Eskom Summary

Multi-Year Price Determination (MYPD) 5

Revenue Application for FY2023 – FY2025

Submission to NERSA

June 2021

DEDICATION

This Multi-Year Price Determination (MYPD5) Application is in memory of our dear colleague and friend Randall Beukes and the many other Eskom employees whose lives were lost due to the COVID-19 pandemic. Randall was an integral member of the Generation Financial Planning and Economic Regulation Department who contributed immensely from the very advent of revenue applications to NERSA. His light hearted humour, candour and his ability to take things in his stride will be sorely missed in those taxing periods leading up to the finalisation of the applications. He leaves a huge professional, technical and emotional void in our lives. Life has gone on, but his memory remains with us and even more so, when we engage in matters of this nature. We dedicate this MYPD5 Application to the memory of the late Randall Beukes and trust that the work he so tirelessly contributed to, will bear fruit. Those who touch our lives stay in our hearts forever.

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Introduction

Eskom MYPD5 Revenue Application Process

This Multi-Year Price Determination (MYPD) 5 revenue application is for the FY2023 to FY2025 period. This revenue application has been prepared in accordance with the MYPD methodology as published by NERSA during October 2016. The NERSA revenue and tariff decisions will be implemented from 1 April 2022 for non-municipal customers and from 1 July 2022 for municipal customers. The previous revenue application was for a three year period and was implemented for the period from 1 April 2019 to 31 March 2022 for non-municipal customers; and 1 July 2019 to 30 June 2022 for municipal customers.

Eskom makes this revenue application, as it still migrates to a level that reflects to the efficient cost of providing the electricity service. This has been a journey that Eskom and NERSA have been on for many years. Thus the average price of electricity still does not cover the full efficient costs and cost of capital that are incurred. The implication is that all electricity consumers have been receiving a subsidy and will continue to do so during this application period.

The MYPD methodology addresses two broad aspects, namely, the MYPD allowed revenue application and the adjustment of the allowed revenue through the regulatory clearing account (RCA) process. The focus of this application is the MYPD revenue application for FY2023 to FY2025. Once NERSA has determined the allowed revenue in terms of the MYPD methodology, the tariffs and price adjustments are determined by NERSA on an annual basis for the three year period. These tariffs and price adjustments are determined in terms of the Eskom retail tariff and structural adjustment (ERTSA) methodology, as published by NERSA during March 2016.

This revenue application recognises the RCA implementation decisions already made by NERSA. The RCA implementation decisions for standard tariff customers already made for the FY2023 are R7 776m (related to FYs 2015 to 2017) and R6 636m (related to FY2019). This totals R14 412m of RCA implementation decisions already made for effect in FY2023. This MYPD5 revenue application does not include any RCA applications where decisions are yet to be made. In terms of the MYPD methodology, Eskom is required to make RCA applications after the announcement of each financial years' audited financial results. The RCA application for the FY2020 (first year of the MYPD4 period) of R8.42bn was submitted to NERSA on 11 December 2020. The process to finalise the RCA balance decision by NERSA is underway. Stakeholders will be afforded an opportunity to engage on the RCA submission. Eskom is required to submit the RCA balance application for the FY2021 after the announcement of the financial results. This is estimated to be submitted during the 2021 calendar year.

Eskom MYPD5 Revenue Application (FY2023 – FY2025) submission pack:

Eskom has included detailed submission documents to allow for further robust debate and understanding. These submission documents include:

1) **Eskom Revenue Application *Summary***, MYPD5 (FY2023 - FY2025)
2) **Eskom *Generation Licensee* Revenue Application**, MYPD5 (FY2023 - FY2025)
3) **Eskom *Transmission Licensee* Revenue Application**, MYPD5 (FY2023 - FY2025)
4) **Eskom *Distribution Licensee* Revenue Application**, MYPD5 (FY2023 - FY2025)
5) **Abbreviations, Acronyms and Glossary**

Note on Casting of Tables

Certain tables may appear not to cast. However, it needs to be noted that in most cases the amounts reflected in the tables are rounded off to the nearest million rand. Thus the totals are a true reflection of the underlying complete amounts.

Executive Summary

The MYPD4 period comes to an end on 31 March 2022. In terms of mainly the Electricity Regulation Act (ERA), Municipal Finance Management Act (MFMA) and the MYPD methodology, Eskom is required to make a revenue application to NERSA timeously to allow for the implementation from 1 April 2022, of a NERSA approved price adjustment. In accordance with the ERA, Eskom can only implement price adjustments that have been approved by the Energy Regulator. This MYPD5 revenue application has been prepared in accordance with the MYPD methodology as published by NERSA during October 2016. The NERSA revenue and tariff decisions will be implemented from 1 April 2022 for non-municipal customers and from 1 July 2022 for municipal customers.

1.1 Eskom is required to meet the legislative and regulatory framework requirements

Key legislative and regulatory requirements that guide Eskom in making include:

1.1.1 Municipal Finance Management Act

This application has met the requirements of the Municipal Finance Management Act (MFMA), (Section 42), where Eskom is required to consult with National Treasury and organised local Government (South African Local Government Association) prior to making a revenue application to NERSA. In addition, Eskom's application needs to be made timeously to allow the National Energy Regulator of South Africa (NERSA) to make revenue and tariff decisions to facilitate Municipal budgeting processes. The optimal timing is the December prior to the Municipal financial year, which in from 1 July to 30 June the next year. Thus, for MYPD5, Eskom understands that NERSA is required to make a decision by December 2021.

1.1.2 Electricity Regulation Act (ERA)

The key requirement for Eskom when it makes its application, and for NERSA when it makes its determination, is the Electricity Regulation Act (ERA) and the Multi-year Price Determination (MYPD) methodology. NERSA requires Eskom to meet the requirements of the MYPD methodology, which is in essence is the translation of the requirements of the ERA, in this instance. The focus of this application is: **NERSA must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return**

1.1.3 Government Support Framework Agreement (GSFA)

In terms of the Government Support Framework Agreement (GSFA), Eskom is required to ensure that collective **approval** is received from the Department of Mineral Resources and Energy (DMRE), Department of Public Enterprises (DPE) and National Treasury for Section 34 (of the ERA) independent power purchases and associated costs.

1.1.4 Other legislative and regulatory requirements and precedents

Various NERSA guidelines and rules including the Minimum Information for Tariff Applications, Prudency assessments, Grid codes and regulatory rules are considered. The outcomes of court judgements and orders will need to be respected. The adherence to the other related legislative including environmental legislative requirements, regulatory and licence requirements form the basis of the MYPD application. Eskom has however allowed for the smoothing of the tariff increases as well a migration towards cost reflectivity.

1.2 Eskom is applying for prudent and efficient costs and a phased-in return

Eskom applies for efficient and prudent costs based on projections for the MYPD5 period. The projections are based on motivations provided for each of the changes in the particular cost element of the regulatory formula. The details in the environment related to each particular efficient cost is also provided, to the extent possible. The MYPD methodology, with regards to the revenue application is based on a particular formula. The regulatory framework in which Eskom's regulated revenue and tariffs are set provides that the licensee is to recover its prudent costs of service. This 'cost of service' approach is a common feature of regulatory pricing frameworks and is employed by NERSA in other sectors; by other economic regulators within South Africa; and by utility regulators globally.

1.3 What revenues is Eskom applying for the MYPD5 period?

Eskom is making a total revenue application of R279bn, R335bn and R365bn for FY2023, FY2024 and FY2025 respectively. NERSA has already determined that in addition to the MYPD5 revenue determination, previous RCA determinations of R14.4bn will be recovered in FY2023.

1.4 How are potential inefficiency, corruption and fraud and related revenue addressed in the revenue application?

Eskom makes an application for revenue related to efficient costs. The details of each of these revenue items are motivated in details in this submission. Appropriate comparisons, trends and benchmarks are provided for NERSA consideration. In response, NERSA makes a decision based on the requirements of its regulatory rules, guidelines on prudency assessment and its analysis. It is envisaged that NERSA also bases its decision on appropriate comparisons, trends and benchmarks. This allows for a robust process where efficient costs are considered for this revenue decision. Any inefficiency is excluded from the revenue decision in this manner. As directed by NERSA, Eskom will address any recovery of funds related to any corrupt activity through a refund in the RCA applications. Thus the consumer is only migrating towards paying for the recovery of the efficient cost of electricity.

1.5 The revenue allows Eskom to continue to provide electricity

Notwithstanding the phasing-in that Eskom has proposed (discussed below), the various elements of the NERSA allowable revenue formula allows Eskom to continue to provide electricity to consumers. These are all essential elements of being able to provide electricity for Eskom or any similar entity. The key elements include revenue related to the following:

1.5.1 Primary energy: Includes key types of fuel to produce electricity

- Eskom related – coal, water, nuclear fuel, diesel for open cycle gas turbines, etc
- External – Independent power producers(IPPs), environmental levy and carbon tax

1.5.2 Operating costs: Includes various aspects of operating the electricity system and related services

- Employee benefits – staff related costs
- Operating and Maintenance – for operating the electricity system and for the upkeep of generators and networks by maintaining these assets
- Other operating cost – includes insurance, metering, information technology, fleet costs, legal and audit services, security, travel expenses, billing costs, etc.

1.5.3 Asset related revenue is recovered over the life of the assets

- Depreciation – on commissioned assets is recovered through the tariff in accordance with a method determined by NERSA over the life of the asset.

- Return on assets (ROA) – Eskom is still migrating towards a level that has been determined by NERSA previously. Thus this full asset related revenue is not being applied for

1.6 Allowable revenue application for MYPD 5 period

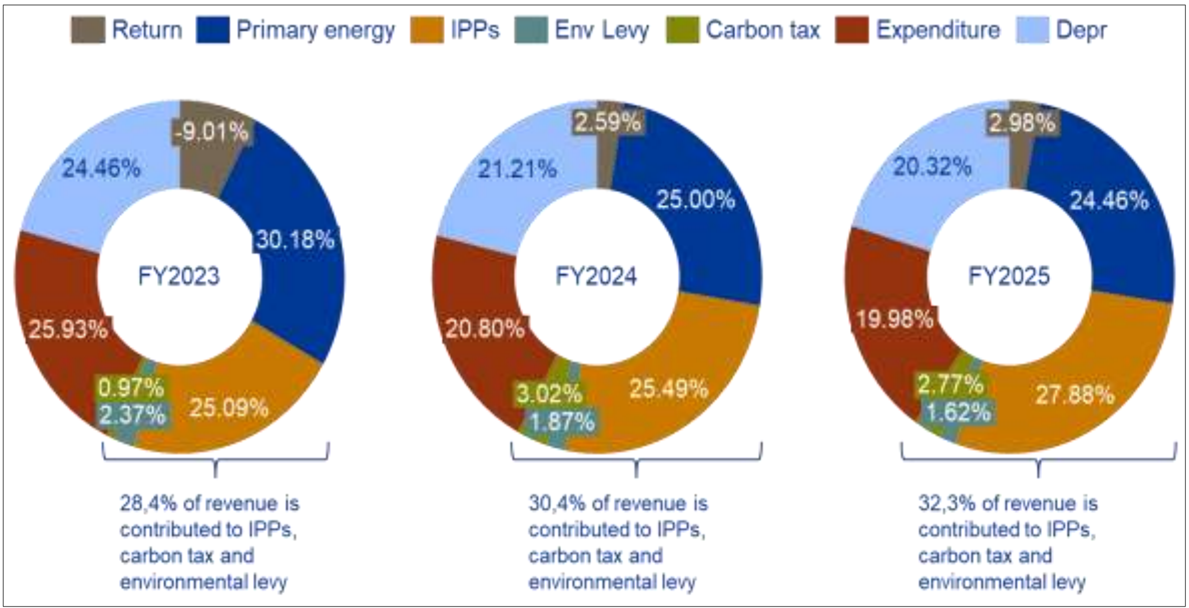
The allowable revenue being applied for in this revenue application is summarised in the table and figure below.

TABLE 1: ALLOWABLE REVENUE APPLICATION FOR MYPD5 PERIOD

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		1 263 247	1 254 636	1 246 151	1 256 395	1 261 675
Return on assets %	ROA	X	0.01%	0.69%	0.87%	1.65%	3.04%
Returns			126	8 682	10 879	20 668	38 292
Returns adjustment to -1,99% RoA in FY2023 to get a 20,5% price increase (i.e customer subsidy)		+	(25 278)	-	-	-	-
Returns applied for			(25 151)	8 682	10 879	20 668	38 292
Primary energy	PE	+	79 627	78 804	84 170	85 462	91 206
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	+	5 666	6 511	7 110	7 802	8 541
Operating costs	E	+	66 690	63 115	65 852	70 327	72 251
Research and Development	R&D	+	-	-	-	-	-
Depreciation	D	+	68 254	71 001	74 214	71 455	72 447
MYPD5 Allowable revenue			**279 018**	**334 676**	**365 195**	**400 437**	**437 562**
Add: Approved RCA's for liquidation	RCA		14 412	-	-	-	-
MYPD5 Allowable revenue including RCA decision already made	R'm		**293 430**	**334 676**	**365 195**	**400 437**	**437 562**

NOTE: RESEARCH AND DEVELOPEMNTS COSTS ARE INCLUDED IN OPERATING COSTS

FIGURE 1: KEY ELEMENTS OF ALLOWABLE REVENUE FOR MYPD5 APPLICATION



1.7 Recovery of efficient costs

a. Primary Energy costs:

Primary energy costs equate to the costing of the electricity supply required to meet demand. The three sources of electricity supply are Eskom own generation, domestic independent power producers (IPPs) and regional imports.

Eskom's primary energy related revenue contributes 30%, 25% and 24% of the allowable revenue corresponding to R80bn, R79bn and R84bn for the application years respectively. Thus a relatively static trend in the Eskom primary energy contribution to allowable revenue is occurring. This is mainly due to production volumes from Eskom decreasing with a moderate increase in the cost of most primary energy components under Eskom's control.

IPP's 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 25.5% to 28% over the application period. 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 from 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. These corresponds to a total cost 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. 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, the 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.

Eskom's strategy for the procurement of coal is based on a portfolio mix, with the majority being sourced from long term contracts. However, it is not possible to contract for all of Eskom's coal requirements on long term contracts. It is prudent to have a portfolio of coal supply agreements that allows flexibility to meet changing electricity demand patterns. The largest component of the projected annual coal costs is the costs from existing and new long term coal sources. This is in line with the first principle of the long term coal supply strategy, namely, securing long term contracts with mines close to power stations.

b. Operating costs:

Eskom's overall operating costs, over the period FY2023 to FY2025 (application years) have grown at a CAGR of approximately 5%. Analysis reflects that employee benefits have an average CAGR increase of 2.32% (after capitalisation) in this horizon. Similarly, the operating and maintenance costs have an average increase in CAGR of 2.15% over the period. The other operating costs see a marked drop with a CAGR of negative 3.34% over the application period.

Significant efficiencies would be achieved over the period by reducing the number of employees through natural attrition and voluntary separation packages. Containing the workforce numbers without compromising the required skills in appropriate areas will be possible. This will be done by re-training, re-deployment and re-skilling of the work-force and natural attrition. Voluntary separation packages were taken in the previous years.

1.8 Eskom has applied for a smoothed phasing-in of return on assets

As required by the MYPD Methodology, Eskom has requested an independent revaluation of its regulatory asset base (RAB) to determine the depreciated replacement cost. This value of the RAB is determined as at 31 March 2020. The opening RAB balance for FY2023 is based on the valuation undertaken by independent external consultants, with a modern equivalent asset value (MEAV), which is then adjusted for the latest capital expenditure forecasts for the period FY2023 to FY2025. This RAB value will differ from the historic cost reflected in Eskom's financial statements, since it is a replacement cost that has been depreciated for the remaining life of the asset.

Return on assets is computed on a revalued regulatory asset base (RAB) with the intention to cover interest costs and earn an equity return. The average starting RAB value for FY2023 is approximately R 1 263bn.

The phased implementation of the return on assets together with depreciation allows for a **significant portion of the interest cost and debt repayment costs to be covered over the three year period**. The allowed revenue being applied for does not cover the full debt commitment costs. Rather, progress is being made towards covering these debt commitment costs. Due to this smoothing of the price, Eskom experiences a significant shortfall in the first year of the MYPD5 period. A net shortfall of approximately R29bn is experienced just to meet Eskom’s debt commitments. Eskom will not be in a position to provide for any return on equity for the entire application period. An EBITDA margin of approximately 35% would be considered reasonable for Eskom presently. However, this EBITDA margin is not reached. Thus the return on assets is being phased-in to allow for the smoothing of the tariff. This is the decision that Eskom is proposing 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 much higher. Eskom is making this proposal, to allow for consumers to experience a smoother price increase. However, this proposal is accompanied by risks which need to be managed. It is unfortunate, that further burden is required to be applied on the fiscus. The efficient costs do not go away and need to be funded. In essence the subsidy provided to all consumers is continued to be provided for a longer period.

The implementation of the MYPD methodology will entail Eskom applying for cost reflective revenue that covers efficient and prudent costs as well as a return on assets corresponding to the weighted average cost of capital. A cost reflective tariff is one that allows Eskom to recover its efficient and prudently incurred costs and earn a reasonable return. The remainder of the building blocks in terms of the NERSA revenue formula, for this revenue application are in accordance with the MYPD methodology. If Eskom applies its approved weighted average cost of capital of 11.5% (real, pre-tax), the average increase in the revenue will be approximately 95% (FY2023), 2% (FY2024) and 7% (FY2025). With even a return on assets of 7.1%, as determined by NERSA for the MYPD4 period, would result in a price increase of approximately 71% in FY2023, 2% increase in FY2024 and 7% increase in FY2025. If Eskom were to ensure that a minimal positive return on assets of 0.01% were to be applied for in the first year of the application period, it would result in a 32% increase of that year. Due to the stage that the country is in with regards to migration towards cost reflectivity, these are not options that Eskom is considering.

As a first step towards the sustainability of Eskom, it would be preferable for Eskom to ensure that the revenue caters for prudent and efficient costs as well as a reasonable return that matches the debt service commitments (interest and debt repayments). Thus the revenue related collectively to depreciation and return on assets must match the debt service commitments entailing the debt repayments and interest payments. This would manifest in an approximate increase of 34% in the FY2023, 4% in FY2024 and 13% in FY2025. However, in the interest of the potential impact on consumers, Eskom has proposed a longer phasing-in period. This is considered to be having a significant impact on consumers and thus is not being applied for.   However, the allowed revenue being applied for does not cover the entire debt commitment costs, equating to a cash shortfall totalling approximately R29bn for the MYPD5 period. This is a significant further phasing being proposed by Eskom in the interest of allowing the economy to adjust as the migration towards cost reflectivity. Eskom will use the proceeds from the liquidation of the RCA decisions to contribute to mitigating the debt service shortfalls.

1.9 Recovery of Medupi, Kusile and Ingula (MKI) capital related costs

The contribution of the capital related costs recovered from the consumer for Medupi, Kusile and Ingula power stations are demonstrated in the table below. As clarified above, the capital related costs are recovered through depreciation and return on assets. For the application years, when Medupi, Kusila and Ingula power stations are collectively considered, then the amount related to these three new power stations is R4 434m, R14 521m and R15 283m for each of the application years respectively. Thus the consumer's contribution accounts for 1.5%, 4.3% and 4.2% of the total allowable revenue being applied for. This corresponds to a very small portion of the price of electricity.

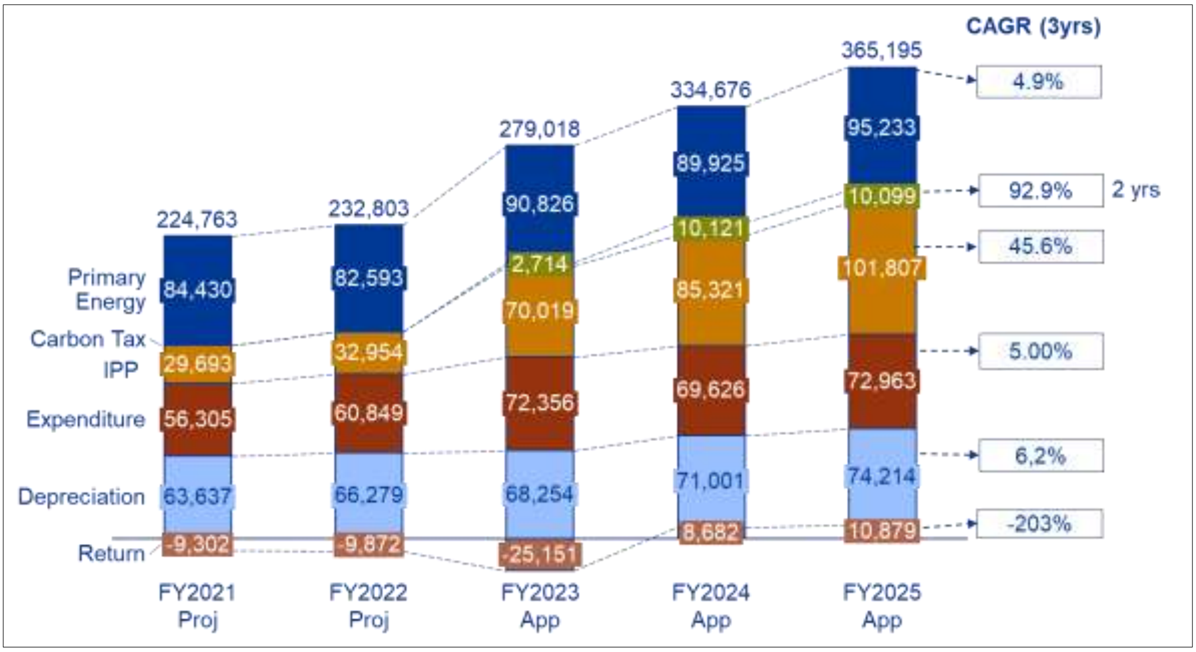
TABLE 2: RECOVERY OF MEDUPI, KUSILE AND INGULA CAPITAL RELATED COSTS

Medupi, Kusile and Ingula (MKI) impact (R'm)	Application FY2023	Application FY2024	Application FY2025
Total Allowable Revenue	293 430	334 676	365 195
MKI Depreciation	11 849	11 922	12 022
MKI RoA	(7 415)	2 599	3 261
MKI Capital Costs included in Total Allowable Revenue	**4 434**	**14 521**	**15 283**

1.10 Stability in Eskom own costs

The figure below illustrates the compounded annual growth rates in the various elements over the MYPD5 revenue application period.

FIGURE 2: COMPOUNDED ANNUAL GROWTH RATES OF KEY ELEMENTS OF ALLOWABLE REVENUE IN MYPD5 APPLICATION



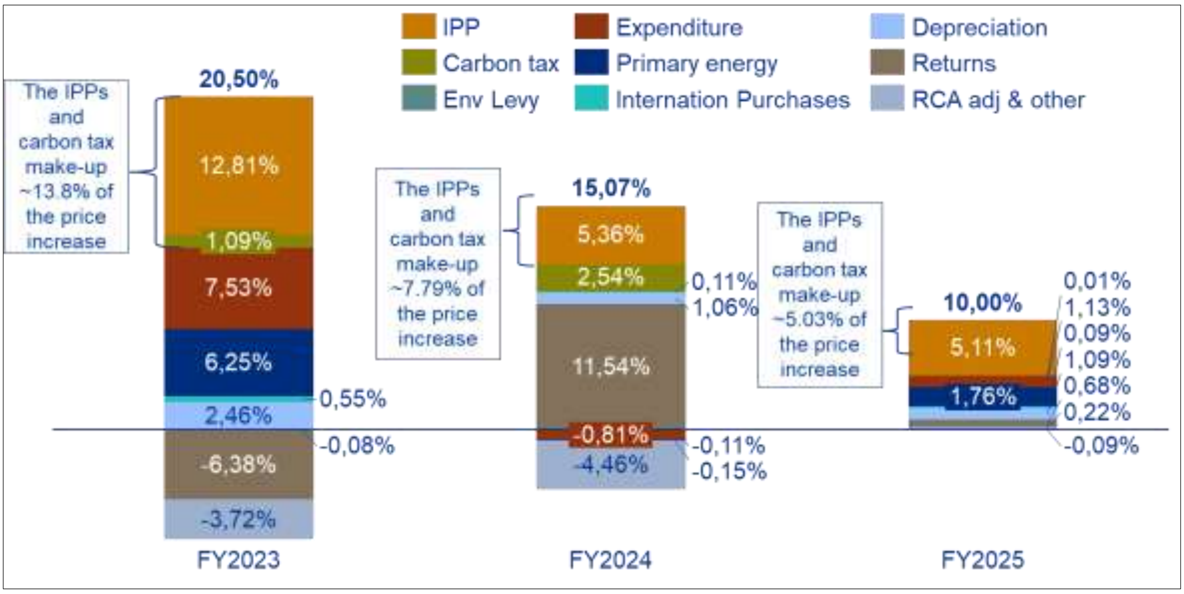
Eskom has achieved a status in the MYPD5 application where it's operating costs and the Eskom primary energy costs have stabilised to 5% CAGR for the three year period. This indicates the level of control Eskom has instituted to reach such a status. Similar trends have been observed for operating costs even in the MYPD4 period. Due to the return on assets being phased-in, the CAGR is negative.

However, increases for IPP due to increases in IPP energy volumes and Carbon tax are significant Significant increases in the compounded annual growth rate (CAGR) is for IPP costs of 46% (due mainly to increased volumes from mainly renewable energy) is seen over the three year period. Similarly, increases in CAGR for carbon tax over the two year period from FY2023 to FY2024 is 93%.

1.11 Year on year increases dominated by IPP increases

The figure below indicates the key contributors to the increase in the price of electrcity on a year-on-year basis.

FIGURE 3: CONTRIBUTION TO YEAR ON YEAR PRICE INCREASES FOR MYPD5 PERIOD



The key contributors for the price increases over the MYPD5 period have been identified. It is surmised that externally controlled elements of the allowable revenue have the biggest impact on the price increase.

- **FY2023** - Of the 20.5% increase IPPs account for 12.81% increase, carbon tax 1.09% increase, elements under Eskom direct control contribute approximately 7% of the increase
- **FY2024** - Of the 15.07% increase, IPPs again account for the highest component of 5.36% increase and carbon tax 2.54% increase. More than half the increase is related to the external factors. Costs under Eskom control contribute approximately 7% of the increase.
- **FY2025** - Of the 10% increase, IPPs again account for the highest contribution of 5.11% increase. More than half the increase is related to external factors. Costs under Eskom control contribute less than 5% of the increase.

The significant increase in IPPs is due to further increases in energy sourced from IPPs, the continual escalation on existing contracts and further technologies being introduced. The trend seen in the MYPD5 period is likely to continue.

1.12 Tariff category increases to be experienced

The resultant standard tariff increases that will result if NERSA approves the allowable revenue, as applied for, are shown in the table below.

TABLE 3: RESULTANT TARIFF INCREASES FOR STANDARD TARIFF CUSTOMERS

Standard tariffs and categories	Application FY2023	Application FY2024	Application FY2025
Standard tariff annual increase	20.50%	15.07%	10.00%
Municipalities			
Municipal tariffs - effective 1 July	21.00%	13.30%	8.90%
Eskom direct customers (non-municipal tariffs)			
Businessrate, Public lighting, Homepower, Homelight 60A, Homelight 20A, Landrate and Landlight	20.50%	15.07%	10.00%
Megaflex, Miniflex, Nightsave Urban, WEPS, Transflex, Megaflex Gen			
• Affordability susbidy charge (where applicable)	15.66%	15.45%	14.74%
• Other tariff charges	20.50%	15.07%	10.00%
*Effective increase including affordability subsidy	20.32%	15.09%	10.18%
Ruraflex, Nightsave rural, Ruraflex Gen	20.50%	15.07%	10.00%
Homelight 20A			
• IBT Block 1: >0 to 350kWh	20.50%	15.07%	10.00%
• IBT Block 2: >350kWh	20.50%	15.07%	10.00%

1.13 Eskom requires reasonable tariff increases to address financial sustainability and liquidity challenges

Liquidity and solvency risks pose an inordinate threat to Eskom's ability to continue as a going concern. To improve liquidity, we have restricted organisational cash requirements through targeted savings. We had to rely on Government support to maintain a positive cash balance, with increases in equity. Due to high debt servicing obligations, maintaining the liquidity buffer at acceptable levels continues to be a challenge.

Although Government's equity support assists with liquidity requirements, it does not adequately enhance our long-term financial sustainability. The only way to achieve financial sustainability is to improve operating cash flows that results in positive free cash flows, with a strong focus on moving to a prudent, cost-reflective tariff.

We acknowledge the importance of cost savings to improve liquidity, with a focused cost curtailment programme over the next three years. Nonetheless, cost savings alone will not be sufficient to improve our financial health. For Eskom and the electricity supply industry to continue to operate and maintain its assets in a reliable state, the price of electricity must migrate towards cost-reflectivity to ensure Eskom's long-term financial sustainability. Without a cost-reflective tariff path, we will remain reliant on Government support, which implies that the taxpayer will continue to foot the bill for the revenue shortfall, which is contrary to the "user pays" principle.

1.14 Economic impact are best managed by continuing to migrate towards cost reflective prices of electricity

It may be tempting to conclude that by limiting electricity tariff increases and requiring that Eskom and/or government borrow the revenue shortfall (and effectively implicitly subsidise the price), it is possible to minimise the negative impacts of rising electricity prices on GDP and employment growth in the short-term.

However, the results of the economy-wide impact analysis show that the fiscal and economic consequences of awarding Eskom a tariff that is much lower than what it requires (to recover its prudently and efficiently incurred costs), do eventually (and arguably have now) become evident.

Our recommendation is that tariff increases should at least be sufficient to transition Eskom towards a more cost-reflective electricity tariff (prudently and efficiently incurred) over the next few years. The protection of vulnerable sectors, including poor households and certain industrial sectors are being addressed by Government-led interventions.

Eskom is dependent on NERSA making revenue and tariff decisions in accordance with its mandate, policy and relevant legislation.

2 Basis of Application

2.1 Legislative and regulatory framework

When Eskom makes its revenue applications, it is required to do so in terms of the relevant legislation and regulations. This ensures that only efficient and prudent costs are recovered from consumers. The key requirement for Eskom to ensure that it complies with, when it makes its application; and for NERSA to comply with when it makes its determination; is the Electricity Regulation Act and the MYPD methodology. NERSA requires Eskom to meet the requirements of the MYPD methodology, which is in essence is the translation of the requirements of the ERA, in this instance. The Supreme Court of Appeal has confirmed that the MYPD methodology is a policy requirement that needs to be adhered to. When a revenue application is made by Eskom, before considering the application, NERSA ensures that the requirements of the MYPD methodology are complied with and Guideline on Minimum Information Requirements for Tariff Applications (MIRTA) are considered. NERSA is required to undertake this confirmation within two weeks of the application being submitted. If compliance is not achieved, then Eskom has to provide further information to reach compliance. In addition, the principles outlined in the judgments of recent reviews of NERSA revenue and RCA decisions are adhered to, as applicable, in this revenue application.

In terms of the Government Support Framework Agreement (GSFA), Eskom is required to ensure that collective **approval** is received from the Department of Mineral Resources and Energy (DMRE), Department of Public Enterprises (DPE) and National Treasury for Section 34 (of the ERA) independent power purchases and associated costs.

In terms of the Municipal Finance Management Act (MFMA), (Section 42), Eskom is required to consult with National Treasury and organised local Government (South African Local Government Association) prior to making a revenue application to NERSA. In addition, Eskom's application needs to be made timeously to allow NERSA to make revenue and tariff decisions to facilitate Municipal budgeting processes. The optimal timing is the December prior to the Municipal financial year, which in from 1 July to 30 June the next year. Thus, for MYPD5, Eskom understands that NERSA is required to make a decision by December 2021.

The adherence to the various related legislative, regulatory and licence requirements form the basis of the MYPD application. Eskom has however allowed for the smoothing of the tariff increases as well a migration towards cost reflectivity. The following are certain key requirements applicable to the determination of Eskom's allowed revenue and resulting tariff adjustments.

2.1.1 Municipal Finance Management Act (Act 56 OF 2003)

Eskom is required to take into account comments from the National Treasury and organised local government on the draft revenue application. The revenue application should include a motivation for adjustment of tariffs; consideration of impact on inflation targets and other macroeconomic policy objectives; Eskom's efficiency improvements and objectives**.** The need to timeously table approved adjusted tariffs in Parliament for implementation for Municipal customers.

2.1.2 Electricity Regulation Act (Act No. 4 of 2006)

Prescribes tariff principles including:

- Revenues enabling an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;
- Avoidance of undue discrimination between customer categories;
- Permitting the cross subsidy of tariffs to certain classes of customers by the Energy Regulator;
- Approval of tariffs by the Energy Regulator

2.1.3 Electricity Pricing Policy

The Electricity pricing Policy (EPP) gives broad guidelines to the Energy Regulator in approving prices and tariffs for the electricity supply industry.

2.1.4 Government Support Framework Agreement

The Government Support Framework Agreement (GSFA) with regards to the Department of Energy procured Independent Power Producers, under section 34 of the Electricity Regulation Act, was signed by Government (represented by the Ministers of Energy, Finance and Public Enterprises) and Eskom in 2012. In accordance with section 3.1.4(e) of the GSFA, Eskom is required to seek approval collectively from the Department of Energy (DOE) 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 any revenue application.

2.2 NERSA Guidelines for Prudency assessment

NERSA issued guidelines for prudency assessment during August 2018. Eskom will base this revenue application on the principles of this guideline. Certain aspects that are pertinent to this application are included here.

S2.4 *The guidelines will formalise the use of a uniform approach and assists licensees in knowing (in advance) the basis on which the assessment was conducted. They will also inform the licensees of the specific area or information that the Energy Regulator will focus on when assessing prudency matters.*

S2.5 *The existence of the guidelines is expected to improve regulatory certainty in the long term and provide a transparent framework by ascertaining whether costs were or will be incurred prudently.*

S5.2.1.4 *The MYPD Methodology requires the Energy Regulator to review the efficiency of all contracts, such as those between Eskom and IPPs, before the conclusion of the contracts, to ensure prudency. It also requires that there be a fair risk allocation between the IPP and Eskom, as the buyer.*

S6.1.1.2 *Whether a cost is prudently incurred depends on how the decision was made, not only the outcome of the decision*

S6.1.1.3 *In assessing prudency, the following will be considered: b. Expenditure that meets a standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by licensee at the time the decision had to me made*

S6.1.2.3 *Efficient costs can also be those that can make the licensee more efficient over the long term and improve the experience of the customers' experience of the licensee's service. NERSA however recognises that that there are instances and circumstances where these may not be the least cost option.*

S8.3 *In assessing prudency, it is necessary to make a distinction between forecast and committed costs*

S8.3.b *Committed costs are costs that the utility has already spent or has entered into a binding commitment to pay or is subject to other legal obligations that leave it with no discretion as to whether to make the payment in future. The disallowance of committed costs is particularly problematic for a regulated entity because the regulated utility and its shareholders will have no choice but to bear the burden of these costs themselves.*

S8.6 *In using the Guidelines for prudency assessment, it should be emphasised that hindsight provides perfect insight, which is not available or could not reasonably have been known to those making the decisions. Therefore it cannot be used to assess the decisions made. The assessment of decisions made must be done by first establishing what was known at the time, as well as what influences were at play at the time the decision was made.*

2.3 Guideline on Minimum Information Requirements for Tariff Applications (MIRTA)

Eskom accepts that MIRTA is not prescriptive. It is a guideline providing direction to the licensee in compiling a revenue application. Eskom will endeavour to address the requirements as far as possible.

2.4 Eskom Retail Tariff and Structural Adjustment (ERTSA) Methodology

The 1 March 2016 ERTSA methodology governs the tariff increases to the Standard tariffs. The ERTSA is applicable to Eskom's Standard tariffs for local authorities (Municipal) and non-local authorities (non-municipal). Eskom is required to submit an ERTSA application prior to the start of each financial year. The revenue decision applicable for the particular year as well as any RCA liquidation decisions made by NERSA will need to be considered when the ERTSA application is made. The ERTSA application consists of an application for the rate of adjustment to Standard tariffs and the proposed Schedule of standard tariffs for each financial year.

Although there may be differentiated impact amongst customers, the basis is that the allowed revenues which include any RCA liquidation decisions together with the NERSA decision forecasted sales would be applied to ensure that only the allowed Eskom revenue is recovered.

2.5 Frameworks - short term and interim long term negotiated pricing agreements

The Department of Mineral Resources and Energy (DMRE) has amended the short term negotiated pricing agreements (NPA) framework and developed an interim long term NPA framework in accordance with the requirements of the Electricity Pricing Policy (EPP). The Short-term NPAs have been specifically structured to provide opportunities to sustain existing businesses that are at risk of failure and permit others that have closed production capacity in recent years, owing to their inability to compete in their markets, to restart these assets. The rationale for the interim long-term framework is to protect vulnerable sectors, improve relative sector competitiveness and attract investment in the long-term. These two frameworks will allow for the relevant vulnerable sectors, which are impacted by the price of electricity and meet the required criteria, to be supported to allow for further contribution to economic activity of the country.

2.6 Various other legislative and license requirements

As is the case for any entity, Eskom is required to comply with a myriad of legislative requirements. This is also reflected in the Eskom licenses, granted by NERSA. Key amongst these legislative requirements is the Public Finance Management Act, Company's Act, various procurement related legislation, health, safety and environmental legislation, nuclear legislation as well as labour related legislation.

The NERSA regulatory principles that are depended upon include transparency, neutrality, integrity, consistency and predictability.

2.7 Outcomes of various High Court applications

The outcomes of various High Court Decisions are respected in this MYPD5 application.

2.8 Multi-Year Price Determination (MYPD) Methodology

The revenue application is based on the requirements of the MYPD methodology as published by NERSA during October 2016. The MYPD methodology addresses two broad aspects, namely, the MYPD allowed revenue application and the adjustment of the allowed revenue through the regulatory clearing account (RCA) process. **The focus of this application is the MYPD revenue application for the FY2023 to FY2025.** It is clarified that this revenue application **does not include any further RCA adjustments**. Focus is the revenue application for the FY2023 - FY2025

NERSA and Eskom are still in the process of aiming to reach a level that corresponds to an average price of electricity that is reflective of the **efficient cost** of producing the electricity and the associated service. It needs to be clarified that NERSA will undertake analysis of Eskom's application, make benchmark comparisons and apply prudency criteria to determine the **efficient costs** of providing the service. Thus, any form of inefficiency, as determined by NERSA, is not included in the price of electricity. In essence, NERSA determines the price level that reflects the efficient cost of electricity. The MYPD methodology allows only for efficient and prudent costs to be recovered through its application.

This approach has been confirmed by NERSA in one of its recent affidavits (related to the FY2018 RCA review) with the following extract:

"Firstly, NERSA makes a provision of Eskom's allowable revenue by forecasting its efficiently incurred costs and reasonable return. This is owing to the fact that the price of electricity is determined in advance (before Eskom incurs expenses for that financial year and before the public makes use of the electricity). This forecast is not a restriction on what Eskom can spend in that financial year. It is a restriction on what Eskom can recover from the public during the financial year.

Secondly, the final determination of Eskom's allowable revenue takes place when the actual expenditure is available and NERSA is able to test it for prudency and efficiency through the Risk Management Control & Pass -Through Mechanism process, commonly referred to as the RCA process".

The High Court decisions, where it was determined that NERSA did not apply its methodology correctly will need to be taken into consideration. Eskom is committed to ensuring that the MYPD methodology, is respected when this revenue application is made. In the interest of the economy, certain migratory processes are factored into the application.

2.9 Application does not include further RCA adjustments

It is clarified that Eskom has not applied for any further RCA adjustments in this revenue application. Only the RCA implementation decisions that have already been made are considered when the average price increase is determined. It is acknowledged that when NERSA makes further implementation decisions, including RCA decisions, this would impact the effective price increase. Eskom does not have any information to this effect presently.

The RCA process is backward looking and allows for adjustment of future tariffs to address past variances (in accordance with the MYPD methodology) between the revenue decision and the actuals that panned out. When a new MYPD revenue application is made, it is forward looking and based on projected assumptions. There is a direct link between MYPD decisions and RCA applications where risks are managed in RCA applications. Thus if a significant risk is passed to Eskom at the stage of a revenue decision, the impact would materialise in a RCA application. Thus the consumer is protected from the risk at an initial stage during the revenue determination. Variances in RCA applications are linked to two key sources:

- Variances in costs due to a changing environment and assumptions that materialise **after** the MYPD decision;
- Assumptions made **during** the MYPD revenue decision which do not materialise.

3 Allowable Revenue

Eskom applies for efficient and prudent costs based on projections for the MYPD5 period. The projections are based on motivations provided for each of the changes in the particular cost element of the regulatory formula. The details in the environment related to each particular efficient cost is also provided, to the extent possible. The MYPD methodology, with regards to the revenue application is based on a particular formula. The regulatory framework in which Eskom's regulated revenue and tariffs are set provides that the licensee is to recover its prudent costs of service. This 'cost of service' approach is a common feature of regulatory pricing frameworks and is employed by NERSA in other sectors; by other economic regulators within South Africa; and by utility regulators globally.

It is submitted that whatever the structure of the industry, a need for the allowable revenue to correspond to the efficient and prudent cost of providing the service will be required. A research document commissioned in 2003 by National Treasury explains that

"In economic theory, efficient prices are defined as prices that approach the marginal cost, which is the level achieved under – perfectly – competitive conditions. Economic regulation is generally introduced when market failures prevent effective competition and is aimed at mimicking the competitive conditions to steer prices towards efficient levels, and ….if well-implemented, economic regulation should lead to efficient prices."

Eskom's revenue requirement application for FY2023 to FY2025 is based on the allowed revenue formula as reflected in the MYPD methodology:

3.1 Allowable Revenue formula

Eskom's revenue requirement application for MYPD5 period FY2023 to FY2025, is based on the allowable revenue formula as reflected in the MYPD methodology:

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

Where:

AR	=	*Allowable Revenue*
RAB	=	*Regulatory Asset Base*
$WACC$	=	*Weighted Average Cost of Capital*
E	=	*Expenses (operating and maintenance costs)*
PE	=	*Primary Energy costs (inclusive of non-Eskom generation)*
D	=	*Depreciation*
$R\&D$	=	*Costs related to research and development programmes/projects*
IDM	=	*Integrated Demand Management costs (EEDSM, PCP, DMP, etc.)*
SQI	=	*Service Quality Incentives related costs*
$L\&T$	=	*Government imposed levies or taxes (not direct income taxes)*
RCA	=	*The balance in the Regulatory Clearing Account (risk management devices of the MYPD)*

3.2 Allowable revenue if MYPD Methodology is applied

In this application, Eskom is allowing the return on assets (ROA) component to be migrated towards the weighted average cost of capital (WACC) during the entire period. Eskom is not at all considering the scenario where a full return on assets is being applied for. It is felt that the resultant increases would be untenable for the consumer. Eskom has decided to only consider options that continue to phase-in the return on assets. During the MYPD5 period, Eskom will not be in a position to provide for any return on equity and will not achieve a reasonable EBITDA margin under the present conditions. This, in essence, further contributes to the delay of the implementation of the Electricity Pricing Policy with regards to reaching cost reflectivity by 2013, shifting the goal posts further down the road. The continual extension for migration towards cost reflectivity results in a shortfall of revenue. This efficient revenue will need to be sources from elsewhere, since it is not being included in the price of electricity. This results in Eskom continuing to burden the fiscus.

3.3 Proposed MYPD5 Allowable revenue application

This revenue application is being made for the MYPD5 period, for FY2023, FY2024 and FY2025 following the Energy Regulator decision for the MYPD4 period, where the allowable revenue decisions of R191bn, R205bn and R215bn corresponded to average nominal price increases of 9.4%, 8.1% and 5.2% for standard tariff customers, respectively, were made.

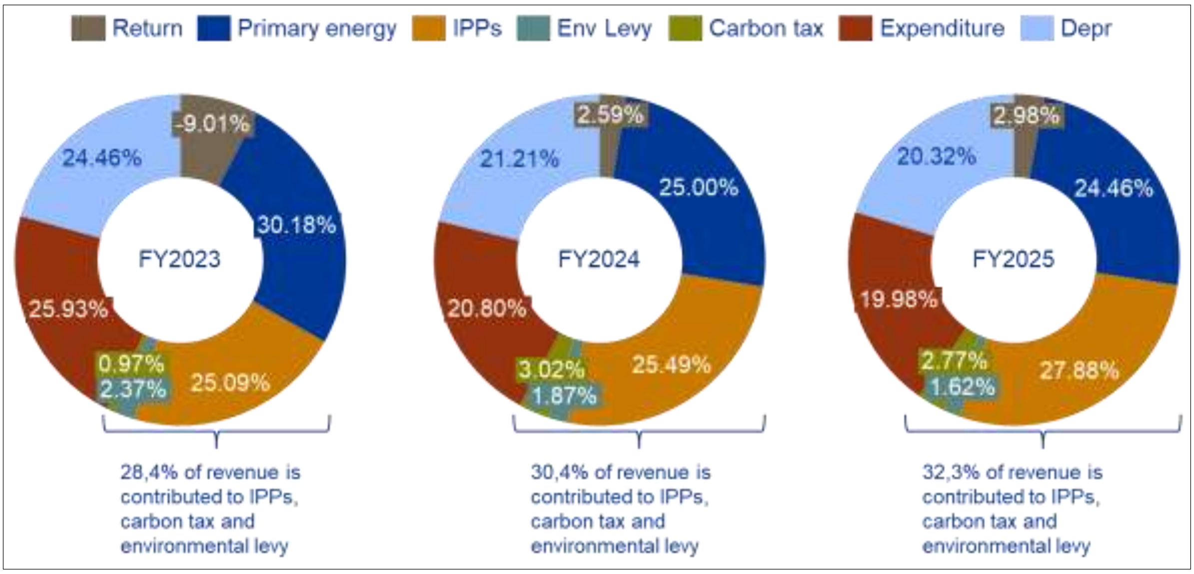
Eskom is making a total revenue application of R279bn, R335bn and R365bn for the FY2023, FY2024 and FY2025 respectively. NERSA has already determined that in addition to the MYPD5 revenue determination, previous RCA determinations of R14.4bn will be recovered in the FY2023. Eskom, in this revenue application has applied the NERSA MYPD methodology, with a smoothed phasing-in of return on assets. Thus the MYPD methodology is not being applied in its fullest form. The phased implementation of the return on assets together with depreciation allows for a **significant portion of the interest cost and debt repayment costs to be covered over the three year period**. The allowed revenue being applied for does not cover the debt commitment costs. Rather, progress is being made towards covering these debt commitment costs. Due to this smoothing of the price, Eskom experiences a significant shortfall in the first year of the MYPD5 period. The debt commitments are barely met in the subsequent two years. A net shortfall of approximately R29bn is experienced just to meet the debt commitments. In addition, at the end of the three year application period, Eskom does not reach the allowed return on assets equivalent to the weighted average cost of capital. Eskom will not be in a position to provide for any return on equity for the entire application period. An EBITDA margin of approximately 35% would be considered reasonable for Eskom presently. This EBITDA margin is not reached. Thus the return on assets are being phased-in to allow for the smoothing of the tariff. The remainder of the cost elements of the revenue application are in accordance with the MYPD methodology. The details are reflected in the summary table below. Further details on each of the elements are provided in subsequent sections of this application.

TABLE 4: PROPOSED ALLOWABLE REVENUE APPLICATION

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		1 263 247	1 254 636	1 246 151	1 256 395	1 261 675
Return on assets %	ROA	X	0.01%	0.69%	0.87%	1.65%	3.04%
Returns			126	8 682	10 879	20 668	38 292
Returns adjustment to -1,99% RoA in FY2023 to get a 20,5% price increase (i.e customer subsidy)		+	(25 278)	-	-	-	-
Returns applied for			(25 151)	8 682	10 879	20 668	38 292
Primary energy	PE	+	79 627	78 804	84 170	85 462	91 206
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	+	5 666	6 511	7 110	7 802	8 541
Operating costs	E	+	66 690	63 115	65 852	70 327	72 251
Research and Development	R&D	+	-	-	-	-	-
Depreciation	D	+	68 254	71 001	74 214	71 455	72 447
MYPD5 Allowable revenue			**279 018**	**334 676**	**365 195**	**400 437**	**437 562**
Add: Approved RCA's for liquidation	RCA		14 412	-	-	-	-
MYPD5 Allowable revenue including RCA decision already made	R'm		**293 430**	**334 676**	**365 195**	**400 437**	**437 562**

Note: Research and development is included in Operating costs

FIGURE 4: KEY ELEMENTS OF ALLOWABLE REVENUE FOR MYPD5 APPLICATION



The figure above demonstrates the contribution of the various elements of the allowable revenue over the three year application period.

The following is noted:

- **The return on assets**, which is being phased-in over the period to cushion the impact on consumers – contributes negative 9%, positive 3% and positive 3% for FY2023, FY2024 and FY2025 respectively towards the allowable revenue. This corresponds to negative 2%, positive 0.7% and positive 0.9% ROA. This is much lower than the conservative 7.1% WACC (as determined by NERSA for the MYPD4 period). The projected WACC, as determined by Eskom, in accordance with the NERSA requirements, is 11.5%. If Eskom were to ensure that a minimal positive return on assets of 0.01% were to be applied for in the first year of the application period, it would result in a 32% increase of that year. This is considered to be having a significant impact on consumers and thus is not being applied for. Together with depreciation, the overall shortfall, to meet debt commitments is approximately R29bn. No equity return can be recovered. This phasing-in negatively impacts the achievement of a reasonable EBITDA margin for this period.

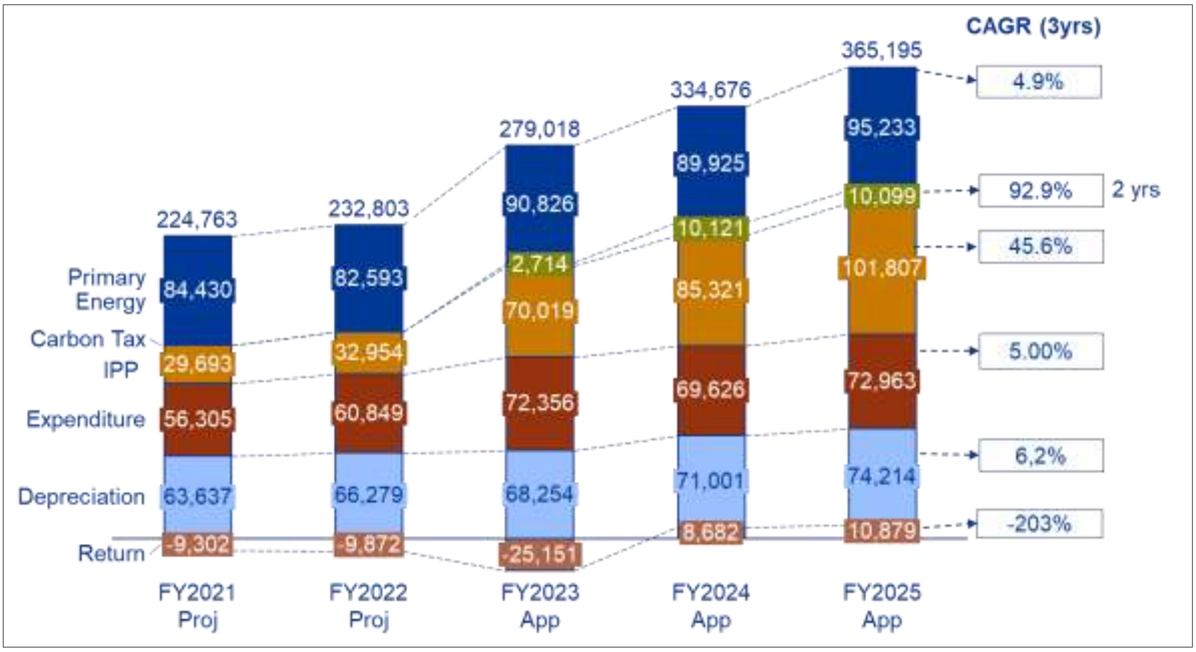
- **Eskom's primary energy** related revenue contributes 30%, 25% and 24% of the allowable revenue corresponding to R80bn, R79bn and R84bn for the application years respectively. Thus a relatively static trend in the Eskom primary energy contribution to allowable revenue is occurring.
- **IPPs** experience 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 remains at 5% in each year of the application respectively. This shows the impact of the introduction of carbon tax liability from January 2023. The implication is that from January 2023, environmental levy and carbon tax account for approximately 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.
- **Operating costs** show a decreasing contribution trend from 26% to 21% and to 20% of the allowable revenue over the period. This corresponds to R67bn, R63bn and R66bn. This indicates relative stability in the operating costs being achieved over the period.

- **Depreciation** over the application period is relatively stable. The contribution to allowable revenue migrates from 24% to 21% to 20% of allowable revenue over the period. This corresponds to R68bn, R71bn and R74bn over the period.

i) Trends in CAGR of revenue components

The figure below illustrates the compounded annual growth rates in the various elements over the MYPD5 revenue application period.

FIGURE 5: COMPOUNDED ANNUAL GROWTH RATES OF KEY ELEMENTS OF ALLOWABLE REVENUE IN MYPD5 APPLICATION



- **Stability in Eskom own costs**

Eskom has achieved a status in the MYPD5 application where its operating costs have stabilised to a CAGR of 5% for the application period. Similar trends have been observed for operating costs even in the MYPD4 period. The Eskom primary energy costs have stabilised to a CAGR of 4.9% for the three year period. This is partly due to lower volumes of primary energy components. This indicates the level of control Eskom has instituted to reach such a status. The depreciation related revenue reflects a CAGR of 6.2%. This is a factor of the underlying regulatory asset base. Due to the return on assets being phased-in, the CAGR is negative.

- **Significant CAGR increases for IPP and Carbon tax**

Significant increases in the compounded annual growth rate (CAGR) is for IPP costs of 46% is seen over the three year period from 2023 to 2025. Similarly, increases in CAGR for carbon tax over the two year period from FY2023 to FY2024 is 93%.

3.4 Allowable revenue for each licensee

Eskom will continue to make ring-fenced applications for the generation, transmission and distribution licensee. This has been the practice since the MYPD 1 application. The allowable revenue for the three licensees, are shown in the table below. Further details on each licensee requirements are included in the detailed licensee submissions, which form part of the MYPD5 revenue application.

TABLE 5: LICENSEE ALLOWABLE REVENUE

Allowable Revenue (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Total Generation allowable revenue	246 339	281 322	309 476	339 873	369 316
Transmission allowable revenue	9 779	13 234	13 880	15 557	18 677
Distribution allowable revenue	37 312	40 119	41 839	45 007	49 568
MYPD5 Total Allowable Revenue	**293 430**	**334 676**	**365 195**	**400 437**	**437 562**

3.5 Revenue recovery

The recovery of the Negotiated Pricing Agreement (NPA) revenue is in accordance with the contracts that have been concluded with the entities. The revenue recovered from international customers would also be in accordance with the contracts with the international customers and utilities. Once the projected revenue for NPA and international customers is deducted from the total revenue, the remainder is recovered from Eskom standard tariff customers. This is in accordance with the manner in which NERSA makes its decisions.

TABLE 6: RECOVERY OF REVENUE

Revenue recovery (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Non standard tariff customers	17 385	20 300	17 167	16 979	17 897	18 933	19 533
Standard tariff (Incl RCA's)	214 759	245 710	276 263	317 696	347 299	381 504	418 029
MYPD5 Allowable Revenue	**232 144**	**266 010**	**293 430**	**334 676**	**365 195**	**400 437**	**437 562**

3.6 Electricity price impact during application period

The impact on the standard tariff price increase of the allowed revenue being applied for is reflected in the table below. An assumption is made on the latest available standard tariff volumes as determined prior to this application being made. In accordance with the NERSA MYPD methodology, a revision of the sales volume to reflect the prevailing situation just prior to NERSA making its decision will be made available by Eskom for consideration by NERSA.

TABLE 7: STANDARD TARIFF AVERAGE PRICE INCREASE

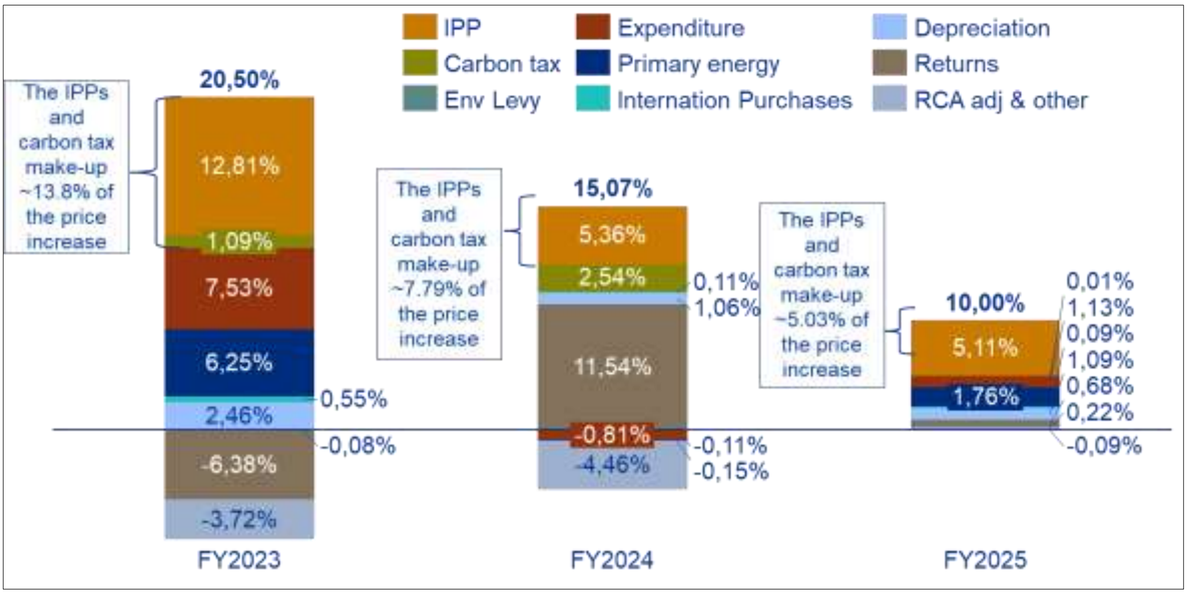
Standard tariff price impact	Unit	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Standard tariff revenue	R'm	214 759	245 710	276 263	317 696	347 299	381 504	418 029
Standard tariff sales volumes	GWh	184 898	183 856	171 549	171 440	170 370	170 141	169 476
Standard tariff price	c/kWh	116.15	133.64	161.04	185.31	203.85	224.23	246.66
Standard tariff price adjustments	**%**	**8.76%**	**15.06%**	**20.50%**	**15.07%**	**10.00%**	**10.00%**	**10.00%**

The table above provides details on the proposed standard tariff price increases for each of the three MYPD5 application years. The RCA decisions already made by NERSA are included in the standard tariff revenue when the standard tariff price adjustments are determined. It needs to be noted that NERSA still has further RCA decisions to be made. In addition, certain court decisions would need to be implemented. The proposed price increases for the three years are 20.5%, 15% and 10% respectively.

3.6.1 Key contributors to year on year price increases

The key contributors for the price increases over the MYPD5 period have been identified. It is surmised that externally controlled elements of the allowable revenue have the biggest impact on the price increase. The key contributors to the year on year price increase of electricity is depicted in the figure below. Eskom's own requirements contribute 6.6% (FY2023); 7.28% (FY2024) and 4.97% (FY2025) during MYPD5 period. This corresponds to less than half of the total price increase for each year resulting from the revenue application.

FIGURE 6: CONTRIBUTION TO YEAR ON YEAR PRICE INCREASES FOR MYPD5 PERIOD



- **FY2023** - Of the 20.5% increase IPPs account for 12.81% increase, carbon tax 1.09% increase. In addition, these increases are off-set by decreases mainly in return on assets and in the RCA adjustment when compared to the FY2022. Thus on a net basis, elements under Eskom direct control contribute to approximately 7% of the 20.5% price increase.
- **FY2024** - Of the 15.07% increase, IPPs again account for the highest component of 5.36% increase and carbon tax 2.54% increase. Due to the return on assets differential been from a negative number, it reflects as a 13.69% increase when compared to the FY2023. In addition, these increases are off-set by decreases mainly in depreciation and in the RCA adjustment when compared to the FY2023. Eskom primary energy and operating costs experience decreases when compared to the previous years. More than half the increase is related to the external factors.
- **FY2025** - Of the 10% increase, IPPs again account for the highest contribution of 5.11% increase and Eskom primary energy 1.76%. Costs under Eskom control contribute less than 5% of the increase. All the other elements make small contributions to the remainder of the 10% increase. More than half the increase is related to external factors.

4 Indicative Standard Tariff Increase

4.1 1 July Municipal (Local authority) tariff increase

Using the ERTSA methodology; the 20.5% average increase translates to a 1 July 2022 local-authority tariff increase of 21% to municipalities. Municipalities continue to pay at the FY2022 rates for the period 1 April 2022 to 30 June 2022 as per the Municipal Finance Management Act (MFMA). This equates to a price increase of 21% from 1 July 2022; a price increase of 13.3% from 1 July 2023 and a price increase of 8.9% from 1 July 2024.

4.2 Eskom direct customers (Non-local authority tariff) increases

The 1 April 2022 non-municipal tariffs' increase including the Homelight 20A tariff is the ERTSA / annual average increase of 20.5% for 1 April 2022; a price increase of 15.07% from 1 April 2023 and a price increase of 10% from 1 April 2024.

4.3 Affordability subsidy charge increase

The affordability subsidy is 15.58% for FY2023, 15.47% for FY2024 and 14.81% for FY2025. In summary; the FY2023 to FY2025 average tariff category increases are set out in the Table below.

TABLE 8: STANDARD TARIFF INCREASES

Standard tariffs and categories	Application FY2023	Application FY2024	Application FY2025
Standard tariff annual increase	20.50%	15.07%	10.00%
Municipalities			
Municipal tariffs - effective 1 July	21.00%	13.30%	8.90%
Eskom direct customers (non-municipal tariffs)			
Businessrate, Public lighting, Homepower, Homelight 60A, Homelight 20A, Landrate and Landlight	20.50%	15.07%	10.00%
Megaflex, Miniflex, Nightsave Urban, WEPS, Transflex, Megaflex Gen			
• Affordability susbidy charge (where applicable)	15.66%	15.45%	14.74%
• Other tariff charges	20.50%	15.07%	10.00%
*Effective increase including affordability subsidy	20.32%	15.09%	10.18%
Ruraflex, Nightsave rural, Ruraflex Gen	20.50%	15.07%	10.00%
Homelight 20A			
• IBT Block 1: >0 to 350kWh	20.50%	15.07%	10.00%
• IBT Block 2: >350kWh	20.50%	15.07%	10.00%

4.4 Protection of poor households

The government and NERSA have put in place a number of measures to ensure that low-income households have access to affordable electricity. These include:

- **The electrification programme**, which subsidises the cost of connecting a house to a 20A (low consumption) electricity supply. This complements an already subsidised tariff.
- **The free basic electricity programme**, which provides 50kWh (more in some local authorities) of free electricity per month to identified indigent customers.
- **The inclining block tariff (IBT),** which, together with **lower-than-average tariff increases**, has resulted in subsidies for all residential customers. These subsidies are currently recovered primarily from Eskom's direct large urban (municipal, industrial and commercial) contribution to Eskom related subsidies because municipalities do not contribute towards the IBT-related affordability

  The Inclining Block Tariff (IBT) was implemented by NERSA to cushion low-income households that use very little electricity. The tariff has been successful in lowering the cost of electricity for the poor. Eskom recognises that even in the absence of a national subsidy framework the poor still need to be protected against the impact of the price increases. NERSA may therefore allow further cross-subsidies between various customer groups to be implemented as part of the annual average price to benefit affected groups.

4.5 Protection of industrial vulnerable sectors

The Department of Mineral Resources and Energy has amended the short term negotiated pricing agreements (NPA) framework and developed an interim long term NPA framework in accordance with the requirements of the Electricity Pricing Policy (EPP). The Short-term NPAs have been specifically structured to provide opportunities to sustain existing businesses that are at risk of failure and permit others that have closed production capacity in recent years, owing to their inability to compete in their markets, to restart these assets. The rationale for the interim long-term framework is to protect vulnerable sectors, improve relative sector competitiveness and attract investment in the long-term. These two frameworks will allow for the relevant vulnerable sectors, which are impacted by the price of electricity and meet the required criteria, to be supported to allow for further contribution to economic activity of the country. Thus it is surmised that for industries that meet the requirements of these two frameworks will be protected to a certain extent from the impact of the price increase. It is understood that these frameworks will contribute towards the

Government's priority industrial policies. It needs to be that the electricity price is only one of the factors that may impact the implementation of Government industrial policy priorities.

4.6 Tariff structural changes during the MYPD5 control period

This revenue application does not address any potential Eskom tariff changes. A separate approval process of restructuring of tariffs has already been undertaken during FY2020 and FY2021, and will continue in subsequent years. As NERSA approves structural changes to the tariff structures, NERSA will determine the timing of their implementation as well.

4.6.1 The summary of the proposals that NERSA is considering are

As per NERSA's request for tariffs to be motivated based on the cost-of-supply, Eskom updated its cost-of-supply study (further referred to as the cost-to-serve or CTS). Eskom has designed all the tariffs in this document based on the CTS results, and included specific objectives/signals to incentivise more optimal use of the system, which is not necessarily cost based, but forward-looking.

Existing tariff structures are outdated and need to be modernised to reflect the changing electricity environment and difficult decisions in this regard need to be made to protect the electricity industry. For example, it is no longer appropriate to recover fixed costs through variable kWh-based charges.

When updating tariffs using a CTS study and implementing structural changes, it is not possible to have zero impact on all customers. So, while the total tariff revenue due to the structural changes is revenue-neutral, that is, comes back to the MYPD approved revenue requirement, individual customers may pay more or less, depending on the change and their consumption profile.

(i) The following are the main objectives of the tariff submission:

- Updating tariffs with the latest CTS (that is, cost allocation and segmentation, not cost justification)
- Optimising customer response and use of the system by revising pricing signals to reflect the current system, such as changing TOU rates and times
- Providing for more economic recovery of cost-reflective tariffs (structurally):
  - Reducing volume risk by increasing fixed charges to reflect fixed costs
  - Reducing the burden on higher voltages by reducing the subsidies on lower voltages for urban LPU tariffs

- Simplifying tariff options, removing IBT, and rationalising municipal tariffs
- Modernising tariff structures in light of evolving customer needs and technology – residential TOU

(ii) The following major structural changes are proposed:

- Updating all charges using the repacked forecast volumes, cost split, and cost allocation methods:
  - Energy rates to reflect updated wholesale energy costs; changes to the TOU ratios (peak, standard, and off-peak) and TOU periods (swopping the peak period and introducing a standard period on Sundays) to be aligned with the wholesale rates
  - Network charges to reflect updated Transmission and Distribution network costs
- Increasing the Distribution fixed-charge network charges component, with a commensurate reduction of the variable charge for all tariffs with network charges
- Rationalising the local-authority tariffs into only three tariff categories: a large power user (LPU) version called Municflex, a small power user (SPU) version called Municrate, and a Public Lighting tariff for non-metered lighting supplies
- Increasing the lower-voltage charges for urban LPU tariffs, thereby reducing the contribution to the low-voltage (LV) subsidies
- Basing service charges on the number of points of delivery (PODs) and not per account
- Removing IBT for Homepower and Homelight tariffs
- Introducing a residential TOU tariff plus a new net billing offset rate for customers with small-scale embedded generation (SSEG)

(iii) The proposed changes will affect customers as follows:

- In order to recover the approved MYPD revenue, structural changes and updating tariffs with the CTS mean that some customers will pay more and others less. It is not possible to make all customers pay the same.
- All tariffs are affected by the changes being proposed, and such changes, except for the changes to the rural tariffs and Homelight, are interlinked. This means that, if a change is approved for one tariff and not for another, this will then have an impact on the overall revenue recovery.
- Combining tariffs where one tariff is cheaper than another means increases to the former tariff.
- A change to TOU ratios and periods means that, depending on load profile, some will benefit, while others will pay more.

The start of an evolving journey …

(iv) The next phase in the journey of tariff design may include:

- annual updating of different rates due to Eskom unbundled and separate divisional increases – no longer a single average increase applied to all rates;
- further changes to the TOU rates and periods to accommodate managing a changing system profile;
- restructuring the energy charges into fixed and variable components through the introduction of payment for energy capacity;
- further rationalisation of tariffs by removing Miniflex and Nightsave tariff versions as options (that is, only having Megaflex for urban tariffs);
- further rebalancing between fixed and variable network charges;
- further development regarding generator use-of-system charges and offset rates;
- moving to making TOU mandatory for all new three-phase SPU connections, and
- introduction of flexible short-term tariff options to address customer needs and Eskom operational requirements.

5 Sales Volumes

For the MYPD5 revenue application, one of the key assumptions is the latest available forecasted sales volumes. In accordance with the NERSA MYPD methodology, a revision of the forecasted sales volume to reflect the prevailing situation must be presented for consideration by NERSA. This is especially pertinent to take into account the impact of the pandemic and the recovery of the South African economy.

Eskom makes every effort to at least maintain its levels of sales and to increase sales, if possible. However, as is demonstrated below, the sales volume is very much an outcome of the economy of the country. However much Eskom may have wished the level of sales to improve, or at least remain at the same level during the pandemic, it was not possible. Eskom is making every effort to address its operational environment to improve its availability within the constraints that Eskom has to operate within. Thus, it is submitted that an improvement in the economic conditions in the country is a requirement for a likely improvement in the level of Eskom sales. Sales volumes cannot be improved in isolation.

Eskom is presently in the process of undertaking a review of the sales forecast. The outcome will be shared with NERSA before it makes the MYPD5 decision thereby incorporating the latest updates. Eskom has experienced the forecasting of its sales to be very dynamic and every effort will be made to provide the latest sales projections.

The forecasted sales volumes as provided below, refer to the FY2023 through to FY2025 for all customer categories that are on standard tariffs, local negotiated pricing agreements (NPA) and international sales (exports). During the MYPD5 period, the forecasted sales volume decline will be 0.5% including the leap year and 0.3% excluding the leap year. In this sales volume forecast, the decrease in sales is anticipated primarily from exports and standard tariffs. Eskom’s projected compounded average growth rate (CAGR) is -0.3% for the MYPD5 period while the average annual growth rate (AAGR) over the MYPD5 period is -0.5%.

TABLE 9: ESKOM SALES VOLUMES

Sales volumes (GWh)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Standard tariff sales	180 868	168 529	172 656	171 549	171 440	170 370	170 141	169 476
Year-on-year growth (%)		*-6.8%*	*2.4%*	*-0.6%*	*-0.1%*	*-0.6%*	*-0.1%*	*-0.4%*
Negotiated pricing agreement	10 118	9 755	9 722	10 282	10 311	10 282	10 282	10 282
Year-on-year growth (%)		*-3.6%*	*-0.3%*	*5.8%*	*0.3%*	*-0.3%*	*0.0%*	*0.0%*
Total local sales	**190 986**	**178 284**	**182 379**	**181 831**	**181 751**	**180 652**	**180 424**	**179 758**
Year-on-year growth (%)		*-6.7%*	*2.3%*	*-0.3%*	*0.0%*	*-0.6%*	*-0.1%*	*-0.4%*
Intenational Sales (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
Year-on-year growth (%)		*-14.6%*	*-6.5%*	*-2.5%*	*-7.4%*	*-0.6%*	*0.0%*	*0.0%*
Total Sales (including Internal sales)	**206 081**	**191 174**	**194 433**	**193 579**	**192 627**	**191 467**	**191 238**	**190 573**
Year-on-year growth (%)		*-7.2%*	*1.7%*	*-0.4%*	*-0.5%*	*-0.6%*	*-0.1%*	*-0.3%*

Eskom's sales growth has generally trended slightly downwards over the past three years, with the outlook remaining relatively depressed in the years ahead. Since 2006, sales have declined by an estimated average of 0.5% per year. The decline can be generally attributed to large power users as a result of low competitiveness, high ore extraction costs and volatile commodity markets – particularly in the ferrochrome, steel, gold and platinum industries.

In this forecast it is assumed that the negotiated pricing agreements (NPAs) in place will be extended in accordance with the interim long-term framework. Further possible NPA concluded during the period may materialise, when approved by NERSA.

The year 2020, saw the global Covid-19 pandemic reach our shores. It is important to emphasise that the SA economy had shown signs of significant distress prior to the onset of the pandemic and its associated lockdowns at the end of March 2020. Although South Africa is still viewed as an emerging market, several factors have contributed to the decline in underlying economic growth of the country. These include, but are not limited to, finite natural resources, low investor confidence, infrastructure bottlenecks, labour unrest, load shedding, rising local debt and unemployment.

The global Covid-19 pandemic emerged during 2020. Lockdowns were introduced to curb the spread of the virus. According to Econometrix year-end Outlook for 2020, this resulted in the steepest downturn in global economic activity since the Great Depression of the early 1930s. In South Africa, lockdown restrictions have had far reaching consequences and added substantial downward momentum to an already compromised economy. According to a recent Quarterly Labour Force Survey Quarter 2: 2020 results, released by Statistics South Africa on 29 September 2020, the South African economy shed 2,2m jobs in the second quarter of 2020. In a further report by StatsSA's titled: "Steep slump in GDP as COVID-19 takes its toll on the economy" it is stated that: "Manufacturing output shrank by 74.9%.

Plagued by work stoppages and lower demand for steel, factories specialising in metals and machinery were severely affected. As can be expected the ban on alcohol sales had a significant impact on the food and beverage division of manufacturing”. This has a downstream effect on the various associated packaging industries.

During lockdown, air travel came to an almost complete halt, contributing to the fall in economic activity in the transport and communication industries. There was also less activity by rail and road freight operators due to restrictions on the production, the movement of various goods locally and port closures.

The closure of tourist accommodation, hospitality and leisure complexes were further notable drags on economic activity. Reduced activity in these sectors has a direct impact on the Commercial and Municipal categories in which the associated customers are embedded. This is echoed by a report from the Department of Tourism revealing the extent of tourist decline.

Wholesalers and motor vehicle traders also reported significant declines, as car rental agencies consumers delayed purchases. This has negatively affected the smelting and fuel industries, due to a rapid decline in demand.

Finance and personal services, these two industries that have shown a great deal of resilience over the last decade, did not escape the maelstrom. The finance industry, which includes banking, insurance services, real estate and business services, fell by 28.9%. Personal services recorded its first quarter of negative growth since 2009. Businesses, such as gyms and hairdressers, closed their doors and hospitals halted elective operations. The cancelation of sporting and recreation events also dragged the industry lower.”

The above impact of the Covid-19 pandemic on Eskom’s electricity sales was immediate, with the largest impact materialising during April and May 2020. As at 30 September 2020, the sales impact has been estimated at approximately 8.24 TWh. A recent United Nations Development Programme (UNDP) study has revealed that the local economy will take up to five years to recover.

Given the numerous factors above, electricity sales growth is expected to be slightly negative over the next few years. However, Eskom’s aim remains to attempt to grow sales over the medium term supported by innovative products, solutions and tariffs in collaboration with customers to address their needs and aspirations.

5.1 Sales volume forecasting assumptions

The sales volume forecast is based on various assumptions reflecting the different types of customers' electricity needs and influences on diverse customer consumption profiles. There are some similar assumptions used for all customers but with varying impacts. Key assumptions include the gross domestic product (GDP) growth, commodity market performance and prices, demand response savings, weather conditions, customer projects, industrial action and impact of the leap year.

5.1.1 Gross domestic product (GDP)

Historical trends indicate that electricity consumption grows at a slower rate than the economy. In the sales volume forecast, the gap between sales growth and GDP is widening due to less energy intensive sales during the forecast years and due to the economy migrating towards a greater service lead economy. In addition, several mines and large industrial customers are down scaling or closing down completely, in line with the factors mentioned above. It is therefore assumed, that the margin between GDP growth and electricity growth will continue to widen into the future.

5.1.2 Commodity prices

A recent slump in commodity prices had led to subdued electricity consumption among energy intensive industries. Ferrous metal commodity prices were further compromised as a result of the pandemic. It is anticipated that true lasting recovery of commodity prices will be slow and steady during the MYPD5 period. As customers with smelting capacity become more pressurised, they will strive towards more efficient furnace utilisation, which based on history, does not bode well for electricity sales. This trend has been assumed in the sales forecast for the entire MYPD5 period.

Platinum mines have been hit by static low commodity prices, labour action such as the Marikana incident, as well as the Pandemic inspired global recession. However, growth in the sector is driven by new projects and expansions at existing mines. Despite some projects having been delayed due to the Pandemic, moderate growth is still expected in the Platinum sector over the MYPD5 period.

Gold prices reached record highs in 2020 as the metal remains a safe haven for investors. The price is expected to remain in favourable territory at least until a proven vaccine for Covid 19 becomes widely available. Gold mines remain under pressure to curb rising labour and extraction cost, with some mines reaching their end of life.

5.1.3 Price elasticity

This is addressed in a separate section of this application.

5.1.4 Energy efficiency demand side management (EEDSM)

The impact of EEDSM initiatives is embedded in the forecasted sales volumes and it is therefore captured in the underlying historic sales volume base used in the trend analysis. The sales volume forecast assumption for EEDSM is that the historic EEDSM savings will continue during the application period.

5.1.5 Weather conditions

Forecasted sales volumes have taken varying local weather conditions into account. Residential and Agricultural sales are weather sensitive by nature. As customary, average weather conditions have been applied as a key input parameter to predict the sales of all-weather sensitive customers.

5.1.6 Leap year impact

Every fourth year, February month has 29 days and this is recognised as a leap year. Consequently, there are additional sales in February 2020, due to the extra day. The leap year impact has also been taken into account for 2024.

5.2 Sales forecasting approach

There are various different influences on customers' current and future electricity consumption determined by individual customers' need for electricity and substitutes to taking supply from Eskom. To practically capture this complex dynamic, the Eskom forecasting encapsulates differing sales assumptions by customer types that are the high-sales and lower-sales end users. For high-sales volume customers, the sales forecasting assumptions comprises individual customer planning inputs. For the lower consumption customers, the sales forecast is informed by historical trends, weather and relevant economic indicators.

Consequently, volume changes in the high-sales customer category requires the application of an individual bottom-up approach, so as to consider specific sales drivers that include individual business plans, responses to price elasticity of demand (if any), commodity prices, and the consideration of external economic factors.

The forecasting of international sales adopts the individual approach given the country specific drivers and the fact that the sales are exported.

Municipalities purchase in bulk from Eskom, distributing to industrial and commercial sectors with a greater part of supply to residential end users. Eskom bulk sales to municipalities differ from one municipality (or metro) to the next, as each municipality's purchase profile shaped by their individual customer-mix. Eskom therefore uses a combination of forecasting methodologies combining an individual consultation with the municipality, in line with the respective local government development plans, as Municipalities there are various aspects that impact their respective electricity consumption profiles.

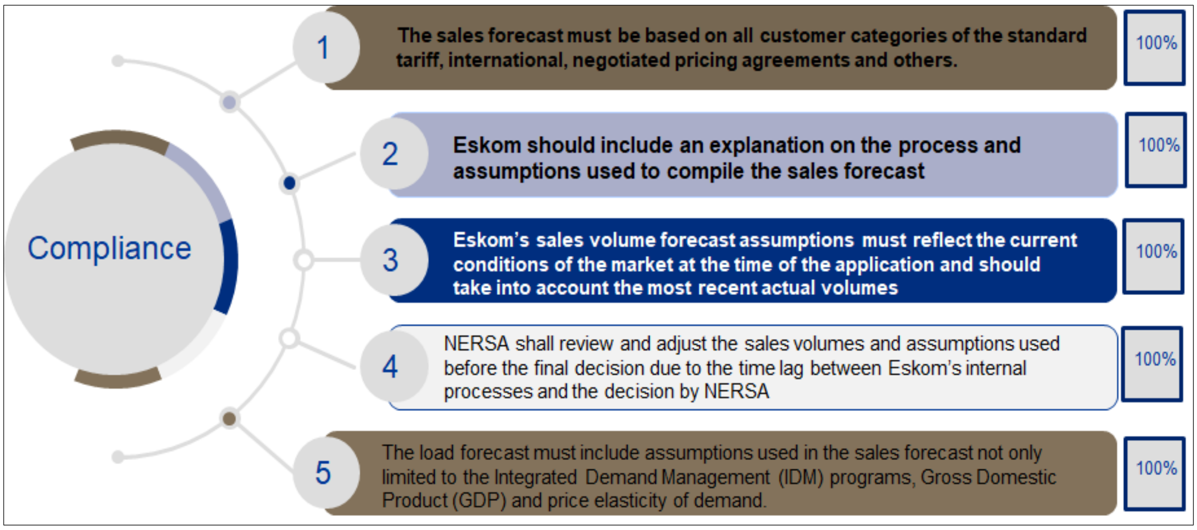
For the residential and commercial sectors, historical trends, weather and economic indicators are the primary indicators that inform the sales forecast

5.3 Sales forecasting process

A five-step process, as depicted in the figure below, is followed to forecast Eskom electricity sales. This process includes the compilation of a six-year monthly detailed forecast with the last four years of the period at an annual level using trends per sector. As the diagram depicts the Sales forecast is a bottom up derived forecast.

Each of the nine Eskom provincial operating units concentrate on their top customers in detail while the other customer sectors is forecasted at summary level to derive a 6 year projection per month with a further 4 years of annual numbers. Detailed analysis and rigorous validation processes follow to ensure consensus that the derived forecast is the most likely scenario given the current information available.

FIGURE 7: AREAS OF COMPLIANCE IN PROVIDING MYPD FORECASTED SALES VOLUMES



Each Eskom Distribution operating unit (OU) tend to the customers that account for 80% of that OU's revenue individually in great detail. Engaging the customer executives and obtaining applicable information from the customers while balancing this view with sectoral trends, the expected economic climate and any other relevant information. It is clarified at this stage, the proposed price increase that NERSA will determine is not known.

Does Eskom have significant influence on levels of electricity sales in South Africa?

With respect to demand or sales growth and its drivers, Eskom had commissioned numerous studies by external independent professional consulting economists. The basic outcome has consistently been that the dominant factors and drivers of electricity demand and thus sales volume have been overall national economic growth; commodity prices; structural changes to the economy (e.g. reduction of mining and manufacturing and growth in services), technological changes, population growth, weather patterns, electricity intensity levels. The policy drivers of the country on investment choices have been found to be paramount. From an electricity perspective, customers require a long-term price path (price stability), reliability of supply (availability), a reliable supply, and competitive pricing (level). Other operational factors that impact sales of electricity in South Africa include:

- Low economic growth internationally – no markets for products (stockpiling).
- Commodity market volatility, particularly in gold, platinum, and ferrochrome.
- Rapid evolution of technology development in the energy industry
- Some of the large power user customers having been liquidated or applied for business rescue due to financial vulnerability and low competitiveness in their sectors
- Some industries that have shut down operations and relocated to Asia due to incentives offered in those countries
- Voluntary contribution to the energy reduction strategies during load shedding accelerated energy efficiency and self-reliance.
- Opting to export un-beneficiated ore due to high market prices.
- Labour costs and relationships
- Reliability and cost of logistics

Eskom has a role to play in contributing to the reliability of supply. Key constraint in this arena that the industry is still grappling with, include the implementation of policy decisions timeously, financial constraints – which results in having to make difficult choices and ensuring the availability of skills. This has been defined as a key focus area for the Eskom

Generation, Transmission and Distribution licensees and details are included in this MYPD5 submission. An appropriate price increase decision will allow these factors to be addressed.

The majority of large industrial customers in South Africa are global companies with plants across the world. Investment in, and decisions to run plant are made on least risk/highest return basis. It would require a holistic approach from a South Africa Incorporated perspective, taking into consideration all the relevant impact points. It is thus submitted that Eskom is not in a position alone to influence the electricity sales trajectory. The impact of the pandemic pays testimony to this. Any attempt by Eskom to arrest the drop in sales due to the pandemic would have been futile. Addressing the impact of the pandemic on the economy of the country and thus the electricity sales volume, requires the concerted effort of various entities.

The DMRE determines the investment in electricity generating infrastructure through the development and implementation of the Integrated Resource Plan (IRP). The DMRE promulgates a long-term IRP where various factors are balanced to determine the optimal generating capacity requirements for the country. The last IRP was promulgated in 2019 for the period up to 2030. Since 2019, the DMRE Minister has made determinations for the procurement of energy. Some of these have materialised and some have not. The sales forecast plays a fundamental role in the DMRE Minister determining the requirements and implementation of the IRP. Once a determination is made for Eskom to build capacity or contract with IPPs, the electricity consumer is accountable for the inclusion of efficient costs in its tariffs related to these investments. This forms part of the allowable revenue that Eskom applies for, in terms of the MYPD methodology. The allowable revenue is recovered through the sales of the electricity. It is assumed that the changes in sales forecasts are considered by the DMRE Minister, as determinations are made.

6 Energy Wheel

Eskom utilises an energy wheel to ensure that a balance between the demand and supply is planned for. The Energy Wheel is a summary of the balance between the Eskom demand and supply of energy. The demand side of the Energy Wheel portrays the total projected Eskom sales which are made up of Distribution national sales and Export sales, inclusive of the transmission and distribution losses. This makes up the total amount of energy that needs to be produced to supply customers' needs and is the starting point of the production planning process. This energy forecast has been discounted with the impact of demand side management options.

The supply side of the Energy Wheel shows the volume of electricity that is required from local and international power stations as well as independent power producers (IPPs) to be supplied to Eskom's distribution and export points (including the losses) to meet the demand.

FIGURE 8: ENERGY WHEEL FY2023 (ALL FIGURES IN GWH)

Generation of Electricity	Application
Generation	180 134
OCGT	211
Pumping	(7 110)
IPP	36 485
Total	**209 721**

Available for Distribution	Application
Generation (incl IPPs)	216 830
International	8 457
Wheeling	2 088
Sub Total	**227 376**
Pumping	(7 110)
Total	**220 266**

Total Imports	Application
International Purchases	8 457
Wheeling	2 088
Total	**10 545**

Total Exports	Application
International Sales	11 748
Wheeling	2 088
Total	**13 836**

South African Power Pool

Internal Use	Application
Generated	(58)
Internal Use	510
Total	**452**

Demand	Application
Sales	193 069
Losses	24 657
Internal	510
Generated	(58)
Wheeling	2 088
Total	**220 266**

External Sales	Application
Local	181 321
International	11 748
Total	**193 069**

Technical & Other Losses	Application
Distribution	18 971
Transmission	5 686
Total	**24 657**

Technical & Other Losses - %	Application
Distribution	9.45%
Transmission	2.50%

Note 1: Total External Dx sales excluding internal sales of 510GWh and including international sales of 11 748GWh

FIGURE 9: ENERGY WHEEL FY2024 (ALL FIGURES IN GWH)

Generation of Electricity	Application
Generation	170 016
OCGT	211
Pumping	(6 636)
IPP	45 063
Total	**208 655**

Available for Distribution	Application
Generation (incl IPPs)	215 290
International	8 481
Wheeling	2 093
Sub Total	**225 864**
Pumping	(6 636)
Total	**219 228**

Total Imports	Application
International Purchases	8 481
Wheeling	2 093
Total	**10 573**

Total Exports	Application
International Sales	10 876
Wheeling	2 093
Total	**12 969**

South African Power Pool

Internal Use	Application
Generated	(58)
Internal Use	510
Total	**452**

Demand	Application
Sales	192 117
Losses	24 567
Internal	510
Generated	(58)
Wheeling	2 093
Total	**219 228**

External Sales	Application
Local	181 241
International	10 876
Total	**192 117**[1]

Technical & Other Losses	Application
Distribution	18 919
Transmission	5 648
Total	**24 567**

Technical & Other Losses - %	Application
Distribution	9.43%
Transmission	2.50%

Note 1: Total External Dx sales excluding internal sales of 510GWh and including International sales of 10 876GWh

FIGURE 10: ENERGY WHEEL FY2025 (ALL FIGURES IN GWH)

Generation of Electricity	Application
Generation	161 168
OCGT	211
Pumping	(6 628)
IPP	52 936
Total	**207 687**

Available for Distribution	Application
Generation (incl IPPs)	214 315
International	8 457
Wheeling	2 088
Sub Total	**224 860**
Pumping	(6 628)
Total	**218 232**

Total Imports	Application
International Purchases	8 457
Wheeling	2 088
Total	**10 545**

Total Exports	Application
International Sales	10 815
Wheeling	2 088
Total	**12 903**

South African Power Pool

Internal Use	Application
Generated	(58)
Internal Use	508
Total	**450**

Demand	Application
Sales	190 959
Losses	24 736
Internal	508
Generated	(58)
Wheeling	2 088
Total	**218 232**

External Sales	Application
Local	180 144
International	10 815
Total	**190 959**[1]

Technical & Other Losses	Application
Distribution	19 113
Transmission	5 623
Total	**24 736**

Technical & Other Losses - %	Application
Distribution	9.57%
Transmission	2.50%

Note 1: Total External Dx sales excluding internal sales of 508GWh + International sales of 10 815GWh

7 Production Plan

7.1 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.

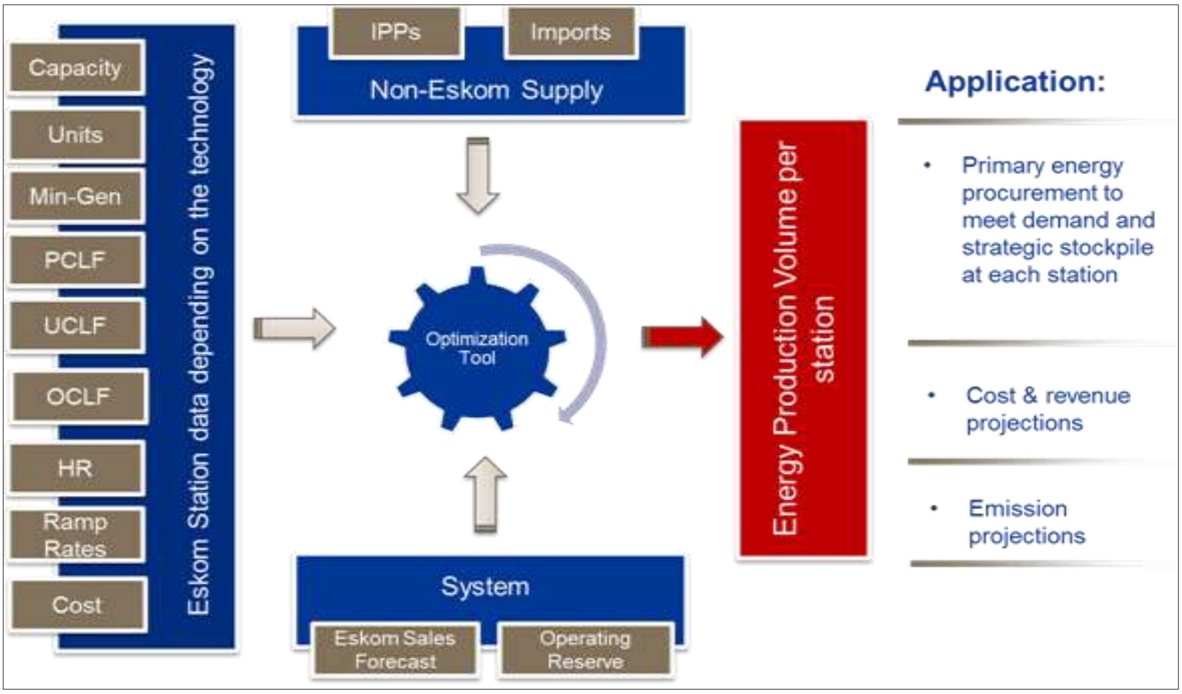
Merit order dispatch is achieved by deriving the merit order from the primary energy costs (mainly coal and diesel cost) as well as power station burn rates (station efficiency and coal quality) resulting in an energy cost (R/MWh) ranking per station from the cheapest to the most expensive. Coal and 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, Limestone, Nuclear, OCGT, Start-up Fuel, Water Treatment, Coal Handling and Environmental Levy) cost projections.

7.2 Production Planning Process

The Production Plan is optimised using a simulation tool called the Plexos Simulation Tool.

FIGURE 11: 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 Eskom 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 and Sanitisation 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. Eskom 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-Eskom generators (Imports and IPPs) are modelled as contracted to Eskom. 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 Eskom generators.

7.3 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:

7.3.1 Eskom 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.

Consideration is taken of 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.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. 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.

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.

FIGURE 12: AGE OF GENERATION'S FLEET AT 1 APRIL 2022

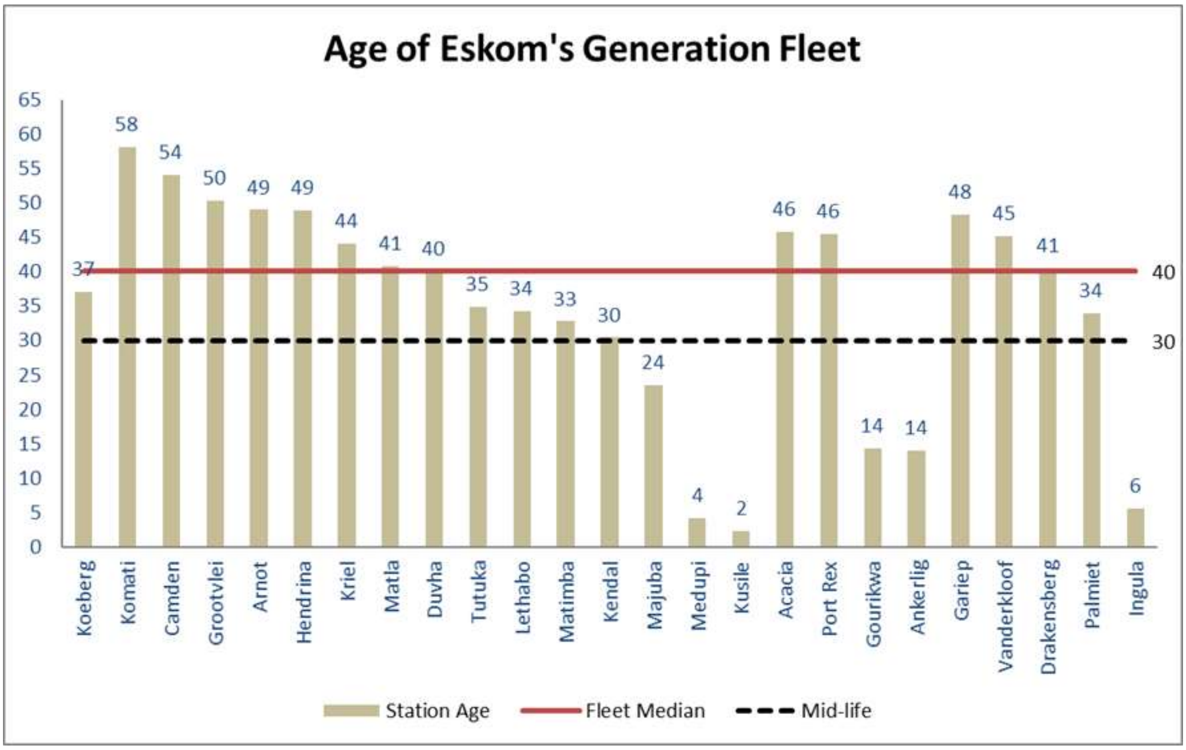


TABLE 10: DEAD STOP DATES

Dead Stop Dates	Hendrina		Arnot		Camden		Grootvlei	
	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		

7.3.2 Possible impact of implementing environmental legislative requirements

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. The initial decisions illustrate that DFFE is requiring strict and full compliance to the MES regulations and limits. Eskom is assessing the impact of the initial decisions, but preliminary work suggests that if implemented, the decision could necessitate expenditure of some R300bn. It would also have very significant impacts on capacity availability, both immediately, and after 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.

7.3.3 Eskom new build capacity assumptions

Eskom new build dates assumed in the production plan inputs are based on latest forecast of commercial operational dates for Medupi and Kusile.

7.3.4 Energy forecast assumptions

As included in the Distribution Licensee submission, the energy forecast is robustly undertaken within Eskom. For production planning purposes, the source of the energy forecast is the Energy Wheel Diagramme. 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.

7.3.5 Non-Eskom supply assumptions

Non-Eskom 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. Eskom generators supply the balance after imports and IPPs have been utilised.

7.3.6 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 11: 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

7.3.7 OCGT usage

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

7.3.8 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 Eskom 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 12: ENERGY PRODUCTION PER PLANT MIX (GWH)

Electricity output	Actuals	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**

7.4 Conclusion on the production plan

As can be observed by the results in table above, the Eskom energy sent-out drops from 214 968 GWh (FY2020) to 146 510 GWh in FY2027, whilst Eskom 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 Eskom system drops from 68% in FY2022 to 54% in FY2027.

7.5 "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 at the third quarter 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 Eskom 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-Eskom new capacity increases. All other assumptions remain the same as for this submission.

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 Eskom 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.

It needs to be noted that Eskom will provide more recent information to NERSA during the consultation phase, prior to the revenue decision being made.

7.6 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 Eskom loss factors calculated as per the Tariff grid code are included.

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

8 Weighted Average Cost of Capital

The weighted average cost of capital (WACC) component of the building blocks to the allowable revenue formula:

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

The WACC is determined in accordance with the requirements of the MYPD methodology. It is clarified that even though the determination for the WACC is made, it is not implemented to the full extent in this MYPD5 revenue application.

Electricity production and distribution is a capital or asset intensive industry i.e. significant up-front capital investment is required in order to acquire the assets which are needed to produce, transmit and distribute the electricity. The capital invested to acquire an asset is thereafter recovered over the full operational life of an asset. The cost of such capital is an inherent cost of the production of electricity and must therefore be recovered through the price of electricity in order for the industry be sustainable, which includes meeting its debt obligations. The capital structure consists of a weighting of equity and debt with Eskom targeting 70% for debt and 30% for equity. Both debt and equity comes at a cost and thus the weighted cost of capital (WACC) is utilised to determine the funding costs for organisations. The NERSA regulatory methodology requires the earning of returns on assets (ROA). These are in lieu of interest costs, which are not separately recovered as a cost component.

In the recent past there have been several developments that have transpired which negatively affected Eskom’s cost of capital. Credit rating downgrades by Standard & Poor’s, Moody’s and Fitch rating agencies coupled with sovereign downgrades has placed further upward pressures on funding costs.

TABLE 13 : COST OF CAPITAL

Weighted Average Cost of Capital	Debt	Equity	WACC
Costs - Nominal	12.78%	22.98%	
Weight	66%	34%	
WACC nominal pre-tax			**16.20%**
Costs - Real	8.23%	18.02%	
Weight	66%	34%	
Inflation			4.20%
WACC real pre-tax			**11.50%**

Eskom's updated WACC real pre-tax is 11.5% which is higher than the MYPD4 application. The reason for the high WACC is:

- An increase in the cost of debt due to the numerous downgrades Eskom has seen
- An increase in the risk free rate. Eskom uses a SA 10Y Bond as per the methodology.

Eskom's updated WACC real pre-tax is 11.5% which is higher than that applied for in this MYPD5 period. During the revenue application only a portion of the WACC is proposed. As alluded to in various parts of this submission, Eskom is only requesting a return on assets that allows for migration of the average price of electricity to a level that corresponds to the efficient cost of electricity. Further details are elaborated in the section on return on assets of this submission.

9 Regulated Asset Base

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, Eskom 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:

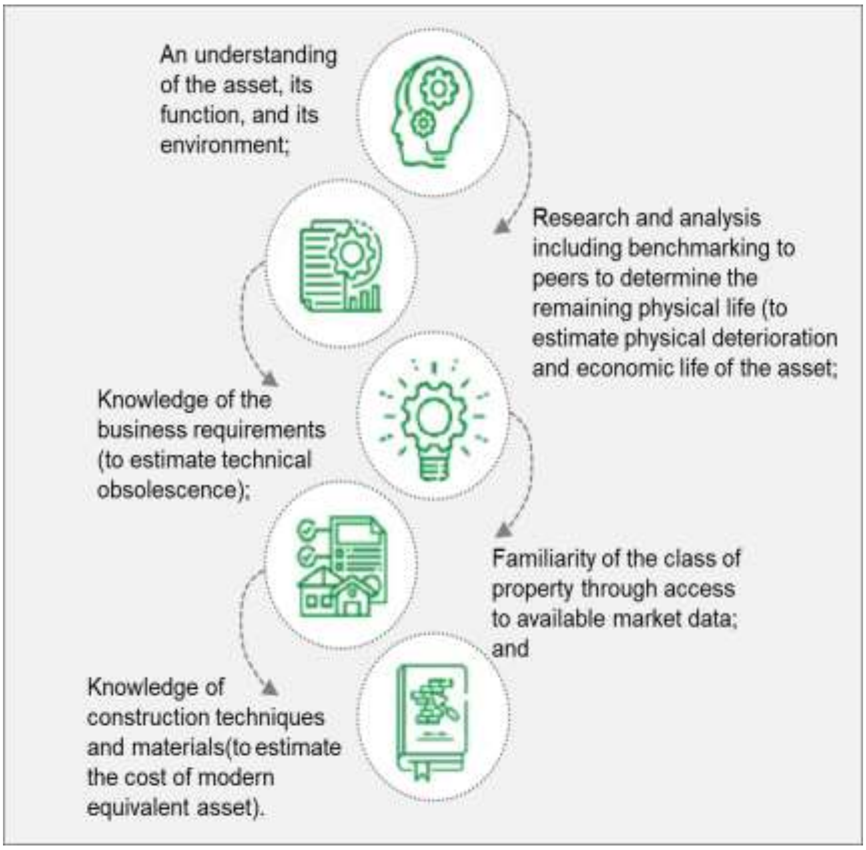
$$AR=(RAB \times WACC)+E+PE+D+R\&D+IDM \pm SQI+L\&T \pm RCA$$

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, Eskom 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. Eskom’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 Eskom 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.

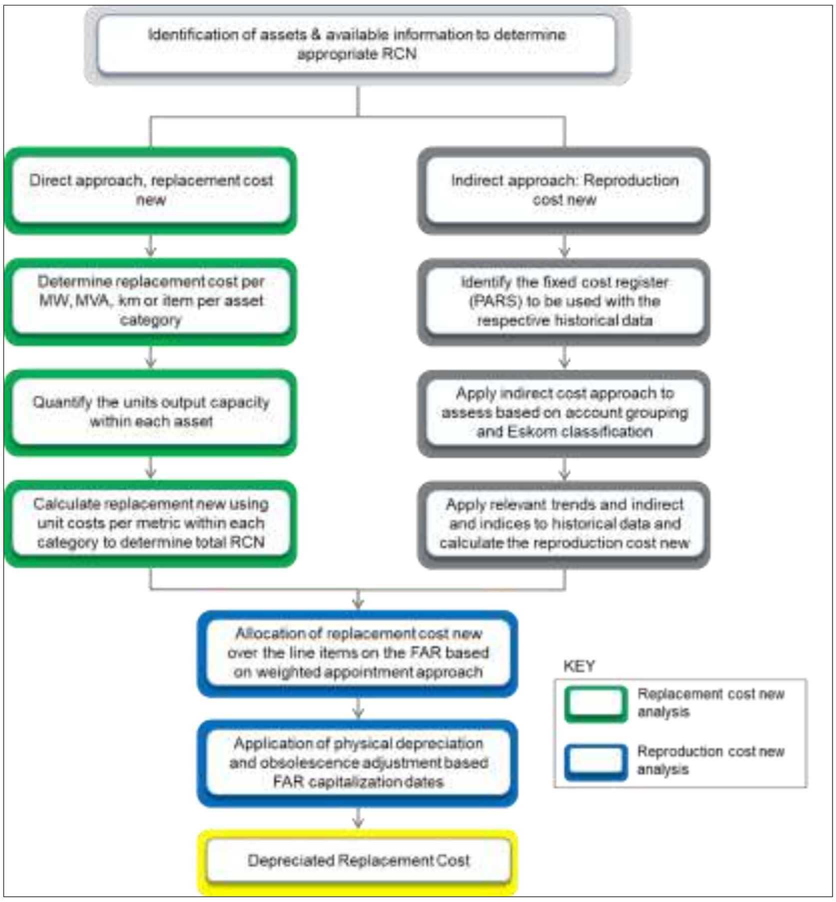
FIGURE 13: VALUATION KEY STEPS



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 14: VALUATION METHODOLOGY



Depreciated Replacement Cost of Eskom's generation, transmission and distribution assets;

The Eskom 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 R80 m (i.e R1bn x 2/25). This valuation forms the basis of the RAB application as shown in the table below.

TABLE 14: 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)	484 959	435 382	915 731	857 384	801 373	748 024	697 033
Assets Tansferred to Commercial Operations	327 446	378 270	183 488	247 809	290 556	319 502	355 057
Work Under Construction (WUC)	24 544	(25 413)	116 596	104 052	97 229	121 680	137 974
Net Working Capital	55 125	64 811	60 250	58 158	69 712	80 058	84 489
Asset Purchases	2 303	2 305	1 779	1 939	2 072	1 982	1 972
Assets funded upfront by customers	-	-	(14 597)	(14 706)	(14 791)	(14 851)	(14 851)
Closing RAB	**894 377**	**855 355**	**1 263 247**	**1 254 636**	**1 246 151**	**1 256 395**	**1 261 675**
Medupi, Kusile & Ingula (included in closing RAB)	369 960	371 608	372 409	375 520	373 571	370 113	363 691

It is noted that the contribution of the three new build power stations (Medupi, Kusile, Ingula) to the total RAB is in the region of R374bn for each of the years of the application.

9.1 Regulatory Asset base components:

In accordance with the MYPD methodology, the regulatory asset base is comprised of the following, where the asset valuation as at 31 March 2020 is first determined and changes in the RAB are then considered

- 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. This is reflected in the table below.

- 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

9.2 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 15: EXTRACT FROM INDEPENDENT VALUATION REPORT

	Cap Cost	NBV	NBV in Scope	Final RCN	Physical Depreciation	Technical Obsolescence	DRC
Transmission (Tx)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)
Telecommunications (6000)	2,277	1,337	1,337	2,977	(2,187)	-	799
Transmission Plant (16000)	65,315	44,942	44,942	294,425	(186,586)	-	107,838
Sub total	**67,592**	**46,279**	**46,279**	**297,402**	**(188,765)**	**-**	**108,637**
Generation (Gx)							
Generation Plant	496,399	382,771	382,771	2,139,774	(1,156,162)	(28,132)	955,474
Sub total	**496,399**	**382,771**	**382,771**	**2,139,774**	**(1,156,162)**	**(28,132)**	**955,474**
Distribution (Dx)							
Telecommunications (6000)	313	12	12	1,074	(1,032)	-	42
Distribution Plant (21000)	93,715	55,768	55,768	321,886	(199,072)	-	122,814
Distribution Electrification Assets (21000)	8,487	663	663	29,150	(24,040)	-	5,109
Government Funded Electrification Assets (21000)	28,366	19,435	19,435	97,429	(30,035)	-	67,394
Sub total	**130,880**	**75,878**	**75,878**	**449,538**	**(254,179)**	**-**	**195,359**
Grand total	**694,872**	**504,928**	**504,928**	**2,886,713**	**(1,599,105)**	**(28,132)**	**1,259,470**

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.

9.3 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.

9.4 Assets excluded from RAB

9.4.1 Assets funded via upfront customer contributions

In terms of the MYPD methodology these assets do not earn a return on assets and their depreciation is not included in the revenue requirement. Depreciation for transmission and distribution assets as shown in table above, include assets that are funded via upfront capital contributions. In terms of the MYPD methodology these assets do not earn a return on assets and their depreciation is not included in the revenue requirement.

TABLE 16: ASSETS FUNDED VIA UPFRONT CONTRIBUTIONS AND DOE

Assets funded via upfront contributions	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening balance	(33 747)	(30 531)	(14 584)	(14 597)	(14 706)	(14 791)	(14 851)
Inflation	-	-	-	-	-	-	-
Transfers to Commercial Operations (CO)	(643)	(704)	(758)	(899)	(926)	(955)	(955)
Depreciation	3 859	4 132	746	789	840	895	955
Closing Balance	**(30 531)**	**(27 103)**	**(14 597)**	**(14 706)**	**(14 791)**	**(14 851)**	**(14 851)**

The transfer to commercial operation (CO) in Table above includes the completed assets which have been funded upfront by customers.

The objective of tracking these assets as a separate asset class (as shown in Table above) is to ensure transparency; therefore both the RAB and the depreciation are reduced accordingly.

9.4.2 Non-operational assets

As required by the MYPD methodology (section 9.1.8.1), fixed assets that are not used or useable withn 12 months are excluded from the RAB. With regards to the generation licensee, and in accordacne with the valuation as at 31 March 2020, the cold reserve stations 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 17: NON-OPERATIONAL ASSETS EXCLUDED FROM RAB

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

9.4.3 Assets funded by third parties

In the distribution licensee, self build assets of R10 404m and DMRE funded electrification assets of R69 322m are excluded from the DRC as at 31 March 2020. Self build assets are defined as assets built by 3rd parties and then handed over to Eskom to operate and maintain.

9.5 Impact of a lower RAB value on the allowable revenue – Stress test scenario

Eskom has provided the details of the RAB value for the purposes of the MYPD5 revenue application. The details are provided above. This stress test scenario is completely fictitious and is only being used to illustrate how the consumer pays for the capital related costs through the tariff.

To reiterate, 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.

As an illustrative example, if the RAB was determined to be R100bn lower than that reflected in this application for the FY2024, the impact on the allowable revenue is determined.

TABLE 18: ILLUSTRATIVE SCENARIO FOR STRESS TEST ON RAB VALUE

ITEM	Application FY2023	Application FY2024	Application FY2025
MYPD5 Standard tariff c/kWh	161.04	185.31	203.85
Standard tariff average price - RAB reduced by R100 bn	159.18	182.29	200.87
Increase/(decrease) in price c/kWh	(1.86)	(3.02)	(2.98)

As a stress test – the table above shows the impact of a lower value of the RAB by R100bn. All other factors being equal for the application years, if the RAB is reduced by R100bn (related to generation assets), the resulting decrease in the price of electricity would be 1.86c (of 161.04c/kWh for FY2023), 3.02c (of 185.31c/kWh for FY2024) and 2.98c (of 203.85c/kWh for FY2025). This illustrates that there would be a slight change in the price of electricity, even if the RAB was valued at R100bn less than the actual value. This minimal impact is mainly due to the capital costs being recovered over the life of the assets. The ROA being migrated towards cost reflectivity also impacts on minimising the impact further.

10 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.

The MYPD methodology requires the following to determine the depreciation related revenue to be included in the revenue application.

Annual Depreciation will be calculated by deducting the Accumulated Depreciation of the previous year (year-1) from the Accumulated Depreciation the current year (year 0) using the following formula:

$\boldsymbol{D} = ACy0 - ACy{-}1$

$\boldsymbol{D}$ = Depreciation and amortisation of replacement cost adjustment

$\boldsymbol{ACy0}$ = MEAV*(remaining economic life year 0/total economic life)

$\boldsymbol{ACy{-}1}$ = MEAV*(remaining economic life year -1/total economic life)

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. Table below reflects the revenue related to depreciation for the MYPD5 period. It needs to be noted that the depreciation is undertaken as component level. Thus each component of the assets are depreciated in accordance with the life of the component.

TABLE 19: DEPRECIATION

Depreciation (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	60 822	58 346	56 012	53 348	50 991
Assets Transferred to Commercial Operations	7 441	12 633	18 192	18 133	21 478
Assets Purchases	737	811	850	869	933
Assets funded upfront by customers	(746)	(789)	(840)	(895)	(955)
Total	**68 254**	**71 001**	**74 214**	**71 455**	**72 447**
Depreciation for Medupi, Kusile & Ingula included in Total above	11 849	11 922	12 022	12 371	11 903

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 for generation and over the normal useful life for all Transmission and Distributions assets.

It is noted that the contribution of the three new build power stations (Medupi, Kusile and Ingula) to the total depreciation for each of the application years is approximately R12bn for each of the application years.

11 Return on Assets

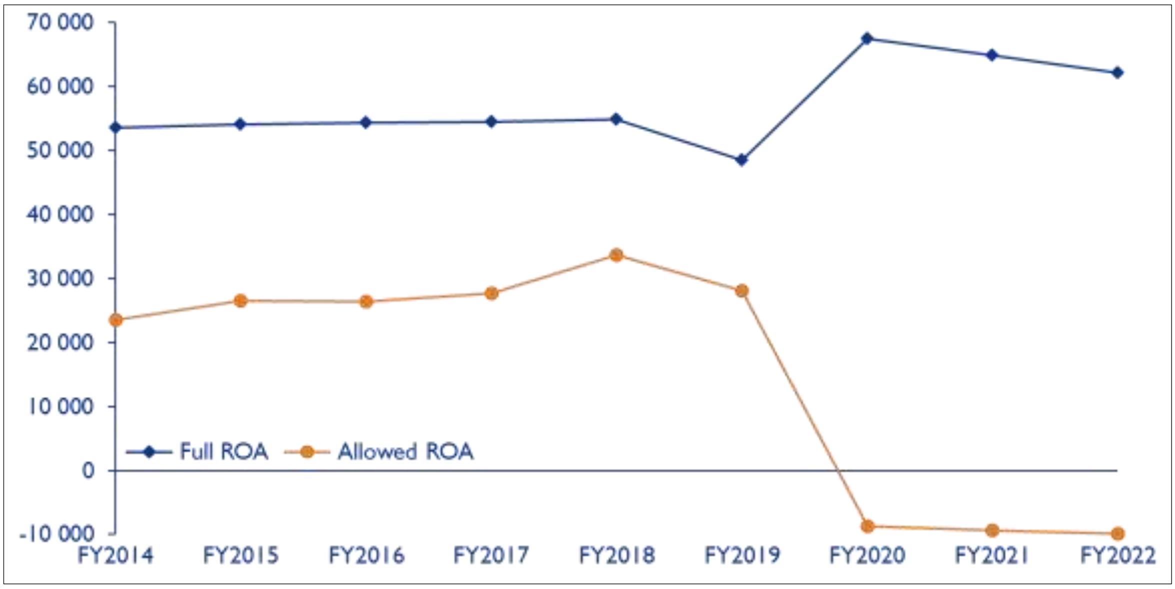
Based on the requirements of the Electricity Regulation Act and MYPD Methodology, Eskom is allowed to earn a reasonable return on assets based on the WACC to ensure that the business can meet its debt commitments costs and generate sufficient reserves to fund future capital investments.

The Electricity pricing policy (EPP) recognises the need for the long term electricity industry to ensure further investment to continue to provide electricity. This is demonstrated by the following extract.

“The common approach among many economic regulators in other parts of the world is to set revenues at a level which would allow the licensee to cover its full cost including a reasonable risk adjusted margin or return. This approach functions well under most circumstances. However, when there is a major discrepancy between asset values used for regulatory tariff setting and new asset values, it creates a potential funding shortfall when new assets are introduced”

The EPP further states, in section 2.3 with reference to cost reflectivity, that tariffs should become cost reflective over a five year period from 2008. Since the inception of the MYPD methodology Eskom has not reached cost reflectivity and specifically the recovery of the return on assets has been protracted. The impact of this delayed recovery on the return has resulted in Eskom’s weakened balance sheet. The graph below illustrates the extent of under-recovery for the ROA.

FIGURE 15: ROA-UNDER RECOVERY



Due to the under-recovery of the ROA as depicted in the graph above, electricity tariff levels have not allowed Eskom to recover sufficient revenue to cover either its full debt commitment costs or establish any reserves for funding of new assets. All costs for Eskom's new build programme have been through debt funding resulting in the higher levels of debt and interest as reflected in Eskom balance sheet and income statement. It should be noted that Eskom has effectively earned an actual return of assets of less than approximately 1% for almost the last decade. This is due to the actual revenue that materialised being lower than envisaged when the revenue decision is made.

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 20: RETURN ON ASSETS

Return on assets	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Closing RAB (R'm)	1 263 247	1 254 636	1 246 151	1 256 395	1 261 675
Real pre-tax WACC %	7.1%	7.1%	7.1%	7.1%	7.1%
Cost reflective RoA (R'm)	89 691	89 079	88 477	89 204	89 579
RoA applied for %	-1.99%	0.69%	0.87%	1.65%	3.04%
RoA applied for R'm	**(25 151)**	**8 682**	**10 879**	**20 668**	**38 292**
Return related Medupi, Kusile & Ingula (included in RoA above)	(7 415)	2 599	3 261	6 088	11 038

The WACC of 7.1%, as determined by NERSA for the MYPD4 period is used as a comparison for the cost reflective return on assets. Eskom's determination of the WACC is 11.5%. However, this 7.1% WACC allows for a conservative estimate, as Eskom migrates towards the cost reflective level.

Return on assets is computed on a revalued regulatory asset base (RAB) with the intention to cover interest costs and earn an equity return. The opening RAB balance for FY2023 is based on the valuation undertaken by independent external consultants, with a modern equivalent asset value (MEAV), which is then adjusted for the latest capital expenditure forecasts for the period FY2023 to FY2025. The average starting RAB value for FY2023 is approximately R 1 263bn.

The ROA specifically related to the Medupi, Kusile and Ingula Power Stations is included in the table above.

Eskom's projected debt commitments for the application period are captured in the table below.

TABLE 21: ESKOM'S PROJECTED DEBT COMMITMENTS

Eskom Debt Commitments (R'm)	Application FY2023	Application FY2024	Application FY2025
Debt repaid	48 204	39 089	41 845
Interest	33 321	35 365	39 202
Total Debt service	81 525	74 454	81 046
Less: Return on Assets + Depreciation	43 103	79 683	85 093
Surplus/ (shortfall) in debt service cover	**(38 423)**	**5 229**	**4 047**
Cummulative (shortfall)/surpluss	**(38 423)**	**(33 193)**	**(29 147)**

The phased implementation of the return on assets together with depreciation allows for a **significant portion of the interest cost and debt repayment costs to be covered over the three year period**. The allowed revenue being applied for does not cover the full debt commitment costs. Rather, progress is being made towards covering these debt commitment costs. Due to this smoothing of the price, Eskom experiences a significant shortfall in the first year of the MYPD5 period. A net shortfall of approximately R29bn is experienced just to meet Eskom's debt commitments. Eskom will not be in a position to provide for any return on equity for the entire application period. An EBITDA margin of approximately 35% would be considered reasonable for Eskom presently. However, this EBITDA margin is not reached. Thus the return on assets is being phased-in to allow for the smoothing of the tariff. This is the decision that Eskom is proposing 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 much higher. Eskom is making this proposal, to allow for consumers to experience a smoother price increase. However, this proposal is accompanied by risks which need to be managed. It is unfortunate, that further burden is required to be applied on the fiscus. The efficient costs do not go away and need to be funded. In essence the subsidy provided to all consumers is continued to be provided for a longer period.

The implementation of the MYPD methodology will entail Eskom applying for cost reflective revenue that covers efficient and prudent costs as well as a return on assets corresponding to the weighted average cost of capital. A cost reflective tariff is one that allows Eskom to recover its efficient and prudently incurred costs and earn a reasonable return. The remainder of the building blocks in terms of the NERSA revenue formula, for this revenue application are in accordance with the MYPD methodology. If Eskom applies its approved weighted average cost of capital of 11.5% (real, pre-tax), the average increase in the revenue will be approximately 95% (FY2023), 2% (FY2024) and 7% (FY2025). With even a return on assets of 7.1%, as determined by NERSA for the MYPD4 period, would result in a price increase of approximately 71% in FY2023, 2% increase in FY2024 and 7% increase in FY2025. If Eskom were to ensure that a minimal positive return on assets of 0.01% were to be applied for in the first year of the application period, it would result in a 32% increase of that year. This is considered to be having a significant impact on consumers and thus is not being applied for. Due to the stage that the country is in with regards to migration towards cost reflectivity, these are not options that Eskom is considering.

As a first step towards sustainability of Eskom, it would be preferable for Eskom to ensure that the revenue caters for prudent and efficient costs as well as a reasonable return that matches the debt service commitments (interest and debt repayments). Thus the revenue related collectively to depreciation and return on assets must match the debt service commitments entailing the debt repayments and interest payments. This would manifest in an approximate increase of 34% in the FY2023, 4% in FY2024 and 13% in FY2025. However, in the interest of the potential impact on consumers, Eskom has proposed a longer phasing-in period. However, the allowed revenue being applied for does not cover the entire debt commitment costs, equating to a cash shortfall totalling approximately R29bn for the MYPD5 period. This is a significant further phasing being proposed by Eskom in the interest of allowing the economy to adjust as the migration towards cost reflectivity. Eskom will use the proceeds from the liquidation of the RCA decisions to contribute to mitigating the debt service shortfalls.

The return on assets are being phased-in to allow for the smoothing of the tariff. This is the decision that Eskom is proposing 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 much higher. Thus Eskom is making this proposal, to allow for consumers to experience a smoother price increase. However, this proposal is accompanied by risks which need to be managed. It is unfortunate, that further burden is required to be applied on the fiscus. The efficient costs do not go away and need to be funded. In essence the subsidy provided to all consumers is continued to be provided for a longer period.

12 Capital Expenditure

12.1 Background

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.

A summary of the capital expenditure to be undertaken in the application period and beyond is provided here. Further details on the capital expenditure projections of each of the licensees is included in the Generation, Transmission and Distribution MYPD5 revenue submissions that forms part of the Eskom MYPD5 revenue submission. It must be noted that the capital expenditure has been constrained during the MYPD4 due to cash restrictions.

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, Eskom capital expenditure plans will focus on delivering the following projects:

- Generation new build programme- commercial operation of further units of Medupi and Kusile with some units on accelerated construction plans
- Replaced, expanded and strengthened transmission grid which gets Eskom closer to N-1 compliance whilst executing the Power Delivery Plan
- Generation technical plan capital expenditure
- Eskom will invest in Cost-Plus mines which will provide Eskom with a more sustainable source of coal. This is included as future fuel.
- Eskom will also invest in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance.
- Investments will be made in the refurbishment and strengthening of existing networks, in building new networks for customers and in connecting IPPs. Eskom does not include DOE funded capex into the regulatory asset base.

12.2 Summary of capital expenditure

A summary of the capital expenditure requirement is summarised in the table below. It is clarified that capital expenditure funded by other entities is not included. This refers mainly to the funding of electrification by the Department of Energy.

TABLE 22 : CAPITAL EXPENDITURE

Capital expenditure (R'm)	Actuals FY2020	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Generation	18 040	20 877	40 422	44 428	44 036	36 126	51 106	49 493
Transmission	2 208	2 067	3 562	11 716	13 523	13 318	15 853	20 326
Distribution (excl DoE)	2 643	2 635	8 459	8 843	10 652	9 100	8 023	7 025
Total Licencee capex	**22 892**	**25 579**	**52 444**	**64 988**	**68 212**	**58 544**	**74 981**	**76 844**
Corporate	363	427	654	672	657	824	774	1 251
Other	0	0	0	0	0	0	2 207	2 019
Total Capex	**23 255**	**26 006**	**53 098**	**65 660**	**68 869**	**59 368**	**77 963**	**80 114**

12.3 Generation Capital Expenditure

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 Power Stations. The projected capital expenditure is as follows
  - Medupi FGD capex – R3 681m (FY2023); R4 963m (FY2024); R7 291m (FY2025)
  - Kusile capex – R7 921m (FY2023); R7 157m (FY2024); R1 758m (FY2025)
- Generation technical plan capital expenditure
- Eskom will invest in Cost-Plus mines which will provide Eskom with a more sustainable source of coal. This is included as future fuel.
- Eskom will also invest in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance.

Eskom 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 Eskom's project life-cycle model. In addition, the repair to the major defects to Medupi and Kusile are being undertaken.

In addition, Eskom 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.

12.4 Transmission Capital Expenditure

Eskom Transmission's network needs to be strengthened and expanded to connect new loads and generation to the network to enable country growth. In addition, investments for asset replacement are required for assets which have reached their end of life in order sustain a reliable supply of electricity.

Strengthening and capacity expansion includes generation integration projects required to ensure that the network is able to evacuate and dispatch power from generation sources to the load centres. It also includes projects for planned new customer connections, strengthening the transmission network to allow for future demand growth and reliability projects relating to Grid Code compliance requirements.

Asset replacement investments are required when assets have reached their end of life and can no longer be reliably operated. These investments are prioritised based on asset condition, network criticality and risk criteria.

Environmental Impact Assessments (EIAs) are conducted in accordance with National Environmental Management Act (NEMA) requirements for expansion and asset replacement projects. Land and servitudes are procured for substation and line construction projects based on valuations from independent and registered land valuators.

NERSA has published rules in the Grid Code governing investment in the transmission network. Transmission plans the network according to the Grid Code and subject to funding & other resource constraints, builds the network in alignment with the Transmission Development Plan (TDP). Where insufficient funds are available for required network investments, a consistent set of rules is applied to prioritise projects and allocate funding in such a way that the maximum benefit is gained for customers.

12.5 Distribution Capital Expenditure

Capital investments support the continued productive life of assets and the technical conditions necessary to maintain continued electricity supply to secure revenue streams and improve customer experience.

The application for capital expenditure is required to strengthen and refurbish the Distribution network, to meet future growth requirements, manage the transition of an evolving distribution landscape with increased Distributed Energy Resource integration, whilst allowing the network to maintain current performance standards.

A key priority is to ensure a reliable and sustainable power supply; the Licensee will balance the need for resolving constrained networks whilst providing the supporting infrastructure for maintenance and operating activities. Historically, the Distribution network performance gains are reflective of the investment choices made in the capital projects.

The Distribution network capital expenditure is deployed in activities that are based on extensive planning in alignment with the required network performance. A 10-year network development plan informs the capital investment program which supports the forecasted economic load and distributed generation growth nodes.

The capital investment program enables the establishment of the required capacity to meet the future electricity demand and capacity, whilst maintaining acceptable levels of network performance and reliability, and operability. The capital expenditure is also reflective of the capacity of the Licensee to execute the capital program in line with its historical performance.

In compliance to the Grid Code, a network development plan is formulated for the immediate 3-5 year period. The MYPD5 submission and the requested Capital allocation are informed by the 3-5 year development plan. Notable redress is required for capital expenditure in the strengthening, IPP related infrastructure and refurbishment categories. It is important to note that:

- An acceleration of the Bid Rounds for the IRP is expected. As neither the location, capacity nor number of IPP's have as yet been announced for these future rounds, the Capex requirements are indicative at this stage to cater for these requirements. The finalisation of the projects for the Bid 4 rounds are largely covered in the 2021/2022 submissions.
- The Cash Upfront top-up projects relate to customer projects that are not on the plan and their Cash Upfront is less than the total project costs. This is the budget for the top-up portion. Which is the difference between the total project cost and cash upfront paid by the customer.
- With regards to electrification, the DMRE have approved the Capex allocation up to 2024. The submission thereafter has been escalated on the basis of a 5% inflationary increase per annum.

12.6 Environmental Requirements

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.

12.6.1 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.

12.6.2 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 16: 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.

12.6.3 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.

12.6.4 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.

13 Primary Energy

13.1 Overall summary of primary energy

A summary of the key elements of the primary energy revenue elements are addressed here. Further details are included in the Generation Licensee MYPD5 revenue submission.

This section will cover the primary energy (PE) and levies & taxes (L&T) components of the building blocks to the allowable revenue formula:

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

Primary energy costs equates to the costing of the production plan (electricity supply required to meet demand). There are three sources of electricity supply comprising Eskom own generation (majority), domestic independent power producers (IPPs) and regional import of supply (international supply).

13.2 Trends in primary energy costs

Eskom’s primary energy cost escalations are summarised as follows:

Eskom’s primary energy related revenue contributes 30%, 25% and 24% of the allowable revenue corresponding to R80bn, R79bn and R84bn for the application years respectively. Thus a downward trend in the Eskom primary energy contribution to allowable revenue is occurring.

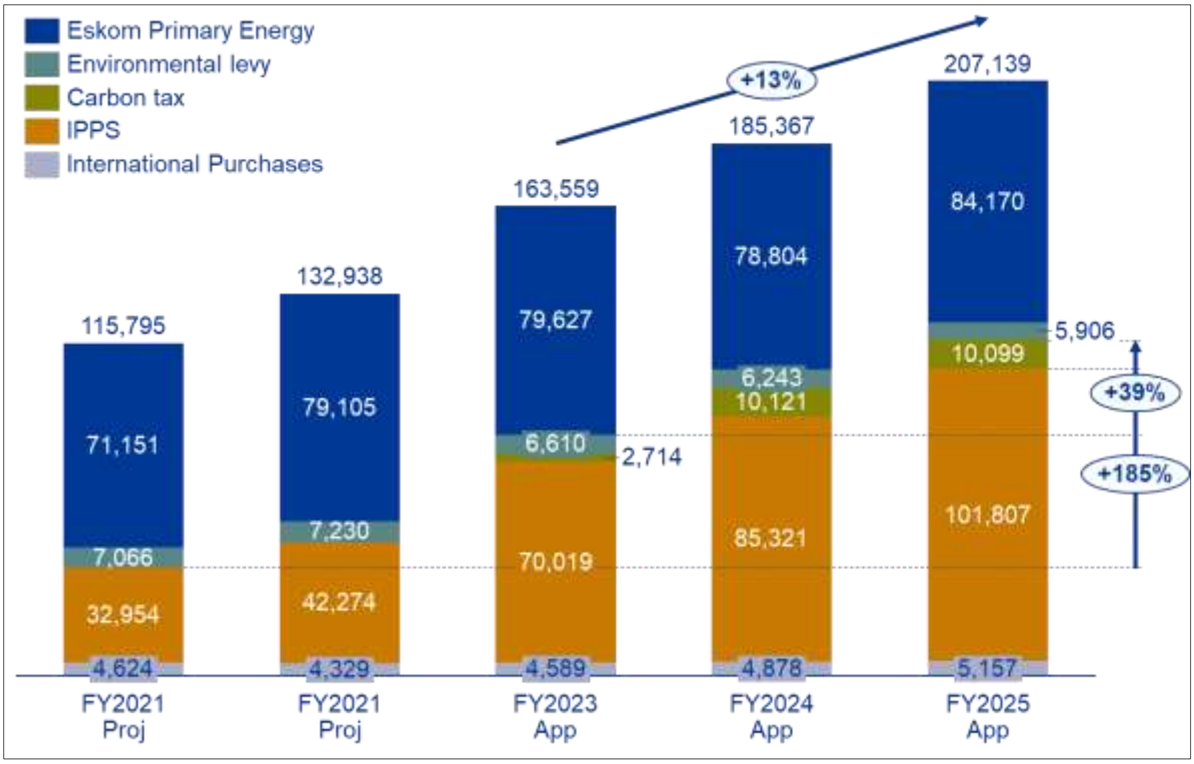
IPPs experience an upward contribution trend towards allowable revenue over the three application years. The contributions to the total allowable revenue for each financial year increases from 25%, to 25% to 28% over the application period. This corresponds to R70bn, R85bn and R102bn for the three years 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.

FIGURE 17: TOTAL PRIMARY ENERGY COST



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%

The table below summarises the primary energy related revenue being applied for in this MYPD5 revenue application.

TABLE 23: DETAILED PRIMARY ENERGY COST

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	-	-	-	-	-	-	-
International purchases (Dx)	12	11	12	13	13	14	15	15
Total Eskom generation	**72 113**	**71 151**	**79 105**	**79 627**	**78 804**	**84 170**	**85 462**	**91 206**
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	**114 123**	**115 794**	**132 938**	**163 559**	**185 366**	**207 139**	**230 186**	**246 030**

13.3 Revenue for coal costs

While Eskom is a regulated entity, the coal market is unregulated, so Eskom 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, Eskom 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.

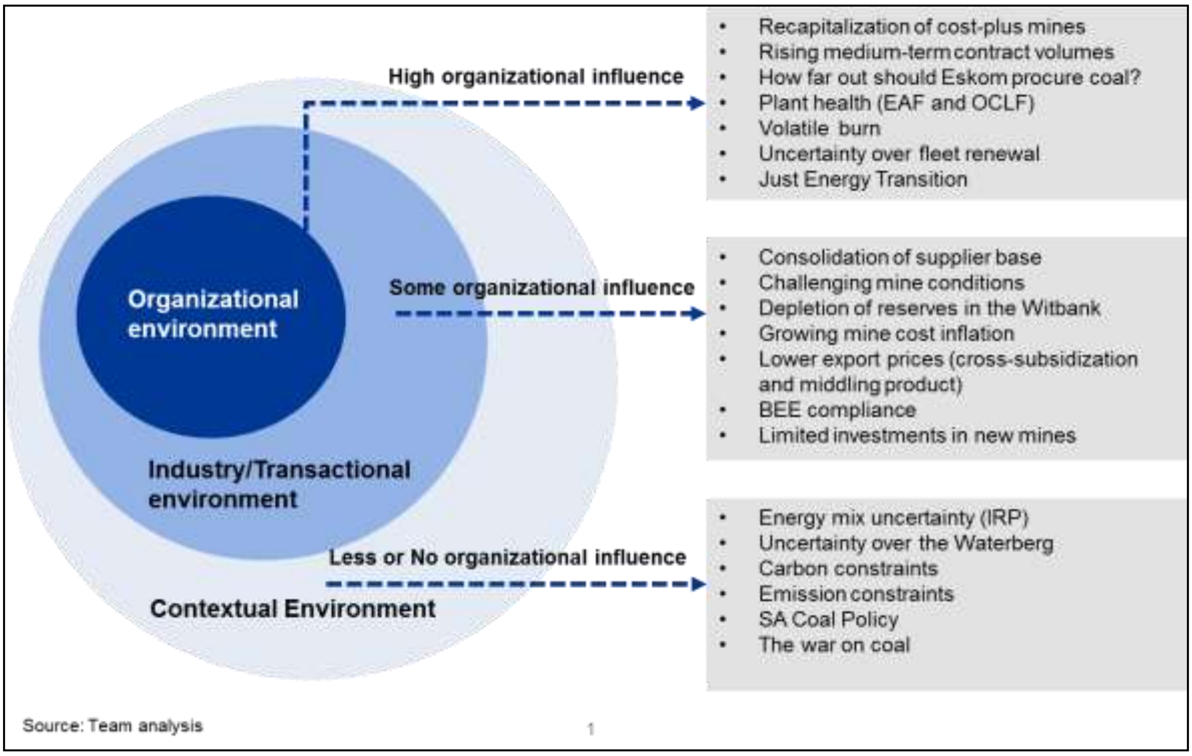
The forecast decrease in volumes from FY2021 manifests in the lower volumes from the Fixed Price (FP) and Short and Medium Term (STMT) contracts. This may be attributed to the following:

- 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) 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, Medupi and Kusile Power Stations.

FIGURE 18: PRIMARY ENERGY VALUE CHAIN

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

FIGURE 19: CHALLENGES FACING GENERATION'S PRIMARY ENERGY FUNCTION



Eskom is, thus, exposed to various factors that have had, and will continue to have implications for costs and security of primary energy supply to Eskom.

13.3.1 Benchmarking

The volumes and prices of coal supplied to the domestic market (primarily Eskom) with that exported is compared. The graph below reflects the trend in the average Eskom 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 Eskom 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 Eskom to prioritise exports at the expense of Eskom.

FIGURE 20: AVERAGE FOT STEAM COAL PRICES(R/T)

Sources:
Richards Bay price: IHS
(ttps://connect.ihs.com/Capabilities/COL#viewer/default%2FDocument%2FShow%2Fphoenix%2F390672%3FconnectPath%3DCapabilities_COL.COL_DTA)
Eskom Plan 22 Feb 2018

13.3.2 Governance

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

There are 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 Eskom.

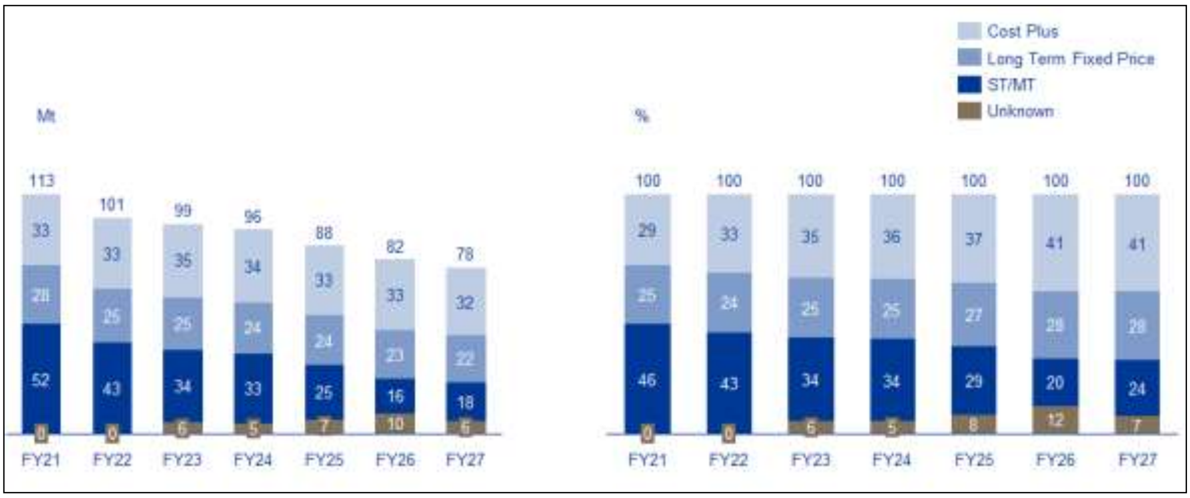
13.3.3 Forecast Coal Supply to meet Coal Burn

Eskom prefers to contract for coal on long term contracts. The presumption is that this provides Eskom 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 Eskom'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 from ST/MT contracts.

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 Eskom needs to procure is also forecast to decline.

13.3.4 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 Eskom's policy to secure long term contracts with mines close to power stations and source only the coal shortfall from sources further away.

13.4 Future Fuel Expenditure

Capital expenditure related to the acquisition of future fuel is required. 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 Eskom 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.

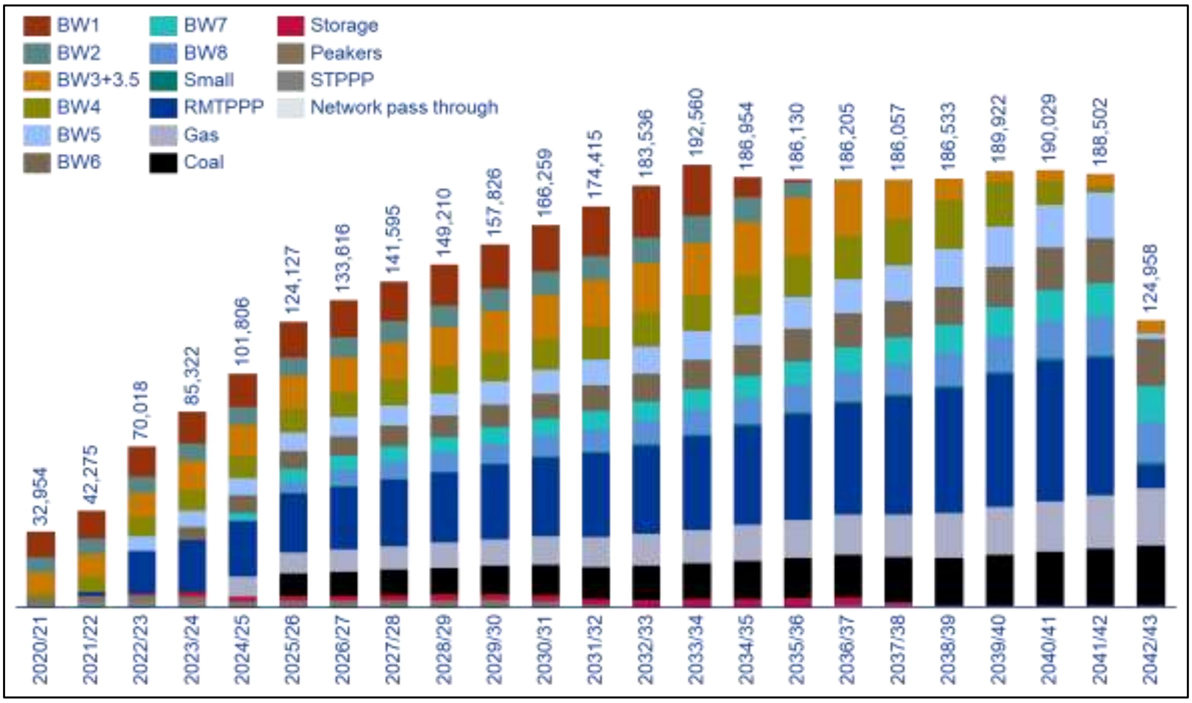
13.5 Independent Power Producers (IPPs)

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), Eskom 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.

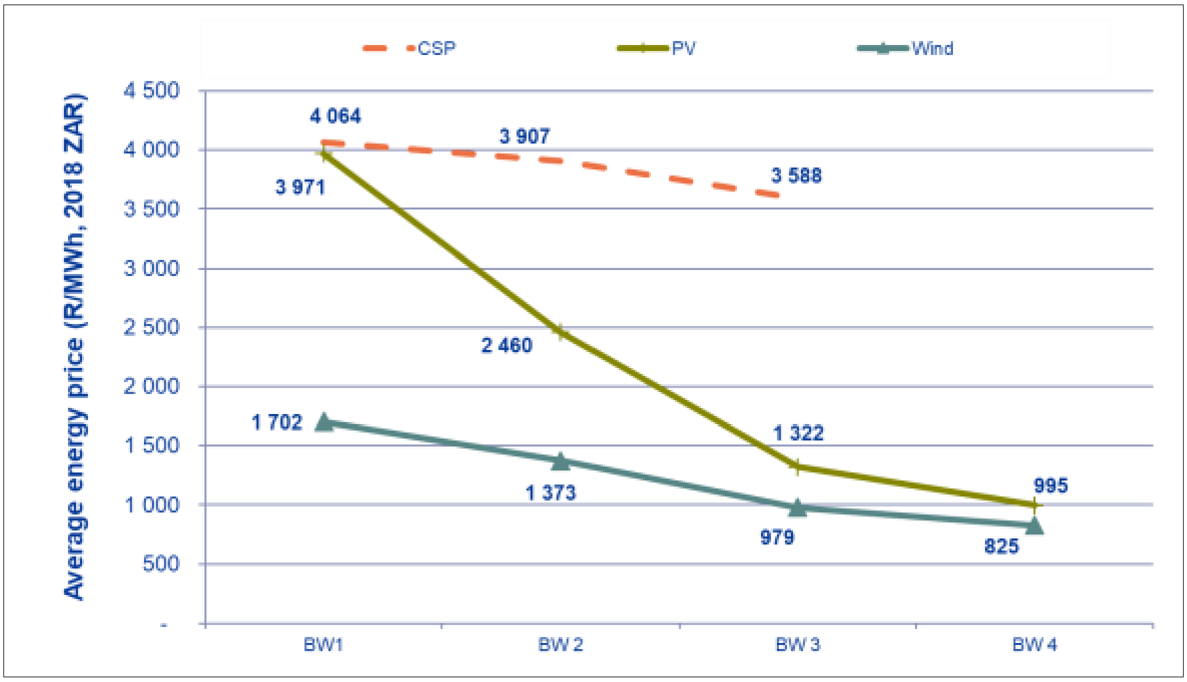
Eskom has undertaken this process. Eskom has received feedback from all three relevant Government Departments, that all concur with the projections on IPP projects to be included in Eskom's MYPD5 revenue application.

FIGURE 22 : 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.

FIGURE 23: DECREASING TREND IN COST OF RENEWABLE TECHNOLOGIES THROUGH BID WINDOWS



It should be noted that a decline in the costs of the concentrated solar power (CSP), Photo voltaic (PV) (Solar) and wind generation over the bid windows are observed. The decrease in wind and PV are significant. This is mainly due to a decrease in the capital costs of developing these technologies. Notwithstanding the decrease in costs of these renewable technologies through successive bid windows, an increase in overall costs related to IPPs will need to be recovered through the price increase. This is related to escalations in existing contracts (usually related to CPI) and the substantial increase in energy sourced from IPPs from renewable and other technologies.

13.6 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 HCB’s 5th generator on a non-firm basis. The forecasts remain fairly consistent at around 10.5 TWh.

13.7 Water costs

Eskom receives raw water from the Department of Water and Sanitation (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.

Over the FY2022 – FY2027 period, the total volume of water consumed decreases, but the total cost of water is expected to increase due mainly 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 and development of additional water augmentation schemes to meet increase water demand. Eskom 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 Eskom 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. Eskom pays for the water it consumes through a series of water tariffs. These are legislated, so Eskom has no control over what they are.

13.8 Open Cycle gas Turbine (OCGT) Fuel

From a production 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%, which translates to 211 GWh per annum. 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 Eskom economic parameters for the forecasting period were used in the calculations of the fuel costs. The diesel used by Eskom is subject to a wholesale discount and a fuel rebate as determined by the Minister of Finance.

13.9 Demand Response

The Demand Response (DR) programme fulfils an important role towards power system security (even during times of surplus capacity) by providing the System Operator (SO) with much needed flexibility and reliability. The SO uses reserves to control the interconnected power system frequency. These reserves are procured from both generators and the

Demand Response (DR) programme through the ancillary services process as defined in the Grid Code.

Factors that could affect the frequency stability of the electricity supply include:

- System constraints caused by severe weather and/or power line faults
- Generator malfunctions (unexpected trips – loss of multiple Generation units)
- Substantial load and renewables forecast errors due to unforeseen circumstances.

13.10 Environmental levy

The environmental levy on the generation of electricity from non-Renewable generators was promulgated in July 2009. All Eskom generators, with the exclusion of Hydro and Pumped Storage Power Stations, were registered and licenced as manufacturing warehouses as required by the legislation.

13.10.1 Environmental levy payment

From 1 July 2012, the environmental rate is 3.5c/kWh. The actual payments to SARS are determined by the true metered generated volumes. For this submission the Production Plan which measures Energy Sent Out as measured after the high voltage transformer is used to derive the assumed cost. To obtain the Generated volume an expected auxiliary consumption, based on actual historical performance, which is unique to each Power Station is added to the Energy Sent Out volume as published in the Production Plan. This derived Generated volume is then charged at the applicable Environmental Levy rate for that period to obtain the forecasted cost per Power Station. It is assumed for the planning period that no further rate increases will occur.

The methodology, as approved by NERSA is based on the principle that the levy is raised at electricity production and that the electricity sales volumes is lower than the production volume. Thus the environmental levy cost is equivalent to the revenue related to the environmental levy.

13.10.2 Carbon Tax

The National Treasury has introduced an additional tax that impacts the electricity price. This is the carbon tax with effect from 1 June 2019. Phase 1 of the implementation of the carbon tax act is from 1 June 2019 to 31 December 2022. During phase 1, Eskom (as a "generator of electricity from fossil-fuels") is allowed to make two further deductions from the carbon tax liability. The first deduction is equivalent to the renewable energy premium and the second deduction is equivalent to the amount equal to the environmental levy. These two deductions in essence are sufficient to nullify the carbon tax liability until December 2022. From 1 January 2023, Eskom becomes liable to pay the carbon tax, where the deductions from the tax liability falls away. In terms of the MYPD methodology, Eskom is required to recover these costs from the consumer. With effect from 1 January 2023, when the carbon tax liability is introduced by National Treasury, an equivalent of approximately 5c/kWh will be due to carbon tax. Further details on the implementation of the carbon tax is addressed later in this submission.

14 Operating Cost

14.1 Overall summary of operating costs

Operating costs include all costs involved with the day-to-day running of the business. Eskom's operating costs include employee benefit, maintenance, other expenses and allocated corporate costs. It should be noted that these costs are net of capitalisation and therefore represent the costs that are directly recoverable. The costs of operating and maintaining new assets are included in the operating costs.

The projection for the operating costs has taken into account the importance of driving cost curtailment in line with the turnaround plan to reduce Eskom's cost base, these initiatives are expected to contribute to the overall Eskom's financial sustainability.

The next section will cover the operating expenditure (E) element of the build blocks to the allowable revenue formula.

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

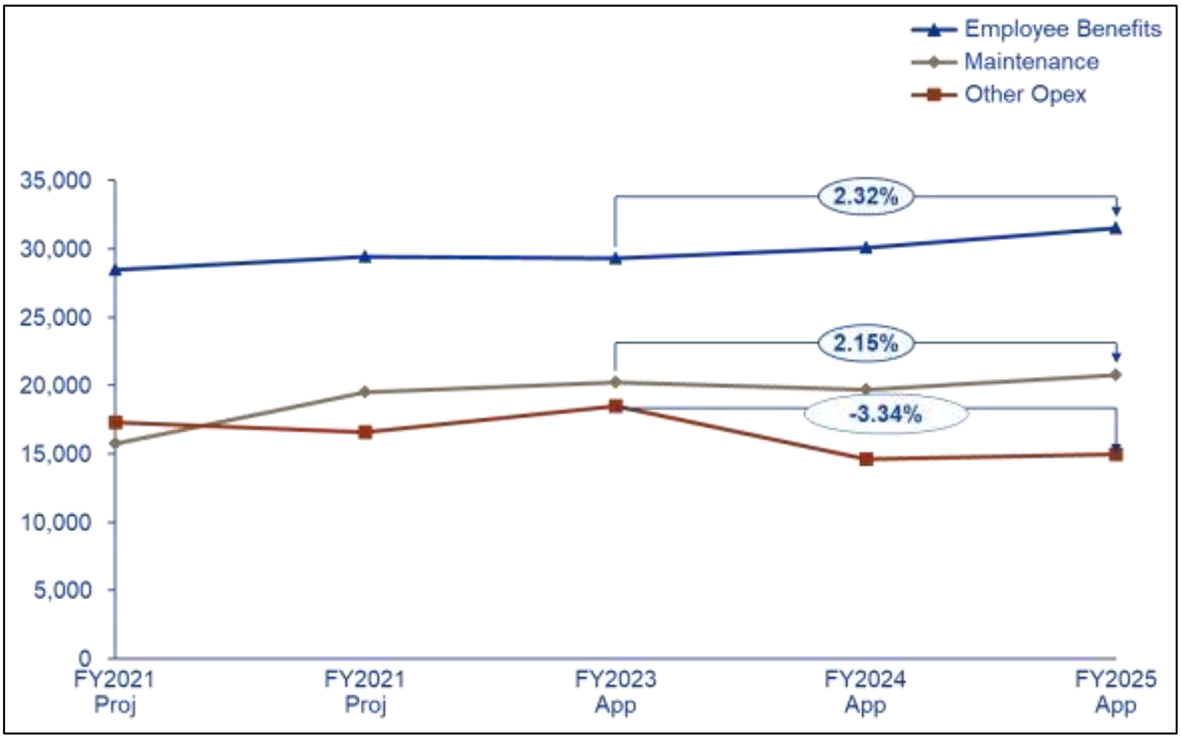
The operating costs at Eskom level are summarised here. Further details on each of the licensees' operating costs are provided in the Generation, Transmission and Distribution MYPD5 Revenue submissions which form part of Eskom's MYPD5 revenue application. Integrated Demand Management is addressed in the Distribution Licensee MYPD5 submission.

TABLE 24 : DETAILED OPERATING COSTS

Operating costs (R'm)	Projections FY2021	Projections FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee benefit costs	28 468	29 396	29 300	30 088	31 486	32 272	33 302
Operating & Maintenance costs	33 023	36 048	38 665	34 327	35 723	39 141	40 035
Maintenance	*15 733*	*19 476*	*20 195*	*19 705*	*20 758*	*20 428*	*20 720*
Opex	*17 290*	*16 572*	*18 470*	*14 622*	*14 966*	*18 713*	*19 315*
Other income	(3 470)	(1 219)	(1 173)	(1 176)	(1 233)	(1 086)	(1 086)
Arrear debts	4 385	5 009	5 666	6 511	7 110	7 802	8 541
Corporate social investment	(111)	(155)	(102)	(124)	(124)	-	-
TOTAL OPERATING COSTS	**62 295**	**69 079**	**72 356**	**69 626**	**72 963**	**78 129**	**80 793**

Eskom's operating costs over the period FY2023 to FY2025 (application years) have remained relatively static. The trends are illustrated in the figure below

FIGURE 24: OPERATING COST TRENDS



Eskom's overall operating costs, over the period FY2023 to FY2025 (application years) have grown at a CAGR of approximately 5%. Analysis reflects that employee benefits have an average CAGR increase of 2.32% (after capitalisation) in this horizon. Similarly, the operating and maintenance costs have an average increase in CAGR of 2.15% over the period. The other operating costs see a marked drop with a CAGR of negative 3.34% over the application period.

Significant efficiencies would be achieved over the period by reducing the number of employees. Containing the workforce numbers without compromising the required skills in appropriate areas will be possible. This will be done by re-training, re-deployment and re-skilling of the work-force and natural attrition. Voluntary separation packages were taken in the previous years.

14.2 Employee Benefits

Workforce optimisation was identified as a major component to drive internal efficiencies, increase productivity and lower operating costs. Approximately 80% of Eskom's staff complement belongs to the bargaining unit and 20% are positioned at managerial level. Eskom has recently relinked all service functions back to operations. The aim of the relinking process is to maximise decision-making, improve levels of accountability at the right levels of business, improve operational and financial efficiencies, maximise execution of strategy and operational plans, financial efficiencies and effective resource allocation and usage, including monetary and personnel.

Employee benefit costs 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 benefit costs.

As part of Eskom'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.

Employees from Technology, Telecommunications, Procurement, Finance, Properties, Research and Human Resources divisions were relinked to licensees since FY2019.

Eskom achieved substantial progress in reducing its headcount since FY16 when this need was identified as one of the strategies to manage increasing employee benefits costs. Eskom achieved this through the implementation of various headcount management levers to reduce the employee benefits costs. Natural attrition has been the primary headcount management lever, supported by a moratorium on recruitment and implementation of voluntary separation packages (depending on the availability of funding).

Eskom will continue to manage its headcount as it implements the new workforce plan over the next three years. This will be achieved through normal attrition, supported by limited recruitment (up to 15% of attrition) and voluntary separation packages (as and when funding is available).

14.3 Operating and Maintenance costs

As the business strives to accelerate maintenance programmes, and with the ageing of plant it is expected that maintenance costs should increase.

14.3.1 Generation maintenance

Eskom 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.

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

- Immediate safety risk as per ERAP inclusive of any emerging technical threat which is deemed to pose immediate and significant personnel or plant risk.
- Statutory requirements 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.

A 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.

14.3.2 Transmission

Maintenance workload is driven by the size of the network and the condition / age of assets. Transmission's maintenance strategy includes the compilation and review of maintenance philosophies, standards and procedures. Incident investigation recommendations requiring modifications to existing standards and procedures are used as additional input during the revision of the standards.

The maintenance philosophy is mostly time-based, but also considers the following:

- Operational information (usage);
- On- and off-line condition monitoring;
- Plant performance information;
- Non-intrusive functional testing;
- Statutory requirements;
- Safety of assets and people.

Live line maintenance is utilised to overcome planned outage constraints or during emergencies. This requires specialised skills and equipment which has an impact on maintenance costs.

The increase in maintenance expenditure is as a result of abnormally low maintenance expenditure in past two years owing to the following reasons:

- Delay in the conclusion of servitude maintenance contracts. This was due to changes in the servitude contract procurement strategy with regards to decentralising the contract management to regional level as opposed to the previous national contract

- COVID-19 pandemic and subsequent level 5 hard lockdown resulted in certain non-urgent maintenance activities being deferred. There were also delays in procurement processes in concluding service contracts, issuing of enquiries and tender evaluations.

Additional Transmission maintenance spend is also required for the following:

- To sustain the aging plant which poses a risk to the system

- To undertake network recovery work following major incidents or plant failures

- To carry out maintenance or repair activities that do not form part of routine maintenance plans such as repairing of major transformer oil leaks and replacement or repair of corroded components.

14.3.3 Distribution

Distribution's existing infrastructure has reached an advanced stage of its asset life; planned electrification networks now means certain networks are at near the end of life. Future connection and changes in the customer base requires a sustainable maintenance regime.

14.3.3.1 The objective of maintenance is to ensure that:

- The asset condition is managed over the asset life cycle.
- Regulatory and Statutory requirements (Safety, Health and Environment) are adhered to.
- The technical performance key performance indicators for interruptions and restoration time are in accordance with the targeted performance levels.

14.3.3.2 The key drivers for the maintenance expenditure include the following:

- **Environmental and safety consideration :** To ensure safe operation of the network with a minimum impact to the environment
- **Asset Base:** Distribution has an installed asset base of approximately 50 035 kms high voltage network, 2 948 substations, 344 732 kms medium voltage network, 469 063 low voltage network. Based on history the asset base grows by approximately 4% per annum. This will increase the maintenance requirements in both the preventative and corrective (fault) environments.
- **Network performance:** Networks need to perform in line with design requirements supporting compliance to technical performance KPIs.
- **Quality of service to the customer:** Apart from supply availability, quality of supply parameters (voltage regulation, voltage dips, voltage unbalance etc.) must comply with National Regulator requirements.
- **Sustainability of network infra-structure:** The network infra-structure is aging and with limited capital investment leading to sub-optimal performance of network.

Eskom Distribution's maintenance regime includes both preventative and corrective maintenance. Preventative maintenance refers to planned maintenance activities on assets whilst corrective maintenance refers to unplanned or fault activity. A gradual increase in maintenance costs is observed.

14.4 Other Operating Expenses

Included in this category are costs such as insurance, IT (information technology), fleet costs, legal and audit services, security, travel expenses, billing costs, connection/disconnection costs, meter reading, vending commission costs and telecoms.

- Insurance cost increases reflect the increase in the asset base as well as global premium increases. Factors that influence cover and pricing include insurance claim trends, loss ratio performance, value of insurance excess, new-build programme, re-insurance costs, increases in insured asset values and risk management efforts.
- The increase in Security expenditure is due to increased initiatives by Eskom to safeguard assets, combat theft incidents and mitigate the related risks.
- Telecommunication services is required for supervisory control and data acquisition (SCADA) and enabling remote access to fault recording systems as well as control centre communications.
- Meter reading - reading of Small Power Users (SPU) and Large Power User (LPU) billed customer meters are done mostly on a quarterly basis.
- Disconnection and Reconnection costs - costs incurred to manage outstanding debt by disconnecting non payers and reconnecting once the payment is made.

14.4.1 The major components comprising other operating costs within Eskom are:

- Insurance premiums of approximately R5bn annually
- Facilities costs of an approximate value of R2bn annually
- Contractor costs
- Environmental expenses (approximately R2.4bn over the MYPD5 application period)
- Security expenses
- Customer related expenses (Vending commissions, billing and meter reading expenses, reconfiguration and prepayment meters etc.)
- Information technology and annual software licensing costs
- Research and development related costs
- Restructuring related costs

14.5 Research, Testing and Demonstration

The electricity industry is going through significant challenges driven by technology disruptors as well as market, policy and industry drivers. The power utility needs to respond to these challenges with the need for greater flexibility, rapid technology advances across the entire value chain and adapting to changing business models. Balancing social, environmental and economic imperatives relies heavily on technology development and breakthrough to provide a way forward when all other routes appear blocked. Eskom Research, Testing and Development (RT&D) is therefore dedicated to finding technology solutions that can be applied primarily within Eskom to ensure it fulfils its mandate to South Africa. '*We are predominantly a technology early follower'* - Except for a few carefully chosen areas, Eskom does not wish to lead technology development. Rather it will focus on technology identification, acceleration and application, not technology development.

Eskom is a needs driven organisation focussed on the systematic acquisition of knowledge and the application, development, refinement or demonstration of new and innovative technologies and solutions to satisfy Eskom's operational and strategic requirements through centres of expertise.

14.6 Insurance

Escap SOC Ltd ("Escap"), a wholly-owned subsidiary of Eskom, is the primary insurer for Eskom other than where Escap does not have the required capacity and/or expertise, mainly nuclear risks.

The main benefits that Eskom derives from having Escap as a primary insurer are:

- Generally, the components of an insurance premium include claims costs, commissions, administration expenses, contingency allowances and profit. Escap's pricing model does not include commissions and profit. Therefore, the insurance premiums charged by Escap are lower than the external market premium.
- The premiums that are not utilised to pay claims and other expenses are retained and invested by Escap. In the absence of Escap, this retained income would have benefited the external markets.
- Provides a protection from the volatility of the insurance market by mitigating against insurance premium increases that are due to market conditions as opposed to increase in risk.
- Promotes risk management through engineering risk surveys

- Provides direct access to the reinsurance market which in turns allows for negotiation of favourable reinsurance premiums
- Ability to provide insurance covers that are not available in the conventional insurance markets.

15 Carbon Tax

15.1 Impact of carbon tax during MYPD5 period

The National Treasury has introduced an additional tax that impacts the electricity price. This is the carbon tax with effect from 1 June 2019. Phase 1 of the implementation of the carbon tax act is from 1 June 2019 to 31 December 2022. During phase 1, Eskom (as a "generator of electricity from fossil-fuels") is allowed to make two further deductions from the carbon tax liability. The first deduction is equivalent to the renewable energy premium and the second deduction is equivalent to the amount equal to the environmental levy. These two deductions in essence are sufficient to nullify the carbon tax liability until December 2022. From 1 January 2023, Eskom becomes liable to pay the carbon tax, where the deductions from the tax liability falls away. In terms of the MYPD methodology, Eskom is required to recover these costs from the consumer. The details of the revenue requirement are addressed in the primary energy section.

15.2 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 Eskom is exempt from the tax, this 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 with the number in the corresponding line of the column ''Threshold'' of that table. Eskom 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 should be noted that there are additional activities listed that Eskom undertakes which are currently "not applicable" which may become applicable in future, notably, category 2G1b, for the "use of electrical equipment".

15.3 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 Environment, Forestry and Fisheries or determined in accordance with the formulas and input values provided for in the act. Since 2017, Eskom already reports greenhouse gas emissions to the

Department of Environment, Forestry and Fisheries using an approved “Tier 1” methodology, as required by the National Greenhouse Gas Reporting Regulations of 3rd April 2017 (notice no 40762).

15.4 Tax rate

The tax rate was introduced at R120/tonne CO2eq 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.

15.5 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.

- 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 become inaccessible from 1 January 2021 as the pilot carbon budgets negotiated with DEFF expire on 31 December 2020 and it is not clear when the draft Climate Change bill and associated regulations (for mandatory carbon budgets) will be finalised.
- The offset allowance requires that an entity purchase offset credits up to a maximum of 10%. Eskom 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).

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

The tax allows Eskom (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.

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

From 1 January 2023, the deductions referred to above in phase 1 fall away and the full carbon tax liability is expected to be passed through to the consumer. The carbon tax liability arising from 1 January 2023 is expected to result in an amount due to the South African Revenue Service in July 2024.

15.8 Opportunities to reduce Eskom'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 Eskom'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 (CO2) 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.

15.9 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.

15.10 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.

16 Context for MYPD5 Revenue application

16.1 Key assumptions to address possible uncertainty during MYPD5 period

Eskom is required to submit this MYPD5 revenue application almost a year prior to the implementation from 1 April 2022. The specific timeframes are to meet the requirements of the MFMA as well as information required for National Treasury budgeting circulars to Municipalities. Eskom will provide NERSA with more recent information, in the event that NERSA wishes to consider these as it makes its revenue determination. This is in accordance with the MYPD methodology.

16.1.1 Covid impact

Covid-19 pandemic has occurred in the midst of an economic slowdown and recessionary environment, pushing the economy into unprecedented territory that will require extraordinary resilience and action to emerge bruised but not ruined. The IMF revised global growth downwards by 6.3% from its January 2020 estimates, with the implication that lockdowns implemented in most countries to deal with the pandemic would lead to the worst recession since the Great Depression during the 1930s, even surpassing the 2008 global financial crisis. Moody's downgrade of the Sovereign rating to sub investment grade at the end of March 2020 is likely to have a material impact on Eskom's financial sustainability, specifically when international investors such as pension funds – whose mandates limit them to investment-grade bonds – will have to start divesting out of South African issued bonds.

The World Bank expects South Africa's economy to contract by up to 8%. Government spending to limit the negative impact of COVID-19 and to provide much-needed relief and stimulus funds will put the already constrained fiscus under severe pressure. This is exacerbated by businesses curtailing operations, entering business rescue or closing down, resulting in greater job losses. South Africa's already unacceptable unemployment rate is expected to grow, with some analysts predicting a loss of around one million formal jobs. The IMF still expects South Africa to record negative GDP growth of 8% for 2020, as noted in its June 2020 World Economic Outlook. Also emerging are protectionist policies and, in some instances, xenophobia and human rights violations. This pandemic is forging the world into a "new normal" which is laden with both risks and opportunities. The long-term effects of the COVID-19 pandemic and the ratings downgrade is likely to have dire consequences for the South African economy, with some economists predicting a decline in economic growth of up to 6% in the current fiscal year. Any decrease in economic activity will have a significant negative impact on Eskom's financial and operational sustainability.

16.1.2 Eskom Turnaround plan

Our turnaround strategy continues the focus on five key areas, namely operational recovery, improving our income statement, addressing our balance sheet, accelerating the restructuring of Eskom into three divisions, and building a high-performance organisation through addressing our corporate culture by energising our Eskom colleagues.

These are largely aligned to the objectives we pursued during the prior year, namely optimising our balance sheet through Government equity support in the absence of adequate tariffs; improving our revenue outlook through migrating towards cost-reflective tariff increases and growing sales volumes; curtailing costs; executing the Generation recovery plan; and working towards the restructuring of Eskom, through divisionalisation as a first step.

We will ensure that the restructuring process receives the necessary attention. Furthermore, divisional boards have been appointed to hold each entity accountable on strategy implementation, business performance and functional compliance. We have ring-fenced all three divisions' financials and are reporting divisional financial statements. The end state of the process is to ensure that all three divisions will be able to operate as standalone, financially viable businesses, and to further mitigate the risks to debt and lender security and the asset base. Any industry restructuring will likely require legislative changes. Eskom has made this application for a three year period. If any industry changes do occur, there would be a need for appropriate changes in the relevant methodologies that govern the revenue application for the relevant independent entities.

In this draft revenue application, It is assumed that no further allocations for Eskom-build will be made for the MYPD5 revenue period in the Integrated Resource Plan should it be updated during the MYPD5 period. No further allocation of Independent Power Producer contracts will be made, in addition to that which has been included in this application, as approved by the relevant Government Departments in accordance with the GSFA.

16.1.3 Carbon Tax implementation

The Carbon Tax Act has been implemented and came into effect from June 2019. The impact of the carbon tax commitments are included in this application. The introduction of the carbon tax when implemented for a full year results in an increase in the allowable revenue of approximately R10bn per annum.

16.1.4 Implementation of the IRP 2019

Investment decisions on generating capacity is governed by the Integrated Resource Plan (IRP), which falls under the jurisdiction of the DMRE Minister. Eskom, becomes the vehicle to realise this Government policy. 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. 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.

17 Governance challenges are being addressed

Eskom acknowledges that there have been governance failures in the recent past. Adjustments in tariffs would need to be made for any recovery from the outcome of the investigations and actions related to governance failures. Eskom takes direction from NERSA in this regard.

On 7 March 2019, the NERSA Media statement as confirmed by the NERSA Chairman at the media briefing was as follows with reference to previous revenue decisions:

"The energy regulator also considered that Eskom conceded that certain governance failures occurred in Eskom. However, at the time of the above decisions and although some of the adjustments were effected, the extent of the governance failures or amounts associated therewith had not been fully quantified. The energy regulator may initiate its own investigation into the governance failures in Eskom and may effect adjustments to Eskom's revenue based on the relevant outcome of its investigation and/or those undertaken by bodies or entities, including, but not limited to, Eskom, National Treasury, the Special Investigating Unit, the South African Directorate for Priority Crime Investigation (Hawks), the Parliament of the Republic of South Africa, or any commission of enquiry as and when they are concluded or a conclusive outcome is reached and the costs associated therewith have been quantified."

Eskom has gone on record in support of this approach as clarified during previous submissions to NERSA. As an example, the recovery from McKinsey has already been included in the RCA balance determination related to the FY2018. Thus, the R1bn recovered has been deducted from the RCA balance that was due to Eskom and included as a benefit to the consumer. Eskom will continue to include further adjustments in subsequent RCA balance applications.

17.1 Major investigations

The finalisation of investigations into former Board members and executives suspected of misconduct combined with legal action to recover financial losses remain a key priority. We continue to provide all necessary information and support to the South African Revenue Service (SARS), the SIU, the South African Police Service (SAPS), the Directorate for Priority Crime Investigation (Hawks), the National Directorate of Public Prosecutions, the Zondo Commission and National Treasury. Nevertheless, criminal convictions and recovery of financial losses are dependent on successful prosecution by law enforcement agencies and the justice system. Regrettably, this remains a lengthy process resulting in slow progress on various matters.

17.1.1 Stefanutti Stocks Isazi JV

The contractor has submitted several compensation event claims against Eskom, which could amount to as much as R1.3bn depending on the degree of success. Eskom is at risk in respect of some of the claims since they are deemed compensation events in terms of the contract. Eskom has also issued its final statement of account of approximately R315m to the contractor. During a hearing in February 2021, the contractor reduced its claims to approximately R450m. The parties are considering the possibility of the measurement dispute being settled by an independent measuring quantity surveyor.

The SIU has referred the matter for investigation to the NPA. After being brought to the attention of the adjudicator, he indicated that he is unable to do anything about the SIU's letter. The contractor has queried the independence of Eskom's expert, HKA, given that the SIU is also using HKA. The parties and adjudicator have agreed that the adjudicator will not deliver his decision, which is available, until so instructed by the parties, pending discussion between the SIU and the contractor.

17.1.2 Impulse International

Impulse International has instituted action against Eskom for claims of approximately R61m, and ERI for claims of approximately R22m. Eskom filed a counterclaim requesting the court to grant an order declaring these contracts be set aside. Eskom is requesting the court to order that it be reimbursed for all payments made to Impulse International pursuant to these contracts. In parallel, Eskom is engaging with the SIU and NPA to ensure a collaborative approach to dealing with the litigation. This is to ensure that Eskom's legal strategy does not negatively influence the legal action being pursued by the NPA and SIU. Eskom is awaiting trial dates for the matters to be set down for hearing.

17.1.3 Tegeta (Brakfontein Mine)

Tegeta (Brakfontein Mine) is under business rescue and Eskom submitted a claim of approximately R359m against the business rescue practitioners for post business rescue penalties for failure to supply coal. The underlying coal supply agreement was set aside in terms of a court order handed down on 4 March 2020. It is anticipated that the business rescue practitioners will reject the claim as the contract was declared invalid and of no force and effect. However, the SIU has instituted proceedings against Tegeta and the business rescue practitioners to repay Eskom approximately R734m as just and equitable relief.

17.1.4 Trillian

Following Trillian and Wood's failure to repay Eskom the court ordered sum of approximately R595m, Eskom launched liquidation proceedings. SARS has intervened as a party to the liquidation proceedings, claiming that Trillian owes it approximately R600m in unpaid taxes. SARS has a preferential claim in this regard. Accordingly, Eskom will submit a claim for R595m to the liquidators but will not contest SARS's claim in the interests of the country.

17.1.5 PwC

PwC was contracted irregularly following a flawed procurement process on a risk-based contract to realise capex savings on Eskom's generation projects. On 16 March 2021, Eskom issued a High Court application against PwC for an order declaring the award of the task order to PwC unlawful, unconstitutional and invalid; reviewing and setting aside the award; reviewing and setting aside the contract concluded with PwC following the award; and claiming repayment of R108m paid to PwC.

17.1.6 Meagra Transport

Meagra submitted fraudulent invoices in the amount of R35m for coal transport between 2016 and 2018. Eskom has recouped R3m from Meagra, and is pursuing the balance. Eskom's Assurance & Forensics Department is liaising directly with the Asset Forfeiture Unit, which is seeking a court order to attach assets to recover Eskom's funds. The owner of Meagra as well as a former Eskom employee are facing 53 counts of fraud and theft before the Specialised Commercial Crimes Court in Johannesburg.

17.1.7 Econ Oil and Energy (Pty) Ltd (Econ Oil) – Overcharging

On 14 December 2020, Eskom received an interim forensics report quantifying possible overcharging by Econ Oil in the amount of approximately R1.2bn over a five-year period from 2012 to 2017. According to the relevant contractual dispute resolution provisions, Eskom instituted arbitration proceedings against Econ Oil on 17 December 2020 to recover this sum. Econ Oil is opposing the application and has served its plea and a special defence based on prescription. The parties are scheduling a pre-arbitration meeting with the arbitrator, to discuss and agree the procedure for the arbitration proceedings and dates for the delivery of further documents and hearing.

17.1.8 Econ Oil Bid Corp 4786 – Review

In a dispute regarding the validity of a contract for fuel oil between Eskom and Econ Oil, the adjudicator found that a contract existed between the parties. Eskom has referred the matter to arbitration. Eskom denies that it concluded a contract with Econ Oil, and launched an application at the High Court on 29 January 2021. In Part A of the application, Eskom requested the Court to suspend dispute resolution proceedings under the NEC3 contract, pending the final determination of Part B, the judicial review. In Part B, Eskom applied to review and set aside its own decision to award the tender to Econ Oil. Econ Oil is opposing this application.

17.1.9 Tenova Mining and Minerals South Africa (Pty) Ltd

Tenova initiated Dispute Adjudication Board (DAB) proceedings against Eskom related to the engineer's rejection of certain claims and claims payment of an additional R339m above the R1.1bn already paid, based on purported settlement agreements that Eskom alleges were not agreed to. The DAB will entertain certain preliminary defences first. The SIU is investigating the directors of the company and it is suspected they had colluded with Eskom personnel, through third-party subcontractors. The parties are concluding the Tribunals' agreement.

17.1.10 Tubular P11A – Air-cooled condenser at Kusile

Tubular submitted an ongoing delay and disruption claim against Eskom for approximately R240m. Eskom successfully opposed the claim at DAB and Tubular later notified dissatisfaction. The civil claims are dormant but the SIU is investigating the matter, and the NPA has charged Tubular's directors and ex-Eskom employees with various fraud and corruption claims. Once further information is available, Eskom will consider instituting a review application to set the contract aside. Tubular has been placed in liquidation.

17.1.11 ABB

Eskom is working with the SIU to set aside a contract that was irregularly awarded to ABB. In December 2020, ABB repaid approximately R1.5bn to Eskom.

17.1.12 Medupi and Kusile new build

Eskom, with the assistance of the SIU, is reviewing various contractual claims submitted by contractors at Medupi and Kusile where it is suspected that there may have been collusion between Eskom employees and contractors.

17.1.13 Optimum Coal Mine (Pty) Ltd

Eskom has submitted a claim of R5bn against Optimum's business rescue practitioners for pre- and post-business rescue penalties. This has subsequently been reduced to R1.28bn after an arbitration ruling.

17.1.14 Deloitte Consulting (Pty) Ltd

In October 2019, Eskom instituted legal proceedings against Deloitte to recover R207m arising from task orders that were awarded irregularly, in the absence of an open and competitive tender process. Eskom and Deloitte reached a settlement agreement in March 2020; Eskom received R150m plus VAT in full and final settlement in May 2020.

17.2 Claims against directors and employees

17.2.1 Eskom v Brian Molefe and 11 others

Eskom is pursuing civil action for R3.8bn against a number of former Eskom directors and executives to recover losses as a result of State Capture and the involvement of the former directors and executives therein. On 3 August 2020, combined summons and particulars of claim were issued against 12 defendants, with the SIU cited as co-plaintiff. Of the 12 defendants, Eskom is only pursuing claims against former Eskom executives and directors (Messrs. Ngubane, Mabude, Pamensky, Molefe, Singh and Koko, as well as Ms Daniels) based on breach of fiduciary duties and breach of contract.

The Acting Deputy Judge President has placed the matter under case management, and a meeting with the case manager is awaited.

17.2.2 Recovery of monies irregularly spent on behalf of directors and executives for legal fees

Eskom has instituted action to recover monies advanced in respect of legal fees to five former directors and executives. An amount of R27 000 has been recovered from one director, while another director as entered into a payment arrangement for R500 000, but he has defaulted on the arrangement. Three other directors (owing R706 000, R595 000 and R201 000) are defending the action. The former Eskom executive (owing R70 000) is also defending the action. Trial dates have been applied for against the three directors, and an application for default judgment has been made against one director and the executive.

17.2.3 Wilge residential development project and former general manager for Facilities

The Wilge residential development project was undertaken in 2012 to build residential units for the Kusile Power Station Project to accommodate artisans during the construction of the power station. A contract was awarded at approximately R260m for the completion of 336 residential flats by December 2013. The cost incurred is approximately R840m, which has been declared fruitless and wasteful expenditure.

Disciplinary proceedings were instituted against the then General Manager, Mr Mamorare, as a result of his conduct in failing to perform his duties and causing significant financial losses to Eskom. He was subsequently dismissed, and a decision was taken to recoup losses attributable to his conduct from him. The amount that may be claimed is being quantified, after which counsel will advise on the next steps.

17.3 Way forward

Eskom is committed to ensuring that any proceeds received from the outcome of any legal or investigative processes will be addressed in subsequent RCA balance applications. This has already been instituted and will continue. This approach is in accordance with the NERSA decision on this matter.

18 Financial constraints need to be addressed

18.1 Liquidity challenges

Liquidity remains one of our biggest challenges, hampering our ability to achieve financial and operational sustainability. Access to cost-effective funding remains restricted due to decreased investor confidence because of continued poor financial performance, saturated borrowing capacity and recent credit rating downgrades. Inadequate price increases granted by NERSA as well as escalating municipal arrear debt further contribute to our liquidity constraints. These liquidity and solvency risks pose an inordinate threat to Eskom's ability to continue as a going concern. To improve liquidity, we have restricted organisational cash requirements through targeted savings on operating and capital expenditure. We had to rely on Government support to maintain a positive cash balance at year end, with increases in equity. We have always deemed it prudent to maintain a liquidity buffer that covers an average of three months of organisational cash flow requirements. Due to high debt servicing obligations, maintaining the liquidity buffer at acceptable levels continues to be a challenge.

18.2 Financial sustainability

We have to reduce our reliance on debt funding as a source of liquidity – equity injections by the shareholder will assist in reducing this reliance in the short term and help to improve liquidity. Although Government's equity support addresses our liquidity requirements, it does not adequately enhance our long-term financial sustainability. The only way to achieve financial sustainability is to improve operating cash flows that results in positive free cash flows, with a strong focus on moving to a prudent, cost-reflective tariff.

We acknowledge the importance of cost savings to improve liquidity, with a focused cost curtailment programme over the next three years. Nonetheless, as we've stated before, cost savings alone will not be sufficient to improve our financial health. For Eskom and the electricity supply industry to continue to operate and maintain its assets in a reliable state, the price of electricity must migrate towards cost-reflectivity to ensure Eskom's long-term financial sustainability. Without a cost-reflective tariff path, we will remain reliant on Government support, which implies that the taxpayer will continue to foot the bill for the revenue shortfall, which is contrary to the "user pays" principle.

Our overarching objective remains to return Eskom to financial and operational sustainability, while improving transparency of reporting to the shareholder and the broader public in order to regain trust.

18.3 What is a cost reflective price of electricity?

In 2007 National Treasury commissioned an independent assessment of the electricity sector which commented that “Government should formulate an electricity pricing policy such that NERSA could award overall revenue levels to Eskom that would enable a migration of prices to Long Run Marginal Costs”. The 2008 Electricity Pricing Policy states that “It is recognised internationally that cost reflective tariffs, as reflected by Long Run Marginal Cost (LRMC) representing the true economic cost, are the best price signal.”

Electricity prices close to the level of LRMC are thus not only required for the purpose of sending the correct price signals, it is also required to ensure the long term viability of the electricity industry. Such prices ensure that the full cost of the production of electricity (and nothing more) is recovered namely the capital investment, the fuel cost and the operational and maintenance cost, over the asset life cycle, in a profile which is not overly “front loaded” (i.e. higher at the beginning of the asset’s life cycle than at the end). It thus results in very stable price levels without price shocks when replacement or expansion of capacity takes place.

It is often argued that higher electricity prices will result in negative macro-economic consequences. This is however not supported by independent economists. In another report commissioned by National Treasury in 2003, it is argued that “continued sub-economic pricing (prices below long-run marginal costs) in the industry ironically run the risk of increasing real costs in the economy (by reducing allocative efficiency). Furthermore, sub-economic energy prices benefit energy and capital intensive growth, and places labour and skills intensive development paths at a disadvantage. Proper economic pricing of power will reverse skewed incentives in the long-term and support South Africa’s primary economic aim, which is to establish labour absorbing development paths”. It further argues that improved macro-economic allocative efficiency would result from “economically efficient prices” and thus actually reduce the cost of doing business in South Africa in the long run (“Moving to cost reflective prices will save real costs in the economy…by encouraging efficient use of energy and capacity (including demand side investments) which, if electricity service is priced correctly, will be cheaper in real resource terms, than new supply capacity…”

When Eskom makes a revenue application to NERSA, all it expects from a revenue determination is for **efficient costs** to be recovered through a tariff application. This is motivated in detail when a revenue application is made. The criteria applied are strictly guided by the relevant legislation and NERSA rules. However, NERSA has not allowed Eskom to recover its efficient costs at a fair return for many years. The efficient cost for a utility can be independently determined using the particular South African circumstances. As judged recently, NERSA has not been fulfilling its legislative mandate in this regard.

This level of efficiency is also provided by government policy. The Integrated Resource Plan (IRP) indicates that there has to be a significant increase (after tax) in Eskom's annual revenue to be comparable to the least-cost option in the IRP. The assumption made by Cabinet in 2014 also supports a similar increase over time. Eskom's financials bear testimony to a similar requirement for the recovery of efficient costs. All the rating agencies have also alluded to the recovery of efficient costs through the regulatory mechanism.

It is understood that migration towards efficient cost recovery with a fair cost of capital is essential to make Eskom sustainable. Recognition is given to the protection of vulnerable sectors, including poor residential consumers.

In a recent analysis undertaken by Eskom through independent experts, the following summary was provided. There is a general misconception that NERSA is justified in limiting the increase in Eskom's average tariff on the basis that it is an effective way to protect consumers and the economy from the negative impact of rising electricity prices. While it may be both necessary and socially desirable to mitigate the impact of energy prices on vulnerable groups, there are more efficient and effective ways to achieve this than by introducing average tariff subsidies.

The economic harm and distortions that are caused by implicit average energy price subsidies are well documented in the international literature; they crowd out pro-poor spending (for example, education and health), discourage private investment in the energy sector, encourage wasteful energy consumption, and result in a variety of harmful market distortions. Energy subsidies also tend to disproportionately benefit energy- and capital-intensive firms and higher-income households.

There are several more appropriate and economically efficient ways to shield the poor and other vulnerable groups from the impact of rising electricity prices than an average tariff subsidy. These include improving the implementation and extent of targeted electricity price subsidies, facilitating a gradual transition to cost-reflective prices and making implicit subsidies more explicit, introducing policy and regulation to promote the uptake of energy-efficient technologies, and continuing to introduce reforms to promote competition in the electricity supply industry over the medium to long term.

In terms of targeted subsidies, the existing free basic electricity grant meets most of the requirements of a “good subsidy” and could be improved to offer increased protection to poor and vulnerable households. Well designed, targeted, and time-limited subsidies could also be used to protect vulnerable industries (trade-exposed and electricity-intensive). Additionally, NERSA could collaborate with other stakeholders such as the DMRE to introduce initiatives to promote the uptake of energy-efficient technologies.

Based on an analysis of the tariff increase that Eskom currently requires to recover its costs and an assessment of the competitiveness of South African electricity prices relative to a series of local and international benchmarks, it has been concluded that there is significant support for the price of electricity need to be increased.

It is highly unlikely, given the sheer magnitude of the revenue shortfall, that Eskom’s approved tariff will be adequate to cover its prudently and efficiently incurred costs. The revenue shortfall is almost equivalent to Eskom’s total employee costs. We conclude that the approved tariff is not cost-reflective and is not sufficient to ensure Eskom’s financial viability.

Comparing Eskom’s current average tariff to a local benchmark for the price of future electricity generation capacity – the “least-cost” scenario (IRP 1) presented in the IRP 2019 – shows that, based on recent IRP estimates, a hypothetical new market entrant, operating a newer, more efficient, “least-cost” generation fleet consisting mainly of wind, solar PV, and gas, would require a further significant increase in current tariff to cover its costs. It is concluded that, based on the available benchmarks and analysis of Eskom’s audit financials, the approved tariff is not cost-reflective and is not sufficient to ensure Eskom’s financial viability. In the event that Eskom is not in a position to recover its efficient costs from the consumer, it becomes more and more reliant on the shareholder to provide equity support. This results in defying the “user-pays” principle and the taxpayer having to continue funding any shortfall in efficient costs and a fair return.

Eskom, thus, proposes that there be relatively quicker migration towards cost-reflective tariffs and less and less reliance on equity injections. There is also a specific need for targeted support for identified vulnerable sectors.

18.4 Cost containment

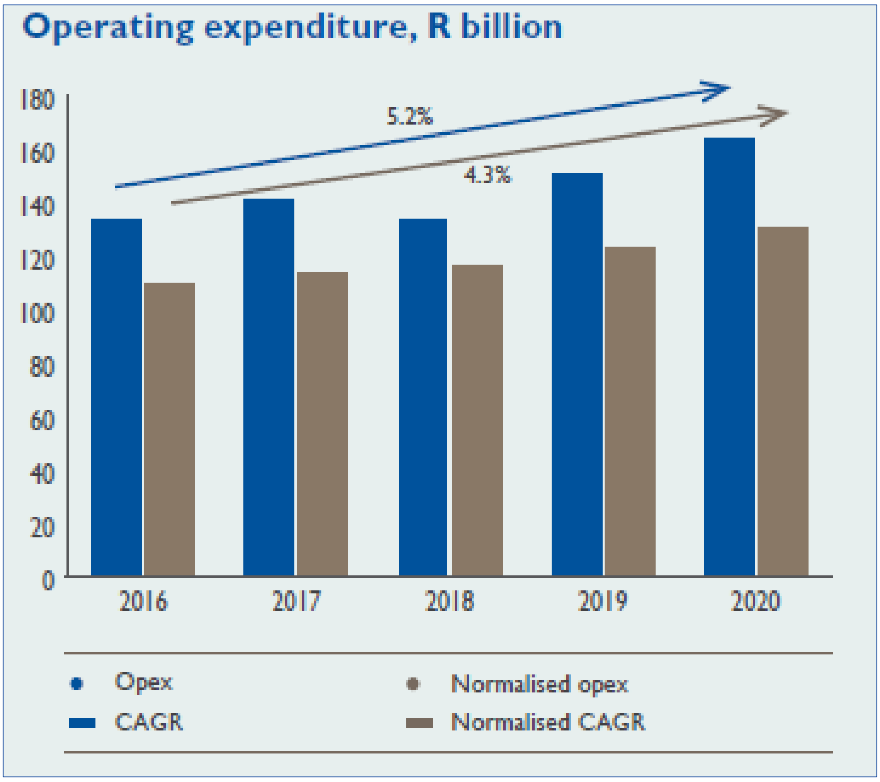
18.4.1 The results of Eskom's cost curtailment efforts

Eskom's financial health has deteriorated over recent years because of declining sales volumes and an electricity price that is not cost-reflective, threatening our long-term financial sustainability. To sustain our operations, it has been imperative that we operate in a prudent and efficient manner while ensuring security of supply. Since 2014, we have implemented various cost curtailment programmes to reduce Eskom's cost base and improve productivity to close the revenue shortfall. The result of these stringent programmes is a sub-inflationary compound annual growth in operating costs of approximately 5.2%, or an overall increase of 23% over the last five years. This is comparable to the average annual consumer price index over the same period of close to 5%.

Operating costs include primary energy costs, employee benefit costs, net impairment charges and other operating expenditure. Normalised operating costs are adjusted for once-off events and those cost elements considered outside of management control. Also excluded is IPP expenditure for contracts concluded under DMRE's RE-IPP Programme – a policy requirement where Eskom had no control over the awarding or pricing of contracts.

Normalised operating costs have recorded compound annual growth of approximately 4.3% over the last five years, emphasising the success of our cost curtailment efforts. The higher than average growth in costs in the last two years was predominately due to more expensive coal being procured from short- and medium-term suppliers to build coal stockpiles, as well as the above-inflation wage settlement for bargaining unit employees concluded in FY2019. While we acknowledge the importance of driving cost curtailment efforts to reduce Eskom's cost base, these initiatives alone will not ensure Eskom's financial sustainability. The price of electricity has to migrate to cost-reflectivity over time to guarantee long term financial sustainability. Nevertheless, we take accountability for all matters under our control.

FIGURE 25: OPERATING EXPENDITURE (R'BN)



18.4.2 Cost savings over the past year

Given the socio-economic conditions of the country, the shareholder indicated its lack of support for an aggressive headcount reduction. Voluntary separation packages were offered to non-core and not-critical employees as well as all employees aged between 60 and 62 to find further efficiencies in employee benefit costs. Cumulative cash savings targeted over the next three years amounts to R55.8bn.

18.5 Addressing Municipal Debt

The top 20 defaulting municipalities constitute 81.15% of total invoiced municipal arrear debt while 38.4% of the total arrear debt is owed by Free State municipalities. The top three Free State municipalities account for R10.8bn, or 31%, of the total arrear debt. There are 47 municipalities with total arrear debt of more than R100m each.

A total of 43 active payment agreements are in place with defaulting municipalities, including 12 of the top 20 defaulting municipalities. However, only 10 of the active agreements are being fully honoured, with two of the top 20 defaulting municipalities fully honouring their agreements. None of the Free State municipalities are honouring their agreements. Although Eskom tries to set a tone of no tolerance, other external interventions continue to hamper progress.

The Board approved a new municipal debt management strategy, which comprises three key objectives, namely to reduce and/or eliminate overdue debt; stop defaulting where it occurs; and prevent future defaulting by paying customers. To this end, we are enhancing and enforcing existing revenue and debt management processes, enforcing Eskom's rights through legal action and attaching assets where possible, and expediting Government interventions, the progress from which has been slower than anticipated.

18.6 Dependence on Equity Support

Eskom is reliant on Government support to provide debt relief and to ensure Eskom's status as a going concern, with equity received from National Treasury being used to settle debt and interest payments; this is subject to Eskom complying with certain reporting conditions. In the absence of cost-reflective tariffs from NERSA as well as Eskom's saturated borrowing capacity, it has been necessary to rely on direct Government equity support in order to maintain a positive liquidity outlook. Eskom is very cognisant of the burden that this equity support places on the fiscus, and ultimately the taxpayer, and is striving to ensure that it can survive within the revised equity support limits committed in the recent 2020 Medium-Term Budget Policy Statement.

19 Environmental Requirements

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 ecologically sustainable development. The National Environment Management Act (NEMA) and several Specific 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 Eskom is obligated to respond to in order to continue operating its power stations. Given the nature of Eskom's activities these requirements are far reaching, they affect all the licenses in some manner, including air quality, protection of the natural environment and biodiversity, water use and the impact on water resources, general and hazardous waste management, the utilisation of ash and licensing processes. These legislative requirements lead to operational and capital expenses which must be allowed to enable Eskom to retain its license to operate.

The most significant environmental costs over the next 10 years are related to air quality, ash dams/dumps and water management. The estimated costs are very significant in the next ten year period. The costs related to meeting the environmental commitments are included in the MYPD5 application. Assumptions are made that in instances where postponements are requested, they would be granted.

19.1 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 Eskom is required to control, sulphur dioxide, nitrogen oxide and particulate matter. Applying new plant standards to existing/aged plant is technically challenging, with only one technology, Flue Gas Desulphurisation (FGD) 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 and associated flue gas conditioning technologies.

Eskom 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, have requested and been granted postponements for some plants in February 2015. Postponements are only valid for 5 years, in Eskom's case some are valid from 2015 – 2020 and others from 2020 to 2025. Therefore a second postponement application was submitted between 2019 and 2020 and the Department of Environment, Forestry and Fisheries (DEFF) is presently evaluating these applications with a decision possible by September 2021.

In parallel to the programme to reduce air emissions at coal fired power stations Eskom is required to embark on an air quality offset project in communities surrounding Eskom 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 Licenses.

19.2 Eskom's emission reduction plan

Logistically it was not possible for Eskom to implement a retrofit programme to meet the Minimum Emissions Standards by 2020; this was due to the long outages required, insufficient water to operate FGD and the impact on the tariff. Eskom decided it would be prudent to prioritise upgrades at higher emitting and newer power stations. Eskom requested postponements of the Minimum Emission Standards compliance timeframes for power stations which are unable to be brought into compliance in time. (Prior to amended regulations published in 2018, the legislation allowed for postponements of up to 5 years to be granted).

Eskom submitted such an application for postponement for all coal-fired power stations (except Kusile Power Station) and Acacia and Port Rex Power Stations in 2014. The postponement applications included a commitment to upgrade certain power stations, in line with Eskom's Air Quality Strategy approved by the Eskom Board in November 2010. The National Air Quality Officer approved most of these postponement requests in 2015 with an additional requirement for FGD at Matimba and Kendal power station. The costs associated to meet these requirements are substantial.

Subsequent to making these commitments, Eskom's emission upgrade plans have changed as a result of technology feasibility studies which have identified the most suitable technology to enable power stations to meet the emission standards, and under pressure to align with Eskom's prioritised available CAPEX budget. With the expiry of the original 5 year postponements Eskom prepared and submitted updated postponement requests between 2019 and 2020. The applications submitted are estimated to cost R73bn and includes implementing FGD at Medupi, completing PM projects at 6 stations and NOx projects at 4 stations.

19.3 Air Quality Offsets

Eskom 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.

Eskom's air quality offset programme will be 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, Eskom is proposing to follow a phased approach to air quality offset implementation

Phase 1 (2017-2023): The initial date for phase 1 for lead implementation was 2017-2019. A number of reasons, including the Covid-19 pandemic led to the delay of implementation. Lead implementations at one Eskom-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. The lead implementation delivery will commence May 2021 at KwaZamokuhle and Ezamokuhle will follow.

Phase 2 (2023-2028): Full implementation. Once the interventions have been refined, they will be rolled out simultaneously at least one community per power station.

The offset programme will cost an estimated R3bn in nominal terms between now and 2028. Around 25 000 households will receive cleaner energy and/or insulation, and many more will be indirectly benefit through community interventions. The successful implementation of air quality offsets promises to meaningfully improve the air quality of the air breathed by hundreds of thousands of people, and should improve the health and create employment opportunities for many.

19.4 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. Eskom produces approximately 30 million tonnes of ash annually, six to eight percent of which is recycled, and 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, when NEMWA was promulgated, triggered the requirement for a WML which in turn triggered the requirement for lining the ashing facilities. It is important to note that the fund allocated to these projects is not only for lining, it is also to ensure the continued safe and efficient operation of the ashing facilities.

19.5 Water management

Eskom is one of the largest 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 Eskom'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, Eskom is required to use water efficiently, to comply with license conditions and ensure that our activities do not cause or potentially lead to pollution of water resources.

This Eskom 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.

20 Price elasticity of electricity demand in SA

The magnitude of the demand response or price sensitivity can be measured by the coefficient of price elasticity. Price elasticity is the relative change in quantity demanded which is caused by a change in price, ceteris paribus. It is defined as the ratio of the percentage change in quantity demanded to the percentage change in price while holding all other factors of demand unchanged. Price elasticity seeks to isolate the percentage change in the quantity demanded, following a one percent change in price. Thus an elasticity study is not the same as a consumer / customer survey. Although price response questions may be included in a survey, the outcomes thereof do not qualify as empirical evidence of consumer behaviour. Moreover, surveys are prone to bias. This could over state or under state the potential findings depending on the biases of the respondents. It follows that elasticity studies must be based on empirical evidence. It is not a subjective test. It is not a sentimental assessment or a consumer / customer survey. Its results must be beyond reproach. They cannot be subject to any form of bias. In addition, for an elasticity study to be credible, it has to pass academic master. That means that an independent researcher should by and large, be able to verify the results of the study given the same sample data and the stated methodology. Only then can the results of such a study be good enough to be used for inference purposes.

20.1 Eskom Approach to Elasticity analysis

In 2009 Eskom conducted a price and income elasticity analysis of its direct customers. On the whole price elasticity of electricity demand was found to be fairly low across most sectors. Electricity demand was deemed to be price inelastic. This was attributed in part to the historically low relative price of electricity. The main determinant of electricity demand was income. Various proxies (e.g. mining production) were used for income in different sectors. These factors were found to have a more pronounced effect on the level of electricity demand in the country. It follows that as economic growth slows, the positive pull that income has on electricity sales will also dwindle. Thus the deterioration economic prospects of South Africa are bound to have a dampening effect on the level of electricity consumed in the country.

In the last decade, electricity price increases have routinely outpaced the inflation rate. That means that the relative price of electricity has increased. In most instances, electricity costs have increased as a ratio of total production costs and as a percentage of disposal income, with respect to firms and households respectively. Therefore the narrative that price elasticity is still as low as it was in 1999 may not hold anymore. The passage of time has allowed for structural changes (i.e. changes in technology) and increases in relative electricity prices to potentially culminate in a material change in consumer behaviour.

Since the release of our 2009 study, several price elasticity studies have been published across the world. The common trend is that price elasticity levels are increasing as energy prices increase and new technologies become cheaper. It can also be observed that in general households have a high demand response to electricity price changes than most other sectors.

20.2 Empirical Analysis

Eskom Treasury conducted a study of the price elasticity (and income) of electricity demand for the 30 year period ending in 2018 at the economy wide level. The following key findings were made:

- Price and income elasticity(s) of demand were time variant. It is important to distinguish between elasticity coefficients when real electricity prices were increasing and when real electricity prices were declining. Elasticity estimates that simply focus on long term averages could be misleading.

- Electricity consumption was unresponsive to price changes in the period of falling real electricity prices (i.e. up to 2005). During this time price was not a significant determinant of electricity demand. The price elasticity coefficient was at or close to zero. During this period, income played a more significant role in explaining electricity demand. These findings are consistent with previous Eskom studies and other published independent studies that focussed on this period.

- Since 2006, electricity demand has been somewhat more responsive to price changes. This marked a period when real prices started increasing. The cumulative effect of these price increases has resulted in a marked change in consumer response over time. This observation is consistent with existing economic literature which indicates that consumers become more sensitive to price changes when real prices of electricity increase. Thus the price elasticity of electricity demand was higher during this period than in the earlier period assessed.

- On the whole the study observed that while real electricity prices were falling, income (output/GDP) was a significant determinant of consumption. However when real prices were on the rise, income elasticity started falling as GDP growth gradually lost its influence on electricity demand. Under the latter regime, prices became a more notable driver of electricity consumption.

- This study used the Kalman Filter technique to observe the evolution of the price and income elasticity coefficients over time. The time variant nature of the elasticity coefficients during this period was confirmed. In its final state, the price elasticity of electricity demand was estimated at -0.288 and it was deemed to be a significant determinant of electricity demand.

- Although the price elasticity coefficient is higher (in absolute terms) than in the previous periods, aggregate electricity demand in South Africa is still price inelastic.

- The final price and income elasticity estimates that were estimated in this analysis are fairly in line with the International levels.

- Historically price elasticity estimates in South Africa have been materially lower than the International levels. This indicates that historically low electricity price levels had depressed consumer response. With the price correction of the last decade or so, the aggregate price elasticity coefficient has become more in line with the international levels.

20.3 Sectoral Analysis

- This study was extended to cover the mining sector for the same period while using the same econometric techniques.

- The results showed that price elasticity of electricity demand in the mining sector has remained fairly low and unchanged during the period under review.

- This indicates that capital intensive sectors which generally do not have the same agility as the aggregate economy to respond to price changes, have had a benign demand response notwithstanding the observed price increases. The price elasticity coefficient in these sectors is somewhat more muted than the country average.

- From these findings it can be inferred that other sectors that are less capital intensive and have higher response agility will have a higher price elasticity coefficient.

- In line with International findings, domestic / household electricity demand is expected to be more responsive than the country average.

20.4 Price Elasticity and Cost Reflectiveness

Electricity demand response in South Africa has increased somewhat during the last decade, especially at the level of the household. Nevertheless, electricity demand has remained price inelastic. That is primarily on the back of a lack of viable substitutes. In addition, the Eskom tariff has remained below the anticipated least cost option tariff path as anticipated by the various IRP documents. The IRP does not foresee any catastrophic collapse in demand owing to a higher price trajectory. Therefore if the Eskom price path is below the IRP level then its impact on demand cannot exceed what was anticipated in the IRP. It is common-cause that as the electricity price increases, some segments of demand may be lost. This speaks to the welfare and affordability considerations in the country. However these considerations must be balanced with the need to recover efficient costs in order to make electricity available in the first place.

20.5 Economics view on utility death spiral

The rise of Distributed Generation technologies has raised concerns in some quarters about whether or not the utility's business case is under siege, the so called "utility death spiral". There is a growing consensus in the economics literature that utilities and the grid can co-exist in a financially sustainable manner if the utilities design their tariffs in a way that better reflect their cost structures. The advent of DGs has necessitated utilities to implement a tariff design that is fit for purpose. Most utilities across the world including Eskom are alive to this reality and are gradually migrating towards a tariff design that differentiates between capacity and energy costs. This will at the very least sustain the utility business model until true price parity between grid and off grid electricity costs is reached. Until then, this change in the tariff structure will prevent the utility from suffering from what would be a self-induced spiral.

Economic analysis indicates that there are several factors that influence the demand for electricity including price, economic output or GDP, population growth, weather patterns and technological change. However, based on a review of the international literature, that growth in economic activity (income) is usually the dominant driver of electricity demand and that electricity demand is generally more responsive to income than to price.

21 Understanding Municipal debt owed to Eskom

In research undertaken by Primaresearch and reflected in a report called "Shedding Light on Eskom", published on 2 August 2019, the following extract proposes the role that NERSA can play in assisting the recovery of municipal debt. "Municipal debtors now constitute 90% of all debtors (compared to 8% in 2013). When Eskom experienced similar issues with defaulting municipalities in the 1990s, the NER advised Eskom and the municipalities that it would revoke the licenses of the defaulting distributors and transfer their supply area to another municipality. This strategy seemed to work at the time and perhaps could be considered with the current impasse". It is thus encouraging to note that NERSA has already decided some time ago to initiate a tribunal to address certain municipalities that are not keeping their electricity accounts in good order. The process to implement this decision seems to be underway. The outcome would be keenly awaited.

TABLE 25: TOTAL ARREAR DEBT FOR THE TOP 20 DEFAULTING MUNICIPALITIES AT 31 MARCH 2021

Name	Province	Total Arrear Debt (R'm)
MALUTI A PHOFUNG LOCAL MUNICIPALITY	FREE STATE	5 804
EMALAHLENI LOCAL MUNICIPALITY	MPUMALANGA	4 668
MATJHABENG LOCAL MUNICIPALITY	FREE STATE	3 719
EMFULENI LOCAL MUNICIPALITY	GAUTENG	2 714
GOVAN MBEKI LOCAL MUNICIPALITY	MPUMALANGA	2 318
NGWATHE LOCAL MUNICIPALITY	FREE STATE	1 320
LEKWA LOCAL MUNICIPALITY	MPUMALANGA	1 292
THABA CHWEU LOCAL MUNICIPALITY	MPUMALANGA	840
DITSOBOTLA LOCAL MUNICIPALITY	NORTH WEST	677
MODIMOLLE-MOOKGOPHONG LOCAL MUNICIPALITY	LIMPOPO	619
CITY OF MATLOSANA LOCAL MUNICIPALITY	NORTH WEST	582
MERAFONG CITY LOCAL MUNICIPALITY	GAUTENG	556
DIHLABENG LOCAL MUNICIPALITY	FREE STATE	502
RAND WEST CITY LOCAL MUNICIPALITY	GAUTENG	493
REST OF THE TOP 20 MUNICIPALITIES		2 571
Total		**28 677**

The top 20 defaulting municipalities constitute 81.15% of total invoiced municipal arrear debt while 38.4% of the total arrear debt is owed by Free State municipalities. The top three Free State municipalities account for R10.8bn, or 31%, of the total arrear debt. There are 47 municipalities with total arrear debt of more than R100m each.

A total of 43 active payment agreements are in place with defaulting municipalities, including 12 of the top 20 defaulting municipalities. However, only 10 of the active agreements are being fully honoured, with two of the top 20 defaulting municipalities fully honouring their agreements. None of the Free State municipalities are honouring their agreements. Although Eskom tries to set a tone of no tolerance, other external interventions continue to hamper progress.

21.1 Actions towards recovery of municipal arrear debt

Eskom continues to execute its municipal debt management strategy to ensure maximum collections from non-paying municipalities. Despite the negative affect of the COVID-19 pandemic, the strategies deployed during the year have yielded benefits in limiting the growth in municipal debt. Eskom has aligned its collection processes with the Intergovernmental Relations Framework Act, 2005 (IRFA). A proposal for National Treasury to take over municipal debt has been shared with National Treasury and discussions are ongoing. This proposal is intended to reinforce National Treasury’s role in providing financial oversight in terms of the MFMA.

The implementation status of activities for management of municipal current accounts, arrear debt and future debt, in terms of the municipal debt management strategy, are provided for 239 municipalities below. Municipality disconnections and Government oversight of municipal debt are also discussed in further detail. Eskom acknowledges that it will not be able to solve the municipal arrear debt problem on its own, and again requests urgent intervention by DPE and stakeholders, including the Political Task Team, to assist in this regard.

21.2 Current account management

The purpose of current account management is to enforce Eskom’s revenue and debt management policies and procedures to ensure payment of current amounts. To address systemic issues within municipalities that are contributing to the non-payment, Eskom is advocating active partnering, whereby Eskom supports municipalities with distribution, reticulation and revenue collection services. The active partnering model has been well received by stakeholders and is gaining traction. Eskom is promoting and pursuing the partnership model to ensure a sustainable Distribution industry and to secure current accounts.

21.3 Arrear debt management

The implementation status in the graph below indicates the number of municipalities for which a particular measure to manage arrear debt is being “fully implemented”, “partially implemented” or “not implemented”. Where the status is indicated as “not applicable/required”, this indicates that the respective municipalities do not require the intervention at present. For example, where Eskom is able to collect against the payment plan, Eskom will not be required to institute an interruption date.

21.4 Future debt management

The purpose of future debt management is to prevent future defaulting through pre-emptive activities, such as reviewing existing supply agreements to restrict, interrupt and terminate supply, as well as considering active partnering with municipalities.

21.5 Municipality disconnections

Eskom continues to explore all avenues to collect the revenue due to it. Interruption of supply due to non-payment remains the last resort. Eskom has issued multiple breach notices during the month of March 2021. No supply interruptions were implemented in March 2021. Regrettably, Eskom has been interdicted from interrupting supply to various defaulting municipalities, with court applications brought by municipalities, third parties – such as municipal customers – or provincial government departments. During litigation, arrear debt continues to escalate as the municipalities take a payment holiday. Eskom has issued summons for debt owed and is pursuing the attachment of municipal assets.

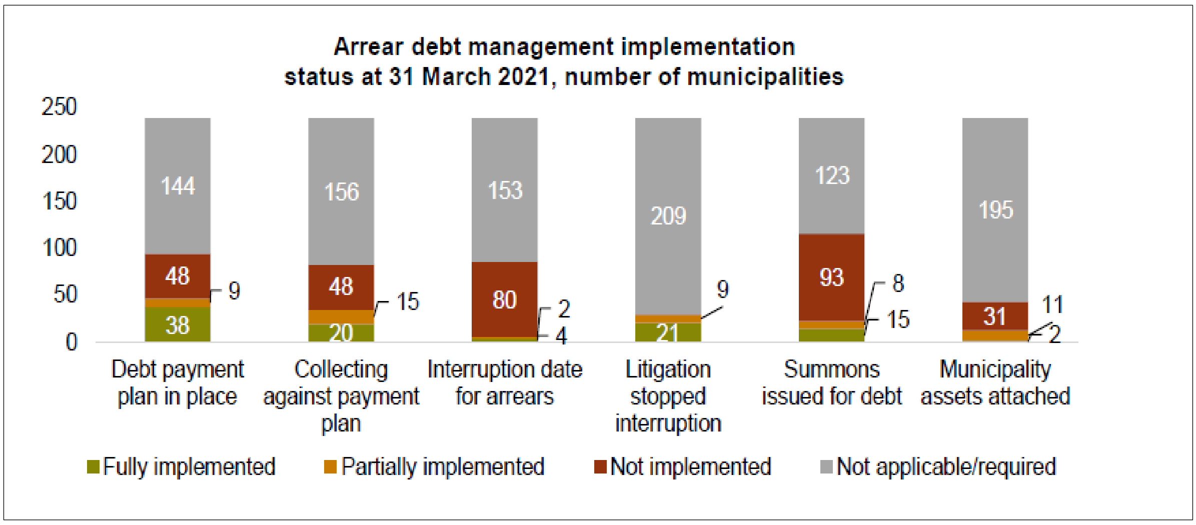
Eskom lost two appeals at the Supreme Court of Appeal (SCA) to cut power supply to two Mpumalanga municipalities. Eskom’s debt collection process has been revised to align with the IRFA process, in compliance with the Supreme Court of Appeal judgment. This impacts the time to collect, and in some instances, municipalities are frivolously declaring disputes to delay the collection process. On 29 January 2021, Eskom filed papers with the Constitutional Court to appeal the ruling of the Supreme Court of Appeal and is awaiting a court date.

21.6 Eskom Political Task Team

The Eskom Political Task Team (PTT) has refocused the roles of Government departments and enforced the message regarding payment for services and the settlement of Eskom accounts, with special focus on the top 20 defaulting municipalities. Eskom is fully participating in the Multi-disciplinary Revenue Committee (MdRC) of the Eskom Political Task

Team. The MdRC is focusing on the roll out of the National Payment for Services Campaign, piloting the installation of smart meters in municipalities and, with support from National Treasury, will consider municipal budget compliance to ensure that current accounts are paid as well as the restructuring of arrear debts owed by municipalities.

FIGURE 26: MUNICIPAL DEBT



21.7 Soweto

The turnaround of the culture of non-payment in areas like Soweto are being managed societally as well as technically. Eskom is deploying a technical solution to convert the conventional meters to prepaid meters. Some success has been realised by Eskom experiencing improved prepaid sales as customers are converted to prepaid meters. The full rollout of the solution is anticipated to be concluded by 2023. These conversions therefore reduce further debt growth as conventional sales and impairment will decrease.

21.8 Current challenges Eskom is facing

- Resistance by consumers to convert from conventional meters to prepaid split metering due to the historic culture of non-payment.
- Increase in prepaid customers buying from "Ghost" Credit Dispensing Units.
- Backyard dwellers exacerbating the non-payment culture. Home owners are collecting rent and not paying for services.
- Periodic protest action. Recent protests are from areas where split metering is not installed.

Some of the key turnaround actions being implemented in Soweto and similar township include:

- Converting of all SPU customers to split / smart meters with vandal proof kiosks, as well as electrification of informal settlements.
- Enforce credit management on remaining conventional customers including audits and disconnect bypassed meters, remove illegal connections by collaborating with security services, Public order policing (POPS) and the Johannesburg Metropolitan Police Department (JMPD).
- Intensify communication to encourage a culture of payment and therefore increase the payment level.
- Aggressively roll-out Free Basic Electricity for qualifying residents, in line with the Metro / Municipal criteria.
- Load reduction to protect Eskom employees and equipment
  Change the Supply Group Code and monitor customer buying patterns, and identify zero buying customers through audits.

22 Credit Ratings Overview

22.1 Criteria used by credit rating agencies to rate utilities like Eskom

All credit rating agencies have a keen interest on the implementation of regulatory decisions to determine the level that they would rate regulated entities such as Eskom.

As an example, Cash Flow from Operations (CFO), if adjusted as done by Moody's (by excluding working capital movements and by adding back the interest expense) is very similar to EBITDA. In essence, it only differs in the sense that 'EBITDA' has not yet deducted the expense for Company Income Tax, whereas 'CFO pre-WC plus interest' has already deducted the expense for Company Income Tax.

The metric of 'CFO pre-WC plus interest: interest' is one of four key financial/credit metrics used by Moody's in their assessment of credit risk of a regulated electric utility. It sets out what value should be achieved in terms of this metric, in order to achieve any of seven levels of credit ratings for regulated utilities. A minimum value of 3x is required to achieve the lowest level of investment grade. A level of below 2x results in the second-from-bottom range of sub-investment/speculative/'junk' credit rating. At that level, research by the ratings agencies indicate that there is approximately a 30% probability of default on debt service obligations within the next seven years.

Extracts of recent analysis by credit rating is provided here.

22.2 FitchRatings

Fitch Downgrades Eskom Holdings SOC Ltd.'s Issuer Default Ratings to 'B'; Outlook Negative: 26 Nov 2020

Fitch Ratings has downgraded Eskom Holdings SOC Ltd.'s (Eskom):

- Long-Term Local-Currency Issuer Default Rating (IDR) to 'B' from 'B+' with a Negative Outlook.
- the senior unsecured debt to 'B'/'RR4' from 'B+'/'RR4' and
- the senior unsecured guaranteed debt to 'BB-' from 'BB'.

(i) Favourable Regulatory Court Determinations**:** Eskom received a favourable judgement in August 2020 in the High Court review of the National Energy Regulator of South Africa's decision regarding the multi-year price determination for FY2020-FY2022 (financial year ending March). Eskom can now recover R69bn through tariff increases over the three-year period. This judgement follows previous judgements in March 2020 and in June 2020, also in favour of Eskom.

FitchRatings believes that any tariff increases implemented as a result of dispute settlements - resulting in stronger cash flows for Eskom - could lead to an offsetting decrease in government support in future years, particularly in the current economic environment.

22.3 Moody's Investors Service (Moody's)

Moody's downgrades Eskom's ratings; maintains negative outlook: 24 November 2020

Moody's Investors Service (Moody's) has today downgraded:

- the long-term corporate family rating (CFR) of Eskom Holdings SOC Limited (Eskom) to Caa1 from B3,
- the zero coupon eurobonds to Caa1 from B3, in line with the CFR.
- the ratings on the senior unsecured global medium term notes to Caa2 from Caa1,
- the probability of default rating (PDR) to Caa2-PD from Caa1-PD and,
- the national scale rating (NSR) long-term corporate family rating to B1.za from Ba3.za.
- Outlook remains negative.
- the rating on Eskom's notes to Ba2 from Ba1 which benefit from the unconditional and irrevocable guarantee of the government of the Republic of South Africa.

The rating action follows Moody's downgrade of the Government of South Africa rating to Ba2 from Ba1 with a negative outlook on 20 November 2020.

(i) Ratings rationale:

<u>For senior unsecured ratings:</u>

In the financial year ended March 2020, Eskom's debt increased despite government equity support as poor operational performance, coupled with the level of tariffs set relative to costs, a high cost base and deteriorating collection of municipalities' debt weighed on the company's cash flows. Eskom's performance will weaken again this year with the impact of the coronavirus pandemic, increasing the company's reliance on the government equity injections to continue operations. **Whilst tariff changes could support Eskom's earnings over the medium term, they will not be enough to put the company on a more sustainable footing without additional measures to bolster balance sheet strength.** In this regard, the lack of meaningful progress in execution of the company's turnaround plan has increased the risks to Eskom's capital structure in the context of significant refinancing risks, rising debt service costs and weakening in the sovereign credit quality.

More generally, Eskom's ratings reflect:

- **Execution risk and investment requirement because of ageing fleet and grid network**
- **Poor plant performance, resulting in load-shedding and cost of utilising of more expensive oil and gas-fired plants.**
- **limited revenue growth, given weak electricity demand and a generally challenging implementation of the regulatory framework for tariff setting relative to operating and capital expenditure;**
- the refinancing risk associated with the company's large debt maturities in the next 12 months. ESG related factors are also material to Eskom's credit quality. **These include the company's weak corporate governance, sensitivity around the level of tariffs, Eskom's high employment levels and its exposure to fairly old and inefficient coal generation assets.**

22.4 Standard & Poor’s (S&P)

South African Power Utility Eskom Holdings 'CCC+' Ratings Affirmed; Outlook Negative: 25 November 2020

a) Ongoing extraordinary government support together with external fundraising are key to the utility’s ability to make upcoming debt repayments.

b) Impact of Covid-19 on operating debt and contribution to increased debt.

c) Covid-19 has also limited debt-raising ability and the government’s ability to support Eskom.

d) Electricity sector reform which is slow is a positive factor, stating that the first step is the operational and financial separation of generation, transmission and distribution which will be followed by legal separation.

(i) Overview

- S&P views Eskom Holdings SOC Ltd.'s remaining government support of South African rand R56bn and R33bn, for use in fiscal years (FY; ended March 31) 2021 and 2022, respectively, as insufficient to fully cover liquidity needs in the next 12 months, in the absence of additional debt-raising, **as the utility struggles with below-cost-inflation tariff increases**, a high cost base, and COVID-19-related lost revenue.

- **Solid access to external financing, cash-flow supportive tariffs**, and favourable cost trends could bolster Eskom's sources of liquidity, but lost cash flow due to the pandemic has delayed a potential improvement in liquidity and leverage, in S&Ps view..
- The negative outlook reflects S&Ps view that COVID-19's impact on power demand, **below cost-inflation tariff increases**, and ongoing difficulty in debt collection will squeeze already-low cash flow; while fiscal support reduces the potential for funding shortfalls over the coming six months, the government's capacity to provide additional support to the utility has diminished, given intensifying fiscal strain.

(ii) Rating Action Rationale:

Financing needs could exceed planned amounts if revenue awards are not in line with the utility's expectations. In S&Ps view, debt-raising requirements could be higher than the about R23bn Eskom plans to raise for fiscal 2022, given high upcoming debt maturities and potential negative impacts on revenue from lower-than-forecast power demand and debt collections. **The utility also continues to struggle with below-cost-inflation tariff increases and cost-containment remains challenging. Significant uncertainty remains regarding the quantum and timing of reimbursement of previous years' revenue under-recovery and excess costs through the regulatory clearing account (RCA) mechanism, given that some amounts have been the subject of court cases and extensive regulatory review. Should the reimbursements be either below Eskom's expectations or over an extended period, financing needs could be higher than the R64bn Eskom expects to raise over the fiscal 2021-2022 period. S&P expects that decisions in relation to these reimbursements and corresponding tariff adjustments will be made in February 2021. However, given uncertainties regarding the quantum and timing of reimbursement, and a history of under-recovery through tariff adjustments, in the base-case scenario, S&P conservatively assume that pending revenue reimbursement decisions and court cases do not result in additional revenue.** Therefore, S&P estimates that if Eskom receives R33bn in government support in fiscal 2022, it could need to raise up to R50bn in debt in fiscal 2022.

COVID-19 has damaged operating cash flows and driven up bad debt. The pandemic has reduced power demand and damaged operating cash flow, **and there have been some delays in tariff award decisions and court decisions related to revenue recoupments through tariffs under the RCA mechanism**. Eskom has achieved some cost-savings in fiscal 2021 from tight capital expenditure (capex) management, voluntary severance arrangements, and reduced coal and power offtake in April and May. However, delays in essential maintenance negatively affected electricity supply stability in the winter months, pushing up generation costs as Eskom needed to run its open-cycle gas turbines to keep the lights on. While power demand will begin to stabilise in second-half fiscal 2021, heightened revenue collection challenges and the ability of consumers to absorb above-inflation tariff increases could strain cash flow well beyond the peak of the pandemic.

(iii) Upside scenario

S&P would consider a positive rating action if Eskom were to sustainably secure more than 12 months of liquidity, **and resolve the matter regarding recognition of R23bn in government support as equity (rather than revenue, as treated by Nersa in its most recent tariff determination process).** More sustainable liquidity could result from a smoother monthly cash flow profile and improved investor sentiment supporting higher levels of committed funding, since government support does not cover Eskom's full liquidity needs. **Liquidity could also benefit from cost-reflective tariff awards that incorporate adequate recoupment of previous revenue shortfalls and allowable above-budgeted costs.** Cost efficiencies that strengthen operating cash flow could also support an upward rating action.

(iv) Liquidity

S&Ps assessment of Eskom's liquidity as weak reflects the hurdles the utility faces, because its revenue is insufficient to compensate for higher costs, continues to require significant capex commitments, and is dealing with reduced growth of electricity demand. In addition, S&P thinks the company has a relatively high dependence on uncommitted funding sources. S&P includes ongoing cash injections from government support in our forecasts.

Liquidity prospects could benefit from improved appetite for its debt and timely financial support from the government for interest, principal, and capex payments. **Also, prior regulatory decisions exacerbate our forecast of negative cash flow generation in fiscal** 2021. Resolution of court actions regarding Eskom's previous tariff and RCA awards could add clarity to the liquidity outlook.

23 Cost of load shedding

In late 2007, South Africans experienced the first of what would become a recurring series of nationwide load shedding episodes. Load shedding refers to the deliberate shutdown of parts of the electricity distribution network to avoid damaging the electricity grid and to safeguard against a national blackout. It is usually implemented after alternative options to balance demand and supply have been exhausted. Load shedding is implemented to reduce electricity demand, preserve grid stability, and to prevent the collapse of the system.

Load shedding has caused significant disruption in the daily lives of South Africans and the national economy. A study was undertaken to provide Eskom with reliable and accurate estimates of the economic cost of load shedding in South Africa.

The study has estimated that load shedding cost the South African economy nearly R35bn in the 12 years between 2007 and 2019. The cost of load shedding (CoLS), expressed in rand per kilowatt-hour, increased over the three main periods in which it occurred. During the first period (2007 to 2008) the CoLS was R7.61/kWh, it rose to R8.80/kWh during the second period (2013 to 2015) and to R9.53/kWh in the third period (2018 to 2019). The results of the total CoLS are similar to the previous estimate of R8.95/kWh, which was produced by Deloitte in 2009.

Another objective of the study was to gain insight into the distribution of the CoLS across different sectors of the economy. The results show that the CoLS is unevenly distributed - four of the nine industries, namely manufacturing, transport and communication, wholesale and retail trade and agriculture, hunting, forestry and fishing, bore 80% of the total cost. The manufacturing sector alone, shouldered nearly 40% of the total cost.

When normalised the CoLS to illustrate the impact of load shedding on each sector relative to its size (contribution to total GDP). For example, while the agricultural sector was the worst-affected, the manufacturing sector, which accounts for 13% of GDP carried the highest proportion of the total CoLS. While the agricultural industry is a relatively small contributor to national GDP (it accounts for 3.6% of total output) it lost 4.2 times more GDP per kWh of load shedding than the average. Manufacturing and utilities lost three times more output than the average. The output of the most service-oriented sectors was largely unaffected by load shedding – this included financial and business and community, social and personal services industries.

The total cost of regular planned outages, as defined in the international literature, is a function of the damages and costs incurred by a firm, its inherent resilience and ability to adapt. A firm may incur costs related to direct and/or indirect damages (e.g. lost production or reduced productivity). The inherent resilience of a particular firm or industry refers to its ability to shift production around outages while the ability to adapt refers to the extent to which it can invest in alternative sources or back-up generation.

There are several reasons, for example, why one would expect service-oriented industries to be inherently more resilient to power outages and better able to adapt. By way of illustration, personnel in the finance and business services industry can continue to work during power outages if the electronic devices they rely on, such as laptops and IT systems, are fitted with back-up power generation sources. Working hours in this industry tend to be more flexible so that people can shift their working hours to better accommodate load shedding. The estimate of CoLS for the finance industry (if the total cost to the economy is normalised to R1/kWh) is just three cents per kWh.

The estimates of the CoLS are based on an econometric analysis of the historical relationship between load shedding and GDP. The estimates capture the CoLS, as reflected in the variation in GDP growth (q/q) around its long-term trend. This includes direct and indirect damages (e.g. loss of output) and the costs of adaptation and mitigation (e.g. higher costs such as investment in back-up generation).

Finally, it was envisaged that the estimates of the CoLS could inform future energy-sector policy and strategic decision making. In particular, measures of the cost of outages are useful in assessing the relative costs of interventions to mitigate against the risk of future load shedding, and so can be used to make socially optimal investment decisions.

24 Cost of Unserved Energy

The difference between the cost of unserved energy (when no warning of load shedding is provided) and cost of load shedding (when timing and duration is known) is illustrated here. The cost of load shedding is an order of magnitude lower than that of unserved energy.

It's important to note that the Cost of Unserved Energy is appropriate for short duration, unplanned electricity interruptions and for which customers have no forewarning. It is inappropriate to use it to estimate the impact of load shedding as has been done by some analysts and commentators in the past as it results in significant overestimation of the economic impacts of load shedding

The national aggregate Direct Economic COUE for 2020 is R29.05 GVA/kWh. GVA refers to gross value added. This number can be interpreted to reflect the weighted average direct economic production lost that can be expected, in an average year, as a result of manifold, short duration, unplanned power outages across the country.

The Total Economic COUE for 2020 is R101.73 GVA/kWh. This number can be interpreted as the weighted average total economic production lost that can be expected as a result of manifold, short duration, unplanned power outages across the country. The latest COUE values as discussed here are under consideration by NERSA.

TABLE 26: COST OF UNSERVED ENERGY 2020

Customer Interruption Costs	Direct Effect (R GVA/kWh)	Total Effect (R GVA/kWh)
Agriculture	20.73	69.49
Mining	12.99	51.46
Manufacturing	8.16	76.00
Electricity and Water Supply	7.67	27.32
Construction	220.25	429.53
Trade	143.08	174.52
Transport and Communication	152.48	609.34
Finance	118.03	456.17
Community Services	51.34	101.09
General Government	155.07	186.04
Residential	N/A	9.03
Total Economy	**29.05**	**101.73**

25 Economic Landscape Changes

25.1 Government policy context

The government's IRP, as published during 2019, indicates the average price of electricity as approximately 133 c/kWh (for all customers) in 2020 rand value. Compared to Eskom's average in 2020 of 102 c/kWh, it represents a revenue shortfall of R67bn (R48bn after company tax) for FY2020, and a shortfall of over R300bn of revenue over the last decade or more. In addition, the Cabinet anticipated increases of 13% for each of the financial years from 2016 to 2018. This was communicated as the outcome of a Cabinet meeting. The reality was 12,69%, 9,4%, and 2,2% increases for the three years, respectively.

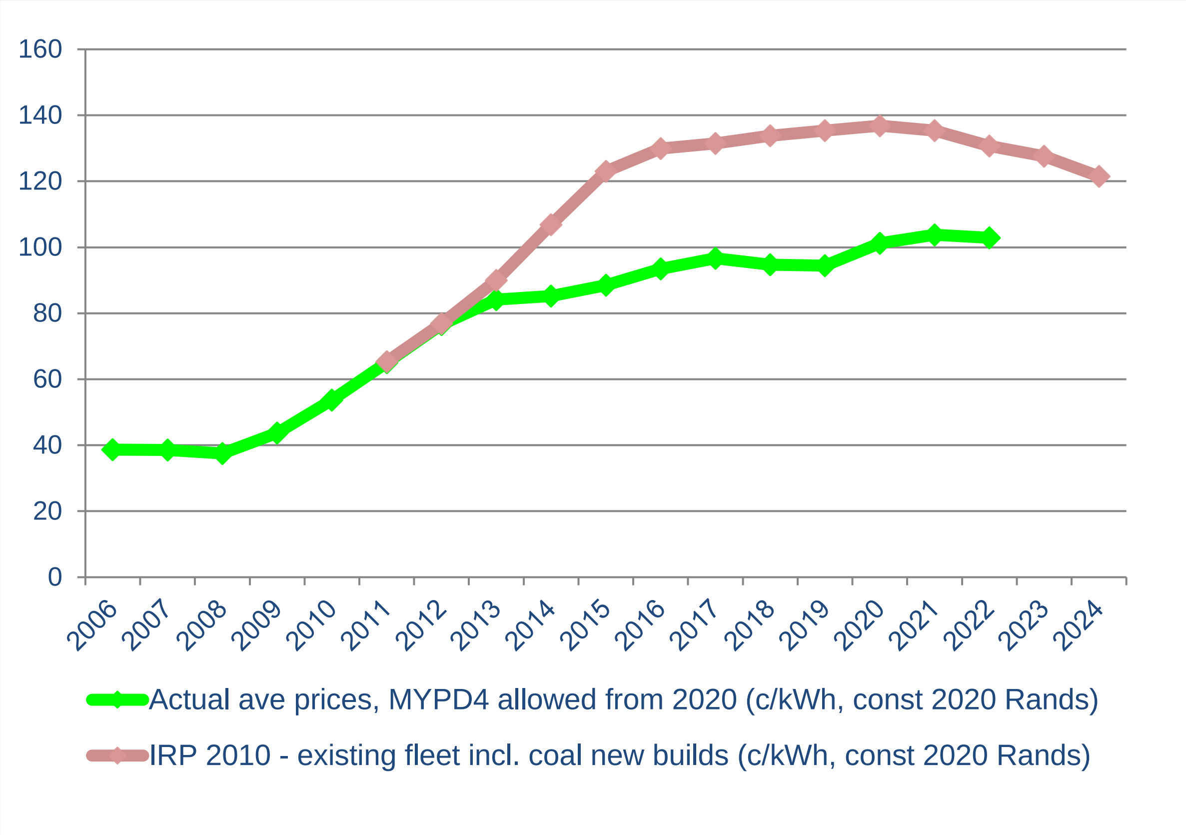
25.2 Eskom electricity prices compared to IRP price paths

On 25 March 2011, the Department of Energy (DoE) published the IRP 2010. It provided a breakdown of the future average electricity price path from 2010 to 2030, in constant 2010 c/kWh. The price path is "built up", starting with the fixed (non-fuel) costs for the existing generation fleet plus the costs of transmission and distribution. The fuel costs of the existing fleet are then added, then total costs of new coal generation capacity (thus, fuel cost and O&M costs per kWh as well as capital costs per kWh as spread over a 40-to-50-year depreciation period). Thereafter, the "cost layers" are added for the (then anticipated) new capacity from nuclear, hydro, CCGT gas, OCGT gas, wind, CSP, and solar PV.

Whereas the IRP 2010 price path was shown in constant 2010 c/kWh, for the graph below, the values were converted to constant 2020 c/kWh. For the sake of the graph, the price path with the "cost layers" only up to the new coal generation capacity was used. The impact on the price path of the further new capacity from nuclear and other technologies is that it will increase by approximately 10% from the 2020 peak of the curve shown in the graph below (thus from ~137 c/kWh to 151 c/kWh). Then, to keep the price stable at that level until 2030, however, it was deemed that the scenario with the "cost layers" only up to the new coal generation capacity was probably the closest comparison of IRP 2010 to 2030 to what actually transpired from 2010 to the present.

The graph below contrasts this price path in accordance with IRP 2010 to 2030 (brown line) with the actual average Eskom price, in constant 2020 c/kWh.

FIGURE 27: COMPARISON OF ESKOM AVERAGE PRICE TO THE IRP 2010 PRICE



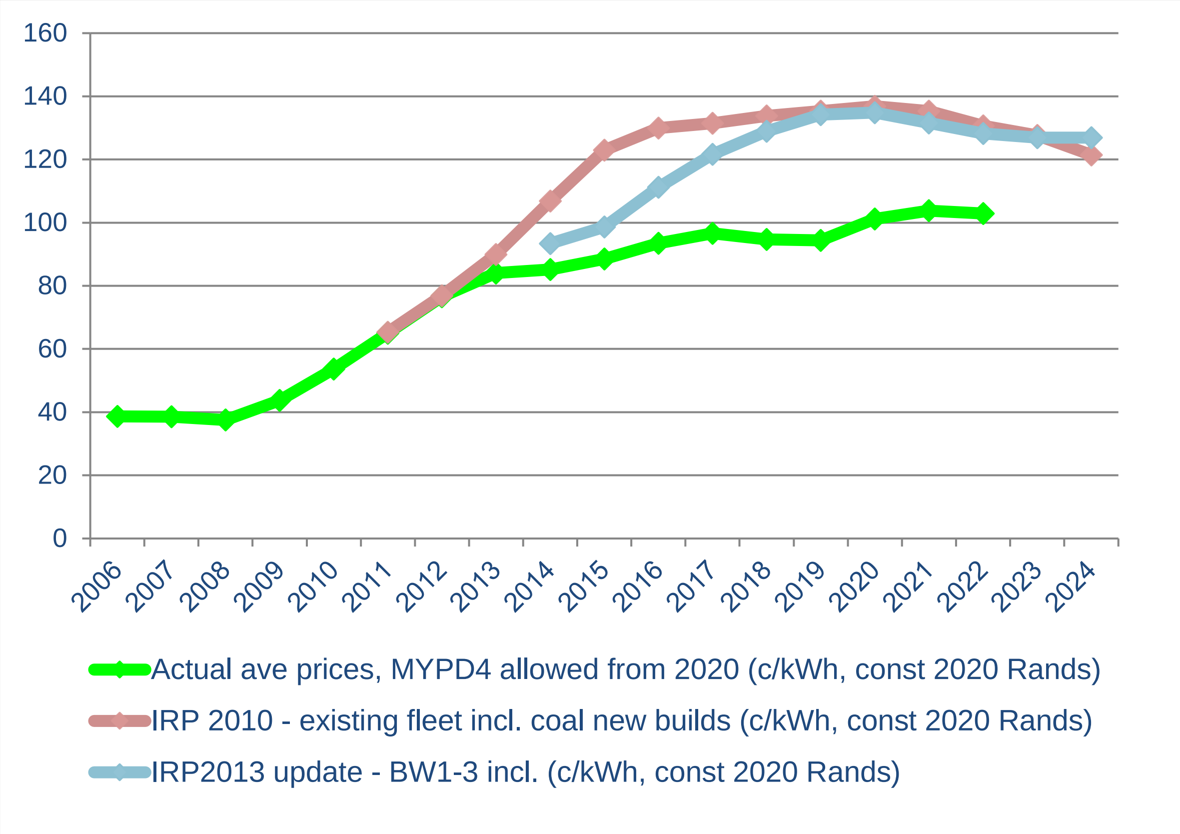
It reflects that, from around 2015 onwards, the price path as anticipated by IRP 2010 was more than 30% higher than Eskom's actual average price.

On 21 November 2013, the DoE published the IRP 2013 Update Report. It provided a breakdown of the future average electricity price path from 2013 to 2050, in constant 2013 c/kWh. The price path is developed in "steps", with further scenario elements introduced with each step.

The price path was converted from constant 2013 c/kWh to constant 2020 c/kWh for the graph below. For the sake of the graph, the price path of "Step 4" (which includes some new capacity beyond REIPPPP Bid Window 1-2) was used, as it was deemed that this scenario was probably the closest comparison from the IRP 2013 update to what actually transpired from 2013 to the present.

The graph below contrasts this price path in accordance with the IRP 2013 update (light blue line) with the price path from IRP 2010, as well as with the actual average Eskom price, in constant 2020 c/kWh.

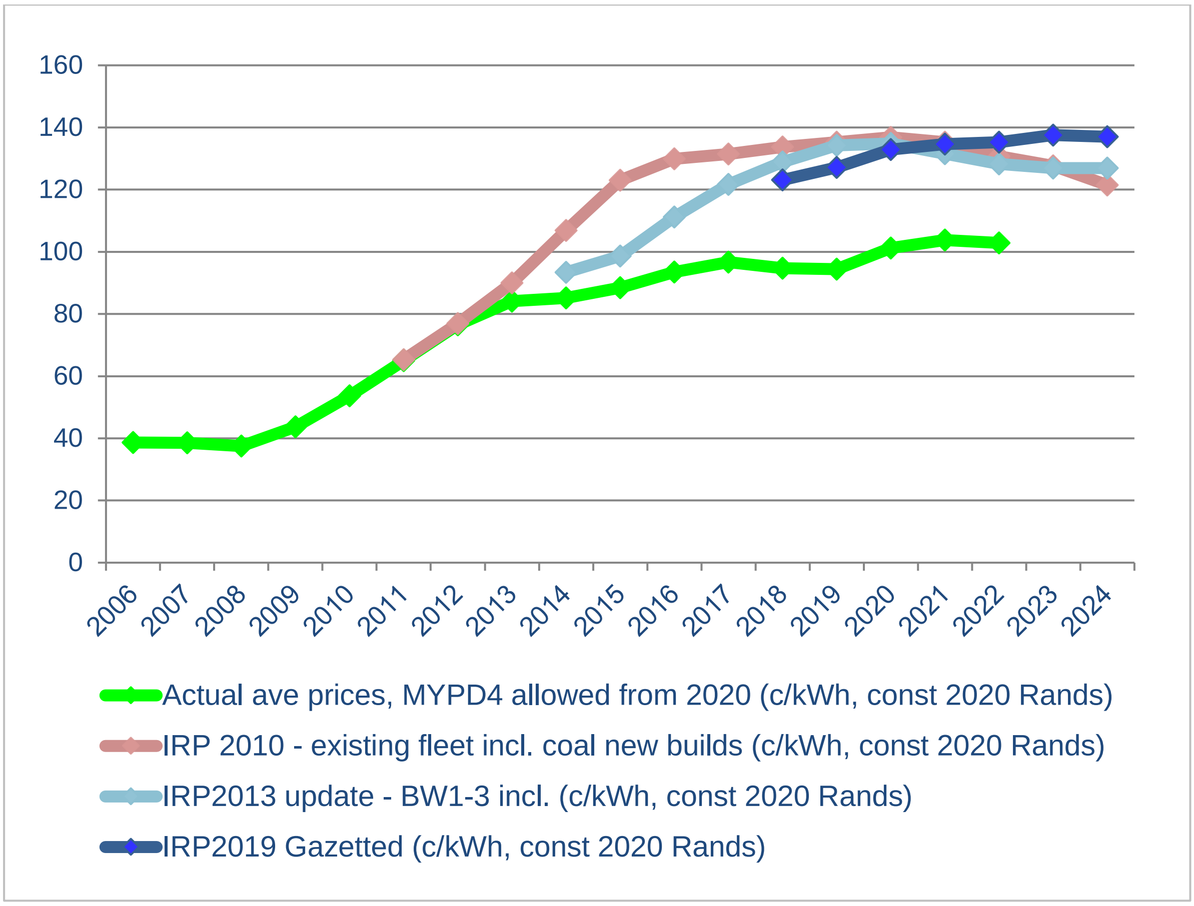
FIGURE 28: COMPARISON OF ESKOM AVERAGE PRICE TO IRP 2010, 2013 UPDATE PRICES



Relative to IRP 2010, this 2013 Update Report price path reflects a shift to the right of around 18 months to two years. However, after the right shift, the price path as anticipated by the IRP 2013 update reaches the same level as the price path from IRP 2010 in or about 2019. Thus, whereas the price gap up to 2015 is somewhat less, by 2016, the price path is 19% higher than Eskom's actual average price. By 2017, it is 26% higher, and from 2018, it is more than 30% higher.

On 18 October 2019, government gazetted IRP 2019. Whereas the IRP 2019 price path was shown in constant 2017 c/kWh, for the graph below, the values were converted to constant 2020 c/kWh. The graph contrasts this price path in accordance with IRP 2019 (dark blue line) with the price path from IRP 2010, as well as with the price path from the IRP 2013 update, as well as with the actual average Eskom price, in constant 2020 c/kWh.

FIGURE 29: COMPARISON OF ESKOM AVERAGE PRICE TO IRP 2010, 2013 UPDATE AND 2019 PRICES



Relative to the relevant price paths from IRP 2010, as well as the IRP 2013 Update Report, the price path from IRP 2019 is quite similar. By 2024, IRP 2019 is 8% higher than the 2013 update and 13% higher than IRP 2010 to 2030. The price path is more than 30% higher than Eskom's actual average price from 2018 to 2020 and also relative to the prices currently projected to the end of MYPD4, that is, FY2021/22. It needs to be noted that the average Eskom price includes IPPs.

Revenue loss implied by prices lower than prudent and efficient costs, and consequent balance sheet impact

For FY2020, the gap in price between IRP 2019 and Eskom's actual average price of ~101 c/kWh implies a revenue loss of R67bn.

Assuming that such additional revenue would have been taxed at the 28% company tax rate, the after-tax loss of revenue is R48bn for the year. With Eskom's actual costs being in line with what the various IRPs have indicated as the expected levels, it implies that Eskom would have had to resort to the raising of additional debt in order to cover the annual costs. This happened every year for which the actual price was below the price paths as indicated by the IRPs. Relative to the lowest price path in each year between the three IRPs, by FY2020, the cumulative after-tax revenue shortfall, including interest at 9% nominal, was over R260bn. Factoring in the annual revenue shortfalls before 2013, it is over R300bn. This is the main reason for Eskom's weak balance sheet reflecting more than R440bn of debt securities and borrowings at 31 March 2019.

This point was also made in the IRP 2010 to 2030 Update 2013. The final report was issued in November 2013, after NERSA had announced the MYPD3 revenue determination. As a scenario, the IRP 2010 to 2030 Update 2013, thus, also modelled the price path as determined by NERSA for MYPD3. The update comments that, due to the too-low prices of MYPD3, Eskom's debt will increase and will exceed a debt:equity ratio of 80:20 by the end of MYPD3. This modelling was very accurate, compared to what actually happened. To deal with the consequently high debt, the update further comments that the prices after the - MYPD3 will have to be higher than they would have been if MYPD3 had awarded a reasonable price path. In this respect, the IRP 2010 to 2030 Update 2013 comments: "*With the MYPD3 price curve, the price increase is delayed but the consequent utility debt escalation requires prices to eventually rise and stay higher for longer in order to reduce the debt situation.*"

A World Bank study in 2016 also indicated that 81% of the gap between Eskom's actual price and the cost-reflective price was due to the under-pricing of electricity.

Thus, it is summarised that the Eskom average electricity price is not at a level that enables efficient costs (when compared to benchmarks) to be recovered. Given that the annual revenue gap exceeds R60bn, it must be pointed out that this exceeds Eskom's entire annual cost for operating, maintenance, and employee benefits. It needs to be noted that Eskom cannot "cost-cut" itself to achieve cost reflectivity with the current supressed tariff. If adjustments are made for tax payment, the gap will be in the region of R48bn per year.

25.3 Eskom 2015 appropriation conditions and assumptions

When the previous R23bn appropriation decision was made in 2014, the expectation by Cabinet was that the average price of electricity by FY2018 would be 102 c/kWh. However, the Eskom average price was 85 c/kWh in FY2018 and then 90 c/kWh in FY2019 as reflected in the table below, as submitted to the SCOA meeting of 26 April 2018. At the Cabinet meeting of 11 September 2014, the feedback received by Eskom was that Cabinet had approved and supported Eskom applying for an average price increase of 13% per annum for the next three years (from 2016 to 2018). In addition, Eskom had to realise a cost saving of R60bn over the five-year MYPD3 period (this was achieved), improve generation performance, and not invest in any new coal mines (this resulted in a gap, since the government did not finalise any alternative investor).

TABLE 27: IMPACT OF AVERAGE 13% PRICE INCREASES AS ASSUMED BY CABINET

	Unit	FY2014	FY2015	FY2016	FY2017	FY2018
MYPD 3 decision allowed revenue	R'mil	143 101	156 057	171 769	186 794	205 213
Actual recovered revenue	R'mil	136 926	147 270	156 132	166 777	
RCA Decision	R'mil	-	-	7 818	11 242	-
MYPD 3 decision price increase	%	8%	8%	8%	8%	8%
MYPD 3 decision average standard tariff price	c/kWh	65.51	70.75	76.41	82.53	89.13
Actual average standard tariff price increase	%	8%	8%	12.69%	9.4%	2.2%
Actual average standard tariff price	c/kWh	65.51	70.75	79.73	87.23	89.13
Expected % price increase in accordance with Government Support Package (GSP)	%	8%	8%	13%	13%	13%
Expected price in accordance with Government Support Package (GSP)	c/kWh	65.51	70.75	79.94	90.34	102.08

This table illustrates that, if the Cabinet expectation had been achieved, Eskom's average price of electricity would have been 102 c/kWh by FY2018. However, the average price was 89 c/kWh. This was due to a delay in the processing of the RCA due to a court intervention by a group of customers. NERSA decided to delay the implementation of the RCAs until the full court process had been finalised. In addition, further delays were experienced as a result of NERSA delaying the processing of the RCAs. The average standard price is 102 c/kWh in FY2020.

25.4 Recovery of efficient costs

When Eskom makes a revenue application to NERSA, all it expects from a revenue determination is for efficient costs to be recovered through a tariff application. The efficient cost for a utility can be independently determined using the particular South African circumstances. For example, for the efficient cost of the construction of generating assets, particular benchmarks as determined by independent entities exist. The entities that undertake these benchmarks include Lazard, the IEA, and the EPRI. Similarly, benchmarks and analysis should be undertaken for other aspects of the electricity value chain. Then, consideration would need to be given to the circumstances and requirements for the South African situation. It is important to consider internationally recognised benchmark criteria.

Eskom’s present costs could also be evaluated for efficiencies. From a regulatory point of view, over the last six years, Eskom has been able to relatively stabilise its primary energy costs and operating costs. The challenge lies with the recovery of asset-related revenue requirements, where NERSA has continuously made inadequate revenue decisions.

25.5 Outcome of research undertaken by customer groupings

In its submissions on the MYPD3 five-year tariff determination, Business Unity South Africa, through its representative, Genesis, proposed a set of increases over MYPD3 that would culminate in a 2017/18 total average tariff of 101,7c/kWh. Similarly, in its submissions on the MYPD3 five-year tariff determination, the Energy Intensive User Group (EIUG) (representing intensive electricity users in South Africa) indicated that Eskom required tariff increases in the range of 10% to 13% to support its viability and fundability over the period up to 2017/18. Increases in this range would have produced a 2017/18 average standard tariff of between 97,69c/kWh and 111,76c/kWh. However, this did not materialise in the decisions that NERSA made. In NERSA decisions, the price of electricity was 89 c/kWh by FY2018. It illustrates that the average price of 102 c/kWh proposed by these independent entities for FY2018 was only achieved in FY2020.

25.6 Determination of efficient costs

Efficient costs are those determined by NERSA by correctly applying its MYPD methodology to allow Eskom to recover its efficient costs and a fair cost of capital. Benchmarks are available for NERSA to make relevant comparisons.

In addition, NERSA could undertake a detailed analysis of Eskom’s revenue submissions to determine the efficient level. It has been Eskom’s experience that this analysis has not been undertaken by NERSA in recent years. There have been many instances where the criteria for benchmarking have changed each time a decision has been made by NERSA. For example, the criteria to determine the efficient number of employees have changed significantly from the MYPD3 decision (FY2014 to FY2018) to the single-year decision for FY2019 and then changed again to the MYPD4 period (FY2020 to FY2023). Similar challenges were experienced for coal costs (R/tonne of coal) – where a decrease of approximately 20% was expected in the FY2019 determination. This was then followed by an increase in the range of 24% to 59% in one year to FY2020 in the MYPD4 determination. Eskom has always applied for efficient costs in its revenue applications. Details on changes from previous years and the motivations for the changes have always been provided.

25.7 Subsidising energy has significant consequences

Where the revenue collected via the tariff is insufficient to cover Eskom's prudently and efficiently incurred costs, the price of electricity is being implicitly subsidised. As the World Bank (2010:22) notes:

"*Subsidising energy use involves providing it at a price below opportunity cost. This includes non-collection or non-payment, selling electricity at a cost that does not reflect the long-run marginal cost of supply including capital maintenance.*"

The economic harm and distortions that are caused by energy subsidies, including artificially low electricity prices, is well-documented in the international literature. Some of the potential macroeconomic, environmental, and social consequences of energy subsidies, as documented by the IMF (2013) were summarised in Deloitte (2017) as follows:

- **Energy subsidies crowd-out growth-enhancing or pro-poor public spending**. Energy subsidies, while often intended to protect consumers crowd-out other priority spending (such as on social welfare, health, and education) and place an unnecessary burden on public finances. Energy subsidies (unless specifically targeted) are a poor instrument for distributing wealth relative to other types of public spending.
- **Energy subsidies discourage investment in the energy sector and can precipitate supply-crises**. Energy subsidies artificially depress the price of energy which results in lower profits for producers or outright loses. This makes it difficult for state-owned enterprises to sustainably expand production and removes the incentive for private sector investment. The result is often an underinvestment in energy capacity by both the public and private sector that results in an energy supply crisis which in turn hampers economic growth. These effects have been felt in SA.
- **Energy subsidies create harmful market distortions**. By keeping the cost of energy artificially low, they promote investment in capital-intensive and energy-intensive industries at the expense of more labour-intensive and employment generating sectors.
- **Energy subsidies stimulate demand, encourage the inefficient use of energy and unnecessary pollution**. Subsidies on the consumption of energy derived from fossil fuels leads to the wasteful consumption of energy and generate unnecessary pollution. Subsidies on fossil-fuel derived energy also reduces the incentive for firms and households to invest in alternative more sustainable forms of energy.
- **Energy subsidies have distributional impacts**. Energy subsidies tend to disproportionately benefit higher-income households who consume far more energy than

lower income groups. Energy subsidies directed at large industrial consumers of energy benefit the shareholders of these firms at the expense of the average citizen.

Deloitte (2017) goes on to give specific examples of the economic harm and distortions that can be attributed to the historic under-pricing or implicit subsidisation of electricity. In South Africa these are argued include:

- **Artificially low electricity tariffs discouraged investment in South Africa's electricity supply industry and helped to precipitate the 2008 power supply crisis**. The subsidised tariffs frustrated attempts by the government to attract private investment in the early 2000s and helped to precipitate the supply crisis of 2008.
- **Subsidised electricity prices promoted investment in capital intensive industries in South Africa at the expense of more labour-absorbing sectors**. Kohler (2014) traced the 40-year change in electricity intensity across a number of countries and country groups and found that South Africa has amongst the highest electricity intensity globally.
- **Subsidised electricity prices, encourage the inefficient use of energy and contributed South Africa to becoming one of the single-largest contributors to global GHG emissions.** Subsidies on the consumption of electricity generated by Eskom which was mostly coal-based have arguably contributed South Africa becoming the 18th largest country-level contributor to global CO2 emissions[1].

25.8 Balanced economic impact studies are necessary to truly understand the impact of price increases

In the past, NERSA conducted economic impact assessments for each of its revenue and RCA balance decisions. In its RFD, NERSA confirmed that it "relied on a set of macroeconomic impact models . . . to determine the magnitude of the impact of electricity tariff increases in the economy". Importantly, NERSA made clear that, when performing its economic impact assessment it ran various scenarios which includes a scenario based on Eskom's application and another based on NERSA's approved decisions.

1 *Based on data from the EDGAR – emissions databased for global atmospheric research. 2015. Available online at: http://edgar.jrc.ec.europa.eu/overview.php?v=CO2ts1990-2015&sort=des9*

In the first place, it is unclear how NERSA undertook its economic modelling. NERSA's economic impact analysis could at best be described as a partial analysis. It is evident that it did not consider the economic impact of not allowing Eskom the revenues due to it. Had NERSA done so i.e. also considered the economic impact of not allowing Eskom the revenues due to it, NERSA would have concluded that the overall economic impact would be worse in that scenario, due to the inevitable consequence that the national fiscus would have to step in to support Eskom. This, in turn, would have negative consequences for the sovereign in terms of its Debt-to-GDP ratio, fiscal deficit and credit ratings, as well as sending negative signals to investors about Eskom's financial recovery and linked to that, the lack of certainty of reliable electricity provision in the future. Therefore, NERSA's economic impact assessments were incomplete and entirely one-sided.

25.9 Independent studies to model Economic impacts of price increases

Independent study was undertaken by Eskom. These include research undertaken by Deloitte, University of Pretoria and research undertaken for inclusion in Eskom's recent affidavits related to recovery of efficient and prudent costs. The study included in the 2020 affidavit addresses the economic impact parameters used by NERSA in making price increase determinations. In addressing public interest considerations, the regulator must endeavour to make a fair and accurate assessment of the broader economic impacts. It concluded however that NERSA's current approach to economic impact evaluations is methodologically flawed. As a result, NERSA has frequently arrived at the naïve and false conclusion, that the tariff increase that minimises the harm to the economy is simply the lowest increase modelled. Critique of NERSA's approach centred on two main issues. Firstly, NERSA had based its recent economic impact analyses on a partial equilibrium model that is particularly ill-suited to the assessment of price shocks. Secondly, that NERSA's previous assessments was conceptually flawed because they ignored the obvious counterfactual to inadequate tariff increases – the negative impact that Eskom's burgeoning revenue shortfall has on the fiscus and government debt levels.

In addition, NERSA erroneously assumed that, if Eskom was awarded an inadequate tariff, it could continue to operate without further financial assistance from the government. The latter clearly refuted by Governments recent equity injections and the passing of the Special Appropriate Bill to assist a financially constrained Eskom, hence placing undue burden on the fiscal budget.

It may be tempting to conclude that by limiting electricity tariff increases, NERSA will also minimise the negative impacts of rising electricity prices on GDP and employment growth.

While this may be true in the short-term (since larger increases have proportionately larger impacts on GDP and employment growth) there is a hidden cost which takes the form of a growing implicit subsidy. As the adage goes, “there is no such thing as a free lunch”.

Since 2013, the tariff increase that NERSA has approved have been insufficient to cover Eskom’s costs. Besides having to now delay operational and capital projects that needed to be carried out timeously to preserve optimal plant performance, Eskom had to fund the latter via debt. This has led to a marked deterioration in Eskom’s financial position, reflected in a widening revenue shortfall that reached approximately R45bn during FY2019. Government has been forced to intervene, extending more than R350bn in government guarantees for Eskom’s debt and injecting R23bn in equity (not counting the R60bn subordinated debt converted to equity in FY2015). Increase government support to Eskom resulted in a sharp rise in government debt and contingent liabilities, and has been cited directly by credit rating agencies as a reason for South Africa’s sovereign credit rating downgrades, which in turn led to an increase in national debt services costs.

Arbitrarily limiting increase in Eskom's average tariff is not an effective way to protect consumers and the economy from the negative impact of rising electricity prices

Economic analysis indicates that while it may be both necessary and socially desirable to mitigate the impact of energy prices on vulnerable groups, there are more efficient and effective ways to achieve this than by introducing average tariff subsidies.

The economic harm and distortions that are caused by implicit energy price subsidies are well-documented in the international literature, they:

- crowd out pro-poor spending (e.g. education and health);
- discourage private investment in the energy sector;
- encourage wasteful energy consumption,
- result in a variety of harmful market distortions.
- tend to disproportionately benefit energy- and capital-intensive firms and higher-income households.

A brief review of the literature revealed that there are several more appropriate and economically-efficient ways to shield the poor and other vulnerable groups from the impact of rising electricity prices than an average tariff subsidy. These include:

- improving the implementation and extent of targeted electricity price subsidies;
- facilitating a gradual transition to cost-reflective prices and making implicit subsidies more explicit;

- introducing policy and regulation to promote the uptake of energy-efficient technologies;

In terms of targeted subsidies, the existing free basic electricity grant meets most of the requirements of a 'good subsidy' and could be improved in its implementation to ensure all vulnerable households received the free basic electricity. Well designed, targeted and time-limited subsidies could also be used to protect vulnerable industries (trade-exposed and electricity-intensive). NERSA could also consider converting the current implicit price subsidy into an explicit subsidy as this would increase transparency and help to facilitate a more gradual transition to cost-reflective tariffs. NERSA could also collaborate with other stakeholders such as the Department of Mineral Resources and Energy to introduce initiatives to promote the uptake of energy-efficient technologies.

25.10 Concluding remarks on economic impacts

It may be tempting to conclude that by limiting electricity tariff increases and requiring that Eskom and/or government borrow the revenue shortfall (and effectively implicitly subsidise the price), it is possible to minimise the negative impacts of rising electricity prices on GDP and employment growth in the short-term.

However, the results of the economy-wide impact analysis show that the fiscal and economic consequences of awarding Eskom a tariff that is much lower than what it requires (to recover its prudently and efficiently incurred costs), do eventually (and arguably have now) become evident.

In conclusion, it would be ill-advised for NERSA to continue to limit Eskom's tariff increases below cost reflective levels. It would also be incorrect given the current context and results of this analysis to assume that this will limit the negative impact on GDP and employment, even in the short-term. Our recommendation is that tariff increases should at least be sufficient to transition Eskom towards a more cost-reflective electricity tariff (prudently and efficiently incurred) over the next few years.

25.11 What does electricity cost around the world?

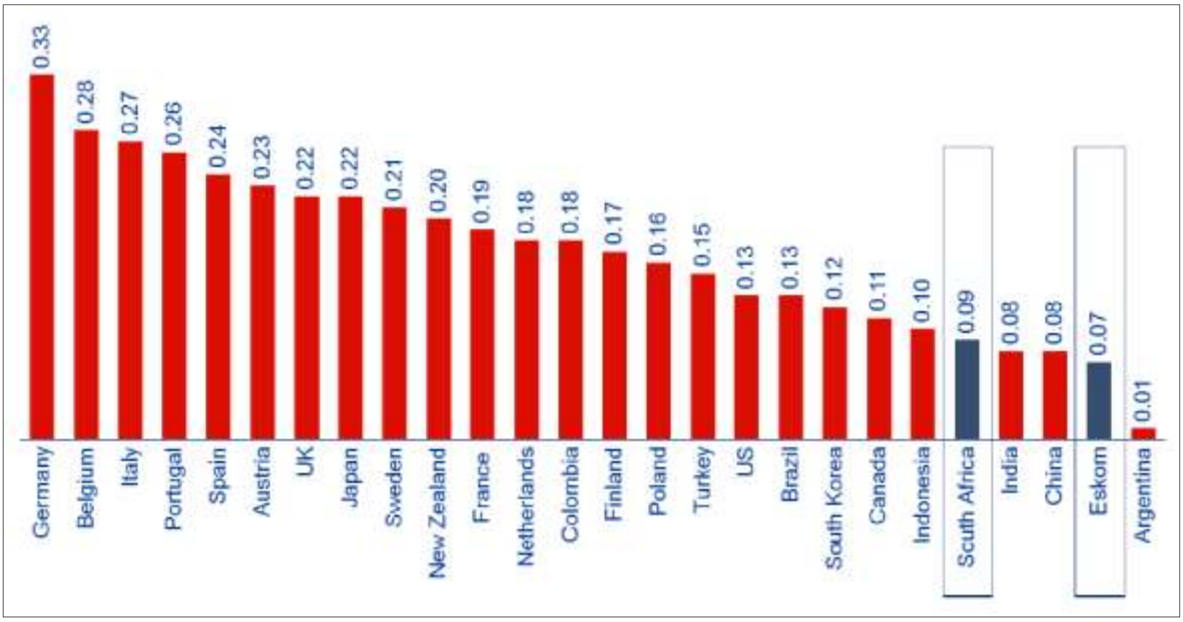
The reason to consider price comparisons is twofold. Firstly, for the industrial sector, the electricity price will contribute to the decision to invest. Thus international comparisons, will be important in guiding the decision to be made. Secondly, it can be assumed that in many developed countries, and certain developing countries, the price of electricity is at a level that allows entities to recover the efficient cost of producing the electricity. Thus this provides a benchmark of comparison. It is recognised that technologies, terrains, proximity, level of subsidies, cross-subsidies and other factors may differ. These factors need to be taken into consideration. It is also important to take into consideration which tariffs are being compared – could be industrial, residential, the average prices or any other tariff. However, the comparisons are provided to be in a position to place Eskom's tariffs into appropriate context.

The two most easily accessible sources for electricity prices are two internet resources that maintain records of prices on an ongoing basis and provide this data for sale as part of their product offering to the market. These are commonly referenced as they provide reliable and easily accessible views of a range statistics. These are Statista.com and GlobalPetrolPrices.com.

25.11.1 Statista

Statista provides a relative benchmark of the average electricity prices in 25 countries, illustrated in the figure below. The benchmarking data is based on a World Energy Council study, "The World Energy Trilemma Index: 2018".

FIGURE 30: STATISTA PRICING BENCHMARK



This dataset indicates prices (October 2018) on a national level at an average price per country ($/kWh). This benchmark indicates that South Africa's electricity prices are low relative to both developed countries as well as the major developing countries listed – China, India, Indonesia, Brazil and Turkey. The only country in this study which reflects a lower cost of electricity is Argentina, which like South Africa has non-cost-reflective tariffs with estimated subsidies equal to $10bn.

25.11.2 GlobalPetrolPrices.com

GlobalPetrolPrices.com also maintains a wide range of energy related datasets on an ongoing basis. The benefit of this source is that that they maintain their data on an ongoing basis and remain up to date with the latest variations in prices. One of the local studies, conducted by PrimaResearch utilised this dataset and the outcomes are discussed below.

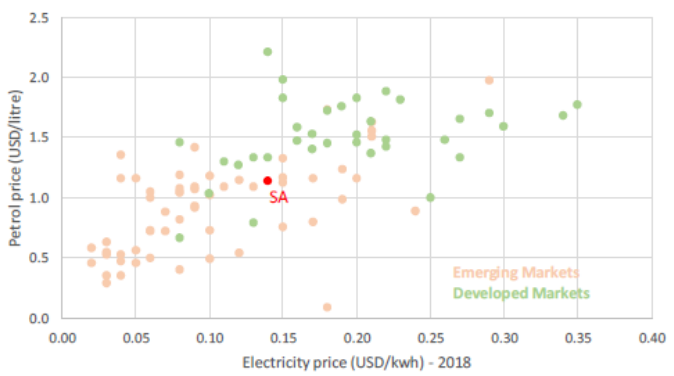
25.11.3 Local studies benchmarking electricity tariffs

25.11.3.1 PrimaResearch study

In August 2019, PrimaResearch released an independent report which took a broad look at various aspects of Eskom's business. One of the aspects they looked at was the price of electricity.

FIGURE 31: PRIMARESEARCH ELECTRICITY PRICE ANALYSIS

Price of electricity and petrol in emerging and developed markets - 2018



Electricity Prices (USD/kwh) in selected countries - 2018

Egypt	0.02
Ghana	0.06
Russia	0.06
Nigeria	0.08
Mexico	0.08
China	0.08
India	0.08
Turkey	0.08
South Korea	0.11
USA	0.13
South Africa	0.14
Brazil	0.17
Philippines	0.19
New Zealand	0.20
UK	0.21
Australia	0.25
Japan	0.27
Portugal	0.29
Germany	0.34
Denmark	0.35

Source: GlobalPetrolPrices.com; Primaresearch

PrimaResearch concluded that: *"In comparison to a list of 94 countries, South Africa's electricity prices (at USD 0.14/kwh) was ranked 49th lowest, placing it close to the midpoint of cheap and expensive markets. However, in the cohort of emerging markets, SA's electricity prices are slightly above average. Consequently, we do not think electricity prices are excessive in South Africa."* It should be noted that this conclusion refers to the South African price - that reflected both Eskom and municipal prices. Their analysis further estimated that in *2018 "the excess profits across all municipalities may have amounted to R8.5bn.*

25.11.3.2 Lazard

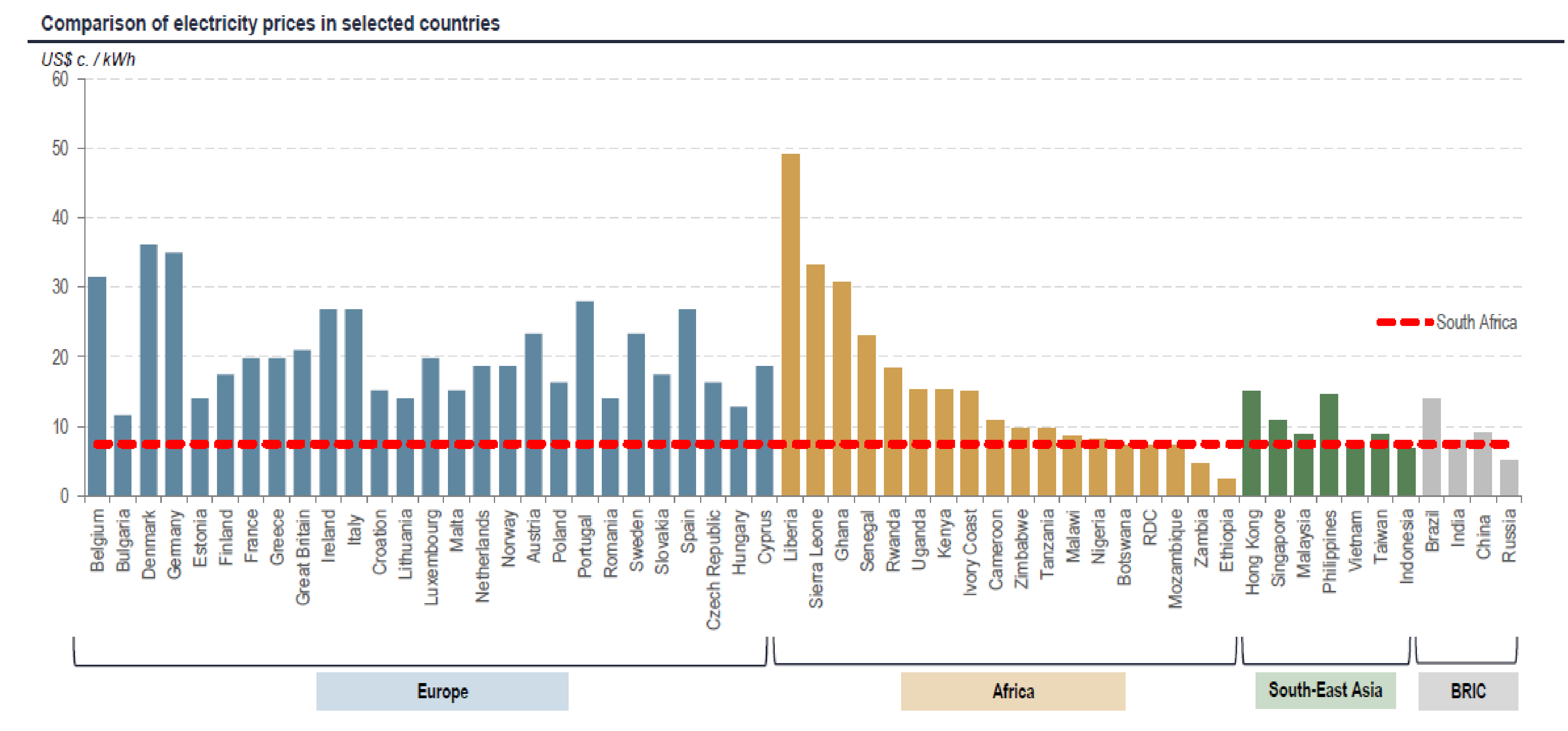
In a 2018 report, Lazard concluded ***"The average price of electricity in South Africa is below all countries in Europe and South-East Asia. In Africa, the majority of countries have higher electricity prices although a few countries have comparable or even lower prices than South Africa's".***

They further noted that amongst the BRICS countries only Russia had lower prices and that amongst African countries only Zambia and Ethiopia had lower prices. These are two countries with excellent hydropower resources.

Lazard drew several conclusions, including that [6]:

1. Eskom tariffs are not cost-reflective, and
2. Eskom's tariffs are low by international standards

FIGURE 32: LAZARD INTERNATIONAL TARIFF COMPARISON [6]



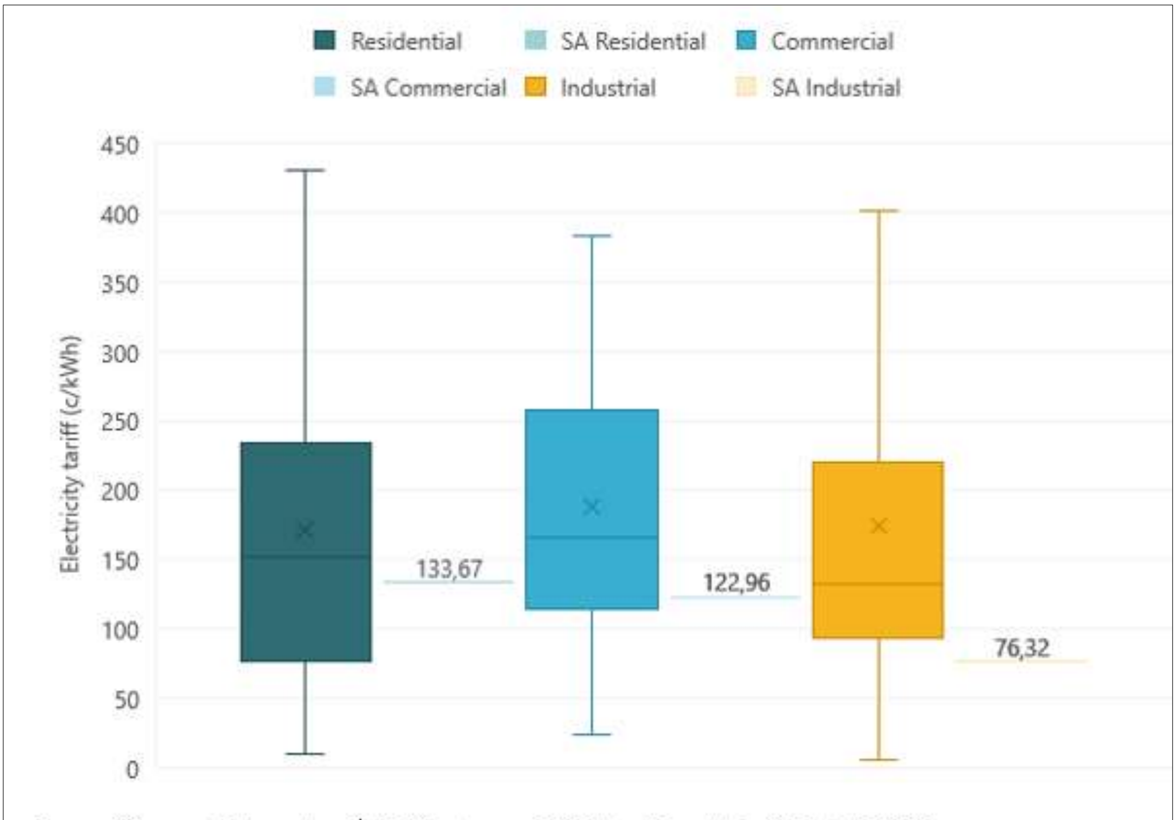
25.11.3.3 Nova Economics

As part of an expert opinion submitted in CASE NUMBER: 37296/2018 in the Gauteng High Court between Eskom and NERSA prepared by Kay Walsh, Chris Reeders and Ahmed Seedat, of Nova Economics, compared the South African price to local and international benchmarks for electricity tariffs.

"We analysed the average electricity tariffs of 100 countries, using data from Bloomberg's BNEF Climate Scope 2019 report. Tariffs are segmented into three categories (residential, commercial, and industrial). *South African electricity price rank competitively across all three segments (Figure 1). South Africa's average residential price of 133.67 c/kWh ranks 47th (i.e. 53 out of the 100 countries in the sample have more expensive residential electricity prices). South Africa's average commercial (122.96 c/kWh) and industrial (76.32 c/kWh) prices are even more competitive ranking 29th and 20th least expensive out of a total of 100 countries."* [8]

They also include the following figure.

FIGURE 33: NOVA ECONOMICS INTERNATIONAL PRICE BENCHMARK [8]



Source: Own analysis based on BNEF Climatescope 2019 data (Esser, Maia, & Ezekiel, 2019)

Part of their conclusion states:

"Our comparison across 100 countries shows that South Africa's current average electricity price rank competitively across all three of the main customer segments - industrial, commercial, and residential. South Africa's residential consumers pay an average of 133.67 c/kWh, which is a lower tariff than more than half (53 of 100) the countries surveyed. South Africa's commercial and industrial electricity tariffs are more competitive by international standards. South Africa's average commercial tariff of 122.96 c/kWh is cheaper than 71 of the 100 countries surveyed, while industrial tariffs (76.32 c/kWh) are among the lowest 20. In support of this analysis, we also presented the results of two other international electricity tariff comparisons (by the World Bank and International Energy Consultants) which confirm that South Africa's average electricity prices remain very competitive by international standards.

Finally, we compared Eskom's current average tariff to a local benchmark for the price of future electricity generation capacity – the 'least-cost' scenario (IRP 1) presented in the IRP 2019. Our analysis shows that based on recent IRP estimates a hypothetical new market entrant, operating a newer, more efficient, 'least-cost' generation fleet consisting mainly of wind, solar PV and gas would require a tariff 40% to 50% higher than Eskom's current tariff to cover its costs. In contrast to NERSA's claim, we conclude that the approved tariff is not cost-reflective and is not sufficient to ensure Eskom's financial viability."

Again, it needs to be noted that the comparison is to the South African price of electricity, not only the Eskom tariff.

25.11.4 A look at the most recent international Price data

A look at the most recent data available from the International Energy Agency (IEA) for comparison provides a similar picture of Eskom's electricity tariffs as those presented by other studies discussed above. Eskom's prices for 2019 are placed in relation to an international comparison conducted annually by the UK National Statistics Department of Business, Energy & Industrial Strategy. This compares electricity tariffs for industrial and domestic customers for the fifteen major EU countries and a sample of other countries across the IEA. The IEA data collected by UK National Statistics is converted to US cents/kWh based on exchange rate data collected by UK National Statistics and benchmarked against Eskom's 2019 tariff data (converted to US cents/kWh) as published on its website and the 2019 Annual Report. This dataset is used as it is updated and maintained by a credible source (UK National Statistics) on a quarterly basis.

Figures below illustrate that relative to the sample of IEA benchmarked in this study, Eskom's prices for industrial and domestic customers are amongst the lowest in the sample, with only Norway's industrial electricity price being lower than Eskom's.

FIGURE 34: ESKOM AVERAGE INDUSTRIAL AND MINING PRICES VS IEA INDUSTRIAL PRICES (WITH ESKOM ANALYSIS)

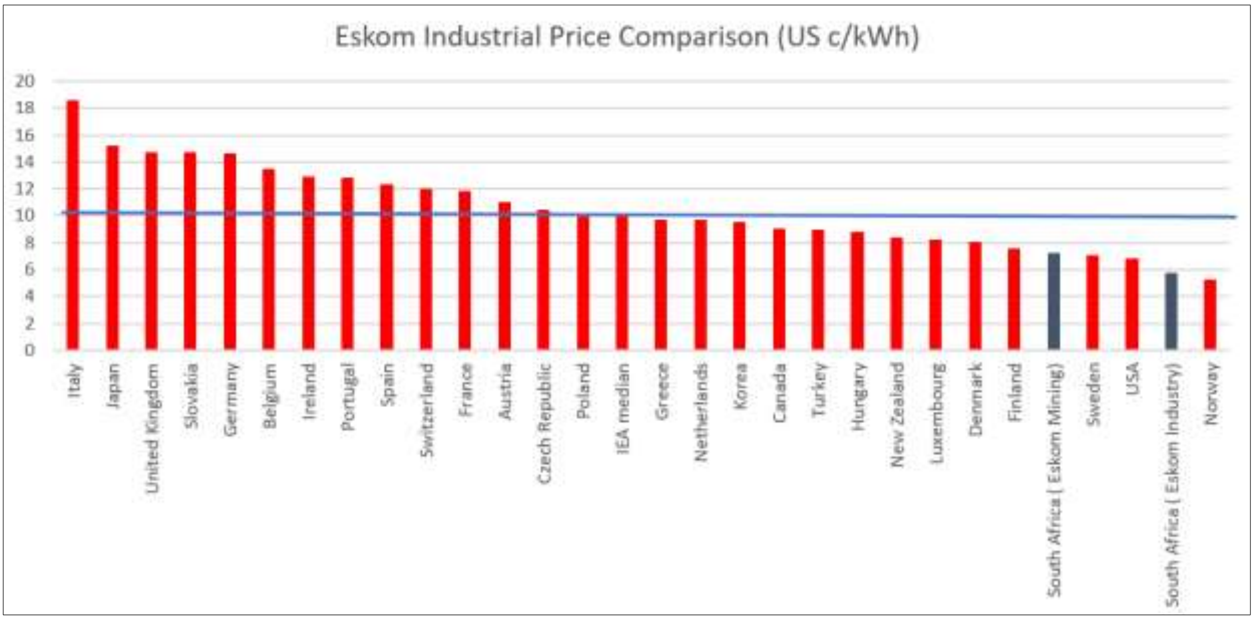
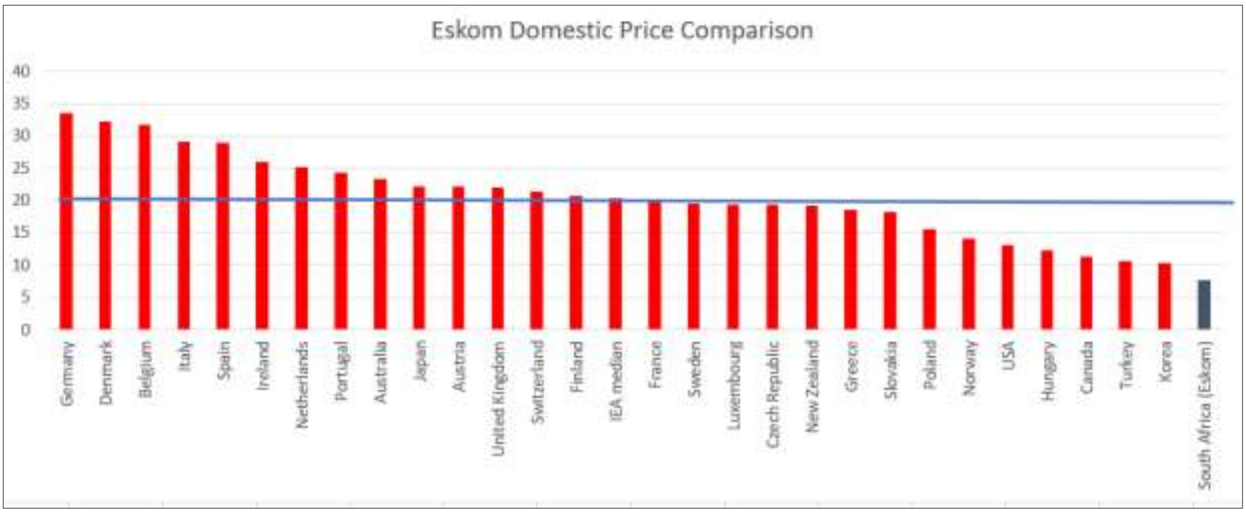


FIGURE 35: ESKOM AVERAGE DOMESTIC PRICES VS IEA DOMESTIC PRICES (WITH ESKOM ANALYSIS)

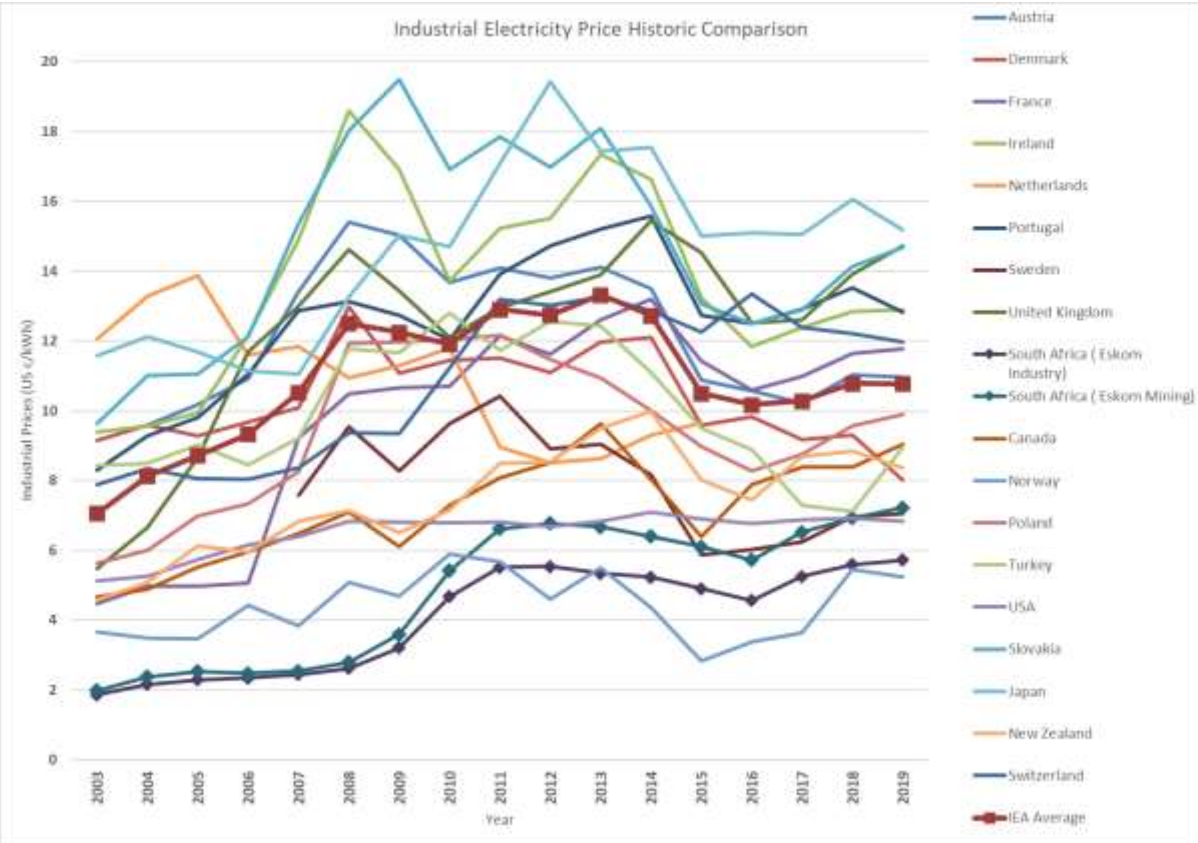


25.11.4.1 Historic price analysis – industrial sector

While Eskom's prices have increased significantly above inflation over the last decade, an international comparison that takes into account both the most recent available prices as well as the historic trend provides insight into how Eskom's prices have changed relative to the international market. This is particularly relevant for the industrial sector in South Africa, where commodities and inputs costs are often dollar denominated or indexed. A dollar based comparison of electricity as an input cost across countries gives a picture of Eskom's (and by extension South Africa's) international price competitiveness as an electricity supplier.

The same 27 country IEA dataset, sourced via UK National Statistics is used for this analysis. This price is compared to the historic price increases available on Eskom's website. The comparison is made in US cents/kWh with the Eskom prices for each year converted to a particular year's US dollar equivalent using the annual average exchange rate data.

FIGURE 36: HISTORIC COMPARISON OF INDUSTRIAL ELECTRICITY PRICES (WITH OWN ANALYSIS)



The figure above illustrates the historic prices (dollar denominated) for Eskom's mining and industrial customers. The era of low electricity pricing in South Africa is clearly visible with Eskom's Industrial price being ~75% below the IEA average until 2009, after which there was a significant increase from 2009-2011. The price margin has been gradually declining since 2009 and by 2019. Eskom's average industrial electricity price was ~47% lower than the IEA average industrial price, with only Norway being lower.

Eskom's Industrial prices have been almost static since 2011, when compared in dollar terms. Between 2011 and 2016 a decrease in price of electricity is observed, with effective increase only since then. Over the full period 2011 to 2019, Eskom's dollar denominated industrial electricity price rose by 3.70% from US 5.53 c/kWh to US 5.73 c/kWh. A similar pattern is seen for mining, which saw steeper increases in the 2009-2011 period and from 2011-2019 increased by 9.07% from US 6.62 c/kWh to US 7.72 c/kWh.

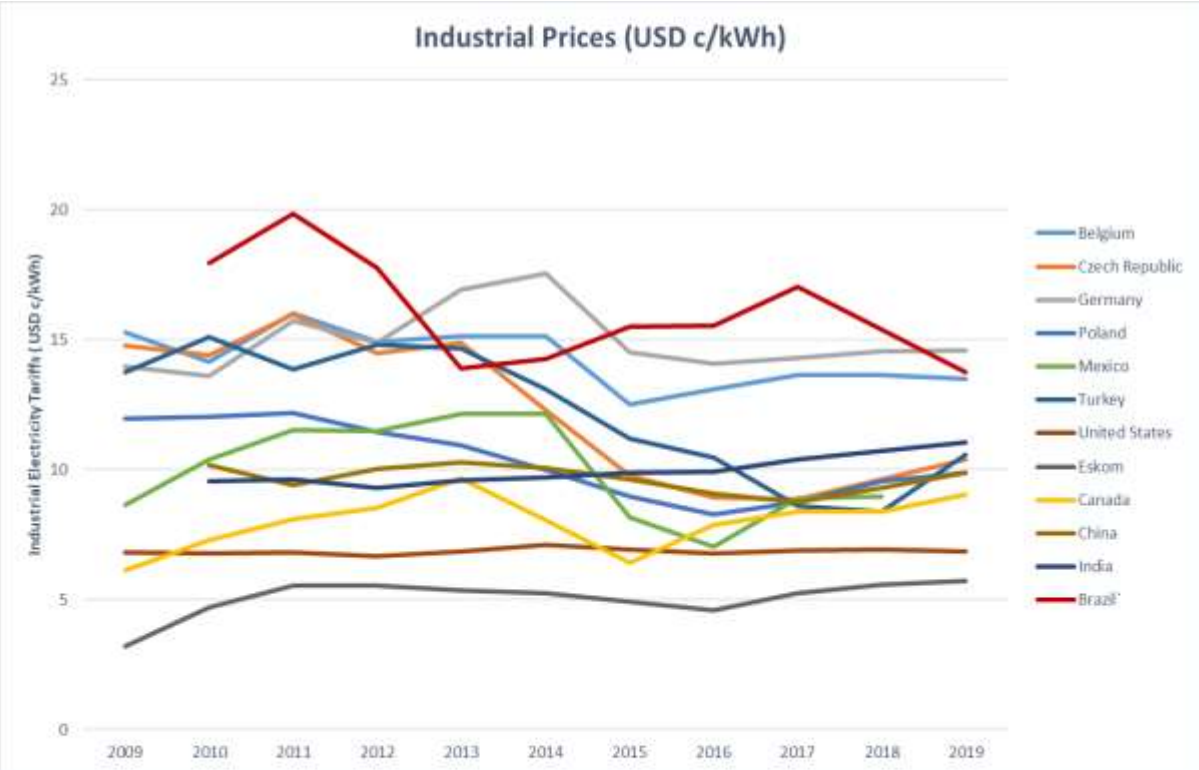
25.11.5 A slightly broader historic comparison

For this analysis the dataset utilised is taken from the IEA Energy Prices and Taxes Statistics database. This dataset contains historic electricity price data for industrial and households for a sample of 36 countries from 2009-2019. This price data is compared to the same historic price increase data available on Eskom website.

25.11.5.1 Industrial prices

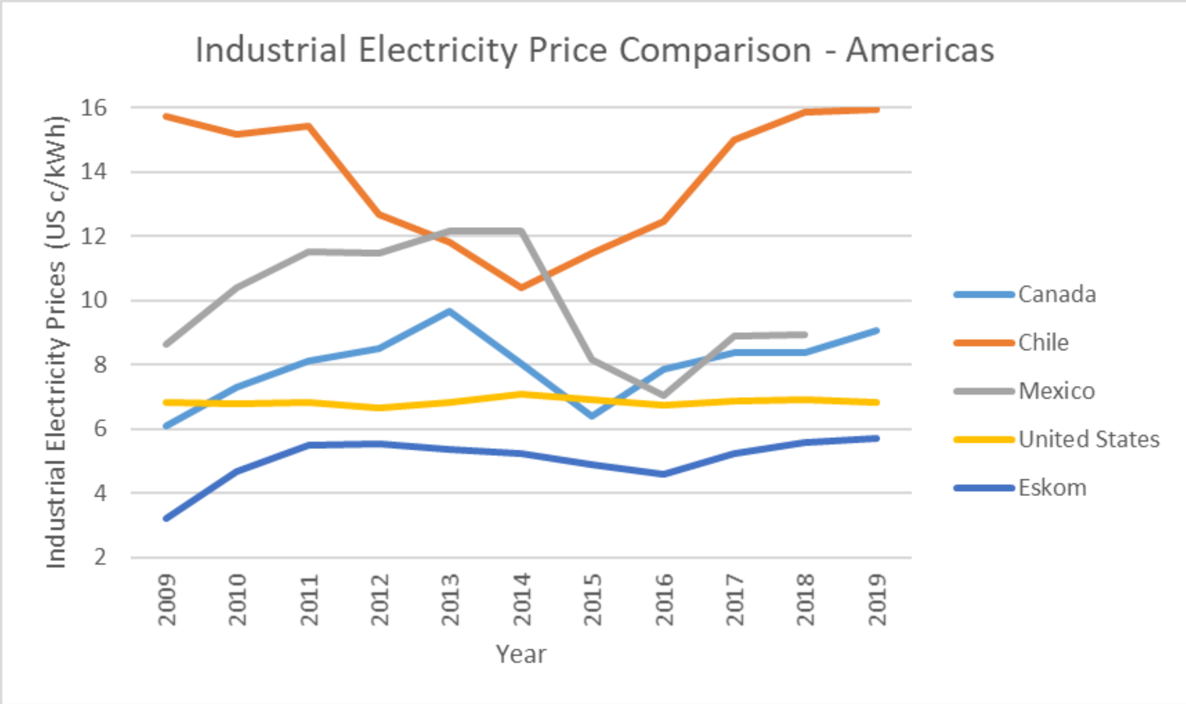
Eskom's industrial prices relative to a small sub-set of the IEA dataset confirms the observation of Eskom's industrial prices being relatively low in dollar terms.

FIGURE 37: INDUSTRIAL PRICE COMPARISON [12] (WITH OWN ANALYSIS)



The figure above shows a comparison of Eskom's industrial prices against a small international sample of countries.

FIGURE 38: REGIONAL INDUSTRIAL PRICE COMPARISONS (WITH ESKOM ANALYSIS)



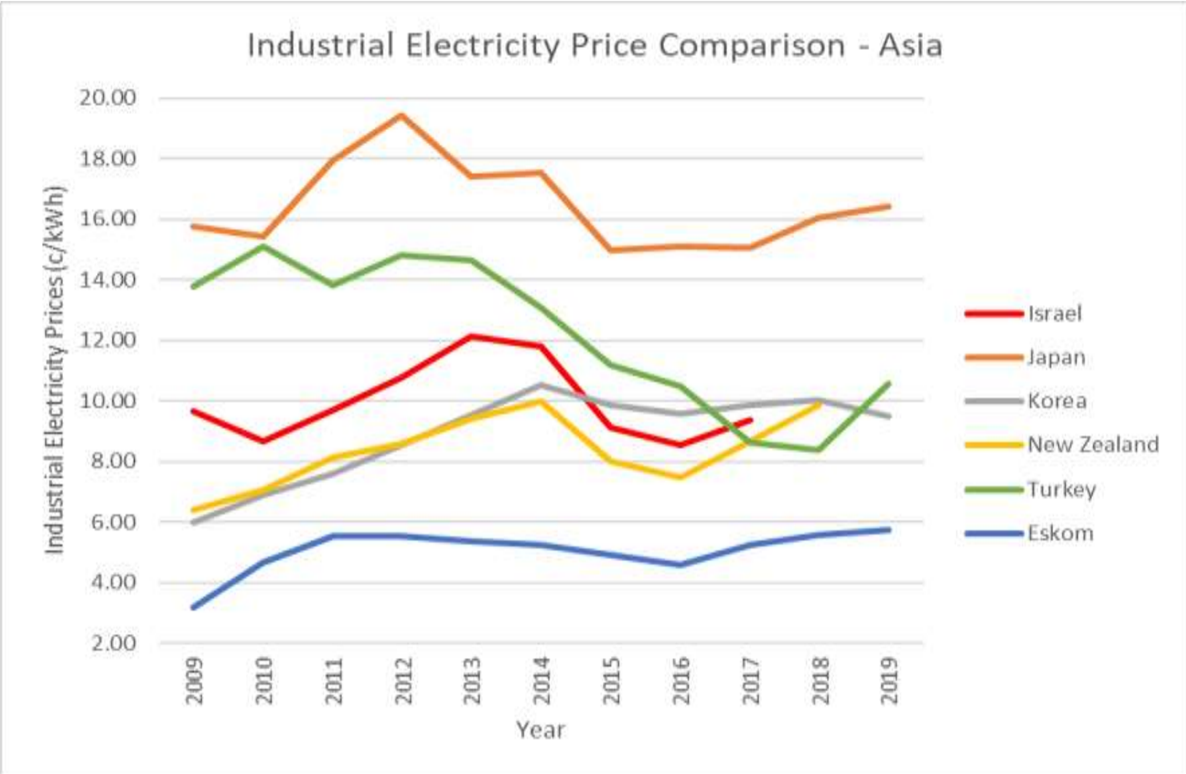
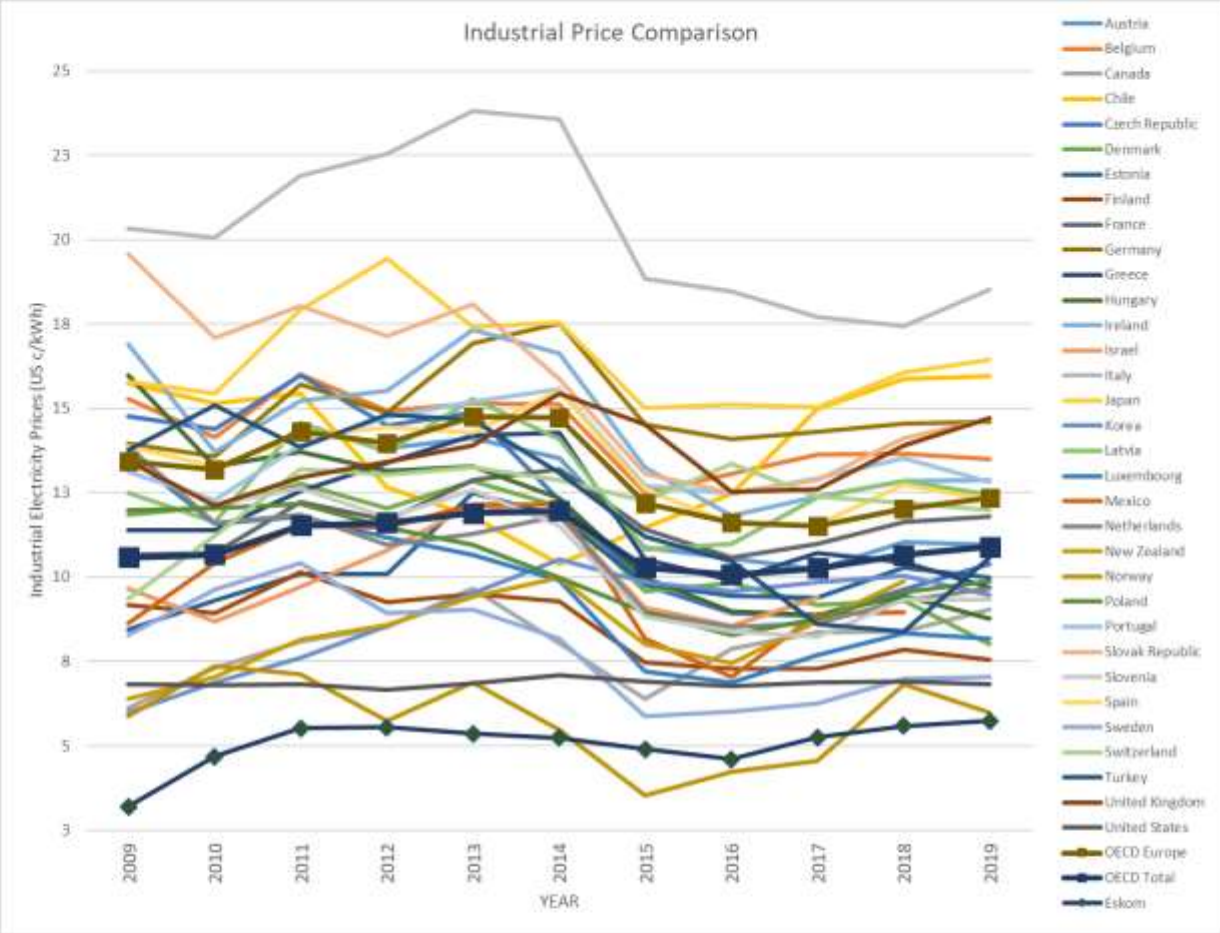


FIGURE 39: INDUSTRIAL ELECTRICITY PRICE COMPARISON WITH 36 IEA COUNTRIES (WITH ESKOM ANALYSIS)



25.11.5.2 Household prices

The same analysis was repeated for household prices and the Americas and Asia region prices.

FIGURE 40: REGIONAL HOUSEHOLD PRICE COMPARISONS (WITH ESKOM ANALYSIS)

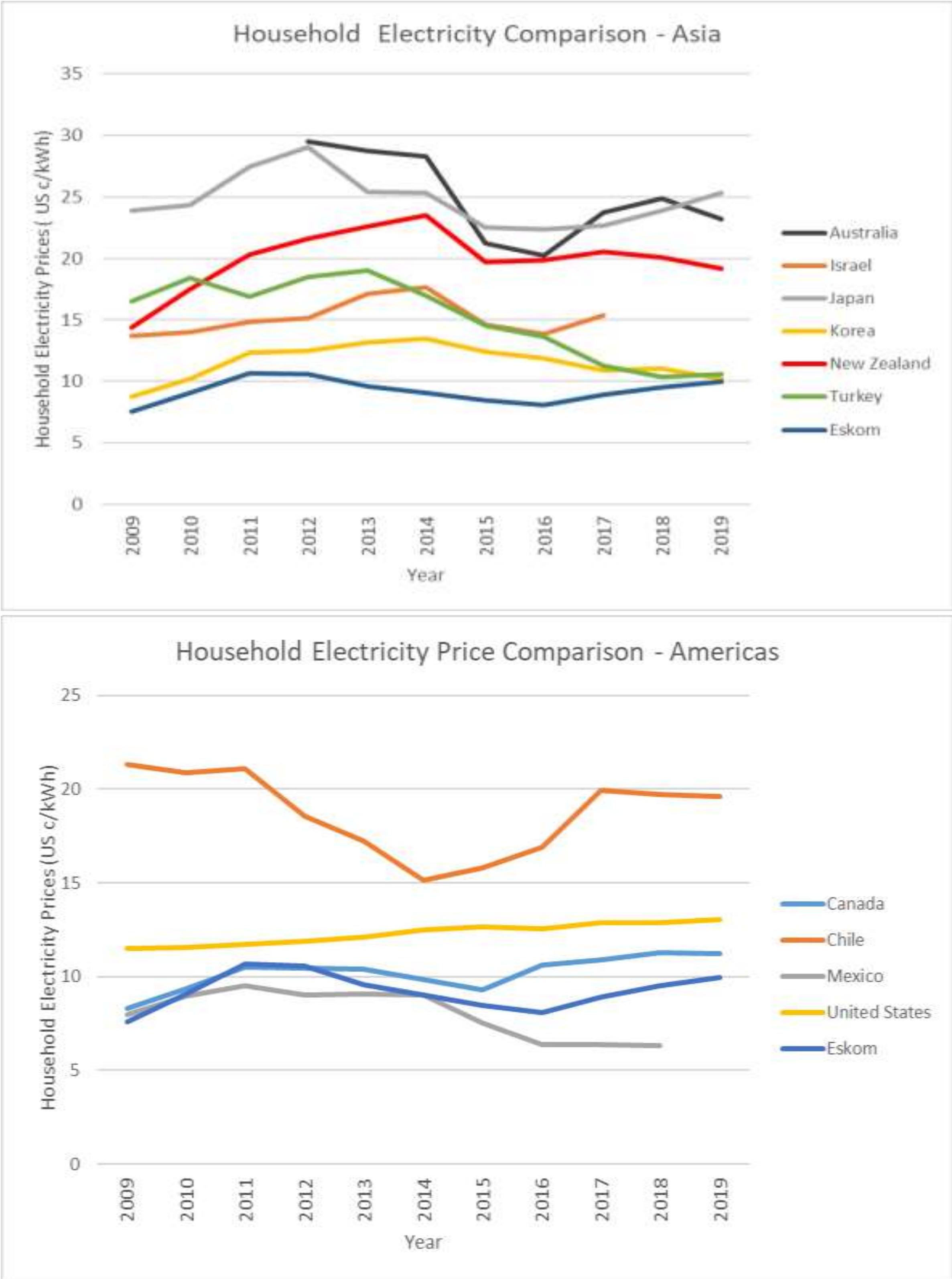
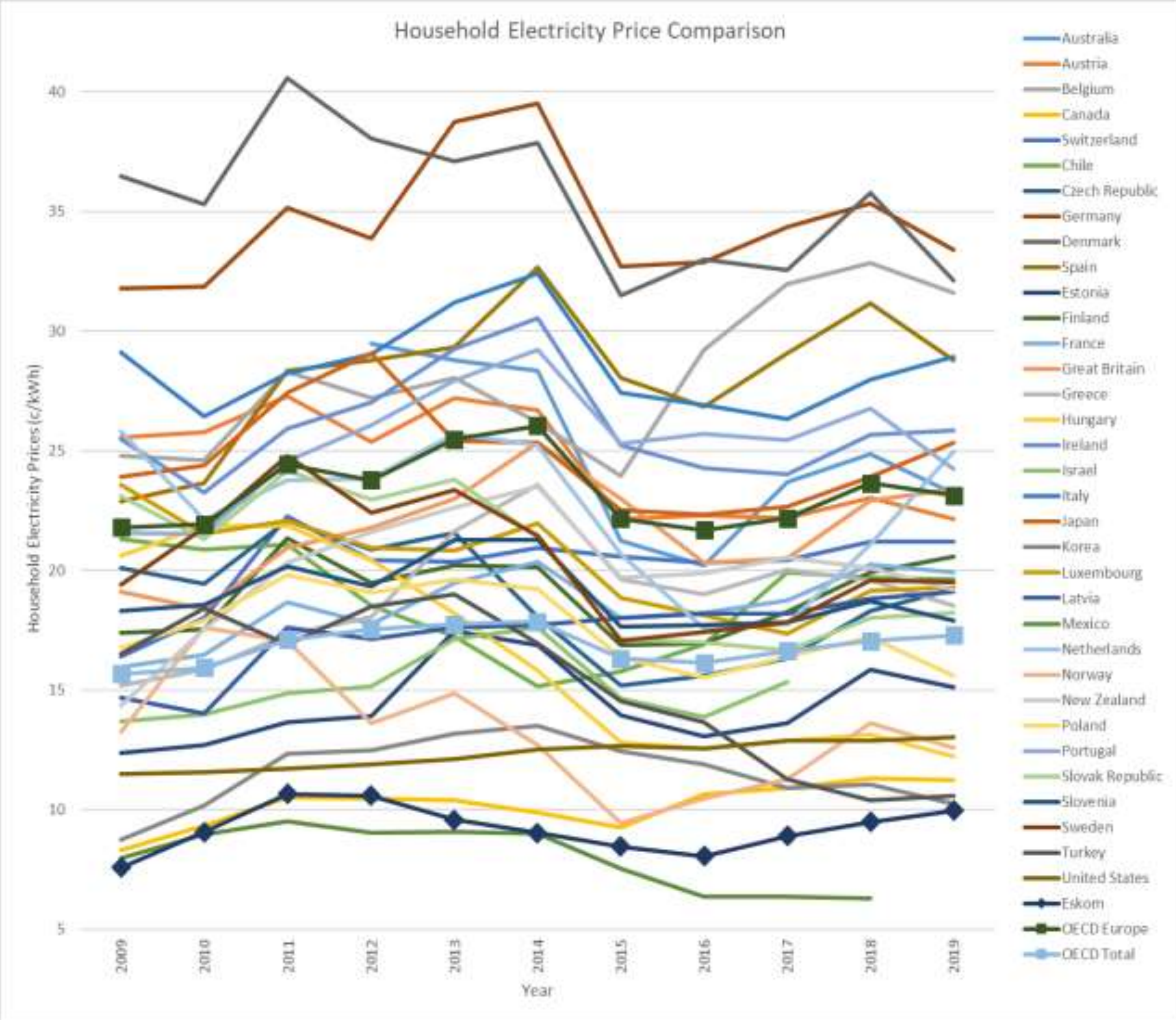


FIGURE 41: HOUSEHOLD ELECTRICITY PRICE COMPARISON WITH 36 IEA COUNTRIES (WITH ESKOM ANALYSIS)



25.11.6 Conclusion on various electricity price comparisons

Eskom has reviewed several local and international data sources and studies comparing Eskom's electricity prices to international benchmarks. The available body of work conducted by several local and international companies and organisations, all independent of Eskom. The results presented are self-explanatory and the conclusions reached across the board benchmarking Eskom's prices conclude that Eskom's overall and per sector tariffs are either competitive or low by international standards.

Eskom's price in most instances have been found to be lower than most other comparators. A distinction needs to be drawn between the **price** of electricity (which is determined by NERSA) and the **cost** of producing the electricity. Eskom. Like any other company continues to strive to improve its efficiencies. NERSA, when it makes a legitimate decision, will only allow for revenue related to efficient costs to be passed through to consumers for recovery from the tariff. NERSA in its reasons for decisions, like any other regulator, will demonstrate how it arrived at this efficient level. Any inefficiencies will not be passed through to the consumer. It is unfortunate that Eskom was one of the key entities that experienced the impact of state capture. These are now being addressed. As guided by NERSA in a previous decision, Eskom has committed to ensuring that any proceeds recovered from incidents of sate capture are allowed to flow through the RCA for the benefit of the consumer. Thus when NERSA makes revenue and RCA decisions, it only allows for the consumer to be liable for efficient costs. Thus, Eskom applies for efficient costs, NERSA uses its benchmarks and analysis to interrogate these applications, to make a decision that sets a level of efficiency. Thus NERSA is empowered to make these decisions and is required to provide meaningful reasons for its decisions.

What these comparators indicate is that Eskom cannot be more special than the majority of producers of electricity. The efficient cost of electricity, for similar technologies, will be the same – whether Eskom produces it or another utility in another country produces it. This is the challenge that Eskom is dealing with presently. By making revenue applications, Eskom is trying to reach the stage where it will reach a level of electricity pricing that only covers the efficient and prudent costs.

26 Impact on consumers of Municipal price increases

(i) Impact on consumers of Municipal price increases approved by NERSA

A study “Shedding light on Eskom” was undertaken by Primaresearch and published on 2 August 2019. Amongst other matters, it addresses the approach to increases to Municipal tariffs, as approved by NERSA. An extract of the report is shown below.

“Municipal margins may have capitalised on tariff increases”

Eskom provides bulk electricity to municipalities who then on-sell it to their customers with some profit margin. Municipalities add a percentage markup to the bulk purchases to cover their costs. However, the issues at Eskom resulted in substantial tariff increases (CAGR of 14.4% over the past ten years), which if passed on to the consumer with a markup, would boost the gross margin earned by municipalities. The expense base of municipalities should be unaffected by the issues at Eskom and should increase at a much lower rate (perhaps at a rate closer to inflation), which in turn could result in excess profits earned by the municipalities (referred to as surplus in municipal accounts).

In the case of the City of Cape Town, electricity revenue increased by 13.1% CAGR over the past ten years, while bulk purchases from Eskom increased by 15.2% p.a. The municipality “absorbed” some of the tariff increases, but still managed to grow gross profit on electricity services by a strong 9.9% CAGR over the ten years. The city has done well to contain its cost growth to 2.9% p.a. and consequently managed to increase its net surplus (profit) from R87m in 2008 to R2.2bn in 2018 (increasing its net margin from 2.5% to 18.6%). Whereas the provision of electricity services could previously be considered to have been a cost centre aiming to breakeven, it has now transformed into a strong profit generator for the municipality. We estimate that the excess profit may have amounted to R1.5bn to R1.9bn p.a. over the past three years (if the net margin was kept at the 2008 level of 2.5%). Even adjusting for normalised expense growth at 7% p.a., the City of Cape Town still generated excess profits over R1bn p.a. over the past 3 years, by our estimates.

In the City of Johannesburg (City Power), revenue increased by 12.9% CAGR of the past ten years, while bulk purchases from Eskom grew by 14.0% p.a. Gross profits also increased strongly by 10.6% CAGR over this period. However, City Power’s expenses have grown by 13.2% p.a. which resulted in net losses for the past two years. We think the high growth in expenses is a management issue and the more than doubling of gross profit from R1.8bn to R3.8bn provided the municipality with an opportunity to fund the expansion of its cost structure.

Regardless, we estimate that excess profits ranging from R900m to R1.8bn may have been earned, which were channeled to its growing cost base.

In the City of Tshwane (Pretoria), the net margin from Electricity services increased from 2.5% (R90.2m) in 2009 to 13.2% (R1.5bn) in 2018.

We estimate the potential excess profits made by all municipalities in South Africa. This analysis shows that in 2018, the excess profits across all municipalities may have amounted to R8.5bn.

In summary, we think some municipalities may have benefitted from the rising electricity tariff increases, which were unduly borne by consumers. We estimate the excess profits made by the municipalities over the past ten years could have amounted to c. R46bn (of which Cape Town and Johannesburg could account for c. R20bn)."

27 National Treasury and SALGA responses

27.1 Summary of key responses provided to comments by National Treasury as part of consultation process for the MYPD5 revenue application

27.1.1 Policy decisions by DMRE on structure of industry

National Treasury recognises that there is a need for the Department of Mineral Resources and Energy (DMRE) to review and develop the energy sector in South Africa which will outline future energy structure and the end-game state.

This is a policy decision for the DMRE to make.

27.1.2 Eskom requires sufficient revenue

One of the key challenges is the achievement of sufficient revenue, since it is a factor that drives the levels of investment in capital expenditure programme (capex) and maintenance to improve plant performance as well as financial health and liquidity position of Eskom. Eskom has been dependent on borrowings and shareholder support to remain a going concern and the missing link has been the tariffs that cover the efficiently incurred costs and allowing for a fair return on assets.

Eskom is making this MYPD5 revenue application in accordance with the requirements of the Electricity Regulation Act with a proviso of migrating towards a fair return on assets.

27.1.3 Eskom's inability to supply electricity impacts economic growth

The country's demand for electricity (although declining) exceeds Eskom's ability to supply electricity. The power system has come under severe strain due to maintenance backlogs and a failure to bring new generating capacity online timeously to match economic and social development. The inability of South Africa to service its electricity needs has led to downward revisions of economic growth and investor confidence in the economy in recent years. These supply constraints have increasingly become stumbling blocks to successful economic development.

Eskom acknowledges that a reliable electricity system will contribute towards the economic growth in the country. However, the situation that South Africa finds itself is due to a complexity of issues. The key factors included severe financial constraints and timeous capacity decisions not being made. There are numerous contributing factors to the performance of Eskom's generation fleet, the root cause goes back to the late 1990's. Eskom 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. 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. 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. Eskom'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, Eskom's lowest quartile was "run harder" than the top quartile of the benchmark stations.

27.1.4 Balance the impact of electricity price increases with the financial sustainability of Eskom

There continues to be a need to strike the delicate balance between the negative socio-economic impacts of the increases, especially in the context of the current global economic environment, whilst simultaneously ensuring a financially sustainable electricity industry. This will enable the necessary investments to be undertaken to augment and maintain the country's generation capacity so as to avoid load shedding. Hence, it is important that projections are as accurate as possible to ensure the right revenue is allowed to enable Eskom to remain financially sustainable. In the long run, cost reflective tariffs including the cost of negative externalities associated with electricity supply, will ensure more efficient use of electricity and allocation of resources in the economy and will raise economic growth rates over time. Correct pricing will also help stimulate investment in more efficient and less environmentally damaging production methods.

Eskom understands that a delicate balance needs to be struck. That is precisely the reason that in the MYPD5 application, Eskom continues to request a return on assets that migrates towards a cost reflective level. Efficient costs do not go away. Thus is costs are not recovered from the tariff, imposes debt or the fiscus. This implies that if the consumer does not pay, then the taxpayer continues to subsidise the electricity consumer. It is submitted that Eskom is making efforts to find further efficiencies in its operations, recover Municipal debt and address matters related to fraud and corruption. Eskom hopes to be in a position to recover its debt commitments through the depreciation and ROA within two years of the MYPD5 period. In addition, as pointed out by National Treasury, RCA decisions (to be made by NERSA) and implementation of court processes will also contribute towards the payment of debt commitments.

Eskom applies for efficient costs in accordance with the MYPD methodology. Detailed motivations are provided for each aspect of the revenue application. NERSA will undertake its own benchmark analysis before making a determination.

27.1.5 NERSA to apply its MYPD methodology

National Treasury is aware that Eskom's revenue application for MYPD5 is made at a time where there have been ongoing legal challenges between Eskom and NERSA over the regulator's decision on MYPD4 including the decision to deduct the R23bn Government equity, which was overturned by the High Court. National Treasury understand that revenue collection is crucial in improving Eskom's liquidity position and long-term sustainability. Therefore, it is important that NERSA appropriately apply its MYPD methodology and other applicable rules to ensure that Eskom is able to recover prudently and efficiently incurred costs for running its regulated business. This will pave a way towards Eskom becoming self-reliant and lessening the burden on the fiscus which is extremely constrained.

Eskom is in agreement.

27.1.6 NERSA to make a timeous MYPD5 decision to meet Municipal budgeting process

Eskom estimates that NERSA will make the decision on the entity's application for revenue and price adjustment by December 2021 to facilitate Municipal budgeting processes, after following its consultation process which includes public hearings that will be undertaken in all Provinces. It is also during December each year that National Treasury usually publishes guidelines for Municipalities to budget timeously for electricity cost adjustments.

Further, the NERSA decision is expected to be made in time to allow for the tabling of the decision in Parliament by 15 March 2022 for implementation on 1 July 2022 as required in terms of the MFMA. Section 42 of the MFMA requires that the Minister of Public Enterprises must table in Parliament the *amendment to the bulk electricity tariff on or before 15 March for the amendment to take effect from 1 July in municipalities.*

Eskom notes the National Treasury requirements.

27.1.7 Sales volume growth is necessary for sustainability of the industry

While National Treasury generally supports the move towards cost reflectivity, the continued reliance on tariff increases as a source of revenue growth whilst not addressing sales volume growth presents a considerable sustainability risk for the business.

Eskom supports that increase in sales would be beneficial. However, it needs to be noted the shortfall in revenue will require a significant increase in sales that are completely dependent on economic development in the country. With respect to demand or sales growth and its drivers, Eskom had commissioned numerous studies by external independent professional consulting economists. The basic outcome has consistently been that the dominant factors and drivers of electricity demand and thus sales volume have been overall national economic growth; commodity prices; structural changes to the economy (e.g. reduction of mining and manufacturing and growth in services), technological changes, population growth, weather patterns, electricity intensity levels. The policy drivers of the country on investment choices have been found to be paramount. From an electricity perspective, customers require a long-term price path (price stability), reliability of supply (availability), a reliable supply, and competitive pricing (level). Other operational factors that impact sales of electricity in South Africa include

- Low economic growth internationally – no markets for products (stockpiling).
- Commodity market volatility, particularly in gold, platinum, and ferrochrome.
- Rapid evolution of technology development in the energy industry
- Some of the large power user customers having been liquidated or applied for business rescue due to financial vulnerability and low competitiveness in their sectors
- Some industries that have shut down operations and relocated to Asia due to incentives offered in those countries
- Voluntary contribution to the energy reduction strategies during load shedding accelerated energy efficiency and self-reliance.
- Opting to export un-beneficiated ore due to high market prices.
- Labour costs and relationships
- Reliability and cost of logistics

Eskom has a role to play in contributing to the reliability of supply. Key constraint in this arena, that the industry is still grappling with include the implementation of policy decisions timeously, financial constraints – which results in having to make difficult choices and ensuring the availability of skills. This has been defined as a key focus area for the Eskom Generation, Transmission and Distribution licensees and details are included in this MYPD5 submission.

27.1.8 Impact on Municipalities and residential customers

Municipalities continue to raise concerns on how Eskom's continuous tariff increases impact their financial performance as they seek to buffer the impact of Eskom increases by not passing on the full impact of the bulk increase burden to their customers. In the last seven years, the number of municipalities in financial distress has more than doubled from 66 to 163, and close to 50 of all municipalities were in financial distress pre-COVID 19, add now the impact of COVID 19 on municipal customers, the impact on municipal budgets is likely to be catastrophic. Hence, there is a risk that municipalities may look towards cheaper alternative electricity sources in an effort to reduce operating costs. Moreover, the unreliability of the system (blackouts) also presents a dilemma for municipalities as there is a growing number of high-income customers moving off the grid, thereby compromising the cross-subsidisation principle that has kept municipalities afloat. In addition, during public hearings on MYPD4, several rural communities and their representatives also raised concerns on the increasing electricity tariffs having the biggest socio-economic impact on the poor, as it contributes to increase crime levels and poverty in these communities.

NERSA makes one decision to determine the average price increase applicable to Eskom. However, two sequential decisions are made with regards to the Municipal average price increase. First, Eskom's average price increase is determined and this informs the Municipal input price that accounts for approximately 75% of the benchmark price determined by NERSA

The second step involves NERSA developing a guideline price adjustment for its different categories of Municipalities. Municipal tariffs are then then approved by NERSA. In addition, certain Municipalities also include additional service charges in their end-customer electricity prices.

These processes ensures that Municipalities can recover the bulk price of electricity. It is submitted that the reasons for the Municipal debt is more complex and related to many other factors. Eskom is working with various stakeholders to address this complex challenge. Similarly, the challenges with Soweto debt is being addressed through various processes.

The DMRE and NERSA ensure that the poor residential customer is protected from the brunt of price increases – by free basic electricity, inclining block tariffs and cross subsidies to minimise residential tariffs to indigent residents.

27.1.9 Primary energy clarification

National Treasury requests further Primary energy information to be included in the MYPD5 submission to NERSA. The focus being on coal and OCGT and IPPs.

Eskom supports such a request and these details will be provided.

27.1.10 RCA and court outcomes

National Treasury requests that NERSA processes RCA applications and implements court decisions. These need to be tempered with the phasing-in towards cost reflectivity and lessening the burden on the state.

Eskom supports this approach.

27.1.11 Operating costs to be as determined by NERSA

National Treasury requests that Eskom keep to employee benefit costs determined by NERSA, since cannot be addressed by the RCA methodology.

The regulatory environment makes provision for the differences between the decision and the actuals to be managed through the Regulatory Clearing Account (RCA). This is the mechanism that Eskom uses to manage the actual revenue compared to the NERSA decision.

The RCA is part of the overall MYPD Methodology, where it is confirmed that the RCA is intended to mitigate and manage the risk of excess or inadequate returns, and further that it does so by adjusting regulated revenue. It further sets out that the costs and cost variances (to be recovered through such revenue adjustment) will be assessed for prudency.

There is a direct link between MYPD decisions and RCA applications where risks are managed in RCA applications. In the event that a significant risk is passed onto Eskom at the stage of a revenue decision, the impact would likely materialise in a RCA application.

Thus the consumer is protected from the risk at an initial stage during the revenue determination. Variances in RCA applications are linked to two key sources:

- Variances in costs and other influences due to a changing environment and assumptions that materialise after the MYPD decision;
- Assumptions made during the MYPD revenue decision which do not materialise.

The RCA mechanism exists to manage the differences between the NERSA Revenue Determination and the actuals that materialise and hence the notion that Eskom must strictly operate within the confines of the NERSA Revenue Determination is misplaced. NERSA, during the assessment of the RCA applications as per the MYPD Methodology, has an opportunity to assess the costs and cost variances (to be recovered through such revenue adjustment) for prudency.

As is evident from the recent Court Judgements on the Eskom Boards review of the RCA Decisions by NERSA, the decisions made by NERSA were found not to be rational and it was found that there were fundamental factual errors. The Judgement accepts that Eskom had put forward a proper case for relief in those key areas where NERSA did not implement its methodology and precedents. It is thus imperative that NERSA implements its methodology as this would go a long way towards ensuring not only the sustainability of Eskom, but the entire industry as well.

In addition, the following extracts from an answering affidavit deposed by Mr Gumede, representing NERSA as the Full Time Regulator Member, primarily responsible for Electricity, clarifies Eskom's response:

Extract of paragraphs from NERSA's Answering Affidavit, Case No: 21896/2020 (the judicial review of NERSA's decision regarding Eskom's RCA application for FY2018-19):

"*6. NERSA is responsible for regulating electricity prices and tariffs. NERSA is empowered by legislation to develop a methodology or guide for it to do so.*
7. NERSA has developed a methodology to guide its application of the broad principles in its electricity pricing determinations, known as the Multi-Year Price Determination ("MYPD") Methodology ("the methodology").
12. The decision or determination in the context of the MYPD process:
12.4. takes place in two steps:
12.4.1. firstly, NERSA makes a provision of Eskom's AR by forecasting its efficiently incurred costs and reasonable return. This is owing to the fact that the price of electricity is determined in advance (before Eskom incurs expenses for that financial year and before the public makes use of the electricity). This forecast is not a restriction on what Eskom can spend in that financial year. It is a restriction on what Eskom can recover from the public during the financial year; and

12.4.2. secondly, the final determination of Eskom's AR takes place when the actual expenditure is available and NERSA is able to test it for prudency and efficiency through the Risk Management Control & Pass -Through Mechanism process, commonly referred to as the RCA process.

14. The analysis of the application involves:

14.4. An entirely fresh assessment of prudency and efficiency that takes place at the RCA stage. This is done on audited financials with information NERSA prescribes in the methodology.

14.5. NERSA making a decision on Eskom's allowable revenue only once the final actual costs have been assessed for prudency and efficiency. It is this decision that ought to permit Eskom to recover its efficiently and prudently incurred costs and the reasonable return."

27.2 Summary of SALGA responses related to the MYPD5 Revenue Application

27.2.1 Sales forecast

Electricity sales in municipalities and even Eskom show a sustained downward trend over the last years and in some cases have dropped significantly.

This trend is noted

27.2.2 Municipal electricity purchasing model

SALGA notes that unfortunately the model of bulk purchases from Eskom and selling kilowatt hours to customers is no longer a profitable and sustainable within the current economic landscape. It is for this reason that SALGA supports municipalities the energy policy that enables the energy transition and new business models such as building own clean generation, partnerships with private sector and purchasing from Independent Power Producers.

Supported

27.2.3 Unit cost comparison

SALGA compares the increase in unit IPP price increases to those of Eskom generation at an average level. Further information in this regard is requested to be submitted to NERSA

Eskom is committed to ensuring that it provides all the detailed information to NERSA to enable it to undertake the required analysis. There are a mixture of technologies in both the IPPs as well as Eskom – thus a comparison of averages does not always provide a true reflection of the underlying trends. It is submitted that IPPs are in a position to recover their full efficient costs and a fair return. However, Eskom is still migrating towards this level.

27.2.4 Trend in employee numbers

Decisive evidence of workforce optimisation and benchmark comparisons is required for submission to NERSA.

Details to this effect will be provided in the submissions to NERSA for each of the licensees.

27.2.5 Depreciation

Further details on each licensees' depreciation is requested to be included in submission to NERSA and evidence of decommissioned assets being removed from depreciation calculations is required.

This will be provided in submission to NERSA.

27.2.6 EEDSM is required

Energy efficiency and demand side management is a central feature of a utility of the future. The piece written in this MYPD on the need for integrated demand management lacks conviction and no evidence of investment in EEDSM is presented.

Further concrete details will be provided in the submission to NERSA

27.2.7 Carbon tax

It would be sensible to group the Carbon tax with primary energy coal costs since coal is responsible for the overwhelming majority of Eskom's emissions. It is also not really an 'externally imposed cost' but a cost that requires the licensee to adopt a responsive business plan.

It is maintained that Eskom has minimal control of the carbon tax, IPP costs and environmental levy. Eskom is not in a position to change these contributions to the allowable revenue required. Eskom is required to implement Government decisions on these matters.

27.2.8 Economic impact comparisons

The view that metros/municipalities made 'windfall profits' by capitalising of Eskom's tariff increases in earlier years. In effect, Eskom is implying that municipalities should absorb some of these costs in order to reduce the impact on the final customer. Comparing electricity prices is not a reason to increase prices.

Economic impact studies were undertaken by various parties. Research undertaken by Primaresearch indicates this “windfall” related to the premiums charged by certain Municipalities. The purpose of including this aspect is for comparison of final prices seen by customers.

It is accepted that the purpose of comparison of electricity prices in various jurisdictions is to benchmark Eskom and South African electricity prices. The complexity of comparisons is noted. Many industries wish to make investment decision based on various criteria, electricity prices being one of these.

28 Revenue requirements for licensees

Eskom's allowable revenue requirement comprises that of Generation, Transmission and Distribution businesses. Generation contributes about 84% of the allowable revenue with the networks making up the balance.

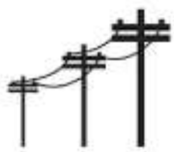
28.1 Generation allowable revenue

Generation revenue requirement over the three year application period is R826bn. Generation own primary energy is approximately R243bn, local IPPs adds R257bn, international purchases of R15bn, levies and taxes of R42bn. The operating expenditure is approximately R105bn. Debt commitments are covered through depreciation and returns of approximately R166bn over the three year application period.

TABLE 28 : GENERATION ALLOWABLE REVENUE

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**

28.2 Distribution allowable revenue

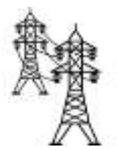


Distribution revenue requirement is R116bn over the three year application period. This covers operating expenditure of R94bn, which is inclusive of arrear debt. Debt commitments are covered through depreciation and returns of approximately R23bn.

TABLE 29 : DISTRIBUTION ALLOWABLE REVENUE

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		134 849	139 596	142 534	145 107	146 059
WACC %	ROA	X	-1.99%	0.69%	0.87%	1.65%	3.04%
Returns			(2 685)	966	1 244	2 387	4 433
Primary energy	PE	+	13	13	14	15	15
International purchases	PE	+	-	-	-	-	-
IPPs	PE	+	-	-	-	-	-
Environmental levy	L&T	+	-	-	-	-	-
Carbon tax	L&T	+	-	-	-	-	-
Arrear debt	E	+	5 666	6 511	7 110	7 802	8 541
Operating costs	E	+	23 966	25 090	26 044	27 256	28 844
Research and Development	R&D	+	-	-	-	-	-
Depreciation	D	+	7 397	7 539	7 426	7 548	7 735
MYPD5 Allowable revenue			**34 357**	**40 119**	**41 839**	**45 007**	**49 568**
Approved RCA's for liquidation	RCA		2 955	-	-	-	-
MYPD5 Allowable revenue including RCAs	R'm		**37 312**	**40 119**	**41 839**	**45 007**	**49 568**

28.3 Transmission allowable revenue



Transmission external revenue requirement over the three year period is R36bn covering expenditure of approximately R17bn. Debt commitments are covered through depreciation and returns of approximately R20bn.

TABLE 30 : TRANSMISSION ALLOWABLE REVENUE

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		126 225	133 217	139 777	147 568	159 405
WACC %	ROA	X	-1.99%	0.69%	0.87%	1.65%	3.04%
Returns			(2 513)	922	1 220	2 427	4 838
Primary energy	PE	+	-	-	-	-	-
International purchases	PE	+	-	-	-	-	-
IPPs	PE	+	-	-	-	-	-
Environmental levy	L&T	+	-	-	-	-	-
Carbon tax	L&T	+	-	-	-	-	-
Arrear debt	E	+	-	-	-	-	-
Operating costs	E	+	5 349	5 678	5 741	6 071	6 441
Research and Development[1]	R&D	+	-	-	-	-	-
Depreciation	D	+	6 334	6 634	6 919	7 059	7 398
MYPD5 Allowable revenue			**9 170**	**13 234**	**13 880**	**15 557**	**18 677**
Approved RCA's for liquidation	RCA		609	-	-	-	-
MYPD5 Allowable revenue including RCAs	R'm		**9 779**	**13 234**	**13 880**	**15 557**	**18 677**

Note that this represents external costs and excludes technical losses and ancillary costs.

29 Conclusion

This Multi-Year Price Determination (MYPD) 5 revenue application is for FY2023 to FY2025. This revenue application has been prepared in accordance with the MYPD methodology as published by NERSA during October 2016. The NERSA revenue and tariff decisions will be implemented from 1 April 2022 for non-municipal customers and from 1 July 2022 for municipal customers. The previous revenue application was for a three year period and was implemented for the period from 1 April 2019 to 31 March 2022 for non-municipal customers; and 1 July 2019 to 30 June 2022 for municipal customers.

Eskom makes this revenue application, as it still migrates to a level that reflects to the efficient cost of providing the electricity service. This has been a journey that Eskom and NERSA have been on for many years. Thus the average price of electricity still does not cover the full efficient costs and cost of capital that are incurred. The implication is that all electricity consumers have been receiving a subsidy and will continue to do so during this application period.

(i) Eskom costs have stablilised

Eskom has achieved a status in the MYPD5 application where it's operating costs and the Eskom primary energy costs have stabilised to approximately 5% CAGR for the application period. This is mainly due to production volumes from Eskom decreasing with a moderate increase in the cost of most primary energy components under Eskom's control. This indicates the level of control Eskom has instituted to reach such a status. Similar trends have been observed for operating costs even in the MYPD4 period.

(ii) However, increases for IPP and Carbon tax are significant

More than half the increases in the three years are due to IPP, environmental levy and carbon tax costs. These are costs that Eskom has no control over. The compounded annual growth rate (CAGR) for IPP costs of 46% is seen over the three year application period. This is due mainly to increases in energy sourced from IPPs. The total energy secured from IPPs increases from a projection of 20TWh in FY2022 to approximately 53TWh by FY2025. Increases in existing contracts, usually in the region of CPI, occur as well. From January 2023, environmental levy and carbon tax costs consumers over 8.5c/kWh.

(iii) Phase-in of return on assets allows to cushion impact on electricity consumers

In order to limit the revenue requirement and therefore the electricity price impact, Eskom has further phased the migration towards cost reflectivity to allow only for the combination of depreciation and return on assets related revenue to significantly address the debt service commitment requirements. A cash shortfall of approximately R29bn relating to debt service commitments still manifests over the application period. This is a significant extension being made by Eskom in a bid to allow for the economy and customers to benefit through this phased approach.

(iv) Indicative price increases

The indicative price increases for the period is 20.5% (FY2023), 15.07% (FY2024) and 10% (FY2025). The Government and NERSA provide protection from the price increases to poor residential customers through various support mechanisms including subsidised electrification, 50kWh free basic electricity per month, subsidised increases and the inclining block tariff. The frameworks for short term and long term negotiated pricing agreements provide support to identified industrial sectors to meet particular Government economic priorities. These frameworks are in the process of being implemented by NERSA.

(v) Eskom requires reasonable tariff increases to address financial sustainability and liquidity challenges

Liquidity and solvency risks pose an inordinate threat to Eskom's ability to continue as a going concern. To improve liquidity, we have restricted organisational cash requirements through targeted savings. We had to rely on Government support to maintain a positive cash balance, with increases in equity. Due to high debt servicing obligations, maintaining the liquidity buffer at acceptable levels continues to be a challenge. Although Government's equity support assists with liquidity requirements, it does not adequately enhance our long-term financial sustainability. The only way to achieve financial sustainability is to improve operating cash flows that results in positive free cash flows, with a strong focus on moving to a prudent, cost-reflective tariff. Without a cost-reflective tariff path, we will remain reliant on Government support, which implies that the taxpayer will continue to foot the bill for the revenue shortfall, which is contrary to the "user pays" principle.

As directed by NERSA, Eskom will address any recovery of funds related to any corrupt activity through a refund in the RCA applications. Thus the consumer is only migrating towards paying for the recovery of the efficient cost of electricity

(vi) Economic impact are best managed by continuing to migrate towards cost reflective prices of electricity

It may be tempting to conclude that by limiting electricity tariff increases and requiring that Eskom and/or government borrow the revenue shortfall (and effectively implicitly subsidise the price), it is possible to minimise the negative impacts of rising electricity prices on GDP and employment growth in the short-term. However, the results of the economy-wide impact analysis show that the fiscal and economic consequences of awarding Eskom a tariff that is much lower than what it requires (to recover its prudently and efficiently incurred costs), do eventually (and arguably have now) become evident.

(vii) NERSA to make a decision in accordance with its mandate

Eskom is dependent on NERSA making revenue and tariff decisions in accordance with its mandate, policy and relevant legislation. It is hoped that NERSA will consider the impact on the consumers as well as and the sustainability of Eskom in making its determination. This revenue application of over R900bn requires a thorough analysis by the Energy Regulator and reasons for decision that are well supported by facts and reasoning in terms of the MYPD methodology and other guiding legislation and regulations.