MYPD 3

(Year 2015/16)

Regulatory Clearing Account Submission to NERSA

15 July 2016

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1 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 2015/16 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 2015/16 RCA balance (hereafter referred to as the '2015/16 RCA Submission' or year 3 of MYPD3) is lodged in accordance with section 14.2.1 of the MYPD Methodology.
2. Information is supported by Eskom's 2015/16 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.

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

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

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

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 2015/16 RCA Submission

The structure of the summary of 2015/16 RCA Submission provided in this document is guided by the MYPD Methodology. With this in mind, an overview of the 2015/16 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 15)

V. Primary Energy - Coal Costs (Section 17)

VI. Primary Energy - Gas Turbine Generation Cost (Section 21)

VII. Primary Energy – Other costs (Section 18)

VIII. Capital Expenditure and Regulatory Asset Base (Section 22)

IX. Operating Costs (Section 25)

X. Determined RCA Balance to Financial Year End

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 2015/16 RCA Submission concludes with reasonableness tests such as EBITDA to interest payments and debt service cover ratio being assessed.

2 Objective

The objective of this 2015/16 RCA Submission is to provide the context for the Regulatory Clearing Account (RCA) process in terms of NERSA's MYPD Methodology requirements. The **2015/16 RCA Submission for the third 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 2015/16 RCA Submission

Eskom's 2015/16 RCA Submission is driven substantially by revenue under-recovery and higher primary energy costs to meet demand, whilst operating in a constrained electricity system. The determined RCA balance of R23 633 million is motivated with evidence for prudent scrutiny by NERSA.

Table 1: Summary of 2015/16 RCA Submission

Regulatory Clearing Account (RCA) for 2015/16	MYPD3 Decision	Actuals	Variance	RCA adjustments	RCA 2015/16
Total Electricity revenue R million	**179 587**	**163 160**	**16 427**	**-849**	**15 578**
Primary Energy , R million					
Coal	39 838	41 775	1 937	1 321	3 258
OCGTs	1 508	8 690	7 182	-6 493	689
Other primary energy	6 040	7 129	1 089	-361	728
Local IPPs and co-generation	14 826	15 106	280	340	620
International purchases	93	3 660	3 567		3 567
Environmental levy	9 300	8 120	-1 180		-1 180
Nuclear decommissioning of R830m from RCA 2013/14 decision phased in over 10 years	-	-		83	83
Nuclear decommissioning R361m from RCA 2015/16 decision phased in over 8 years				45	45
Demand Market Participation (DMP)	-	248	248	-	248
Total primary energy , R million	**71 605**	**84 728**	**13 123**	**-5 065**	**8 058**
Capital Expenditure Clearing Account (CECA), R million	**42 065**	**56 978**	**14 913**	**332**	**332**
Integrated Demand Management (IDM) , R million	**819**	**413**	**-406**	**38**	**-368**
Operating [1] costs , R million	**42 292**	**55 198**	**12 905**	**1 061**	**-134**
Service Quality Incentive (SQI) , R million	**-**	**-**	**-**	**318**	**318**
Inflation adjustments , R million	**-**		**-**	**-152**	**-152**
Total RCA balance , R million					**23 633**

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

3.1 Revenue

The revenue variance of R15 578 million which is calculated on Eskom's electricity revenue to all customers is due to lower electricity sales volumes. In addition, Eskom has specifically excluded the loss of revenue attributable to the load shedding and load curtailment impacts of R849 million thereby reducing the revenue variance to R15 578 million.

3.2 Primary energy

Due to the constrained electricity system, unplanned outages and delays in new build projects, Eskom was required to operate a more expensive mix of plant compared to the assumptions in the MYPD3 decision in order to avoid/minimize load shedding. This included a combination of higher levels of supply from local and regional IPPs, more OCGTs usage and a change in the mix of the coal fleet which was required in trying to meet demand and more importantly to protect the stability of the overall electricity system. Eskom has included R8 058 million for primary energy costs in the RCA submission.

3.3 Environmental levy

The lower production volumes and the change in production mix resulted in Eskom incurring environmental levy costs of R1 180 million lower than the assumption made in the MYPD3 determination. The RCA methodology 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 applications. The first tranche of R83 million was granted in the RCA 2013/14 decision. Thus this application represents the third installment.

A further increase in the nuclear provision of R361million was raised during the 2015/16 year. Eskom has phased this over the remaining 8 years and thus R45 million is included in the RCA.

3.5 International electricity purchases

In the MYPD3 RCA 2013/14 decision, NERSA adopted a total approach for revenue and corresponding costs to include regional components. Eskom has taken this on board and has accordingly applied this to the RCA treatment for international purchases relating to the 2015/16 period. The international purchases cost variance contributes R3 567 million to the total primary energy category of the RCA balance.

3.6 Capital expenditure variance

Eskom Company capital expenditure of R56 978 million exceeded the NERSA decision of R42 065million by R14 913 million in 2015/16. 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 capex is excluded when computing the balance for RCA purposes. For RCA purpose the capital expenditure clearing account (CECA) adjustment is R332 million.

3.7 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 2015/16 the operating costs expenditure of R56 258 million (R55198m + R1061m) exceeded the decision of R42 292 million by R13 966 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.

3.8 Integrated demand management

Eskom's energy efficiency and demand side management (EEDSM) programs produced less capacity (in MW) savings during the year resulting in a pay back to consumers of R368 million for RCA purposes.

3.9 Other income

Other income is included under the operating costs section and comprises the sale of scrap assets for R134 million.

3.10 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 R152 million in favour of customers.

3.11 Service Quality Incentives (SQI)

Eskom has achieved the service quality incentive targets set by NERSA for Distribution and Transmission during 2015/16. This resulted in Distribution achieving an SQI of R233 million and Transmission of R85 million, equating to a total of R318 million.

3.12 Reasonableness test

Eskom has computed reasonableness tests, namely the EBITDA: Interest cover ratio and Debt service cover ratio. These tests reflect that the RCA adjustment decision will contribute towards the recovery of full efficient costs and allow Eskom to earn the allowed return. Further, the ratio analysis reflects that even with the RCA adjustment, each measure is well below the acceptable range.

3.13 Trend analysis of MYPD3 RCAs

Eskom has presented the RCA 2013/14 decision and provided the summary of the RCA submission for 2014/15 and RCA 2015/16 below.

Table 2: RCA Trend Analysis over the past 3 years

RCAs trend analysis	Decision RCA 2013/14	Application RCA 2014/15	Application RCA 2015/16
Revenue	6 175	8 787	15 578
Local IPPs	580	4 346	620
International purchases	2 700	3 299	3 567
Coal	2 000	574	3 258
Open Cycle Gas Turbines (OCGTs)	1 252	1 944	689
Other primary energy	72	1 355	728
Environmental levy	-312	-683	-1 180
Nuclear decommissioning of R830m from RCA 2013/14 decision phased in over 10 years	83	83	83
Nuclear decommissioning R361m from RCA 2015/16 decision phased in over 8 years	-	-	45
Integrated Demand Management (IDM)	-432	-149	-368
Demand Market Participation (DMP)	-905	-379	248
Capital Expenditure Clearing Account (CECA)	9	91	332
Service Quality Incentives (SQI)	339	236	318
Inflation adjustment - Opex	33	209	-152
Other income	-353	-528	-134
RCA balance R'millions	**11 241**	**19 185**	**23 633**

3.14 Conclusion

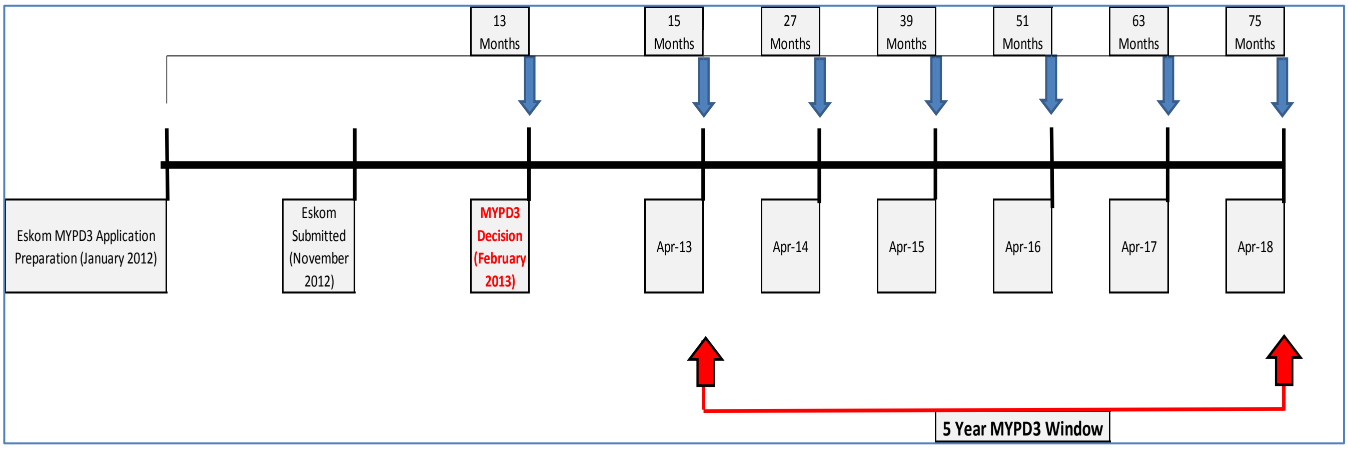
The RCA balance submission of R23 633 million excludes operating costs in excess of the decision of R13 966 million (R12905m + R1061m). Furthermore, in aligning to the NERSA decision precedent set in the RCA 2013/14 decision, Eskom absorbed a large OCGT cost variance of R6 493 million.

4 Factors impacting on 2015/16 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 1: 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 235 TWh by March 2016.	Sales growth averaged a reduction of 0.9% from a starting value of 216.5TWh in March 2013 to 214.5 TWh in March 2016	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 2015/16.	Actual average EAF was 71% with improvement in the last quarter of FY2016	Actual plant performance is lower than that anticipated at the time of preparing the application in early 2012.
New build commission dates for 1st units Medupi – June 2013 Kusile - 2015/16 Ingula – 2013/14 Sere – 2013/14	New build commission revised dates for 1st units: Medupi – Commissioned August 2015 Kusile – July 2018 Ingula – First unit commissioned during 2016 and three others synchronized Sere – Commissioned on 31 March 2015	Due to labour disturbances, contractor failures, and inadequate project management capability, the new build projects have been delayed
Coal country compact < 10%price increases	Efficiency savings implemented through business productivity programme.	Price increases will most l likely exceed the less than the10% assumption.

OCGTs – load factors assumed at 3% based on certain other assumptions materialising	OCGTs – actual load factors >3% due to the other assumptions made at time of application not materialising	OCGTs were utilized as last resort to avoid load shedding
IPPs – local and international	Substantial increase in IPP programs related to DOE programs and securing regional IPPs to address capacity constraints	At the time of the MYPD 3 application, the extent of the IPP programs were not envisaged and additional IPP purchases were required to prevent loadshedding as a cheaper options than OCGTs
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 41 020 by FY 2018	Business Productivity Program (BPP) savings initiative launched in the business.
Maintenance	More maintenance was undertaken than initially envisaged	Addressing the reduced plant performance and maintenance backlog
Other Opex	Roll out of BPP saving plan	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 2015/16 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 revenue variances where the variance of total actual revenue differs from the total allowed revenue.
>
> *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. Other income is classified as operating costs and is therefore discussed under that section

5.2 Calculation of the revenue variance

The table below shows the sales volume and revenue variance with the total average price being marginally below the MYPD3 decision.

Table 4 : Calculation of MYPD3 revenue variance for 2015/16

Revenue variance for 2015/16		MYPD3 Decision	Actuals	Variance
Total external electricity revenue	(R'm)	179 587	163 160	-16 427
Total external sales volumes	(GWh)	235 210	214 487	-20 723
Total average selling price	(c/kWh)	76.35	76.07	-0.28

**Note that the actual revenue reflected above excludes the load reduction impact. Once the load reduction impact of R849m is added back it reduces the revenue variance from R16 427m to R15 578m.*

5.3 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 2015/16 (R'million)	Eskom Company	Notes
Revenue per AFS	163 395	1
Less : Non-electricity revenue	**-1 707**	2
Deferred income recognised	-152	
Other revenue	-1 555	
External electricity revenue	**161 688**	
Add : IAS 18 unrecognised revenue	1 472	3
Internal electricity revenue	-	
Revenue before load reduction adjustments	**163 160**	
Add : Load reduction adjustment	849	4
Revenue for RCA purposes (R' million)	**164 009**	

Note 1: Revenue as reported in Eskom's 2016 AFS:

Revenue from continuing operations of R163 395 million, reported on page 84 of Eskom's 2016 AFS, provides the starting point for obtaining the MYPD equivalent for actual revenue.

Actual electricity revenue was R161 688 million; other revenue was R1 707 million (including deferred income of R152 million) for 2015/16.

Table 6: Revenue note from AFS for March 2016

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
32. Revenue					
Electricity revenue		161 688	146 268	161 688	146 268
Other revenue		1 707	1 423	1 707	1 423
		163 395	147 691	163 395	147 691

Electricity revenue of R1 647 million (2015: R 597 million) was not recognised as it was assessed that there is a high probability that the related economic benefits will not materialise. In addition, 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.

Source: Eskom Annual Financial Statements, 31 March 2016 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 R1 647 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, R175m 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 R1 472 million which is added back to actual revenue for the RCA.

Note 4: Estimated Load Reduction impact on revenue loss for 2015/16

During the third year of MYPD3 there were several interruptions and thus load reduction estimated at 1 064.5 GWh comprised a combination of load shedding and/or load curtailment. Load shedding and/or load curtailment contributed 643.6 hours of interruptions during the year as depicted in the table below. Eskom will thus need to reduce their volume variances to cater for the impact of load reductions.

Eskom has computed the **revenue loss impact using the principle of standard tariff rate.** The load reduction impact of **1 064.5GWh is multiplied by the average standard tariff price of 79.73c/kWh as was determined by NERSA in para 4 of the 2013/14 RCA decision.** . This equates to a total revenue loss attributable to the load reductions of **R849 million**.

Table 7 : Load shedding and curtailment impact in 2015/16

Month	Load shedding Hours	Load Curtailment Hours	Total Load Shedding and/or Curtailment Hours	Load reduction GWh	Standard average price c/kWh	Revenue loss impact R'million
Apr-15	133.2	133.8	136.8	235.2		
May-15	215.6	213.1	225.1	360.4		
Jun-15	129.6	9.0	130.0	213.8		
Jul-15	114.7	30.0	115.0	190.9		
Aug-15	28.9	5.0	28.9	59.3		
Sep-15	2.3	-	2.3	3.4		
Oct-15	-	5.5	5.5	1.5		
Nov-15	-	-	-	-		
Dec-15	-	-	-	-		
Jan-16	-	-	-	-		
Feb-16	-	-	-	-		
Mar-16	-	-	-	-		
Total FY 2016	**624.2**	**396.4**	**643.6**	**1 064.5**	**79.73**	**848.7**

Demand (MW) per hour is taken as the estimated energy consumption for that hour and all hours shed was added to get the total energy (MWh) that was shed for that specific month. This gives an estimated maximum energy consumption impact for that specific month.

The amount of energy reduced by mandatory load reduction is purely an estimation, and has always been indicated as such. This load reduction is a combination of load shedding and/or curtailment, neither of which can be accurately measured. It is also important to note that the behaviour of customers during and around times of load reduction is not normal. Hence the estimated energy reduction is based on how the expected demand compares against the actual demand supplied. Known variances such as demand behaviour on the day, the time of day, the day in the week and the season of each reduction event is also compensated for. Verification is done on the order of magnitude of each event, using the expected reduction for the relevant stage and duration of load shedding and/or curtailment. Hence the final estimation, although having a margin of error, will give a good indication of the behaviour and magnitude of each reduction event. These estimated values are aggregated monthly, as shown in the table above.

Power system emergency declarations and load shedding

From 1 April to 8 August 2015, a total of 79 load reductions were required, particularly over evening peaks. Since then, Eskom had no load shedding, apart from one incident on 14 September 2015, when a low frequency event led to load shedding for 2 hours and 20 minutes. Load to key customers had to be curtailed on 9 October 2015, when five generating units tripped or had to be taken off load.

The reduction in load shedding since August can be attributed to Medupi Unit 6 going into commercial operation on 23 August 2015, adding a nominal capacity of 720MW to the national grid, the implementation of the Generation maintenance strategy, lower than expected demand and other interventions. No load shedding is currently forecast for 2016/17. Additional generation capacity is planned to be commissioned by both Eskom and IPPs in the new financial year. However, the system remains vulnerable to incidents of simultaneous high unplanned outages or partial load losses, and high demand.

5.4 Allowed Revenue

The allowed revenue of R179 587 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 MYPD2 RCA decision.

Table 8: Allowed revenue

Allowed Revenue 2015/16	R'million	Extract ref
MYPD3 Revenue	171 769	**1**
MYPD2 RCA decision	7 818	**2**
Total Revenue	**179 587**	

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)

Extract 2:

Source: NERSA "The implementation plan of Eskom MYPD 2 Regulatory Clearing Account (RCA)

THE DECISION

Based on the available information and the analysis of Eskom's MYPD2 Regulatory Clearing Account (RCA) balance implementation plan, Energy Regulator, at its meeting held on 17 September 2014 decided as follows:

1. The RCA balance of R7 818m be recoverable from the standard tariff customers as well as all other Eskom customer categories. The recovery should be in proportion to the contribution by the two customer groups to the forecasted sales volume for the years of implementation (2015/16).

2. The RCA balance of R7 818m be implemented for the 2015/16 financial year only.

3. The average tariff for standard customers be increased by 12.69% for 2015/16 financial year.

4. The amounts of R7 085m be recovered from standard tariff customers for the 2015/16 financial year only.

5. The amounts of R733m be proportionally recovered for the 2015/16 financial year only from the other customers of Eskom as defined

5.5 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 Operation and maintenance (O&M) costs in the current 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 included in the returns and depreciation building blocks of the allowed revenue for regulatory purposes.

5.6 Allowed vs Actuals volumes

Table 9 : Sales volume variance

Sales volumes variance per tariff category (GWh)	MYPD3 Decision	Actuals	Variance
SPA sales	11 333	9 684	-1 649
Add: Standard tariff sales including internal sales	213 544	192 089	-21 455
Total Distribution sales	**224 877**	**201 773**	**-23 104**
Add: International sales [2]	10 761	13 376	2 615
Total Sales to all customers [1]	**235 638**	**215 149**	**-20 489**
Less: Internal sales	-428	-661	-233
Total external electricity sales	**235 210**	**214 487**	**-20 723**

Note 1: The 235 638 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 13 465GWh (13 376GWh + 89GWh) which are based on the geographical location in which the sale occurred.

For regulation the 89GWh is not shown as International sales as this is sold by Distribution and as such forms part of Distribution sales.

Table 54: Approved sales volumes forecast, MYPD3 decision

GWh	2013/14	2014/15	2015/16	2016/17	2017/18	MYPD3 Total
Standard tariff sales	206 587	208 441	213 544	218 193	223 217	1 069 982
Negotiated pricing agreement	11 303	11 303	11 333	11 302	11 302	56 543
Exports	9 513	9 769	10 761	9 618	9 507	49 168
Approved sales forecast	227 403	229 513	235 638	239 113	244 026	1 175 693
GDP	2.6	3.6	3.6	3.9	4.0	

5.7 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 three years

Table 10: MYPD3 Sales volume

Total Eskom Sales (GWh)	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
MYPD3 sales (GWh)	222 756	227 403	229 513	235 638	239 113	244 026
MYPD3 growth %	-1.10%	2.09%	0.93%	2.67%	1.47%	2.05%
Actuals sales (GWh)	216 561	217 903	216 274	214 487		
Actual sales growth %	-3.66%	0.62%	-0.75%	-0.83%		

5.7.1 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.

5.7.2 Critical changes in assumptions relevant during 2011 in deriving forecasts

Table 11 : GDP forecasts used for MYPD3 in 2011

GDP growth %	2 012	2 013	2 014	2 015	2 016	2 017
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%		

- The actual GDP growth rates were approximately half the forecasted assumptions as received from various economic forecasts at the time.
- The most rapid growth in recent decades has been in the less energy intensive services sectors, while the contribution of the energy intensive Mining sector started to dwindle.
- Price increases will continue for the 3 years up to 2015/16 (combined increase of 25%). In addition, the price was already +/- 3 times what it was in 2008/9.
- A substantial amount of furnace load would not be utilized in winter because of the higher winter prices.
- Furnace utilization would be about 95% in the summer months.
- Large Co-gen projects that are in an advanced stage in the commissioning process have been included in the budget.
- Municipality generation assumed for inclusion of Power Purchase Agreements (PPAs) up to 2013/14, thereafter normal own generation.
- Variance in the forecasted Commodity Prices used in the Decision vs the Actual average prices were higher than assumed.

Table 12: Commodity Prices assumed

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

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

5.7.3 Sales volume variance explanation for FY2016

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

Table 13 : Sales volume variance

Sales volume variance per customer category (GWh)	Actual Sales	MYPD 3	Variance
International	**13 376**	**10 761**	**2 615**
Distribution sales	**201 773**	**224 877**	**(23 104)**
Re-distributors	89 591	98 510	(8 920)
Industrial	50 150	60 145	(9 995)
Mining	30 629	36 210	(5 582)
Traction	2 852	3 133	(281)
Residential	4 034	4 555	(521)
Commercial	10 150	9 729	421
Agricultural	5 733	5 276	457
Prepayment	7 820	6 802	1 019
International A	89	89	0
Internal Sales	661	428	234
Other	64	-	64
Total electricity sales volumes	**215 149**	**235 638**	**(20 489)**
Exclude Internal sales	-661	-428	(234)
Total external electricity sales volumes	**214 487**	**235 210**	**(20 723)**

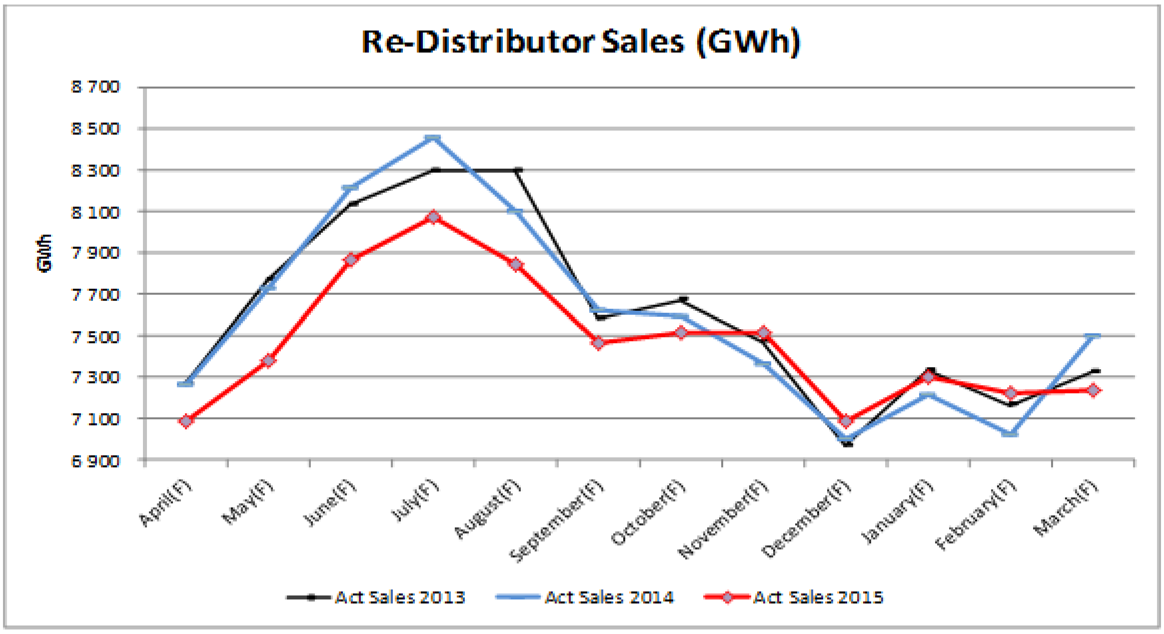
From the table above, which reflects the variance between the decision and Actual sales for the year, it can be seen that the unfavorable variance of 23 104GWh in respect of distribution sales is mainly due to three categories, namely Redistributors, Industrial and Mining. The unfavorable variances in these three categories were partially offset by the favorable variance of 2 615 GWh from the export sales and 1 019 GWh from the prepayment environment.

5.7.3.1 Redistributors: 8 920 GWh unfavourable

The unfavorable variance in this category is spread over most of the Municipalities and metro's and 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 2015 the abnormal warm winter also reduced the energy consumption.
- Rotational load shedding had a further impact on the consumption in the Metro's and Municipalities.
- 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.
- NUMSA strikes also negatively affected the consumption in certain Metro's in 2015.
- 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 2 : Performance of Re-distributors



5.7.3.2 Industrial: 9 995 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 (1 260 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 7 211 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 very high 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 only three customers Highveld steel, IFM and ASA metals is a reduction in demand of 3 194 GWh.

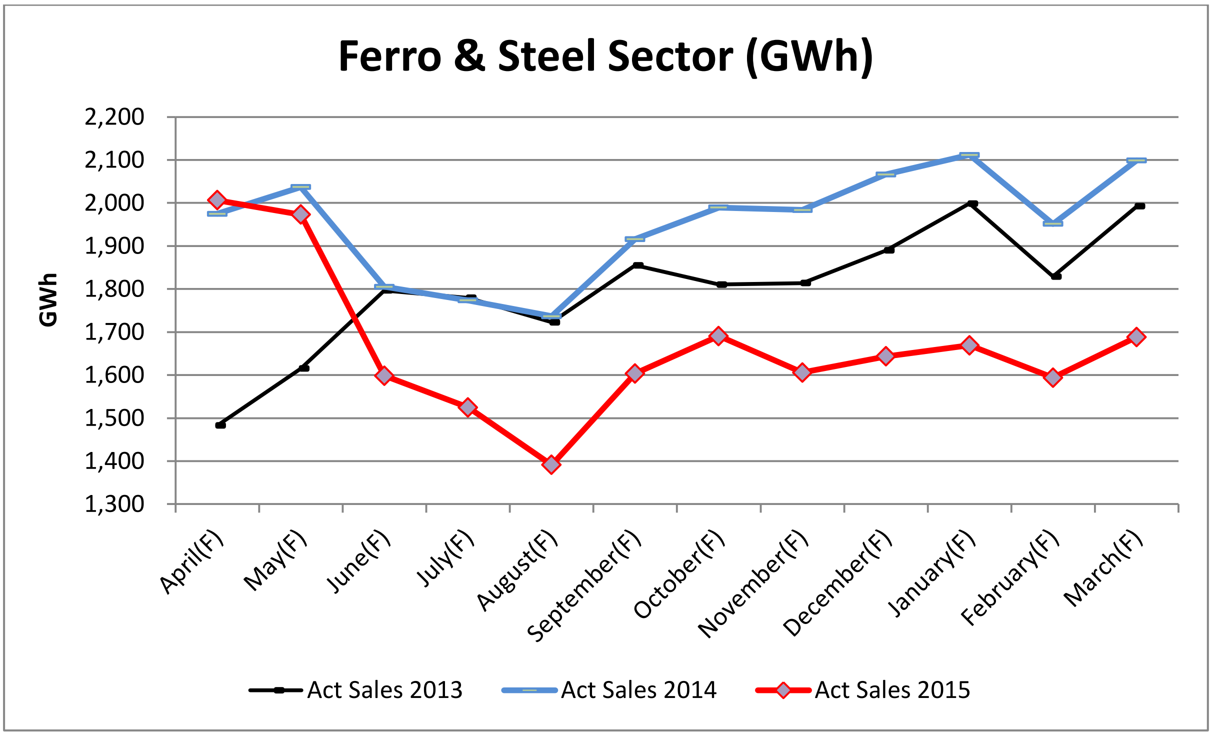
- The Titanium sector posted a decline of 1 087 GWh mainly due to the the drop in world demand for their product and the resultant very weak commodity price. This caused the partial closure of furnaces at RBM (883 GWh) which forced production cuts at the plant.
- The closure of EB Steam customers also affected the sales unfavourably.

Table 14 : Commodity prices

	Unit	2014 CY	2015 CY	2016 Q1
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, December 2015

Figure 3 : Performance of Ferro and Steel



5.7.3.3 Mining: 5 582 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 18% year-on-year in 2015, according to figures from Statistics South Africa. Worst hit were Platinum Group Metals (PGM's), which declined by 23.7%, Manganese ore (-24.3%) and iron ore (21.4%). Coal production dropped 15.8% and Gold production was 7.4 % lower. Part of the drop in Platinum output is attributable to a closure at Amplats refinery and Implats 14 Shaft. 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 2 578 GWh drop in consumption against the MYPD NERSA decision mainly due to
    - labour unrests which caused shaft closures . The Platinum Industry has endured the longest strike in history during 2014.

- 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

- The Gold sector realized a 2 435 GWh drop in consumption against the budget 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.

5.7.3.4 Prepayment: 1 019 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.

5.7.3.5 International: 2 615 GWh favourable

The favourable variance against the MYDP NERSA decision was mainly due to the higher than budgeted sales mainly due to the delay of BPC Morupule power station being commissioned. This resulted in more sales to. neighbouring countries.

The drought affecting the Southern African region continued in 2015/16, resulting in reduced hydroelectric capacity available in the DRC, Zambia and Zimbabwe. This continues to provide Eskom with a market for additional electricity sales. Non-firm sales are being made to ZESCO and the Copperbelt Energy Corporation, both of Zambia, and ZESA of Zimbabwe. The lower water levels also led to reduced generation specifically at Ruacana which meant increased Sales from Eskom to NamPower.

Exports Sales

Eskom has bilateral electricity trading agreements with most SAPP members and continues to export and import electricity. Eskom is aware of its responsibility to South Africa regarding the exporting of electricity when the domestic supply-demand balance is constrained. Eskom has ensured that the contracts with SAPP trading partners are sufficiently flexible to allow for the following controls:

- During emergency situations in South Africa, non-firm agreements (Botswana and Namibia) and industrial customers across the border (Mozal and Skorpion Zinc) are interrupted in line with the terms of their agreements
- The remaining firm supply agreements (Swaziland and Lesotho) continue to be supplied in full, but they are urged to reduce consumption. During load shedding in South Africa they are required to undertake proportional load shedding.

5.8 Conclusion on the 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 revenue variance of R15 578m in 2015/16.

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 2015/16. Embedded in Eskom's MYPD3 application was an assumption for EEDSM which was taken into consideration when determining the sales forecasts. In the 2015/16 year, NERSA assumed 763 GWh of energy savings at a cost of R819 million which culminated in 187 MW of capacity savings.

In reality, EEDSM achieved lower savings during the year generating 119 MW of capacity savings at a cost of R413 million. For RCA purposes, however, the verified MW savings of 102.8MW at March 2016 is used results in an underachievement incorporated in the RCA mechanism.

In addition, NERSA assumed DMP costs of zero in 2015/16 while actual expenditure was R248 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 which is compiled on an accrual basis. 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 RCA implementation risks

Eskom is concerned that NERSA has determined that a proportion of the RCA award should be recovered from local SPAs and cross border customers. Local SPA revenue is based on bilateral contracts between Eskom and the counter parties and a major portion of export revenue is also based on bilateral contracts with counter parties. Hence, Eskom is of the opinion that it would be virtually impossible to recover the respective RCA amounts from these customer categories.

9 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:

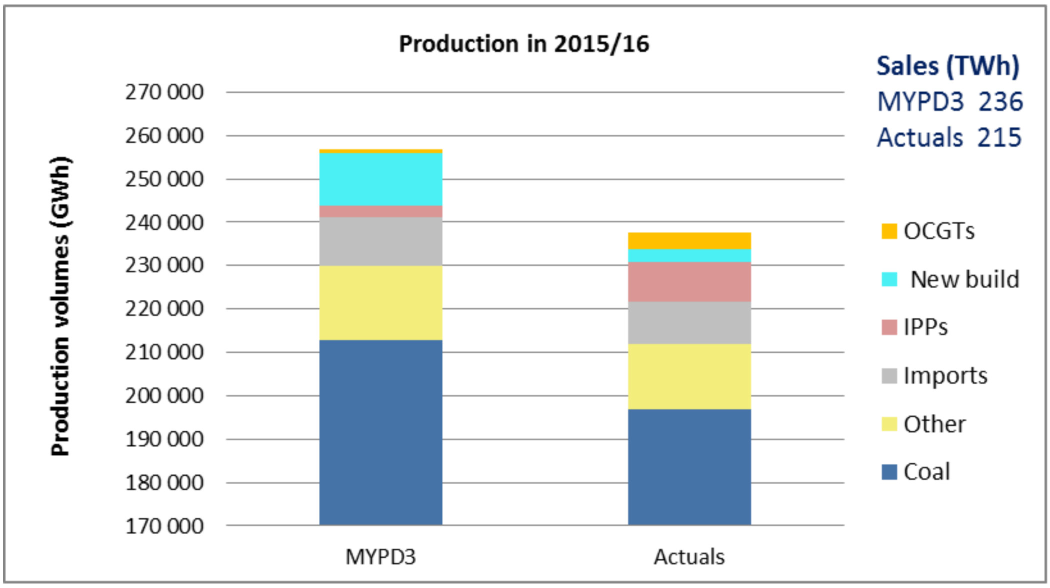
In compiling this document Eskom has adhered to globally-accepted standards of sound regulation

10 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 21TWh, delays in new build commissioning, 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 4: Production FY 2016



11 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.

11.1 Primary energy variances and RCA impact for 2015/16

Total primary energy allowed for 2015/16 was R71 605 million. Eskom incurred R84 728 million in the year which resulted in an extra cost of R13 123 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. OCGTs – Eskom has aligned the OCGT RCA amount to the precedent adopted by NERSA in their 2013/14 RCA decision.
4. 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 2015/16 RCA and
   - Implementation of the current 2015/16 provision of R361 million over the remaining life of 8 years i.e R45m inclusion in the RCA
5. 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 R340 million is deemed to be accounted for as an IPP purchase.

Hence the sum of all these adjustments is R5 065 million and thereby reduces the total primary energy variance to R8 058 million. Refer table below for the RCA calculation for total primary energy.

Table 15 : Total primary energy comparison and RCA impact for 2015/16

Primary Energy , R million	MYPD3 Decision	Actuals	Variance	RCA adjustments	RCA 2015/16
Coal	39 838	41 775	1 937	1 321	3 258
OCGTs	1 508	8 690	7 182	-6 493	689
Local IPPs and co-generation	14 826	15 106	280	340	620
International purchases	93	3 660	3 567	-	3 567
Environmental levy	9 300	8 120	-1 180	-	-1 180
Nuclear decommissioning of R830m from RCA 2013/14 decision phased in over 10 years	-	-	-	83	83
Nuclear decommissioning R361m from RCA 2015/16 decision phased in over 8 years	-	-	-	45	45
Water	2 101	1 673	-428	-	-428
Start up gas & oil	1 631	2 288	657	-	657
Coal handling	1 186	1 728	542	-	542
Water treatment	281	365	84	-	84
Nuclear	498	918	420	-361	59
Fuel procurement	287	156	-131	-	-131
Sorbent	56	1	-55		-55
Primary energy , R million	**71 605**	**84 480**	**12 875**	**-5 065**	**7 810**
Demand market participation	-	248	248	-	248
Total primary energy , R million	**71 605**	**84 728**	**13 123**	**-5 065**	**8 058**

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

Extract from the AFS, March 2016 reflects the actual total primary costs of R84 728m below.

Table 16: Primary energy actual costs per note 34 in the AFS of 2016, pg 35

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
34. Primary energy					
Own generation costs		**57 594**	61 630	**57 594**	61 630
Environmental levy		**8 120**	8 353	**8 120**	8 353
International electricity purchases		**3 660**	3 679	**3 660**	3 679
Independent power producers		**15 106**	9 453	**15 106**	9 453
Other		**248**	310	**248**	310
		84 728	83 425	**84 728**	83 425

Own generating costs relates 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.

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

11.2 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.

11.2.1 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). As at 1 April 2015 only one contract (of 13 MW) remained in operation under this programme, as the others had all expired.

11.2.2 Municipal Base-load Purchases

Following continued capacity concerns Eskom approached municipalities to assist with additional generation. Of these contracts only one remained operational during the 2015/16 financial year (with City Power for 250 MW).

11.2.3 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.

11.2.4 Wholesale Electricity Pricing System (WEPs) programme

Eskom enters into annual contracts with embedded generators outside of the ambit of the MTPPP and short-term contracts. These contracts are paid at wholesale prices (effectively Eskom’s average price of generation, inclusive of external energy purchases). For the 2015/16 year 87MW of capacity was contracted.

11.2.5 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, and is the designated purchaser of supplied energy.

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

Power purchase agreements (PPAs) of 1 005MW for the Avon and Dedisa plants were entered into on June 2013 and became effective on 29 August 2013. Commissioning of Dedisa took place on 30 September 2015 (335 MW), while Avon is expected during mid-2016.

11.2.7 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).

Eskom has now signed contracts for a total of 3 900MW under the RE-IPP Procurement Programme. As at 31 March 2016, a total of 2 145MW has been connected and is providing power to the grid. An average load factor of 30.7% was achieved during the year. Renewable IPPs are driven by wind and solar PV technologies.

Figure 5: IPPs contracted and connected (by province)

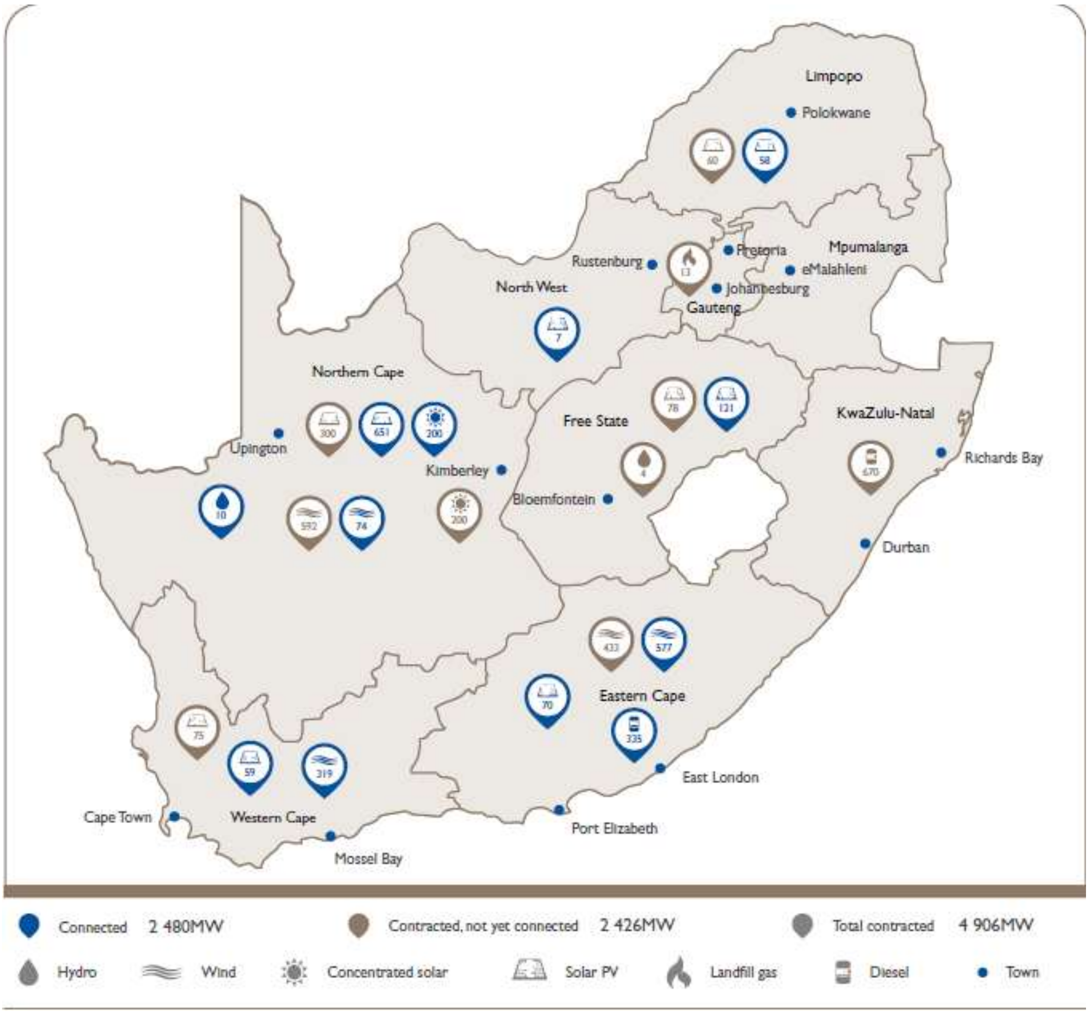


Figure 6: IPP operational capacities by type and location at 31 March 2016

Province, MW	RE-IPP Programme				Diesel	Other short term	Total
	Concentrated solar power	Photo-voltaic	Hydro and biomass	Wind			
Eastern Cape		70		577	335		982
Free State		121				114	235
Gauteng						250	250
KwaZulu-Natal						123	123
Limpopo		58					58
Mpumalanga						413	413
Northern Cape	200	651	10	74		12	946
North West		7					7
Western Cape		59		319			377
Total operational	200	965	10	970	335	912	3 392
Total contracted	400	1 479	27	1 995	1 005	912	5 818

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.

11.3 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.

11.4 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.

11.5 Regulatory rules for power purchase cost recovery

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

> ***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.*

11.6 Allowed vs Actual IPP costs for 2015/16

Eskom was awarded a total of R14 826 million for IPP's in the MYPD 3 decision for 2015/16. This includes IPP ancillary costs of R388 million.

Actual costs amounted to R 15 397 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 2 031 GWh more energy from IPPs when compared to the MYPD3 decision in 2015/16.

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

Table 17: IPPs costs and volumes

Independent Power Producers (IPPs) 2015/16	Costs (R'million)			Volumes (GWh)			Average Costs (R/MWh)			Note
	Actuals	Decision	Variance	Actuals	Decision	Variance	Actuals	Decision	Variance	Reference
Non-renewable programs	**3 674**	**-**	**3 674**	**3 969**	**-**	**3 969**	**926**	**-**	**926**	
MTPPP	56	-	56	44	-	44	1 269		1 269	A
STPPP	2 682	-	2 682	2 816	-	2 816	952		952	B
Municipalities	858	-	858	976	-	976	879	-	879	B
WEPS	78	-	78	132	-	132	595		595	C
Renewable IPP's	**11 182**	**13 243**	**-2 061**	**5 003**	**6 835**	**-1 832**	**2 235**	**1 938**	**298**	
Renewable IPPs energy	11 158	13 243	-2 085	5 003	6 835	-1 832	2 230	1 938	293	D
Renewable IPPs - deemed energy payment	24	-	24	-	-	-				D
DOE Peaker	590	1 195	-605	62	168	-106	9 540	7 130	2 410	E
Total IPPs	**15 446**	**14 438**	**1 008**	**9 034**	**7 002**	**2 031**	**1 710**	**2 062**	**-352**	
IPP ancilliary costs	-	388	-388							F
Total IPPs for RCA	**15 446**	**14 826**	**620**	**9 034**	**7 002**	**2 031**				

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

11.6.1 Reasons for IPP variances in 2015/16

Eskom utilized 2 031 GWh more energy from IPPs when compared to the MYPD3 decision in 2015/16, resulting in R620 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 a number of large REIPPP projects that experienced commissioning delays and some projects performing below the expected P50 values in the PPAs.

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 R23.9 million for the year were made due to:

- The delay in grid connection for two projects
- A System Event relating to grid connection for one project

- A System Event relating to extended network disruption for one project

Not included as deemed energy (but paid as part of the total) is an additional payment for a Compensation Event for one IPP of R11.9 million.

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. 4, 2% for the period of operation) relative to the expected 5%.

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

F. TRANSMISSION ANCILLIARY COSTS

NERSA approved R388 million for Transmission ancillary costs in the MYPD3 determination for FY 2016. 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 2016 the total payment for use of system charges was R48,6 million. This is included in the total payment for REIPP.

Energy capacity and purchases

This table summarises the IPP capacity available and the actual energy procured under various IPP programmes for the year to 31 March 2016, including the comparative year ending 31 March 2015.

Figure 7: IPP capacity available and the actual energy procured

Measure and unit	Actual 2015/16	Actual 2014/15
Total capacity, MW	**3 392**	2 606
Total energy purchases, GWh	**9 033**	6 022
Total spent on energy, R million	**15 446**	9 454
IFRIC 4 reallocation, R million	**(340)**	–
Total spent after reallocation, R million	**15 106**	9 454
Weighted average cost, c/kWh	**171**	157

1. The weighted average cost has been calculated on the total energy cost before the IFRIC 4 reallocation.

Eskom entered into a power purchase agreement with the IPP peaker Dedisa. For IFRS purposes, the capacity charge is treated as an arrangement that contains a lease in terms of IFRIC 4. The lease has been assessed as a finance lease and is accounted for under property plant and equipment at a fair value of R3 492 million. The IPP cost for Dedisa of R541 million under primary energy has been reduced by R292 million, and depreciation of R135 million and interest of R302 million will be charged to the income statement.

During the peak demand hour in 2015 renewable IPPs were producing at 24% of their total capacity (with wind generating at 52% of capacity, but none from solar photovoltaic as the peak hour occurred during the evening.) Deemed energy payments of R23.9 million were made during the year (2014/15: R129 million), due to delays in grid connection for two projects and a network failure at a substation taking power from the IPP, which resulted in 24 hours of lost generation. Furthermore, a deemed energy payment of R11.9 million was required for a delay in the issuing of the grid compliance certificate for one IPP. These amounts are included in the total RE-IPP expenditure.

Projects that have signed PPAs are in various stages of construction.

Table 18: IPPs contracted and connected

MW	Connected to date	Contracted not yet connected	Total contracted
RE-IPP Programme	2 145	1 756	3 901
DoE Peaker Programme	335	670	1 005
Long-term IPPs	2 480	2 426	4 906
Short-term IPPs	912	–	912
Total	3 392	2 426	5 818

11.7 IPP variance for 2015/16 RCA

IPP variance = Actual IPP costs – Allowed IPP costs

Eskom **spent R15 106m** for local IPPs which **exceeded** the **IPP allowance** of **R14 826m** resulting in an over expenditure of **R280m** during 2015/16.
In addition the accounting adjustment of **R340m** was reversed for regulatory purposes, resulting in a total RCA of **R620m.**

12 International purchases

Eskom acquired electricity from neighboring countries that resulted in purchases of R3 660 million which generated energy inflows of 9 703 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 19: International purchases

International purchases , R million	MYPD3 Decision	Actuals	RCA 2015/16
International purchases	93	3 660	3 567

** Actuals includes Aggreko purchases of R643 million*

Cross-border sales and purchases of electricity

The drought affecting the Southern African region continued in 2015/16, resulting in reduced hydroelectric capacity available in the DRC, Zambia and Zimbabwe. This continues to provide Eskom with a market for additional electricity sales. Non-firm sales are being made to ZESCO and the Copperbelt Energy Corporation, both of Zambia, and ZESA of Zimbabwe.

Eskom is providing support to the region to the extent possible, but given the domestic constraints, support is mainly limited to off-peak hours. We are aware of our responsibility to South Africa regarding the exporting of electricity when the domestic supply-demand balance is constrained. 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 20 : Cross border sales and purchases

GWh	Actual 2015/16	Actual 2014/15
International sales	**13 465**	12 000
International purchases	**9 703**	10 731
Net sales/(purchases)	**3 762**	1 269

12.1 Regional IPPs - Aggreko

In order to enable Eskom to address its short-term supply side challenges (as identified in the Medium Term Risk Mitigation Strategy) in the Integrated Resources Plan 2010, energy purchases from cross border base-load and peaking generation plant were to be considered. Eskom through its Southern African Energy (SAE) Unit, entered into a PPA with AIPL (Aggreko International Projects Limited) for a contracted capacity of 92.5MW from the Aggreko-Shanduka Gas Fired Plant in Ressano Garcia, Mozambique.

Eskom had received approval from NERSA for cost recovery of the Aggreko project in terms of the regulatory rules for cost recovery for power purchases. The project was exempted by the Minister of Energy from the requirement to obtain a Ministerial Determination under regulation 11 of the Electricity Regulations on New Generation Capacity of 04 May 2011, due to the short term nature of the project, and to allow Eskom to address its short term challenges.

A due diligence of the AIPL project also showed that the power station would reduce overall transmission losses between RSA and Mozambique, and also deload the transformer in Maputo. The AIPL price was higher than most of the conventional fossil fuel base load plants, but lower than gas and most of the renewable energy technologies. In addition the lead time for fossil fuel base load plants is at least 5 years, whereas AIPL has a lead time of 4 months, which was in line with the maintenance requirements of Eskom. Renewable technologies had longer lead times than the AIPL project, are intermittent in nature, and more expensive than AIPL.

On the basis of the above, NERSA approved the cost recovery on the 6 June 2012, for a period of 2 years, for 92.5MW as a base load power station with 100% load factor. Eskom had envisaged that there would be no requirement to extend the agreement after the expiry date as the coal base load plants would be online then and therefore did not include the costs associated with this project in its MYPD3 application to the Energy Regulator.

However, due to delays in new build coal plants, Eskom applied for the extension of this PPA by 14 months (from 01 July 2014 to 31 August 2015), the approval of which was granted. The recovery of the actual costs will occur via the RCA.

The supply profile was now based on a load profile that would maximize the benefits of the power from the plant i.e. off-setting the OCGT's; hence the plant would now be operated as mid-merit (delivering a minimum of 100MW off-peak hours, and a maximum of 148MW peak hours).

This project was used as a lever to contribute towards the supply and demand challenges. During 2015/16 Eskom incurred R643 million costs to acquire energy from regional sources.

13 Coal Burn Costs

13.1 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".

13.2 NERSA's decision on coal benchmark and alpha

The following information was received from NERSA:

Table 21: NERSA's decision on coal benchmark and alpha

Coal benchmark	Unit	MYPD3 2015/16
Coal burn costs	R'm	39 838
Coal burn volumes	kt	128 000
Benchmark avg cost rate	R/t	311.2

13.3 Coal cost – RCA 2016 calculation

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

13.3.1 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 2015/16
*PBR cost (Rand) =(((0.95 X R378.8) + (1-0.95) X R311.2)) X 114 806 Mt)/**1000***
PBR cost (Rand) = R43 096m

Where
Alpha = 0.95
Actual coal burn volume = 114 806 Mt
Actual unit cost of coal burn = R378.8 per ton
Coal burn benchmark cost = R311.2 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 R41 775m and adding back the reversal of R1 709m take or pay contractual amount which results in cost of R43 484m. Thereafter the adjusted actual cost of R43 484m is divided by the volume of coal burn of 114 806Mt resulting in an average actual R/t of R378.8.

Table 22: Working Coal Mechanism

Workings of coal mechanism	Unit	MYPD3	Actuals	Variance
Coal burn	R'm	39 838	41 775	1 937
Coal disallowed for qualifying actuals costs	R'm	-	1 709	1 709
- Medupi take or pay agreement	R'm		1 709	
- Kusile take or pay agreement	R'm		-	
Coal burn costs	R'm	39 838	43 484	3 646
Coal burn tons	Mt	128 000	114 806	-13 194
Costs rate per ton	R/t	311.2	378.8	67.5
Alpha - sharing mechanism	%	95%	95%	
Coal rate after incl Alpha	R/t	295.7	359.8	64.2
Adjusted MYPD3 decision with alpha		375.4		

13.3.2 Step 2 – Calculate the pass through coal burn costs

For 2015/16

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

Pass-through Coal Burn Cost = R43 096m – R39 838m
Pass-through Coal Burn Cost = **R3 258m**

Where
PBR cost = R43 096m
Allowed coal burn cost = R39 838m (per MYPD3 decision)

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

Table 23: The coal burn breakdown for the RCA

Coal burn variance breakdown	Unit	RCA 2015/16
Coal burn price variance	R'm	8 211
Coal burn volume variance	R'm	-4 953
Coal burn costs included in RCA	R'm	**3 258**

The coal burn variance of R 3 258m 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 R4 953m 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 variance of R8 211m 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 = 128000 X ((R378.8 – R311.2) X 0.95)

Coal price variance = 128000 X R64.2

Coal price variance = **R8 211m**

Where:

Allowed coal burn tons (Mt) = 128 000 Mt

Actual Price (R/t) = R378.8

Allowed Price (R/t) = R311.2

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 = (R311.2 + ((R378.8- R311.2) X 0.95)) X (114 806 – 128 000)

Coal volume variance = (R311.2 + R64.2) X -13 194

Coal volume variance = R375.4 X -13 194

Coal volume variance = -**R4 953m**

Where:

Allowed coal burn tons (Mt) = 128 000 Mt

Actual coal burn tons (Mt) = 114 806 Mt

Allowed Price (R/t) = R311.2

13.4 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 24: MYPD 3 Assumptions vs. Actual 2015/16

MYPD3 FY16 Assumptions	Actual 2015/16
Electricity production from coal fired plant would be 229 194 GWh.	Electricity production from coal fired plant was 199 061 GWh.
Cost Plus and Fixed Price mines produce at expected levels, except for Arnot	Cost Plus and Fixed Price mines produced below expected levels by 19 899 kt.
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, primarily because of funding constraints.
The new power stations (Medupi and Kusile) use flue gas desulphurisation (FGD) at 0.45 litres per units sent out (l/USO).	Medupi and Kusile did not come into commercial operation.
Majuba heavy haul line and other rail infrastructure are approved, constructed and commissioned on schedule.	Rail infrastructure was delayed
Water consumption per unit was 1.54 litres for coal fired power stations	Water consumption per unit was 1.56 litres for coal fired power stations
Current infrastructure is old and the backlog of maintenance will also result in an increase to the water tariff.	The DWA was unable to carry out all planned maintenance and still has a backlog.

13.4.1 Different mix and efficiency of power stations generating electricity

The utilisation of the coal power station fleet to generate electricity resulted in a price variance driven by:

- The delay in commissioning of Medupi Power Station.
- The under production of Arnot and New Denmark collieries meant that more expensive coal, had to be sourced for Arnot and Tutuka.

13.5 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.

13.5.1 Long term fixed price contracts

The total cost of coal includes the cost from different types of contracts and a transport cost for ST/MT contracts. The fixed price contracts were the cheapest source of coal. The pricing structure of these contracts is linked to the volumes delivered by the supplier. 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. The bulk of this coal is from mines that are next to the power stations that they supply, so the transport cost is minimal and is via conveyor belt. Approximately 28% of coal for FY16 was sourced from long term fixed price contracts.

13.5.2 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. In this type of contract where the total output is dedicated to Eskom, the bulk of the risk is carried by Eskom in return for coal prices per ton which are generally lower than any other type of contracts. Additional capital investments and operating expenditures are required to improve the quality of coal or to increase the annual production volumes will impact the price per ton of coal to Eskom.

Historically, when Eskom required the Cost Plus mines to supply coal volumes in excess of their contractual obligations, the mines were willing to do so. The only cost to Eskom, and the consumer, was the variable rate of return that the mines earned, so it was cheaper than buying coal elsewhere. Between 1996 and 2011, the Cost Plus mines supplied Eskom's power stations 51.6 Mt more than their contractual volumes. The impact of this has been felt in the more recent past. The mines depleted reserves that would have been supplied to Eskom in later years. As electricity demand increased, additional reserves needed to be accessed and new equipment was required. Because of funding constraints, future fuel expenditure on the Cost Plus mines is one of the items that has been reduced. The result has been lower production from these mines and a consequent increase in the R/ton cost. This lower production is one of the reasons for the increase in coal purchased on ST/MT contracts.

The under production during FY16 occurred, mostly, at Arnot, New Denmark, New Vaal and Matla mines. There has been limited investments in the cost plus mines in recent years which have impacted negatively on the production from these mines. It is foreseen that this impact will be felt during the remainder of MYPD3, as well. Cost plus mines provided approximately 33% of the coal procured in FY16.

13.5.2.1 ST/MT contracts

Coal from the ST/MT contracts is the most expensive coal supply source. One reason is that the contracts are of a shorter duration, so suppliers do not have the security that comes with long term contracts. The mining operations under these coal supply agreements have generally been commissioned after the mines under the Cost Plus and Fixed price agreements and thus they do not have the benefit of historically lower cost of infrastructure and establishment. However, the primary reason is because the cost of coal on ST/MT contracts includes a significant transport cost element.

This coal is typically further away from the power station than coal on long term contracts. It, therefore, is transported by road or rail, sometimes a combination of the two. The rate per ton/km is influenced by the distance of a route and the condition of the road, with longer routes are more expensive. In addition to the actual transport cost, a handling cost is incurred when coal is loaded and offloaded. This handling cost is increased if coal is taken to a rail siding before being sent on to a power station.

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. During the life cycle of a contract the coal prices are typically not directly impacted by the price of export coal but the export price may have an impact at inception in that the supplier may reference this price at the time of negotiations. However, Eskom's policy has been to pay the operating cost of extracting the coal plus a fair return on the required capital investment. Whether this price correlates to the export price at any given time during the life cycle of the contract is likely to be purely coincidental. These contracts supplied approximately 39% of the coal in FY16.

In FY16 Eskom burned less than forecasted with the cost plus and fixed price contracts produced fewer tons than forecasted. Although electricity generation was lower than forecasted, ST/MT purchases at some stations were higher such as Arnot, Tutuka and Matla because of production problems at these stations' dedicated mines. Purchases were also higher at Majuba and Camden (supplied by ST/MT contracts) due to actual production being higher than anticipated following changes in mix of stations.

The additional cost associated with purchasing ST/MT coal is the transport cost. Coal may be transported by conveyor, rail, road or a combination of modes. ST/MT coal is typically unable to be transported by conveyor.

13.6 Future Fuel

Future fuel had a variance of R1 747million when compared to the decision. This was primarily due to reprioritisation of capital expenditure. As shown in Table below, this comprises R46 M from future fuel (Water) and R1 702m from future fuel (Coal) respectively.

Table 25: Future Fuel (Coal & Water)

	MYPD3 decision	FY16 Actual Expenditure	Decision vs Actual
Coal	2,318	617	1,702
Water	53	7	46
Total	2,371	624	1,747

13.7 Coal Qualities

In FY16, Tutuka and Matla Power Stations accounted for approximately 97% of coal-related load losses. The partial load losses reduction plan is divided into 3 phases, short-, medium-, and long-term. The short term solutions have already been implemented successfully in the priority power stations, namely Matla and Tutuka. The thermal load loss indicator as a gatekeeper in the allocation of losses will also be implemented as a short-term solution.

13.8 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 dominant transport source is conveyor (62%), road (27%) and rail (11%).

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 FY16.

b. Rail

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

c. Road

Road is the most expensive mode of transport. Because of rail infrastructure constraints, ST/MT coal to all stations, is transported by road or a combination of road and rail (multi-mode transport). In some instances, this multi-mode may be more expensive than road alone because of the costs associated with rail sidings, loading and offloading. The increase in volumes on road is a result of the change in the station/burn mix (i.e. increase in burn at stations without rail infrastructure and stations that do not have dedicated mines, such as the RTS stations.

13.9 Medupi Take or Pay payment

A take or pay payment was incurred because of the delay in the construction of Medupi Power Station. The provision was reduced by R1 727 million.

13.10 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. Eskom provided for the amounts payable in terms of the risk sharing agreement during FY13. During FY16, interest of R18m was incurred on the provision.

13.11 Securing our coal requirements

Table 26: Securing our coal requirements

Measure and unit	Actual 2015/16	Actual 2014/15
Coal burnt, Mt	114.81	119.18
Coal purchased, Mt	118.70	121.67
Coal stock days	58	51
Road-to-rail migration (additional tonnage transported on rail), Mt SC	13.6	12.6

The significantly higher than targeted stock days is largely due to more coal than that required being delivered to Lethabo and Medupi Power Stations. Lethabo is supplied by a cost-plus mine, where there is no financial benefit in reducing the coal production. The high coal stock level at Medupi is caused by us taking delivery of coal in terms of the take-or-pay contract, even though the commissioning of units at Medupi has been delayed.

14 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).

14.1.1 Allowed other primary energy costs

Other primary energy costs in the MYPD 3 decision for 2015/16 is R6 040m. The details are presented in the table below.

14.2 Allowed vs Actual other primary energy

Eskom incurred R7 129m relating to other primary costs during 2015/16 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 040 million by R1 089 million. By effecting the necessary adjustments the RCA claim is R856 million as highlighted in the table below.

Table 27: Other Primary Energy

Other Primary Energy , R' million	MYPD3 Decision	Actuals	Variance	RCA adjustments	RCA 2015/16	Reference
Water	2 101	1 673	-428	0	-428	
Start up gas & oil	1 631	2 288	657	0	657	
Coal handling	1 186	1 728	542	0	542	
Water treatment	281	365	84	0	84	
Nuclear	498	918	420	-361	59	
Fuel procurement	287	156	-131	0	-131	
Sorbent	56	1	-55		-55	
Other primary energy before nuclear provisions	**6 040**	**7 129**	**1 089**	**-361**	**728**	
Nuclear decommissioning of R830m from RCA 2013/14 decision phased in over 10 years	-	-	-	83	83	Note 1
Nuclear decommissioning R361m from RCA 2015/16 decision phased in over 8 years	-	-	-	45	45	Note 2
Other primary energy after nuclear provisions	**6 040**	**7 129**	**1 089**	**-233**	**856**	

Note 1: 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 2015/16 RCA and

Note 2: Implementation of the current 2015/16 provision of R361 million over the remaining life of 8 years i.e R45m inclusion in the RCA

14.2.1 Reasons for start-up gas and oil costs variance

Start-up gas and oil contributes R657 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 2015/16 than what was anticipated at the time of the MYPD3 application and hence the use of fuel oil increased significantly as well. An improvement of 13% from previous year in terms of UAGs performance from 5.63 to 4.72 (UAGS/7000 was experienced.

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).”

14.2.2 Reasons for coal handling costs variance

A variance of R542 million in favour of Eskom arose, due to movement of coal within the power stations being more than was originally envisaged.

The main contributor to the coal handling variance was the Majuba coal silo incident.

14.2.2.1 Majuba coal silo collapse

A coal storage silo at Eskom's Majuba power station in Mpumalanga collapsed on Saturday, 1 November 2014. At the time of the incident all units were on load. Operating personnel reported a visible crack on Silo 20 and immediately evacuated all personnel working in the area. Fortunately no injuries occurred. The generation capacity at Majuba power station was curtailed as coal could not be fed to the affected units, and load shedding had to be implemented.

The increase in coal handling costs due to this event has contributed towards the RCA amount for this category.

A short-term gap solution has been implemented to resolve the shortfall of electricity generated at Majuba as a result of this incident. This entailed the relocation and repair of the incline conveyors, previously fed by the collapsed Silo 20, and the installation of associated supporting infrastructure. Coal is being fed through an elevated mobile boom feeder, directly to the repaired incline conveyors through to the power station, with a coal throughput of 800 tons per hour. This has now enabled the power station to run at full load on all six units during the morning and evening peak and at an average of 85% load during non-peak periods. A second elevated mobile boom feeder was installed at the end of March 2015 to further ramp up plant performance.

A more cost-effective interim coal handling system has been implemented. This solution entails the commissioning of a conveyor system to deliver coal to a distribution bin, with one conveyor delivering to each incline conveyor gantry at the station. This enabled Eskom to reduce the high operational expenditure associated with the short-term gap solution.

The feasibility study for a permanent solution has commenced. The reconstruction of the collapsed silo and the reinforcement of the remaining silos are underway and are scheduled for completion by the end of 2017.

14.2.3 Reasons for water costs variance

NERSA granted Eskom R2.1 billion for Water costs in FY16. Actual expenditure was R1.6 billion resulting in under expenditure of R458 million compared to the decision and R940 million compared to the application.
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.

14.2.4 Reasons for fuel procurement costs variance

A variance of R131 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.

14.2.5 Water treatment costs variance

Higher water treatment costs incurred at Kendal, as chemical usage escalated due to resin approaching its maximum shelf life.

- Matimba: The anion resin was planned to be purchased in FY2015, but it was rephased to FY2016.
- Kriel: Because of the poor quality of water, more chemicals were used than anticipated.

14.2.6 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 R420 million more than the decision.

The nuclear spent fuel provision once-off adjustment of R361million relates to an increased estimate of the costs of metal casks. However, for RCA purposes the provision of R361 million is disclosed separately as it is phased in over 8 years.

15 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 180m less than the MYPD3 determination for 2015/16. The fundamental driver to the variance for the environmental levy is due to a substantial decrease in volume offset by a slight decrease in renewable production 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 2015/16.

16 Demand Market Participation

16.1.1 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	2015/16
DMP and Power buy-back Applied for	
Funding	1 972
Demand Savings (MW)	3 355
R/MW	0.59
DMP and Power buy-back Adjusted	
Funding	-1 972
Demand Savings (MW)	-3 355
R/MW	-0.59
DMP and Power buy-back Approved	
Funding	-
Demand Savings (MW)	-
R/MW	-

Source: Table 36 of MYPD3 decision, 28 February 2013

16.1.2 Actual DMP

Demand market participation had a variance of R248 m during the year.

Table 29: DMP comparison for RCA

Demand market participation (DMP) in 2015/16	MYPD3 Decision	Actuals	RCA 2015/16
DMP (R'm)	-	248	248

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 or has a lower impact that uncontrolled load shedding.

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.

17 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)."

17.1 Allowed OCGT spend

For purposes of its revenue decision, NERSA assumed R1 508m for OCGT fuel cost from a production of 540 GWh requiring 152 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. A summary of the allowed OCGTs costs, rates and volumes as disclosed below.

Table 30 : Summary of allowed OCGTs components

Allowed OCGT Usage and Spend	GWh	R million	Fuel million litres	Rand/Litre	R/MWh
Ankerlig	337	957	95	9.54	2 839
Gourikwa	189	513	53	9.66	2 712
Acacia	7	19	2	9.54	2 783
Port Rex	7	20	2	9.56	2 788
Total	**540**	**1 508**	**152**		

** Note: Ankerlig Rand/litre excludes other costs component of R53.9million*

17.2 Actual OCGTs costs

The actual OCGTs energy cost was R8 690 million to produce 3 937 GWh requiring 152 million litres during 2015/16 as presented in the table below.

Table 31: Summary of OCGTs actual results for 2015/16

Actual OCGT Usage and spend	GWh	R'million	Fuel million litres	Rand/Litre	R/MWh
Ankerlig	2 504	5 423	786	6.84	2 166
Gourikwa	1 307	2 788	417	6.69	2 133
Acacia	57	217.7902	19.6602	11.08	3 833
Port Rex	69	261.3462	24.0948	10.85	3 768
Total	**3 937**	**8 690**	**1 246**		

** Note: Ankerlig Rand/litre excludes other costs component of R44.3million*

17.3 Computation of OCGTs claim for RCA purposes in 2015/16

In this RCA submission, Eskom has adopted the approach used in NERSA decision for RCA 2013/14 and is as follows:

1. Price pass through impact up to the 152ML per MYPD3 decision
2. Volumes above the assumed GWh are compensated at the actual average coal costs rate

The OCGTs impact for RCA purposes for 2015/16 is R689 million which is summarised below with details for each component disclosed later. This is far lower than the actual variance of R7 182 million.

Table 32: OCGTs RCA summary

OCGT Summary	RCA amount (R'm)
Excess volumes above allowed GWh recovered at average coal cost	**1 106.6**
Price variance on allowed 152ML	**-407.5**
Other related OCGT costs	**-9.7**
Total OCGT RCA R'million	**689.4**

17.3.1 Price impact up to allowed diesel litre usage of 152ML (million litres)

The MYPD methodology allows for the rate variance to be adjusted through the RCA mechanism as highlighted **below**.

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…"* .

During the 2015/16 period the actual price per litre varied between R6.69/L (Gourikwa) to R10.89/L (Acacia) which is compared to decision rates for the respective power stations. Favourable price variances occurred at Ankerlig and Gourikwa where the majority of usage materialised. Cognisance must be taken of the fact that Ankerlig and Gourikwa use diesel fuel whereas Port Rex and Acacia make use of jet fuel. A summary is disclosed in the table below with the **overall price variance of R408 million for the consumers' benefit.**

Table 33 : OCGTs price impact for 152ML

Price variance limited to the decision volumes (ML)	Decision Rand/Litre	Actuals Rand/Litre	Variance Rand/Litre	Allowed ML	RCA amount (R'm)
Ankerlig	9.54	6.85	-2.69	95	**-255.6**
Gourikwa	9.66	6.69	-2.97	53	**-157.2**
Acacia	9.54	10.89	1.35	2	**2.7**
Port Rex	9.56	10.81	1.25	2	**2.5**
Total price variance impact (R'm)				**152**	**-407.5**

17.3.2 Excess volumes above GWh recovered at average coal costs

The excess of 3 397GWh above the allowed levels for the year is recovered at the average coal cost of 32.58c/kWh, resulting in a recovery of R1 106 million in Eskom's favour as reflected in the table below.

Table 34: OCGTs RCA claim related to excess volumes above allowed GWh

	Allowed MYPD3 volumes (GWh)	Actual volumes (GWh)	Excess volumes (GWh)	Coal variable unit cost (c/kWh)	RCA amount (R'm)
Ankerlig	337	2 504	2 167	32.58	**705.8**
Gourikwa	189	1 307	1 118	32.58	**364.3**
Acacia	7	57	50	32.58	**16.2**
Port Rex	7	69	62	32.58	**20.3**
Total excess volume compensation (R'm)	**540**	**3 937**	**3 397**		**1 106.6**

17.3.3 Other related OCGT costs

Other related OCGT costs are in respect of standby trucks, tank rentals and storage costs for Ankerlig power station. There was a favourable variance of R10 million for the 2015/16 year as reflected in the table below.

Table 35 : OCGTs other costs

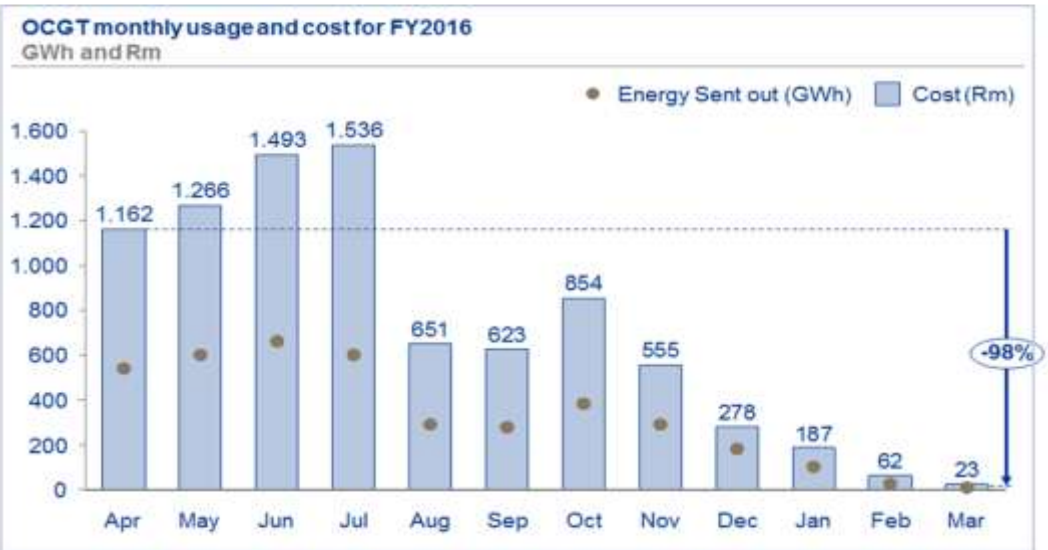
Other OCGT related costs	R'million	MYPD3 decision	Actuals	RCA 2015/16
Ankerlig		54	44	-10

17.4 OCGT usage in 2015/16

The diesel powered open-cycle gas turbines (OCGTs) production has decreased significantly from August 2015 to March 2016 due to improved Generation capacity available, lower demand, as well as increased production by IPPs. OCGT production for the eight months from August 2015 to March 2016 (since load shedding has ceased) totalled 1 539GWh, compared to production of 2 397GWh for the four months from April to July 2015 (during regular load shedding).

For the year ending 31 March 2016, the OCGT production of 3 936GWh exceeded the MYPD3 assumption of 540GWh by 3 396GWh. This translates to an actual cost of R8 690 million, an overspend of R7 182 million against the MYPD3 allowance of R1 508 million. However, for RCA purposes Eskom is submitting R689 million in the RCA application having applied the 2013/14 RCA NERSA decision as a precedent.

Figure 8 : Monthly OCGTs costs and production in 2015/16



17.5 Summary of OCGT RCA claim

OCGTs for RCA = Price pass through limited to 152 ML per decision +

Excess volumes of 3396 GWh compensated at average coal costs rate 32.58c/kWh

Eskom incurred **OCGTs actual costs of R8 690m** compared to the **assumed costs in MYPD3 decision of R1 508m** which results in a **variance** of additional expenditure of **R7 182m. However for RCA purposes,** Eskom used the approach taken by NERSA in its RCA 2013/14 decision to compute the OCGTs RCA for 2015/16 which results in a claim of **R689 million.**

Eskom believes that based on the conditions of the day and choices which were available in 2015/16, the operation of the OCGTs in and outside of peak hours was the correct decision for the country.

17.5.1 Managing supply-and –demand constraints

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.

17.5.2 Actual Plant performance in 2015/16

Attached below is extracts from the 2015/16 integrated report which highlights the performance of the generation fleet.

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 2015/16, while
- PCLF improved from an average of 9.91% in 2014/15, to 12.99% in 2015/16
- EAF increased from an average of 69.85% in the last quarter of 2014/15, to 73.51% in the last quarter of 2015/16

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.

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.

Generation technical performance

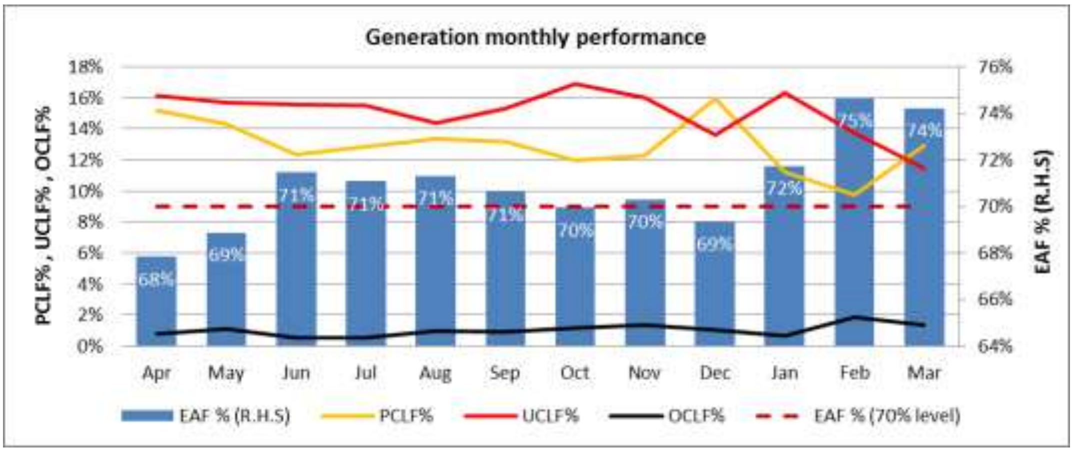
Generation's technical operations are assessed in terms of the following:

- 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 16.15% in April 2015 to 11.48% in March 2016, 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 9 : Generation technical performance



Duvha Unit 3 over-pressurisation incident

On 30 March 2014, Eskom experienced an over-pressurisation incident in the boiler of Unit 3 at Duvha Power Station, taking the 575MW unit out of service. This continues to have a material impact on the current UCLF.

The letter of commitment for the construction contract has been accepted by both parties, paving the way for site establishment and mobilisation. The contract is expected to be awarded in mid-2016. Demolition of the damaged property will commence in 2016, whilst concurrently finalising the detailed design of the new boiler. It is envisaged that the unit will be commercially operational in 2020.

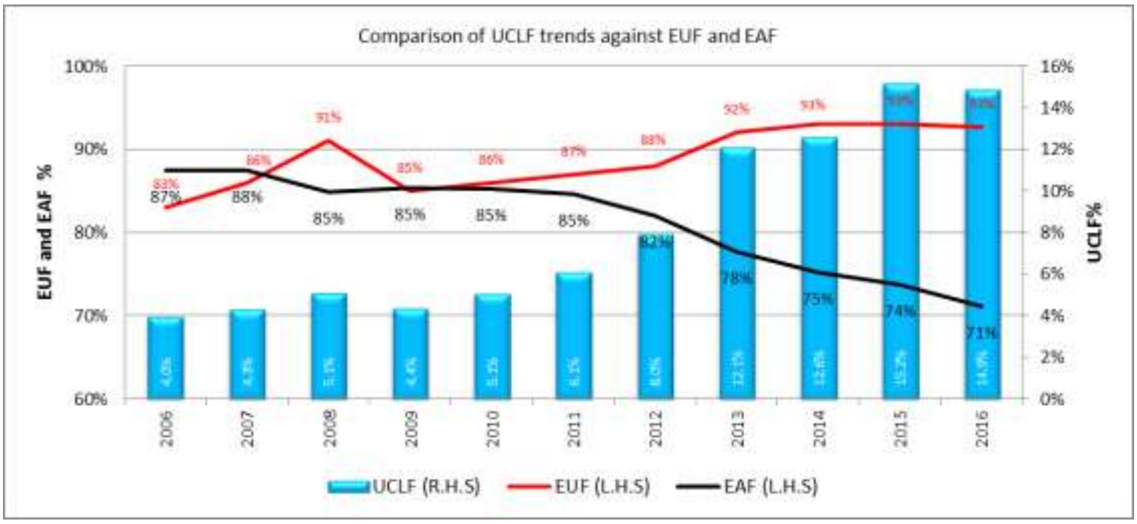
Collapse of the Majuba coal silo

Following the collapse of the coal silo at Majuba Power Station on 1 November 2014, construction of a coal silo interim solution has been completed with conveyor belts running from the permanent stockpiles to ensure greater efficiency in the coal handling process. The contract for a permanent solution for the rebuilding of Silo 20, the reinforcement of Silos 10 and 30 and the reinstatement of the coal conveyor system has been awarded. Detail design and construction activities are currently under way. The permanent coal handling plant is expected to be completed by the end of 2016.

17.5.2.1 Relationship between EUF, EAF and UCLF

This deterioration in availability performance is a direct result of the constrained system due to insufficient generating capacity being added timeously. This necessitated both the rolling of outages and limited the space to perform all the necessary maintenance required to both stabilise and improve station performance. In addition, the constrained system has necessitated sustained and high load factors of the coal fleet, at the limit of design levels, which have led to higher stresses, particularly on the boilers. On top of this, the regular operation of units in a compromised condition (for example with a boiler tube leak), in order to avoid system load-shedding, has caused additional consequential damage and contributes significantly to the performance deterioration.

Figure 10 : Relationship between high EUF to EAF and EUF



The figure above indicates that the utilisation / load factors (EUF – Energy Utilisation Factor) for **Eskom's coal fleet increased from around 83% in 2006 to over 90% from 2013.** More significant, however, is that the **average design parameter for the coal fleet** was for a **EUF of around 82%-85%.** This means that over the last decade Eskom's coal fleet has been operating at EUF levels above their design parameters. This has contributed to the upward trend in UCLF over this horizon.

The EAF trend has been decreasing over the past few years especially since 2010 when EUF was operating at levels approaching and exceeding 90% as disclosed in figure above. The high operating levels of coal plants over the last decade has affected the EAF performance which reached 71.07% by March 2016. Energy availability factors are an outcome of the planned and unplanned maintenance which has occurred.

EAF has improved from a monthly average of 67.84% in April 2015 to 74.21% in March 2016. This improvement in EAF is indicative of the turnaround in Generations performance.

Plant utilisation (EUF) for the year to 31 March 2016 was 82.69%, compared to 83.42% for the previous year. The utilisation of coal-fired power stations was 92.66%; Koeberg Nuclear Power Station was 99.19% and the peaking stations 20.26%. Eskom's EUF is approximately 20% above the international norm, indicating the high levels at which we are operating our plant.

18 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.

18.1 Regulated asset base adjustment for CECA

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

The actual capital expenditure incurred during 2015/16 was R56 978 million compared to the MYPD3 decision assumption of R42 064 million thus resulting in a variance of R14 914 million. However, only capex changes that affect the RAB are adjusted for CECA purposes.

The total variance of R14 914 million comprises Generation capex overspend by R20 764 million, Transmission underspend by R 3 500 million, Distribution underspend by R3 264 million with the balance attributable to other capital expenditure. Included in Generation were new build expenditures which exceeded the MYPD3 assumptions by R18.5 billion, comprising Medupi of R6.4 billion, Kusile of R8.6 billion and Ingula of R3.5 billion. The under expenditure in the network businesses were due to Eskom reprioritisation of its capital expenditure portfolio following the MYPD3 decision.

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 R14 914 million, only R9 180 million qualifies as RAB expenditure.

18.1.1 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 variance of R 4 590 million (i.e R 9180 million divided by 2).

Table 36: Calculation average capital expenditure

CECA Calculation -Variance between actual and allowed capex	Calculation ref	Eskom Company
Allowed MYPD capital expenditure		42 064
Less: Allowed capital expenditure excluded for CECA purposes	**A**	(16 541)
Future fuel		(3 315)
Technical and refurbishment capital expenditure		(13 226)
Capex subject to re-measurement for CECA	**B**	25 523
Actual MYPD capital expenditure		56 978
Less: Actual capital expenditure excluded for CECA purposes	**C**	(22 276)
Future fuel		(2 114)
Payment received in advance recognised to revenue		(1 706)
Technical and refurbishment capital expenditure		(18 455)
Actual Capex subject to re-measurement for CECA	**D**	34 702
Annual difference		14 914
Technical and refurbishment capital expenditure excluded for CECA purposes	**A - C**	5 735
Capex subject to CECA re-measurement	**D - B**	9 180
Average capital expenditure difference for CECA calculation	**(D-B)/2**	**4 590**

18.1.2 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 R332 million is computed by applying the allowed RoA to the capex variance.

Table 37: CECA Calculation: Return due to/ (by) Eskom

CECA Calculation : Return due to/(by) Eskom	Calculation ref	Eskom Company
MYPD3 Regulatory assets base		709 952
Add /(Deduct): Current year average capex variance		4 590
Add/ (Deduct): Cumulative prior year capex variances		4 316
Adjusted RAB	**A**	**718 857**
MYPD3 allowed return on assets	**B**	26 436
Return on adjusted RAB	**A * C**	26 768
Increase / (Decrease) in return for RCA	**(A*C)-B**	**332**
MYPD3 allowed return expressed as a percentage of the rate base	**C**	3.72%

Note: For purposes of the calculating the CECA claim, the allowed RAB of R709 952m is adjusted for the capex variance of the current year of R4 590 million and prior year of R 4 316 million.

18.2 MYPD3 decision

Below are extracts from MYPD3 decision reflecting approved RAB of R710bn and returns on asset at 3.72%, generating returns of R26 436 million and assuming a capital expenditure of R42 064 million.

Table 38 : Regulatory asset base for 2015/16

R'm	2015/16
RAB Applied for	919 662
RAB Adjustment	-209 712
RAB Approved	**709 950**

Source: Table 10 of MYPD3 decision, 28 February 2013

Table 39: Returns and percentage allowed in 2015/16

R'm	2015/16
Real Pre-tax WACC (%)	3.7%
Return (R'm)	26 436

Source: Table 9 of MYPD3 decision, 28 February 2013

Table 40: Capital expenditure in 2015/16

R'm	2015/16
Capex Applied for	64 835
Capex Adjustment	-22 770
Capex Approved	**42 065**

Source: Table 11 of MYPD3 decision, 28 February 2013

18.3 Reasons for new build higher expenditures

Medupi: The over-expenditure of R6.4bn is mainly due to; *Basic cost* – Increase of R2.7bn 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 as a result of access delays, force majeure events (including labour unrest) and construction challenges on the Boiler, Turbine and Civil packages.
- The impact of the revision of the project completion date from December 2014 to June 2019.

Escalation – Decrease of R0.4bn

- Due to CPA linked to various indices and changing from time to time this might be favourable or unfavourable as compared to the projected amount.

Owners Development Cost (ODC) – Increase of R1.9bn

- Increase 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

Contingency - Increase of R2.3bn

- Increase of R0.8bn 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 R1.5bn 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.

Kusile: The over-expenditure of R8.6bn is mainly due to *Basic cost* – Increase of R3.0bn due to;

- The MYPD 3 expenditure that was based on the 2014 synchronization date whereas the current expenditure is based on the increase expenditure to support the 2016 synchronization date.

Escalation – Increase of R0.4bn

- Due to CPA actual expenditure being higher mainly because of the increase on labour indices.

Owners Development Cost (ODC) – Increase of R2.5bn

- Increase of R1.4bn due to cost incurred but not allowed in the determination.
- Increase of R1.1bn due to hiring of strategic personnel and changes on working hours in order to meet the 1st unit synchronization date.

Contingency – Increase of R3.1bn

- 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.

Ingula: The over-expenditure of R3.5bn is mainly due to the following:

- In the MYPD 3 applications for Ingula it was planned for the project to be completed by the 2014/15 financial year. Costs were however incurred in 2015/16 due to the delayed completion of the project mainly due to the accident on the inclined high pressure shaft 3 & 4 on 31 October 2013.
- Since the tragic incident progress was significantly impacted resulting in limited progress for a period of approximately 12 months.

18.4 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 41: Reconciliation of capex from Integrated report to CECA disclosures

Capital Expenditure R'million	Actuals
Total Eskom Group Capex per Integrated Report	57 352
Exclude : Eskom Enterprises	-373
Total Capex for CECA disclosure	**56 979**

Detailed extract of capital expenditure of R57.3 billion is disclosed in table below.

18.5 Detailed Capital expenditure for 2015/16

Table 42: Capital expenditure (excluding capitalised borrowing costs) per division

Division, R million	Actual 2015/16	Actual 2014/15
Group Capital	**33 799**	31 691
Generation	**11 440**	10 555
Transmission	**998**	1 121
Distribution	**5 490**	6 073
Subtotal	**51 727**	49 440
Future fuel	**2 114**	1 651
Eskom Enterprises	**373**	439
Other areas including intergroup eliminations	**3 138**	1 547
Total Eskom group funded capital expenditure [1]	**57 352**	53 077

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

18.6 Delivering on the capital expansion

Since 2005, Eskom has been expanding its generation and transmission capacity to meet the country's growing demand for energy. Eskom's nominal generating capacity in 2005 was 36 208MW. The programme will increase this by 17 384GW by 2019/20. The key generation expansion projects are the 4 764MW Medupi and 4 800MW Kusile coal-fired stations, and the Ingula pumped-storage scheme in the Drakensberg, which will deliver 1 332MW of hydroelectricity during peak demand periods. Transmission line length and substation capacity will also increase substantially, increasing IPP and customer connections, as well as asset maintenance and replacement projects. .

Since inception, our capacity expansion programme has increased installed generation capacity by 7 031MW, mainly through the RTS programme and most recently, Medupi Unit 6; transmission lines by 6 162km and substation capacity by 32 090MVA. The programme has cost R289.5 billion to date (excluding capitalised borrowing costs).

Ongoing schedule delays have impacted the total cost of projects, specifically Medupi and Kusile, necessitating the revision of business cases, thereby increasing the available amounts to R145 billion for Medupi and R161.4 billion for Kusile (previously R105 billion and R118.5 billion respectively).

18.7 New build projects

Medupi Power Station

Commercial operation of Medupi Unit 6 was achieved on 23 August 2015 in line with commitments to accelerate delivery of all current new build projects, This marks the first new unit commissioned under our capacity expansion programme, delivering nominal capacity of 720MW (compared to installed capacity of 794MW) to the national grid, although the schedule was impacted by low productivity due to labour unrest as well as support provided to National Control to maintain the stability of the grid during times of constrained supply.

Satisfactory progress is being maintained on Units 4 to 1, although schedule pressure on Unit 5 has caused some contractors to pull resources from later units to achieve scheduled milestone dates on Unit 5. The risk that work may be further delayed by industrial action is very low, and manpower levels are back to planned levels following the year-end break. The integrated master schedule has been finalised, providing planning and construction guideline dates for critical activities for all five remaining units.

Commercial operation of Unit 5 is currently planned for the first half of 2018, with the final unit expected to be in commercial operation by the first half of 2020. The cumulative cost incurred on the project is R94.9 billion (March 2015: R84.7 billion) against the revised budget of R145 billion. All amounts exclude capitalised borrowing costs.

Kusile Power Station

The project continues to achieve set milestones, on track for Unit 1 commercial operation by the second half of 2018. Good progress is also being made on Units 2 to 6, with the final unit expected to be in commercial operation by the second half of 2022.

The project achieved a number of significant milestones since April 2015, and achieved all planned milestones during the year, only missing the commissioning of the diesel generator in December 2015. Milestones achieved include the boiler reheater hydro test, turbine air-cooled condenser leak test and super heater hydro test of Unit 1. Further areas of significant progress during the year include the Unit 1 stator coolant system flush that was successfully completed; commencement of Unit 6 boiler steel erection; as well as starting the pre-setting of fan blades and shrouds for all units, in preparation for fan testing. Progress on Unit 2 is also positive, with the air-cooled condenser condensate tank building structure being completed, turbine lube oil piping starting on 27 August 2015, and the generator stator being transported and set into position on 23 September 2015. Commissioning of the auxiliary cooling tower was completed on 29 September 2015. The sewerage plant was also commissioned.

The cumulative cost incurred on the project is R95.1 billion (March 2015: R78.7 billion) against the revised budget of R161.4 billion. All amounts exclude capitalised borrowing costs.

Ingula Pumped Storage Scheme

Ingula Unit 3 was successfully synchronised to the national grid on 3 March 2016 and performed excellently for over a month. Ingula Unit 4 was successfully synchronised to the national grid on 25 March 2016. However, an unfortunate incident occurred on 6 April 2016 when the unit faulted and was damaged during commissioning and optimisation by the contractor. A full investigation to evaluate the extent of the damage is under way. The unit will be repaired, ready for commercial operation before the end of the 2016/17 financial year.

Overall construction is 86% complete at the end of March 2016. Commercial operation of Units 3 and 4 is planned for the 2016/17 financial year, with commercial operation of Units 2 and 1 targeted for the second half of 2017. Work on the critical path is being closely monitored to ensure that key dates and associated milestones on the accelerated schedule are not at risk of being delayed. The demobilisation of local labour is being managed through engagement with various stakeholders, to avoid negative outcomes.

The cumulative cost incurred on the project is R26.8 billion (March 2015: R22.8 billion) against a budget of R25.9 billion. The project budget will require revision prior to project completion, after conclusion of the legal reviews of contract-related disputes. All amounts exclude capitalised borrowing costs.

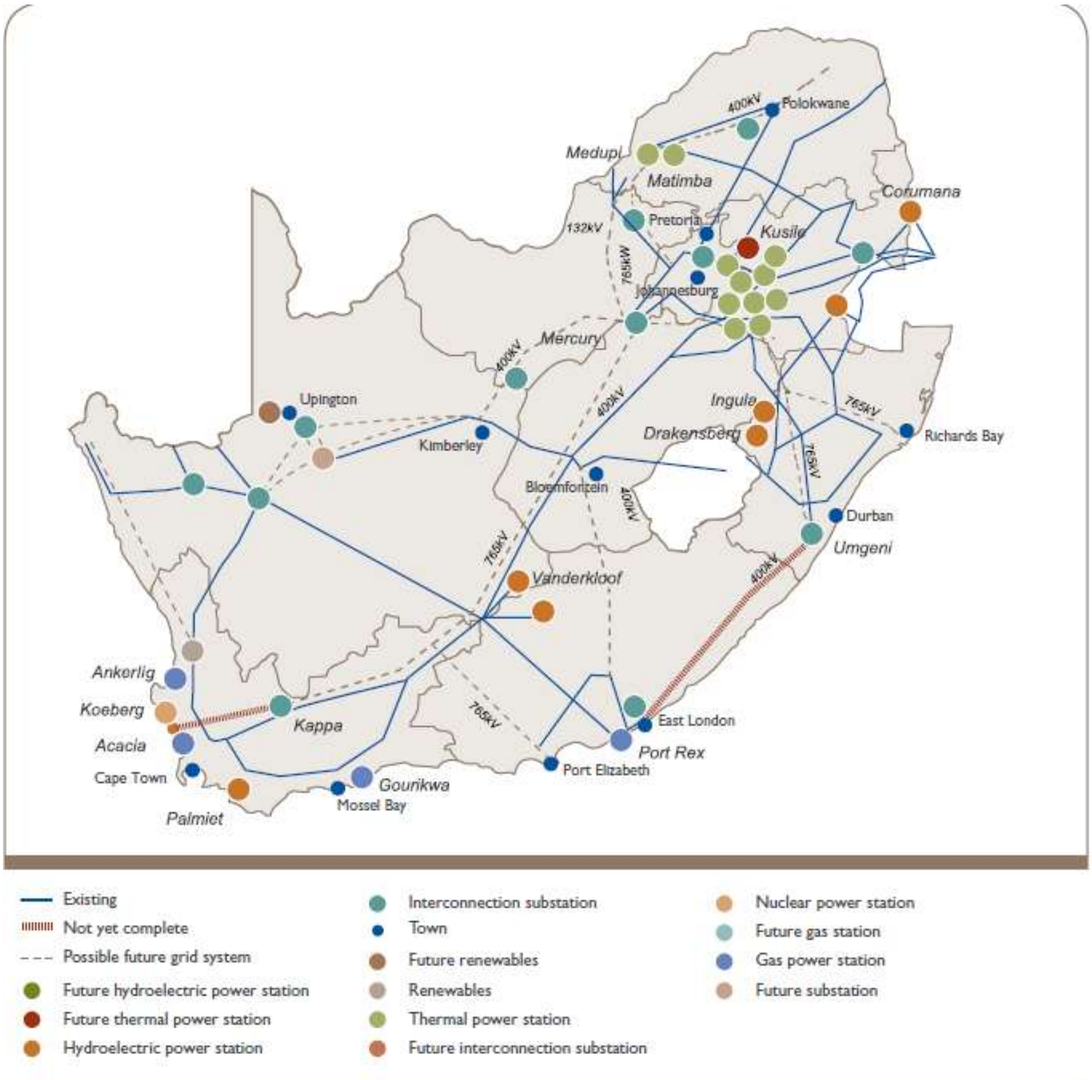
Power lines and substation capacity

During the year, we installed 345.8km of high-voltage transmission lines and commissioned substation capacity of 2 435MVA under the new build programme, bringing the total since inception of the capacity expansion programme to 6 162km transmission lines and 32 090MVA substation capacity.

The Gamma-Kappa 765kV line was energised, together with the Eros-Vuyani 400kV line, Mercury-Mookodi 400kV line, Ferrum-Mookodi 400kV line and the Anglo deviation line, Borutho 400kV line and Hendrina-Gumeni 400kV line, a total of 887.6km during the year.

A key risk in achieving the transmission strengthening project remains the time required to obtain environmental approvals, securing land and obtaining the required water-use licences from the Department of Water Affairs. Funds available for Transmission strengthening projects are currently limited, which will extend the time taken to meet network reliability requirements and constrain our ability to connect customers.

Figure 11 : Transmission projects at March 2016



18.8 Conclusion on capital expenditure

A number of key strategic challenges exist that require a Eskom Capital Portfolio greater than R300bn, as opposed to NERSA assumption of R230bn for purposes of the MYPD3 revenue decision

A rigorous process incorporating world's best practices for capital prioritisation and optimisation was utilised to allocate the R251bn funding available over the MYPD3 period.

19 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 43: Inflation Data

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

The qualifying expenses of R 39 582 million for the inflation calculation comprise employee benefits cost of R 19 844 million and other operating costs of R 19 738 million. Refer to the table below for the Inflation RCA claim.

Table 44 : Inflation adjustment

Inflation adjustment for 2015/16	Calculation ref	2015/16
Total operating costs allowed	A	39 582
Decision inflation index	B	1.178
Actual inflation index	C	1.173
Restated allowed costs based on actual inflation	D=A/B*C	39 430
Inflation adjustment R'm	**D-A**	**-152**

Due to the actual compounded CPI index of 1.173 in 2015/16 being lower than allowed compounded CPI index of 1.178, this results in an inflation adjustment of R152 million in favour of the customer.

20 Energy efficiency and demand side management (EEDSM)

20.1 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:

- The focus in the residential sector was the rollout of Phase 3 of compact fluorescent lamps (CFLs), a total of 390 643 CFLs were installed inception-to-date, against a target of 500 000. It must be noted that the roll-out period spans 2 financial years.
- The solar water-heater programme – Demand savings of 24.1 MW and energy savings of 153.0 GWh were installed and verified as part of the DoE SWH Programme at a cost of R2m for FY 2015/16.

20.2 Energy-efficiency measures

Eskom's Power Alert and "5pm to 9pm" campaigns were utilised to reduce power demand during the evening peak. The average weekday evening peak impact for the period under review for all colours (green, orange and red) is 224 MW. The average impact for the red flightings in the evening peak on the worst constrained day is 294 MW. Eskom's utilised the 49M campaign, a long-term behavioural-change initiative that encourages energy efficiency practices, particularly for residential users, which has the ultimate goal of reducing energy consumption by 10%. This includes targeted seasonal campaigns such as the "beat the peak" campaign and the "live lightly" campaign.

Integrated Demand Management (IDM) plays a key role in assisting us to balance power supply and demand during periods of generation constraints. 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.

Table 45: Demand management costs

R million	Actual 2015/16	Actual 2014/15
Total energy efficiency demand side management	413	656
Power buybacks	–	–
Demand response	248	309
Total (excluding transfer pricing)	661	965

Table 46: Actual savings (not verified) and internal energy efficiency savings

Measure and unit	Actual 2015/16	Actual 2014/15
Demand savings (evening peak), MW	214.9	171.5
Internal energy efficiency, GWh	1.7	10.4

Actual expenditure is below budget due to IDM programmes being on hold for the first three months of the financial year, and due to the new contracting model, which makes provision for payments to be made only once demand savings have been verified.

IDM runs a number of programmes to manage demand and improve energy efficiency. The Demand Response Programme has a combined certified capacity of 1 466MW of dispatchable load (2014/15: 1 356MW), 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 1 696 120 CFLs since the project commenced in February 2104, of which 1 305 477 have been installed in in the current year. A second phase rollout of 10 million CFLs is planned for 2016/17 and 2017/18. Our Power Alert and “5pm to 9pm” campaigns continue to reduce power demand during the evening peak.

20.3 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.

20.3.1 Allowed EEDSM for 2015/16

The allowed rate for EEDSM savings is R4.38m/MW with 187MW savings being assumed which will cost R819m.

Table 47: Allowed EEDSM

R'm	2015/16	
	Applied for	Approved
Funding	**1 862**	**819**
Programmes Peak Demand savings (MW)	221	187
Programmes Annualised Energy savings (GWh)	826	763
Programme Costs	1 581	468
Operating Costs including Depreciation	485	351
Other costs	-204	-
R/MW	8.42	4.38
R/kWh	2.25	1.07

Source: Table 40 of MYPD3 decision, 28 February 2013

20.3.2 Actual EEDSM

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.

Demand savings of 171.5 MW (including DOE savings of 24.1 MW) were substantially lower than the MYPD3 decision of 294 MW.

As verified MW is 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 a reconciliation is required to determine the verified MW as presented in the table below.

Table 48: Reconciliation between demand savings MWs used in RCA Calculation

Reconciliation between demand savings MWs reported in AFS to MWs used in RCA	2015/16
MWs achieved in current year (incl DOE) per AFS and Integrated report	214.9
Less : MWs installed but not verfied in current year	-112.1
Less : DOE funded MWs achieved	0
Add : MWs achieved in the prior year but verfied in current year	0
Total verfied demand savings (MW) for RCA	**102.8**

See Annexure 7 for details on measurement and verification report

Hence the total capacity verified for 2015/16 after all the adjustments is 102.8 MW as is reflected in the M&V report submitted to NERSA.

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

Table 49: EEDSM comparison for RCA in 2015/16

Energy Efficiency & Demand Side Management (EEDSM)	Unit	MYPD 3	Actuals	Variance
Funding	R'm	819	413	-406
Programmes - Peak Demand savings	MW	187	102.8	**-84**
Programme costs	R'm	763		
Operating costs incl. depreciation	R'm	468	216	
Other costs	R'm	351	197	
EEDSM Rate	R/MW	**4.38**	4.02	-0.36
EEDSM Rate based on verfied MW savings for RCA	R/MW		4.02	-0.36
MW savings for RCA purposes	MW		102.8	
RCA Penalty for not achieving MW savings	R'm			**-369**

Table 50: Actual EEDSM

R million	Actual 2015/16	Actual 2014/15
Total energy efficiency demand side management	413	656
Power buybacks	–	–
Demand response	248	309
Total (excluding transfer pricing)	661	965

Note 1 – For RCA purposes, the verified MW savings is used which results in a lower average rate of R4.02/MW (R413m/102.8MW) when compared to the decision rate of R4.38/MW. This benefit is passed onto Eskom as the lower actual rate benefit is applied to the verified savings of 102.8MW resulting in a benefit to R37 million. Thus in absolute terms Eskom underspent by R406 million but is being penalised to payback R369m. The difference is attributable to the benefit of the efficient overall rate benefit of R37m. Thus the MYPD methodology is reflecting the correct penalty of R369m.

20.3.3 Computation of EEDSM for the RCA

Following the MYPD3 RCA 2013/14 decision, NERSA has computed the EEDSM which comprised a **penalty for under achieving MW savings** multiplied by the allowed rate (R/MW). Eskom has computed the IDM impact for the RCA purposes on the basis of

shortfall of 84MW multiplied by allowed rate of R4.38m/MW equating to an **RCA impact of R369m in favour of the consumer.**

EEDSM penalty = R4.38m/MW X - 84MW = - R369m

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.

21 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.

21.1 Allowed operating costs in 2015/16

The MYPD3 decision comprised the building blocks for allowed revenue per the MYPD Methodology as described earlier in the document. The allowed operating costs disclosed allowed for total revenue of R906bn over the five year horizon. However, following the subsequent revision of the total revenue from R906bn to R863bn, which was attributable to the operating cost component and which was thus reduced to cater for the revision.

The total operating cost allowed is R42 292 million as shown below.

Table 51: Total Operating Cost Allowed

FY2016 Allowed operating cost	R'million	Note ref
Employee benefits	19 844	1
Other opex	19 738	2
Other income	-	
Net impairment loss	1 031	3
Cost of cover	1 679	4
Total	**42 292**	

Note1: Allowed employee benefits

Table 52: Employee benefits are reconciled as follows

Employee benefits allowed	R'million	Source ref
Total GTD	17 586	**A**
Add: Corporate Overheads	3 188	**B**
Less: Corporate depreciation	-930	**C**
Total Employee benefits allowed	**19 844**	

Source A: Total GTD allowed employee benefits per NERSA decision

Table 53: The allowed employee costs for Generation, Transmission and Distribution

R'm	2015/16
Manpower Applied for	20 984
Manpower Adjustments	-3 398
Approved Manpower	**17 586**

Source: Table 43 of MYPD3 decision, 28 February 2013

Source B: Total corporate overheads allowed

Table 54: Allowed Corporate Costs in 2015/16

R'm	2015/16
Corporate overheads Applied for	7 194
Corporate overheads Adjustments	-4 006
Approved Corporate overheads	**3 188**

Source: Table 51 of MYPD3 decision, 28 February 2013

The R3 188 million above includes R930 million in respect of corporate depreciation which is reallocated from corporate overheads to depreciation.

Source 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 55: The depreciation per annum is reflected in the table below.

Total Corporate depreciation allowed (R'million)	2014	2015	2016	2017	2018	Total MYPD3
Corporate Depreciation	434	678	930	1 091	769	**3 902**

Note 2: Other opex

Other operating costs comprise repairs and maintenance and other costs, refer below.

Table 56: Allowed Maintenance Costs

R'm	2015/16
Maintenance Applied for	15 674
Maintenance Adjustments	-2 175
Approved Maintenance	**13 499**

Source: Table 44 of MYPD3 decision, 28 February 2013

Table 57: Other costs

R'm	2015/16
Other costs Applied for	16 632
Other costs Adjustments	-10 393
Approved Other costs	**6 239**

Source: Table 50 of MYPD3 decision, 28 February 2013

Note 3: Net impairment loss (Arrear debt)

Table 58: Allowed Arrear Debts

R'm	2015/16
Arrear Debt Applied for	1 215
Arrear Debt Adjustments	-184
Approved Arrear Debt	**1 031**

Source: Table 49 of MYPD3 decision, 28 February 2013

Note 4: Cost of cover

Table 59: Allowed Cost of Cover

R'm	2015/16
Cost of Cover applied for	1 679
Cost of Cover adjustments	-
Approved Cost of Cover	**1 679**

Source: Table 48 of MYPD3 decision, 28 February 2013

21.2 Allowed vs Actual operating costs

During 2015/16 Eskom incurred operating costs excluding IDM of R56 258m which compares to the MYPD3 assumption of R42 292m resulting in over expenditure of R13 966m. As there is an overall over expenditure position, Eskom operating costs don't qualify for the RCA adjustment except for the inflation adjustment.

Table 60: Summary of Operating costs in 2015/16

Operating Costs	R'millions	Allowed	AFS actuals	Variance	Regulatory adjustments	RCA actuals	RCA balance
Employee benefits		19 844	24 720	4 876	-91	**24 629**	4 785
Other opex1		19 738	25 170	5 432	-309	**24 861**	5 123
Other income		-	2 471	2 471	-9	**2 462**	2 462
Net impairment loss		1 031	1 159	128	1 470	**2 629**	1 598
Cost of cover		1 679	1 677	-2	-	**1 677**	-2
Total Operating Costs	**R'millions**	**42 292**	**55 198**	**12 905**	**1 061**	**56 258**	**13 966**

21.3 Variances in operating costs

21.3.1 Employee benefits

Actual staff costs have exceeded the MYPD3 decision due to

- Higher salary settlement of 8.5% compared to decision assumption of 5.4%, 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 61: Trend in gross employee benefits

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

Gross employee benefits has reflected a downward trajectory with 1.9% (2014/15) and -2.1% (2015/16).

21.3.2 Maintenance

Overall Eskom underspend on maintenance. Generation and Transmission maintenance exceeded the MYPD3 decision and in 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.

21.3.3 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.

21.3.3.1 Response strategies for debt collection

The top 20 defaulting municipalities contributed R4.8 billion at 31 March 2016, constituting 80% of total municipal arrear debt. Soweto arrear debt (excluding interest) increased to R4.7 billion at year end (March 2015: R4 billion).

The rollout of smart prepaid meters is progressing well, with 18 997 conventional meters in Soweto and 4 227 in Kagiso being converted to prepaid at 31 March 2016. A total of 5 923 smart meters were installed in Sandton and Midrand, while the conversion to prepaid will resume in July 2016.

Table 62: Municipal and Soweto arrear debt at 31 March 2016

R m	2015/16	2014/15
Municipal debt		
Total municipal debt (including interest)	**11 325**	9 849
Municipal arrear debt (>15 days)	**6 005**	4 953
Percentage arrear debt to total debt	**53%**	50%
Soweto debt		
Total Soweto debt (excluding interest)	**4 746**	4 182
Soweto arrear debt (> 15 days)	**4 678**	**4 022**
Average Soweto payment level, %	**18%**	16%

Total arrear municipal debt as at 31 March 2016 has increased to R6 005 million, compared to R4 953 million at 31 March 2015. At year end, a total of 11 municipalities had total overdue debt greater than R100 million each; the top 20 defaulting municipalities contributed R4 819 million to arrear municipal debt, or approximately 80% of the total arrears. Furthermore, 82% of the arrear municipal debt is concentrated in the Free State, Mpumalanga and North West municipalities, contributing 47%, 24% and 11% respectively. Soweto arrear debt has increased to R4 678 million (March 2015: R4 022 million), with the payment level during the period at 18%.

21.3.3.2 Residential revenue management

Every effort is made to ensure that customers pay their accounts on time. Eskom constantly monitors payments and are willing to enter into reasonable payment arrangements that take into account defaulting customers' circumstances. Considerable effort also goes into building stronger relationships with these customers. Disconnection of supply remains a last resort.

Customers are increasingly experiencing adverse market conditions, negatively impacting revenue and debtor's days.

In Gauteng, we have embarked on an Eskom Operational Efficiency Service Level Improvement Programme (EOESLIP, previously branded Switch Ova!) focusing mainly on Soweto, Kagiso and other problematic areas, as well as Midrand and Sandton. The programme comprises several initiatives:

- Decreasing energy losses by removing illegal connections, conducting meter audits, rectifying faulty or tampered meters and curbing ghost vending by introducing new supply group codes
- Installing split smart prepayment meters within protective enclosures to prevent tampering, as well as bulk meters on supplies to hostels and entering into supply agreements with the owners
- Improving payment levels by stepping up disconnections for customers not honouring their current accounts
- Increasing debt collection from businesses by stepping up disconnections, entering into payment arrangements for arrears and installing split prepayment meters

Soweto split prepaid metering rollout

Soweto has approximately 180 000 customers, 80% of whom are on the conventionally billed metering system (post-paid) and the remainder on the prepaid metering system. The plan is to convert all meters to split prepaid meters within five years from 2014/15.

The programme started off slowly due to numerous community protest actions. Nonetheless, at 31 March 2016, a total of 18 997 meters of previously post-paid customers were converted to prepaid in Soweto, representing 48% of the initial target of 39 794 customers. Due to community unrest, the strategy was changed to complete installation of meters in steel enclosures before conversion to prepaid.

Since inception, the conversion of meters to prepaid has improved revenue collected by R60.79 million. Furthermore, conversions have resulted in an increase in revenue billed from R0.2 million in July 2014 to R4 million per month in March 2016, as demand is now being metered, as well as a drop in energy demand, due to customers now having to pay for their consumption.

Smart prepaid metering rollout in Sandton and Midrand

In May 2015, we made a strategic decision to convert our post-paid residential customers to prepaid, starting with Sandton and Midrand residential customers. The project plans to convert 33 885 single phase and three-phase post-paid customers in these areas. At 31 March 2016, a total of 5 923 meters were installed; conversions to prepaid will resume in July 2016 once the upgrade of the Online Vending System to cater for prepaid recovery of network charges is complete. The project is targeted for completion by the end of the 2016/17 financial year.

21.3.3.3 Impairment of arrear debt

Previously, Eskom recognised revenue and thereafter impaired the debtor if the amount was later deemed not to be collectable. In the current year, we applied the IAS 18 principle of not recognising revenue if it is deemed not to be collectable at the date of sale. As the revenue and corresponding debtor is never accounted for, there is no need to impair the debtor. At year end, this has resulted in external revenue and debtors of R1472m being derecognised, and impairment amounting to R566m from the previous year being reversed.

21.3.4 Energy losses and theft

During the year, total energy losses were 8.59% (March 2015: 8.79%). Non-technical losses due to illegal connections and electricity theft in Distribution were estimated at between 1.61% and 2.57% (or between 3 467GWh and 5 546GWh). Transmission energy losses was 2.61% and Distribution energy losses was 6.43% during the year.

The following progress was made on interventions aimed at reducing energy losses and recovering revenue:

- Just under 87% of the feeders that require energy balancing have been balanced
- A total of 8 065 large power user meter audits, 66 150 small power user meter audits and 646 160 prepaid meter audits were completed during the course of the year
- Recovery of revenue, as a result of billing historically unbilled energy owing to meter tampers, faulty/vandalised metering installations or customers not loaded correctly on the system, amounting to R371.8 million was billed to large and small power customers

- Fines realised from prepaid customers tampering with their electricity meters amounted to R32.8 million at the end of financial year
- A total of 3 565 tipoffs on electricity theft have been received from the public
- Other interventions are in progress, such as the implementation of technologies (such as split metering and protective enclosures) to prevent access to the metering unit to restrict meter tampering, conversion of customers to prepaid, as well as the conversion of supply group codes on prepaid meters to prevent the use of illegal prepaid vouchers

21.4 Savings through Business Productivity Programme

The Business Productivity Programme (BPP) aims to deliver cost savings to the value of R61.9 billion were identified over the five years to 31 March 2018. For the year ended 31 March 2016, savings of R17.5 billion were achieved against a target of R13.4 billion. Inception-to-date savings amount to R28.5 billion against a target of R25.9 billion, an overall stretch of R2.6 billion.

21.5 Other Income

21.5.1 Actual other income in 2015/16

In the course of Eskom operations in 2015/16, Eskom also generated total other income of R2 471 million which is disclosed under the Income Statement for March 2016 shown in Annexure 1.

Table 63 : Other income for 2015/16

		Group		Company	
	Note	2016 Rm	2015 Rm	2016 Rm	2015 Rm
33. Other income					
Insurance proceeds		917	2 732	1 393	5 111
Services income		355	213	-	-
Insurance premium income		79	116	-	-
Management fee income		-	-	117	261
Operating lease income		262	275	226	219
Dividend income		32	29	32	19
Sale of scrap		134	186	134	186
Other income		611	893	569	849
		2 390	4 444	2 471	6 645

21.5.2 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

Based on the precedent above, all items mentioned thereto do not qualify for inclusion in the RCA. Refer to extract below which shows the actual other income breakdown as per the AFS.

21.5.3 Other income included for RCA

21.5.3.1 Sale of scrap

Revenue from sale of scrap and disposal of property, plant and equipment (PPE) are generated in relation to CECA. The RCA assessment provides for variances to be included in CECA to which these additional revenue streams relate and are therefore included in the RCA. Eskom generated other income of R134m from the sale of scrap assets.

The sale of scrap (R134 million) is included as other income in the RCA submission in favour of the customer as it was generated through costs allowed in the MYPD.

21.6 Operating cost variance for 2015/16 RCA

Operating cost variance = Actual operating costs – Allowed operating costs

Based on **RCA equivalent actual operating costs of R56 258 million** and allowed other operating costs in the **decision of R 42 292 million**, Eskom has incurred an **additional R13 966 million** during the year. In terms of the MYPD Methodology Eskom **cannot submit these additional expenses for RCA purposes** and will have to **absorb 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 which is described lower down.

21.7 Why symmetrical treatment of operating costs is needed

Current approach in MYPD Methodology:

The current MYPD methodology allows for under expenditure to be clawed back in favour of the customer and over expenditure must be absorbed by Eskom. This approach is biased as it implies that any over expenditure is deemed inefficient and cannot be recovered through the RCA process, which violates the NERSA mandate in terms of the Electricity Regulation Act to allow utilities to recover full efficient costs.

Proposed approach:

Amendment to current methodology for symmetrical treatment of operating costs

Motivation

- **Aligned with policy and legislation**

It is proposed that the symmetrical treatment of operating expenses would be in line with the intention of the Electricity Regulation Act in terms of which tariffs "*must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return*".

The Electricity Pricing Policy also stipulates that "*the revenue requirement for a regulated licensee must be set at a level which covers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values*".

- **Provides licensees with greater assurance**

The symmetrical treatment of operating cost variances would provide Eskom with greater assurance of adequate revenue to undertake the necessary operating and maintenance activities required for the optimal operation of the electricity system. The undertaking of such activities would still be subject to prudence review by the Energy Regulator.

Only adjusting for prudently incurred under-expenditure would not enable Eskom to provide the best service to its customers. As one example, it might be prudent to defer a particular expenditure by one year – under a non-symmetrical treatment of variances it would result in the under-expenditure being clawed-back to the benefit of the consumer but the over-expenditure in the subsequent year not being recovered by Eskom. This disincentive is illustrated by Eskom spending more on maintenance costs. The over expenditure is not considered for prudency reviews, yet the current state of Generation plant requires extra efforts for maintenance.

- **Allows for optimal management decisions**

- A symmetrical treatment of operating costs would avoid perverse incentive with unintended consequences. A symmetrical mechanism would not imply an uncontrolled ability to spend – the normal prudence assessments undertaken by NERSA will require Eskom to substantiate any under and over-expenditure (when compared to assumptions made in the MYPD revenue decision) and thus act as sufficient incentive for efficiency.

- **Provide comfort to rating agencies**

The methodologies applied by the credit rating agencies in terms of which they rate regulated electricity utilities also make that point, with non-symmetrical revenue adjustment rules leading to higher regulatory risk assessment and thus lower credit ratings. Symmetrical mechanisms are one of the key characteristics that are considered during the assessments of the regulatory framework by credit rating agencies. For example, the guidance given by Standard & Poor's Ratings Services for a 'strong' rating is "*Any incentives in the regulatory scheme are contained and symmetrical*" ("Key Credit Factors for the Regulated Utilities Industry", November 2013).

A positive assessment of the regulatory framework is crucial for credit ratings, as the regulatory framework and environment are critical factors considered during a credit ratings assessment – for example in Moody's Global Investors Service's methodology it comprises 50% of the total credit risk assessment of a regulated electricity utility ("Rating Methodology - Regulated Electric and Gas Utilities", November 2013).

For example an operating costs expenditure of say R1 million in March 2015 may not occur in that month due to logistic and governance processes. Hence if all assumptions and costs panned out to be exactly as per the MYPD decision other than this item, then according to the current MYPD methodology:
RCA FY2015 - Eskom pays back this under expenditure through the RCA process
RCA FY2016 - During the next month (April 2015), once the processes have been resolved the same prudent and efficient expenditure is incurred. Assuming that all else being exactly the same as per MYPD decision, Eskom is not allowed to claim the R1 million over expenditure relating to RCA for FY 2016 according to current methodology.
Thus penalised twice for the same item, once for the under expenditure and secondly for over expenditure once cost is incurred as it cannot be recovered through the RCA. This highlight the need to revise the operating costs treatment to become symmetrical

22 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 64 : Trends in networks performance

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

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

Transmission achieved excellent system performance, with system minutes lost < 1 of 2.41, as well as the best ever reported performance of 1.51 line faults per 100km. This was supported by a high level of maintenance execution, as well as improved plant availability. There was one major incident at Witkop Substation in Limpopo Province, resulting in the supply to Polokwane and surrounding areas being interrupted for approximately 100 minutes. Performance risks still remain, with ageing assets and vulnerabilities due to network infirmness.

Although the system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) are better than target, there is a worsening trend in network performance. Eskom remain focused on Distribution sustainability through refurbishment, reliability improvements and addressing maintenance backlogs. The longer term performance of the Distribution network is at risk given the prevailing resourcing constraints, which could lead to an inability to sustain network performance within regulatory norms.

Table 65 : Summary of SQI performance in 2015/16

Licensee Service Quality Incentives (SQI)	Incentive/ (Penalty)	2015/16
Distribution SQI	Incentive	233
Transmission SQI	Incentive	85
Total SQI for 2015/16 R'm)	**Incentive**	**318**

22.1 Transmission service quality incentives (SQI) for 2015/16

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 2015/16 has been finalized and the subsequent financial reward / penalty based on these results has been computed. The SQI reflects a reward of R85m for system minutes less than 1 minute as reflected in the table below.

Table 66: Transmission SQI performance in 2015/16

Transmission Service Quality Incentives (SQI)	Performance result	Incentive / (Penalty) R'm	Comment
SM<1	2.41	24.50	Reward
Major incidents	1	20	Reward
Line faults / 100km	1.51	40	Reward
Total Transmission SQI for 2015/16 (R'm)		**84.50**	

Transmission system performance reflects significant improvements with an improvement in minutes lost from 2.85 in 2014/15 to 2.41 in 2015/16.

Figure 12: Transmission system minutes (<1)

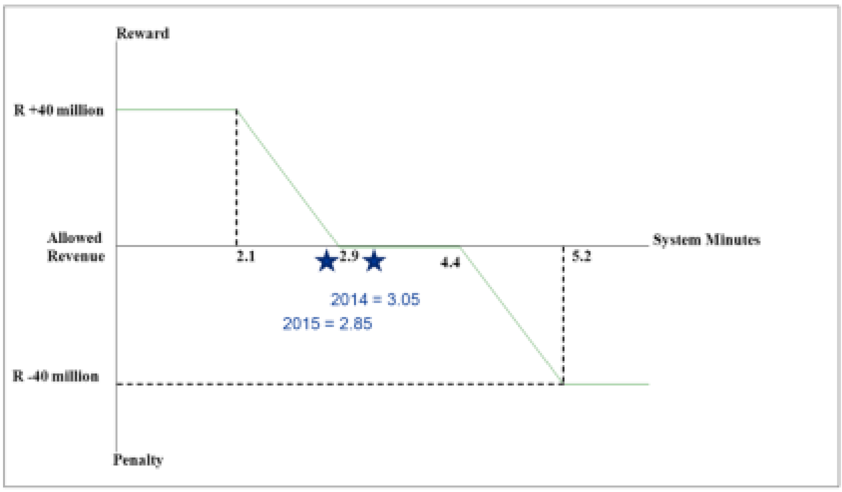
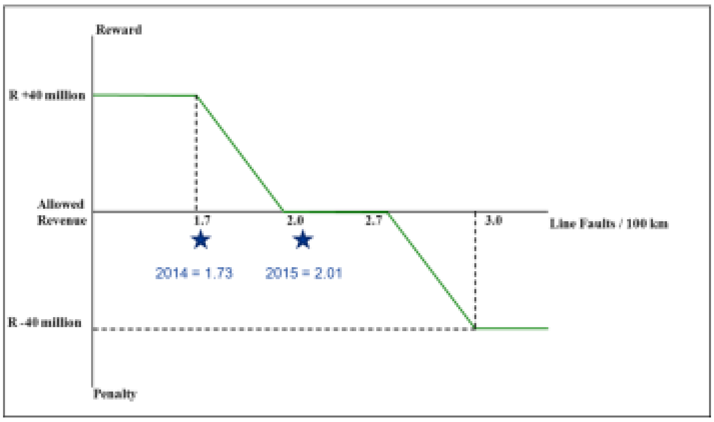


Table 67: Transmission number of major incidents (>1SM)

Number of Major Incidents (>1SM)

Incentive (Rm)	Major Incidents (No)	
R 40	0	★ 2014 = 0
R 20	1	
R 0	2	★ 2015 = 2
-R 20	3	
-R 40	4	

Figure 13 : Line faults /100km



22.2 Distribution Service Quality Incentive Scheme (SQI) for 2015/16

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 2015/16 of MYPD3 and earned incentive rewards as indicated in the table below. The DSLI performance deteriorated during the same period and resulted in a penalty for year 2 and year 3 of MYPD3 cycle. The net impact of the SQI performance is positive for Eskom. The outcome of the SQI performance is summarised in the table below.

Table 68: Distribution SQI performance in 2015/16

Distribution Service Quality Incentives (SQI)	Incentive/ (Penalty)	2015/16
SAIDI	Incentive	145.90
SAIFI	Incentive	116.72
DSLI	Penalty	-29.18
Distribution total SQI R'm	**Incentive**	**233.44**

Distribution system performance reflects significant improvements with a declining trend in SAIDI interruption durations reducing from 45.8 minutes in 2012/13 to 32.3 minutes by 2015/16.

Informative Notes

NOTE 1: The reported Distribution data is only for sustained supply interruptions (loss of supply for two or more minutes).

NOTE 2: The performance figures show all events excluding agreed/approved exclusion events and 50% of planned SAIDI contribution (as per the NERSA approved Distribution SQI for MYPD3).

NOTE 3: The performance figures in the mid-year report for April 2015 to September 2015 were preliminary numbers and are marginally different from the year-end report now that all events for the 2015/16 year have been closed.

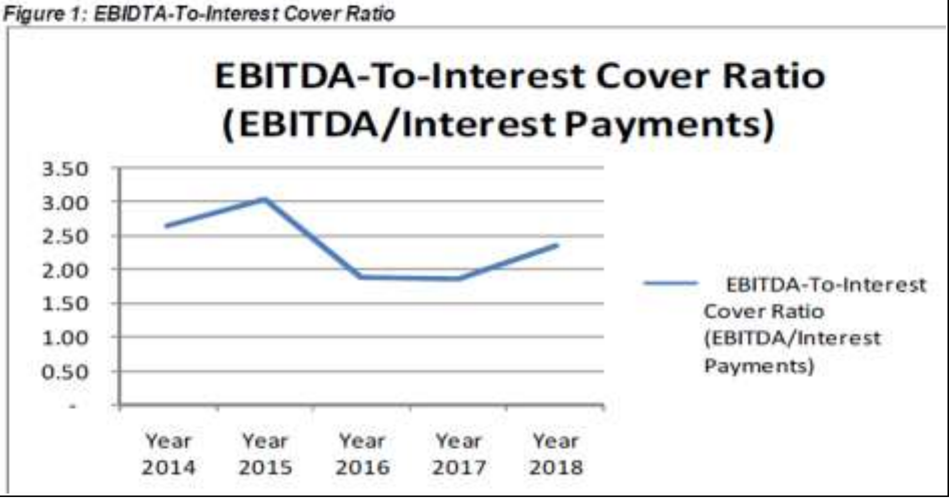
23 Reasonability tests

23.1 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 14 : EBITDA-To-Interest Cover Ratio

Figure 1: EBIDTA-To-Interest Cover Ratio



The figure above reflects around 3.0 for 2015/16

23.2 Understanding the ratio

NERSA's ratio might be similar to Moody's ratio of "Cash from Operations pre-working capital +/- Interest " – if so then the appropriate benchmark range for that type of ratio should be used. The minimum for investment grade on Moody's ratio is 3. Even for a Ba rating (below investment grade) the ratio is 2 to 3. Although this measure only looks at the interest portion of total debt obligations i.e. does not consider the ability to meet the obligations regarding payment of debt principal, it indirectly measures that ability by using a higher benchmark range i.e. >3. NERSA's target of 3.0 for 2015/16 (reducing to below 2.5 by 2017/18, per the figure) would thus not be appropriate for this ratio as it would be targeting sub-investment grade levels. Clearly this is not NERSA's intention given that NERSA's comment in the MYPD2 RCA implementation plan was that it "*is not expected to negatively affect the credit rating*". However, to achieve that, a value of >3 is probably required – 2.6 (and below) would certainly be very unfavorable to Eskom's credit ratings.

Alternatively, if the intention is to directly measure the ability to meet **debt obligations, then the EBITDA should be compared to interest plus debt principal**, not just interest – and in this case a lower benchmark range would be appropriate.

Thus in deciding on the **ratio to be measured** it is critical to **understand the intention** as that will contribute to the elements required in the proper ratio calculations. In addition the ratio selected must be accompanied with the appropriate target benchmark range for measurement purposes. NERSA's stated intention is that Eskom must be able to meet its debt obligations. This is confirmed by the Electricity Regulation Act s.16 (1) (a), as well as government's Electricity Pricing Policy of 2008 that states:

"Tariffs, therefore, need to be set at a level which would not only ensure that the utility generates sufficient revenues to cover the full costs (including a reasonable margin or return) but would also allow the utility to obtain reasonably priced funding on a forward looking basis. Rating agencies and lenders focus on a range of appraisal factors including profitability, e.g. Return on Assets (ROA) and Return on Equity (ROE), financial leverage (debt to equity) and debt service (e.g. interest coverage). It is important for the sake of financial sustainability that all these indicators move between acceptable norms and standards on a forward looking basis over the short, medium and long term. If the financial performance of the regulated entity deviates from these norms and standards investors will either be reluctant to extend credit or increase the cost of finance, ultimately resulting in higher tariffs or State support (e.g. guarantees, subsidies) or even bankruptcy in the case of private owners.

Ultimately the decision to lend money to a regulated utility is made by the financial institution and not the regulator. The regulator, therefore, has a duty to measure the projected results from its regulatory methodologies (taking into account investment cycles and other cost trends) using the same criteria that reasonable commercial lenders would employ. The *regulator needs to consult with commercial lenders when assessing the financial viability of the industry on an ongoing basis."*

23.3 Interest cover ratio

A further approach would be to use a conventional 'interest cover ratio', in which case the appropriate revenue item to use is **EBIT** (Earnings before interest and tax), not EBITDA. The reason for deducting Depreciation and Amortisation (thus, to use EBIT instead of EBITDA) is that these are the elements used for the loan repayment. Thus EBIT is used when one measures only interest cover. The objective of the interest cover ratio is used to determine how easily a company can pay interest on outstanding debt. It is a debt and profitability ratio.

23.4 Debt service cover ratio (Interest + Capital)

Therefore an **EBITDA** interest cover ratio > 1 may not necessarily mean Eskom has enough available to pay interest unless the effect of the principal loan repayments are also taken into account, i.e. if EBITDA is used then it should be compared to total debt service obligations (interest plus debt principal). Thus EBITDA is used when one measures the ability to cover the full debt obligations comprising interest plus debt principal.

23.5 Computation of ratios for FY 2015

The financial information used to compute the ratios is disclosed below.

Table 69: Financial information for ratios in 2015/16

Financial Information for ratios workings		2015/16
Calculation of EBITDA		
EBITDA	**A**	29 592
Profit before net finance (cost)/ income - EBIT	**B**	13 075
Plus: Depreciation and amortisation expense		16 517
Calculation of Total debt serviced		
Finance cost		**30 603**
Debt securities and borrowings	**C**	23 333
Derivatives IRS and CCS		3 151
Employee benefit obligations		1 130
Provisions		2 583
Finance lease payables		406
Finance income		**-1 651**
Investment in securities		-347
Loans receivable		-446
Cash and cash equivalents		-858
Net interest per AFS	**D**	**28 952**
Add / (deduct) items excluded for purposes of the framework :		**115**
Provisions and Employee benefit obligations		-1 130
Finance lease payables		-406
Finance income		1 651
Total interest used for calculation		**29 067**
Add : Debt repaid		11 013
Total debt serviced	**E**	**40 080**

Various ratios have been computed as summarised below. Eskom's 2015/16 AFS reports on such interest cover ratio and reflects it as 0.45 which is way below the minimum of 2.5 required to remain in the lower range of investment grade ratings. Alternatively, if the focus was on debt service cover then the actual result in 2015/16 is 0.74. Irrespective of whether interest cover ratio (using EBIT) or debt service cover ratio (using EBITDA) are used to measure the financial situation, the actual outcome on both are poor in 2015/16 compared to their acceptable ranges of over 2 (and that reference value has also been confirmed by NERSA).

If the EBITDA; Interest cover ratio is used then the acceptable range for lower investment grade ratings would be >3. When using ratios that seem similar to this ratio the rating agencies set >3 as the minimum for lower investment grade, with <3 being rated as sub-investment grade.

23.6 EBIT Interest cover ratio

The results reflects an EBITDA interest cover ratio 0.45 which entails that Eskom did not generate sufficient earnings to cover its interest commitments. In order for Eskom to cover its interest costs the cover ratio must be at least 1. Therefore at 0.45, Eskom's earnings during 2015/16 do not even cover half the interest costs for the year.

Table 70: EBIT Interest Cover

EBIT Interest cover	Calculation Reference	2015/16
EBIT Interest cover	B/D	**0.45**
EBIT	B	13 075
Interest	D	28 952

23.7 EBITDA: Total debt service ratio

The results reflect an EBITDA: debt service ratio of 0.74 which means that Eskom did not earn enough to cover interest plus debt repayments, thereby being placed in a situation to refinance debt. The results reflect a shortfall of R10 488m (R40 080m minus R29 592m) which was effectively refinanced in 2015/16.

Table 71: EBITDA Debt service cover during 2015/16

EBITDA : Total debt serviced (Revised calculation to account for debt repaid)	Calculation reference	2015/16
EBITDA : Total debt serviced	B/E	0.74
EBITDA	B	29 592
Total debt serviced	E	40 080

24 Conclusion

Eskom’s approach to RCA 2015/16 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 and OCGTs.** 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.

Eskom’s 2015/16 RCA Submission is driven substantially by revenue under recoveries, higher expenditure for IPPs, an aligned OCGTs submission and other primary energy. Eskom has not claimed the over expenditure of R13 966m 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. In addition Eskom has applied the NERSA approach to OCGTs resulting in the organization absorbing R6 493m relating to OCGTs. Ultimately the 2015/16 RCA Submission of R23 633m will allow Eskom the opportunity to earn the allowed revenue and to recoup efficient costs which qualify for the RCA that exceeded the assumptions made in the MYPD3 decision for 2015/16. The need for a significant RCA adjustment is demonstrated by the actual debt cover ratios being well below acceptable norms.

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

Annexures:

Revenue:

Annexure 1: Income Statement in AFS 2016, page 15

Income statements

for the year ended 31 March 2016

		Group		Company	
			Restated [1]		Restated [1]
		2016	2015	2016	2015
	Note	Rm	Rm	Rm	Rm
Continuing operations					
Revenue	32	163 395	147 691	163 395	147 691
Other income	33	2 390	4 444	2 471	6 645
Primary energy	34	(84 728)	(83 425)	(84 728)	(83 425)
Employee benefit expense	35	(29 257)	(25 912)	(24 721)	(22 187)
Net impairment loss	36	(1 170)	(3 766)	(1 159)	(3 755)
Other expenses	37	(18 663)	(15 771)	(25 170)	(22 083)
Profit before depreciation and amortisation expense and net fair value loss (EBITDA)		31 967	23 261	30 088	22 886
Depreciation and amortisation expense	38	(16 531)	(14 115)	(16 517)	(14 001)
Net fair value loss on financial instruments, excluding embedded derivatives	39	(1 452)	(4 117)	(1 492)	(4 208)
Net fair value gain on embedded derivatives		997	1 310	996	1 310
Profit before net finance cost		14 981	6 339	13 075	5 987
Net finance cost		(7 919)	(6 109)	(8 776)	(6 769)
Finance income	40	3 447	2 996	2 667	2 360
Finance cost	41	(11 366)	(9 105)	(11 443)	(9 129)
Share of profit of equity-accounted investees after tax	11	43	49	-	-
Profit/(loss) before tax		7 105	279	4 299	(782)
Income tax	42	(2 488)	(37)	(1 697)	160
Profit/(loss) for the year from continuing operations		4 617	242	2 602	(622)
Discontinued operations					
Loss for the year from discontinued operations		-	(42)	-	-
Profit/(loss) for the year [2]		4 617	200	2 602	(622)

1. Refer to note 49

2. A nominal amount is attributable to the non-controlling interest in the group. Theremainder is attributable to the owner of the company. Refer to note 49.

Restatement note 49, page 94 AFS 2016

Notes to the financial statements (continued)

for the year ended 31 March 2016

49. Restatement of comparatives

Change in measurement basis of cross-currency swaps classified as derivatives held for risk management

Eskom makes use of a valuation technique in terms of IFRS to determine the fair value of cross-currency swaps that are held for risk management. Eskom reviewed and improved the valuation technique to better reflect non-performance risk, in particular credit risk taking into account the credit value adjustment (CVA) of the counterparty and debit value adjustment (DVA) of Eskom. This resulted in a value that is more representative of the net credit exposure to a counterparty.

As the improvements in the valuation technique are relevant to determine the fair value in prior years and given the size of the adjustments related to prior years, the prior year financial statements have been restated.

The impact of the restatement is as follows:

	Group			Company		
	Previously reported Rm	Adjustments Rm	Restated Rm	Previously reported Rm	Adjustments Rm	Restated Rm
Statements of financial position at 31 March 2015						
Assets						
Non-current						
Derivatives held for risk management	19 242	(4 939)	14 303	19 242	(4 939)	14 303
Equity						
Capital and reserves attributable to owner of the company	122 247	(5 083)	117 164	116 040	(5 083)	110 957
Liabilities						
Non-current						
Derivatives held for risk management	520	2 121	2 641	520	2 121	2 641
Deferred tax	20 131	(1 977)	18 154	19 825	(1 977)	17 848
Income statements for the year ended 31 March 2015						
Continuing operations						
Profit before depreciation and amortisation expense and net fair value gain/(loss) (EBITDA)	23 261	-	23 261	22 886	-	22 886
Depreciation and amortisation expense	(14 115)	-	(14 115)	(14 001)	-	(14 001)
Net fair value gain/(loss) on financial instruments excluding embedded derivatives	630	(4 747)	(4 117)	539	(4 747)	(4 208)
Net fair value gain on embedded derivatives	1 310	-	1 310	1 310	-	1 310
Profit before net finance cost	11 086	(4 747)	6 339	10 734	(4 747)	5 987
Net finance cost	(6 109)	-	(6 109)	(6 769)	-	(6 769)
Finance income	2 996	-	2 996	2 360	-	2 360
Finance cost	(9 105)	-	(9 105)	(9 129)	-	(9 129)
Share of profit of equity-accounted investees, net of tax	49	-	49	-	-	-
Profit before tax	5 026	(4 747)	279	3 965	(4 747)	(782)
Income tax	(1 366)	1 329	(37)	(1 169)	1 329	160
Profit for the year from continuing operations	3 660	(3 418)	242	2 796	(3 418)	(622)
Discontinued operations						
Loss for the year from discontinued operations	(42)	-	(42)	-	-	-
Profit for the year	3 618	(3 418)	200	2 796	(3 418)	(622)

Annexure 2: The Eskom energy wheel (Eskom Fact sheet 2016)

****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

Generation of electricity	2015/16	2014/15
Generation	216 043	222 591
OCGT	3 936	3 709
Own generation	219 979	226 300
IPPs	9 033	6 022
Generation (including IPPs)	229 012	232 322
Pumping	(4 046)	(4 114)
Total	224 966	228 208

Available for distribution	2015/16	2014/15
Generation (including IPPs)	229 012	232 322
International purchases	9 703	10 731
Wheeling [1]	3 930	3 623
Subtotal	242 645	246 676
Pumping	(4 046)	(4 114)
Total	238 599	242 562

Total imports	2015/16	2014/15
International purchases	9 703	10 731
Wheeling [1]	3 930	3 623
Total	13 633	14 354

Total exports	2015/16	2014/15
International sales [2]	13 465	12 000
Wheeling [1]	3 930	3 623
Total	17 395	15 623

Southern African Power Pool

Internal use	2015/16	2014/15
Internal use	661	791
Generated	(71)	(53)
Total	590	738

Demand	2015/16	2014/15
External sales	214 487	216 274
Technical and other losses	19 895	20 940
Internal use	661	791
Generated	(71)	(53)
Wheeling	3 930	3 623
Unaccounted/rephasing	(303)	988
Total	238 599	242 562

External sales	2015/16	2014/15
Local sales	201 022	204 274
International sales [2]	13 465	12 000
Total	214 487	216 274

Technical and other losses	2015/16	2014/15
Distribution	13 866	14 920
Transmission	6 029	6 020
Total	19 895	20 940
Distribution %	6.43%	6.78%
Transmission %	2.61%	2.53%
Total %	8.59%	8.79%

1. Wheeling is the buying and selling of electricity between Eskom and foreign parties without the power being available to the South African grid.
2. International sales includes exports by Distribution International to Lesotho. The actual volumes were 89GWh for both 2016 and 2015.

Annexure 3: Sales volumes GWh – Statistical tables for 2015/16

Electricity sales per customer category, GWh

Category	2015/16	2014/15
Local	**201 022**	204 274
Redistributors	**89 591**	91 090
Residential [1]	**11 917**	11 586
Commercial	**10 150**	9 644
Industrial	**50 150**	53 467
Mining	**30 629**	29 988
Agricultural	**5 733**	5 401
Rail	**2 852**	3 098
International	**13 465**	12 000
Utilities	**4 018**	2 797
End users across the border	**9 447**	9 203
	214 487	216 274

International sales to countries in southern Africa, GWh

	2015/16	2014/15
	13 465	12 000
Botswana	**1 099**	1 237
Lesotho	**205**	230
Mozambique	**8 281**	8 360
Namibia	**1 746**	924
Swaziland	**1 044**	882
Zambia	**344**	16
Zimbabwe	**252**	108
Short-term energy market [2]	**494**	243

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 mil

Category	2015/16	2014/15
Local	**154 959**	140 074
Redistributors	**66 353**	60 051
Residential [1]	**12 824**	11 361
Commercial	**10 100**	8 599
Industrial	**31 406**	30 377
Mining	**24 133**	20 848
Agricultural	**7 278**	6 247
Rail	**2 754**	2 591
IPP network charge	**111**	–
International	**8 055**	6 306
Utilities	**8 055**	2 988
End users across the border		3 318
Gross electricity revenue	**163 014**	146 380
Environmental levy included in revenue [2]	**513**	485
Less: Revenue capitalised [3]	**(367)**	-
Less: IAS 18 revenue reversal [4]	**(1 472)**	(597)
Electricity revenue per note 32 in the annual financial statements	**161 688**	146 268

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 recovered through sales.

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 R1 472 million was thus not recognised at 31 March 2016.

Primary Energy

Annexure 4: Primary Energy Note 34 extract AFS March 2016, page 85

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
34. Primary energy					
Own generation costs		**57 594**	61 630	**57 594**	61 630
Environmental levy		**8 120**	8 353	**8 120**	8 353
International electricity purchases		**3 660**	3 679	**3 660**	3 679
Independent power producers		**15 106**	9 453	**15 106**	9 453
Other		**248**	310	**248**	310
		84 728	83 425	**84 728**	83 425

Own generating costs relates 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.

Reasonability test

Annexure 5: Finance income note 40 and Finance cost note 41 (Extracts AFS March 2016, page 86-87)

Notes to the financial statements (continued)

for the year ended 31 March 2016

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
40. Finance income					
Investment in securities		723	739	347	513
Loans receivable		825	799	446	422
Finance lease receivables		65	68	65	68
Trade and other receivables		951	677	951	676
Cash and cash equivalents		883	713	858	681
		3 447	2 996	2 667	2 360
41. Finance cost					
Debt securities and borrowings		23 242	19 699	23 333	19 731
Eskom bonds		10 202	9 381	10 202	9 381
Promissory notes		6	5	6	5
Commercial paper		587	677	573	627
Eurorand zero coupon bonds		520	458	520	458
Foreign bonds		3 637	2 041	3 637	2 041
Development financing institutions		4 777	3 192	4 777	3 192
Export credit facilities		1 560	1 345	1 560	1 345
Subordinated loan from shareholder		1 208	2 228	1 208	2 228
Other loans		745	372	850	454
Derivatives held for risk management		3 151	2 496	3 151	2 496
Employee benefit obligations	28	1 158	1 060	1 130	1 034
Provisions	29	2 588	2 877	2 583	2 875
Finance lease payables		387	87	406	107
Trade and other payables		266	275	266	275
Gross finance cost		30 792	26 494	30 869	26 518
Capitalised to property, plant and equipment	8	(19 426)	(17 389)	(19 426)	(17 389)
		11 366	9 105	11 443	9 129

Operating expenses

Annexure 6: OPEX note 38 extract from AFS March 2016, page 86

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
35. Employee benefit expense					
Salaries		20 092	18 681	18 517	17 446
Overtime		1 970	1 682	1 657	1 446
Post-employment medical benefits		583	473	573	465
Leave		675	767	635	714
Annual and performance bonus		2 140	1 383	2 133	1 256
Pension benefits		2 089	1 976	1 943	1 845
Direct costs of employment		27 549	24 962	25 458	23 172
Direct training and development		147	197	117	176
Temporary and contract staff costs		3 124	2 743	843	883
Other staff costs		1 703	1 016	1 569	962
Gross employee benefit expense		32 523	28 918	27 987	25 193
Capitalised to property, plant and equipment		(3 266)	(3 006)	(3 266)	(3 006)
		29 257	25 912	24 721	22 187

Notes to the financial statements (continued)

for the year ended 31 March 2016

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
36. Net impairment loss					
Impairment		1 644	3 905	1 623	3 882
Property, plant and equipment	8	789	1 157	789	1 156
Inventories		11	5	11	5
Loans receivable	15	14	15	-	-
Trade and other receivables	19	830	2 728	823	2 721
Reversal		(469)	(132)	(459)	(120)
Property, plant and equipment	8	(2)	(7)	(2)	(7)
Inventories		-	(21)	-	(14)
Loans receivable	15	(3)	(1)	-	-
Trade and other receivables	19	(464)	(103)	(457)	(99)
Bad debts recovered		(5)	(7)	(5)	(7)
		1 170	3 766	1 159	3 755

Notes to the financial statements (continued)

for the year ended 31 March 2016

	Note	Group 2016 Rm	Group 2015 Rm	Company 2016 Rm	Company 2015 Rm
37. Other expenses					
Managerial, technical and other fees		563	715	505	678
Direct research and development		38	35	38	35
Operating lease expense		1 117	1 397	412	753
Auditors' remuneration [1]		94	97	80	84
Net loss on disposal of property, plant and equipment		358	111	494	103
Government grant		-	-	-	-
Income		(23)	(209)	(23)	(209)
Expenses incurred		23	209	23	209
Repairs and maintenance, transport and other expenses		16 493	13 416	23 641	20 430
		18 663	15 771	25 170	22 083

Annexure 7: Verified EEDSM savings

Breakdown of performance of IDM Solution

IDM initiative	Number of projects	Verified demand savings (MW)	Verified energy savings (GWh)
ESCO	14	23.98	46.3
Standard Offer	3	0.8	6.2
Standard Product	3	10.8	75.9
Residential Mass Roll-out	7	67.2	18.5
Total	**27**	**102.8**	**146.9**

25 Abbreviations

BPP	Business Productivity Programme
Capex	Capital Expenditure
c/kWh	Cent per kilowatt hour
COD	Commercial Operation Date
CoGTA	Department of Cooperative Governance and Traditional Affiars
COS	Cost of Supply
CPI	Consumer Price Index
CSP	Concentrated Solar Power
DoE	Department of Energy
DMP	Demand Market Participation
DPE	Department of Public Enterprises
DRC	Depreciated Replacement Cost
Dx	Distribution
EAF	Energy availability factor (see glossary)
EBITDA	Earnings before interest, taxation, depreciation and amortisation
EPP	Electricity Pricing Policy
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
Gx	Generation
HVAC	Heating, Ventilation and Air Conditioning
IBT	Inclining Block Tariff
IDC	Interest during construction
IDM	Integrated demand management

IPP	Independent power producer (see glossary)
IRP 2010	Integrated Resource Plan 2010-2030
KIC	Key industrial customers
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
MKI	Medupi, Kusile and Ingula
Mt	M tons
MTPPP	Medium Term Power Purchase Programme
MVA	Megavolt-ampere
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)
OCLF	Other Capability Loss Factor
ODC	Owner's Development Cost
Opex	Operating Expenditure
PE	Primary Energy
PPA	Power Purchase Agreement
PPI	Producer Price Index
PCLF	Planned Capability Loss Factor
PAJA	Promotion of Administrative Justice Act, 2000
PFMA	Public Finance Management Act, 1999
R&D	Research and Development

R/kVA	Rand per kilovolt ampere
R/kWh	Rand per kilowatt hour
R/MW	Rand per Megawatt
R/MWh	Rane per Megawatt hour
R'm	Rand million
RAB	Regulatory Asset Base
RCA	Regulatory Clearing Account
RCN	Replacement Cost New
RTS	Return-to-Service
SADC	Southern African Development Community
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SBP	Single Buyer Procurement
SM	System Minutes
SQI	Service Quality Incentive
STPPP	Short Term Power Purchase Programme
SWH	Solar Water Heaters
TOU	Time-of-Use
Tx	Transmission
UAGS	Unplanned automatic grid separations
UCLF	Unplanned Capability Loss Factor (see glossary)
UOS	Use-of-System
WACC	Weighted Average Cost of Capital
WUC	Work Under Construction

26 Glossary and Terms

49M	The 49M initiative aims to inspire and rally all South Africans behind a common goal: to save electricity and create a better economic, social and environmental future for all
Base-load plant	Largely coal-fired and nuclear power stations, designed to operate continuously
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
Daily peak	Maximum amount of energy demanded by consumers in one day
Debt/equity including long-term provisions	Net financial assets and liabilities plus non-current retirement benefit obligations and non-current provisions divided by total equity
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

Embedded derivative	Financial instrument that causes cash flows that would otherwise be required by modifying a contract according to a specified variable such as currency
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
Forced outage	Shutdown of a generating unit, transmission line or other facility for emergency reasons or a condition in which generating equipment is unavailable for load due to unanticipated breakdown
Free basic electricity	Amount of electricity deemed sufficient to provide basic electricity services to a poor household (50kWh/month)
Free funds from operations	Cash generated from operations adjusted for working capital
Gross debt	Debt securities and borrowings plus finance lease liabilities plus the after-tax effect of provisions and employee benefit obligations
Gross debt/EBITDA ratio	Gross debt divided by earnings before interest, taxation, depreciation and amortisation
Independent non-executive director	Someone who is: Not a full-time salaried employee of the company or its subsidiary Not a shareholder representative Has not been employed by the company and is not a member of the immediate family of an individual who is, or has been in any of the past three financial years, employed by the company in any executive capacity Not a professional advisor to the company Not a significant supplier or customer of the company

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 management	Activities to influence the level and shape of demand for electricity so that demand conforms to the present supply situation, long-term objectives and constraints
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
Lost-time injury (LTI)	A work injury, including any occupational disease/illness or fatality, which arises out of and in the course of employment and which renders the injured employee or contractor unable to perform his/her regular/normal work on one or more full calendar days or shifts other than the day or shift on which the injury occurred
Lost-time injury rate (LTIR)	Proportional representation of the occurrence of lost-time injuries over 12 months per 200 000 working hours
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
Peaking capacity	Generating equipment normally operated only during hours of highest daily, weekly or seasonal loads
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)
Working capital ratio	(Inventory plus the current portion of payments made in advance, trade and other receivables and taxation assets) divided by (the current portion of trade and other payables, payments received in advance, provisions, employee benefit obligations and taxation liabilities)