Distribution Licensee (Dx)

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

Submission to NERSA

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1 Executive Summary

1.1 Introduction

This document details the Distribution Licensee revenue application for the FY2023 to FY2025 setting out key challenges and revenue requirements. This application for the Distribution License of Eskom Holdings Ltd (herein after referred to as the Licensee) is to be read in conjunction with the submissions of the other Eskom licensees.

The Licensee application supports the Eskom mission to provide sustainable electricity solutions to promote economic growth and social prosperity for South Africans. This is achieved through operating the distribution network to supply electricity to customers in its area of supply as specified within the Distribution licence. This supports the right of entry to third parties such as Independent Power Producers (IPPs) to the Distribution network for the distribution of power.

The Licensee application for the MYPD5 control period is prepared as per the prescribed MYPD methodology. The table below summarises the efficient revenue being applied for in the MYPD5 period. NERSA has already determined that in addition to the MYPD5 revenue determination, previous RCA determinations of R2 955m will be recovered in FY2023.

TABLE 1: DISTRIBUTION FY2023 – FY2025 REVENUE REQUIREMENT (R'M)

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**

Note: Research and Development revenue requirement is included in operating costs

The Licensee will respond to a changing market conditions by:

- Stimulating local demand by engaging customers to maintain and grow existing sales.
- Grow the market by attracting new customers and incentivise large customers to invest in the country.

The Licensee intends to optimally manage all costs. This is planned to be achieved through:

- Prioritising capital investments to build assets that support network performance in order to deliver reliable network performance.
- Ensuring adequate maintenance spend in support of regulatory compliance.
- Ensuring accurate and timeous billing of customers for sustainable revenue streams.
- Optimising manpower cost while maintaining the critical and scare skills required for operations.

The salient factors that underpin the requested Distribution licensee revenue requirement are sales volumes, return on assets, maintenance, employment benefit cost, impairment and other cost.

1.2 Sales volumes

Eskom's sales have declined over the past 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. A significant decline is attributed to large power users as a result of high ore extraction costs and volatile commodity markets, particularly in the ferrochrome, steel, gold and platinum industries. During the MYPD5 period the decrease in sales is anticipated primarily from exports and standard tariffs. Eskom's projected compounded average growth rate (CAGR) is -0.5% for the MYPD5 period while the average annual growth rate (AAGR) of 0.043%. The forecast sales volumes are detailed in the table below.

TABLE 2: SALES FORECAST VOLUMES (GWH)

Sales Volume (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Standard customers	180 868	168 529	172 656	171 549	171 440	170 370	170 141	169 476
NPA	10 118	9 755	9 722	10 282	10 311	10 282	10 282	10 282
Total LOCAL sales	**190 986**	**178 284**	**182 379**	**181 831**	**181 751**	**180 652**	**180 424**	**179 758**
International (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
Total Eskom sales	**206 081**	**191 174**	**194 433**	**193 579**	**192 627**	**191 467**	**191 238**	**190 573**

1.3 Return on Assets

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

The MYPD5 RAB values as are based on an independent asset valuation study as well as the planned capital expenditure. These capital investments are required to strengthen and expand the grid to connect new loads, generation sources and to replace assets which have reached the end of their technical life.

The RAB value increases over the MYPD5 period as new assets are brought into commercial operation and planned projects investments are incurred. Distribution capital investment requirements for FY2023 – FY2025 are included in the table below.

TABLE 3: ACTUAL AND PLANNED CAPITAL INVESTMENTS (R'M)

Capital expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Direct Customers	1 003	931	1 099	1 282	1 235	1 384	1 539	1 601
Strengthening	962	947	1 667	1 857	2 236	2 193	2 569	2 747
Refurbishment	457	451	990	1 424	1 208	1 868	1 311	1 400
Land & Rights	9	15	53	39	41	59	124	134
IPP Connections	55	61	71	430	730	1 030	1 215	1 015
Asset Purchases	157	230	298	564	678	492	126	128
BESS project	-	-	4 281	3 247	4 524	2 074	1 139	-
Eskom funded	**2 643**	**2 635**	**8 459**	**8 843**	**10 652**	**9 100**	**8 023**	**7 025**
DMRE Funded	2 432	2 691	2 339	3 013	3 165	3 323	3 489	3 663
Total capex	**5 075**	**5 326**	**10 798**	**11 856**	**13 817**	**12 423**	**11 512**	**10 688**

1.4 Operating Expenditure

Operating expenditure includes all costs involved with the day-to-day running of the business. Distribution's operating expenditure includes employee costs, maintenance and other expenses. The compound average growth rate (CAGR) for the period FY2023 – FY2025 for operating costs is 3.8%, which is below expected inflation.

The CAGR for the period FY2023 – FY2025 for employee expenses is 3.5%, which is below projected inflation. In alignment with cost reduction objectives, the Distribution headcount will be contained over the planning period as outlined in the table below.

TABLE 4: DISTRIBUTION EMPLOYEE EXPENSES (R'M) AND HEADCOUNT

Employees expenses	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses (R'm)	11 414	11 560	11 862	12 032	12 545	13 158	13 827	14 699
Head count	17 453	17 594	17 604	17 520	17 422	17 314	17 714	17 714

The CAGR for the period FY2022 to FY2025 for maintenance and other operating costs, is 5.1% and 5.6% respectively.

1.5 Depreciation

Depreciation allows the Licensee to incrementally recover the principal of the capital invested in its assets over their lifetime. The asset valuation is aligned with the MYPD Methodology, which requires the use of an asset valuation methodology that accurately reflects replacement value using the MEAV technique. The depreciation reflected in the table below was calculated based on the asset valuation study conclusions as well as considering new asset investments planned for transfer to commercial operation.

TABLE 5: REGULATORY ASSET BASE AND DEPRECIATION (R'M)

Regulatory Asset Base and depreciation (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulatory Asset Base	90 853	89 917	134 849	139 596	142 534	145 107	146 059
Depreciation	7 617	8 335	7 397	7 539	7 426	7 548	7 735

1.6 Arrear debt - Impairment costs

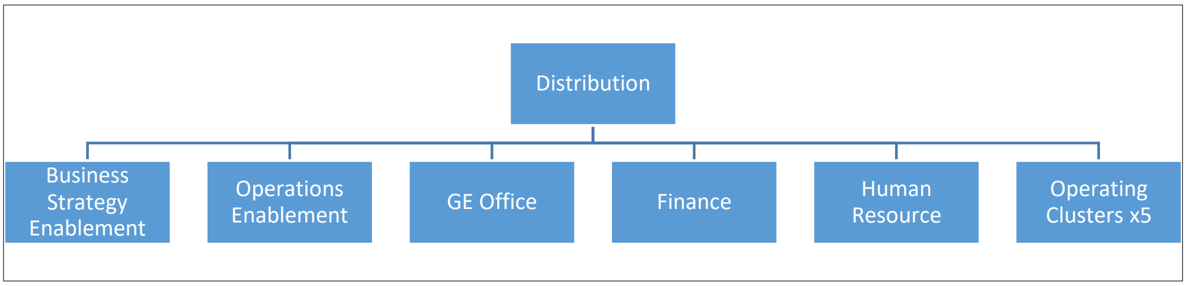
While the licensee records good payment from large industrial, commercial and major metropolitan customers, however there are areas of major concern regarding residential and municipal debt. Municipal overdue debt has increased significantly in the past few years and remains a concern.

In this application Eskom has limited the impairment to 2% of revenue despite the fact that our current actuals are closer to 4%. The 2% impairment implies a payment level of 98% of all billed revenue including interest. The 2% impairment will cater for credit losses incurred as a result of liquidated business; as well as non-payment by certain customer groups.

2 Distribution Licensee context

This section describes the role and responsibilities of the Distribution Licensee. The Licensee, distributes and supply electricity to customers in its supply areas by operating the network, as specified in the Distribution License granted by the National Energy Regulator of South Africa (NERSA). Distribution Licensee operating structure is reflected on the Figure below.

FIGURE 1: REPRESENTATION OF THE DISTRIBUTION LICNSEE ORGANISATION



The Licensee's mandate is to enable economic growth by harnessing employee expertise to provide reliable energy and related services to our customers by building, operating, and maintaining assets in a financially sustainable manner. The operating clusters are a result of an amalgamation of certain provincial operating units. Key to a sustainable Distribution business will be to focus on the following strategies:

- Sustain sales
- Intensify revenue collection efforts
- Reduce energy losses
- Improve network performance
- Enhance customer experience

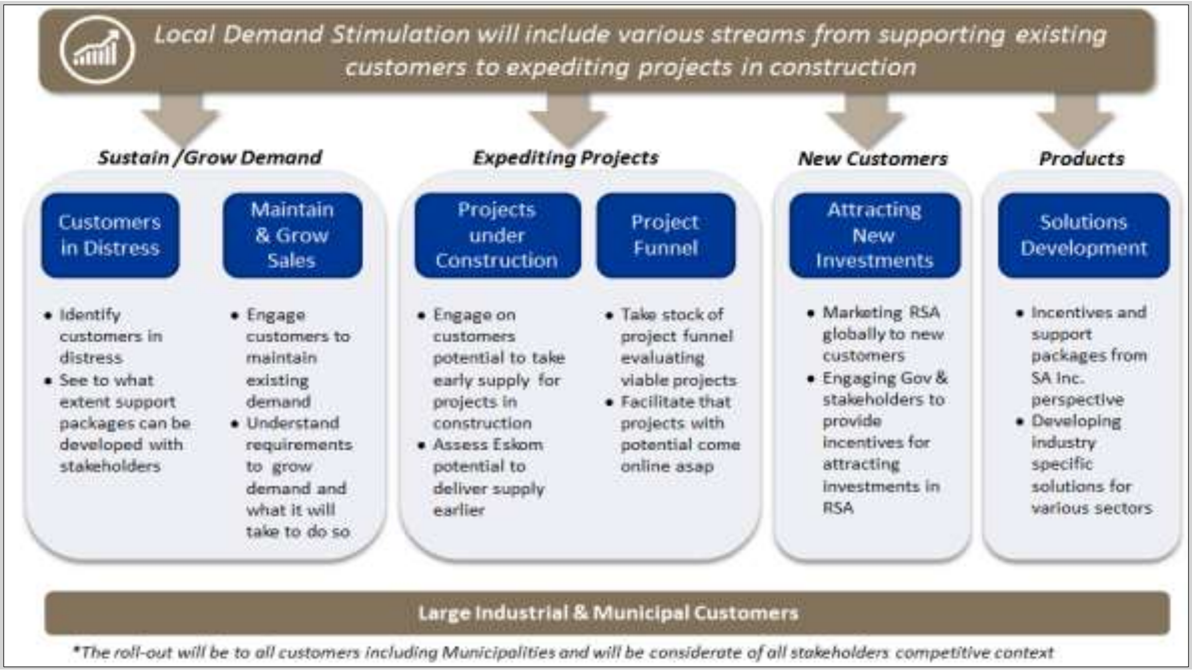
2.1 Sales growth initiatives

Eskom sales volumes have been on the decline due to constrained economic conditions, systems constraints, perceived high prices and customer energy usage optimization and migration. The global economic impact from the Pandemic has exacerbated the downward trend and recovery is expected over many years to come, albeit it being slow. Internal IDM initiatives has also accelerated energy efficiency among customers. Municipal and other sectors anticipated to take slightly longer to recover on account that SA economy was already in a recession prior to the onset of the COVID pandemic.

Eskom will continue to grow sales by stimulating demand for local and export sales. The growth strategy will be achieved by, *"Retaining sales, growing sales and revenues by responding to customer needs, speeding up connections and collections, whilst consistently delighting customers."*

Eskom has developed a demand stimulation framework with four key elements that are sustaining and growing demand, expediting projects, attracting new customers and implementing innovative products.

FIGURE 2: DEMAND STIMULATION FRAMEWORK



Research and information from individual customer engagements highlighted the need for more flexible and incentivized electricity pricing and product offerings. Product development has consequently anchored itself along four areas that are incentivizing incremental sales, unlocking new connections, expert advice to facilitate additional use of electricity and solutions development for new markets and technologies to sustain and increase future sales.

To unlock barriers to grid connection, Eskom successfully piloted the funding of upfront connection charges to large power users with flexible repayment periods available to the customers. This option is now available to customers that declined quotations due to affordability.

To fully benefit from the demand stimulation framework, establishing a country platform with the involvement of all key role players to sustain local industrial and mining operations and all sectors of the economy is required. With an integrated and focused country approach there is the opportunity to encourage local investment from new and existing customers making the most of the South African growth potential in the medium to longer term.

2.2 Customers served

The Licensee in the fulfilment of its mandate provides energy to 6.7m customers and focuses is on sales growth (sell), revenue collection (collect) and customer satisfaction (experience).

In the past seven years, an additional 1.6m new customers were added to the network. The key driver for growth in customer numbers was is in the prepaid segment from the electrification program in support of the universal access. Once these customers are connected they form a part of the Eskom customer base to be serviced. The number of Eskom customers is shown in the table below.

TABLE 6: NUMBER OF ESKOM CUSTOMERS

Customer Category	Actual FY2017	Actual FY2018	Actual FY2019	Actual FY2020	Projection FY2021	Growth to date
Redistributors	802	800	800	805	804	-1
Residential	5 838 754	6 120 122	6 358 523	6 577 905	6 720 150	142 245
Commercial	50 956	51 848	52 556	52 909	52 880	-29
Industrial	2 706	2 703	2 705	2 684	2 649	-35
Mining	1 012	993	981	961	945	-16
Agriculture	81 806	81 638	81 303	80 451	79 115	-1 336
Rail	510	501	493	475	475	0
Local Customers	**5 976 546**	**6 258 605**	**6 497 361**	**6 716 190**	**6 857 018**	**140 828**

At the end of the FY2021, municipalities, industrial and mining customers accounted for 84% of the total sales volumes. Residential customers supplied by Eskom make up 98% of the number of Eskom customers but only consumes 6% of the local sales volumes.

2.3 Tariffs

Eskom sales revenues are recovered through the Distribution Licensee.

Customers purchase electricity sales through standard tariffs, local and international negotiated pricing agreements (NPAs) and international utility tariffs. Standard tariffs provide pricing options to meet different customers' electricity consumption patterns and service needs.

There are different standard tariffs based on supply size, complexity, geographic location, municipal and non-municipal supplies as well as generator tariffs. There are three main standard tariff categories that are the same for municipal and non-municipal customers, that is, urban large, rural and residential. Standard tariffs include inter-tariff subsidies to rural and residential tariffs to support customer affordability.

The objectives for the tariffs per the Eskom's "Strategic direction and tariff design principles for Eskom's tariffs" are as follows:

- Improved cost-reflective tariff structures (within the allowed revenue) i.e. fixed versus variable charges are representative of the cost structure.
- Partner for mutual benefit with our customers for sharing of volume risk.
- Ensure reasonable compensation for the use of networks by generators and loads.
- Incentivize customers to stay connected to the grid.
- Increase sales and ensure adequate recovery of costs
- Enable better management of demand and supply.

In pursuit of the tariff objectives, Eskom submitted the Retail Tariff plan (RTP) to NERSA in 2020 for approval. Upon NERSA approval, the standard tariffs will be adjusted in the year of implementation to reflect the allowable price level through the annual increase adjustment as required by the NERSA ERTSA process.

2.4 Energy losses management

Eskom Distribution monitors energy losses continuously and has embedded within its operations various interventions aimed at addressing the energy losses. These interventions are from a technical, commercial, and social perspective. Some of these interventions are:

- Reconciliation of the energy delivered and energy sold (i.e. energy balancing) at the reticulation feeder level in order to prioritize high loss feeders for normalization
- Disconnection of illegal connections, meter tampers and imposition of penalties (tamper substantiate with fines)
- Estimation and recovery of revenue for historic unaccounted energy where tampered, faulty or missing metering installations are encountered
- Revision of Supply Group Codes on prepaid meters to prevent the use of illegal prepaid vouchers
- Implementation of technologies in the form of smart/split meters with steel enclosures to prevent access to the meter
- Customer education, social mobilization and partnership campaigns to drive behavior change
- Investigations and subsequent prosecution of criminals/syndicates perpetrating electricity theft through the sale of illegal prepaid vouchers and providing illegal electrification and meter tampering services

2.5 Electrical supply networks

To meet customer needs the Licensee builds, operates and maintains the Eskom medium and low-voltage electricity supply networks (distribution and reticulation networks). This is to ensure reliable, secure and environmentally sustainable supply of electricity which meets customer expectations, supports government's universal access agenda and the Eskom growth strategy.

Geographically, the distribution network spans a landscape of approximately 49 107 km of distribution lines, 301 916 km of reticulation lines, and more than 7 734 km of underground cables in South Africa, this represents the largest power-line system in Africa. Distribution operating structure is represented in cluster of 5 operating units that are divided into 27 operating zones with execution of work through 306 Customer Network Centres (CNCs).

The Licensee aspirations for the immediate and near future are:

- **Operate a sustainable Distribution network that delivers on customer expectations**
  Distribution will aim to build and maintain its ageing network by maintaining the current network performance levels and limiting energy losses. This is sustained through disciplined execution.
- **Migrate towards compliance with the regulatory framework governing network performance**
  The business continues to manage its regulatory obligations whilst balancing investment choices with customer's needs.
- **Zero Harm to employees, Contractors and Environment**
  The Distribution Group aims to make significant step changes through Zero Harm initiatives coupled with supplier and public education programs, to improve safety performance.
- **Create an agile and innovative workforce**
  Further improve employee productivity by reviewing the efficiency and effectiveness of Eskom's business model, and ensuring a motivated workforce. Emphasis will be placed on retaining core skills together with the management of skills and talent.
- **Proactively partner towards a sustainable distribution industry**
  Actively partner with stakeholders to evolve the wider Electricity Distribution Industry in South Africa. This is to ensure provision of accessible and sustainable electricity.
- **Electrification**
  Electrification remains a priority with thousands of households to be connected during the next three years and plans to expedite government's Universal Access Program

(UAP). Eskom acts on behalf of the government in executing the electrification program that is fully funded from the DMRE.

Distribution’s current network performance in the past few years has improved and stabilised in terms of the duration and frequency of customer interruptions. In order to sustain the current network performance, Distribution Group aims to prudently invest capital and maintain the plant maintenance regime.

2.6 Integrated demand management (IDM)

In terms of Section 14 of the MYPD methodology, Eskom is required to implement integrated demand management (IDM). The IDM role in Eskom is a vital mechanism to manage the electricity supply and demand balance using a multi-pronged energy management approach. In this MYPD5 application, the IDM allowable costs are included in the Distribution Licensee.

3 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 to 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%.

The table below shows the Eskom Sales projected and forecasted sales from FY2021 to FY2027 split between Standard customers, the NPA and International sales.

TABLE 7: TOTAL ESKOM SALES FROM FY2021 TO FY2027

Sales Volume (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Standard customers	180 868	168 529	172 656	171 549	171 440	170 370	170 141	169 476
		-6.8%	2.4%	-0.6%	-0.1%	-0.6%	-0.1%	-0.4%
NPA	10 118	9 755	9 722	10 282	10 311	10 282	10 282	10 282
		-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**
		-6.7%	2.3%	-0.3%	0.0%	-0.6%	-0.1%	-0.4%
International (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
		-14.6%	-6.5%	-2.5%	-7.4%	-0.6%	0.0%	0.0%
Total Eskom sales (Including internal)	**206 081**	**191 174**	**194 433**	**193 579**	**192 627**	**191 467**	**191 238**	**190 573**
		-7.2%	1.7%	-0.4%	-0.5%	-0.6%	-0.1%	-0.3%

Eskom's sales growth has trended 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.

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.

According to Econometrix year-end Outlook for 2020, the impact of lockdown 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 contributed to the substantial downward momentum of 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%.

Furthermore, 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.

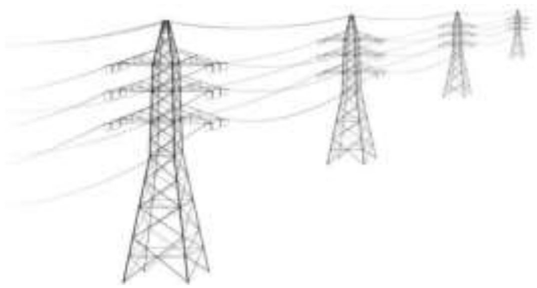
The closure of tourist accommodation, hospitality and leisure complexes were further notable drags on economic activity. Reduced activity in these sectors has a direct impact on the Commercial and Municipal categories in which the associated customers are embedded. This is echoed by a report from the 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 declining over the next few years. However, Eskom's aims to grow sales over the medium term supported by innovative products, solutions and tariffs in collaboration with customers to address their needs and aspirations.



3.1 Sales volume forecasting assumptions

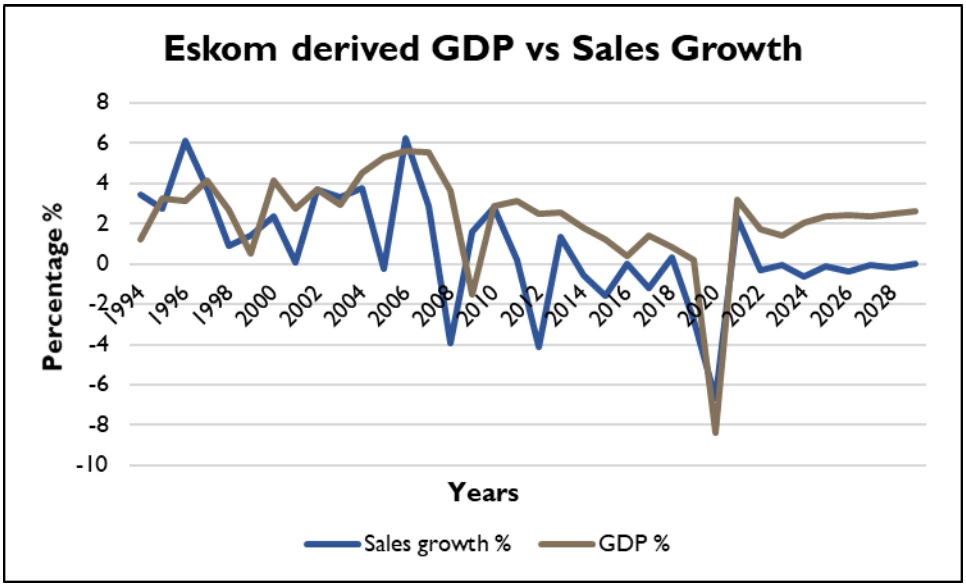
The sales volume forecast is based on various assumptions reflecting the different types of customers' electricity needs and influences on diverse customer consumption profiles. There are some similar assumptions used for all customers but with varying impacts.

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.

3.1.1 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 the economy migrating towards a greater service oriented 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. The figure below illustrates the anticipated gap between GDP and sales growth as explained above.

FIGURE 3: ACTUAL AND PROJECTED GDP VS SALES GROWTH RATES



3.1.2 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 the recovery of commodity prices will be slow and steady during the MYPD5 period. As customers with smelting capacity become more pressurised, these customers will migrate towards more efficient furnace utilization, which 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, 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.

TABLE 8: COMMODITY PRICES (SOURCE: WORLD BANK COMMODITY OUTLOOK)

World Bank Commodities Price Forecast (nominal US dollars) — Released: October 22, 2020

								Forecasts						
Commodity	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030
Metals and Minerals														
Aluminum	$/mt	1 867	1 665	1 604	1 968	2 108	1 794	1 660	1 680	1 731	1 784	1 838	1 894	2 200
Copper	$/mt	6 863	5 510	4 868	6 170	6 530	6 010	6 050	6 300	6 374	6 449	6 525	6 602	7 000
Iron ore	$/dmt	97.0	55.9	58.4	71.8	69.8	93.8	107.0	105.0	103.2	101.5	99.7	98.0	90.0
Lead	$/mt	2 095	1 788	1 867	2 315	2 240	1 997	1 820	1 860	1 885	1 911	1 937	1 963	2 100
Nickel	$/mt	16 893	11 863	9 595	10 410	13 114	13 914	13 500	13 800	14 213	14 639	15 078	15 530	18 000
Tin	$/mt	21 899	16 067	17 934	20 061	20 145	18 661	16 900	17 100	17 673	18 264	18 876	19 508	23 000
Zinc	$/mt	2 161	1 932	2 090	2 891	2 922	2 550	2 200	2 300	2 321	2 343	2 365	2 387	2 500
Precious Metals														
Gold	$/toz	1 266	1 161	1 249	1 258	1 269	1 392	1 775	1 740	1 698	1 658	1 618	1 580	1 400
Silver	$/toz	19.1	15.7	17.1	17.1	15.7	16.2	21.0	18.1	18.1	18.1	18.1	18.1	18.0
Platinum	$/toz	1 384	1 053	987	948	880	864	875	870	906	943	982	1 022	1 250

3.1.3 Furnace load reduction in winter

It is assumed that a substantial amount of furnace load will not be utilised during winter due to the high winter energy prices. As a result of the seasonal tariff the majority of smelters usually perform maintenance on their furnaces during the winter months. Depending on trading conditions, furnace utilisation is assumed at around 90% in the summer months.

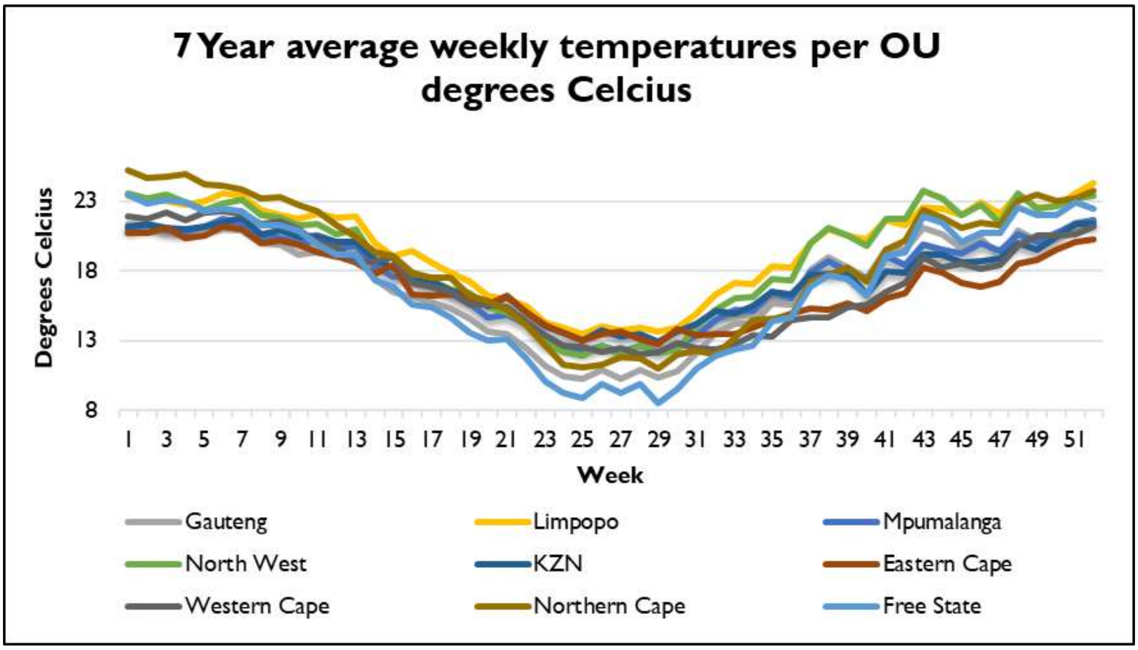
3.1.4 Energy efficiency demand side management (EEDSM)

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. No new EEDSM initiatives has been taken into consideration for future years.

3.1.5 Weather conditions

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 the weather sensitive customers. These average weather profiles per region is shown in the figure below.

FIGURE 4: 2014-2020 YEARLY AVERAGE TEMPERATURES



(SOURCE: VITAL WEATHER)

3.1.6 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.

3.1.7 New customer projects (loads)

Only projects that have a high probability of start-up and have budget quotations accepted by customers are included in the sales forecast.

3.1.8 Co-generation (Co-gen)

The sales forecast also incorporates the co-generation capacity of large customers, which have the capability to generate and wheel energy between each their respective sister plants.

It should be noted that their respective co-generation usage is dependent on plant availability and performance.

On the contrary, there are also co-generation customers that are envisaged to sell electricity to the Eskom system operator. These have been excluded from the sales volume forecast, as they are regarded as independent power producers (IPPs).

3.2 Forecasted sales volumes by customer category

The figure below shows the percentage split per forecasted sales category. The Distributors' (Municipal) sales volume of 46% reflects Eskom's sales to all municipalities and Metro's. In many municipal areas, the majority of sales are consumed by residential and commercial consumers. The Industrial sector contributes 23% of Eskom Sales, while Mining constitutes a further 15%. The remaining sectors contribute to the residual 16% of Eskom sales. The customer categories used to derive the forecasted sales volumes are based on sectors as shown in the table below.

FIGURE 5: SALES PER CATEGORY AS AT Q3 FY2021

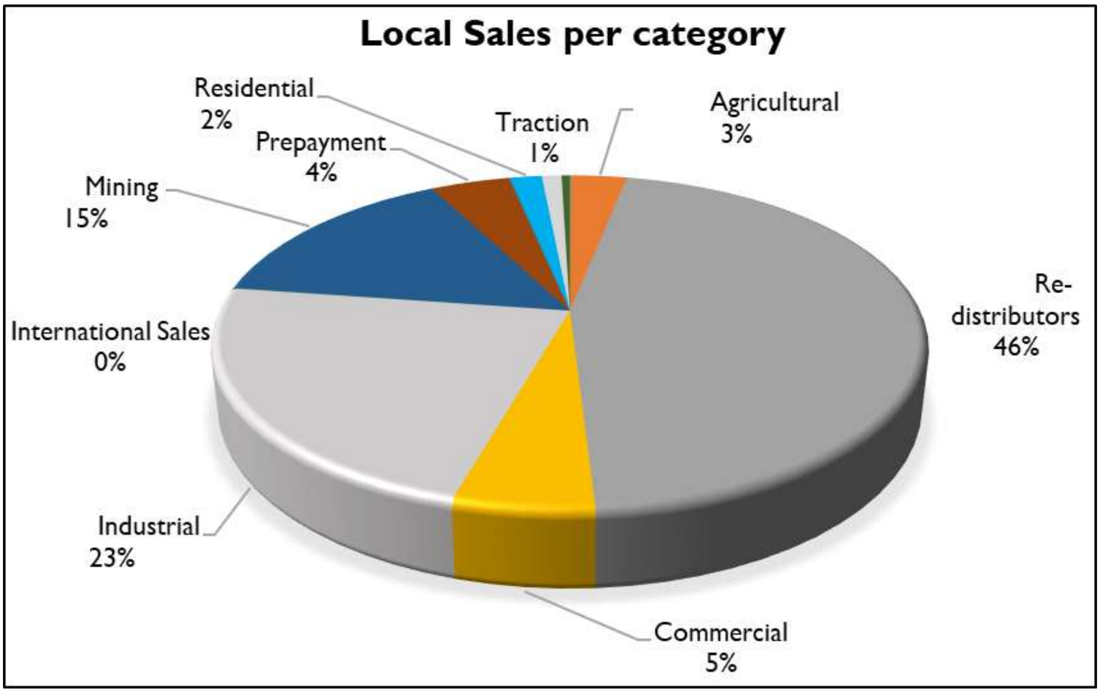


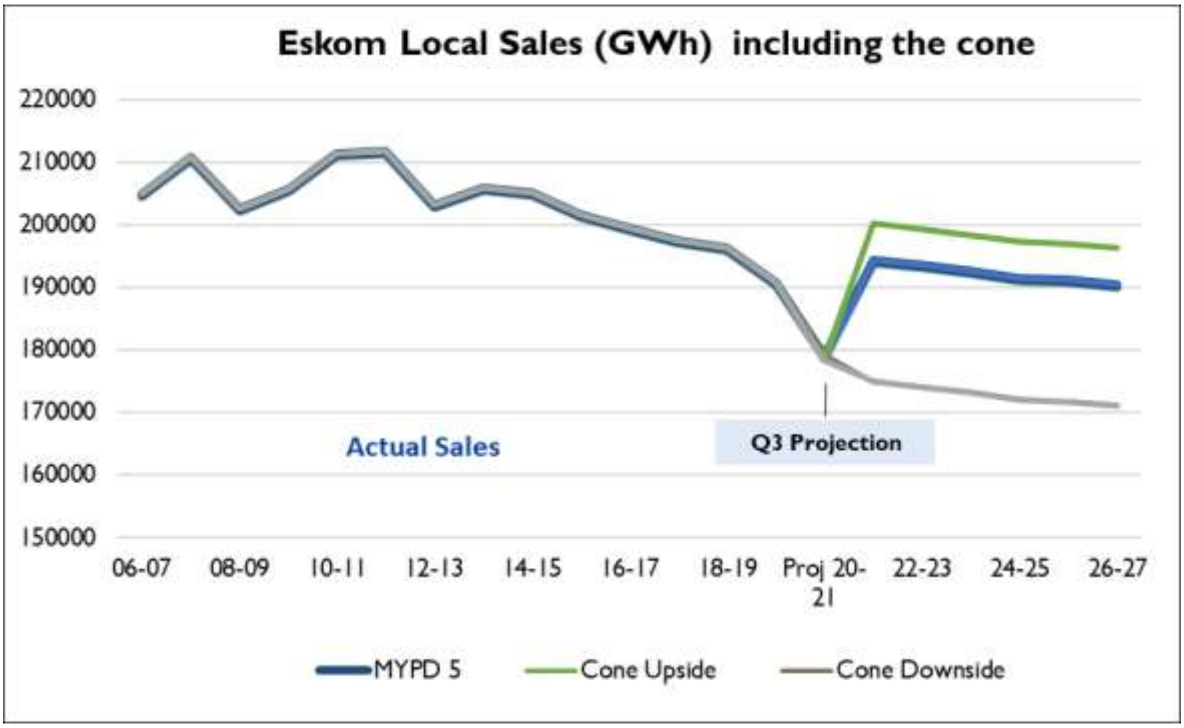
TABLE 9: MYPD5 FORECASTED SALES PER SECTOR

Sales Volume (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Distributors	85 898	82 231	83 455	82 875	82 463	81 750	81 364	80 962
Industrial	45 610	40 351	42 067	42 047	42 341	42 154	42 272	42 129
Mining	28 703	26 689	27 502	27 593	27 557	27 407	27 307	27 120
Gold Mining	9 708	8 836	8 696	8 631	8 436	8 250	8 081	7 852
Platinum Mining	11 537	10 513	11 038	11 175	11 276	11 293	11 339	11 377
Other Mining	7 458	7 339	7 768	7 787	7 845	7 863	7 886	7 891
Traction	2 600	1 963	2 158	2 162	2 178	2 184	2 280	2 292
Residential incl Public light	3 418	3 379	3 360	3 340	3 329	3 303	3 285	3 269
Commercial	10 486	9 707	9 959	9 965	10 005	9 988	10 006	10 029
Agricultural	5 770	5 617	5 646	5 647	5 668	5 654	5 659	5 665
Prepayment	7 875	7 584	7 555	7 526	7 535	7 539	7 578	7 620
International A	94	87	94	94	94	94	95	95
Internal Sales	447	592	511	510	510	508	507	507
IPP	85	85	71	71	71	71	71	71
Other								
Local sales	190 986	178 284	182 379	181 831	181 751	180 652	180 424	179 758
International (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
Total Eskom Sales	206 081	191 174	194 433	193 579	192 627	191 467	191 238	190 573

3.3 Uncertainty of the sales volume forecast

The demand for electricity is highly uncertain at the best of times. The post Covid-19 sales forecast anticipates elements of a slow recovery in the global economy and mostly subdued commodity prices, while local growth is expected to trail behind that of other emerging economies. Eskom sales is also expected to be negatively impacted by the gradual transition to alternative energy sources. The figure below depicts the sales forecast indicating the level of possible gains and losses as identified in the tables to follow.

FIGURE 6: TOTAL LOCAL SALES SHOWING THE CONE OF UNCERTAINTY



The tables below illustrates and quantifies the various upside and downside factors associated to the above sales forecast over the MYPD period. The factors are justifiable, given the volatile and unpredictable nature of elements largely beyond Eskom's control. The risks are also graded by probability and assigned a status of high, medium or low.

TABLE 10: POSSIBLE DECREASE IN ENERGY CONSUMPTION

Sales in GWh								
Downside Factor	Possible Decrease explanation	Probability	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
IPP Impact	Alternative IPP energy used by Munics	High	(1 042)	(1 060)	(1 443)	(1 451)	(1 458)	(1 477)
Ferrochrome Sector	Weaker global demand/lower furnace utilisation	Med-High	(460)	(460)	(565)	(543)	(543)	(460)
Ferrosilicon Sector	Decline in orders	Med-High	(47)	(47)	(48)	(47)	(47)	(47)
Ferromanganese Sector	Lower commodity prices / strong Rand	Med-High	(104)	(155)	(158)	(155)	(155)	(155)
Steel Sector (incl. Stainless)	Weaker commodity prices / strong Rand	Med-High	(155)	(145)	(155)	(166)	(181)	(182)
Gold Sector	Earlier shaft closures / lower Gold price	Med-High	(102)	(52)	(52)	(52)	(52)	(52)
Platinum Sector	Project delays / downscaling	Med-High	(420)	(502)	(563)	(573)	(601)	(623)
Traction Sector	Sluggish economy & vandalism	Med-High	(56)	(60)	(70)	(75)	(84)	(93)
Temperature & Rainfall	Warmer than average / higher rainfall	Med-High	(650)	(650)	(650)	(650)	(650)	(650)
Eskom Supply Constraints	Load Shedding / Curtailment / Reductions	Med-High	(1 600)	(1 568)	(1 537)	(1 506)	(1 476)	(1 446)
Increased Co-gen	Higher co-gen levels (Sasol, Kelvin + Other)	Med-High	(550)	(550)	(550)	(550)	(550)	(550)
Industrial Action	Labour action & community protests	Med-High	(600)	(600)	(600)	(600)	(600)	(600)
Economic Growth	Lower than expected growth post Covid-19	Med-High	(1 122)	(598)	(224)	-	-	-
Covid-19 Pandemic	Shutdowns from re-emergence of virus	Med-High	(2 243)	(748)	(374)	-	-	-
Aluminium Sector	Decline of revised NPA Framework	Low-Med	(10 282)	(10 282)	(10 311)	(10 282)	(10 282)	(10 282)
Total Downside Impact			**(19 434)**	**(17 475)**	**(17 299)**	**(16 650)**	**(16 679)**	**(16 617)**

The largest risk presents in the Aluminium sector at a possible loss of 10.2 TWh. It is reported that an Aluminium smelter that was on a commodity linked pricing deal (NPA), which has expired on 31 July 2020 would be rendered unsustainable if it was to be subjected to standard Eskom tariffs.

The Covid-19 pandemic is a further notable risk of 2.2 TWh, given the unknown trajectory of the virus as well as the efficacy of possible vaccines. The impact of IPP sales to Municipalities is another key factor which has the capability to reduce sales by 1 TWh. Further risks include that of load shedding (1.6 TWh), lower than anticipated economic growth (1.1 TWh) and warmer than average winter temperatures (0.6 TWh). Since customers are exposed to a multitude of external factors, smaller risks are also inherent at sector level and contribute the remaining of the above risk quantity.

TABLE 11: POSSIBLE INCREASE IN ENERGY CONSUMPTION

Sales in GWh									
Upside Factor	Possible Decrease explanation	Probability	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Ferrochrome Sector	Improved trading conditions/Re-opening of Mogale Alloys	Low-Med	813	813	760	771	771	813
Ferrosilicon Sector	Improved commodity prices / weak Rand	Low-Med	114	114	113	114	114	114
Ferromanganese Sector	Higher commodity prices/Re-opening of South32 Meyerton	Low-Med	343	280	276	280	280	280
Steel Sector (incl. Stainless)	Higher steel demand/re-opening of Saldanha Steel	Low-Med	1 184	1 197	1 183	1 170	1 152	1 150
Gold Sector	Higher than average Gold price / weaker Rand	Low-Med	147	78	51	46	48	43
Platinum Sector	Low probability expansions / weak Rand	Low-Med	165	167	169	169	170	170
Traction Sector	Infrastructure repair & higher economy	Low-Med	162	160	152	149	142	136
Temperature & Rainfall	Colder than average / lower rainfall	Med-High	1 040	1 040	1 040	1 040	1 040	1 040
Load Shedding / Curtailment	Lower supply constraints	Med-High	150	190	240	290	340	390
Short-Term Incentives	Approved short term pricing incentives(Smelters)	Med-High	300	300	300	300	300	300
Economic Growth	Faster than expected growth post Covid-20	Low-Med	897	479	179	-	-	-
Lower Co-gen	Lower levels of Co-gen	Med-High	495	495	495	495	495	495
Aluminium Sector	Full Capacity with new NPA	Low	-	-	-	-	-	-
Total Upside Impact			**5 810**	**5 312**	**4 959**	**4 824**	**4 851**	**4 931**

The figure in the table above highlights the upside or positive movement of sales in relation to the MYPD5 forecast. This refers to a potential sales increase that could arise, should certain conditions materialise.

A key factor in this regard is that of colder than average winter temperatures. This implies that additional sales of 1 TWh could transpire, should colder winter temperatures emerge over the applicable years.

A further favourable factor lies with the large industrial smelters. As previously stated, several large smelters have closed and downscaled over the past few years. There remains a total opportunity of up to 2.4 TWh, should the relevant market conditions improve in the short term.

Higher than expected economic growth is expected to yield 0.8 TWh additional in the first year, while lower levels of customer co-generation could see 0.5 TWh additional.

3.4 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.

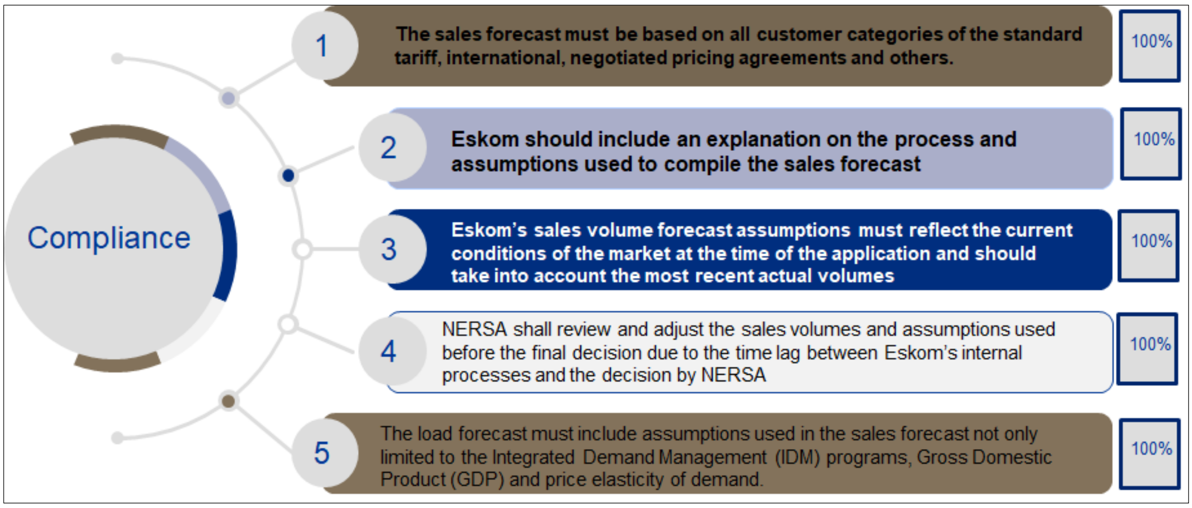
For the residential and commercial sectors, historical trends, weather and economic indicators are the primary indicators that inform the sales forecast.

3.5 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 THE MYPD FORECASTD SALES



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.

4 Energy Losses

Eskom Distribution Energy loss is defined as the difference between energy purchased (measured at the Transmission main substations and at Independent Power Producers plants) and energy sold to all Distribution customers (measured or estimated). This includes both technical energy losses (also known as copper and iron losses) and non-technical energy losses. It excludes non-payment or bad debt.

4.1 Energy losses benchmark

The proposed distribution losses targets in this forecast are well within the regulator's (NERSA) benchmark of 10% as stipulated in the regulators cost to supply framework Section3.2.1.1 a) (i). The cost of supply framework states that utilities should manage distribution losses within the tolerable range of 5 – 12%.

4.2 Energy losses forecast

The energy losses volume and percentage are derived from the purchases (from Transmission, IPPs, International Imports and distribution owned generators) and sales to customers are shown in the equation below, as the difference between purchases (input) and the sales (output):

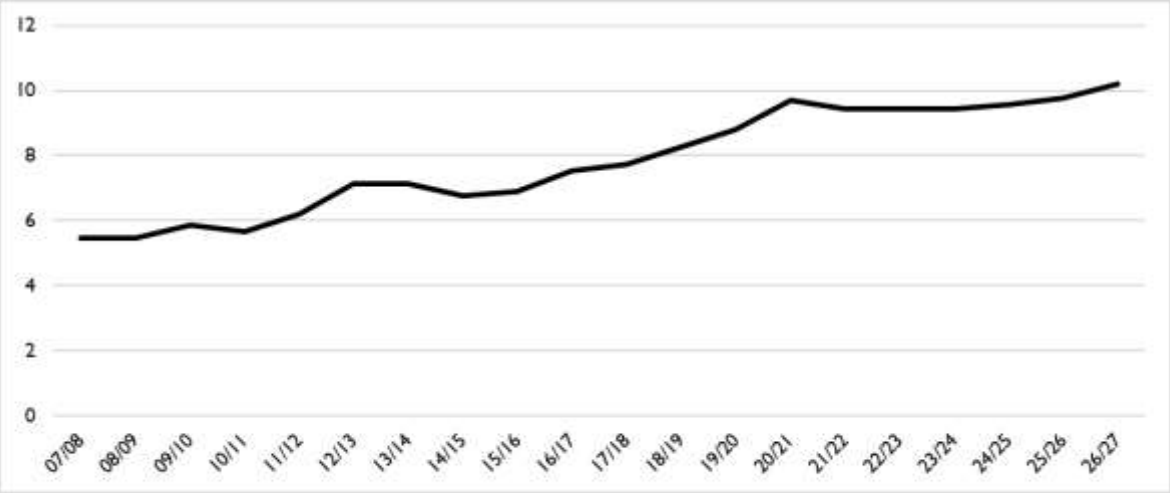
- Losses [GWh] = Purchases [GWh] – Sales [GWh]

The % percentage losses is also expressed as a ratio of losses volume to the purchases volume:

- $\% \, Losses = \frac{Losses \, [GWh]}{Purchases \, [GWh]}$

The losses forecast is based on a trend analysis of the past performance. The actual percentage energy losses recorded for the FY 2008 to FY2021 and the forecast for FY2022 to FY2027 is reflected on figure below.

FIGURE 8: ENERGY LOSSES TREND



The proposed forecast is informed by the historical performance of the past period on which data analysis was performed. Data analysis of the historical performance was performed and the sales forecast for the application period was performed. This resulted in the losses volume and percentage forecast as given in the table below.

TABLE 12: PROPOSED ENERGY LOSSES TARGETS

Distribution Losses	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
GWh	18 436	19 190	19 046	18 971	18 919	19 113	19 554	20 414
%	8.8%	9.7%	9.5%	9.4%	9.4%	9.6%	9.8%	10.2%

The table above depicts the losses figures, both in volume and percentage that Distribution is applying for.

4.3 Forecast assumptions

There are various factors drawn from the different customer categories forecast are assumed to continue to influence the losses forecast in the following way.

- The negative forecasted growth of sales to high voltage customers, which are redistributors, industrial and mining, will result in higher percentage of losses, and not so much to the volumes as these customers have low loss-factors. The historical furnace load reduction in winter is expected to continue and reduce base of high voltage sales and purchases, thus increasing the losses percentage.
- Residential customers due to our electrification program, are expected to grow. The customers are connected in low voltage as such, contributing to an increase in volume losses.

- The increasing trend is also influenced by the factors discussed in Section 4.4. A number of initiatives have been implemented to reduce the losses.

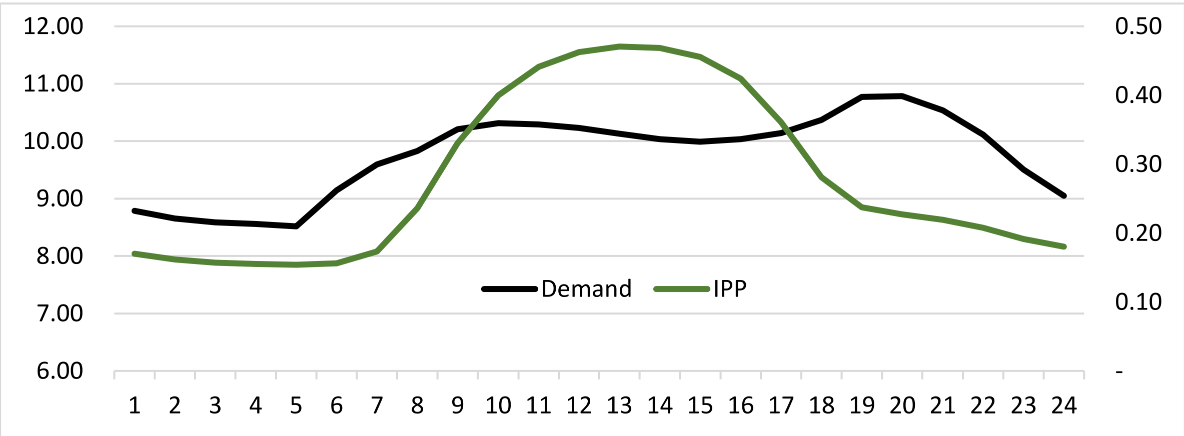
4.4 Factors impacting the losses forecasts

Distribution monitors energy losses continuously and has embedded within its operations various interventions aimed at addressing the challenge. While various losses reduction interventions have been implemented, the business has realized varying levels of success across different customer sectors.

The increase in total distribution energy losses is attributable to the following:

- Preliminary analysis suggests that there is an increase in the non-technical component of losses (theft) due to prevailing economic conditions. Theft is not limited only to the residential customer sector, but across different customer sectors.
- The ageing nature of distribution networks, which are often constrained and overloaded, results in an increase in the technical component of energy losses.
- Increase in IPP operations provides additional technical losses: Independent Power Producers (IPP) are predominantly renewables in nature. Renewable IPP's locations are restricted by the availability of the natural resource be it solar, wind or hydro. This will mostly not be as per the load requirement.

FIGURE 9: TYPICAL DAILY PROFILE OF RENEWABLE IPP AGAINST DISTRIBUTION DEMAND



The profiles of renewable IPPs are not matching the load profile (see figure above). The IPPs, which are mostly renewable, are not to be optimally positioned, for Distribution load as the IPP are established at the primary source solar or wind. The IPP energy is available during time periods when the local demand is lower than the supply, with energy being evacuated back to transmission grid to be consumed elsewhere. During this process, additional technical losses are incurred in the Distribution network.

4.5 Energy losses management

Eskom Distribution monitors energy losses continuously and has embedded within its operations various interventions aimed at addressing the energy losses. These interventions aim to address losses from a technical, commercial, and social perspective. Some of these interventions are:

- Reconciliation of the energy delivered and energy sold (i.e. energy balancing) at the reticulation feeder level in order to prioritize high loss feeders for normalization
- Auditing and repairing of faulty customer meter installations
- Disconnection of illegal connections, meter tampers and imposition of penalties (tamper substantiate with fines)
- Improvement of process and data anomalies correction
- Estimation and recovery of revenue for historic unaccounted energy where tampered, faulty or missing metering installations are encountered
- Revision of Supply Group Codes on prepaid meters to prevent the use of illegal prepaid vouchers
- Implementation of technologies in the form of smart/split meters with steel enclosures to prevent access to the meter
- Customer education, social mobilization and partnership campaigns to drive behavior change
- Investigations and subsequent prosecution of criminals/syndicates perpetrating electricity theft through the sale of illegal prepaid vouchers and providing illegal electrification and meter tampering services

Eskom is to continue with the various losses reduction interventions.

4.6 Conclusion on Distribution energy losses

The proposed losses percentage (9.4%, 9.4% and 9.6%) are within the NERSA losses benchmark of 5 -12%. The energy losses interventions implemented have assisted in containing energy losses growth and with the increasing number of IPPs connected to Distribution network it is anticipated that the technical losses component from a forecast perspective to increase.

5 Regulated Asset Base, Return and Depreciation

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.

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:

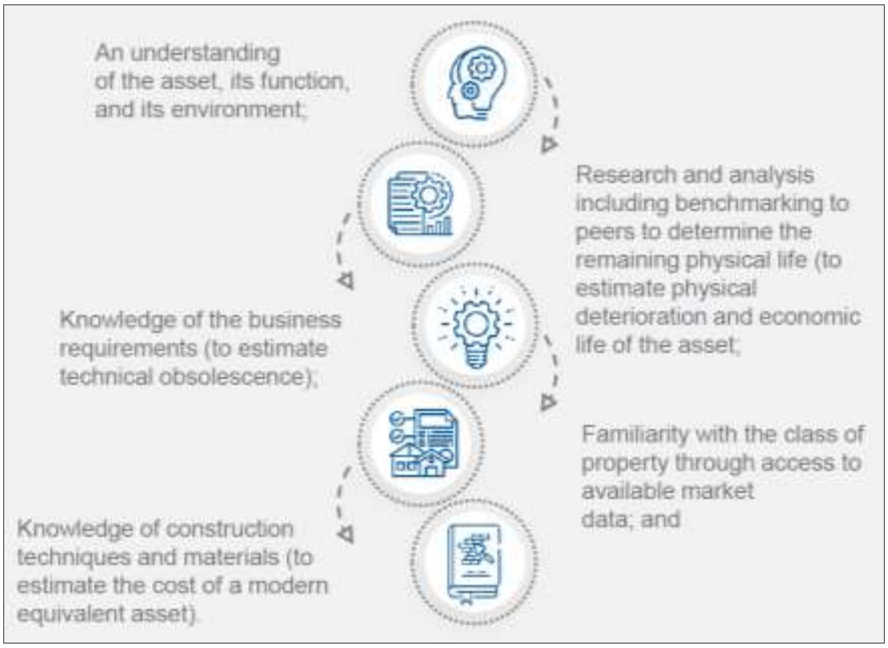
$$AR=(RAB\times WACC)+E+PE+D+R\&D+IDM\pm SQI+L\&T\pm RCA$$

The ERA and the Electricity Pricing Policy (EPP) require 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-19 pandemic.

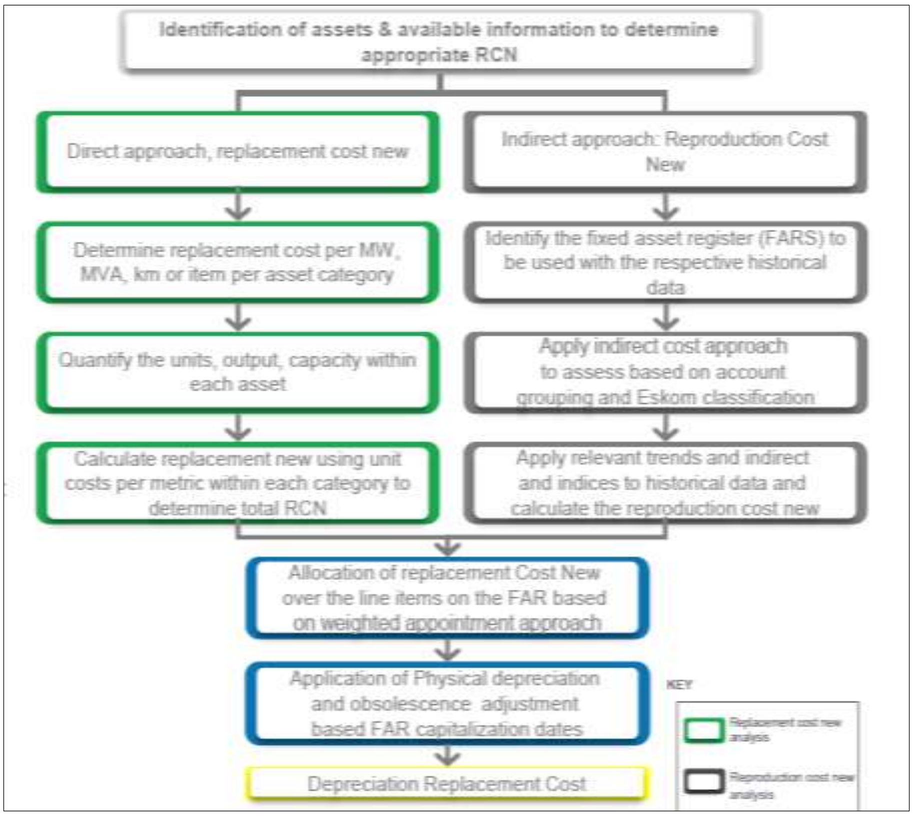
In determining the depreciated replacement cost, the independent consultants ensured that the following key elements were undertaken.

FIGURE 10: 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 11: VALUATION METHODOLOGY



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 13: 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)	46 579	39 611	100 187	93 208	86 527	80 149	74 035
Assets Transferred to Commercial Operations	20 751	25 538	18 477	22 218	27 553	40 482	45 111
Work Under Construction (WUC)	3 930	2 573	7 882	13 295	15 397	8 599	8 562
Net Working Capital	18 285	20 839	21 454	23 971	26 146	29 184	31 785
Assets Purchases	1 308	1 357	975	1 148	1 248	1 099	982
Assets funded upfront by customers			(14 127)	(14 244)	(14 338)	(14 406)	(14 415)
Closing RAB	**90 853**	**89 917**	**134 849**	**139 596**	**142 534**	**145 107**	**146 059**

5.1 Regulatory Asset base components:

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

- Depreciated replacement cost assets: these are assets as per the March 2020 asset valuation. The valuation includes assets already in use in the distribution of electricity as at 31 March 2020. All other assets in construction are not included in the valuation but rather in the WUC.
- Assets transferred to commercial operations: This refers to distribution 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 e.g. Equipment and vehicles, production equipment etc.

5.2 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 14: EXTRACT FROM INDEPENDENT VALUATION REPORT

	Cap Cost	NBV	NBV in Scope	Final RCN	Physical Depreciation	DRC
Distribtion (Dx)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)
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
Land	284	284	-	-	-	N/A
Buildings	2.682	2.210	-	-	-	N/A
Sub total	**133.847**	**78.372**	**75.878**	**449.538**	**(254.179)**	**195.359**

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.

5.3 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 commercial operation (CO) do these assets incur depreciation costs.

The transfers to CO from WUC are grouped into the categories of substations and lines. For Distribution, these new assets are depreciated on a normal useful life of 30 years for substations and 40 years for lines.

5.4 Depreciation

The depreciation is the cost of usage over the life of the asset. This is generally a proxy for the recovery of the capital portion of the debt incurred. As is required by the MYPD methodology, the annual depreciation allowance is determined by dividing the cost of the asset by the estimated useful life of that asset. The table below reflects the revenue related to depreciation for the MYPD5 period.

TABLE 15: DEPRECIATION

Depreciation (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	7 278	6 980	6 680	6 378	6 114
Assets Transferred to Commercial Operations	600	1 039	1 251	1 766	2 305
Assets Purchases	244	287	312	275	245
Assets funded upfront by customers	(724)	(767)	(817)	(871)	(930)
Total	**7 397**	**7 539**	**7 426**	**7 548**	**7 735**

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 post 31 March 2020 are depreciated over the normal useful life.

5.5 Assets excluded from RAB

Depreciation as shown in the table above includes 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. The total assets and the depreciation have therefore been reduced by the values as shown in the table below to exclude such assets.

TABLE 16: ASSETS FUNDED VIA UPFRONT CONTRIBUTIONS

Regulatory asset base (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening balance	(32 375)	(29 292)	(14 108)	(14 127)	(14 244)	(14 338)	(14 406)
Inflation	-	-	-	-	-	-	-
Transfers to Commercial Operations (CO)	(643)	(704)	(743)	(883)	(910)	(939)	(939)
Depreciation	3 726	3 990	724	767	817	871	930
Closing RAB	**(29 292)**	**(26 006)**	**(14 127)**	**(14 244)**	**(14 338)**	**(14 406)**	**(14 415)**

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

In distribution, self-build assets of R 10 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.

5.6 Return on assets

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

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

TABLE 17: RETURN ON ASSETS

Return on Assets	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Closing RAB (R'm)	134 849	139 596	142 534	145 107	146 059
Real pre-tax WACC %	7.1%	7.1%	7.1%	7.1%	7.1%
Cost Reflective RoA (R'm)	9 574	9 911	10 120	10 303	10 370
RoA Applied for RoA %	-1.99%	0.69%	0.87%	1.65%	3.04%
RoA Applied for (R'm)	(2 685)	966	1 244	2 387	4 433

6 Revenue Related Information – Operating Costs

The Licensee's operations spans across South Africa to service all customers ensuring that the networks are available for continued electricity supply and revenue streams. The Licensee operates out of 5 operating clusters consisting of 27 operating zones to manage 306 customer network centres (CNCs).

The Licensee's operating cost (OPEX) components in this application consist of employee benefits, maintenance, other costs and impairments. The table below reflects the Licensee operating costs.

TABLE 18: DISTRIBUTION OPERATING AND MAINTENANCE COSTS (R'M)

Operating expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee benefit costs	11 414	11 560	11 862	12 032	12 545	13 158	13 827	14 699
Maintenance	3 399	3 728	4 940	5 184	5 418	5 731	6 045	6 347
Other operating expenses	3 821	3 747	4 757	5 056	5 363	5 596	5 631	5 923
Corporate Overheads	2 637	2 956	2 475	2 448	2 564	2 382	2 561	2 683
Other Income	(592)	(427)	(478)	(509)	(530)	(534)	(536)	(536)
Total operating expenditure	**20 679**	**21 564**	**23 556**	**24 211**	**25 360**	**26 333**	**27 528**	**29 116**
Corporate Overheads: portion excluded from revenue requirement		(57)	(266)	(245)	(270)	(289)	(272)	(272)
Total operating expenditure	**20 679**	**21 621**	**23 290**	**23 966**	**25 090**	**26 044**	**27 256**	**28 844**

6.1 Employee expenses

Distribution employees are engaged in service to the customer, operating and maintaining the electrical network and associated infrastructure thereby ensuring compliance to the license conditions whilst providing sustainable supply of electricity to all South Africans. The table below provides a summary of employee expenses and headcount.

TABLE 19: DISTRIBUTION EMPLOYEE HEADCOUNT

Employees expenses and Headcount	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses (R'm)	11 414	11 560	11 862	12 032	12 545	13 158	13 827	14 699
Head count	17 453	17 594	17 604	17 520	17 422	17 314	17 714	17 714

Eskom has consistently benchmarked the salaries and related benefits of all levels of employees to ensure alignment to the market. The Licensee has an employee complement of 17 594, with 7% of employees at managerial level and 93% of employees within operations. Employee benefits costs are influenced by three main factors: Staff numbers; Employee benefits increases and Level of remuneration.

The employee numbers in this application includes a planned employee reduction which is primarily based on natural attrition and the implementation of efficiency improvement initiatives to provide a transitional path without disrupting effective service and operations to customers.

The CAGR for the period FY2022 to FY2025 for employee expenses (manpower costs) is 3.5%, which is below inflation. In alignment with cost reduction objectives, Licensee employee numbers will be contained over the application period.

6.2 Maintenance

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. The table below summarises the breakdown of Distributions' maintenance costs.

TABLE 20: DISTRIBUTION MAINTENANCE COSTS (R'M)

Total Maintenance Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
High Voltage Networks	168	185	258	285	313	347	382	419
Medium Voltage Networks	306	336	469	518	569	630	695	762
Low Voltage Networks	390	428	598	661	725	804	886	971
Substations	275	302	422	467	512	567	626	685
Vegetation Maintenance	161	176	246	272	299	331	365	400
Wood Pole Maintenance	229	252	352	389	427	473	521	571
Total Planned Maintenance	**1 530**	**1 678**	**2 347**	**2 592**	**2 844**	**3 152**	**3 476**	**3 808**
Unplanned (Corrective) Maintenance	1 869	2 050	2 594	2 592	2 574	2 579	2 569	2 539
Total Maintenance	**3 399**	**3 728**	**4 940**	**5 184**	**5 418**	**5 731**	**6 045**	**6 347**

The objective of maintenance is to ensure that:

- Asset condition is managed over the asset life cycle.
- Regulatory and Statutory requirements are adhered to (Safety, Health and Environment).
- The technical performance KPIs focusing on interruptions and restoration time are in accordance with the agreed performance levels between Eskom and Regulator.

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:** Geographically, the distribution network spans a landscape of approximately 49 107 km of distribution lines, 301 916 km of reticulation lines, and more than 7 734 km of underground cables in South Africa, this represents the largest power-line system in Africa. 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.

6.2.1 Planned (preventative) maintenance

Distribution maintains the network infra-structure (lines, substations, transformers etc.) as specified in the maintenance standards. The key planned maintenance activities for the different asset classes include:

- Network inspections and defect clearing; Substation inspections and defect clearing; on load tap changer maintenance; breaker and isolator maintenance; power transformer and neutral earthing compensator oil sampling and analysis; substation earthing inspection, testing and remedial work; substation infra-red scanning and remedial work; battery bank and charger testing and maintenance; protection relay testing and maintenance; tele-control testing and maintenance; metering testing and maintenance; ring main unit maintenance; voltage regulator maintenance; and wood pole testing and replacement.

The above activities prescribed in the maintenance standards is to ensure that the asset performs in line with its design intent. This includes frequency of interruptions and functional performance e.g. voltage regulation on on-load tap changers.

Wood pole inspection and replacement of power line wooden poles ensure safety of public and security of supply. Wood pole maintenance is a scheduled maintenance program based on a set cycle (currently 10 years) to effectively manage the inspection and replacement of defective High Voltage, Medium Voltage and Low Voltage wooden poles.

In ensuring the safe mechanical and electrical operation of its power lines, Distribution maintains vegetation on the power line servitudes to meet its environmental obligations. All vegetation posing a risk to the lines or prevents access must be managed without interfering in the natural attributes of the environment in compliance with environmental and safety requirements.

6.2.2 Unplanned (corrective) maintenance

Unplanned maintenance includes identifying, isolating, and repairing faults so that the failed equipment can be repaired/replaced and the system restored to an operational condition within the tolerances or limits established for in-service operations.

The theft of equipment e.g. conductor, pole mount transformers, poles etc. is on the increase specifically in electrification areas. Apart from the negative impact on technical performance, resources are being directed away from preventative maintenance activities to address faults relating to vandalism and theft.

6.3 Other operating costs

Other operating expenses include insurance, fleet and travel costs, security services, telecommunications, safety equipment and general office expenses. Other operating expenses are essential for the Licensee's operations; these costs are contained to within the CPI inflation parameters, to the extent possible. Other operating costs are defined in the table below.

TABLE 21: DISTRIBUTION OTHER OPERATING EXPENSES (R'M)

Other cost operating costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance	1 175	1 440	1 528	1 611	1 685	1 774	1 856	1 949
Security cost	502	506	527	550	576	609	658	690
Information technology costs	430	447	457	476	492	517	543	570
Fleet cost	307	155	24	52	68	66	88	92
Facilities cost	423	450	575	635	698	766	810	857
Telecomms	176	165	146	147	147	148	150	157
Materials/Stores expenses	77	53	62	48	50	61	94	99
Contractor expenses	79	(146)	179	130	244	258	237	346
Customer related:								
Vending Commission	448	410	501	537	587	637	674	707
Customer billing related expenses	92	91	127	132	134	135	138	146
Legal Fees & Debt Collection	14	36	32	33	35	37	39	41
Wheeling cost	44	37	56	58	60	63	65	68
Bank Related Costs	19	20	21	22	24	25	26	27
Reconfigure Prepayment meters			84	164	70	81	93	-
IDM cost	26	66	384	433	420	339	64	68
Business related expenses	9	17	54	28	73	80	96	106
Total other cost	**3 821**	**3 747**	**4 757**	**5 056**	**5 363**	**5 596**	**5 631**	**5 923**

The increases in the "Other operating" costs over the MYPD5 control period are generally linked to inflation and fixed in nature. Where possible the Licensee has implemented cost saving measures whilst improving operating efficiencies. The main contributors to the "Other operating" costs are the following:

6.3.1 Insurance

The business must ensure that there is adequate insurance cover is in place to manage its increasing asset base and exposure against insurable incidents such as natural occurrence, theft, vandalism and public liability claims. The market prices for the premium are hugely driven by replacement cost of assets and past claims history. Insurance covers risk beyond the maximum tolerance levels for the business.

6.3.2 Security cost

Many of the Distribution sites are designated national key points which in terms of legislation require these assets and people to be safe guarded. There has been an increase in theft and vandalism of equipment which warrants the need to safe guard assets for continuity of operations. Security related activities are to safe guard assets, property and employees.

6.3.3 Information technology costs

Information management systems are key to the current and future business operations to support improvement in efficiency, productivity and decision making. The vastness and complexity of network infra-structure requires a number of integrated management systems for network management, outages, dispatching and customer interface and interaction. The information systems enable optimal and efficient network operating, optimal customer billing and revenue collection. The changing customer needs necessitate investment in digital platforms which require continued maintenance to support delivery of the desired customer experience and service delivery.

6.3.4 Fleet and Travel cost

The Distribution network infrastructure footprint is across South Africa mainly in deep rural areas. Employees are required to extensively travel to service all customers. This involves operating, maintaining and repairing networks to comply with regulatory and service standards. Key to the cost is employee recoveries of kilometers travelled for business related activities and associated subsistence allowances. The employees are reimbursed at the SARS travel rates and the Eskom policy aligned to National Treasury Directive on cost containment.

6.3.5 Facility cost

The geographical customer spread across the country, accessibility, convenience to the customer and the business value proposition to meet customer expectations required the establishment and maintenance of customer network centres, hubs and local offices in close proximity to the customer locations. These properties are either owned or leased and the business carries all associated servicing costs. The driver of the facility cost relate to rentals, water and lights, rates and taxes and maintenance.

6.3.6 Telecommunications

Telecommunication is core in enabling protection systems of the distribution infra-structure. The network control centers communicate with all the distribution equipment through the telecommunication network to have real time visibility of high voltage field equipment to remotely operate in response to network incidents. The telecommunication networks are used for data transfer from network control center to equipment and from equipment to other equipment for purpose of operational decision making. Over and above the network requirements this infrastructure also enables communication between the call center, resource management center and field staff to address customer and network faults.

6.3.7 Vending commission

The prepaid customer base is served through a network of vending agents located in close proximity through various platforms for ease of access for the customer. Vending commissions are costs paid to the agents that sell electricity on behalf of Eskom.

6.3.8 Customer billing and meter reading expenses

Billed customer meters are read in intervals through meter reading agents to ensure accurate and timeous billing for energy consumed. The meter reading agents are compensated for the actual number of customer meters read at a predetermined rate. The business also incurs costs for the generation of the customer bill and the distribution thereof.

6.3.9 Reconfiguration of prepayment meters

STS is a secure standard (protocol) used to create encrypted tokens by the Online Vending System (OVS) and is issued by the vending outlets from different suppliers. Each Supply Group Code (SGC) is linked to a key revision number (KRN).The current key revision number is 1 since 1993 (base date) and all vending keys have a life span of 30 years.

The Token Identifier is a 24 bit field, contained in STS compliant tokens, that identifies the date and time of the token generation. It is used to determine if a token has already been used in a payment meter. The Token-ID represents the minutes elapsed since the base date of 1st January 1993.

All STS prepayment meters will be affected by Token ID roll over on 24/11/2024. Any tokens generated after this date and utilizing the 24 bit Token-ID will be rejected by the meters as being “old tokens” as the Token-ID value embedded in the token will have reset back to 0.

To address this, all the meters will have to be changed to a new key revision number and a new base date. This means reconfiguring every meter either ourselves or getting our customers to do it.

Failure to implement this project will disrupt electricity service delivery, leading to irate, unhappy customers, which in turn may trigger temptations for meter tampering, illegal connections or illegal electricity purchases. All these will cause revenue loss and also exacerbate non-technical energy losses and social unrest.

TABLE 22: METERS TO BE CODED (MILLION)

Item (reflected in millions)	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Total
Number of meters to be coded	0	2.2	3.2	1.1	6.5

6.4 Other income

In servicing the customer and maintaining the network the business recognises the following categories of other income.

TABLE 23: OTHER INCOME (R'M)

Other income (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance proceeds/recovery	(444)	(283)	(316)	(317)	(324)	(318)	(314)	(314)
Operating lease income	(7)	(11)	(9)	(9)	(9)	(7)	(7)	(7)
Sundry income	(141)	(133)	(153)	(183)	(197)	(209)	(215)	(215)
Total other income	**(592)**	**(427)**	**(478)**	**(509)**	**(530)**	**(534)**	**(536)**	**(536)**

The main contributors to the “Other income” are the following:

- **Insurance proceeds/recovery:** This relates to proceeds received from insurance, for claims submitted for all insurable incidents as covered in the insurance policy.
- **Operating lease income:** This relates to proceeds received from Operating leases.
- **Sundry Income:** Income for the management of the Electrification program from the Department Mineral Resources and Energy and various other sundry income.

7 Arrear Debt - Gross Impairments

Most retail industries face the challenge of non-payment as part of their efforts in collecting the billed revenue from their customers.

In the current economic climate; customers will experience a continued difficult environment as a result of business closures; increased unemployment & other factors resulting them in not paying their accounts; leaving Eskom with the credit risk. Very few retail businesses are immune against such credit default. This is evident from the financial reports and statements issued by retailers including banks that their impairment provisions are significantly increasing given the macroeconomic challenges presented by COVID-19; rating agency downgrades; high unemployment and very low economic growth. Eskom is no exception; and despite the rigorous credit management processes we employ; credit risk will remain part of our operational cost.

7.1 Percentage impairment applied for

Eskom has limit its impairment application to 2% of revenue; despite its current actuals being higher than 4%; and despite the fact of an increase in risk due to the tougher economic conditions on the customer. This limitation of 2% will result in more than R4.7bn of projected impairment costs not being included in our submission in order not to burden the customer with Eskom’s debt collection challenges especially in the Municipality sector.

A 2% impairment equates to a collection level / payment level of 98% of all billed revenue.

In the previous decade; payment levels of 99% were achieved by Eskom; hence a 0.5% impairment application was applied for. However, with the struggling SA economy; increase in debt levels of the average South African consumer; and municipalities struggling to be financially sustainable; a 0.5% impairment (99.5% payment level) can’t be considered as a realistic application for prudent costs.

In instances where Eskom is prohibited from executing its credit management processes in full (for example: political pressure; litigation preventing Eskom from applying for recovery of outstanding debt in accordance with the Promotion of Administrative Justice Act (PAJA), etc.), this results in additional arrear debt. From a prudency point of view, this indicates that certain factors are beyond Eskom’s control.

The 2% debt impairment level of revenue application assumes significant improvements in the Distribution debt trajectory compared to the current performance; despite the higher risk profile of the average consumer and the deteriorating financial state of some municipalities.

7.2 Debtors & gross impairment

Eskom is managing the payments from small power users (SPU), large power users (LPU) and Top Customer sector reasonably well, with payment levels greater than 99% for most of the financial years.

Only a small portion of Eskom's customer base is contributing to the increase in the overdue debt. During the last few years the overdue debt increased significantly for mainly municipalities and Soweto debtors.

7.2.1 Municipalities

The municipal overdue debt has increased significantly from R13 570m (FY2018) to R35 524m (FY2021). This equates to annual growth in overdue debt of between R7bn – R8bn per annum.

Eskom continues to execute its municipal debt management strategy to ensure maximum collections from non-paying municipalities. In the recent past, Eskom has had to resort to the Courts to enforce contractual credit control measures. However, arising out of a judgement handed down by the Supreme Court of Appeal, our collection process has been revised to utilise the provisions of the Intergovernmental Relations Framework Act. This has been found to significantly impact the time to enforce the contractual commitments made by Municipalities. Eskom understands that NERSA has approved a process to address the Municipalities not meeting their license conditions in this regard.

It is acknowledged by various stakeholders that the key reason for non-payment is due to the systemic failures within municipalities. To address the systemic issues within municipalities pertaining to electricity distribution that are leading to the non-payment, Eskom is advocating an Active Partnering solution whereby Eskom supports municipalities with distribution, reticulation and revenue collection services. We are promoting and pursuing the partnership model to ensure that we create a sustainable Distribution industry and securing the current accounts. The full benefits of this programme will be only be realized over the next 5 - 10 years. It is assumed that all the efforts to recover the municipal debt will result in a decrease in the annual growth rate of the municipal capital portion of the overdue debt, therefore the decrease in the projected gross impairment for municipalities.

7.2.2 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 realized 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.

Current challenges Eskom is facing includes:

- Resistance by consumers to convert from conventional meters to pre-paid 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.

7.2.3 Top Customers

Top Customers have an excellent payment record, the payment levels were close to 100% for FY2020. However, due to the adverse market conditions, the risk of non-payment by key customers do exist and can have a significant impact on the impairment if just one of the big customers default. Small impairment values have been provided for Top Customers over the MYPD5 period to cater for such risk. A non-payment level of 0.5% to 0.7% per annum has been allowed as part of the Top Customer impairment calculation; which still result in projected payment levels in excess of 99.5% on average over the MYPD5 period.

7.3 Impairment calculation methodology

Eskom is applying the IFRS 15 / IFRS 9 international accounting standards to calculate its impairment. At the core of the IFRS 9 requirement is the need to measure credit impairments in an objective and unbiased manner, using information regarding past events, current conditions and economic forecasts. As per IFRS 15, where the collectability criterion is not met, a "cash basis" approach is followed for the relevant customers with regards to impairment. For the MYPD5 application, the revenue & impairment are shown at gross level (before any accounting adjustments), which is in line with the regulatory accounting principles.

7.4 Gross impairment and customer payment levels

Eskom has limited its impairment application to only 2% of revenue; despite projecting a much higher impairment %. The tables below shows the gross impairment and payment levels per customer segment respectively.

TABLE 24: GROSS IMPAIRMENT (R'M)

Gross Impairment (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027	3 Year MYPD5 Application
Soweto	(1)	298	283	122	-	-	-	-	
Munics	7 912	6 940	7 947	7 251	6 905	6 785	6 701	7 371	
Top Customers	64	70	173	182	202	231	252	277	
Other LPU & SPU	252	253	655	686	761	871	949	1 044	
Impairment cost based on projected overdue debt	**8 228**	**7 561**	**9 058**	**8 241**	**7 868**	**7 887**	**7 902**	**8 693**	**23 996**
Limited to 2% of revenue				(2 575)	(1 356)	(777)	(101)	(151)	(4 708)
Impairment costs applied for	**8 228**	**7 561**	**9 058**	**5 666**	**6 511**	**7 110**	**7 802**	**8 541**	**19 288**

TABLE 25: SUMMARY OF PAYMENT LEVELS PER CUSTOMER SEGMENT

Payment Level per Sector (%)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Munics	92.0%	93.0%	93.1%	94.2%	95.0%	95.6%	96.0%	96.0%
Soweto excl Interest	20.7%	19.3%	22.7%	24.8%				
Top Customers	100.4%	100.1%	99.8%	99.8%	99.8%	99.8%	99.8%	99.8%
Other SPU & LPU	99.9%	99.3%	98.6%	98.7%	98.7%	98.6%	98.6%	98.6%
Total	**96.2%**	**96.4%**	**96.3%**	**96.9%**	**97.3%**	**97.6%**	**97.8%**	**97.8%**

The projected FY2022 payment level of 96.3% is projected to increase to 97.8% in FY2027.

Overdue debt for municipalities is the biggest component of the projected overdue debt increase. The overdue debt is projected to reduce over the MYPD5 application period through improved payment levels and debt reduction strategies which Eskom is embarking on. The summary of the overdue debt is shown in the table below.

TABLE 26: SUMMARY OF OVERDUE DEBT

Overdue Debt (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Top Customers	350	325	414	529	666	826	1 013	1 240
Other Large Power Users (LPU)	359	387	626	877	1 130	1 312	1 563	1 860
Other Small Power Users (SPU)	1 369	1 451	1 636	1 890	2 184	2 368	2 758	3 212
Municipalities	28 042	35 524	43 924	51 924	59 524	66 744	73 964	81 864
Soweto (including interest) *	12 711	8 172	4 323	4 532	4 611	4 702	4 805	4 922
Total	**42 832**	**45 859**	**50 923**	**59 753**	**68 115**	**75 952**	**84 103**	**93 098**

Non-payment of the Munic current accounts excluding interest is currently more than R6bn per annum. Our projection for the application years assume significant improvements in the payment of the current accounts, improving the current R6bn annual non-payment to only R3bn by FY2025, assuming that the major defaulting municipalities significantly improve their current account payments to Eskom; and that our active partnering strategy is yielding the desired results. The table below presents the municipal overdue debt annual growth.

TABLE 27: MUNICIPAL OVERDUE DEBT ANNUAL GROWTH (CAPITAL AND INTEREST SPLIT)

Overdue Debt - Municipalities (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
New Interest raised	3 010	1 310	1 820	2 610	3 370	4 090	4 790	5 250
New Capital debt	5 144	6 172	6 580	5 390	4 230	3 130	2 430	2 650
Total annual overdue debt growth	**8 154**	**7 482**	**8 400**	**8 000**	**7 600**	**7 220**	**7 220**	**7 900**
Total	**28 042**	**35 524**	**43 924**	**51 924**	**59 524**	**66 744**	**73 964**	**81 864**

7.4.1 Additional strategies to mitigate against increase in Impairments

In order to limit the growth of bad debt (impairment) to the Eskom cost base, the company has adopted an approach to limit debt growth whilst enabling electricity sales that includes:

- **Continuous review and enhancement of credit management policies processes:** Eskom's debt and credit management policies, processes and strategies are reviewed on a regular basis to ensure the robust application of our credit controls in order to minimize the impact of escalating debt.
- **Prepaid sales:** Out of Eskom's customer base of 6.7m (March 2021), there are 6.5m prepaid customers (95%). The strategy is to continue to offer new customers the prepaid option and convert existing postpaid customers to prepayment. High risk customers have been identified in all provinces and are converted to prepayment. The conversion process is in progress. A number of large power accounts are also on a payment in

advance option, to reduce the debt risk to Eskom. Prepayment for large power supplies are being investigated and will be supported through smart metering.

- **Deposits / security:** Ensuring an increase in deposits and securities to mitigate future risk by customers identified as potential high risk defaulters. The process to ensure adequate account security across all customer segments will be managed over time to balance this requirement and the unintended consequence of an increase in overdue debt.
- **Innovation:** Eskom has successfully piloted revenue collection for two municipalities. This included the replacement of meters in the municipality, maintenance as well as billing large power customers. The results indicated a reduction in overall municipal losses and an increased cash flow to fund business operations within the municipality. Different operating models are being investigated to ensure viability and sustainability in the future electricity industry.

The service delivery proposals make provision for different working arrangements with municipalities as agreed in the service delivery framework. In extreme cases it may even be requested that Eskom takes over the electricity service delivery within financially distressed municipalities.

The consultative activities have included and will continue to include:

- Engagements with the respective municipal Executives.
- Inter-Governmental Provincial meetings with all the relevant stakeholders.
- Regular National Governmental meetings including Active Partnering.

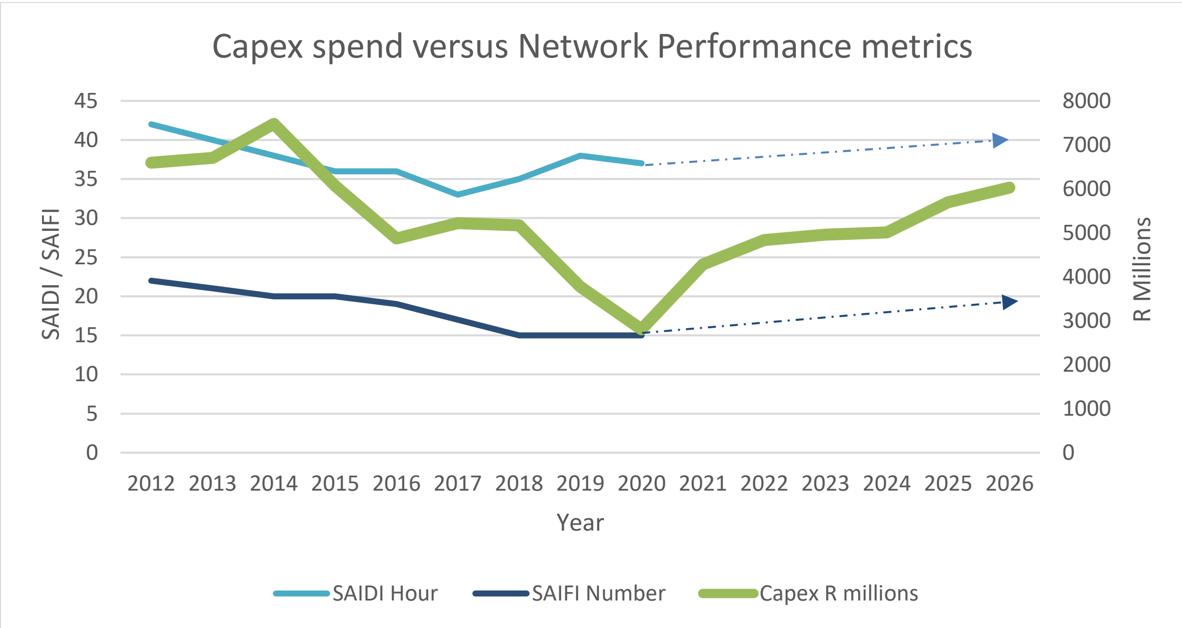
8 Revenue Related Information - Capital Expenditure

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.

FIGURE 12: HISTORICAL NETWORK PERFORMANCE



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. The table below indicates the planned expenditure in the various categories for the MYPD5 period. It is important to note that:

- An acceleration of the Bid Rounds for the IRP program 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 finalization 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.
- 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.

TABLE 28: CAPEX EXPENDITURE REQUIREMENTS (R'M)

Capital expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Direct Customers	1 003	931	1 099	1 282	1 235	1 384	1 539	1 601
Strengthening	962	947	1 667	1 857	2 236	2 193	2 569	2 747
Refurbishment	457	451	990	1 424	1 208	1 868	1 311	1 400
Land & Rights	9	15	53	39	41	59	124	134
IPP Connections	55	61	71	430	730	1 030	1 215	1 015
Asset Purchases	157	230	298	564	678	492	126	128
BESS project	-	-	4 281	3 247	4 524	2 074	1 139	-
Eskom funded	**2 643**	**2 635**	**8 459**	**8 843**	**10 652**	**9 100**	**8 023**	**7 025**
DMRE Funded	2 432	2 691	2 339	3 013	3 165	3 323	3 489	3 663
Total capex	**5 075**	**5 326**	**10 798**	**11 856**	**13 817**	**12 423**	**11 512**	**10 688**

8.1 Distribution networks investment drivers

The following factors are the key drivers for the CAPEX expenditure:

- Enabling capacity as a precursor for growth in the economy and support to government led initiatives, including the IRP 2019 plan, up until 2025.
- Further progressing towards meeting regulatory and statutory requirements as stipulated by NERSA

- Ensuring commitment to a Distribution landscape that is focussed on the evolution of new requirements, Universal Access, Distributed Energy Resource Integration and technology advances (including disruptive technologies such as battery storage), whilst maintaining current network performance and reliability measures.
- The historical capital investment backlog is extensive and although continued investment is provided in this area, - given the deterioration in the network's aging profile and regression in the performance of the aged distribution networks, the requested investment may not fully suffice.
- Capital for strengthening and refurbishing existing Distribution networks and for new IPP and SSEG projects.
- Capital to support the evolution of the Distribution landscape to cater for a bi-directional flow of electricity, the required management of associated disruptive technologies, whilst meeting the needs of prosumers and generators, in addition to the normal load-based customer requirements.

8.2 Capital expenditure per category

8.2.1 Direct customer connections

Direct customers are end-users that are supplied by Eskom. The customers in this category exclude prepayment customers that are electrified as part of the DMRE Electrification program. These customers require investment in network infrastructure funded by the requested CAPEX. Customer projects are driven by the economic growth within the country and the projected applications made by customers. Key drivers for this category are the following:

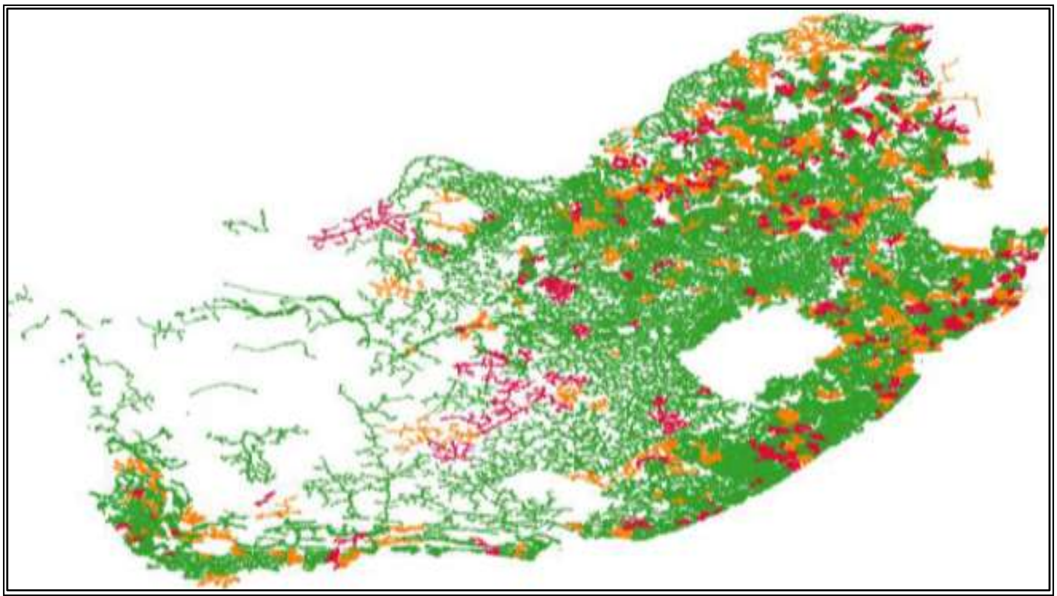
- New customer connections in the small to medium category
- Customer willingness to pay for the required incremental load.
- Constrained networks in some parts of South Africa; constrained networks dilute the potential to connect new customers to the network that can support Eskom sales growth.
- The Licensee will continue to connect new customers to the grid within the agreed time parameters where capacity is available on the grid. The grid is continuously strengthened, based on the most recent network development plans. The ensuing needs from the Development Plans are prioritized, and projects are then executed based on the capacity and the availability of budgetary funding.

8.2.2 Network Strengthening

Network strengthening can be defined as the expansion and or upgrading of plant to increase capacity or improve the quality of supply for a defined network or area. The strengthening program expenditure is geared towards providing the shared network infrastructure for customers and generators as required by the Distribution Network Code. Correspondingly, the projects within this program provide supporting network infrastructure for electrification programmes and Government led initiatives such as the National Development Plan, the Integrated Resource Plan of 2019 and the Strategic Infrastructure Build projects. The program further ensures that network constraints are averted, as these could affect future load growth in these areas.

The funding is required in the short term due to a historically low strengthening spend. The number of constrained MV feeder networks in the Distribution business remains high, and 797 of the 8 557 MV feeders remain voltage constrained, whilst 447 networks are currently exceeding their thermal capacity. The expenditure requirements will address some of the historical issues; avert potential risk in accommodating existing customer requirements and regulatory standards. The figure below details the extent of MV networks that are currently voltage constrained (Note that the networks highlighted in red are currently voltage constrained).

FIGURE 13: VOLTAGE CONSTRAINED MV FEEDERS IN 2019

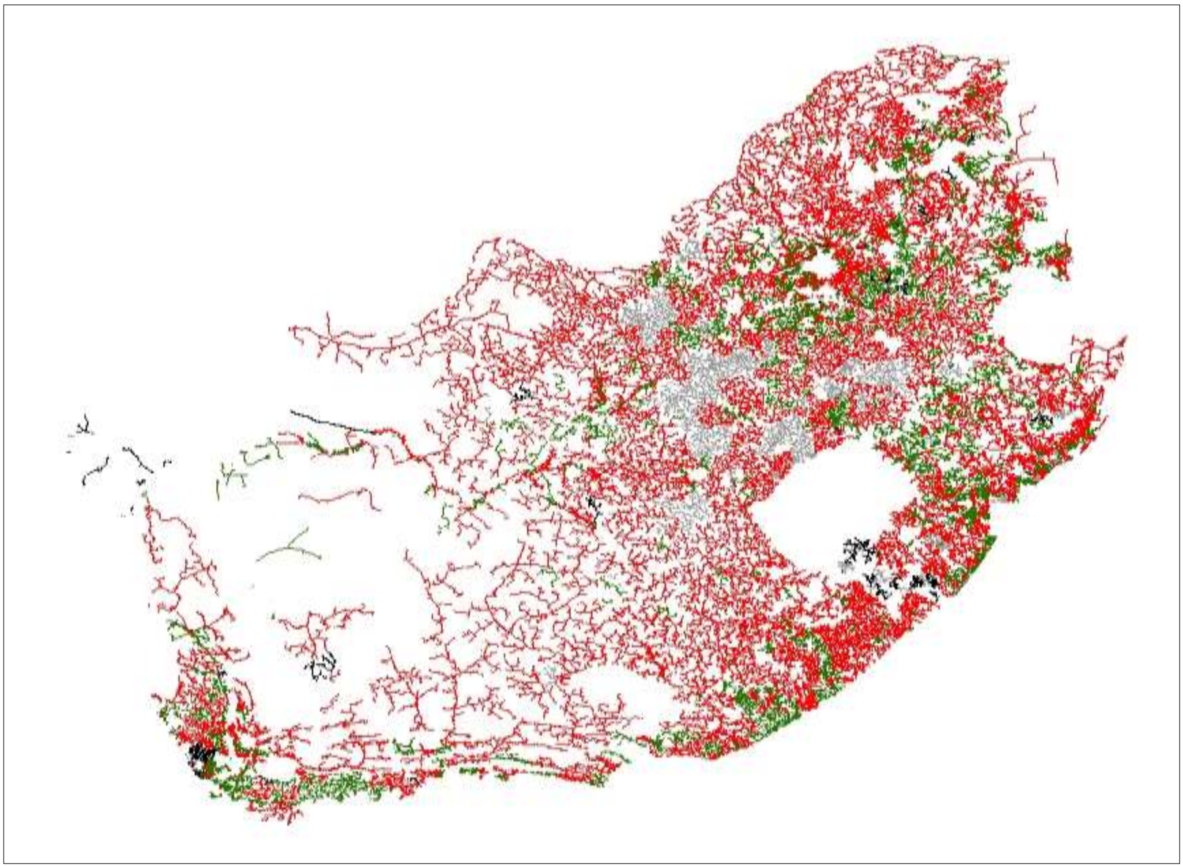


The reliability program, as a sub-set of the strengthening program, supports compliance to the Regulatory standards, Network Code compliance and a maintenance of current network performance levels. The program is geared towards providing acceptable performance, and improved power quality within the different levels of the network infrastructure. Further improvement interventions plan to enable the reliability of networks by:

- Reducing the number of faults by addressing constrained networks, and applying more robust substation and line designs
- Limiting impacts of outages by reducing the number of customers per feeder, through splitting or adding more feeders, and implementing fuses at transformers.
- Limiting the duration of outages by automating and installing substation RTU and fault path indicators.
- Continuously improving the network visibility for operational purposes

Should the strengthening and reliability projects materialize the following illustrative network outlook could materialise. The figure below illustrates the potential impact of the number of constrained feeders that could increase dramatically if the associated investment does not materialise.

FIGURE 14: ILLUSTRATIVE EXAMPLE OF POTENTIAL IMPACT OF AN INCREASE IN CONTRAINED MV FEEDERS



The impact of an increase of constrained feeders in the country will have an impact of limiting the electrification program, reduce the potential of increased revenue as limited numbers of new customers will be able to be connected to the networks. Additionally the network performance will deteriorate, safety related incidents increase, whilst impacting the cost of unserved energy to the country.

The Licensee will include the following technology advancements into its strengthening program to enhance the reliability of its networks:

- The introduction of Distribution Automation platforms for selected networks to improve the monitoring, maintenance and operability of the Power System, taking into account the bi-directional flow of energy emanating from Distributed Generators.
- The introduction of Non-Wire alternative solutions, such as Battery Energy Storage and other hybrid solutions, to assist with the evolution of network and customer requirements.
- The introduction of a Meter Data Management System (MDMS) as part of the integration of the Smart Metering capability for the business. Eskom is experiencing an increase in overdue debt across all market sectors, non-technical energy losses (illegal connections) and an imbalance of supply and demand (overloading of the system). This system will enable the business in addressing non-payment, meter tampering, load management, online monitoring of customer usage patterns and online purchasing of electricity. It anticipates that the projected expenditure will ensure business agility and readiness in tackling illegal theft, and sustaining the financial position through effective revenue collection.
- The installation of cameras, drones and monitoring capability due to a high level of theft of equipment and an increase in number incidents impacting the safety of staff. This investment will improve the safety and security of personnel and secure equipment at remote locations.

8.2.3 Refurbishment

The primary objective of refurbishment is to extend the life of assets and the maintenance of expected performance levels. Failure to refurbish assets timeously will have a negative impact on the maintenance and operations of the network and associated equipment, with respect to increased maintenance, increased fault activity, increased maintenance resource requirements (labour, materials, fleet, budgets etc.) and deteriorating technical performance metrics. Refurbishment requirements are derived from the asset base and its associated condition. Asset obsolescence and maintainability also form an input into the refurbishment plan.

"Refurbishment is a special case of maintenance and it refers to the replacement of equipment in compliance with current technical practice, safety standards and the desired operating performance. In this case, the existing plant life is realised or even extended. Whilst maintenance focuses on supply

service enhancement, refurbishment focuses on the replacement of components of particular equipment or the entire equipment. Maintenance and refurbishment do not result into new income stream but ensures that the original stream is secured or improved." (Davidson, 2005, p.340)[1].

The refurbishment program deals with assets at the end of their life cycle that are replaced with new assets, to ensure that the networks continue to perform at accepted levels, whilst maintaining a supply to the current customer base, served by these assets. As stipulated by NERSA, a minimum level of performance is required on the Distribution Networks, which is based on the National Regulatory Standards (NRS).

A substantive amount is required for refurbishment of networks due to historical low spend within the refurbishment environments. The refurbishment plan aligns to a balanced approach between the existing performance of the networks, and the requirement to refurbish old and poorly performing networks.

For this application period, the strategies for refurbishment projects will consider the following elements:

- Condition of the network classified in terms of: Age, Maintainability/obsolescence and Safety performance of the asset
- Reducing high failure rates and safety concerns
- Normalisation of assets to new standards
- Mitigating the risks associated with any unsafe networks or equipment

8.2.4 Independent power producers (IPPs) and small scale embedded generators (SSEG)

The capital expenditure associated with Independent power producers (IPP's), is informed by the Integrated Resource Plan 2019 (published by DMRE in October 2019). It calls for an increase in generation capacity using a mix of resources, including Renewables. The actual implementation of the IRP is through ongoing Ministerial Determinations, as determined by the REIPPP process and by provisions made for Emergency Procurement programs, such

[1] Utility asset management in the electrical power distribution sector; Innocent E. Davidson.; 2005 IEEE Power Engineering Society Inaugural Conference and Exposition in Africa

as the RMIPPPP. The table below indicates the expectations emanating from the IRP 2019 program.

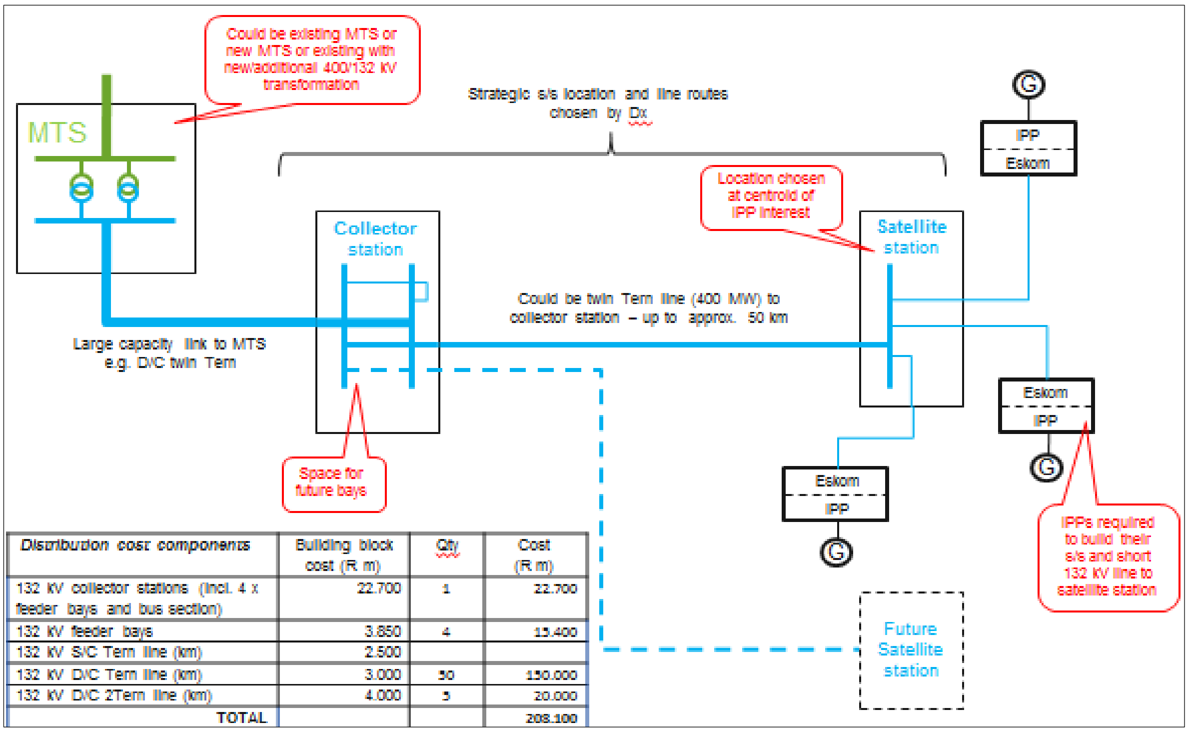
TABLE 29: IRP 2019 PROGRAM REQUIREMENTS PER SOURCE CATEGORY (PG.44)

	Coal	Coal (Decommissioning)	Nuclear	Hydro	Storage	PV	Wind	CSP	Gas & Diesel	Other (Distributed Generation, CoGen, Biomass, Landfill)
Current Base	37 149		1 860	2 100	2 912	1 474	1 980	300	3 830	499
2019	2 155	-2373					244	300		Allocation to the extent of the short term capacity and energy gap.
2020	1 433	-557				114	300			
2021	1 433	-1403				300	818			
2022	711	-844			513	400 / 1000	1600			
2023	750	-555				1000	1600			500
2024			1860				1600		1000	500
2025						1000	1600			500
2026		-1219					1600			500
2027	750	-847					1 600		2000	500
2028		-475				1000	1 600			500
2029		-1694			1575	1000	1 600			500
2030		-1050		2 500		1 000	1 600			500
TOTAL INSTALLED CAPACITY by 2030 (MW)	33364		1860	4600	5000	8288	17742	600	6380	
% Total Installed Capacity (% of MW)	43		2.36	5.84	6.35	10.52	22.53	0.76	8.1	
% Annual Energy Contribution (% of MWh)	58.8		4.5	8.4	1.2*	6.3	17.8	0.6	1.3	

- Installed Capacity
- Committed / Already Contracted Capacity
- Capacity Decommissioned
- New Additional Capacity
- Extension of Koeberg Plant Design Life
- Includes Distributed Generation Capacity for own use

The Eskom Capital allocation for IPP's, provides for the shared network infrastructure that is to be created to allow for the evacuation of power from the IPPs on the DMRE program. To cater for the expectations of the IRP 2019 program, a series of Collector Stations will have to be constructed in anticipation of the IPP connections to the Distribution networks, and for the evacuation of the power into the grid. The figure below portrays a typical layout of the Collector Station.

FIGURE 15: COLLECTOR STATION REQUIREMENTS FOR THE EVACUATION OF IPP GENERATED POWER WITHIN AN MTS AREA



Distribution cost components	Building block cost (R m)	Qty	Cost (R m)
132 kV collector stations (incl. 4 x feeder bays and bus section)	22.700	1	22.700
132 kV feeder bays	3.850	4	15.400
132 kV S/C Tern line (km)	2.500		
132 kV D/C Tern line (km)	3.000	50	150.000
132 kV D/C 2Tern line (km)	4.000	5	20.000
TOTAL			208.100

The IPP is responsible for its own network establishment cost up to the point of connection. The required funding is for the related upstream strengthening projects, which are borne by the Distributor in line with the Grid Code requirements. The initial establishment cost will also have to be funded by the Distributor, to enable the aggregation of connections at the Collector Stations. The apportioned cost up to the point of connection will be for the account of the IPP, however shared network infrastructure investments will be borne by the Distributor.

8.2.5 Battery Energy Storage System (BESS)

The following elements were considered when the final list of sites were consolidated in line the project objectives for the Battery Storage Project:

- Proximity of the site to renewable energy sources (World Bank emphasis)
- Resolution of network constraint capability by using BESS
- Charging capacity available on the network in question for the BESS
- Suitable land availability to ensure project is able to be completed within timelines as agreed with the World Bank
- Planning proposals were primarily shaped by the philosophy that the Primary Use Case for the BESS installation was for Peak Shaving support (energy support service) for the System Operator during System Peak periods and for the provision of ancillary services when the system would require frequency and voltage support.

The project is to be completed in two phases, and the first phase of the project is envisaged for completion early in 2022. The balance will be commissioned in the ensuing years. Phase one of the project consists of 6 sites, and a combined 197.5 MW of BESS, with a capacity of 827 MWh is to be connected. The second phase consists of five sites, and 145.5 MW of BESS, with a capacity of 622 MWh will be connected. In addition, 60 MW of Solar PV is to be connected as part of the project. The total Capital requirements will be determined when the Design proposals are finalised and a clearer indication of BESS efficiencies, impact of ambient temperature, charging capabilities, technology types and capacity requirements, are made available.

The premise for the current Planning Proposal aligns with the overall BESS project capex requirement of R15,3bn for the project (Phases 1 and 2 respectively), dependent on the technology used for the projects.

Whilst the overall cost is yet to be determined, the justification of the projects are based on the fact that the BESS units will provide ancillary and energy support services to the system, and provide local load shaving opportunities for constrained networks, whilst providing an investment deferral option to the respective Operating Units at the same time.

In addition, the installation of BESS will provide ancillary support in terms of enhanced frequency control of the network, reactive power support and improved quality of supply performance in close proximity to existing Distributed Generation Renewable Energy plants

8.2.6 Asset purchases

The expenditure required for asset purchases includes the acquisition and replacement of workshop, production and office equipment of a capital nature. This expenditure is required to expand, operate and maintenance new and existing distribution networks. These assets include amongst others test equipment, toolboxes, live-line equipment, ladders and specialized tools for line construction.

Live-line equipment is used for maintenance of networks, while ensuring an uninterrupted supply to customers. In order to minimize customer interruptions the prior acquisition of mobile substations, strategic transformers and critical spares are required. These strategic assets are essential whilst work is carried out on the network for maintenance or in the case of failures of sub-station equipment e.g. transformers. These mobile substations and critical spares are placed in strategic location across the country for quick supply restoration essential to sustain uninterrupted supply to customers.

The extensive vehicle fleet used by the Distribution Business to operate and maintain its assets, and to service the customer requirements, has to be maintained at an acceptable level. Allowance is thus made for the replacement of vehicles that have served their useful life, and where the vehicles are no longer in a roadworthy condition to meet these requirements.

8.2.7 Electrification

Eskom continues to increase electrification connections in support of Government's objective of universal access to electricity. Funding is provided by the DMRE to meet these stated objectives for the remaining customers to be electrified. It is intended that universal access is achieved by 2025 and Eskom is currently electrifying approximately 200 000 customers per annum in line with the gazetted program, and in association with the Municipal Electrification objectives around the country.

8.2.8 Operating technology (OT) requirements

The Licensee operating systems support the daily operations and management of the Distributors Plant and Equipment. Obsolescence and limited support for outdated technology require upgrades or new systems. This intends to facilitate a changing business landscape as it increasingly gravitates towards a smart and interconnected grid.

The following operating technologies will require changes during the MYPD5 control period:

- The replacement of the distribution management system (DMS) and Supervisory Control and Data Acquisition (SCADA) with an advanced DMS due to obsolescence. This system of software and hardware allows the Licensee to control processes, operate, and to monitor and gather real time information of the electricity network for normal operations, outage scheduling and in cases of faults and emergencies. It will also allow for the integration of Energy Management systems, as required for the integration and management of technology disruptors, such as Battery Energy Storage integration requirements.
- The SmallWorld repository upgrade to the SmallWorld Enterprise Office (SWEO) system will ensure that the repository of all equipment and its associated attributes are spatially maintained (via a geo-based location). The system includes planning functionalities, and links to all performance and maintenance requirements for reporting on various performance indicators e.g. SAIDI and SAIFI.
- The implementation of a Data Analytic tool, supported by an Enterprise Historian to acquire and store real time analysis data, as required for the transition into the Fourth Industrial Revolution.

- The implementation of the Meter Management Data System (MDMS) for the management of the smart meters in the field as part of the program to manage and collect revenue, outage management and smart grid implementation.
- Due to obsolescence of customer engagement channel systems and software, there is a need to invest in the required technology to support the realization of the channel optimization project aims. This will ensure the transition to the customer required digital services.
- The acquisition of the required Operational Technology requirements for the establishment of a Distribution System Operator and Energy Trader.

9 Integrated demand management

In terms of Section 14 of the MYPD methodology, Eskom Integrated Demand Management (IDM) is required to implement Energy Efficiency and Demand Side Management (EEDSM) programmes.

The role of IDM is to influence the electricity demand profile of its customer base for the benefit of Distribution business, the entire Eskom value chain and the country as whole.

Over the past 11 years, whilst Eskom experienced a supply shortfall, IDM focused mainly on energy usage reduction and load management. It is anticipated that the country will continue experiencing a shortfall in generation capacity in the short to medium term.

In particular, EEDSM measures will also support the Distribution System Operations (DSO) by providing flexible services (dispatchable supply and demand) to maintain adequate operating reserve levels reducing evening peak demand in the industrial, commercial and residential sectors to manage grid stability and congestion on the local and national networks. Furthermore, EEDSM measures continue to be used to optimise capital expenditure on constrained networks by deferring network upgrades through localised demand-side management programmes where feasible.

Past experience has proven the valuable contribution EEDSM programmes can make to stabilising the electricity system. The demand / supply situation is cyclical and maintaining the EEDSM capacity is essential. More so, having EEDSM capacity that uses the principle of efficient energy when required by business as a means to support both excess and constrained supply situations will be a considerable asset to the industry and the economy.

9.1 EEDSM – Load management delivery channels

Eskom IDM is responsible for developing solutions and managing the delivery of energy and demand savings through a variety of programmes in the commercial, industrial, residential, and agricultural sectors

Irrespective of whether or not Eskom is in a period of excess or constrained supply, the system demand profile has a significant impact on the future supply requirements and the sources and cost of generation. The system load profile is becoming more “peaky”, resulting in high production cost during peak periods and low power station utilisation during the night.

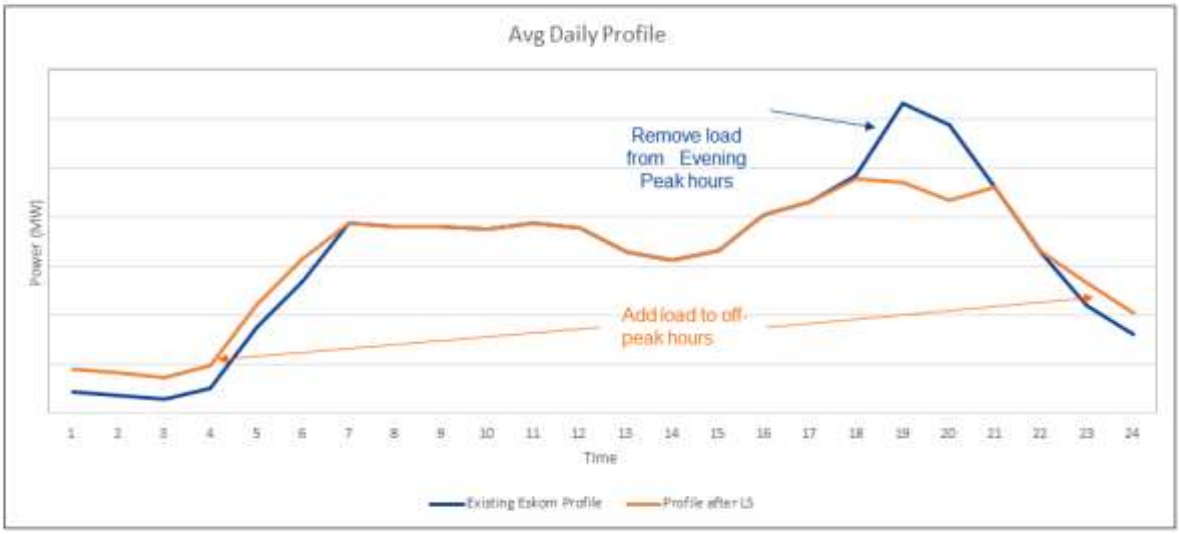
Through the Eskom Distribution Additional Capacity Programme, a number of stream initiatives have been developed. The Customer Load Management (CLM) being one of the streams was designed on EEDSM hardwired principles, to assist the grid with additional capacity. The approved sub-streams under the CLM stream are namely, Load Shifting Programme, Industrial Commercial Energy Efficiency Programme and Residential Existing Ripple Programme. The following are the key delivery channels for IDM EEDSM programmes:

9.1.1 Load Shifting Programme

The objective of the programme is to implement load shifting from evening peak periods to off peak periods, aligned to the Mega-flex TOU periods). Alleviating pressure on the power system through shifting of load by large customers has been identified as a key initiative by ESKOM in balancing the supply versus demand challenge. The benefits of implementing Load Shifting programme projects are as follows:

- Load Shifting projects change the time of day during which electricity is consumed without reducing sales volumes.
- Load Shifting projects have been seen to be rapidly implementable and cost effective compared to OCGT utilisation.
- The short-term national demand-supply situation is cyclical and maintaining capacity for future periods of supply shortage is essential.
- A flatter system load profile will reduce future generation costs and will benefit ESKOM in alleviating pressure on the power system.

FIGURE 16: LOAD SHIFTING IMPACT

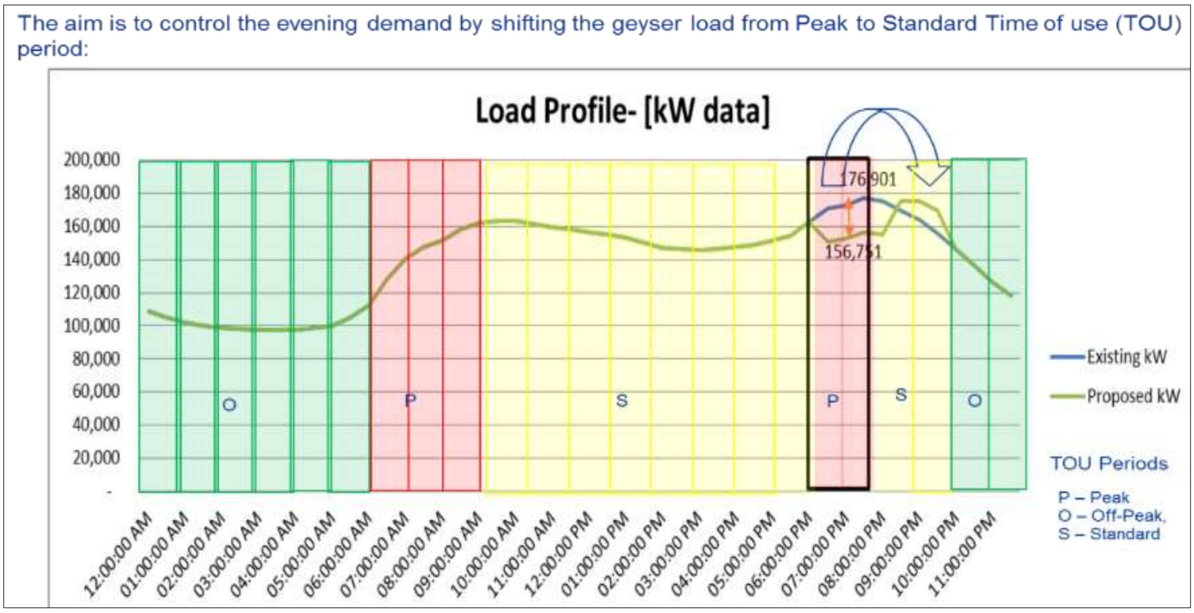


The figure above depicts management of customers load profiles such that the evening peak load is shifted to off-peak periods hence reducing OCGT utilisation in the evening peak periods.

9.1.2 Residential Existing Ripple Programme

Eskom Distribution plans to use Residential Load Management smart technologies, as part of the smart grid strategy, to shift residential peak demand to off-peak through management of residential hot water cylinders/geysers in various households within its area of supply as well as throughout South Africa in collaboration with municipalities. The smart technology will allow introduction of flexibility and central dispatchability as all the smart control systems could be aggregated for use by the Distribution System Operations as one of the levers to manage demand during constrained periods. By introducing flexibility in optimising the system load profile and supporting an optimal future generation mix, EEDSM remains a key financial and operational driver. The figure below shows a typical residential profile showing a shift of 20 MW peak demand to off peak using geyser control system

FIGURE 17: A TYPICAL RESIDENTIAL PROFILE LOAD SHIFTING (GEYSER CONTROL SYSTEM)



9.1.3 Industrial and Commercial Energy Efficiency Programme

The energy efficiency programme entails hardwired solutions that will reduce the energy consumption through the implementation of energy efficient technologies (efficient lighting, VSDs, HVAC systems, Process Optimization etc.) to produce the same output requirements.

EEDSM is used in the planning, implementation, and monitoring of distribution network utility activities, designed to influence customer use of electricity in ways that will produce desired changes in the load shape, which includes load shifting, energy conservation and strategic energy efficient load growth.

The programme designs are based on performance verification over a contracted sustainability term. IDM therefore provides financial incentives incrementally for savings realised during the sustainability phase. Not only do customers benefit from the incentive, but Eskom in the short-term reduces generation cost and in the long term delays generation expansion, thus providing a win-win solution and benefits downstream within the electricity value chain

9.2 Targeted communications programme

Eskom has initiated three campaigns to assist in stabilizing the system and reducing load. Eskom Distribution will introduce additional campaigns to support Energy Efficiency and load management technologies to the different market segments.

This programme is part of the ‘Eskom Distribution Additional Capacity Programme’, which assists the System Operator when the grid is tight, by reducing the demand for electricity. It involves behavioral measures in order to influence the demand. The savings are measured during the Eskom defined standard and peak periods in accordance with the approach to operating costs; a symmetrical treatment of variances is included.

The campaigns are to provide marketing/communications support to demand management solutions technologies by putting in place Load Management Marketing Mix Elements to encourage consumers to reduce demand, keeping in mind the load management key principles. The campaigns must consider the following “BIG IDEA” and rational in formulating Marketing campaigns i.e. Be Greener, Planet Issue, (Find enduring term that looks at the cyclical behavior of energy demand). The campaign must run for several years until such time that Load Management is no longer required i.e. system is stabilized and consumers are repeat buyers of technologies promoted.

The following targeted communications solutions are included:

- **Residential** – “Use electricity smartly” campaign: Create a national mass media campaign to rally the country to assist to limit or avoid load shedding, with specific focus areas:
    - 9am – 5pm period (beat the peak) – Residential mass media broadcasting campaign focusing on higher LSMs (LSM 8 -10).
    - Channels: Multi-channels (radio, digital and social media) radio focusing on evening drive-time (4pm – 6:30pm) demand reduction by switching-off and implementing saving tips, especially during constrained periods, while social media will share the campaign messaging during the day.

The estimated voluntarily demand reduction size is 15 MW / annum over the MYPD5 period. Proposed social media positioning: (#PleaseUseOnlyWhatYouNeed)

- **Business – "Use electricity smartly" campaign:** Create a national mass media campaign to rally the country to assist to limit or avoid load shedding, with specific focus areas:
    - Business hours (7am – 3pm) period
    - Channels: Business mass media broadcasting campaign (radio, digital and social media) focusing on morning drive time and through the day to manage the heating and cooling load (heating ventilation and air-conditioning HVAC load) in all sectors, during constrained periods.
    - Position Energy Advisors as energy experts who assist businesses with load optimization and energy efficient advice.

The estimated voluntarily demand reduction size is 35 MW per annum over the MYPD5 period.

- **Load management technologies support campaigns:** Put in place specific awareness campaigns for the industrial / agricultural / commercial markets. Campaigns focused at improving energy efficiency and load management in the Industrial, Agricultural & Commercial markets.
    - Channels used to educate specific segments of the market include: Appropriate print media, Appropriate Events/shows, Social media, SMS and Internet

9.3 Measurement and verification

Measurement and verification is the independent third party measurement, verification and tracking of demand and energy savings realised by the implementation of EEDSM projects by project developers. Eskom contracted a number of measurement and verification teams to independently measure, verify and report the verified savings. This improves the credibility and acceptability of the reporting to the various stakeholders. As and when needed, additional independent teams may be contracted.

Planning and budgeting for the measurement and verification function is largely dependent on the work volume received from EEDSM programme. These activities and expenses on EEDSM projects or programmes are recovered from the IDM budget, and are therefore included in this plan.

9.4 IDM key focus areas and approach

A number of key focus areas that drive integrity and quality of the various programmes underpins IDM.

Key Focus Areas	IDM Approach
Robust project management approach	IDM has built up an extensive project and contract management capacity. Where, due to variations in workload, additional capacity may be required, external resources will be contracted. For large projects, multi-functional project teams will be created, following robust project management methodologies.
Project governance and approval	Eskom governance processes will be complied with.
Ensuring that estimated savings do realise as anticipated	Measurement and Verification (M&V) is responsible for independent third party measurement, verification and tracking of demand and energy savings.
Pro-actively address potential fraud	All IDM programmes are subject to the Eskom audit requirements.
Safety	Eskom will specify compliance to safety, health and environmental requirements and standards.

9.5 Technical and cost calculations

9.5.1 Energy and Demand savings

The estimated demand savings in the IDM plan are based on a combination of a projection of estimated savings of the various individual projects and large-scale initiatives, and the technical potential of savings that can be achieved per sector.

Maximum demand is measured at the maximum point of the load profile and is generally measured in Megawatts (MW). It is also the maximum electricity consumed at a given point in time. EEDSM programmes targets and reports peak demand and energy savings. This is based on the average demand measured during Eskom evening peak periods (6pm to 8pm summer and 5pm to 7pm winter), refers to the full year and is measured in MW.

IDM aims to implement measurable and sustainable demand and energy-reduction interventions by introducing energy efficiency and load-reduction technologies and behaviours into customers" electricity purchasing patterns. If adequately funded, Eskom's current IDM initiatives can rapidly contribute to closing the foreseen energy gap. This is important, because the risk of load shedding and the requirements to reduce energy consumption are crucial to ensuring security of supply.

9.5.2 Cost benchmarks

The cost benchmarks are programme specific and are expressed as a maximum monetary value or expenditure cap up to which Eskom IDM will fund a project. Additional project costs falling above this benchmark are to be funded by the customer. Given the levels of the rebates, the customer business cases are generally very lucrative with short payback periods that incentivise their investments. When calculating the value of the benchmark consideration is made regarding the incentive level that would yield sufficient uptake, of the offer, by the market, the cost of implementation and consideration to cost avoidance. In addition, IDM is driven by the objectives of Supplier Development and Localisation. Cost benchmarks are also adapted to ensure sufficient uptake from these sectors. The benchmarks are used to determine the project cost and are usually specified in R'm per MW.

9.5.3 Project costs

The annual cost estimates are based on the actual historically incurred project costs from invoicing schedules and are spread equally over the duration of implementation of a project. In general, costs are calculated based on the expected peak demand savings (MW) to be delivered during a financial year, as well as associated cost to deliver the demand savings. The Load management and Residential Load Management Programmes are Performance Contracting models and will have an impact on the budgeting process, in that project funding will be payable over a three year sustainability period after implementation. It is assumed that all costs are incurred in the same year as the realised savings.

9.6 IDM MYPD5 application costs

The IDM MYPD5 application includes the EEDSM programme and the Targeted Communications programme. The total estimated cost over the MYPD5 period is R1.192bn. The IDM MYPD5 cost breakdown is provided in the table below.

TABLE 30: IDM MYPD5 APPLICATION COST

IDM Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
EEDSM - Load Management Programmes	-	-	253	288	264	172	51	55
Measurement and Verification (M&V)	-	1	10	17	20	23	9	9
Marketing - EEDSM Programme Support	26	65	5	6	7	9	4	4
Targeted Comunications Programme	0	0	116	122	129	134	-	-
Total IDM	**26**	**66**	**384**	**433**	**420**	**339**	**64**	**68**

The Targeted Communications Programme cost is R385m over the MYPD5 period. The cost breakdown over the MYPD5 period is provided in the table below.

TABLE 31: TARGET COMMUNICATIONS PROGRAMME COST

Targeted Communications Programme Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Residential: Use Electricity Smartly	-	-	32	34	36	37	-	-
Business: Use Electricity Smartly	-	-	74	77	82	84	-	-
Load Management Support	-	-	10	11	12	13	-	-
Total	**-**	**-**	**116**	**122**	**129**	**134**	**-**	**-**

The EEDSM programme cost is R724m at a benchmark cost of R2.5m/MW to achieve 290 MW peak demand savings over the MYPD5 period. The tables below provide EEDSM Programme demand savings and cost breakdown respectively.

TABLE 32: EESDSM PROGRAMME – DEMAND SAVINGS (MW)

EEDSM Programme Demand Savings (MW)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
EEDSM - Load Management Programmes	-	-	101	115	106	69	25	27

TABLE 33: EEDSM PROGRAMME COSTS

EEDSM Programme Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
EEDSM - Load Management Programmes	-	-	253	288	264	172	51	55

10 Revenue Recovery

Eskom allowable revenues are recovered through the Distribution Licensee by way of Standard tariffs and non-standard tariffs, that is, Negotiated Pricing Agreements (NPAs) and international utility tariffs. This is after the pass-through of the MYPD allowable revenues to the Distribution Licensee, see table below.

In this MYPD5 application, the existing NPAs (local and international) and international utilities revenues are escalated as per their respective contracts that were implemented with NERSA prevue. Consequently, the increase to the Standard tariffs is to recover the balance of the NERSA allowed revenues after subtracting the revenues from NPAs and international utilities.

TABLE 34: MYPD5 REVENUE RECOVERY

Revenue recovery R'm	Application FY2023	Application FY2024	Application FY2025
Non standard tariff customers	17 167	16 979	17 897
Standard tariff (including RCA's)	276 263	317 696	347 299
Total Allowable Revenue	**293 430**	**334 676**	**365 195**

10.1 Revenue recovery through tariff increases

The NERSA allowable revenue decisions will be implemented prior to the commencement of each Eskom financial year of the MYPD5 control period. The implementation will be through the applicable NERSA methodology and decisions including the NERSA RCA decision(s) and court outcomes, NERSA ERTSA decisions and other tariff and pricing decisions (such as updates to tariff structures. The annual tariff adjustment implementation will be effective 1 April for non-municipal customers and from 1 July for municipal customers in compliance to the Municipal Finance Management Act (MFMA).

The annual MYPD allowable revenue decision is aligned to the Eskom financial year, that is, 12 months from 1 April to 31 March of the following year. The Municipal Finance Management Act (MFMA) requires that electricity price increases to municipalities are only effective on 1 July, subject to Eskom (as the electricity supplier) tabling the adjusted rates in Parliament on or before 15 March in the implementation year. The Eskom directly supplied customers' (non-municipal) tariffs are therefore, effective 1 April and the municipal tariff increase is on 1 July.

NERSA's ERTSA methodology governs the calculation of the tariff increases to be applied to the different tariff charges, and this includes a separation of municipal and non-municipal tariffs to ensure that:

- Over the 12 months of the Eskom financial year, the municipal and non-municipal tariffs annual average increases are the same.

Because for the first 3 months of the Eskom financial year, the prior year's municipal tariffs are effective, the municipal price increase for the last 9 months ensures that for the 12 months of the Eskom financial year, the average municipal increase results in the same average increase with non-municipal tariffs as above.. Consequently, the 1 July Eskom municipal tariff increase applied to the tariff charges may be different from the non-municipal increase, that is, could be higher or lower depending on the prior year's 1 July municipal increase.

The tariff increases applied to the NPAs and the international utility agreements are specified in their supply agreement contracts. In the MYPD5 application, the NPA and international utilities revenues are escalated to reflect these contracts contribution to the requested Eskom allowable revenues for the respective years of the MYPD5 control period.

10.2 Pass-through of allowable revenues to the Distribution Licensee

The MYPD methodology facilitates the recognition of the Generation (Gx) and Transmission (Tx) costs in the Distribution Licensee through the pass-through rule. This enables the recovery of the Eskom allowable revenues from Standard tariffs and non-standard tariffs (NPAs and international utilities' tariffs).

The total Generation allowable revenues including the costs from Transmission for use of Tx networks, ancillary and Tx losses are passed-through to the Distribution Licensee.

The Transmission allowable revenues less those included in the Generation pass-through are passed through to Distribution. This sharing in the Transmission allowable revenues is in compliance with the Grid Code that requires Transmission to allocate its allowable revenues to generators (Generation Licensee) and to loads (Distribution Licensee).

In order to separate the Standard tariff allowable revenues from non-standard tariff customers (NPAs and international utility tariffs) the sales revenues for international sales and local NPAs are subtracted from total allowable revenues passed through to the Distribution Licensee, see table below.

TABLE 35: PASS-THROUGH TO DISTRIBUTION

Allowable Revenue (R'm)	Application FY2023	Application FY2024	Application FY2025
Generation (Gx)	246 339	281 322	309 476
Transmission (Tx)	9 779	13 234	13 880
Distribution (Dx)	37 312	40 119	41 839
Eskom total	**293 430**	**334 676**	**365 195**
	Pass-through to Distribution Licensee (R'm)		
	FY2023	FY2024	FY2025
Eskom Total	**293 430**	**334 676**	**365 195**
Generation (including costs from Tx)	247 222	283 247	311 291
Transmission	8 897	11 310	12 065
Distribution Licensee allowable revenues	37 312	40 119	41 839
Dx Licensee after pass-through	**293 430**	**334 676**	**365 195**
Non-standard tariff customers	17 167	16 979	17 897
Standard tariffs	276 263	317 696	347 299

10.3 Indicative annual standard tariff increases at an Eskom total level

The indicative annual standard tariff increases based on the requested MYPD5 allowable revenues and this application's forecasted sales are as shown in the table below.

TABLE 36: INDICATIVE ANNUAL STANDARD TARIFF INCREASES AT AN ESKOM LEVEL

Standard tariff price impact (R'm)	Unit	Decision FY2022	Application FY2023	Application FY2024	Application FY2025
Standard tariff revenues	R'm	245 710	276 263	317 696	347 299
Standard tariff sales volumes	GWh	183 856	171 549	171 440	170 370
Standard tariff average price	c/kWh	133.64	161.04	185.31	203.85
Standard tariff annual average increase	**%**	**15.06%**	**20.50%**	**15.07%**	**10.00%**

In accordance with the NERSA MYPD methodology, NERSA may revise this application's forecasted sales volumes to reflect the prevailing situation prior to an MYPD5 decision. In this regard, the tariff increases would be adjusted accordingly as they are subject to the NERSA decision forecasted sales and allowed revenues for each year of the MYPD5 control period.

10.4 Determination of standard tariff category increases

The annual tariff increase is implemented to recover the MYPD decision allowed revenues. Annual standard tariff increases are by tariff category that is municipal and non-municipal. The increase Affordability subsidy charge reflects the change in this subsidy charge value.

The NERSA ERTSA methodology is applied to determine tariff category increases as follows:

- The annual average standard tariff increase (based on the Eskom financial year), as per Rule 5 of the ERTSA methodology is used further to determine the individual municipal and non-municipal annual revenues to equal annual average tariff increases.
- The 1 July municipal (Local authority) tariff increase is calculated as per Rule 6 of the ERTSA methodology that requires the recovery of the change in the 12-month municipal revenues through a 1 July tariff increase.
- The non-municipal (Non-local authority) average increase is the annual average Standard tariff increase as per rule 5.8 of the ERTSA methodology.
- The Affordability subsidy charge increase follows on Rule 7.1 and Rule 7.2 of the ERTSA methodology that provides for the Energy Regulator as part an MYPD decision to allow cross-subsidies for implementation as a part of the annual average Standard tariff increase.
- The Affordability subsidy charge caters for the recovery of the historic lower increases to the Homelight 20A tariff and it therefore recovers the cumulative difference of lower tariff increases to the Homelight 20A tariff since 2013/14.

The ERTSA standard tariff category increases do not result in structural changes and implementation of new tariffs as per the current (at the time of this MYPD5 application) ERTSA methodology rule 3.2.

During the MYPD5 Eskom will make applications for tariff structural changes after the allowable revenue decision. Upon the NERSA approval of the updated tariff structures, Eskom will adjust the updated tariff rates using the ERTSA methodology to reflect the implementation year's price levels.

10.5 Indicative MYPD5 standard tariff increases

The indicative increases to the standard tariffs in this MYPD5 application only include the consideration of this application's applied for allowable revenues and forecasted sales.

The indicative 2022/23, 2023/24 and 2024/25 tariff increases by standard tariff categories are set out in the table below.

The 28 February 2013 MYPD3 decision provides that the affordability subsidy charge is recovered from key industrial and urban non-municipal customers (that is, not from municipal tariffs). Consequently, the large industrial and urban (non-municipal tariffs paying the affordability subsidy) will on average experience a -0.18% to the 1 April 2022 20.50% increase due to 15.66% increase to the affordability subsidy; an additional 0.02% from 1 April 2023 and an additional 0.18% from 1 April 2024.

TABLE 37: STANDARD TARIFF CATEGORY 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%

Note: The above is based on the current tariff structures. Following a tariff structure, the increases may differ e.g. if the structure of the affordability charges change then the increase will also change.

10.6 Environmental levy and Carbon tax (Levy) recovery

A c/kWh rate is used to recover the costs of the applied for recovery of the environmental levy and carbon tax costs from all customers. For standard tariffs, the recovery of the levies' costs is embedded in the energy tariff rates. For the local NPA and international sales an explicit levy c/kWh charge is raised.

11 Conclusion

The Licensee application supports the Eskom mission to provide sustainable electricity solutions to promote economic growth and social prosperity for South Africans. This is achieved through operating the distribution network to supply electricity to customers in its area of supply as specified within the Distribution licence.

Eskom's sales have declined over the past years, with the outlook remaining relatively depressed in the years ahead. A significant decline is attributed to large power users as a result of high ore extraction costs and volatile commodity markets, particularly in the ferrochrome, steel, gold and platinum industries. The measures that Eskom has undertaken to arrest this trend have been provided. It needs to be noted that the sales are a feature of the economy of the country and requires a concerted effort from various stakeholders.

Distribution's operating expenditure that includes employee costs, maintenance and other expenses has experienced a compound average growth rate (CAGR) for the period of 3.8%, which is below expected inflation. This has been a result of efficiency improvements since the MYPD4 period. Prioritising capital investments to build assets that support network performance in order to deliver reliable network performance. Due to the phasing-in of the return on assets, the consumer continues to enjoy a subsidy.

While good payment from large industrial, commercial and major metropolitan customers has been received, the areas of major concern are certain residential and municipal debt. Municipal overdue debt has increased significantly in the past few years and remains a concern. Interventions including with Government Departments and task teams are assisting in providing innovative solutions to address the fundamentals of challenges being faced.