NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

DECISION AND REASONS FOR DECISION

ESKOM HOLDINGS SOC LIMITED:

ESKOM'S MYPD4 REGULATORY CLEARING ACCOUNT (RCA) APPLICATION FOR THE 2021/22 FINANCIAL YEAR

REASONS FOR DECISION

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

In the matter regarding the

Fourth Multi-Year Price Determination (MYPD4) Year 3 (2021/22) Regulatory Clearing Account (RCA) Application

By

ESKOM HOLDINGS SOC LIMITED ('ESKOM')

Decision

Based on the available information and the analysis of the Regulatory Clearing Account (RCA) application for the 2021/22 financial year, the Energy Regulator, at its meeting held on 30 July 2024, approved the following:

1. Eskom's RCA balance of R8 095m for the 2021/22 financial year, as per Table 1 below

Table 1: RCA balance for 2021/22 financial year

RCA for FY 2022	Decision FY2022	Actuals FY2022	Variance	RCA adjustment	RCA FY2022	NERSA Adjustment	NERSA Decision
Revised Return	13 123	12 946	-177		-177	-90	-267
Expenditure	57 019	73 966	16 947	-9 825	7 122	-4 825	2 297
Primary Energy	68 330	84 729	16 400	766	17 166	-10 853	6 312
Independent Power Producers (local)	40 631	36 714	-3 917		-3 917	0	-3 917
International purchases	3 426	5 306	1 880		1 880	0	1 880
Depreciation	66 279	58 151	-8 128		-8 128	0	-8 128
Research & Development	151	149	-2		-2	0	-2
Levies & taxes	7 266	7 512	246		246	0	246
Revenue	233 229	246 520	-13 291	22 814	9 523	0	9 523
Service Quality Incentives (SQI) -		69	69		69	0	69
FY 2022 RCA Balance due to Eskom/(Customers) Applied for					**23 778**	**-15 768**	**8 012**
Nuclear decommissioning from RCA 2013/14 decision liquidated over 10 years - (9th year of 10 years)					83	0	83
Total RCA balance per this application					**23 861**	**-15 768**	**8 095**

Note: Eskom applied for a return of -R180m, not the -R177m as shown in the table. An amount of -R177 was used to show correct adjustments of -R90 and a decision of -R267. This is due to NERSA using the correct RAB value and not as applied for by Eskom.

2. The RCA balance of R8 095m is to be recoverable from the standard tariff customers, local Special Pricing Arrangement (SPA) customers and international customers

3. The Reasons for Decision (RfD) will be published once the applicable requirements, including, but not limited to, the confidential treatment of some information, have been finalised

4. An implementation plan for the 2021/22 RCA balance will be developed for approval by the Energy Regulator.

DRAFT REASONS FOR DECISION

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ABBREVIATIONS

BER	Bureau for Economic Research
Capex	Capital Expenditure
CPI	Consumer Price Index
DAB	Dispute Adjudication Board
DMP	Demand Market Participation
DSCR	Debt Service Coverage Ratio
DSLI	Demand Supply Loss Index
DSM	Demand Side Management
Dx	Distribution
EAF	Energy Availability Factor
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
EEDSM	Energy Efficiency and Demand Side Management
ELS	Electricity Subcommittee
ER	Energy Regulator (NERSA board)
ERA	Electricity Regulation Act, 2006 (Act No. 4 of 2006)
ERTSA	Eskom's Retail Tariff Structural Adjustments
EUF	Energy Utilisation Factor
ERI	Eskom Rotek Industries
FY	Financial Year
GDP	Gross Domestic Product
GLF	Generation Load Factor
GWh	Gigawatt hour
Gx	Generation
HV	High Voltage
IAS	International Accounting Standard
IDM	Integrated Demand Management
IPP	Independent Power Producer
IRP	Integrated Resource Plan
km	Kilometre
kWh	Kilowatt hour
MIRTA	Minimum Information Requirements for Tariff Applications
MW	Megawatt
MWh	Megawatt hour
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa
NPA	National Prosecuting Authority
OCGT	Open Cycle Gas Turbine
Opex	Operating expenditure
PAJA	Promotion of Administrative Justice Act
PPA	Power Purchase Agreement

PPE	Property Plant and Equipment
RAB	Regulatory Asset Base
RCA	Regulatory Clearing Account
REC	Regulator Executive Committee
REIPP	Renewable Energy Independent Power Producer
RfD	Reasons for Decision
SADC	Southern African Development Community
SAPS	South African Police Service
SARS	South African Revenue Service
SIU	Special Investigation Unit
SOC	State-Owned Company
Tx	Transmission
UoS	Use-of-System
WUC	Work Under Construction

1. LEGAL MANDATE

1.1 Section 4(c) of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ('NERA') empowers the National Energy Regulator of South Africa (NERSA) with the responsibility to undertake the functions detailed in section 4 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the ERA').

1.2 The ERA sets out NERSA's powers and functions. Of relevance to this application is section 4(a)(ii), wherein NERSA is empowered and required to regulate prices and tariffs.

1.3 In performing its mandated functions, NERSA is required to ensure that the following objects are achieved:

a) The efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure in South Africa
b) That the interests and needs of present and future electricity customers and end-users are safeguarded and met, having regard to the governance, efficiency, effectiveness and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in the Republic
c) That investment in the electricity supply industry is facilitated
d) That universal access to electricity is facilitated
e) That the use of diverse energy sources and energy efficiency is promoted
f) That competitiveness and customer and end-user choice are promoted
g) That a fair balance among the interests of customers and end-users, licensees, investors in the electricity supply industry and the public is facilitated.

1.4 To facilitate compliance with the regulatory framework and create regulatory certainty regarding Eskom's revenue applications, NERSA developed the Multi-Year Price Determination (MYPD) Methodology in line with section 14(1)(g)[1] of the ERA and Minimum Information Requirements for Tariff Applications (MIRTA) in line with section 14(1)(e)[2] of the ERA, which Eskom must comply with. However, these do not restrain the Energy Regulator from using its discretion when taking a decision.

1.5 The licences issued to Eskom set out conditions for the setting and approval of tariffs, charges, prices and rates charged by Eskom.

1.6 In terms of section 15 of the ERA, a licence condition relating to the setting and approval of tariffs, charges and prices, and the regulation of revenue must, inter alia, enable an efficient licensee to recover the full cost of its licensed activities, including

[1] The Regulator may make any licence subject to conditions relating to -the regulation of the revenues of licensees
[2] The Regulator may make any licence subject to conditions relating to - the methodology to be used in the determination of rates and tariffs which must be imposed by licensees

a reasonable margin or return; provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided; and give end users proper information regarding the costs that their consumption impose on the licensee's business.

1.7 The previous judgement against NERSA has shown that before discretion is exercised on the issues of deviation from the agreed methodology, such discretion should be exercised reasonably with due regard to the country's economy, as well as the interests of the customers and those of Eskom as a licensee. Failure to exercise these principles of discretion may result in prejudice against the already afforded rights within the agreed methodology.

2. THE APPLICANT

2.1 Eskom Holdings SOC Limited, registration number 2002/015527/06, is a schedule 2 South African state-owned enterprise (SOE) in terms of the Public Finance Management Act, 1999 (Act No. 1 of 1999), wholly owned by the South African Government. Eskom Holdings is regulated under licences granted by the Energy Regulator to generate, transmit and distribute electricity (three licences) in terms of the ERA.

2.2 Eskom generates, transmits and distributes electricity to industrial, mining, commercial, agricultural, residential customers, as well as other distributors. Eskom also buys electricity from and sells electricity to the countries of the Southern African Development Community (SADC). Until 2023, this import/export function was carried out under a Transmission licence.

2.3 Through its subsidiary, Eskom Enterprises (Pty) Limited, Eskom is also active in local unregulated markets and various African countries. The activities include providing electricity-related services to countries connected to the South African grid.

3. BACKGROUND AND INTRODUCTION

3.1 On 14 September 2018, Eskom applied for revenues of R219bn, R252bn and R291bn for the 2019/20, 2020/21 and 2021/22 financial years, respectively, as detailed in Table 2 below.

3.2 On 7 March 2019, the Energy Regulator approved the allowable revenues as shown in Table 2 below.

Table 2: Decision on allowed revenues

MYPD4	Application 2019/20	Adjustment	Decision 2019/20	Application 2020/21	Adjustment	Decsion 2020/21	Application 2021/22	Adjustment	Decsion 2021/22
Total expected revenues from all customers (R'm)	**219 537**	**-13 157**	**206 380**	**252 292**	**-30 449**	**221 843**	**291 542**	**-58 464**	**233 078**
Negotiated price agreement and International customers (R'm)	15 045	396	15 441	16 340	396	16 736	18 084	396	18 480
Revenues from tariffs based sales (R'm)	**204 492**	**-13 553**	**190 939**	**235 952**	**-30 845**	**205 107**	**273 458**	**-58 860**	**214 598**
Forecast sales to tariff customers (GWh)	189 584	-3 520	186 064	190 218	-5 320	184 898	191 699	-7 843	183 856
Standard average tariff (c/kWh)	**107,86**		**102,62**	**124,04**		**110,93**	**142,65**		**116,72**
Percentage tariff increase (%)	15,00%		9,41%	20,88%		8,10%	28,59%		5,22%

3.3 Eskom submitted its application for the 2021/22 Regulatory Clearing Account (RCA) balance of R23 861m as shown in Table 3, as required primarily by section 17.2 of the MYPD4 Methodology.

3.4 Eskom indicated that the application has no confidential information, therefore, there was no need to treat any information in the application as confidential.

4. THE DECISION-MAKING PROCESS

4.1 On 26 April 2023, NERSA received Eskom's MYPD4 RCA revenue application for the 2021/22 financial year (**Annexure A**). This RCA related to the third year of the MYPD4 revenue decision. On receipt of the RCA application, the NERSA MYPD team conducted a screening to ensure that the application complies with the MYPD4 Methodology and MIRTA requirements.

4.2 On 14 June 2023, NERSA published Eskom's MYPD4 RCA application for the 2021/22 financial year (FY) on the NERSA website, along with an invitation to stakeholders to submit written comments.

4.3 The closing date for written stakeholder comments was 27 July 2023.

5. LIST OF STAKEHOLDERS WHO COMMENTED ON THE APPLICATION

5.1 NERSA received written comments from the following three stakeholders by the end of the consultation period:

5.1.1 AgriSA

5.1.2 Minerals Council of South Africa

5.1.3 Energy Intensive Users Group (EIUG).

5.2 On 24 August 2023, NERSA conducted a national public hearing were interested and affected stakeholders were given an opportunity to make oral presentations. The following stakeholders gave oral presentations during the public hearing:

5.2.1 Eskom

5.2.2 Minerals Council SA

5.2.3 BUSA (Business Unity)

5.2.4 Agri Western Cape.

5.3 These comments are analysed in the RfD.

6. SUMMARY OF THE APPLICATION

6.1 As a claw-back mechanism, the key purpose of the RCA, other than its risk-management function, is to ensure that both the industry and consumers are treated fairly and are not subjected to unfair gains or losses because of incorrect forecasting, inaccurate information and system shocks.

6.2 Table 3 below shows the RCA balance of R23 861m applied for in favour of Eskom.

Table 3: Eskom's MYPD4 Year 2 RCA application (2021/22)

RCA for FY 2022	Decision FY2022	Actuals FY2022	Variance	RCA adjustment	RCA FY2022
FY2022Regulated Assets Base (RAB)	875 039	863 043	-11 996		-11 996
Return on Assets (ROA)	1,50%	1,50%			
Return (Adjusted for government assistance)	-9 874	-10 054	-180		-180
Expenditure	57 019	73 966	16 947	-9 825	7 122
Primary Energy	68 330	84 729	16 399	766	17 166
Independent Power Producers (local)	40 631	36 714	-3 917		-3 917
International purchases	3 426	5 306	1 880		1 880
Depreciation	66 279	58 151	-8 128		-8 128
Research & Development	151	149	-2		-2
Levies & taxes	7 267	7 512	245		245
Revenue	233 229	246 520	-13 291	22 814	9 523
Service Quality Incentives (SQI) -		69	69		69
FY 2022 RCA Balance due to Eskom/(Customers) Applied for					**23 778**
Nuclear decommissioning from RCA 2013/14 decision liquidated over 10 years - (9th year of 10 years)					83
Total RCA balance per this application					**23 861**

6.3 Eskom's RCA submission is driven substantially by revenue variance, primary energy, operating costs and international purchases. NERSA analysed the allowable revenue for evidence of prudent and efficient spending by Eskom.

6.4 The major contributing items to the RCA balance are as follows:

a) Primary energy R17 166m

b) Revenue variance R9 523m

c) Operating expenditure (Opex) R7 122m

d) International purchases R1 880m

7. ANALYSIS OF ESKOM'S 2021/22 RCA APPLICATION

7.1 REVENUE VARIANCE

Summary of the application

7.1.1 Eskom has applied for a revenue variance of R9 523m for the 2021/22 financial year, as shown in Table 4 below.

Table 4: RCA revenue variance 2021/22 (R'm)

Revenue Variance (Rm)	Decision FY2022	Actuals FY2022	Variance
Total Eskom Revenue (AFS)	233 229	246 520	(13 291)
Add/(deduct): RCA adjustments		(22 814)	22 814
Load shedding (1605 GWh @ 133,64 average c/kWh)		2 145	(2 145)
Electricity Revenue Variance	**233 228**	**223 706**	**9 523**

7.1.2 The revenue variance is adjusted for revenue that is not recognised from IFRS15 accounting standards. This revenue might not be recoverable, although it has been billed. The revenues are also adjusted for internal sales that are netted off for accounting reporting but should be included in the calculation of the revenue variance. In addition, the revenue is adjusted for load-shedding, as the revenue variance arising from load-shedding should not be recovered from customers (R2.145bn).

7.1.3 The revenue variance is driven by a difference of 7 711 GWh between the actual sales and the decision, as shown in Table 5.

Table 5: Variance between actual sales and the decision in 2021/22 (GWh)

Sales volumes variance per tariff category (GWh)	Decision FY2022	Actual FY2022	Variance
Standard tariff sales including internal sales	183 856	175 423	(8 434)
NPA sales	9 750	10 079	329
Total Local sales	**193 606**	**185 501**	**(8 105)**
Add: International sales (incl. Dx international sales)	12 904	13 298	394
Total Sales to all customers	**206 510**	**198 799**	**(7 711)**

7.1.4 The variance is largely driven by standard customer sales (8 114GWh). The biggest variance under standard sales is the re-distributor sales (1 810 GWh), followed by mining sales (1 475 GWh), residential sales (1 330 GWh) and commercial sales (1 196 GWh). A breakdown of sales variances is shown in Table 6 below.

Table 6: Sales variance per customer category 2021/22 (GWh)

Category	Decision FY2022	Actual FY2022	Variance
Agricultural	5 902	5 382	(520)
Re-distributors	85 741	83 931	(1 810)
Commercial	11 068	9 872	(1 196)
Industrial	46 079	45 120	(959)
Mining	29 505	28 030	(1 475)
Residential	11 850	10 520	(1 330)
Dx international sales[1]	2 858	2 128	(730)
Traction	94	-	(94)
External sales	**193 097**	**184 983**	**(8 114)**
Internal sales	509	518	9
Total Local sales	**193 606**	**185 501**	**(8 105)**
International sales	**12 904**	**13 298**	**394**

NERSA Analysis

7.1.5 This section will deal with the factors that affected sales volumes form the supply and demand side.

Supply-side issues

7.1.6 The plant performance trajectory continues to decline to unprecedented low levels year after year. Figure 2 below shows historic performance figures for the Eskom fleet. Looking from FY2017/18, plant performance has been on a downward decline, driven by the unabated increase in UCLF.

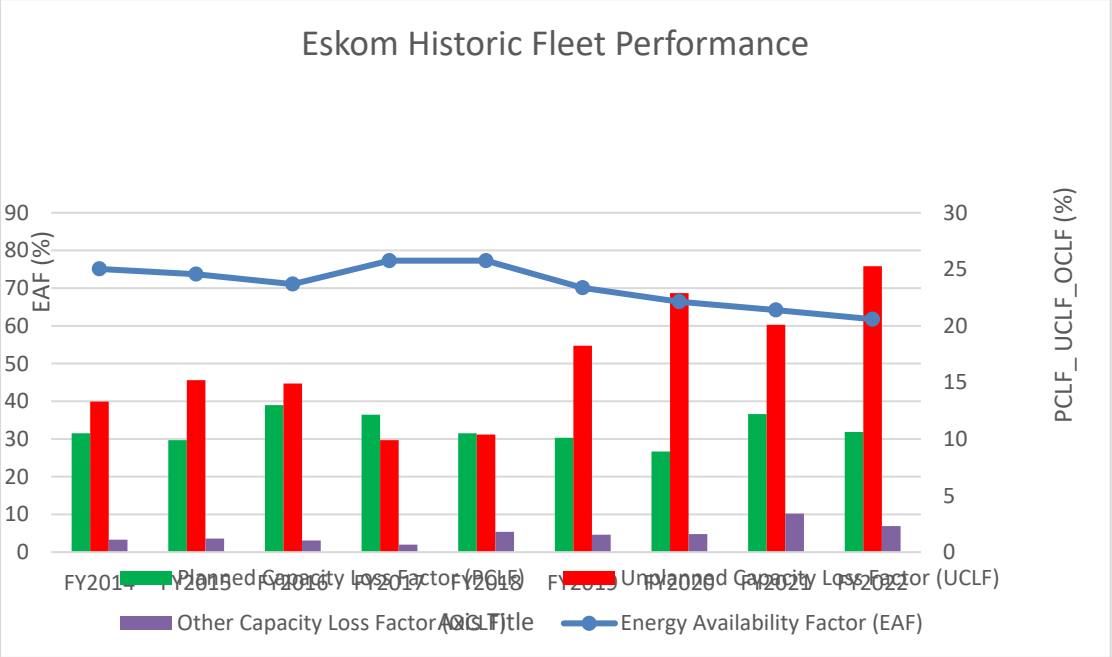

Figure 1: Historical Eskom fleet performance statistics

7.1.7 Eskom's coal fleet's performance is the most significant driver of system adequacy. The decline in the fleet's availability directly contributes to increasing levels of load-shedding. Figure 2 below shows the volumes of load-shedding since 2015.

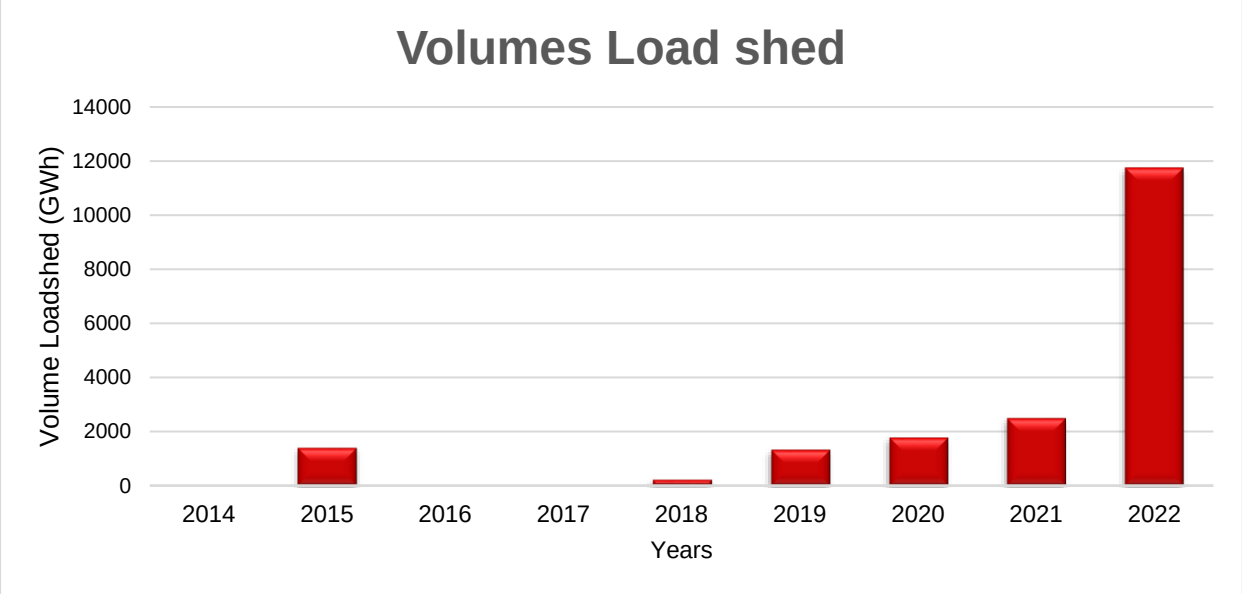

Figure 2: Volumes of load-shedding since 2015

7.1.8 The Medium-Term System Adequacy Outlook 2022 highlighted that improving the Eskom fleet's Energy Availability Factor (EAF) to above 65% reduced the energy gap from 18 088GWh to 2 850GWh in 2023. This demonstrates that it is still worthwhile to focus on improving Eskom's performance, as it is the most effective

way to resolve the energy crisis, given that the Eskom fleet comprises dispatchable baseload plants.

7.1.9 The reasons advanced by Eskom for poor plant performance have remained the same since the start of the crisis. The biggest drivers of the increasing UCLF remain the PLLs that require maintenance to be implemented. Eskom has put in place several plans over the years, the latest being the 9-point plan. However, it is yet to deliver results that improve the system and reduce the devastating disruptions to the economy and everyday life for South Africans. Outage slippages are the second driver of plant unavailability; Eskom can manage this if outage planning is better executed.

7.1.10 Eskom still indicates that funding for maintenance is a challenge. Eskom has managed to keep their PCLF at the 10% per their projections so maintenance has been executed. Therefore, it seems that Eskom is spending its maintenance budget on maintenance activities, however, most funding is spent on emerging issues rather than planned maintenance interventions. It is recommended that the focus should remain on preventative maintenance, as the improvement of the Eskom's fleet's performance is still the most effective way to get the country out of the energy crisis.

7.1.11 The performance of the new-build station remains a great concern. Kusile is operating at an EAF of 27%, which is much lower than where it should be. Although Medupi is at an EAF of 67%, it is below where it should be. The interventions to address the current design challenges are stalling for various reasons, including failure to reach contractual agreements with contractors, which is concerning.

7.1.12 Eskom's plant performance remains a great concern and Eskom must focus on the following:

- 7.1.12.1 Improving partial load losses by executing the planned maintenance to deal with these, particularly the quick wins that can get some units operating at full load
- 7.1.12.2 Improving the monitoring system for boiler tube leaks
- 7.1.12.3 Prioritising the new-build repair projects
- 7.1.12.4 Focusing on outage management.

Demand-side issues

7.1.13 Section 17.2.4.1 of the MYPD4 Methodology states that 'variances between the forecast and actual sale volumes shall be assessed and analysed to determine the cause of the variance, then the Energy Regulator will make a decision on

whether to allow such variances.' The approach followed is to assess Eskom's contribution towards the decline in sales.

7.1.14 NERSA had adopted an approach when making the MYPD4 determination, as stated in section 6.1.5 of the MYPD Methodology. Section 6.1.5 indicates that Eskom's sales volume forecast assumptions must reflect the current conditions of the market at the time of the application and should take into account the most recent actual volumes.

7.1.15 In its application, Eskom blames the slow economy for the lower than forecast sales. However, Eskom's capacity constraints have also contributed to the slow economic growth. The impact of load-shedding is one of the major reasons for lower sales.

7.1.16 Figure 3 below shows an increase in load-shedding from 2018. Even though Eskom has adjusted the load-shedding impact, such impact is broader than just load-shedding. It includes discouraged investors who, due to Eskom's capacity constraints, have not invested in the acquisition of new capacity or in expanding existing operations.

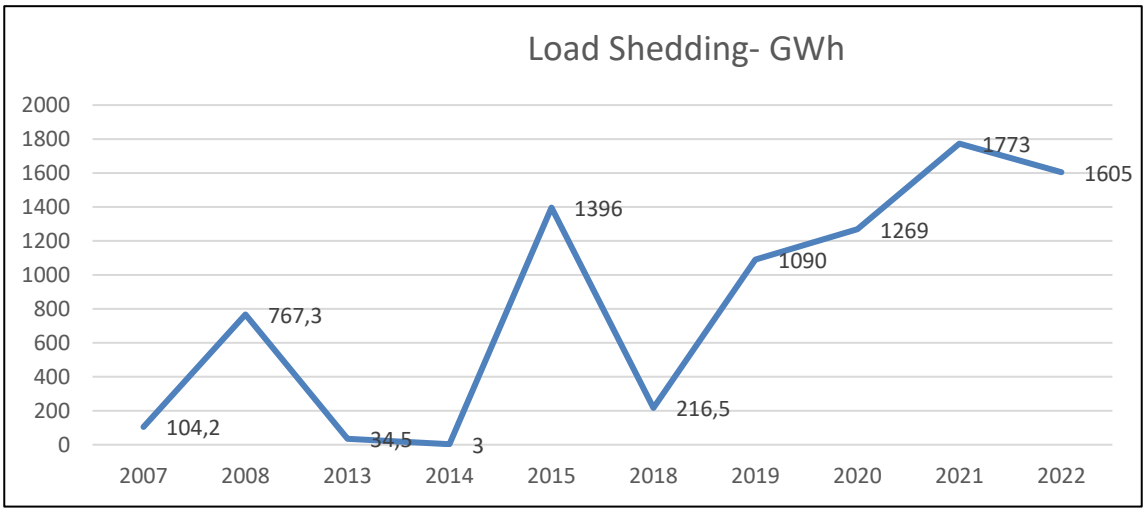

Figure 3: Eskom load-shedding (GWh)

7.1.17 A study commissioned by Eskom to NOVA economists found that load-shedding reduced the South African Gross Domestic Product (GDP) by R35 billion between 2007 and 2019, with the agricultural sector, utilities and manufacturing sector being the most affected.

7.1.18 An analysis conducted by the South African Reserve Bank ('the Bank') found that load-shedding has the most severe negative impact on energy-intensive users, such as those in the mining and manufacturing industries. The report estimated the impact to be around 0.5% quarter-on-quarter annualised GDP growth rate in 2019 for the first quarter (Q1) of 2019. The report highlighted that should this

persist the whole year, GDP would decrease by 0.3% from the annual growth rate. The Bank also estimated that the economy would lose R385m per day at stage 1 load-shedding and R753m per day at stage 4 (nominal terms).

7.1.19 A report by the Centre for Scientific and Industrial Research (CSIR) estimated the impact on the economy to be between R60bn and R120bn in 2019. Load-shedding up to stage 6 was experienced during this period.[3] There is no data for 2020/21, however, it can be assumed that the impact was more severe due to more load-shedding taking place in 2020/21 than in any other year.

7.1.20 A PwC report estimated that the impact of load-shedding on the South African economy was a reduction of the economy by 2.3% and that it had cost the economy up to 275 000 jobs in 2020/21. This means the economy would have grown by 4.6% and created 565 000 jobs.[4]

7.1.21 In the previous public hearings, the Nelson Mandela Bay Chamber of Commerce (on behalf of the Casting, Forging and Machining Cluster of South Africa and regional business chambers) stated in its written response that Eskom's sales decline was partly due to frequent load-shedding and capacity constraints. The capacity constraints and the declining EAF (more than 10% in 2020) made it impossible for Eskom to market its capacity to existing and potential investors, which led to sale losses.[5] These comments are still relevant today.

Approach/methodology used

7.1.22 Although the provision in 17.2.4.1 is found in the MYPD4 Methodology, the Methodology does not prescribe the approach for allowing/disallowing revenue variances. This lack of clarity in the methodology poses a limitation to what the Energy Regulator can do to adjust for revenue variance. NERSA has previously sought to allow a revenue variance that will allow the recovery of fixed costs only to the exclusion of variable costs, in instances where Eskom has contributed to the decline in sales. This approach has been successfully challenged in court by Eskom. No adjustment is therefore made to the Sales Revenue variance; Eskom is therefore granted revenue variance as applied for as shown in Table 7 below.

Table 7: Revenue decision

Revenue Variance (R'm)	Eskom Application RCA 2022	Actual FY 2022	Variance	NERSA Adjustment	NERSA Decision
Electricity Revenue Variance	233 229	223 706	9 523	-	9 523

[3] CSIR Energy Centre, 2020, Setting up for the 2020's: Addressing South Africa's electricity crisis and getting ready for the next decade.
[4] PwC, South Africa Economic Outlook, a consumer led recovery, https://www.pwc.co.za/en/assets/pdf/economic-outlook/economic-outlook-consumer-led-recovery.pdf
[5] Submission dated 20 January 2020.

Conditions for approval

7.1.23 There are no conditions for approval since this is a decision to recover costs already incurred.

7.2 REGULATED ASSET BASE (RAB)

Summary of the application

7.2.1 Eskom applied for a variance of R180m in favour of the customers with regard to the return, after taking government assistance into account, as shown in Table 8 below. This return is based on an average RAB value of R863 043m (closing RAB R849 223m).

Table 8: RAB and return on assets (RoA) variance

RAB and RoA	Decision FY2022	Actual FY2022	Variance
Depreciated Replacement Costs (DRC)	462 484	462 521	37
Completed assets after FY2016	378 271	255 325	(122 946)
Asset purchases	2 305	2 200	(105)
Work Under Construction (WUC)	-25 414	106 415	131 829
Working capital	64 812	51 178	(13 634)
Assets funded by customers upfront	(27 103)	(28 416)	(1 313)
Closing RAB values	**855 355**	**849 223**	**(6 132)**
Average RAB Values per Table 1 of the RfD	875 039	863 043	(11 996)
Percentage Return on Assets	1.5%	1.5%	
Return on assets before government assistance	13 126	12 946	(180)
Less: Government assistance	(23 000)	(23 000)	
Return after the government assistance	**(9 874)**	**(10 054)**	**(180)**

7.2.2 Moreover, Eskom has applied for a depreciation variance of R8 128m in favour of the customers, as shown in Table 9 below. Eskom indicated that this was mainly due to lower transfers to commercial operation.

Table 9: Depreciation variance

Depreciation	Decision FY2022	Actual FY2022	Variance
Fixed assets - DRC Values	53 005	52 998	(7)
Fixed assets - Transfers to CO	14 849	8 843	(6 005)
New Investments (Asset purchases)	576	550	(26)
Assets funded by customers upfront	(4 132)	(4 241)	(109)
Depreciation per the RAB calculation	**64 299**	**58 151**	**(6 147)**
Additional depreciation per Table 1 of the RfD	1 980	0	(1 980)
Total Depreciation per Table 1 of the RfD	**66 279**	**58 151**	**(8 128)**

Approach/methodology used

7.2.3 Section 9 of the MYPD4 Methodology details the 'Criteria for including an asset in the asset base for the depreciation and return purposes.

7.2.4 In calculating the average RAB value used to determine the return, it must be considered that the RCA consists of the following aspects:

a) Depreciated Replacement Cost (DRC), which is a Modern Equivalent Asset Valuation (MEAV) times the (remaining economic life of a plant divided by the total economic life of the plant).
b) Asset Purchases (New Investments), which include items such as acquisition of vehicles, IT equipment, workshop and furniture equipment, among others.
c) Work Under Construction (WUC), which is the Capital Expenditure that consists of material and direct labour and any cost directly attributed to the creation of an asset, if the construction period will be for a duration of more than twelve months.
d) Working capital, which refers to trade receivables, reasonable incurred future fuel, less trade payables required for the operation of the regulated business
e) Assets funded by customers upfront, which are assets that are excluded from the RAB because they are funded upfront via customers' contributions and some by the Department of Mineral Resources and Energy (DMRE).

Table 10: Return calculation

RAB Summary (R'millions)	NERSA 2021/22 decision	Eskom actual 2021/22	Variance	NERSA Adjustment	NERSA RCA 2021/22 decision
Depreciated Replacement Costs (DRC)	462 484	462 521	37	0	37
Completed assets after FY2016/ transfers from WUC	378 271	255 325	(122 946)	0	(122 946)
Asset purchases	2 305	2 200	(105)	(299)	(404)
Work Under Construction (WUC)	-25 414	106 415	131 829	(10 908)	120 921
Working capital	64 812	51 178	(13 634)	0	(13 634)
Assets funded by customers upfront	-27 103	(28 416)	(1 313)	0	(1 313)
Closing RAB	**855 355**	**849 223**	**-6 131**	**-11 207**	**-17 339**
Average RAB (A)	**874 865**	**863 043**	**(11 822)**	**(6 003)**	**(17 825)**
Return on Assets (ROA) (B)	1,5%	1,5%	1,5%	1,50%	1,5%
ROA before government assistance (C) = (A) X (B)	13 123	12 946	(177)	(90)	(267)
Return after Government assistance (E) = (C) + (D)	**13 123**	**12 946**	**(177)**	**(90)**	**-267**

7.2.5 Eskom applied for an adjustment of R11 822m in favour of the customers (closing RAB balance of R849 223m), while it is NERSA's decision to adjust the RAB by R17 825m (closing balance of R838 016m) as shown in Table 8. This resulted in a return of R267m awarded to customers when compared to the R180m that Eskom applied for as shown in Table 8. These adjustments that make up the RAB awarded are discussed below. These are not revenue adjustments, but adjustments that contribute to the revised return.

7.2.6 In its application, Eskom used an amount of R875 039m to reflect the NERSA MYPD4 decision, which is in line with Table 2 of that decision. However, the correct decision is that of R874 865m, in line with the RAB section in the MYPD4. NERSA used the R874 865m average RAB value to correct the original capturing error in Table 2 of the MYPD4 decision.

7.2.7 NERSA is satisfied that the actual balances applied for by Eskom closely resemble the original 2021/22 NERSA decision and are lower in many instances, with the exception of asset purchases and WUC. These adjustments are discussed below.

7.2.8 In the MYPD4 revenue determination, the approach adopted was that fixed assets must be used and usable, which means that assets must be in a condition that makes it possible to supply electricity within 12 months according to the MYPD4 Methodology. Furthermore, the methodology states that fixed and other assets that are not used and/or in a useable form do not qualify to be part of the RAB.

Asset Purchases

7.2.9 As part of the prudency assessment, NERSA verified the actual movements for asset purchases using the additional information submitted by Eskom 29 August 2023. These amounted to R1 901m and not R2 200m, as indicated in Table 58 on page 97 of Eskom's application.

Table 11: Actual Capex of asset purchases for FY2021/22

New investment- Asset purchase (R'm)	NERSA 2021/22 Decision	Origional Eskom Application	Revised Eskom Actuals	Origional Variance	Adjustment	RCA 2021/22 decision
Opening balance	2 303		1 957			-346
Capital expenditure excluding IDC, property plant & future fuel	578		418			-160
Depreciation	-576		-475			101
Closing asset values	**2 305**	**2 200**	**1 901**	**-105**	**-299**	**-404**

7.2.10 There was a discrepancy between the Eskom application and the spreadsheets submitted as additional information, as the numbers did not correspond. The asset purchases were adjusted down to R1 901m in line with the additional information submitted by Eskom, as shown in Table 11 above. The R1 901 comprises the following: Gx = R65m, Tx = R290m and Dx = R952m. NERSA's decision is to allow a variance of R404m instead of R105m in favour of customers.

Work Under Construction (WUC)

Table 12: Total WUC

Total WUC (R'm)	NERSA 2021/22 Decision	Eskom Actual	Variance	Adjustment	RCA 2021/22
Opening balance	24 544	138 148	113 604	0	113 604
Written off both impairment and others (AFS Note 9)	0	-516	-516	0	-516
Capital expenditure excluding IDC, property plant & future fuel	15 716	27 132	11 416	-11 282	134
Transfers to commercial operation (CO)	-65 673	-57 975	7 698	0	7 698
Closing asset values	**-25 413**	**106 789**	**132 202**	**-11 282**	**120 920**

7.2.11 Eskom applied for a WUC closing balance of R132 2020m and NERSA's decision is to award R120 920m due to adjustments of R11 282m. To determine the closing balance for the WUC, the opening balance has been adjusted to reflect additions to the RAB in the form of prudently incurred capital expenditure and net of reductions in the form of transfers to capital expenditure, as shown in **Table** 12 above. The capital expenditure (Capex) has been adjusted by a cumulative amount of R11 282m (from Generation [Gx], Transmission [Tx] and Distribution [Dx]), which is made up as set out below.

Generation Capex

Table 13: Total Generation Capex

Total Generation Capex (R'm)	NERSA 2021/22 Decision	Eskom Actual 2021/22	Variance	Adjustment	RCA 2021/22 decision
New Build and major Projects	1 983	11 698	9 715		9 715
Outage capex		7 291	7 291	-7 291	0
Technical Plan capex		2 971	2 971	-2 971	0
Renewables capex		0	0		0
Land and rights		0	0		0
Nuclear future fuel		552	552	-552	0
Coal and water future fuel		1866	1 866	-1866	0
Asset purchases		133	133		133
Other		0	0		0
Closing asset values	**1 983**	**24 511**	**22 528**	**-12 680**	**9 848**

7.2.12 Eskom applied for Generation Capex of R22 528m. NERSA's decision is to award R9 848m, meaning R12 680m was disallowed. This is because future fuel has been disallowed, as this has already been catered for under working capital.

7.2.13 Furthermore, it is NERSA's decision to disallow the R7 291m and R2 971m for Outage and Technical Plan Capex, respectively, because this is an expenditure relating to maintenance and is defined as the replacement of assets to ensure network stability; it is not a creation of additional capacity. Section 9.6.4.1 of the MYPD4 Methodology states that 'The WUC projects to be included in RAB are with respect to the creation of additional generation, transmission and distribution capacity'.

Transmission Capex

7.2.14 Transmission applied for a Capex variance of R6 226m in favour of customers in its 2021/22 RCA application. NERSA disallowed a refurbishment of R640m. The NERSA decision is to allow R6 866m in favour of customers, as shown in **Table** 14 below.

Table 14: Transmission Capex

Eskom Transmission Capex (R'm)	NERSA 2021/22 Decision	Eskom Actual 2021/22	Variance	Adjustment	2021/22 decision
Strengthning and Expansion	9 000	2 296	-6 704	0	-6 704
Refurbishment	0	640	640	-640	0
EIA and Servitudes	232	72	-160	0	-160
Asset purchases	19	17	-2	0	-2
Total	**9 251**	**3 025**	**-6 226**	**-640**	**-6 866**
Eskom adjustment (Asset purchase adjustment			0		0
Total Transmission Capex included in RAB	**9 251**	**3 025**	**-6 226**	**-640**	**-6 866**

Strengthening and Expansion Capex

7.2.15 The Energy Regulator approved R2 296m for the strengthening and expansion of the grid as applied for by Eskom Transmission.

7.2.16 The Capex was allowed, because it met the requirements of section 9.6.4.4 of the MYPD4 Methodology, as Transmission provided a 'disaggregated Capex with full details on the activities to be undertaken'.

7.2.17 In the RCA application, Eskom Transmission provided a list of assets completed and commissioned during this control period, which include a total of 161.5 kilometres (km) of transmission lines and 815 Megavolt Ampere (MVA) of transformer capacity.

7.2.18 A prudency assessment was conducted for Transmission's strengthening and expansion Capex, as indicated in Table 15 below, to ensure that the lines and transformation equipment had been built in accordance with the cost allocations provided in the Energy Regulator's MYPD4 decision. This test was conducted by NERSA by comparing the MYPD decision average cost per km of line and the average cost per MVA to the RCA's average costs.

Table 15: Prudency assessment on strengthening and expansion Transmission Capex

Prudency Assessment for Transmission Strengthening & Expansion		
Transmission Strengthening & Expansion Capex		RCA FY2022
Strengthening & Expansion (R'm)	**A**	**2 296**
Assets planned to be constructed:		
Lines Assets (km)	C	161
Transformation Assets (MVA)	D	815
Average Asset Creation Costs:		
Average cost per km of line (Rm)	E	4.316
Average cost per MVA (Rm)	F	2.158
Total average Asset Creation Costs:		
Lines Asset Creation Cost (Rm) = C*E		694.876
Transformation Asset Creation Cost (Rm)=D*F		1758.77
Total Average costs for Srengthening & Expansion Capex (R'm)	**B**	**2453.646**
Variance (A - B)		**-158**

7.2.19 The prudency assessment results revealed that the Transmission division completed, commissioned and installed assets below the average values used to build lines as approved during the MYPD approval stage and installed transformation assets by R158m, as B is greater than A in the prudency assessment results (shown as variance).

EIA and Servitudes, including Asset Purchases

7.2.20 NERSA allowed the Environmental Impact Assessment (EIA) and Servitude amounting to R72m as applied for by Eskom, because Eskom was greatly dependent on negotiation agreements between Eskom and the affected landowners. Out of the R72m, R64m was used to acquire servitudes for lines, and R9m was used to acquire land for substations.

7.2.21 Furthermore, NERSA allowed asset purchases of R17m, as this was used as part of Transmission capacity creation. These include asset-related equipment for conducting tests, information technology (IT) assets, assets related to transportation and special-purpose vehicles.

Refurbishment Capex

7.2.22 Section 9.6.4.1 of the MYPD4 Methodology was used as a yardstick to evaluate the Transmission Capex. As a result, the R640m for refurbishment was disallowed, because this section of the MYPD4 Methodology only allows WUC projects to be included in the RAB if those projects relate to the creation of additional Transmission capacity.

7.2.23 In addition, section A.1.5.2(L) of the South African Transmission Tariff Grid Code (which is a licence condition) only allows Eskom Transmission to recover the cost of refurbishment of standard connection assets through Transmission Use-of-System (TUOS) charges and the cost of refurbishment of premium connection from a new set of connection charges.

7.2.24 Section A.1.5.2(L) of the South African Transmission Code affirms that the cost of refurbishment must be disallowed from the Transmission Capex.

Distribution Capex

7.2.25 Eskom applied for a Distribution Capex variance of R2 457m in favour of customers. It is NERSA's decision to approve R2 799m in favour of customers, as shown in Table 16 below. The adjustments are discussed below.

Table 16: Distribution RAB summary

Eskom Dx Capex	NERSA 2021/22 Decision	Eskom Actual 2021/22	Variance	Adjustment	2021/22 decision
Direct customers	1 671	955	-716	0	-716
Strengthening (75%)	2 750	479	-2 271	0	-2 271
Refurbishment	0	298	298	-298	0
Land & Rights	80	14	-66	0	-66
IPP new connections	0	44	44	-44	0
Asset Purchase	389	643	254		254
Customer service	0				0
Total Transmission Capex included in RAB	**4 890**	**2 433**	**-2 457**	**-342**	**-2 799**

Direct Customer Capex

7.2.26 The Energy Regulator will allow the direct customer Capex of R955m as applied for by Eskom Distribution because Eskom Distribution used this Capex to connect end-users supplied by Eskom. These include customer categories such as:

a) new customer connections in the small to medium category.
b) customers willing to pay for the required incremental load; and
c) constrained network that are strengthened upstream to facilitate direct customer connections.

Strengthening Capex

7.2.27 Eskom Distribution did not provide the actual number of kilometres of lines it built, including the additional capacity, in terms of MVA transformer capacity. However, during the actual MYPD4 application, Eskom Distribution forecast that it would build 1 974 km of distribution lines for FY2021/22 at different voltage levels.

7.2.28 Therefore, as part of the prudency assessment, NERSA used a different approach from the one used for Transmission. However, it must be noted that the kilometres used for the RCA calculation were provided for the MYPD4 NERSA decision (i.e. they are not actual values provided by Eskom Distribution).

Table 17: Distribution Capex trend

Distribution Capex (R'm)	MYPD4 NERSA Decision			NERSA RCA Decision FY2022
	2019/20	2020/21	2021/22	2021/22
Direct Customers	1440	1570	1671	955
Strengthening (75%)	2400	2750	2750	479
Refurbishment	0	0	0	0
Land & Rights	70	75	80	14
IPP Connections	0	0	0	0
Total Capex for WUC	**3910**	**4395**	**4501**	**1448**
Total kilometres	1719	1986	1974	1791
R/km	**2,27**	**2,21**	**2,28**	**0,81**
Average	2,26			

7.2.29 From the above analysis, the R/km to build a line is within the range of R2.26/km used in the MYPD4 decision. As a result, the total WUC of R1 448 million was allowed, as shown in Table 17 above.

Land and Rights

7.2.30 NERSA decided to allow R14 million for land and rights as applied for by Eskom Distribution, because Eskom was greatly dependent on negotiation agreements between Eskom and the affected landowners.

Refurbishment Capex

7.2.31 Section 9.6.4.1 of the MYPD4 Methodology was used as a yardstick to evaluate Distribution Capex. As a result, the R298 million for refurbishment was disallowed, because the MYPD4 Methodology only allows WUC projects to be included in the RAB if those projects relate to the creation of additional Distribution capacity.

IPP Connection Capex

7.2.32 The Energy Regulator's MYPD4 decision disallowed Independent Power Producer (IPP) Capex of R44m because such Capex should be recovered from IPPs and not form part of the Distribution Capex.

7.2.33 In its RCA application and justification, Eskom Distribution is contesting that it requires this Capex to create shared network infrastructure. It further states that the required funding is for the related upstream strengthening projects, which are borne by the Distributor in line with the Grid Code requirements.

7.2.34 However, the NERSA analysis conducted in line with section 9.7 of the connection charge approach of the Distribution Tariff Code, version 6.2 of January 2022, states the following on how the upstream strengthening should be treated, and the charge type applicable, as set out in Table 18:

Table 18: Upstream assets treatment

Asset	***Asset boundary***	***Definition***	***Cost determination***	***Charge type***
Upstream assets	*Beyond point 'C'*	*Assets used for the benefit of many customers and that cannot be directly allocated to one or an identified group of customers. Assets that deliver system wide net benefits and are based on least-cycle economic cost (refer to section 7.2.3 of the Dx Network Code).*	*Shall be recovered from all customers. An Early Termination Guarantee shall be raised*	*Use of System Charges + Early Termination Guarantee*

7.2.35 In conclusion, it would result in double counting if IPP Capex as applied for is allowed to form part of Distribution Capex, because there is already a mechanism for Eskom Distribution to recover such Capex from IPPs.

Net Working Capital

7.2.36 Eskom applied for a net working capital variance of R13 633m in favour of customers, and it is NERSA's decision to approve it as applied for.

Table 19: Net working capital

Total Net Working capital	**2021/22 Decision**	**Actual 2021/22**	**Variance**	**Adjustment**	**2021/22 decision**
Invetory	49 576	47 681	-1 895	0	-1 895
Debtors	27 077	28 074	997	0	997
Future fuel	9 839	6 304	-3 535	0	-3 535
Creditors	-21 681	-30 881	-9 200	0	-9 200
Closing working capital balance	**64 811**	**51 178**	**-13 633**	**0**	**-13 633**

Depreciation

7.2.37 Eskom applied for depreciation adjustment of R8 128m in its RCA application in favour of customers. It is NERSA's decision to allow the depreciation as applied for, as the depreciation has been reduced to align with transfers to commercial operation that is lower than initially planned. This was mainly driven by less than projected transfers to commercial operation of fixed assets. Significant variances

in the commissioning of Eskom's Generation, Transmission and Distribution capital projects occurred during the MYPD4 period, where the actuals were lower than the decision by R80.2bn.

7.2.38 Eskom indicated that the reasons for this were that it had reprioritised capital expenditure due to the shortfall in the revenue decision, challenges with timeous authorisations, challenges with the availability of skilled contractors and Eskom's project management and procurement processes.

7.2.39 NERSA has decided to allow a depreciation amount of R8 128m in favour of customers as applied for by Eskom. In accordance with sections 9.3 and 17.2.6 of the MYPD4 Methodology, a depreciation amount of R8 128m will be clawed back in favour of customers. Section 9.3.1 on regulatory depreciation and return on the RAB provides the regulatory mechanisms under which capital investment costs are recovered on a cost-reflective basis over the course of its economic/regulatory economic life. Section 9.3.2 states 'In line with the EPP, full cost reflectivity with respect to depreciation and return on assets cost recovery will be implemented over a reasonable period to allow Eskom reasonably priced funding for investment'. According to section 9.3.3, 'The Energy Regulator will, however, apply reasonable regulatory judgment in balancing between the need to smooth price increases, allowing the licensee a reasonably cost reflective return on investment, and preventing excessive or inadequate returns. Section 17.2.6 of the MYPD4 Methodology states as follows: '17.2.6.1 Certain aspect of RAB will have to be forecasted at the beginning of the MYPD cycle. Therefore, the value of RAB that earns a return will change/deviate from the forecast in line with global market factors such as exchange rates, availability and costs of financing, and costs of key inputs.' Section 17.2.6.2 states 'To accommodate the unstable environment, the approach for adjusting RAB for cost and timing variances will be as follows: a) Eskom will annually report to the Energy Regulator on its capital expenditure programme, providing information on timing, cost variances and reasons including reconciliations. b) The Energy Regulator will then assess the capital expenditure variances under the following categories for each of Eskom's regulated businesses: I. Depreciation; ii. Net Working Capital; iii. WUC; and iv. Other Asset Movements (e.g. mothballing).' Section 17.2.6.3 provides that 'Eskom's actual capital expenditure will be assessed against MYPD original assumptions. As part of the submission of its Capital Expenditure Programme, Eskom will detail the reasons for the variances, after which the Energy Regulator will assess these for prudence.' Section 17.2.6.4 states: 'Any over-expenditure deemed prudent by the Energy Regulator will be allowed/added to the RAB to allow Eskom to recover additional returns. The opposite scenario where an under expenditure is recorded will be treated the same by deducting it from the RAB value to earn a lessor return.' According to section 2.6.5, 'Such variances can emanate from the categories listed

in 17.7.2.2'. Section 17.2.6.6 states 'This approach will ensure that Eskom is not allowed to earn undue returns on the delayed build, scrapped assets or any other variances that are as a result of Eskom's inefficiencies or decisions that are not in the original MYPD decision'. As a result of applying these sections of methodology, a depreciation amount of R8 128m will be clawed back in favour of customers.

Approach/methodology used

7.2.40 Section 17.2.6 of the MYPD4 Methodology, as detailed in the paragraph above, provides the RCA process. Section 9.2 of the MYPD4 Methodology, which references the basis of valuation of the RAB, was used in the analysis and adjustments of the regulatory assets base. Section 9.2.1 states:

Policy position 1 (a) of the Electricity Pricing Policy (Electricity Pricing Policy GN 1398 of 19 December 2008) states 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. The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that accurately reflects the replacement value of those assets such as to allow the electricity licensee to obtain reasonably priced funding for investment; to meet Government defined economic growth. In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator."

Stakeholder comments

7.2.41 AgriSA indicated that the divergence between Eskom's capital expenditure assumptions and NERSA's determinations underscores the significance of effective communication and coordination. The discordant evaluations accentuate the challenges arising from inadequate synchronisation between these regulatory bodies.

7.2.42 NERSA's view is that while the need for effective communication between NERSA and Eskom is acknowledged, this must be done in a manner that would not be perceived to be regulatory capture.

7.2.43 AgriSA further indicated that the disallowed generation Capex poses substantial challenges for Eskom, especially in light of NERSA's suggestion to seek 'other sources' for funding. The lack of clarity regarding these 'other sources' points to a pressing concern regarding communication and coordination between NERSA and Eskom.

7.2.44 NERSA's analysis of the comment is that NERSA disallowed the Outage and Technical Plan Capex, respectively, because these are expenditures relating to maintenance and are defined as the replacement of assets to ensure network stability, not the creation of additional capacity. Section 9.6.4.1 of the MYPD4 Methodology states that the only WUC projects to be included in the RAB are those relating to the creation of additional generation, transmission and distribution capacity. The Methodology already allows for maintenance costs to be claimed by Eskom – these are the other sources. The MYPD4 decision might not have been clear in that regard.

7.2.45 Depreciation was significantly below target (R8.1bn). A smaller transfer of Capex was made into commercial operations (which speaks directly to the excessive use of Open Cycle Gas Turbine (OCGT) capacity, as insufficient base-load energy was available).

7.2.46 This is an adjustment in favour of the consumer. While BUSA has not made an adjustment, there is a case to be made for a smaller adjustment in favour of the customer if the suggested OCGT principle is followed, as this would imply that additional expenditure would have been capitalised in productive capacity.

7.2.47 When the MYPD4 decision was made, a certain level of depreciation was assumed. However, the figure did not materialise, hence the clawback in favour of customers. Allowing anything above the actual amounts would be imprudent and result in undue or excess revenues to Eskom to the detriment of the customers.

Conditions for approval

None.

7.3 OPERATING EXPENDITURE

Summary of the application

7.3.1 Section 17.2.7.1 of the MYPD Methodology states, 'In determining over- and under-expenditure, the Energy Regulator will consider controllable and non-controllable elements of the operating costs. This is to ensure that Eskom minimises the costs that are under its control and to encourage it to reduce those that are not under its control'.

7.3.2 Allowable expenses relate to all expenses incurred in the production and supply of electricity. These costs include normal operating expenditure, maintenance

(excluding refurbishment costs that must be capitalised), manpower or labour costs, and overheads (centrally administrative and general expenses allocated) that are normally recovered within one financial year. This excludes Integrated Demand Management (IDM), which is treated separately for RCA purposes.

Table 20: Eskom's application

Allowed operating costs (Rm)	Decision FY2022	Actual FY2022	Variance	RCA adjustments	RCA FY2022
Employee benefits	21 879	24 040	2 160	-	2 160
Maintenance	17 337	19 101	1 764	-	1 764
Other Opex	9 740	17 455	7 715	(1 377)	6 339
Arrear Debt	1 457	9 865	8 408	(8 448)	(40)
Corporate Services	9 046	4 376	(4 670)	-	(4 670)
Other income	(1 301)	(872)	429	-	429
Less: IDM, R&D and Corporate Social Investment	(1 139)	0	1 139	-	1 139
Total Allowed opex	**57 019**	**73 966**	**16 947**	**(9 825)**	**7 122**
Research & Development Costs (R&D)	151	149	(2)	-	(2)
Operating costs including R&D	**57 170**	**74 115**	**16 945**	**(9 825)**	**7 120**

7.3.3 Table 20 above captures the summary of Eskom's application for operating costs. The overall operating cost variance is in favour of Eskom. All elements of the operating costs, with the exception of Corporate Services, illustrate variances in favour of Eskom.

7.3.4 Within the employee benefits category, the number of employees has decreased over the financial year. This is an area where further efficiencies have been achieved over the financial year. However, due to the nature of the original employee benefit revenue decision and collective bargaining agreements over multiple years with Eskom's bargaining unit employees, the resulting employee benefit costs did not see a concomitant decrease.

7.3.5 Maintenance variances in favour of the consumer were observed due to various factors, such as delays in placing maintenance contracts because of COVID-19 lockdown restrictions. These are conditions within Eskom's control in delivering its maintenance programmes, hence Eskom is applying for R1.7m in its favour. Significant variances were also experienced within Corporate Services for the benefit of consumers. These variances are discussed in detail below.

Employee Benefit Costs

Summary of the application

Table 21: Summary of employee costs

R'm	2022 Decision	Actual	Variance
Employee Costs	21 879	24 040	2 161

7.3.6 The employee benefit costs comprise direct remuneration (salary, pension, medical aid, bonus and overtime) and indirect remuneration (training and development, and remuneration of temporary and contract staff).

7.3.7 Employee benefit costs are the manpower costs incurred by Eskom in its Generation, Transmission and Distribution businesses. Eskom is applying for R2 161m for employee benefit cost variance, in its favour as shown in Table 21. These costs exclude those costs that were included under corporate overheads in

7.3.8 Table 20 above.

7.3.9 Eskom indicated that in the Generation restructuring and divisionalisation process, employees in Corporate Services and Support functions were relinked to line functions. Ultimately, the aim of the relinking process was to:

a) strengthen operations and maximise decision-making.
b) improve levels of accountability at the right levels of business.
c) improve operational and financial efficiencies.
d) maximise execution of strategy; and
e) improve productivity and value delivery – shortest sustainable lead time.

7.3.10 Employees from Technology, Risk and Sustainability, Procurement, Finance, Security, Environmental Management, Safety, Quality, Properties, and Human Resources – Generation Academy of Learning were relinked to Generation.

7.3.11 It was further indicated that Generation workforce optimisation has been identified as a major component for driving internal efficiencies. The increase in Generation employee numbers was mainly as a result of the relinking of staff and external appointments. The relinking of employees had an impact on the direct cost of employment in Generation, as this had not been anticipated at the time of the MYPD4 application.

7.3.12 Eskom also indicated that growth in Transmission employee expenses is mainly as a result of an increase in employee numbers as an outcome of the organisational restructuring implemented since the 2019/20 financial year. This relinking and resourcing of key functions was only concluded during FY2021/22.

7.3.13 At Distribution level, Eskom stated that the network is currently operating under challenging conditions due to the age of the network and ongoing support to the electrification programme. It is essential for the Distribution licensee to build capacity, with motivated and high-performing work teams to respond to current and future needs. The sustainability of the Distribution business depends on its

ability to create, develop and maintain a reliable and flexible network to meet customer demands.

7.3.14 Eskom indicated that employees are engaged in providing a service to the customer, operating and maintaining the electrical network and associated infrastructure. This is to ensure compliance with Eskom's conditions of supply, while providing sustainable supply of electricity to all South Africans.

NERSA Analysis

7.3.15 Table 22 below shows the actual amount of R23 997m spent during the 2021/22 financial year, the amount of R23 204m as initially applied for, and the NERSA decision of R21 879m. The table further shows the number of employees in FY2021/22, and the corresponding number of employees applied for.

7.3.16 There is an increase of 11.6% in the number of employees compared to the number of employees applied for. As shown in Table 22 , Eskom Transmission's staff has increased by 44%, followed by Generation at 12% and Distribution at 8%. Eskom indicated that the increase in the Transmission staff complement was due to staff relinking in FY2021/22.

Table 22: Employee costs per licensed business

	Employees costs per business				Number of employees		
R'million	Decision FY 2022	Application FY 2022	Actual FY2022	Variance	Application FY 2022	Actual FY 2022	% Change
Generation		10 527	10 595	68	11 422	12 792	12%
Transmission		1 644	2 134	490	1 802	2 593	44%
Distribution		11 033	11 268	235	16 027	17 254	8%
Sub Total	21 879	23 204	23 997	2 118	29 251	32 639	11,6%
SAE			22				
DSM			21				
Total incl SAE &DSM			**24 040**				

7.3.17 Figure 4 below shows the employee costs and head count over a six-year period for the Generation, Transmission and Distribution businesses.

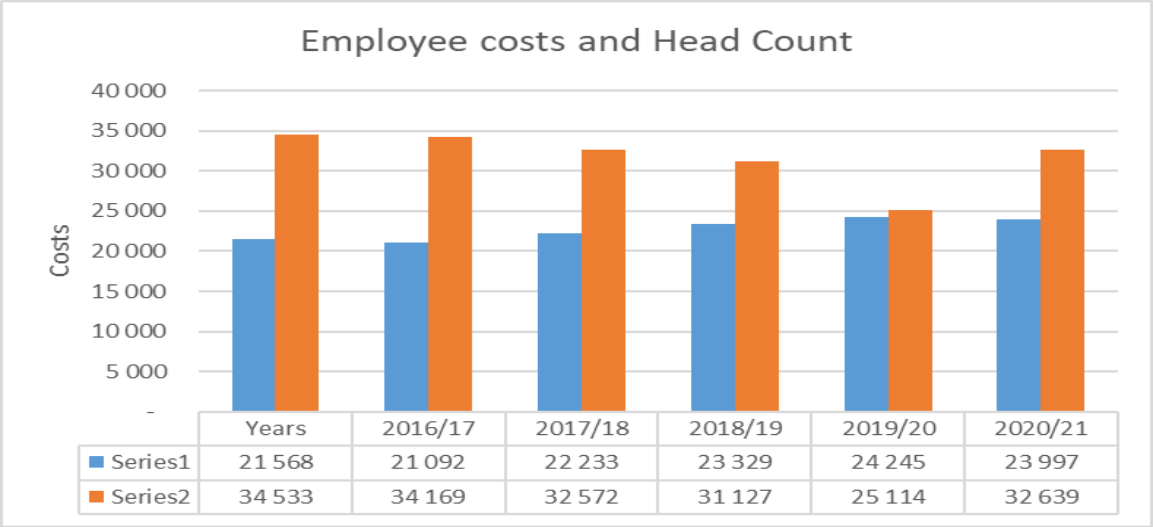

Figure 4: Employee costs over a four-year period

7.3.18 In FY2021/22, the Energy Regulator decided that an amount of R21.8bn would be allowed for employee costs for the three businesses. NERSA has observed Eskom's performance under employee benefit costs as per the table below. Eskom's expenditure performance is not aligned with NERSA's decision, and the gap is widening. Table 23 below demonstrates the costs for each business over the six-year period.

Table 23: Costs per business

	Emplyee costs	Actual	Actual	Actual	Actual	Actual	Actual
	Years	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Busness	Generation R'm	9 733	9 592	9 873	10 283	10 705	10 595
	Transmission R'm	1 558	1 413	1 561	1 729	2 059	2 134
	Distribution R'm	10 277	10 087	10 799	11 317	11 481	11 268
	Total Emplyee cost	21 568	21 092	22 233	23 329	24 245	23 997

7.3.19 Table 24 below demonstrates the number of employees for each business, the contribution of each business to the total business, and the percentage change when comparing the actual and application amounts.

Table 24: Number of employees per business

Staff Complement	Actual 2016/17	Actual 2017/18	Actual 2018/19	Actual 2019/20	Actual 2020/21	Application 2021/22
Generation	12 940	12 986	11 939	11 685	12 580	12 010
Transmission	2 169	2 182	2 111	2 084	2 523	1 851
Distribution	19 424	19 032	18 250	17 358	17 254	16 841
Total Headcount Exl Corporate	**34 533**	**34 200**	**32 300**	**31 127**	**32 357**	**30 702**
% increase/ drecrease		**-1%**	**-6%**	**-4%**	**4%**	**-5%**

7.3.20 From the table above, it can be concluded that the number of employees is decreasing, which corresponds with the declining costs, although the decrease in costs is not significant.

Approach/methodology used

7.3.21 Section 10.4.2 of the MYPD4 Methodology states that 'manpower costs should be allowed in accordance with the allowable revenue; any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges.

7.3.22 As shown in Table 25 below, NERSA has decided to maintain its decision of R21 879m for FY2021/22. However, to allow for inflation adjustment, the amount has been adjusted by 4.6% according to BER's actual inflation as for the year 2022 plus betterment of 2.3%. This has resulted in a revised NERSA decision of R23 389m form original decision of R21 879 before adjusting for inflation. Given the applied for variance of R2 161m, the NERSA-approved decision will be R 1 510m after effecting adjustments of R651m. This is to align with the Methodology requirement that any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges.

Table 25: Employee costs decision based on Inflation adjustment

Employee benefits costs(R'm)	Eskom Application(a)	NERSA Allowed(b)	NERSA allowed inflation adjuste	Variance between Eskom Application and NERSA decision	NERSA decision Inflation Adjusted
Inflation adjustment	24 040	21 879	23 389	- 651	23 389
Decision	2 161			- 651	1 510

Stakeholder comments

7.3.23 None.

Conditions for approval

7.3.24 None

Maintenance

Summary of the application

7.3.25 The RCA application for maintenance for the Generation, Transmission and Distribution businesses amounts to a total of R1 764m to the benefit of Eskom. Generation was the driver of the cost various, and this had been the case in the previous year. Eskom applied for R18 536m for maintenance for FY2021/22 and was allowed R17 337m. However, the actual maintenance costs for FY2021/22

have come to R19 101m, as per the application. The variance is R1 764m for the benefit of Eskom, as shown in Table 26 below.

Table 26: Summary of maintenance cost application

Maintenance costs (R'm)	Application FY2021/22	Decision FY2021/22	Actual FY2021/22	Variance
Generation	11 719	10 520	14 695	4 175
Transmission	902	902	770	-132
Distribution	5 915	5 915	3 637	-2 278
Total	**18 536**	**17 337**	**19 101**	**1 764**

7.3.26 Table 26 above shows Eskom's summary of the maintenance cost application. The Generation maintenance cost allowed for FY2021/22 in the MYPD 4 was R10 520m. However, the actual maintenance cost was R14 595m. This amount is due to the use of the Hendrina, Komati and Grootvlei power stations and higher costs (more than double) for the Kusile and Medupi power stations. This causes the variance to be R4 175m, for the benefit of Eskom, which is the RCA amount applied for Generation maintenance.

7.3.27 For Transmission, there is a maintenance cost variance of R132m, for the benefit of the customer. Eskom applied for an amount of R902m, which was allowed in full, however, the actual cost is R770m. Transmission spent less on maintenance due to failure in securing servitudes and performing less than planned line maintenance. They also performed less than planed high voltage (HV) plant maintenance and there were delays in the conclusion of servitude maintenance contracts, as result of delays in procurement processes.

7.3.28 Distribution also experienced delays in placing of maintenance contracts due to COVID-19 lockdown restrictions. Therefore, there is a variance of R2 278m, for the benefit of the customer, from the applied for and allowed amount of R5 915m, and the actual spend of R3 637m.

NERSA Analysis

Generation

7.3.29 In its application, the EAF target for FY2021/22 was 73.5% for the Generation fleet, however, it only achieved 61.77% for FY2021/22. Eskom reasons that this is due to assumed system capacity that did not materialise and that the revenue applied for was not awarded, thus limiting the available funds, which resulted in running at high utilisation factors, and subsequently increasing wear. This, in turn,

manifested in a higher Unplanned Capacity Load Factor (UCLF) and, thus, a lower EAF.

7.3.30 System capacity that did not materialise should have been mitigated by allowing room for maintenance instead of running units until they wear out, as this will require even more maintenance costs. Multiple load-shedding periods experienced during this MYPD4 period were a good opportunity for carrying out maintenance. It was then assumed that maintenance was carried out, hence the reasoning that there was less maintenance due to a lack of system space does not apply.

7.3.31 To answer the question, is Eskom allowed to conduct load-shedding and is it to the benefits of Eskom and its customers? Eskom operates power stations to ensure that the lights are kept on, as far as possible, until power stations become unsafe to operate due to wear, which is when maintenance is prioritised and scheduled. This is in line with clause 2.1.1(1) of the System Operating Code regarding System reliability and safety. Clause 2.1.1(10) also states 'The System Operator may shed customer load to maintain system integrity.'

7.3.32 Therefore, it can be confirmed that Eskom can schedule maintenance that will result in load-shedding.

7.3.33 The issue of lack of funds is also not a valid argument, because Eskom applied for R11 719m and was allowed R10 520m, which is a difference of only about 10.3%, whereas the actual over-expenditure was about 40%. Therefore, even if Eskom had been allowed what it had applied for, it would still have overspent. This means that the reason for not carrying out maintenance was not that funds were not available, but that planning had not been done or funds had been used inappropriately.

7.3.34 Kusile and Medupi power stations are the newest stations in the Eskom fleet, however, they have the highest maintenance costs. As indicated in Table 27 below, their actual costs are more than double the allowed costs.

7.3.35 Eskom explains that Medupi and Kusile's maintenance costs result from a combination of plant design and construction defects, and operational and maintenance inefficiencies, which is why the two stations have low levels of performance and reliability.

7.3.36 If this is true, then Eskom must take the blame because it appointed the contractor for plant design and construction. All the defects should have been the contractor's responsibility, as its product must meet the owner's specifications

before the plant handover. All these issues should be dealt with during contracting, and specific clauses are used to safeguard against what is currently happening at the two stations. Therefore, it is determined that the exorbitant maintenance costs for these stations should not be paid for by the customer, and they are not allowed.

7.3.37 Overspending of such huge proportions can only be because of a lack of or poor maintenance and maintenance planning. This is supported by outage overruns and breakdowns that happen shortly after the plants have been brought back from outages. Therefore, it cannot be allowed.

7.3.38 At some power stations, maintenance costs were incurred to produce more energy to reduce reliance on OCGTs and the effects of load-shedding. This benefited both the customers and the economy, because less costly energy was used in these instances, and the load-shedding ensured that the economy did not suffer more than it would have.

7.3.39 However, in some instances, the maintenance cost, especially for Kusile and Medupi, has resulted from contracts that do not include rigorous clauses that ensure that Eskom is not exposed to risks of a dysfunctional station and a lack of maintenance competency. This is based on Eskom's admission that it is a learning process, and it is developing measures to address issues at these stations. Therefore, these costs were not prudently incurred and are not allowed.

Table 27: Generation maintenance costs

Generation maintenance cost (R'm)	Decision FY2022	Actuals FY2022	Variance
Kusile	443	1 070	627
Medupi	259	1 518	1 259
Duvha	853	1 185	331
Kendal	930	1 106	176
Lethabo	687	791	103
Majuba	814	861	47
Matimba	514	638	124
Matla	770	1 186	415
Tutuka	773	700	(73)
Arnot	785	804	18
Camden	818	818	
Grootvlei	-	485	485
Hendrina	-	815	815
Komati	-	222	222
Kriel	727	1 318	591
Koeberg	1 890	1 178	(713)
Peaking	209	209	
Renewables	33	19	(14)
Group Capital	-	(209)	(209)
Head office	7	(17)	(25)
Total Maintenance costs	**10 515**	**14 695**	**4 180**
* *Balancing*	5		
Total Maintenance costs	**10 520**	**14 695**	**4 175**

7.3.40 Eskom does not explain in detail why the cost for Generation maintenance is much higher than budgeted. The only explanation given is the important reasons for the inability to meet the country's electricity demand consistently, which in turn have led to load-shedding and high OCGT usage. It lists these as:

a) inadequate installed capacity nationwide.
b) Poor performance of the Generation coal fleet, evidenced by the low EAF due to inadequate national capacity occurring from around 2003; and
c) insufficient funds to perform the required maintenance due to the sub-cost-reflective revenues.

Transmission and Distribution

7.3.41 Transmission and Distribution did not perform maintenance as anticipated due to the delays in the contract placing process. Many of the delays were related to the strict COVID-19 lockdown restrictions Eskom and the contractors faced, however, some level of maintenance had been carried out.

7.3.42 What is concerning about these divisions is that at a later stage, they might request much more maintenance funding because of the backlog in maintenance, which will push the maintenance costs to unacceptable levels. To prevent this from happening, Eskom must share its plans for undertaking this maintenance in the future and its projected costs to avoid steep changes in the cost of maintenance.

Approach/methodology used

7.3.43 Section 10.3 of the MYPD Methodology states:

Costs related to Operation and Maintenance (O&M) will be allowed. The reasonableness of such expenses will be determined by the Energy Regulator on a case-by-case basis.

7.3.44 Section 10.4.3 also states:

Expenses must be incurred in the normal operations and supply of electricity, including an acceptable level of repairs and maintenance costs.

7.3.45 NERSA uses these two clauses from the MYPD Methodology for the reasons stated below.

NERSA adjustments and reasons

7.3.46 The maintenance costs for Generation remains very high for most of the plants, especially for the newly built stations. The high costs do not reflect improvement in the reliability of the plants, and the EAF continues to decrease. Therefore, any further maintenance costs for Generation must not be allowed.

7.3.47 The reasons stated for the high costs of maintenance at new and some old stations are not provided in detail in order to support the amounts applied for. NERSA does not wish Eskom to see the high maintenance costs as the new normal.

7.3.48 The high maintenance costs for Kusile and Medupi, as shown in Table 31, are due to Eskom's failure to ensure that the contracts that it had entered into with contractors place the responsibility for defects and non-reliability of products with the contractors.

Table 28: Maintenance cost decision

Maintenance costs (R'm)	NERSA Decision (MYPD4 2021/22)	Eskom Actuals FY2022	Variance	NERSA Adjustments	RCA Decision FY2022
Generation	10 520	14 695	4 175	-4 175	0
Transmission	902	770	-132	0	-132
Distribution	5 915	3 637	-2 278	0	-2 278
Total	**17 337**	**19 101**	**1 764**	**-4 175**	**-2 410**

Stakeholder comments

7.3.49 Some stakeholders, particularly Agri Western Cape, agree that Generation maintenance is not at an acceptable level.

7.3.50 The Minerals Council South Africa was also concerned about the high maintenance levels, particularly for Generation. It also raised a concern regarding the Transmission and Distribution divisions not carrying out maintenance. Although the Minerals Council of South Africa did not mention its exact concern, it may refer to the higher-than-normal maintenance costs when Eskom decides to implement this maintenance.

Other Costs

Summary of the application

7.3.51 Operating costs include all costs involved in the day-to-day running of the business. The Licensee's operating costs have taken into account the importance of driving cost curtailment in line with the turnaround plan to reduce Eskom's cost base. These initiatives are expected to contribute to Eskom's overall financial sustainability.

7.3.52 Eskom is applying for other costs variance of R6 339m as shown in Table 29 below. This amount includes the three regulated businesses, namely Generation, Transmission and Distribution.

Table 29: Other costs

Other Costs (R'm)	NERSA Decision MYPD4 2021/22	Eskom's Actuals FY2022	Variance	RCA Adjustments	RCA FY2022
Other Costs	9740	17455	7715	-1377	6399

Source: Eskom application

Generation Business

Contractor Costs

7.3.53 The appointment of contractors is governed in terms of the Eskom Procurement and Supply Chain Management Procedure. The full details are outlined below.

7.3.54 The Procurement and Supply Chain Management Policy and the Procurement and Supply Chain Management Procedure are put into effect and maintained. This procedure describes the processes and procedures to be followed by the

Procurement and Supply Chain Management Department (P&SCM), employees, end-users and subject matter experts across the various operational areas within Eskom (including its subsidiaries) when procuring goods/works/services on behalf of end-users. The P&SCM strives to achieve customer satisfaction, efficiency and compliance within the regulatory framework in all transactions and to fulfil its strategic objectives and that of Eskom as a whole.

7.3.55 The purpose of the procedure is to ensure that the processes followed are legally, commercially, financially and technically sound, and that they support the constitutional principles of fairness, equitability, transparency, competitiveness and cost-efficiency.

7.3.56 This procedure provides the employees with clear procedural information, key controls, accountabilities and responsibilities required to execute the P&SCM's business processes to ensure the efficient and effective achievement of the P&SCM's mandate.

7.3.57 The P&SCM's mandate is to optimally, cost-effectively and safely manage the procurement and supply chain management of the organisation, so that it will be compliant with all relevant regulatory and legislative frameworks and:

7.3.57.1 have a clear line-of-sight over all external spend, including Eskom's wholly-owned subsidiaries; and

7.3.57.2 enable Eskom to achieve best in class capabilities in the areas of:

a) procurement,
b) inventory management,
c) warehousing and logistics,
d) supplier management and development,
e) contract lifecycle management.

Internal Electricity Revenue Consumption

7.3.58 Generation power station electricity accounts are treated similarly to external customers. The total value of Generation's internal electricity purchases comprises energy charges and other monthly charges.

Net Insurance Expense

7.3.59 Maintenance and asset renewal are good measures to treat the risk of failures due to an ageing plant. The net insurance expense could increase, considering the ageing generation fleet and postponed maintenance activities, as these increase plant risk.

7.3.60 Considering the severely constrained system (capacity and financial), Eskom cannot execute all the outages required to significantly improve the plant condition and, thus, performance. Eskom utilises a capacity planning process that optimises the planned outages continually based on the prevailing constraints and outage priority.

7.3.61 All statutory maintenance required in the 12-month planning period is accommodated in the plan. Due to the capacity constraints, this leaves little to no room to move, extend or add outages, or accommodate outage delays or major incidents/events. Outage delays on certain large machines can result in significant pressure on the system, and ultimately result in higher levels of load-shedding.

Travel and fleet costs

7.3.62 Travel expenses include local and international business travel undertaken by employees for the operational course of business, or to attend training or meetings on behalf of Eskom.

Fleet Management Services (FMS)

7.3.63 The Fleet Management Services is a single, centrally managed entity within the Eskom Shared Services Division that takes ownership of the total Eskom Fleet and integrates the total fleet management process within Eskom Holdings Ltd. Fleet Management Services operates on a break-even basis and recovers costs from clients (i.e. users).

Transmission Business

7.3.64 Transmission continues to embark on and promote operational cost efficiencies. Other operating costs are fixed in nature; therefore, increases are due to inflation. In FY2021/22, the increase in other operating costs is mainly due to the growth in staff complement (because of the organisational restructuring that began in FY2020/21), which has a direct impact on various cost categories, such as IT services, travelling and insurance premiums.

7.3.65 Most of Transmission’s substations are in remote areas where security reaction units are unavailable. Therefore, security guards and other technological systems are employed to mitigate the increased risk of copper theft and vandalism of facilities, as well as to preserve the integrity of assets and continuity of supply.

7.3.66 Transmission has experienced an increase in the number and severity of security incidents.

7.3.67 A Security Action Plan was developed, and it comprises key deliverables aimed at dealing with identified security threats within the Division. The key objectives of this action plan include the following:

a) Conducting Security Threat Assessments and Security Plans within the various business units (BUs)
b) Reviewing the current security strategy within various Transmission BUs
c) Developing the Transmission Security Nerve Centre (TSNC)
d) Ensuring security regulatory compliance
e) Implementation of the Intelligence and Investigation Contract at key high-risk sites to ensure intelligence gathering, arrests, convictions, syndicates, and scrap dealer profiling
f) Rolling-out of the Bernina-Hera security technology standard to the high-risk substations and radio sites across Transmission to ensure the deterrence, detection, delay and response to criminal incidents.

7.3.68 In addition to the Security Action Plan, the Division is also involved in the security quick-wins project that explores technology-based security solutions by installing all-in-one solution motion sensors that illuminate the area and have audible alarms when triggered. Because of its success, more units have been procured and will be installed at selected high-risk substations.

7.3.69 Furthermore, the following measures were put in place on different grids to decrease the number of incidents.

Changing of clocking points

7.3.70 The common practice within the different grids was that the clocking points would be scattered around the perimeter fence. However, this practice has yielded negative results. It was then recommended that the clocking points be situated around the HV yards and the patrol intervals be shortened. This measure increases the movement and visibility around the HV yards and allows the officers to always have a clear view of the asset.

Posting of guards

7.3.71 Security officers will not be posted at the main guardhouse at night; instead, they will be moved to a central point near the HV yard.

Panic clocking points

7.3.72 Additional strategic panic points should be installed, which should only be clocked in cases of emergency or panic.

Rotation of guards

7.3.73 The security service providers were encouraged to rotate some of the guards to avoid complacency.

Consulting costs

7.3.74 The Procurement Department and the Panel Control Committee run the procurement of professional services. An open tender to be on the Eskom panel is advertised and services are appointed on a fixed term. Adjudication is done on technical and price considerations. Some panels have fixed rates. Where the rates are fixed, the Panel Control Committee will allocate work on a rotational basis to the companies on the panel.

7.3.75 When it is not possible to have agreed fixed rates (since there is no defined scope of work upfront), a tender is issued to the companies on the panel (previously approved in terms of technical and financial capability). The Procurement Department and the Panel Control Committee will adjudicate and select a winning bidder. In summary, all work is issued through tender.

Fleet and Travel

7.3.76 This includes both the local and international business travel undertaken by employees for the operational course of the business, as well as to attend training and meetings on behalf of Eskom. The significant decrease in expenditure is due to the classification of some fleet expenses as part of maintenance costs. The Transmission vehicle fleet is almost exclusively used by employees to access different sites for plant maintenance and repairs.

Facilities

7.3.77 These costs are to service and maintain buildings and facilities. The costs incurred are for rates and taxes, municipal services, maintenance, repairs, cleaning services and related items. The transfer of properties from Eskom Real Estate to line division has contributed to increase of facility related costs such as municipal rates & taxes. This costs where not provided for in the MYPD4 revenue application.

7.3.78 Facility costs are used to service and maintain buildings and facilities. The costs incurred are for rates and taxes, municipal services, maintenance, repairs, cleaning services and related items. The transfer of properties from Eskom Real Estate to the line division has contributed to an increase in facility-related costs, such as municipal rates and taxes. These costs were not provided for in the MYPD4 revenue application.

Distribution Business

7.3.79 The increases in the 'Other costs' are linked to inflation and are fixed in nature. Where possible, the Licensee has implemented cost-saving measures while improving operating efficiencies.

7.3.80 Distribution other operating cost drivers are as follows:

Insurance cost

7.3.81 The business must ensure that it has adequate insurance cover to manage its increasing asset base and exposure against insurable incidents, such as natural occurrences, theft, vandalism and public liability claims. The market prices for the premium are hugely driven by the replacement cost of assets and past claim history. The insurance covers risk beyond the business's maximum tolerance levels.

Information technology costs

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

Fleet and travel cost

7.3.83 The Distribution network's infrastructure footprint is across South Africa, mainly in rural areas. Employees are required to travel extensively to provide services to all customers. This involves operating, maintaining and repairing networks to comply with regulatory and service standards. Key to the cost is employee recovery of the costs for the kilometres travelled for business-related activities and the associated subsistence allowances. The employees are reimbursed at the South African Revenue Service (SARS) travel rates, and the Eskom policy is aligned with the National Treasury's Directive on Cost Containment.

Telecommunications

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

NERSA Analysis

7.3.85 Figure 5 below shows that Eskom's expenditure does not align with NERSA's decision. It is evident that from FY2013/14 to FY2019/20, Eskom consistently spent more than the NERSA decision. Eskom states that the reason for the over-expenditure is that NERSA's decision could not be considered as a base because Eskom's business model was not taken into account. However, NERSA considers all elements when assessing the application before making the final determination.

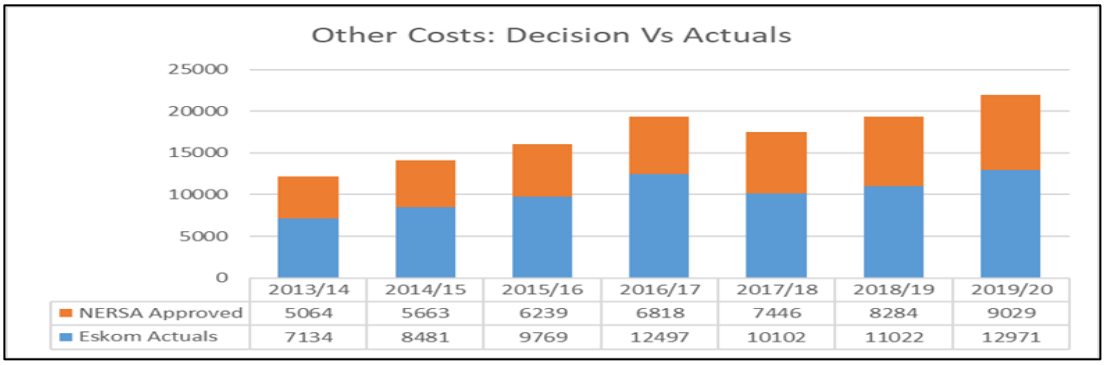

Figure 5: Operating actual costs compared to NERSA's decisions

Approach/methodology used

7.3.86 Section 10.4.8 of the Methodology states that other expenses that unrelated to the core business of supplying electricity will also be disallowed, and section 10.4.10 further states that other expenses referred to under other costs must be unbundled.

7.3.87 There was no deviation from the Methodology.

Stakeholder comments

7.3.88 The Energy Intensive Users Group of Southern Africa (EIUG) mentioned that NERSA must thoroughly scrutinise the costs to ensure prudency and efficiency. NERSA will allow prudently and efficiently incurred costs.

NERSA adjustment and reasons

7.3.89 The Licensee has implemented cost-saving measures, while improving operating efficiencies. Therefore, what it is applying for is allowed, as per Table 30 below. The expenditure has been verified through the annual financial statements (AFSs) and regulatory financial reports (RFRs).

Table 30: NERSA final decision – other costs

Other Costs (R'm)	NERSA Decision MYPD4 2021/22	Eskom's Actuals	Variance	Eskom Adjustment	NERSA Adjustments	NERSA Decision
Other Costs	9740	17455	7715	-1377	0	6399
Total	9740	17455		-1377	0	6399

Arrear Debt

7.3.90 Arrear debt is the amount of debt accrued from the date the first payment was due. Eskom has applied for a variance of R40m for the benefit of the customers in the financial year under consideration, as seen in Table 31 below.

Table 31: Arrear debt

Arrear debt calculation	Decision FY2022	Actual FY2022	RCA FY2022
Electricity revenue	233 228	223 706	
Less: Revenue from international customers	13 740	11 335	
Less: Load shedding (1605 GWh @ 133.64 average c/kWh)		2 145	
Revenue from local customers	219 488	210 226	
Arrear debt	**1 457**	**1 396**	**(61)**
Arrear debt allowed in FY2022 decision expressed as a % of allowed revenue from local customers	*0.66%*		
SAE arrear debt	**-**	**22**	**22**
*** Total RCA claim**	**1 457**	**1 417**	**(40)**

Source: Eskom Application, pg. 145

7.3.91 Eskom indicated that although the arrear debt reflected in its AFS is significantly higher, this RCA balance application only considers arrear debt within the cap of 0.6% of the allowed revenue for FY2021/22. Eskom further indicated that due to the revenue being lower than that determined by NERSA, the arrear debt variance (excluding Southern African Energy [SAE]) is in favour of consumers and that Eskom does not include the total arrear debt for the RCA balance determination.

Approach/methodology used

7.3.92 In the past years, NERSA has been implementing a 0.5% allowance as a provision for arrear debt. This means that NERSA expects Eskom to have a 99.95% revenue collection rate, which is considered reasonable.

NERSA Analysis

7.3.93 Eskom has struggled to collect 99.95% of its revenue from its customers in the past. However, Eskom is applying for arrear debt for the benefit of customers in this RCA application.

7.3.94 Therefore, NERSA allows the variance of R40m for the benefit of customers, as illustrated in Table 32 below.

Table 32: NERSA 2021/22 RCA Decision – Arrear Debt

R'm	NERSA Decision FY2022	ESKOM Actual FY2022	Variance	NERSA Adjustment	NERSA Decision
Arrear Debt	1457	1417	-40	0	-40

Corporate Services

Summary of the application

7.3.95 Table 33 below shows that the three major categories of NERSA's determination for the corporate division comprised a determination of R4 746m for employee benefits, R3 515m for operating costs and depreciation of R1 177m, which totals R9 438m. This, contrasted against the actual spend of R5 518m for the year under review (which includes net impairments), reflects a R3 920m negative variance.

Table 33: Corporate Services

Operating costs (R'm)	Decision FY2022	Actual FY2022	Variance	RCA adjustments	RCA FY 2022
Employee benefits	4 746	3 817	(929)	-	(929)
Other Opex	3 515	1 275	(2 240)	-	(2 240)
Arrear debt	-	-	-	-	-
Other income	(392)	(1 141)	(749)	-	(749)
Depreciation	1 177	425	(752)	-	(752)
Total	**9 046**	**4 376**	**(4 670)**	**-**	**(4 670)**
Research and development	151	149	(2)	-	(2)
Other income	(392)	-	392	-	392
Less: IDM, R&D, CSI (Table 135 of RfD)	(1 139)	-	1 139	-	1 139
Total operating costs	**7 666**	**4 525**	**(3 141)**	**-**	**(3 141)**

7.3.96 In preparation for the divisionalisation or ring fencing of Eskom, some of the services at an operational level that formed part of the approved spend have been relinked to the line divisions, namely Generation, Transmission and Distribution. Group Technology has been relinked from a central corporate role to Generation. Hence, all costs associated with these services now reside with the relevant line division.

7.3.97 Services, including finance, security, procurement, fleet services and revenue management within the remaining corporate functions, which are considered to be better managed within the licensees, have also been relinked.

Approach/methodology used

7.3.98 Section 10.4.2 of the Methodology states that 'manpower costs should be allowed in accordance with the allowable revenue; any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges.

7.3.99 Furthermore, section 10.3 of the Methodology states that costs related to Operation and Maintenance (O&M) will be allowed. The reasonableness of such expenses will be determined by the Energy Regulator on a case-by-case basis.

7.3.100 There was no deviation from the Methodology.

Corporate Employee Benefit Costs

Summary of the application

7.3.101 The NERSA determination on employee benefits is based on FY2007/08 employee numbers and a ratio of one corporate staff member to support six employees from the overall Eskom business. This equates to 4 772 corporate employees, as indicated in Table 34 below.

Table 34: Corporate employee benefit costs

Corporate Employee costs	Decision FY2022	Actual FY2022	Variance
Employee Costs (R'm)	4 746	3 817	(929)
Employee number	4 772	3 033	(1 739)

7.3.102 The year-end actual head count of 3 033 is 1 739 employees less than the amount in the determination. This is mainly due to staff re-linking to the Generation, Transmission and Distribution divisions in line with the decentralisation of Eskom. Employee benefit costs have a variance of R929m for the benefit of consumers. This is due, in part, to staff that have been re-linked to the Distribution, Transmission and Generation divisions, and targets set in Eskom's strategic workforce plan that have been achieved (R686m).

7.3.103 Group IT (R345m) has a variance in favour of the consumer due to lower annual increases to bargaining unit employees, no increases to management and stricter control of overtime. The Procurement and Supply Chain Management Department (R382m) could not attract and retain skills as originally planned, resulting in a variance of R382m in favour of the consumer.

7.3.104 There has also been a re-determination of the pension benefit obligation with respect to the whole organisation, which resulted in a variance of R484m in favour of Eskom. This variance has been ring-fenced at a corporate level for this financial year.

Depreciation

7.3.105 A variance in corporate depreciation for the benefit of the consumer of R752m is primarily due to planned capital expenditure having been decentralised (R163m) to Generation, Transmission and Distribution.

7.3.106 In addition, vehicle fleet (R387m), real estate (R86m) and group technology assets (R14m) have been transferred to the Distribution, Transmission and Generation divisions. Thus, a concomitant increase in depreciation in the various licences will be seen. With respect to Group IT, there have been delays in capital project execution, resulting in delays in transferring planned assets to commercial operation (R102m).

Corporate Other Opex

7.3.107 Other operating expenses underspent by R2240m. The variance is mainly due to the reasons provided below.

7.3.108 Group IT's cost recovery method was revised to allow for direct charges to specific divisions (R395m).

7.3.109 The overhead variance (R615m) is due to savings on hardware maintenance costs, delays in software licence renewal and delays in establishing planned information security contracts.

7.3.110 A total of R533m is due to functions that have been relinked to the Distribution, Transmission and Generation divisions (mainly fleet, strategic functions and real estate).

7.3.111 Further costs have been reduced because of a decrease in travelling after the Covid-19 pandemic, as well as savings achieved through a deliberate savings drive throughout corporate services (R547m).

Corporate Other Income

7.3.112 Planned income was exceeded by R749m primarily due to unplanned dividends from ESCAP (R660m), increased dividends from Montraco (R46m), and the unplanned sale of IT assets (R83m) (Group IT disposed of these assets because of a change in strategy to Hybrid IT).

NERSA adjustments and reasons

7.3.113 The overall application amount for the FY2021/22 is R3 141m for the benefit of the customer. NERSA decided to approve the amount as per the application, as shown in Table 35 below.

Table 35: Corporate Services Decision

R'm	NERSA Decision FY2022	ESKOM Actual FY2022	Variance	NERSA Adjustment	NERSA Decision
Corporate Services	7666	4525	-3 141	0	-3 141

Other Income

Summary of the application

7.3.114 In the course of its operations in FY2021/22, Eskom generated total other income of R429m, which is shown Table 36 below.

Table 36: Summary of other income application

Other Income	Decision FY2022	Actual FY2022	Variance
Generation	(473)	(209)	264
Transmission	(10)	(97)	(87)
Distribution	(426)	(566)	(141)
Corporate services	(392)	(1 141)	(749)
IDM & SAE	-	-	-
Total	**(1 301)**	**(2 013)**	**(712)**
Less: Corporate services [1]	-	1 141	1 141
Other income for RCA purposes	**(1 301)**	**(872)**	**429**

Note: Other income actuals for Corporate Services are included under the corporate services costs. Therefore, it is deducted here so as not to double count other income for RCA purposes.

NERSA analysis

7.3.115 Eskom could not have reasonably estimated such additional revenue at the time of the application, as the other income value in the application was determined based on historical trends. Other income is difficult to forecast with any reasonable degree of accuracy.

7.3.116 Under the Transmission Division, other income was R97m compared to the NERSA determination of R10m.The main reason for the variance is insurance proceeds, which are not planned, as the pay-outs on insurance claims cannot be determined upfront.

7.3.117 Under the Distribution Division, other income was R140m higher than the decision of R426m. Higher insurance proceeds/recoveries, because of more insurance work, contributed an additional R298m to other income. Sundry income exceeded the determination by R93m.

7.3.118 The overall application amount for the FY2021/22 is R429m for the benefit of Eskom, as shown in Table 37 below.

Table 37: Other Income Decision

R'm	NERSA Decision FY2022	ESKOM Actual FY2022	Variance	NERSA Adjustment	NERSA Decision
Other Income	-1301	-872	429	0	429

7.3.119 Table **38** below provides a summary of the operating costs decision.

Table 38: Overall Operating Costs Decision

R'm	Eskom Application RCA 2022	NERSA Adjustment	NERSA Decision
Employee Benefit Costs	2161	-651	1510
Maintenance	1764	-4174	-2410
Other opex	6339	0	6339
Arrear Debt	-40	0	-40
Corporate Services	-4670	0	-4670
Other Income	429	0	429
Less IDM, R&D and corporate social investment	1139	0	1139
Operating costs Excl IDM	**7122**	**-4825**	**2297**

7.4 PRIMARY ENERGY

Summary of the application

7.4.1 Primary energy is one of the key areas of this RCA application, with a total RCA amount of R17 166m in favour of Eskom.

7.4.2 As shown in
Table 39 below, the glaringly high amounts are as a result of coal usage, gas and oil (coal-fired start-up), and the over-usage of OCGTs.

7.4.2 Table **39** below provides a summary of the primary energy variances based on NERSA's decision and the actual amounts consumed during FY2021/22. The total coal-burn variance is R2 104m in favour of Eskom, comprising a price variance of R1 654m for the benefit of the consumer, and a volume variance of R37 589m in favour of Eskom, when comparing the actuals to the decision.

7.4.3 Regarding OCGTs, the variance between the assumptions in the decision and actuals for FY2021/22 is very large. The variance accounts for R9 020m in favour of Eskom.

7.4.4 Start-up fuel-oil variances contribute R4 243m to the RCA balance in favour of Eskom. A variance of R17 166m in favour of Eskom is summarily applied for under primary energy, which excludes variances in environmental levy, IPPs and international purchases.

Table 39: Total primary energy comparison and RCA

Primary Energy (R'm)	Decision FY2022	Actual FY2022	Variance	RCA adjustment	RCA
Coal usage	60 471	61 809	1 338	766	2 104
Water usage	3 135	2 500	(635)	-	(635)
Fuel procurement service	153	226	73	-	73
Coal handling	1 990	2 370	380	-	380
Water treatment	544	616	72	-	72
Sorbent usage	300	137	(163)	-	(163)
Gas and oil (coal fired start-up)	1 698	5 941	4 243	-	4 243
Nuclear	460	775	315	-	315
Coal and gas (Gas-fired)	-	1	1	-	1
OCGT fuel cost	1 013	10 033	9 020	-	9 020
Demand response and cogeneration	339	312	(27)	-	(27)
International Purchases (Dx)	-	10	10	-	10
Other	(1 773)	-	1 773	-	1 773
Primary Energy	**68 330**	**84 729**	**16 399**	**766**	**17 166**
IPPs costs per table 2 of the RfD	**40 631**	**36 714**	**(3 917)**	**-**	**(3 917)**
Independent Power Producers (IPPs)	40 733	36 714	(4 019)	-	(4 019)
Other IPPs refer table 2 of the RfD	(102)	-	102	-	102
International Purchases (SAE)	3 426	5 306	1 880	-	1 880
Environmental levy	7 267	7 512	245	-	245
Total primary energy	**119 654**	**134 261**	**14 607**	**766**	**15 374**

Summary of the application

7.4.5 below shows the coal burn cost as per the Eskom application. Eskom produced 10 923 GWh (excluding pre-commissioning energy) less electricity from coal-fired stations than what was planned for FY2021/22. However, the total coal burnt was 993 ktons more than assumed in the application and 3 825 ktons more than the decision. The total burn variance between the actual costs and the decision is R2 104m (R1 338m [variance] + R766m [RCA adjustment]), in favour of Eskom, with the actual costs being higher than the determination. The total amount of coal burnt per contract type and the variances are depicted in

7.4.6 **Table 40** below.

Table 40: Coal burn RCA variances breakdown

Coal Burn (R'm)	Decision FY2022	Actuals FY2022	Variance
Cost Plus	18 833	18 141	(692)
Fixed Price	13 574	15 130	1 556
Medium Term	27 780	26 496	(1 284)
Short Term	284	2 470	2 186
Total Coal Burn Cost	**60 471**	**62 237**	**1 766**
Add Coal Obligation provision	-	**(429)**	**(429)**
Total Coal Burn Cost	**60 471**	**61 808**	**1 337**

7.4.7 The reasons for the variance of R1 337m are summarised below. Some assumptions were realised, while others were not realised. In addition, the variance can be attributed to the following:

i) The total coal purchase volumes were 2 351ktons less than assumed in the Eskom application. The lower volumes were mainly due to lower sales. Purchases were lower on the cost-plus and fixed-price contracts.

ii) The R/ton coal price was 12% lower than the price in the application, on average. The lower R/t prices on medium-term (MT) and cost-plus purchases were offset partially by higher prices on the fixed-price and short-term (ST) 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.

iii) The cost-plus mines provided approximately 31% of the coal procured in FY2021/22 against an assumption of 33% in the application. During FY2021/22, the volumes from cost-plus mines were 8% less than expected.

iv) Approximately 28% of coal for FY2021/22 was sourced from long-term fixed price contracts against an assumption of 31% in the Eskom application.

v) MT/ST contracts supplied approximately 41% of the coal in FY2021/22 against an assumption of 36% in the application.

Approach/methodology used

7.4.8 The MYPD Methodology states that the Energy Regulator will approve the coal benchmark price (i.e. average R/ton) per contract type (cost plus, fixed price, medium term and short term) and Alpha for each contract type in the final MYPD decision (MYPD Methodology, paragraph 12.2.1). The Energy Regulator determines the coal benchmark price to be used in comparison with the actual coal cost for determining pass-through costs. 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 per contract type:

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

Stakeholder comments

7.4.9 Stakeholders provided the following comments on coal burn during the public hearing.

7.4.10 The EIUG is of the opinion that Eskom should not be granted the R2 104bn it has applied for under this RCA. The reason for this is that the EIUG sees Eskom's explanation for the volume variance as that Eskom has burnt more coal for less electricity production. According to the EIUG, the application does not justify the volume variance for any reason other than what could be considered inefficiency.

7.4.11 Business Unity South Africa (BUSA) stated that when the primary energy costs for coal that were initially approved at R60.5 billion are compared to the said variance of R61.8bn, there is a mere 10-point difference or R1.3bn variance. BUSA asked why this gap persists and falls on the shoulders of consumers. BUSA went on to say that in 2020, 108mt of coal provided generation of 194GWh. Fast forward to 2022, where 110mt of coal yielded 10GW less electricity, the question echoes: Is this a mere efficiency hiccup or is something more intricate at play? In such circumstances, why is the customer left to pick up the sliding/declining efficiency? If the burn rate was maintained at 1.79GWh/Mt in 2020, why did Eskom not persist in maintaining this equilibrium? If the FY2019/20 performance of 1.79 GWh/Mt was maintained, Eskom could have realised a cost saving of R4.5 billion. BUSA's view is that NERSA should disallow R4.5 billion from the coal adjustment in the RCA, thus translating to an adjustment of more than R2 billion in favour of the consumer.

NERSA Analysis

7.4.12 The following were identified as the causes of the coal burn cost over-expenditure of R1 766m, as per MT/ST contracts supplied approximately 41% of the coal FY2021/22, against an assumption of 36% in the application. Table 41 below shows the coal burn cost variance.

Table 41: Total coal burn cost variance

Coal Burn Price Variance Breakdown	Cost Plus	Fixed Price	Medium Term	Total
Allowed Rm	18 833	13 574	28 064	60 471
Actual Rm	18 141	15 130	28 966	62 237
Coal burn price Variance (R'm)	692	-1 556	-902	-1 766

7.4.13 Total coal purchase volumes were 2 351ktons less than assumed in the Eskom application. The lower volumes were mainly due to lower sales. Purchases were lower on the cost-plus and fixed-price contracts.

7.4.14 The R/ton coal price was 12% lower than the price in the application, on average. The lower R/t prices on medium-term and cost-plus purchases were offset partially by higher prices on the fixed price and short-term 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.

7.4.15 The cost-plus mines provided approximately 31% of the coal procured in FY2021/22, against an assumption of 33% in the application. During the FY2021/22, the volumes from cost-plus mines were 8% less than expected.

7.4.16 Approximately 28% of coal for FY2021/22 was sourced from long-term fixed price contracts, against an assumption of 31% in the Eskom application.

7.4.17 MT/ST contracts supplied approximately 41% of the coal in FY2021/22, against an assumption of 36% in the application.

Boiler inefficiencies

7.4.18 Eskom's coal-fired stations seem to suffer from inefficiencies, as evidenced by the imbalance between the burn rate and the power generated. In the RCA application, Eskom stated that performance was lower at the coal-fired stations, where 3 825 ktons more volumes were burnt, yet the anticipated generation was 10 923 GWh lower than targeted. Therefore, NERSA agrees with both the EIUG and BUSA that Eskom's boilers have exhibited a trend of reduced efficiency over the years.

7.4.19 The reduction in the efficiency of the boilers can be attributed to the poor quality of maintenance and the poor quality of coal used. This implies that there is a maintenance challenge and/or backlog. The consequence of the deteriorating efficiency is that more coal is required to produce a unit of electricity. For example, for FY2019/20, NERSA approved 191 GWh to be produced from the coal fleet, using a total of 107 million tons (mt) of coal. This translates to a burn rate of approximately 0.56kg/kWh. However, Eskom produced approximately 185 GWh from its coal fleet, instead of the anticipated 191 GWh, using approximately 110mt of coal, as shown in

7.4.20 Table **42**. This translates to a coal burn rate of approximately 0.59kg/kWh. This is an increase of almost 6% in the amount of coal burnt to produce a unit of electricity.

Table 42: Approved vs actual coal burn rate

NERSA approved Energy 2022 (GWh)	NERSA approved coal burn 2022 (mt)	Burn Rate (kg/kwh)	Eskom Actual Energy 2022 (GWh)	Eskom actual coal burn 2022 (mt)	Burn Rate (kg/kwh)	Burn Rate difference (%)
191	107,28	0,561675393	185	110	0,594595	5,86%

7.4.21 If Eskom had maintained the burn rate of approximately 0.56kg/kWh, it would have only burnt 103mt coal to produce 185 GWh, instead of the actual 110mt of coal that was burnt, as per Table 47 above. This translates to a difference of 7mt of coal. Therefore, Eskom must pay attention to increase its boiler efficiency to ensure that the proper tonnage of coal is burnt to produce a unit of electricity in line with benchmarks. The cause of excessive amounts of coal burnt could also be attributed to poor coal quality. Poor coal has more ash content and lower calorific values, which means that more coal is needed to produce a unit of electricity than it would have been the case if better quality coal were used.

Coal Quality

7.4.22 The article entitled *Understanding Eskom's high failure rate* published by GroundUp, Stacey (2022)[6] analyses the research done by Professor Josias van der Merwe, the Head of School at the Wits School of Chemical and Metallurgical Engineering, and KG Moloko, a postgraduate researcher in the school. Van der Merwe and Moloko conducted a range of chemical analyses on boiler tubes from Eskom power stations to determine the mechanisms and causes behind their corrosion.

[6] https://www.groundup.org.za/article/scientists-identify-one-of-the-main-culprits-in-loadshedding/

7.4.23 The research found that the main culprit is sulphidation, a chemical process that degrades steel through the formation of brittle compounds of iron and sulphur. Two chemical conditions must be in place for this to occur – the presence of sulphur and a low concentration of oxygen, which allows the sulphur to react with iron rather than being oxidised. The Wits analysis indicated that these conditions were both present at the examined Eskom boilers, creating a chemical pre-condition that leads to heightened corrosion rates and frequent failures.

7.4.24 The issue is not what coal South Africa has but what coal Eskom chooses to buy and use. This has long been a politicised matter, and Eskom has a proven history of purchasing sub-standard coal, having spent hundreds of millions purchasing coal containing 2% sulphur from the Gupta-owned Tegeta mine, which is well above the specified limit of 1.3% sulphur. Investigators also found evidence that coal inspection processes had been interfered with, with samples from one mine allegedly having been swapped to obscure their sulphur content.

7.4.25 Other aspects of coal quality have previously come to light, with reports that some of the coal supplied to Eskom had even been mixed with sand and rocks to increase the weight of what is sold. The fact that such sub-standard products manage to make it into Eskom's boilers reveals a management lapse on Eskom's side, leading to shocking deficiencies in inspection and quality control, leaving South Africa entirely at the mercy of unscrupulous coal producers. NERSA is of the opinion that the issue of poor coal quality is also directly linked to boiler inefficiencies, as per Eskom's application.

NERSA adjustments and reasons

7.4.26 The PBR formula was applied per contract type, as shown in **Table 43** below. According to the PBR formula, the allowable pass-through coal burn cost is R62 504m. The Alpha for MT/ST contracts is set so that the risk is borne by consumers more than by Eskom. In future, this should change to ensure that the risk is shared equally between Eskom and customers.

Table 43: Allowed RCA coal burn cost

7.4.27 According to the PBR formula, the maximum amount allowed as a pass-through cost is R62 504.15.

7.4.28 The following adjustments are based on the PBR formula and the inefficiencies discussed in paragraphs 7.4.14 to 7.4.16 above:

7.4.28.1 The adjustments shown in **Table 44** are based on the MYPD PBR formula, which bases the allowable pass-through costs to customers on the prescribed formula. However, Eskom incurred a total coal cost of R61 809m, with the RCA adjustment of R766m, which is a total of R62 575. Therefore, a total amount of R62 504 is allowed based on the formula. This allows for an adjustment of R71m, resulting in an RCA decision of R2 033m due to Eskom.

7.4.28.2 The total coal burn volumes are adjusted based on the MYPD Methodology, which is based on section 15(1) of the Electricity Regulation Act. The MYPD quotes section 15(1)(a), which states that the Energy Regulator 'must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return'. This implies that an inefficient licensee should not be allowed to recover the full costs. In particular, the inference here is that NERSA should disallow costs incurred inefficiently. A suitable methodology for penalising Eskom for inefficiencies should be sought in the future. No further adjustments were made for inefficiencies, as shown in 47 below.

Table 44: Coal RCA decision

Primary Energy	Decision FY22	Actual FY22	Variance	RCA Adjustments	RCA FY22	NERSA RCA Adjustments	NERSA RCA Decision
Coal	60 471	61 809	1 338	766	2 104	-71	2 033

*Other inefficiencies were not adjusted for

7.4.29 In the MYPD4 determination, Eskom's R/ton price inflation adjustment was based on the escalation of mining input costs using its internal forecasting models. It was expected that these internally determined inflation forecasts should be close to the inflation figures determined by external organisations. NERSA used the Producer Price Inflation (PPI) from the Bureau of Economic Research (BER) to adjust the R/ton base price as per the MYPD4 Methodology. NERSA also tested the prudency of the FY2019/20 base price assumed by Eskom before applying inflation adjustments.

Conditions for approval

7.4.30 The approval of the RCA as a pass-through cost to customers should be granted after consideration of the following conditions:

7.4.30.1 Boiler efficiency

7.4.30.2 The coal quality used

7.4.30.3 Reasons for over-reliance on short-term and medium-term contracts whose price (R/t) is higher than fixed price and cost-plus contracts

7.4.30.4 Sufficient coal stock levels as per the grid code requirement for minimum of 20 contingency stock, which should be used before resorting to ad-hoc suppliers that tend to charge exorbitantly.

Open Cycle Gas Turbines (OCGTs)

Summary of the application

7.4.3 According to Eskom, volumes from the OCGTs were higher, mainly due to extensive utilisation by the System Operator. With an increasingly tight capacity situation, compounded by the lower-than-expected Renewable Energy Independent Power Producer (REIPP) output, the System Operator was forced to utilise more diesel generation (from the Eskom fleet and the DMRE peakers).

7.4.31 Eskom further submits that the System Operator was required to dispatch OCGTs (both those of Eskom and IPPs) in excess to what had been assumed in the NERSA decision or Eskom's application, and the dispatching of these OCGTs was undertaken in accordance with the NERSA Scheduling and Dispatch Rules.

7.4.32 The utilisation of OCGTs contributed towards minimising load-shedding. In accordance with the MYPD Methodology, gas turbine usage should be allowed as it was incurred to ensure the security of supply and was done as a last resort before implementing load-shedding.

7.4.33 OCGTs were used during peak and off-peak periods throughout the year. OCGT and IPP usage reduced load-shedding by providing additional capacity. The use of OCGTs must be considered with all other available options to manage the power system.

7.4.34 Reduced usage of the OCGTs would have increased the incidents, duration and severity of load-shedding. The knock-on effect of this would be the worsening of plant performance and a longer time to return to a more normal state of operation.

Approach/methodology used

7.4.35 The analysis of the OCGT costs is based on following principles:

7.4.35.1 Sections 12.3.1 and 17.2.9.4 of the MYPD 4 Methodology

7.4.35.2 Section 8 of the Scheduling and Dispatch Rules – Generation Maintenance Outage Coordination

7.4.35.3 Section 4.1 of the System Operation Code – The Operating Reserves.

7.4.36 Section 12.3.1 states that *Gas turbines are provided to operate during peak periods and emergencies. Subject to the conditions set out in the MYPD Methodology, gas turbine generation costs will be allowed as a full pass-through cost, but limited to the volumes allowed by the Energy Regulator, except where such use was necessary to ensure the security of supply due to events outside management's control.*

7.4.37 The MYPD decision limited the use of OCGT due to the declared high availability of the Eskom coal fleet, for which Eskom is compensated via appropriate depreciation and return on assets allowed as part of the MYPD decision. At the time of approval, the assets were considered used and usable for electricity generation or should have been available for use. Eskom had to make extensive use of OCGTs because of supply constraints on its part rather than as a result of increased demand. Therefore, it is submitted that the fleet's performance was and still is within Eskom management's control.

7.4.38 The MYPD Methodology further indicates that the capacity constraints shall be mitigated by gas turbine generation as a last resort. This means that gas turbine generation should be employed before the implementation of load-shedding activities. It is evident that OCGTs were not only used to prevent load-shedding or

for emergency purposes, but were also deployed as mid-merit closed cycle gas turbines (CCGTs), which explains the high utilisation and the resultant excessive cost of diesel.

7.4.39 In the MYPD4 determination, it was stated that in terms of the System Operation Grid Code, OCGTs are classified as emergency reserves and are provided for emergency response, not as base-load or mid-merit generators due to the high cost of fuel. For this reason, they are constrained to produce a maximum of 1% load factor per annum to cater for unforeseen events occurring in the system and to ensure efficiencies by minimising the over-use of this expensive technology. The allocation of 1% load factor translates to 211GWh per annum.

7.4.40 Under the system operation code, OCGTs are classified as emergency reserves and ought to be used as such (for emergencies). OCGTs should be used when the Interconnected Power System (IPS) is not in a normal condition and to return the IPS to normal conditions while slower reserves are activated. The System Operator can use these reserves for supply and demand balancing, network stability and voltage constraints. These reserves shall be activated, on request, within ten minutes and shall be sustainable for two hours. The fact that Eskom had a higher number of units that were not available for dispatch compromised the sequence of dispatching the operating reserves (instantaneous reserve, regulating reserve and ten-minute reserve), as shown in Figure 6 below.

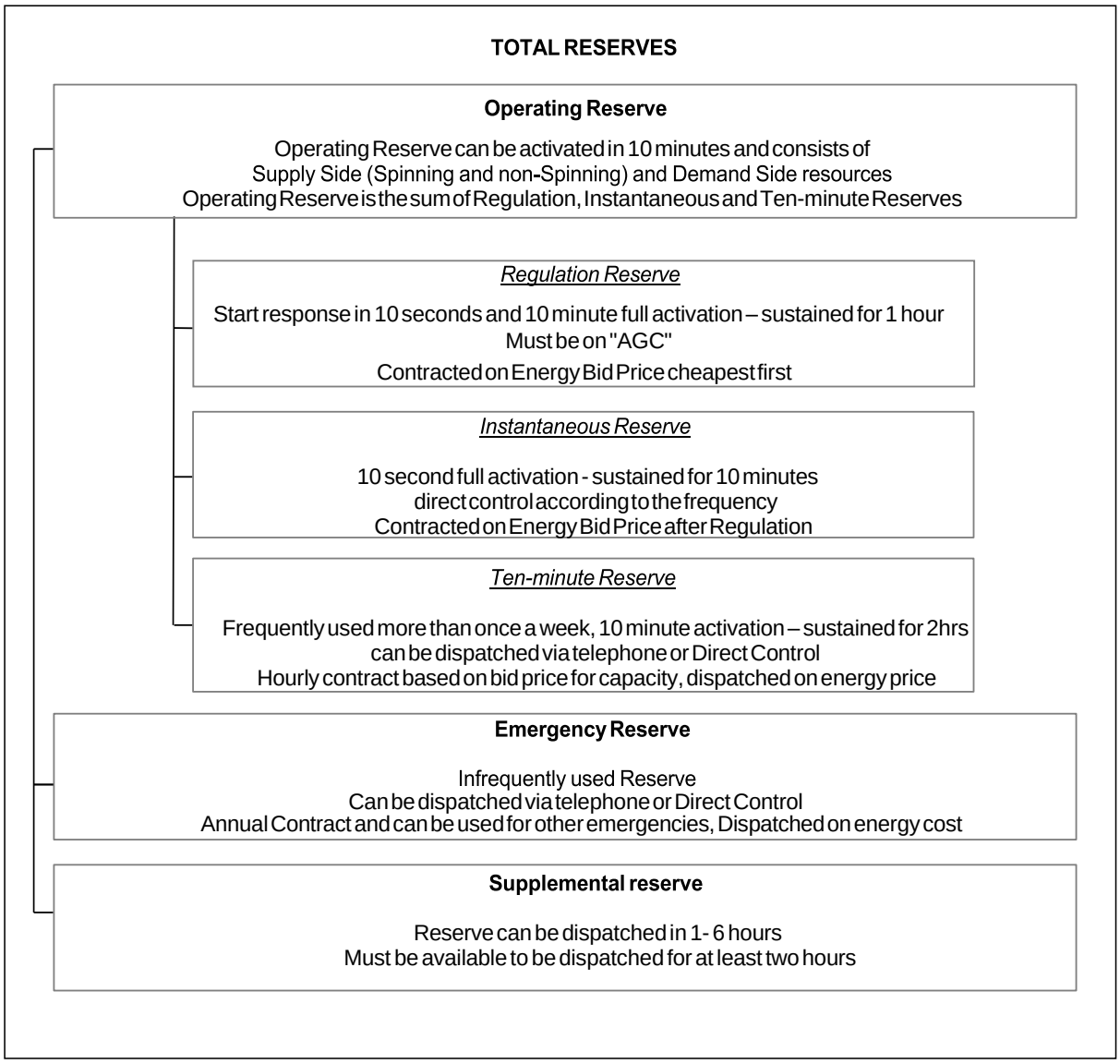

Figure 6: Total reserves

7.4.41 In light of section 12.3.1, while it may have been technically justifiable for Eskom to run OCGTs excessively to prevent load-shedding, the fact that the excessive use was due to inefficiencies in Eskom's management of its generation fleet cannot be overlooked.

7.4.42 Lastly section 17.2.9.4 states the following:

Usage of OCGT above the MYPD approved levels will be recovered through the RCA at the average cost of Eskom's plant that should have been available according to the production plan submitted to the Energy Regulator, if the Energy Regulator assessment shows that the unavailability was within Eskom management's control. For example, if coal generation availability resulted in higher than planned use of the OCGT generation, the additional OCGT energy will be recouped at the coal average cost.

7.4.43 The methodology therefore enables the Energy Regulator to assess the reasons for the variance between planned and actual diesel volumes and decide at what level that variance will be allowed.

Stakeholder comments

7.4.44 Stakeholders provided the following comments during the public hearing:

7.4.44.1 The EIUG stated that while it is true that Eskom's use of OCGTs was necessary to ensure the security of supply, it is not correct to assume that this was singularly due to events outside of management's control. The threats to the security of electricity supply were due to Eskom's poor performance, which is entirely within the control of management despite Eskom's deflection of external factors, such as late decisions made over 20 years ago by the government.

7.4.44.2 For this reason, the volume of diesel used could be allowed but this risk should be shared between consumers and Eskom. Two options could be considered for the risk-sharing, one being calculated at a coal-generated electricity production cost rate per GWh multiplied by OCGT GWh, which has been done in the past. This represents a like-for-like comparison, considering that OCGTs were used to offset coal-generated electricity production losses.

7.4.44.3 Alternatively, the same logic used by Eskom must be used in quantifying the load-shedding adjustment of GWh multiplied by the standard tariff rate. In the alternate rate option, this will result in 1 615 GWh multiplied by 133.64 c/kWh, equalling R2.158 billion. Therefore, at best, Eskom can be compensated at R2.158 billion for diesel, but ideally, an amount linked to the coal-generated electricity production cost rate would be more appropriate. Any amount higher than R2.158 billion should automatically trigger a load-shedding adjustment equivalent to the true cost of load-shedding to the economy.

7.4.44.4 Minerals Council South Africa echoed the same sentiments as the EIUG, stating that the OCGT costs should be priced at a coal parity price.

7.4.44.5 BUSA asked why consumers should bear the cost of inefficiency. A compelling plea emerges for shared risk, where the responsibility does not fall squarely on the consumer. The R10 billion claimed by Eskom is 8.9 times above the NERSA-approved amount of R1 013m, meaning that excess utilisation occurred. The 1.8TWh of electricity produced from OCGT plants means that OCGT utilisation was 7.6 times above target of

211GWh the average fuel cost was R17.15/l compared to R15.01/l in the NERSA decision, thus costing Eskom R5.59/kWh.

7.4.44.6 The following are grounds that could have led to a lower cost implication:

- Had the performance of the base load been better, excessive use of OCGT would not have been necessary (this is directly in Eskom's control).
- From a cost/l perspective, the cost would have been lower if the Minister had granted Eskom the necessary wholesale licence (this is directly in the control of government).

7.4.44.7 Previously, Eskom did not recover the full OCGT cost overrun – the fuel was priced at the coal equivalent (32c/kWh – 36c/kWh if the environmental levy is added). If the same principle is applied, the RCA adjustment would have been R580 million vs R9 billion.

NERSA Analysis

7.4.45 In line with the Methodology, the usage of OCGT volumes should be reviewed for prudency. The usage of OCGTs is aimed at operating during peaking periods, namely morning (05:00 – 08:00) and evening (17:00 – 20:00), to supply power to the grid, as well as during emergencies.

7.4.46 In terms of the System Operation Grid Code, OCGTs are classified as emergency reserves and provided for emergency response, not as baseload or mid-merit generators due to the high fuel cost. For this reason, NERSA decided to allow a maximum of 1% load factor per annum to cater for unforeseen events occurring in the system and ensure efficiencies by minimising the over-use of this expensive technology. The allocation of 1% load factor translated to 211GWh per annum.

7.4.47 Eskom experienced a low EAF of 58%. The low plant availability is mainly driven by a lack of quality maintenance, an ageing coal fleet, prolonged heavy rains, historical plant operation and critical maintenance deferral, which have led to the country-wide rotational load-shedding and high utilisation of OCGTs. The view is that OCGTs should not be seen as a supplement to compensate for the poor performance of the Eskom fleet and to be used as a baseload or mid-merit generator.

7.4.48 Eskom had applied for OCGT usage of 502 GWh, which translates to a 4.2% load factor, and the Energy Regulator decided to allow 211 GWh. The variation between what Eskom had applied for and its actuals is almost 2000%. This huge variance is not in line with the MYPD4 Methodology, which states, in section 12.3.6, that Eskom must ensure that the plant performance projections that form the basis of

MYPD applications are as accurate as possible to prevent the large variations between planned and actual plant performance. The projections should have taken into account all/any relevant historical conditions that have resulted in the plant's current condition.

NERSA adjustments and reasons

7.4.49 The variance that Eskom applied for is set out in **Table 45** below.

Table 45: OCGT variances

OCGT Production	Application FY 2022	NERSA Adjustment	NERSA Decision	Actuals FY 2022	Variance FY 2022
Total OCGT Production (GWh)	502	-291	211	1 826	1 615
Total OCGT Fuel Burn Cost (Rm)	2 410	-1 397	1 013	10 033	9 020

7.4.50 Section 17.2.9.4 of the MYPD4 Methodology states that 'Usage of OCGT above the MYPD approved levels will be recovered through the RCA at the average cost of Eskom's plant that should have been available according to the production plan submitted to the Energy Regulator, if the Energy Regulator assessment shows that the unavailability was within Eskom management's control. For example, if coal generation availability resulted in higher than planned use of the OCGT generation, the additional OCGT energy will be recouped at the coal average cost'. The energy in excess of the allowed volumes amounted to 1 517 GWh for FY2020/21. This volume is allowed at the actual marginal cost of coal generation of 29c/kWh, resulting in a cost of R384m in favour of Eskom.

7.4.51 The actual marginal cost of coal generation includes all actual primary energy costs related to coal generation for the 2021/22 financial year. **Table 46** below summarises NERSA's RCA decision.

Table 46: OCGT application summary

OCGT Summary	NERSA Decision
Allowable Volume at Decision (GWh)	211
Emergency and Peaking Volumes (GWh)	309
Total Volumes (GWh)	520
Cost (R'mil) @ R5,49/kWh	R 2 854
Less Allowed Cost at Decision (R'mil)	R 1 013
Add: Excess volumes (1 517GWh) above allowed GWh recovered at average coal 29c/kWh	440
Decision RCA FY2022	**R 2 191**

Conditions for approval

7.4.52 The OCGT costs incurred by Eskom should not be allowed as a pass-through cost to customers while Eskom's coal fleet is performing at an EAF below 65%, which is still below the international norm of more than 80%. Furthermore, OCGTs should be used as a last resort before load-shedding, not as a tool to free up coal plants for maintenance purposes due to a lack of reserve capacity. Therefore, Eskom must provide sufficient proof that it only utilised OCGTs in emergencies and did not use them as reserve capacity while coal plant units were undergoing maintenance.

Other Primary Energy: Water

Summary of the application

7.4.53 NERSA granted Eskom R3 135m for water costs in the one-year revenue application for FY2021/22. The actual expenditure was R2 500m, resulting in under-expenditure of R635m for the consumer's benefit.

Table 47 below breaks down the costs associated with water usage.

Table 47: Water costs

Water Usage Costs (R'm)			
Cost component	**Decision FY 2022**	**Actual FY2022**	**Variance**
Amortisation	2	3	1
O&M	273	199	-74
Pumping	674	522	-152
CUC	1 212	1 192	-20
Water Research Levy	18	20	2
Water Resource Charge	15	13	-2
VRT	646	577	-69
Waste Discharge Charge	120		-120
Operational Risk transfers	174		-174
Third Party		-100	-100
Total Coal Stations	3134	2426	-708
Peaking Stations		67	67
Renewables			
Nuclear - Koeberg		5	5
Group Capital		2	2
Total Generation Water Usage Costs	3134	2500	-634

Approach/methodology used

7.4.54 The aim of the MYPD Methodology is to outline how the prudency of the costs will be tested.

Stakeholder comments

7.4.55 With regard to water usage, a stakeholder provided the following comment during the public hearing:

7.4.55.1 AGRI Western Cape stated that it is clear that the productivity of demineralised water has decreased drastically. Although not one of the major cost drivers, it serves as an indication of how difficult revenue decisions have become.

NERSA Analysis

7.4.56 The tariffs gazetted by the government have an impact on the price of water. Eskom assumed water-related costs would increase by the Producer Price Index (PPI) of 6%. The actual legislated tariffs and the volume of water consumed had an impact on the total costs. While the operating and maintenance costs, capital unit charge (CUC), pumping costs and Vaal River Transfer (VRT) costs had a variance in favour of the consumer, amortisation and the water research levy had a variance in favour of Eskom. The Department of Water and Sanitation (DWS) did not implement the waste discharge charge, which also contributed to the variance in favour of the consumer.

7.4.57 The water costs are the costs incurred by Eskom for the water it consumes from the DWS. Eskom does not have control over the average price charged since the rate is legislated. The DWS conducts all repairs and maintenance on the water pipelines and charges the costs to the users. Eskom does not control or manage the maintenance.

7.4.58 The R74m under-expenditure on operations and maintenance is due to the DWS's underspending on maintenance in recent years. Eskom has escalated this risk to the Director-General of the DWS.

7.4.59 Primarily, the electricity produced by the power stations drives the volumes of water consumed. The volume consumed to generate a unit of electricity varies per power station. The total consumption will depend on the mix of stations used to generate electricity, with older stations consuming more. Most of Eskom's stations are beyond the halfway mark of their lifespans. Although the coal-fired stations produced less than assumed, actual water consumption per unit of electricity was higher at most stations than was assumed, resulting in a total increase in the water used.

7.4.60 The overall water performance at coal-fired power stations for FY2021/22 was 1.57 l/USO. The stations consumed 68 715 million litres more than expected despite generating fewer GWh. Ageing water infrastructure and lower production at the dry-cooled stations – the Kendal, Medupi and Kusile power stations – resulted in a higher consumption rate. The MYPD4 revenue application assumed higher production from the newer dry-cooled power stations. Both Medupi and Kusile generated less than what was assumed in the application. The application also assumed that Grootvlei and Komati would not generate in FY2021/22, however these stations did.

Water Treatment Costs

7.4.61 NERSA granted Eskom R544m for water treatment costs in the MYPD 4 decision for FY2021/22. The actual expenditure was R616m, resulting in an over-expenditure of R73m compared to the decision, as shown in Table 48 below. This is due to the water treatment costs within the power stations being less than originally envisaged.

Table 48: Water treatment costs

	Decision FY 2022	Actuals FY 2022	Variance
Water Treatment Cost (Rm)	544	616	73

7.4.62 Water volumes used for production are expected to decrease in line with the reduction in sales volumes. Therefore, it is reasonable to expect the treatment cost to decrease accordingly. However, an increase in the cost of chemicals resulted in the costs increasing by inflation.

NERSA adjustments and reasons

7.4.63 As shown in **Table 47**, NERSA granted Eskom R3 135m for water costs in FY2021/22. The actual expenditure was R2 500m, resulting in a variance of R634m for the benefit of consumers. No further adjustments have been made by NERSA.

Conditions for approval

7.4.64 The increase in the water treatment cost is largely related to higher demineralised water production. In turn, this is mainly related to an increase in the power stations' demineralised water consumption and a deterioration in the reliability and efficiency of the demineralised water treatment plants. Therefore, the performance of the water treatment plants must be improved through proper maintenance.

7.4.65 The reduction in high-demineralised water consumption and the improvement in demineralised water production must be recognised. A demineralised water availability strategy to sustainably address this risk should be developed.

Other Primary Energy: Start-up Gas and Fuel

Summary of the application

7.4.66 NERSA granted Eskom R1 698m for start-up fuel in its one-year revenue application for FY2021/22. However, Eskom reported R5 941m actual expenditure, resulting in an over-expenditure of R4 243m. Eskom cited that the large variance of R4 243m was due to the significantly higher number of unplanned outages and trips in FY2021/22 than anticipated at the time of the application. Hence, the use of fuel oil increased significantly.

7.4.67 Table 49 below summarises Eskom's application. Eskom cited that the large variance of R4 243m was due to the significantly higher number of unplanned outages and trips in FY2021/22 than anticipated at the time of the application. Hence, the use of fuel oil increased significantly.

Table 49: Summary of Eskom application

FY 2022	NERSA Decision	Actuals FY2022	Variance FY2022
Start-up gas and oil (R'm)	1 698	5 941	4 243

Approach/methodology used

7.4.68 According to the MPYD Methodology, the criteria for allowing start-up oil and gas are that Eskom must determine the costs, demonstrate (detailed calculation) how the costs were determined and provide the assumptions considered when determining the costs.

Stakeholder comments

7.4.69 Concerning start-up gas and fuel, stakeholders provided the following comments during the public hearing:

7.4.69.1 The EIUG stated that inadequate maintenance and lack of spares are considered to be directly within the control of management. As indicated earlier, coal quality is within Eskom's management mandate. Wet coal and moisture in summer are all known factors in electricity coal production that can be mitigated or should have been provided for in the MYPD4 application of R1.862 billion for fuel oil. Therefore, unless Eskom can prove that for a portion of this variance, there was more wet coal in FY2021/22, there is no basis for consumers to pay for inefficiencies that were directly in the control of management. Besides the technical inefficiencies, the case of corruption at the Tutuka Power Station mentioned earlier indicates there are also inefficiencies associated with corruption, which may apply to other power stations. Therefore, this amount should not be allowed as a pass-through cost.

7.4.69.2 AGRI Western Cape stated that the variance of R4 243 million for start-up fuels in favour of Eskom is a serious concern, as it was due to calculation errors that had been identified (although not fully disclosed).

7.4.69.3 BUSA commented that the gas, oil, and start-up costs are exorbitant and warrant deeper analysis. BUSA asked why such costs are shifted onto consumers and what lies at the root of these start-up expenses. There is a cost overrun of R4.2bn with volumes at 2.8 times more than the approved amount. Likewise, the fuel cost is at R9.93/l actual vs the R8/l approved. No adjustment should be made for the volume overrun, as this is due to

inefficiencies in the Eskom Generation system. However, an adjustment for the higher fuel price is arguably warranted despite the Minister's reluctance to issue the licence. As such, BUSA believes that the adjustment should be 212Ml x R1.18 = R409m.

NERSA Analysis

7.4.70 The price and volume variances are quantified in Table 50 below. The variance was largely driven by the actual volumes being significantly higher than what had been decided. Eskom explained that the large variance resulted from more start-ups and combustion support being required than initially anticipated. Eskom's forecast of its consumption of start-up gas and oil was 248ML in its application. This prediction was incorrect by 350ML.

7.4.71 It is considered that Eskom should be able to reasonably and accurately forecast these costs based on past performance and other reasonable assumptions based on the UCLF trend that has had a downward trend for a protracted period. Therefore, it was not reasonable to assume that the power plants would improve in performance. The average cost is dependent on external factors that are hard to predict, therefore, this will be left unadjusted but limited to allowed volumes. The start-up gas volumes are adjusted as per **Table 50** below.

Table 50: Price variance

Start-up gas & oil Average R/Litre	NERSA Decision	Actual R/Litre
Start-up gas & oil	8	9,93

Table 51: Volume variance

Start-up Gas & oil consumption volumes (ML)	NERSA Decision	Actual Consumption Volume
Start-up Gas & oil	212	598

NERSA adjustments and reasons

7.4.72 **Average price variance =** (Actual price - Decision price) x Actual litres = (9.93 - 8.00) x **597 997 531 litres** = **R1 156m**.

7.4.73 **Volume variance =** (Actual litres - Decision litres) x Decision price = (**597 997 531 – 212 237 956**) x R8.00 = **R3 086m.**

7.4.74 **Total variance = R4 242m** due to Eskom before adjustment.

7.4.75 Start-up gas and oil volumes utilised are proportional to the level of the Unplanned Capability Loss Factor (UCLF) incurred. Therefore, NERSA has adjusted the volumes of start-up gas and oil according to Eskom's projected UCLF of 16% versus the actual UCLF of 25,27%. An efficient operator cannot allow the UCLF to get to the level of 25%. This has resulted in the inefficient use of start-up gas and oil, resulting in three times the allowed volumes. Consequently, the allowed volumes have been adjusted by 386ML in line with section 15(1)(a) of the Electricity Regulation Act, which states that NERSA should only allow an efficient licensee to recover its full costs.

7.4.76 Price variance due to higher than projected prices of Star-up gas and oil will be allowed as a pass-through, but limited to the allowed volumes.

Table 52: Adjusted RCA decision (R/L)

Start-up gas & oil Average R/Litre	NERSA Decision	Actual R/Litre	Eskom Applied	adjustment	RCA 2020 NERSA Decision	Actual R/Litre
Start-up gas & oil (R/L)	8	9,93	7,51	0	9,93	9,93

7.4.77 **Average price variance = (**Actual price - Decision price) x Allowed litres = (9.93 - 8.00) x **212 237 956** litres = **R410m**.

7.4.78 Adjustment was made to the actual volumes by trimming 386ML above the decision of 212ML because the 386ML was consumed inefficiently due to the actual UCLF of 25,27%.

Table 53: Adjusted RCA decision (ML)

Start-up Gas & oil consumption volumes (ML)	NERSA Decision	Actual Consumption Volume	Eskom Applied	adjustment	RCA 2022 NERSA Decision	Actual Consumption Volume
Start-up Gas & oil	212	598	248	-386	212	598

7.4.79 **Volume variance =** (Actual litres - Decision litres) x Decision price = (**212 237 956 – 212 237 956**) x R8.00 = **0m.**

7.4.80 **Total variance = R410m** due to Eskom after adjustments.

7.4.81 In the MYPD4 determination, NERSA's approach was to compare Eskom's prices with the increase in Rand/Dollar exchange and international oil prices to determine whether Eskom's predictions are reasonable.

7.4.82 In the MYPD4 revenue determination, NERSA measured the efficient use of start-up fuels. The historical performance of litres/USO for each individual power station was used to predict the fuel quantities required during the MYPD4 period. The NERSA-revised production programme was also used to estimate the quantities.

Conditions for approval

7.4.83 The other primary energy costs (nuclear, hydro, other costs) are considered stable and less risky and are, therefore, not allowed as a pass-through cost. It is considered that Eskom must be able to accurately forecast these costs to prevent large RCA adjustments that result in unpredictable prices.

Other Primary Energy: Coal Handling

Summary of the application

7.4.84 Eskom is applying for a coal-handling cost variance of R381m for the 2021/22 financial year, as shown in

7.4.85 Table 54 below.

Table 54: Coal-handling costs

Coal Handling (R'm)	Decision FY2022	Actuals FY2022	Variance
Coal handling	1 990	2 370	381

7.4.86 Coal handling refers to all the activities necessary to get the coal to the boiler once it has been delivered to the power station. These activities include building stockpiles, reclaiming from stockpiles, stockpile maintenance and maintenance of the conveyor system.

7.4.87 The major drivers of coal-handling costs are allocated according to the following breakdown:

a. Labour – 60%
b. White and yellow plants – 25%
c. Fuel for yellow and white plants – 15%.

Approach/methodology used

7.4.88 The MYPD4 Methodology is mute on how coal-handling costs should be assessed at the RCA level. In this regard, the team assessed the prudency with which the extra costs applied for were incurred. The team assessed whether the reasons for incurring the costs were within Eskom's control and whether these resulted in improvements in the utility's performance.

NERSA Adjustments and reasons

7.4.89 NERSA has assessed the overall costs for coal handling as applied for by Eskom, as per Table 55 below.

7.4.90 Eskom did not show prudence in its spending, as it had excessively spent at certain power stations and did not justify the costs.

7.4.91 In its conclusion, NERSA decided to adjust the coal-handling costs based on the previous performance.

Table 55: Coal-handling decision

MYPD Decision FY22	Actuals FY22	Variance	Adjustment	NERSA FY2022 RCA Decision
1 990	2 370	380	-121	259

Conditions for approval

No conditions.

Other Primary Energy: Nuclear Fuel Costs

Summary of the application

7.4.92 Nuclear fuel costs form part of the other primary energy costs. It is the cost incurred for manufacturing, enhancing and delivering nuclear fuel assemblies. The assemblies are wholly imported; therefore, international fuel prices are used to determine the best price for Eskom to enter into contracts for nuclear fuel. Nuclear fuel costs are affected by market conditions, and because the majority of the costs are foreign, they are subject to exchange rate deterioration and foreign inflation.

Table 56: Nuclear fuel costs

Nuclear Fuel (R'm)	NERSA Adjustment	Decision FY2022	Actuals FY2022	Variance
Nuclear fuel costs	-290	460	775	315

7.4.93 Table **56** above shows the variance in the nuclear fuel cost for the RCA period applied for, namely FY2021/22. In its application for FY2021/22, Eskom applied for R750m. NERSA disallowed R290m and allowed R460m based on previous decisions. However, according to Eskom, the actuals are R775m, resulting in a variance of R315m.

7.4.94 Table **57** below provides a breakdown of the costs to show where the variance originates.

Table 57: Breakdown of cost variances

Nuclear Fuel Cost (R'm)	Decision FY2022	Actuals FY2022	Variance
Nuclear Fuel other	92	7	-85
Nuclear unit 1 usage	325	342	17
Nuclear Unit 2 usage	256	318	62
Nuclear spent fuel	77	109	31
Nuclear fuel cost	**460**	**775**	**315**

7.4.95 In terms of nuclear fuel, some variances are in favour of the consumer. The variance of R56m where fuel write-off was not incurred was because the outage at Unit 1 was undertaken earlier than intended, resulting in a lower burnup of fuel assemblies. Only fuel assemblies with a burnup above 40000MWD/tu are written off.

7.4.96 A variance of R25m was due to an outage at Unit 2 being delayed because of the Covid-19 lockdown in the previous year, where the outage before this one started later than planned. This had a knock-on effect on the start date of Unit 2's outage. The variance of R8m is due to only two minor fuel studies having been undertaken. This figure comes to R89m, as opposed to the R86m arrived at by Eskom.

7.4.97 The actual costs of recovery of fuel assemblies were R17m more than planned for the fuel assemblies loaded after Unit 1's outage. On Unit 2, the actual cost of recovery of fuel assemblies was R62m more due to the Covid-19 lockdown and the Unit 2 outage being deferred by four months. A change in the decommissioning strategy during the 2017/18 financial year resulted in a change in the timing of cash flows and the split between variable and fixed costs. The capitalised assets are only based on variable costs, which increase per spent fuel assembly in actual mode. Amortisation of spent

fuel assets was more than planned due to the higher value of spent fuel assets, which resulted in a cost reduction of about R31m, bringing the total cost to R24m, as opposed to R315m mentioned in the Eskom application. The detailed calculation and assumption considered demonstrate how the costs were determined.

Approach/methodology used

7.4.98 According to the MYPD Methodology, the nuclear fuel cost is part of other primary energy costs. Since all the fuel used at Koeberg is imported, the cost for nuclear fuel is a pass-through as per the MYPD Methodology. Therefore, the costs applied for by Eskom in the RCA will be wholly passed through to the customer.

Stakeholder comments

7.4.99 No comments were received on the nuclear fuel costs.

NERSA Analysis

7.4.100 Eskom erred in its calculations of the FY2021/22 decision and variance, stating that the total decision was R460m and the variance was R315m, as indicated in Table 58. The total decision is calculated to be R750m, and the variance is calculated to be R24m, as indicated in Table 58 below.

7.4.101 Nuclear fuel is wholly imported, from sourcing uranium to refining and transportation. This is done through tender processes and entering into contracts for a certain period. This means that Eskom is locked into contracts with fixed prices until the next tender period. With the current fluctuation in the Rand against the USD, this is a better option, as it hedges the price against any local currency fluctuations.

Table 58: Breakdown of cost variances

MYPD Decision FY22	Actuals FY22	Variance	Adjustment	NERSA FY2022 RCA Decision
460	775	315	0	315

NERSA adjustments and reasons

7.4.102 No adjustments are proposed for nuclear fuel because the nuclear fuel cost is a pass-through cost, and there are no major changes that require costing outside of the normal operation of the plant.

Other Primary Energy: Demand Response and Cogen

Summary of the application

7.4.103 Eskom is applying for a demand response and cogen of R27m for the 2021/22 financial year.

7.4.104 Demand response describes the situation where Eskom pays high demand users to use less electricity rather than build new power plants to meet higher demand.

Approach/methodology used

7.4.105 Section 11.3 of the MYPD Methodology discusses the approach for demand response and cogen. In summary, section 11.3.1.4 states that the *tariff/price should benchmark at the cost of OCGT (including capital, operating and fuel costs) applicable at the time as a base and will be escalated with the Consumer Price Index (CPI) annually. OCGT is used for supplying peak demand; therefore, demand response is used to provide a flexible and cheaper alternative to OCGT*.

NERSA Adjustments and reasons

7.4.106 No adjustments were made for demand response.

Conditions for approval

7.4.107 No conditions.

Other Primary Energy

Summary of the application

7.4.108 Eskom is applying for other primary energy of R1 773m for the 2021/22 financial year.

Approach/methodology used

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

NERSA Adjustments and reasons

7.4.110 No adjustments were made under other primary energy.'

Conditions for approval

7.4.111 No conditions.

Summary of NERSA's PE decision

7.4.112 Eskom applied for a total primary energy RCA of R17 166m. After NERSA's adjustments totalling R10 854m, NERSA's RCA decision for primary energy is R6 312m due to Eskom, as shown in **Table 59** below.

Table 59: NERSA FY2021/22 RCA PE decision after adjustments

Primary Energy	Decision FY22	Actual FY22	Variance	RCA Adjustments	RCA FY22	NERSA RCA Adjustments	NERSA RCA Decision
Coal	60 471	61 809	1 338	766	2 104	-71	2 033
Water Usage	3 135	2 500	-635		-635	0	-635
Fuel procurement service	153	226	73		73	0	73
Coal handling	1 990	2 370	380		380	-121	259
Water treatment	544	616	72		72	0	72
Sorbent usage	300	137	-163		-163	0	-163
Gas and oil (Coal fired start-up)	1 698	5 941	4 243		4 243	-3 833	410
Nuclear	460	775	315		315	0	315
Coal and gas (Gas-fired)		1	1		1	0	1
OCGT fuel cost	1 013	10 033	9 020		9 020	-6 829	2 191
Demand response and cogen	339	312	-27		-27	0	-27
International Purchases (Dx)		10	10		10	0	10
Other	-1 773		1 773		1 773	0	1 773
Primary Energy (R'm)	**68 330**	**84 730**	**16 400**	**766**	**17 166**	**-10 854**	**6 312**

7.5 INDEPENDENT POWER PRODUCERS

Summary of the application

7.5.1 Eskom's application indicates an expenditure of R36 714m for buying power from REIPPs and the DMRE peaker IPPs (the Avon and Dedisa plants) against the approved amount of R40 630m.

REIPP Costs

7.5.2 Eskom spent R30 554m against the approved amount of R38 220m for REIPPs. This includes deemed energy payments of R33.8m and use-of-system charges of R237.87m.

OCGT Costs

7.5.3 The actual OCGT cost of R6 159m is 145% more than the approved amount of R2 513m. This can be attributed to lower output from the REIPPs, where only 15 073GWh was produced versus the planned amount of 18 577GWh. This resulted in OCGTs being utilised more to produce an actual amount of 899GWh versus the planned 88MWh.

7.5.4 Table 60 below shows the costs applied for by Eskom.

Table 60: Eskom's IPPs 2021/22 RCA application

Independent Power Producers	Cost (R'm)			Volumes (GWh)			Average costs (R'm)		
FY2022	Decision	Actuals	Variance	Decision	Actuals	Variance	Decision	Actuals	Variance
Renewable IPP Programme	38 220	30 554	(7 665)	18 577	15 073	(3 504)	2 057	2 027	(30)
DoE Peaker	2 513	6 159	3 647	88	899	811	28 577	6 849	(21 729)
Other (Table 2)	(102)		102						
Total IPP's	**40 630**	**36 714**	**(3 917)**	**18 665**	**15 973**	**(2 692)**	**2 177**	**2 299**	**122**
IPP ancillary costs	-	-	-	-	-	-	-	-	-
Total IPP's	**40 630**	**36 714**	**(3 917)**	**18 665**	**15 973**	**(2 692)**	**2 177**	**2 299**	**122**

Approach/Methodology used

7.5.5 The review of IPP costs is guided by section 13 of the MYPD4 Methodology. Section 13.3 of the Methodology 'provides for all Power Purchase Agreement (PPA) costs, including energy payments, capacity payments and any other payments, to be allowed as a full pass-through cost'.

7.5.6 Section 13.9 of the Methodology, however, requires each pass-through cost item to be evaluated to ensure that it was incurred efficiently and in compliance with the terms and conditions of the contracts.

Analysis of Renewable Energy IPPs

7.5.7 Renewable Energy IPPs were procured by the DMRE, and it was determined that Eskom should be the buyer in accordance with section 34 of the Electricity Regulation Act of 2006.

7.5.8 Under this programme, Eskom is entitled to recover the PPA costs from the tariffs.

7.5.9 The PPA was negotiated among the DMRE, IPPs and Eskom to ensure that it is bankable. NERSA then approved the terms and conditions of the PPA. The costs incurred by Eskom under this programme qualify to be treated as pass-through

costs, provided they were incurred in accordance with the terms and conditions of the PPA.

7.5.10 Eskom's RCA application costs for REIPPs are R30 554m for the procurement of 15 073GWh. This is against NERSA's decision of R38 220m for the procurement of 18 577GWh. Eskom attributed the lower amount of energy procured from REIPPs to the delays in reaching the commercial operation dates (CODs) by the Bid Window 4 (BW4) projects. Eskom says the delays were caused by the Covid-19-induced global lockdown measures, which had a negative impact on the production and procurement of the parts and equipment required for the completion of the construction of the projects. However, this is not entirely true. The delays in reaching CODs were caused by Eskom's well-documented refusal to sign the PPAs for the BW 3.5 and 4 projects.

7.5.11 Based on the facts above, the RCA applied for should be allowed.

Deemed Energy Payments

7.5.12 The deemed energy payments are allowable in the PPA, but the buyer must prove that it was operating prudently and that it efficiently incurred each deemed energy payment made, as required by section 13.10 of the Methodology.

7.5.13 Deemed energy payments for FY2021/22 were due to curtailment events. Curtailment is a prudent action by the system operator when there is over-generation in the system, such as when the thermal generators are already at their minimum stable generation level and cannot be ramped down further without shutting them down, which would result in greater start-up costs and risk of start-up failure.

7.5.14 Eighteen curtailment events occurred during FY2021/22. The total cost of these deemed energy payments was R33.7m (included in the RE cost applied for). This cost should be allowed as a pass-through cost because it was incurred in accordance with the terms and conditions of the PPA and was incurred prudently to save the system. Curtailment of renewable energy IPPs during low-demand situations is a prudent response to the system risk where thermal generators are severely constrained from ramping down further (due to operating at or near the minimum stable generation level).

Use-of-System Charges

7.5.15 The use-of-system (UoS) charges incurred by the buyer in line with the PPA will be allowed as a full pass-through cost in compliance with the MYPD Methodology.

7.5.16 The total UoS charges for the 2021/22 financial year are R237.87m and are included in the R30 554m. Therefore, the UoS charges incurred by the IPPs are treated as a pass-through cost to the buyer in accordance with the PPA.

DoE Peakers

7.5.17 Eskom fully dispatches the peaker stations, and the payment is split between capacity and energy payments. Eskom spent R6 159m on buying 899GWh from the DMRE peaker stations (Avon and Dedisa) against the approved amount of R2 513m for buying 88GWh.

7.5.18 This translates to a 10.28% dispatch load factor against the decision load factor of 1%. This dispatch load factor is also 71% higher than the design load factor of 6%. To meet demand, Eskom had to dispatch the peaker stations more often to mitigate the lower REIPP output to meet demand.

7.5.19 Therefore, the variance of R6 159m should be allowed because the over-utilisation was caused by lower REIPP output due to the BW4 projects' delay in reaching the COD, which is beyond Eskom's control.

7.5.20
7.5.21
7.5.22

7.5.23 Table 61 below shows that a total of R3 917m is in favour of the customers.

Table 61: Allowable RCA cost

Independent Power Producers 2021/22	Cost (R'm)		
	RCA Application	NERSA Adjustment	NERSA RCA Decision
Renewable Energy IPPs	-7 665	0	-7 665
DoE Peaker	3 647	0	3 647
Other (correction on Decision and Dec)	101	0	101
Total IPPs for RCA	**-3 917**	**0**	**-3 917**
FY2022 RCA Variance	**-3 917**	**0**	**-3 917**

7.6 INTERNATIONAL PURCHASES

Summary of the application

7.6.1 In the application submitted to NERSA, Eskom indicated that some energy was sourced from neighboring countries, and it resulted in purchases of R6 459million, which generated energy inflows during the financial year. The details of the variance between the actuals and the NERSA decision are outlined in the **Table** 28 below.

Table 28: International Purchases

International Purchases (R'm)	Decision	Actuals	Variance
	FY2023	FY2023	
International Purchases	4 589	6 459	1 870

7.6.2 As with the past years of MYPD, the majority of cross–border purchases are from Hidroelectrica de Cahora Bassa (HCB), which is a hydro electrical plant in Mozambique. Eskom indicated that during the FY2022, HCB performed better than its historical trend as used in the MYPD application.

7.6.3 Eskom also indicated that, when HCB performs higher than their Contractual Maximum Demand (CMD) of 1 150MW consistently, the energy cost and reliability premium costs as per the bilateral contract increases. In addition, Eskom indicated that in line with the contract, they pay a higher rate to HCB, for any excess power supplied. In summary, the improved performance resulted in higher volumes being purchased, at a higher rate than in the application, and hence at a higher overall cost to the contract.

7.6.4 Lastly, the application also indicated that the contract provides for a 5 yearly tariff reset based on the avoided cost of Eskom generation and transmission. The calculation is based on the most recent Eskom AFS, whose outcome could not be reasonably determined at the time of the application. The new tariff was effective 1 January 2023, covering portion of the above period.

NERSA ANALYSIS

Approach/principle used

7.6.5 Cross border IPPs purchase costs is guided by section 13 of the MYPD4 Methodology. Section 13.3 of the Methodology provides for all Power Purchase Agreement (PPA) costs, including energy payments, capacity payments and any other payments, to be allowed as a full pass-through cost.

7.6.6 Section 13.9 of the Methodology, however, requires each pass-through cost item to be evaluated to ensure that it was incurred efficiently and in compliance with the terms and conditions of the contracts.

Analysis of the application

7.6.7 Eskom submitted the invoices of HCB indicating energy and costs associated with the contracted energy purchases. In addition to the invoices, energy wheel data indicating actual energy purchases was also submitted.

7.6.8 The total energy imported during FY2023 was about 8 654GWh, priced differently, depending on the applicable contractual tariff rate i.e. high rate and low rate.

7.6.9 The source of energy from international purchases (mainly from HCB) is baseload, and compared to energy from other local baseload IPPs or intermittent renewable energy IPPs, it is still competitive, and hence it is the preferred source whenever it is available.

7.6.10 The power received, at competitive prices, from external countries was beneficial to South Africa during the periods of constrained power supply and load shedding.

7.6.11 Given the positive benefit of international energy purchases highlighted above, the variance of R1.870billion is allowed for Eskom to recover the variance in FY2023. Table 29 summerises the allowable variance for FY2023.

Table 29: International Purchases decision

	Cost (R'm)				
International Purchases (FY2023)	NERSA MYPD 5 (FY2023) Decision	Actual FY2023	Eskom RCA Application	NERSA Adjustment	NERSA RCA Decision
Purchases (R'm)	4 589	6 459	1 870	0	1 870

Stakeholder comments

7.6.12 No specific comments were received for international purchases.

Conditions for approval

7.6.11 None.

7.7 DEMAND RESPONSE

Summary of the application

7.7.1 Demand Response (DR) was allocated R381million and R298million was spent on the programme cost. Eskom is applying for the RCA amount of R83million in favour of the customers as shown in Table 628 below.

Table 62: Demand Response (DR) RCA FY2022/23 Application

Demand Response (R'm)	Decision FY2023	Actual FY2023	Variance
Instantaneous (Rm)	-	141	-
Supplemental (Rm)	-	126	-
Programme Admin cost	-	31	-
Total programme costs	**381**	**298**	**(83)**

7.7.2 Power Alert was allocated R40million and R59million was spent on the programme cost. Eskom is applying for the RCA amount of R19million in favour of Eskom as shown in Table 63 below.

Table 63: Power Alert RCA FY2022/23 Application

Power Alert (R'm)	Decision FY2023	Actual FY2023	Variance
Total programme costs	**40**	**59**	**19**

NERSA Analysis

7.7.3 The Demand Response programme provides the System Operator (SO) with flexibility and reliability to maintain adequate daily operating reserve margins to cater for unforeseen circumstances that could affect the stability of the supply. Factors that could affect the stability of the electricity supply among others include the system constraints caused by severe weather and/or power line issues and generator malfunctions.

7.7.4 The Instantaneous Reserve from Demand Response is consumer load contracted to respond to a reduction in frequency. The purpose of Instantaneous Reserve is to arrest the frequency at acceptable limits following a contingency, for example a generator trip. The Supplemental Demand Response is a tool used by the SO to balance the supply and demand constraints. Eskom is applying for the Demand Response RCA amount of R83million in favour of the customer as per Table 628 above.

7.7.5 The Power Alert programme entails Power Alert meters that will give an indication of the strain on the electricity supply network and will urge the public to switch off avoidable appliances if the need arises. The Power Alert meter creates real-time awareness and voluntary reaction by the public when broadcasted. Eskom is

applying for the Power Alert RCA amount of R19million in favour of Eskom as per Table 639 above.

Approach/methodology used

7.7.6 Demand response programme costs are analysed in line with the MYPD4 Methodology.

NERSA adjustments and reasons

7.7.7 The amount of R83million not spent on DR programmes will be returned to the consumer in line with the MYPD4 Methodology. NERSA has not made any adjustments, as shown in Table 30 below.

Table 30: Demand Response FY2022/23 NERSA RCA Decision

Demand Response (R'm)	NERSA Decision MYPD5 (2022/23)	Eskom's Actuals	Variance	Adjustments	NERSA Decision
Demand Response Programme (R'm)	381	298	-83	-	-83

7.7.8 The amount of R19million on Power Alert programmes will be credited to Eskom in line with the MYPD4 Methodology. NERSA has not made any adjustments, as shown in Table 31 below.

Table 31: Power Alert FY2022/23 NERSA RCA Decision

Power Alert (R'm)	NERSA Decision MYPD5 (2022/23)	Eskom's Actuals	Variance	Adjustments	NERSA Decision
Power Alert (R'm)	40	59	19	-	19

Stakeholder comments

7.7.9 No comments were received from stakeholders.

Conditions for approval

7.7.10 No conditions

7.8 SERVICE QUALITY INCENTIVES

Summary of the application

7.8.1 NERSA approved the targets for the service quality incentives (SQIs) for Transmission and Distribution for the MYPD4 period. Eskom uses these targets, based on the performance of its two divisions, to determine the RCA amounts to apply for. The value of the scheme is set to 1% of the allowed revenue requirements for both Transmission and Distribution.

7.8.2 Eskom is applying for R69m as part of its performance on service quality incentives (SQIs) during the financial year for Distribution, and R0m for Transmission. Eskom used the approved pre-selected parameters to calculate the amount applied for, based on its System Average Interruption Frequency Index (SAIFI) performance.

7.8.3 Table 64 below shows the summary of the SQIs.

Table 64: Summary of service quality incentives

Eskom SQIs	Incentive/ (Penalty)	RCA R ('m)
Distribution SQIs	Incentive	69
Transmission SQIs	Neutral	0
Total SQI		69

7.8.4 Eskom Transmission Service Quality Incentive Scheme with NERSA comprises the following three measures:

a) System minutes (<1)
b) Number of major incidents (SM>1)
c) Line faults / 100 k.

7.8.5 Table 65 below shows the performance results for these measures for Transmission.

Table 65: Transmission service quality incentives

Transmission SQIs	Performance Results	Incentive / (Penalty)	Rand Value (R'm)
SM<1	2.88minutes	-	0
Major incidents	2	-	0
Line faults / 100km	2.56 faults	-	0
Total Transmission SQIs (R'm)		-	0

7.8.6 Eskom Distribution Service Quality Incentive Scheme with NERSA comprises the following three measures:

a) System average interruption duration index (SAIDI)
b) SAIFI
c) High voltage supply loss index (HSLI).

7.8.7

7.8.8 Table 66 below shows the performance results for these measures for Distribution.

Table 66: Distribution service quality incentives

Distribution Service Quality Incentives (SQI)	Performance Results	Incentive / (Penalty)	Rand Value (R'm)
SAIDI	35.36	-	0
SAIFI	12.34	Incentive	69
HSLI	12.83	-	0
Total Distribution SQI (R'm)		-	69

NERSA Analysis

7.8.9 Eskom used the MYPD4 targets to calculate the performance levels achieved in order to determine the amount to apply for. The amount is correct according to the approved targets, and the performance is correct according to the report NERSA received.

7.9 ENVIRONMENTAL LEVIES

Summary of the application

7.9.1 The government imposes certain taxes and levies, which are payable by Eskom.

7.9.2 The environmental levy rate has been 0.035c/kWh since July 2012. These are actual payments to SARS, determined by the true metered generated volumes. For this submission, Eskom indicated that the production plan, which measures energy sent out as measured after the high voltage transformer, was used to derive the assumed cost. This derived generated volume is then charged at the applicable environmental levy rate for that period to obtain the forecast cost per power station. It is assumed that no further rate increases will occur in the planning period.

7.9.3 Table 67 below shows that Eskom was allowed R7 266m for the environmental levy. However, it spent R7 512m and claimed a variance of R246m. The amount is based on GWh volumes sent out. The above variance was because the production

plan volume and the volume used in calculating environmental levies did not correspond.

Table 67: Environmental levy cost calculation of RCA balance (R'm)

Environmental levy	Decision FY 2022	Actuals FY 2022	Variance
Total Non-Renewable energy sent out (GWh)	207 608	196 643	-10 965
Add: Auxilliary volumes (GWh)	0	17 988	17 988
Generating volumes	**207 608**	**214 631**	**7 023**
Rate in c/kWh	3,5	3,5	3,5
Generation Environmental Levy Cost	**7 266**	**7 512**	**246**

Approach/methodology used

7.9.4 Section 16.4.1 of the MYPD4 Methodology states that taxes and levies will be treated as a pass-through cost in the MYPD with section 16.4.2 clearly indicating that Taxes and levies be treated as a separate account in the Eskom revenue determination.

7.9.5 When making the MYPD4 determination, NERSA adopted an approach stated in section 16.4.4 of the Methodology, which requires that any over or under recovery be adjusted through the RCA mechanism.

NERSA adjustments and reasons

7.9.6 Table 68 below shows that Eskom incurred environmental levy costs of R246m more than the NERSA decision for FY2021/22. The actual amount of R7 512m claimed by Eskom as actual expenditure on environmental levies corresponds with the regulatory reports. NERSA has independently verified the environmental levy amount through the RFRs' distribution licence submission IS2 and annual financial statements, and the levy amount corresponded in both reports. Therefore, the variance of R246m due to Eskom is allowed as applied for.

Table 68: Environmental levy cost – NERSA decision (R'm)

Environmental levy	Decision F2021	Actuals F2021	Variance	Adjustments	NERSA Decision
Total Non-Renewable energy sent out (GWh)	207 608	196 643	-10 965	0	-10 965
Add: Auxilliary volumes (GWh)	0	17 988	17 988	0	17 988
Generating volumes	**207 608**	**214 631**	**7 023**	**0**	**7 023**
Rate in c/kWh	3,5	3,5	3,5	0	3,5
Generation levy cost (Rm)	**7 266**	**7 512**	**246**	**0**	**246**

Stakeholder comments

7.9.7 No comments were received from stakeholders.

Conditions for approval

7.9.8 There will be no conditions of approval, as the levies are policy issues enacted by the government.

8. ECONOMIC IMPACT

Summary of the Application

8.1. In terms of the 2022/23 RCA application submitted by Eskom there is no section looking at the economic impact of the inclusion of the RCA balance in future Allowable Revenue (AR). However, Eskom has indicated that the electricity sales during the period under review reflect a challenging macro-economic environment and load shedding. The application indicates other reasons for the negative variance relating to severe load-shedding, poor economy, and in some instances severe floods, as well as the increased price of the fuel compared to the NERSA decision. Eskom has also indicated that the overall impact of loadshedding has thus been minimized due to OCGT's having been dispatched in accordance with the NERSA regulatory rules and codes. Although the application does not have a line item looking into the economic impact, Eskom does acknowledge the difficulties facing the economy which have an impact on electricity.

NERSA Analysis

8.2. The energy sector has been and continues to be, a driving factor in the South African economy. Electricity prices impact several economic agents and macroeconomic factors. To be specific, the electricity industry plays a significant role in the economy as it forms part of the production process of various key economic sectors.

8.3. The South African economy is made up of various energy-intensive industries, such as mining, iron and steel, and other metals, among others. Any electricity price increase would undermine economic growth and poverty reduction. It is

crucial to note that the decision by the Energy Regulator on Eskom's Regulatory Clearing Account (RCA) application for the 2022/23 financial year is taken at a time when the country is facing several economic and political challenges.

8.4. The South African economy managed to escape a technical recession with two consecutive quarters of 0.2% quarter-on- quarter contractions in the middle of 2023. Although this was followed by a slight quarterly expansion in the fourth quarter of 2023, unfortunately in the first quarter of 2024, it contracted to 0.1% quarter-on-quarter (q-o-q). According to the Bureaux for Economic Research (BER) (July 2024), the contraction resulted from contractions in most industries as well as the plunge in domestic demand compared to the fourth quarter of 2023.

8.5. The continued crumble in private sector investment has become a frustrating factor with the capex now measuring to pandemic lows (about 25% lower than pre-pandemic level). Furthermore, this crumble is being felt across board with the exception of the machinery and equipment which has been championed by the rise in renewable energy-solar-investment. Private fixed investment is expected to decline by 2% in 2024 before recovering to 5.4% in 2025.

8.6. The absence of load-shedding for a sustained period of time is expected to have a positive impact on trade, production and if sustained, sentiment and investment spending in the coming years (BER, July 2024). If sustained and further local rail and port disruptions are alleviated, some trade benefits should be seen and spill over to faster growth going into 2025. Further positive impact of no loadshedding has been as follows:

a. **Industrial activity** - manufacturing production jumped in April (5.2% month-on-month (m-o-m); 4.9% year-on-year (y-o-y)) however, it retracted in May (3.2% m-o-m; 0.6% y-o-y) despite the absence of load-shedding. The jump and subsequent drop in mining output was less prominent (0.8% m-o-m increase in April and 0.6%

drop in May). The drop in mining output is likely resulting from the lingering of Transnet rail and port issues while prevailing low Platinum Group Metals (PGM) prices were not conducive to ramping up production (BER, July 2024). A sustained improvement in Eskom's coal-fired generation plants could have a positive impact on coal production.

b. **Consumer spending** – according to BER (July 2024), a previous study by Discovery Bank and Visa showed that load-shedding increases spending on restaurants and on takeaways. While the absence of load-shedding has the opposite impact on consumer spending, the other reason could also reflect a consumer under pressure and opting to make food at home.
c. **Sentiments** – the absence of load-shedding has the ability to positively impact sentiments however, it will take a while for trust and confidence to rebuild.
d. **Profitability** - businesses that are dependent on diesel generators for power to escape load-shedding should have seen a decline in costs however, the question is whether this filters through to higher profitability or translates to slower price increases (and thus lower inflation) for consumers. Households as well as businesses that have switched to solar energy may experience additional benefits resulting from lower electricity bills (depending on the financing of the initial solar installation).
e. **Net trade dynamics** – less usage of open-cycle gas turbines (OCGTs), lower diesel imports as well as reduced private sector diesel generator usage should benefit net trade dynamics. Exports should also benefit from a sustained period of no load-shedding and a higher electricity availability factor (EAF).

8.7. On the political front, according to BER (July 2024), the Government of National Unity (GNU) has given South Africa hope for the future. Given the current political certainty and the expectation of some positive steps on the policy front, the GNU should assist in improving consumer and business sentiment in the second half of the year. The improved sentiment can lead to lower inflation as well as a decline in borrowing costs which may boost growth in the coming quarters.

8.8. In terms of the unemployment, an increase of 158 000 in unemployed persons was recorded in the second quarter of 2024 following an increase of 330 000 in

the first quarter of 2024 (Statssa, July 2024). Unfortunately, this is the third consecutive increase from the fourth quarter of 2023. The official unemployment rate has increased to 32.9% in the first quarter of 2024 from 32.1% in the fourth quarter of 2023.

8.9. Real household consumption slowed further, in annual growth terms, from 0.7% year-on-year in the third quarter of 2023 to a mere 0.3% year-on-year in the fourth quarter of 2023. Final consumer spending is expected to increase by 0.6% in 2024, followed by increases of 2% and 2.1% in 2025 and 2026, respectively. This outlook is based on the expectation of an improvement in consumer confidence leading to willingness to spend in the second half of 2024.

8.10. In addition, a moderation in food inflation and an increase of R20 (5.7%) in the Social Relief of Distress (SRD) Grant should pave the way for food & beverage sales to improve during 2024. This increase in the SRD grant is the first increase since it was initially introduced at a monthly rate of R350 in the year 2020. Over the course of a year, the 9.2 million recipients of the SRD grant will receive an additional R2.2 billion in their pockets thanks to the rise to R370 per month.

8.11. The start to 2024 was uncertain with inflation outcomes worse than expected which led to repricing of rate projections. However, recent developments have been slightly positive. South Africa's inflation trajectory exhibited a new trajectory, with the annual headline inflation rate advancing to 5,6% in February (increasing from 5,3% in January) followed by a decrease to 5.3% in March. This was followed by another decrease to 5.2% in April and May (has remained constant). The declining trend continued further between June and July with 5.1% and 4.6%, respectively.

8.12. In July 2024, the SARB considered the inflation forecast risks to be broadly balanced following the slightly better than expected CPI performance since March. Following this, the SARB revised the inflation projection to the 4.9% (revised from 5.1%) for 2024. The consumer price index (CPI) is now expected to drop below the

4.5% midpoint over the coming months due to food and fuel prices as well as the stronger rand. To be exact, CPI is expected to average 4.8% in the third quarter of 2024 and 4.1% in the fourth quarter of 2024 (BER, July 2024). Furthermore, it is expected that CPI will average 4.6% and 4.5% in 2025 and 2026, respectively. While inflation expectations do not yet reflect the 4.5% midpoint objective over the medium term they are certainly moving in the right direction. Achieving the 4.5% midpoint objective will assist in improving the economic outlook and reducing borrowing costs.

8.13. The SARB has identified additional measures that can further improve the economic conditions as the following:

a. keeping real wage growth in line with productivity gains;
b. lowering administered price inflation;
c. improving the functioning of network industries; and
d. reaching a prudent public debt level.

8.14. The exchange rate of the rand has been particularly volatile since March as it has traded in a range of R19.32 per US$ (April 19) to R18.05 per US$ (May 22) (SARB, May 2024). It briefly appreciated to a 10-month high against the dollar towards the end of May 2024, however, remained roughly unchanged in July. The rand is driven by inflation and the interest rate differentials between South Africa and the United States and has scope to strengthen further once the US Fed starts easing. The rand is expected to appreciate to R18.33 in 2024 (from R18,45 in 2023) and R17,82 in 2025. However, a depreciation of between 1.2% and 1.7% y-o-y can be expected between 2026 and 2029. A stronger rand supports a favourable inflation outlook, although high global interest rates still present a risk to the currency.

Approach/methodology used

8.1 The MYPD Methodology is not prescriptive in terms of economic impact. The Methodology does not indicate how economic impact is factored into the decision-making process. NERSA has developed a suite of macroeconomic models to assess the different liquidation scenarios of the approved RCA balance. The liquidation

scenarios are quantified using the following set of economic models applied in tandem: The Leontief Price Impact modelling system based on the Social Accounting Matrix (SAM), the International Trade Model, and the Macroeconomic Impact Assessment Model (MEIA). These models are used to assess the impact of liquidating scenarios on the GDP, inflation, investment, employment, key economic sectors and households' income 'ceteris paribus'.

NERSA adjustments and reasons

8.2 The current MYPD Methodology has no adjustment factor that is linked to the economic impact.

Stakeholder comments

8.3 Various stakeholders presented at the public hearing and highlighted that the RCA is a source of price instability and unpredictability, which ultimately has an impact on companies' investment decisions. One stakeholder (Minerals Council of South Africa) recommends that the RCA be promptly liquidated in full, whereas the Agri Western Cape is of the view that the outstanding RCA balance should be recouped over time.

8.4 NERSA agrees that the electricity industry plays a significant role in the economy, as it forms part of the production processes of various key economic sectors. Any electricity price increase would undermine economic growth and poverty reduction. However, NERSA disagrees with the proposal to liquidate the RCA balance in full, as this vicious cycle is likely to result in continued harm to consumers/customers who are unable to switch to alternative energy sources.

Conditions for approval

8.5 No conditions can be stated since a thorough analysis of the economic impact will be provided in the RCA implementation plan.

Conclusion

8.6 NERSA will provide a full ex-ante socio-economic impact assessment of the approved RCA balance in the RCA liquidation assessment (implementation plan) in due course. The assessment will consider the different scenarios, and each scenario will include all economic and social issues and various written inputs provided by stakeholders during the public participation process. In principle, NERSA agrees that any unjustifiable electricity tariff increase will have far-reaching consequences on the economy and its ability to generate and sustain jobs.

9. FINANCIAL IMPACT

Summary of the application

9.1 Eskom stated that the viable financial ratios that NERSA aimed to achieve in the revenue decision have still not been achieved after the RCA application was made. The appropriate ratio to be considered is the debt service cover ratio, and the Earnings Before Interest, Tax, Depreciation, and Amortisation (EBITDA) is used as a proxy for cash from operating activities. The ratio of 0.29 times (without taking into account the R31 693m government equity) and 0.51 times (when taking into account the R31 693m government equity) indicated that the EBITDA was insufficient to cover the debt service commitments. Even when the RCA balance was included in the EBITDA to determine the impact the RCA would have on the ratios, the ratios were still significantly below 2 times. As acknowledged by NERSA, the equity support was incorrectly deducted in the original revenue decision. This incorrect deduction has significantly worsened Eskom's financial situation, which cannot be remedied by this RCA application.

NERSA Analysis

9.2 Eskom is liable for both the interest expense and the principal debt. Therefore, it is necessary to measure the EBITDA-to-debt service coverage ratio (DSCR)[7]. The DSCR measures Eskom's ability to pay off its total incurred debt (principal and interest). The acceptable DSCR level is 1.25 times. This implies that Eskom makes 25% more income than it needs to cover its debt in a given period.

9.3 In Eskom's current case, the DSCR levels range between 0.29x and 0.51x, with the exclusion and inclusion of the R31 693m government equity, respectively. Based on the two scenarios stated above, the below 1x mark means that Eskom only has sufficient income to cover 29% and 51% of its annual debt repayments, respectively.

9.4 Eskom functions in an investment-driven segment; hence, it is important that its liquidity position must be better managed. As a result, when the debt is addressed effectively, the much-needed investment will be enabled, and the company will meet its financial obligations. For this reason, Eskom is always encouraged to manage its debt.

Approach/methodology used

[7] $EBITDA\ to\ Debt\ Coverage\ Ratio = \frac{Earnings\ Before\ Interest\ Tax\ Depreciation\ and\ Amortization\ (EBITDA)}{Total\ Debt\ (Principal+Interest)}$

9.5 The financial impact will be analysed in line with Eskom's debt and interest expenses since it is not detailed in the MYPD 4 Methodology.

NERSA adjustments and reasons

9.6 A detailed financial impact analysis on Eskom's ability to service its debt and interest expenses, as well as the impact on customers, will be presented in the implementation plan. In addition, the plan will detail how the approved RCA balance will be recovered.

Stakeholder comments

9.7 No comments were received from stakeholders.

Conditions for approval

9.8 No conditions can be stated, as a detailed analysis of the financial impact will be provided in the implementation plan.

10. CONFIDENTIALITY

10.1 All figures are confidential until the RfD document has been approved for publication.

11. CONCLUSION AND RECOMMENDATION

11.1 From a conspectus of the facts and evidence presented to the Energy Regulator, it is appropriate to consider the review of Eskom's FY2021/22 RCA application.

End.