remaining life of the respective assets as reflected at the end of March 2020.

All subsequent transfers to commercial operation after 31 March 2020 are depreciated over the asset life but limited to the remaining life of the power station.

7.4 Assets Excluded from RAB – Non Operational Assets

As per the MYPD methodology (9.1.8.1), fixed assets that are not used or useable within 12 months are excluded from the RAB. With regards to the generation licensee, and in accordance with the valuation as at 31 March 2020, the reserve storage units were included in the valuation as non-operational assets but were excluded from the RAB. The table below shows the results from the valuation of these units.

TABLE 64: VALUATION OF RESERVE STORAGE UNITS

Power Station	Units	Cap Cost (ZAR millions)	NBV (ZAR millions)	NBV in Scope (ZAR millions)	MEAV (ZAR millions)	Final RCN (ZAR millions)	Physical Depreciation (ZAR millions)	Technical Obsolescence (ZAR millions)	DRC (ZAR millions)
Grootvlei	UN04	1,209	364	364	5,952	4,778	(2,889)	(1,861)	28
	UN05	2,188	1,070	1,070	10,613	8,520	(5,219)	(3,252)	49
	UN06	830	417	417	4,179	3,355	(2,117)	(1,218)	19
Hendrina	UN01	437	124	124	8,596	6,900	(5,886)	(944)	70
	UN03	559	30	30	10,043	8,061	(6,878)	(1,101)	82
	UN08	559	207	207	6,953	5,581	(4,381)	(1,144)	57
	UN09	678	269	269	6,541	5,251	(3,906)	(1,291)	53
Komati	UN01	1,515	32	32	4,440	3,564	(2,772)	(759)	33
	UN02	1,409	27	27	4,129	3,314	(2,576)	(707)	31
	UN03	1,726	45	45	4,835	3,881	(2,892)	(953)	36
	UN04	1,491	536	536	4,459	3,579	(2,802)	(744)	33
	UN05	1,357	40	40	4,193	3,366	(2,688)	(647)	31
	UN06	1,423	33	33	4,404	3,535	(2,828)	(675)	33
	UN07	1,467	38	38	4,489	3,603	(2,736)	(834)	33
	UN08	926	26	26	3,258	2,615	(2,184)	(407)	24
Duvha	UN03	478	159	159	20,869	16,752	(12,405)	(4,249)	98
Total		**18,253**	**3,419**	**3,419**	**107,953**	**86,655**	**(65,160)**	**(20,786)**	**709**

7.5 Return on assets

The WACC, as determined by NERSA for the MYPD period, is used as a comparison for the cost reflective return on assets. It is likely that this value has increased since then. However, it allows for a conservative estimate, as Generation migrates towards the cost reflective level.

The return on assets is being phased to allow for the smoothing of the tariff as shown in the table below. This is the phasing that Generation has to make to allow the average price of electricity to migrate towards cost reflective tariffs. In the absence of such a phasing, the price increase being requested will be significantly higher. This migration is accompanied by risks which need to be managed. It is unfortunate, that further burden is required to be applied on the fiscus. In essence the subsidy provided to all consumers is continued to be provided for a longer period. The table below depicts the return on assets being applied for over the MYPD5 period in a phased manner to allow for the smoothing of the tariff price increase over the period.

TABLE 65: RETURN ON ASSETS

Return on Assets	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Closing RAB (R'm)	1 002 173	981 823	963 840	963 719	956 211
Real pre-tax WACC %	7.1%	7.1%	7.1%	7.1%	7.1%
Cost Reflective RoA (R'm)	71 154	69 709	68 433	68 424	67 891
RoA Applied for RoA %	-1.99%	0.69%	0.87%	1.65%	3.04%
RoA Applied for (R'm)	(19953)	6 794	8 414	15 853	29 021

8 Capital Expenditure

8.1 Introduction

The MYPD methodology allows for the capital related costs to be recovered over the life of the assets through return on assets and depreciation. Thus it is clarified that capital expenditure is not included in the allowed revenue regulatory formula.

The long life capital nature of the electricity industry requires significant focus on build and replacement of assets for the functioning and reliability of the industry to provide the service of delivering electricity. In the application window, Generation related capital expenditure plans will focus on delivering the following projects:

- Generation new build programme- commercial operation of remaining units of Medupi and Kusile
- Generation technical plan capital expenditure
- Generation will invest in Cost-Plus mines which will provide Generation with a more sustainable source of coal. This is included as future fuel.
- Generation will also invest in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance.

TABLE 66: GENERATION CAPEX SUMMARY

Total Generation Capex (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
New build and major projects	8 861	9 239	17 052	18 611	18 441	14 019	32 289	31 682
Outage capex	7 157	7 843	11 965	13 263	13 278	9 349	7 370	4 148
Technical Plan capex	947	1 723	8 954	9 156	8 974	8 708	7 854	10 055
Nuclear future fuel	505	1 155	573	971	787	1 426	893	1 165
Coal & Water future fuel	502	638	1 690	2 230	2 370	2 349	2 154	1 868
Renewables	-	9	21	15	19	61	351	374
Asset Purchases	68	272	167	182	167	214	195	201
Total Gx Licence Capex	**18 040**	**20 877**	**40 422**	**44 428**	**44 036**	**36 126**	**51 106**	**49 493**

8.2 Generation New build and major technical plan projects

8.2.1 Overview

Generation is executing the largest capital expansion programme in Africa and executes projects that ensure environmental compliance, transmission strengthening, customer connections and refurbishment of existing assets in accordance with Generation's project lifecycle model. In addition, the repair to the major defects to Medupi and Kusile are being undertaken.

In addition, Generation is in the process of constructing the following key generation projects:

- Upgrading other existing plants
- Executing other Generation coal projects, such as emission compliance projects and fabric filter plant (FFP) retrofits.
- Constructing a 68 km railway between Majuba Power Station and the coal railway hub in the town of Ermelo in Mpumalanga.
- Executing the Koeberg steam generator replacement project for units 1 and 2.
- Executing the Ankerlig Transmission Koeberg Second Supply (ATKSS) Project.

Inception to 31 March 2021, a large amount of construction work was completed, adding 13 936 MW of new generation capacity to the national grid. The remaining capacity until FY2025 includes 3 196 MW of generation capacity. Once completed by FY2025, Generation's capacity expansion programme will increase new generation capacity by 17 132MW. This will enable Generation to provide security of electricity supply to South African homes and businesses, powering economic expansion and extending electricity to millions of households who currently rely on other fuel sources for domestic cooking and heating.

To date, Generation has completed the following projects:

- Construction of the Ingula Pumped Storage Scheme, with a total installed capacity of 1 332 MW. The first unit was commercialised in March 2016 and the fourth and final unit in January 2017.
- Construction of two new gas-turbine plants, namely Ankerlig and Gourikwa Open Cycle Gas Turbines (OCGTs), completed between March 2007 and March 2009, at a total combined installed capacity of 1 785.9 MW.
- Re-commissioning of three coal-fired plants that were previously mothballed, namely Camden, Grootvlei and Komati Return-to-Service Power Stations. The Return-to-Service (RTS) programme was completed by September 2014, with a total combined installed capacity of 3 741 MW.
- Capacity increase at Arnot Power Station of 300 MW, completed by March 2012.

- Conversion of the 14 OCGT units at Ankerlig and Gourikwa to dual-fuel capability by June 2017. Dual-fuel capability means that the units can be operated with diesel and gas.

- Construction of a renewable energy plant, Sere Wind Farm, commercialised March 2015 at an installed capacity of 100 MW.

- Completion of the Majuba Silo 20 Collapse Recovery Project in December 2016.

Furthermore, Medupi Units 6, 5, 4, 3 and 2 successfully achieved commercial operation in August 2015, April 2017, November 2017, July 2019 and November 2019, respectively, adding 3 970 MW to the national grid (each unit rated at 794 MW installed capacity). Kusile Units 1, 2 and 3 successfully achieved operation in August 2017 and October 2020 and March 2021, respectively, adding 2 397 MW to the national grid. The Generation Board and management are committed to complete Medupi and Kusile Power Stations within the revised; Board approved completion dates of FY2021 and FY2025, respectively.

The major plant defects correction plan, as part of the 9-point Generation recovery plan, is being executed and closely monitored to effectively resolve all the major new plant defects at Medupi and Kusile Power Stations. The operations and maintenance inefficiencies are also being addressed as part of this plan.

The major plant defects correction plan, as part of the 9-point Generation recovery plan, is being executed and closely monitored to effectively resolve all the major new plant defects at Medupi and Kusile Power Stations. The operations and maintenance inefficiencies are also being addressed as part of this plan. The figure below provides a progress update on the design modifications roll-out and outages:

FIGURE 48: MEDUPI AND KUSILE DEFECT RESOLUTION PROGRESS

✓ Milestone Completed

Medupi Power Station

- **December 2020: Evaluation tests and inspections completed on Medupi Unit 3.** Roll-out of successful modifications is progressing and further improvements are being developed.
- **Design modifications** roll-out include:
  - ✓ **June 2020:** Unit 6 - Gas Air Heater and Fabric Filter Plant
  - ✓ **September 2020:** Unit 1 - Gas Air Heater, Fabric Filter Plant, Erosion Protection, Short Lead Items on Milling Plant
  - ✓ **October 2020:** Unit 4 - Gas Air Heater, Fabric Filter Plant, Erosion Protection, Short Lead Items on Milling Plant
  - ✓ **January 2021:** Unit 2 Gas Air Heater, Fabric Filter Plant, Erosion Protection, Short Lead Items on Milling Plant
  - **March 2021:** Unit 5 – 75 day outage start
  - Mill long lead items approved and installation to be done during mill outages

Kusile Power Station

- Boiler plant modification outages to start mid 2021 for running units (1, 2 and 3)
- Boiler plant modifications on construction units (4, 5 and 6) to be done before Commercial Operation of each respective unit
- Unit 3 is currently in its testing and optimisation phase
- June 2021: Unit 1 – 75 day outage start
- September 2021: Unit 2 – 75 day outage start
- January 2022: Unit 3 – 75 day outage start
  - Mill long lead items approved and installation to be done during upcoming unit and mill rebuild outages

Generation has approved and committed to complete construction of the following projects:

- Completion of the Medupi and Kusile coal-fired power stations
- Execution of Generation emissions-control and technical plan projects
- Constructing a 68 km railway between Majuba Power Station and the coal railway hub in the town of Ermelo in Mpumalanga
- Executing the distributed battery storage project, as an alternative to a 100 MW Concentrated Solar Power (CSP) plant, at Generation distribution constrained sites close to renewable energy Independent Power Producer (IPP) plants and at Sere Wind Farm
- Executing the Medupi Fuel Gas Desulphurisation (FGD) project

8.2.1.1 Key issues

Some challenges and key issues that have affected the performance of the new build projects include the following:

- Requirement for thorough and long commercial processes, challenges with contractor performance in certain instances, stability on site due to labour unrest, vandalism and material unavailability and/or theft result in projects falling behind schedule
- Unavailability and reliability impacts of new units at Medupi and Kusile, due to having to address the plant defects
- Covid-19 lockdown and pandemic
- Inclement weather
- Requirement for thorough and long National Treasury approval processes prior to the placement of contracts

8.2.1.2 Current and significant project risks

There are five (5) high priority risks, namely: site stability, construction productivity, contractor liquidity, new unit performance (i.e. reliability, availability) and the Coronavirus (COVID-19) pandemic and lockdown are being managed. These high priority risks continue to be monitored through the effective implementation of mitigation actions, as reflected in the table below:

TABLE 67: SIGNIFICANT PROJECT RISKS

High Priority Risks	Mitigation Actions
Stability challenges at construction sites due to community unrest, protests and industrial action (protected and unprotected), leading to production delays and/or property damage across the construction sites and safety incidents (injuries).	• Continuous implementation of the Partnership Agreement. • Continuous implementation of Internal and External stability plans. • Visibility of Employee Relations personnel. • Effective stakeholder engagement. • Continuous implementation of skills development and transfer programmes.
Productivity challenges, caused by outbreak of the Coronavirus, poor contractor performance, inadequate skills and capacity, ineffective Generation oversight, site instability, ineffective construction risk prevention and management, negatively impacting projects in various ways, such as schedule delays and cost escalations, low productivity, high rework rates (including defects repairs), labour unrest and work stoppages, among others.	• Continuously implement productivity improvement initiatives, including focused and micro contractor management. • Enforce all applicable contractual rights for delays and non-delivery. • Continuous review and implementation of Covid-19 readiness and response plans for effective return to work and ensuring a safe work place.
Contractor liquidity challenges, leading to abandoning contracted works midstream, thereby	• Timeous payment of invoices. • Perform micro contractor management.

High Priority Risks	Mitigation Actions
exposing asset creation initiatives and further attracting reputational damage and financial loss.	• The Contracts Management Office (CMO) addresses on the challenges experienced as a result of contractors' cash flow problems and the associated challenges experienced by the wage bureau. • The CMO plays a monitoring and oversight role in terms of identifying potential contractual related issues and assisting with the necessary mitigating actions to reduce/eliminate the impact on the business.
New Units (Availability and Reliability): Poor availability and reliability of new units leading to system constraints, cost escalation (reworks, designing and construction), affecting generation plant availability and planned outages.	Effective implementation of the Generation New Plant Major Defect Correction Plan (for Ingula, Medupi and Kusile Units). This is in accordance with Generation's 9 point plan.
Coronavirus (Covid-19) pandemic outbreak impacting construction productivity, contractor liquidity, capital programme schedule, leading to financial and commercial challenges.	Covid-19 readiness and response plans have been developed and are being implemented and continuously reviewed for the effective return-to-work of employees.

8.2.2 Environmental compliance

The environmental clause in the Bill of Rights sets the context for environmental protection, providing for an environment which is not harmful to health and well-being and for ecological sustainable development. The National Environmental Act and several Strategic Environmental Management Acts (SEMAs) give effect to the environmental right in the Constitution. The development of environmental legislation has resulted in new and more stringent requirements which Generation is obligated to respond to in order to continue operating its power stations. Given the nature of Generation's activities, these requirements are far reaching; they affect all the divisions and subsidiaries in some manner, including air quality, protection of the natural environment and biodiversity, water use and preventing pollution of water resources, general and hazardous waste management, the utilisation of ash and licensing processes. These legislative requirements are enforced through licences and permits. They lead to operational and capital expenses. To retain the licence to continue to operate, these expenses must be allowed for in the tariff, preferably in a manner which separates non-negotiable statutory requirements from refurbishment and maintenance expenses.

The most significant environmental costs over the next 10 years are for air quality, air quality offset, ash dams/dumps and water management However, based on the preliminary outcomes of a postponement application submitted to DFFE in 2019, there remains a possibility that Generation would require at least R300bn to comply with the minimum emissions standards.

8.2.2.1 Air Quality Implementation Plan

Minimum Emission Standards were published in 2010 in terms of the National Environmental Management: Air Quality Act, 2004 requiring facilities to comply with “existing plant” standards by 2015 and for existing plants to comply with “new plant” standards by 2020. There are three pollutants which Generation is required to control; sulphur dioxide, nitrogen oxide and particulate matter. Applying new plant standards to existing/aged plant is technically challenging, with limited Flue Gas Desulphurisation (FGD) technologies which can meet the regulated sulphur dioxide limits. FGD is very costly to install and will significantly increase both Capex and Opex requirements. Nitrogen oxide limits require the installation of low NOx burners and Particulate Matter limits require the installation of fabric filter bags or electrostatic precipitators (ESPs) and associated flue gas conditioning technologies.

Generation is required to embark on a programme to implement the required pollution control technologies but due to the cost, water requirements and logistics to implement. In February 2019, Generation requested a postponement, alternative limits and or suspensions for some plants. Generation has yet to receive a formal response from the DFFE but revised legislation promulgated in 2018 is very restrictive and could lead to the shutdown of up to 19 000MW of installed capacity immediately on receiving the decision and a further 10 000MW from 2025.

Generation has made progress with the prioritised and phased emissions reduction plan.

In parallel to the programme to reduce air emissions at coal fired power stations, Generation is required to embark on an air quality offset project in communities surrounding Generation power stations. This project will reduce the most significant contributor to health impacts in low income communities. The offset project is a legal requirement enforced through the approval of the postponement application and as a condition of Atmospheric Emission Licences.

8.2.2.2 Air Quality Offsets

Generation is required to implement air quality offsets as a condition of the approved Minimum Emission Standards postponements, and a condition of all Highveld power stations’ Atmospheric Emission Licences. Air quality offsets are designed to reduce human exposure to harmful levels of air pollution by reducing emissions from local sources, like domestic coal burning and waste burning.

FIGURE 49: OPPORTUNITIES FOR AIR QUALITY OFFSETS: REDUCING LOCAL WASTE BURNING (LEFT) OR DOMESTIC COAL BURNING (RIGHT)

Generation's air quality offset programme is intended to reduce emissions from coal/wood burning in Mpumalanga (through insulating houses and swopping existing coal stoves for LPG heaters and combined electric and LPG stoves), and from local waste burning in the Vaal. The offset programme has been informed by a desktop pre-feasibility study conducted in 2012/13, in which many options to reduce household emissions were evaluated, and two pilot studies conducted on 120 households in KwaZamokuhle, 17 km from Hendrina Power Station, over the winters of 2015 and 2016.

Offsets need to be implemented on at least one settlement of reasonable size for each power station. Areas are prioritised based on the impact of emissions from the power station, but only areas where there is a potential for non-compliance with ambient air quality standards and where opportunities for improving ambient air quality through offsetting exist, are considered.

Since air quality offsets have not been tested at scale yet, Generation is proposing a phased approach to air quality offset implementation:

Phase 1 (2021-2023): *Lead implementations* at one Generation-impacted community per district municipality. The logistics required to implement offsets on the scale of a whole settlement will be tested. Housing insulation and LPG devices will be distributed in KwaZamokuhle (next to Hendrina) and Ezamokuhle (next to Amersfoort), and interventions to reduce waste burning will be rolled out in Sharpeville.

Phase 2 (2023-2027): *Full implementation*. Once the interventions have been refined, they will be rolled out simultaneously at at least one community per power station.

Around 40 000 households will receive cleaner energy and/or insulation, and many more will be indirectly affected through community interventions. The successful implementation of air quality offsets promises to meaningfully improve the air quality of the air breathed by thousands of people, and should improve the health and create employment opportunities for many.

8.2.2.3 Ash dam/dump extensions

Ash dams and dumps are a key component in the generation of electricity. Without an ashing facility the power station cannot continue to operate. Generation produces approximately 30 million tonnes of ash annually, six to eight percent of which is recycled. The remaining ash is sent from the power station and disposed of in an ash dam or dump.

In terms of the National Environment Management Waste Act (NEMWA), ash is classified as a hazardous waste. Prior to the promulgation of the Act there was no requirement for a Waste Management Licence (WML) for ashing facilities. However, the extension of ashing facilities beyond their original planned ashing footprint triggered the requirement for a WML which in turn triggered the requirement for lining the ashing facilities. Since Generation was not able to install the lining immediately on dry ashing facilities, the DFFE, at Generation's request, granted an exemption to install the lining within four/five years of receiving the WML.

8.2.2.4 Water management

Generation is one of the largest industrial consumers of fresh water in South Africa, accounting for approximately 2-3% of the country's total water consumption annually. The reliability of water infrastructure and the availability and quality of water have a significant impact on Generation's ability to produce electricity and to use water efficiently. In terms of the National Water Act 36 of 1998 and the National Water Resource Strategy 2, Generation is required to use water efficiently, to comply with licence conditions and ensure that our activities do not cause or potentially lead to pollution of water resources.

Generation's Water Strategy was developed to set the direction on water-related issues and address compliance. The strategy outlines the key activities required to ensure efficiency and compliance, these include the lining of all dirty water dams, design and construction of separate dirty and clean water systems, the installation/upgrade of water treatment plants.

8.3 Generation Technical Plan Projects

8.3.1 Overview of the life of plant plan (LOPP) for a power station

- Every station has an LOPP to address refurbishment, replacement and compliance requirements to sustain the plant throughout its lifespan.
- The 10 year, 5 year and 1 year capital project plans are produced from the LOPP.

- The age based replacement required for LOPP is refined with condition and risk assessments in annual plant strategy documents produced by Engineering.

TABLE 68: EXAMPLES OF REFURBISHMENT/REPLACEMNT INTERVALS

Examples of Refurbishment or Replacement Intervals		
Component	Interval (years)	Insights on Failure and Refrubishment
Gen Transformer	20-25	The health of transformers is determined by conditining monitoring analysisof oil/gas
Smaller Transfomer	30-35	The health of transformers is determined by conditining monitoring analysisof oil/gas
C&I Migration	15-20	Computers become obsolete after 5 years
Generator Rewind	35	Due to insulation breakdown
Turbine Rotor Replacement	40	Cracks can no longer be manged through maintenance
Condensor Re-tubing	30-35	Replacement once in the life when a significant % of tube are plugged
Large Motors	30	Replacement once in the life when they have been rewound 3 times
High Pressure Piping	30-40	Replacement required once piping shows signs of needing major replacements

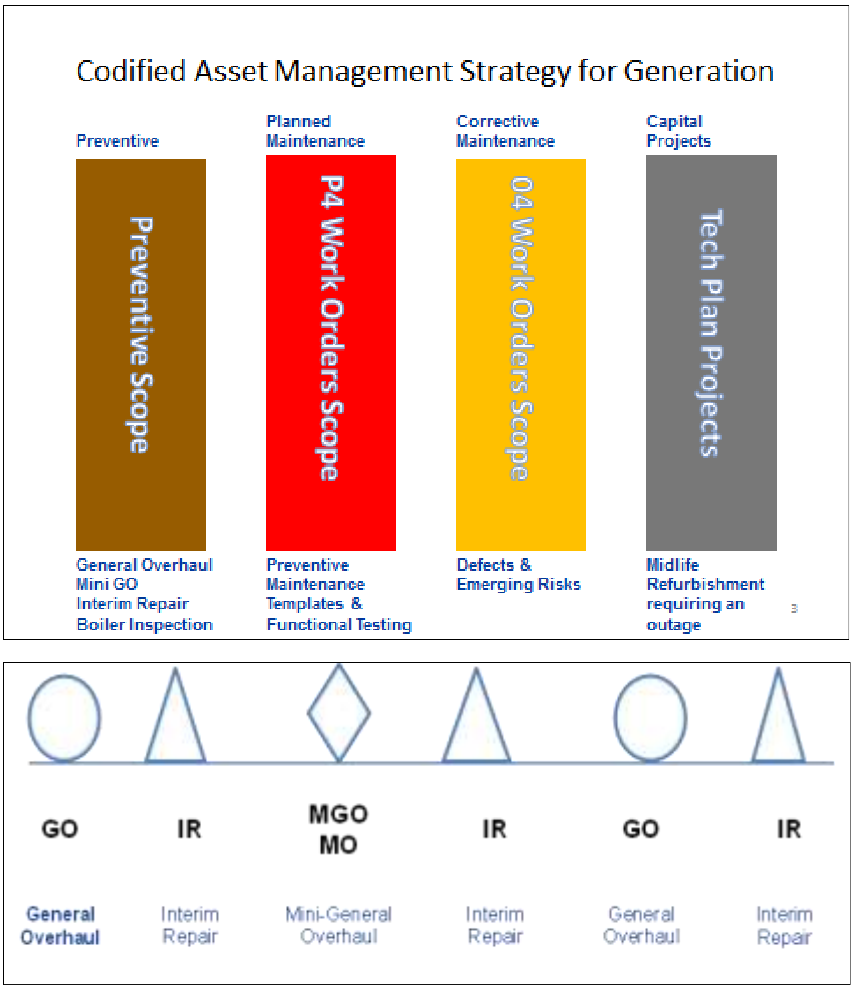
8.3.2 TechPlan Capex

The LOPP Capex requirements are prioritised based on evolving requirements and conditions, along with implement-ability and expectation of available funding to determine priority projects. This results in the Technical Plan (TechPlan) Capex requirement as shown in the table in Section 8.1. The stations approaching economic end of life remain necessary to ensure supply capacity adequacy, to support the reliability maintenance recovery and until the New Build design defects are resolved as well as in case the assumptions in the Production Plan do not materialise. The life cycle costs up to FY2025 have thus been included for these sites. These amounts are thus a risk mitigation as well as a proxy for unforeseen Capex requirements throughout the fleet.

8.4 Outage Capex

Generation has a codified preventive maintenance strategy in place for each Power Station.

FIGURE 50: CODIFIED ASSET MANAGEMENT STRATEGY FOR GENERATION



8.4.1 Overview of outage maintenance strategy

There are numerous cyclical maintenance interventions required on a power plant. If an activity is required at least twice in the life of a station and will require plant shutdown, the implications are required to be documented in a document called the outage philosophy. All stations have specific requirements but generic rules exist:

- General Overhaul (GO): Every 10 – 12 years plant shutdown to do inspection and repair of turbine & generator.
- Mini GO / MO: Every 5 - 6 years inspection of low pressure turbines, and statutory pressure test.
- Interim Repair (IR): 18 – 36 monthly plant is shutdown to inspect and repair the boiler components.
- Boiler Inspection (IN): Between IRs, an inspection is carried out to review condition of the boiler and scope the next outage.

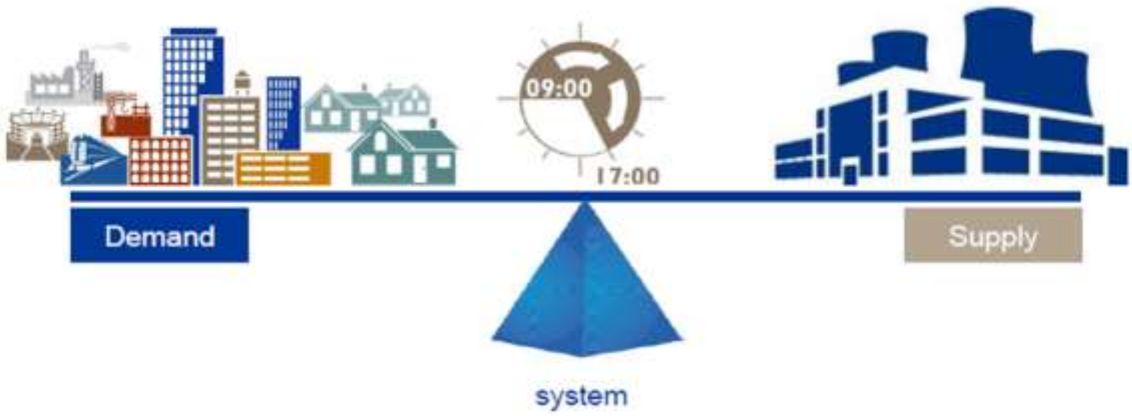
- Opportunity maintenance frequently leads to the above schedule being modified which gives rise to adaptions of the sequence, but every effort is made to recover the sequence to ensure plant safety and operability.

8.4.2 Prioritisation of outages:

- Immediate safety risk as per ERAP inclusive of any emerging technical threat which is deemed to pose significant personnel or plant risk.
- Statutory such as pressure tests.
- Licence to operate' risks such as major contraventions of legislation.
- Reliability scope is included in the outages based on the durations available.

8.4.3 Capacity planning

The objective is to ensure that there is enough capacity to meet the demand and operating reserves whilst performing required maintenance.

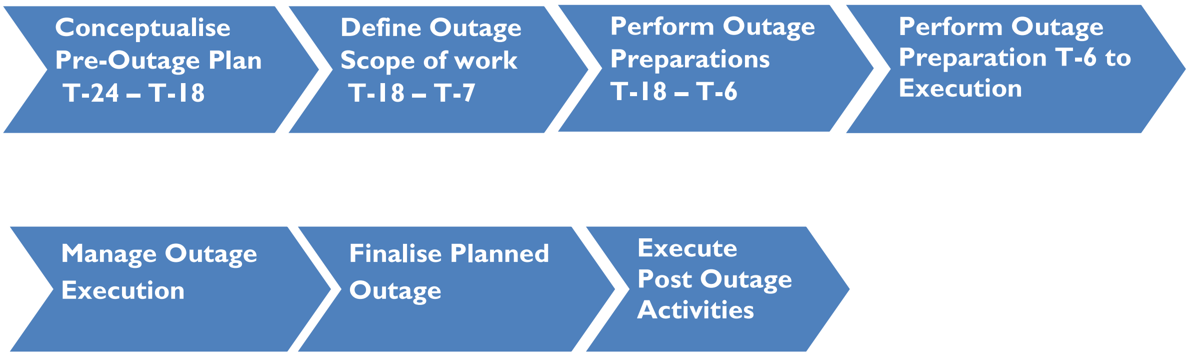


The Capacity Plan illustrates, on a daily basis (at peak), the ability to meet the demand, considering planned and unplanned maintenance, and required operating reserves.

8.4.3.1 Capacity planning process

- The stations enter their plans on the GPSS system according to their maintenance strategy provisions.
- The plans should cover at least a period of 10 years and are not optimised at this point.
- Once all the plans are consolidated / aligned, a workshop is conducted to optimise the first year.
- The workshops have a mandate to achieve a certain capacity available in summer and winter to meet the demand, i.e. we need more capacity available in winter than in summer.
- This is achieved through an outage plan which is later visualised in a Tetris plan.

8.4.3.2 Outage planning timeline



8.4.4 Process of costing an outage

8.4.4.1 10 Year Financial Plan

The 10 Year Financial Plan provides the detail of all the Capex and Opex budget requirements for 10 years. It will include all planned outages and departmental requirements as well as the following.

- The 10 Year Financial Plan indicated by specific years and outage type is compiled and up-loaded into SAP FI.
- The Order of Magnitude estimates has been developed and included into the Scope Statement for a specific outage.
- The Semi-definite Estimate is developed and used to control outage expenditure and manage cash flow by giving accurate forecasts.
- Outage costs breakdown are manpower, materials, external services, general expenses, interdivisional charges by detail account and categorised as Capex or Opex for each GO, MO, IN, IR, or any other outage type.

8.4.4.2 Outage User Requirement specification 24-22 months prior to commencement of an outage (T-24)

A User Requirement specification is drawn up by site engineering 24 months prior to outage commencement which makes provision for the following:

- High level summary of scope of work.
- Summary of level scope of work (i.e. Turbine, Boiler and Generator).
- Technical plan projects.
- List of long lead spares items for the outage.
- Safety, Health and Environment requirements.

- National Regulations, Generation Directives, Policies and Procedures as well as the Value of Zero Harm.
- Records and history requirements.
- Scope of work including inspection and test history.
- Outage cost history from Outage Close-out Reports after the previous outage.

An outage Management Plan is drawn up by Outage Management 18 months (T-18) prior to outage commencement.

Outage costs are driven by both labour and equipment, and differ in costs and duration owing to aging of plant and equipment. For instance they are 83 outages scheduled for FY2022, with 13 rolled over from FY2021. The coal powered stations accounts for 44 outages, Peaking 25 outages and 1 for Koeberg.

Generation expects to require R32.5bn for the MYPD5 period to undergo maintenance outages to prevent future failures, address load losses, meet statutory requirements and fix broken equipment. As indicated in the background, this based on each station philosophy and outage capacity plan to optimally sustain the plant and avoid prolonged load-shedding. It has also been indicated that the activities for each stations are costed individually based on bench-marked prices. The table below shows the expected outage Capex requirements.

TABLE 69: OUTAGE CAPEX (R'M)

Power Stations (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Arnot	466	585	458	600	541	760	314	-
Camden	487	587	532	705	621	685	-	-
Duvha	645	557	926	690	1 030	1 206	731	701
Grootvlei	155	15	-	-	-	-	-	-
Hendrina	194	226	452	290	510	473	0	0
Kendal	444	754	999	1 000	651	618	450	550
Koeberg	45	121	126	155	165	350	320	440
Komati	16	27	-	-	-	-	-	-
Kriel	750	1 174	937	1 024	1 128	1 412	1 263	0
Kusile	-	-	100	50	250	-	300	300
Lethabo	1 263	798	911	940	525	1 700	940	-
Majuba	977	816	815	810	29	1 277	983	1 012
Matimba	453	810	282	500	815	250	886	702
Matla	330	470	723	608	250	878	138	114
Medupi	0	0	230	10	565	400	450	45
Tutuka	821	1 058	151	398	1 300	750	550	250
Peaking	3	17	20	20	20	20	45	34
Coal 1	-	-	(3675)	(4629)	(3059)	(1105)	-	-
Gx DE Office	108	(173)	7 979	10 092	7 937	(326)	-	-
Total Outage Plan	**7 157**	**7 843**	**11 965**	**13 263**	**13 278**	**9 349**	**7 370**	**4 148**

8.4.5 Conclusion on Outage Capex

The compound annual growth rate (CAGR), for Outage Capex is -16.0% which reflects a negative growth which is below inflation. This is a downtrend over the MYPD5 period and beyond.

8.5 Future Fuel Capex

8.5.1 Coal future fuel

See Section 5.9.9.

8.5.2 Water future fuel

See Section 5.9.9.

8.5.3 Nuclear future fuel

See Section 5.15.1

8.6 Asset purchases

TABLE 70: GENERATION ASSET PURCHASES (R'M)

Asset Pruchases (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Asset Purchases	68	272	167	182	167	214	195	201

Asset purchases refer to the purchases of production equipment, transport equipment, computer equipment, computer software and small plant assets.

These types of assets typically last for 3-5 years and have to be replaced at regular intervals when they reach the end of their useful lives.

8.7 Conclusion on capital expenditure

Medupi and Kusile will be completed by the end of the MYPD5 period.

Significant amounts of capital will be spent on the Medupi FGD and environmental compliance projects at the existing fleet of power stations to meet stricter environmental legislation.

To improve and maintain the technical performance at the existing fleet of stations, technical plan projects and Outage Capex, aligned to the Life of Plant Plan must increase in the short term.

9 Conclusion

Generation operates an ageing generation fleet that has been run at high utilisation factors for a number of years under severe financial constraints. Despite this, this application assumes increases of less than inflation in almost all areas and overall Opex costs as well as manpower numbers compare favourably with international benchmarks. This reflects efficiency improvements throughout the business, and especially in reserve storage stations that will not be required to produce energy should all the assumptions in the Production Plan be met. It should be noted that the Production Plan assumes 72% EAF and there is a high risk that this will not be met as projected FY2021 EAF is 65.11% and improvement remains a challenge.

Primary energy costs are under severe pressure due to the coal sourcing environment and significant capital expenditure is required in the cost plus mines to ensure the continued supply of reasonably priced coal that is assumed in this application.

Environmental considerations also require considerable capital expenditure and logistical challenges, including the impact on the electricity price mean that a phased approach with postponements to meeting some of the Minimum Emissions Standards is assumed in this application.

This application is based on efficiency improvements in a challenging environment and a negative return on assets to smooth the impact on the customer. It is reflective of an efficient and prudent operator.