Eskom

MYPD 3

(Year 2014/15)

Regulatory Clearing Account Submission to NERSA

13 May 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 2014/15 and in accordance with the Multi-Year Price Determination Methodology (hereafter referred to as the 'MYPD Methodology')[1]. This document contains the following:

1. Information provided in regard to Eskom's 2014/15 RCA balance (hereafter referred to as the '2014/15 RCA Submission' or year 2 of MYPD3) is lodged in accordance with section 14.2.1 of the MYPD Methodology.
2. Information is supported by Eskom's 2014/15 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 2014/15 RCA Submission

The structure of the summary of 2014/15 RCA Submission provided in this document is guided by the MYPD Methodology. With this in mind, an overview of the 2014/15 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 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 2014/15 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 2014/15 RCA Submission is to provide the context for the Regulatory Clearing Account (RCA) process in terms of NERSA's MYPD Methodology requirements. The **2014/15 RCA Submission for the second 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.

<u>The RCA process has two steps:</u>

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** through 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 2014/15 RCA Submission

Eskom's 2014/15 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 R19 185m is motivated with evidence for prudent scrutiny by NERSA.

Table 1: Summary of 2014/15 RCA Submission

RCA for 2014/15	Actuals	Variance	RCA adjustment	RCA 2014/15
Total Electricity revenue R million	**146 267**	**9 790**	**-1 003**	**8 787**
Primary Energy , R million				
Coal	45 195	8 578	-8 004	574
OCGTs	9 546	6 836	-4 892	1 944
Other primary energy	6 890	1 355		1 355
Local IPPs and co-generation	9 454	4 346		4 346
International Purchases	3 679	3 299		3 299
Environmental levy	8 353	-683		-683
Nuclear decommissioning from RCA 2013/14 decision phased in over 10 years			83	83
Demand Market Participation (DMP)	309	-379	-	-379
Total primary energy , R million	**83 426**	**23 352**	**-12 813**	**10 539**
Capital Expenditure Clearing Account (CECA) , R million	**54 394**	**9 281**	**91**	**91**
Integrated Demand Management (IDM) , R'million	**654**	**-299**	**150**	**-149**
Operating[1] costs , R million	**44 982**	**5 565**	**4 552**	**-528**
Service Quality Incentive (SQI) , R million	**-**	**-**	**236**	**236**
Inflation adjustments , R million		**-**	**209**	**209**
Total RCA balance , R million				**19 185**

3.1 Revenue

The revenue variance of R8 787m is calculated on Eskom's electricity revenue to all customers because of lower electricity sales volumes. In addition, Eskom has specifically excluded the loss of revenue attributable to the load shedding and load curtailment impacts.

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 R10 539m 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 R683m 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 R834 million, over a period of 10 years, in equal installments of R83m via future RCA applications. The first tranche of R83 million was granted in the RCA 2013/14 decision.

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 2014/15 period. The international purchases cost variance contributes R3 299m to the total primary energy category of the RCA balance.

3.6 Capital expenditure variance

Eskom's Company capital expenditure for regulatory purposes of R54 394 million exceeded the NERSA decision of R45 113 million by R9 281 million in 2014/15. 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.

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 2014/15 the operating costs expenditure of R49 534m exceeds the decision of R39 417m by R10 117m 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 R149m for RCA purposes.

3.9 Other income

Other income is included under the operating costs section and comprises the sale of scrap assets for R186m and R342m relating to the EDI restructuring levy.

3.10 Inflation adjustments

Section 14.1.1 of the MYPD methodology states "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 R209m in favour of Eskom.

3.11 Service Quality Incentives (SQI)

Eskom has achieved the service quality incentive targets set by NERSA for Distribution and Transmission during 2014/15. This resulted in Distribution achieving an SQI of R233m and Transmission of R3m, equating to a total of R236m.

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 Comparison of RCA 2014/15 submission to RCA 2013/14 decision

Eskom has compared the RCA submission for 2014/15 to the decision made by NERSA for the RCA balance for 2013/14. This submission reflects an escalation of R7 944 million which is substantially attributable to an increase in revenue variance and higher utilization of independent power producers and other primary energy.

Table 2: RCA Trend Analysis

RCAs trend analysis	Decision RCA 2013/14	Application RCA 2014/15	Movement RCA Decision 2014 to RCA 2015
Revenue	6 175	8 787	2 612
Local IPPs	580	4 346	3 766
International Purchases	2 700	3 299	599
Coal	2 000	574	-1 426
Open Cycle Gas Turbines (OCGTs)	1 252	1 944	692
Other primary energy	72	1 355	1 283
Environmental levy	-312	-683	-371
Nuclear decommissioning from RCA 2013/14 decision phased in over 10 years	83	83	-
Integrated Demand Management (IDM)	-432	-149	283
Demand Market Participation (DMP)	-905	-379	526
Capital Expenditure Clearing Account (CECA)	9	91	82
Service Quality Incentives (SQI)	339	236	-103
Inflation adjustment - Opex	33	209	176
Other income	-353	-528	-175
RCA balance R'millions	**11 241**	**19 185**	**7 944**

3.14 Conclusion

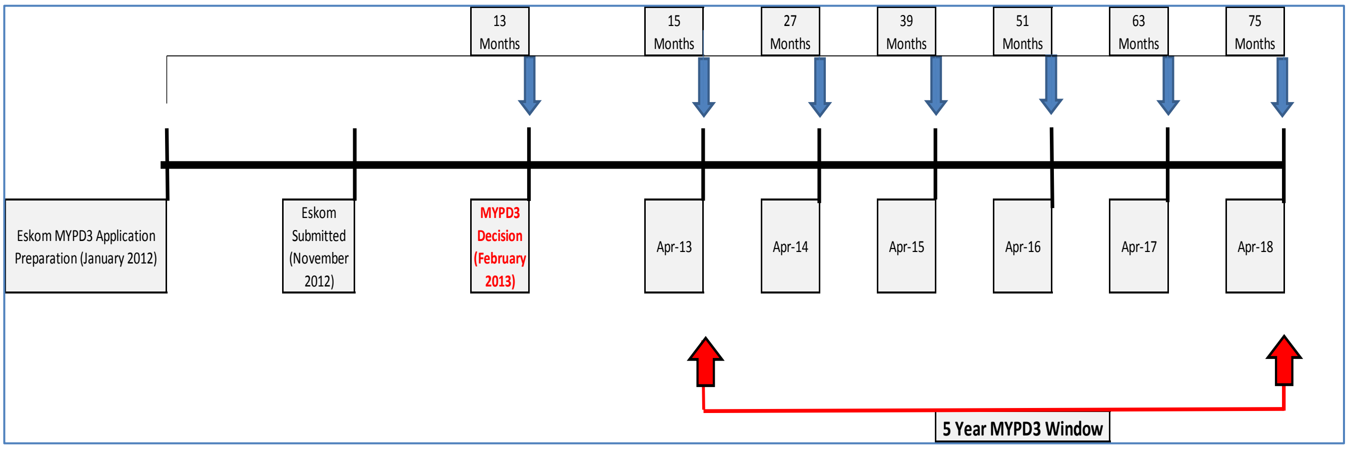
The RCA balance submission of R19 185m excludes operating cost variances. Furthermore, in aligning to the NERSA decision precedent set in the RCA 2013/14 decision, Eskom absorbed a large OCGT cost variance.

4 Factors impacting on 2014/15 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	Sales forecast average growth was 0.9% p.a. with an actual starting value of 217TWh in March 2013	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 between 82% for 2014/15.	Actual average EAF is approximately 74%	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 - 2014/15 Ingula – 2013/14 Sere – 2013/14	New build commission revised dates for 1st units: Medupi – Commissioned August 2015 Kusile – July 2018 Ingula – Jan 2017 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 between the MYPD3 decision and equivalent revenue which was actually derived in year 2 (2014/15) of the MYPD3. This document will highlight Eskom's approach to the revenue variance calculation and provide reconciliation between the revenue disclosed in the 2014/15 Eskom annual financial statement (AFS) and the MYPD3 revenue determination by NERSA for 2014/15. In addition, it will explain why non-electricity revenue is not included in the revenue variance calculation for RCA purposes.

6 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 tariff, 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

7 Calculation of the revenue variance

The table below shows the sales volume and revenue variance.

Table 4 : Calculation of MYPD3 revenue variance for 2014/15

Revenue variance for 2014/15		MYPD Decision	Actuals	Variance
Total external electricity revenue	(R'm)	156 057	147 271	-8 786
Total external sales volumes	(GWh)	229 183	216 274	-12 909
Total average selling price	(c/kWh)	68.09	68.09	0.00

7.1 Revenue computed on an equivalent basis

When computing the RCA balance, it is important to compare the same reference points. Eskom 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 2014/15 (R'million)	Eskom Company	Notes
Revenue per AFS	147 691	
Less: Non-electricity revenue	**-1 423**	**1**
Deferred income recognised	-143	
Other revenue	-1 280	
External electricity revenue	**146 268**	
Add : IAS 18 unrecognised revenue	597	2
Revenue before load reduction adjustments	**146 865**	
Add : Load reduction adjustment	406	3
Revenue for RCA purposes (R' million)	**147 271**	

Revenue as reported in Eskom's 2015 AFS

Revenue from continuing operations of R147 691m, reported on page 91 of Eskom's 2015 AFS, provides the starting point for obtaining the MYPD equivalent for actual revenue. Actual electricity revenue was R146 268m; other revenue was R1 280m and deferred income of R143m for 2014/15.

Table 6: Revenue note from AFS for March 2015

		Note	Group 2015 Rm	Group 2014 Rm	Company 2015 Rm	Company 2014 Rm
32.	**Revenue**					
	Electricity revenue		146 268	136 869	146 268	136 869
	Deferred income recognised	26	143	143	143	143
	Other revenue[1]		1 280	1 301	1 280	1 301
			147 691	138 313	147 691	138 313
	Electricity revenue of R597 million (2014: Rnil) was not recognised as it was assessed that there is a high probability that the related economic benefits will not materialise. Despite this, Eskom continues to actively pursue recovery of these amounts. Refer to note 4.1.					

Source: Eskom Annual Financial Statements, 31 March 2015 page 91.

Note 1: 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:

2.19 Deferred income

Grants

Government grants received relating to the creation of electrification assets are included in liabilities as deferred income and are credited to profit or loss within *depreciation and amortisation* expense on a straight-line basis over the expected useful lives of the related assets.

Capital contributions received from customers

Contributions received in advance from electricity customers up to 30 June 2009 for the construction of regular distribution and transmission assets (with a standard supply) are credited to profit or loss within *other revenue* when the customer is connected to the electricity network (refer to note 2.18).

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 2: IAS 18 adjustment

In terms of IAS 18 electricity revenue of R597 million was not recognized as revenue as it was assessed that there is a high probability that the economic benefit will not materialized, 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.

Note 3: Estimated Load Reduction impact on revenue loss for 2014/15

During the second year of MYPD3 there were several interruptions and thus load reduction estimated at 574GWh comprised a combination of load shedding and load curtailment. Load shedding contributed about 359 hours of interruptions (60%) and load curtailment about 229 hours of interruptions (40%) 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 as was determined by NERSA in para 31 of the MYPD3 RCA 2013/14 decision.** The load reduction impact of **574GWh is multiplied by the actual average standard tariff price (70.65c/kWh**). This equates to a total revenue loss attributable to the load reductions was calculated at **R406 million**. This amount is added back to reduce the amount of revenue variance claimed as part of the RCA submission.

Table 7 : Load shedding and curtailment impact in 2014/15

Load shedding and Curtailment impact in 2014/15						
Month	Load shedding Hours	Load Curtailment Hours	Total Load Shedding & Curtailment Hours	Load reduction GWh	Standard average price c/kWh	Revenue loss impact R'million
Apr-14	-	-	-	-		
May-14	-	-	-	-		
Jun-14	5.6	2.6	8.2	6.5		
Jul-14	-	-	-	-		
Aug-14	-	-	-	-		
Sep-14	-	-	-	-		
Oct-14	-	4.0	4.0	0.7		
Nov-14	78.5	4.0	82.5	112.8		
Dec-14	61.0	39.0	100.0	122.3		
Jan-15	32.5	20.6	53.1	48.8		
Feb-15	152.0	130.0	282.0	237.4		
Mar-15	29.0	29.0	58.0	45.7		
Total 2014/15	**358.6**	**229.2**	**587.8**	**574.2**	**70.65**	**405.6**

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.

It should be noted that the risk in using these estimates is that it can be too high or too low as the demand to be shed was a request to the customers and they could have shed more or less during those hours. These figures are estimates as they are not measured and no feedback from the customers was obtained to ascertain the amount that was actually shed during the various hours. Once the load shedding ended, some of the load (energy consumption being impacted), did return.

7.2 Allowed Revenue

The allowed revenue used for purposes of the RCA calculation is as per the reasons for decision for MYPD 3 Year 1 RCA, as follows:

1. On 18 October 2012, the National Energy Regulator of South Africa (NERSA) received Eskom's Revenue Application: third Multi-Year Price Determination (MYPD3). The application covered a five-year period from 01 April 2013 to 31 March 2018.

2. On 28 February 2013, the Energy Regulator approved Eskom's MYPD3 Revenue Requirement for the control period 2013/14 to 2017/18 as follows.

Table 1: MYPD3 decision of 28 February 2013

	2013/14	2014/15	2015/16	2016/17	2017/18
Allowed revenues from tariffs based sales (R'm)	142 746	155 477	171 838	189 396	209 025
Forecast sales to tariff customers (GWh)	217 890	219 744	224 877	229 495	234 519
Standard average price (c/kWh)	65.51	70.75	76.41	82.53	89.13
Percentage price increase (%)	8.0%	8.0%	8.0%	8.0%	8.0%
Total expected revenue from all customers (R'm)	149 937	163 584	180 332	196 378	216 322

3. The Energy Regulator, at its meeting held on 30 September 2014, reconciled the original MYPD3 decision of 28 February 2014 (Table 1) with the revised decision as per Table 2 below. The purpose of the reconciliation was to adjust for the exclusion of the ancillary charges and to adjust the forecasted sales volume for standard tariff customers.

Table 2: The reconciled MYPD3 decision before MYPD2 RCA

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

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

7.3 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 need to continue to incur these fixed 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.

7.4 Volumes: Allowed vs Actuals

Table 8 : Sales volume variance

Sales volumes variance per tariff category (GWh)	MYPD 3 Decision	Actuals	Variance
SPA sales	11 303	9 920	-1383
ADD: Standard tariff sales including internal sales	208 441	195 234	-13 207
Total Distribution sales	219 744	205 154	-14 590
Less Internal sales	-423	-791	-368
Total external Distribution sales	**219 321**	**204 363**	**-14 958**
Add: International sales	9 862	11 911	2 049
Total Eskom external sales	**229 183**	**216 274**	**-12 909**

Note 1: Decision volumes used; Table 54 as per the NERSA MYPD3 decision shown below reflects a total sales volume of 229 513GWh for 2014/15.

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	

- Table 8 above shows a total sales volumes of 229 183 GWh as the decision volumes.
- The difference of 330GWh is due to internal sales and en-route sales as shown below.

Internal sales are excluded as the RCA deals with external electricity revenue and the AFS similarly excludes internal revenue from the results.

Table 9 : Reconciliation of decision volumes

Reconciliation of MYPD3 decision sales to Eskom calculation for RCA	2014/15
Total volumes per NERSA MYPD3 decision	229 513
Less: Internal sales	-423
Add: En route sales	93
Total decision volumes	229 183

7.5 Sales volume variance explanation

The MYPD forecast is normally finalized in the 2 years preceding the MYPD determination. This becomes 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.

The table below highlights the difference between MYPD3 forecasts and actual reality over the last three years. The MYPD3 growth over the 5 year period (i.e. 2013/14 to 2017/18 volumes) was assumed to be 7.3 % while the average growth rate per annum was assumed to be 1.8%.

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			
Actual sales growth %	-3.66%	0.62%	-0.75%			

The actual sales variance was 5.7% less than the forecast of 229 513 GWh for 2014/15.

7.5.1 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 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.

7.5.2 Critical 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
- 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.
- High price increases will continue for the next 3 years (25% up to 2014/15). The price was already +/- 2.7 times what it was in 2008/9.
- A substantial amount of furnace load will not be utilized in winter because of the high winter prices.
- Furnace utilization will 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 PPA up to 2013/14, thereafter normal own generation.
- Variance in the forecasted Commodity Prices used in the Decision vs the Actual average prices.

Table 12: Commodity Prices Variance

Commodity Prices	MYPD3 Decision	Actual average prices
FeCr	$1.20/lb - $1.32/lb	$0.76/lb
Aluminum	$2 500/ton - $2 750/ton	$1 867/ton
Platinum	$1 480/oz - $2 000/oz	$1 384/oz

- High probability new projects are included.
- Average weather conditions have been used.

7.5.3 Sales volume variance explanation for FY2015

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 [1]	**11 911**	**9 862**	**2 049**
Distribution sales	**205 154**	**219 744**	**-14 590**
Re-distributors	91 090	95 986	-4 896
Industrial	53 467	59 172	-5 705
Mining	29 988	35 122	-5 134
Traction	3 098	3 117	-19
Residential	4 199	4 505	-306
Commercial	9 644	9 527	117
Agricultural	5 401	5 184	217
Prepayment	7 386	6 620	767
International A	89	88	1
Internal sales	791	423	368
Total electricity sales volumes	**217 065**	**229 606**	**-12 541**
Exclude Internal sales	-791	-423	-368
Total external electricity sales volumes	**216 274**	**229 183**	**-12 909**

Note 1 – International sales is the sum of 11911GWh + International A 89GWh to equal 12000GWh

From table 7 above, which reflects the variance between the MYPD NERSA decision and Actual sales for year 2014/15, it can be seen that the unfavorable variance of 14 590GWh 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 2 049 GWh from the export sales and 767 GWh from the prepayment environment.

7.5.3.1 Redistributors: 4 896 GWh unfavourable

The unfavorable variance in this category is spread over most of the Municipalities and metro's and are mainly due to:

- 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. Also in the Southern Region the expectation was that the Coega development project would have started up but due to the absentee of "the anchor project", very little development have materialized up to this point. Cape Town Municipality introduces 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.
- Rotational load shedding was introduced since November 2014 and it had a significant negative 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 2014.
- Due to the very high price increases, price elasticity also played a role due to 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 budgeted for in the MYPD NERSA decision.

7.5.3.2 Industrial: 5 705 GWh unfavourable.

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

- The impact from the closure of the Bayside Aluminium smelter which had an unfavourable impact of 1 480 GWh on the Aluminium sector as can be seen from the sales recon table above.
- Sasol Infra Chem commissioned their own gas generation plant and displaced 324 GWh from the “Manufacturing of basic Chemicals” sector as seen in the sales recon table above for details.
- The Ferro and steel smelting industry realized a drop in consumption against the MYPD NERSA decision of 3 119 GWh due to the very high winter prices, low demand for their products and unfavourable commodity prices that led to diminishing orders and downsizing and closure of customers. 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 is considering full closures. See Sales Recon table above for details.

7.5.3.3 Mining: 5 134 GWh unfavourable

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

- The Platinum sector realized a 3 064 GWh drop in consumption against the MYPD NERSA decision due to mainly labour unrests which caused shaft closures and many projects to be delayed and some projects were cancelled in the Platinum sector. The Platinum Industry has endured the longest strike in history and the estimated impact was 775 GWh.
- The unfavourable Platinum price and demand for platinum also negatively affect the start-up of project as well as the cancelation of some projects.

- The Gold sector realized a 2 039 GWh drop in consumption against the budget due cost pressure as a result of labour unrest and high salary increases which caused high cash costs and resulted in down scaling and shaft closures in many of the Gold mines. We also had some Gold mines that were liquidated and shafts that closed. Many shafts were also put under care and maintenance due to cost pressures. The unfavourable commodity price also played a major role in escalating the cost pressures.

The unfavorable variance in Sales volumes against the MYPD NERSA decision was offset by the large favorable variance in the Prepayment sales and SAE sales.

7.5.3.4 Prepayment: 767 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

7.5.3.5 International: 2 049 GWh favourable

Exports were higher than budget, predominantly due to BPC experiencing problems at Moropule B during the 2nd half of the financial year, hence depending on Eskom to make-up their shortfalls.

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. To reduce the impact of exports, 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

8 Conclusion of 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 R8787m in 2014/15.

9 Impact of demand responses on sales volumes

As part of the MYPD3 determination, NERSA does allow for demand response initiatives to be utilised which comprise EEDSM and DMP for 2014/15. Embedded in Eskom's MYPD3 application was an assumption for EEDSM which was taken into consideration when determining the sales forecasts. In the 2014/15 year, NERSA assumed 1 204 GWh of energy savings at a cost of R953 million which culminated in 294 MW of capacity savings.

In reality, EEDSM achieved lower savings during the year with 816 GWh of savings, generating 247.9 MW of capacity savings at a cost of R654 million. The under achievement is addressed through the RCA mechanism which deals with EEDSM.

In addition, NERSA assumed DMP costs of R688 million in 2014/15 and actual expenditure was R309 million.

10 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.**

This principle is demonstrated by Eskom adding back R597 million to actual revenue which was treated as unrecognized revenue in terms of accounting standards in the annual financial statements.

11 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 believes that practically it would be difficult to recover the respective RCA amounts from these customer categories.

12 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:

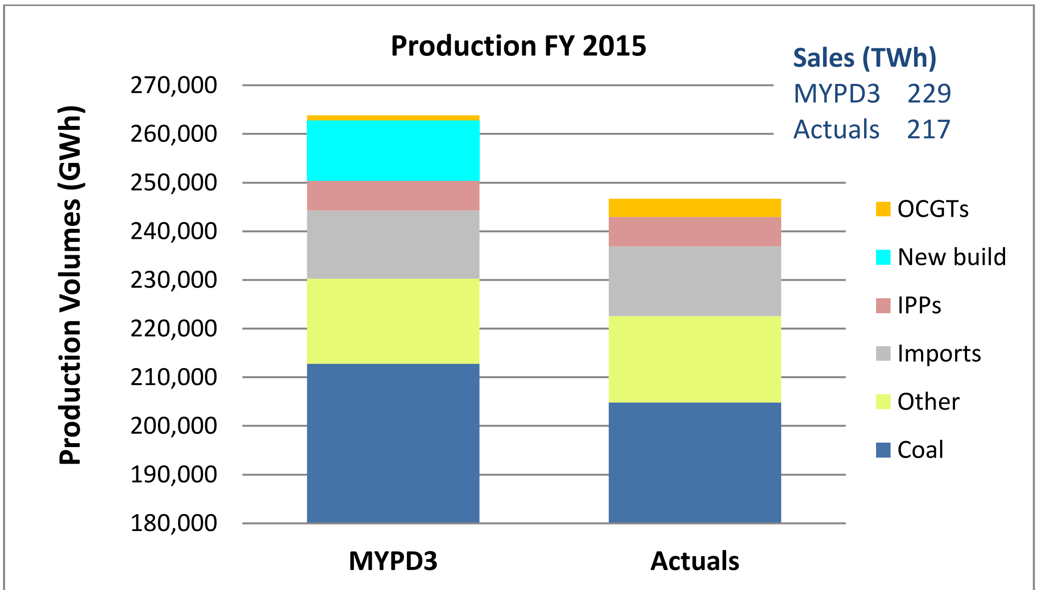
In compiling this document Eskom has adhered to globally-accepted standards of sound regulation

13 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. Therefore 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 12 TWh, 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 2: Production FY 2015



14 Primary energy

Following the NERSA RCA 2013/14 decision, where the Regulator compared revenue as well as primary energy on a total company approach, **Eskom has aligned the treatment for RCA 2014/15 to match that per the RCA 2013/14 decision.** This entails that total primary energy including international purchases are compared to the MYPD3 decision for RCA purposes.

14.1 Primary energy variances and RCA impact for 2014/15

Total primary energy allowed for 2014/15 was R60 074 million. Eskom incurred R83 426 million in the year which resulted in an extra cost of R23 352 million. However, not all the cost variances qualify for RCA inclusion. In particular the following RCA adjustments were processed:

1. Coal costs – Medupi and Kusile take or pay 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 RCA 2013/14 decision and treatment of OCGTs.
4. Nuclear decommissioning provision – implementation of the 10 year phasing of the provision of R833 million in equal tranches.

Hence the sum of all these adjustments is R12 813 million and thereby reduces the total primary energy variance to R10 539 million.

Table 14 : Total primary energy comparison and RCA impact for 2014/15

Primary Energy (R'million)	MYPD 3 Decision	Actuals	Variance	RCA Adjustments	RCA 2014/15
Coal	36 617	45 195	8 578	-8 004	574
OCGTs	2 710	9 546	6 836	-4 892	1 944
Local IPPs and co-generation	5 108	9 454	4 346	-	4 346
International purchases	380	3 679	3 299	-	3 299
Environmental levy	9 036	8 353	-683	-	-683
Nuclear decommissioning from RCA 2013/14 decision phased in over 10 years	-	-	-	83	83
Water	1 957	1 455	-502	-	-502
Start up gas & oil	1 570	2 634	1 064	-	1 064
Coal handling	1 119	1 699	580	-	580
Water treatment	265	384	119	-	119
Nuclear	352	532	180	-	180
Fuel procurement	272	186	-86	-	-86
Primary energy , R million	**59 386**	**83 117**	**23 731**	**-12 813**	**10 918**
Demand market participation	688	309	-379	-	-379
Total primary energy , R million	**60 074**	**83 426**	**23 352**	**-12 813**	**10 539**

Source : Allowed total primary energy is table 17, MYPD3 decision; Source: Actuals , Primary energy note 34, AFS, March 2015

Extract from the AFS, March 2015 reflects the actual total primary costs of R83 425m below.

Table 15: Primary energy actual costs per note 34 in the AFS of 2015

	Note	Group 2015 Rm	Group 2014 Rm	Company 2015 Rm	Company 2014 Rm
34. Primary energy					
Own generation costs		61 630	54 186	61 630	54 186
Environmental levy		8 353	8 530	8 353	8 530
International electricity purchases		3 679	3 311	3 679	3 311
Independent power producers		9 453	3 266	9 453	3 266
Other		310	519	310	519
		83 425	69 812	83 425	69 812

Own generating costs relates to the cost of coal, uranium, water and liquid fuels that are used in the generation of electricity. Eskom uses 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.

15 Independent Power Producers

Eskom acknowledges the role that IPPs must play in the South African electricity market and remain 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.

15.1 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 290.6 MW (excluding one contract that was awarded but never became operational due to the IPP failure to meet obligations). At 1 April 2014 only one contract (of 13 MW) remained in operation under this programme, as the others had all expired.

15.2 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 2014/15 financial year (with City Power for 420 MW).

15.3 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. As at 31 March 2015 the combined contracted capacity under the STPPP was 289 MW.

15.4 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 2014/15 year 87MW of capacity was contracted.

15.5 Long-term IPP programmes

The Department of Energy (DoE) has instituted long term IPP programmes in which Eskom's role is that of designated purchaser of supplied energy, as well as being the network operator where Eskom owns the network and grid connection infrastructure.

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

Power purchase agreements (PPAs) of 1 005MW for the Avon and Dedisa plants were entered into during June 2013 and became effective on 29 August 2013. Commissioning of Dedisa was expected in the second half of 2015, while Avon is expected during the first half of 2016. These did not produce energy during 2014/15 as anticipated.

15.5.2 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.

Eskom has now signed contracts for a total of 3 887MW under the RE-IPP Procurement Programme. As at 31 March 2015, a total of 1 795MW has been connected and is providing power to the grid. An average load factor of 30.85% was achieved during the year. Renewable IPPs are driven by wind and solar PV technologies.

15.6 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.

15.7 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.

15.8 Regulatory rules for power purchase cost recovery

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

> ***14 Pass through of costs***
>
> *For authorised power purchases, net recoverable costs will be passed through to customers via an adjustment of the buyer's revenue allowance (albeit subject to review by NERSA as set out in rule 17 below). This will require a reconciliation of accounts comparing forecast recoverable costs to actuals.*
>
> ***17 Duration***
>
> *17.1 An authorisation for power purchase cost recovery should remain valid for the duration of the relevant PPA. Investors will need to be confident in the buyer's ability to make payments into the future, and the buyer will need an appropriate level of regulatory certainty in regard to its recovery of power purchase costs.*
>
> *17.2 For the avoidance of doubt, the review process set out in rule 16 is limited to reconciling cost variances and draw-down of the power purchase account balance, and is not a retrospective review of the general authorisation or the basis on which cost effectiveness was established*

15.9 IPP allowed costs for 2014/15

In the MYPD3 decision NERSA had awarded Eskom a total of R4 835m for energy related costs for local IPP costs as summarised below. These costs covered Eskom own IPPs under the MTPPP of R92m and Short Term programmes of R503m and Renewable IPPs R4 240m. No costs were assumed for the DOE peaking stations for 2014/15.

15.10 Actual IPP costs for 2014/15

Eskom incurred costs of R9 454 m relating to energy costs for Local IPPs during 2014/15.

Note: The IPP purchase volumes (Energy) for the NERSA decision were inferred from the costs associated with each programme as no energy was disclosed in the MYPD3 decision.

Eskom utilized 3 435 GWh more energy from IPPs when compared to the MYPD3 decision in 2014/15.

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

Table 16: IPPs costs and volumes

Independent Power Producers (IPPs)	Costs (R'million)			Volumes (GWh)			Average Costs (R/MWh)		
FY 2014/15	Actuals	Decision	Variance	Actuals	Decision	Variance	Actuals	Decision	Variance
Non-renewable programs	**2 772**	**595**	**2 177**	**3 006**	**654**	**2 352**	**922**	**910**	**12**
MTPPP	62	92	-30	55	114	-59	1 127	807	320
STPPP (incl Munics)	2 635	503	2 132	2 805	540	2 265	939	931	8
WEPS	75	-	75	146	-	146	514		514
Renewable IPP's	**6 682**	**4 240**	**2 442**	**3 017**	**1 934**	**1 083**	**2 215**	**2 192**	**22**
Renewable IPPs energy	6 553	4 240	2 313	3 017	1 934	1 083	2 215	2 192	22
Renewable IPPs - deemed energy payme	129	-	129	-	-	-			
DOE Peaker	-	-	-	-	-	-			
Total IPPs	**9 454**	**4 835**	**4 619**	**6 023**	**2 588**	**3 435**	**1 570**	**1 974**	**-404**
IPP ancilliary costs	-	273	-273						
Total IPPs for RCA	**9 454**	**5 108**	**4 346**	**6 023**	**2 588**	**3 435**			

Total capacity of 5 701MW has been contracted with IPPs as at 31 March 2015, of which 3 887MW relates to contracts under DoE's renewable energy (RE-IPP) programme. At 31 March 2015, a total of 1 795MW of renewable IPP generation capacity has been connected and is providing power to the grid. An average load factor of 30.85% was achieved during the year. Short- and medium-term contracts which were expiring at the end of March 2015 were renewed for another year, so they can continue to contribute to reducing the supply shortage.

IPPs provide much needed renewable energy to the energy mix; they also play a vital role in balancing supply and demand, as well as providing space for maintenance and reducing the need for load shedding.

The costs of R9 454m incurred in 2014/15 is highlighted in the extract form Eskom's Integrated Report 2015 below:

Table 17: Actual energy procured through IPP programme in 2014/15

Measure and unit	Actual 2014/15	Actual 2013/14
Total energy purchased, GWh [1]	**6 022**	3 671
Total spent, R million [1]	**9 454**	3 266
Weighted average cost, c/kWh	**157**	88

Source: Integrated Report 2015, Page 56

15.10.1 Reasons for IPP variances in 2014/15

Medium Term Power Purchase Programme (MTPPP)

Lower costs were incurred due to the reduced volumes, partially offset by the higher average cost due to the mid-merit operation of one of the IPPs.

Volume variance: All three providers under the MTPPP operated at a lower load factor than was expected at the time of the MYPD3 decision. 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 IPPs are incentivised under the MTPPP to operate on a mid-merit basis which some have been able to execute. These IPPs benefit from the higher price applicable over the peak period in the contract (defined as between 06h00 and 22h00). This is higher than the assumed average rate in the MYPD3 decision.

Short Term Power Purchase Programmes (STPPP)

At the time of the MYPD3 decision it was expected that the short term contracts would expire in December 2013 as the system capacity shortfall would be ameliorated by Eskom new build. The delays in the new build has necessitated the extension of the STPPP and municipal generation contracts leading to the increased purchase volumes and associated costs.

Price variance: the average STPPP price was in line with the expectation at the time of the MYPD3 application.

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.

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 substantially higher than that assumed in the NERSA MYPD3 determination. Renewable generators have mostly commissioned at, or close to, the scheduled commissioning dates and are generating close to their contracted volumes.

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 R129m for the year was made to two IPPs due to delays in grid connection:

- The connection of one IPP facility was impacted by delays in project approval, as well as project construction being delayed when landowners denied contractors access to the work site due to seasonal agricultural activities.

- The second IPP facility was impacted by the need to review the environmental impact assessment, as well as construction material delivery delays resulting from industrial action.

15.11 IPP variance for 2014/15 RCA

IPP variance = Actual IPP costs – Allowed IPP costs

Eskom **spent R9 454m** for local IPPs which **exceeded** the **IPP allowance** of **R4 835m** resulting in an over expenditure of **R4 619m** during 2014/15

A. Transmission Ancillary Costs

NERSA approved R273 m for Transmission ancillary costs in the MYPD3 determination for FY 2015. 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.

Ancillary variance = Ancillary actual – Ancillary decision

Eskom **did not spend any costs** for Transmission **ancillary charges** attributable to **IPPs** and thus has **over recovered** in 2014/15 by **R273m**

16 International purchases

Eskom acquired electricity from neighbouring countries that resulted in purchases of R3 679 million which generated energy inflows of 10 731 GWh during the year. The actual costs are agreed to international electricity purchases as disclosed under note 34 for primary energy in the AFS. As mentioned earlier the Aggreko purchases are disclosed separately from other imports.

Table 18: International purchases

International Purchases, (R'million)	MYPD 3 Decision	Actuals	RCA 2014/15
Imports	380	2 529	2 149
Regional IPPs - Aggreko		1 150	1 150
Total international purchases, R million	380	3 679	3 299

16.1 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.

Eskom also considered the alternative of an existing 100MW peaking station in Zambia, but the AIPL project was preferred as the Zambian option relied on wheeling power through Zimbabwe, where the transmission network is constrained.

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 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), 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 2014/15 Eskom incurred R1 150m costs to acquire energy from regional sources.

17 Coal Burn Costs

17.1 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".

17.2 NERSA's decision on coal benchmark and alpha

<u>The following information was received from NERSA:</u>

Table 19: NERSA's decision on coal benchmark and alpha

Coal Benchmark price		2014/15
Coal burn costs	(R'm)	36 617
Coal burn volumes	(kt)	129
Benchmark price	(R/t)	282.6

17.3 Coal cost – RCA 2015 calculation

<u>The costs to be included in the RCA are calculated as follows:</u>

17.3.1 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 2014/15
*PBR cost (Rand) =(((0.95 X R313.61) + (1-0.95) X R282.6)) X 119 179 Mt)/**1000***
PBR cost (Rand) = R37 191m

Where
Alpha = 0.95
Actual coal burn volume = 119 179 Mt
Actual unit cost of coal burn = R313.61 per ton
Coal burn benchmark cost = R282.6 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 R45 195m and deducting the R7 819m take or pay contractual amount which results in cost of R37 376m. Thereafter the adjusted actual cost of R37 376m is divided by the volume of coal burn of 119 179Mt resulting in an average actual R/t of R313.61.

Table 20: Working Coal Mechanism

Workings of coal mechanism		MYPD3	Actuals	Variance
Coal burn	(R'm)	36 617	45 195	8 578
Coal disallowed for qualifying actuals costs	(R'm)	-	-7 819	-7 819
- Medupi take or pay agreement	(R'm)		-7 803	
- Kusile take or pay agreement	(R'm)		-16	
Coal burn costs	(R'm)	36 617	37 376	759
Coal burn tons	(Mt)	129 561	119 179	-10 382
Costs rate per ton	(R/t)	282.6	313.6	31.0
Alpha - sharing mechanism	(%)	95%	95%	
Coal rate after incl Alpha	(R/t)	268.5	297.9	29.4
Adjusted MYPD3 decision with alpha		312.2		

Note 1: An amount in actual mode of R7 803m is for Medupi and R16m Kusile risk sharing agreement which have not been considered as coal burn costs.

17.3.2 Step 2 – Calculate the pass through coal burn costs

For 2014/15

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

Pass-through Coal Burn Cost = R37 191m – R36617m
Pass-through Coal Burn Cost = **R574m**

Where
PBR cost = R37 191m
Allowed coal burn cost = R36617m (per MYPD3 decision)

Coal burn for RCA is based on a performance based regulation formula.

Table 21 : Coal burn pass-through

Coal burn passthrough costs		RCA 2014/15
Coal burn based on PBR formula	(R'm)	37 191
Coal burn allowed per MYPD3	(R'm)	36 617
Coal burn costs included in RCA	**(R'm)**	**574**

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

Table 22: The coal burn breakdown for the RCA

Coal burn variance breakdown		RCA 2014/15
Coal burn price variance	(R'm)	3 814
Coal burn volume variance	(R'm)	-3 240
Coal burn costs included in RCA	**(R'm)**	**574**

The coal burn variance of R574m 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 R3 240m 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 R3 814m in favour of Eskom.

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 = 129561 X ((R313.61 – R282.6) X 0.95)

Coal price variance = 129561 X R29.4

Coal price variance = **R3 814m**

Where:

Allowed coal burn tons (Mt) = 129561 Mt

Actual Price (R/t) = R313.61

Allowed Price (R/t) = R282.6

Alpha = 0.95

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 = (R282.6 + ((R313.61- R282.6) X 0.95)) X (119 179 – 129 561)

Coal volume variance = (R282.6 + R29.4) X -10382

Coal volume variance = R312 X -10 382

Coal volume variance = -**R3240m**

Where:

Allowed coal burn tons (Mt) = 129 561 Mt

Actual coal burn tons (Mt) = 119 179 Mt

Allowed Price (R/t) = R282.6

17.4 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 23: MYPD 3 Assumptions vs. Actual 2014/15

MYPD3 FY15 Assumptions	Actual 2014/15
Electricity production from coal fired plant would be 222 661 GWh.	Electricity production from coal fired plant was 204 818 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 6 262ktons (Cost Plus) and 5 838ktons (Fixed Price)
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.
Prices from future medium term contracts have been based on existing contractual delivered cost.	The increase in the price of ST/MT coal was higher than expected.
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.

17.4.1 Lower electricity production from coal fired stations

Total coal burnt was 10 382 kt less than planned. The coal fired power stations generated 17 843 GWh less than have planned. This resulted in a positive volume variance.

17.4.2 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:

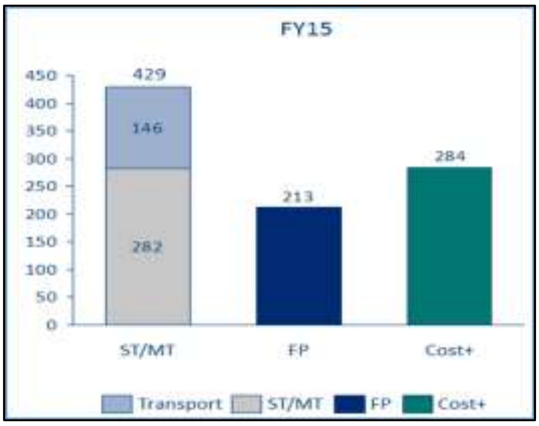
- The unavailability of the conveyor from the mine to Duvha Power Station meant that the coal had to be trucked to the station. In addition, excess coal that could not be burnt or stockpiled at Duvha was trucked to other power stations.
- The delay in commissioning of Medupi Power Station.
- The under production of Arnot and New Denmark collieries meant that more expensive coal, had to be sourced for Arnot and Tutuka.
- Production at the Return to Service (RTS) stations, Majuba and Tutuka was higher than planned, requiring additional coal to be sourced.
- The effects of industrial actions at the mines during the financial year.

17.5 Coal Purchases

17.5.1 Eskom's coal costs contracts

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 is summarized below.

Figure 3: Coal costs R/ton in 2014/15



17.5.1.1 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 in FY14. Two of Eskom's Fixed Price agreements are artificially low as there is a built-in cross subsidization clause that was negotiated some years ago. The pricing structure of these contracts is linked to the volumes delivered by the supplier. The base price of the contract is negotiated with an annual price adjustment that is applied. 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.

These mines supply contractual volumes. The price is determined by the terms of the contract, e.g. an annual escalation may be applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. None of the existing contracts are impacted on directly by the price of export coal.

17.5.1.2 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 contract (however in cases where cost-plus contracts are subsequently converted to fixed-indexed in order to better utilize export quality coal which became available from that colliery, the negotiation dynamics at the time of converting the contract might provide the opportunity for a fixed-indexed price which may be lower than had such contracting approach been followed from the beginning). It also implies that any additional capital investments and operating expenditures which 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.

17.5.1.3 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 Thus; they do not have the benefit of historically lower cost of infrastructure and establishment. However, the primary reason is because he 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. 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. In FY15, a higher proportion of ST/MT coal was moved by rail instead of road. This lowered the average cost of transport to 34% of the cost of coal from ST/MT contracts.

These contracts may extend over 1-10 years. The suppliers supply contractual volumes. As with the long term fixed price contracts, the price is determined by the terms of the contract, e.g. an annual escalation may be applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. 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 is 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.

17.5.2 Coal cost variance

The coal cost variance was a result of lower expenditure on the Cost Plus and Fixed Price contracts. At the cost plus mines, the rephasing of equipment overhauls to FY15 and postponing of the rehabilitation of the Arnot opencast mine contributed to the lower expenditure. Lower conveyor availability at Hendrina Power Station, and a damaged conveyor from the mine to Duvha Power Station resulted in lower volumes from the fixed price mines.

17.5.2.1 Coal Qualities

Arnot and Tutuka account for more than half of coal related partial load losses which lead to OCLF of 0.82%. The potential solutions to these problems, which generally imply additional capital investment and operating expenses are, explained under the Cost Plus mines above. Wet coal challenges, as well as the implementation of moisture control, between Grootegeluk Colliery and Matimba Power Station remain a concern. The initiatives implemented at Matla continue to yield benefits.

17.5.2.2 Mode of Transport

Coal is transported by conveyor, rail, road or a combination of modes. The dominant transport source is conveyor (61%), road (29%) and rail (10%).

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 FY15.

b. Rail

Rail is the next cheapest mode of transport. However, there are only two stations, Majuba and Tutuka, which have rail infrastructure. Lower total purchases (in part because of lower total electricity production), as well as logistical constraints on both Eskom's side and Transnet Freight Rail's (TFR) part also contributed to the lower rail volumes.

c. Road

Road is the most expensive mode of transport. Because of rail infrastructure constraints, ST/MT coal to all stations, apart from Majuba, is transported by road or a combination of road and rail (multi-mode transport). In some instances, this mode may be more expensive than road alone 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.

17.5.3 Medupi Take or Pay payment

A take or pay payment was incurred because of the delay in the construction of Medupi Power Station. The construction is ongoing and Eskom has received 144kT of coal in terms of the agreement with Exxaro during 2012/13. Eskom is projecting to receive coal during May 2014 in preparation for the testing and commissioning of the first unit at the power station during the latter part of FY15. Eskom was supposed to take coal from 1 February 2014.

Due to the heavy rains, labour problems and technical difficulties experienced at Medupi during FY13 & FY14, the construction of the stock pile base was delayed. This resulted in Eskom providing Exxaro with a different ramp-up profile compared to what was previously agreed. An amount of R7 803m was provided for to compensate Exxaro for costs due to the revised delivery profile. This was not envisioned at the time that the MYPD3 revenue application was submitted.

17.5.4 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 FY15, interest of R16m was incurred on the provision.

18 Other Primary energy

The MYPD methodology allows for other primary energy as pass through. Coal burn, OCGTs, IPPs and environmental levy have specific rules.

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).

18.1 Allowed other primary energy in 2014/15

Other primary energy costs assumed for 2014/15 for purposes of the MYPD3 revenue decision was R5 535m. The details regarding some elements are presented hereafter.

18.1.1 Allowed other primary energy costs for 2014/15

The categories of costs allowed for 2014/15 will be referenced to the primary energy costs disclosed in table 25. Therefore other primary energy contains assumed costs such as start-up gas and oil of R1 570m, water costs of R1 957m, coal handing of R1 119m, water treatment costs of R265m, fuel procurement of R272m and nuclear cost of R352m as presented earlier.

18.2 Actual other primary energy in 2014/15

Eskom incurred R6 890m relating to other primary costs during 2014/15 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 R5 535 million by R1 355 million. The overall other primary increased by R1438 million once the phasing in of the nuclear provision of R83 million is incorporated. In NERSA's decision on 1 March 2016, the Regulator awarded the phasing in of nuclear decommissioning provision of R843 million in 10 equal instalments of R83 million per annum.

Table 24: Other Primary Energy

RCA for 2014/15	Actuals	Variance	RCA adjustment	RCA 2014/15
Other Primary Energy				
Water	1 455	-502	0	-502
Start up gas & oil	2 634	1 064	0	1 064
Coal handling	1 699	580	0	580
Water treatment	384	119	0	119
Nuclear	532	180	0	180
Fuel procurement	186	-86	0	-86
Decommisioning nuclear - phased in per RCA 2013/14 decision			83	83
Other primary energy for RCA , R million	**6 890**	**1 355**	**83**	**1 438**

18.2.1 Reasons for start-up gas and oil costs variance

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 2014/15 than what was anticipated at the time of the MYPD3 application and hence the use of fuel oil increased significantly as well. It should be noted that long-term outages which were required for mid-life refurbishment of mechanical and control and instrumentation plant were delayed on the existing fleet. This contributed to the increase in trips and unplanned outages.

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 R365m due to the unfavourable fluctuation in the Rand/Dollar exchange rate and issues that were outside management control (e.g. torrential rainfall).”

18.2.2 Reasons for coal handling costs variance

A variance of R580m in favour of Eskom arose, due to movement of coal within the power stations being more than was originally envisaged.

The main stations which contributed to the coal handling variance are highlighted below.

18.2.2.1 Kendal

More coal was reclaimed from the strategic to the seasonal coal stockpile than anticipated. In addition strikes at the mines resulted in more coal reclaimed than planned.

18.2.2.2 Kriel and Arnot

Higher actual coal handling rates incurred when compared to planning assumptions

18.2.2.3 Komati and Grootvlei

Additional staff required to meet coal challenges at these stations

18.2.2.4 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.

18.2.3 Reasons for water costs variance

A variance of R502m materialised due to lower expenditures. The variance can be attributed mainly to the following factors:

- The implementation of the Waste Discharge Charge being delayed.
- Water augmentation projects were delayed
- The lower than planned electricity tariff increases this resulted in lower water prices.
- Although the coal fired stations produced less than planned, actual water consumption per unit of electricity was higher at most stations than had been estimated for purposes of the MYPD3 revenue application.

18.2.3.1 Water volumes

The volumes of water consumed are driven primarily by the electricity produced by the power stations. The volume consumed to generate a unit of electricity varies per power station, so the total consumption will depend on the mix of stations used to generate electricity.

Older stations generally consume more water. Most of Eskom's stations are beyond their half-lives. Although the coal fired stations produced less electricity than planned, actual water consumption per unit of electricity was higher at most stations than was planned. The overall water performance for FY15 was 1.56 l/uso against an assumption of 1.54 l/uso.

18.2.4 Reasons for fuel procurement costs variance

A variance of R86m occurred due to lower expenditure. The variance was primarily because of lower expenditure on consultants planned for studies on the Waterberg strategy and on legal consultants.

18.2.5 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 was R61m (13%) more than what was applied for and thus a driver to the variance was the amount allowed by NERSA. Detailed reasons for the R119m disallowance were not disclosed in the reasons for decision for MYPD3.

18.2.6 Water treatment costs variance

Higher water treatment costs incurred at Kendal, as chemical usage escalated due to passing valves not being repaired based on the need to operate the plant and thus not having space to make the repairs. Due to the floods that occurred at Matimba, the quality of the raw water quality deteriorated which required more chemicals to treat the water.

18.3 Other primary energy variance in 2014/15 RCA

Other Primary energy variance = Other PE Actuals – Other PE decisions

Actual other primary costs of **R6 890m** was incurred during **2014/15** which is more than the costs assumed in the **decision of R5 535m** that resulted in an **over expenditure of R1 355m** which is included in the RCA submission

19 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 R683m less than the MYPD3 determination for 2014/15. 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 2014/15.

Environmental levy variance = Levy Actuals – Levy decision

Eskom incurred **actual** environmental **levy costs of R8 353m** which was **lower** than the assumed levy costs of **R9 036m** in the **MYPD3 decision** equating to **under expenditure** of **R683 m**

20 Demand Market Participation

20.1.1 Allowed DMP in 2014/15

Demand market participation and power buybacks assumed in the MYPD3 decision was R688m during the year.

Table 25: Approved Demand Response (DR) Expenditure for MYPD3

R'm	2014/15
DMP and Power buy-back Applied for	
Funding	1 973
Demand Savings (MW)	3 355
R/MW	0.59
DMP and Power buy-back Adjusted	
Funding	-1 285
Demand Savings (MW)	-1 618
R/MW	-0.19
DMP and Power buy-back Approved	
Funding	688
Demand Savings (MW)	1 737
R/MW	0.40

Source: Table 36 of MYPD3 decision, 28 February 2013

Of the 171.5 MWs saved under the EEDSM initiatives, total projects verified during the 2014/15 year were 147.4 by Eskom and 24.1 by the Department of Energy.

20.1.2 Actual DMP in 2014/15

Demand market participation was underspent by R379 m during the year.

Table 26: DMP comparison for RCA in 2014/15

Demand market participation (DMP) in 2014/15	MYPD3 Decision	Actuals	Variance
DMP (R'm)	688	309	-379

The Demand Market Participation experienced challenges in uptake with reasons listed below.

- The uptake from customers was not to the level as originally anticipated. With industrial, a threshold seems to have been reached where further uptake does not seem to be materialising.
- New demand response products were proposed to attract further interest from customers. However, the response was disappointing.
- Generally, customer appetite for Demand Response is low.
- The lack of further growth in the economy resulted in fewer opportunities for potential customers to respond.

20.1.3 Computation of DMP variance for RCA in 2014/15

Eskom spent R309m for DMP progammes which was lower than the decision of R688m equating to under spend of R379m for the year.

21 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)."

21.1 Reasons for OCGTs variance

During the 2014/15 financial year Eskom utilised OCGTs at 2 653 GWh more than was assumed in the MYPD3 decision with the main intention to avoid load shedding. This is clearly stated in the MYPD Methodology para 8.4.2. "*For* ***avoidance of doubt****, gas turbine generation should be* ***employed before implementation of load shedding activities".***

The cost of running the OCGTs for the additional 2 653 GWh resulted in Eskom incurring an additional R6 836m to reduce the impact of load shedding on the economy.

Before the OCGTs were utilised, Eskom considered cheaper alternatives which included a combination of demand and supply levers from local and regional IPPs and demand response initiatives were considered. Eskom spent R4345m more on local IPPs and R1150m more on regional IPPs. Eskom did underspend by R379m on DMP due to a lower uptake from customers than originally anticipated. For industrial customers, a threshold seems to have been reached where further uptake does not seem to be materialising.

Additionally the lack of further growth in the economy resulted in fewer opportunities for potential customers to respond.

Eskom has spent R299m less on DSM projects during the year. The major reason for the under spend was in response to the NERSA MYPD3 decision, where the demand aggregator programme fell away, and the focus reverted to the key industrial load.

21.2 Balancing the power supply system

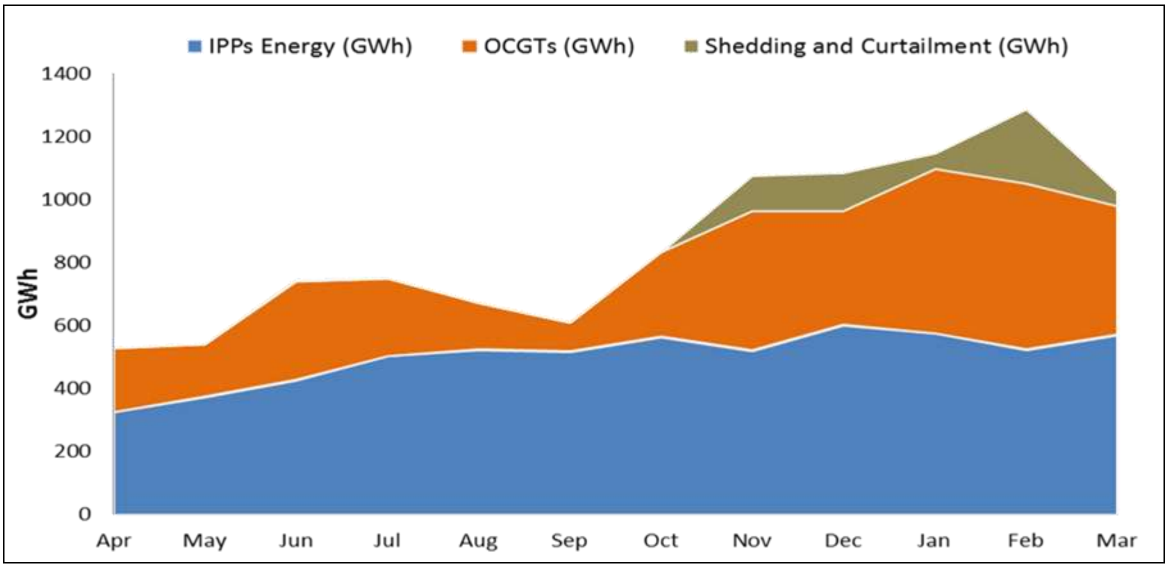
For many hours of the day, the reserve margin is sufficiently adequate. However, during peak hours or when abnormal events occur, demand at times exceeds supply. When this occurs, Eskom implements demand and supply-side management strategies, including the demand response programme where selected large 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.

21.2.1 Actual OCGTs usage and load shedding in 2014/15

During 2014/15, a substantial number of load reduction events occurred when the available supply was insufficient to meet the demand. While only three events occurred over evening peak during winter, we had to implement load shedding and/or load curtailment on 34 days between 1 November 2014 and 31 March 2015. This resulted in supply interruptions of 574GWh after utilising both OCGT's and IPPs. This meant that OCGTs were used during peak and off peak periods through the year.

- OCGTs and IPPs usage reduced load shedding by providing additional capacity
- Load reductions occurred substantially between November 2014 and March 2015.

Figure 4 : Load shedding impact in 2014/15



21.3 OCGTs allowed in MYPD 3 for 2014/15

For purposes of its revenue decision, NERSA assumed R2 710m for OCGT fuel cost. 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 27 : Summary of allowed OCGTs components

Open Cycle Gas Turbines - 2014/15 Power stations	GWh	R million	Fuel Litres ML	Rand/Litre	R/MWh
Ankerlig	658	1 646	185	8.91	2 503
Gourikwa	368	934	103	9.02	2 534
Acacia	15	40	4	9.04	2 638
Port Rex	15	40	4	9.06	2 644
Non related fuel energy costs		51			
Total / Averages	**1 056**	**2 710**	**297**		**2 566**

In addition to the decision above, a further decision was taken by NERSA in January 2015 to increase the allowed OCGT usage in the last months of 2014/15 (i.e. January to March) to a total of 450GWh per month.

21.4 Actual OCGTs costs in 2014/15

The actual OCGTs energy cost was R9 546 million to produce 3 709 GWh during 2014/15 as presented in the table below.

Table 28: Summary of OCGTs actual results for 2014/15

Open Cycle Gas Turbines - 2014/15 Power stations	GWh	R'million	Fuel Litres ML	Rand/Litre	R/MWh
Ankerlig	2 351	5 940	742	8.00	2 527
Gourikwa	1 226	3 031	385	7.88	2 472
Acacia	65	267	21	12.62	4 138
Port Rex	67	257	24	10.76	3 813
Non fuel related energy costs		51			
Total/Averages	**3 709**	**9 546**	**1 172**		**2 574**

21.5 Computation of OCGTs claim for RCA purposes in 2014/15

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 297ML 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 2014/15 is R1 944 million which is summarised below with details for each component disclosed later. This is far lower than the actual variance of R6 836 million.

Table 29: OCGTs RCA summary

OCGT Summary		RCA amount (R'm)
Excess volumes above allowed GWh recovered at average coal cost	-	**538**
Price variance on allowed 297ML	-	**-263**
Recovery of 450 GWh for Jan~Mar 2015, provides 206 ML	-	**1 669**
Total OCGT for RCA		**1 944**

21.5.1 Price impact up to allowed diesel litre usage of 297ML (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 2014/15 period the actual price per litre varied between R8.00/L (Ankerlig) to R10.76/L (Port Rex) 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. A summary is disclosed in the table below with the **overall price variance of R263 million for the consumers' benefit.**

Table 30 : OCGTs price impact for 297ML

Price variance limited to the decision volumes (ML)	Decision Rand/Litre	Actuals Rand/Litre	Variance Rand/Litre	Allowed ML	RCA amount (R'm)
Ankerlig	8.91	8.00	-0.91	185	-168
Gourikwa	9.02	7.88	-1.14	103	-118
Acacia	9.04	12.62	3.57	4	16
Port Rex	9.06	10.76	1.70	4	7
Total price variance				297	-263

21.5.2 Excess volumes above GWh recovered at average coal costs

Eskom generated 2244 GWh for the 9 months (Apr 2014 to Dec 2014) which exceeded the allowed 479 GWh by 1765 GWh. In addition excesses of 75GWh (Jan 2015) and 79 GWh (Feb 2015) were produced, resulting in a total of 1919 GWh above the allowed levels.

Thus the **total excess of 1919 GWh above the allowed levels** for the year is recovered at the **average coal cost of 28c/kWh**, resulting in a **recovery of R538 million in Eskom's favour.**

Table 31: OCGTs RCA claim related to excess volumes above allowed GWh

Excess volumes above allowed GWh recovered at average coal cost	Apr 2014 - Dec 2014	Jan-15	Feb-15	Mar-15	Total
Original decision (GWh)	479	115	255	207	1 056
Additional volumes allowed based on 450GWh cap (GWh)		335	195	204	734
Total Allowed GWh	479	450	450	411	1 790
Actual GWh	2 244	525	529	411	3 709
Excess volumes claimed at average coal cost (GWh)	1 765	75	79	-	1 919
Average coal costs c/kWh	28	28	28		
OCGTs RCA realted to excess volumes above decision (R'm)	**495**	**21**	**22**		**538**

21.5.3 Recovery of the 450 GWh for January 2015 to March 2015

Eskom approached NERSA in January 2015 requesting approval of higher OCGTs usage for the 3 months covering January 2015 to March 2015. NERSA granted the approval of OCGTs usage up to 450GWh per month on 23 January 2015. This resulted in an additional 206ML being utilised which is recovered via the RCA at the actual rates per station. Therefore the **RCA recovery for the 206ML is R1 669 million** as disclosed in the table below.

Table 32 : Special allowance for OCGTs usage up to 450GWh per month (Jan~Mar 2015) provides an additional 206ML

Price variance based on 450GWh cap	Actuals Rand/Litre	Additional ML based on 450GWh cap	RCA amount (R'm)
Ankerlig	8.00	128.3	**1 027**
Gourikwa	7.88	71.3	**562**
Acacia	12.62	3.2	**41**
Port Rex	10.76	3.6	**39**
Total price variance		**206.5**	**1 669**

21.5.4 OCGTs variance for 2014/15 RCA

OCGTs for RCA = Price pass through limited to 297 ML per decision +

Excess volumes of 1 919 GWh compensated at average coal costs rate 28c/kWh +

Special allowance for 450 GWh per month (Jan2015~Mar2015), adds a further 206ML

Eskom incurred **OCGTs actual costs of R9 546m** compared to the **assumed costs in MYPD3 decision of R2 710m** which results in a **variance** of additional expenditure of **R6 836m. However for RCA purposes,** Eskom used the approach taken by NERSA in its RCA 2013/14 decision to compute the OCGTs RCA for 2014/15 which results in a claim of **R1 944 million.**

Eskom believes that based on the conditions of the day and choices which were available in 2014/15, the efficient and prudent option of operating the OCGTs in and outside of peak hours was the correct decision for the country.

21.5.5 Actual Plant performance in 2014/15

This section will focus on four measures viz. UCLF, PCLF, EAF and EUF. During 2014/15 the Generation fleet delivered plant performance which was lower than that assumed in the MYPD3 determination. The drop in EAF is primarily attributable to the high UCLF.

Table 33 : Definitions of technical performance parameters

Measure	Descriptions
EAF	Measures plant availability including planned and unplanned unavailability and energy losses not under plant management control
UCLF	Measures the lost energy due to unplanned energy losses resulting from equipment failures and other plant conditions.
PCLF	Energy loss during the period because of planned shutdowns
OCLF	Energy loss during the period because of unplanned shutdowns due to conditions that are outside Generation management control
EUF	Measures the degree to which energy was produced compared to the extent to which it could have been produced.

Table 34 : Comparison of Generation technical performance

Generation Fleet Plant Performance	MYPD3 Decision 2014/15	Actuals
EAF	81.8%	73.7%
PCLF	11.4%	9.9%
UCLF	5.9%	15.2%
OCLF	0.9%	1.1%

For 2014/2015, EAF was 73.73%, lower than the 75.13% for 2013/14 .The MYPD3 was based on an assumption of 81.83%. The lower EAF was primarily due to high unplanned energy losses, indicated by a UCLF of 15.22%.

The unplanned capability loss factor (UCLF) for the year 2014/15 is slightly higher than previous years, indicative of ageing generating plant, the related deteriorating plant health and the high utilisation of the plant. The UCLF for 2014/15 was 15.22% compared to 12.61% in 2013/14 and 12.12% in 2012/13.

The energy efficiency improvement programme aims to improve the heat rate of the units at Eskom's 13 coal-fired stations. Heat rate measures the efficiency of the conversion of heat from the energy source (coal) to electricity generated. Improvements would indicate an improvement in plant performance and will help reduce Eskom's environmental footprint, including its carbon emissions.

Table 35: Average Eskom coal power station heat rate for period 20112/13 to 2014/15

Heat Rate Trends	2014/15	2013/14	2012/13
Average coal power station heat rate, MJ/kWh	11.45	11.49	11.25

The overall heat rate (plant performance) improved in 2014/15 by 0.35%, when compared to in 2013/14.

21.5.5.1 Unplanned capability loss factor

The unplanned capability loss factor (UCLF) has reflected a deteriorating trend from a UCLF of 8% (2012) to a UCLF of 15.22% (2015) indicative of ageing plant and related deteriorating plant health conditions as well as the increased utilisation of the plant.

Table 36: Breakdown of system UCLF (%)

Generation fleet technical performance	Actual Mar-15
Normal UCLF	15.22
Less: Constrained UCLF	1
Underlying UCLF	14.22
Less: Total major/significant incidents	0.95
Underlying UCLF excluding other major/significant events	13.27
Less: Outage slips	1.37
Underlying UCLF excluding other major/significant events and outage slips	11.9

21.5.5.2 The main contributors to UCLF were as follows:

21.5.5.2.1 Partial load losses

The partial load losses continue to contribute significantly to the system total unplanned losses, and continue to increase. The unplanned capability loss factor to these losses was 5.65%, contributing 37% of the system UCLF.

The main reasons for the partial load losses were unavailable space for maintenance outages to resolve problems at the draught plant (22%), mills (13%), turbine (17%), gas cleaning (14%) and feed water (9%). Maintenance was focused on safety and philosophy outages which were prioritised.

This figure excludes the partial load losses that occurred due to the silo collapse at Majuba Power Station, which contributed 0.26% to the partial load losses UCLF of 5.65%.

21.5.5.2.2 Boiler tube failures

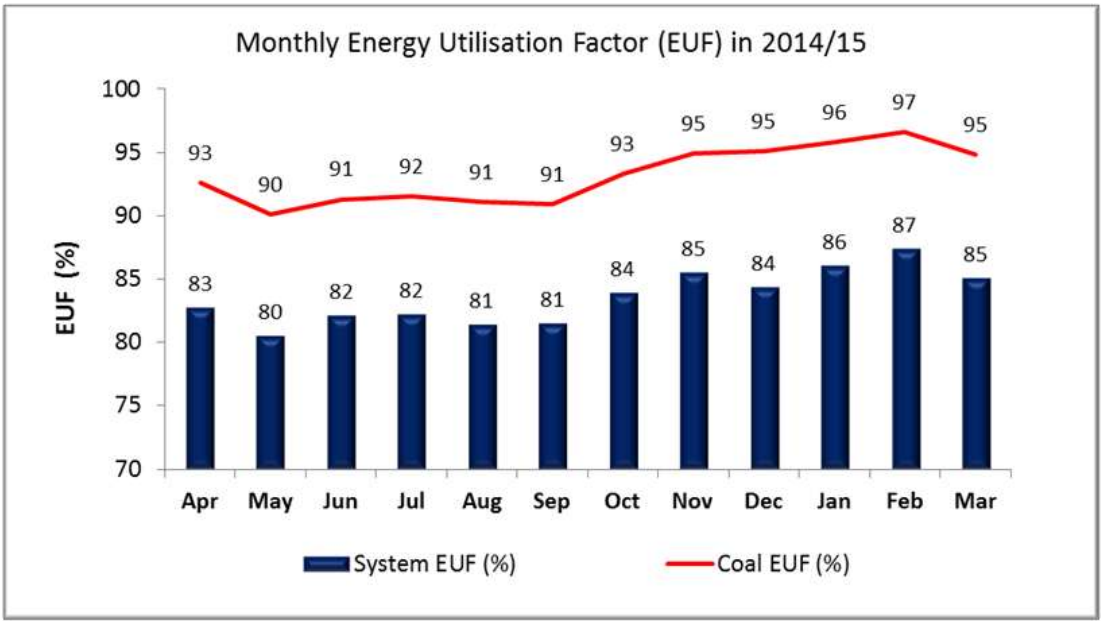
Boiler tube failures are typically the result of welding repair damage, corrosion and fly ash erosion. In the year to March 2015, there were 203 boiler tube failures, with a UCLF of 2.00%, contributing 13% to the system UCLF. This is lower in both number and UCLF contribution when compared to the previous year when a total number of 210 failures and a UCLF contribution of 2.18% were recorded.

The unplanned energy loss attributed to boiler tube failures has been decreasing since January 2014, showing an improving trend.

21.5.5.3 Energy utilisation factor (EUF)

Energy utilisation of the available plant was high with the coal fleet, in particular, being utilised significantly above design levels.

Figure 5 : Monthly Energy Utilisation Factor in 2014/15

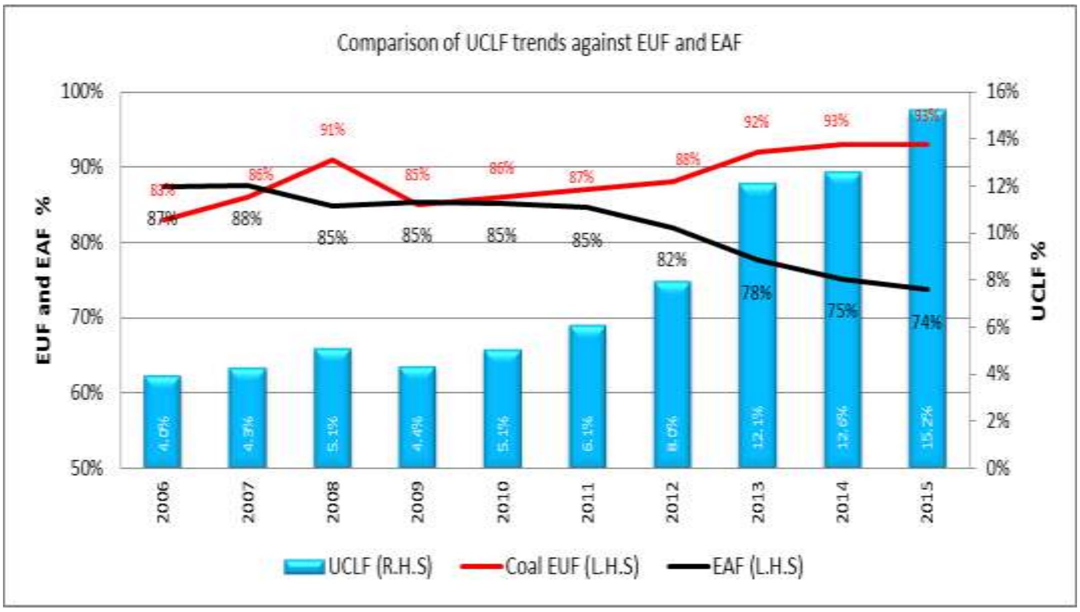


The utilisation of available plant capacity (EUF) was significantly higher than industry norms and that of the coal fleet was higher than the previous four years due to the increased loading of available plant to match the demand. The overall fleet EUF was at 83.42% (2013/14: 83.55%). The utilisation of the coal-fired units for the year to 31 March 2015 was 93.02%; nuclear at 99.47% and peaking stations (including the OCGT stations) achieved 20.63%.

21.5.5.4 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 6 : 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 73.73% by March 2015. Energy availability factors are an outcome of the planned and unplanned maintenance which has occurred.

22 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.

22.1 Regulated asset base adjustment for CECA

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

The actual capital expenditure for the RAB incurred during 2014/15 was R54 394m compared to MYPD3 decision assumption of R45 113m thus resulting in a variance of R9 281m. However, only capex changes that affect the RAB are adjusted for CECA purposes.

The total variance of R9 281m comprises Generation capex overspend by R11 703m, Transmission underspend by R1 738m, Distribution underspend by R1 284m and balance is attributable to other capital expenditure.

However, for RCA purposes not all changes to capital expenditure affect the regulatory asset base and thus will not qualify for RCA related changes. After making these adjustments the RAB is adjusted downwards with R1723m.

22.1.1 Step 1: Computing change in RAB

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 R1 890m.

Table 37: Calculation average capital expenditure

CECA Calculation -Variance between actual and allowed capex	Calculation ref	Eskom Company
Allowed MYPD capital expenditure		45 113
Less: Allowed capital expenditure excluded from the RAB	**A**	(15 355)
Future fuel		(3 014)
Technical and refurbishment capital expenditure		(12 341)
Allowed MYPD RAB capital expenditure	**B**	29 758
Actual MYPD capital expenditure		54 394
Less: Actual capital expenditure excluded from the RAB	**C**	(20 857)
Future fuel		(1 651)
Payment received in advance recognised to revenue		(1 423)
Technical and refurbishment capital expenditure		(17 783)
Actual MYPD RAB capital expenditure	**D**	33 537
Annual difference		(1 723)
Technical and refurbishment capital expenditure excluded from RAB	**C - A**	(5 502)
RAB capital expenditure	**D - B**	3 779
Average capital expenditure difference for CECA calculation	**(D-B)/2**	1 890
Allowed Return - NERSA MYPD 3 decision	**E**	3.75%

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 claim of R91m is computed by applying the allowed RoA to the capex variance.

22.1.2 Calculation of the CECA claim

For purposes of the calculating the CECA claim, the allowed RAB of R706 391m is adjusted for the capex variance of the current and prior year.The current year capex variance used is the average of the annual movement in the RAB capex of R3779m shown in table 34 above which equates to R1890m.

Table 38: CECA Calculation: Return due to/by Eskom

CECA Calculation : Return due to/(by) Eskom	Calculation ref	Eskom Company
MYPD3 Regulatory assets base		706 391
Add /(Deduct): Current year average capex variance		1 890
Add/ (Deduct): Cumulative prior year capex variances		536
Adjusted RAB	**A**	708 817
MYPD3 allowed return on assets	**B**	26 511
Return on adjusted RAB	**A * C**	26 602
Increase / (Decrease) in return for RCA	**(A*C)-B**	91
MYPD3 allowed return expressed as a percentage of the rate base	**C**	3.75%

22.2 MYPD3 decision

Below are extracts from MYPD3 decision reflecting approved RAB of R706bn and returns on asset at 3.75%, generating returns of R26 511m and assuming a capital expenditure of R45 513m.

Table 39 : Regulatory asset base for 2014/15

R'm	2014/15
RAB Applied for	852 265
RAB Adjustment	-145 874
RAB Approved	**706 391**

Source: Table 10 of MYPD3 decision, 28 February 2013

Table 40: Returns and percentage allowed in 2014/15

R'm	2014/15
Real Pre-tax WACC (%)	3.8%
Return (R'm)	26 511

Source: Table 9 of MYPD3 decision, 28 February 2013

Table 41: Capital expenditure in 2014/15

R'm	2014/15
Capex Applied for	67 941
Capex Adjustment	-22 828
Capex Approved	**45 113**

Source: Table 11 of MYPD3 decision, 28 February 2013

22.3 Reasons for variance between actual and decision

Looking back on 2014, the single biggest commitment was to achieve the first synchronisation of Medupi Unit 6 in the second half of 2014, with a target date of 24 December 2014. However, first synchronisation was delayed to 2 March 2015, due to labour unrest during 2014, as well as a number of technical challenges experienced during the ramp-up period. Commercial operation of Medupi unit 6 occurred on 23 August 2015.

The first wind turbines of the 100MW Sere Wind Farm were energised in October 2014 as planned, and Sere was placed in commercial operation on 31 March 2015.

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.

Table 42: Capital expenditure for 2014/15

Capital expenditure (excluding capitalised borrowing costs) per division for the year ended 31 March 2015

Division, R million	Target 2014/15	Actual 2014/15	Actual 2013/14	Actual 2012/13
Group Capital	28 822	**31 691**	33 475	37 690
Generation	9 998	**10 555**	10 326	8 512
Transmission	1 180	**1 121**	1 516	893
Distribution	7 706	**6 073**	10 265	8 317
Subtotal	47 706	**49 440**	55 582	55 412
Future fuel	4 893	**1 651**	2 675	2 634
Eskom Enterprises	0	**439**	453	376
Other areas including intergroup eliminations	2 721	**1 547**	1 093	1 711
Total Eskom group funded capital expenditure[1]	55 320	**53 077**	59 803	60 133

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

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

Table 43: Capital Expenditure (excluding capitalised borrowing costs) per division

Reconciliation between Eskom Integrated Report capex and CECA disclosures	2014/15
Group capital	31 691
Generation	10 555
Transmission	1 121
Distribution	6 073
Subtotal	**49 440**
Add Adjustments :	**4 954**
Exclude DOE capex included as part of Distribution	-
Include Future fuel capex	1 651
Include Corporate and other	3 303
Total per CECA disclosure	**54 394**

22.4 Delivering on 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. The capacity expansion programme has cost R265billion (excluding capitalised borrowing costs) to date. Since inception, the programme has resulted in additional generation capacity of 6 237MW, mainly through the RTS programme, 5 816km of transmission lines and 29 655MVA of substation capacity.

22.4.1 Medupi

First **synchronisation** (or first power) of Medupi Unit 6 was **achieved on 2 March 2015,** with full load achieved on 26 May 2015, at which time the unit delivered full power of 794MW to the national grid. **Commercial operation** was achieved on the **23rd August 2015**. The unit is the biggest coal-fired unit of its kind in Africa, and the first coal-fired unit to be brought online since the last unit of Majuba in 2001.

During the testing phase, while combustion optimisation of the unit continues, output from the unit is variable. The testing phase ensures that all systems are fully operable and reliable for handover, and the unit is safe to operate and perform as designed for the next 50 years. Normal commissioning and optimisation issues are being resolved as they arise, without any significant holdups to reaching commercial operation expected.

Additional resources were mobilised to Unit 6 by both the boiler and C&I (control and instrumentation) contractors to mitigate any resource-driven delays. Additional shifts were introduced 24 hours a day, seven days a week in order to accelerate progress on site. We continue to work with contractors to resolve any issues that could affect the schedule.

The critical path to first synchronisation included the delivery, installation, testing and integration of the boiler protection system, together with the distributed control system. The recovery strategies that were put in place to implement solutions to the post-weld heat treatment that were reported previously were successful and the technical issues surrounding welding on the Unit 6 boiler reported last year were resolved. The weld procedure requalification exercise was completed, with all weld procedures verified and accepted by both Eskom and the authorised inspection authority. Furthermore, a number of key milestones were achieved during the past year, all leading up to first synchronisation

- Successful completion of the boiler chemical clean, the draught group test run and the site integration tests for Unit 6 and the balance of plant, as well as the water treatment plant
- First coal was delivered to the coal stockyard, Coal Stacker 1 was safety cleared and commissioning of the coal stacker and coal mills is progressing well

- First oil fire of Unit 6 on 17 October 2014, followed by first coal fire on 27 November 2014,
- Boiler blow-through on 2 January 2015 and steam to set on 12 February 2015

The Transmission integration implementation is ready for the synchronisation of all six units to the Eskom grid, and all required auxiliary services for the whole power station are ready to deliver power to the grid, as and when the remaining units come online.

Originally, the commissioning of the next unit, Unit 5, was forecast to occur within six months of bringing Unit 6 online. However, due to the challenges experienced at Unit 6 this will not be possible, as resources were redeployed from Unit 5 in an attempt to recover the schedule at Unit 6.

The cumulative cost incurred on the project is R84.7 billion (2013/14: R77 billion) against a total budget of R105 billion, as disclosed in the Eskom Integrated Report March 2015. All amounts exclude capitalised borrowing costs.

22.4.2 Kusile

Eskom signed a mutual termination agreement with Alstom regarding the C&I works, after which a contract was awarded to ABB to supply the C&I systems for all units at Kusile. This is considered to be an important step in mitigating one of the largest risks on the project.

A number of important milestones on Unit 1 have been achieved over the past year, including successful completion of the steam turbine lube oil system flush, setting the generator step-up transformer into place and the unit being placed on electrical barring. Work related to the flue gas desulphurisation scope of work was also completed recently. Unit 1’s boiler air leak test and hydrotest were successfully conducted during April 2015.

Good progress has been made on the civil works for all units, with the boilers of Units 1 to 5 in various stages of construction. Boiler erection, already completed at Unit 1, is expected to drive the critical path for Units 2 to 6.

With effect from 1 September 2014, the Kusile Execution Team and contractors began implementing productivity improvement plans that include working additional shifts, more weekends, as well as selected crews and contractors working critical areas during the traditional builders’ break in December. The ramp-up to commissioning of Unit 1 will include strategies to support around-the-clock commissioning activities. The project team remains focused on critical activities necessary to achieve the earliest possible first synchronisation of Unit 1, as well as improving productivity and clawing back schedule on all six units.

The cumulative cost incurred on the project is R78.7 billion (2013/14: R66.6 billion) against a total budget of R118.5 billion, as disclosed in the Eskom Integrated Report March 2015. All amounts exclude capitalised borrowing costs.

22.4.3 Ingula

The Mine Health and Safety Act (MHSA) Section 54 work stoppage was lifted completely in September 2014, allowing underground works to resume, although the Presiding Officer’s report has not yet been received. Since the tragic incident on 31 October 2013, progress was significantly impacted resulting in limited progress for a period of approximately 12 months. However, the lifting of the work stoppage will enable acceleration of the construction schedule.

Despite the delays, the operation floors of Units 3 and 4 have been completed and handed over to mechanical and electrical contractors; the machine hall of Unit 1 was also completed and handed over. In addition, diesel generator safety clearance and cold commissioning were achieved in September 2014, while all four generator-transformers have been installed underground, with the gas-insulated switchgear systems connected on the high-voltage side of the transformers. To date, two of the transformers have been filled with 83 000 litres of oil each. Environmental authorisation and water-use licences have also been received.

However, industrial action has led to delays in installation of the heating, ventilation and air conditioning (HVAC) ducting for the control room. Delays have also been experienced in the main underground civil works.

The cumulative cost incurred on the project is R22.8bn (2013/14: R19.4bn) against a total budget of R25.9bn, as disclosed in the Eskom Integrated Report March 2015. All amounts exclude capitalised borrowing costs.

22.5 New build cost changes

On the back of the new build delays in commissioning, there have been costs increases in these projects when compared to the MYPD3 decision as summarised below.

22.5.1 Medupi: Cost overruns

The project experienced deviations mainly due to the movements on Packages, claims and Owner Development Costs (ODC).

Drivers of cost increases include the following:

- **Schedule delays**
  - Historical delays due to labour unrest, poor productivity and Force Majeure events.
- **Owners Development Costs (ODC)**
  - New manpower structure with additional positions in critical roles to address key risks (e.g., quality).
  - Dispute Adjudication Board (DAB) team to support claims management.
  - Delay in demobilization of resources in line with schedule delays.

22.5.2 Kusile : Cost overruns

These schedule impacts have been the major driver of cost increases. Eskom has taken critical steps to **mitigate** against some of the challenges at Medupi and Kusile.

- **Schedule delays**
  - Industrial actions
  - Quality issues / welding repairs in boiler.
  - Design change and increased scope due to permitting requirements.
  - Culvert permit delays.

- Failed Contractors (COSIRA and NIC Failures),
- Overall poor productivity by all contractors with Hitachi and GLTA being the largest contributors.

- **<u>Interventions include these challenges include</u>**:

- Signed a modified Partnership Agreement (PA) between Eskom, contractors, and labour.
- Reviewed and optimized the model according to which contractors are managed.
- Removed C&I scope from Alstom at Kusile due to underperformance.
- Signed Memorandum of understanding with boiler contractor to turnaround boiler contractor performance.
- Eskom now taking a lead to pro-actively manage the contractors. Panel members now provide support to Eskom teams.
- Co-location of key technical experts from Eskom and Contractors at sites to provide quick turn around on key decisions in support of fast tracked schedules.
- War-rooms set up at Medupi and Kusile sites. This is meant to deal with issues on a daily basis as and when they arise.

22.5.3 Ingula : Cost variances

<u>The **total project cost at Ingula is at risk** mainly due to the following</u>:

- Package cost / Compensation Events from the Main Underground Civil Contractor.
- **Owners Development Cost (ODC)** – Schedule delays will result in additional ODC due to delayed de-mobilisation.
- **Cost Price Adjustment (CPA)** – Schedule delays with result in additional CPA due to later cost flows.

22.5.4 Delays in new build capacity

The first contributor to the capacity shortage is the delays of new build capacity. According to the 1998 Energy White Paper the investment decision for new base load power stations needed to be made by, not later than, 1999 in order to meet increasing demand by 2007. However, the approval for Eskom to embark on the build programme was made in late 2004, with the final approval of the first new base load capacity investment decision (Medupi) being made in December 2006, thus at least 7 years later than the latest date envisaged in the Energy White Paper. This resulted in the needed capacity not being available when needed. The project execution has been exacerbated by time constraints for the planning and feasibility stages (which commenced at end 2004) which did not allow nearly enough planning and development work upfront on Medupi and Kusile. This and other factors such as it being the first major project in sixteen years resulted in it not being possible to emulate the international best practice time-period of around 54 months to commissioning of the first units nor the average construction time of 60 to 66 months (however, typically for power stations of two units not six units).

Lazard's 'Levelized Cost Of Energy Analysis—Version 7.0' of August 2013 gives typical coal power station construction time as 60-66 months. However this is mostly based on US data. The typical coal power stations that have been constructed in the US over the last decade or so were sized between 300MW to 850MW and consisted of, e.g. just in 2010 there were 10 such plants commissioned in the US. It might well be that it takes longer to get to commercial operation of the first unit if such unit is part of a 6 unit power station, compared to a one or two unit station.

<u>In addition to that, there are further factors to take into account in 'translating' the 60-66 month period to SA for purposes of establishing an efficient norm (not an exhaustive list):</u>

• **Locality**:
Much longer distances from suppliers, less skilled local workforce, less developed local infrastructure etc.
• **Project management and construction capacity**:
Very little construction activity on new coal power plant since completing the previous build-phase around 1992 (the only activity was the delayed completion of Majuba). Eskom's project management skills and capacity was mostly lost after 1992. The industrial policy from 1997 to 2004 also prohibited Eskom from further generating capacity investments. "Eskom is not allowed to invest in new generation capacity in the domestic market". The contractors' local facilities and skills were also lost over this period. Eskom thus had to completely re-establish its new-build project management capability when the ESI policy changed in late 2004 and Eskom got approval to commence with the

build programme, as did many of the contractors. It would have also had to acquire new skills and competencies based on the new technologies available.

- **Learning curve**:

After a sixteen year interval, for Eskom the new-build process implied the starting point of the learning curve again.

- **Up-front planning and preparatory work**:

When the new-build task was restored to Eskom it was already apparent that there was a generation capacity crisis. Commencing in 2005 the preparation of the 'business cases', the investment decisions, the technical designs for the process of requesting tenders, and the adjudicating and awarding of such tenders were completed. The approval of the first new base load capacity investment (for 3x700 MW = 2100 MW) was made in December 2005 and revised by December 2006 to become the 4 764 MW 'Medupi' – all within less than two years from receiving the go-ahead. Medupi's main contracts were placed in October 2007, with Kusile shortly after. Time constraints did not allow nearly enough planning and development work upfront – e.g. Eskom could not follow the normal process for Medupi but went ahead with tendering and contracting based on 'virtual' designs i.e. Eskom went to the market using the designs for the 4110MW Majuba power station, which had been designed in the 1980s.

- **Total projects portfolio**:

In parallel with the programme to construct the 4 764 MW Medupi base load coal plant, Eskom also:

- Embarked on the programme to construct the 4 800 MW Kusile;
- Started and have since completed the refurbishment and re-commissioning of three older coal fired power stations (23 units of 3 500 MW in total over the period July 2005 to October 2013);
- Constructed and commissioned 2 000 MW of OCGT capacity;
- Commenced construction of 1332 MW Ingula pumped storage; and
- Executed large Transmission projects

Starting with the US norm of 60-66 months, some months should be added for each factor to arrive at a more realistic norm for the construction duration given the specific South African and Eskom context. The 60-66 months US norm very quickly becomes 84-90 months or more, in this context.

Overall the root cause is the failure of the previous ESI policy to attract IPP investment for power plants of the required size and at the required time. Additional years were lost before that situation, as well as the crisis regarding commencement of the new build programme, became apparent. It further resulted in the loss of project management skills and construction skills and capacity in Eskom (and also in the local contractors). These factors impeded Eskom and set them further back on the learning curve, forcing a rushed design and commercial process, once approval was obtained. In the end the Medupi start-date was already behind schedule by approximately eight years.

22.6 Why the RAB must be indexed

MYPD Methodology:

The MYPD Methodology (section 6.4.4) requires the RAB to be valued at Modern Equivalent Asset Value (MEAV) where;

"*Each year the MEAV value will change. Because it is not practical to conduct an entire MEAV study every year, the value from the last year studied will be increased by the Producer Price Index, each year, until the next MEAV study is carried out, after which the process will repeat itself*".

Why indexation

- The annual indexation of the RAB is required due to the use of a 'real' (rather than a 'nominal') rate of return. The inflation impact that would otherwise be reflected in the value of the 'nominal' rate of return is instead reflected through the annual inflation indexing of the RAB.
- This allows for the recovery of the shortfall in the return of that original year by spreading it over the remaining operational life of the asset.
- In the event that a 'real' rate of return is used, annual indexation of the RAB is required in order to achieve full cost recovery (as stipulated by the ERA and the EPP) over the life of the assets.

- Due to very long asset lives; mergers of companies; changes in accounting systems etc., it can in practice be difficult to track original acquisition costs and accumulated depreciation in detail per asset over the long asset life.
- A valuation methodology such as depreciated MEAV is often used as an acceptable and reasonable proxy for the inflation indexing of depreciated historical acquisition cost.

Annual increase by inflation rate

Given that it is quite onerous to perform a complete MEAV every year, section 6.4.4 provides for annual increase the MEAV value by the inflation rate, in between formal revaluations. Given that the typical main driver of an annual change in the MEAV will in any event be the annual inflation rate, inflation indexing would be a reasonable proxy for an annual change in the MEAV

CECA mechanism for indexation

At the time of publishing the Methodology the changes to the RAB were probably envisaged to be due to movements in capex. However since the MYPD3 decision did not factor in the annual indexation at the beginning as part of the Decision (or, by implication assuming the inflation rate on the RAB at nil), it would be appropriate to include the indexation adjustment on each year's RAB opening balance into the CECA mechanism i.e. to reflect the change between the actual inflation rate and the inflation rate as assumed for purposes of the MYPD3 revenue decision (in this case, nil percent).

The MYPD3 Reasons for Decision also confirms that the RAB would be subject to periodic revaluation – it is assumed that this implies annual revaluation, as required by the MYPD Methodology. Obviously if such revaluation takes place it will mean little if the revaluation is not factored into the CECA. Eskom recommends including the effect of the annual indexation into the CECA mechanism, with the resultant revenue adjustment thus being addressed through the RCA.

22.7 Conclusion on capital expenditure

A number of key strategic challenges exist that require a Eskom Capital Portfolio of R300bn, as opposed to NERSA assumption of R230bn for purposes or 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.

23 Inflation adjustment

In compiling the inflationary adjustment, cost of cover and arrear debts 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 of 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 44: Inflation Data

Inflation data	2013/14	2014/15
Inflation - Decision	5.60%	5.70%
Inflation index - Decision	1.056	1.057
Inflation - Actual	5.70%	6.10%
Inflation index - Actual	1.057	1.121

Table 45 : Inflation adjustment

Inflation adjustment for 2014/15	Calculation ref	2014/15
Total operating costs allowed	A	36 717
Decision inflation index	B	1.115
Actual inflation index	C	1.121
Restated allowed costs based on actual inflation	D=A/B*C	36 926
Inflation adjustment R'm	**D-A**	**209**

24 Energy efficiency and demand side management (EEDSM)

24.1 Demand side management

Demand side management is divided into two broad programmes, as discussed below:

24.1.1 The demand-response programme

Consists of a range of sub-programmes which offers commercial and industrial customers financial incentives to reduce their electricity requirements as and when needed. Before being placed on hold, the requirements for taking up demand response programme products (standard product and standard offering) were amended to allow smaller companies to participate in the programme. Eskom spent R309m on demand market participation and R653m on demand side management programmes. The reduction in costs from previous year was mainly attributable to the decrease in the power buyback programme.

24.1.2 The Residential mass roll-out programme

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

It includes the following sub-programmes:

- 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 2014/15.

24.2 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.

24.3 Energy Efficiency demand Side Management (EEDSM)

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.

24.3.1 Allowed EEDSM for 2014/15

The allowed rate for EEDSM savings is R3.24m/MW with 294MW savings being assumed which will cost R953m.

Table 46: Allowed EEDSM

R'm	2014/15	
	Applied for	Approved
Funding	**2 709**	**953**
Programmes Peak Demand savings (MW)	358	294
Programmes Annualised Energy savings (GWh)	1 361	1 204
Programme Costs	2 419	612
Operating Costs including Depreciation	481	341
Other costs	-191	-
R/MW	7.57	3.24
R/kWh	1.99	0.79

Source: Table 40 of MYPD3 decision, 28 February 2013

24.3.2 Actual EEDSM for 2014/15

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 as outlined below.

Table 47: Verified demand side management and internal energy efficiency savings

Measure and unit	Actual 2014/15	Actual 2013/14
Demand savings (evening peak), MW	**171.5**	409.6
Energy savings, GWh	**816.2**	1 363.0
Internal energy efficiency, GWh [1]	**10.4**	19.4

1. Target not set, as funds have not yet been allocated.

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

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 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	2014/15
MWs achieved in current year (incl DOE) per AFS and Integrated report	171.5
Less : MWs installed but not verfied in current year	
Less : DOE funded MWs achieved	-24.1
Add : MWs achieved in the prior year but verfied in current year	100.5
Total verfied demand savings (MW) for RCA	**247.9**

The table above strips out the DOE funded EEDSM programmes of 24.1 MW which is excluded from the RCA as the tariff did not fund the initiatives. Prior year savings relating to tariff funded projects which are verified in 2014/15 of 100.5 MW are included in the RCA. Hence the total capacity verified for 2014/15 after all the adjustments is 247.9 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 2014/15

Energy Efficiency & Demand Side Management (EEDSM)		MYPD 3	Actuals	Variance
Funding	(R'm)	953	654	-299
Programmes - Peak Demand savings	(MW)	294	172	-123
Programmes - DOE funded actual MW savings	(MW)		24	24
Programme costs	(R'm)	612	440	-172
Operating costs incl. depreciation	(R'm)	341	205	-136
Other costs	(R'm)	-	9	9
EEDSM Rate	(R/MW)	3.24	4.43	1.19
EEDSM Rate based on verfied MW savings for RCA	(R/MW)	3.24	2.64	-0.60
MW savings for RCA purposes	**(MW)**	**294**	**248**	**-46**

Note 1 – Actual EEDSM using the AFS results equates to R3.81/MW (R654m/(172MW-24MW). The actual savings MW includes DOE funded savings which is excluded to determine the pure MYPD3 actual rate.

Note 2 – For RCA purposes, the verified MW savings is used which results in a lower average rate of R2.64/MW (R654m/248MW)

This adjusted rate arises because of the implied timing difference between when programmes are implemented and when the capacity (MW) savings are verified. Based on this rate of R2.64/MW compared to the decision of R3.24/MW, Eskom should have received a benefit for delivering progammes at the lower rate.

24.3.3 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 46.1MW multiplied by allowed rate of R3.24m/MW** equating to an **RCA impact of R149m in favour of the consumer.**

EEDSM penalty = R3.24m/MW X - 46.1MW = - R149m

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

25 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.

25.1 Allowed operating costs in 2014/15

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 was attributable to operating cost component and thus reduced to cater for the revision.

The allowed total operating cost was R39 417 million, which is represented by operating costs excluding the ancillary charges of R40 095m reduced by corporate depreciation of R678m included in the total corporate overheads.

Table 50 : Total operating costs in MYPD3 decision

R'm	2014/15
Total Applied for	57 527
Total Adjustments	-17 432
Total Approved excl Ancilliary charges	**40 095**
Transmission Loss & Ancilliary charges	8 470
Total Approved	**48 565**

Source: Table 52 of MYPD3 decision, 28 February 2013

Some of the cost categories within operating costs are presented below.

25.1.1 Allowed employee costs in 2014/15

Table 51: The allowed employee costs for Generation, Transmission and Distribution

R'm	2014/15
Manpower Applied for	19 103
Manpower Adjustments	-2 646
Approved Manpower	**16 457**

Source: Table 43 of MYPD3 decision, 28 February 2013

25.1.2 Allowed maintenance costs in 2014/15

Table 52: Allowed Maintenance Costs

R'm	2014/15
Maintenance Applied for	13 119
Maintenance Adjustments	-1 246
Approved Maintenance	**11 873**

Source: Table 44 of MYPD3 decision, 28 February 2013

25.1.3 Allowed arrear debts in 2014/15

Table 53: Allowed Arrear Debts

R'm	2014/15
Arrear Debt Applied for	1 051
Arrear Debt Adjustments	-180
Approved Arrear Debt	**871**

Source: Table 49 of MYPD3 decision, 28 February 2013

25.1.4 Allowed cost of cover in 2014/15

Table 54: Allowed Cost of Cover

R'm	2014/15
Cost of Cover applied for	1 829
Cost of Cover adjustments	-
Approved Cost of Cover	**1 829**

Source: Table 48 of MYPD3 decision, 28 February 2013

25.1.5 Allowed corporate costs in 2014/15

Table 55: Allowed Corporate Costs in 2014/15

R'm	2014/15
Corporate overheads Applied for	7 557
Corporate overheads Adjustments	-4 155
Approved Corporate overheads	**3 402**

Source: Table 51 of MYPD3 decision, 28 February 2013

25.1.6 Other operating costs in 2014/15

Table 56 : Other operating costs

R'm	2014/15
Other costs Applied for	14 868
Other costs Adjustments	-9 205
Approved Other costs	**5 663**

25.2 Actual operating costs in 2014/15

During 2014/15 Eskom incurred operating costs excluding IDM of R49 534m which compares to the MYPD3 assumption of R39 417m resulting in over expenditure of R10 117m. As there is an overall over expenditure position, Eskom operating costs don't qualify for the RCA adjustment except for the inflation adjustment. .

Table 57: Summary of Operating costs in 2014/15

Operating costs in 2014/15	MYPD 3 Decision	Actuals	Regulatory Adjustments	RCA Actuals	RCA Balance
Employee benefits	19 181	22 187	-89	22 098	2 917
Other Opex [1]	17 536	22 083	-573	21 510	3 974
Other income	-	-6 645	4 615	-2 030	-2 030
Net impairment loss	871	3 755	599	4 354	3 483
Cost of cover	1 829	3 602	-	3 602	1 773
Total Operating costs R'million	**39 417**	**44 982**	**4 552**	**49 534**	**10 117**

25.3 Reasons for variance in operating costs

25.3.1 Employee benefits

Actual staff costs have exceeded the MYPD3 decision due to firstly the higher salary settlement of 8.5% compared to decision assumption of 5.4%, and secondly the 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.

25.3.2 Maintenance

Eskom spent R567m more for maintenance following the introduction of the Generation sustainability programme to arrest the escalating unplanned outages across the power station fleet. Relative to the assumptions made by NERSA for purposes of the MYPD3 revenue decision, Transmission also spent more on maintenance, however Distribution spent less on maintenance during 2014/15. 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.

25.3.3 Arrear debt

Arrear customer debt has increased across all segments over the past year, with approximately 38% of debt being outstanding for more than 60 days; the most significant increase was seen in arrear municipal debt.

Arrear bad debt was 2.17% of external revenue for the year which is more than double (0,5% in decision) the assumption in the MYPD3 decision. Electricity debtors (before provision for impairment) increased to R22 657m while the provision for impairment increased to R7 430m. The increase in the provision for impairment is largely due to an increase in arrear municipal debt, coupled with a decision to provide for all overdue debt over 15 days – being the contractual due date – for certain defaulting municipalities, as well as those not honouring their payment plan agreements.

25.3.3.1 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 R597m being derecognised, and impairment amounting to R566m being reversed. Despite this, we continue to actively pursue recovery of these amounts. The amounts mentioned earlier are net of the adjustment.

25.3.3.2 Debt collection

Debt collection from municipalities and small power users, particularly in Soweto, remains a concern. At 31 March 2015, ten municipalities had total overdue debt greater than R100 m each; the top 20 defaulting municipalities contributed approximately 80% of the total arrear municipal debt. Total Soweto debt, including interest was R8 611 m at 31 March 2015.

25.3.3.3 Response strategies for debt collection

Debt collection from municipalities and small power users, particularly in Soweto, remains a concern. At 31 March 2015, ten municipalities had total overdue debt greater than R100 m each; the top 20 defaulting municipalities contributed approximately 80% of the total arrear municipal debt.

Table 58: Arrear municipal and Soweto debt (excluding interest) at 31 March 2015

R m	2014/15	2013/14	2012/13
Municipal debt			
Total municipal debt (including current amounts)	**9 849**	6 928	5 142
Municipal arrear debt (>15 days)	**4 953**	2 593	1 202
Percentage arrear debt to total debt	**50.3%**	37.4%	23.4%
Soweto debt			
Total Soweto debt (including current amounts)	**4 182**	3 622	3 159
Soweto arrear debt (> 15 days)	**4 022**	**3 442**	3 078
Average Soweto payment level, %	**16%**	20%	16%

Historically, payments by municipalities were strongly correlated to them receiving their quarterly equitable share payment from National Treasury. Previously this funding was sufficient to settle outstanding electricity debt, although this is no longer the case, as municipalities face increased electricity prices and reduced funding. A number of other issues also contribute to non-payment by municipalities, such as inadequate skills and competencies to manage municipal functions, poor management of revenue management processes, misalignment of tariffs between Eskom and the municipalities, as well as cash flow challenges.

Eskom has made cross-functional teams available to municipalities to share best practices in managing electricity portfolios and offered prepayment options to all municipalities to limit the growth of arrear debt.

On 6 March 2015 National Treasury issued a cautionary procedure to all local municipalities advising them to pay their current bulk services accounts and honour their payments. Failure to comply would result in National Treasury withholding the payment of their quarterly equitable shares.

Furthermore, in April 2015 Eskom notified the top 20 defaulting municipalities across the country that Eskom would be interrupting their bulk electricity supply from 5 June 2015, should they not settle their accounts or make payment arrangements by then, as the organisation can no longer continue supplying electricty without receiving payment in return.

Since the announcement, the majority of municipalities have made payment arrangements, therefore they will not have their bulk electricity supply interrupted. In the event that we cannot reach a satisfactory solution with a municipality, it will be permanently disconnected until its debt is paid in full.

25.3.3.4 Residential revenue management

The residential revenue management strategy, which includes Soweto, drives energy protection and energy loss programmes, such as Switch OVA!, to enhance safety, improve quality of supply and reduce energy theft. It also aims to improve debt collection among small power users through the following initiatives:

- Installation of split metering with protective enclosures to prevent tampering
- Converting the meters of non-paying credit metering customers to prepaid meters, with new supply group codes to eliminate ghost vending
- Focused credit management process, together with disconnections, to recover outstanding debt
- Driving other recoveries in a structured approach through the Business Productivity Programme

The programme was approved late in the 2013/14 financial year. Implementation commenced in Soweto in July 2014 and was expanded since 1 November 2014, with 18 000 households targeted to be converted to prepaid. As part of the process, we engage with customers to educate them on energy efficiency, safety, free basic electricity, inclining block tariffs, buying of prepaid power through legal vendors, as well as the need for household budgeting to provide for electricity purchases.

25.3.4 Cost of cover

The cost of cover incurred was R3 577m compared to decision of R1 829m resulting in over expenditure of R1 748m.

Eskom only budgets for the premium portions (cost of cover / interest differential portion) of forward exchange contracts (FECs). Due to the volatility of the rand, Eskom does not consider the spot to spot movements which should offset in any case, as it would more or less have an equal and opposite movement when comparing the exchange fluctuations on the FEC to the underlying loan or contract (build project) being hedged. Ignoring the different accounting treatment of FECs which are fair valued while loans are booked at amortised cost.

The main reason for the increased premium cost is due to a significant portion of the loan book being hedged with FECs for a much longer period than anticipated. Eskom’s preferred hedging tool for foreign loans are Cross Currency Swaps. However Eskom can only enter into Cross Currency Swaps once Eskom is sure of the repayment profile of the loans and/or the size of the loan on book which makes it worthwhile to enter into a Cross Currency Swap. Due to the delay in the build programme drawdowns on the foreign facilities (DFI&ECA financing) were slower than expected and the repayment profiles unclear, hence loans are hedged for a longer period with FECs. In addition Eskom tries to apply cash flow hedge accounting when entering into Cross Currency Swaps to avoid volatility in the income statement, and to do this critical terms (maturity, principal, cash flows) of the Cross Currency Swap and the loan needs to match as closely as possible.

One must be cognisant of the fact that even though the FEC premium cost is much higher we will have an offsetting saving in finance cost due to Cross Currency Swaps not being executed as explained above.

25.4 Savings through Business Productivity Programme

Eskom implemented the BPP programme, which focuses on the reduction of the cost base, increased productivity, operational efficiencies and revisions of the business model and strategy, to assist in closing the MYPD 3 revenue shortfall. Cash saving opportunities to the value of R61.9 billion over the five years to 31 March 2018 have been identified through the development of various value packages.

At the end of the year, cash savings of R9 billion have been banked. Although the targeted savings for 2014/15 were not achieved, Eskom continues to aim to improve. Although critical, a reduction in costs, in terms of estimated savings to be realised under the BPP programme, may be difficult to achieve.

25.5 Other Income

25.5.1 Actual other income in 2014/15

In the course of Eskom operations in 2014/15, Eskom also generated total other income of R6 645 million which is disclosed under the Income Statement for March 2015 shown in Annexure 1.

Table 59 : Other income for 2014/15

Other Income	Actuals per AFS	RCA
Insurance proceeds	5 111	
Management fee income	261	
Operating lease income	219	
Dividend income	19	
Sale of scrap	186	186
Other	849	342
Total other income R'm	**6 645**	**528**

Eskom could not have reasonably estimated such additional revenue at the time of the MYPD3, Eskom does acknowledge that it did indeed realise additional revenue, some of which may be relevant for the purposes of the RCA.

25.5.2 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**,
"Para 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."

Similarly for 2014/15, other income from insurance proceeds (R5111 million), management fee income (R261million), operating lease income (R219million) and dividend income (R19m) do not qualify as other income for RCA purposes. This is because it relates to operating expenditure that does not form part of the RCA.

Eskom had a sundry other income of R849m, which relate essentially to the sale of ash and unclaimed monies. Included under sundry other income is an amount of R342 million relating to EDI restructuring levy which is being paid back through the RCA.

Table 60 : Other income note in 2014/15 AFS

	Note	Group 2015 Rm	Group 2014 Rm	Company 2015 Rm	Company 2014 Rm
33. Other income					
Insurance proceeds		2 732	–	5 111	384
Services income		213	362	–	–
Insurance premium income		116	117	–	–
Management fee income		–	–	261	751
Operating lease income		275	331	219	175
Dividend income		29	27	19	21
Sale of scrap		186	199	186	199
Other income		893	405	849	343
		4 444	1 441	6 645	1 873

25.5.3 Other income included for RCA

25.5.3.1 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 R186m from the sale of scrap assets.

The sale of scrap (R186 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.

25.6 EDI Holdings levy

Monies were received from customers via the tariff specifically for EDI Holdings. However this was not paid over due to the closure of the EDI restructuring office. Hence R342m is a variance in favour of the customer through the RCA.

25.7 Operating cost variance for 2014/15 RCA

Operating cost variance = Actual operating costs – Allowed operating costs

Based on **RCA equivalent actual operating costs of R49 534m** and allowed other operating costs in the **decision of R 39 417m**, Eskom has incurred an **additional R10 117m** 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 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.

25.8 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 (prep missing) 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).

26 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.

Table 61 : Summary of SQI performance in 2014/15

Licensee Service Quality Incentives (SQI)	Reward/ Penalty	2014/15
Distribution SQI	Reward	233
Transmission SQI	Reward	2.5
Total SQI for 2014/15 R'm)	**Reward**	**235.5**

26.1 Transmission service quality incentives (SQI) for 2014/15

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 2014/15 as been finalized that summarizes the financial reward / penalty based on these results. The SQI reflects a reward of R2.5m for system minutes less than 1 minute as reflected in the table below.

Table 62: Transmission SQI performance in 2014/15

Transmission Service Quality Incentives (SQI)	Performance Result	Incentive/ Penalty R'm	Comment
SM<1	2.85	2.50	Reward band
Major incidents	2.00	0	Deadband
Line faults / 100km	2.01	0	Deadband
Total Transmission SQI for 2014/15 R'm)		**2.50**	

Transmission system performance reflects significant improvements with a declining trend in minutes lost from 4.73 in 2012 to 2.85 in 2015.

Figure 7: Transmission system minutes (<1)

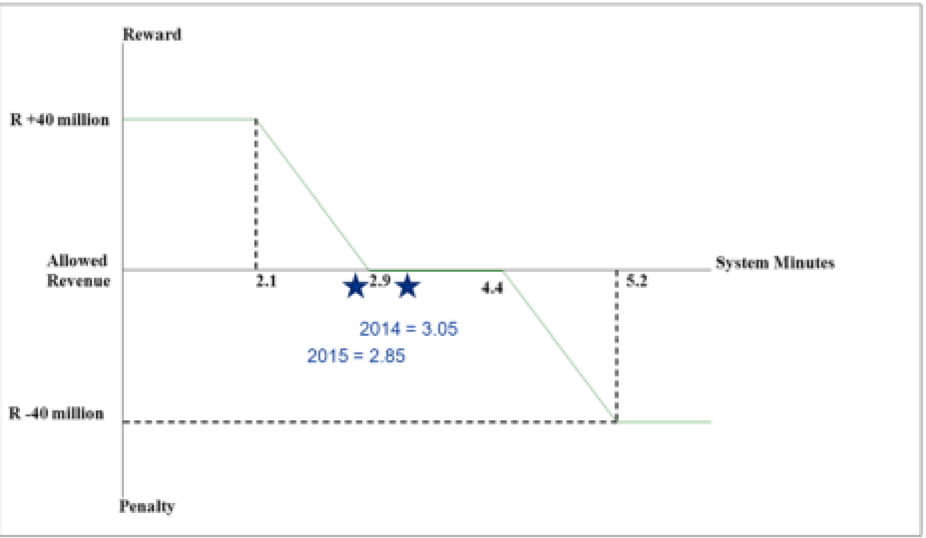
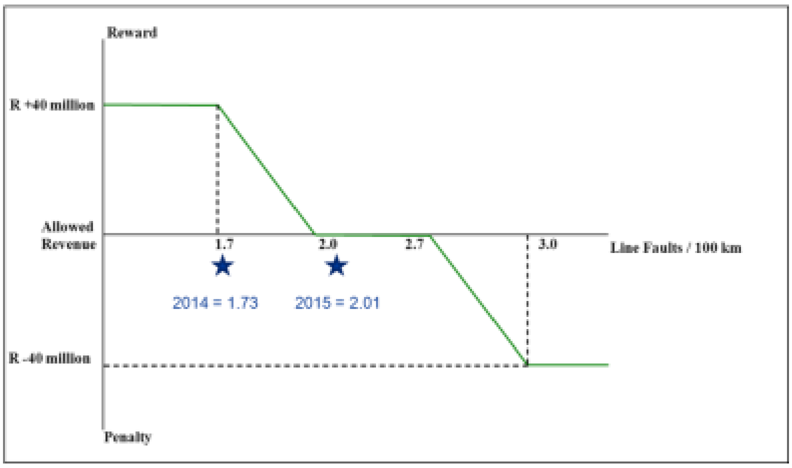


Table 63: Transmission number of major incidents (>1SM)

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 8 : Line faults /100km



26.2 Distribution Service Quality Incentive Scheme (SQI) for 2014/15

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 SAID and SAIFI performance have shown on-going improvements during 2014/15 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 of MYPD3. The net impact of the SQI performance is positive for Eskom. The outcome of the SQI performance is summarised in the table below.

Table 64: Distribution SQI performance in 2014/15

Distribution Service Quality Incentives (SQI)		Incentive/ Penalty	2014/15
SAIDI		Incentive	145.90
SAIFI		Incentive	116.72
DSLI		Penalty	-29.18
Distribution total SQI	**R'm**	**Incentive**	**233.44**

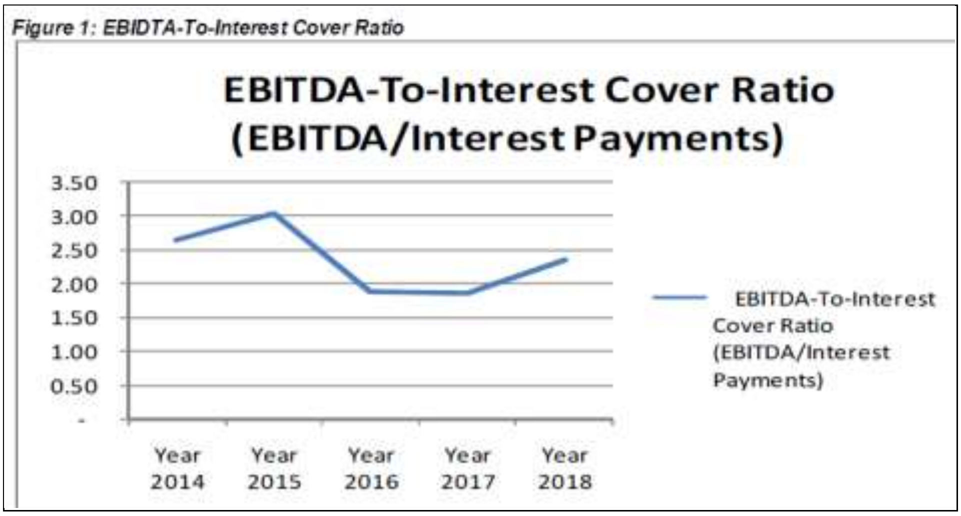
Distribution system performance reflects significant improvements with a declining trend in SAIDI interruption durations reducing from 45.8 minutes in 2012 to 36.2 minutes by 2015.

27 Reasonability tests

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

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

Figure 9 : EBITDA-To-Interest Cover Ratio



The figure above reflects around 3.0 for 2014/15

27.2 Understanding the ratio

NERSA's ratio might be similar to Moody's ratio of "Cash from Operations pre-working capital + Interest / 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 2014/15 (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 unfavourable 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."*

27.3 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.

27.4 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.

27.5 Computation of ratios for FY 2015

The financial information relating to debt obligations and the earnings for 2014/15 is presented in table below showing EBITDA of R24 735m, EBIT of R10 734m , net interest payments of R19 999m and debt service costs of R35 250m (interest of R19 999m plus debt repayments of R15 251m).

Table 65: Financial information for ratios in 2014/15

Financial Information for ratios workings		2014/15
Calculation of EBITDA		
EBITDA	A	**24 735**
Profit before net finance (cost)/ income - EBIT	B	10 734
Plus : Depreciation and amortisation expense		14 001
Calculation of Total debt serviced		
Finance cost		**24 015**
Debt securities and borrowings	C	19 731
Less gov loan interest		-2 228
Derivatives IRS and CCS		2 496
obligations		3 909
Finance lease payables		107
Finance income		**-935**
Investment in securities		-513
Loans receivable		-422
Net interest per AFS	**D**	**23 080**
purposes of the framework :		**-3 081**
obligations		-3 909
Finance lease payables		-107
Finance income		935
Total interest used for calculation		**19 999**
Add : Debt repaid		15 251
Total debt serviced	**E**	**35 250**

Various ratios have been computed as summarised below. Eskom's 2014/15 AFS reports on such interest cover ratio and reflects it as 0.47 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 2014/15 is 0.7. 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 2014/15 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 rates as sub-investment grade.

27.6 EBIT Interest cover ratio

The results reflects an EBITDA interest cover ratio 0.47 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 0.47, Eskom's earnings during 2014/15 do not even cover half the interest costs for the year.

Table 66: EBIT Interest Cover

EBIT Interest cover	Calculation	2014/15
EBIT Interest cover	B/D	**0.47**
EBIT	B	10 734
Interest	D	23 080

27.7 EBITDA: Total debt service ratio

The results reflect an EBITDA: debt service ratio of 0.70 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 515m which was effectively refinanced in 2014/15.

Table 67: EBITDA Debt service cover during 2014/15

EBITDA : Total debt serviced (Revised calculation to account for debt repaid)	Calculation reference	2014/15
EBITDA : Total debt serviced	B/E	0.70
EBITDA	B	24 735
Total debt serviced	E	35 250

28 Conclusion

Eskom's approach to RCA 2014/15 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 respective to the RCA process and outcomes.

Eskom's revenue is determined by NERSA through a revenue application process and the RCA process which this document 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 2014/15 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 R10 117m 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 R4 892m relating to OCGTs. Ultimately the 2014/15 RCA Submission of R19 185m 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 2014/15. The need for a significant RCA adjustment is demonstrated by the actual debt cover ratios being well below acceptable norms.

Eskom intends to submit the RCA 2015/16 application shortly after the release of the annual financial statements for March 2016.

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

Annexures:

Revenue:

Annexure 1: Income Statement in AFS 2015

Income statements

for the year ended 31 March 2015

	Note	Group 2015 Rm	Group Restated[1] 2014 Rm	Company 2015 Rm	Company Restated[1] 2014 Rm
Continuing operations					
Revenue	32	147 691	138 313	147 691	138 313
Other income	33	4 444	1 441	6 645	1 873
Primary energy	34	(83 425)	(69 812)	(83 425)	(69 812)
Net employee benefit expense	35	(25 912)	(25 622)	(22 187)	(22 384)
Depreciation and amortisation expense	36	(14 115)	(11 937)	(14 001)	(11 934)
Net impairment loss	37	(3 766)	(1 557)	(3 755)	(1 549)
Other expenses	38	(15 771)	(19 177)	(22 083)	(24 340)
Profit before net fair value gain/(loss) and net finance cost		9 146	11 649	8 885	10 167
Net fair value gain/(loss) on financial instruments, excluding embedded derivatives	39	630	(620)	539	(753)
Net fair value gain on embedded derivatives		1 310	2 149	1 310	2 149
Profit before net finance cost		11 086	13 178	10 734	11 563
Net finance cost		(6 109)	(4 058)	(6 769)	(4 619)
Finance income	40	2 996	3 189	2 360	2 622
Finance cost	41	(9 105)	(7 247)	(9 129)	(7 241)
Share of profit of equity-accounted investees after tax	8	49	43	–	–
Profit before tax		5 026	9 163	3 965	6 944
Income tax	42	(1 366)	(2 137)	(1 169)	(1 520)
Profit for the year from continuing operations		3 660	7 026	2 796	5 424
Discontinued operations					
(Loss)/profit for the year from discontinued operations	21	(42)	63	–	–
Profit for the year		3 618	7 089	2 796	5 424

Annexure 2: The Eskom energy wheel (Eskom Integrated report 2015, page22)

****Note:** All figures are in GWh unless otherwise stated.

Eskom energy flow diagram

The energy wheel shows the volume of electricity that flowed from local and international power stations and independent power producers (IPP) 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	2014/15	2013/14
Generation	222 591	227 508
OCGT	3 709	3 621
Pumping	(4 114)	(3 862)
IPP	6 022	3 671
Total	228 208	230 938

Available for distribution	2014/15	2013/14
Generation (including IPPs)	232 322	234 800
International purchases	10 731	9 425
Wheeling [1]	3 623	3 353
Subtotal	246 676	247 578
Pumping	(4 114)	(3 862)
Total	242 562	243 716

Total imports	2014/15	2013/14
International purchases	10 731	9 425
Wheeling [1]	3 623	3 353
Total	14 354	12 778

Total exports	2014/15	2013/14
International sales [2]	12 000	12 469
Wheeling [1]	3 623	3 353
Total	15 623	15 822

South African Power Pool

Internal use	2014/15	2013/14
Generated	(53)	(129)
Internal use	791	465
Total	738	336

Demand	2014/15	2013/14
External sales	216 274	217 903
Technical and other losses	20 940	21 488
Internal use	791	465
Generated	(53)	(129)
Wheeling	3 623	3 353
Unaccounted/ re-phasing [3]	988	636
Total	242 562	243 716

External sales	2014/15	2013/14
Local sales	204 274	205 434
International sales [2]	12 000	12 469
Total	216 274	217 903

Technical and other losses	2014/15	2013/14
Distribution	4 920 (6.8%)	15 824 (7.1%)
Transmission	6 020 (2.5%)	5 664 (2.3%)
Total	20 940	21 488

1. Wheeling is the buying and selling of electricity between Eskom and foreign parties without the power entering into South Africa.
2. International sales includes exports by Distribution International to Lesotho. The actual amounts for 2015 and 2014 were 89GWh and 91GWh respectively.
3. Includes 352GWh allocated for the BPP sales adjustment.

Annexure 3: Sales volumes GWh – Statistical tables for 2014/15

Electricity sales per customer, GWh

Category	2014/15	2013/14
Local	**204 274**	205 525
Redistributors	**91 090**	91 262
Residential [1]	**11 586**	11 017
Commercial	**9 644**	9 605
Industrial	**53 467**	54 658
Mining	**29 988**	30 667
Agricultural	**5 401**	5 191
Rail	**3 098**	3 125
International	**12 000**	12 378
Utilities	**2 797**	3 401
End users across the border	**9 203**	8 977
	216 274	217 903

International sales to countries in southern Africa, GWh

	12 000	12 378
Botswana	**1 237**	1 608
Mozambique	**8 360**	8 314
Namibia	**924**	1 248
Zimbabwe	**108**	154
Lesotho	**230**	122
Swaziland	**882**	741
Zambia	**16**	143
Short-term energy market [2]	**243**	48

1. Pre-payments 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 contract.

Primary Energy

Annexure 4: Primary Energy Note 34 extract AFS March 2015, page 91

	Note	Group 2015 Rm	Group 2014 Rm	Company 2015 Rm	Company 2014 Rm
34. Primary energy					
Own generation costs		61 630	54 186	61 630	54 186
Environmental levy		8 353	8 530	8 353	8 530
International electricity purchases		3 679	3 311	3 679	3 311
Independent power producers		9 453	3 266	9 453	3 266
Other		310	519	310	519
		83 425	69 812	83 425	69 812

Own generating costs relates to the cost of coal, uranium, water and liquid fuels that are used in the generation of electricity. Eskom uses 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 2015, page 93)

		Note	Group 2015 Rm	Group 2014 Rm	Company 2015 Rm	Company 2014 Rm
40.	**Finance income**					
	Investment in securities		739	988	513	823
	Loans receivable		799	719	422	353
	Finance lease receivables		68	70	68	70
	Trade and other receivables		677	468	676	468
	Cash and cash equivalents		713	944	681	908
			2 996	3 189	2 360	2 622
41.	**Finance cost**					
	Debt securities and borrowings		19 699	16 312	19 731	16 302
	Eskom bonds		9 381	8 316	9 381	8 316
	Promissory notes		5	–	5	–
	Commercial paper		677	697	627	586
	Eurorand zero coupon bonds		458	405	458	405
	Foreign bonds		2 041	1 507	2 041	1 507
	Development financing institutions		3 192	1 865	3 192	1 865
	Export credit facilities		1 345	1 304	1 345	1 304
	Subordinated loan from shareholder		2 228	2 044	2 228	2 044
	Other loans		372	174	454	275
	Derivatives held for risk management		2 496	1 523	2 496	1 523
	Employee benefit obligations	27	1 060	905	1 034	886
	Provisions	28	2 877	1 456	2 875	1 452
	Finance lease payables		87	89	107	116
	Trade and other payables		275	252	275	252
	Gross finance cost		26 494	20 537	26 518	20 531
	Capitalised to property, plant and equipment	6	(17 389)	(13 290)	(17 389)	(13 290)
			9 105	7 247	9 129	7 241

Operating expenses

Annexure 6: OPEX note 38 extract from AFS March 2015, page 92

Notes to the financial statements (continued)

for the year ended 31 March 2015

	Note	Group 2015 Rm	Group 2014 Rm	Company 2015 Rm	Company 2014 Rm
38. Other expenses					
Managerial, technical and other fees		1 197	2 906	1 160	2 826
Direct research and development		35	35	35	35
Operating lease expense		1 397	1 272	753	587
Auditors' remuneration[1]		97	126	84	105
Net loss on disposal of property, plant and equipment		111	179	103	176
Government grant		–	(43)	–	(43)
Income		(209)	(312)	(209)	(312)
Expenses incurred		209	269	209	269
Repairs and maintenance, transport and other expenses		12 934	14 702	19 948	20 654
		15 771	19 177	22 083	24 340

IDM

Annexure 7: EEDSM costs in 2014/15 Annual report

IDM spending		Cost (Rm)
CFL Roll-out	*5*	
Compressed Air	*27*	
Demand Reduction	*107*	
Heat Pumps	*14*	
Lighting and HVAC	*168*	
Process Optimisation	*107*	
Renewables	*11*	
Shower Heads	*2*	
Projects		440
Marketing and communications		62
M&V		53
Operating costs		99
TOTAL		654

Programmes	Demand savings (MW)	Annualised energy savings (GWh)	No. of projects
CFL Roll-out	9.4	28.24	6
Compressed Air	0.9	50.37	2
Demand Reduction	41.2	-4.79	16
Heat Pumps[1]	3.5	25.74	13
Lighting and HVAC	50.5	254.59	25
Process Optimisation	41.7	308.90	23
Renewables	0.0	0.13	2
MYPD total	**147.4**	**663.18**	**87**
SWH	24.1	153.04	36
DoE total	**24.1**	**153.04**	**36**
GRAND TOTAL	**171.5**	**816.23**	**123**

IDM reporting category	Status	Demand savings (MW)	Annualised energy savings (GWh)	No. of projects
MYPD	Installed and verified FY2015	147.4	663.2	87
DoE-funded	Installed and verified FY2015	24.1	153.0	36
TOTAL Eskom IDM savings		**171.5**	**816.2**	**123**

IDM reporting category	Status	Demand savings (MW)	Annualised energy savings (GWh)	No. of projects
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TOTAL Eskom IDM savings		**171.5**	**816.2**	**123**

OCGTs

Annexure 8: Copy of NERSA letter approval of 450GWh

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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Mr T Matona
Chief Executive
Eskom Holdings SOC Ltd
P O Box 1091
JOHANNESBURG
2000

Dear Mr Matona

Approved usage of Open Cycle Gas Turbines (OCGTs) by Eskom vis-a-vis the MYPD3 decision.

Your letter dated 5 January 2015 refers.

On 16 January 2015, the National Energy Regulator of South Africa (NERSA) considered your request for running of Open Cycles Gas Turbines (OCGTs) and decided that:

- Eskom's utilisation of Open Cycle Gas Turbines (OCGTs) above the approved limit within the MYPD3 decision up to a limit of 450 GWh per month is approved;
- Cabinet's five point plan to address electricity challenges facing the country is noted; and
- Eskom must submit a revised OCGTs usage plan for the remainder of the MYPD3 period.

I trust that you will find this in order.

Yours sincerely

PBaleni

Phindile Baleni (née Nzimande)
Chief Executive Officer

Date: 23/01/2015

29 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

30 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)