Revenue Application

FY2018/19

August 2017

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Preface

The revenue application for the 2018/19 financial year is submitted to NERSA after receiving comments from National Treasury and organised local Government (SALGA) in terms of section 42 of the Municipal Finance Management Act (MFMA). It is understood that the National Energy Regulator (NERSA), will use this submission as part of its public consultation process affording opportunities to stakeholders to comment on the application.

This revenue application has been prepared in accordance with MYPD methodology as published by NERSA during October 2016. Due to uncertainty in the environment presently, NERSA has approved that Eskom can make a revenue application for the 2018/19 financial year only. The revenue application has been updated in accordance with the NERSA decision on the request for condonation. Assumptions, as guided by NERSA, have been made to provide details. Thus the NERSA revenue and tariff decisions will be implemented for the period 1 April 2018 to 31 March 2019 for non-municipal customers and from 1 July 2018 to 30 June 2019 for municipal customers. The five year MYPD 3 period was applicable for the period 1 April 2013 to 31 March 2018 for the non-municipal customers and 1 July 2013 to 30 June 2018 for municipal customers.

The MYPD methodology addresses two broad aspects, namely, the MYPD allowed revenue application and the adjustment of the allowed revenue through the regulatory clearing account (RCA) process. **The focus of this application is the MYPD revenue application for the 2018/19 financial year.** It is clarified that this revenue application **does not include any RCA adjustments**. Once NERSA has determined the allowed revenue in terms of the MYPD methodology, the tariffs and price adjustments are calculated in terms of the Eskom retail tariff and structural adjustment (ERTSA) methodology, as published by NERSA during March 2016. The tariffs and price adjustments are then approved by NERSA. **This application does not include any RCA adjustments.**

Executive Summary

This revenue application is being made for the year 2018/19, after the Energy Regulator maintained its revenue decision made in 2013 for the 2017/18 year, where it approved the total allowable revenue of R205 billion. The allowed revenue resulted in an average increase of 2.2% due to the base adjustments made in the preceding years following the approved Regulatory Clearing Account (RCA) balances for Eskom (12.69% for 2015/16 for MYPD2 and 9.4% for 2016/17 for the first year of MYPD3).

The 2.2% average increase resulted in consumers receiving an effective decrease in electricity prices, in a situation where costs to produce the electricity are increasing. Inflation related increases were not catered for. It is thus demonstrated that there would be a marked jump in electricity prices in the 2018/19 year partly due to the increases from an artificially low base and would not allow for smoothing of price increases. It would have a compounding effect over a number of years.

NERSA has approved that Eskom could submit a one year revenue application for the 2018/19 year. Eskom, in this revenue application for the 2018/19 year has applied the NERSA MYPD methodology of 2016, with a phasing in of return on assets being applied, resulting in a total allowable revenue of R219 514m. The building blocks for the revenue application, in accordance with the MYPD methodology are reflected in the summary table below.

TABLE 1 : TOTAL ALLOWABLE REVENUE FOR 2018/19

Allowable Revenue (R'millions)	AR	Formula	Application 2018/19
Regulated Asset Base (RAB)	RAB		763 589
WACC %	ROA	X	2.97%
Returns			22 690
Expenditure	E	+	62 221
Primary energy	PE	+	59 340
IPPs (local)	PE	+	34 209
International purchases	PE	+	3 216
Depreciation	D	+	29 140
IDM	I	+	511
Research & Development	R&D	+	193
Levies & Taxes	L&T	+	7 994
RCA	RCA	+	
Total Allowable Revenue	R'm		**219 514**

Note – there are no RCA adjustments in the 2018/19 revenue application

1.1 Key elements of allowed revenue for the 2018/19 financial year

Eskom's allowed revenue requirement is based on the Electricity Regulation Act, 2006 (Act No.4 of 2006), Section 15(1) which states:

- *Must enable an efficient licensee to recover full cost of its licensed activities, including a reasonable margin or return*

This basis is reinforced in the Electricity Pricing Policy and the MYPD Methodology.

1.2 Recovery of efficient costs

a. Primary Energy costs:

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

Due to the roll out of DOE renewable IPP progammes up to bid window 4.5, local IPPs have grown over the last few years. International supply is represented substantially by the supply from Cahorra Bassa reflecting declining trend recently attributable to the drought conditions. Eskom's own generation is used to meet the balance of supply as renewables are non-dispatchable. The expected revenue requirement related to the renewable IPP programme is R31 230m for the 2018/19 financial year. The DOE Peaker programme has been fully operational from 20 July 2016 with a total capacity of 1005 MW. The expected load factor of the two power stations (as dispatched by Eskom) is 1% in each year, leading to an expected energy output of 88 GWh per year. The allowed revenue related to these IPPs is R2 380m for the application year.

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

The compound average annual increase in the delivered R/ton cost of coal between the FY17-FY19 period is ~5%. The average increase in R/ton cost from the three main contract types is:

- Cost plus mines: 1%
- Long term fixed price mines: 13%
- Short/medium term fixed price contracts: 7%

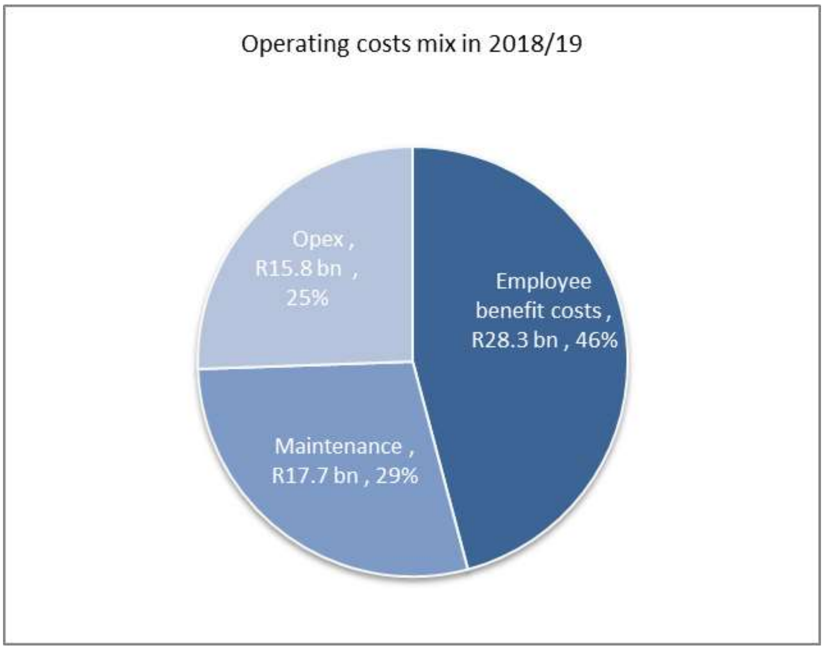
Cross border purchases from substantially Cohorra Bassa will cost approximately R3.2bn.

An amount of R8bn is the allowed revenue related to environmental levy costs based on a rate of 3.5c/kWh energy generated. It is assumed for the planning period that no further rate increases will occur. This environmental energy revenue is paid to SARS.

b. Operating costs:

Operating expenses are expected to escalate on a year on year basis from 2016/17 at less than inflation. Almost half of the operating cost is attributable to employee benefits (46%) with the maintenance (29%) and other opex (25%) making up the remainder.

FIGURE 1 : OPERATING COSTS BREAKDOWN



It is expected that employee costs will increase by inflation when compared to projections for 2017/18. Significant efficiencies would be achieved over the period by reducing the number of employees without compromising the required skills in appropriate areas. Eskom's employee benefit escalations are compared to the overall generic labour market. However the bargaining unit element is referred to as the average settlements. The employee benefits comprised the direct remuneration (salary, pension, medical aid, bonus, overtime) and indirect remuneration (training and development, temporary and contract staff). Eskom's total labour costs escalations over the last 5 years has tracked the market escalations.

As the business strives to accelerate maintenance programmes, and with the aging plant it is expected that maintenance costs should increase. Eskom will ensure that maintenance is carried out prudently and efficiently.

The growth in other operating costs is less than inflation after 2016/17. Included in this category are costs such as insurance, information technology, fleet costs, legal and audit services, security, travel expenses, billing costs, connection/disconnection costs, meter reading, vending commission costs and telecoms.

1.3 Earning a reasonable return on assets

Return on assets is computed on a revalued regulatory asset base (RAB) with the intention to cover interest costs and earn an equity return. The regulatory mechanism is based a pre-tax real return as interest and tax are not separate line items in the allowable revenue formula. The opening RAB balance for FY2019 is based on the MYPD 3 decision which is then adjusted for the latest capital expenditure forecasts for the period FY2014 to FY2018. The average RAB value for FY2019 is R764bn.

Eskom has maintained the principle to phase-in the return on assets as the full return on assets will place further upward pressure on the electricity price. Thus this revenue application for 2018/19 assumes a return on assets at 2.97% (amounting to R22.7bn) compared to a cost of capital of 8.4%.

Depreciation was computed by dividing the RAB over the remaining life of the respective assets. A depreciation cost of R29bn has remained relatively similar to 2017/18 cost as the RAB has not changed significantly and in accordance with the methodology.

1.4 Revenue recovery

Eskom's Company revenue is recovered from international customers, negotiated pricing agreement (NPA) customers, with the balance from standard tariff customers.

TABLE 2: REVENUE RECOVERY

Revenue recovery (R'millions)	MYPD 3 2017/18	Application 2018/19	Change	% growth
NPA and International customers	6 259	13 309	7 050	112.6%
Standard tariff customers	**198 954**	**206 205**	**7 251**	**3.6%**
Total Allowable Revenue	205 213	219 514	14 301	7.0%

The growth in total allowed revenue from FY2017/18 to FY2018/19 is 7% with the contribution being almost 50:50 split between standard tariff revenue and non-standard tariff revenue. Standard tariff consumers are required to contribute R7.2 billion (3.6%) more when compared to the 2017/18 decision. Eskom's strategy to maximise export sales and revenue impacts positively on the balance required from standard tariff customers.

However, the price impact would be much higher due to the allowed revenue being recovered from a lower sales volume. The impact on the electricity price due to the extent of the drop in volumes when compared to the MYPD3 over 5 years of some 30 TWh is 9.4% in 2018/19.

1.5 Electricity price impact in 2018/19

Standard tariff revenue has increased by R7 251 million which equates to revenue increase of 3.6% from NERSA's decision for the 2017/18 year. As the revenue is recouped from a lower sales volume, the overall price increase required is 19.9% for 2018/19. Two major contributors to the price increase are the sales volume rebasing (9.4% price impact) and growth in IPPs (5.5% price impact).

TABLE 3 : STANDARD TARIFF PRICE INCREASE

Standard tariff price impact	Unit	MYPD3 Decision 2017/18	Application 2018/19
Standard tariff revenue	R'm	198 954	206 205
Standard tariff sales volumes	GWh	223 217	192 953
Standard tariff price	c/kWh	89.13	106.87
Standard tariff price adjustments	**%**	**2.2%**	**19.9%**

The 19.9% average increase translates to a 1 July 2018 local-authority tariff increase of 27.5% to municipalities. Municipalities continue to pay at the 2017/18 rates for the period 1 April 2018 to 30 June 2018. This is due to the Municipal Finance Management Act (MFMA) requiring Municipal tariff changes to be made only from 1 July each year.

2 Basis of Application

2.1 Legislative and regulatory framework

The adherence to many related legislative, regulatory and license requirements form the basis of the MYPD application. The following are applicable to the determination of Eskom's allowed revenue and resulting tariff adjustments.

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

Prescribes tariff principles including:

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

2.1.2 Electricity Pricing Policy

EPP gives broad guidelines to the Energy Regulator in approving prices and tariffs for the electricity supply industry.

2.1.3 Municipal Finance Management Act (Act 56 OF 2003)

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

2.1.4 Multi-Year Price Determination (MYPD) Methodology

The revenue application is based on the requirements of the MYPD methodology as published by NERSA during October 2016. The MYPD methodology addresses two broad aspects, namely, the MYPD allowed revenue application and the adjustment of the allowed revenue through the regulatory clearing account (RCA) process. **The focus of this application is the MYPD revenue application for the 2018/19 financial year.** It is clarified that this revenue application **does not include any RCA adjustments**. As decided by NERSA, Eskom has made assumptions to meet the requirements of the MYPD methodology.

2.1.4.1 Focus is the revenue application for the 2018/19 financial year

Eskom's MYPD 3 cycle comes to an end on 31 March 2018. This necessitates NERSA to make a further revenue determination in accordance with its mandate. On 31 October 2016, Eskom requested NERSA that only a single year application is to be made (as opposed to a multi-year application). On 23 February 2017, the Energy Regulator approved that Eskom will submit a revenue application for a single year for the period 1 April 2018 to 31 March 2019.

2.1.4.2 Application does not include RCA adjustments

On 23 February 2017, the Energy Regulator decided that "NERSA is unable to process RCA applications until its appeal on the Gauteng High Court decision has been heard and decided upon". Since then, the appeal was heard by the Supreme Court of Appeal on 4 May 2017 and an order where the appeal was upheld was made on 6 June 2017. An appeal of this decision to the Constitutional Court was not granted. Eskom will await guidance from NERSA with regards to the processing of already submitted and further RCA submissions.

It is clarified that Eskom has not applied for any RCA adjustments in this revenue application. The RCA process is backward looking and allows for adjustment of future tariffs to address past variances (in accordance with the MYPD methodology) between the revenue decision and the actuals that panned out. When a new MYPD revenue application is made, it is forward looking and based on projected assumptions.

2.1.5 Eskom retail tariff and structural adjustment (ERTSA) methodology

Once NERSA has approved the allowed revenue for a particular cycle in terms of the MYPD methodology, the ERTSA methodology is applied annually. The ERTSA allows for rate adjustments to tariffs applicable to the customer groups and schedule of standard prices applicable to the different Eskom tariffs for each year of the MYPD period.

An indication of the impact on tariffs to the customer categories will be included in the revenue application document. NERSA will first approve the allowed revenue for Eskom, which will then be used to finalise the Eskom Schedule of Standard prices in accordance with the ERTSA methodology.

3 Changes in landscape with regards to supply demand balance

3.1 Medium term system adequacy outlook

Around the time that the MYPD 3 application was being prepared by Eskom, the prevailing demand-supply balance was described in the 2010 Medium term risk mitigation project for electricity in South Africa (included as part of the IRP 2010). The risk of load shedding was significant unless extra-ordinary steps were taken to accelerate the realisation of a range of supply and demand side measures as set out by this project. The base case outlook up to 2016, based on the IRP 2010 moderate demand scenario, suggested a high likelihood that there will be an energy supply shortfall over the period until 2015. The supply/demand balance will be tightest during 2011-2012 as additional supply options are relatively limited until new build capacity starts to come on stream. The base case forecasted a supply shortfall of 9 TWh of energy in 2012, which is comparable to the energy produced by ~1000 MW of base-load capacity in a year."

Since 2010, medium term outlooks (MTO) have been determined by Eskom during the period 2014 to 2016. The MTO provides an adequacy assessment of South Africa's electricity supply system in the medium term. The method to assess the system adequacy uses an hourly optimisation tool that balances energy demand from existing and committed generation capacity. The system's adequacy to meet the demand is then measured against the Generation Adequacy Metrics where any violations to the adequacy metric are identified as supply shortfall and quantifies how much capacity (MW) is needed to restore the system to acceptable reliability as defined by the adequacy metrics.

With particular assumptions made on demand, generation performance and new build delivery dates, the following trends were identified:

- **2014:** The system will be constrained and will continue to be challenged until the commercial operation of new build units and improvements in plant performance are achieved.
- **2015:** The commissioning of new builds on schedule will not be enough to restore the system to adequacy if plant performance deteriorates. It further shows that worsening plant performance has the biggest impact on the gap sizes.

- **2016:** The system is adequate from 2018 and can then accommodate a medium to high growth in demand. Based on a high demand growth and low plant performance scenario, there would be a requirement for additional capacity in all years for an adequate system. However, it is unlikely that a high growth in demand is sustainable.

As can be summarised from the above trends, based on particular assumptions, the 5 year horison has shown a trend from a significant gap in 2010 to an adequate system in 2016.

4 Generation landscape

The improved performance of the power generating units coupled with additional capacity from some of the new build projects has resulted in a stable power system, with excess capacity being exported to neighbouring countries. Unit 6 of Medupi Power Station has been in commercial operation since August 2015. Medupi Unit 5 became commercially operational during April 2017. Good progress is also being made on Unit 4 of Medupi. The Kusile Power Station project is making substantial strides. Unit 1 continues to achieve fixed milestones, on the path to commercial operation by August 2017. Following the success of the maintenance plan, Eskom has delivered on focused areas for the past year, with no load shedding and load curtailment of key customers since August 2015.

Eskom is moving from a period of a severely constrained environment to one of adequate or even excess capacity. The reasons for this include improved generating plant availability, low demand growth and the introduction of new capacity, both Eskom and IPPs. The significant drop in the sales assumed during the MYPD 3 application and what has materialised is addressed in the sales forecast section. In essence the sales have remained fairly static from the beginning of the MYPD 3 period. The Eskom generating plant availability has improved over the last year. The details are provided in the operating costs section. The availability of new generating capacity from Eskom plant and IPPs are discussed as part of the capital expenditure and IPP sections respectively. This situation is expected to allow for the plant to be operated at lower utilisation factors, thus reducing stress on plant components and systems and will also provide adequate space for all required maintenance without the risk of load shedding.

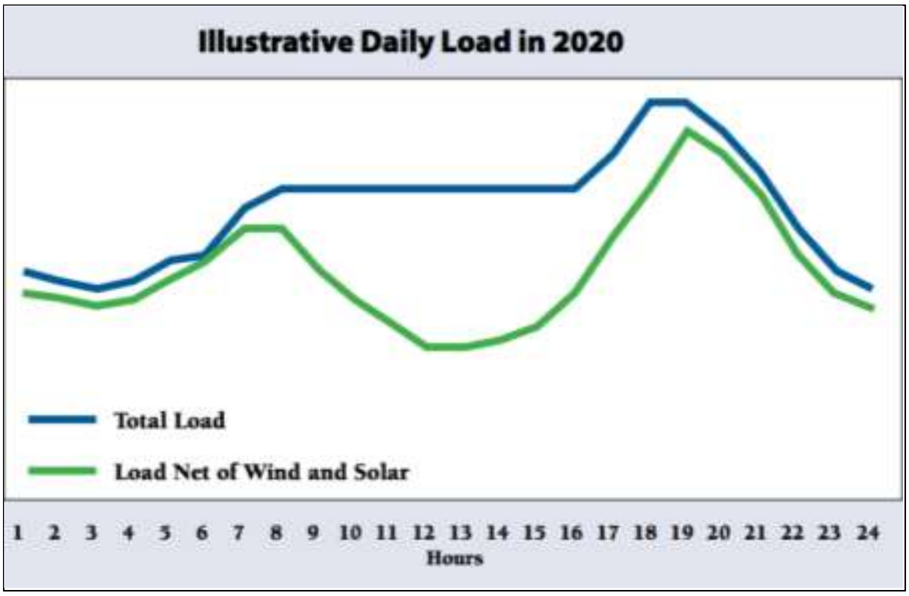
This will also allow for least-cost merit order production to be followed more often (within various constraints, such as network stability), thus focussing the burn on the cheaper stations and reducing burn at the more expensive stations and reducing overall primary (coal) energy costs.

At the same time, other challenges are introduced or exacerbated. Lower loads often mean that, particularly, at night, less generation is required. This means that some units either have to be shut down during these low load periods or else a number of units are required to operate stably at very low power levels. Shutting down units at night and restarting for the morning when demand picks up is known as “two-shifting” and this places enormous stresses in many of the plants’ systems leading to increasingly degraded performance.

Shutting down units for longer periods also requires various interventions to ensure that damage does not occur during this off-period and that the unit is available when required again. In the case of operating at low power levels, various interventions, ranging from operating procedure changes to major plant modifications may be required in order to ensure that the unit can operate stably at these power levels.

Another challenge that will become increasingly important as the amount of capacity from renewable generation sources increases is related to the “duck curve”, an illustrative example of which is shown below.

FIGURE 2: ILLUSTRATIVE DAILY LOAD IN 2020



Solar PV and wind, in particular, are considered to be non-dispatchable generation sources. This means that the system operator cannot call on them as required, but has to run them when available. However, their energy is only available when the sun shines or when the wind blows. If we subtract the energy provided by wind and solar from the total load, we get the net load – the green curve in the illustrative example above. Here it can be seen that the slope of this net load is much steeper than that of the total load (blue curve) and the difference between the peaks and minimum load is greater. This exacerbates the challenge, as mentioned above, of having adequate capacity to meet the evening peak at the same time as being able to reduce generation significantly during the low loads at night. In addition, the steeper slope of the curve means that, stations need to be able to both increase and decrease power levels faster than before. Certain stations can achieve this more easily than others and many will again require interventions ranging from procedural updates to plant modifications.

A depiction of South Africa's experience since 2014 to the 2017 calendar years is reflected in the figures below. Please note

- Dispatchable generation includes all Eskom generation, international imports, as well as generation from Dispatchable IPPs (i.e. Avon and Dedisa at this stage).
- Non-dispatchable generation refers to all generation that is self-dispatched. At this stage it includes all Renewable IPPs and conventional IPPs (WEPS, STPPP, MTPPP). Note that WEPS, STPPP and MTPPP contracts were discontinued from 1 April 2017.
- Only energy sent-out (GWh) is shown
- All calculations are for calendar years (01 Jan to 31 Dec).

The figures on the left hand side reflect the actual total weekly energy sent-out – which is dispatchable and non-dispatchable (top of orange line) and the dispatchable generation (black line). The figures on the right hand side reflect the total daily energy sent out from both dispatchable and non-dispatchable generators (red line) and energy sent out from only dispatchable generators (blue line).

2014

FIGURE 3: ACTUAL TOTAL WEEKLY ENERGY SENT-OUT

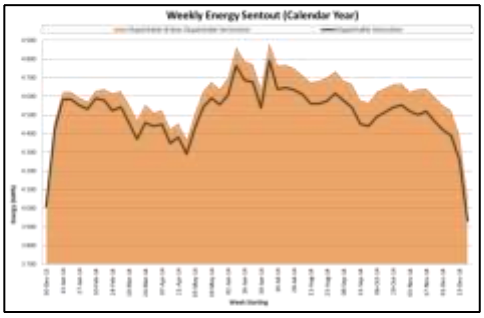
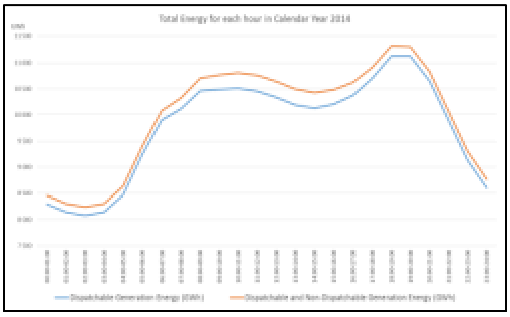


FIGURE 4: TOTAL DAILY ENERGY SENT OUT



2015

FIGURE 5: ACTUAL TOTAL WEEKLY ENERGY SENT-OUT

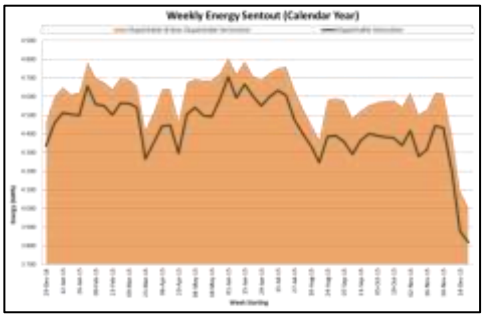
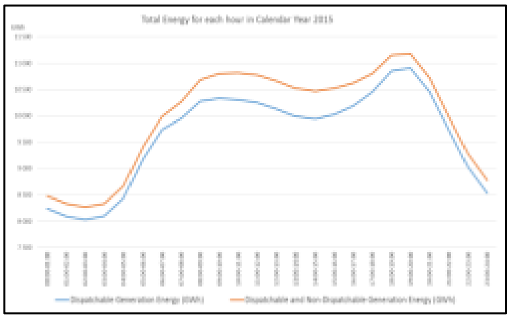


FIGURE 6: TOTAL DAILY ENERGY SENT OUT



2016

FIGURE 7: ACTUAL TOTAL WEEKLY ENERGY SENT-OUT

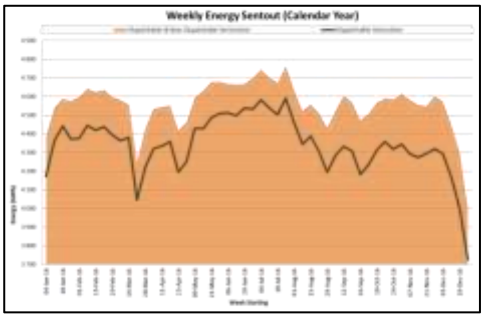
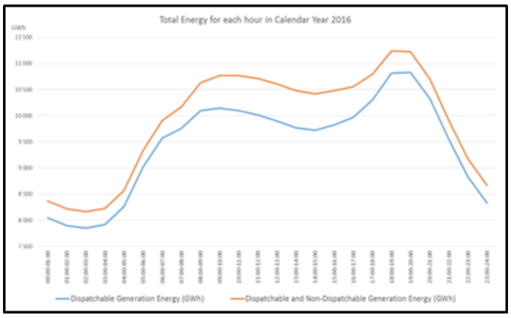


FIGURE 8: TOTAL DAILY ENERGY SENT OUT



2017

FIGURE 9: ACTUAL TOTAL WEEKLY ENERGY SENT-OUT

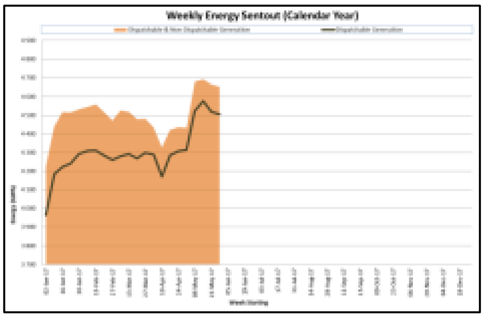
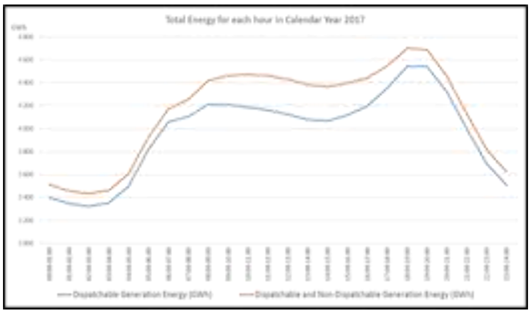


FIGURE 10: TOTAL DAILY ENERGY SENT OUT



As is evident, from 2014 to 2017 (year to date) the contribution from renewables has been increasing over the years.

In addition, there is a widening gap during the day which closes during the peaks and night when Eskom generation is required as a result of Solar not being available except for

Concentrated Solar Power (CSP) with storage (anything between 10MW and 150MW) and wind (anything between 0MW and 950MW).

Thus the challenges related to the duck curve are being experienced already. This phenomenon will be further addressed in subsequent revenue submissions.

5 Energy Wheel

The energy forecast is the starting point of the production planning process. The source of the forecast is the Eskom Energy Wheel diagram which provides total projected Eskom sales. The Energy Wheel diagram forecast provides energy forecast which is made up of Distribution and Transmission national sales, Export sales, Transmission and Distribution losses. This energy forecast has been discounted of impact of demand side management options.

The energy wheel shows the volume of electricity that flowed from local and international power stations and independent power producers (IPPs) to Eskom's distribution and export points during, including the losses incurred in reaching those customers. Supply electricity sources are captured in the top half the energy wheel figure, while sales and losses are included in the bottom portion of the energy wheel figure.

The energy wheel for the projection year 2017/18 is presented below.

FIGURE 11 : ENERGY WHEEL 2017/18

ESKOM HOLDINGS SOC LTD
ENERGY WHEEL
2017/18 Projections
ALL FIGURES IN GWh

Generation of Electricity	2017/18
Generation	221 184
OCGT	211
Pumping	(5 931)
IPP	12 208
Total	**227 672**

Available for Distribution	2017/18
Generation (incl IPPs)	233 603
International	9 670
Wheeling	2 562
Sub Total	**245 835**
Pumping	(5 931)
Total	**239 905**

Total Imports	2017/18
International Purchases	9 670
Wheeling	2 562
Total	**12 232**

Total Exports	2017/18
International Sales	13 930
Wheeling	2 562
Total	**16 492**

South African Power Pool

Internal Use	2017/18
Generated	(162)
Internal Use	488
Total	**326**

Demand	2017/18
Sales	213 981
Losses	23 035
Internal	488
Generated	(162)
Wheeling	2 562
Total	**239 905**

External Sales	2017/18
Local	200 051
International	13 930
Total	**213 981**

Technical & Other Losses	2017/18
Distribution	16 270
Transmission	6 765
Total	**23 035**

Technical & Other Losses - %	2017/18
Distribution	7.5%
Transmission	2.8%

The energy wheel for the application year 2018/19 is presented below.

FIGURE 12 : ENERGY WHEEL 2018/19

ESKOM HOLDINGS SOC LTD
ENERGY WHEEL
2018/19 Application Forecast
ALL FIGURES IN GWh

Generation of Electricity	2018/19
Generation	216 560
OCGT	211
Pumping	(5 783)
IPP	18 429
Total	**229 418**

Available for Distribution	2018/19
Generation (incl IPPs)	235 201
International	9 381
Wheeling	2 453
Sub Total	**247 035**
Pumping	(5 783)
Total	**241 252**

Total Imports	2018/19
International Purchases	9 381
Wheeling	2 453
Total	**11 834**

Total Exports	2018/19
International Sales	13 634
Wheeling	2 453
Total	**16 087**

South African Power Pool

Internal Use	2018/19
Generated	(159)
Internal Use	499
Total	**339**

Demand	2018/19
Sales	215 710
Losses	22 750
Internal	499
Generated	(159)
Wheeling	2 453
Total	**241 252**

External Sales	2018/19
Local	202 076
International	13 634
Total	**215 710**

Technical & Other Losses	2018/19
Distribution	15 952
Transmission	6 798
Total	**22 750**

Technical & Other Losses - %	2018/19
Distribution	7.3%
Transmission	2.8%

6 Allowable Revenue

6.1 Allowed Revenue formula

Eskom's revenue requirement application for 2018/19 is based on the allowed revenue formula as reflected in the MYPD methodology:

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

Where:

AR = Allowable Revenue

RAB = Regulatory Asset Base

$WACC$ = Weighted Average Cost of Capital

E = Expenses (operating and maintenance costs)

PE = Primary Energy costs (inclusive of non-Eskom generation)

D = Depreciation

$R\&D$ = Costs related to research and development programmes/projects

IDM = Integrated Demand Management costs (EEDSM, PCP, DMP, etc.)

SQI = Service Quality Incentives related costs

$L\&T$ = Government imposed levies or taxes (not direct income taxes)

RCA = The balance in the Regulatory Clearing Account (risk management devices of the MYPD)

TABLE 4: ALLOWABLE REVENUE

Allowable Revenue (R'millions)	AR	Formula	Application 2018/19
Regulated Asset Base (RAB)	RAB		763 589
WACC %	ROA	X	2.97%
Returns			22 690
Expenditure	E	+	62 221
Primary energy	PE	+	59 340
IPPs (local)	PE	+	34 209
International purchases	PE	+	3 216
Depreciation	D	+	29 140
IDM	I	+	511
Research & Development	R&D	+	193
Levies & Taxes	L&T	+	7 994
RCA	RCA	+	
Total Allowable Revenue	R'm		**219 514**

Notes to allowed revenue

1. Other income has been included under the expenditure element.

6.2 Revenue recovery

Company revenue is recovered from international customers, negotiated pricing agreement (NPA) customers, with the balance from standard tariff customers

TABLE 5: REVENUE RECOVERY

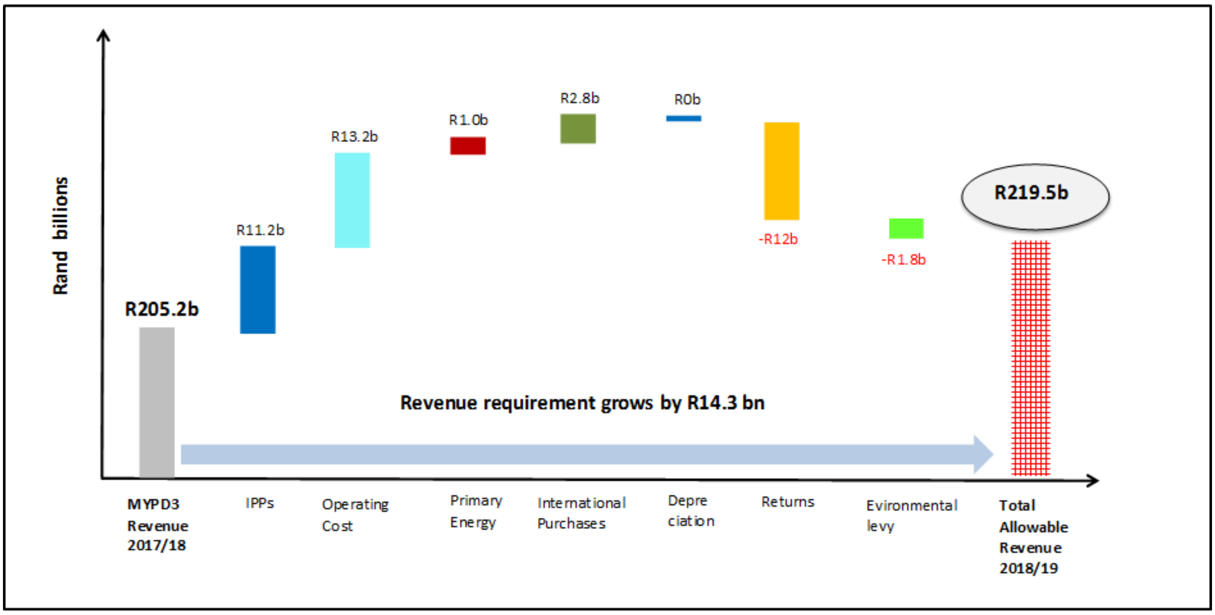
Revenue recovery (R'millions)	MYPD 3 2017/18	Application 2018/19	Change	% growth
NPA and International customers	6 259	13 309	7 050	112.6%
Standard tariff customers	**198 954**	**206 205**	**7 251**	**3.6%**
Total Allowable Revenue	205 213	219 514	14 301	7.0%

The growth in total allowed revenue from FY2017/18 to FY2018/19 is 7% with the contribution being almost 50:50 split between standard tariff revenue and non-standard tariff revenue. Standard tariff consumers are required to contribute R7.2 billion (3.6%) more when compared to the 2017/18 decision. Eskom's strategy to maximise export sales and revenue impacts positively on the balance required from standard tariff customers.

However, the price impact would be much higher due to the allowed revenue being recovered from a lower sales volume. The impact on the electricity price is 9.4% in 2018/19 due to the extent of the drop in standard tariff volumes when compared to the MYPD3 over 5 years of some 30 TWh.

The growth in revenue from the 2017/18 MYPD3 decision is attributable to IPPs of R11.2bn, operating costs of R13.2bn and international purchases of R2.8bn. Revenue requirement is reduced by a drop in returns of R12bn and lower environmental levy of R1.8bn.

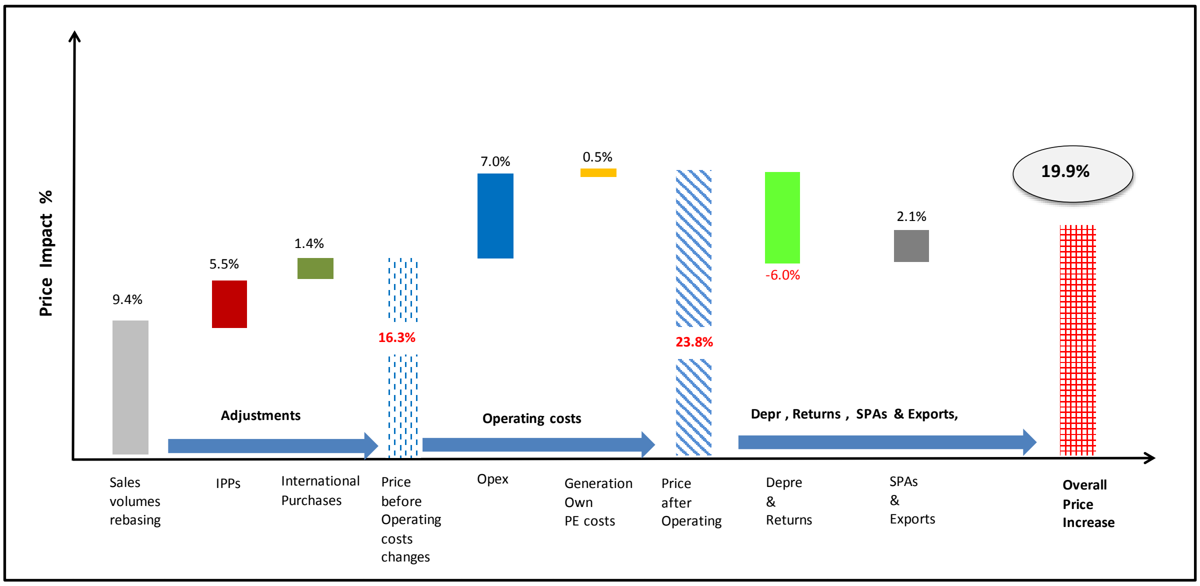
FIGURE 13 : TOTAL REVENUE GROWTH OF R14.3 BILLION



6.3 Electricity price impact in 2018/19

Standard tariff consumers are required to contribute R7 251 million (3.6%) more when compared to the 2017/18 decision. The reasons for the proposed standard price increase of 19.9%, which is much higher than the revenue increase, is unpacked into 3 categories. These categories are adjustments that need to be made prior to considering Eskom's costs; secondly allowing for operating costs impacts and accounting for the depreciation, returns, SPAs and exports.

FIGURE 14 : FACTORS IMPACTING ON PRICE INCREASE



Step 1: Adjustments that need to be made prior to considering Eskom's own cost.

These are:

- Price adjustment of 9.4% due to sales volume rebasing
- Price adjustment of 5.5% due to further increase in IPPs costs
- Price adjustment of 1.4% due to NERSA correction for treatment of international purchases

Thus, before considering any of Eskom's own cost movements, NERSA will be required to consider a price increase of 16.3% for the 2018/19 year.

Step 2: Allows for Eskom's own primary energy costs increasing by 0.5% while operating cost increase by 7%.

Step 3: Return on assets is reduced when compared to MYPD3 2017/18 resulting in a 6% price reduction. The final factor relates SPAs and exports which increases the price by 2.1%.

6.4 Rebasing of sales volumes

Over the entire MYPD3 period Eskom's sales volumes have been significantly lower than the assumption made in the MYPD3 decision. The key reason for this is slower economic recovery in the country than anticipated. NERSA did not adjust the sales volumes through their regulatory processes to reflect current realities. This volume adjustment to reflect the actual sales will occur during the revenue application for 2018/19. Even if the allowed revenue was not increased for the 2018/19 year, the recovery through lower sales volume will result in a price increase. The net impact of this sales volume rebasing is a 9.4% price increase being required after accounting for primary energy savings on the lower volumes. Standard tariff sales volumes has declined by 30TWh from 223TWh (2017/18 decision) to 193TWh (2018/19 application).

Assuming the same standard tariff revenue in 2017/18 of R198 954 million is maintained for 2018/19, and adjusting for lower sales, will result in a primary energy savings of R10 812m based on an average variable primary energy production cost of 32c/kWh. This corresponds to a drop in allowed revenue to R188 142 million recovered over the lower volumes of 192 953GWh which equates to standard tariff price increase of 9.4% from 89.13c/kWh to 97.5c/kWh.

It is important to correct the sales volumes, as embedded in the sales is the recovering of Eskom's fixed costs (operating costs are fixed in the short term). Eskom is not receiving the full allowed operating costs, depreciation and returns when volumes are lower than the assumption in the NERSA decision.

TABLE 6 : SALES VOLUME REBASING IN 2018/19

Rebasing of sales volumes		MYPD 3 Decision	Application
		2017/18	2018/19
Standard tariff revenue	(R'm)	198 954	198 954
Savings on primary energy due lower sales	(R'm)		- 10 812
Revised standard tariff revenue after lower sales	(R'm)		188 142
Standard Tariff volumes	(GWh)	223 217	192 953
Standard tariff average electricity price	(c/kWh)	89.13	97.5
Price adjustments for rebasing sales volumes			9.4%

6.5 Inclusion of full international purchases

In the MYPD3 decision, NERSA had included a net cost for international purchases and not the gross costs. Subsequently through the RCA 2013/14 decision and the revised MYPD methodology, the gross purchases are included to set off the inclusion of international revenue. Therefore, the primary energy cost base will reflect the change in 2018/19, effectively resulting in international purchases increasing by R2.8 billion for regulatory purposes from 2017/18.

6.6 Operating costs increase

Eskom continues to strive to extract efficiencies over the MYPD3 period through the implementation of a business productivity programme initially and later updated to a ‘design to cost’ approach. The compounded average growth rate reflects that year on year operating and maintenance costs have grown by 7.3% between 2013/14 to 2018/19. Employee benefits have a CAGR of 4.9% p.a. over the same period. The significant adjustment is linked to the starting point of a low base which adds 7.0% to the price impact.

6.7 Depreciation and return on assets

The depreciation amount will be based on a revalued asset base in terms of the MYPD methodology. Return on assets will be based on the weighted average cost of capital (WACC). The WACC will not be implemented in its entirety in 2018/19 as a phased in amount of 2.97% is utilised. The ROA % will be phased-in to cost reflectivity in order to minimise the impact on the overall price increase in the application. The phasing in of ROA will result in a reduction in the price of electricity by 6.0%.

7 Indicative Standard Tariff Increase

7.1 Tariffs

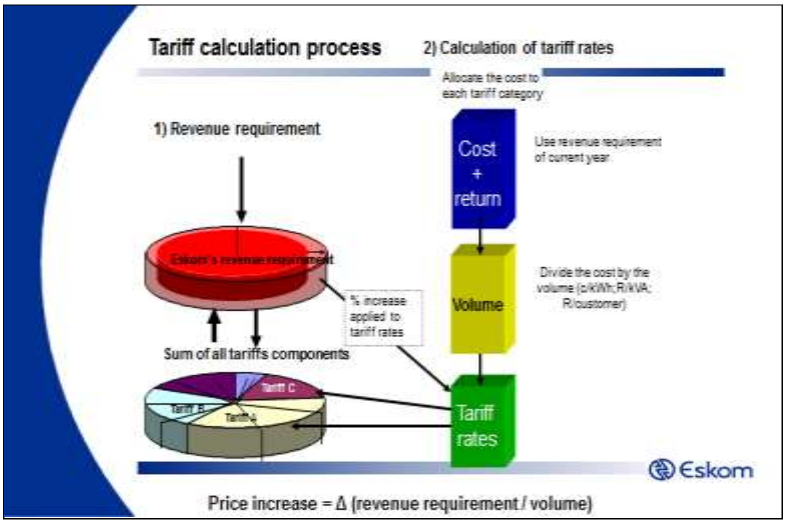
Eskom's total sales revenue recovery is from three categories; Standard tariffs, local negotiated pricing agreements (NPAs) and International sales. The applicable prices and increases for the NPAs and the international utility agreements are specified in long-term supply agreement contracts. As a result, the annual tariff adjustment only applies to the Standard tariffs that make up the Eskom Schedule of Standard prices.

7.2 Standard tariff increases

Once NERSA has determined the allowed revenue, Eskom is required to submit its retail tariff and structural adjustment application for Standard tariffs to NERSA in accordance with the Eskom Retail Tariff and Structural Adjustment (ERTSA) methodology.

The ERTSA is the Eskom application for the rate of adjustment to tariffs applicable to the respective customer groups, as well as the resultant Eskom Schedule of Standard prices applicable to each of the customer groups. The figure below summarises the approach required by ERTSA.

FIGURE 15: TARIFF CALCULATION PROCESS



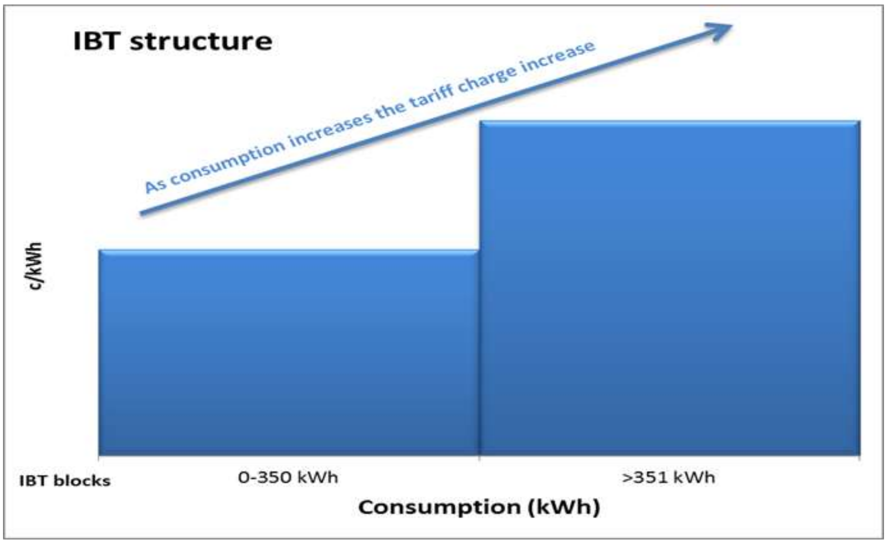
It is applicable to Eskom's local authority and non-local authority customers.

7.3 Catering for the poor

Poor households are particularly vulnerable to high increases in electricity tariffs. It is important to protect these poor households from the full impact of the electricity price increase through targeted subsidies, with a transparent cross-subsidy structure aligned with a national cross-subsidy framework to be developed for the country. To date, tariff subsidies have evolved in the absence of a subsidy framework and there has been very little analysis of the long-term impact on consumers, whether subsidy contributors, recipients, or even the economy as a whole.

The IBT was implemented by NERSA to cushion low-income households that use very little electricity. The structure, which also provides an incentive for all households to use electricity efficiently, divides consumption into two blocks. The unit tariff per kWh is stepped up as consumption increases as illustrated in figure below.

FIGURE 16: INCLINING BLOCK TARIFF STRUCTURE



The tariff has been successful in lowering the cost of electricity for the poor.

7.4 Illustrative Standard tariff category increases for 2018/19

Standard tariffs for the 2018/19 application contribute R206 205 million on assumed volume of 192 953GWh of sales, at an average price of 106.87c/kWh. The increase in the average Standard tariff price when compared to the 2017/18 MYPD3 and ERTSA Nersa decisions is an average increase of 19.9%.

TABLE 34: 2018/19 STANDARD TARIFF AVERAGE INCREASES

Standard Tariffs Total	Decision 2017/18	Application 2018/19
Annual Average Increase - ERTSA(%)	2.20%	19.90%
Annual Average Price (c/kWh)	89.13c	106.87
Standard Tariff Forecasted Sales Volumes (GWh)	223 219	192 953
Standard Tariff Allowed Revenues (R'm)	198 954	206 205

NERSA may allow cross-subsidies between various customer groups to be implemented as part of the annual average price to benefit affected groups. This may result in changes to the non-municipal and/or municipal increases.

For example; if NERSA continues to protect the poor with lower tariff increases to the Homelight 20A tariff similarly as it did for the MYPD3 decision, the applicable tariff category increases after applying the ERTSA methodology would be as shown in Table 7. This Homelight 20A tariff was 2.4% less than average for Block 1 (>0-350kWh) and 0.4% less than average for Block 2 (>350kWh) in the MYPD 3 decision.

TABLE 7: STANDARD TARIFF CATEGORY INCREASES

Total Standard tariffs	19.90%
Municipal - 1 July	27.53%
Key industrial and urban	
Other tariff charges	19.90%
Affordability subsidy	22.04%
Rural	19.90%
Homelight 20A	
Block 1 (>0-350kWh)	17.50%
Block 2 (>350kWh)	19.50%
Homelight 60A	19.90%
Homepower	19.90%

8 Sales Volumes

8.1 Introduction to sales volumes

The basis of the sales forecast is all customer categories of the standard tariff, negotiated pricing agreements (NPA) and international (exports).

The forecasted sales are for a short-term period and it is for projecting consumption at the customer meter so as to obtain the total energy usage, kilowatt-hours, for all customers. The sales forecast is translated into revenues that needs to be as accurately as possible for tariff calculation and cash flow purposes.

The sales forecast for the financial years 2016/17 to 2018/19 is reflected in the table below.

TABLE 8: SALES VOLUMES FORECASTS

Sales volumes (GWh)	Actuals	Projections	Application
	2016/17	2017/18	2018/19
Standard tariff sales	189 845	190 917	192 953
Negotiated pricing agreement	9 750	9 621	9 621
Export sales	14 995	13 930	13 634
Total Sales	**214 590**	**214 468**	**216 208**
Year-on-year growth (GWh)	- 559	- 122	1 740
Year-on-year growth (%)	-0.26%	-0.06%	0.81%

All sales are from Eskom's regulated business as all Eskom electricity sales are regulated in terms of a NERSA decision. Sales refer to all end-customers directly supplied by Eskom. This includes sales to Municipalities purchasing in bulk from Eskom as well as all sales to any point of delivery that belongs to Eskom or any Eskom subsidiary. The associated costs for the purchase of the electricity are included in the operational costs of that entity. Entities such as Roshcon is regarded as fully fledged Eskom customer paying the Nersa approved Eskom Standard tariffs.

The sales forecast differs from the network demand forecast and the generation production plan forecast as follows:

- The network demand forecast projects network capacity (MW) is to advise on the network capacity (energy and demand) available for the connection of existing and future customers to generators.
- The generation production informs on the generation capacity (peak and sent out) available to meet the customer electricity requirements and cater for a sufficient reserve margin. This forecast incorporates Independent Power Producers (IPPs) generation and is aligned to Government determinations

This sales forecast section of the application for the NERSA approval first discusses the sales forecasting approach for Standard tariffs and NPAs. Following this a discussion on the assumptions that include but are not limited to considerations of integrated demand management (IDM) programmes and the Gross domestic product (GDP) trend.

A myriad of factors differently impact future sales including the price elasticity of demand captured through the application of customers' future consumption projections during the sales forecasting process. Thereafter, provided is an explanation of the sales forecasting process, leading to the overview and analysis of the 2018/19 forecasted sales as well as the Eskom initiative to grow sales.

8.2 Sales forecasting approach

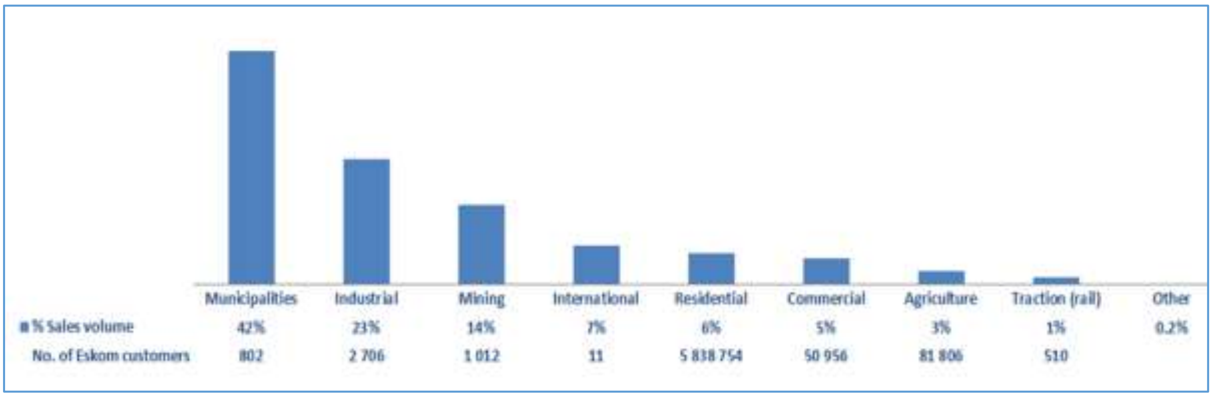
There are various different influences on customers' current and future electricity consumption that are determined by individual customers' need for electricity and substitutes to taking supply from Eskom. To practically capture this complex dynamic, the Eskom forecasting practice recognises differing sales assumptions by sector. For high-sales volume customers, the sales forecasting assumptions include individual customer expected energy requirements and consultation with respective customers and industry representatives. This forecasting approach therefore combines the use of quantitative and qualitative techniques.

Municipalities purchase in bulk from Eskom and distribute to industry and commercial sectors with a good measure of supply to residential end-customers. Eskom bulk sales to municipalities differ from one municipality (or metro) to the next as each municipal electricity customer-mix shapes each municipality's Eskom purchase profile. Eskom therefore uses a combination of forecasting methodologies, individual municipality consultation with reference to the respective local government development plans. For the residential and commercial sectors, primarily historical trends, weather, and economic indicators inform the sales forecast.

This individual forecasting approach applies to rail customers albeit that rail sales represent 1% of total sales on 509 active service agreements.

The forecasting of international sales adopts the individual approach given the country specific drivers and that the sales are to 7 international utilities and 4 international end-users.

FIGURE 17: 2015/16 NUMBER OF CUSTOMERS AND CONTRIBUTION TO TOTAL SALES



Note: The residential total includes pre-payment and public lighting

Eskom sales are mainly to Municipalities, industrial and mining customers and this was at 78% sales volumes at the end of the 2016/17 from 4 547 customers (or active service agreements). Consequently, electricity sales changes in any of these three segments requires application of an individual bottom-up approach so as to consider specific sales usage drivers that include customers' business plans, commodity prices, and consideration of customer plans.

8.3 Sales volume forecasting assumptions

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

Key assumptions include 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.

8.3.1 Gross domestic product (GDP)

Anticipated changes in GDP growth while an important input into the sales volume forecast are one of the many sales volume forecasting inputs. In sectors where there is a strong correlation between electricity demand and GDP growth, such as bulk sales to Municipalities, changes to the GDP have a greater weighting on the sales volume projections.

The GDP percentage growth (%) used in this Application 2018/19 forecast was derived from an average of 4 different sources that are the Eskom treasury forecast, International Monetary Fund (IMF) forecast and Investec forecast.

TABLE 9: GROSS DOMESTIC PRODUCT (GDP) FORECASTS

Gross domestic product (GDP) forecasts	2017	2018	2019
Application GDP Forecast	**1.90%**	**2.40%**	**2.70%**
Eskom Treasury	1.50%	2.40%	3.00%
Investec	2.20%	2.70%	3.00%
World Bank	2.40%		
IMF	1.20%	2.10%	2.40%

National Treasury latest outlook was that GDP would increase from 0.5% (2016) to a forecast of 1.3% (2017).

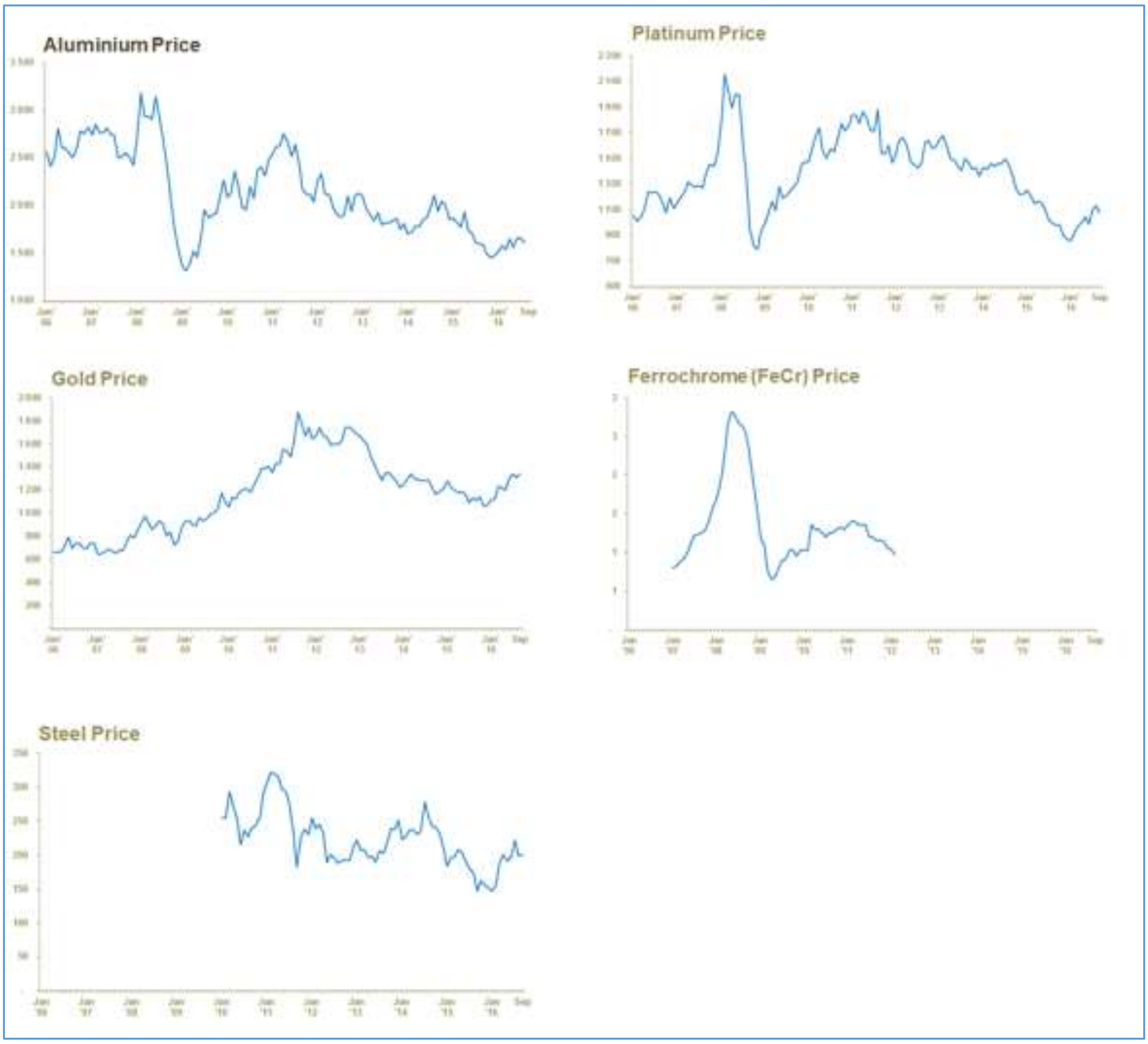
8.3.2 Commodity prices

The commodity price assumptions are primarily for aluminium, gold, platinum, steel and Ferrochrome that influence mining and industrial customers’ electricity use. For the commodity prices referred to in the sales volume forecast, most are at lower levels than in the past. The sales forecast assumes that this trend will continue for the entire application period with only moderate growth expected for some commodity prices; see below Table 10 for the main commodity prices.

TABLE 10: COMMODITY PRICES

Commodity prices	2015	2016	2017	2018	2019
Aluminium ($/ton)	5 503	4 690 -15%	4 788 2%	4 725 -1%	4 663 -1%
Gold ($/oz)	1 160	1 221 5%	1 251 2%	1 313 5%	1 406 7%
Platinum ($/oz)	1 053	960 -9%	1 044 9%	1 219 17%	1 344 10%
Ferro Chrome (FeCr)(c/lb)	107	86 -20%	93 8%	100 8%	105 5%

FIGURE 18 : HISTORIC COMMODITY PRICE LEVELS



8.3.3 Price elasticity

In order to have a measure of price elasticity with an exact impact on sales volumes, there is need to isolate the impact of tariff increases, weakening global economic growth, collapse of commodity prices, seasonal changes (temperature and rainfall variations) and weak demand for commodities. The quantum of change in the sales volumes does not demonstrate a direct correlation to the change in average price.

Given the foregoing context, measuring price elasticity would require investment in research to arrive at a quantifiable measure of the price elasticity. Price elasticity is captured for large industrial and mining customers through the consideration of their business plans during the sales forecasting process.

8.3.4 Furnace load reduction in winter

Industrial customers respond to the winter tariff signals by shifting high consumption away from winter tariffs (June, July and August) and investing in their plant maintenance during this cold period. Notable is a substantial amount of furnace load that is not used in winter; comparatively, furnace utilisation during the summer months is at a high ±95%.

8.3.5 Energy Efficiency Demand Side Management (EEDSM) savings

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

TABLE 11: EEDSM FORECASTS

Energy Efficiency & Demand Side Management (EEDSM)	Projections	Application
	2017/18	2018/19
EEDSM Programmes - Peak demand Savings (MW)	110	130
EEDSM Programmes - annualised energy Savings (GWh)	239.8	283.4

8.3.6 Weather conditions

Weather has a strong correlation to changes in the use of electricity. For example, in winter electricity consumption increases due to very low temperatures as for example heaters are used. In summer very high temperatures give rise to higher consumption motivating amongst others the use of air-conditioning. However, the sales volume forecasting does not attempt to forecast weather; at best, a weather forecast is only accurate for a max of +/- 7 days ahead.

Instead, the sales volume forecasting applies average temperatures (or average weather), to determine the level of sales volumes under *"normal"* temperatures. Average weather conditions are inputs used to forecast weather sensitive customers. By using *"normal"* (or average) weather conditions, in the event of a very cold winter, the difference in the forecasted and actual consumption sales volume is limited to *"normal"* level. Conversely, if the sales forecast considers a warmer winter and instead a colder winter is experience, the change in the sales volumes is also limited to the difference to the *"normal"* winter level.

The sales volume forecasting considers that each Eskom regional forecast has some variation in weather patterns and regional customers react differently to weather changes. Furthermore, it is also recognised that there is a "dead band" in temperature and/or weather changes that do not affect electricity consumption. There is also a threshold temperature level for low and high temperatures above / below which would advise electricity consumption changes.

8.4 Forecasted sales for the application

The sales forecast is on the back of declining sales from the MYPD3 period. Going forward, the expectation is slow-growth reflecting the low economic growth projections and in line with the actual trend experienced since 2012.

TABLE 12: FORECASTED SALES VOLUMES

Sales volumes (GWh)	Actuals	Actuals	Actuals	Actuals	Projections	Application
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Standard tariff sales	194 762	195 258	192 089	189 845	190 917	192 953
Negotiated pricing agreement	11 229	9 896	9 684	9 750	9 621	9 621
Export sales	12 378	11 911	13 376	14 995	13 930	13 634
Total Sales	**218 369**	**217 065**	**215 149**	**214 590**	**214 468**	**216 208**
Year-on-year growth (GWh)	1 808	- 1 304	- 1 916	- 559	- 122	1 740
Year-on-year growth (%)	0.83%	-0.60%	-0.88%	-0.26%	-0.06%	0.81%

The forecasted growth between projections for 2017/18 and the Application 2018/19 is 0.8% compared to an average decline in sales growth rate over the MYPD3 period of 1.8%. As required by the methodology, Eskom will alert NERSA to any changes in the sales forecast closer to the time of the NERSA decision.

For the 2017/18 financial year compared to year 2016/17, the sales trend remains the same from additional negotiated pricing agreement and international sales. The total forecasted sales growth is an additional 1 740 TWh for 2018/19. There are additional but minimal sales attributable to the ±100 000 new electrification customers supplemented with an assumed increase in residential consumption.

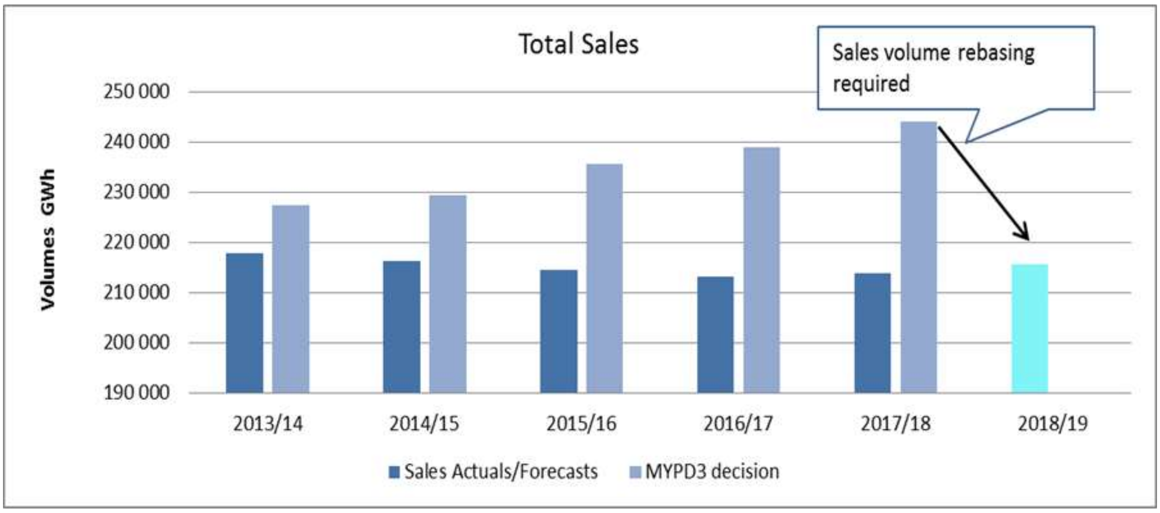
TABLE 13: SALES CATEGORIES

Sales volumes into categories (GWh)	Actuals	Application	Change FY2014 ~FY2019
	2013/14	2018/19	
Industrial	54 567	48 700	- 5 867
Mining	30 667	31 302	635
Municipalities	91 262	90 298	- 964
Residential + Prepayment	10 818	12 311	1 493
Other	31 055	33 597	2 542
International Sales	12 378	13 634	1 256
Traction	3 125	2 786	- 339
Commercial	9 605	10 577	972
Agriculture	5 192	5 810	618
Public lights	199	204	5
Other	556	586	30
Total Sales	**218 369**	**216 208**	**- 2 161**

The switching off of furnaces by large customers during winter and many industrial customers scaling down or closing due to the current slump in commodity prices influence the sales trend. With low commodity prices and electricity price increases expected to be higher than inflation for the entire period, the expectation is that this low growth trend will continue.

Compared to the MYPD3 decision's forecasted sales, the actual sales were lower and this trend is reflected in the 2018/19 forecasted sales. These lower sales volumes present the need to rebase the sales volumes for 2018/19 so as to be in line with the sales trend and provide a realistic reference point for 2018/19.

FIGURE 19: ESKOM SALES VOLUME GAP OVER MYPD3



In discussions with key industrial customers various reasons other than the price of electricity were highlighted as drivers for the current situation. The declining trend in the in Eskom sales can be attributed to a number of driving forces:

- Electricity price increases have played a part in constraining growth as the cost of electricity for certain industries is a high percentage of production cost
- South African industrial plants have overcapacity while commodity prices either remains static or reduce together with the remote location from major markets
    - China is taking our market share in a fiercely competitive market.
    - Other input costs, particularly where electricity cost intensity is lower also play a role, i.e. expensive transport and location of plants from the markets
- Availability of electricity and energy efficiency drives during period of capacity constraint created permanent loss in sales/revenue
    - Eskom communicated to customers to reduce sales since load shedding
    - Energy efficiency initiatives implemented: Eskom required a 10% reduction in load from its Key Industrial Customers (KICs)
    - Electricity Conservation Scheme (ECS) rules were also embedded in Electricity Supply Agreements with customers

- Reluctance by global companies to invest in SA due to a lack in competitiveness and the uncertain situation in SA from a political and sustainable financial perspective (i.e. credit rating, labour and transport)
- Internationally governments (not utilities) assist in dropping the price of electricity for large energy intensive users in their countries

In line with the MYPD methodology, the mitigation of the sales variance can be addressed through the consideration of a more recent sales forecast at the time of the NERSA decision.

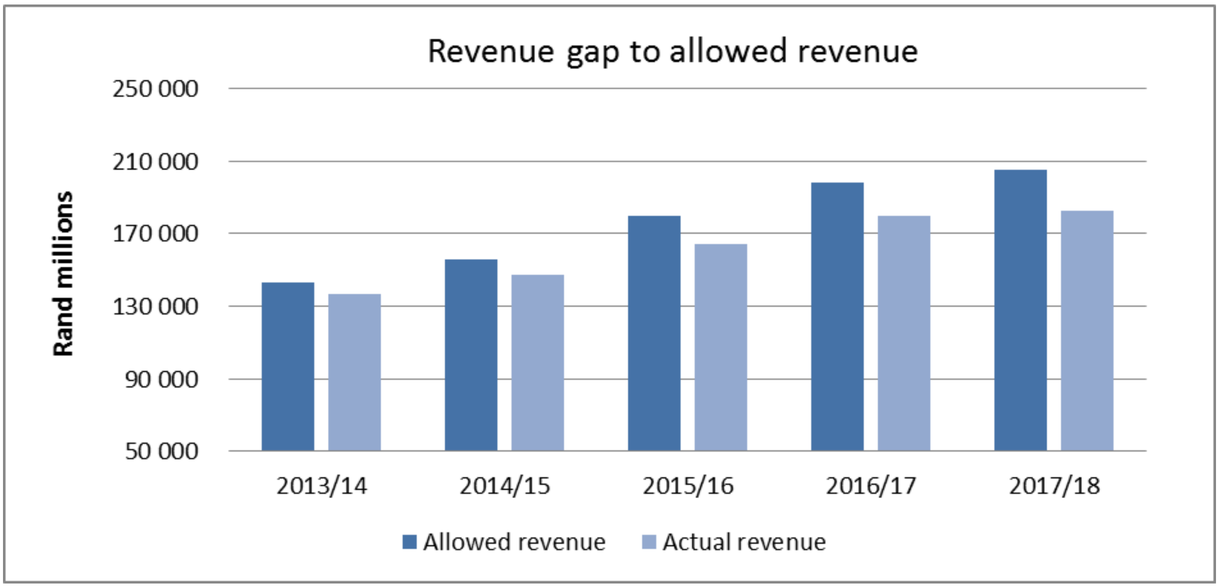
To avert the declining trend Eskom has put in place a growth initiative to grow sales as explained in this application. A sustainable solution requires a coordinated national (SA Inc) effort and should consider all options. Eskom is completely supportive of any policy interventions by the Government in ensuring further economic growth that is likely to attract further industrial investment.

8.5 Under-recovery of allowed revenue in MYPD3

Lower sales volumes over the MYPD3 window has meant that Eskom did not recover the allowed revenue which was awarded by the Regulator. As described earlier, although the sales volumes in actual mode have decreased marginally on a Year-on-Year basis, the gap to the sales volumes when compared to the MYPD3 decision has widened over time. The revenue has been recovered in the respective years.

Below is a summary of the revenue under-recovery which has occurred during the last few years and the cumulative shortfall for the 4 years of the MYPD3 period (FY2014 to FY2017) is R48 billion. Based on projections for year 5 (FY2018) this gap will escalate by another R20 billion, resulting in a combined under-recovery of allowed revenue over the MYPD3 period of in the region of R68 billion.

FIGURE 20 : UNDER-RECOVERY OF ALLOWED REVENUE



In order to compute the difference to the actual revenue as reflected in Eskom's annual financial statements, Eskom makes the following adjustments:

- Reversal of revenue impairments disclosed in the Annual financial Statements (AFS) – this has the effect of increasing the revenue reported and thus lowering the amount of the revenue gap.
- Load shedding interruptions are accounted for by reducing the revenue gap further
- Allowed revenue in 2015/16 and 2016/17 are increased from the original MYPD3 decision to cater for the regulatory clearing account decision which were granted by NERSA.

In order to allow for the NERSA revenue decision to be recovered, it is essential for the sales volumes to be adjusted in 2018/19 decision to reflect the current reality. If this is not done in accordance with the latest information available (as required by the MYPD methodology) the under-recovery of the allowed revenue will again be repeated. As discussed below, Eskom is making every effort to maintain the current sales volumes and to grow sales volumes into the future. This will allow for revenue to be recovered over a larger volume.

8.6 Initiatives to grow sales volumes

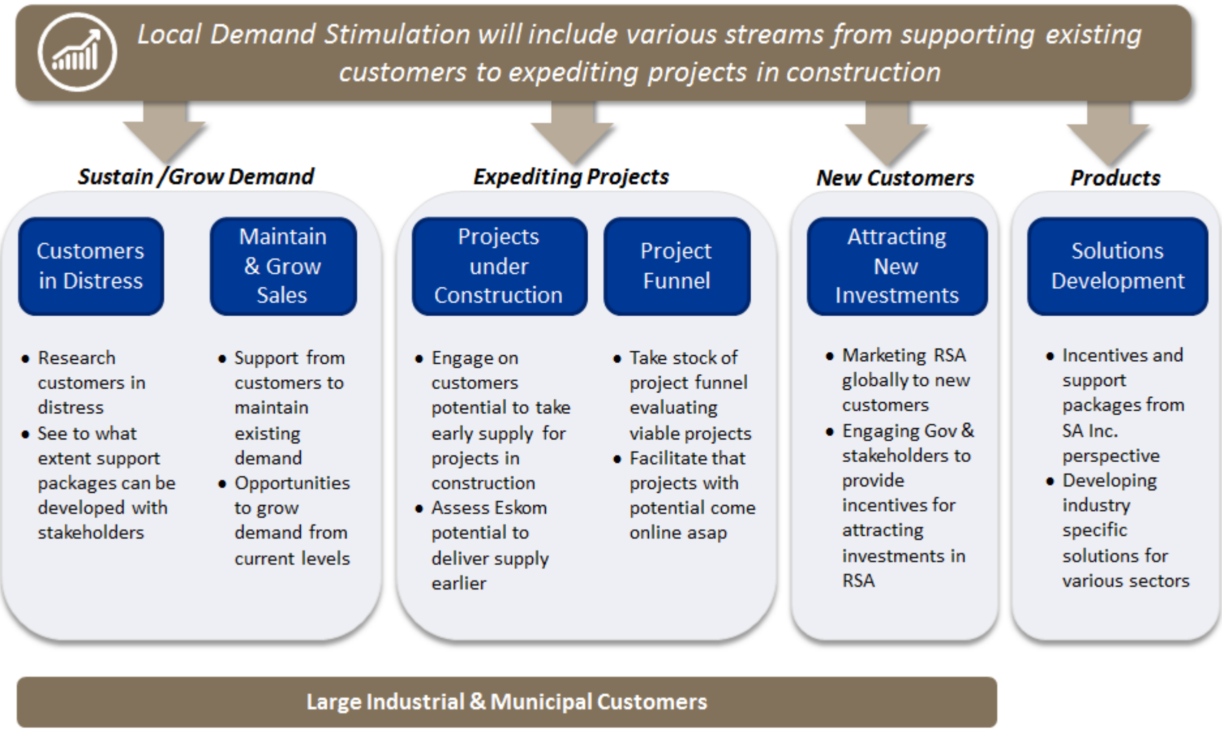
Eskom is experiencing low electricity sales growth which is set to continue in line with the sluggish international and local economic growth and low commodity price projections. Specifically, electricity sales to Eskom's industrial and mining customers are declining as they are faced with increasing operational and market challenges, including the erosion of competitive advantage from previous low-electricity prices in South Africa.

Additionally, the large industry and mining market context has changed recently and is marked by diminished competitive advantage from previous low-electricity prices. This is driving industrial customers to seek alternatives and move production to lower priced electricity markets.

This trend, coupled with the commissioning of new power stations has moved Eskom into a position of excess operational generation capacity. In order to remedy the situation, Eskom has embarked on a Growth and Sustainability Strategy with the objective of stemming the declining sales trend, thereby sustaining our current sales and pursuing sales growth opportunities to increase electricity sales over time (i.e. in addition to what is in the sales forecast). Eskom has developed a framework to stimulate local demand that has 4 key elements geared to supporting existing customers to expediting projects in construction. All projects will be pursued on their sound and mutual business merits.

Eskom has developed a framework to stimulate local demand with 4 key elements geared to supporting existing customers to expediting projects in construction. The roll-out will be to all customers including Municipalities and will be considerate of all stakeholders competitive context. The merits for the consideration of any project will be the soundness and mutual business benefits.

FIGURE 21: LOCAL DEMAND STIMULATION- KEY ELEMENTS



As cost drivers are not only electricity prices, growth initiatives must be driven from a country platform together with the key role players, including Department of Trade and Industry, Department of Public Enterprises, Economic Development Department, Industrial Development Corporation, National Treasury, Department of Energy, and the National Energy Regulator of South Africa.

The success of the Growth and Sustainability Strategy is dependent on establishing a country platform together with all key role players to ensure an integrated and focused SA Incorporated approach to encourage existing and new customers to invest in the country and maximize the growth potential of South Africa.

8.7 Debt owing to Eskom

Eskom is managing the payments from customers reasonably well. As at September 2016 the overall payment level was 97%. A relatively small portion of Eskom's customer base is battling to fully and timeously settle their accounts resulting in the increase of overdue debt and decrease in customer payment levels. Since March 2014 to March 2016 the overdue debt has increased significantly of which the main increase are with the Municipal and Soweto customers.

8.7.1 Strategies to improve debt collections

Eskom will continue with the deployment of appropriate technologies that may prove to be a successful preventative measure to curb arrear debt and to assist with increased payment levels due to increased effective credit control. For e.g.:

- Split metering (protective enclosures).
- Automated Metering Interface (Smart Metering).
- Transfer supplies from conventional metering to prepaid as an affordable means to customers.
- The deployment of smart metering beyond the municipal structures.
- Evaluating municipal recovery plans and to agree on a payback plan to settle arrears as well as ensuring that there will be sustainable income in the future that will not impact Eskom materially.

8.7.2 Arrear Debts

Eskom's arrear debts have been increasing over the last few months. This meant that Eskom needed to implement interruptions in lieu of receiving payments. However the percentage of arrear debt to revenue currently exceeds the MYPD3 allowance of 0.5%. Several interventions have been introduced and will continue to be rolled out including prepaid meters which will contribute to arresting the arrear debts going forward. Although current arrear debt levels are high as 2% of allowed revenue, Eskom has maintained the NERSA previously determined rate of 0.5% for arrear debt/impairments in this application.

9 Production Plan

9.1 Background to the production plan

The purpose of production planning is to optimise Eskom production on a power station basis to meet Eskom demand in the short to medium-term, while maintaining least cost dispatch given the known constraints, legal and environmental policies. Constraints may include emissions, water shortages, coal shortage or surplus, network constraints, plant technical capabilities and any other constraints. The mandate for the production plan is to strictly stick to merit order dispatch at all times.

The Production Plan is used to provide the following:

- Eskom with the expected production level at each station so as to establish cost and revenue projections.
- Primary Energy Department (PED) with fuel requirements of the stations so as to procure adequate fuel to meet projected levels of production and to maintain the required strategic stockpile at each station.

Least cost dispatch is mainly derived from primary energy cost (coal and diesel cost). The process to prioritise stations is undertaken as follows:

- OCGT production – OCGT load factor is restricted to 1%.
- Due to the operational requirements for nuclear, Koeberg is always dispatched first when available.
- Hydro plants are dispatched based on water release agreements between Eskom and Department of Water Affairs.
- The remaining available units are dispatched from the cheapest to the most expensive.
- With the system availability improvement experienced over the past few months, it is critical that merit order dispatch is followed to support financial sustainability initiatives.
- Renewable IPPs are non dispatchable and run when available.

The Production Plan also takes the following into consideration:

- The energy forecast – This is based on the latest Energy Wheel Diagram which forecasts Eskom energy sales monthly and annually and includes Distribution and

Transmission national sales, export sales, Transmission and Distribution losses and pumping energy requirements.

- Eskom Generation Capacity – The plan includes Eskom's existing and new-build plants; Medupi, Kusile and Ingula. Non-commercial units are included from the projected Commercial Operation (CO) Dates.
- Plant performance – The Generation technical performance plan was used. This is derived from Planned Capability Loss Factor (PCLF), Unplanned Capability Loss Factor (UCLF) and Other Capability Loss factor (OCLF) assumptions.
- Non-Eskom Generation – the total energy supplied by non-Eskom suppliers (IPPs and Imports) is discounted from the total energy demand to determine Eskom generation requirements.

9.2 Production Plan Assumptions

9.2.1 The Energy Forecast

The energy forecast is the starting point of the production planning process. The source of the forecast is the Eskom Energy Wheel diagram which provides total projected Eskom sales. The Energy Wheel diagram forecast provides energy forecast which is made up of Distribution national sales, Export sales, Transmission and Distribution losses. This energy forecast has been discounted of impact of demand side management options.

The production planning model requires an hourly demand forecast for each of the years being studied. The hourly forecast is developed from the wheel diagram monthly/annual energies and the Medium-Term Outlook hourly profile as a reference of hourly demands. The hourly demands of the reference profile are scaled until the given annual energy figures are satisfied. The peak demands for each of the years of the study period are also the result of this scaling process. In order to determine the Net Generation energy for a particular year, the energy used for Generation pumping and the Distribution energy are subtracted from the demand for that particular year.

9.2.2 Eskom Generation Capacity

Eskom Generation currently, as at 31 January 2017, operates 44 034 MW of commercially operating fleet. The bulk of this, 36441 MW, is coal fired and also includes 1860 MW nuclear, 2409 MW of gas turbines, 600 MW hydro and 2724 MW pumped storage. The Production Plan is based on 60 year power station life for coal fired stations except Komati.

Acacia and Port Rex also reach end of life during the planning horison. Komati units reach end of life from FY2024 as per life of each unit, Acacia and Port Rex units reach end of life from FY2027.

Eskom renewable plant (Sere) with 50 units of 2 MW (100 MW) each is also included in the production plan. Ingula pump storage is projected to be fully operational by beginning of FY2018. The new stations included in this planning horison are coal-fired base-load plant Medupi and Kusile.

9.2.3 Plant performance data

Plant performance data determines the availability of the generating plant. This data includes unplanned capability loss factor (UCLF) estimates, other capability loss factor (OCLF) estimates and planned capability loss factor (PCLF). The Generation technical performance plan was used for this study as shown below.

TABLE 14: GENERATION TECHNICAL PERFORMANCE PLAN

Generation Technical performance	Actuals	Projections	Application
	2016/17	2017/18	2018/19
Energy Availability Factor (EAF)	77.3	78.0	79.0
Planned Capacity Loss Factor (PCLF)	12.2	10.0	10.0
Unplanned Capacity Loss Factor (UCLF)	9.9	10.9	9.9
Other Capacity Loss Factor (OCLF)	0.7	1.1	1.1
Gross Load Factor (GLF)		56.2	53.3

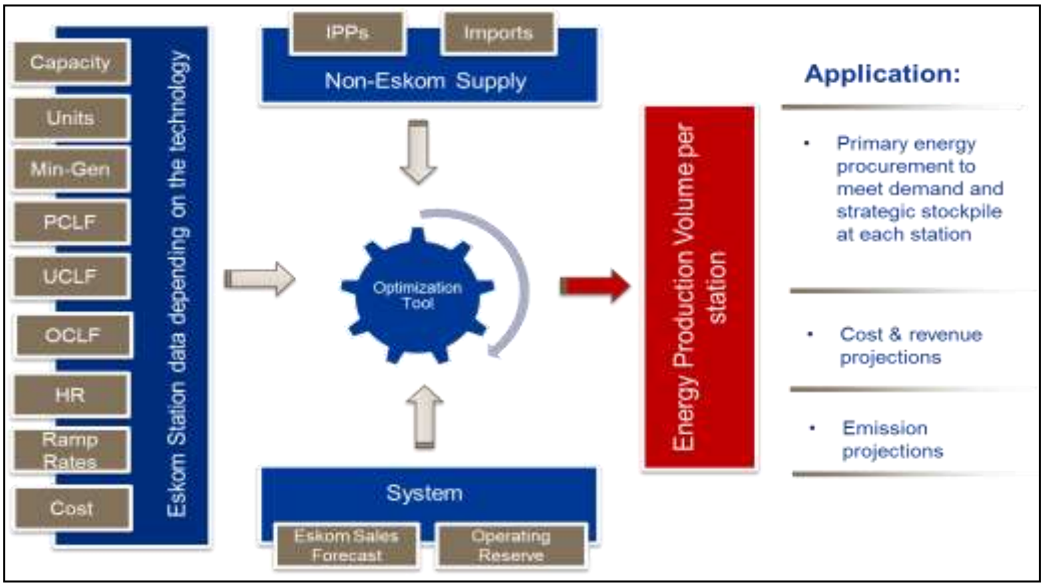
9.2.4 Non-Eskom Generation

The total energy supplied by non-Eskom generators is reduced from the total energy demand to determine the Eskom generation requirement. Non-Eskom generation include the international imports (purchases, imports and wheeling) as per the wheel diagram input and Eskom IPPs and Renewables. The Eskom IPPs include MTPPP, DoE Peakers and Short Term Purchases. Renewable IPPs from Wind, Concentrated Solar Plant (CSP), Solar PV, Hydro and Other. IPPs considered in the production plan are up to Bid Window 4.5.

9.3 Production Planning Process

The Production planning methodology is shown in the figure below.

FIGURE 22: PRODUCTION PLANNING METHODOLOGY



The production plan is optimised using an Integrated Energy Model. This is a simulation tool that uses data handling, mathematical programming and stochastic optimisation techniques to provide analytical framework for power market analysis. It is able to optimally dispatch schedule of generating units based on user defined constraints and respecting technical limits. This modelling tool determines the least cost dispatch of generating resources within given system constraints to meet the power demand from a single period to daily, weekly, monthly or annual timeframes. The merit order costs are not actual running costs, but rather approximate energy cost in R/MWh which is derived from fuel cost projections per station.

9.3.1 Base load

The coal-fired and nuclear stations are baseload stations and form the bulk of the capacity and will be utilised first to meet the demand. The base-load stations are restricted in their output through their available capacity, utilisation factors and their position in the merit order. A base-load station first in the merit order (e.g. Koeberg) will generate at full available output in all hours, whilst an expensive base-load station will follow the load pattern from hour-to-hour taking into account their minimum generating levels.

9.3.2 Gas Turbines

Similar to the baseload units, the OCGTs are not fuel constrained but restricted by their availability and position in the merit order. For this submission, Eskom and IPP (Avon and

Dedisa) OCGTs are restricted to minimum 1% annual load factor for grid stability purposes (Eskom OCGTs – 1% load factor and IPP OCGTs – 1% load factor).

9.3.3 Pumped Storage

The pumped storage units are constrained by their reservoir sizes and pumping requirements. They are modelled such that their top reservoirs must be full at the beginning of every week. The historically generating pattern have been taken into account hence they were given minimum load factors.

9.3.4 Hydro

The approach restricts the generation capability of the hydro stations (Gariep and Vanderkloof) to historical annual generation patterns due to water availability. The full capacity of these stations is thus not available in all hours; they can only be dispatched for a limited number of hours per day.

The Generation Production Planning serves as the guide in resource utilisation for Eskom power stations based on the current assumptions. The production plan gives an indication of surplus energy as early as FY19 going forward. Eskom has to develop an asset utilisation strategy to deal with excess capacity as there are several factors which must be taken in account. Production planning depends on many forecast parameters, including:

- Government policies with regards to REIPPPP (Renewable Energy Independent Power Producers Procurement Programme)
- Environmental compliance
- The impact of the Integrated Resource Plan (IRP) to Eskom
- Changes in the plant performance
- Delivery and performance of IPP’s.
- Recovery of the economy which will have impact on demand forecast
- Changes in Import as supplied by Southern African Energy

9.4 Production plan results

FIGURE 23: PRODUCTION PLAN

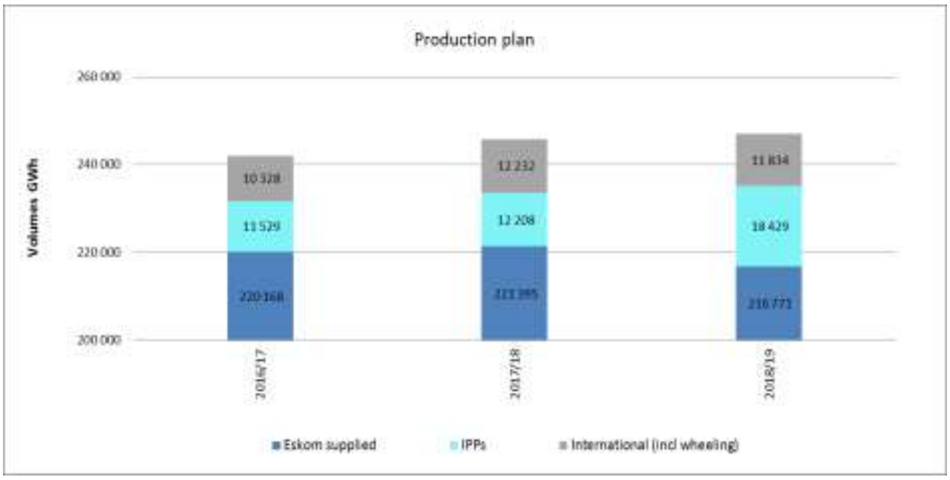


Figure above reflects escalating supply from IPPs, while Eskom's own supply is trending downwards.

TABLE 15 : DETAILS OF PRODUCTION PLAN

	Actuals	Projections	Application
Electricity output	2016/17	2017/18	2018/19
Power sent out by Eskom stations, GWh (net)	220 166	221 395	216 771
Coal-fired stations, GWh (net)	200 893	201 796	198 908
Hydroelectric stations, GWh (net)	579	695	693
Pumped storage stations, GWh (net)	3 294	4 394	4 282
Gas turbine stations, GWh (net)	29	211	211
Wind energy, GWh (net)	345	282	277
Nuclear power station, GWh (net)	15 026	14 017	12 400
IPP purchases, GWh	11 529	12 208	18 429
Wheeling, GWh	2 910	2 562	2 453
Energy imports from SADC countries, GWh	7 418	9 670	9 381
Total Gross Production , GWh	**242 023**	**245 835**	**247 035**
Less Pumping	4 809	5 931	5 783
Total Net Production , GWh	**237 214**	**239 905**	**241 252**

9.5 Energy Losses

The nature of transporting electricity from generator to the end-users involves losses in energy volumes (electrical or technical losses) that reduce the amount of electricity volumes available for sale to end-customers. In addition, other energy losses may occur due to non-metered usage related to electricity theft (non-technical losses). The representation of the measure for the levels of the combined total technical and non-technical losses is by way of loss factors.

Energy loss is an inherent risk in the electricity business and utilities globally are addressing this issue, which costs billions of rand annually with developing countries being the worst affected. Energy losses are incurred when energy is transferred from the suppliers to the loads through the network. This energy lost, is approximately equal to the difference between the energy supplied and the energy consumed.

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

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

10 Cost of Capital

The next section will cover the weighted average cost of capital (WACC) component of the build blocks to the allowable revenue formula:

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

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

Since the MYPD3 decision where a pre-tax real WACC target of 7.65% was allowed, several developments have occurred affecting Eskom's cost of capital. Recently the credit ratings downgrade of Eskom by Standard & Poors and Fitch rating agencies coupled with the sovereign downgrade by S&P has placed upward pressures on funding costs. .

TABLE 16 : COST OF CAPITAL

Weighted Average Cost of Capital WACC Pre-tax	Debt	Equity	WACC
Costs nominal	11.9%	23.2%	
Weight	70%	30%	
WACC nominal pre-tax	8.3%	7.0%	**15.3%**
Costs Real	5.2%	15.9%	
Weight	70%	30%	
Inflation			6.3%
WACC Real pre-tax	3.7%	4.8%	**8.4%**

Eskom's updated WACC real pre-tax is 8.4% which is higher than the MYPD3 decision by 75 basis points. During the revenue application only a portion of the WACC is claimed against the regulated asset base (RAB).

11 Regulated Asset Base

The next section will cover the regulated asset base (RAB) component of the build blocks to the allowable revenue formula:

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

The ERA and the electricity pricing policy require the recovery of efficient costs and earning a fair return on revalued asset valuations. The NERSA regulatory methodology allows for the earning of returns for works under construction as interest costs are not separately recovered as a cost component.

The opening RAB balance for FY2019 is based on the MYPD 3 decision which is then adjusted for the latest capital expenditure forecasts for the period FY2014 to FY2018. The average RAB value for FY2019 is R764bn.

TABLE 17 : REGULATORY ASSET BASE (RAB)

Regulatory asset base (Rand millions)	2018/19 Application
Assets	592104
Working capital & WUC	171485
Eskom RAB	**763589**

Power stations comprise a large proportion (72%) of the Eskom RAB at R550bn, with Transmission contributing R109bn and Distribution R105bn.

TABLE 18 : LICENSEE BREAKDOWN OF RAB

Regulatory asset base (Rand millions)	2018/19 Application
Generation	549527
Transmission	109371
Distribution	104691
Eskom RAB	**763589**

12 Return of Assets

The next section will cover the return on assets which is a function (RAB X WACC) component of the build blocks to the allowable revenue formula:

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

Eskom has continued the approach of NERSA by phasing in the returns on the regulated asset base resulting in a 2.97% ROA being requested; which equates to R22.7 billion. These returns are lower than the 4.7% awarded in 2017/18 resulting in a drop of R12 billion in the revenue requirement. These returns do not cover the full interest costs forecasted at R36 billion in 2018/19. Eskom has already paid R26 billion for interest in 2016/17. The escalation in interest costs is directly correlated to the debt funding raised. Notwithstanding the price increases awarded between 2008 and 2016, Eskom's debt continued to grow even with the increase in the price of electricity since 2008.

TABLE 19 : ESCALATING DEBT DESPITE RECEIVING PRICES INCREASES

This reduction in ROA is chosen to help keep the revenue and price impact as low as possible. Eskom's submission of 2.97% is a third of its cost of capital rate of 8.4%, resulting in sacrificing on allowed revenue. The drop in debt in 2016/17 is attributable to the conversion of the shareholder loan of R60 billion into equity.

TABLE 20 : RETURN ON ASSETS

Return on Assets (Rand millions)		2018/19 Application
Average RAB	(R'm)	763 589
Full Return on Assets (ROA)	%	8.4%
Returns	(R'm)	64 142
Phased in ROA	%	2.97%
Phased in Returns	(R'm)	22 690
Returns sacrificed	(R'm)	-41 452

The MYPD methodology allows for the returns on assets as a proxy for the recovery of interest costs and an equity return to the shareholder. As a result of the phased in returns of R22 690million which does not fully cover the forecasted interest costs of R36 billion there is no residual available for equity returns. In terms of earning a full ROA of 8.4%, Eskom is sacrificing R41 452 million. It is evident that the process for phasing-in of reasonable returns is being further extended.

If Eskom were to apply for the full return on assets of 8.4% the allowed revenue would be R261bn, which corresponds to an average price increase of 44% for the 2018/19 year.

13 Depreciation

The next section will cover the depreciation (D) component of the build blocks to the allowable revenue formula:

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

In accordance with the MYPD methodology, depreciation is computed by dividing the RAB over the remaining life of the respective assets. Therefore the depreciation amounts have remained relatively similar to 2017/18 as the RAB has not changed significantly. The weighted average life for assets included in the RAB is 25 years. The depreciation disclosed for regulatory purposes (in terms of the MYPD methodology) is based on a revalued modern equivalent asset base and is thus different to the depreciation disclosed in the AFS which is based on historic valuations.

TABLE 21 : DEPRECIATION

Depreciation (Rand millions)	2018/19 Application
Generation	19 062
Transmission	3 833
Distribution	6 245
Total Depreciation	**29 140**

14 Capital Expenditure

In this revenue application window, Eskom capital expenditure plans will focus on delivering the following projects:

- New Build programme (Commercial operation of Medupi and Kusile) with some units on accelerated construction plans
- Expanded and strengthened transmission grid which gets Eskom closer to N-1 compliance whilst executing the Power Delivery Plan
- Investments into other projects including Kusile Ash Dump, Majuba Silo recovery and rail, Medupi FGD, Duvha Unit 3,
- Generation technical plan capital expenditure
- Primary Energy will invest into Cost-Plus mines which will provide Eskom with cheaper coal.
- Eskom will also invest in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance.
- Investments will be made in the refurbishment and strengthening of existing networks, in building new networks for customers and in connecting IPPs.
- Eskom does not include DOE funded capex into the regulatory asset base.

TABLE 22 : CAPITAL EXPENDITURE

Capital Expenditure (excluding IDC)	2016/17	2017/18	2018/19
(Rand millions)	Actuals	Projections	Application
Generation	44 685	44 823	46 494
Transmission	5 971	6 814	11 492
Distribution	5 221	7 372	8 381
Total licensee capex excluding future fuel	55 877	59 009	66 367
Future fuel	114	2 864	3 911
Total licensee capex	55 991	61 873	70 278
Corporate capex	2 932	3 910	6 663
Eskom Capex portfolio (excl IDC)	**58 923**	**65 783**	**76 941**
Electrification (DOE Funded)	3 233	3 373	3 475

- The new build capital expenditure for Medupi and Kusile contributes R20 billion to Generation capex spend of R46 494 million in 2018/19.
- Electrification capex funded by the Department of Energy assumed to be in the region of R3.4 billion

- Transmission growth is attributable substantially to capital expansion projects, together with refurbishments, servitudes and environmental impact assessments (EIA)
- Distribution capital expenditure focusses on the strengthening of networks
- In addition to the above capital expenditure requirements, Eskom is pursuing alternate funding options.

15 Primary Energy

15.1 Overall summary of primary energy

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

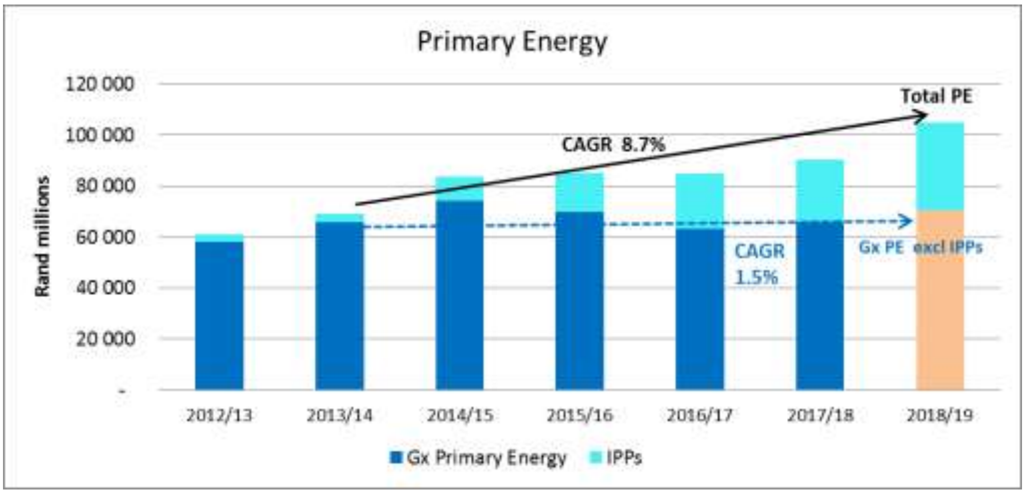
$AR=(RAB \times WACC)+E+PE+D+R\&D+IDM \pm SQI+L\&T \pm RCA$

Primary energy costs equate to the costing of the production plan (electricity supply required to meet demand). There are three sources of electricity supply comprising Eskom own generation (majority), domestic independent power producers (IPPs) and regional import of supply (international supply). Due to the roll out of renewable IPP domestic progammes driven by DOE, there has been a growing trend in local IPPs over the last few years. International supply represents substantially the supply from Cahora Bassa reflecting declining trend recently attributable to the drought conditions. Therefore, Eskom's own generation is used to meet the balance of supply as renewables are non-dispatchable.

Eskom's primary energy costs escalations are summarised as follows:

- Generation own costs have a compounded average growth rate (CAGR) of 1.5% per annum from 2013/14 to 2018/19
- Own costs peaked in 2014/15 and 2015/16 when OCGTs were utilised during periods of supply shortages to minimise/prevent load shedding
- In later years (2016/17~2018/19) the growth in local IPPs results in displacement of Eskom power stations
- Local IPPs grew substantially from a low base and contributed positively especially during supply challenges
- Total primary energy costs reflect a CAGR of 8.7% per annum between 2013/14 to 2018/19
- Coal burn costs reflect a CAGR over the period of 7% per annum

FIGURE 24 : PRIMARY ENERGY COST ESCALATIONS



The figure above highlights the drop in primary energy costs following the reduction in OCGTs utilisation since September 2015. Eskom has assumed a maximum load factor of 1% of gas turbines in 2017/18 and 2018/19.

FIGURE 25 : GRAPHIC ANALYSIS OF PRIMARY ENERGY COSTS

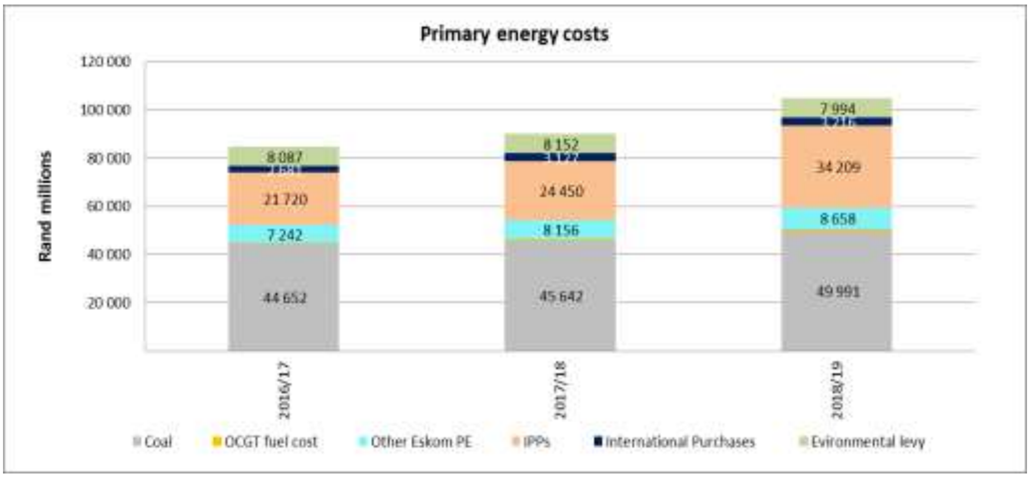


TABLE 23 : DETAILED PRIMARY ENERGY COST

	Actuals	Projections	Application
Primary energy costs R'million	2016/17	2017/18	2018/19
Coal usage	44 164	45 642	48 687
Coal obligations provisions	488		1 304
Water usage	1 751	2 185	2 310
Fuel & Water procurement service	163	211	223
Coal handling	1 758	1 874	1 974
Water treatment	423	465	490
Sorbent usage	-	36	63
Gas and oil (coal fired start-up)	2 216	2 268	2 405
Total coal	**50 963**	**52 681**	**57 456**
Nuclear	727	808	865
Coal and gas (Gas-fired)	10	8	9
OCGT fuel cost	340	638	691
Demand Market Participation	194	301	319
Total Eskom generation	**52 234**	**54 436**	**59 340**
Environmental levy	8 087	8 152	7 994
IPPs	21 720	24 450	34 209
International Purchases	2 681	3 127	3 216
Total primary energy	**84 722**	**90 165**	**104 759**

***Note**: The primary energy costs reflected in the Annual Financial Statements for 2016/17 is R82760 million. The difference to the R84 722 million is because for regulatory purposes the IFRIC 4 adjustment relating to the DOE Peaking station is reversed as the MYPD methodology allows for a full pass through of IPP costs.*

Primary energy will be unpacked into more detailed for the three sources starting with IPPs which is followed with international purchases and concludes with Eskom's own generation costs.

15.2 Independent Power Producers (IPPs)

IPP costs will increase from a 5% (FY2014) contribution to 26% (FY2018) of the primary energy costs with the costs escalating from R3bn to R24bn over the MYPD3 period.

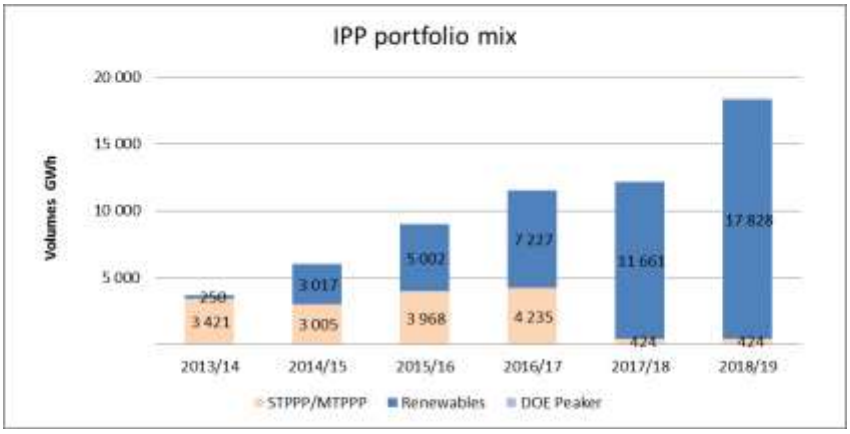
15.2.1 IPP summary

TABLE 24 : SUMMARY OF IPPS

	Energy (GWh)			Cost (R million)		
IPPs (local)	2016/17	2017/18	2018/19	2016/17	2017/18	2018/19
Eskom short term programmes	4 235	424	424	3 952	274	302
MTPPP	29	0	-	37		-
STPPP (incl Munic)	4 101	0	-	3 845		-
WEPS	105	424	424	70	274	302
Section 34 programmes (-RE)	67	122	176	2 186	2 377	2 485
DoE Peaking	67	88	88	2 186	2 338	2 380
Co-generation	-	34	88	-	39	105
Renewable IPP	7 227	11 661	17 828	15 582	21 631	31 230
Renewable IPPs Round 1	3 593	3 845	3 834	8 958	10 276	10 850
Renewable IPPs Round 2	2 671	3 072	3 074	5 430	5 917	6 191
Renewable IPPs Round 3	963	3 073	4 493	1 194	3 943	6 452
Renewable IPPs Round 3.5	-	-	590	-	-	2 308
Renewable IPPs Round 4	-	501	2 931	-	449	2 514
Renewable IPPs Round 4.5	-	1 091	2 721	-	939	2 629
Small-scale renewable		79	185	-	107	286
Total IPP	11 529	12 207	18 428	21 720	24 282	34 017
Network costs (UoS)					168	192
Total IPP	**11 529**	**12 207**	**18 428**	**21 720**	**24 450**	**34 209**

Production from IPPs over the MYPD3 period consisted of Eskom programmes (STPPP/MTPPP) and those driven by the DOE (Renewables and Peaker). The figure below reflects a movement away from STPPP/MTPPP to that of DOE progammes.

FIGURE 26 : IPP MIX OVER MYPD3 PERIOD



Supply from renewable IPPs have increased from R389 million (250GWh) in 2013/14 reaching R15 582 million (7 227GWh) by March 2017. During the same period, Eskom's own IPP initiatives (STPPP and MTPPP) incurred R 2877 million (3 421GWh) by March

2014, growing to R3 952 million (4 235GWh) by March 2017. However, the need for these programmes were removed and therefore forecasts to March 2019 reflect a mere R302 million (424GWh).

A. Department of Energy IPP Peaker Programme

The Peaker programme has been fully operational from 20 July 2016 with the Avon power station joining the Dedisa power station in commercial operation, bringing the total capacity to 1 005 MW. These power stations are compensated for available capacity on the system separately to the energy produced as they are fully dispatched by Eskom's System Operator. The expected load factor of the two power stations (as dispatched by Eskom) is 1% in each year, leading to an expected energy output of 88 GWh per year.

B. Renewable IPP Programme

The Renewable IPP Programme (REIPPP) has concluded on seven bid windows (bid window 1, 2, 3, 3.5, 4, 4.5 and the first bid window of the Smalls programme). This application provides the expected energy purchased from these programmes only, assuming that further programmes do not reach commercial operation during the application period. The summary of the expected energy and total costs per bid window is indicated in Table 24 above. The costs for bid windows 4, 4.5 and the Small scale programme are based on adjusted contract prices received from the IPP Office to account for foreign exchange movements to July 2015. The final price for these contracts will be determined when the contracts are signed as there is an adjustment for foreign exchange, amongst others, relative to the bid prices.

C. Co-generation programme (only current window)

The IPP Office has concluded one contract under the Co-generation programme (with a capacity of 11 MW). The expected energy and costs associated with this contract are indicated in Table 25 table below.

TABLE 25: CO-GENERATION EXPECTED ENERGY AND COSTS

	Energy (Gwh)			Cost (R'm)		
Co-generation	2016/17	2017/18	2018/19	2016/17	2017/18	2018/19
Combined Heat Power	-	34	88	-	39	105

15.3 International purchases

Electricity supply from neighbouring countries is mainly driven by imports from Cahora Bassa (HCB) with expected supply of approximately 1200~1400MW. This source has been subject to fluctuations in recent years due to network constraints or drought conditions affecting the level of the dam and thus reducing supply by around 500MW in certain instances. The forecasts remain fairly consistent at around 9.5 TWh. Eskom and South Africa have benefited from the low costs linked to the HCB contract.

TABLE 26 : INTERNATIONAL PURCHASE VOLUMES

	Actuals	Projections	Application
International purchases (GWh)	2016/17	2017/18	2018/19
Imports	**7 418**	**9 670**	**9 381**
Mozambique (HCB)	6 454	9 658	9 373
Other sources	964	12	8
Wheeling	**2 910**	**2 562**	**2 453**
Total international purchases	10 328	12 232	11 834

15.4 Eskom own primary energy market overview

15.4.1 Overview of the Primary Energy Business Environment

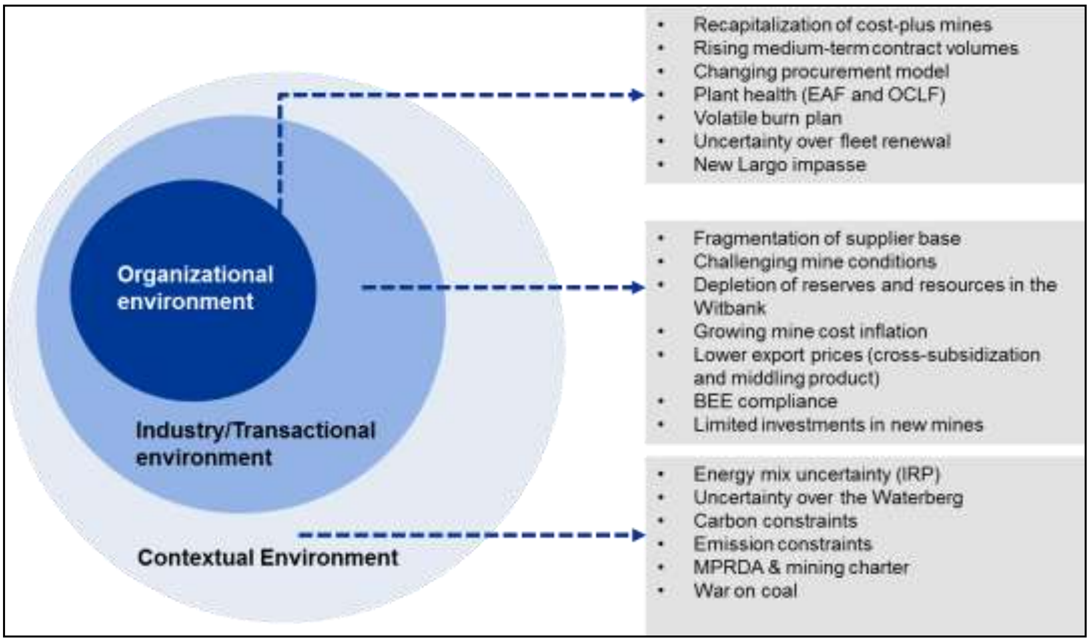
Eskom Primary Energy Division's mandate is to **safely and sustainably identify, develop, source, procure and deliver** the necessary amounts of primary energy (**coal, water, limestone and biomass**) of the **required quality** for Eskom's power stations, at the **right time and at optimal cost.**

The division's accountability covers a range of functional areas extending from the source of fuel to delivery and stockpiling at the power stations:

FIGURE 27: PRIMARY ENERGY VALUE CHAIN

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

FIGURE 28: CHALLENGES FACING PRIMARY ENERGY DIVISION



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

- **Impact of economic uncertainty on the long term growth trend -** Continued uncertainty and economic instability increases the risk of over or under contracting of coal supply, which necessitates the requirement for Eskom to increase the volume flexibility in the portfolio of coal contracts. However, this flexibility will bear a cost.
- **Changing the coal industry structure -** The commodity boom has ended. This has positive and negative implications for Eskom. On the positive side, one would expect Eskom's bargaining power during contract negotiations to be stronger. Eskom may now not be competing with the export market for coal. On the negative side, where South

Africa previously seen the emergence of more junior and BEE miners in the coal sector, the current cyclical downturn has resulted in a dearth of new mines.

- **Mines are currently facing a multi-year price rout -** Export coal prices are currently at multi-year lows due to a structural oversupply of seaborne thermal coal. Many investment decisions were made at the height of the last commodity boom, and now these new mines are coming on line.
- **Deteriorating resource/reserve base –**

  The mines in the Mpumalanga basin are entering a phase where the cost of coal is driven upwards by factors such as deteriorating coal quality, increased occurrence of geological disturbances, thinner coal seams, depleting reserves in the currently accessible reserve blocks, high investments to access the remaining new small reserve blocks and longer 'on-mine' transport distances.
- **Increased transport distances between mines and power stations -** The procurement of coal from sources, which are great distances from the power stations, will incur some kind of logistics cost to deliver that coal to the Power Station which will result in an increase in the coal cost.
- **Increasing environmental pressure -** Water and coal are the most prevalently used resources in coal fired generation. Eskom's coal-focused generation mix also requires significant volumes of water. The opening of new coal mines is expected to place unsustainable pressure on the already strained environment and on water catchments, while the increased burn at the power stations will have an adverse impact on air qualities in Mpumalanga.
- **A constraint on water supplies -** Eskom is a strategic user of water, consuming approximately 2% of the total annual use of the country, which is equivalent to the consumption of the City of Cape Town.
- **Supply constraints in key mining inputs -** Most mine input costs have been increasing at rates higher than general inflation over 2008-2014.

15.4.2 Key elements of Eskom strategy in response to trends and market forces

Eskom historically procured coal for its power stations on a dedicated-mine basis, where the power station is built to the specification of the coal available and built as close as possible to the mine. To cover full requirements, these long-term contracts were predominantly either a cost plus or fixed price agreement. However, a long-term coal contracting model was not always feasible, and in certain cases medium-term coal supplies were utilised, which required coal to be transported over long distances, resulting in further cost increases.

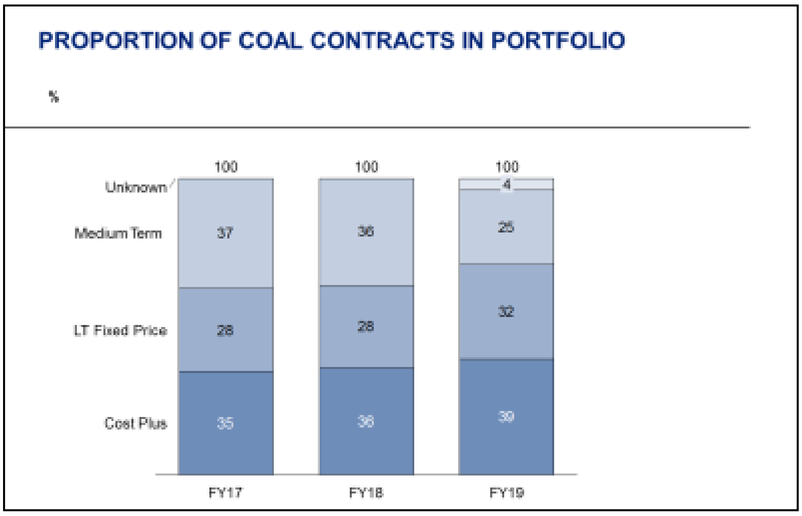
In spite of these challenges, Eskom has managed to grow and diversify its supplier base and continue to provide quality coal and water supply to ensure the powering of stations. Furthermore, Eskom has identified coal sources for all of its power stations and has put in place measures to establish contracts for the majority of its coal requirements.

15.4.3 Coal Supply to meet Coal Burn requirements

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

In FY17, approximately 63% of coal was procured on long term contracts. These are historical contracts with original durations of 40 years, which were designed to match the life of the associated power station(s). In FY19, this proportion increases to 70% because of the increase in coal procured on the Medupi contract. There is also a planned small increase in the proportion of coal from the cost plus contracts. This, combined with a decrease in the total coal procured, results in less coal having to be planned for on medium term contracts, as is evidenced in the figure below.

FIGURE 29: PLANNED COAL SUPPLY (MT)



i. Cost Plus Mines

The planned quantity from the cost-plus mines increases from 42 Mt in FY17 to 46 Mt in FY19. There are a number of reasons for this:

- Production from these mines has declined over the past few years as the mines have aged and reinvestment has stagnated. Earlier production from the cost plus mines exceeded contractual obligations. In more recent years, the situation has reversed.
- Individual cost plus contracts are coming to the end of their terms.
- Operational issues can result in the mine being temporarily unable to mine or mining at a lower rate.
- Investments in these mines will help increase volumes

ii. Fixed Price Mines

Eskom has four Fixed Price contracts. Three of these contracts are historical long term contracts that supply coal to Matimba, Duvha and Hendrina Power Stations. A more recent addition has been the contract with Exxaro to supply coal to Medupi Power Station.

- The coal contract for Hendrina Power Station expires at the end of 2018. It is assumed that the coal will then be purchased on medium term contracts
- Matimba Power Station has a contract with Exxaro for 13 - 14 Mt p.a. Depending on the electricity demand and how Matimba is scheduled to run, excess coal is stored on the

station's stockpile. When stockyard capacity is reached, the take or pay payments need to be made. Prior to that coal from the contract with Exxaro is stockpiled until the stockyard reaches full capacity. Thereafter, provision has been made for the take or pay payment.

- It is important to note that most of the coal supply agreements have a take or pay arrangement. The geographical location of Grootegeluk mine supplying Medupi and Matimba Power Station make it expensive logistically to deal with an oversupply situation.

iii. Medium Term and uncontracted coal

Coal contracted on medium term contracts to fill the gap between long term contracts and the coal requirement.

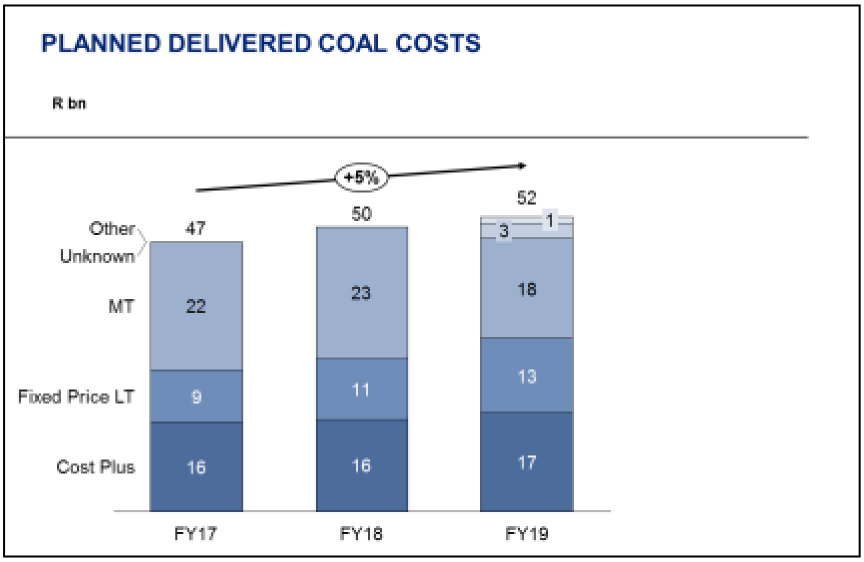
Procurement of coal from medium term (MT) contracts declines over the period as production from coal fired stations declines. This plan also includes increased production from the cost plus mines as investment in the mines are rolled out. Arnot Power Station receives its coal from MT contracts since the cost plus contract expired at the end of 2015. Majuba, Komati, Grootvlei and Kusile Power Stations do not have dedicated mines. These stations still plan for all their coal from medium term contracts.

15.4.4 Annual coal purchases costs

The largest component of the projected annual coal expenditure is the costs from existing and new long term coal sources. This is in line with the first principle of the long term coal supply strategy, namely, securing long term contracts with mines close to power stations. Over the FY17-FY19 period, compound average growth rate of the annual coal expenditure is ~5%.

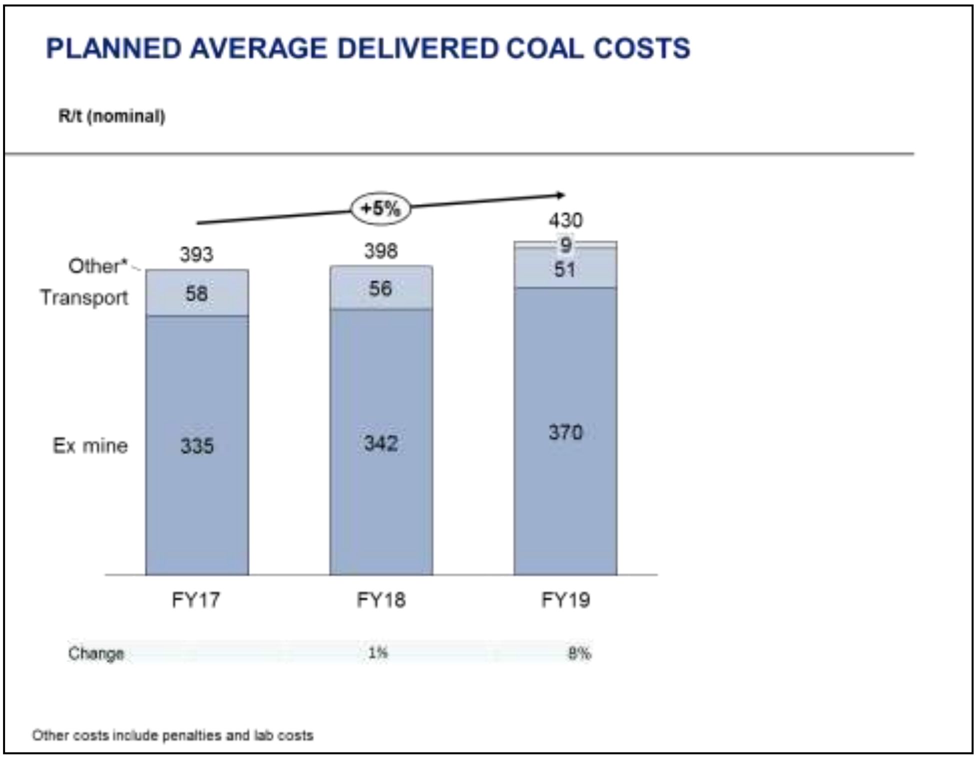
'Other' costs referred to below, includes coal sampling costs and amortisation of logistics investments.

FIGURE 30: ANNUAL COAL EXPENDITURE PER SUPPLY SOURCE



The average delivered cost will be affected by the transport solutions that are introduced over the period and by the volume of medium term coal, as this coal is typically transported over longer distances than the long term cost plus and fixed price coal. The mode of transport is by road and/or rail, which is more expensive than conveyor. The average annual increase is 5%, as per the figure below.

FIGURE 31: AVERAGE DELIVERED R/TON COAL COST



The bulk of the average cost of a ton of coal delivered to a power station is the ex-mine cost of the coal. This is around 84% of the cost. Transport as a percentage of total average delivered coal cost is around 14%. Other costs, such as take or pay payments and laboratory fees, comprise about 2%. The average increase in FY19 is 8%. The increase in the unit cost of long term cost plus coal is 8%, long term fixed price coal is 14%, and short/medium term coal is 8%.

15.4.5 Detailed coal burn costs

Further details on coal burn costs, in accordance with the MYPD methodology are reflected in Appendix 1. NERSA requires burn to be submitted per station, per contract type and per supplier. Eskom calculates coal burn on a weighted-average-cost basis. A single coal stock pile is maintained for all coal delivered to the stock yard, irrespective of the contract type. The coal is burnt as a single, mixed product and not as three different product types. Accordingly, coal burn does not differentiate between contract types (i.e. cost-plus, fixed-price or medium term). Eskom has submitted coal burn assumptions per power station. Eskom has furthermore made assumptions to split coal burn by contract type, calculating coal burn in the same ratio as coal purchases.

15.4.6 Transport Costs

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

- Conveyor – this is the mode used for coal from collieries located close to the power station receiving the coal. It is the cheapest mode.
- Rail – Transnet Freight Rail provides the rolling stock. Coal is railed from the supplier to the power station, if the supplier and the power station have the infrastructure. Alternatively, coal may be transported by a combination of rail siding and truck. The more complex the transport arrangement, the more expensive the transport cost is likely to be.
- Road – Coal is trucked to its destination when conveyor and rail are not possible.

Rail is preferred over longer distances. However, only Majuba and Tutuka Power Stations have the infrastructure for coal to be railed to the station. Grootvlei and Camden Power Stations are located close to rail sidings. Rail has, historically, been cheaper than road. Transnet is the only provider of freight rail and determines the tariff, which varies with the type of service required, e.g. open top wagons are cheaper than closed containers. Tariffs are escalated annually in accordance with a basket of published indices agreed to by Eskom and Transnet. This increase has been higher than general inflation over the past five years. The current contract with Transnet expires in March 2018. A new contract has not been finalised as yet. This plan assumes that:

- There will be a step change in the rate in that year. Thereafter, the rate is forecast to increase at 12%p.a.
- The new contract will not include any minimum volume clauses.

The volume on rail increases from 13.2 Mt in FY17 to 14.5 Mt in FY19. It is assumed that new coal purchases will be delivered via rail. These sources at the time of this document have not yet been established or been through the required commercial processes.

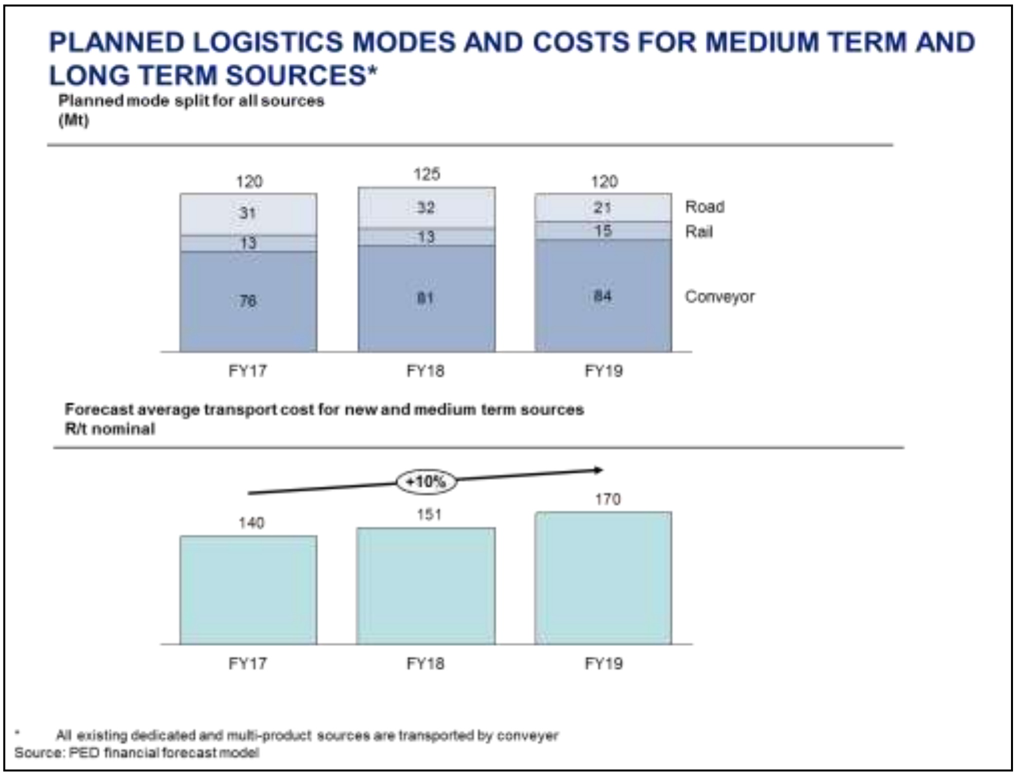
Transport on road is managed using two types of contracts:

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

FCA contracts expire at the end of March 2018. The assumption is that the same terms and conditions will apply to any further contracts and that there will be additional costs incurred.

The table below indicates the total annual cost of transport and the volumes per transport mode.

FIGURE 32: PLANNED LOGISTICS MODES AND COSTS FOR LONG AND MEDIUM TERM SOURCES



The average annual cost of getting a tonne of coal from the source to the power station increases by 10% p.a. Coal transported by rail will often include a road component because there may not be an available rail link. In some instances, the multi-mode trip may be more expensive than a direct road trip, but rail is preferred because the reduced time on the road translates into fewer opportunities for road accidents.

Further details on assumptions on escalation rates and transport costs are provided in Appendix 1.

15.4.7 Coal Stock

Closing stock levels in FY15 were 51 days. From FY17, planned stock levels exceed the system maximum. This is because of increasing levels of stock at Lethabo, Matla, Medupi, Matimba and Kusile Power Stations. More details on coal stock have been included in Appendix 1.

15.5 Water costs

Eskom pays for the water it consumes through a series of water tariffs. These are legislated, so Eskom has no control over the tariffs. Historically, water costs have been very low as a percentage of the Eskom operating costs. The main reason for this is that the water infrastructure assets (Eskom's and that of DWA) were constructed several years ago and are almost completely depreciated. As new infrastructure and water charges have been introduced, the demand for water and the cost have increased. Furthermore, the cost increases as the distances over which water needs to be transferred increase and as new tariffs are introduced into legislation.

New water infrastructure includes augmentation to the Vaal, Komati and Mokolo water schemes. The DWA National Water Pricing Strategy allows DWA to implement these projects "off budget" and to recover associated costs via a tariff. The Komati and Mokolo costs are recovered on a take or pay pricing basis.

The water financial plan comprises the following cost elements:

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

15.5.1 Key drivers for water costs

i. The Department of Water Affairs under-spent on maintenance and refurbishment of bulk water infrastructure over the years. This has resulted in a backlog of maintenance and refurbishment that is required to be planned and implemented in the forthcoming years to ensure plant reliability and availability.

ii. The development and implementation of new water infrastructure, such as Mokolo Crocodile River (West) Water Augmentation Programme (MCWAP) 2 required for water to the Waterberg, will increase the cost of water.

iii. Water costs are regulated in line with the prevailing National Water Pricing Strategy. A new draft Water Pricing Strategy has been issued. Water tariffs could change during the latter part of MYPD3 or during this application period. Water cost increases are primarily driven by increasing water demands of the new build and Return to Service power stations, which require new water infrastructure and therefore higher capital tariffs to repay off the financing debt. The MCWAP2 pipeline to Medupi Power Station has a take or pay contract.

iv. The water deficit in the Integrated Vaal River System has resulted in Eskom driving water conservation and demand management initiatives to reduce its freshwater footprint and diversify its water mix. As part of its planned projects, Eskom will increase its use of treated mine water, thereby increasing the capital requirements for the development and implementation of mine water treatment plants and the management of waste.

v. The Department of Water Affairs is also rationalising and reforming its water institutions at catchment and national levels which may result in increasing water management fees being levied on all water users.

vi. Increased volumes of contaminated water at collieries will result in higher costs of water management.

With ageing bulk water supply infrastructure, deteriorating water quality and competition for water resources, especially during drought conditions, Eskom needs to ensure provision of water to its power stations are secure.

More details on water costs, manner of determining water costs and key drivers of water costs are included in Appendix 3.

15.6 Sorbent

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

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

15.7 Nuclear fuel

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

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

Koeberg Power Station consists of two reactors requiring each a loading of the reactor core of 157 fuel assemblies to achieve an even energy output as one third of the fuel assemblies are replaced at each refuelling cycle. These fuel assemblies remain in the reactor core and are “burnt” over a period between 45 and 54 months depending on the Production Plan and the refuelling strategies. The costs of the fresh fuel assemblies are amortised over the anticipated burn period and are reflected in Primary Energy costs. Factors influencing Koeberg’s primary energy (nuclear fuel) costs include:

15.7.1 Nuclear Fuel Price

Nuclear fuel procurement comprises mainly of four distinct phases, being procurement of uranium, conversion of the uranium into the gas $UF_{6,}$ enrichment of the U-235 isotopes to the required level, and the fabrication and delivery of the fuel assemblies. All these activities are undertaken internationally and are subject to market price and foreign exchange fluctuations. Eskom has contracts that cover 100% of Koeberg’s demand until the end of 2017 with procurement currently in progress to acquire uranium, conversion and enrichment services for the period up until 2028. For the fuel assembly fabrication phase, Eskom recently concluded contracts for the supply of fabricated assemblies up until 2022 with an option to extend to 2026.

Production Plan is influenced by Koeberg's need for refuelling every eighteen months as well as it maintenance regime which requires it to replace and modify its plant components. The fuel is burnt over a period of three reload cycles of approximately eighteen months each, being a total of 54 months, however based on the energy requirements some fuel assemblies may be changed and replaced with fresh fuel after only two cycles. These partially burnt assemblies are then expensed fully and removed from the reactor.

Spent Fuel Management Costs - The costs associated with the management, including the disposal of the Spent Fuel Assemblies generated by Koeberg is quantified from extensive studies which is incorporated into the Reference Technical Plan and reflected into a Spent Fuel Management Provision. The costs in raising the liability to safely and responsibly manage the spent fuel is amortised over the burn period of the fuel in the reactor core. The Spent Fuel Reference Technical Plan, which is based on extensive consulting studies, is revised every three years or when deemed necessary. In 2014, Koeberg experienced a significant increase in the costs anticipated in the management of used fuel, mainly due to the weakening pf the Rand against other trading partners, and an adjustment of R 830m to the Primary Energy costs was adjusted.

TABLE 27 : KOEBERG NUCLEAR FUEL COSTS

Nuclear fuel	Actuals	Projections	Application
	2016/17	2017/18	2018/19
Fuel burnt	638	712	713
Depreciation of Decomm Asset	39	65	77
Decomm provision adjustment			
Total	727	808	865

These costs represent the fuel burnt as per the Production Plan. The fuel assemblies loaded are expected to be burnt over a period of three cycles which equates to 54 months.

15.7.2 Fuel burnt

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

The Spent Fuel assemblies are stored in the Spent Fuel Pools at Koeberg Power Station; however given that Koeberg is over 30 years in use, the pools are reaching their capacity. The station has commenced acquiring Spent Fuel Casks which will allow the spent fuel to be removed from the pools and stored in dual-purpose, storage and transport casks. With each fresh reload of fuel into the reactor core the displaced spent fuel from the core will require older and cooler spent fuel to be removed from the pool. Hence the cash flow expenditure relating to the Spent Fuel Provision is now being incurred in the 2017 financial year and will continue through to the end of life of the station. Unlike the Plant Decommissioning expenditure which is mainly incurred at the end of life of the station, the spent fuel decommissioning expenditure is a current and ongoing cost.

15.7.3 Nuclear Other

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

15.8 Open Cycle GasTurbines (OCGTs)

The OCGT's (Ankerlig and Gourikwa) are heavy duty industrial gas turbines (Siemens) and can be used over a wide variety of loading regimes from peaking to base load. The OCGT's (Acacia and Port Rex) are based on jet engine technology.

15.8.1 Decision Making Criteria

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

TABLE 28 : OCGTS DECLINING USAGE

Open Cycle Gas Turbines (OCGTs)	Actuals	Projections	Application
Unit	2016/17	2017/18	2018/19
Volumes GWh	24	211	211
OCGTs costs R'm	340	638	691

Eskom's utilisation of gas turbines has decreased from R10.6bn (2013/14), R9.5bn (2014/15) and R8.7bn (2015/16) to R691 million in 2018/19.

The price used to forecast costs of gas fired stations was based on the ruling rate of 2 November 2016. The price was then escalated with the CPI inflation parameters of 6.3% for 2018. There is monthly storage fees included for the fuel tanks where diesel stocks are kept.

It must be noted that the costs of R340 million incurred in 2016/17 included an amount of R281 million for storage costs. Therefore the balance of R59 million is linked to the actual burn volumes of 24 GWh.

15.9 Start-up fuel

Heavy fuel oil starts and shuts down a coal fired power station and stabilises the boiler flame on occasion e.g. when operated at low load. The increase in 2014 is a result of increased generation by Medupi and Kusile Power Stations.

15.10 Water treatment

The quality of water from the various sources also impacts on the water treatment cost. From 2009 to 2010, the increase in the consumption of water from the Usutu Vaal by power stations on the Komati system meant that these stations needed to spend more on treating water. Similarly, the cost of water treatment increases from 2011 as the transfers from the Vaal system increase to augment the Komati and Usutu Vaal systems.

Further details on water treatment costs are included in Appendix 4.

15.11 Coal Handling

Coal handling refers to all the activities that are necessary to get the coal to the boiler once it has been delivered to the power station. This includes stockpile maintenance, and coal reclamation. It is an integral part of power production and the costs reflect a moderate increase over the planning period.

Further information with regards to Eskom coal handling costs per power station is included in Appendix 2. Assumptions are made with regards to the contribution of drivers for the coal handling costs.

15.12 Environmental levy

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

15.12.1 Environmental levy payment

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

TABLE 29 : ENVIRONMENTAL LEVY

	Actuals	Projections	Application
Environmental levy	2016/17	2017/18	2018/19
Energy sent out (GWh)	220 166	221 395	216 771
Non Renewable ESO (GWh)	215 948	216 024	211 519
Renewable ESO (GWh)	4 218	5 371	5 252
Generated volume (GWh)	232 462	232 900	228 390
System average auxilliary %	7.65%	7.81%	7.98%
Environmental levy rate (c/kWh)	3.50	3.50	3.50
Environmental levy cost (R'm)	**8 086**	**8 152**	**7 994**

15.12.2 Equivalent Revenue from Environmental Levy

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

The environmental levy cost is raised on the production electricity volumes that are made up of auxiliary consumption, electrical losses and electricity sales volumes. Electricity sales are a combination of renewable and non-renewable electricity generated. Utilising the sum of the renewable and non-renewable volumes in the cost allocation solves for the limitation of separately identifying non-renewable electricity sales volumes. The approach of an equal flat c/kWh approach to allocate the environmental levy costs facilitates an equal allocation of the environmental costs across the total supply when the volume is categorised either as auxiliary consumption, electrical losses or electricity sales. The retail charges to recover the environmental levy costs are informed by the factors causing the levy’s costs and recovery as well as the tariff regulations and the cost recovery principles.

16 Operating Cost

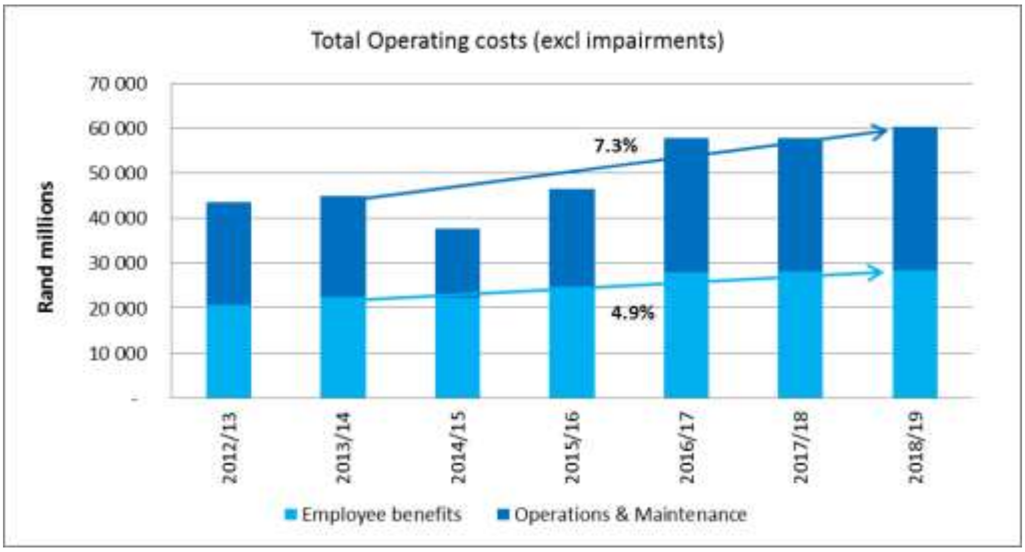
16.1 Overall summary of operating costs

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

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

Eskom's operating costs, excluding impairments, over the period 2013/14 to 2018/19 (application year) have grown at rates that approximate inflation. Analysis reflects that employee benefits have a CAGR of 4.9% in this horizon. Similarly, the operating and maintenance costs have a CAGR of 7.3% over the period. There is a relative plateau in the Eskom's overall operating costs in the later years of this period. Operating costs remains flat in 2017/18 followed by 4.6% increase in costs in 2018/19 before taking into account costs not claimed in this application.

FIGURE 33 : TRENDS IN OPERATING COSTS



The significant drop in operating costs in the 2014/15 financial year can be explained by receipt of other income of R6.7 billion related mainly to insurance proceeds. This situation is repeated in 2015/16, with other income of R3.3 billion.

Significant efficiencies would be achieved over the period by reducing the number of employees. Containing the workforce numbers without compromising the required skills in appropriate areas will be possible. This will be done by re-training, re-deployment and re-skilling of the work-force and natural attrition. The growth in maintenance costs escalates due mainly to the increased maintenance in the network businesses.

TABLE 30 : DETAILED OPERATING COSTS

Eskom	Actuals	Projections	Application
Operating costs R'million	2016/17	2017/18	2018/19
Employee benefit costs	27 902	28 213	28 363
Operating & Maintenance	32 025	30 995	33 461
Maintenance	14 087	15 610	17 665
Opex	17 938	15 385	15 796
Other income	-2 093	-1 478	-1 452
Operating costs before Arrear debts	**57 834**	**57 730**	**60 372**
Impairments	4 325	3 968	4 080
Operating costs with Arrear debts	**62 159**	**61 698**	**64 452**
Costs not claimed in application			- 3 251
Arrear debt more than 0.5% of allowed revenue			- 2 981
Treasury management fee not recovered			- 19
Corporate Social Investments			- 251
Total operating costs per application (excluding depreciation)	**62 159**	**61 698**	**61 201**

To align to the operating costs of R62 221million in the NERSA regulatory formula, the total operating costs of R61 201m (reflected above) should be adjusted by the following:

- Include Corporate depreciation cost of R 1 724 m (depreciation of R 29 140 million in the regulatory formula applies only to the Generation, Transmission and Distribution licensees),

- Exclude research costs of R 193 m (reflected separately in the regulatory formula) and

- Exclude IDM costs of R 511 m (reflected separately in the regulatory formula).

Eskom has maintained the approach in the MYPD3 decision to allow for 0.5% arrear debt/impairments allowance which means that the actual arrear debt of approximately 2% is reduced in the application.

16.2 Employee Benefits

Approximately 80% of Eskom's staff complement belongs to the bargaining unit and 20% are positioned at managerial level.

Employee benefits costs are influenced by three main factors:

- Staff complements
- Employee benefits increases
- Level of remuneration

16.2.1 Staff complement

The planned number of employees are assume to decrease from 43 640 to 39 186 by 2018/19. This will occur through planned attrition or alternates that support savings initiatives and efficiencies.

16.2.2 Employee benefits increases

When comparisons are made to Eskom's employee benefit escalations, they are either to the overall generic labour market (Market move) or to average settlements (for bargaining unit). The employee benefit costs comprise of direct remuneration (salary, pension, medical aid, bonus, overtime) and indirect remuneration (training and development, temporary and contract staff).

In assessing Eskom's market position the following is important:

i. Eskom has consistently benchmarked the salaries and related benefits of all levels of employees to ensure meaningful market alignment. For this purpose Eskom participates in market surveys conducted by both the Deloitte Salary Survey and the PE Corporate Services salary survey. The two surveys cover 850 South African employers, and more than 1.5 million employees. This process allows for the meaningful comparison of Eskom remuneration levels within the broader labour market.

ii. Eskom operates from more than 450 geographic worksites across the country placing strain on the supply and retention of skills in general. The extend of and the duration of technical training and safety authorisation of employees deployed on the Generation, Transmission and Distribution side of the business, further requires that measures are put into place to stabilise the work force and minimise turnover.

iii. As a responsible employer and with due regard to the social and economic challenges, salaries at lower level of the business are positioned above the market median, however managerial level remuneration are closely aligned with the market.

TABLE 31 : EMPLOYEE COSTS

													Headcount Adjusted Benchmarks	
Component	2011 (R'm)	2012 (R'm)	% Change	2013 (R'm)	% Change	2014 (R'm)	% Change	2015 (R'm)	% Change	2016 (R'm)	% Change	5 Year % Change	Market Move	Inflation
Direct Remuneration	12 997	15 472	19.0%	17 984	16.2%	19 011	5.7%	20 196	6.2%	21 422	6.1%	64.8%	50%	42%
Indirect Remuneration	5 640	6 479	14.9%	7 846	21.1%	9 059	15.5%	8 395	-7.3%	6 564	-21.8%	16.4%	50%	42%
Total	18 637	21 950	17.8%	25 829	17.7%	28 070	8.7%	28 591	1.9%	27 986	-2.1%	50.2%	50%	42%

Note: The above employee costs are based on annualised costs and not the actual amount incurred in the respective year.

Total labour costs, including direct and indirect remuneration, increased by 50.2% over the period analysed which is aligned to the market average move of 50%.

- The year on year increase in Total Labour cost has slowed from 17.8% in 2012 to -2.1% in 2016. This demonstrates that increased focus and management was placed on controlling the Labour costs during the latter years of the period of analysis.
- The increased focus and management is mainly evident in the indirect remuneration component, which increased by 16.4% over the period.
- The low increase in indirect remuneration component in comparison to the Headcount Adjusted Market Move Benchmark is primarily influenced by a reduction in cost seen in 2015 and 2016.
- In addition, the Direct Remuneration component also exhibits evidence that, from 2014 to 2016, control has been placed on the increase in this cost component.

- This control in Direct Remuneration cost component increase is noticed through the reduced increase percentages observed (2012 equals a 19% increase while 2016 equals a 6.1% increase) despite headcount movements remaining relatively stable (2012 a 4.5% headcount increase and in 2016 a 2.2% headcount increase).

The table below summarises various factors related to employee benefit settlements. These are comparison of the NERSA assumed CPI to the actual CPI; Eskom bargaining unit increases; average settlements in the market and reported market movements.

TABLE 32 : EMPLOYEE BENEFITS INCREASES COMPARED TO INFLATION

	Year on Year Increases				
Employee benefits Settlements	2013	2014	2015	2016	2017
NERSA assumed CPI	5.60	5.60	5.60	5.60	5.60
CPI	5.90	6.20	4.50	6.30	6.00
Eskom Bargaining Unit	6.50	8.50	8.50	8.50	8.50
Average Settlements	7.90	8.00	7.70	7.50	7.40
Market Movements	7.00	7.20	7.00	6.80	6.80

- NERSA assumed CPI for the MYPD 3 period fixed at an average of 5.6%

- With the exception of 2015, actual CPI over the period was consistently slightly above NERSA assumptions

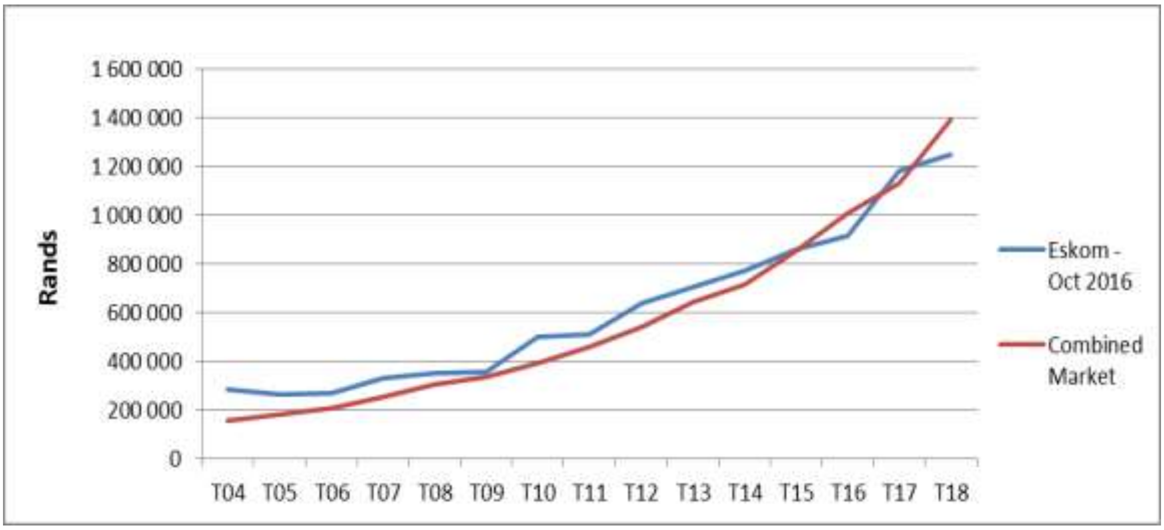
- The average settlement agreed in the unionised labour (bargaining unit) market was consistently above the average movement in salaries in the general market environment.

Eskom salary movement over the period is thus well aligned with the average settlements in the collective bargaining environment.

16.2.3 Level of remuneration

Eskom’s remuneration levels for (bargaining unit) staff reflects packages which are higher than the combined market reference based on unions requests being premised on improving the living standards of members. Alternatively at managerial level the Eskom is either tracking the market or below as presented below.

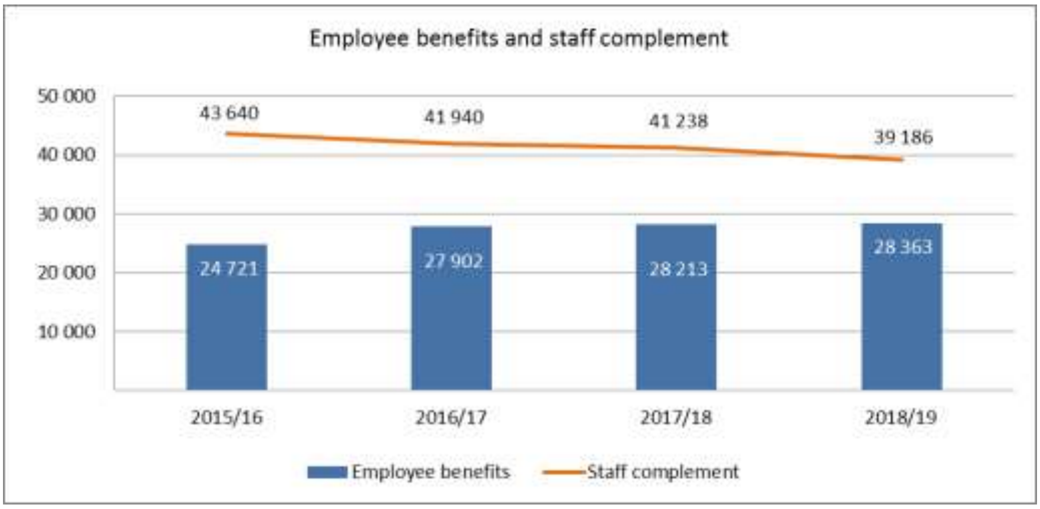
FIGURE 34 : LEVEL OF REMUNERATION



16.2.4 Total Employee benefit costs

The total employee benefits costs in 2018/19 are R28.4 billion. Employee benefit costs are forecasted to remain relatively flat between 2016/17 (R27.9 billion) and 2017/18 (R28.2 billion). There is an escalation of 1% to 2017/18 and a further 0.5% growth to 2018/19.

FIGURE 35 : EMPLOYEE BENEFITS AND STAFF COMPLEMENT



Employee benefit expenses consist of both payroll and non-payroll expenses (indirect costs such as training and development). The average cost per head is calculated by dividing the payroll costs for permanent employees by the number of permanent headcount. Dividing gross employee benefit expenses by permanent headcount would therefore overstate the average cost per head.

Eskom will embark on a drive to review the operating model to ensure the right balance of skills and workforce numbers are embedded across the business. Workforce optimisation was identified as a major component to drive internal efficiencies, increase productivity and lower the operating cost.

Eskom’s headcount will be reduced over the next few years. The gross costs are inclusive of cost to company remuneration and other staff related expenditures such as training, professional fees, overtime and contingency travel costs.

The gross employee benefit costs directly incurred for capital projects are allocated to the projects (capitalised) and recovered over the life of the capital asset through amortisation when the asset is depreciated. The costs are therefore not recovered immediately through the revenue application as a major portion is recovered over the life assets.

In conclusion it is impossible to assume that unionised labour will settle for CPI increases which go against the drive to improve the living standards of their members. Furthermore this sector of labour is exposed to different inflationary basket driven through transport, food and clothing costs which creates “skewness” from a CPI perspective.

16.3 Operating and Maintenance costs

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

16.3.1 Generation maintenance

Generation maintenance is driven by the ageing fleet which now on average about 30 years old and high UCLF impact on maintenance costs. The outlook for the future reflects a real increase in maintenance costs on this ageing fleet.

In the last 3 years a steep increase in maintenance costs was experienced. The fruit of this expenditure is evidenced by the significant improved technical performance of the power stations and projection to improve performance further in the next couple of years. It needs to be highlighted that the operating costs for the new power stations generally reduce. Costs are high initially, as only one unit of Medupi is initially operational, but as further units are commissioned over the planning horison and capacity is added, the overall costs are expected to reduce. Over time, the operating costs of the new stations will be about half of that of the older fleet of stations. This can be expected as maintenance costs on the new stations are a lot less than at the old stations and economies of scale contribute further with the bigger new units with the latest, more efficient technologies.

16.3.2 Transmission

Transmission maintenance workload is driven by the size of the network and the age of assets. The expansion of the transmission network will result in increased maintenance workload going forward. Transmission's maintenance strategy includes the compilation and review of maintenance philosophies, standards and procedures.

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

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

Maintenance is planned and executed in accordance with maintenance standards and procedures. A maintenance management system is used for maintenance planning and scheduling.

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

16.3.3 Distribution

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

The following factors are important maintenance expenditure considerations

- **Aging Network:** Refurbishment requirements have been identified to address the aging network. Inadequate refurbishment will contribute to increased maintenance requirements. The inability to address these maintenance requirements will lead to further declines in performance.
- **Access to Skills:** Maintenance requirements are based on Distribution having sufficiently skilled resources. Reduction in these will compromise preventative and corrective maintenance requirements
- **Universal Access:** Acceleration of the Universal Access Programme will result in corresponding growth in the asset base which impacts the maintenance regimen.

Distribution maintenance strategy includes both preventative (planned) and corrective maintenance (faults/unplanned).

An increased focus is placed on planned maintenance in shifting performance and will be achieved through a number of key actions:

- Increase the ratio and time spent on planned maintenance and corresponding reduction in unplanned maintenance towards the end of the application period
- Focus on Low Voltage (LV) networks due to its close proximity to the customer base, specifically in the electrification areas
- A new proactive vegetation management which supports and aids the reduction of conductor faults and leads to improved performance in reliability and quality of supply.

Distribution continues to embrace efficiency measures through its condition based maintenance programs in its maintenance standards and regimes. These regimes are further reflected within the maintenance strategies

16.4 Other Operating Expenses

Other operating costs are forecasted to grow from R15.4 billion in 2017/18 to R15.8 billion in 2018/19. Included in this category are costs such as insurance, IT (information technology), fleet costs, legal and audit services, security, travel expenses, billing costs, connection/disconnection costs, meter reading, vending commission costs and telecoms.

- Insurance cost increases reflect the increase in the asset base as well as global premium increases. Factors that influence cover and pricing include insurance claim trends, loss ratio performance, value of insurance excess, new-build programme, re-insurance costs, increases in insured asset values and risk management efforts.

- The increase in Security expenditure is due to increased initiatives by Eskom to safeguard assets, combat theft incidents and mitigate the related risks.
- Telecommunication services is required for supervisory control and data acquisition (SCADA) and enabling remote access to fault recording systems as well as control centre communications.
- Meter reading - reading of Small Power Users (SPU) and Large Power User (LPU) billed customer meters are done mostly on a quarterly basis.
- Disconnection and Reconnection costs - costs incurred to manage outstanding debt by disconnecting non payers and reconnecting once the payment is made.
- Shared services costs for billing customers – management of inflow and revenue management compliance

16.5 Integrated Demand Management

The role of Integrated Demand Management (IDM) is to influence the electricity demand profile of its customer base for the benefit of Eskom and the country. Over the past 8 years, whilst Eskom experienced a supply shortfall, IDM focussed mainly on energy usage reduction. With the improved generation plant performance and progress on the new build programme, it is anticipated that Eskom will be entering a period of operational excess capacity.

Irrespective, 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. This leads to inefficiencies and resulting high generation costs. IDM remains a key tool to ensure an optimal system load profile, supporting an optimal future generation mix in line with the requirements of the Integrated Resource Plan.

In particular, IDM will support the System Operator by providing demand response (DR) to maintain adequate operating reserve levels through the supplemental and instantaneous DR programmes, reducing evening peak demand. The focus of the IDM will transition to also support sustainable economic growth brought about by using energy efficient technologies for new growth. Past experience has proven the valuable contribution IDM can make to stabilising the electricity system. The demand / supply situation is cyclical and maintaining the IDM capacity is thus essential.

16.5.1 IDM Programmes

The following key IDM programmes are targeted during the 2018/19 financial year.

- **Load Reduction Projects:** Implement measurable and sustainable peak demand reduction and load shifting interventions. This is crucial to ensuring security of supply and optimises short and long term generation cost specifically during peak demand periods. This is mainly done through the ESCO process and is focussed on large projects. Such programmes are becoming more expensive with load shifting opportunities reducing.

- **Mass rollout programmes**: These are specific mass rollout rebate programmes, where products are procured and installed, either by Eskom directly or by an ESCO, and implement in bulk. These large-scale rollouts are mainly in the residential market for example the CFL roll-out programme. This includes the procurement of 1 million LEDs.

- **Energy Advisory Services:** Professional services to customers regarding their electricity consumptions, advising customers on best practices of utilising energy in the Industrial, Commercial and Agricultural sectors.

- **Power Alert:** Interactive media communication system aimed at the residential sector to influence consumption patterns during weekday evening-peak-periods, yielding an average of 300MW of short term load reduction. Prior to Winter 2017, Power Alert was not operational. The national electricity network was stable and Power Alert switched off in order to save cost. However, future system volatility remains a possibility

- **Sales Growth / Greenfield Project:** An opportunity exists to drive energy efficient growth. IDM products will be developed to provide a set of products that sales advisors can utilise to drive energy efficient growth, assisting customers in creating sustainable business operations whilst growing energy consumption.

16.5.2 IDM COSTS

IDM costs constitute EEDSM programme costs, overhead costs and measurement and verification costs. The estimated cost of IDM for financial years 2018/19 is R511 million, of which the EEDSM programme cost amounts to R325 million at an average benchmark of

R2.5m/MW. The DR programme costs are excluded, and will form part of primary energy costs.

16.5.3 Summary of Savings

The table below indicates the peak demand savings (in MW) of the past, current and future IDM programmes.

TABLE 33: IDM PROGRAMME SAVINGS

IDM Programme Savings (MW)	Actuals 2016/17	Projection 2017/18	Application 2018/19
ESCO Process	76	38	78
CFL/LED Roll-out	153	72	52
DoE Projects	8	0	0
Total	**237**	**110**	**130**

16.5.4 Summary of Costs

The tables below indicate the IDM programme cost and the IDM total cost respectively.

TABLE 34: IDM PROGRAMME COSTS

IDM Programme Cost (Rm)	Actuals 2016/17	Projection 2017/18	Application 2018/19
ESCO Process	117	95	195
CFL/LED Roll-out	83	180	130
DoE Projects	0	0	0
Total	**200**	**275**	**325**

TABLE 35: IDM TOTAL COSTS

IDM Total Cost (Rm)	Actuals 2016/17	Projection 2017/18	Application 2018/19
Programme Cost	200	275	325
Depreciation	1	1	1
Measurement & Verification	14	18	16
Marketing	47	53	42
Manpower	99	105	111
Other	15	28	16
Total	**376**	**480**	**511**

16.6 Research, Testing and Demonstration

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

Eskom is a needs driven organisation focussed on the systematic acquisition of knowledge and the application, development, refinement or demonstration of new and innovative technologies and solutions to satisfy Eskom's operational and strategic requirements through centres of expertise. Research costs of R193 million is required in 2018/19.

The table below provides a summary of the key areas where research projects are planned to be undertaken for the application year.

TABLE 36: KEY PLANNED RESEARCH PROJECTS FOR APPLICATION YEAR

Project	NERSA Criteria	Environmental Criteria	Grand Challenge
Coal	Lower operating costs	Not Applicable	Coal
Clean Coal	Environmental criteria	Better usage of water, less pollution and less global warming	Clean Coal
Water	Environmental criteria	Better usage of water, less pollution and less global warming	Water
Gas	Environmental criteria	Better usage of water, less pollution and less global warming	Gas
Renewables	Environmental criteria	Renewable energy sources	Renewables
Nuclear	Build, plan or demo plant that might form part of a future build plan	Not Applicable	Nuclear
Generation Plant Performance and Asset Management	Improved efficiency	Not Applicable	Generation Plant Performance and Asset Management

Project	NERSA Criteria	Environmental Criteria	Grand Challenge
Transmission Plant Performance and Asset Management	Improved efficiency	Not Applicable	Transmission Plant Performance and Asset Management
Transmission Build Solutions	Build, plan or demo plant that might form part of a future build plan	Not Applicable	Transmission Build Solutions
Distribution Plant Performance and Asset Management	Improved efficiency	Not Applicable	Distribution Plant Performance and Asset Management
Future Customer	Better understanding of load behaviour	Not Applicable	Future Customer
Flexibility	Improved efficiency	Not Applicable	Flexibility

Eskom will undertake a stakeholder consultation process during the analysis of this revenue application. The purpose of this consultation will be to provide Nersa with feedback on stakeholder views on Eskom's research project plans for the 2018/19 year.

16.7 Insurance

Escap SOC Ltd ("Escap"), a wholly-owned subsidiary of Eskom, is the primary insurer for Eskom other than where Escap does not have the required capacity and/or expertise, mainly nuclear risks. Eskom insurance costs are approximately R3.5 billion in 2018/19.

16.7.1 Methods used to determine insurance premiums

- **Actuarial pricing method** which uses statistical analysis to determine insurance premiums. An actuarial model is used to estimate future claims where key assumptions used in developing the model are the frequency and severity of future losses. First, the model is used determine the insurance premiums without taking into account the risk that is retained by the business (i.e. total risk profile). Thereafter, it is used to determine insurance premiums at different levels of risk retention by Eskom.
- **Burning cost method -** is an experience-based method of determining insurance premiums. It uses the average of past claims to estimate future claims. Escap's experience has shown that this method does not produce acceptable results.
- **Market - pricing method-** The insurance premiums in respect of risks that are not insured by Escap are determined by the external insurance market.

16.7.2 Nuclear Insurance

Nuclear insurance is not placed with Escap due to its complexity and significance of financial impacts that may arise from a nuclear incident. It is for this reason that insurance risks are generally underwritten by nuclear pools. The risk for property damage and business interruption is insured by the South African Nuclear Pool and the European Mutual Association for Nuclear Insurance (“EMANI”). The insurance for nuclear liability is provided by the South African Nuclear Pool and European Liability Insurance for the Nuclear Industry (“ELINI”). Eskom is a member of the EMANI and ELINI and Escap of the South African Nuclear Pool.

16.7.3 Engineering Risk Surveys

Escap’s Lead insurers conduct independent engineering risk surveys of Eskom’s power stations on annual basis. The purpose of the surveys is to identify risks that may result in insurance claims and make recommendations on prevention of these risks. The implementation of the recommendations is monitored by Eskom, Escap and Escap Lead insurers.

16.7.4 Value of ESCAP as a Primary Insurer

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

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

- Ability to provide insurance covers that are not available in the conventional insurance markets.

17 Credit Ratings Overview

Credit ratings assigned to Eskom by the rating agencies (Moody’s and S&P) are critical measurements of Eskom’s creditworthiness for investors and various other counterparties from which Eskom secures funding.

Eskom’s credit rating is currently sub-investment grade, resulting in a number of facilities covenants’ triggers and challenging investor sentiment for Eskom. By virtue of being a State Owned Company (SOC), Eskom’s credit rating is intrinsically linked to that of the South African Government (the Sovereign); for this reason, Eskom’s credit rating gets uplift for Sovereign support.

17.1 Impact of credit rating on funding

The impact of further downgrades of Eskom’s credit rating, directly or as a result of a downgrade of the Sovereign, will have a negative impact on the sourcing of the R330 billion funding, averaging R60 billion per annum. The impact on the cost and available funding will be amplified if Eskom or the Sovereign were to experience further credit rating downgrades. The consequence of Eskom’s weaker credit rating will be evident in:

- Increased cost and a decreased volume of funding available for future borrowings
- Decrease in investor base due to investor/ trustee mandates excluding sub-investment grade assets
- Reduced volume available for investment within the still available investor mandates
- Reduction in loan tenors
- Investors requesting stricter loan covenants
- Lack of demand and reduced investor appetite;
- Inability to rollover or refinance existing exposures;
- Increases in hedging costs; and
- Counterparty banks reducing credit limits for Eskom.

Ratings agencies have raised a number of key concerns which could result in a further ratings downgrade: a Sovereign rating downgrade; a weakened liquidity position and/or a prolonged state of poor liquidity; free funds from operations as a percentage of debt below 5%; and operational weakness.

18 Economic Landscape Changes

18.1 Economic Impact Study

Eskom has commissioned two studies with regards to economic impact. The first is an overview and analysis of economic trends in relation to electricity. Certain trends are discussed here to illustrate the changes in the economic landscape in South Africa. The second study aims to provide an understanding of the macroeconomic impacts of alternative scenarios to meet Eskom's five-year revenue requirement. Each study is summarised here.

18.2 Economic Landscape Changes

Deloitte Consulting has undertaken to provide an overview and analysis of economic trends in relation to electricity in South Africa. Certain trends are discussed here to illustrate the noticeable changes in the economic landscape in South Africa.

18.2.1 Overview of historical trend in electricity consumption in South Africa

Below is a brief overview of the historical trend in electricity consumption in South Africa, the changing composition of electricity sales by sector, key determinants of demand, methods of decomposing demand, and a brief analysis of the medium-term energy demand outlook.

The relatively energy-intensive mining and manufacturing industries remain the dominant consumers of electricity in South Africa – they account for circa 60% of national electricity consumption and about 22% of GDP. The results of several local and international studies on the key determinants of electricity consumption suggest that income or GDP is the dominant driver of demand. The sensitivity of consumers to changes in electricity prices appears to vary significantly over time and depends on the direction and magnitude of price increases and the prevailing price level.

There is evidence of strong positive correlation between GDP growth and growth in electricity sales in the country - the correlation coefficient between Eskom's local sales of electricity and GDP over the 20 years between 1997 and 2016 is 0.93. A previous study found that the income elasticity of demand over the period 1990 to 2005 almost unit elastic meaning that a 1% increase in GDP was associated with close to a 1% rise in electricity demand (once the influence of other important determinants such as price, supply constraints has been accounted for).

In recent years and particularly since FY2012, growth in Eskom's local electricity sales has been much lower than growth in GDP. While GDP expanded at an average rate of 1.9% y/y between FY2012 and FY2016 Eskom's local electricity sales were falling, averaging -0.9% y/y. In FY2013 electricity sales fell by ~4.2% y/y as a sharp fall in the global demand for commodities hit production in South Africa's relatively electricity-intensive mining and manufacturing industries.

Supply constraints also put a brake on demand as Eskom re-introduced rotational loadshedding in early 2014, and there was regular loadshedding between November 2014 and September 2015.

Electricity sales fell at an average rate of -0.3% y/y over the first three years of the 5-year MYPD3 period which runs for 2013/14 to 2017/18 - much lower than the annual growth in electricity sales of 1.8% that it forecast for these years when submitted its MYPD3 application. Much of the sales forecast variance can be attributed to disappointing GDP growth - Eskom assumed that real annual GDP growth would average 4.5% but GDP growth averaged just 1.5% in the first three years of MYPD3. The slower-than-anticipated sales in first three years of MYPD3 were however also a result of unforeseen falls in global demand for commodities and the re-emergence of local supply constraints. With annual GDP growth forecast to average 1.8% for the 5-year period to 2021 (IMF & EIU forecasts), growth in electricity sales is unlikely to average more than 1% per annum particularly given evidence of a persistent trend-decline in the electricity intensity of growth and assuming that real electricity prices will continue to rise as Eskom transitions to a tariff that is more reflective of its prudently and efficiently incurred costs.

18.2.2 Trend in electricity prices

For much of the four decades to 2008/9 real (inflation-adjusted) electricity prices in South Africa were on the decline. By 2007 electricity tariffs in South Africa were among the lower in the world, but the power supply crisis that had been threatening for several years had also reached a critical point. Eskom introduced loadshedding and was given the green light to embark on a massive build programme – the first major increase in power generation capacity the utility had undertaken in almost 30 years.

Between 2008 and 2013 NERSA approved several sharp increases in annual tariffs which, in line with the regulatory methodology, would enable Eskom to raise the future revenue streams in needed to cover the new build - electricity prices more than

doubled in real terms (inflation-adjusted) rising by a cumulative 114%. The sharp increases in real electricity prices over the 5-year period were met with increasing public resistance. NERSA subsequently awarded Eskom increases of roughly CPI plus 2% for the 5-year MYPD3 period. **The tariff increases awarded by NERSA over the MYPD3 period (since 2013) have proved inadequate and Eskom's revenue shortfall has begun to mount.** In November 2016, S&P Rating's agency further deepened Eskom's non-investment grade status to reflect Eskom's deteriorating financial position which continues to put South Africa's sovereign credit rating at risk.

By maintaining artificially low tariffs, the South African government has effectively continued to implicitly subsidise the cost of electricity. While electricity subsidies have largely been implicit or off-budget they are subsidies nonetheless, and fiscal consequences do eventually become evident. The substantial support provided by government to Eskom over the past 10 years both in the form of equity and a R350bn guarantee facility has contributed meaningfully to the deterioration in Government's overall debt metrics (and subsequent credit rating downgrades). **In addition, the economic harm and distortions that are caused by energy subsidies is wide-ranging and include**:

- Energy subsidies can crowd-out growth-enhancing or pro-poor public spending.
- Energy subsidies discourage investment in the energy sector and can precipitate supply-crises.
- Energy subsidies often promote investment in capital and energy-intensive industries at the expense of more labour-absorbing and employment generating sectors.
- Energy subsidies stimulate demand and encourage the inefficient use of energy and unnecessary pollution.
- Energy subsidies have distributional impacts where larger consumers benefit disproportionately from subsidies.

18.2.3 International competiveness of SA electricity tariffs

Despite the sharp 147% compounded increase in real inflation-adjusted electricity prices since 2008, a survey of the delivered price of electricity (12-month 1000KW contract) by NUS Consulting in June 2015, showed that South Africa's tariff at 0.085 $US/kWh is still below the mean for the group of 18 mostly high-income countries. Furthermore, while South Africa has the 9th lowest tariff of the 18 countries, there was less than 0.5 US cents per kilowatt hour separating 4th placed Czech Republic and South Africa in 9th place.

A comparison of industrial electricity tariffs by the IEA shows that in 2014, Eskom's industrial electricity tariffs were still the lowest (or at least among the lowest if a more conservative benchmark tariff was chosen) among the 30 countries surveyed. The inclusion of South Africa in the IEA's ranking of countries' residential tariffs in 2014, suggests that Eskom's residential tariffs were the 3rd most competitive of the 30 countries surveyed. A comparison of the standard residential electricity tariffs charged by 7 of the 187 municipalities was sufficient to show there are large discrepancies in the tariff charged by municipalities. Ekurhuleni placed 17th in the IEA's residential tariff ranking which puts the municipality among the 50% of countries with the most expensive residential tariffs in the OECD group.While City Power (Johannesburg) tariffs were similar to the Eskom tariff, Ekurhuleni tariffs are 85% higher.

18.2.4 Requirements of an efficient electricity pricing regime

Electricity pricing regimes often try to satisfy a range of social, economic and political objectives, but we argue that the primary objective must be to ensure that resources are allocated efficiently. In terms of economic theory, a 'cost-reflective' tariff is defined as a tariff equal to the long-run marginal cost (LRMC) of supply. While a theoretically robust, LRMC is difficult to accurately estimate and operationalise. It is argued that the RoR methodology usually gives rise to tariffs that are equivalent to LRMC. The extent to which tariffs under the ROR methodology approximates LRMC appears to depend on the basis for asset valuation and/or the rules for depreciating the asset base. While an efficient pricing regime is a necessary requirement to ensure the efficient delivery of electricity services by the utility (even if a monopoly) it is not sufficient – internationally accepted governance practices must be adhered to to ensure that sound and least-cost investment decisions are made. **Eskom estimates that approved tariff of 67.7c/kWh in 2014/15 would need to have risen by 23% in order to reach the fully cost-reflective tariff of 83.9c/kWh.** It is noted however that the gap between actual and cost-reflective tariffs is not static, particularly during a period of capacity expansion when new assets are being added to the regulatory asset base.

Specific strategies for the transition to cost-reflective electricity tariffs in South Africa include:

- Encourage open conversations on the implicit electricity price subsidies which are heavily reliant on the limited fiscal resources. Support the conversation with a coherent communication strategy that provides the public with information on the magnitude of the subsidy and their shortcomings. The regulator must review its approach on the regulation of municipal tariffs to address large discrepancies in tariffs levied by municipal distributors as this is an obstacle to the transition to cost-reflective tariffs.
- Government should develop a clear plan for the transition to cost-reflective tariffs, with appropriate phasing and provision of targeted subsidies and other mitigating measures for vulnerable groups.

18.3 Macroeconomic impacts of alternative scenarios

18.3.1 Background and context

In the three decades between 1978 and 2004 government allowed real (inflation-adjusted) electricity prices in South Africa to decline to artificially low levels. During this period, the real average price of electricity[1] fell by more than 40% to 30.1 c/kWh (in 2016 rands) in 2004/5 - at which point South Africa's tariffs were among the lowest in the world. (Deloitte, 2017).

In 2008, a power supply crisis that had been threatening to emerge for several years, reached a critical point and Eskom introduced nationwide load-shedding. As a result, Eskom was given the green light to embark on the massive build programme to increase power generation capacity. To enable Eskom to raise the capital it required, the NERSA approved several sharp tariff increases. In the five years between 2008 and 2013, electricity prices more than doubled in real terms (inflation-adjusted) rising by a cumulative 114% while nominal prices rose by 191% over the same period. (Deloitte, 2017).

The sharp increases in real electricity tariffs over this period prompted a public outcry, and NERSA subsequently decided to award Eskom revenue that would limit the increase in real electricity tariffs to ~2% per year for the 5-year period from 2013. This was much lower than Eskom's requested increase of CPI plus ~10% per annum. The tariff increases that NERSA

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1 *Average prices are calculated as the total electricity revenue realised by Eskom divided by the total kWh produced in a given period, these are then adjusted for inflation to calculate real prices and expressed in 2016 Rands.*

awarded Eskom over the MYPD3 period have proven to be inadequate, and Eskom's financial position has deteriorated as its annual revenue shortfall has mounted. According to Eskom (2016) the revenue shortfall that the utility faced in 2014/15 alone, was R35 billion. At the time of finalising the modelling for this report in January 2017, we noted that the ongoing deterioration in Eskom's financial position would have meaningful fiscal consequences (in the form of rising government debt and/or contingent liabilities), and that there was a significant risk that this would trigger a sub-investment downgrade (S-IG) of South Africa's sovereign credit rating. On the 3rd of April 2017, shortly after this first version of this report was finalised, Standard & Poor's downgraded South Africa's long-term foreign currency sovereign credit rating to sub-investment grade or "junk" and on the 7th of April 2017, Fitch ratings agency followed suit.

S&P noted that the downgrade reflected their view that "contingent liabilities to the state, particularly in the energy sector [i.e. government guarantees on debt issued by Eskom] are on the rise and that previous plans to improve the underlying financial position of Eskom may not be implemented in a comprehensive and timely manner." This indicates that the steady rise in government debt and contingent liabilities (guarantees of Eskom-issued debt) associated with Eskom's lower-than-required electricity tariff increases contributed meaningfully to S&P's recent decision to downgrade South Africa's credit rating on foreign currency debt to 'junk'.

We argue in a recent analysis of the historical trends and policies in the electricity sector, Deloitte (2017), that previous assessments of the macroeconomic impacts of rising electricity prices failed to acknowledge the economic impacts of the implicit electricity subsidy Eskom requires from government when the revenue it raises via the tariff is insufficient to cover its costs. This implicit subsidy usually takes the form of an increase in debt (implicitly or explicitly guaranteed by government) or an additional equity injection from government. Government in turn has three main ways to raise the funds required to support Eskom – either by issuing more debt (borrowing) and/or by raising additional tax revenue or reducing / re-prioritising expenditure away from other government services and functions.

In its 'Reasons for decision on Eskom's MYPD3 tariff application', NERSA (2013) presented an economic impact of rising electricity tariffs on GDP, inflation, and employment under low, medium, and high tariff path scenarios. However, NERSA did not acknowledge or model the consequences of rising government / Eskom debt associated with 'low tariff path scenarios. Rather, in assessing the potential economic impact of its tariff decisions NERSA, appears to implicitly assume that if Eskom is not able to recover sufficient revenue to cover all its prudently and efficiency incurred costs, that those costs would not be incurred.

18.3.2 Aim of the study

The aim of this study is to provide an understanding of the macroeconomic impacts of alternative scenarios to meet Eskom's five-year revenue requirement. While, like previous studies, the study should show the impacts on GDP, employment, and inflation during the five-year period, it should also demonstrate the impact on the fiscus (debt ratios and budget balance). We have also attempted to demonstrate some of the broader or longer-term economic consequences of government debt accumulation in scenarios where tariff increases generate insufficient revenue to cover Eskom's costs – this included a scenario where government debt accumulation associated with low tariff increases, triggers a sub-investment grade credit rating downgrade.

18.3.3 Key scenario assumptions, and scenarios modelled

For this modelling exercise, Eskom advised Deloitte to model the impacts associated with three alternative tariff scenarios – average annual increases over a five-year period of 8%, 13% and 19% respectively. In November 2016, when this study commenced, Eskom had not yet finalised its forthcoming tariff application nor had it decided whether it would submit a tariff application for a single-year or for a multi-year period. As such official estimates of Eskom's required revenue and sales forecasts over the next five years were not available, the scenarios are therefore hypothetical and we have made the following key assumptions:

- We assume that the upper-bound annual average increase of 19% is what Eskom requires to reach and maintain a cost-reflective electricity tariff over the 5-year period from 2017 to 2021.
- We assume that Eskom's total revenue requirement is the same across all tariff scenarios and that it is equivalent to the revenue that would be raised if tariffs increased at an annual average rate of 19%. For example, under the 8% tariff scenarios, Eskom experiences an annual revenue shortfall equivalent to the difference between the total revenue raised under a compounded 19% tariff increase and the compounded 8% increase. We then have further scenarios to model how the shortfall will ultimately be recovered– e.g. by raising additional government debt (borrowing) or taxes.

Eskom has indicated that based on an analysis of their financial position as at May 2017, it seems unlikely that the utility will require an annual nominal tariff increase as great as 19% to close the gap between costs (prudently and efficiently incurred) and revenue over a five-year period. There are however some upside risks to this forecast, these include:

- **Purchase of additional renewable energy capacity** - current estimate of the required tariff is based on the assumption that Eskom will not purchase any additional renewable energy capacity from IPPs (beyond that which is has already committed to). If Eskom signs additional power purchase agreements (PPAs) under the renewable energy independent power producers programme (REIPPP) the utility's average cost of electricity provision will rise further. The average cost of energy purchased from new renewable IPPs is currently more than double Eskom's average cost of own generation (largely from coal-fired power stations) on a levelised cost of energy basis and the cost multiple is even greater when relative intermittency of renewable sources and higher transmission costs are considered.
- **Lower-than-anticipated electricity demand or sales** – Analysts have revised their forecasts of South Africa's real GDP and fixed investment growth lower following the downgrade of South Africa's long-term foreign currency rating to sub-investment grade and are now generally expecting real GDP growth of between 0% and 1% y/y in 2017. Given the strong positive relationship between electricity sales and real economic activity, Eskom may face lower than expected demand.
- **New build programme** – the current estimate of tariff required to close the revenue gap is based on anticipated capital expenditure under the approved new build programme including the completion of Medupi and Kusile. If, however Eskom initiates a further new build programme within the next 5 years, such as the potential nuclear build, real tariffs would need to rise faster to accommodate additional capital expenditure.

Three main categories of policy simulations were modelled, each with a different set of assumptions and for three tariff path options – 8%, 13% and 19% (where applicable)[2]. This

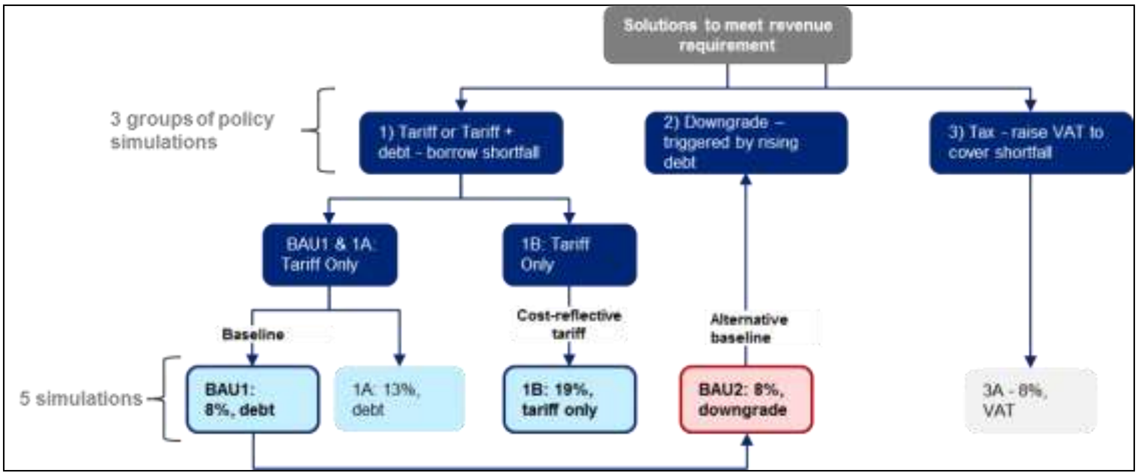
[2] *In the interim modelling report produced by the University of Pretoria, another two groups of scenarios were considered – 1) a tax credit reducing VAT and 2) a tax credit reducing production taxes. We have decided to omit these two scenarios as the added unnecessary complexity and did not materially alter the findings. We have also re-labelled/re-coded the scenarios for the readers of the final report.*

resulted in a total of five simulations all of which represent an alternative potential solution to meet Eskom's total revenue requirement over a five-year period. The scenarios modelled included a 'tariff-only' option where electricity tariffs increase at an annual rate of 19% over five years and a baseline scenario (BAU) where tariffs increase at an average rate of 8% and the revenue shortfall is funded by raising additional government debt. Further scenarios included a 13% annual tariff increases with a debt-funded shortfall, an 8% increase with tax-hike funded shortfall and a downgrade scenario, explained further below. At the time the modelling was undertaken (January 2017) we judged that there was also a significant risk that steadily rising government debt levels associated with the baseline tariff scenario of 8% would trigger a sub-investment grade (S-IG) credit rating downgrade[3].

To simulate the economic impacts of this downgrade risk materialising we ran an alternative baseline simulation (BAU2) where a steadily rising debt-to-GDP ratio and deteriorating budget balance that is associated with an 8% average tariff increase triggers a S-IG credit rating downgrade. A visual summary of the five simulations modelled is provided in the figure below.

3 *At the time of writing and finalisation of this study, South Africa maintained an investment grade rating on both its foreign- and domestic-currency denominated debt. On the 3rd of April 2017, Standard & Poor's downgraded South Africa's long-term foreign currency sovereign credit rating to sub-investment grade or "junk" and on the 7th of April 2017, Fitch ratings agency followed suit. By 7th April 2017 the yields on 10-year government bonds had risen by nearly 1 percentage point or 100bps from their mid-March lows from around 8.4% to just over 9%. Please see the Addendum to this report, dated 7 April 2017 for the likely implications of rising debt under the (1A 8%: debt) scenario post the S-IG downgrade event.*

FIGURE 36: SUMMARY OF SCENARIOS MODELLED



18.3.4 Interpreting results of hypothetical scenarios – particularly post-downgrade

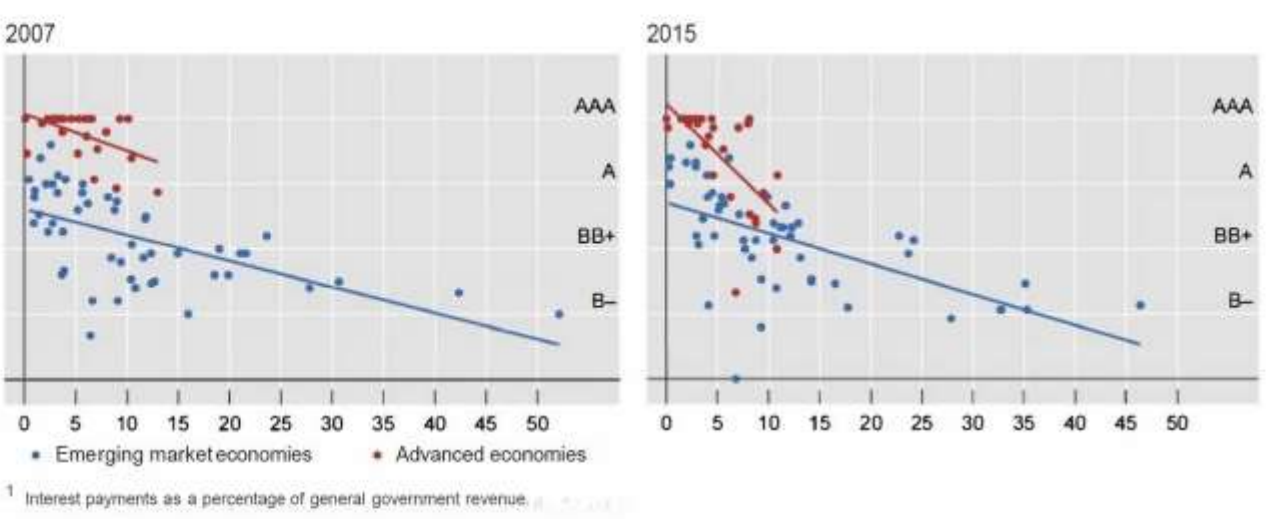
As explained above, the tariff increases are hypothetical. In addition, the potential S-IG downgrade we modelled under the 'alternative baseline' (BAU2:8%, debt) has, in effect, already transpired. While the magnitude of the tariff increases chosen are hypothetical the scenarios still usefully illustrate the relative macroeconomic impacts of the various options available to meet Eskom's revenue requirement which include 1) Increasing the tariff alone 2) a combination of low tariff increases and raising government debt and 3) a combination of low tariff increases and tax hikes.

Furthermore, while the anticipated S-IG downgrade has already occurred, it does not mean that credit-rating downgrade risk associated with debt accumulation under a 'much lower-than-required' tariff increase is now irrelevant or even diminished. As RMB (2017) notes, countries that are downgraded to sub-investment-grade typically experience a continual negative feedback loop. Following a SI-G event, as sentiment sours and interest rates increase, the fiscal position deteriorates. As the fiscal position deteriorates, interest rates rise and economic growth slows, further credit rating downgrades within 'junk' territory are triggered. As RMB (2017) notes, "countries take seven to nine years, on average, to recoup their investment-grade rating, following a downgrade, to speculative grade".

While there is no simple linear relationship between subsequent credit rating downgrades (post a SI-G event) and interest rates the two are inversely correlated and as downgrades occur, interest rates tend to rise. A graph presented in an analysis by the Bank of International Settlements (2015) illustrates how the proportion of total revenue that

Governments spend servicing interest on debt tends to rise sharply as the foreign currency rating falls into sub-investment grade territory. As further credit rating downgrades take place governments' find they have less and less 'fiscal space' or flexibility in their spending choices and are forced to focus on preserving and improving their financial position and trying to meet obligations to deliver essential services (e.g. social grants, health and education).

FIGURE 37: FOREIGN CURRENCY RATING VS. INTEREST PAYMENT BURDEN



Source: Bank of International Settlements (2015).

18.3.5 Approach

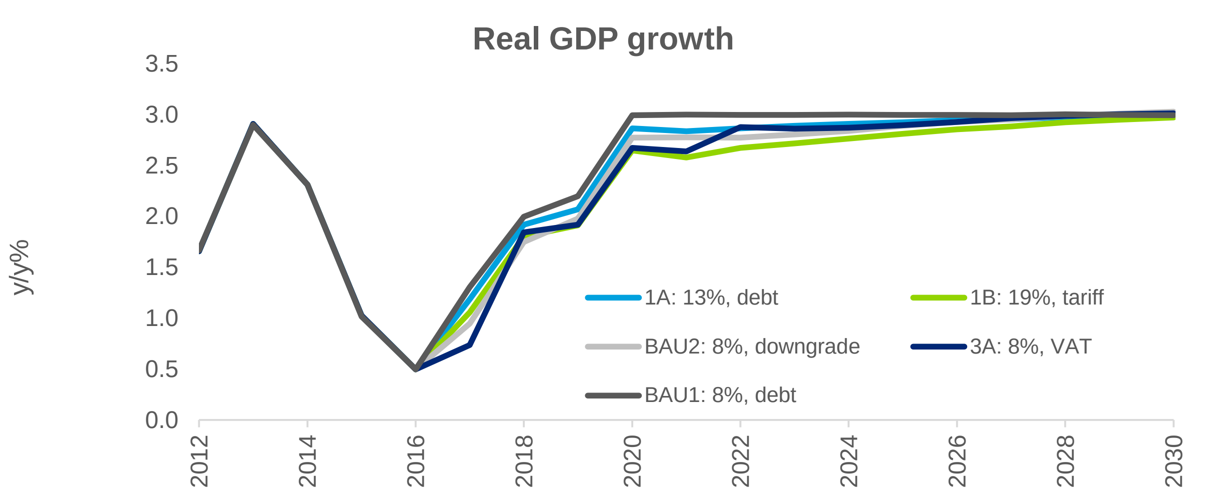
The model selected for the simulation of the alternative scenarios to meet Eskom's revenue requirement is the University of Pretoria General Equilibrium Model (UPGEM) described in Bohlmann et al. (2015). UPGEM is a flexible Computable general equilibrium (CGE) model that for purposes of this study is used in standard recursive-dynamic mode.

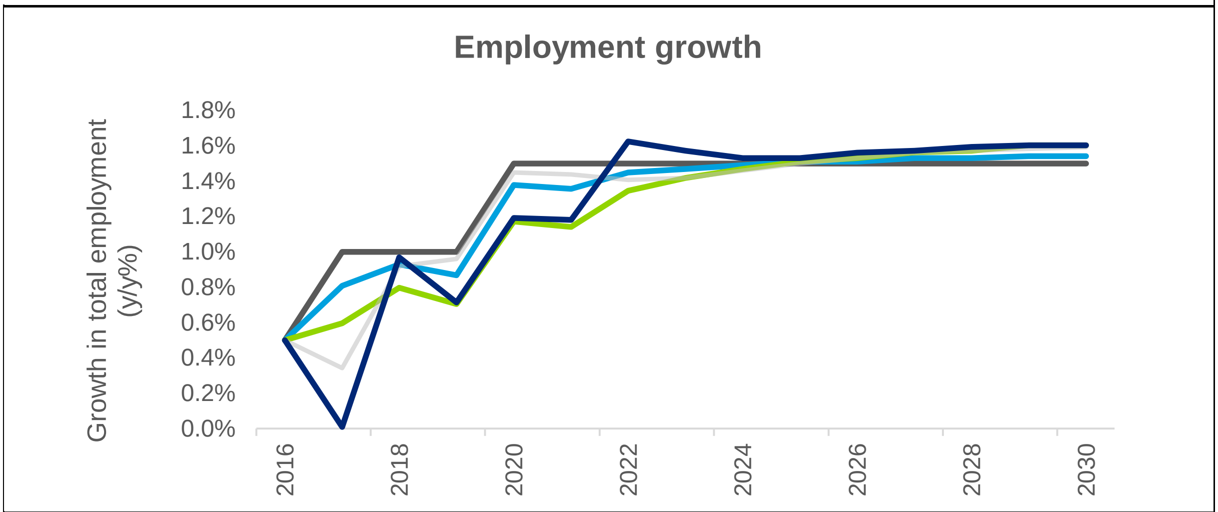
18.3.6 Key findings and results

The results show that an annual tariff increase of 19% is expected to have a slightly negative impact on GDP and employment growth relative to the baseline scenario (where tariffs rise by 8% a year and government borrows the shortfall). For example, under the 19% tariff scenario (1B), GDP is forecast to expand at an average rate of 2.0% y/y, which is 0.3 percentage points lower than the 2.3% y/y growth forecast in the baseline (BAU1). Total employment is expected to grow at an average rate of 0.9% y/y under a 19% tariff increase compared to 1.2% y/y in BAU1. This implies that under a 19% tariff increase scenario, 137000 fewer jobs will be created and sustained annually over the period 2017 to 2021, relative to BAU1. These results are consistent with those NERSA (2013) obtained when it presented the economic impact of similar tariff scenarios in its reason for decision on Eskom's MYPD3 tariff application[4].

4 *NERSA noted in its economic impact study that a 16% annual tariff increase over a five-year period was expected to lower average annual GDP growth by 0.3 percentage points, reducing forecast GDP growth from* 3*.7% to 3.4%. NERSA also found that a series of five 16% tariff increases would compromise 652 654 jobs. We assume that NERSA was referring to the cumulative number of jobs that would be foregone over 5 years in which case our results are similar. Our results suggest that 137000 fewer jobs will be created and sustained annually under the 19% tariff scenario (1A) relative to the BAU1 over the five years to 2021. If this is expressed differently, the cumulative deviation in the total employment from baseline (BAU1) in 2021 is 685 000 jobs.*

FIGURE 38: IMPACT ON TREND IN REAL GDP AND EMPLOYMENT GROWTH – 1A, 1B, 3A RELATIVE TO BAU1 AND BAU2

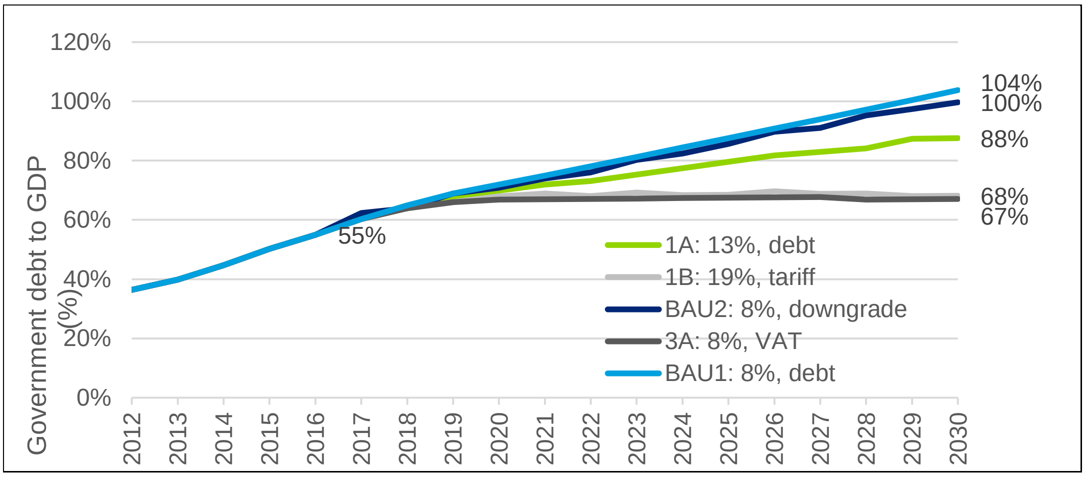




Our results however suggest that the impact of higher tariff increases on CPI inflation over the next five-year period would be more muted than what NERSA (2013) previously indicated. The simulation results suggest that scenarios with higher annual electricity price increases of 13% and 19% (1A and 1B respectively) have very little impact on CPI inflation - inflation rises in both cases by less than 0.1 percentage point, averaging 5.8% y/y in the five-year period from 2017 to 2021 and 5.5% y/y thereafter. While the low-CPI impact associated with relatively high tariff increases may seem counterintuitive, it can be attributed to the fact that higher tariff increases are expected to have a negative impact on GDP growth and employment. Given that GDP growth was already expected to be relatively subdued over this period (relatively to potential GDP growth of 3%), sluggish demand is likely to keep inflation in check.

We noted previously that in the economic analysis that NERSA presented in 2013, the regulator did not acknowledge the fiscal consequences of 'lower-than-required' tariff increases. Our results show that under the 8% tariff baseline scenario (BAU1) there is a steady and marked deterioration in government's budget balance and that the government debt-to-GDP ratio is expected to reach 75% by 2021 and 104% by 2030 (Figure 39). By contrast under the 19% tariff scenario, the debt-to-GDP ratio stabilises at ~66% (Figure 39). Given the sharp accumulation of government debt under a 'much-lower-than-required tariff increase', we also noted that it was likely that BAU1: 8%, debt would trigger a sub-investment grade credit rating downgrade and as such that it would be more accurate to compare the economic impacts of a 19% tariff scenario with a scenario where an 8% tariff increase triggers a SI-G downgrade (BAU2:8%, downgrade).

FIGURE 39 IMPACT ON GOVERNMENT DEBT-TO-GDP RATIO - 1A, 1B, 3A RELATIVE TO BAU1 AND BAU2



As noted earlier, the risk of a S-IG downgrade that we modelled under the 'alternative baseline' (BAU2:8%, debt) has in effect, already materialised. On the 4th of April 2017, Standard & Poor's announced the downgrade of South Africa's long-term foreign currency sovereign credit rating to sub-investment grade.

The results of our downgrade scenario show that when the rise in government debt that is associated with a 'much-lower-than required' tariff increase is sufficient (together with other economic and political risk factors) to trigger a sovereign credit-rating downgrade (BAU2: 8%, debt), South African's end up worse-off than under a 19% annual tariff increase and the negative economic impacts are likely in aggregate to be more severe[5] for the following reasons:

Firstly, our results show that under the 'BAU2: 8%, downgrade' scenario, growth in GDP and employment will slow by almost as much as they would under a 19% annual tariff increase. Simulation results show that under both the downgrade scenario (BAU2: 8% downgrade) and 19% tariff scenario (1B:19%, debt) annual GDP growth will be 0.3 percentage points lower than in BAU1. Similarly, under BAU2 and total employment growth is expected to average 1.0% y/y which is an average of 0.2 percentage points lower than in BAU1, while under scenario 1B: 19%, tariff employment will increase at an average rate of 0.9% y/y or 0.3 percentage points lower than BAU1.

Secondly, while our results suggest that the negative impact on GDP and employment that follow a downgrade due to debt accumulation under a 'much-lower-than-required' tariff is almost equivalent to a 19% tariff increase, South Africans are likely to end up worse-off in aggregate under the downgrade scenario because of a simultaneous rise in debt and interest rates that doesn't occur under the tariff only scenario. Borrowing costs (or the required return on investment) will rise by 1 percentage point (100bps) under BAU2 relative to the 19% tariff scenario (1B) and the government debt-to-GDP ratio will rise steadily reaching ~75% by 2021 and 100% by 2030 under BAU2, while under the 19% tariff scenario, the debt-to-GDP ratio stabilises at ~66%.

Finally, under any scenario (including BAU1, BAU2 and 1B) where the revenue collected via the tariff is insufficient to cover Eskom's prudently and efficiently incurred costs, the price of electricity is being implicitly subsidised. As the World Bank (2010:22) notes:

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

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5 *The way in which the effects of a potential downgrade were modelled was conservative -we assumed that the key impact of an S-IG event would be that interest rates (or the return required on capital investment) would rise by an average of 100 basis points over the five-year period.*

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

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

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

- **Artificially low electricity tariffs discouraged investment in South Africa's electricity supply industry and helped to precipitate the 2008 power supply crisis**. The subsidised tariffs frustrated attempts by the government to attract private investment in the early 2000s and helped to precipitate the supply crisis of 2008.
- **Subsidised electricity prices promoted investment in capital intensive industries in South Africa at the expense of more labour-absorbing sectors**. Kohler (2014) traced the 40-year change in electricity intensity across a number of countries and country groups and found that South Africa has amongst the highest electricity intensity globally.
- **Subsidised electricity prices, encourage the inefficient use of energy and contributed South Africa to becoming one of the single-largest contributors to global GHG emissions.** Subsidies on the consumption of electricity generated by Eskom which was mostly coal-based have arguably contributed South Africa becoming the 18th largest country-level contributor to global CO2 emissions[6].

18.4 Concluding remarks

It may be tempting to conclude that by limiting electricity tariff increases to 8% per annum and requiring that Eskom and/or government borrow the revenue shortfall (and effectively implicitly subsidise the price), it is possible to minimise the negative impacts of rising electricity prices on GDP and employment growth in the short-term.

However, the results of the economy-wide impact analysis show that the fiscal and economic consequences of awarding Eskom a tariff that is much lower than what it requires (to recover its prudently and efficiently incurred costs), do eventually (and arguably have now) become evident. Our results show that when the gap between the required and actual tariff increases is large (an 8% increase awarded over five years when we assumed 19% was required) and the shortfall is covered by raising debt, there is a steady and marked deterioration in government's budget balance and debt-to-GDP ratio. For example, under the baseline 8%, debt scenario government debt-to-GDP ratio is expected to reach 75% by 2021 and 104%

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

by 2030. By contrast under the 19% tariff scenario, where all the required revenue is raised via the tariff, the results show the debt-to-GDP ratio stabilising at ~66%.

Over the past 10-years there has been a marked deterioration in both the financial position of Eskom and the fiscal health of the South African government and this is evident from the change in debt and credit metrics that is summarised. Since 2008, South Africa's long-term foreign-currency rating has been downgrade by 3 notches from lower-medium grade to speculative grade or 'junk' by two of the three major rating agencies. Eskom's long-term local-currency corporate bond rating has been downgraded by between 5 and 10 notches, from upper-medium grade in 2008 is now rated 'highly-speculative' by Standard and Poor's.

A summary of key debt metrics shows that since 2008 (when Eskom embarked on its massive capital expansion programme) the South African government's capacity to meet its debt obligations (and to raise additional debt or issue guarantees on debt of state-owned enterprises) has become far more constrained and as such vulnerability to eventual non-payment has increased. In terms of the National Treasury broad risk management guidelines (updated in 2008)[7] – net loan debt, provisions and contingent liabilities should not exceed 50 per cent of GDP while the broader SADC macroeconomic convergence target was to limit the metric to 60 per cent of GDP. While this metric stood comfortably within these prudential limits at 34.4% GDP in 2008, in 2017 it stands at 67% of GDP – exceeding both the self-imposed risk guideline and broader SADC convergence target. Net loan debt (excluding provisions and contingent liabilities) is expected to reach 47% of GDP in 2017/18 (up from 22.6% in 2007/8). Government now spends 11.5% of its total revenue servicing the interest on debt (up from 8.9% in 2007/8) illustrating how the fiscal space is becoming increasingly constrained.

It is also clear that substantial support provided by government to Eskom over the past 10 years both in the form of equity and guarantees has contributed meaningfully to the deterioration in Government's overall debt metrics (and subsequent credit rating downgrades). Eskom initially received support from government in the form of a R60bn shareholder loan which was converted into equity in 2015 and in the form of a further R23bn

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7 *National Treasury (2008) National Budget Review, February 2008.*

equity injection completed in March 2016[8]. Government also approved R350bn worth of guarantees on Eskom's debt of which Eskom had drawn on R218bn worth by 2017/18 (the agreement is to be extend to 31 March 2023). Government guarantees of SOE debt rose from R65bn in 2008 to a total of R445bn in 2017 and 77% of this is for the electricity sector which also covers Eskom's power purchase agreements with IPPs.

Following the sub-investment grade downgrade of South Africa's long-term foreign currency in April 2017 and subsequent downgrade of Eskom's corporate debt by S&P to 'highly-speculative grade', neither Eskom nor the South African government will be in a position to raise further debt to meet Eskom's future revenue requirement without the risk of triggering further sovereign credit rating downgrades.

In the present context, if Eskom is awarded much-lower-than-required tariff increases, it will put South Africa at greater risk of remaining within the continual negative feedback loop that countries typically experience following an SI-G event. Our analysis shows that under low tariff scenarios, Eskom's revenue shortfall grows, the fiscal position deteriorates, interest rates rise, sentiment sours, economic growth slows, further credit rating downgrades within 'junk' territory are triggered and the toxic loop repeats. As RMB (2017) notes, "countries take seven to nine years, on average, to recoup their investment-grade rating, following a downgrade, to speculative grade".

Our simulation results show that in terms of the overall economic impacts - even a sharp 19% annual tariff increase over five-years would be preferable to a scenario where rapid debt accumulation associated with a much-lower-than-required '8% tariff increase triggers further credit rating downgrades.

While our results suggest that the negative impact on GDP and employment that follows a downgrade due to debt accumulation under a 'much-lower-than-required' tariff is almost equivalent to a 19% tariff increase, South Africans are likely to end up worse-off in aggregate under the 'low-tariff downgrade scenario' because of a simultaneous rise in debt and interest rates triggered by a downgrade. In addition, in the low-tariff scenarios, the price of electricity remains implicitly subsidised, and as outlined in detail in Deloitte (2017), energy price subsidies are associated with a wide-range of market distortions and economic harm.

8 *Moody's Investor Service (2017) Moody's places Eskom's Ba1/A2.za ratings on review for downgrade*

In conclusion, it would be ill-advised for NERSA to continue to limit Eskom's tariff increases below cost reflective levels. It would also be incorrect given the current context and results of this analysis to assume that this will limit the negative impact on GDP and employment, even in the short-term. Our recommendation is that tariff increases should at least be sufficient to transition Eskom towards a more cost-reflective electricity tariff (prudently and efficiently incurred) over the next 5 years. This will reduce of the risk of South Africa being trapped for a prolonged period in the continual negative feedback loop that countries typically experience following an SI-G rating downgrade.

Eskom has indicated that based on an analysis of their financial position as at May 2017, it seems unlikely that the utility will require an annual nominal tariff increase as great as 19% to close the gap between costs (prudently and efficiently incurred) and revenue over a five-year period. Eskom and its key stakeholders should also take care to ensure that the upside risks to forecasts of the tariff required to meet its revenue requirement over the next five years are carefully managed – these include obligations to purchase additional renewable energy capacity, risk of lower-than-anticipated electricity demand or sales and additional capital expenditure and associated costs that will be incurred if Eskom and the Department of Energy deems it prudent and necessary embark on a new build programme within the next five years.

19 National Treasury and SALGA responses

19.1 Summary of key responses provided by National Treasury as part of consultation process

19.1.1 Period of the MYPD submission

National Treasury raised concerns about Eskom making a one year application. A multi-year application is preferred to provide investment certainty and allow for phasing in of electricity price increases towards cost reflective levels over a longer period of time.

Eskom notes this concern and understands the concern. This National Treasury guidance will be considered for subsequent applications.

19.1.2 Economy-wide impacts of the proposed tariff

National Treasury's own analysis of the first round impacts on inflation shows that a 20 per cent increase (before taking into account municipal tariff increases) in electricity prices would increase headline CPI by 0.2 percentage points in 2018 and 2019 and have no further effects in the outer years. A 27 per cent increase (i.e. municipal tariff increase), would increase CPI by 0.4 percentage points in 2018 and 0.3 percentage points in 2019. It must be stressed that this analysis does not take into account the second round effects that would manifest themselves on the production side of the economy, which are likely to be more significant.

Furthermore, National Treasury concurs that shortages of electricity have a more detrimental impact on the economy than higher prices which are used to enable the financing of capacity expansion. Various studies have shown that load shedding (especially unplanned load shedding) has very large negative economic impacts, far more so than various other options which may include running the gas fired power stations, buying back power from large consumers, demand market participation and other alternatives.

Higher prices tend to have smaller economic impacts as they redistribute electricity and thus production from least productive (less efficient) to be more productive (more efficient) firms. This results in more optimally allocated resources. This is true to the extent that electricity prices converge to cost reflective levels, which are not inflated by operational inefficiencies, *poor management and unjustified cost overruns. In the long run, cost reflective tariffs, including the internalisation of the cost of negative externalities associated with electricity supply, will ensure more efficient use of electricity and efficient allocation of resources in the economy and will raise economic growth rates over time. It will provide the right signals for investment in the electricity sector for both Eskom and Independent Power Producers (IPPs) as well as in cogeneration opportunities. The correct pricing of electricity will help to stimulate investment in more efficient and less environmentally damaging production methods and incentivise residential consumers to consume electricity more efficiently. In the short-run, electricity prices also have an important role to play in managing the supply and demand balance. Nevertheless, it is critical to smooth the transition to cost-reflectivity in order to allow consumers to adjust and avoid unnecessary employment and output losses.*

Impact of electricity price increases

National Treasury also ran a shock in its Computable General Equilibrium (CGE) model incorporating a higher price (both the 20 percent increase for Eskom, and the 27 per cent increase for municipalities) in electricity generation and distribution. On a macro scale, both price increases display very similar and marginal impacts. A 20 per cent increase in the price of electricity reduces the Gross Domestic Products (GDP) at market prices by 0.1 percentage points from the base. The same is true for a 27 per cent increase in the price of electricity. The macroeconomic effects are tabled below.

Macroeconomic effects of an increase in the price of electricity

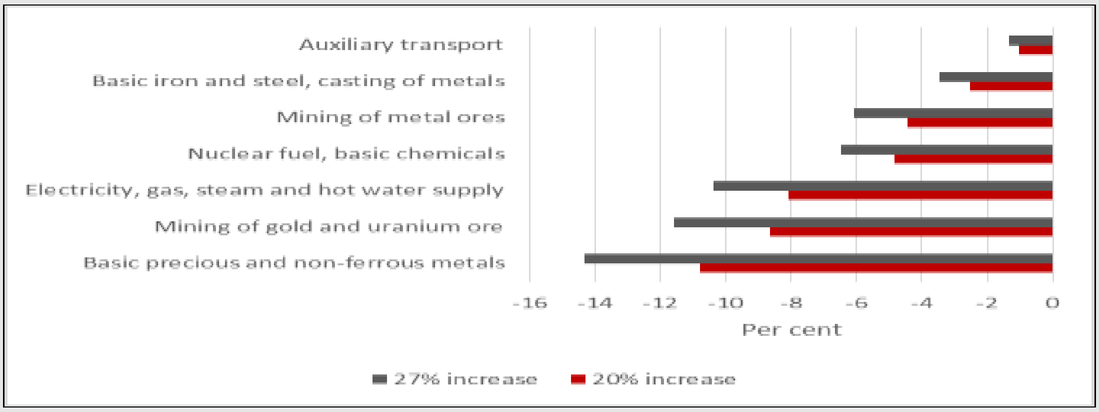
	Percentage point change from the base	
	20 per cent	*27 per cent*
Absorption	*-0.1*	*-0.1*
Private consumption	*-0.3*	*-0.4*
Fixed investment	*-0.1*	*-0.1*
Change in inventories	*0.0*	*0.0*
Government consumption	*0.6*	*0.7*
Exports	*-0.3*	*-0.4*
Imports	*-0.3*	*-0.4*
Gross domestic product at market prices	*-0.1*	*-0.1*

Source: National Treasury

Job losses can be seen across all levels of skills. When compared to the base, a decrease of between 8.3 and 10.6 per cent is seen in employment when considering a 20 per cent and 27 per cent price increase, respectively.

On a sectoral basis, there are pronounced negative effects on the mining sectors, as these are energy-intensive industries, as well as directly on the electricity industry. The electricity industry is directly affected by weaker demand owing to the large increase in the price of electricity. Weaker demand for electricity is seen across the household income groups, but is relatively stronger for the higher income households who can switch to alternative forms of energy.

Impact of industry's GVA



Source: National Treasury

Impacts of the proposed tariff on Eskom customers

The following comments are based on the research conducted by National Treasury into the impact of electricity tariff increases on households and select listed companies. The findings of the research indicated that the impact on households will be as follows:

a. Using household data from the Income and Expenditure Survey, even under a relatively low projected electricity tariff path,[9] *electricity expenditure by households will*

9 *10 per cent increase per annum in 2017, 2018, 2019, 2020 and 2021, and an inflation-related increase thereafter until 2030.*

almost double by 2030. Lower income households, particularly deciles 1 to 5, will be the most affected as electricity represents a larger proportion of their expenditure basket.

b. *However, low income groups (LSMs 1 to 4) will be able to adjust more easily as they can use basic non-electricity based appliances to reduce their electricity consumption (e.g. gas/ paraffin cookers) and thus electricity expenditure.*
c. *A sharp increase in electricity tariffs will make electricity-alternative household appliances (e.g. gas stoves, heaters, rooftop PV's) relatively cheaper. This means that households in the higher income groups (LSMs 8, 9 and 10) will be able to mitigate the impacts of the tariff increases on their overall household expenditure.*
d. *Although low and high income households will be able to mitigate the effects of electricity price increases somewhat, National Treasury's findings suggest that middle income households (LSM 5 and LSM 6 in particular) will be the most vulnerable to rising tariffs. This is due to their higher electricity consumption, yet lower average income that limits their ability to invest in appliances that will reduce their electricity consumption more significantly. Thus electricity prices increases will likely have a large negative effect on these households.*

On the other hand, the findings of the research indicated that the impact on households will be as follows:

e. *By analysing the financials of 21 listed companies it was determined that under a high tariff scenario, the net present values of the operating profits of firms could be reduced by up to 17 per cent, dependent on energy intensity.*
f. *The viability of Own-generation of electricity is growing and some firms have already reached the point where it makes sense from a financial perspective, even in a moderate tariff trajectory.*
g. *If firms continue to undertake these investments or improve their energy efficiency they will be able to mitigate the impact of the tariff increases somewhat.*

Impacts of the proposed tariff on Eskom and municipalities

The mitigation strategies employed by households and firms described above will have an adverse impact on electricity sales for Eskom and municipalities. Looking at households specifically, under relatively conservative assumptions and a moderate tariff path (of a ten per cent per annum increase over the next 5 years), about twenty six per cent of total *residential electricity sales could go off-grid by 2030.*

From an analysis of listed companies, National Treasury estimates show that the equivalent of up to thirty-four per cent of mining, eight per cent of industrial (from a sample size of 21 companies) and one per cent of commercial electricity generation sales currently supplied by Eskom has the potential to go off-grid, by 2040. Furthermore, a sharp hike in electricity tariffs will increase the prevalence of non-technical load losses, as certain households can no longer afford the higher tariffs yet still continue to use electricity.

Eskom notes the analysis by National Treasury. Eskom has also commissioned two economic impact studies that have been finalised subsequent to the submission of the draft revenue application to SALGA and National Treasury. The analysis has yielded similar results to that reflected in National Treasury's study. The details of the studies will be included in the final submission to be made to NERSA.

19.1.3 Sales volume assumptions

The sales forecast is perhaps one of the most crucial assumptions as it ultimately determines not only what the price will be but also what expenses need to be covered. National Treasury suggests that further clarity be provided on how sales volumes were assumed.

It is evident that a significant sales volume adjustment has been implemented in this revenue application. As reflected in the document a 9.4% price increase is needed for just adjusting the change in volume between what NERSA had approved for the 2017/18 year to Eskom's assumption (for NERSA approval) for the 2018/19 year. This exerts tremendous pressure on Eskom's ability to request an increase in revenue. The revenue increase being requested is approximately 7% for customers. However, due to the recovery over significantly lower volumes – results in a much higher price increase. It is therefore understandable that National Treasury is concerned that the same will happen if the application sales target is over optimistic.

Eskom concurs with National Treasury with regards to the significance of the sensitivity of the sales volume. The process that Eskom follows in arriving at a sales volume assumption is a very rigorous one and a huge amount of effort is put into the process to ensure the compilation of an accurate sales forecast over a period of 6 months. It can be confirmed that

Eskom definitely compares the bottom up with a top down approach to make sure that the forecast makes sense from all angles and that the bottom up approach is realistic. To test that the bottom up approach forecast is in line with historic trends the total sales growth with many years of history is analysed and interrogated. A “linear and exponential trend line” to the total sales trend is normally used to check the budget trend line.

Eskom further look at a wide variety of relationships, especially the relationship of electricity demand to other macro variables, e.g. GDP, commodity prices, exchange rates. An important part of the forecast is to focus on these relationships specifically for the Key Industrial Customers (KIC) and mines who are reliant on exchange rate and commodity prices. The submission document also shows the major commodity tables and economic parameters that is utilised.

In determining price elasticity proper analyses is done with available information and the findings tested with KICs. It is important to note that when you consider income elasticity, one should be careful not to double count the impact of price elasticity. In the price elasticity impact determination there is already a component of the income elasticity, as price elasticity inherently sends a message as to what level customers will be able to tolerate higher electricity bills when competing for spending on other more/equal important expenditures, such as food, water and other. In addition Eskom also had a look at inflation rates, mostly for the residential type of customers, but price elasticity and the savings drives overshadowed that impact.

In representative customer engagements, time was spent to discuss the proposed price path and the implication on energy intensive users, but Eskom takes note of National Treasury’s suggestion that the price elasticity impact of such a high increase could be more what was anticipated in the submission. In line with the MYPD methodology, the mitigation of the sales variance can be addressed through the consideration of a more recent sales forecast at the time of the NERSA decision.

When considering the 2018/19 submission with the projected 2017/18 consumption it must be noted to avert the declining trend Eskom has put in place a growth initiative with stretched targets to grow additional sales over and above what will transpire from the market. A sustainable solution requires a coordinated national (SA Incorporated) effort and should consider all options. Eskom is completely supportive of any policy interventions by the Government in ensuring further economic growth that is likely to attract further industrial investment.

19.1.4 Regulatory Clearing Account

National Treasury notes that the RCA has not been taken into account in preparing this application and that this may result in amendments to the increases presented by Eskom in the draft application.

National Treasury is correct. Eskom will not be including any RCA adjustments in the 2018/19 revenue application. NERSA has decided not to analyse any RCA submissions until the outcome of the appeal process is finalised. The outcome of the appeal process has been determined on 6 June 2017. The subsequent appeal to the Constitutional Court was not successful. It needs to be clarified that if the RCA process is implemented, then any RCA adjustments will likely to be in a subsequent year after the 2018/19 financial year.

19.1.5 Primary energy

National Treasury is of the view that the assumed coal increases of 7% between 2015 to 2019 financial years seem quite low (less than 10%).

Further analysis of primary energy costs have been undertaken since the draft submission. Many of the areas highlighted by National Treasury have been addressed. These will be provided to NERSA as part of the final submission.

19.1.6 Operating expenditure

National Treasury has requested further details on the key operating costs with regards to employee benefit costs, maintenance costs and other operating costs. Including in this are the details related to research costs and Energy Efficiency and Demand Side Management (EEDSM)

It is accepted that further details on the operating costs would need to be provided to NERSA to make a revenue decision based on the operating costs. These will be provided in the final submission to be made to NERSA.

19.1.7 Corporate Social Investment

In respect of Eskom's Corporate Social Investment (CSI), it appears that this it is not included in their application.

National Treasury is correct. In accordance with the MYPD methodology, any CSI is specifically excluded from the revenue application. This will be funded by Eskom's bottom line.

19.1.8 Regulatory asset base

National Treasury has raised concerns about Eskom not undertaking a revaluation of its regulatory asset base (RAB). National Treasury has also noted Eskom's proposed Return on Assets (RoA) which is less than Eskom's current cost of capital which is marginally higher than 7.65%.

The National Treasury concern on the valuation of the RAB is noted and appreciated. Due to the revised methodology being finalised in October 2016, insufficient time was available for Eskom to finalise the revaluation of the RAB timeously. The revaluation process was initiated soon after the revised methodology was published. The process was unfortunately not finalised timeously for inclusion in Eskom's 2018/19 revenue application. Eskom has requested NERSA to condone this aspect of the methodology requirement for this revenue application. Eskom will be in a position to meet this requirement for the next application. It needs to be noted that for the purposes of migrating towards cost reflectivity, Eskom would be required to allow for phasing-in of certain revenue requirements. Continuing with the asset valuation of the RAB, as determined by NERSA for the MYPD 3 period, was one of the opportunities exploited to address the phasing-in requirement.

As pointed out by National Treasury, it is crucial for the return on assets being requested, to at least allow for the recovery of interest costs. It needs to be recognised that this lever has to be one of the options to consider for migration towards cost-reflectivity.

19.1.9 Independent Power Producers

Clarification was sought on which bid windows for the IPP programmes have been included *in the revenue application. Clarity was sought on the comparison of IPP costs with primary energy costs.*

It is incumbent upon Eskom to include the responses received in terms of the Government Support Framework Agreement (GSFA) for DOE related IPP projects. This reflects an assumption, as for all other costs, for NERSA to make a decision on. The NERSA MYPD methodology requires all IPP costs to be included as a primary energy costs.

19.2 Summary of SALGA responses related to the 2018/19 Revenue Application

19.2.1 Impact on economy and affordability

Concerns have been raised on Eskom applying for an average 19.9% average price increase. This corresponds to 27.29% increase for Municipal customers to be implemented from 1 July 2018. This percentage increase is based on below inflation increase for the 2017/18 year of an average of 2.2% increase for which corresponds to a 0.3% increase for Municipal customers. SALGA proposes that CPI related increase needs to be awarded to Eskom.

Eskom understands the concerns raised by SALGA in its responses related to impact on customers. Eskom is required to make an application in terms of the relevant price determination methodology as approved by NERSA. It is understood that NERSA will apply its mandate in making a final decision on the revenue application. The percentage increase in prices is also a factor of the very low increase in the 2017/18 year. It is important to note that this low increase translated in an increase of only 0.3% to municipalities that will continue until 30 June 2018. This has assisted municipalities to keep their increases for 2017/18 well below inflation.

Eskom needs to recover the NERSA allowed revenues within its financial year that is determined by the PFMA and runs from 1 April to 30 June of the following year. In terms of the MFMA the financial year of Municipalities runs from 1 July to 30 June of the following year. To be fair and in accordance with the NERSA approved ERTSA methodology Municipalities will experience exactly the same average annual increase over the period of the Eskom financial year. As a result municipalities will not experience any increases during April to June of the new financial year. In order to recover the fair share of the approved allowed revenue from municipalities the balance of the allowed revenue needs to be recovered over 9 months only - causing a higher than the annual average price increase from 1 July.

As has been rightly pointed out by SALGA the actual increase in allowed revenue being applied for by Eskom is approximately a 7% increase in total allowed revenue from NERSA's decision for 2017/18 (R205bn) to the application for 2018/19 (R219bn).

It is clearly shown in the submission that Eskom maintains its current business at increases of around inflation – a significant adjustment is related to a decrease in sales volume. It is critical for Eskom to re-base the sales volumes for 2018/19 to make sure that the average price that is determined will indeed recover the allowed revenue if applied to a much lower sales volume; otherwise one will again sit with the same situation of Eskom not recovering the required revenue.

As reflected in Eskom's submission to SALGA, a myriad of factors account for a downturn in the economy. It is argued that the price elasticity of demand is not the only contributing factor. A detailed economic impact study will be included in Eskom's submission to explore this aspect further. The holistic approach to the recovery of efficient and prudent costs for the production of electricity is discussed in this study.

It is accepted that there is a world-wide phenomenon for migration to self-generating options. The relevant roleplayers in the industry and Government will be required to give further attention to this.

19.2.2 Impact of sales volume

SALGA is concerned about the increase in costs despite the continuing decline in sales volume. Clarity is sought on why costs do not drop when sales volume decrease. Concerns are raised on the NERSA MYPD and ERTSA methodology that allows Eskom to increase the tariff to cover for lower sales to maintain the rand value of the income. .

Eskom's allowed revenue in terms of the MYPD Methodology is to cover variable costs (mainly primary energy) and fixed costs (operating costs + depreciation + returns).

Eskom agrees with SALGA's response that as sales volumes drop, lower variable costs should result - it is only variable costs that can respond to increases and decreases in sales volumes in the short term. Eskom's application has taken this into account and the variable costs reduce in line with the decline in sales. However, Eskom continues to incur the fixed costs as the power stations; the networks, staff etc. do not disappear immediately when the sales volume increases or decreases.

As sales volumes increase or decrease, there would be a concomitant increase or decrease in variable costs. The key variable costs for the electricity industry are related to primary energy costs. An insignificant variance in certain operating and maintenance costs will also be experienced.

Primary energy cost variances due to lower sales have been included in each of the primary energy cost elements in the application. This is in accordance with the MYPD methodology that considers coal burn and other primary energy costs including water, nuclear fuel, environmental levy and coal handling costs. The key fixed costs elements include operating costs, depreciation and returns.

In order for Eskom to recover the fixed cost element the full revenue must be recovered even if the volume is lower, with the net effect being that Eskom only recovers the 'gross margin'.

The above mechanism also applies in the case of volumes being higher, where the allowed revenue is recovered over a higher sales volume. It is intuitive that additional primary energy costs would also be required. This mechanism is standard global regulatory practice for cost-of-service type methodologies.

SALGA has raised concerns on the NERSA approved MYPD and ERTSA methodologies. Eskom has implemented the methodologies, as required by NERSA.

19.2.3 Operating costs

SALGA has raised concerns about the employee benefit costs for this application contributing to approximately 45% of operating costs. Proposals have been made for austerity measures and NERSA audits.

The 2018/19 revenue application illustrates that operating expenses are expected to escalate on a year on year at a rate of below inflation. Eskom has undertaken a detailed design to cost process that has realised efficiencies which are reflected in the application. NERSA conducts audits on Eskom processes regularly and Eskom welcomes the outcomes and findings of these audits.

19.2.4 Primary energy costs

SALGA requested a clarification of how coal mix changes result in increased unit cost. SALGA agrees with Eskom that lower sales volume should result in lower primary energy volumes.

The mix variance refers to the combination of power stations that are used to generate electricity. The delivered average cost of coal differs between power stations. The cost of coal is impacted by:

- The quality of the coal, which must comply with the station design requirements. Generally, coal of a higher quality costs more.
- The logistics costs associated with getting the coal to the station – conveyor, rail or road.
- The source of the coal – coal is generally cheaper from a mine next to the station with a long term coal supply contract than coal from short and medium term contracts. Coal contracts may be broadly grouped into three contract types:
  - **Cost plus –** long term contracts where the mine is located close to the power station. The coal is dedicated to the power station. There are no additional logistics costs incurred.
  - **Long term fixed price contracts –** historically the mine has also been located next to the power station, but supplies both Eskom and other parties. This coal may be relatively cheap because the mine recovers its costs from multiple buyers and because conveyor is the mode of transport.
  - **Shorter term fixed price contracts –** these contracts are generally used to breach the gap between coal supplied from long term contracts and the coal required, if there is a shortfall. They are of a shorter duration, usually relatively small quantities and more expensive than long term coal. This coal is transported by rail, road or a combination of both.

Ideally, all power stations should have a mine next door and a conveyor delivering the coal from the mine to the station. In reality, stations receive coal from more than one source by more than one transport mode for the following reasons:

- Not all stations have mines next to them
- The long term contract has expired
- The long term contract does not meet all of the stations coal requirements.

All of the factors above determine the cost of coal at each of the power stations. So, a reduction in electricity demand and generation will only result in a reduction in coal burn costs if it is possible to reduce generation at stations where the cost of coal is higher.

19.2.5 Transmission capital costs

SALGA requests clarification on why Transmission infrastructure costs have increased substantially.

The NERSA Grid Code rules govern investment in the transmission network. Eskom, as the licensed Transmission Network Service Provider (TNSP), plans the network according to this code and, subject to funding and other resource constraints, builds the network according to these plans. Where insufficient funds are available to develop the network, a consistent set of criteria is applied to prioritise projects and allocate funding in such a way that the maximum benefit is gained for customers.

Eskom's transmission network needs to be strengthened and expanded to connect new loads and generation to the network to enable country growth. In addition, refurbishment investments are required to sustain a reliable supply of electricity.

The capital plan includes generation integration projects required to ensure that the network is able to evacuate and dispatch power from new generation sources to load centres. The plan also includes projects for strengthening the transmission network to allow for future demand growth, reliability projects to ensure compliance with the Grid Code requirements as well as refurbishment projects essential for sustaining the network. The increased planned expenditure for the application year resulted from the phasing of project expenditure peaking over this period.

19.2.6 Impact of credit rating

Clarification is sought on the processes being undertaken by Eskom to minimise the potential Eskom credit rating downgrade.

Rating agencies conduct management review meetings with Eskom bi-annually when they visit South Africa for their due-diligence processes. Eskom also has quarterly engagements scheduled with rating agencies either in South Africa or London where business updates are provided to the rating agencies, particularly on their issues of concern. Besides the rating agencies annual visits and quarterly engagements, Eskom and the rating agencies engage on an ad-hoc basis whenever there is an immediate issue to be addressed. These engagements also allow Eskom to timeously comply with all rating agency reporting requirements.

Ratings agencies have raised a number of key concerns which could result in a further ratings downgrade: a Sovereign rating downgrade; a weakened liquidity position and/or a prolonged state of poor liquidity; free funds from operations as a percentage of debt below 5%; and operational weakness, with costs rising well above the budgeted targets. We are confident that our financial plan adequately addresses these concerns.

Short-term liquidity will be managed closely by delivering operational and cost efficiencies, and ensuring revenue uplift, as well as assessing options to rephase debt redemptions between 2017/18 and 2020/21. Debt servicing is anticipated to increase over the next five years, driven by increases in interest repayments, as well as debt repayments as loans mature.

In addition, cost containment is another key component of our strategy. We have developed programmes which will deliver long-term sustainable savings and/or avoid cost escalation. These include delivering a total-cost-of-ownership (TCO) based procurement programme on major commodities; limiting the escalation of coal costs by increasing volumes from cost-plus mines, and improving the negotiation of other coal contracts; and reducing our company headcount, while also supporting productivity through skills-based assessments and targeted hiring programmes. Given this context, the financial health of Eskom is dependent on a price of electricity that allows for recovery of efficient costs and earning returns which can cater for debt service commitments.

19.2.7 Renewables

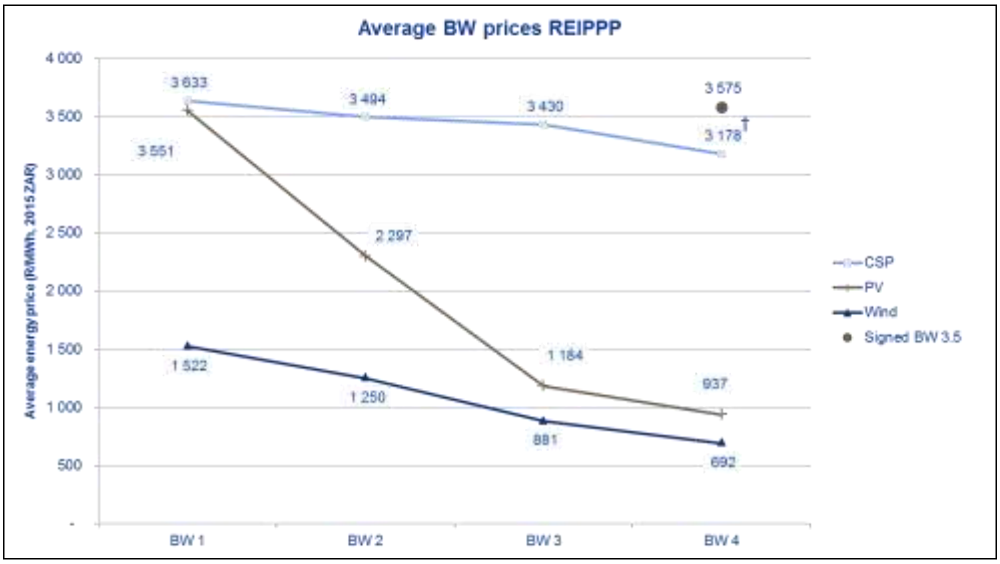
Concerns on the price of electricity from renewable sources are raised. A comparison is made between the average cost of renewable IPPs and average cost of Eskom primary energy. Request for Government to include Municipalities as buyers of renewable energy is made. This is in response to Eskom not willing to sign further IPPs before further discussions are held with Government. To address the higher average costs of renewable generation, SALGA proposes the difference be funded through the fiscus (including the environmental levy).

The policy issues raised by SALGA are best addressed by Government. These include defining the buyer of electricity from IPPs in terms of the Electricity Regulation Act and the provision funding of variance in cost of renewables from average cost through the fiscus.

It needs to be clarified that although IPP costs are considered primary energy costs in terms of NERSAs MYPD methodology, they correspond to total generating costs. Thus a like-for-like comparison has to be made. It is clarified that Eskom is in the process of discussing the signing of further IPPs with Government. The outcome of this discussion will provide guidance on the way forward.

The procurement of renewable energy through the REIPPP gives effect to the outcome of the IRP 2010 which proposed a significant shift in generation capacity in the electricity sector. The steady increase in renewable capacity before 2025 was deliberately intended to stimulate localisation of RE technology capabilities in South Africa and encourage a gradual decline in RE costs. The experience of the three completed rounds (bid windows) of the REIPPP as well as the subsequent but incomplete rounds highlights the effectiveness in reducing the costs of RE. The figure below indicates the declining prices related to bid windows 1 through 4 (particular for Solar photovoltaic and wind generators).

FIGURE 40: AVERAGE BW PRICE REIPPP



Source: Single Buyer Office estimated payments in April 2019 (when all operating), adjusted to 2016 ZAR. Some BW2 and BW 3 projects have partial indexation (leading to over-estimation of cost relative to others not using partial indexation). CSP average prices reflect expected generation over peak which carries substantial price premium. CSP in BW 3.5 reflected under BW 4; BW 4 costs reflect the bid prices(not yet adjusted for foreign exchange which will occur at financial close).

However the average RE costs indicated in the submission still reflect the high costs of the first and second bid windows and will continue to do so until additional rounds are completed to reduce the average price and South Africa is able to capitalise on the increasing RE capacity (and the “school fees” inherent in the earlier rounds). The legacy costs associated with bid windows 1 and 2 will continue until the expiry of the contracts after 20 years but these could decline in significance with additional RE energy procurement. Stopping the RE procurement process now would result in the continued payment of the “school fees” and the painful legacy of these rounds but no alleviation from cheaper RE that would follow.

19.2.8 Economic Activity to be improved

Concerns have been raised on South Africa’s economic decline – especially in the industrial environment. It is reasoned that the economic decline will be reversed by Eskom charging lower price increases.

The comment suggests that the economic decline will be reversed by only implementing reasonable electricity prices. The current decline in economic activity is much more complex than that and more stakeholders are required to take up their accountability and to collaborate in finding a solution instead of only relying on Eskom to turn the tide on its own.

Eskom accept that the increase in electricity prices in the last few of years had partial impact on the decrease in sales. However, in discussions with various industrial customers various other reasons were highlighted as drivers for the current situation. The declining trend in the in Eskom sales can be attributed to a number of driving forces including:

- Electricity price increases have played a part in constraining growth as the cost of electricity for certain industries is a high percentage of production cost
- South African industrial plants have overcapacity while commodity prices either remains static or reduce together with the remote location from major markets
  - China is taking our market share in a fiercely competitive market
  - Other input costs, particularly where electricity cost intensity is lower also play a role, i.e. expensive transport and location of plants from the markets
- Availability of electricity and energy efficiency drives during period of capacity constraint created permanent loss in sales/revenue
  - Eskom communicated to customers to reduce sales since load shedding
  - Energy efficiency initiatives implemented: Eskom requested a 10% reduction in load

  - Energy Conservation Scheme (ECS) rules were embedded in Electricity Supply Agreements

- Reluctance by global companies to invest in SA due to a lack in competitiveness and the uncertain situation in SA from a political and sustainable financial perspective (i.e. credit rating, labour)
- Internationally governments (not utilities) provide mechanisms for incentivised electricity prices for large energy intensive users in their countries
- A sustainable solution requires a coordinated national (SA Inc) effort and should consider all options. Eskom is completely supportive of any policy interventions by the Government in ensuring further economic growth that is likely to attract further industrial investment.
- As reflected in Eskom's application, Eskom is making every effort to increase local in cross-border sales. However, as alluded to earlier a concerted effort by the country is needed to improve economic conditions.

As cost drivers are not only electricity prices, growth initiatives are driven from a country platform together with the key role players, i.e. Department of Trade and Industry, Economic Development Department, Industrial Development Corporation, National Treasury, Department of Energy, and the National Energy Regulator of South Africa to ensure an integrated and focused SA Inc approach to maximise growth stimulation.

The Government has initiated the establishment of a work group facilitated by the Department of Public Enterprises to find alternative options that can be implemented. This include short term price incentives for electricity intensive users as well as more cost reflective tariffs for energy intensive industrial customers.

19.2.9 Impact on Municipal Debt

SALGA is concerned that any price increase will result in further debt burden on Municipalities. Approximately 50% of Municipal electricity customers are residential customers. Approximately 40% of these are indigent. It is felt that this is a vicious cycle.

It is agreed that the Municipal debt challenge needs to be addressed. It is submitted that the challenge needs to be looked at holistically from a Municipality financial sustainability point of view. The economic impact study undertaken by Eskom illustrates the impact of price increases on various economic factors.

Eskom has committed to look at some of the items which the Municipalities deem to be contributing to the Municipal debt situation.

Eskom has agreed to implement the following (after following due governance processes)

1. Changing the interest rate charged on overdue amounts from Prime plus 5% to Prime plus 2.5%
2. Changing the payment cycle from 15 days to 30 days
3. Changing the payment allocation to Capital debt first and then interest
4. Allowing municipalities to pay connection charges for new/upgrading of supply points over a period of time instead of on a cash upfront basis.

It is proposed that these concessions would make it easier for the municipalities to deal with the debt situation.

20 Revenue requirements for licensees

Eskom's allowable revenue requirement comprises that of Generation, Transmission and Distribution businesses. Generation contributes about 75% of the allowable revenue with the networks making up the balance.

20.1 Generation allowable revenue

Generation revenue requirement is R175 158 million with the production costs contributing almost R96 billion which represents 55% of the allowable revenue. Generation own primary energy is R59 340 million, IPPs adds R34 209 million and international purchases of R3216 million. Core operating expenditure is R35 200 which includes their share of corporate overheads adding R6 988 million. Debt commitments are covered through depreciation and returns of R35 391 million.

TABLE 37 : GENERATION ALLOWABLE REVENUE

Generation Allowable Revenue (R'millions)	AR	Application 2018/19
Regulated Asset Base (RAB)	**RAB**	549 527
WACC %	**ROA**	2.97%
Returns		16 329
Expenditure	**E**	35 200
Primary energy	**PE**	59 340
IPPs (local)	**PE**	34 209
International purchases	**PE**	3 216
Depreciation	**D**	19 062
IDM	**I**	
Research & Development	**R&D**	
Levies & Taxes	**L&T**	7 994
RCA	**RCA**	
Total Allowable Revenue	**R'm**	**175 351**
Not claimed in application		
Corporate social investment (CSI)		- 193
Allowable Revenue for Generation		175 158

20.2 Distribution allowable revenue

Distribution revenue requirement is R33 257 million covering expenditure of R23 434 which includes their share of corporate overheads adding R3 510 million. Debt commitments are covered through depreciation and returns of R9 356 million.

TABLE 38 : DISTRIBUTION ALLOWABLE REVENUE

Distribution Allowable Revenue (R'millions)	AR	Application 2018/19
Regulated Asset Base (RAB)	RAB	104 691
WACC %	ROA	2.97%
Returns		3 111
Expenditure	E	23 434
Primary energy - net import	PE	
IPPs (local)	PE	
International purchases	PE	
Depreciation	D	6 245
IDM	I	511
Research & Development	R&D	
Levies & Taxes	L&T	
RCA	RCA	
Total Allowable Revenue	R'm	**33 301**
Not claimed in application		
Corporate social investment (CSI)		- 44
Allowable Revenue for Distribution		33 257

20.3 Transmission allowable revenue

Transmission external revenue requirement is R11 112 million covering expenditure of R4 029 million which includes their share of corporate overheads adding R921 million. Debt commitments are covered through depreciation and returns of R7 083 million.

TABLE 39 : TRANSMISSION ALLOWABLE REVENUE

Transmission Allowable Revenue (R'millions)	AR	Formula	Application 2018/19
Regulated Asset Base (RAB)	RAB		109 371
WACC %	ROA	X	2.97%
Returns			3 250
Expenditure	E	+	4 029
Primary energy	PE	+	
IPPs (local)	PE	+	
International purchases	PE	+	
Depreciation	D	+	3 833
IDM	I	+	
Research & Development	R&D	+	
Levies & Taxes	L&T	+	
RCA	RCA	+	
Total Allowable Revenue	R'm		**11 112**
Not claimed in application			
Corporate social investment (CSI)			- 15
Allowable Revenue for Transmission (external)			11 097

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

21 Conclusion

Eskom has been striving to keep cost escalations close to inflationary levels which have been highlighted as follows:

- Eskom's own primary energy costs excluding local IPPs growing at a CAGR of 1.5% per annum
- The total primary energy increasing by CAGR of 8.7% per annum after IPPs costs are added into the supply mix
- Employee benefits escalating by CAGR of 4.9% per annum and reduction of staff complement
- Operating and maintenance costs escalating with a CAGR 7.3%. This drops to less than inflation from 2016/17 to 2018/19
- Capital expenditure grows with focus on completing new build projects, maintaining existing power stations, strengthening and expanding network businesses

Eskom's allowable revenue applied for in 2018/19 grows by R14 billion from the R205 billion allowed in 2017/18, equating to an absolute revenue growth of 7%. Half of the increase in revenue will be recovered from exports and negotiated pricing customers and the remainder being recouped from standard tariff customers.

As described in this application one of the major drivers to the price increase is that this application requires a rebasing of sales volumes in the region of 30 TWh. In terms of NERSA's methodologies Eskom needs to recover the allowable revenue as this provides for contribution to fixed costs. Over the MYPD3 period the organisation has been unable to recover the allowed revenue which reflects a under recovery by March 2017 of approximately R48 billion. Actual sales volumes have remained relatively flat over the last few years and expected to continue in the next 2 years based on the current economic environment. Eskom appreciates the importance of maintaining and growing sales volumes as described in sales initiatives and recent emphasis to grow cross border sales.

In order to limit the revenue requirement and therefore the electricity price impact, Eskom has reduced the returns when compared to the decision made by NERSA for the 2017/18 year. The revenue requirement results in the average electricity of price of 107c/kWh.

Finally, NERSA has mechanisms to help protect targeted customer categories and customers will require flexibility in these areas to maintain and grow sales volumes in trying circumstances whilst balancing the needs of consumers and ensuring the financial sustainability of Eskom.

22 Appendix 1 - Coal Burn Costs

22.1 Coal Burn Costs and Volume(Kt) per Power Station

Table 40: Assumed Coal Burn Costs per Power Station

Coal Burn Costs (R 'M)				Purchases cost ratio FY19			Burn allocation FY19 (R 'M)			
Power Stations	Actuals 2016/17	Projection 2017/18	Application 2018/19	Cost Plus	Fixed Price	MT	Cost Plus	Fixed Price	MT	Total
Kusile	[redacted]									
Medupi	[redacted]									
Duvha	[redacted]									
Kendal	[redacted]									
Lethabo	[redacted]									
Majuba	[redacted]									
Matimba	[redacted]									
Matla	[redacted]									
Tutuka	[redacted]									
Arnot	[redacted]									
Camden	[redacted]									
Grootvlei	[redacted]									
Hendrina	[redacted]									
Komati	[redacted]									
Kriel	[redacted]									
	[redacted]									
Total Coal Burn Costs (R'million)	44 164	45 642	48 687				17 140	11 442	20 105	48 687

The above Coal burn allocations per contract type were done at a high level basis using purchases as a proxy.

Table 41: Coal Burn volume (Kt) per Power Station

Coal Burn Kt				Purchases volume ratio FY19			Burn allocation FY19			
Power Stations	Actuals 2016/17	Projection 2017/18	Application 2018/19	Cost Plus	Fixed Price	MT	Cost Plus	Fixed Price	MT	Total
Kusile	[redacted]									
Medupi	[redacted]									
Duvha	[redacted]									
Kendal	[redacted]									
Lethabo	[redacted]									
Majuba	[redacted]									
Matimba	[redacted]									
Matla	[redacted]									
Tutuka	[redacted]									
Arnot	[redacted]									
Camden	[redacted]									
Grootvlei	[redacted]									
Hendrina	[redacted]									
Komati (Comm)	[redacted]									
Kriel	[redacted]									
Total Coal Burn (Kt)	113 737	116 099	112 397				45 944	30 898	35 555	112 397

The above Coal burn allocations per contract type were done at a high level basis using purchases as a proxy.

22.1.1 Explanation of Coal Burn Costs

NERSA requires burn to be submitted per station, per contract type and per supplier. Eskom calculates coal burn on a weighted-average-cost basis. A single coal stock pile is maintained for all coal delivered to the stock yard, irrespective of the contract type. The coal is burnt as a single, mixed product and not as three different product types. Accordingly, coal burn does not differentiate between contract types (i.e. cost-plus, fixed-price or medium term).

Eskom has submitted coal burn per station. Eskom furthermore, has made assumptions to split coal burn by contract type, calculating coal burn in the same ratio as coal purchases. When coal burn is calculated in the same ratio as coal purchases, the following factors would need to be taken into account:-

22.1.2 The treatment of opening stock in the first year

Opening stock volumes in the first year are not segregated in accordance with the contract type which covered the purchase. Opening stock will therefore be weighted in line with the ratio of purchases of the previous year, for example, **xx** Cost-Plus, **xx** LT Fixed-Price and **xx** MT Fixed-Price. A second assumption is made on the value of each category of coal in the opening stock. The assumption could be that the unit cost is the same as the previous year's average purchases unit cost for that contract type, for example, if the average MT Fixed Price purchases R/t was **Rxx/t**, this would be the unit cost of **xx%** of the coal in the opening stock. Another further assumption is made to allocate common costs to each contract type.

22.1.3 Coal burn

The assumption is that opening stock per contract type and purchases per contract type are added to obtain an average unit cost per contract type for the year. Coal burn is calculated in the ratio of the sum of the opening stock plus purchases per contract type.

22.1.4 Closing stock

When the opening stock and burn are calculated as explained in the preceding paragraphs, closing stock would be opening stock plus purchases less burn per contract type.

22.1.5 Adjustments to stock

An assumption would need to be made for adjustments to the stock, for example, adjustments after the quarterly stock surveys.

22.2 Coal Purchase Ratio used to calculate coal burn per contract type

It is assumed that coal burn will be occurring in the ratio that coal purchases have occurred. Thus assumptions in accordance with this are made for coal burn.

22.3 Coal cost escalation assumption for FY 2019

Eskom used a R/ton percentage increase of **x%** on the cost of coal.

22.4 Coal stockpile volumes

Emergency stockpiles at Arnot, Henrina, Duvha, Camden and Grootvlei hold coarse coal to alleviate coal handling problems during the rainy season. The table below reflects the tonnes of coal on stockpiles during FY17 and the first quarter of FY18. The results are from the coal stock survey conducted at in February 2017 and in May 2017. They will therefore differ from the final stock volumes at the end of March 2017.

TABLE 42: VOLUME OF COAL ON STOCKPILE (TONNES)

		Actuals FY17				FY18		
	Emergency	Strategic	Seasonal	Live	Emergency	Strategic	Seasonal	Live
Arnot	[redacted]							
Kriel	[redacted]							
Lethabo	[redacted]							
Tutuka	[redacted]							
Hendrina	[redacted]							
Matla	[redacted]							
Duvha	[redacted]							
Kendal	[redacted]							
Majuba	[redacted]							
Matimba	[redacted]							
Camden	[redacted]							
Grootvlei	[redacted]							
Komati	[redacted]							
Medupi	[redacted]							
Kusile	[redacted]							
TOTAL	**455 351**	**23 788 816**	**2 396 452**	**1 603 351**	**458 992**	**22 965 642**	**2 163 985**	**1 226 401**

22.5 Rail transport indices and escalations

The following table is indicative of the escalation components for FY18. However, the contract with TFR ends at the end of FY18. For FY19, an 8% escalation rate was assumed.

TABLE 43: ESCALATION COMPONENTS FOR FY18

Component	Portion	Source Document	Index	Weighted Index
PPI Component	[redacted]			
Labour				
Fuel				
Electricity				
Total				

22.6 Road transport indices and escalations

The following table provides indications of values related to road transport indices and escalations.

TABLE 44: ROAD TRANSPORT INDICES AND ESCALATIONS

Component	Proportion	Index Linked To	Cycle
Labour	[redacted]		
Cost of Capital (Applicable to vehicles not fully depreciated)			
Fuel (Diesel)			
Maintenance			
Lubricant and tyres			
Depreciation			
CPI			
Total			

23 Appendix 2 – Coal handling Costs

23.1 Coal handling costs

The major activities include the Provision of Coal handling, Operating, Maintenance, Cleaning and Maintenance from the Coal Mine (some Mines are still responsible for the operation and maintenance of the conveyor belts) to the Coal Conveyor Plant and Coal Stockyard. This requires the management of operations 24 hours a day 7 days a week on the Coal plant, conveyor system and cleaning so as to ensure the efficient operations of the various plants.

Coal handling costs in 2018/19 accounted for 2.9% of the Total Eskom Generation Primary Energy costs of R67 015m. The Coal handling costs increased by approximately CPI year-on-year, despite the new units of Medupi and Kusile being commissioned within this time frame. The new units added additional coal handling costs to the Generation cost base.

23.2 The major cost drivers for coal handling

The major drivers for coal handling costs can be allocated to the following roles:

- Labour
- Yellow plant (machinery)
- White plant (machinery/vehicles)
- Fuel for yellow and white plant
- Contingencies

23.2.1 Labour

The number of staff, their responsibilities and labour inflation assumptions are covered in the SLA of each power station and are negotiated centrally for the whole Generation fleet of stations to obtain better rates.

23.2.2 Yellow and white plant description and functions:

TABLE 45: YELLOW AND WHITE PLANT DESCRIPTION AND FUNCTIONS

Item	Plant Description (Yellow)	Job Description
1.	Bull Dozer	Pushing of import coal for reclaim the coal
2.	Front end loader	Pushing up coal and load coal into the mobile feeders
3.	Dump Trucks	To move coal to various and difficult areas
4.	Motor Grader	To grade the roads on coal stockpiles and associated gravel roads
5.	Tipper Trucks	Transport coal to various where it's required
6.	Smooth Drum Roller	Compact seasonal and strategic stockpiles and gravel roads
7.	Water Tanker	Dust suppression on coal stockpiles and gravel roads
8.	Tractor loader bucket/TLB	Clean sumps and dig trenches
9.	Excavator	To lead tipper and dump trucks. To break strategic piles loose.
Item	**Plant Description (White)**	**Job Description**
1.	LDVs	To transport spares and tools
2.	7, 12 & 23 seater bus	To transport people onsite and home work home

23.3 Coal handling costs per power station

Further information with regards to Eskom coal handling costs per power station is presented below. Assumptions are made with regards to the contribution of drivers for the coal handling costs.

TABLE 46: COAL HANDLING COSTS PER POWER STATION

Coal handling R'million	Actuals 2016/17	Projection 2017/18	Application 2018/19
Kusile	0	10	39
Medupi	20	25	60
Duvha	194	204	216
Kendal	95	73	106
Lethabo	162	174	188
Majuba	240	281	303
Matimba	46	49	52
Matla	134	148	157
Tutuka	201	203	215

Coal handling R'million	Actuals 2016/17	Projection 2017/18	Application 2018/19
Arnot	163	170	180
Camden	92	108	115
Grootvlei	106	111	118
Hendrina	107	105	0
Komati	73	76	80
Kriel	127	136	144
Total Coal Handling costs	**1 758**	**1 874**	**1 974**

Coal handling costs differ from power station to power station. At one extreme coal handling costs amounted to R52m for Matimba in 2018/19 and at the other extreme, amounted to R253m at Majuba in 2018/19. Valid reasons are provided for this variance between power stations.

23.4 Coal handling costs per cost driver

TABLE 47: COAL HANDLING COSTS PER COST DRIVER

Coal handling per cost driver R'million	Actuals 2016/17	Projection 2017/18	Application 2018/19
Labour(60%)	1 055	1 124	1 184
Yellow plant(15%)	264	281	296
White plant(5%)	88	94	99
Fuel for plant(15%)	264	281	296
Contingencies(5%)	88	94	99
Total Coal Handling costs	**1 758**	**1 874**	**1 974**

Assumptions are made on derived allocations for the split in coal handling costs per cost driver based on historical trends.

24 Appendix 3 – Water Costs

Further information with regards to Eskom water costs per power station is presented below.

TABLE 48: WATER COSTS PER POWER STATION

Water costs R'million	Actuals 2016/17	Projection 2017/18	Application 2018/19
Arnot	134	164	201
Camden	116	137	126
Duvha	79	227	281
Gariep	2	2	2
Grootvlei	29	25	35
Hendrina	122	143	
Kendal	72	64	73
Koeberg	3	3	3
Komati	101	93	148
Kriel	305	261	295
Kusile	0	40	57
Lethabo	30	50	52
Majuba	72	137	140
Matimba	54	72	77
Matla	253	273	328
Medupi	125	219	232
Renewables	1	1	1
Tutuka	202	280	267
Vanderkloof	52	55	59
Efficiency target	-	-61	-65
Total Water Costs	**1 751**	**2 185**	**2 310**

Eskom pays for the water it consumes through a series of water tariffs which are legislated, and beyond the control of Eskom. Historically, water costs have been very low as a percentage of the Eskom operating costs. The main reason for this is that the water infrastructure assets (Eskom's and that of the Department of Water & Sanitation (DWS)) were constructed several years ago and are almost completely depreciated. As new infrastructure and water charges have been introduced, the demand for water and the cost have increased. Furthermore, the cost increases as the distances over which water needs to be transferred increase and as new tariffs are introduced into legislation.

New water infrastructure includes the augmentation to the Vaal (VRESS - Vaal River Eastern Subsystem), Komati (KWASAP – Komati Water Augmentation Scheme) and Mokolo (MCWAP – Mokolo Crocodile West Augmentation Project) water schemes. The DWA National Water Pricing Strategy allows DWA to implement these projects “off budget” and to recover associated costs via a tariff. The Komati and Mokolo costs are recovered on a take or pay pricing basis.

24.1 Water Volumes (ML)

TABLE 49: WATER VOLUMES PER POWER STATION

Power Stations	Actuals 2016/17	Projection 2017/18	Application 2018/19
Kusile	-	2 055	2 770
Medupi	477	4 447	5 727
Duvha	21 958	30 805	31 651
Kendal	5 694	3 188	3 421
Lethabo	36 997	40 075	39 830
Majuba	22 103	23 050	21 926
Matimba	4 273	3 382	3 412
Matla	37 486	39 219	41 916
Tutuka	34 169	32 545	28 979
Arnot	25 494	26 035	25 416
Camden	17 873	18 277	15 821
Grootvlei	8 965	11 189	13 695
Hendrina	19 533	18 981	-
Komati	15 082	18 956	18 526
Kriel	34 249	30 042	30 779
Total Water Volumes (ML)	**284 352**	**302 245**	**283 869**

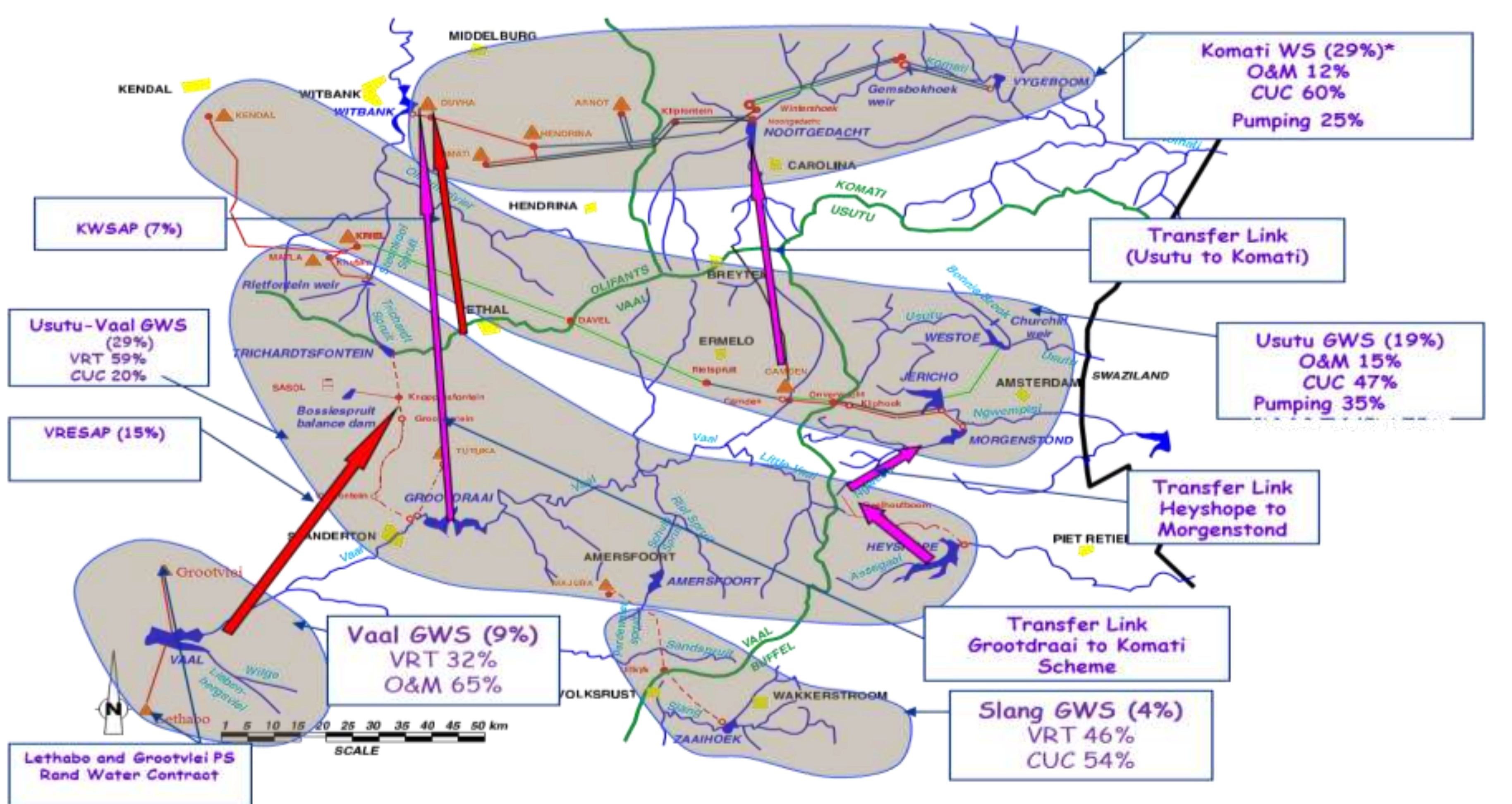
24.2 Major Water Schemes and Contracts

The following table illustrates the scheme(s) which supply water to each power station and the cost components that apply to each power station.

TABLE 50: WATER SCHEMES AND POWER STATIONS SUPPLIED

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

FIGURE 41: INTEGRATED VAAL RIVER SYSTEM (IVRS)



* Figures in parentheses indicate the approximate expenditure for that scheme as a percentage of Eskom's water cost

The water financial plan comprises the following cost elements, which are also the primary cost drivers:

- Water cost - levies, including cost of new water infrastructure
- Electricity (pumping costs)
- Operations and maintenance – incurred by Eskom on the Komati Water Scheme and by DWS on the Usutu, Usutu-Vaal, Vaal and Slang
- Amortization and capital spend

The coal fired power stations in the Highveld are supplied from the Integrated Vaal River System which is supported with water transfers from Lesotho and the Thukela River in KZN. In Mpumalanga there are 3 subsystems, *viz.* Komati Water Scheme, Usutu Water Scheme and the Usutu Vaal Water scheme that are interconnected and supply the Mpumalanga power stations. Water can be transferred between each subsystem to manage any water supply risk. DWS runs a computer model yearly to determine what volumes of water need to be transferred between subsystems and into the greater Vaal River system to manage future water supply risks. Water tariffs are legislated by the National Water Pricing Strategy. The water tariffs in each subsystem differ as determined by the statutory tariffs applicable to that subsystem and by the operating and infrastructure costs incurred by the DWS.
Lethabo and Grootvlei Power Stations obtain water directly out of the Vaal dam. Majuba Power Station is supplied from a subsystem called the Slang. All of these are still within the IVRS.

The water supply to Matimba and Medupi Power Stations is from this system, which is being developed in phases. Phase 1 supplies water from Mokolo Dam located in the region. The future water supply will be from the Crocodile River (West) and will be transferring excess return flows (treated water from Gauteng's sewage works) to the Lephalale Area. The water tariffs include statutory tariffs levied, operating and infrastructure costs as determined by the DWS's National Water Pricing Strategy. These future phases will have a significant impact on the pumping costs and the capital unit charges.

The costs are incurred before the water enters the power station. The meter for payment of the water is located before the power stations raw water storage reservoir. Eskom is billed by DWS on the reading as per these meters. When the water is consumed at the power stations, the costs that are incurred (primarily water treatment costs) are relatively small compared to the costs incurred before the power station.

25 Appendix 4 – Water treatment costs

Further information with regard to Eskom water treatment costs per power station is presented below.

TABLE 51: WATER TREATMENT COSTS PER POWER STATION

Water treatment R'million	Actuals 2016/17	Projection 2017/18	Application 2018/19
Kusile	0	2	6
Medupi	0	3	7
Duvha	13	20	23
Kendal	38	42	45
Lethabo	40	46	50
Majuba	35	35	38
Matimba	31	33	35
Matla	35	39	42
Tutuka	86	90	96
Arnot	40	41	44
Camden	7	6	7
Grootvlei	24	23	24
Hendrina	17	19	0
Komati	19	21	23
Kriel	39	44	51
Total Water Treatment cost	**423**	**465**	**490**

Water treatment costs in 2018/19 amount to 0.7% of the Total Eskom Generation Primary Energy costs of R67 015m. Water treatment costs for Total Generation costs increase by approximately CPI year-on-year. This is despite new units from Medupi and Kusile being commissioned in the period and thus adding costs to the Generation cost base.

25.1 Water Treatment Cost per process

TABLE 52: WATER TREATMENT COST PER PROCESS

Water treatment per process R'million	Actuals 2016/17	Projection 2017/18	Application 2018/19
Cooling water(85%)	360	395	417
Potable water(10%)	42	46	49
Demineralised water(5%)	21	23	25
Total Water Treatment cost	**423**	**465**	**490**

The split of water treatment costs per process was done in the same ratio as that of the water usage at a power station.

25.2 Cost of water treatment materials/chemicals

The other main drivers of water treatment cost are the cost of the chemicals used to treat the raw water. It is assumed that the costs of the chemicals will increase by CPI each year.