MYPD 3: Regulatory Clearing Account Submission to NERSA

FY2016/17

July 2017

Eskom

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Preface

This document summarises information submitted by Eskom Holdings (SOC) Ltd to the National Energy Regulator of South Africa (hereafter referred to as NERSA, or the Energy Regulator) pertaining to the Eskom's Regulatory Clearing Account (RCA) balance for the year 2016/17 and in accordance with the Multi-Year Price Determination Methodology published during December 2012 (hereafter referred to as the 'MYPD Methodology')[1]. This document contains the following:

1. Information provided in regard to Eskom's 2016/17 RCA balance (hereafter referred to as the '2016/17 RCA Submission' or year 4 of MYPD3) is lodged in accordance with section 14.2.1 of the MYPD Methodology.
2. Information is supported by Eskom's 2016/17 audited annual financial statements
3. Information is supported by NERSA's RCA 2013/14 reasons for decision published on 29 March 2016

1.1 The basis of submissions

The basis of this submission is derived primarily from **section 14 of the MYPD Methodology (published December 2012)** which provides for a Risk Management Device (S. 14.1) administered by way of the RCA (S. 14.2) i.e.:

"14.1 The risk of excess or inadequate revenues is managed in terms of the RCA. The RCA is an account in which all potential adjustments to Eskom's allowed revenue which has been approved by the Energy Regulator is accumulated and is managed as follows:

14.1.1 The nominal estimates of the regulated entity will be managed by adjusting for changes in the inflation rate.

14.1.2 Allowing the pass-through of prudently incurred primary energy costs as per Section 8 of the MYPD Methodology.

14.1.3 Adjusting capital expenditure forecasts for cost and timing variances as per Section 6 of the MYPD Methodology.

1 See in particular sections 14.0, 8.0 and 9.0 of the Multi-Year Price Determination Methodology 1st Edition, published December 2012

14.1.4 Adjusting for prudently incurred under-expenditure on controllable operating costs as may be determined by the Energy Regulator.

14.1.5 Adjusting for other costs and revenue variances where the variance of total actual revenue differs from the total allowed revenue. In addition, a last resort mechanism is put in place to trigger a re-opener of the price determination when there are significant variances in the assumptions made in the price determination."

The RCA is part of the overall MYPD Methodology, where section 14.1 confirms that the **RCA is intended to mitigate and manage the risk of excess or inadequate returns, and further that it does so by adjusting regulated revenue.** Section 14 further sets out that the costs and cost variances (to be recovered through such revenue adjustment) will be assessed for prudency.

1.2 The structure of 2016/17 RCA Submission

The structure of the summary of 2016/17 RCA Submission provided in this document is guided by the MYPD Methodology. With this in mind, an overview of the 2016/17 RCA submission is first provided summarizing the RCA inputs and balances as calculated by Eskom. This is followed by individual sections covering each of the RCA components as indicated in sections 14.1, 8 and 9 of the MYPD Methodology. The format of the summary of submission is as outlined below.

Summary of RCA Submission

I. Overview of the RCA Submission (Section 3)

II. Components of the RCA balance account (Section 3.1-3.12)

III. Revenue Variances (Section 5)

IV. Purchases from Independant Power Producers (Section 10)

V. Primary Energy - International Purchases (Section 11)

VI. Primary Energy - Coal Costs (Section 12)

VII. Primary Energy – Other costs (Section 13)

VIII. Primary Energy - Gas Turbine Generation Cost (Section 16)

IX. Capital Expenditure and Regulatory Asset Base (Section 17)

X. Operating Costs (Section 20)

XI. Service Quality Incentives (Section 21)

Eskom has provided reconciliations and reasons for variances between actual results and the MYPD3 decision. Thereafter the variances are applied to the MYPD Methodology to determine the amount of the respective components which qualify for the RCA balance.

The 2016/17 RCA Submission concludes with reasonableness tests such as EBITDA to interest cover ratio being assessed.

2 Objective

The objective of this 2016/17 RCA Submission is to provide the context for the Regulatory Clearing Account (RCA) process in terms of NERSA's MYPD Methodology requirements. The **2016/17 RCA Submission for the fourth year of the MYPD 3** period provides reasons for variances between actual results and the assumptions as made for purposes of the MYPD3 revenue decision.

This **submission is based on the MYPD Methodology, as published by NERSA during December 2012.** It is **further influenced by the MYPD3 RCA 2013/14 decision** made by NERSA on 1 March 2016 and the reasons for decision published on 29 March 2016.

The RCA process has two steps:

1. The **decision** on the **RCA balance** that is due to Eskom or the consumer, and
2. The RCA balance decision will then be subject to an **implementation decision** guiding subsequent adjustments in tariffs.

In summary the RCA mechanism allows Eskom the opportunity to achieve the initial revenue that was allowed during the MYPD3 revenue decision and to increase/decrease the allowed revenue due to changes in costs that are subject to re-measurement as outlined in the MYPD Methodology.

3 Overview of the 2016/17 RCA Submission

Eskom's 2016/17 RCA Submission is driven substantially by revenue under-recovery and higher primary energy costs to meet demand, whilst operating in an electricity system. The determined RCA balance of R23 786 million is motivated with evidence for prudent scrutiny by NERSA. This submission is increased by R83 million relating to the phasing in of the nuclear decommissioning provision from the 2013/14 RCA decision resulting in a total RCA balance of R23 869 million.

TABLE 1: SUMMARY OF 2016/17 RCA SUBMISSION

RCA for 2016/17 (Year 4 of MYPD3)	MYPD3 Decision	Actuals 2016/17	Variance to MYPD3	RCA adjustments	RCA 2016/17
Total Revenue R million	**198 035**	**175 094**	**-22 941**	**2 925**	**20 016**
Primary Energy , R million					
Coal	44 245	44 652	407	-766	-359
Open Cycle Gas Turbines (OCGTs)	1 599	340	-1 259	-	-1 259
Other primary energy	6 327	7 049	722		722
Independent Power Producers	19 269	21 721	2 452		2 452
International Purchases	399	2 681	2 282		2 282
Environmental levy	9 490	8 086	-1 404		-1 404
Demand Market Participation (DMP)	-	194	194		194
Total primary energy , R million	**81 329**	**84 723**	**3 394**	**-766**	**2 628**
CECA for RCA , R million	**46 655**	**58 924**	**12 269**	**636**	**636**
EEDSM for RCA , R million	**712**	**376**	**-336**	**336**	**-**
Operating costs for RCA , R million	**45 896**	**61 211**	**15 315**	**-**	**-**
SQI for RCA , R million	**-**			**343**	**343**
Inflation adjustments , R million	**-**			**162**	**162**
FY2017 RCA					**23785**
Nuclear decommissioning from RCA 2013/14 decision phased in over 10 years	**-**	**-**	**-**	**83**	**83**
Total RCA balance , R million					**23 868**

***Note 1**: Operating costs over expenditure are not allowed to be claimed as part of the RCA in terms of current MYPD Methodology*

3.1 Revenue

The revenue variance of R20 016 million which is calculated on Eskom's electricity revenue to all customers is due to lower electricity sales volumes. No load interruptions occurred in during 2016/17.

3.2 Primary energy

During the year, the introduction of new generation capacity, the improvement in power stations availability and higher IPPs has contributed to Eskom meeting demand requirements. This resulted is minimal utilization of OCGTs resulting in lower spend when compared to the MYPD3 decision.

Total primary costs incurred in 2016/17 was R84 723 million which exceeded the MYPD3 decision of R81 329 million by R3 394 million. This application provides for claw backs of coal (R359m) and OCGTs (R1259m). Eskom is claiming the extra spend of IPPs (R2452m), international purchases (R2282m), other primary energy (R722m) and DMP (R194m).

3.3 Environmental levy

The lower production volumes and the change in production mix resulted in Eskom incurring environmental levy costs of R1 404 million lower than the assumption made in the MYPD3 determination. The RCA caters for taxes and levies as a pass through item which requires that under expenditures are for the benefit of consumers in the RCA calculation.

3.4 Phased nuclear decommissioning provision per MYPD3 RCA 2013/14 decision

In its 2013/14 RCA decision, NERSA has allowed Eskom to claim the nuclear decommissioning provision of R830 million, over a period of 10 years, in equal installments of R83 million via future RCA liquidations. The first tranche of R83 million was granted in the RCA 2013/14 decision. Thus this application represents another installment.

3.5 Capital expenditure variance

Eskom Company capital expenditure of R58 924 million exceeded the NERSA decision of R46 655million by R12 269 million in 2016/17. The variance is attributable to higher costs incurred for new build projects, outage capital costs and partially reduced by lower expenditures incurred for the Transmission and Distribution networks; following Eskom's capital expenditure reprioritisation process. The technical and refurbishment capital expenditure is excluded when computing the balance for RCA purposes. For RCA purpose the capital expenditure clearing account (CECA) adjustment is R636 million in favour of Eskom.

3.6 Operating costs

The Methodology requires that “prudently incurred under expenditure on controllable operating costs” is paid back to consumers. However, when the situation is reversed the Methodology does not allow for prudently incurred overspend to be included in the RCA. During 2016/17 the operating costs expenditure of R61 211 million exceeds the decision of R45 896 million by R15 315 million and hence does not qualify for inclusion in the RCA balance. This implies that Eskom absorbs the over expenditure even though costs may have been prudently incurred in delivering electricity. The RCA Methodology allows for the impact of changes in inflation. The actual inflation was higher than the decision resulting in R162 million in favour of Eskom.

3.7 Energy Effiiciency and Demand Side Management (EEDSM)

Eskom’s energy efficiency and demand side management (EEDSM) programs produced more verified capacity (in MW) savings during the year resulting in a R336 million claim in Eskom’s favour. However, the MYPD Methodology does not allow for symmetrical treatment of EEDSM performance. Therefore this RCA reflects a zero impact relating to EEDSM.

3.8 Other income

Other income is included under the operating costs section.

3.9 Inflation adjustments

Section 14.1.1 of the MYPD Methodology states that “The nominal estimates of the regulated entity will be managed by adjusting for changes in the inflation rate.”

Inflation adjustments on operating costs amount to R162 million in favour of Eskom.

3.10 Service Quality Incentives (SQI)

Eskom has achieved the service quality incentive targets set by NERSA for Distribution and Transmission during 2016/17. This resulted in Distribution achieving an SQI of R263 million and Transmission of R80 million, equating to a total of R343 million.

3.11 Trend analysis of MYPD3 RCAs

The value of RCA submissions over the MYPD3 period is been consistently about R23 billion per annum as summarized in the table below.

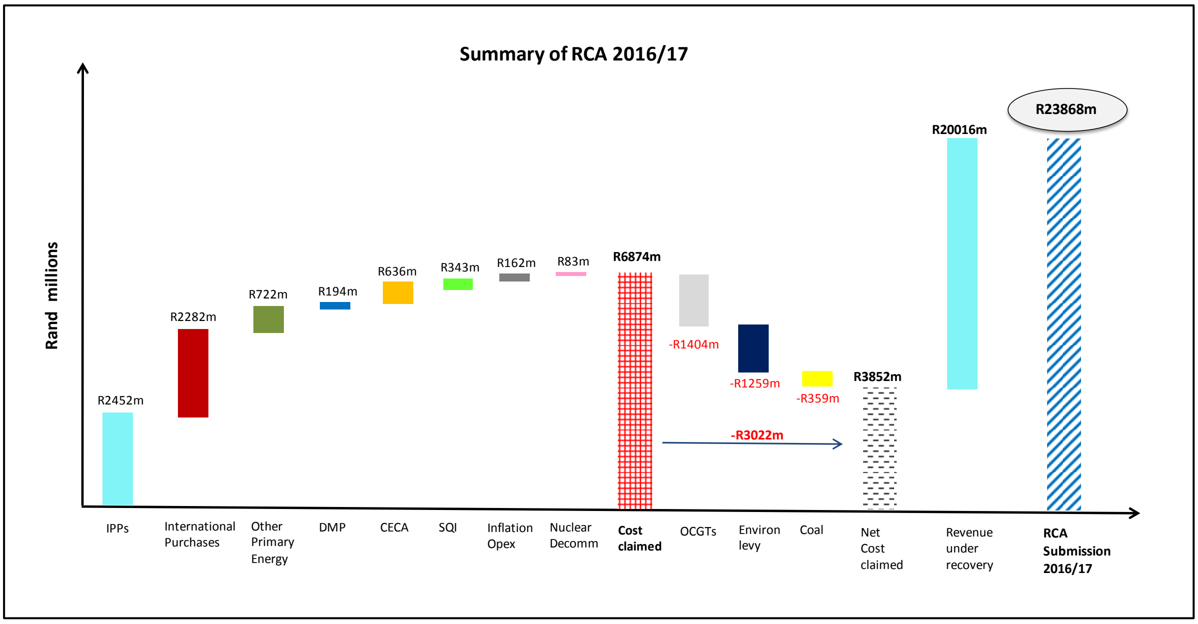
TABLE 2: RCA TREND ANALYSIS OVER THE MYPD3

MYPD3 RCA Trends	Decision RCA 2013/14	Application RCA 2014/15	Application RCA 2015/16	Application RCA 2016/17
Revenue	6 175	8 787	15 578	20 016
Independent Power Producers	580	4 346	620	2 452
International purchases	2 700	3 299	3 567	2 282
Coal	2 000	574	3 258	-359
Open Cycle Gas Turbines (OCGTs)	1 252	1 944	689	-1 259
Other primary energy	72	1 355	728	722
Environmental levy	-312	-683	-1 180	-1 404
Nuclear decommissioning of R830m from RCA 2013/14 decision phased in over 10 years	83	83	83	83
Nuclear decommissioning R361m from RCA 2015/16 decision phased in over 8 years	-	-	45	-
Energy Efficiency & Demand Side Management (EEDSM)	-432	-149	-368	-
Demand Market Participation (DMP)	-905	-379	248	194
Capital Expenditure Clearing Account (CECA)	9	91	332	636
Service Quality Incentives (SQI)	339	236	318	343
Inflation adjustment - Opex	33	209	-152	162
Other income	-353	-528	-134	-
RCA balance R'millions	**11 241**	**19 185**	**23 633**	**23 868**

3.12 Conclusion

In this submission **Eskom is paying back R3 022 million** comprising of coal burn (R359m), OCGTs (R1259m) and environmental levy (R1404m). **Eskom is claiming costs of R6 874m** consisting of other primary energy (R722m), DMP (R194 million), IPPs (R2452m), international purchases (R2282m) and other components (R1224m). Thus the net cost of R3 852 million is being claimed with the balance attributable to the **revenue under recovery of R20 016 million** linked to lower sales volumes. The RCA 2016/17 submission of R23 868 million excludes operating costs of R15 315 million which exceeded the MYPD3 decision.

FIGURE 1: WATERFALL CHART OF RCA 2016/17



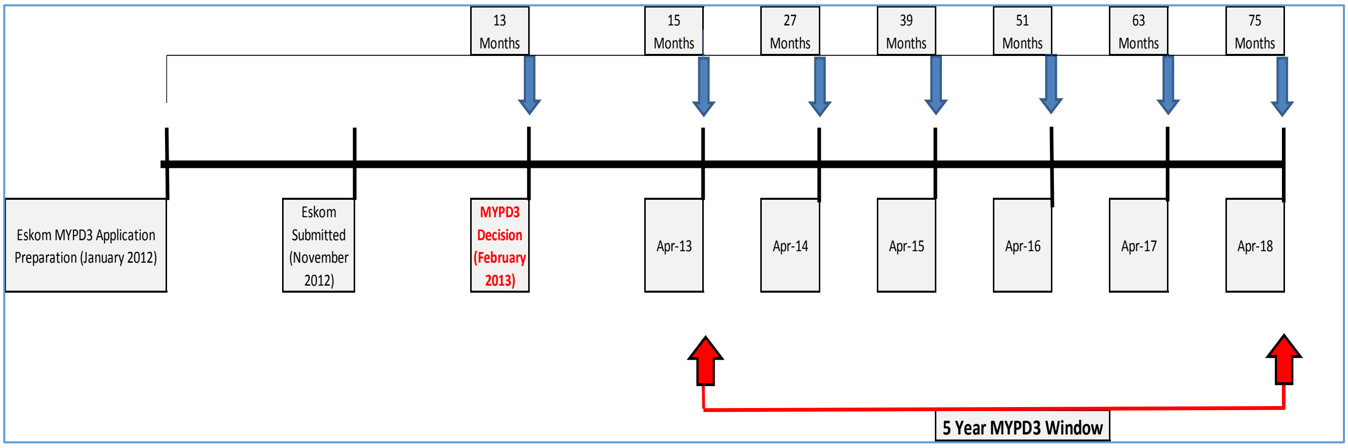
Finally the RCA 2016/17 submission of R23 868 million excludes operating costs of R15 315 million which exceeded the MYPD3 decision.

4 Factors impacting 2016/17 RCA Submission

4.1 Timeline for application and decision

The time lapse between Eskom preparing for the MYPD3 revenue application and its actual implementation date is at least 15 months. Taking into account that the MYPD3 is a 5 year decision it will potentially equate to a 75 month period in which many of the initial assumptions, policies, environmental and economic conditions will change. Thus the RCA mechanism will address the impact of these changes in assumptions made for the purpose of the revenue decision, compared to how it has unfolded in the actual mode.

FIGURE 2: TIME LAG BETWEEN APPLICATION AND ACTUALS



4.2 Changes in fundamental assumptions since MYPD3 application

TABLE 3: KEY ASSUMPTIONS WHICH HAVE CHANGED

MYPD3 Application	Current Situation	Comment
Sales forecast average growth of 2% p.a. assumed with a starting value of 222TWh in March 2013 reaching 239 TWh by March 2016.	Sales growth averaged a reduction of 0.9% from a starting value of 216.5TWh in March 2013 to 214.1 TWh in March 2017	Sales forecast did not materialise due to major changes in the assumptions plus the adverse global economic situation not recovering as anticipated
Generation plant performance (Energy availability factor – EAF) assumed at an average 82% for 2016/17.	Actual average EAF was 77% with a peak of 81% and low of 74% during the year.	Actual plant performance improved significantly over this period compared to FY2016.
New build commission dates for 1st units Medupi – June 2013 Kusile - 2016/17 Ingula – 2013/14 Sere – 2013/14	New build commissioning revised dates as follows: Medupi Unit6 – Aug 2015 Medupi Unit5 – Apr 2017 Kusile Unit 1- Sept 2017 Ingula – All units commissioned by Mar 2017 Sere – 31 Mar 2015	Over the past 18 months, Eskom has been meeting its revised commissioning dates.
Coal country compact < 10%price increases	Efficiency savings implemented through business productivity programme and design to cost initiatives.	Coal burn escalations dropped significantly in 2016/17 compared to historical trends. In fact coal burn variance is clawed back in favour of the consumer.
OCGTs – load factors assumed at 3% based on certain other assumptions materialising	OCGTs – actual load factors have been <1% in 2016/17	OCGTs usage reflects a successful turnaround with a significant under spend being clawed back in this submission.
IPPs – local and international	Increase in non-renewable IPP programs to contribute to balancing supply and demand.	At the time of the MYPD 3 application, non-renewable IPPs usage was not anticipated.
Capex – R337bn over the five year period	Capex – given the lower revenue decision, Eskom reprioritized capex to a projected portfolio of R251bn over the five year period.	In response to MYPD3 revenue decision Eskom has reprioritised capex spent which resulted in movements of expenditures between licensees.
Staff costs – complement of 43 000 growing to 46 000	Revised staff outlook decreasing staff complement to 41 238 by FY 2018	Business Productivity Program (BPP) savings initiative launched in the business reflects cumulative savings of R49 billion at 31 March 2017.
Maintenance	More maintenance was undertaken than initially envisaged	Better maintenance planning is reaping the rewards in terms of plant performance
Other Opex	Roll out of BPP saving plan and design to cost initiatives	Despite cost efficiency and saving programme other operating cost exceeded the decision

5 Revenue Variance

The objective of this section is to demonstrate and explain the revenue variance. It will provide reconciliation between the revenue disclosed in the 2016/17 Eskom annual financial statement (AFS) and the actual revenue to be used for RCA purposes to ensure the same reference point is used. In addition, it will explain why non-electricity revenue is excluded in the revenue variance calculation for RCA purposes.

5.1 MYPD Methodology

The regulatory clearing account (RCA) balance is calculated by determining the variances which arise by comparing the NERSA MYPD3 decision to the Eskom actuals for particular revenues and costs as provided for in the Methodology. The calculation of the revenue variance to be included in the RCA is in terms of paragraph 14.1.5 of the MYPD Methodology as shown below.

> 14.1.5 Adjusting for other costs [(5)] and <u>revenue variances where the variance of total actual revenue differs from the total allowed revenue</u>.
>
> *Footnote 5 as above: Includes but not limited to taxes and levies (as defined), sales volumes and customer number variances.*

Eskom company revenue is made up of electricity and non-electricity revenue. Eskom's electricity revenue is derived from 3 customer categories viz. standard tariffs, local special pricing agreements and exports (international) customers. Non-electricity is made up of deferred income recognized and other revenue.

The table below shows the sales volume and revenue variance with the total average price for all customers being marginally higher than the MYPD3 decision by 0.13c/kWh.

TABLE 4 : CALCULATION OF MYPD3 REVENUE VARIANCE FOR 2016/17

Revenue variance for 2016/17		MYPD3 Decision	RCA actuals	Variance
Total external electricity revenue	(R'm)	198 035	178 019	-20 016
Total external sales volumes	(GWh)	239 113	214 601	-24 512
Total average selling price	(c/kWh)	82.82	82.95	0.13

**Note* that the total external electricity revenue of R175 094 has been increased by the net revenue impairment adjustment of R2 925m to R178 019m (refer to table 5 below).*

5.2 Revenue computed on an equivalent basis

When computing the RCA balance, it is important to compare the same reference points. Eskom's annual report discloses Group and Company information. NERSA regulates substantially the Company performance with some adjustments required to present a like for like comparison to the MYPD3 decision.

The table below shows the items that need to be excluded from Eskom Company revenue in order to calculate revenue variance for RCA purposes

TABLE 5 : RECONCILIATION OF AFS REVENUE TO RCA REVENUE

Actual Revenue for RCA calculation in 2016/17 (R'million)	Eskom Company	Notes
Revenue per AFS	177 136	1
Less : Non-electricity revenue	**-2 042**	**2**
Deferred income recognised	-	
Other revenue	-2 042	
External electricity revenue	**175 094**	
Add : IAS 18 unrecognised revenue	2 925	3
Internal electricity revenue	-	
Revenue for RCA purposes (R' million)	**178 019**	

Note 1: Revenue as reported in Eskom's 2017 AFS:

Revenue from continuing operations of R177 136 million, reported on page 84 of Eskom's 2017 AFS, provides the starting point for obtaining the MYPD equivalent for actual revenue. Actual electricity revenue was R175 094 million; other revenue was R2 042 million (including deferred income of R271 million) for 2016/17.

TABLE 6: REVENUE NOTE FROM AFS FOR MARCH 2017

	Group 2017 Rm	Group 2016 Rm	Company 2017 Rm	Company 2016 Rm
32. Revenue				
Electricity	175 094	161 688	175 094	161 688
Other	2 042	2 551	2 042	2 551
	177 136	164 239	177 136	164 239

Electricity revenue of R3 196 million (2016: R1 647 million) was not recognised as it was assessed that there is a high probability that the related economic benefits will not materialise. In addition, R271 million (2016: R175 million) of previously not recognised revenue has now been recognised in the current year. Eskom continues to actively pursue recovery of these amounts. Refer to note 5.1.2(a).

Source: Eskom Annual Financial Statements, 31 March 2017, page 84.

Note 2: Basis for excluding non-electricity revenue

In terms of IFRS, other revenue and deferred income recognized are included in revenue. The accounting policy notes describe the nature of the originating transaction as follows:

Deferred income recognized and other revenue:

2.16 Payments received in advance

Payments received in advance consist mainly of capital contributions received from customers for the construction of assets and government grants received for electrification and energy efficiency initiatives.

Capital contributions received for the construction of regular distribution and transmission assets (with a standard supply) after 30 June 2009 are recognised in profit or loss within other revenue immediately when the customer is connected to the electricity network. Capital contributions received before 30 June 2009 are allocated to deferred income when the customer is connected to the electricity network (refer to note 2.17).

Government grants for energy efficiency initiatives are recognised in profit or loss within other expenses when the related expenses are incurred. Government grants for electrification are recognised in deferred income when the related asset has been connected to the electricity network (refer to note 2.17).

In contrast to IFRS, paragraph 6.1.5 states that "the RAB should, however, exclude any capital contributions by customers, though allowance will be made for electrification assets to allow for future replacement of such assets by Eskom at the end of their useful life".

It is therefore in the light of paragraph 6.1.5 that non-electricity revenue is removed from electricity revenue (not taken into account when calculating the revenue variance) and credited under capital expenditure (this will reduce capital expenditure and the return on assets).

Note 3: IAS 18 adjustment

In terms of IAS 18 electricity revenue of R3 196 million was not recognized as revenue as it was assessed that there is a high probability that the economic benefit will not materialize (i.e. high probability that not all revenue billed will be collected). In addition, R271m of previously not recognized revenue has now been recognised in the current year. Eskom continues to actively pursue recovery of these amounts.

However, for regulatory purposes this revenue is added back since in terms of the regulatory framework the sale of energy took place and non-recovery of revenue is currently dealt with in a different manner. The net impact of the IAS adjustment is R2 925 million which is added back to actual revenue for the RCA.

5.3 Allowed Revenue

The allowed revenue of R198 035 million as shown in the table below is derived from the NERSA documentation as shown in the extracts below comprising the MYPD3 revenue determination and the MYPD3 RCA decision.

TABLE 7: ALLOWED REVENUE

Allowed Revenue R'million	2016/17	Extract Ref
MYPD3 Allowed Revenue	186 794	1
MYPD3 RCA 2013/14 decision	11 241	2
Total Revenue	**198 035**	

Extract 1:

Source: NERSA's reasons for decision on Eskom's Regulatory Clearing Account Balance- Third Multi Year price determination (MYPD3) Year 1 (2013/14)

2. The Energy Regulator, at its meeting held on 30 September 2014, reconciled the original MYPD3 decision of 28 February 2013 (Table 2) to the revised decision as per Table 3 below. The purpose of the reconciliation was to adjust for the exclusion of the ancillary charges and to adjust the forecasted sales volume for standard tariff customers.

Table 3: The reconciled MYPD3 decision before MYPD2 RCA

	2013/14	2014/15	2015/16	2016/17	2017/18
Allowed revenue from tariff based sales (R'm)	135 226	147 481	163 179	180 070	198 954
Forecast sales to tariff customers (GWh)	206 412	208 442	213 545	218 194	223 219
Standard Average Price (c/kWh)	65.51	70.75	76.41	82.53	89.13
Percentage price increase (%)	8.0%	8.0%	8.0%	8.0%	8.0%
Total expected revenue from all customers (R'm)	143 101	156 057	171 769	186 794	205 214

Source: NERSA "MYPD3 ERTSA decision for 2016/17"

Extract 2:

Source: NERSA "The implementation plan of Eskom MYPD 3 Regulatory Clearing Account (RCA) for 2013/14

NATIONAL ENERGY REGULATOR

In the matter regarding

Eskom's Regulatory Clearing Account (RCA) Application – Third Multi-Year Price Determination (MYPD3) Year 1 (2013/14)

By

ESKOM HOLDINGS SOC LIMITED ('ESKOM')

THE DECISION

Based on the available information and the analysis of the Regulatory Clearing Account (RCA) Application for Year 1 (2013/14) of the third Multi-Year Price Determination (MYPD3) the Energy Regulator, at its meeting held on 01 March 2016 decided that:

1. the RCA balance of R11 241m be recoverable from the standard tariff customers, local SPAs and international customers in the financial year 2016/17;
2. the amount of R10 257m be recoverable from standard tariff customers for the 2016/17 financial year only;
3. the average tariff for standard tariff customers be increased by 9.4% for the 2016/17 financial year only;
4. the amount of R983m be recoverable from Eskom's local SPA customers and international customers for the 2016/17 financial year only; and

5.4 Sales volumes contribute to recovery of fixed costs

The MYPD3 allowed total revenue covers variable and fixed costs. The NERSA MYPD 3 RCA 2013/14 decision supports that Eskom is required to recover the allowed revenue as reflected in the MYPD 3 decision. However these revenues are only fully recovered if all the sales are achieved as assumed in the decision. Therefore, **in the event of lower sales materialising, it results in Eskom not recovering the allowed revenue components as was assumed.**

Eskom's allowed revenue in terms of the MYPD Methodology and MYPD3 decision is to cover variable costs (mainly primary energy) and fixed costs (operating costs + depreciation + returns). Eskom would still need to continue to incur these costs, 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. Operating and maintenance costs are not included in the determination of the RCA balance and not subject to RCA variance analysis, as higher expenditure on operating and maintenance (O&M) costs in the current MYPD Methodology cannot be recovered through the RCA by Eskom. Primary energy cost variances due to lower sales have been included in each of the primary energy cost elements in the RCA balance computation.

Fixed costs include interest and debt repayments which are represented by the return on assets and depreciation in the building blocks of the allowed revenue for regulatory purposes.

5.5 Allowed vs Actuals volumes

TABLE 8 : SALES VOLUME VARIANCE

Sales volume variance per tariff category (GWh) FY 2017	MYPD3 Decision	Actuals	Variance
NPA Sales	11 302	9 750	(1 552)
Add: Standard tariff sales including internal sales	218 193	189 845	(28 348)
Total Distibution sales	**229 495**	**199 595**	**(29 899)**
Add: International sales (see note 2)	9 618	15 006	5 387
Total sales to all customers (see note 1)	239 113	214 601	**(24 512)**
Less: Internal sales	(398)	(480)	(82)
Total external electricity sales	**238 715**	**214 121**	**(24 594)**

Actual external electricity sales volumes of 214 121GWh are disclosed in Annexure 3.

Note 1: *The 239 113 GWh is as per Table 54 from the NERSA MYPD3 decision. Refer table below.*

Note 2: *The international sales shown in the Annual Financial Statements reflect 15 093GWh (15 006GWh + 87GWh) which are based on the geographical location in which the sale occurred.*

For regulation the 87GWh is not shown as International sales as this is sold by Distribution and as such forms part of Distribution sales.

TABLE 9: APPROVED SALES VOLUMES FORECAST, MYPD3

GWh	2016/17
Standard tariff sales	218 193
Negotiated pricing agreement	11 302
Exports	9 618
Approved sales forecast	239 113

Source: Table 54 Approved Sales Volumes Forecast, MYPD3 Decision

5.6 Sales volume variance explanation

The MYPD forecast is normally finalized in the 2 years preceding the MYPD determination. This in itself poses a high risk as many economic assumptions can change during this period while the MYPD submission is analyzed and a determination is made.

In the case of MYPD3, the MYPD forecast was finalized on 14 September 2011 when the prospects for a higher economic growth were still viable as we recovered from the recession in 2007/08. At that time the GDP growth assumptions were still high.

The unfavorable variance in sales volumes against the MYPD NERSA decision was offset by the large favorable variance in the prepayment sales and export sales.

The table below highlights the difference between MYPD3 forecasts and actual reality that has transpired over the last four years.

TABLE 10: MYPD3 SALES VOLUME

Total Eskom Sales (GWh)	2012/13	2013/14	2014/15	2015/16	2016/17
MYPD3 Sales (GWh)	222 756	227 403	229 513	235 638	239 113
MYPD3 Sales Growth %	-1.10%	2.09%	0.93%	2.67%	1.47%
Actual Sales (GWh)	217 022	218 368	217 097	215 149	214 601
Actual Sales Growth %	-3.66%	0.62%	-0.58%	-0.90%	-0.25%

5.6.1 The process in deriving the 5 year forecast

The 5 year sales forecast used in the application was compiled using a bottom up approach from customer level. Each of the six Eskom Regions forecasted the Regional sales (covering the 9 provinces) using a bottom up approach from customer level for their specific Regions. Each Regional forecast were scrutinized on a one on one basis after which the six Regional forecasts and the Top Industrial Customer’s forecast were consolidated into one Eskom view.

5.6.2 Critical changes in assumptions relevant during 2011 in deriving forecasts

TABLE 11 : GDP FORECASTS USED FOR MYPD3 IN 2011

GDP growth %	2012	2013	2014	2015	2016	2017
MYPD3 GDP growth %	4.0%	4.0%	4.0%	4.5%	5.0%	5.0%
Actual GDP growth %	2.2%	2.2%	1.5%	1.3%	0.3%	

- The actual GDP growth rates were approximately half the forecasted assumptions as received from various economic forecasts at the time for the first part of MYPD3; declining to about 20% of the forecast in the last 2 years.
- The most growth in recent decades has been in the less energy intensive services sectors, while the contribution of the energy intensive industrial and mining sectors declined rapidly.
- A substantial amount of furnace load has not been utilised in winter because of the higher winter prices. Furnaces were taken out for maintenance in winter.
- Municipality and other STPPP generation assumed for inclusion of Power Purchase Agreements (PPAs) continued up to the end of the 2016/17 financial year; a much longer period than anticipated that has off-set the drop in sales from other sectors.
- The forecasted commodity prices used in the MYPD3 were higher than the actual average commodity prices that were realised.

TABLE 12: COMMODITY PRICES ASSUMED

Commodity Prices	MYPD3 Decision	Actual
FeCr	$1.20/lb - $1.32/lb	$0.96/lb
Aluminum	$2 500/ton - $2 750/ton	$1 604/ton
Platinum	$1 480/oz - $2 000/oz	$986/oz

- High probability new projects were included but were delayed with the downturn of the economy and much lower commodity prices.
- Average weather conditions have been used.

5.6.3 Sales volume variance explanation for FY2017

The table below shows the sales volume variance that will provide the reasons for the decrease in sales volumes compared to the decision.

TABLE 13 : SALES VOLUME VARIANCE

Sales volume variance per customer category (GWh)	Actual Sales	MYPD 3	Variance
International	**15 005**	**9 618**	**5 387**
Distribution sales	**199 596**	**229 495**	**(29 899)**
IPP Network Charge	52	-	52
Re-distributors	89 666	100 176	(10 510)
Industrial	48 295	61 697	(13 402)
Mining	30 559	37 191	(6 632)
Traction	2 849	3 133	(284)
Residential	3 911	4 591	(680)
Commercial	10 339	9 903	436
Agricultural	5 405	5 344	61
Prepayment	8 115	6 972	1 143
International A	87	90	(3)
Internal Sales	480	398	82
Other	(162)	-	(162)
Total electricity sales volumes	**214 601**	**239 113**	**(24 512)**
Exclude Internal sales	-480	-398	(82)
Total external electricity sales volumes	**214 121**	**238 715**	**(24 594)**

From the table above, which reflects the variance between the decision and actual sales for the year 2016/17, it can be seen that the unfavorable variance of 29 899 GWh in respect of distribution sales is mainly due to three categories, namely Re-distributors, Industrial and Mining. The unfavorable variances in these three categories were partially offset by the favorable variance of 5 387 GWh from the international sales and 1 143 GWh from the prepayment environment.

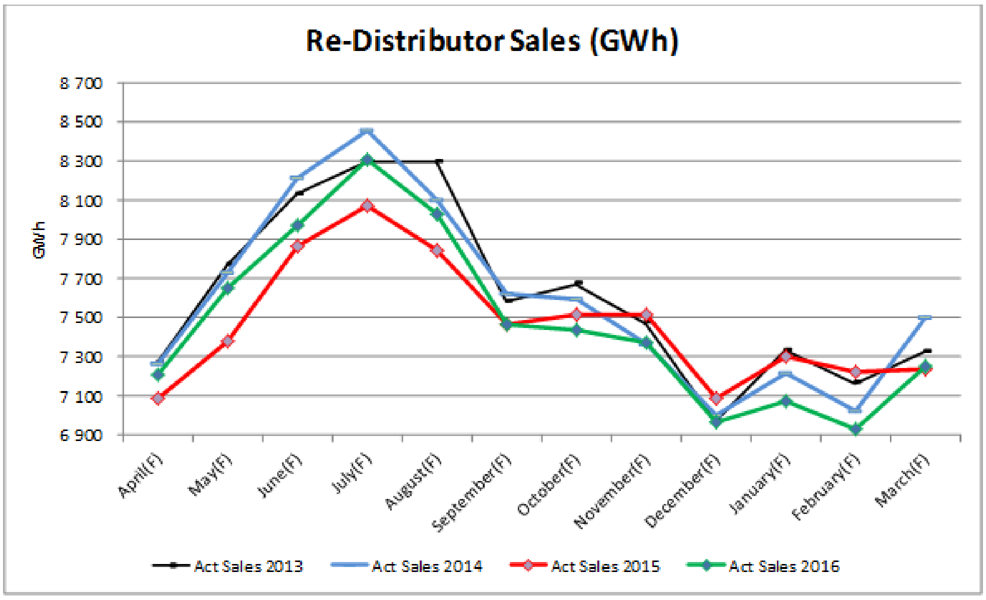
5.6.3.1 Redistributors: 10 510 GWh unfavourable

The unfavorable variance in this category is spread over most of the Redistributors are mainly due to the following:

- The largest unfavorable impacts are seen in the City Power and Ekurhuleni Metro's due to the sluggish economic growth. City Power and Ekurhuleni are within the economic hub of South Africa and thus severely affected by the slow local & global economic growth.
- In the Southern Region the expectation was that the Coega development project would have started up but due to the absence of "the anchor project", very little development have materialized up to this point.

- Cape Town Municipality introduced a huge savings drive to save 10% of their total consumption.
- Other Metro's and Municipalities were also severely negatively affected due to the slow local & global economic growth.
- In eThekwini Metro, a large customer, Tata Steel closed down. In addition the sluggish economic growth resulted in a substantial decline in sales growth.
- In 2016 the abnormal low summer temperatures also reduced the energy consumption.
- Due to the Global economy that did not pick up as expected as well as the fluctuation of the ZAR exchange rate, the manufacturing sector behind the bulk meters in the municipalities were not able to secure orders, thus producing less with a resultant drop in energy consumption.
- Due to the price increases, price elasticity also played a role resulting in savings from customers, especially in the lower LSM's.
- DSM initiatives also impacted the sales negatively due to the roll outs of CFL's, installation of PV panels and installation of solar geysers.
- The closure of EB Steam customers by Eskom also affected the variance unfavourably especially in the Western Cape, Eastern Cape and KZN as they were included in the assumptions of the MYPD decision.

FIGURE 3 : PERFORMANCE OF RE-DISTRIBUTORS



5.6.3.2 Industrial: 13 402 GWh unfavourable.

This category was the most severely affected category and it is mainly due to the following:

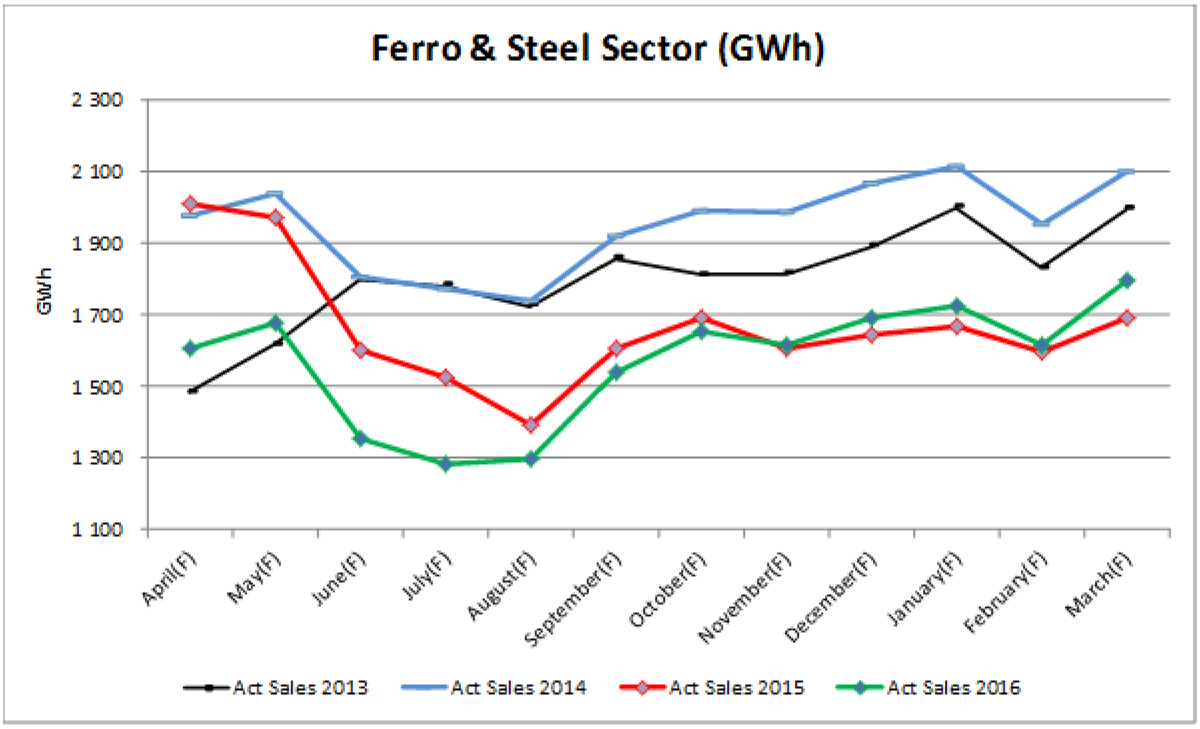
- The Aluminium sector posted a decline of 1 760 GWh mainly resulting from the closure of the Bayside smelter (1 679 GWh) and the very weak commodity price which forced production cuts due to a drop in world demand for Aluminium.
- Sasol Infra Chem commissioned their own gas generation plant and displaced 324 GWh from the “Manufacturing of basic Chemicals” sector.
- The Ferro and steel smelting industry realized a drop in consumption against the MYPD NERSA decision of 10 591 GWh due to the low demand for their products as a result of the collapse of commodity prices and cheaper imports from China that led to diminishing orders and downsizing and closure of customers. Refer to the table below on commodity prices.
- As a result the smelting industry opted to take furnaces out during the three winter months to save on costs due to the winter price of electricity.
- Many customers are downsizing and some considering full closures as a result of a low demand for their product. The combine impact of three customers Highveld steel, IFM and ASA metals is a reduction in demand of 4 271 GWh.
  - The Titanium sector posted a decline of 1 157 GWh mainly due to the drop in world demand for their product and the resultant very weak commodity price. This caused the partial closure of furnaces at RBM (843 GWh) which forced production cuts at the plant.
  - The closure of EB Steam customers also affected the sales unfavourably.

TABLE 14 : COMMODITY PRICES

	Unit	2014 CY	2015 CY	2016 QI
Copper	$/tonne	6,862	5,515	4,700
Aliminium	$/tonne	1,867	1,658	1,380
Zinc	$/tonne	2,164	1,942	1,600
Nickel	$/tonne	16,867	11,827	9,000
Lead	$/tonne	2,096	1,790	1,720
Tin	$/tonne	21,893	16,062	14,000
Manganese ore	$/mtu CIF	4,5	2,9	1,9
FeCr (EU contract)	c/lb	119	107	92
Molybdenum oxide	$/lb	11	7	5
Cobalt (99.8%)	$/lb	14	13	12
Steel Average HRC	$/tonne	598	417	343
Steel Scrap - average #1HMS	$/tonne	327	209	155
Iron Ore- Australian Fines	c/mtu fob	142	81	70
Iron Ore- Australian Lump	c/mtu fob	166	100	82
Spot 62% Fe iron ore China	$/t cfr	97	55	48
Thermal Coal- Australian Spot	$/t fob	71	59	53
Thermal Coal- JFY contract	$/t fob	82	68	82
Hard coking coal	$/t fob	126	102	81
Semi-soft coking coal	$/t fob	93	78	65
LV PCI coal	$/t fob	104	84	69
Coke - China export spot	$/t fob	195	145	110
Gold	$/oz	1,266	1,157	1,140
Silver	$/oz	19	16	15,10
Platinum	$/oz	1384	1,051	875
Palladium	$/oz	803	692	580
Uranium Spot	$/lb	33	37	36
Rhodium	$/oz	1,206	961	750
Rand basket price	ZAR/oz	12,991	11,762	11,031

Source: LME, Platts, CRU, Metal Bulletin, Marquarie Research, March 2017

FIGURE 4 : PERFORMANCE OF FERRO AND STEEL



5.6.3.3 Mining: 6 632 GWh unfavourable

This category was also affected severely and it is mainly due to the Gold and Platinum sectors:

Mining production in South Africa slumped year-on-year in 2016, according to figures from Statistics South Africa. The biggest factors affecting production are commodity prices, followed by cutbacks, official and unofficial go slows, Section 54 and 55 safety stoppages and strikes.

- The Platinum sector realized a 3 397 GWh drop in consumption against the MYPD NERSA decision mainly due to:
  - Labour unrests which caused shaft closures.
  - The unfavourable Platinum price and demand for platinum that negatively affected the start-up of projects (delayed in the hope of an upturn in the markets) while others were cancelled
- Section 54 and 55 safety stoppages.
- The Gold sector realized a 2 509 GWh drop in consumption against the forecast due cost pressure as a result of labour unrest and high salary increases. This again caused high cash costs and resulted in down scaling and shaft closures in many of the Gold

mines. Some Gold mines were liquidated while others closed their shafts. Many shafts were put under care and maintenance due to cost pressures. The unfavourable commodity price also played a major role in escalating the cost pressures.

5.6.3.4 Prepayment: 1 143 GWh favourable

In the Prepaid environment a significant favorable variance against the MYPD NERSA decision was realized mostly in the Northern Region due to the changing of the supply group codes that eliminated most of the ghost CDU's in that Region, resulting in higher Sales volumes than anticipated in the MYPD NERSA decision.

5.6.3.5 International: 5 387 GWh favourable

The favourable variance against the MYDP3 NERSA decision was mainly due to the higher than budgeted sales caused by the drought experienced in the neighboring countries.

The drought impacted the Southern African region throughout 2016/17, resulting in reduced available hydroelectric capacity in the DRC, Zambia and Zimbabwe. This provided Eskom with an opportunity to realise additional electricity sales. Non-firm electricity sales were made to ZESCO and the Copper belt Energy Corporation, both of Zambia, and ZESA of Zimbabwe. The lower water levels at the Gove dam also led to reduced generation specifically at Ruacana which resulted in increased sales to NamPower.

5.7 Conclusion on the sales volume and revenue variance

The revenue variance calculated and explained above is consistent with the requirements of the Regulatory Framework i.e. rule 14.1.5. Eskom believes they have supplied the necessary explanations required for the sales volume and revenue variance of R20 016m in 2016/17.

6 Impact of demand responses on sales volumes

As part of the MYPD3 determination, NERSA allowed for demand response initiatives to be utilised which comprise EEDSM and DMP for 2016/17. Embedded in Eskom's MYPD3 application was an assumption for EEDSM which was taken into consideration when determining the sales forecasts. In the 2016/17 year, NERSA assumed 939 GWh of energy savings at a cost of R712 million which culminated in 196 MW of capacity savings.

In reality, EEDSM achieved higher verified savings during the year of 290 MW of capacity. However, in terms of the RCA Methodology - EEDSM will incur penalties for under achieving their targets and EEDSM is not compensated for MW savings exceeding MW savings in the decision.

In addition, NERSA assumed DMP costs of zero in 2016/17 while actual expenditure was R194 million.

7 Collectability of revenue does not impact RCA

It is important to note that the revenue variance compares the revenue as reflected in the audited annual financial statements. For RCA purposes the risk of uncollectibility is removed as the amount deducted in the annual report under IAS18, R2925 million is added back. This means that revenue is recognized on the basis of billed revenues. Thus **collectability of revenue** and ability for consumers to pay are excluded in revenue amount and thus **excluded** in the **revenue variance for RCA purposes** which **implies that all revenue billed is assumed to be collected.**

8 Prudency and Efficiency

South African Legislation

Section 16(1) (a) of the Electricity Regulation Act determines that

"*A licence condition determined under section 15 relating to the setting or approval of prices, charges and tariffs and the regulation of revenue -*

(a) must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return". This principle is confirmed by the Electricity Pricing Policy, which also states that "*…. an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future …..*"

International references:

The concept of 'prudence' is usually defined as "*a test of reasonableness of the* [utility's] *decision under all of the circumstances known at the time*". The majority of regulatory jurisdictions in the US that conduct prudence reviews have adopted this common definition – e.g. the Missouri Public Service Commission have defined prudence as:

"[The] company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company …… In accepting a reasonable care standard, the Commission does not adopt a standard of perfection. Perfection relies on hindsight. Under the reasonableness standard relevant factors to consider are the manner and timelines in which problems were recognized and addressed. Perfection would require a trouble-free project".

The Australian Energy Regulator states the following in a 2013 document:

"*Prudent expenditure is that which reflects the best course of action, considering available alternatives*"

"*In ex post reviews, however, we must account for only information and analysis that the NSP* [Network service provider] *could reasonably be expected to have considered or undertaken when it spent the relevant capex*"

"*However, in determining whether capex meets the criteria, we must account for only information and analysis that the NSP could reasonably be expected to have considered or undertaken when it undertook the relevant capex*".

Conclusion:

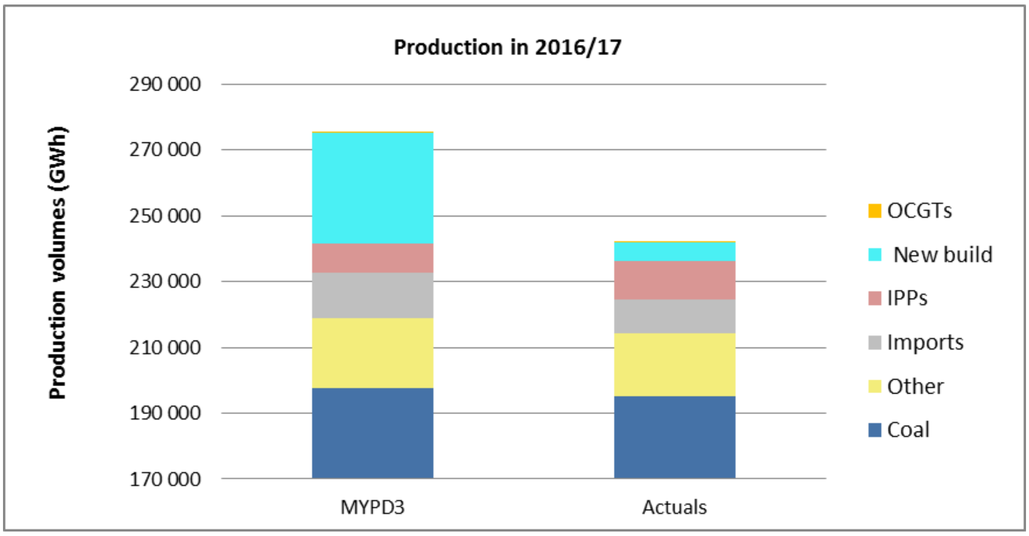
In compiling this document Eskom has adhered to globally-accepted standards of sound regulation

9 Factors which influence Eskom production plans

Sales are a critical factor which influences production plans. Demand side options are incorporated in the eventual sales requirements which must be met by a corresponding production plan. In addition to sales, supply options from new build capacity, local and regional supply sources plus the performance and maintenance requirements of the existing fleet all contribute to the eventual production plans.

Due to changing assumptions and environment, the figure below outlines the change between the assumed production plans and the actual production results. At a glance the drop in sales requirements by some 25TWh, new build commissioning dates, performance of existing coal fleet and levels for IPPs and OCGTs all contribute to the actual production results. The details surrounding the supply options and new build commissioning including the Generation power station performance will be discussed later in the document. The volumes of electricity produced will drive the cost impacts under primary energy which will be explained in the next section.

FIGURE 5: PRODUCTION FY 2017



10 Primary energy

Eskom has aligned the treatment of primary energy to the 2013/14 RCA decision which looks at primary energy on a total company approach. This means that total primary energy now includes international purchases when compared to the MYPD3 decision.

10.1 Primary energy variances and RCA impact for 2016/17

Total primary energy allowed for 2016/17 was R81 329 million. Eskom incurred R84 723 million in the year which resulted in an extra cost of R3 394 million. However, not all the cost variances qualify for RCA inclusion. In particular the following RCA adjustments were processed:

1. Coal costs – Medupi take or pay and Kusile risk sharing amounts have been excluded where no coal burn materialised.
2. Coal costs – Applying the MYPD Methodology requires that the coal burn component is subject to an alpha adjustment
3. Nuclear decommissioning provision: Implementation of the 2013/14 provision of R830 million in ten equal tranches as per the 2013/14 RCA decision. i.e. R83m inclusion in the 2016/17 RCA and
4. IPP's – In terms of IFRS, a portion of the Dedisa contract is accounted for under "IFRIC 4 Determining whether an arrangement contains a lease". However for regulatory purposes, an adjustment of R1 964 million is deemed to be accounted for as an IPP purchase.

Hence the sum of all these adjustments is R766 million and thereby reduces the total primary energy variance to R2 628 million. Refer table below for the RCA calculation for total primary energy.

TABLE 15 : TOTAL PRIMARY ENERGY COMPARISON AND RCA IMPACT FOR 2016/17

Primary Energy , R million	MYPD3 Decision	Actuals 2016/17	Variance	RCA adjustments	RCA 2016/17
Coal	44 245	44 652	407	-766	-359
Open Cycle Gas Turbines (OCGTs)	1 599	340	-1 259		-1 259
Independent Power Producers	19 269	21 721	2 452		2 452
International Purchases	399	2 681	2 282		2 282
Environmental levy	9 490	8 086	-1 404		-1 404
Water	2 188	1 751	-437		-437
Start-up gas & oil	1 695	2 227	532		532
Coal handling	1 257	1 758	501		501
Water treatment	298	423	125		125
Nuclear	446	727	281		281
Fuel procurement	304	163	-141		-141
Sorbent usage	139	0	-139		-139
Demand Market Participation	-	194	194		194
Primary energy , R million	**81 329**	**84 723**	**3 394**	**-766**	**2 628**
Nuclear decommissioning from RCA 2013/14 decision phased in over 10 years				83	83
Total primary energy variance R million	**81 329**	**84 723**	**3 394**	**-683**	**2 711**

Source: Allowed total primary energy -table 17, MYPD3 decision; Actuals - Primary energy note 34, AFS, March 2016

Extract from the AFS, March 2017 reflects the actual total primary costs of R82 760m below.

TABLE 16: PRIMARY ENERGY ACTUAL COSTS PER NOTE 34 IN THE AFS OF 2017

	Group 2017 Rm	Group 2016 Rm	Company 2017 Rm	Company 2016 Rm
34. Primary energy				
Own generation costs	52 042	57 594	52 042	57 594
Environmental levy	8 086	8 120	8 086	8 120
International electricity purchases	2 681	3 660	2 681	3 660
Independent power producers	19 757	15 106	19 757	15 106
Other	194	248	194	248
	82 760	84 728	82 760	84 728

Own generation costs relate to the cost of coal, uranium, water and liquid fuels that are used in the generation of electricity. Eskom use a combination of short-, medium- and long-term agreements with suppliers for coal purchases and long-term agreements with the DWA to reimburse the department for the cost incurred in supplying water to Eskom.

Note A:

For regulatory purposes, the IFRIC 4 adjustment for IPPs which capitalises a portion of the DOE Peaker costs is reversed as the MYPD Methodology allows for full pass through of IPP expenditure. Therefore the total for IPP's in the AFS of R19 757 million is increased by R1 964 million resulting in a total for IPP's of R21 721 million.

With the summary information disclosed, the next section will provide more detail on the respective primary energy components.

10.2 Independent Power Producers

Eskom acknowledges the role that IPPs must play in the South African electricity market and remains committed to facilitating the entry of IPPs, to strengthen the system adequacy and meet the growing power demand. Eskom has procured a combination of short, medium and long term supply from IPPs.

10.2.1 Medium-term Power Purchase Programme (MTPPP)

Eskom initiated the MTPPP in 2008 in order to procure base-load capacity from private generators. The total capacity procured under the MTPPP amounted to 294 MW (excluding one contract that was awarded but never became operational due to the IPP failure to meet obligations). The 13MW remaining under this programme expired on 31 March 2017.

10.2.2 Municipal Base-load Purchases

Eskom's contract with City Power for 250MW expired on 31 March 2017. On 27 January 2017 the maximum contract value of the City Power contract was reached, with no energy purchases from that date until expiry.

10.2.3 Short-term Power Purchases Programme (STPPP)

The capacity constraints also prompted Eskom to launch the STPPP in order to attract additional capacity from private generators on a short-term basis. Short-term contracts with private generators with a combined contracted capacity of 812.3MW.
Short-term contracts with private generators with a combined contracted capacity of 557MW expired on 31 March 2017.

10.2.4 Wholesale Electricity Pricing System (WEPs) programme

Eskom enters into annual contracts at wholesale prices with co-generators outside the ambit of the MTPPP and short-term contracts. A total of 92MW of capacity has been contracted during the year to March 2017. These contracts expired on 31 March 2017 and were not renewed.

10.2.5 Long-term IPP programmes

In the procurement process for DoE's long-term IPP programmes, Eskom's role is that of network operator, where Eskom owns the network and grid connection infrastructure, as well as the designated purchaser of energy supplied.

10.2.6 IPP open cycle gas turbine ("Peaker") programme

Power purchase agreements of 1 005MW were entered into for the Avon and Dedisa plants. Dedisa was commissioned on 30 September 2015 (335MW), while the commissioning of Avon (670MW) took place on 20 July 2016.

The load factors for the year to March 2017 have been much lower than target, due to the lower dispatch requirement from Eskom. With lower volumes, the fixed capacity charge increases the unit cost of OCGT Peakers power.

10.2.7 Renewable Energy Independent Power Producer (RE-IPP) procurement programme

The DoE launched the RE-IPP Programme during 2011, which called for 3 725MW of renewable energy technologies in commercial operation between mid-2014 and the end of 2016. Developers were invited to submit proposals for the financing, construction, operation, and maintenance of any onshore wind, solar thermal, solar photovoltaic, biomass, biogas, landfill gas, or small hydro technologies. This has since been extended with additional Ministerial Determinations (adding 3200 MW in 2012 and 6300 MW in 2015).

Renewable projects with signed power purchase agreements are in various stages of construction. New operational contracts during the year include 449MW wind, 509MW solar PV, 4MW hydro and 3MW landfill gas.

TABLE 17: RENEWABLE IPP AGREEMENTS

MW	Mar-17	
	Signed Contracts	Operational Contracts
RE-IPP	4 000	3 110
Load Factor %	-	30.7

Deemed energy expenditure of R477 million was incurred during the year (R24 million for year to March 2016), due to delays in grid connection for a number of projects, as well as system curtailment events.

TABLE 18: IPP OPERATIONAL CAPACITIES BY TYPE AND LOCATION AT 31 MARCH 2017

Province, MW	RE-IPP Programme					Diesel	Other short term	Total
	Concentrated solar power	Photo-voltaic	Hydro and biomass	Wind	Landfill			
Eastern Cape		70		947		335		**1 352**
Free State		196	4				114	**314**
Gauteng					3		250	**253**
KwaZulu-Natal						670	123	**793**
Limpopo		118						**118**
Mpumalanga							423	**423**
Northern Cape	200	950	10	153				**1 313**
North West		7						**7**
Western Cape		134		319			2	**455**
Total	**200**	**1 475**	**14**	**1 419**	**3**	**1 005**	**912**	**5 028**

1. Capacities (MW) indicate the contract maximum (or operational capacity if lower).

2. Other short-term refers to hydro, biomass, coal, gas turbines and engines, mixed fuels, etc. of which 460MW relates to coal and 253MW to gas turbines and engines.

10.3 Legal basis for IPPs per the MYPD Methodology

Section 9 in the MYPD Methodology deals with the treatment of IPPs:

9.1 In accordance with the provisions of Section 14(f) of the Electricity Regulation Act, the Energy Regulator shall, as a condition of licence, review power purchase agreements (PPAs) entered into by licensees before signature. This also includes all PPAs considered under the Ministerial Determination by the Department of Energy (DoE). In evaluating the MYPD, the cost associated with the Independent Power Producers (IPPs) will be done based on the conditions of the respective PPAs.

9.2 The Energy Regulator will review the efficiency and prudency of the IPP before and after PPA contracts are concluded.

9.3 Purchases or procurement of energy and capacity from IPPs, including capacity payments, energy payments and any other payments as set out in the PPA, will be allowed as a full pass-through cost.

9.5 Energy output (deemed payments) that would otherwise be available to the buyer but due to a System Event or a Compensation Event (e.g. system unavailability) was not incurred in accordance with provisions of power purchase agreements reviewed by the Energy Regulator, will be allowed as full pass-through costs.

9.10 The variances (i.e. difference between MYPD allowed costs and actual incurred costs) together with reasons shall be presented to the Energy Regulator. After the review, the variance will be debited/credited to the RCA.

10.4 IPP Approvals

All the IPP Power Purchase Agreements (PPA) entered into during the MYPD3 period was approved as part of the licensing process by NERSA prior to being finalised and signed. Eskom has secured recovery of costs associated with all IPP contracts in accordance with the regulatory rules for power purchase cost recovery.

10.5 Regulatory rules for power purchase cost recovery

The following are extracts of relevant portion of the regulatory rules for power purchase cost recovery as published in November 2009:

14 Pass through of costs

For authorised power purchases, net recoverable costs will be passed through to customers via an adjustment of the buyer's revenue allowance (albeit subject to review by NERSA as set out in rule 17 below). This will require a reconciliation of accounts comparing forecast recoverable costs to actuals.

17 Duration

17.1 An authorisation for power purchase cost recovery should remain valid for the duration of the relevant PPA. Investors will need to be confident in the buyer's ability to make payments into the future, and the buyer will need an appropriate level of regulatory certainty in regard to its recovery of power purchase costs.

17.2 For the avoidance of doubt, the review process set out in rule 16 is limited to reconciling cost variances and draw-down of the power purchase account balance, and is not a retrospective review of the general authorisation or the basis on which cost effectiveness was established.

10.6 Allowed vs Actual IPP costs for 2016/17

Eskom was awarded a total of R19 269 million for IPP's in the MYPD 3 decision for 2016/17. This includes IPP ancillary costs of R97 million.

Actual costs amounted to R 21 721 million resulting in extra spend of R 2 452 million.

Note: *The IPP purchase volumes (Energy) for the NERSA decision were inferred from the costs associated with each programme as no energy was disclosed in the MYPD3 decision. Eskom utilized 3 098 GWh more energy from IPPs when compared to the MYPD3 decision in 2016/17.*

A summary of the costs and volumes from IPPs are presented in the table below:

TABLE 19: IPPS COSTS AND VOLUMES

Independent Power Producers	Cost (R'm)			Volumes(GWh)			Average Costs (R/MWh)			Note
2016/17	Actuals	Decision	Variance	Actuals	Decision	Variance	Actuals	Decision	Variance	Ref
Non-Renewable	**3953**		**3953**	**4235**	**0**	**4235**	**933**			
MTPPP	37		37	29		29	1 276			**A**
STPPP	2861		2861	3003		3003	953			**B**
Municipalities	985		985	1098		1098	897			**B**
WEPS	70		70	105	0	105	667			**C**
Renewable IPP's	**15582**	**16386**	**-804**	**7227**	**7991**	**-764**	**2156**	**2051**	**106**	
Renewable IPP Energy	15105	16386	-1281	7227	7991	-764	2156	2051	106	**D**
Renewable IPP - Deemed Energy Payments	477		477							**D**
DOE Peaker	**2186**	**2786**	**-600**	**67**	**440**	**-373**	**32627**	**6332**	**26295**	**E**
Total IPPs	**21721**	**19172**	**2549**	**11529**	**8431**	**3098**				
IPP Ancilliary Cost	0	97	-97							**F**
Total IPP for RCA	**21721**	**19269**	**2452**	**11529**	**8431**	**3098**				

Note: *The actual costs include the RCA adjustment amount relating to IFRIC 4 adjustment.*

10.6.1 Reasons for IPP variances in 2016/17

Eskom utilized 3 098 GWh more energy from IPPs when compared to the MYPD3 decision in 2016/17, resulting in R2 452 million more spent on IPPs compared to the MYPD3 decision.

A. Medium Term Power Purchase Programme (MTPPP)

At the time of the MYPD3 application it was expected that the MTPPP contracts would have expired by FY 2016. The delay in the new build has necessitated the extension of the last MTPPP contract resulting in the additional energy purchases and additional cost.

Volume variance: There is only one IPP remaining in the MTPPP. As a gas turbine (operating on piped gas) the generator has significant flexibility and operates in a mid-merit basis. This is in line with the contract parameters and is encouraged through differential pricing between the peak and off-peak periods.

Price variance: As mentioned above the last IPP under the MTPPP operates on a mid-merit basis and thus benefits from the higher price applicable over the peak period in the contract (defined as between 06h00 and 22h00).

B. Short Term Power Purchase Programmes (STPPP)

At the time of the MYPD3 application it was expected that the short term contracts would be phased out during FY 2015 as the system capacity shortfall was ameliorated by Eskom new build. The delay in the new build has necessitated the extension of the STPPP and municipal generation contracts leading to the increased purchase volumes and associated costs.

C. WEPS

The WEPS price reflects the NERSA approved WEPS tariff. Eskom buys energy from embedded generators at the average energy rate as determined by NERSA in the approved WEPS tariff. These contracts are annual contracts limited to generators ability to connect to the Eskom Distribution network at above 1 kVA. These were not included in the NERSA revenue determination.

D. Renewable IPPs

Price variance: Prices were marginally higher due to price adjustments between bid announcement and financial close, offset by lower actual CPI escalations (compared to forecast).

Volume variance: The volumes produced by REIPP generators were lower than that assumed in the NERSA MYPD3 determination. There were significant delays in the implementation of bid window 3 caused by delays in financial close as well as some REIPPP projects that experienced commissioning delays.

Deemed energy payments

Deemed energy payments are payments made to the IPP (in particular under the Renewable IPP programme) for energy that would otherwise have been produced if it were not for a system event (either curtailment, network unavailability or a delay in grid connection not caused by the IPP).

Deemed energy payments of R171 million for the year were made due to:

- Delays in grid connection for number of projects
- System Curtailment Events relating to a system requirement to reduce generation in specific hours.

In addition a provision of R306 million was made for potential deemed energy payments relating to current disputes.

E. DOE Peaker

Price variance: The payment to the Peaker is split between capacity payments and energy payments (for utilization) as it is fully dispatchable by Eskom. The average rate paid is higher than anticipated in the MYPD3 decision due to lower utilization (approx. 1% for the period of operation) relative to the expected 5%.

Volume variance: As explained above the volumes were lower, mainly due to lower utilization by Eskom, but also that one project went into commercial operation later than originally anticipated.

F. TRANSMISSION ANCILLIARY COSTS

NERSA approved R97 million for Transmission ancillary costs in the MYPD3 determination for FY 2017. These costs have not been incurred. This portion of the allocation has been added to the budget to accommodate network use of system charges to the IPP which are a pass through to the Eskom Buyer's Office. During FY 2017 the total payment for use of system charges was R75.13 million. This is included in the total payment for REIPP.

11 International purchases

Eskom acquired electricity from neighboring countries that resulted in purchases of R2 681 million which generated energy inflows of 7 418 GWh during the year. The actual costs are agreed to be the international electricity purchases as disclosed under note 34 for primary energy in the AFS.

TABLE 20: INTERNATIONAL PURCHASES

International purchases R million	MYPD3 Decision	Actuals	RCA 2016/17
International purchases	399	2 681	2 282

11.1 Cross-border sales and purchases of electricity

Eskom's current excess capacity has provided an opportunity to make additional international electricity sales. International sales for the year to 31 March 2017 have increased by 12% compared to the previous year. This as a result of a focused strategy to boost export sales in order to partly offset the reduction in revenue from local sales, utilise excess operational capacity as well as alleviate the effect of the drought affecting the Kariba Power Station on the Zambezi River, which supplies Zimbabwe and Zambia.

The lower volume of cross-border purchases can be attributed primarily to Cahora Bassa (HCB) reducing their supply due to water levels at HCB being affected by the drought in the region.

Eskom is providing support to the region to the extent possible, whilst ensuring local demand is met. Eskom has ensured that sales contracts with Southern African Power Pool trading partners are sufficiently flexible to allow us to restrict supply during emergency situations in South Africa.

TABLE 21 : CROSS BORDER SALES AND PURCHASES

GWh	Actual 2014/15	Actual 2015/16	Actual 2016/17
International Sales	12000	13465	15093[A]
International Purchases	10731	9703	7418
Net Sales/(Purchases)	1269	3762	7675

***Note A:** The international sales shown in the Annual Financial Statements reflect 15 093GWh (15 006GWh + 87GWh) which are based on the geographical location in which the sale occurred. For regulation the 87GWh is not shown as International sales as this is sold by Distribution and as such forms part of Distribution sales.*

12 Coal Burn Costs

12.1 Extract of MYPD Methodology on Coal adjustments

"Criteria for Allowing Primary Energy Costs

8.1 All rules applicable to operating expenditure shall apply to the primary energy costs.

8.2 In considering the allowable primary energy costs, the Energy Regulator will consider the most appropriate generation mix that can be achieved practically to the best interest of both the customer and the supplier.

8.3 Coal Costs

8.3.1 Coal will be treated as a single cost centre without differentiating between the various coal sources (for example cost plus contracts, fixed price contracts, short-term contracts and long-term contracts).

8.3.2 The Energy Regulator will determine and approve the coal benchmark cost (i.e. an average cost of coal R/ton), and Alpha for each year will be determined as part of the MYPD3 final decision.

8.3.3 The coal benchmark price is determined by the Energy Regulator in order to be used in comparison with the actual coal cost for the purpose of determining pass-through costs.

8.3.4 The coal benchmark price will be compared to Eskom's actual cost of coal burn (R/ton) using a Performance Based Regulation (PBR) formula. The PBR formula is the maximum amount to be allowed for pass-through, calculated by applying the following formula

PBR cost (Rand) = (Alpha x Actual Unit Cost of Coal Burn+ (1 – Alpha) x Coal burn

Benchmark price) X Actual Coal Burn Volume

.

Where*: Actual Cost = Actual unit cost of coal burn in a particular financial year Benchmark*

Price = Allowed coal burn cost/coal burn volume (R/ton) Actual Coal Burn Volume = Actual ton of coal burn in a particular financial year Alpha = Alpha is the factor that determines the ratio in which risks in coal burn expenditure is divided: i.e. those that are passed through to the customers, and those that must be carried by Eskom. Any number of the alpha between 0 and 1, set to share the risk of the coal cost variance between licensees and its customers.

8.3.5 The pass-through component of the coal burn cost is equal to the coal burn volume variance plus Alpha times the coal burn cost variance:

Pass through coal burn cost = PBR cost (Rand) minus Allowed Coal burn cost (Rand) = Coal burn Volume variance + Alpha

Where*: Actual Cost = Actual unit cost of coal burn in a particular financial year Benchmark Price = Allowed coal burn cost/coal burn volume (R/ton) Actual Coal Burn Volume = Actual ton of coal burn in a particular financial year Alpha = Alpha is the factor that determines the ratio in which risks in coal burn expenditure is divided: i.e. those that are passed through to the customers, and those that must be carried by Eskom. Any number of the alpha* *between 0 and 1, set to share the risk of the coal cost variance between licensees and its customers.*

8.3.6 The coal benchmark price will be used to determine the resulting allowed actual coal burn cost (R/ton) and transferred to the RCA. The amount transferred to the RCA will therefore be calculated as the difference between the PBR amount and the amount forecast/allowed in the MYPD decision.

8.3.7 The coal stock level (stock days) will be reviewed by the Energy Regulator when necessary".

12.2 NERSA's decision on coal benchmark and alpha

The following information was received from NERSA:

TABLE 22: NERSA'S DECISION ON COAL BENCHMARK AND ALPHA

Coal benchmark	Unit	MYPD3 2016/17
Coal burn costs	R'm	44 245
Coal burn volumes	kt	129 000
Benchmark avg cost rate	R/t	343.0

12.3 Coal cost – RCA 2017 calculation

The costs to be included in the RCA are calculated as follows:

12.3.1 Step 1 – Calculate the performance base regulation cost allowance

PBR cost (Rand) = (Alpha x Actual Unit Cost of Coal Burn+ (1 – Alpha) x Coal burn Benchmark price) X Actual Coal Burn Volume

For 2016/17

*PBR cost (Rand) = (((0.95 X R388.1) + (1-0.95) X R343)) X 113 737 Mt)/**1000***

PBR cost (Rand) = R43 886m

Where

Alpha = 0.95

Actual coal burn volume = 113 737 Mt

Actual unit cost of coal burn = R388.1 per ton

Coal burn benchmark cost = R343.0 per ton

In deriving the actual R/t costs, Eskom first deducts the costs relating to coal which are incurred but does not result in burn and energy being produced (Medupi take or pay and Kusile risk sharing agreement contracts). As presented below the actual R/t is computed by taking actual coal costs of R44 652m and deducting the R510m in respect of the take or pay contractual amount, resulting in a total cost of R44 142m. Thereafter the adjusted actual cost of R44 142m is divided by the volume of coal burn of 113 737Mt resulting in an average actual R/t of R388.1

TABLE 23: WORKING COAL MECHANISM

Workings of coal mechanism	Unit	MYPD3	Actuals	Variance
Coal burn	R'm	44 245	44 652	407
Coal disallowed for qualifying actuals costs	R'm	-	-510	-510
- Medupi take or pay agreement	R'm		-510	
- Kusile take or pay agreement	R'm		-	
Coal burn costs	R'm	44 245	44 142	-103
Coal burn tons	Mt	129 000	113 737	-15 263
Costs rate per ton	R/t	343.0	388.1	45.1
Alpha - sharing mechanism	%	95%	95%	
Coal rate after incl Alpha	R/t	325.8	368.7	42.87
Adjusted MYPD3 decision with alpha		385.8		

12.3.2 Step 2 – Calculate the pass through coal burn costs

For 2016/17

Pass-through Coal Burn Cost = PBR Cost - Allowed Coal Burn Cost

Pass-through Coal Burn Cost = R43 886m – R44 245m

Pass-through Coal Burn Cost = -**R359m**

12.3.3 Step 3 – Split the pass through coal burn cost into volume variance and price variance summarised below.

TABLE 24: THE COAL BURN BREAKDOWN FOR THE RCA

Coal burn variance breakdown	Unit	RCA 2016/17
Coal burn price variance	R'm	5 530
Coal burn volume variance	R'm	-5 889
Coal burn costs included in RCA	R'm	**-359**

The coal burn variance of minus R 359m is a result of a combination of the variances in volume of coal and the unit cost of coal when compared to the benchmark as determined by NERSA.

A coal volume variance of R5 889m in favour of the consumer is included as a result of lower coal utilisation due to lower sales volumes. A variance from the unit benchmark cost of coal was experienced. This resulted in a price variance of R5 530m in favour of Eskom.

Step 3a. Coal price variance determines the price impact of actual results compared to that assumed during the decision and allowing for the alpha and multiplying by the allowed volumes of coal burn tons.

Coal price variance = Allowed coal burn tons X (Actual – Allowed Price in R/t X Alpha)

Coal price variance = 129000 X ((R388.1 – R343) X 0.95)

Coal price variance = 129000 X R42.87

Coal price variance = **R5 530m**

Where:

Allowed coal burn tons (Mt) = 129 000 Mt

Actual Price (R/t) = R388.1

Allowed Price (R/t) = R343

Alpha = 0.95

Step 3b. Coal burn volume variance determines the impact of change in volumes when comparing actual volumes to that assumed in the decision and multiplying by the decision price plus the price variance after accounting for the alpha.

Coal volume variance = Adjusted price r/t with Alpha X variance in coal burn tons
Coal volume variance = (R343 + ((R388.1- R343) X 0.95)) X (113 737 – 129 000)
Coal volume variance = (R343 + R42.87) X -15 263
Coal volume variance = R385.87 X -15 263
Coal volume variance = -**R5 889m**

Where:
Allowed coal burn tons (Mt) = 129 000 Mt
Actual coal burn tons (Mt) = 113 737 Mt
Allowed Price (R/t) = R343.0
Actual Price (R/t) = R313.7
Alpha = 0.95

12.4 Coal burn cost variance explanations

The differences in assumptions made in the MYPD 3 decision process and what actually transpired are listed in the table. The details of the differences follow in the explanations below.

TABLE 25: MYPD 3 ASSUMPTIONS VS. ACTUAL 2016/17

MYPD3 – Assumptions for 2016/17	Actual 2016/17
Electricity production from coal fired plant would be 237 921 GWh.	Electricity production from coal fired plant was 199 495 GWh.
Cost Plus and Fixed Price mines produce at expected levels, except for Arnot	Cost Plus and Fixed Price mines produced below expected levels.
New long term mines are producing	Only a portion of the coal could be accepted at Medupi Power Station because the station construction was delayed.
Coal qualities have been adjusted to reflect the impact of the washing plants.	Some delays were experienced with coal quality improvement initiatives.
The new power stations (Medupi and Kusile) use flue gas desulphurisation (FGD) at 0.45 litres per units sent out (l/USO).	FGD has not yet been implemented at Medupi and Kusile
Majuba heavy haul line and other rail infrastructure are approved, constructed and commissioned on schedule.	Rail infrastructure was delayed

12.5 Coal purchases

The average price Eskom pays for coal is determined by the volume of coal procured from each type of contract (cost plus, fixed price and ST/MT) and the price of coal from each type of contract, comprising average ST/MT costs of R458/t, Cost plus costs of R388/t and fixed price costs of R262/t.

The average price Eskom pays for coal is determined by the volume of coal procured from each type of contract (cost plus, fixed price and ST/MT) and the price of coal from each type of contract. These are impacted by various factors:

12.5.1 Long term fixed price contracts

This category comprises the Duvha, Hendrina, Matimba and Medupi contracts. The mines supply contractual volumes. The price is determined by the terms of the contract, e.g. an annual escalation may be applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. None of the existing contracts are impacted on directly by the price of export coal. Approximately 28% of coal for FY17 was sourced from long term fixed price contracts against a plan of 33%.

12.5.2 Cost plus contracts

Coal from Cost Plus contracts is the second cheapest coal supply source. The cost of this coal comprises all expenditure incurred at the mine, overheads, capex and a return on the mines' initial investment. The age of these mines and levels of investment in them has reduced over time resulting in lower production volumes in recent years. Lower production volumes result in a higher R/ton cost because Eskom is contractually liable for the operating costs of the colliery. However, the transport cost is also minimal because coal is transported by conveyor to the power station. Coal supplied under these agreements is, on average, cheaper than coal from ST/MT contracts.

The mines will attempt to supply contractual volumes. There are circumstances which may prevent this, e.g. geological difficulties, the age of the mines and historical supply profiles. The unit price (R/ton) will be the total cost of operating that mine for that period divided by the production volumes. The export price has little direct impact. Cost plus mines provided approximately 33% of the coal procured in FY17 against the plan of 35%.

12.5.2.1 ST/MT contracts

These contracts are of varying durations. They are essentially fixed price contracts, but are differentiated from the original 40 year contracts referred to above as long term fixed price contracts. The suppliers supply contractual volumes. As with the long term fixed price contracts, the price is determined by the terms of the contract, e.g. an annual escalation may be applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. The export price may have an impact in that the supplier may reference this price at the time of negotiation. However, Eskom's policy is to pay the cost of coal plus a fair return. Whether this price correlates to the export price at any given time is likely to be purely coincidental. These contracts supplied approximately 34% of the coal in FY17 against the plan of 37%.

12.6 Mode of Transport

Coal is transported by conveyor, rail, road or a combination of modes. The additional cost associated with purchasing ST/MT coal is the transport cost. The mix between the transport sources is conveyor (59%), road (10%) and rail (31%).

a. Conveyor

Conveyor is the cheapest mode of transport. The Cost Plus and Fixed Price mines, which are located close to the stations, use this mode. Because of lower production from these mines, fewer tons were transported by conveyor in FY17.

b. Rail

Rail is the next cheapest mode of transport. However, there are only four stations, Majuba, Tutuka and Camden which have rail infrastructure.

c. Road

Road is the most expensive mode of transport. Although total volumes purchased were lower than planned, higher burn at Majuba and the RTS stations meant that coal needed to be transported to these stations. Because of rail infrastructure constraints, ST/MT coal to the power stations is transported by road or a combination of road and rail (multi-mode transport). In some instances, this mode may be more expensive than road alone. During FY17, more coal was transported by road than planned, because of the issues discussed above and because the additional rail infrastructure that was planned for has been delayed. This contributed to the higher R/ton cost.

12.7 Medupi Take or Pay payment

A take or pay payment of R488 million was incurred because of the delay in the construction of Medupi Power Station.

12.8 Kusile Risk Sharing Agreement

The construction of Kusile Power Station is ongoing. Eskom is still negotiating with Anglo Coal in an attempt to secure the long term coal for the station. The parties have signed a risk sharing agreement with certain milestone dates The risk sharing payment for the FY2017 year amounted to R22 million. Securing our coal requirements

TABLE 26: SECURING OUR COAL REQUIREMENTS

Measure and unit	Actual 2016/17	Actual 2015/16	Actual 2014/15
Coal burnt, Mt	113.74	114.81	119.18
Coal purchased, Mt	120.25	118.7	121.67
Coal stock days	74	58	51
Road-to-rail migration (additional tonnage	13.2	13.6	12.6

Although coal stock stood at 74 days, adjustments are made for volumes at certain power stations to arrive at normalised coal stock days of 38 days, which is slightly higher than the overall target of 37 days. All power stations' stock days were maintained above minimum levels, except for Arnot, Kriel, Tutuka, Duvha and Majuba Power Stations. Deliveries were negatively impacted by heavy rains, and rail tippler breakdowns' at Majuba further impacted deliveries. Plans are in place to improve the stockholding at these stations in the coming financial year.

The following volume adjustments are made to arrive at normalised coal stock days:

- The high coal stock level at Medupi (11Mt) is excluded. This results from Eskom taking delivery of coal in terms of the colliery contract, rather than pay a penalty, even though the commissioning of units at Medupi was delayed
- Likewise coal at Kusile (1.9Mt) is excluded, as the station is not yet in production
- Lethabo is serviced by a cost-plus mine, where there is no financial benefit to Eskom to reduce coal production, resulting in the higher than targeted stockholding of 70 days at Lethabo (which is normalised to the target of 30 days)

13 Other Primary energy

The MYPD Methodology allows for other primary energy as pass through. Coal burn, OCGTs, IPPs and environmental levy have specific rules and are dealt with separately in the document.

MYPD Methodology - Other Primary Energy Costs

8.5.1 Other primary energy costs such as nuclear, hydro, and sorbent, will be allowed as pass-through costs.

8.5.2 Primary energy costs at the coal-fired power stations, for example water treatment, start-up fuel and coal handling costs will be allowed as a pass-through and will be reviewed by the Energy Regulator based on the percentage cost increase (inflation forecast).

13.1 Allowed other primary energy in 2016/17

13.1.1 Allowed other primary energy costs

Other primary energy costs in the MYPD 3 decision for 2016/17 excluding demand market participation (i.e. DMP) is R6 327m. The details are presented in the table below.

13.1.2 Allowed vs Actual other primary energy

Eskom incurred R7 049m relating to other primary costs during 2016/17 with the major items being start up gas and oil, coal handling and water which is summarised in table below. The actual costs exceeded the MYPD3 decision of R6 327 million by R722 million as highlighted in the table below.

TABLE 27: OTHER PRIMARY ENERGY

Other Primary Energy R'millions	MYPD3 Decision	Actuals 2016/17	RCA 2016/17
Water	2 188	1 751	-437
Start up gas & oil	1 695	2 227	532
Coal handling	1 257	1 758	501
Water treatment	298	423	125
Nuclear	446	727	281
Fuel procurement	304	163	-141
Sorbent usage	139	0	-139
Other primary energy for RCA , R million	**6 327**	**7 049**	**722**

13.1.3 Reasons for start-up gas and oil costs variance

Start-up gas and oil contributes R532 million to the RCA. Heavy fuel oil starts and shuts down a coal fired power station and stabilizes the boiler flame on occasion e.g. when operating at low load. The number of starts are driven by the number of outages (planned and unplanned) and the number of trips (UAGS) at the units of a station. The number of unplanned outages and trips were significantly higher in 2016/17 than what was anticipated at the time of the MYPD3 application and hence the use of fuel oil increased significantly as well.

Fuel oil costs decreased by R63m from FY2016 to FY2017 (therefore a real decrease year-on-year). Since 2013/14 when Generation spent R3bn on fuel oil, fuel oil costs had been reduced substantially in subsequent years to R2.2bn in 2016/17.

The price of fuel oil is mainly driven by the US dollar price of fuel oil which is beyond the control of Eskom. The price of oil and the rand/dollar exchange rate is very volatile and difficult to predict into the future with accuracy.

This principle to allow for price fluctuations was implemented in the NERSA RCA 2013/14 decision, with an extract presented below:

“Para 56. Eskom is allowed R365 million due to the unfavourable fluctuation in the Rand/Dollar exchange rate and issues that were outside management control (e.g. torrential rainfall).”

13.1.4 Reasons for coal handling costs variance

A variance of R501 million in favour of Eskom arose, due to movement of coal within the power stations being more than was originally envisaged.

However, the year-on-year coal handling costs increased by 3% only (below inflation) even though Medupi unit 6 is fully operational. As a result of the collapse of coal silo 20 at Majuba, there was an excessive use of yellow plant equipment in 2015/16. Due to the earlier than planned commissioning of the interim solution of silo 20, coal handling costs were reduced due to a lesser usage of yellow plant equipment and diesel in comparison to the previous financial year.

13.1.5 Reasons for water costs variance

NERSA granted Eskom R2 188 million for Water costs in FY16. Actual expenditure was R1751 million resulting in under expenditure of R437 million compared to the decision.
The capital unit charge (CUC), Vaal River Tariff (VRT) and the Waste Discharge Charge are the significant contributors to the under expenditure. These are legislated tariff based costs. Expenditure on pumping and O&M was also significantly lower than planned.

13.1.6 Reasons for fuel procurement costs variance

A variance of R141 million occurred due to lower expenditure. The primary components of fuel procurement expenditure and the reasons for the bulk of the under expenditure are:

- Manpower was underspent because of savings initiatives, during which a moratorium was placed on hiring staff.
- Savings on consulting fees due to the studies planned for the Waterberg strategy did not materialise.

13.1.7 Water treatment costs variance

A variance of R125 million in favour of Eskom arose, due to water treatment costs within the power stations being more than was originally envisaged. The drought in South Africa impacted the quality of water at all the power stations and hence the stations spent more on chemicals to treat the poor quality water.

13.1.8 Nuclear costs variance

According to para 60 of the MYPD3 decision, it was confirmed that the fuel used at Koeberg is wholly imported. Consequently international benchmarks (Rand per kilogram) were used to determine the approved price. The actual nuclear fuel costs were R281 million more than the decision.

TABLE 27: NUCLEAR FUEL COSTS 2016/17

Nuclear fuel costs R'million	Actuals 2016/17	MYPD3 Decision 2017/18	Variance to MYPD3
Nuclear other	28	103	- 75
Nuclear fuel burn U1	334	349	- 15
Nuclear fuel burn U2	320	295	25
Nuclear spent fuel	45	20	25
Eskom MYPD3 Application	**727**	**767**	**- 40**
Nersa disallowed		- 321	321
Total Nuclear Fuel costs	**727**	**446**	**281**

13.1.8.1 Nuclear other

Fuel write-off for partially burnt fuel assemblies were less than estimated at the time of the MYPD3 Decision. Also a change in future loading of fuel assemblies and no provision adjustments were made during the 2016/17 financial year. The MYPD3 Application assumed that 64 fuel assemblies will be loaded, but only 56 were loaded as currently there is no storage space.

13.1.8.2 Nuclear fuel burn U1

The cost of fresh fuel assemblies loaded after outage 122 was lower than originally estimated at the time of the MYPD3 Application, leading to a lower cost of recovery of fuel burn every month.

13.1.8.3 Nuclear fuel burn U2

Outage 222 that was scheduled to start on 20 March, was shitfted out to the next financial year and hence more fuel was burnt. Also, no UCLF incidents were incurred on unit 2 during the financial year.

13.1.8.4 Nuclear spent fuel

Changes on the spent fuel asset implemented at the end of 2013/14 increased the amortisation of the fuel assemblies loaded in the core in each outage.

13.1.9 Sorbent costs variance

The time lag in implementing FDG at Medupi power station has resulted in no sorbent costs being incurred during 2016/17 thus resulting in a claw back of R139 million in the RCA submission.

14 Environmental levy

The MYPD Methodology allows for (under)/over recovery to be adjusted through the RCA mechanism as presented in the extract below:

13. Taxes and Levies (not income taxes)

13.1 The Government imposes certain taxes and levies that are payable by Eskom.

13.2 Levies are any charges that the Government may impose and payable by Eskom arising from its licensed activity.

13.3 Taxes are any amount arising from an enacted legislation that the Government may require Eskom to pay which amount will be calculated in terms of such legislation.

13.4 **Principles regarding taxes and levies**

13.4.1 The taxes and levies are exogenous and will be treated as a pass-through cost in the MYPD.

13.4.2 Taxes and levies will be treated as a separate account in the Eskom revenue determination.

13.4.3 Eskom must ensure that the cost of the taxes and levies is specified and that the calculation thereof is clear and concise.

13.4.4 The amount provided for the taxes and levies must be ring-fenced and any over or under-recovery will be recorded in the RCA.

Eskom incurred environmental levy costs of R 1 404m less than the MYPD3 determination for 2016/17. The fundamental driver to the variance for the environmental levy is due to a substantial decrease in coal volume due to lower sales compared to MYPD3 plus the additional supply from IPPs and an increase in the system average auxiliary percentage.

The MYPD 3 submission and subsequent NERSA decision was based on an assumption of the levy rate of 3.5c/kWh for the full period. The rate remained unchanged during 2016/17.

15 Demand Market Participation

15.1 Allowed DMP

No DMP and power buybacks were allowed in the MYPD 3 decision.

TABLE 28: APPROVED DEMAND RESPONSE (DR) EXPENDITURE FOR MYPD3

R'm	2016/17
DMP and Power buy-back Applied for	
Funding	1 835
Demand Savings (MW)	3 855
R/MW	0.48
DMP and Power buy-back Adjusted	
Funding	-1 835
Demand Savings (MW)	-3 855
R/MW	-0.48
DMP and Power buy-back Approved	
Funding	-
Demand Savings (MW)	-
R/MW	-

Source: Table 36 of MYPD3 decision, 28 February 2013

15.1.1 Actual DMP

Demand market participation had a variance of R194 m during the year.

TABLE 29: DMP COMPARISON FOR RCA

Demand market participation (DMP)	MYPD3 Decision	Actuals	RCA 2016/17
DMP (R'm)	-	194	194

Nersa has disallowed all revenue related to Demand Market Participation (DMP) in this year of the MYPD decision. The funds for DMP are crucial in ensuring security of supply. DMP is an appropriate lever as it used over short periods, allows the customer the flexibility to make up production at different times of the day and is a lower cost than running open cycle gas turbines.

Furthermore, demand response programmes will be needed by the system operator even after a healthy reserve margin is established. This is due to the need to deal with unforeseen events on a daily and hourly basis such as higher than expected demand and plant trips, particularly in view of the technical risks associated with the significant levels of renewable power stations to be connected to the grid. Demand response programmes are considered a best practice for modern system operators and should continue. Thus the costs associated with the DMP programmes were utilised to provide these reliability and security of supply reasons.

16 Open cycle gas turbines (OCGTs)

The usage and cost of open cycle gas turbines are allowed as pass through costs subject to prudency review of volumes. The current year volumes exceed that assumed in the MYPD decision as highlighted in section 8.4 of the MYPD Methodology.

The MYPD Methodology states that as per para 8.4.1 *"costs will be allowed as a full pass-through cost, but limited conditional to volumes allowed by the Energy Regulator,* ***except*** *where such use is necessary to ensure security of supply…"* .

This situation is further reinforced in para 8.4.2 "Capacity constraints shall be mitigated by gas turbine generation as a last resort. For **avoidance of doubt**, gas turbine generation should be **employed before implementation of load shedding activities**".

Para 8.4.3 " … any variances in the operation of the gas turbine, the reasonableness of such expenses will be subject to review by the Energy Regulator to determine the efficiency and prudency review in which Eskom has to demonstrate that it has maximised the availability and **utilisation of cheaper resources** such as Integrated Demand Management (IDM) and Demand Market Participation (DMP)."

16.1 Allowed OCGT spend

For purposes of its revenue decision, NERSA assumed R1 599m for OCGT fuel cost from a production of 533 GWh requiring 150 ML of diesel. This was based on the assumptions made by Eskom in their MYPD3 application surrounding the timing of new build commissioning dates and Generation plant performance.

The improved performance in the existing fleet in terms of energy availability, commissioning new power stations and growth in IPPs have resulted in a turnaround in the usage of OCGT to almost zero in 2016/17. Therefore OCGTs costs of R1259 million were saved in the year and claw back in terms of this RCA submission.

TABLE 30: OCGT

Open Cycle Gas Turbines (OCGTs)	MYPD3 Decision	Actuals	Variance
OCGTs costs (R'million)	1 599	340	-1 259
OCGTs volumes (GWh)	533.00	29.28	-504

The OCGT cost for the year R340 million. This comprises OCGT burn of R60 million and diesel storage and demurrage costs of R280 million, incurred as a result of not running the OCGTs.

16.1.1 Managing supply-and –demand constraints

16.1.1.1 Role of the System Operator

The System Operator provides an integrative function for the operation and risk management of the interconnected power system by balancing supply and demand in real time, trading energy internationally and buying energy from IPPs, all of which enable us to supply electricity to our customers in accordance with our mandate.

In order to balance and protect the power system, Eskom has to apply demand management practices, which include supply-side and demand-side options. Supply-side options focus on increasing electricity supply, including utilising OCGTs, pumped storage schemes, supply by IPPs as well as international power imports. Demand-side options, which are contingent upon the support of customers, focus on reducing demand, and include demand response programmes which utilise interruptible load agreements, demand side management, energy efficiency initiatives as well as the “5pm to 9pm” demand reduction campaign and higher winter tariffs.

The System Operator places great focus on risk management to protect the stability of the power system. The various defence systems in place are frequently tested to ensure their effective response capability to prevent a major system event.

For many hours of the day, the reserve margin is sufficiently adequate. However, during peak hours or when abnormal events occur, demand at times exceeds supply. When this occurs, Eskom implements demand and supply-side management strategies, including the demand response programme where selected large customers reduce their demand at Eskom’s request. As a last resort, Eskom introduces rotational load shedding to protect the integrity of the power system. Failure to do so could lead to a full national power blackout with severe consequences for the country. Clear protocols are in place for the event where the last option is to resort to load shedding.

16.1.2 Actual Plant performance in 2016/17

Attached below is extracts from the 2016/17 integrated report which highlights the performance of the generation fleet.

16.1.2.1 Operating highlights

- There has been no load shedding since 8 August 2015, except for one incident on 14 September 2015, and load curtailment of key customers on 9 October 2015
- The Tetris planning tool has assisted in optimising the scheduling of outages
- Adhered to the summer and winter maintenance budget (planned and unplanned) of 11.5GW and 8.5GW respectively
- Medupi Unit 6 has been in commercial operation since August 2015
- UCLF improved from an average of 15.22% in 2014/15, to 14.91% in 2016/17, while
- PCLF improved from an average of 9.91% in 2014/15, to 12.99% in 2016/17
- EAF increased from an average of 69.85% in the last quarter of 2014/15, to 73.51% in the last quarter of 2016/17

Eskom is committed to accomplishing the overarching goals of meeting the country's demand and also improve the performance of Generation. This commitment will be fulfilled whilst avoiding load shedding and still conducting regular maintenance on the Generation fleet to sustain improved performance.

16.1.2.2 Generation technical performance

Generation's technical operations are assessed in terms of the following:

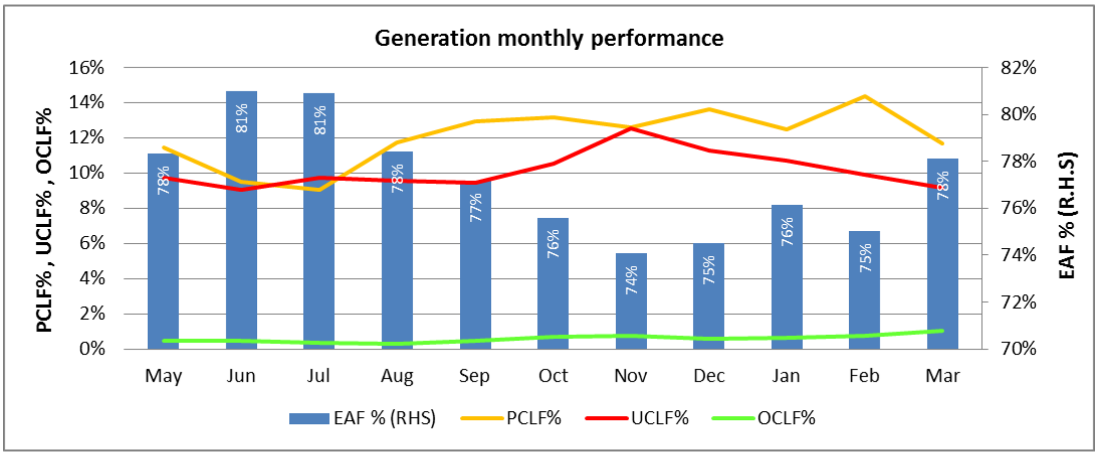
- Energy availability factor (EAF), which measures plant availability and takes account of planned and unplanned unavailability and energy losses not under the control of plant management
- Unplanned capability loss factor (UCLF), which measures unplanned energy losses resulting from equipment failures and other plant conditions
- Planned capability loss factor (PCLF), which measures energy losses because of planned shutdowns during the period

Unplanned breakdowns (UCLF) have also improved from a monthly average of 10.95% in April 2016 to 9.2% in March 2017, due to a focus on partial load losses and improvements due to previous planned maintenance.

Although the current efforts have helped to improve system performance, it is critical to note that the system remains constrained. Strategies are in place to address system constraints. Pressure on the system is expected to ease further as Medupi, Ingula and

Kusile are progressively commissioned, combined with further increased production from IPPs.

FIGURE 6 : GENERATION TECHNICAL PERFORMANCE



16.1.2.3 Generation Sustainability Strategy

Until recently, Eskom has deferred some maintenance as a result of capacity constraints. Since August 2015, the extent of unplanned breakdowns has improved and new capacity has been added. This has enabled Eskom to adopt a revised maintenance strategy, which aims to perform all required maintenance, whilst adhering to the strict maintenance target (planned and unplanned) of 11 500MW in summer and 8 500MW in winter.

Eskom has improved its outage scheduling using the Tetris planning tool. This provides a graphical representation of the maintenance schedule and the capacity outlook, and is able to provide a forward-looking view. This allows for more informed decision making regarding the prioritisation of maintenance and rescheduling to minimise the risk of load shedding.

17 Capital expenditure clearing account (CECA)

Capital expenditure variance is monitored through the CECA and the change in regulatory asset base is multiplied by the return on asset percentage awarded in MYPD3 decision.

17.1 Regulated asset base adjustment for CECA

Capital expenditure will affect the value of the regulated asset base (RAB).

The actual capital expenditure incurred during 2016/17 was R58 924 million compared to the MYPD3 decision assumption of R46 655 million thus resulting in a variance of R12 269 million. However, only capex changes that affect the RAB are adjusted for CECA purposes.

The total variance of R12 269 million comprises Generation capex overspend by R24 034 million, Transmission underspend by R7 991 million, Distribution underspend by R5 782 million with the balance of R2 009 attributable to other capital expenditure. Included in Generation were new build expenditures which exceeded the MYPD3 assumptions by R22.44 billion, comprising Medupi of R6.12 billion, Kusile of R14.69 billion and Ingula of R1.63 billion.

However, for RCA purposes not all changes to capital expenditure affect the regulatory asset base and thus do not qualify for RCA related changes. Of the total variance of R12 269 million, only R5 827 million qualifies as RAB expenditure.

17.1.1 Step 1: Computing the qualifying RAB capital expenditure variance

The change in RAB is determined in terms of rule 6.7.2.3 as shown below.

6.7.2 To accommodate the unstable environment in which the WUC cost will be undertaken, the approach for adjusting works under construction for cost and timing variances will be as follows:

6.7.2.1 Eskom will annually report to the Energy Regulator on its capital expenditure programme, providing information on timing and cost variances.

6.7.2.2 At the end of each financial year, Eskom will provide the Energy Regulator with a final reconciliation report of the actual works under construction incurred.

6.7.2.3 On receipt, the Energy Regulator will record all efficient works under construction above or below the approved amount on the works under construction carryover account (CECA) and quantify Eskom's exposure.

The capital expenditure is adjusted to exclude the following items

a) future fuel because it is accounted for as working capital and

b) Technical and refurbishment capex as it is not re-measured under the current Methodology.

The calculation below reflects an increase of the RAB by the average capital expenditure variance of R 2 914 million (i.e. R 5 827 million divided by 2) for FY2017.

Table 31: Calculation average capital expenditure

CECA Calculation -Variance between actual and allowed capex	Calculation Reference	Eskom company
Allowed MYPD capital expenditure	**A**	**46 655**
Less: Capital expenditure excluded	**B**	17 830
Future fuel		3 647
Technical and refurbishment capital expenditure		14 183
Allowed RAB capital expenditure	**A-B**	28 825
Actual MYPD capital expenditure	**C**	**58 924**
Less: Capital expenditure excluded	**D**	24 272
Future fuel		114
Payment received in advance recognised to revenue		2 042
Technical and refurbishment capital expenditure		22 116
Actual RAB capital expenditure	**C-D**	34 652
Total actual minus total allowed capital expenditure	**C-A**	**12 269**
Less: Variance on capital expenditure excluded	**D-B**	6 442
Variance on RAB capital expenditure	**E**	**5 827**
Average capital expenditure difference for CECA calculation	**E/2**	**2 914**
Allowed Return - NERSA MYPD 3 decision	**E**	**3.9%**

17.1.2 Step 2: Computing the CECA

Extract from MYPD Methodology:

6.7.3 Balances on the CECA will be adjusted as follows in the Regulatory Clearing Account (RCA) as follows:

6.7.3.1 At the end of the financial year, if there is any under-expenditure compared to forecasted works under construction, the value of the RAB will be adjusted downwards for works under construction not undertaken and the revenues for the subsequent financial year adjusted to compensate for the return earned on unused funds in the previous MYPD. For any over-expenditure approved by the Energy Regulator compared to forecasted works under construction, the balance will be added to the RAB and Eskom will be allowed additional returns on the CECA balance to recover the costs of the over-expenditure for that year. This approach will effectively minimise any potential windfall losses or gains should the approved capital expenditure differ from the actual expenditure.

The section below illustrates how the CECA of R636 million is computed by applying the allowed ROA to the capex variance.

Table 32: CECA Calculation: Return due to/ (by) Eskom

CECA Calculation : Return due to/(by) Eskom	Calculation Reference	Eskom company
MYPD3 Regulatory assets base (RAB)		713 380
Add /(Deduct): Current year average capex variance		2 914
Add/ (Deduct): Cumulative prior year capex variances		13 495
Adjusted MYPD3 Regulatory assets base (RAB)	**F**	**729 789**
MYPD3 allowed return on assets (ROA)	**G**	27 657
Return on adjusted RAB	**F*H**	28 293
Increase / (Decrease) in ROA for RCA	**(F*H)-G**	**636**
MYPD3 allowed ROA %	**H**	3.88%

Note: For purposes of the calculating the CECA claim, the allowed RAB of R713 380m is adjusted for the capex variance of the current year of R2 914 million and prior year of R 13 495 million , resulting in an adjusted RAB of R729 789 million.

17.2 MYPD3 decision

Below are extracts from MYPD3 decision reflecting approved RAB of R713bn and returns on asset at 3.88%, generating returns of R27 657 million and assuming a capital expenditure of R46 655 million.

Table 33 : Regulatory asset base for 2016/17

R'm	2016/17
RAB Applied for	981 853
RAB Adjustment	-269 073
RAB Approved	**712 780**

Source: Table 10 of MYPD3 decision, 28 February 2013

Table 34: Returns and percentage allowed in 2016/17

R'm	2016/17
Real Pre-tax WACC (%)	3.9%
Return (R'm)	27 657

Source: Table 9 of MYPD3 decision, 28 February 2013

Table 35: Capital expenditure in 2016/17

R'm	2016/17
Capex Applied for	66 626
Capex Adjustment	-19 971
Capex Approved	**46 655**

Source: Table 11 of MYPD3 decision, 28 February 2013

17.3 Reasons for new build higher expenditures

17.3.1 Medupi:

The over-expenditure of R6.1bn is mainly due to;

17.3.1.1 Basic cost

- Increase of R1.9bn due to;
- Additional variation requests due to design changes, design integration challenges and additional employer policy requirements such as the Partnership Agreement.
- Claim costs mainly due to prolongation, because of access delays, force majeure events (including labour unrest) and construction challenges on the Boiler, Turbine and Civil packages.
- Unplaced packages that were not allowed such as costs relating to excess coal stockyard and others.
- The impact of the revision of the project completion date from December 2014 to May 2020.

17.3.1.2 Escalation

- Increase of R1.3bn
- Due to the increase in Basic cost.

17.3.1.3 Owners Development Cost (ODC)

- Increase of R1.6bn
- Increase of R0.04bn due to cost incurred but not allowed in the determination.
- Increase of R1.56bn due to the new manpower structure with additional positions in critical roles (e.g. quality), DAB team to support claims management and the delay in the demobilization of resources in line with schedule delays

17.3.1.4 Contingency - Increase of R1.4bn

- Increase of R0.5bn due to cost incurred but not allowed in the determination as contingency was only limited to 10% of the placed contracts basic cost and CPA.

- Increase of R0.9bn due to Increase in the accrual for work done not assessed for all plant areas, it now includes all progressed milestones for all units to date including Variation Orders.

17.3.2 Kusile:

The over-expenditure of R14.7bn is mainly due to;

17.3.2.1 Basic cost

- Increase of R5.5bn due to;
- The MYPD 3 expenditure that was based on the 2014 synchronization date of Unit 1 whereas the current expenditure is based on the increase expenditure to support the 2016 synchronization date of Unit 1 and the final completion date of Unit 6 of Sep 2022.

17.3.2.2 Escalation

- Increase of R2.6bn due to the increase in Basic cost.

17.3.2.3 Owners Development Cost (ODC)

- Increase of R3.1bn
- Increase of R1.1bn due to cost incurred but not allowed in the determination.
- Increase of R2bn due to hiring of strategic personnel and changes on working hours in order to meet the synchronization date of Unit 1.

17.3.2.4 Contingency –

- Increase of R3.5bn
- Due to cost incurred but not allowed in the determination as contingency was only limited to 10% of the placed contracts basic cost and CPA.

17.3.3 Ingula:

The over-expenditure of R1.6bn is mainly due to the following;
In the MYPD 3 application for Ingula it was planned for the project to be completed by the 2014/15 financial year. Cost was however incurred in 2016/17 due to the delayed completion of the project mainly due to the fatal accident at the inlet tunnels which resulted in a work stoppage of the affected area imposed by the Department of Mineral Resources (DMR). This work stoppage was on the section of the plant that was on the project schedule critical path and resulted in project delays and late completion of the project.

17.4 Actual Capital Expenditure

Eskom spends approximately half on new build projects through the Group Capital division and the other half incurred on the combined portfolio of existing Generation assets, Transmission and Distribution networks.

The table below shows the reconciliation of capital expenditure between the integrated report as shown above and amount used in the CECA calculation.

Table 36: Reconciliation of capex from the integrated report to CECA disclosures

Capital Expenditure R'million	Actuals
Total Eskom Group Capex per Integrated Report	60 032
Exclude : Eskom Enterprises	-1 107
Total Capex for CECA disclosure	**58 925**

Detailed extract of capital expenditure of R60.0 billion is disclosed in table below.

TABLE 37: CAPITAL EXPENDITURE (EXCLUDING CAPITALISED BORROWING COSTS) PER DIVISION

Division, R million	Actual 2016/17	Actual 2015/16
Group Capital	35 458	33 799
Generation	14 376	11 440
Transmission	940	998
Distribution	5 220	5 490
Subtotal	**55 994**	**51 727**
Future fuel	114	2 114
Eskom Enterprises	1107	373
Other areas including intergroup eliminations	2 817	3 138
Total Eskom group funded capital expenditure 1	**60 032**	**57 352**

1. *Capital expenditure includes additions to property, plant and equipment, intangible assets and future fuel, but excludes construction stock and capitalised borrowing costs.*

18 Inflation adjustment

In compiling the inflationary adjustment, cost of cover, arrear debts (net impairment loss) and DSM are excluded in the computation. Operating costs are subject to an adjustment for inflation as per paragraph 14.1.1 in the MYPD Methodology. The consumer price index (CPI) is used to determine the rate of inflation for purposes of these adjustments. The adjustment corrects the assumption on inflation that went into the revenue determination, with the actual inflation during the period. In other words, the costs assumed in the decision are restated using the actual inflation over the period, and compared with the costs allowed at the time of the determination.

Table 38: Inflation Data

Inflation data	2013/14	2014/15	2015/16	2016/17
Inflation CPI - Decision	5.60%	5.60%	5.60%	5.60%
Inflation index - Decision	1.056	1.115	1.178	1.244
Inflation CPI - Actual	5.70%	6.10%	4.60%	6.40%
Inflation index - Actual	1.057	1.121	1.173	1.248

The qualifying expenses of R 43 651 million for the inflation calculation comprise employee benefits cost of R 22 118 million and other operating costs of R 21 533 million. Refer to the table below for the Inflation RCA claim. Qualifying expenses excludes arrear debts, EEDSM, costs of cover and ancillary services as they are treated separately for RCA purposes.

Table 39 : Inflation adjustment

Inflation adjustment for 2016/17	Calculation ref	2016/17
Total operating costs allowed	A	43 651
Decision inflation index	B	1.244
Actual inflation index	C	1.248
Restated allowed costs based on actual inflation (A/B * C)	D	43 813
Inflation adjustment R'm	**D-A**	**162**

Due to the actual compounded CPI index of 1.248 in 2016/17 being higher than allowed compounded CPI index of 1.244, this results in an inflation adjustment of R162 million in favour of the Eskom.

19 Energy efficiency and demand side management (EEDSM)

19.1 Actual EEDSM

In view of the improved power system status and outlook, the focus of the IDM function is shifting to balancing electricity demand and sales management, and creating space for future sales growth initiatives by shifting demand from peak to off-peak periods.

Eskom is working towards its objectives through:

- Implementing a "step change" in demand management delivery through an integrated and innovative portfolio of demand management initiatives;
- Optimally using Eskom and national resources to deliver the national demand-side management initiative; and
- Partnering with stakeholders through a proactive and collaborative approach to contribute to national energy efficiency objectives.

Demand side management interventions encourage customers to use electricity more efficiently, thereby reducing the gap between supply and demand in the short to medium term. During the year, IDM conducted a number of programmes to manage demand and improve energy efficiency.

19.2 The Residential mass roll-out programme

This Programme aims to reduce residential electricity usage by encouraging households to use energy-efficient technologies. The programme is a significant lever to reduce demand during periods of system constraint.

It includes the following sub-programmes:

- Residential Compact Fluorescent Lamps (CFLs)
- The DoE solar water heating programme

19.3 Other Energy-efficiency measures

IDM runs a number of programmes to manage demand and improve energy efficiency.

- The Demand Response Programme has a average certified capacity of 1 267MW of dispatchable load (2015/16: 1 466MW), which can be reduced for short intervals to restore system security, if requested by the System Operator.
- The compact fluorescent light (CFL) sustainability programme has installed a total of 4 765 921 CFLs since the project commenced in November 2015, of which 2 705 699 have been installed in in the current year. The last phase of the rollout of 10 million CFLs is planned for 2017/18.
- The solar water-heating programme – demand savings of 7.8 MW and energy savings of 81.9 GWh were installed and verified as part of the DoE SWH Programme.
- Power Alert - A consequence of the improved power system status and outlook, was that "RED" flightings [in the absence of load shedding, the worst constraint day RED, is the day with least amount of reserve] were stopped. The methodology for determining the colour codes in Power Alert was changed at the end of July 2016. The change is that OCGT plant (both Eskom owned and IPP) is now included as normal generating capacity in the Power Alert calculations, as opposed to emergency generating capacity.

Only GREEN flightings occurred - GREEN flightings request the public to use energy wisely and savings are expected to be sustainable (i.e. switch off unnecessary lights).

TABLE 40: DEMAND MANAGEMENT COSTS

R million	Actual 2016/17	Actual 2015/16	Actual 2014/15
Total energy efficiency demand side management	376	413	656
Demand response	194	248	309
Total (excluding transfer pricing)	570	661	965

TABLE 41: ACTUAL SAVINGS (NOT VERIFIED) AND INTERNAL ENERGY EFFICIENCY SAVINGS

Measure and unit	Actual 2016/17	Actual 2015/16	Actual 2014/15
Demand savings (evening peak), MW	236.9	214.9	271.5
Internal energy efficiency, GWh	5.9	1.7	10.4

As verified demand savings [MWs] are used for determining the savings for the RCA computation, there exists a roll over between financial years relating to the time when projects are implemented and the actual verification of the MW savings. Therefore reconciliation is required to determine the verified MW as presented in the table below.

TABLE 42: RECONCILIATION BETWEEN DEMAND SAVINGS MWS USED IN RCA CALCULATION

Reconciliation Between Demand Savings (MW) reported by Energy Audit and IDM	Demand Savings (MW)
Total Verified by Energy Audit (not Incl DoE)	290.3
Less Projects Claimed by IDM in FY 2015	-9.5
Less Projects Claimed by IDM in FY 2016	-51.7
Total IDM Claimed	**229.1**
Plus DoE- Solar Water Heating Projects	7.79
Total IDM Claimed for FY 2017	**236.9**

The total capacity verified for 2016/17 of 290.3 MW is used for the RCA calculation.

19.4 Extracts from the MYPD Methodology

The MYPD Methodology deals with demand side management and demand market participation separately with their respective rules. The energy efficiency demand side management is disclosed below:

IDM

11.1.1.8 IDM will incur penalties for under achieving their targets. In case of non-performance, the penalty will be calculated as follows:

Penalty(R) = total allowed revenue /projected MW target X MW unsaved
= R/MW X MW unsaved

EEDSM performance is computed on verified MW savings.

19.4.1 Allowed EEDSM for 2016/17

The allowed EEDSM costs, MWs and the associated rate are shown in table 46 below.

TABLE 43: THE ALLOWED EEDSM COSTS

EEDSM	2016/17
	Approved
Funding	**712**
Programmes Peak Demand savings (MW)	196
Programmes Annualised Energy savings (GWh)	939
Programme Costs	348
Operating Costs including Depreciation	365
Other costs	-
R/MW	3.64
R/kWh	0.76

Source: Table 40 of MYPD3 decision, 28 February 2013

The EEDSM performance relating to capacity savings and costs are summarised in the table below.

TABLE 44: EEDSM COMPARISON FOR RCA IN 2016/17

Energy Efficiency & Demand Side Management (EEDSM)	Unit	MYPD 3 2016/17	Actuals 2016/17	Variance
Funding	R'm	712	376	-336
Programmes - Peak Demand savings	MW	196	290	94
Programme costs	R'm	348		
Operating costs incl. depreciation	R'm	365	373	
Other costs	R'm	-	3	
EEDSM Rate	R/MW	3.63	1.30	-2.34
EEDSM Rate based on verfied MW savings for RCA	R/MW		3.63	-
MW savings for RCA purposes	MW		290	
Annualised energy savings	GWh	939		
RCA incentive for achieving more MW savings	R'm			**342**

The current EEDSM regulatory rule does not allow for an incentive where the MW savings exceed the assumed targets and is a one sided rule which penalises Eskom when capacity savings are not met.

Hence due to the MYPD Methodology not allowing for symmetrical incentives on achieving extra MW savings, Eskom has included a zero impact for this RCA submission.

20 Operating costs

Operating costs comprises employee benefits, maintenance and other operating costs. It excludes IDM which is treated separately for RCA purposes.

Operating costs

14.1.1 The nominal estimates of the regulated entity will be managed by adjusting for changes in the inflation rate.

14.1.4 Adjusting for prudently incurred under-expenditure on controllable operating costs as may be determined by the Energy Regulator.

20.1 Allowed operating costs in 2016/17

The total operating cost allowed is R45 896 million as shown below.

TABLE 45: TOTAL OPERATING COST ALLOWED

Allowed operating costs R'million	2016/17	Note Ref
Employee benefits	22 118	1
Other Opex	21 533	2
Other Income	0	
Net Impairment loss	1 219	3
Cost of cover	1 026	4
Total	**45 896**	

Note1: Allowed employee benefits

TABLE 46: EMPLOYEE BENEFITS ARE RECONCILED AS FOLLOWS

Employee benefits allowed R'million	2016/17	Note Ref
Total GTD	18 875	A
Add : Corporate	3 243	
Corporate Overheads	4 334	B
Less: Corporate depreciation	-1 091	C
Total Employee Benefits allowed	**22 118**	

Reference A: Total GTD allowed employee benefits per NERSA decision

TABLE 47: THE ALLOWED EMPLOYEE COSTS FOR GENERATION, TRANSMISSION AND DISTRIBUTION

R'm	2016/17
Manpower Applied for	23 345
Manpower Adjustments	-4 470
Approved Manpower	**18 875**

Source: Table 43 of MYPD3 decision, 28 February 2013

Reference B: Total corporate overheads allowed

TABLE 48: ALLOWED CORPORATE COSTS IN 2016/17

R'm	2016/17
Corporate overheads Applied for	7 569
Corporate overheads Adjustments	-3 235
Approved Corporate overheads	**4 334**

Source: Table 51 of MYPD3 decision, 28 February 2013

The R4 334 million above includes R1 091 million in respect of corporate depreciation which is reallocated from corporate overheads to depreciation.

Reference C: Corporate depreciation

The total allowed corporate depreciation over the MYPD 3 period is R 3 902 million. Refer paragraph 112 from the NERSA decision below.

112. Eskom has applied for depreciation of R13 255m as part of its corporate expenses. However, the value of the applicable capex as applied for by Eskom is only R4 813m, to be depreciated over 5 years. Therefore the allowed deprecation is limited to R3 902m over the MYPD3 control period. Therefore the amount disallowed for depreciation is R9 353m which is included in the corporate overheads adjustments in Table 51.

TABLE 49: THE DEPRECIATION PER ANNUM IS REFLECTED IN THE TABLE BELOW.

Total Corporate depreciation allowed R'million	2013/14	2014/15	2015/16	2016/17	2017/18	Total MYPD3
Corporate depreciation	434	678	930	1 091	769	3 902

Note 2: Other opex

Other operating costs of R21 533 million (R14715m+R6818m) comprises repairs and maintenance and other costs as shown below.

TABLE 50: ALLOWED MAINTENANCE COSTS

R'm	2016/17
Maintenance Applied for	17 941
Maintenance Adjustments	-3 226
Approved Maintenance	**14 715**

Source: Table 44 of MYPD3 decision, 28 February 2013

TABLE 51: OTHER COSTS

R'm	2016/17
Other costs Applied for	16 130
Other costs Adjustments	-9 312
Approved Other costs	**6 818**

Source: Table 50 of MYPD3 decision, 28 February 2013

Note 3: Net impairment loss (Arrear debt)

TABLE 52: ALLOWED ARREAR DEBTS

R'm	2016/17
Arrear Debt Applied for	1 388
Arrear Debt Adjustments	-169
Approved Arrear Debt	**1 219**

Source: Table 49 of MYPD3 decision, 28 February 2013

Note 4: Cost of cover

TABLE 53: ALLOWED COST OF COVER

R'm	2016/17
Cost of Cover applied for	1 026
Cost of Cover adjustments	-
Approved Cost of Cover	**1 026**

Source: Table 48 of MYPD3 decision, 28 February 2013

20.2 Allowed vs Actual operating costs

During 2016/17 Eskom incurred operating costs excluding IDM of R61 211m which compares to the MYPD3 assumption of R45 896m resulting in over expenditure of

R15 315m. Eskom operating costs don't qualify for the RCA adjustment except for the inflation adjustment. Actual operating costs are presented in Annexure 1 and Annexure 5.

TABLE 54: SUMMARY OF OPERATING COSTS IN 2016/17

Operating Costs R'millions	Allowed	AFS actuals	Variance	Regulatory adjustments	RCA actuals	RCA balance
Employee benefits	22 118	27 902	5 784	-99	**27 803**	5 685
Other opex	21 533	30 950	9 417	-274	**30 676**	9 143
Other income	-	-2 094	-2 094	1	**-2 093**	-2 093
Net impairment loss	1 219	1 629	410	3 196	**4 825**	3 606
Cost of cover	1 026		-1 026	-	**-**	-1 026
Total Operating Costs R'millions	**45 896**	**58 387**	**12 491**	**2 824**	**61 211**	**15 315**

20.3 Variances in operating costs

20.3.1 Employee benefits

Actual staff costs have exceeded the MYPD3 decision due to

- Higher salary settlement of 8.5% compared to decision assumption of 5.6%, and
- Starting point for the staff costs base being referenced to MYPD2 decision. The difference in staff costs is attributable to the starting point where NERSA used the MYPD2 revenue decision, made in 2009, as their reference for making the MYPD3 decision. Allowance was not made for the changes that occurred between the MYPD2 revenue decision and the actuals during MYPD2. Hence the starting point was too low, thus contributing to the difference included in the RCA.

TABLE 55: TREND IN GROSS EMPLOYEE BENEFITS

Actual employee costs	2013/14	2014/15	2015/16	2016/17
Net employee costs (before capitalisation)	22 384	22 187	24 721	27 902
Employee costs capitalised to assets	5 685	6 404	3 266	3 655
Gross employee costs R'm)	**28 069**	**28 591**	**27 987**	**31 557**
Growth in gross employee benefits	8.7%	1.9%	-2.1%	12.8%

Gross employee benefits have averaged 5.3% per annum over the last 4 years.

20.3.2 Maintenance

Overall Eskom underspent on maintenance. Generation and Transmission maintenance exceeded the MYPD3 decision whilst Distribution maintenance was underspent. For purposes of the MYPD3 revenue decision, NERSA did substantially base its assumptions regarding maintenance cost on the amounts as estimated by Eskom in its revenue application.

20.3.3 Arrear debt

Arrear debt refers only to overdue amounts, excluding interest, and is not the total amount due. Debt collection in the municipal and residential segments remains a significant challenge, although the rollout of smart prepaid meters is assisting in improving revenue recovery. Management of energy protection and revenue losses, through Operation Khanyisa and other initiatives are ongoing.

20.4 Other Income

20.4.1 Actual other income in 2016/17

In the course of Eskom operations in 2016/17, Eskom generated total other income of R2 094 million which is shown in the table below:

TABLE 56 : OTHER INCOME FOR 2016/17

	Group		Company	
	2017 Rm	2016 Rm	2017 Rm	2016 Rm
33. Other income				
Insurance proceeds	-	917	812	1 393
Services income	256	355	-	-
Management fee income	-	-	146	117
Net surplus on disposal of property, plant and equipment	-	-	-	-
Operating lease income	296	262	231	226
Dividend income	40	32	32	32
Sale of scrap	202	134	201	134
Other	779	690	672	569
	1 573	2 390	2 094	2 471

20.4.2 Principles for treatment of other income in the RCA

The **principle used for the treatment** of other income for RCA purposes is based on whether the **other income** has a **corresponding cost item which qualifies for RCA adjustments**. In the event where the other income component represents credits for operating cost items which do not qualify for RCA purposes, then the other income similarly does not qualify for RCA inclusions.

This **principle was implemented by NERSA in their RCA 2013/14 decision as the extract disclosed below**,

> 103. As shown in Table 17 below, Eskom did not apply for the inclusion of other income from insurance proceeds (R384m), management fee income (R751m), operating lease income (R175m) and dividend income (R21m). This is allowed because it relates to operating expenditure that does not form part of the RCA.

Source: Paragraph 103, NERSA 2013/14 RCA decision

20.5 Based on the precedent above, other income does not qualify for inclusion in the RCA. Operating cost variance for 2016/17 RCA

Operating cost variance = Actual operating costs – Allowed operating costs

Based on **RCA equivalent actual operating costs of R61 211 million** and allowed other operating costs in the **decision of R 45 896 million**, Eskom has incurred an **additional R15 315 million** during the year. In terms of the MYPD Methodology Eskom **cannot submit these additional expenses for RCA purposes** and have thus **absorbed the variance**

It is Eskom's opinion that this non-symmetrical treatment of variances such as in the case of operating costs is not in line with sound regulatory practice.

21 Service Quality Incentives

NERSA has approved the targets for service quality incentives for Distribution and Transmission below. NERSA is currently developing service quality incentives for Generation.

Transmission plans, operates and maintains our transmission assets, while our Distribution network relays electricity from the high-voltage transmission network to customers, including municipalities that manage their own distribution networks.

TABLE 57 : TRENDS IN NETWORKS PERFORMANCE

Measure and unit	Actual 2016/17	Actual 2015/16	Actual 2014/15
Number of system minutes lost <1 minute, minutes SC	3.8	2.41	2.85
Number of major incidents >1 minute, number	-	1	2
System average interruption frequency index (SAIFI), events SC	18.9	20.5	19.7
System average interruption duration index (SAIDI), hours SC	38.9	38.6	36.2

Note: *One system minute is equivalent to interrupting the entire South Africa at maximum demand for one minute.*

TABLE 58 : SUMMARY OF SQI PERFORMANCE IN 2016/17

Licensee Service Quality Incentives (SQI)	Incentive/ (Penalty)	2016/17
Distribution SQI	Incentive	262.6
Transmission SQI	Incentive	80.0
Total SQI for 2016/17 (R'millions)	**Incentive**	**342.6**

21.1 Transmission service quality incentives (SQI) for 2016/17

Eskom Transmission Service Quality Incentive Scheme Results with NERSA comprises of the following 3 measures:

- System Minutes (<1)
- Number of Major Incidents (SM>1)

- Line Faults / 100 km

The performance results for these measures as reported in the Eskom Integrated reports for the financial years 2016/17 has been finalized and the subsequent financial reward / penalty based on these results has been computed. The SQI reflects a net reward of R80m for 2016/17.

TABLE 59: TRANSMISSION SQI PERFORMANCE IN 2016/17

Transmission Service Quality Incentives (SQI)	Performance result	Incentive / (Penalty) R'm	Comment
SM<1	3.8	0	Dead band
Major incidents	0	40	Reward
Line faults / 100km	1.6	40	Reward
Total Transmission SQI for 2016/17 (R'm)		**80**	

FIGURE 7: TRANSMISSION SYSTEM MINUTES (<1)

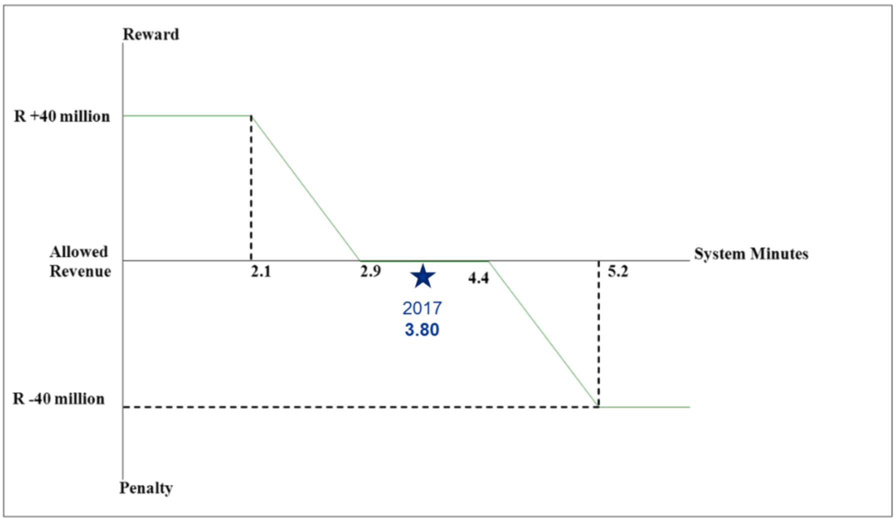


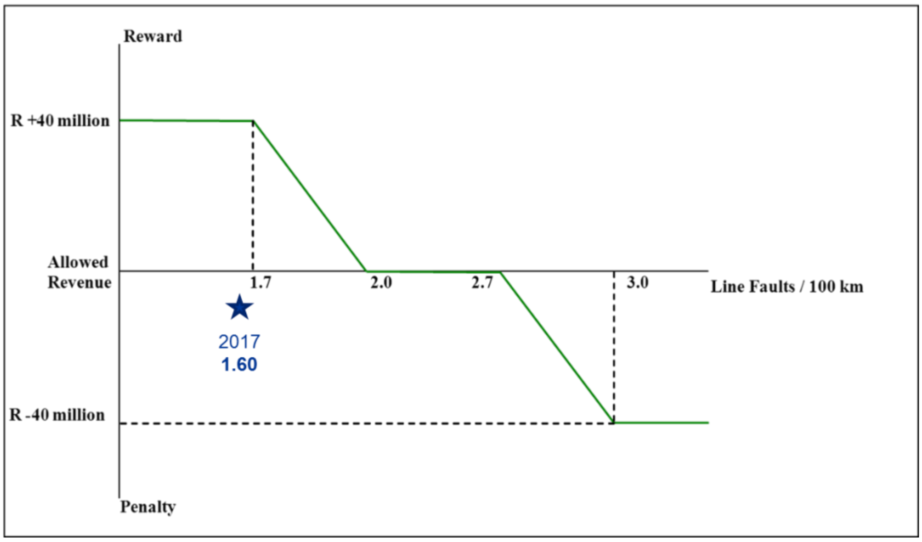
TABLE 60: TRANSMISSION NUMBER OF MAJOR INCIDENTS (>1SM)

Number of Major Incidents (>1SM)

Incentive (Rm)	Major Incidents (No)
R 40	0
R 20	1
R 0	2
-R 20	3
-R 40	4

★ 2017 = 0

FIGURE 8 : LINE FAULTS /100KM



21.2 Distribution Service Quality Incentive Scheme (SQI) for 2016/17

The Energy Regulator, at its meeting held on 28 October 2014, approved the Distribution Service Quality Incentive Scheme (SQI) for the third Multi-Year Price determination (MYPD3). The Distribution SQI had been designed to encourage Distribution to earn additional revenue for improved performance levels but also to penalize Distribution for deteriorating performance levels.

The Distribution SQI for MYPD3 comprises of 3 measures:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Distribution Supply Loss Index (DSLI).

The value of the scheme was set at 1% of the allowed revenue requirements for Distribution. The total value of the scheme is limited to R291.80m per annum and a total of R1 459bn over the five-year control period.

The SADI and SAIFI performance have shown on-going improvements during 2016/17 of MYPD3 and earned incentive rewards as indicated in the table below. The DSLI performance has improved from 2014/15 resulting in no penalty being incurred. The net impact of the SQI performance is positive for Eskom. The outcome of the SQI performance is summarised in the table below.

TABLE 61: DISTRIBUTION SQI PERFORMANCE IN 2016/17

Distribution Service Quality Incentives (SQI)	Incentive/ (Penalty)	2016/17
SAIDI	Incentive	145.90
SAIFI	Incentive	116.72
DSLI	Penalty	0.00
Distribution total SQI (R'millions)	**Incentive**	**262.62**

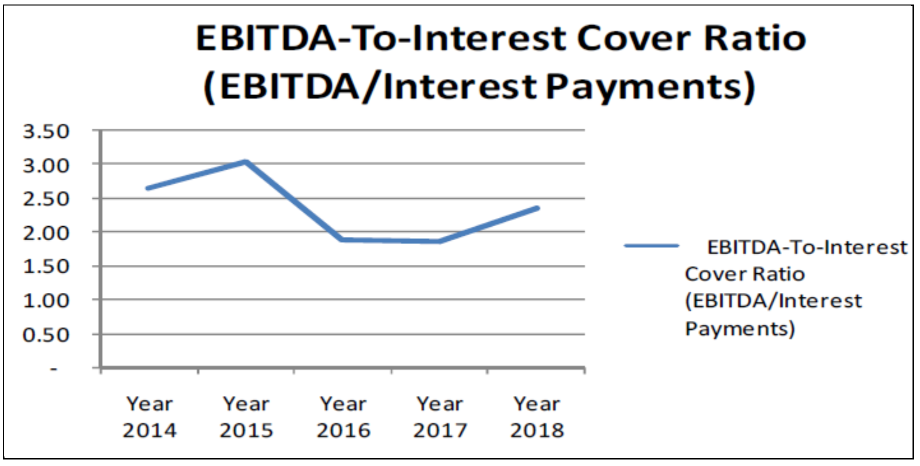
Distribution system performance reflects significant improvements with a declining trend in SAIDI interruption durations reducing from 45.8 minutes in 2012/13 to 29.69 minutes by 2016/17.

22 Reasonability tests

22.1 EBITDA-To-Interest Cover Ratio (EBITDA / Interest Payments)

*Para 31 of the MYPD3 decision states that "The allowed returns will **enable Eskom to meet its debt obligations"**. The figure below illustrates that Eskom's Earnings Before Interest Depreciation Tax & Amortisation (EBIDTA)-To-Interest cover ratio is more than 2 times at the end of MYPD3 control period".*

FIGURE 9 : EBITDA-TO-INTEREST COVER RATIO



The figure above reflects a ratio of approximately 2 for 2016/17.

If the above Nersa definition is applied to the actual results for the 2017 financial year, the ratio is as follows:

TABLE 62: EBITDA COVER

EBITDA Interest Cover	Calculation Reference	2016/17
EBITDA Interest Cover	A/B	1.38
EBITDA	A	35.989
Interest	B	26.003

Reference A: 2017 Annual financial statements, Company Income statement (see Annexure 1)

Reference B: 2017 Annual financial statements, Note 41 (see Annexure 4)

23 Conclusion

Eskom's approach to RCA 2016/17 was based on the MYPD Methodology (published December 2012) and the NERSA RCA 2013/14 reasons for decision which was published on 29 March 2015. **This RCA submission adopts the principles utilized by NERSA in making their decision especially when it refers to the treatment of revenue.** Eskom believes that this application will contribute towards Eskom and NERSA achieving closer alignment with respect to the RCA process and outcomes.

Eskom's revenue is determined by NERSA through a revenue application process and the RCA process which this submission addresses. The RCA is meant to ensure that Eskom can recover its full efficient costs as the actual realities have occurred differently than that assumed during the MYPD3 decision.

In this submission of R23 868 million, Eskom is paying back R3 022 million comprising of coal burn (R359m), OCGTs (R1259m) and environmental levy (R1404m). Eskom is claiming back a total of R6 873 million consisting of other primary energy (R722m), DMP (R194 million), IPPs (R2452m), international purchases (R2282m) and other components (R1224m). Thus the net cost of R3 851 million is being claimed with the balance attributable to the revenue under recovery of R20 016million linked to lower sales volumes.

Eskom has not claimed the over expenditure of R15 315m relating to operating costs as these costs don't qualify for the RCA resulting in Eskom absorbing the entire variance as the MYPD Methodology does not cater for symmetrical treatment of operating costs.

Finally, a reasonableness test has been conducted to highlight the need for the RCA adjustment as demonstrated by the actual EBITDA to Interest Cover ratio being below MYPD3 decision assumption. The MYPD Methodology states that risk of excess or inadequate returns is managed in terms of the RCA.

>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>> **END >>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>**

Annexures:

Revenue:

Annexure 1: Income Statement in AFS 2017, page 15

Income statements

for the year ended 31 March 2017

	Note	Group 2017 Rm	Group Restated [1] 2016 Rm	Company 2017 Rm	Company Restated [1] 2016 Rm
Revenue	32	177 136	164 239	177 136	164 239
Other income	33	1 573	2 390	2 094	2 471
Primary energy	34	(82 760)	(84 728)	(82 760)	(84 728)
Employee benefit expense	35	(33 178)	(29 257)	(27 902)	(24 721)
Net impairment loss	36	(1 669)	(1 170)	(1 629)	(1 159)
Other expenses	37	(23 570)	(18 663)	(30 950)	(25 170)
Profit before depreciation and amortisation expense and net fair value loss (EBITDA)		37 532	32 811	35 989	30 932
Depreciation and amortisation expense	38	(20 300)	(16 633)	(20 277)	(16 619)
Net fair value loss on financial instruments, excluding embedded derivatives	39	(3 342)	(1 452)	(3 203)	(1 492)
Net fair value gain on embedded derivatives		1 611	997	1 611	996
Profit before net finance cost		15 501	15 723	14 120	13 817
Net finance cost		(14 377)	(7 919)	(15 389)	(8 776)
Finance income	40	5 212	3 447	4 290	2 667
Finance cost	41	(19 589)	(11 366)	(19 679)	(11 443)
Share of profit of equity-accounted investees after tax	11	35	43	-	-
Profit/(loss) before tax		1 159	7 847	(1 269)	5 041
Income tax	42	(271)	(2 696)	399	(1 905)
Profit/(loss) for the year [2]		888	5 151	(870)	3 136

Annexure 2: The Eskom energy wheel (Eskom Fact sheet 2017)

Note: All figures are in GWh unless otherwise stated.

Eskom's energy flow diagram

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 the past two years, including the losses incurred in reaching those customers.

All figures in GWh, unless otherwise indicated.

Generation of electricity	2016/17	2015/16
Generation	220 137	216 043
OCGTs	29	3 936
Own generation	220 166	219 979
IPPs	11 529	9 033
Generation (including IPPs)	231 695	229 012
Pumping	(4 808)	(4 046)
Total	226 887	224 966

Available for distribution	2016/17	2015/16
Generation (including IPPs)	231 695	229 012
International purchases	7 418	9 703
Wheeling [1]	2 910	3 930
Subtotal	242 023	242 645
Pumping	(4 808)	(4 046)
Total	237 215	238 599

Total imports	2016/17	2015/16
International purchases	7 418	9 703
Wheeling [1]	2 910	3 930
Total	10 328	13 633

Total exports	2016/17	2015/16
International sales [2]	15 093	13 465
Wheeling [1]	2 910	3 930
Total	18 003	17 395

Southern African Power Pool

Internal use	2016/17	2015/16
Internal use	480	661
Generated	(20)	(71)
Total	460	590

Demand	2016/17	2015/16
Total sales	214 121	214 487
Technical and other losses	21 399	19 895
Internal use	480	661
Generated	(20)	(71)
Wheeling	2 910	3 930
Unaccounted	(1 675)	(303)
Total	237 215	238 599

External sales	2016/17	2015/16
Local sales	199 028	201 022
International sales [2]	15 093	13 465
Total	214 121	214 487

Technical and other losse	2016/17	2015/16
Distribution	16 293	13 866
Transmission	5 106	6 029
Total	21 399	19 895
Distribution %	7.55%	6.43%
Transmission %	2.22%	2.61%
Total %	8.85%	8.59%

1. Wheeling refers to the movement of electricity between international customers through our network, without the power being available to customers on the South African grid.
2. International sales includes exports by Distribution International to Lesotho. The actual volumes were 87GWh for 2016/17 and 89GWh for 2015/16.

Annexure 3: Sales volumes GWh – Statistical tables for 2016/17

Electricity sales per customer category, GWh

Category	2016/17	2015/16
Local	**199 028**	201 022
Distributors	**89 718**	89 591
Residential [1]	**11 863**	11 917
Commercial	**10 339**	10 150
Industrial	**48 295**	50 150
Mining	**30 559**	30 629
Agricultural	**5 405**	5 733
Rail	**2 849**	2 852
International	**15 093**	13 465
Utilities	**5 750**	4 018
End users across the border	**9 342**	9 447
	214 121	**214 487**

International sales to countries in southern Africa, GWh

	2016/17	2015/16
	15 093	**13 465**
Botswana	**984**	1 099
Lesotho	**252**	205
Mozambique	**8 120**	8 281
Namibia	**2 089**	1 746
Swaziland	**986**	1 044
Zambia	**352**	344
Zimbabwe	**1 743**	252
Short-term energy market [2]	**567**	494

1. Prepayments and public lighting are included under residential.
2. The short-term energy market consists of all the utilities in the southern African countries that form part of the Southern African Power Pool. Energy is traded on a daily, weekly and monthly basis as there is no long-term bilateral

Electricity revenue per customer category, R million

Category	2016/17	2015/16
Local	**167 813**	154 959
Distributors	**73 009**	66 396
Residential [1]	**14 070**	12 884
Commercial	**11 279**	10 157
Industrial	**32 701**	31 412
Mining	**25 915**	23 895
Agricultural	**7 659**	7 349
Rail	**2 990**	2 755
IPP network charge	**190**	111
International	**10 682**	8 055
Utilities	**6 632**	4 163
End users across the border	**4 050**	3 892
Gross electricity revenue	**178 495**	163 014
Environmental levy included in revenue [2]	**512**	513
Less: Revenue capitalised [3]	**(717)**	(367)
Less: IAS 18 revenue reversal [4]	**(3 196)**	(1 472)
Electricity revenue per note 32 in the annual financial statements	**175 094**	**161 687**

1. Prepayments and public lighting are included under residential.

2. The environmental levy of 2c/kWh tax was effective from 1 July 2009 to 31 March 2011. On 1 April 2011 the levy was raised to 2.5c/kWh. On 1 July 2012 the levy was raised to 3.5c/kWh. The levy is payable for electricity produced from non-renewable sources (coal, nuclear and petroleum). The levy is raised on the total electricity production volumes and is

3. Revenue from the sale of production while testing generating plant not yet commissioned, capitalised to plant.

4. The IAS 18 principle of only recognising revenue if it is deemed collectable at the date of sale, as opposed to recognising the revenue and then impairing the customer debt when conditions change, has been applied since 2015. External revenue to the value of R3 196 million was thus not recognised at 31 March 2017.

Reasonability test

Annexure 4: Finance income note 40 and Finance cost note 41 (Extracts AFS March 2017, page 86-87)

Notes to the financial statements (continued)

for the year ended 31 March 2017

	Note	Group 2017 Rm	Group 2016 Rm	Company 2017 Rm	Company 2016 Rm
40. Finance income					
Investment in securities		**1 001**	723	**518**	347
Loans receivable		**885**	825	**483**	446
Finance lease receivables		**59**	65	**59**	65
Trade and other receivables		**1 349**	951	**1 349**	951
Cash and cash equivalents		**1 918**	883	**1 881**	858
		5 212	3 447	**4 290**	2 667
41. Finance cost					
Debt securities and borrowings		**25 872**	23 242	**26 003**	23 333
Eskom bonds		**12 598**	10 202	**12 598**	10 202
Promissory notes		**7**	6	**7**	6
Commercial paper		**489**	587	**492**	573
Eurorand zero coupon bonds		**587**	520	**587**	520
Foreign bonds		**3 662**	3 637	**3 662**	3 637
Development financing institutions		**5 895**	4 777	**5 895**	4 777
Export credit facilities		**1 643**	1 560	**1 643**	1 560
Subordinated loan from shareholder		**-**	1 208	**-**	1 208
Other loans		**991**	745	**1 119**	850
Derivatives held for risk management		**4 439**	3 151	**4 439**	3 151
Employee benefit obligations	28	**1 552**	1 158	**1 515**	1 130
Provisions	29	**3 758**	2 588	**3 754**	2 583
Finance lease payables		**1 922**	387	**1 922**	406
Trade and other payables		**279**	266	**279**	266
Gross finance cost		**37 822**	30 792	**37 912**	30 869
Capitalised to property, plant and equipment	8	**(18 233)**	(19 426)	**(18 233)**	(19 426)
		19 589	11 366	**19 679**	11 443

Operating expenses

Annexure 5: OPEX note 38 extract from AFS March 2016, page 86

36. Net impairment loss

	Note	Group 2017 Rm	Group 2016 Rm	Company 2017 Rm	Company 2016 Rm
Impairment		2 462	1 644	2 417	1 623
Property, plant and equipment	8	1 128	789	1 128	789
Inventories		-	11	-	11
Loans receivable	15	32	14	-	-
Trade and other receivables	19	1 302	830	1 289	823
Reversal		(787)	(469)	(784)	(459)
Property, plant and equipment	8	(644)	(2)	(644)	(2)
Loans receivable	15	-	(3)	-	-
Trade and other receivables	19	(143)	(464)	(140)	(457)
Bad debts recovered		(6)	(5)	(4)	(5)
		1 669	1 170	1 629	1 159

37. Other expenses

	Note	Group 2017 Rm	Group 2016 Rm	Company 2017 Rm	Company 2016 Rm
Managerial, technical and other fees		1 351	563	1 325	505
Operating lease expense		940	1 117	375	412
Auditors' remuneration [1]		119	94	109	80
Net loss on disposal of property, plant and equipment		260	358	263	494
Government grant		-	-	-	-
Income		-	(23)	-	(23)
Expenses incurred		-	23	-	23
Repairs and maintenance, transport and other expenses		20 900	16 531	28 878	23 679
		23 570	18 663	30 950	25 170

33. Other income

	Group 2017 Rm	Group 2016 Rm	Company 2017 Rm	Company 2016 Rm
Insurance proceeds	-	917	812	1 393
Services income	256	355	-	-
Management fee income	-	-	146	117
Net surplus on disposal of property, plant and equipment	-	-	-	-
Operating lease income	296	262	231	226
Dividend income	40	32	32	32
Sale of scrap	202	134	201	134
Other	779	690	672	569
	1 573	2 390	2 094	2 471

1 Abbreviations

BPP	Business Productivity Programme
Capex	Capital Expenditure
c/kWh	Cent per kilowatt hour
CPI	Consumer Price Index
DMP	Demand Market Participation
EAF	Energy availability factor (see glossary)
EBITDA	Earnings before interest, taxation, depreciation and amortisation
ERTSA	Eskom’s Retail Tariff Structural Adjustments
EUF	Energy utilisation factor (see glossary)
GDP	Gross Domestic Product
GW	Gigawatt = 1 000 megawatts
GWh	Gigawatt-hour = 1 000MWh
IDM	Integrated demand management
IPP	Independent power producer (see glossary)
kt	Kiloton = 1 000 tons
Km	Kilometer
kV	Kilovolt
kWh	Kilowatt-hour = 1 000 watt-hours (see glossary)
L/USO	Litres per unit sent out
M&V	Measurement and Verification
Ml	Megalitre = 1 m litres
Mt	M tons
MTPPP	Medium Term Power Purchase Programme
MW	Megawatt = 1 m watts

MWh	Megawatt-hour = 1 000kWh
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa
O&M	Operations and Maintenance
OCGT	Open-Cycle Gas Turbine (see glossary)
ODC	Owner's Development Cost
Opex	Operating Expenditure
PE	Primary Energy
PPA	Power Purchase Agreement
PCLF	Planned Capability Loss Factor
R/kWh	Rand per kilowatt hour
R/MW	Rand per Megawatt
R/MWh	Rand per Megawatt hour
R'm	Rand million
RAB	Regulatory Asset Base
RCA	Regulatory Clearing Account
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SM	System Minutes
SQI	Service Quality Incentive
STPPP	Short Term Power Purchase Programme
SWH	Solar Water Heaters
UAGS	Unplanned automatic grid separations
UCLF	Unplanned Capability Loss Factor (see glossary)
WUC	Work Under Construction

2 Glossary and Terms

Cost of electricity (excluding depreciation)	Electricity-related costs (primary energy costs, employee benefit costs plus impairment loss and other operating expenses) divided by total electricity sales in GWh multiplied by 1 000
Debt service cover ratio	Cash generated from operations divided by (net interest paid from financing activities plus debt securities and borrowings repaid)
Decommission	To remove a facility (e.g. reactor) from service and store it safely
Demand side management	Planning, implementing and monitoring activities to encourage consumers to use electricity more efficiently, including both the timing and level of demand
Electricity EBITDA margin	Electricity revenue (excluding electricity revenue not recognised due to uncollectability) as a percentage of EBITDA
Electricity operating costs per kWh	Electricity-related costs (primary energy costs, employee benefit costs, depreciation and amortisation plus impairment loss and other operating expenses) divided by total electricity sales in kWh multiplied by 100
Electricity revenue per kWh	Electricity revenue (including electricity revenue not recognised tue to uncollectability) divided by total kWh sales multiplied by 100
Energy availability factor (EAF)	Measure of power station availability, taking account of energy losses not under the control of plant management and internal non-engineering constraints
Energy efficiency	Programmes to reduce energy used by specific end-use devices and systems, typically without affecting services provided
Energy utilisation factor (EUF)	Utilisation of the available plant
Independent power producer (IPP)	Any entity, other than Eskom, that owns or operates, in whole or in part, one or more independent power generation facilities

Interest cover	EBIT divided by (gross finance cost less gross finance income)
Kilowatt-hour (kWh)	Basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour
Load	Amount of electric power delivered or required on a system at any specific point
Load curtailment	Typically larger industrial customers reduce their demand by a specified percentage for the duration of a power system emergency. Due to the nature of their business, these customers require two hours' notification before they can reduce demand
Load shedding	Scheduled and controlled power cuts that rotate available capacity between all customers when demand is greater than supply in order to avoid blackouts. Distribution or municipal control rooms open breakers and interrupt load according to predefined schedules
Maximum demand	Highest demand of load within a specified period
Off-peak	Period of relatively low system demand
Open-cycle gas turbine (OCGT)	Liquid fuel turbine power station that forms part of peak-load plant and runs on kerosene or diesel. Designed to operate in periods of peak demand
Outage	Period in which a generating unit, transmission line, or other facility is out of service
Peak demand	Maximum power used in a given period, traditionally between 06:00–10:00, as well as 18:00–22:00 in summer or 17:00-21:00 in winter
Peak-load plant	Gas turbines, hydroelectric or a pumped storage scheme used during periods of peak demand
Primary energy	Energy in natural resources, e.g. coal, liquid fuels, sunlight, wind, uranium and water

Pumped storage scheme	A lower and an upper reservoir with a power station/pumping plant between the two. During off-peak periods the reversible pumps/turbines use electricity to pump water from the lower to the upper reservoir. During periods of peak demand, water runs back into the lower reservoir through the turbines, generating electricity
Reserve margin	Difference between net system capability and the system's maximum load requirements (peak load or peak demand)
Return on assets	EBIT divided by the regulated asset base, which is the sum of property, plant and equipment, trade and other receivables, inventory and future fuel, less trade and other payables and deferred income
System minutes	Global benchmark for measuring the severity of interruptions to customers. One system minute is equivalent to the loss of the entire system for one minute at annual peak. A major incident is an interruption with a severity ≥ 1 system minute
Technical losses	Naturally occurring losses that depend on the power systems used
Unit capability factor (UCF)	Measure of availability of a generating unit, indicating how well it is operated and maintained
Unplanned capability loss factor (UCLF)	Energy losses due to outages are considered unplanned when a power station unit has to be taken out of service and it is not scheduled at least four weeks in advance
Used nuclear fuel	Nuclear fuel irradiated in and permanently removed from a nuclear reactor. Used nuclear fuel is stored on-site in used fuel pools or storage casks
Watt	The watt is the International System of Units' (SI) standard unit of power. It specifies the rate at which electrical energy is dissipated (energy per unit of time)