**NATIONAL ENERGY REGULATOR OF SOUTH AFRICA**

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**Decision and Reasons for Decision**

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# Eskom Holdings SOC Limited: Eskom’s revenue application for 2018/19

**NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)**

In the matter regarding

**Eskom's revenue application for 2018/19**

By

**ESKOM HOLDINGS SOC LIMITED ('ESKOM')**

**THE DECISION**

Based on the available information and analysis performed, the Energy Regulator decided at its meeting on 15 December 2017, that:

1. The allowed revenues, standard prices and percentage increase are approved for Eskom's financial year 2018/19 as detailed in Table 1.

**Table 1: Allowed Revenue Decision**

| | Units | Eskom Application 2018/19 | NERSA Adjustment | NERSA Decision 2018/19 |
|---|---|---|---|---|
| Total expected revenues from all customers (A+B) | Rmillion | 219 514 | -29 166 | 190 348 |
| Negotiated Pricing Agreements and International customers (A) | Rmillion | 13 308 | 630 | 13 938 |
| Revenues from tariff based sales (B) | Rmillion | 206 206 | -29 796 | 176 410 |
| Forecast sales to tariff customers (C) | GWh | 192 953 | -4 871 | 188 082 |
| Standard average price (B ÷ C * 100) | c/kWh | 106.87 | | 93.79 |
| % Price increase | % | 19.90% | | 5.23% |

2. The allowed revenue of R190 348 million is to be recovered by Eskom through its various elements as detailed in Table 2.

**Table 2: Eskom Allowed Revenue by Element for 2018/19**

| Elements (Rmillion) | Eskom Application 2018/19 | NERSA Adjustments | NERSA Decision 2018/19 |
|---|---|---|---|
| Return | 22 690 | 5 427 | 28 117 |
| Expenditure | 62 221 | -11 099 | 51 122 |
| Primary Energy | 58 331 | -10 777 | 47 554 |
| Open Cycle Gas Turbines (OCGTs) | 691 | -346 | 345 |
| Demand Market Participation (DMP) | 319 | -29 | 290 |
| Independent Power Producers (local) | 34 209 | -7 613 | 26 596 |
| International Purchases | 3 216 | - | 3 216 |
| Depreciation | 29 140 | -4 237 | 24 903 |
| Integrated Demand Management (IDM) | 511 | -511 | - |
| Research and Development | 193 | -81 | 112 |
| Levies and Taxes | 7 994 | 99 | 8 093 |
| **Total Allowed Revenues** | **219 515** | **-29 167** | **190 348** |

3. The allowed revenues must be recovered from both Eskom standard and non-standard tariff customers (Negotiated Pricing Agreements and International Customers) based on the previously approved tariff principles and structures using the Eskom Retail Tariff Structural Adjustment (ERTSA) Methodology as approved by NERSA.

4. NERSA will consider the ERTSA for the 2018/19 financial year following submission of the application by Eskom.

**Abbreviations and Acronyms**

| | |
|---|---|
| AGR | Automatic Generation Control |
| AFS | Annual Financial Statement |
| AICD | Australian Institute of Company Directors |
| BER | Bureau of Economic Research |
| BUSA | Business Unity South Africa |
| BW | Bidding Window |
| c/kWh | Cents per kilowatt hour |
| CAGR | Compounded Annual Growth Rate |
| Capex | Capital expenditure |
| CAPM | Capital Asset Pricing Model |
| CECA | Capital Expenditure Clearing Account |
| CFL | Compact Fluorescent Lamp |
| CODs | Commercial Operation Dates |
| COGEN | Co-generation |
| CoGTA | Department of Co-operative Governance and Traditional Affairs |
| CPA | Contract Price Adjustment |
| CPI | Consumer Price Index |
| CSP | Concentrated Solar Photovoltaic |
| DMP | Demand Market Participation |
| DoE | Department of Energy |
| DR | Demand Response |
| DSCR | Debt Service Coverage Ratio |
| DSLI | Distribution Supply Loss Index |
| DTC | Design to Cost |
| dti | Department of Trade and Industry |
| DWS | Department of Water Affairs and Sanitation |
| EA | International Energy Agency |
| EAF | Energy Availability Factor |
| EBSST | Electricity Basic Services Support Tariff |
| EEDSM | Energy Efficiency and Demand Side Management |
| EIA | Environmental Impact Assessment |
| EPP | Electricity Pricing Policy |
| EPRI | Electric Power Research Institute |
| ERA | Electricity Regulation Act |
| ERTSA | Eskom's Retail Tariff Structural Adjustments |
| ESCO | Energy Services Company |
| FBE | Free Basic Electricity |
| FBS | Free Basic Services |

| | |
|---|---|
| FGD | Flue Gas Desulphurisation |
| FY | Financial Year |
| GDP | Gross Domestic Product |
| GHG | Green House Gases |
| GLF | Generation Load Factor |
| GO | General Overhaul |
| GWh | Gigawatt hour |
| IDC | Interest during Construction |
| IDM | Integrated Demand Management |
| IEA | International Energy Agency |
| IMF | International Monetary Fund |
| IPPs | Independent Power Producers |
| ISMO | Independent System and Market Operator |
| km | Kilometre |
| kWh | Kilowatt hour |
| L&T | Levies and Taxes |
| LEC | Lesotho Electricity Company |
| LED | Light Emitting Diode |
| LF | Load Factor |
| MIRTA | Minimum Information Requirement for Tariff Application |
| MTPPP | Medium-Term Power Purchase Program |
| MTSAO | Medium-Term System Adequacy Outlook |
| MW | Megawatt |
| MWh | Megawatt hour |
| MYPD | Multi-Year Price Determination |
| NERA | National Energy Regulator Act No. 40 of 2004 |
| NERSA | National Energy Regulator of South Africa |
| NGO | Non-Governmental Organisation |
| NMD | Notified Maximum Demand |
| NPAs | Negotiated Pricing Agreements |
| OCGT | Open Cycle Gas Turbine |
| OCLF | Other Capacity Load Factor |
| OPEX | Operating Expenditure |
| PAJA | Promotion of Administrative Justice Act |
| PAMSA | Paper Manufacturers Association of South Africa |
| PBR | Performance Based Regulation |
| PCLF | Planned Capacity Load Factor |
| PDD | Project Design Development |
| PE | Primary Energy |
| PED | Primary Energy Division |
| PoD | Point of Delivery |

| | |
|---|---|
| PPA | Power Purchase Agreement |
| PPI | Producer Price Index |
| PV | Photovoltaic |
| R&D | Research and Development |
| RAB | Regulatory Asset Base |
| RCA | Regulatory Clearing Account |
| RE | Renewable Energy |
| REIPP | Renewable Energy Independent Power Producer |
| RFD | Reasons for Decision |
| ROA | Return on Assets (ROA) |
| ROA | Return on Assets (ROA) |
| SADC | Southern African Development Community |
| SAE | Southern African Energy |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SALGA | South African Local Government Association |
| SAPP | Southern African Power Pool |
| SAPPI | South African Pulp and Paper Industries |
| SAPVIA | South African Photovoltaic Industry Association |
| SASSA | South African Social Security Agency |
| SMMEs | Small, Medium and Micro Enterprises |
| SOC | State-Owned Company |
| SPA | Special Pricing Agreement |
| SQI | Service Quality Incentives |
| STATSSA | Statistics South Africa |
| STPPP | Short-Term Power Purchase Programme |
| UCF | Unit Capacity Factor |
| UCLF | Unplanned Capacity Load factor |
| UoS | Use-of-System |
| WACC | Weighted Average Cost of Capital |
| WEPs | Wholesale Electricity Pricing System |
| WUC | Work Under Construction |

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**LEGAL MANDATE**

1. Section 4(c) of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ('NERA') empowers and saddles 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) ('ERA').

2. The ERA sets out the functions of NERSA. Specifically relevant to this application is section 4(a)(ii), in terms of which NERSA is empowered to regulate prices and tariffs.

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; and
   (g) that a fair balance between the interests of customers and end users, licensees, investors in the electricity supply industry and the public is facilitated.

4. In order to facilitate compliance with the regulatory framework and create regulatory certainty regarding Eskom's revenue applications, NERSA developed a Multi-Year Price Determination Methodology (Methodology) and Minimum Information Requirements for Tariff Applications (MIRTA), which are binding.

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

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

**BACKGROUND AND INTRODUCTION**

7. Eskom's third Multi-Year Price Determination (MYPD3) control period started on 1 April 2013 and comes to an end on 31 March 2018.

8. Eskom should have submitted an application for its fourth Multi-Year determination (MYPD4) control period from 1 April 2018.

9. However, on 31 October 2016, Eskom submitted a request to the National Energy Regulator of South Africa (NERSA or 'the Energy Regulator') to consider a one-year revenue application for 2018/19. The following uncertainties were cited as the main reasons for its request:

   a) the pending update of the Integrated Resource Plan (IRP) for electricity;
   b) the pending update of the Integrated Energy Plan (IEP);
   c) the 3 000MW shortfall no longer being a factor and excess capacity being available during certain hours;
   d) the utilisation of Eskom's generation capacity needed to be re-considered as indications reflected the need to put into cold reserve, mothball or decommission several power stations, which would have far reaching economic and socio-economic implications;
   e) the further supply from Independent Power Producers (IPPs) needed to be resolved with Government; and
   f) Eskom's responsibility for the procurement for the nuclear build programme.

10. On 23 February 2017, the Energy Regulator approved Eskom's request to submit a one-year revenue application for the period 1 April 2018 to 31 March 2019.

11. On 28 March 2017 Eskom requested the Energy Regulator to grant it condonation from meeting specific requirements of the Multi-Year Price Determination (MYPD) Methodology and Minimum Information Requirements for Tariff Applications (MIRTA).

12. The Energy Regulator made a determination on Eskom's request for condonation from meeting specific requirements of the MYPD Methodology and MIRTA requirements on 27 July 2017 as follows:

    12.1. The Energy Regulator did not grant condonation on the following:

      i. MYPD Methodology:

a) Coal Volumes;
b) Coal Handling Costs per Station;
c) Water Costs; and
d) Water Treatment.

ii. MIRTA Requirements:
a) Sales Revenue and Demand Forecast;
b) Assets by Assets Class and Asset;
c) Capital Expenditure;
d) Asset Disposal and Impairment;
e) Depreciation;
f) Coal Purchase and Burnt;
g) Transport Costs;
h) Environmental Levy; and
i) Cash Flow Statements.

12.2. The Energy Regulator granted condonation on the following:

i. Valuation of Regulatory Asset Base (RAB). NERSA will use the MYPD3 closing balances as the base after taking into account, among others:
a) prudently incurred expenditure on assets;
b) assets retired based on excess capacity; and
c) the depreciation of assets since the MYPD3 revaluation.

ii. The condonation is only granted in respect of the one-year (2018/19) application. Eskom must revalue the asset base in time for its next MYPD application.

iii. Information is to be provided on the deferred debits and credits[1]. Condonation was granted as no RCA balance exists.

13. The Energy Regulator had further instructed Eskom to conduct consultations with key stakeholders for Research and Development (R&D) projects before the Energy Regulator decision on the revenue application was made. Eskom invited NERSA to the industry stakeholder review, which took place on 22 November 2017. The stakeholder workshop took place as scheduled and there was general support relating to the R&D projects to be undertaken by Eskom.

[1] Deferred debts and credits refer to balances in the RCA

## THE APPLICATION

14. On 25 August 2017, Eskom submitted an application to the Energy Regulator that was compliant with the MYPD Methodology and MIRTA as condoned.

15. Eskom has applied for a total allowable revenue of R219 514m for its 2018/19 financial year. The details of the revenue application are reflected in Table 3.

16. The focus of the Eskom application is on the required revenue for the 2018/19 financial year. This application does not include any Regulatory Clearing Account (RCA) adjustments arising out of the MYPD3 control period. The RCA applications for the MYPD3 control period will be dealt with in a separate process.

17. Eskom's revenue application for the 2018/19 financial year consists of nine broad categories of qualifying expenditure namely:

    a) Return on Assets (ROA);
    b) Operating expenditure (OPEX);
    c) Primary Energy (PE);
    d) Independent Power Producers (IPPs);
    e) International Purchases;
    f) Depreciation;
    g) Integrated Demand Management (IDM);
    h) Research and Development (R&D); and
    i) Levies and Taxes.

**Table 3: 2018/19 Total Allowable Revenue applied for (Eskom Table)**

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

*Source: Eskom Application 25 August 2017*

## THE APPLICANT

18. Eskom Holdings SOC Limited, Registration number 2002/015527/06, is a Schedule 2 South African state-owned enterprise 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 three licences granted by the Energy Regulator to generate, transmit and distribute electricity in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006).

19. Eskom generates, transmits and distributes electricity to industrial, mining, commercial, agricultural and residential customers, as well as other distributors. It also buys electricity from and sells electricity to the countries of the Southern African Development Community (SADC).

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

## THE DECISION-MAKING PROCESS

21. On 25 August 2017, the Energy Regulator received Eskom's revenue application for the 2018/19 financial year.

22. On 13 September 2017, the Energy Regulator published Eskom's application on the NERSA website with an invitation to stakeholders to submit written comments.

23. The closing date for comments was 13 October 2017.

24. The Energy Regulator conducted public hearings in eight provinces of South Africa from 30 October 2017 to 20 November 2017 to afford interested and affected stakeholders an opportunity to submit their views, facts and evidence.

25. The following is a list of all public hearings held:

    25.1. Western Cape, Cape Town: 30 & 31 October 2017

    25.2. Eastern Cape, Port Elizabeth: 1 November 2017

    25.3. Kwa-Zulu Natal, Durban: 2 & 3 November 2017

    25.4. Northern Cape, Kimberley: 6 November 2017

    25.5. Mpumalanga, Nelspruit:10 November 2017

    25.6. North West, Klerksdorp: 13 November 2017

    25.7. Free State, Bloemfontein: 15 November 2017

    25.8. Gauteng, Johannesburg: 16, 17 & 20 November 2017

26. The public hearing in Limpopo scheduled for 8 November 2017 did not take place as there were too few registrants to present at the hearing. The two presenters from Limpopo were accommodated through a videoconferencing facility during the Mpumalanga hearing.

27. The Energy Regulator made its determination on Eskom's revenue application for the 2018/19 financial year on 15 December 2017.

## STAKEHOLDER COMMENTS

28. In excess of 23 000 written stakeholder comments were received from private individuals, small users, intensive energy users, Non-Government Organisations (NGOs) and environmental activists, as well as local government and other stakeholders.

29. NERSA granted three requests to submit comments late and duly received the submitted comments as follows:

    29.1. Business Unity South Africa (BUSA) – 31 October 2017.

    29.2. Paper Manufacturers Association of South Africa (PAMSA) – 31 October 2017

    29.3. The South African Photovoltaic Industry Association (SAPVIA) – 20 October 2017.

30. Public hearings were held in eight provinces and 96 oral presentations were made.

31. All inputs received have been analysed as part of this report and are detailed in the following annexures:

    31.1. Summary of written comments – **Annexure A**

    31.2. Summary of issues raised at public hearings – **Annexure B**

**KEY ISSUES ARISING OUT OF STAKEHOLDER COMMENTS**

**32.** Having conducted the public hearings in terms of NERA and PAJA, comments and submissions made by stakeholders needed to be considered prior to making the decision. Stakeholders raised the following legal/regulatory and policy issues:

    32.1. Legal/regulatory issues

        32.1.1. Abandoning the processing of the application

        32.1.2. Lack of detailed information in the application

        32.1.3. Public interest

    32.2. Policy issues

        32.2.1. Electricity Pricing Policy (EPP)

        32.2.2. Environmental Levy Charge (electricity generated)

        32.2.3. Free Basic Electricity (FBE)

## LEGAL/REGULATORY ISSUES

33. Abandoning the processing of the application

33.1. Stakeholders requested that the Energy Regulator abandon the processing of Eskom’s application due to, among other reasons, a lack of detailed information in the application.

33.2. It is common cause that the Energy Regulator approved the MYPD Methodology in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) (‘ERA’) in October 2016 with the sole purpose of it being used to consider any subsequent revenue applications after the expiry of the MYPD3.

33.3. It is further common cause that the Energy Regulator determined that Eskom may submit a one-year revenue application for the 2018/19 financial year.

33.4. The Energy Regulator further made a determination on Eskom’s request for condonation from specific sections of the MYPD methodology (see paragraph 6 above).

33.5. On 25 August 2017, Eskom submitted its revenue application. The Energy Regulator noted that the application complied with the requirements of the MYPD Methodology and MIRTA including the decision of the Energy Regulator to condone non-compliance with certain aspects of the Methodology. On the basis of this assessment, the Energy Regulator took a decision to continue with the processing of the application.

33.6. A compliant application brings the process thereafter within the realms of procedural fairness requirement of section 10 of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) (‘NERA’) and Promotion of Administrative Justice Act, 2000 (Act No. 3 of 2000) (‘PAJA’), as well as the principles of the ERA.

33.7. Once the application is deemed to have complied with the MYPD Methodology and the MIRTA, the Energy Regulator does not have the discretion not to consider it and make a decision. It must be emphasised that in terms of PAJA, failure to take a decision is considered to be a decision that can be reviewed. The application has passed all the stages at which the Energy Regulator could have raised insufficiency or non-compliance issues, therefore it is trite that administrative law and ERA principles enjoin the Energy Regulator to consider this application.

33.8. Should the Energy Regulator accede to the request to abandon the consideration of the application, the following are the most pertinent legal and regulatory implications:

33.9. Eskom may take the decision for review by the High Court in terms of PAJA read with NERA or dispute resolution in terms of the Intergovernmental Relations Framework Act;

33.10. In line with the recent court judgement[2] , no tariff is to be charged to the customers for the period applied for; and

33.11. It would stifle the regulatory framework contemplated in section 2 of the ERA.

33.12. On the basis of the above, NERSA could not accede to the request not to process the application.

34. Lack of detailed information in the application

34.1. Stakeholders raised, amongst others, the following issues relating to lack of detailed information in the Eskom application:

34.1.1. No detailed information on Eskom coal costs;

34.1.2. No IPPs contracts details;

34.1.3. No detail on the R77bn on the capital expenditure;

34.1.4. The RAB information is non-existent;

34.1.5. Primary Energy calculations per methodology are missing;

34.1.6. Cost and subsidisation of special pricing arrangement and foreign sales are not disclosed; and

34.1.7. Integrated five year IDM plan is missing, but cost is part of the application.

34.2. Prior to publishing the revenue application, the Energy Regulator determined that the application meets the MIRTA and would provide sufficient detail to enable members of the public to properly comment.

[2] National Energy Regulator of South Africa and Another v Borbet SA (Pty) Ltd and Others, Eskom Holdings Soc Limited and Another v Borbet SA (Pty) Ltd and Others (1288/2016, 1309/2016) [2017] ZASCA 87; [2017] 3 All SA 559 (SCA) (6 June 2017)

34.3. Some of the information requested by stakeholders had been deemed confidential by the Energy Regulator after receipt of an application from Eskom for the confidential treatment of information. The Energy Regulator decided that the information contained in the request by Eskom deserves protection in terms of PAIA and cannot be disclosed to any third party, unless Eskom gives consent. PAIA contains an internal appeal process in the instance that a person who has requested the information is not satisfied with the reasons for refusing to provide the information.

34.4. The Energy Regulator duly considered the sufficiency of the application and resolved that it will enable the Energy Regulator to take a decision.

35. Public interest

35.1. Stakeholders raised, amongst others, the following issues relating to public interest:

35.1.1. Affordability;

35.1.2. Survival of businesses;

35.1.3. High unemployment;

35.1.4. Job losses;

35.1.5. Decrease in manufacturing capacity;

35.1.6. Dependence on imports; and

35.1.7. Poor governance at Eskom and its impact on tariffs

35.2. The NERA enjoins the Energy Regulator to, amongst others, consider public interest in taking a decision. NERA does not expand on the characters that should form part of public interest consideration when making a decision.

35.3. The Methodology has entrenched the above premise of public interest by highlighting that the Energy Regulator may apply reasonable judgement on the application by considering what may be in the best interest of the overall South African economy and the public.

35.4. Public interest judgement in this determination also required balancing the interests between Eskom's sustainability, its excess capacity position and the impact of increased operating and employee costs on consumers and the South African economy in support of Government's socio-economic objectives.

35.5. In light of the absence of pre-set characters, the Energy Regulator exercised its discretion whilst making the decision factoring such elements which it considers rational and reasonable and are more reflected in the economic impact analysis of this this reasons for decision. In addition, NERSA has exercised its judgement as required by the Methodology.

**POLICY ISSUES**

36. Electricity Pricing Policy (EPP)

36.1. Stakeholders raised, amongst others, the following key issues relating to the EPP:

36.1.1. Implementation of the cost of supply studies

36.1.2. Valuation of the regulatory asset base

36.1.3. Depreciation should not be allowed in a one year application.

36.2. The relevance of the Electricity Pricing Policy (EPP) is predicated on ensuring that electrification targets are met, providing low cost electricity, ensuring better price quality, financial viability, and proper co-ordination of operation and investments and retention of a competent work force.

36.3. The Department of Energy (DoE) is the custodian of the EPP and the role of NERSA in the development of the EPP is that of stakeholder commentary and not decision making.

36.4. Section 4(a)(iv), of the ERA requires the Regulator to issue rules designed to implement the national government electricity policy framework.

36.5. All policy issues relating to the EPP that have been raised during the public hearing and stakeholder submission process have been noted and will be directed to the Department of Energy as the EPP custodian.

37. Environmental Levy Account for Electricity Generation

37.1. Stakeholders raised, amongst others, the following issues relating to the Environmental Levy Account for Electricity Generation:

37.1.1. Since the objective of the levy is to penalize the customer for the use of non-renewable source of primary energy it is tantamount to double taxation to expect the same customer to also pay for the full cost of switching to renewable energy;

37.1.2. It is therefore proposed that the levy be reduced to 2c/kWh and that the potential savings of R3 426m will be achieved.

37.2. The development of an Environmental Levy Account for Electricity Generation originates from the Customs and Excise Act, 1964 (Act No. 91 of 1964) and the related powers to formulate policy resides with National Treasury (NT) and the South African Revenue Services (SARS). NERSA cannot amend or review the policy relating to the environmental levy, but will ensure that NT is made aware of the concerns raised.

37.3. The determination of the levy amount is a function dedicated to the National Treasury. The inclusion of the amount related to environmental levies for electricity generation prevents NERSA from removing the amount from the application.

37.4. All policy issues relating to the Environmental Levy Account for Electricity Generation that have been raised during the public hearing and stakeholder submission process have been noted and will be directed to the National Treasury as the Environmental Levy Account for Electricity Generation custodian.

38. Free Basic Electricity (FBE)

38.1. The stakeholders raised, amongst others, the following issues relating to Free Basic Electricity;

38.1.1. The units of Free Basic Electricity be increased by 200%.

38.1.2. Entitlements to FBE are not well communicated.

38.1.3. There appears to be lack of clarity between the application of IBT (Inclining Block Tariff) and FBE.

38.1.4. VAT should be removed from the electricity tariff.

38.2. The National Government made an announcement on the provision of Free Basic Services (FBS) including Free Basic Electricity (FBE) to households in 2001. Subsequently, the DoE introduced the Electricity Basic Services Support Tariff (EBSST) policy in 2003, which makes provision for 50kWh of electricity to be provided to indigent households identified by municipalities and connected to the national grid.

38.3. The FBE funding is provided by National Treasury to local authorities through the Equitable Share allocation as identified by the Department of Cooperative Governance and Traditional Affairs (CoGTA). The Local Government Equitable Share are funds that flow from the National Government and are equitably distributed to local authorities to supplement their internally generated revenues and provide basic services to poor households.

38.4. In areas where Eskom is the supplier, the municipality enters into an agreement with Eskom, who then supplies households that are in the Eskom supply areas within the municipal boundaries. The terms and conditions under which the service is provided and paid for are set out in a service level agreement between Eskom and the municipality

38.5. NERSA does not have the mandate on FBE implementation and can only annually review the NFBE rate that Eskom charges the municipalities for supplying FBE to households that are in the Eskom supply areas within the municipal boundaries. However, NERSA implements the DoE EBSST policy that was introduced in 2003.

38.6. All policy issues relating to the FBE that have been raised during the public hearing and stakeholder submission process have been noted and will be directed to the Department of Energy as the FBE custodian.

**ANALYSIS OF THE ESKOM REVENUE APPLICATION FOR 2018/19**

39. NERSA considered reasons, facts and evidence presented in various forms including, but not limited to, audit reports, management accounts, additional information requested from Eskom written and oral representations made by stakeholders at the public hearings when making its final determination.

40. For this application, given the condonation decision on the RAB, NERSA assessed the RAB for prudency in line with the MYPD Methodology as well as the applicable laws.

41. NERSA reviewed Eskom's forecast sales volumes based on the latest available information and current market conditions. The analysis resulted in a revision of the sales volumes and production plan. The revised production plan was developed taking into account a review of the production mix based on the adjusted production volumes. The alignment of the sales volumes, energy wheel and production plan is evident in the application as required by the

MYPD Methodology. The revised production plan was costed taking into consideration the amended production volumes, which resulted in the revised Primary Energy cost.

**SALES VOLUMES**

42. In its revenue application for 2018/19, Eskom is applying for a total sales volume of 216 208GWh for 2018/19, which is made up of Standard Tariff volumes of 192 953GWh, Negotiated Pricing Agreements of 9 621GWh and Export Sales volumes of 13 634GWh.

43. Table 4 illustrates Eskom's sales volumes forecast for 2018/19, together with its projection for 2017/18 in its application submitted on 25 August 2017 and actual sales achieved for the 2016/17 financial year.

44. Historic Eskom forecasting inaccuracies

44.1. Figure 1 illustrates that the gap between forecast volumes provided by Eskom in previous MYPD applications and actual sales volumes achieved. Eskom has consistently over-forecast its sales volumes with the difference for the 2017/18 tariff year being as high as 32 302GWh.

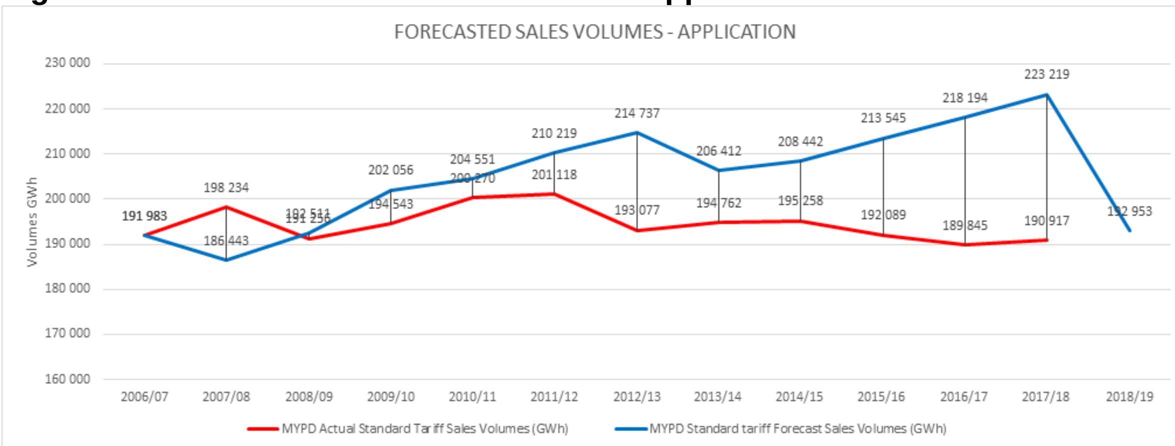
44.2. In the revenue application for 2018/19, Eskom has based the sales volumes on the current trend derived from the actual sales volumes achieved and estimates the 2018/19 sales volumes to be 192 953GWh. This is Eskom's reflection of the current condition of the market as required by clause 6.1.5 of the MYPD4 Methodology.

**Table 4: Eskom 2018/19 Sales Volumes Forecast (Eskom Table)**

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

*Source: Eskom Application 25 August 2017*

**Figure 1: Sales Volume Actuals vs. MYPD Approved Eskom Forecasts**




45. Eskom’s adjustment for what it terms ‘rebasing’ of sales volumes

45.1. In the application submitted on 25 August 2017, Eskom modelled for illustrative purposes, the impact of declining standard tariff sales volumes, by assuming the revenue requirement for the 2018/19 financial year is maintained as that of the 2017/18 financial year of R198 954 million less the savings realised on primary energy of R10 812 million due to lower sales volumes. The average standard tariff of 89.13c/kWh for the 2017/18 financial year when compared to the modelled average standard tariff of 97.50c/kWh for the 2018/19 financial year $\frac{(R198\ 954\ mil - R10\ 812 mil)}{192\ 953 GWh}$ would result in an average standard tariff increase of 9.4%.

45.2. However, the MYPD and ERTSA Methodologies do not contain or make reference to any concept of ‘rebasing’. The MYPD Methodology states:

> *‘6.1.5 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.*
>
> *6.1.6 NERSA shall review and adjust the sales volumes and assumptions used before the final decision due to the time lag between Eskom’s internal processes and the decision by NERSA.’*

45.3. The reason for this provision is to make sure that the decision uses the most accurate forecast available as this has an impact on the price and Eskom’s revenue recovery. However, since the price is calculated by dividing the allowed revenue by the forecast sales, if the sales decrease the price will increase provided the Allowed Revenue remains the same. If all the components of the Allowed Revenue formula change in line with the sales volumes, then changing sales volumes would not have an impact on the price.

45.4. Although NERSA's methodology requires the adjustment of the sales volumes to reflect current market conditions, it is incorrect to use the previous year's revenues as a base for the following year, because the revenue required by Eskom is a function of the costs (allowable revenue) and the sales volumes forecast to be achieved. Both the sales volumes and allowable revenue need to be adjusted. The adjusted sales volumes cannot be done in isolation from the related adjustment of costs. Therefore, the Energy Regulator has evaluated Eskom's allowable revenue taking into consideration the sales volume levels anticipated to be achieved in the 2018/19 financial year.

46. Eskom's Forecasting Methodology:

46.1. During the public hearings held in Gauteng Province on 16 November 2017, Eskom presented a revised sales volumes forecast based on the latest available information. Eskom also submitted a formal letter to NERSA on 28 November 2017 communicating these numbers. The MYPD4 Methodology clause 6.1.5 states that the 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. Table 5 shows the original sales forecast as per Eskom application 25 August 2017 versus its revised sales volumes submitted on 28 November 2017.

**Table 5: Eskom 2018/19 Sales Volumes Forecast (original vs. revised)**

| Category | 25 August 2017 (Original) (GWh) | 28 November 2017 (Revised) (GWh) | Difference (GWh) |
|---|---|---|---|
| Standard Tariff | 192 953 | 188 082 | -4 871 |
| Negotiated Pricing Agreements | 9 621 | 9 750 | 129 |
| Export Sales | 13 634 | 13 634 | 0 |
| **Total** | **216 208** | **211 466** | **-4 742** |

46.2. Eskom states that the sales volumes were forecast using a bottom-up approach, based on the 80/20 principle. They individually engage customers that make up 80% of the sales per category, to determine their consumption forecast. In addition, all top industrial customers consuming above 100GWh per annum are individually engaged to determine their consumption forecast regardless of whether they fall within the 80% sampling threshold or not.

46.3. The forecast utilised a total of 384 accounts (including 146 top industrial and mining customers). Forecasting is undertaken at the lowest level, meaning that it is done per point of delivery (POD). A total of 1 246 PODs were utilised in the forecast.

46.4. Table 6 illustrates how Eskom categorises its top industrial and mining customers. There are 193 top industrial customers and 146 of them were consulted.

**Table 6: Eskom categorisation of top industrial and mining customers consulted**

| Tariff Category | Industry | No. of customers | Type of customer |
|---|---|---|---|
| Megaflex | Smelters<br>Factories<br>Steel<br>Stainless Steel Plants<br>Cement Producers | 84 | Industrial |
| Megaflex | Coal<br>Iron Ore<br>Copper<br>Gold<br>Diamond | 109 | Mining |

46.5. Eskom stated that consultation with stakeholders and customers takes place when it submits the revenue application to NERSA. The application is then taken to the public domain and Eskom starts to consult with stakeholders/customers. Eskom further stated that the purpose of this consultation is not to consult on the sales forecast, but to inform stakeholders on the foundation and reasons for the costs, as well as the implications, of the revenue application. Furthermore, Eskom mentioned that there is no consultation on what the customer response will be if the 19.9% increase is approved by NERSA.

46.6. Eskom indicated that consultation started as early as February 2017, when active gathering of customer information was done by key customer executives until the close of the projecting cycle around June or July 2017.

46.7. The forecasting approach undertaken by Eskom is considered reasonable as customers were informed of the foundation and reasons for the costs in their application.

47. Utility Death Spiral

47.1. A utility death spiral is a term used to describe a negative cycle where utilities need to recover their costs from an ever diminishing customer base and declining sales volumes. In Eskom's case, continued increases in tariffs has seen commensurate decreases in consumption, which have been attributed to, among others, affordability limits having been reached by its customers in a depressed economic environment and a stagnant economy.

47.2. The vicious cycle is that of increasing electricity prices leading to declining sales, which results in the utility having to recover the same cost base (utilities generally have a significant component of fixed or sunk costs) from a shrinking customer base. This then results in an application for higher tariff increases. Sales decline further and the cycle starts again, which will result in a 'utility death spiral' if not arrested by way of deliberate and focused intervention.

47.3. The reduced demand manifests itself as a result of, among others, customers generating their own electricity (self-generation), large power users closing down plants or production allocations being moved to other countries where the price of electricity is lower and/or more stable.

47.4. Eskom argued against stakeholder comments during the public hearings that it is in the throes of a 'utility death spiral' by saying that electricity demand in South Africa is relatively inelastic in terms of price sensitivity. However, the economic modelling done by NERSA shows that this is not the case.

47.5. In order to break the vicious cycle, Eskom needs to either reduce its costs (including its fixed cost base) and hence its allowable revenue requirement while growing its sales volumes, thereby driving its tariffs to their most efficient level. This should result in smaller tariff increases going forward that will attract additional sales volumes, which will result in even smaller tariff increases and even higher sales volumes going forward and so on, allowing it to transition to a virtuous cycle, which is the desired future state.

48. NERSA analysis of Eskom's sales volume forecast

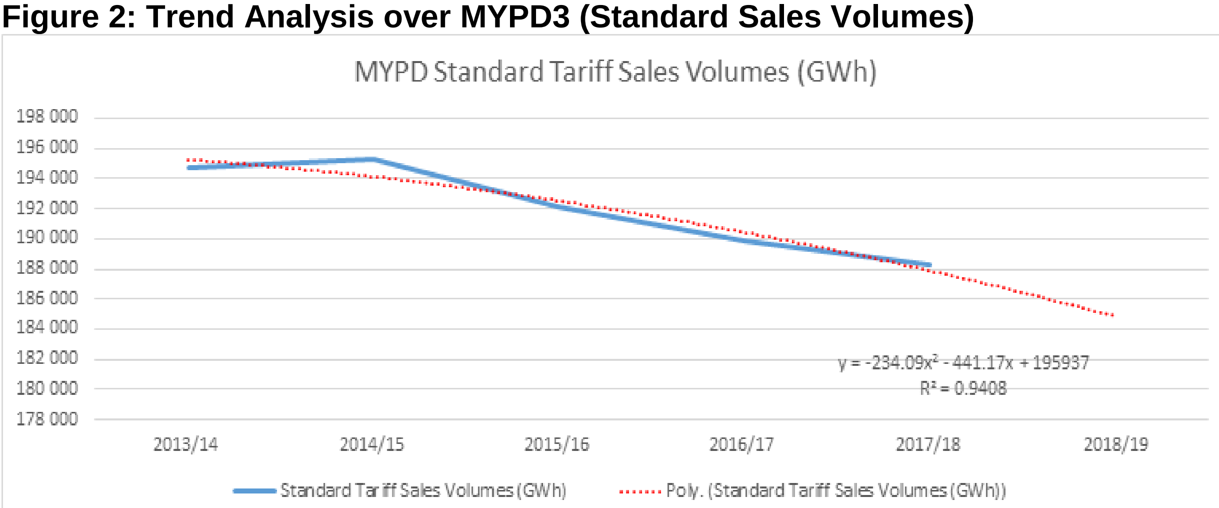
48.1. The information submitted by Eskom is evaluated by conducting polynomial trend analysis to verify the accuracy of the information. The polynomial analysis is most suited because it mirrors the actual data more accurately, as it uses the coefficient of determination ($R^2$), which is a measure of good fit to illustrate how well the trend line approximates the real data points. The R2 value is a number from 0 to 1 that reveals how closely the estimated values for the regression line correspond to the actual data, where 1 is a perfect fit.

48.2. The 12-year polynomial trend analysis (Figures 3, 5 and 7) is not a good reflection of the actual data points, when compared to the five-year polynomial trend analysis (Figures 2, 4, 6) as indicated by the lower R-squared. This seems to indicate that the market conditions have changed in recent times requiring reliance on more recent data. NERSA has therefore chosen to use the five-year polynomial trend analysis to forecast sales volumes.

48.3. Standard tariff sales volumes analysis

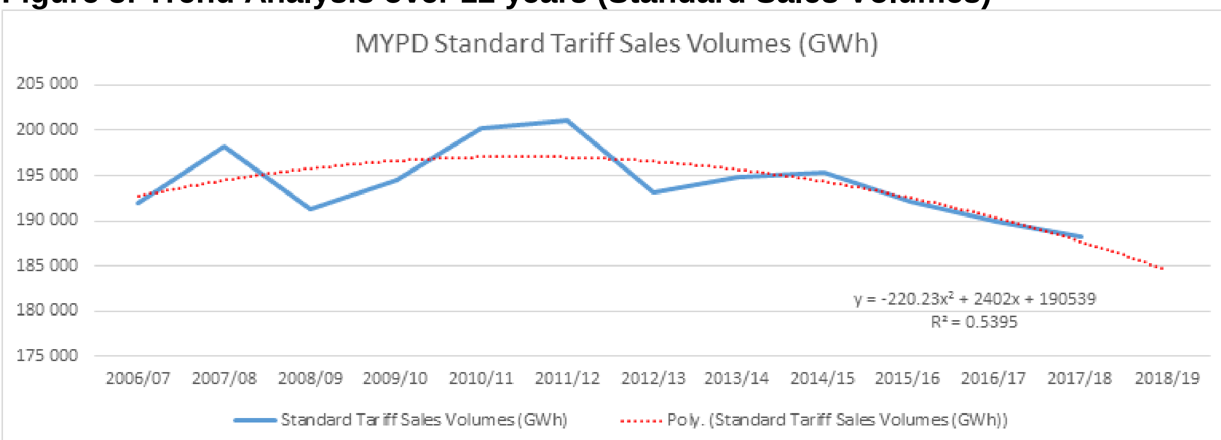
48.3.1. When assessing the standard tariff sales volumes, NERSA determined that in the second year of the MYPD3 period there is an increase of 0.25% in Standard tariff sales volumes. However, in the third and fourth years, there is a decline of 1.62% and 1.17% respectively. In the fifth year, Eskom has projected a decline in sales volumes of 1.47%. Figure 2 illustrates the trend analysis of the standard sales volumes over the MYPD3 period of five years and Figure 3 the analysis over 12 years.

**Figure 2: Trend Analysis over MYPD3 (Standard Sales Volumes)**



48.3.2. Figure 2 illustrates the polynomial trend analysis, which is used to determine the forecast standard tariff sales volumes for 2018/19. Using the formula $Y= -234.09X^2-441.17X + 195937$, NERSA calculated the standard tariff sales volumes to be 184 862.74 GWh. The difference between NERSA's standard tariff sales volumes of 184 862.74 GWh and Eskom's forecast volumes of 188 082 GWh is 3 219.26 GWh (a difference of less than 2%). NERSA has allowed the standard tariff sales volumes of 188 082 GWh as Eskom's forecast is derived from a bottom-up approach of the latest available information and consultation with key customers.

**Figure 3: Trend Analysis over 12 years (Standard Sales Volumes)**

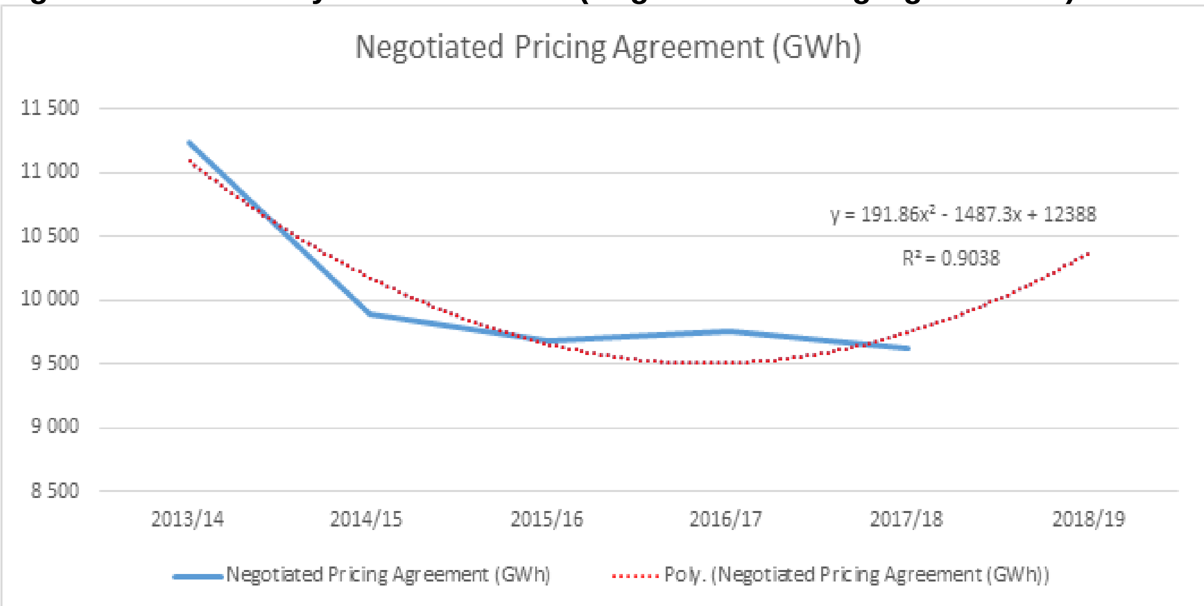



48.4. Negotiated Pricing Agreements (NPAs) volume analysis

48.4.1. Eskom has two local customers and two international customers on negotiated pricing agreements. The international negotiated pricing agreements (NPAs) are classified as export sales.

48.4.2. When assessing the NPA volumes, NERSA determined that in the second and third years of the MYPD3 period, there is a decrease of 11.4% and 2.14% respectively. However, in the fourth and fifth years there is an increase of 0.68% and 1.44% respectively. Figure 4 illustrates the trend analysis of the NPA volumes over the 5-year MYPD3 period, while Figure 5 provides the analysis over 12 years.

**Figure 4: Trend Analysis over MYPD3 (Negotiated Pricing Agreements)**



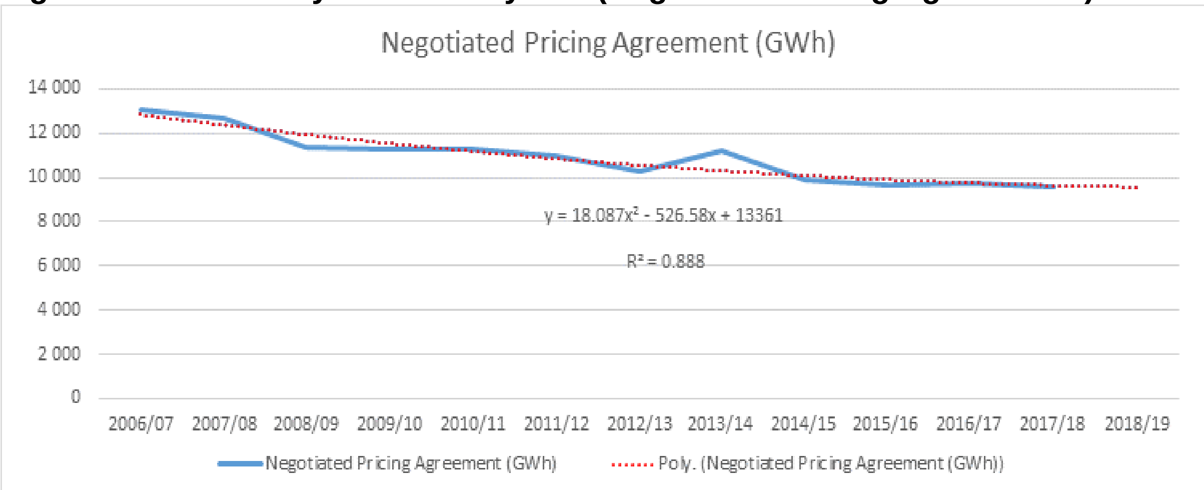

48.4.3. Figure 4 illustrates the polynomial trend analysis, which is used to determine the forecast NPA volumes for 2018/19. Using the formula $Y=191.86X^2-1\,487.3X+12388$, NERSA calculated the NPA volumes to be 10 371.16GWh. The difference between NERSA's NPA volumes of 10 371.16 GWh and Eskom's forecast volumes of 9 750GWh is 621.16GWh (less than 7% difference).

48.4.4. NPA smelter volumes for the 2018/19 financial year as approved by the Energy Regulator on 24 August 2017, were not forecast under NPA volumes by Eskom. Therefore, NERSA used its NPA determination to forecast the volumes correctly under the NPA pricing category. According to Eskom, NPA smelter production is dependent on various factors including the availability of relevant skilled resources and specific electrodes.

48.4.5. Based on the agreement between Eskom and the smelter with an approved NPA, the normal consumption of the two plants was calculated to be 1 235 GWh, with which NERSA has adjusted the negotiated pricing agreement sales volumes.

48.4.6. NERSA has calculated a negotiated pricing agreement sales volume of 10 985 GWh (9 750 GWh + 1 235 GWh) as these volumes are reasonable taking into account the volumes in the agreement and considering the assumption (based on an aggregate Notified Maximum Demand of 1 205 MVA) on energy sales volumes.

**Figure 5: Trend Analysis over 12 years (Negotiated Pricing Agreements)**




48.5. Export Sales Volume Analysis

48.5.1. When assessing the export sales volumes, NERSA determined that in the second year of the MYPD3 period there is a decrease of 3.77%. However, in the third, fourth and fifth years there has been an increase of 12.30%, 12.19% and 0.15% respectively.

48.5.2. Figure 6 illustrates the trend analysis of the Export sales volumes over the 5-year MYPD3 period, while Figure 7 is the analysis over 12 years.

48.5.3. Figure 6 illustrates the polynomial trend analysis, which is used to determine the forecast Export sales volumes for 2018/19. Using the formula $Y=-100.45X^2 + 1222.3X + 10811$, NERSA calculated the Export sales volumes to be 14 528.6 GWh. The difference between NERSA's Export sales volumes of 14 528.60GWh and Eskom's forecast volumes of 13 634GWh is 894.60GWh (a difference of less than 7%).

**Figure 6: Trend Analysis over MYPD3 (Export Sales)**

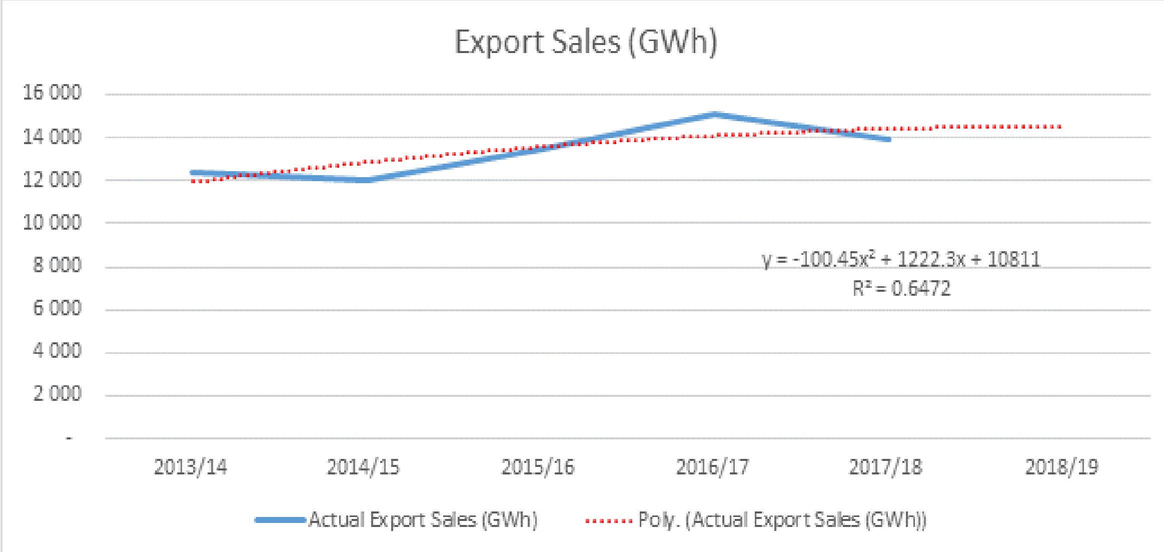
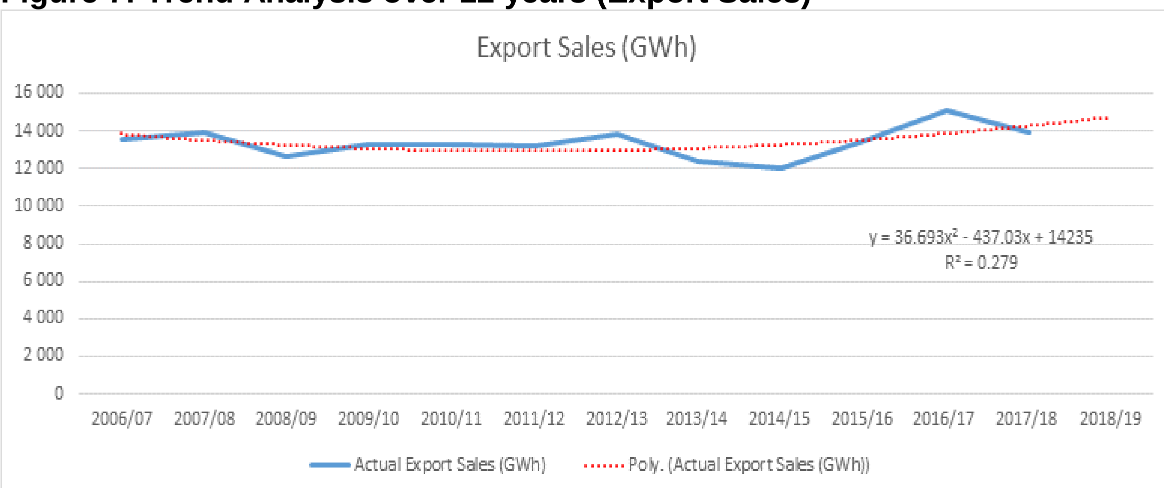



**Figure 7: Trend Analysis over 12 years (Export Sales)**




48.5.4. In assessing the sales volume forecast, NERSA has taken into consideration the declining sales volume trend over the MYPD 1, 2 and 3 periods and the risk of Eskom not achieving the forecast sales volumes for the 2018/19 financial year. The growing variance between what was forecast and the actual volumes achieved since 2008/9 is evident in Figure 1 and poses a significant risk to achieving the allowed revenues in the year they are allocated.

48.5.5. The 2018/19 one-year revenue application, presents an opportunity to monitor (before the MYPD 4 application) the ability of Eskom to achieve the sales volumes as determined in Table 8. The risk of volume variance is mitigated due to assumptions such as GDP growth not being factored into the forecasting. Historically, there was a strong correlation between GDP growth and sales volumes, but due to the increasing upward pressure on electricity prices, this correlation has diminished. The polynomial trend analysis was therefore used to determine the sales volume forecast for this determination.

48.5.6. For Eskom's 2018/19 revenue decision, NERSA has determined the forecast sales volumes shown in Table 7.

**Table 7 : NERSA Determination of Eskom 2018/19 Sales Volumes Forecast**

| Categories | Eskom Application* (GWh) | Eskom Revised Application** (GWh) | NERSA Adjustment (GWh) | NERSA Decision (GWh) |
|---|---|---|---|---|
| Standard Tariffs | 192 953 | 188 082 | - | 188 082 |
| Negotiated Pricing Agreements | 9 621 | 9 750 | 1 235 | 10 985 |
| Export Sales | 13 634 | 13 634 | - | 13 634 |
| **Total** | **216 208** | **211 466** | **1 235** | **212 701** |

**Eskom Application 25 August 2017*
***Eskom Revised Application 28 November 2017*

**PRODUCTION PLAN**

49. The MYPD4 Methodology requires that Eskom must provide the Energy Regulator with a risk adjusted Production Plan. This is a Production Plan that considers all current conditions and is therefore most likely to be achievable.

50. The Production Plan submitted by Eskom complies with the requirements of the Methodology, as it considers all the relevant demand and supply conditions and is likely to be achieved taking into account Eskom's current excess capacity situation.

50.1. The Production Plan takes the following into account:

50.2. The Energy Forecast based on the most recent information available to Eskom, taking into account current economic conditions. This is Eskom's energy forecast including distribution national sales, export sales, transmission and distribution losses.

50.3. All non-Eskom generation including Renewable Independent Power Producers (REIPP) and imports contracted to Eskom.

50.4. Eskom generation capacity, including new build plants coming online in the application year as well as Eskom's Renewable plants.

51. Eskom plant performance data.

51.1. Eskom's fleet availability was on the decline until 2015/16, but has shown an improving trend since then. The Unplanned Capacity Loss Factor (UCLF) and Other Capacity Loss Factor (OCLF) numbers have also improved since 2013/14 with a marked improvement from 2015/16 to 2016/17. The combined unplanned and other capacity loss factor was 14.4% in 2013/14 and projected to be 12% for the current 2017/18 period with 11% applied for in 2018/19. The detailed figures are provided in Table 8.

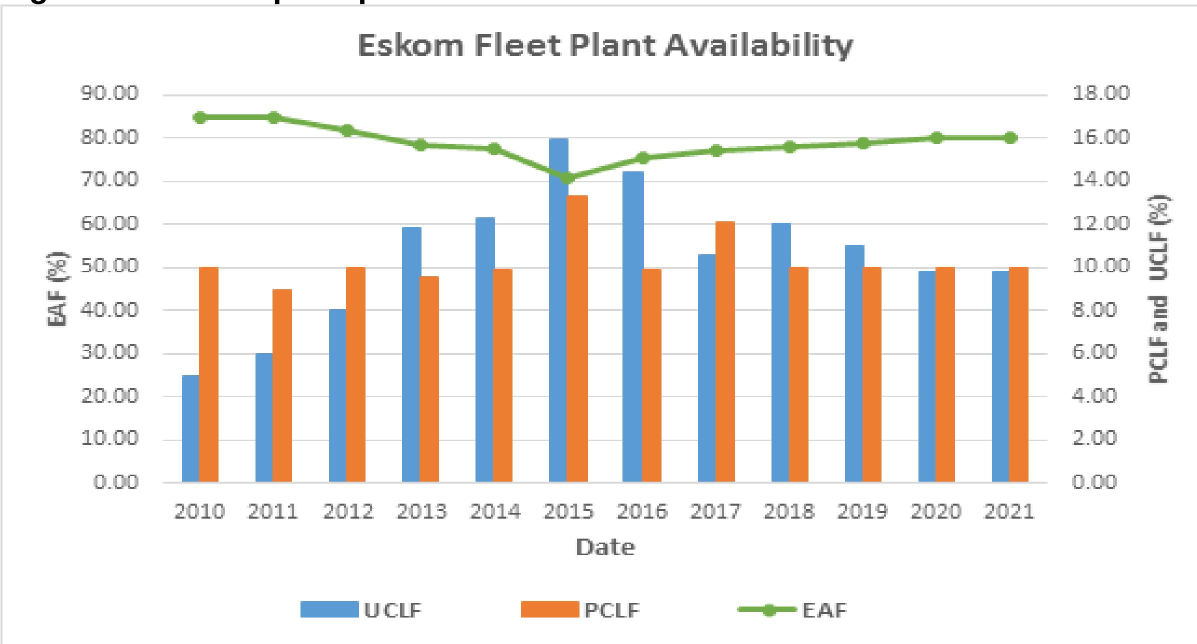
**Table 8: Eskom Generation Fleet Technical Performance**

| Generation Technical Performance (%) | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|
| | Actual | Projection | Application |
| Energy Availability Factor (EAF) | 77.3 | 78.0 | 79.0 |
| Planned Capacity Loss Factor (PCLF) | 12.1 | 10.0 | 10.0 |
| Unplanned Capacity Loss Factor (UCLF) | 9.9 | 10.9 | 9.9 |
| Other Capacity Loss Factor (OCLF) | 0.7 | 1.1 | 1.1 |
| Gross Load Factor (GLF) | | 56.2 | 53.3 |

51.2. Historically Eskom's Energy Availability Factor (EAF) was comfortably above 85%, which is an acceptable standard for a coal-fired plant, until 2011 when the EAF started to decline, reaching 77.3% in 2016/17. Since then, there has been some improvement and according to the current Eskom forecast, EAF is projected to reach levels above 80% from 2019/20 onwards. Figure 8 provides a graphical representation.

51.3. Should Eskom close the less reliable power plants, plant performance data should revert back to globally acceptable levels.

**Figure 8: Historic plant performance of the Eskom fleet**




52. Excess Capacity

52.1. In the Medium-Term System Adequacy Outlook (MTSAO) published by Eskom on 30 October 2017, the excess capacity over the period 2018 to 2022 is in the range of 3 800 MW to about 8 000 MW under the low growth (0.4%) scenario. Under the high growth scenario of 2% growth, the excess capacity would be at an average of 4 000 MW over the period. Based on the NERSA estimate and Eskom’s demand growth projections, the excess capacity would be in the range of 3 200 to 4 000 MW, the upper limit being subject to the commissioning of either Medupi 3 or Kusile 2 earlier than planned.

52.2. The MTSAO is based on calendar years while the Eskom application for 2018/19 covers financial years. The approximate excess capacity from NERSA’s analysis for the 2018 calendar year is 3 428 MW, at a year-on-year demand growth for 2018 of 1.26% and 1.46% under low and moderate demand growth respectively.

52.3. The Eskom application for the 2018/19 financial year is based on demand growth of 1.066%. At this growth rate and actual peak demand of 35 301 MW for 2017, the projected peak demand for 2018/19 is 35 677 MW. When taking into account the projected Eskom installed capacity of 46 368[3] MW in the MTSAO study excluding contracted renewable capacity contribution and a planning reserve margin of 19%[4], the excess capacity for 2018/19 could be conservatively estimated at about 3 912 MW.

52.4. Operating with a reserve margin in excess of 35% (when considering only Eskom supply) means that Eskom has a large excess capacity. This is more than double the required reserve margin[5]. A reserve margin of 13% is estimated by the European Network of Systems Operators for Electricity (ENTSO-E). The reserve margin is the estimated margin between the amount of electricity needed at peak times and the electricity that can be produced with the available generation capacity for the European Union (EU) as a whole. The high reserve margin results in Eskom's fixed and variable costs remaining high.

52.5. In light of this excess capacity, NERSA took the most expensive conventional power station, Arnot, with an installed capacity of 2 232MW, out of the production plan, That is, the energy production of Arnot is set to zero and the energy is re-allocated to the other power stations in the production plan. This resulted in cost savings in, amongst others, coal burn costs of R1 286 million and maintenance of R711million, which are discussed later in the Reasons for Decision (RfD). In respect of coal burn costs, this decision is based on the fact that Arnot power station has a high average R/ton coal price in relation to the other power stations. Furthermore, based on Eskom's application for 2018/19, Hendrina is not expected to produce any electricity as it will be placed on cold reserve. It is expected that Eskom will optimise its production plan accordingly.

53. Impact of Sales Volumes adjustment on the Production Plan

53.1. Eskom's original application figures for both the supply and demand side are shown in Table 9 and Table 10 respectively. On 28 November 2017 Eskom submitted revised production and sales plans. NERSA has effected adjustments to the original sales and production plans Eskom submitted and these are also reflected in tables 19 and 10.

[3] Eskom projected installed capacity for the 2018/19 is 46 189MW as per production plan submitted with the application, plus 100MW of Sere, p52 of Eskom Application
[4] Decisions, G.E., 2007. Electrical Resource Needs Analysis: Adequate Reserve Margin for Development of Third National Integrated Resource Plan for South Africa. Pretoria, Republic of South Africa.
[5] ENTSO-E: 2015 Scenario Outlook & Adequacy Forecast

53.2. The revised sales for standard tariff customers was not adjusted by NERSA. However, the revised sales from NPAs were adjusted to incorporate the volumes from a smelter NPA (1 235GWh). The export sales remained as per Eskom's revised adjustment. In order to balance the supply and demand the coal-fired generation production was increased by the additional sales as illustrated in Table 9.

**Table 9: Supply Side Categories**

| Eskom Original Application | | Eskom Adjustment | | NERSA Adjustment | |
|---|---|---|---|---|---|
| **Supply** | **GWh** | **Supply** | **GWh** | **Supply, GWh** | **Supply, GWh** |
| **Eskom Supply** | **216 771** | **1 400** | **218 171** | | **219 852** |
| Eskom Coal | 198 908 | 1 400 | 200 308 | 1 787 | 202 095 |
| Eskom Nuclear | 12 400 | | 12 400 | | 12 400 |
| Eskom Hydro | 693 | | 693 | | 693 |
| Pumped Storage | 4 282 | | 4 282 | | 4 282 |
| Gas Turbines | 211 | | 211 | -106 | 105 |
| Wind | 277 | | 277 | | 277 |
| | | | | | |
| ***Non Eskom supply*** | **30 421** | | **24 118** | | **23 672** |
| IPPs | 18 428 | -6 304 | 12 125 | -446 | 11 679 |
| Dx | 159 | | 159 | | 159 |
| Tx imports | 9 381 | | 9 381 | | 9 381 |
| Wheel and withdraw | 2 453 | | 2 453 | | 2 453 |
| | | | | | |
| **TOTAL SUPPLY** | **247 192** | | **242 289** | **1 235** | **243 524** |

Note: The 446GWh is a further reduction by NERSA from Eskom's revised REIPP generation

**Table 10: Demand Side Categories**

| Eskom Original Application | | Eskom Adjustment | | NERSA Adjustment | |
|---|---|---|---|---|---|
| **Demand** | **GWh** | **Demand** | **GWh** | **Demand, GWh** | **Demand, GWh** |
| **Total Sales** | **216 208** | **-4 743** | **211 465** | | **212 700** |
| Standard Tariff Sales Volumes | 192 953 | -4 872 | 188 081 | | 188 081 |
| Negotiated Pricing Agreemen | 9 621 | 129 | 9 750 | 1 235 | 10 985 |
| Export Sales | 13 634 | 0 | 13 634 | | 13 634 |
| | | | | | |
| **Total Non-sales** | **30 986** | | **30 824** | | **30 824** |
| Transmission Losses | 6 798 | | 6 663 | | 6 663 |
| Distribution Losses | 15 952 | | 15 925 | | 15 925 |
| Pumping | 5 783 | | 5 783 | | 5 783 |
| Wheel and withdraw | 2 453 | | 2 453 | | 2 453 |
| | | | | | |
| **TOTAL DEMAND** | **247 194** | | **242 289** | **1 235** | **243 524** |

54. Adjustment of production plan for delayed REIPPs, WEPs, and OCGTs

54.1. In its production plan, Eskom had factored in production from the REIPP plants in the 2018/19 application. These are from the unsigned Power Purchase Agreements (PPAs) that will not materialise during the application year due to the applicable lead times. More details are provided in the Primary Energy section. Generation from these non-Eskom generators will be reallocated to cheaper Eskom plants. The following adjustments have been made to the production plan to make provision for the unsigned PPAs that will not come into commercial operation during the 2018/19 application year totalling 6 237GWh :

54.1.1. Renewable Bidding Window (BW) 3.5 (one project);

54.1.2. Renewable BW 4;

54.1.3. Renewable BW 4.5; and

54.1.4. Small Scale Renewable Energy IPPs.

54.2. Adjustments to the production plan are also made to the following generation sources:

54.2.1. Wholesale Electricity Pricing System (WEPs) IPPs generation (424GWh) will also be re-allocated as it is not needed due to Eskom current excess capacity;

54.2.2. Co-generation plants (88GWh) for which PPAs have not been signed; and

54.2.3. Open Cycle Gas Turbine (OCGT) generation will only be allowed at 0.5% load factor. The disallowed generation from OCGTs will also be moved to cheaper Eskom generation fleet.

54.3. The generation movements listed above will be moved to the Eskom coal fleet as it is still the cheapest technology currently available within the technology mix of Eskom. This generation movement will result in changes to the primary energy costs, the details are provided in the Primary Energy section.

54.4. The revised production plan results in 1 787GWh (1 235GWh + 446GWh + 106GWh) more coal generation than applied for in the revised Eskom production plan. This in turn will result in an additional coal requirement in Primary Energy.

54.5. Eskom is directed to reduce the excess capacity and consequently the reserve margin to be in line with the acceptable standard as described in this section above.

**PRIMARY ENERGY**

55. Primary energy is an important component of the Eskom application. The main objective is to ensure that adequate budget is available to implement the production plan that will be in line with the projected demand. Any changes in the sales volumes will have an impact on the energy wheel, production plan, as well as the costs of primary energy. Therefore alignment is critical across these four components.

56. When considering the allowable cost for primary energy, the following factors are taken into consideration:

    a) the reduction of the sales volumes (Table 5);
    b) Generation movement from IPPs as indicated in Table 9;
    c) coal cost adjustments to exclude cost inefficiencies and to integrate the impact of coal generation volume adjustments;
    d) environmental levy changes, due to the reduced sales volumes and the need to increase coal generation to replace REIPP; and
    e) that these adjustments are allowed at coal prices, due to the flexibility and availability of the coal generation fleet (<60% GLF), as well as the excess capacity in the system.

57. The increase in coal production volumes does not only affect coal usage, but it also proportionally affects the other fuel and consumable components related to total coal costs. Taking the above into consideration, the adjusted primary energy costs are presented in Table 11. The analysis of each of the adjusted elements follows thereafter.

**Table 11: Summary of Primary Energy Costs Allowed**

| Primary Energy Category | Eskom Application Rmillions | NERSA Production Amendment Adjustment Rmillions | NERSA Revised Costs Rmillions | NERSA Adjustment Rmillions | NERSA Decision Rmillions |
|---|---|---|---|---|---|
| Coal usage | 48 687 | 522 | 49 209 | -10 032 | 39 177 |
| Net coal obligation raised/(reversed) | 1 304 | | 1 304 | -1 304 | 0 |
| Coal obligations provisions | | | 0 | | 0 |
| Water usage | 2 310 | 26 | 2 336 | 17 | 2 353 |
| Fuel procurement service | 223 | 3 | 226 | -187 | 39 |
| Coal handling | 1 974 | 22 | 1 996 | 14 | 2 010 |
| Water treatment | 490 | 6 | 496 | 3 | 499 |
| Sorbent usage | 63 | 1 | 64 | | 64 |
| Gas and oil (coal fired start-up) | 2 405 | | 2 405 | -283 | 2 122 |
| Coal and gas (Gas-fired) | 9 | | 9 | | 9 |
| Environmental levy | 7 994 | | 7 994 | 99 | 8 093 |
| **Total Coal** | **65 459** | **580** | **66 039** | **-11 673** | **54 366** |
| OCGT fuel cost | 691 | | 691 | -346 | 345 |
| Nuclear | 865 | | 865 | -366 | 499 |
| **Total Eskom Generation** | **67 015** | **580** | **67 595** | **-12 385** | **55 210** |
| IPPs | 34 209 | | 34 209 | -7 613 | 26 596 |
| International Purchases | 3 216 | | 3 216 | | 3 216 |
| DMP | 319 | | 319 | -29 | 290 |
| **Total Primary Energy** | **104 759** | **580** | **105 339** | **-20 027** | **85 312** |

58. Coal usage

58.1. Eskom applied for R48.687bn for coal burn, however this was revised by NERSA to R49.209bn. This increase was as a result of the revised production plan taking into account the adjustments in sales volumes, NPAs, REIPP generation, OCGT generation and WEPs purchases (adjustments are discussed in more detail under the production plan section). The net effect was an increase in energy generated from the coal fleet, therefore resulting in a corresponding increase in the volume of coal burn from 112.4MTons (million tons) to 114.3MTons.

58.2. The re-allocation of energy from REIPP generation that will not materialise within 2018/19 to the coal fleet resulted in an overall additional cost of R522m in primary energy (Table 12). Eskom shall produce a re-optimised production plan and ensure that the additional generation is allocated to the cheapest available power stations.

58.3. The overall energy adjustments resulted in an additional 1 787GWh to be generated from the coal fleet.

**Table 12: REIPP-Coal Adjustments**

| | Energy (GWh) | Average coal cost R/kWh | Cost (Rm) |
|---|---|---|---|
| OCGT | 106 | 0.29 | 30.95 |
| IPPs | 446 | | 130.23 |
| NPA Sales volumes | 1235 | | 360.62 |
| | **1787** | | **522** |

58.4. In terms of adjusting the price of coal, the R/Ton price in the RCA 2013/14 decision was used as a base and adjusted by a Composite index adjustment [mining PPI and transport Consumer Price Index (CPI)] to arrive at the 2018/19 R/Ton. The mining PPI considers the cost of producing coal, while transport CPI considers the cost of transporting coal. NERSA tested and approved the 2013/14 RCA costs, hence it is a reasonable starting point.

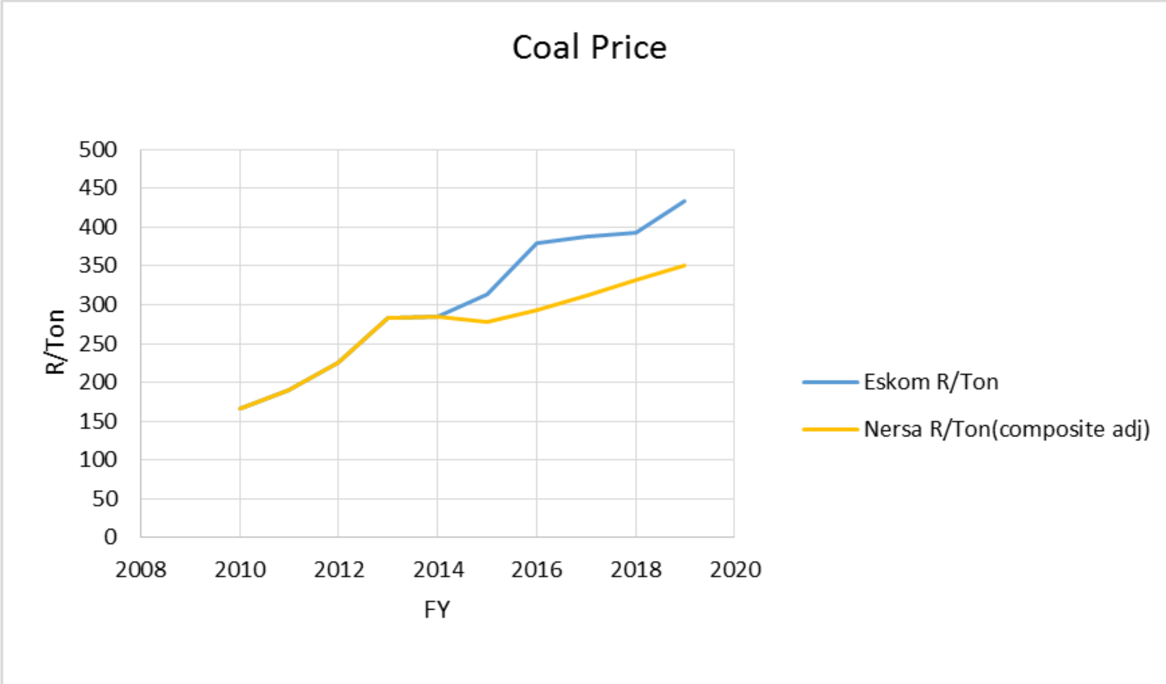
58.5. The years subsequent to 2013/14 could not be used as a reasonable starting point because NERSA has not tested and approved those costs. Furthermore, Eskom could have signed new coal contracts after 2013/14 and that would provide an inflated starting point. This is demonstrated by the double digit Eskom adjustments (Table 13), which are far higher than the industry inflation (composite index adjustment).

**Table 13: Eskom vs. Composite Index Annual Adjustment**

| | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **Eskom Adjustment** | 10.09% | 20.77% | 2.52% | 1.24% | 6.00% |
| **Composite Index Adjustment** | -2.52% | 5.07% | 6.67% | 5.44% | 5.37% |

58.6. In its application, Eskom assumed 2016/17 to be the base year, which included double digit escalations from the previous two years, which were significantly higher than industry inflation (composite index). The resultant Eskom 2016/17 average R/Ton price for coal is higher than the NERSA 2016/17 average R/Ton price. The historic and future price comparison and projections are provided in Figure 9.

**Figure 9: R/Ton Comparison**




58.7. Paragraph 12.2.1 of the MYPD methodology requires the Energy Regulator to approve the coal benchmark price (i.e. average R/Ton) per contract type as shown in Table 14.

58.7.1. The R/Ton adjustment was derived from the following:

a) application of the industry composite index adjustment to the approved 2013/14 RCA R/Ton prices tested and approved by NERSA; and

b) substituting of load allocated by Eskom to Arnot power station with power stations with a cheaper coal price. Arnot has a high R/Ton price. It is prudent and efficient to utilise the cheapest production cost power stations to their fullest extent before the highest and the adjustment was done on that basis.

58.7.2. The cost impact of replacing generation from Arnot power station with cheaper power stations resulted in a reduction of the coal burn costs by R1.286bn. This effectively places Arnot into cold reserve for the purposes of this analysis, as set out in Table 15.

**Table 14: R/Ton Adjustment Applied per Contract Type**

| Contract type | Eskom Application | Adjustment | Decision |
|---|---|---|---|
| | R/Ton | R/Ton | R/Ton |
| Cost Plus | [redacted] | | |
| Fixed price | | | |
| Medium Term | | | |
| Short Term | | | |
| **Weighted average** | | | |

**Table 15: Coal Cost impact of Arnot in 'Cold Reserve'**

| | Volumes (Mtons) | Nersa allowed R/Ton | Nersa allowed Rmil |
|---|---|---|---|
| Arnot | [redacted] | | |
| Coal fleet excluding Arnot | | | |
| Adjustment | | | |

58.8. Table 16 indicates the overall reduction of R10.033bn in coal burn costs after the adjustments discussed above.

**Table 16: Coal Burn Costs Allowed**

| Contract Type | Eskom Application | NERSA Amended as per revised Production Plan | NERSA Adjustment | NERSA Decision |
|---|---|---|---|---|
| | Rmillion | Rmillion | Rmillion | Rmillion |
| Cost Plus | 17 140 | 17 324 | -3 532 | 13 792 |
| Fixed Price | 11 442 | 11 565 | -2 358 | 9 207 |
| Medium Term | 18 757 | 18 958 | -3 865 | 15 093 |
| Short Term | 1 348 | 1 362 | -278 | 1 084 |
| **Total** | **48 687** | **49 209** | **-10 033** | **39 176** |

58.9. Paragraph 12.2.1 of the MYPD methodology requires the Energy Regulator to approve Alpha values per contract type as indicated in Table 17.

**Table 17: Alpha per Contract Type**

| Contract type | Alpha |
|---|---|
| Cost Plus | [redacted] |
| Fixed Price | |
| Medium Term | |
| Short Term | |

58.9.1. Alpha is a factor that determines the ratio in which risks in coal burn expenditure are divided between Eskom and its customers. Alpha is a number between 0 and 1 and sets the risk share of the coal cost variance between licensees and customers.

[redacted]

58.9.3. The actual Alpha will be used during the RCA review process.

58.9.4. The allowed coal cost for the purpose of RCA was determined by comparing the benchmark R/Ton with Eskom's actual R/Ton cost using a Performance Based Regulation (PBR) formula per contract type.

59. Net coal obligation raised/(reversed)

59.1. Net coal obligation costs refer to the take-or-pay coal contract penalties to be incurred at Medupi power station. These penalty provisions are disallowed due to Eskom's inefficiencies in managing the new-build programme, which resulted in Eskom failing to burn the purchased coal, as outlined in Table 18.

**Table 18: Net Coal Obligations**

| | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| | Rmillion | Rmillion | Rmillion |
| Net Coal Obligation raised/(reversed) | 1 304 | -1 304 | 0 |

60. Water Usage

60.1. The water costs are the costs incurred by Eskom for the water it consumes from the Department of Water and Sanitation (DWS). Eskom has no control over the average price charged since the rate is legislated. However, Eskom does have control over the quantity consumed.

60.2. Table 19 details the forecast tariff, volumes in million cubic meters (mcm) and tariff billing in millions of Rand for 2017/18. The budgeted amounts for tariffs, volumes and tariff billing from 2018/19 until 2020/21 has also been included.

60.3. In consideration of the Litre/kWh (1.35L/kWh) sent out, the 2013/14 allowance approved by the Energy Regulator was selected to test for efficiency and prudency.

60.4. The 2018/19 application L/kWh sent out is calculated at 1.29L/kWh. The reduction is due to the additional kWh produced by both Medupi and Kusile power plants since they both use dry cooling, which uses less water per kWh sent out.

**Table 19: Water Costs**

| Project | Actual/Forecast 2017/2018 | | | Budget 2017/2018 | | | 2018/2019 | | | 2019/2020 | | | 2020/2021 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Tariff | Volume (mcm) | Tariff Billing (R million) | Tariff | Volume (mcm) | Tariff Billing (R million) | Tariff | Volume (mcm) | Tariff Billing (R million) | Tariff | Volume (mcm) | Tariff Billing (R million) | Tariff | Volume (mcm) | Tariff Billing (R million) |
| LHWP | | | | | | | | | | | | | | | |
| LHWP, LHWP2 & AMD- VRS | 2.7100 | 1 647 | 4 463 | 2.7139 | 1 606 | 4 359 | 3.0465 | 1 606 | 4 893 | 3.5802 | 1 604 | 5 741 | 3.7184 | 1 605 | 5 966 |
| BWP (3 months)1 April - 30 June | 0,6300 | 87 | 55 | 0,6300 | 87 | 55 | 0,6000 | 68 | 41 | 0,5700 | 68 | 39 | 0,3023 | 69 | 21 |
| BWP (9 months)1 July - 30 March | 0,6000 | 238 | 143 | 0,6000 | 263 | 158 | 0,5700 | 233 | 133 | 0,3023 | 236 | 71 | 0,2388 | 238 | 57 |
| VRESAP-ESKOM | 1.1294 | 240 | 271 | 1.1294 | 243 | 274 | 1.5820 | 212 | 336 | 1.6674 | 208 | 346 | 1.7575 | 209 | 367 |
| VRESAP-SASOL | 2.0000 | 81 | 162 | 2.0000 | 82 | 164 | 2.1800 | 85 | 185 | 2.2977 | 85 | 195 | 2.4218 | 85 | 205 |
| MMTS (3 months)1 April- 30 June | 0,4840 | 97 | 47 | 0,4840 | 99 | 48 | 0,5180 | 100 | 52 | 0,5509 | 100 | 55 | 0,5807 | 100 | 58 |
| MMTS (9 months)1 July- 30 March | 0,5180 | 296 | 153 | 0,5180 | 296 | 153 | 0,5509 | 294 | 162 | 0,5807 | 294 | 170 | 0,6120 | 294 | 180 |
| KWSAP | 13 200 | 90 | 119 | 1.3200 | 88 | 117 | 1.9091 | 73 | 139 | 2.0122 | 73 | 148 | 2.1209 | 76 | 161 |
| MCWAP | 12.0204 | 22 | 266 | 12.0204 | 22 | 266 | 12.6700 | 22 | 280 | 1.1248 | 22 | 249 | 11.2484 | 22 | 249 |
| LHWP2 | | | | | | | | | | | | | | | |
| Total Tariff Receivable | | | 5 677 | | | 5 592 | | | 6 220 | | | 7 014 | | | 7 264 |

Source: Department of Water and Sanitation

60.5. The costs for water usage as applied for by Eskom are reasonable given the analysis done above. However, an upward adjustment was necessary to cater for the net effect of adjusting the production plan for delayed IPPs and WEPs as well as lower sales volumes. See Table 20.

**Table 20: Water Usage**

| | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Water Usage | 2 310 | 43 | 2 353 |

61. Fuel Procurement Service

61.1. Fuel procurement costs are incurred to operate the Primary Energy Division (PED). This division specialises in the procurement of coal, water and sorbent. The major cost drivers for fuel procurement services are manpower and the exclusion of power stations from the production plan.

**Table 21: Fuel Procurement Service**

| | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Fuel Procurement Service | 223 | -184 | 39 |

61.2. A total of R184m (manpower and exclusion from the production plan) was disallowed from fuel procurement services since this was already covered under operational expenditure. See Table 21.

62. Coal Handling

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

62.2. The major drivers for coal handling costs are allocated according to the following breakdown:

62.2.1. Labour – 60%

62.2.2. Yellow plant (machinery) – 15%

62.2.3. White plant (machinery/vehicles) – 5%

62.2.4. Fuel for yellow and white plant – 15%

62.2.5. Contingencies – 5%

62.3. The costs for coal handling (outsourced to Roshcon Pty Ltd) were considered reasonable since the increase was in line with CPI when compared to the 2013/14 RCA decision, which NERSA had tested and approved.

62.4. Coal handling costs are adjusted as shown in Table 22.

**Table 22 Coal Handling Costs per Cost Driver**

| | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| | Rmillion | Rmillion | Rmillion |
| Labour – 60% | 1 184 | - | 1 184 |
| Yellow plant (machinery) – 15% | 296 | - | 296 |
| White plant (machinery/vehicles) – 5% | 99 | - | 99 |
| Fuel for yellow and white plant – 15% | 296 | - | 296 |
| Contingencies – 5% | 99 | - | 99 |

62.5. The revised production plan taking into account adjustments in sales volumes, NPAs, REIPP generation, OCGT generation and WEPs purchases resulted in additional coal burn volumes and a corresponding increase in coal handling costs of R36m (Table 23).

**Table 23: Coal Handling Costs**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Coal Handling | 1 974 | 36 | 2 010 |

63. Water Treatment

63.1. Water treatment costs are costs related to the chemicals used to clean the water used by Eskom in the generation of electricity which involves the following three processes:

63.1.1. Cooling water (85%)

63.1.2. Potable water (10%)

63.1.3. Demineralised water (5%)

63.2. The water volumes used for production are reducing in line with the reduction in sales volumes. It is therefore reasonable to expect the treatment cost to reduce accordingly. However, an increase in the cost of chemicals resulted in costs increasing by inflation.

63.3. The net effect of adjusting the production plan for the delayed IPPs and WEPs, as well as the lower sales volumes, resulted in additional coal generation costs. The additional water treatment costs associated with this increase in coal generation resulted in an increase of 1.22% (Table 24).

**Table 24: Water Treatment Costs**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Water Treatment | 490 | 6 | 496 |

64. Sorbent Usage

64.1. Sorbent (limestone) is required for the flue gas desulphurisation (FGD) technology at Medupi and Kusile Power Stations. This is in line with the government objective of the reduction of Green House Gases (GHG) emission into the atmosphere.

**Table 25: Sorbent Costs (Eskom application)**

| **PPI** | 5.5% | 6.0% | 6.0% |
|---|---|---|---|
| Sorbent Costs | Actuals 2016/17 | Projection 2017/18 | Application 2018/19 |
| **Kusile:** | | | |
| GWh | | 2 345 | 3 934 |
| | | | |
| Sorbent consumption (t/MWh) | 0.02 | 0.02 | 0.02 |
| Sorbent consumption (tons) | 0 | 36 680 | 61 523 |
| | | | |
| **Real:** | | | |
| Sorbent cost (R/t) | 150 | 150 | 150 |
| Transport cost (R/ton) | 716 | 716 | 716 |
| Sorbent cost (Rands) | 0 | 5 502 062 | 9 228 514 |
| Transport cost (Rands) | | 26 263 176 | 44 050 773 |
| **Total Sorbent costs (real)** | | **31 765 238** | **53 279 286** |
| | | | |
| **Nominal:** | | | |
| Sorbent cost (R/t) | 158 | 168 | 178 |
| Transport cost (R/ton) | 755 | 801 | 849 |
| Sorbent cost (Rands) | 0 | 6 152 956 | 10 939 462 |
| Transport cost (Rands) | 0 | 29 370 110 | 52 217 698 |
| **Total Sorbent costs (Rands)** | | **35 523 066** | **63 157 160** |

64.2. The Sorbent consumption of 0.016t/MWh is what can be expected from Limestone, the transport cost equates to R1.07/Ton/km (the number was calculated by transport costs of R716/Ton over the distance of 667km), which is reasonable when compared to other material transport costs.

64.3. The net effect of the production plan adjustment has resulted in an increase in coal volumes that in turn resulted in an upward adjustment of sorbent cost from R63 million to R64 million as per Table 26.

**Table 26: Sorbent Usage**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Sorbent Usage | 63 | 1 | 64 |

65. Gas and Oil (Coal-fired start-up)

65.1. Gas and Oil (coal-fired start-up) costs are the expenditure incurred in purchasing the heavy fuel oil used for the start-up and shut down of a coal-fired power station and stabilises the boiler flame on occasion e.g. when operated at low load. The start-up fuel is also used during emergency situations to prevent flame out, such as during unit trips or should the coal supply be interrupted or unstable.

65.2. Eskom submitted to NERSA the fuel supply contracts, which show unit price and delivery costs for the start-up fuel per power station. The contracts have a base dated 31 March 2017. Using Bureau for Economic Research (BER) tables (R/$ exchange and Oil price), NERSA estimated an average fuel price for 2018/19 as indicated in Table 27.

**Table 27: Gas and Oil R/Litre per Coal-Fired Station**

| Power Station | Fuel Type | Eskom Application | NERSA | | NERSA Estimate |
|---|---|---|---|---|---|
| | | | Fuel Cost | Transport | |
| | | R/Litre | R/Litre | R/Litre | R/Litre |
| Duvha | Catlight | 11.55 | 10.28 | 0.41 | 10.69 |
| Duvha | Chemical Sulphur | 3.51 | 3.32 | 0.19 | 3.51 |
| Komati | Diesel | 11.66 | 11.33 | 0.33 | 11.66 |
| Kriel | Diesel | 14.86 | 14.64 | 0.22 | 14.86 |
| Kusile | Fuel Oil 150 | 7.50 | 5.88 | 0.20 | 6.08 |
| Matla | Fuel Oil 150 | 5.99 | 5.72 | 0.27 | 5.99 |
| Medupi | Fuel Oil 150 | 7.50 | 6.13 | 0.56 | 6.69 |
| Duvha | Fuel Oil 150 | 6.73 | 5.97 | 0.19 | 6.16 |
| Kendal | Fuel Oil 150 | 6.32 | 6.00 | 0.18 | 6.18 |
| Lethabo | Fuel Oil 150 | 6.47 | 6.08 | 0.18 | 6.26 |
| Majuba | Fuel Oil 150 | 6.16 | 5.85 | 0.31 | 6.16 |
| Matimba | Fuel Oil 150 | 8.40 | 6.13 | 0.56 | 6.69 |
| Tutuka | Fuel Oil 150 | 5.60 | 5.48 | 0.12 | 5.60 |
| Camden | Fuel Oil 150 | 5.00 | 4.46 | 0.54 | 5.00 |
| Grootvlei | Fuel Oil 150 | 7.53 | 5.90 | 0.22 | 6.12 |
| Komati | Fuel Oil 150 | 9.52 | 6.76 | 0.33 | 7.09 |
| Kriel | Fuel Oil 150 | 11.15 | 10.56 | 0.22 | 10.78 |
| Kriel | LCO Flux Oil | 11.46 | 10.56 | 0.22 | 10.78 |
| Komati | Propane Gas | 36.04 | 35.71 | 0.33 | 36.04 |

65.3. Estimated Coal-Fired Start-up Fuel Quantity (Litres)

65.3.1. NERSA's approach is to measure the efficient use of start-up fuels on historical performance using litres/USO for each individual power station. The fuel quantity per station is shown in Table 28.

**Table 28: Coal-Fired Start-up Fuel Quantity**

| Station | Eskom Application | Adjustment | NERSA Evaluation |
|---|---|---|---|
| | Litres | Litres | Litres |
| Kusile | 8 837 412 | 909 454 | 9 746 866 |
| Medupi | 9 544 405 | 982 210 | 10 526 615 |
| Duvha | 28 670 406 | -1 687 151 | 26 983 255 |
| Kendal | 8 497 359 | 874 459 | 9 371 818 |
| Lethabo | 7 825 000 | 475 180 | 8 300 180 |
| Majuba | 49 702 000 | 5 114 811 | 54 816 811 |
| Matimba | 5 412 340 | 556 981 | 5 969 321 |
| Matla | 7 284 920 | 749 688 | 8 034 608 |
| Tutuka | 57 602 000 | 4 642 247 | 62 244 247 |
| Arnot | 13 764 200 | -13 764 200 | 0 |
| Camden | 39 326 000 | 3 907 854 | 43 233 854 |
| Grootvlei | 31 401 070 | 3 231 470 | 34 632 540 |
| Komati | 30 208 248 | -3 162 225 | 27 046 023 |
| Kriel | 27 869 348 | -3 073 295 | 24 796 053 |
| **TOTAL** | **325 944 708** | **-242 517** | **325 702 191** |

65.3.2. The exclusion of some IPPs and WEPs from the production plan resulted in a decrease in the fuel quantity by 242 kilolitres (Table 29) and in a R283m total saving on coal-fired station start-up fuel costs. Table 29 provides the NERSA decision.

**Table 29: Gas and Oil (Coal-Fired)**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Gas and Oil (Coal-Fired Start-up) | 2 405 | -283 | 2 122 |

66. Coal and Gas (Gas-fired)

66.1. This relates to the fuel for the Kendal black start facility. The black start facility is required by the System Operator to enable restoration of the power system following loss of all generation (blackout). The budget is therefore not adjusted. The black start facilities have to be tested at specified intervals during the year. This is to ensure that they are ready if and when they are called upon by the system operator. See Table 30.

**Table 30: Coal and Gas (Gas-fired)**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Coal and Gas (Gas-Fired Start-up) | 9 | 0 | 9 |

67. Environmental Levy

67.1. Environmental Levy costs are the costs incurred for generating electricity from non-renewable (fossil) fuels and environmentally hazardous (nuclear) sources.

67.2. Eskom applied for an amount of R7 994m. The figure was tested by multiplying the non-renewable electricity sent out (228 390 GWh) by the 3.5c/kWh rate as promulgated by National Treasury.

67.3. NERSA has adjusted the production plan, which resulted in an increase in the energy generated from non-renewable fuel sources. The net effect of the adjustment of the production plan resulted in an increase in the environmental levy by R99m from R7 994m to R8 093m.

67.4. NERSA effected an upwards adjustment of the environmental levy allowance to R8 093m. See Table 31.

**Table 31: Environmental Levy**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Environmental Levy | 7 994 | 99 | 8 093 |

68. Open Cycle Gas Turbine (OCGT) Fuel Cost

68.1. The cost of diesel per Litre provided by Eskom is lower than the diesel wholesale price projection made by the BER, which is R11.96/L and R12.85/L for 2018 and 2019 respectively. NERSA has considered the price of diesel as supplied by Eskom since this is based on the contracts it has in place and other diesel cost rebates it is entitled to.

68.2. There has been an improvement in the Eskom fleet performance, with fleet availability forecast to be 79% for 2018/19 compared to actuals of 75.1% in 2013/14 and a low point of 71.1% in 2015/16. This is due to an improvement in unplanned outages from 14.4% in 2013/14 to a forecast of 11.1% in FY2018/19. This improvement directly effects a reduction in the use of OCGTs.

68.3. The assumption made in the latest Medium-Term System Adequacy Outlook of October 2017 (MTSAO) study published by Eskom regarding plant performance is in line with the assumptions made in this application. Both show the EAF reaching 78% in 2017/18 and 79% in 2018/19.

68.4. Electricity demand has also been declining due to the current economic climate and additional capacity is being brought into service due to the new-build programmes. Both the Eskom programme and the IPP programme contribute to the reduced use of OCGTs. The Eskom fleet Generator Load Factor (GLF) is also declining, as the projected GLF for 2018/19 is 54% compared to 63% in 2013/14. This highlights the current excess capacity in the electricity system, which is projected to last up to 2022 according to the MTSAO.

68.5. MTSAO October 2017 shows that in 2017, Eskom OCGTs did not generate more than 0.5% LF per month. Given the actual energy of 29.28GWh in 2016/17 and the declining demand as well as added capacity from new build plants, NERSA is only allowing 0.5% LF for OCGT generation.

68.6. The NERSA OCGT fuel cost adjustment is shown in Table 32.

**Table 32: OCGT Fuel Costs**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| OCGT Fuel Cost | 691 | -346.00 | 345.00 |

69. Nuclear Fuel

69.1. Nuclear fuel costs relate to procurement of nuclear fuel and comprises mainly of four distinct phases, namely, procurement of uranium, conversion of the uranium into the gas UF6[6], enrichment of the U-235 isotopes[7] to the required level, and the fabrication and delivery of the fuel assemblies.

69.2. NERSA recognised that primary energy costs, such as nuclear fuel costs, will be allowed as pass-through costs upon completion of the prudency test. This is because the costs are dependent on international market prices and affected by foreign exchange fluctuations.

69.3. In the MYPD3 application, Eskom included costs for nuclear primary energy, the spent fuel storage and spent fuel management costs. Eskom's cost of acquiring fuel assemblies for Koeberg power station consists of a mix of forecast price (60%) and spot price (40%), which is

[6] Uranium hexafluoride is a chemical compound consisting of one atom of uranium combined with six atoms of fluorine.
[7] U-235 Is an isotope of uranium making about 0.72% of natural uranium.

the historical break down of the contractual and spot market price, this was particularity done in the MYPD3. However, in its 2018/19 application Eskom provided a forecast of the nuclear fuel price that is higher than the one in the MYPD3.

69.4. Nuclear fuel is procured through four intermediate products, i.e. uranium, uranium conversion, uranium enrichment and fuel fabrication. Normally the nuclear fuel contracts have separate pricing structures for each of these products. Thus there is no predetermined pricing mix, e.g. 80% / 20%, but the mix is rather a product from strategy, offers received through tender process and the market at that time.

69.5. When conducting the efficiency test, the nuclear cost line items, i.e. fuel cost, storage cost and decommission cost, was analysed and the storage cost was disallowed to avoid double counting, as the costs should form part of CAPEX. Furthermore, the MYPD3's approved nuclear costs were adjusted by CPI to hold Eskom to the prevailing market conditions.

69.6. Eskom applied for Nuclear Primary Energy costs of R856m for 2018/19, however after calculation and analysis, an adjustment of R366m was made, which resulted in Eskom being allowed R499m.

69.7. The adjustment to the nuclear fuel costs is as per Table 33 below and the subsequent discussion.

**Table 33: Nuclear Fuel Costs**

| Rmillion | Eskom Application | NERSA Adjustment | NERSA Decision |
|---|---|---|---|
| Nuclear Fuel Costs | 865 | -366 | 499 |

70. Independent Power Producers (IPPs)

70.1. Eskom applied for R34 209m for the procurement of 18 428GWh from Independent Power Producers (IPPs). The IPP cost breakdown according to various IPP programmes is as shown in Table 34. The table also reflects the adjustments made by NERSA and the resultant Energy and Cost figures.

70.2. The Medium-Term Power Purchase Programme (MTPPP) and Short-Term Power Purchase Programme (STPPP) will not be extended in 2018/19 and were not included in the application. Eskom currently has excess capacity, therefore there is no need to buy power from private generators.

70.3. Eskom did not budget for procurement of power from private generators under the WEPs Power Purchase Programme in 2017/18 because it has excess capacity.

**Table 34: Energy and Purchase costs from Local IPPs**

| | Energy (GWh) | | | Cost (R million) | | |
|---|---|---|---|---|---|---|
| **IPPs (local)** | **Eskom application** | **Adjustments** | **NERSA Decision** | **Eskom application** | **Adjustments** | **NERSA Decision** |
| **Eskom Short Term Programmes** | **424** | **-424** | **0** | **302** | **-302** | **0** |
| MTPPP | 0 | 0 | 0 | 0 | 0 | 0 |
| STPPP (Incl Munics) | 0 | 0 | 0 | 0 | 0 | 0 |
| WEPS | 424 | -424 | 0 | 302 | -302 | 0 |
| **Section 34 Programmes (RE)** | **176** | **-88** | **88** | **2 485** | **-105** | **2 380** |
| DoE Peaking | 88 | 0 | 88 | 2 380 | 0 | 2 380 |
| Co-generation | 88 | -88 | 0 | 105 | -105 | 0 |
| **Renewable IPP** | **17 828** | **-6 237** | **11 591** | **31 230** | **-7 014** | **24 216** |
| Renewable IPPs Round 1 | 3 834 | 0 | 3 834 | 10 850 | 0 | 10 850 |
| Renewable IPPs Round 2 | 3 074 | 0 | 3 074 | 6 191 | 0 | 6 191 |
| Renewable IPPs Round 3 | 4 493 | 0 | 4 493 | 6 452 | 0 | 6 452 |
| Renewable IPPs Round 3.5 | 590 | -400 | 190 | 2 308 | -1 585 | 723 |
| Renewable IPPs Round 4 | 2 931 | -2 931 | 0 | 2 514 | -2 514 | 0 |
| Renewable IPPs Round 4.5 | 2 721 | -2 721 | 0 | 2 629 | -2 629 | 0 |
| Small Scale Renewable | 185 | -185 | 0 | 286 | -286 | 0 |
| **Total IPP** | **18 428** | **-6 749** | **11 679** | **34 017** | **-7 421** | **26 596** |
| Network costs (UoS) | | | | 192 | -192 | 0 |
| Total IPPs | **18 428** | **-6 749** | **11 679** | **34 209** | **-7 613** | **26 596** |

70.4. Eskom is applying to spend R302 million for procuring 424GWh from IPPs under the WEPs programme for the 2018/19 financial year. NERSA has disallowed this cost because Eskom has excess capacity and it can generate the energy from its coal-fired plants at a much cheaper rate. Furthermore, Eskom was able to identify only 10 IPPs that are willing to participate in WEPs with a combined production capacity of 205GWh. From the 2013/14 financial year to the 2016/17 financial year, the maximum energy produced by WEPs IPPs was 146MW, which was achieved in the 2014/15 financial year.

70.5. Eskom applied for R2 380 million in power purchases from the DoE Peaking plants, namely Avon and Dedisa. These two OCGTs are operational under a PPA. Eskom used a load factor of 1% for the IPP OCGTs, which is the same as its application for its own OCGTs. The tariff being charged is as per the PPAs signed by Eskom. The amount in Eskom's application is not adjusted as it is in line with the PPA. Furthermore, these two peaking plants are important for the stabilisation of the grid in emergency and peak demand periods as they can be deployed in a very short time.

70.6. Tugela Energy (Pty) Ltd (RF) ('Tugela Energy') is a co-generation project, which is wholly owned by Sappi Southern Africa Ltd. It was announced as a preferred bidder under the DoE co-generation Procurement Programme. Although the plant is already operational, it is one of the projects that has not yet signed a PPA with Eskom. Eskom indicated that this project is not included with the projects that are negotiating with the DoE for the signing of their PPAs. The cost of this IPP is therefore disallowed. The production cost for the 88 GWh that should have been realised from Co-generation IPP (Tugela) was moved to the cheapest coal generation option in Eskom's generation fleet and the coal cost was adjusted accordingly.

70.7. Eskom applied for purchases of R31 230 million from Renewable Energy (RE) IPPs under Bid Windows 1 to 4.5, as well as small-scale renewable projects. Only projects from Bid Window 1, 2 and 3 are currently operational. The tariffs to be charged are in line with the signed PPAs. The volumes to be produced were validated using the past production figures and are the same as in Eskom's application.

70.8. In bid Window 3.5, there were only two projects, which are both Concentrated Solar Photovoltaic (CSP). Only one has a signed PPA and construction is at an advanced stage. The expected Commercial Operation Date (COD) is 1 June 2018. The cost for this bid window was adjusted accordingly to disallow the cost of the project on which construction has not started and which will not reach COD in the one-year MYPD period being applied for, even if construction were to commence immediately.

70.9. One (CSP) project from bid window 3.5 and all the projects from bid windows 4, 4.5 and Small-Scale Renewables have not yet signed PPAs with Eskom.

70.10. All projects with unsigned PPAs will not be able to reach COD within the 2018/19 financial year. The costs associated with those IPPs will not be incurred by Eskom during this application period and are therefore not allowed.

70.11. The total adjustment for REIPPs is R7 014 million. The production cost for the 6 237 GWh that would have been realised from REIPPs were moved to the cheapest coal generation option in Eskom's generation fleet and the coal cost was adjusted accordingly.

70.12. Eskom is also applying for R192 million for Network Use-of-System (UoS) for IPPs. Eskom indicated that all generators contribute to the maintenance cost of the transmission network. Eskom would invoice the IPPs for UoS and the IPPs then add this cost to the energy charge to Eskom for payment.

70.13. Eskom is therefore effectively getting the UoS cost from the customers. The PPA makes provision for the UoS charges to be passed through for IPPs. This provision was specifically included in anticipation of an Independent System and Market Operator (ISMO) or Transmission Operator. Since Eskom's application also includes transmission costs, which are inclusive of transmission operational costs, transmission loses, transmission capital costs, manpower costs, etc, this would result in Eskom double counting. The inclusion of UoS costs on IPP generation would also distort the real cost of IPPs to Eskom versus its own generation. The cost for UoS is not allowed.

71. International Purchases

71.1. Eskom has budgeted [redacted] to buy 9 373GWh and 8GWh from Cahora Bassa hydro power plant (Mozambique) and Lesotho Electricity Company (LEC) respectively. Eskom also included 2 453GWh that will be wheeled through its network as part of the International purchases.

71.2. This brings the total International purchases to 9 381GWh at a total cost of [redacted]. Although Eskom now has excess capacity, it has long-term PPAs with Cahora Bassa (Mozambique) and LEC that have to be honoured. Furthermore, the import cost is [redacted], which is cheaper than Eskom's coal generation cost.

71.3. Table 35 provides a breakdown of the international purchase costs applied for. NERSA did not make any adjustments.

**Table 35: International Purchases**

| | Energy (GWh) | | | Cost (R'm) | | |
|---|---|---|---|---|---|---|
| **International Purchases** | **Eskom application** | **Adjustments** | **NERSA Decision** | **Eskom application** | **Adjustments** | **NERSA Decision** |
| **Imports** | **9 381** | **0** | **9 381** | [redacted] | | |
| Mozambique (HCB) | 9 373 | 0 | 9 373 | | | |
| Other Sources (LEC) | 8 | 0 | 8 | | | |
| **Wheeling** | **2 453** | -2 453 | 0 | | | |
| **Total International Purchases** | **11 834** | **-2 453** | **9 381** | | | |

71.4. The 2 453MWh that Eskom will wheel through its network is misplaced from an international purchase point of view. This energy is not purchased by Eskom, but is provided to Eskom to compensate for loses in Eskom's network when one country (SAPP member) sells energy to another country through Eskom's network.

72. Demand Market Participation (DMP)

72.1. DMP (Instantaneous and Supplementary) is used by the System Operator to manage frequency decline during system constraints and also to balance supply and demand in order to keep the system stable.

72.2. NERSA assumed the latest available (2016/17) actual unit costs for Instantaneous DMP and Supplementary DMP as a base year. For 2016/17, the Instantaneous DMP unit cost was R0.165m/MW and R0.0014m/MWh for Supplementary DMP. Table 36 shows the 2018/19 unit costs for Instantaneous DMP and Supplementary DMP after adjusting the base year unit costs by CPI.

**Table 36: DMP unit costs for FY2018/19**

| DMP category | Eskom Application | Adjustment | Decision |
|---|---|---|---|
| Instantaneous (Rm/MW) | 0.218 | -0.0353 | 0.183 |
| Supplementary(Rm/MWh) | 0.0016 | -0.0001 | 0.0015 |
| Instantaneous(MW) | 600 | - | 600 |
| Supplementary(GWh) | 105 | - | 105 |

72.3. The CPI adjustments of the unit costs resulted in a reduction of DMP costs by R29 million as shown in Table 37.

**Table 37: DMP Costs for FY2018/19**

| DMP category | Eskom Application | Adjustment | Decision |
|---|---|---|---|
| Instantaneous (Rm) | 131 | -21 | 110 |
| Supplementary(Rm) | 170 | -8 | 162 |
| DMP programme administration (Rm) | 18 | - | 18 |
| **Total (Rm)** | **319** | **-29** | **290** |

73. Integrated Demand Management (IDM)

73.1. Eskom IDM has applied for an amount of R511 million and projected savings of 130MW for the 2018/19 application. Eskom has applied for an Energy Services Company (ESCO) process control programme and a Compact Fluorescent Lamp (CFL)/Light Emitting Diode (LED) roll-out programme for 2018/19.

73.2. Eskom has excess generation capacity and there are therefore no funds allocated for Eskom IDM programmes in 2018/19 as shown in Table 38. IDM costs that may be incurred resulting from contractual obligations in 2018/19 will be considered during the 2018/19 RCA application, after consideration of prudency and efficiency.

**Table 38: IDM Costs for FY2018/19**

| IDM Programmes | FY2018/19 | | |
|---|---|---|---|
| | Eskom application | Adjustment | NERSA Decision |
| **IDM Funding (Rm)** | **511** | **-511** | **-** |
| Programmes - Peak Demand Savings(MW) | 130 | -130 | - |
| Programme Unit Cost (Rm/MW) | 2.50 | -2.50 | - |
| Programme Costs (Rm) | 325 | -325 | - |
| Operating Costs (Rm) | 170 | -170 | - |
| Measurement and Verification (M&V) costs (Rm) | 16 | -16 | - |

## WEIGHTED AVERAGE COST OF CAPITAL (WACC)

74. The WACC represents the risk adjusted opportunity cost of capital, and is perceived as the minimum return for an investment in order to continue to attract capital, given the risks.

75. Eskom's cost of capital details as applied for are provided in Table 39.

76. Eskom calculated a required Return on Assets (ROA) of 8.4%. However, Eskom indicated that it is only applying for an ROA of 2.97% in the 2018/19 financial year due to the need to phase-in the return. The return claimed is R22 690 million in monetary terms. The portion of the return not claimed will be forfeited.

77. Table 39 illuminates NERSA's analysis of Eskom's WACC. According to NERSA's calculation, Eskom's real WACC before tax is 6.9%, which is lower than Eskom's calculated WACC of 8.4%. The major difference between the two calculations emanates from the cost of equity, as Eskom is of the view that its equity holders require a higher rate of return.

78. In estimating Eskom's cost of equity, NERSA used the Capital Asset Pricing Model (CAPM). CAPM is based on the premise that equity holders need to be compensated for their assumption of systematic risk in the form of a risk premium or the amount of market return in excess of a stated risk-free rate. Unsystematic risk is company specific and can be avoided through

diversification. Therefore equity holders are not compensated for unsystematic risk.

**Table 39: Eskom WACC Calculation (Eskom Table)**

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

79. Eskom's beta was extrapolated from a group of comparable companies. Firstly, predicted levered betas where sourced from Bloomberg for each of the comparable companies. These beta values where then unlevered using the market values for each company's debt and equity information. This information, together with the marginal tax rate assumptions, enabled NERSA to unlever the individual betas and calculate an average and a median unlevered beta for the peer companies as shown in Table 40 below.

**Table 40: Comparable Companies Unlevered Beta**

| Comparable Companies Unlevered Beta | | | | | | |
|---|---|---|---|---|---|---|
| Company | Predicted Levered Beta[4] | Market Value of Debt | Market Value of Equity | Debt/ Equity | Marginal Tax Rate | Unlevered Beta |
| AMERICAN ELECTRIC POWER | 0.311 | 1492328.40 | 761584.20 | 196.0% | 35.0% | 0.14 |
| EDP-ENERGIAS DE PORTUGAL SA | 1.061 | 632436.20 | 239254.60 | 264.3% | 21.0% | 0.34 |
| EDF | 1.316 | 439602.10 | 198980.60 | 220.9% | 33.0% | 0.53 |
| KOREA ELEC POWER CORP-SP ADR | 0.944 | 1191383.80 | 830557.70 | 143.4% | 22.0% | 0.45 |
| ALLETE INC | 0.552 | 41387.30 | 25999.20 | 159.2% | 35.0% | 0.27 |
| Enel SpA | 0.712 | 1492328.40 | 761584.20 | 196.0% | 24.0% | 0.29 |
| **Mean** | **0.82** | | | **196.6%** | | **0.34** |
| **Median** | **0.83** | | | **196.0%** | | **0.31** |

80. NERSA then re-levered the median unlevered beta of 0.33 at Eskom's previously determined target capital structure of 233.3% debt/equity ratio, using its marginal tax rate of 28%. This provided a levered beta of 0.90 as shown in Table 41 below.

**Table 41: Eskom Re-levered Beta**

| Eskom Relevered Beta | | | | |
|---|---|---|---|---|
| | Mean Unlevered Beta | Target Debt/ Equity | Target Marginal Tax Rate | Relevered Beta |
| **Relevered Beta** | 0.34 | 233.3% | 28.0% | **0.90** |

81. Using the Capital Asset Pricing Model (CAPM) as shown in Table 42 below, NERSA calculated a cost of equity for Eskom.

**Table 42: WACC Calculation by NERSA**

| **WACC Calculation** | |
|---|---|
| ***Capital Structure*** | |
| Debt-to-Total Capitalization | 70.0% |
| Equity-to-Total Capitalization | 30.0% |
| | |
| ***Cost of Debt*** | |
| Risk free rate | 8.596% |
| Debt premium | 1.061% |
| **Cost of Debt before tax** | **9.7%** |
| | |
| ***Cost of Equity*** | |
| Risk-free Rate(1) | 8.596% |
| Market Risk Premium(2) | 5.3% |
| Levered Beta | 0.90 |
| **Cost of Equity after tax** | **13.4%** |
| Tax rate | 28.0% |
| **Cost of Equity before tax** | **18.6%** |
| | |
| **Nominal WACC before tax** | **12.3%** |
| Inflation | **5.1%** |
| **Real WACC before tax** | **6.9%** |

(1) Source 10 year government bond, Bloomberg
(2) Source Credit Suisse
(3) logic Spread between R186 and ES2
(4) Sourced from bloomberg

82. Taking economic impact considerations and Eskom's liquidity and debt servicing requirements into account, NERSA has decided to allow Eskom a ROA of 4%, which equates to a return R5 427 million higher than what Eskom had applied for. This return, including the allowed depreciation, should assist Eskom in meeting its interest obligations for the 2018/19 financial year. The rest of the return is forfeited and will not be claimable from customers in future.

## REGULATED ASSET BASE (RAB)

83. The Eskom RAB value applied for represents the value to be used for the purposes of determining a return and depreciation to be allowed to Eskom. In accordance with the MYPD Methodology, Eskom should undertake a revaluation of its asset base by the time of the next application. However,

Eskom has been granted condonation not to comply with this aspect for this application with the following condition:

*NERSA will use the MYPD3 closing balances as the base after taking into account amongst others:*

- *prudently incurred expenditure on assets;*
- *assets retired based on excess capacity; and*
- *the depreciation of assets since the MYPD3 revaluation*

84. Evaluation of the Eskom RAB

84.1. The projected opening RAB balance of R745 124 million as per the application takes into account movements from the approved opening balance of the MYPD3 and the year 1 RCA of R699 909 million and takes into account movements in the elements making up the RAB to get to the forecast value of R763 694 million in the application year.

84.2. This has resulted in the opening RAB value exceeding the MYPD3 decision of R717 513 million by R27 724 million. The reason for the higher RAB value can mainly be attributed to capital expenditure that has exceeded the budget over the MYPD3 period, resulting in the higher balance in the final MYPD3 year. The various elements making up the RAB are analysed in detail below.

84.3. Eskom has applied for an average RAB of R763 591 million for 2018/19. NERSA's decision is to approve an average of R702 929 million. The total average adjustment to the Eskom RAB application is R60 663 million as demonstrated in Table 43. The elements of the adjustment are discussed in detail below.

**Table 43: Detailed RAB**

| Detailed Average RAB (R'm) | Actual | Projection | | 2018/19 | |
|---|---|---|---|---|---|
| | 2016/17 | 2017/18 | Eskom application | Adjust | NERSA decision |
| Property and Plant | 591 603 | 594 070 | 587 709 | (54 655) | **533 054** |
| Equipment & Vehicles | 4 783 | 4 663 | 4 398 | (14) | **4 383** |
| Total Work Under Construction | 108 450 | 114 947 | 134 770 | (1 604) | **133 166** |
| Total Working Capital | 27 321 | 31 557 | 36 715 | (4 390) | **32 326** |
| **Total average RAB** | **732 157** | **745 237** | **763 591** | **(60 663)** | **702 929** |

84.4. Eskom's RAB has been analysed and adjusted under the following four categories, which are the elements that make up the total RAB:

a) Property and Plant;
b) Equipment and Vehicles;
c) Work Under Construction (WUC); and
d) Net working capital.

84.5. Property and Plant

84.5.1. Eskom has applied for an average property and plant value of R587 709 million for 2018/19. NERSA's decision is to approve an average of R533 054 million as shown in Table 44.

**Table 44: Property and Plant for 2018/19**

| Property and Plant 2018/19 (R'm) | Eskom application | | | | Adjustments | NERSA decision | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Generation | Transmission | Distribution | Total | | Generation | Transmission | Distribution | Total |
| Opening Balance | 412 153 | 104 239 | 80 810 | 597 202 | -106 667 | 412 153 | 104 239 | 80 810 | 490 534 |
| Opening balance adjustment (due to MYPD3 window) | -18 684 | -8 110 | 9 096 | -17 698 | 0 | -18 684 | -8 110 | 9 096 | -17 698 |
| Transfer to commercial operation | 15 637 | 6 643 | 4 523 | 26 803 | -5 832 | 9 805 | 6 643 | 4 523 | 20 971 |
| Less: Depreciation | -18 518 | -3 639 | -5 935 | -28 092 | 1 777 | -15 328 | -3 639 | -5 935 | -24 902 |
| **Closing P&P** | **390 588** | **99 133** | **88 494** | **578 215** | **-109 310** | **387 946** | **99 133** | **88 494** | **468 906** |
| **Total Average P&P** | **401 371** | **101 686** | **84 652** | **587 709** | **-54 655** | **400 049** | **101 686** | **84 652** | **533 054** |

84.5.2. These adjustments relate to adjustments to the opening balance, transfers to commercial operation and depreciation.

84.5.2.1. The adjustments to the opening balance of R106 667 million are as a result of the downward adjustment of the following: Historic over-expenditure (R72 255 million), an amount of R19 302 million relating to adjustments to the provision for escalation on historic capital expenditure, the removal of Arnot (R8 939 million) and Hendrina (R6 171 million) in line with Table 45 below.

**Table 45: Adjustments to opening balance Property and Plant for 2018/19**

| **Opening balance adjustments (R'm)** | |
|---|---|
| MYPD3 over expenditure | 72 255 |
| Escalation provision adjustment | 19 302 |
| Arnont | 8 939 |
| Hendrina | 6 171 |
| **Total opening balance adjustment** | **106 667** |

84.5.2.2. Transfers to commercial operation have been adjusted by R5 832 to exclude the Majuba rail project, which had been double counted in the Eskom application. No capacity is expected to come on stream in 2019.

84.5.2.3. The projects expected to be capitalised in 2018/19 relate to Kusile Temp coal infrastructure, Majuba rail and Koeberg Steam Generator Replacement (SGR).

84.5.3. Depreciation

84.5.3.1. Eskom has applied for depreciation of R29 140 million for 2018/19. NERSA's decision is to approve R24 902 million as per Table 46.

**Table 46: Depreciation**

| Annual Depreciation (R'm) | Actual | Projection | Year 2019 | | |
|---|---|---|---|---|---|
| | 2016/17 | 2017/18 | Eskom | Adjust | NERSA |
| Generation | (18 962) | (19 196) | (19 062) | 3 733 | (15 328) |
| Transmission | (4 016) | (4 103) | (3 833) | 194 | (3 639) |
| Distribution | (5 916) | (5 925) | (6 245) | 311 | (5 935) |
| **Total Depreciation** | **(28 895)** | **(29 224)** | **(29 140)** | **4 237** | **(24 902)** |

84.5.3.2. The adjustments relate mainly to Generation depreciation, which has been adjusted downwards to reflect the MYPD3 revaluation values as shown in Table 47.

84.5.3.3. Eskom Generation applied for a depreciation of R19 062 million for 2018/19. NERSA's decision is to approve R15 872 million. This value has been adjusted downwards by R3 190 million in the areas of base load and peaking plants. This is due to Eskom and NERSA using different DRC and remaining useful lives to calculate depreciation. NERSA has used the figures from the last revaluation that were done during MYPD3. Eskom and NERSA values should not differ in the absence of an asset revaluation.

**Table 47: Generation Depreciation**

| Depreciation (R'm) | Eskom | | | NERSA | | | |
|---|---|---|---|---|---|---|---|
| | DRC | Remaining Life | Depreciation | Adjustments | DRC | Remaining Life | Depreciation |
| Base load plants | 237 886 | 222 | 13 804 | -2 260 | 209 523 | 206 | 11 543 |
| Peaking plants | 17 284 | 14 | 1 235 | -830 | 12 333 | 213 | 404 |
| New build plants | 146 642 | 136 | 3 079 | - | 146 642 | 136 | 3 079 |
| Equipment | 2 283 | 4 | 544 | - | 2 283 | 4 | 544 |
| Other | 10 341 | 213 | 401 | -99 | 11 172 | 187 | 302 |
| **Total** | **414 436** | | **19 062** | **-3 190** | **370 782** | | **15 872** |

84.6. Equipment and Vehicles

84.6.1. Eskom has applied for an average of R4 398 million for equipment and vehicles for 2018/19. NERSA has approved an average of R4 383 million as shown in Table 48.

84.6.2. The adjustment is due to Eskom having excluded disposals in its movements from opening to closing balance. The R29 million adjustment relates to the disposals for 2016/17 as per the AFS. This is a conservative approach, which assumes that the same levels of disposals will be prevalent in 2018/19.

**Table 48: Equipment and Vehicles**

| Equipment & Vehicles 2018/19 (R'm) | Eskom application | | | | | NERSA decision | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Generation | Transmission | Distribution | Total | Adjustments | Generation | Transmission | Distribution | Total |
| Opening Balance | 2 283 | 913 | 1 408 | 4 603 | - | 2 283 | 913 | 1 408 | 4 603 |
| New assets transferred to operations | 435 | 56 | 145 | 636 | - | 435 | 56 | 145 | 636 |
| Disposals | - | - | - | - | -29 | -29 | - | - | -29 |
| Less: Depreciation | -544 | -194 | -311 | -1 048 | - | -544 | -194 | -311 | -1 048 |
| **Total Equipment & Vehicles** | **2 174** | **775** | **1 242** | **4 192** | -29 | **2 145** | **775** | **1 242** | **4 163** |
| **Total Average Equipment & Vehicles** | **2 229** | **844** | **1 325** | **4 398** | -15 | **2 229** | **844** | **1 325** | **4 383** |

84.7. Work Under Construction (WUC)

84.7.1. Eskom has applied for WUC of R134 770 million for 2018/19. NERSA's decision is to approve R133 166 million. See Table 49.

84.7.2. WUC movements include transfers to commercial operation of R26 803 million, which have been adjusted down by R5 832 million as indicated under the Property and Plant section.

84.7.3. Eskom has included a total amount of R24 314 million as part of WUC movements, which it indicated is to be aligned with the actual commercial operation dates of the MYPD3 decision. Eskom further states that it has done so because the MYPD3 Methodology did not allow for the actual and decision of commercial operation dates to vary, since the forecast commercial operation dates are fixed. Should there be delays, RAB cannot be adjusted. Adjustments to correct this variance are therefore made when actual commercial operation takes place.

**Table 49: Work Under Construction**

| Works Under Construction 2018/19 (R'm) | Eskom | | | | NERSA | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Generation | Transmission | Distribution | Total | Adjustments | Generation | Transmission | Distribution | Total |
| Opening Balance | 114 927 | -6 428 | 8 302 | 116 801 | - | 114 927 | -6 428 | 8 302 | 116 801 |
| Capex excl IDC | 23 897 | 9 818 | 5 349 | 39 064 | -9 676 | 16 671 | 9 009 | 3 708 | 29 388 |
| Other | 15 428 | 20 906 | -12 020 | 24 314 | - | 15 428 | 20 906 | -12 020 | 24 314 |
| Less: Transfer to Commercial Operations | -15 637 | -6 643 | -4 523 | -26 803 | 5 832 | -9 805 | -6 643 | -4 523 | -20 971 |
| Transfers to/(out) commercial operations (CO) to Match the decision | - | - | - | - | - | | | | - |
| **Closing WUC** | **138 179** | **17 597** | **-3 037** | **153 376** | **-3 844** | **137 220** | **16 845** | **-4 533** | **149 532** |
| **Average WUC** | **126 553** | **5 584** | **2 633** | **134 770** | **-1 604** | **126 073** | **5 208** | **1 885** | **133 166** |

84.7.4. NERSA is of the view that since Eskom has used actual capital expenditure throughout the MYPD3 period as a base for its application, adjustments to transfers to commercial operation to match the MYPD3 decision are not allowed, as these should be in line with actual spend. As a result, this amount of R24 314 million for the reversal of these adjustments has been allowed, as it represents a reversal of amounts transferred to commercial operation to align with the MYPD3 decision and these transfers resulted in an overstated balance.

84.8. Capital Expenditure

84.8.1. The manner in which Eskom has structured the capital expenditure in its application is misleading as it applied for a capital expenditure budget of R76 941 million (R80 418 million minus the DoE-funded R3 475 million). This is the capital expenditure budget that the public commented on during public hearings. However during the assessment of the application, it became clear that Eskom was actually applying for R39 064 million as indicated in Table 50.

84.8.2. Eskom has not distinguished between RAB (to be funded from the current revenue application) and non-RAB (to be funded from other sources) capital expenditure. Eskom has also not distinguished between tariff-funded and Eskom-funded capital expenditure, hence the difference of R37 877 million. However, additional information submitted has made a clear distinction between the two, as demonstrated in Table 50.

**Table 50: Capex (Eskom Table)**

| Capex - Actual/Forecast (R'm) | ACTUAL | | | | Forecast | |
|---|---|---|---|---|---|---|
| | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 |
| Generation - RAB | 28 832 | 28 437 | 29 350 | 28 069 | 28 515 | 23 897 |
| Generation - Non RAB | 14 494 | 11 887 | 14 950 | 16 730 | 19 172 | 26 508 |
| | | | | | | |
| Transmission - RAB | 3 725 | 3 656 | 3 779 | 5 314 | 5 802 | 9 818 |
| Transmission - Non RAB | 448 | 506 | 1 132 | 658 | 1 012 | 1 674 |
| | | | | | | |
| Distribution - RAB | 4 881 | 4 183 | 4 078 | 3 346 | 4 760 | 5 349 |
| Distribution - Non RAB | 5 384 | 3 924 | 3 620 | 5 186 | 5 986 | 6 509 |
| | | | | | | |
| Corporate - Non RAB | 2 520 | 3 824 | 2 277 | 2 932 | 3 910 | 6 663 |
| **Total Approved capex** | **60 283** | **56 417** | **59 185** | **62 234** | **69 157** | **80 418** |
| **Total approved capex is split as follows:** | | | | | | |
| **Total Approved - RAB** | **37 437** | **36 276** | **37 206** | **36 728** | **39 077** | **39 064** |
| **Total Approved - Non RAB** | **22 846** | **20 142** | **21 978** | **25 506** | **30 080** | **41 354** |

84.8.3. As a result, the capital expenditure amount under consideration is R39 064 million, not R76 941 million as reflected in the application.

84.8.4. Eskom has indicated that it reflected the R76 941 million for completeness to include all projects it envisages to undertake.

84.8.5. The projects that make up the R39 064 million have been scrutinised further to ensure that the amounts applied for are efficient. Generation new build has been benchmarked internationally using the Electric Power Research Institute (EPRI), Lazard and the International Energy Agency (IEA) benchmarks.

84.8.6. The results of the findings are presented in the Generation section below. Transmission and Distribution has been tested to ensure that only relevant projects are included and these have been allowed at reasonable expected cost projections in light of past trends. This has been done to ensure that Eskom embarks only on prioritised projects in light of the current electricity surplus that is prevalent.

84.8.7. As a result, Eskom should not be taking an aggressive capital expenditure approach, but should rather prioritise key projects. This implies that non-priority projects can be delayed to future years when capacity will be required.

84.9. Generation Capital Expenditure

84.9.1. Eskom Generation has applied for capital expenditure of R23 897 million for 2018/19. NERSA's decision is to approve R16 671 million as shown in Table 51.

84.9.2. The adjustment of R7 227 million emanates from unplaced contract costs that relate to escalation costs of packages, and owners' development costs being disallowed. The contingency is being limited to 10% of basic cost. The escalation caters for fluctuations from the forecasts.

**Table 51: Generation RAB Capex**

| Generation Projects 2018/19 (R'm) | Eskom | Nersa adjustments | NERSA decision |
|---|---|---|---|
| **Group Capital Gx Projects (RAB Capex)** | **23 462** | **-7 227** | **16 671** |
| Medupi | 8 555 | -2 543 | 6 012 |
| Kusile | 11 191 | -4 683 | 6 508 |
| Ingula | 71 | - | 71 |
| Sere | - | - | - |
| Kusile Tem Coal Infrstr | 162 | - | 162 |
| Majuba Rail | 410 | - | 410 |
| Acacia | 1 665 | - | 1 665 |
| Koeberg SGR | 1 408 | - | 1 408 |
| **Asset Purchases (New Investments)** | 435 | - | 435 |
| **Total** | **23 897** | **-7 227** | **16 671** |

84.9.3. In order to evaluate the efficiency and prudency of the new build, an overnight cost method was used to compare the capital costs (USD/kW) for installed capacity. It is defined as the capital cost of a power plant incurred overnight. The cost is expressed in terms of USDs cost per kilowatt of installed capacity converted to the same base year, thereby enabling a like-for-like comparison. To ensure like-for-like comparisons, international benchmarks (EPRI, Lazard and IEA) are adjusted to a common base.

84.9.4. Comparing the costs of constructing different power plants is challenging due to differences in size, construction time, inflation, technology, location, etc. Overnight cost is an internationally accepted method used to compare the construction cost of different power plants on a common basis. It includes costs associated with civils and construction, mechanical equipment, electrical work, control and instrumentation, project management and development. The interest during construction (IDC) of the project is excluded.

**Table 52: Overnight costs benchmarks**

| REFERENCE | 2017 $ | NERSA Benchmarks | | | Eskom Benchmarks | |
|---|---|---|---|---|---|---|
| | | Min | Max | Notes | Min | Max |
| LAZARD Nov 2017 | $/kW | 3000 | 8400 | USA capital costs for pulverised coal (PC) are based on Ultra Supercritical (USC) with Carbon Capture & Storage (CCS) therefore not comparable with Eskom. USC w/t CCS cannot be built in USA now due to the environmental regulations | 2520 | 6845 |
| AEO | $/kW | 3636 | | USA capital costs for pulverised coal (PC) are based on Ultra Supercritical (USC) with Carbon Capture & Storage (CCS) therefore not comparable with Eskom. USC w/t CCS cannot be built in USA now due to the environmental regulations | **N/A** | |
| NERSA benchmarg based on EPRI 1 Jan 2017 excl FGD | $/kW | 2368 | 2725 | Developed for RSA IRP 2017 and most applicable benchmark for RSA. The minimum cost is for 6x750 MW no FGD identical to Eskom plant. The max is for single unit | 2400 | |
| NERSA benchmark based on EPRI 1 Jan 2017 incl FGD | $/kW | 2950 | 3397 | Developed for RSA IRP 2017 and most applicable benchmark for RSA. The minimum cost is for 6x750 MW no FGD identical to Eskom plant. The max is for | 2990 | |
| IEA 2015 | $/kW | 2222 | 2533 | The minimum is Eskom estimate in 2015 for pulverised coal | 1618 | 3064 |
| | | | | | | |
| Medupi Eskom estimate | $/kW | | | It is an estimate since the plant is not completed | 2769 | 2900 |
| Kusile Eskom estimate | $/kW | | | It is an estimate since the plant is not completed | 2906 | 2974 |
| | | | | | | |
| Difference EPRI w/t FGD & Eskom | $/kW | 401 | 175 | | | |
| Kusile & Medupi Capacity | MW | 8640 | | | | |
| Estimate of Medupi and Kusile capex above the minimum of EPRI applicable for 6 pack station | million $ | **3 465** | **1 512** | | | |

84.9.5. According to Eskom, in line with Table 52, Medupi and Kusile's overnight costs are In line with the available international benchmarks. Depending on the benchmark provider, costs at Medupi and Kusile are either at the lower end or upper end of benchmark sample. (Generation License, p.43)

84.9.6. According to NERSA's overnight costs benchmarks, provided in the same Table 52, Medupi and Kusile's costs fall above or within the benchmarks for without FGD or with FGD respectively.

84.10. Cost overruns

84.10.1. Eskom's Generation RAB Capex for the new-build programme is expected to exceed NERSA's allocation by R72 255 million in total over the MYPD3 period which represents 29% over-expenditure in 2013/14, with the highest over-expenditure of 241% in 2016/17 as demonstrated in Table 53.

**Table 53: Generation RAB Capex Variance (Eskom Table)**

| Generation Capex MYPD 3 Variance | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | Total |
|---|---|---|---|---|---|---|
| **Group Capital Gx Projects** | **6 107** | **9 171** | **17 147** | **19 804** | **18 630** | **70 858** |
| Medupi | 2 903 | 4 157 | 6 385 | 6 123 | 7 683 | 27 250 |
| Kusile | 158 | 4 280 | 8 568 | 14 685 | 14 717 | 42 408 |
| Ingula | 2 213 | 2 508 | 3 541 | 1 628 | 410 | 10 301 |
| Sere | 1 953 | -1 089 | -636 | 1 | - | 229 |
| Kusile Tem Coal Infrstr | -42 | -43 | 33 | 70 | 275 | 293 |
| Majuba Rail | -888 | -1 616 | 406 | 669 | 1 671 | 241 |
| Acacia | 19 | 17 | 25 | 29 | 346 | 437 |
| Koeberg SGR | 9 | 1 016 | 725 | 667 | 1 545 | 3 961 |
| Tutuka Rail | -68 | - | - | - | - | -68 |
| Underground Coal Gasification | -150 | -58 | - | - | - | -208 |
| Medupi FDG | - | - | - | -1 218 | -7 827 | -9 045 |
| Concentrated Solar Power | - | - | -1 900 | -2 850 | -190 | -4 940 |
| **Asset Purchases** | **340** | **727** | **-103** | **22** | **411** | **1 397** |
| **Total** | **6 447** | **9 898** | **17 044** | **19 826** | **19 040** | **72 255** |
| **Percentage variance** | **29%** | **53%** | **139%** | **241%** | **201%** | **102%** |
| **Summary** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** | **Total** |
| MYPD3 approved | 22 385 | 18 539 | 12 306 | 8 243 | 9 474 | 70 947 |
| Actual | 28 832 | 28 437 | 29 350 | 28 069 | 28 515 | 143 202 |
| **Total variance** | **6 447** | **9 898** | **17 044** | **19 826** | **19 040** | **72 255** |

84.10.2. Detailed below are some of the reasons provided by Eskom for the cost overruns.

*84.10.2.1. Medupi*

a) The total cost overruns for Medupi amounted to R19.6 billion for the first four years of the MYPD3, consisting of Owners Development Costs of R8.2 billion, contingency costs of R8.2 billion and basic costs of R3.2 billion. According to Eskom, the main cost drivers are additional manpower costs due to delayed demobilisation, additional variations including design integration and scope changes, claims arising from access delays, and force majeure events.

*84.10.2.2. Kusile*

a) The total cost overruns for Kusile amounted to R 27.6 billion for the first four years of MYPD3. The main increases are the Owners Development Costs of R8.2 billion, contingency costs of R7.7 billion and basic costs of R7.1 billion. The main cost drivers for

Kusile, according to Eskom, are the claims arising from access delays, delays in demobilising resources due to schedule delays, and escalation from Contract Price Adjustments (CPA) (largely driven by adjustments to labour indices).

*84.10.2.3. Ingula*

a) The total cost escalations for Ingula amount to R9.8 billion for the MYPD3. The costs escalations primarily emanate from contingency costs increase, Owners Development Costs and basic costs. The main costs drivers are the contract package costs escalations and penalties for access delays.

84.10.3. These costs were tested for efficiency and prudency and it was concluded that they were inefficiently incurred. More precisely, Owners Development Costs are Overhead costs and do not belong under Capex, but are catered for under operating expenditure.

84.10.4. Furthermore, Escalation costs seem to have excessively exceeded planning parameters like PPI, which is normally a yardstick for copper intensive equipment like turbines and generators. Also, IDC has been escalating at an alarming rate due to delays, most of which were not as a result of force majeure events (i.e. 'Acts of God' such as rain, earthquakes, etc.).

84.10.5. In line with the above analysis, the historic R72 255 million cost overruns as indicated in Table 53 have been disallowed. However Eskom will be allowed an opportunity to prove to the Energy Regulator that the overruns were prudently incurred. This process will be outside of the one-year 2018/19 tariff application process.

84.11. Excess Capacity

84.11.1. Excess capacity is conservatively estimated to be about 3 912MW in 2018/19, in line with the reserve margin benchmarking and excess capacity analysis that was undertaken.

84.11.2. The conclusion of this analysis is that the removal of some of the excess capacity results in an efficient generation level. Hendrina and Arnot have been removed from the RAB for the purposes of earning a return and their associated depreciation to allow Eskom a return on efficient production capacity only.

84.12. Transmission Capital Expenditure

84.12.1. Eskom Transmission has applied for capital expenditure of R9 818 million for 2018/19, NERSA's decision is to approve R9 009 million in line with Table 54. This value has been adjusted downwards by R809 million in order to address historic underspend and to enforce prevalent trends as discussed below.

84.12.2. The trend analysis of the MYPD3 period in Table 55 shows that Eskom has underspent NERSA's allocation by R19 552 million in total over the MYPD3 period. These variances indicate under-expenditure of 51% for the year 2013/14, under-expenditure of 39% for 2014/15, under-expenditure of 44% for 2015/16 and under-expenditure of 56% for 2016/17.

**Table 54: Transmission RAB Capex**

| Transmission RAB Capex (R'm) | Eskom | | | | | | NERSA | |
|---|---|---|---|---|---|---|---|---|
| | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 Forecast | Eskom application | Adjustments | NERSA decision |
| Capacity Expansion (RAB Capex) | 3 107 | 3 282 | 3 751 | 4 819 | 5 095 | 8 468 | -808 | 7 660 |
| EIA & Servitude | - | - | - | 468 | 664 | 1 293 | - | 1 293 |
| Production Equipment | 30 | 23 | 28 | 27 | 42 | 56 | - | 56 |
| Total other Tx Capex Allowed | 588 | 351 | - | - | - | - | - | - |
| **Total Tx Capex Allowed** | **3 725** | **3 656** | **3 779** | **5 314** | **5 802** | **9 818** | -808 | 9 009 |
| Km Line Construction | 1 741 | 1 698 | 1 633 | 2 143 | 2 110 | 3 064 | | 3 064 |
| R/km (R'm) | 1.8 | 1.9 | 2.3 | 2.2 | 2.4 | 2.8 | -0.3 | 2.5 |

**Table 55: Transmission RAB Capex Variance**

| Transmission RAB Capex (R'm) | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 Forecast | Total |
|---|---|---|---|---|---|---|
| MYPD3 approved | 7 545 | 6 019 | 6 790 | 12 143 | 9 331 | 41 827 |
| Actual | 3 725 | 3 656 | 3 779 | 5 314 | 5 802 | 22 275 |
| **Total variance** | **-3 820** | **-2 363** | **-3 012** | **-6 829** | **-3 529** | -19 552 |
| Percentage of approved CAPEX not use | -51% | -39% | -44% | -56% | -38% | -47% |

84.12.3. This trend is expected to change as massive generation projects come online, however this will not happen overnight. Meaning that as more units are commissioned, Eskom Transmission will be required to strengthen its network in order to accommodate the new capacity and evacuate the energy to the grid.

84.12.4. This is based on a trend analysis as indicated in Table 53. The trend analysis shows that it costs less to build a kilometre of line than what Eskom has applied for. This results in Eskom executing all the projects under its Transmission Development Plan (TDP) at a lower than applied for cost which results in an under-expenditure.

84.12.5. Therefore, Eskom should be allowed an average of R2.5m/km for the 2018/19 financial year.

84.12.6. This will result in a reduction of R808 million from the scheme strengthening projects without affecting the 3 064km to be built under the TDP for the year of application and without affecting the EIA & Servitudes budget as shown in Table 54.

84.13. Distribution Capital Expenditure

84.13.1. Eskom Distribution has applied for capital expenditure of R5 349 million for 2018/19. NERSA's decision is to approve R3 836 million in line with Table 56. This value has been adjusted downwards to exclude IPP connections and Accelerated Universal Access projects as discussed below.

**Table 56: Distribution RAB Capex**

| Distribution RAB Capex (R'm) | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 Forecast | Eskom application | Adjustments | NERSA decision |
|---|---|---|---|---|---|---|---|---|
| Direct Customer | 2 099 | 2 065 | 1 597 | 1 436 | 1 284 | 1 036 | - | 1 036 |
| Strengthening | 2 203 | 1 438 | 1 262 | 1 233 | 1 641 | 2 242 | - | 2 242 |
| Asset Purchase | 556 | 513 | 186 | 531 | 273 | 145 | - | 145 |
| **Continuous business improvement** | **23** | **165** | **1 034** | **146** | **1 562** | **1 926** | (1 641) | **285** |
| Land & Rights | 37 | 97 | 52 | 65 | 96 | 113 | - | 113 |
| IPP (Solar/Wind/CSP) | | | | | 29 | 128 | (128) | - |
| Accelerated Universal access project | | | | | 1 437 | 1 513 | (1 513) | - |
| IDM pilot project | | | | | - | 172 | - | 172 |
| Other | (15) | 68 | 982 | 80 | | | - | |
| **Total Eskom Funded** | **4 881** | **4 183** | **4 078** | **3 346** | **4 760** | **5 349** | (1 641) | **3 708** |

84.13.2. An amount of R1 513 million for the Universal Access Project (electrification) has been disallowed, because this project is funded by the DoE. However, Eskom has decided unilaterally to accelerate this programme for both 2017/18 and 2018/19, which leads to an additional requirement of R1 437 million and R1 513 million for the years 2017/18 and 2018/19 respectively.

84.13.3. Eskom should not be allowed additional funds for this purpose, as these funds have already been allocated under the DoE's electrification programme.

84.13.4. Furthermore, an amount of R128 million for IPP connections has been disallowed. In line with the Transmission/Distribution tariff code, Eskom incurs no costs when connecting IPPs as these costs are wholly borne by the customers.

**Table 57: Distribution RAB Capex Variance**

| Distribution RAB Capex (R'm) | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 Forecast | Total |
|---|---|---|---|---|---|---|
| MYPD3 approved | 6 013 | 5 199 | 6 427 | 8 440 | 6 537 | 32 616 |
| Actual | 4 881 | 4 183 | 4 078 | 3 346 | 4 760 | 21 247 |
| **Total variance** | **-1 132** | **-1 016** | **-2 349** | **-5 094** | **-1 777** | **-11 369** |
| Percentage of approved CAPEX not used | 19% | 20% | 37% | 60% | 27% | 35% |

84.13.5. The trend analysis of the MYPD3 period shows that Eskom will underspend NERSA's allocation by R11 369 million in total for the MYPD3 period as indicated in Table 57.

84.13.6. The variance shows an under-expenditure of 19% for 2013/14, an under-expenditure of 20% for 2014/15, an under-expenditure of 37% for 2015/16 and an under-expenditure of 60% for 2016/17, while the forecast under-expenditure for 2017/18 is 27%.

**Table 58: Total RAB Capex**

| Total RAB Capex (R'm) | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 Forecast | Total |
|---|---|---|---|---|---|---|
| MYPD3 approved | 35 942 | 29 757 | 25 523 | 28 826 | 25 342 | 145 390 |
| Actual | 37 437 | 36 276 | 37 206 | 36 728 | 39 077 | 186 725 |
| **Total variance** | **1 495** | **6 519** | **11 683** | **7 903** | **13 735** | **41 334** |

84.13.7. Eskom's funding shortfall as a result of the total over expenditure in generation over the MYPD3 period (R72 255 million) has been significantly offset by the under expenditures in Transmission (R19 552 million) and Distribution (R11 369 million) respectively throughout the same period. Eskom finances this shortfall by raising funds. In addition to exploring alternative funding sources. Eskom indicated that it is committed to finding efficiencies to close the funding shortfall. Table 58 demonstrates RAB Capex variances between the MYPD3 approved and actual expenditure.

84.14. Net working capital

84.14.1. Eskom applied for a net working capital of R36 715 million for 2018/19. The amount for net working capital is adjusted by R4 390 million to R32 326 million as demonstrated in Table 59. The adjustment emanates from a reduction in inventory and debtors.

**Table 59: Working Capital for 2018/19**

| Working Capital 2018/19 (R'm) | Eskom | | | | NERSA | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Generation | Transmission | Distribution | Total | Adjustments | Generation | Transmission | Distribution | Total |
| Inventory at year end | 36 371 | 2 892 | 2 901 | 42 164 | -4 914 | 31 457 | 2 892 | 2 901 | 37 250 |
| Plus: Closing accounts receivable (45 days) | 282 | 202 | 21 982 | 22 466 | -3 865 | 282 | 202 | 18 117 | 18 601 |
| Plus: Future Fuel (amortised value) | 9 781 | - | -1 | 9 780 | - | 9 781 | - | -1 | 9 780 |
| Less: Closing accounts payable (60 days) | -25 218 | -2 114 | -8 166 | -35 498 | - | -25 218 | -2 114 | -8 166 | -35 498 |
| **Closing Working Capital** | 21 217 | 980 | 16 716 | 38 912 | -8 779 | 16 302 | 980 | 12 851 | 30 133 |
| **Average Working Capital** | 19 377 | 1 256 | 16 082 | 36 715 | -4 390 | 16 920 | 1 256 | 14 149 | 32 326 |

84.14.2. Eskom included coal stockpiles exceeding 42 days as part of inventory. The amount for these stockpiles have been disallowed and only coal stock piles with 42 days and less are allowed by NERSA.

84.14.3. The allowed amount for debtors is limited to the principal debt (excluding interest) with a period of 45 days and less in line with the MYPD4 Methodology.

## OPERATING EXPENDITURE AND MAINTENANCE

85. Operating expenditure includes all costs incurred in the day-to-day running of the business. These include manpower costs, maintenance costs, other costs, arrear debt and corporate overheads. Eskom is applying for a total of R61 201m for the 2018/19 revenue application, which excludes corporate depreciation of R1 724m but includes R&D of R193m and IDM of R511m, which is dealt with separately.

86. Eskom's application relating to operating expenditure excludes all aspects of unregulated business. According to the MYPD Methodology, only regulated business-related revenue is allowed. In line with the Methodology, Eskom has removed R19m for a Treasury management fee that must not be recovered from regulated businesses, as well as R251m for Corporate Social Investment. The Methodology states that broad social development activities cannot be included as qualifying regulated expenses and must be paid for from the bottom line.

87. The split between the regulated and unregulated businesses is shown in Table 60.

**Table 60: Regulated versus Unregulated Business Split for 2018/19**

| R'm | 2018/19 Application | |
|---|---|---|
| | **Regulated Business** | **Unregulated Business** |
| **Employee benefit cost** | **22436** | **0** |
| Generation | 10810 | 0 |
| Transmission | 1508 | 0 |
| Distribution | 10118 | 0 |
| **Maintenance** | **17664** | **0** |
| Generation | 11681 | 0 |
| Transmission | 843 | 0 |
| Distribution | 5140 | 0 |
| **Other Costs** | **11022** | **0** |
| Generation | 6218 | 0 |
| Transmission | 765 | 0 |
| Distribution | 4039 | 0 |
| **Corporate Overheads** | 11441 | **675** |
| Employee benefit cost | **5776** | 0 |
| Other Costs | 4346 | 0 |
| Depreciation | 1724 | 0 |
| Treasury Management Fee | 0 | 19 |
| Corporate Social Investment | 0 | 251 |
| Other Income | -405 | 405 |
| **Other Income** | 11846 | 1046 |
| Generation | 0 | 565 |
| Transmission | 0 | 9 |
| Distribution | 0 | 472 |

88. Other income from the three divisions amounting to R1 046m includes income from non-core electricity. This income is related to various activities such as insurance proceeds and sale of scrap. Within the corporate division, other income amounts to R405m, which includes recovery of contracts executed on

behalf of subsidiaries as well as meal and bus tickets sales. Other income is not regulated revenue and is not included in the requested revenue.

89. The breakdown of the operating costs is shown in Table 61 as provided by Eskom.

**Table 61: Eskom Application – Detailed Operating Costs**

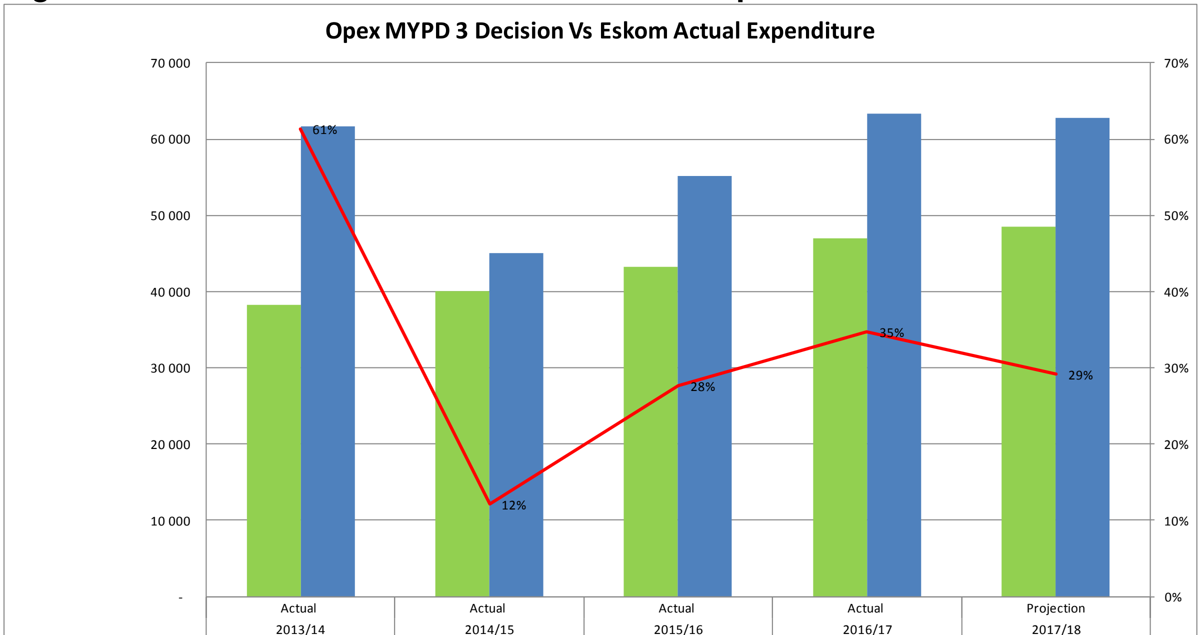
| Eskom | Actuals | Projections | Application |
|---|---|---|---|
| Operating costs R'million | 2016/17 | 2017/18 | 2018/19 |
| Employee benefit costs | 27 902 | 28 213 | 28 363 |
| Operating & Maintenance | 32 025 | 30 995 | 33 461 |
| Maintenance | 14 087 | 15 610 | 17 665 |
| Opex | 17 938 | 15 385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

90. The graph in Figure 10 compares the MYPD3 approved decision and Eskom's actual expenditure. The trend analysis shows that Eskom has been overspending significantly above the approved MYPD3 figures in the 2013/14 and 2016/17 financial years. In the year 2014/15, there was a decline of 27.1% in Eskom's expenditure, which brought the costs very close to the approved amounts. This shows that Eskom could manage to contain its costs in line with the NERSA-approved figures.

91. Eskom's consistent over-expenditure on what was allowed by NERSA shows lack of cost control measures by Eskom.

92. In reaching its decision, NERSA considered Eskom's unwillingness to implement stringent measures to contain its costs. In light of this, NERSA has adjusted the expenditure taking this into consideration.

**Figure 10: MYPD3 decision vs. Eskom actual expenditure**




| | Actual 2013/14 | Actual 2014/15 | Actual 2015/16 | Actual 2016/17 | Projection 2017/18 |
|---|---|---|---|---|---|
| NERSA decision | 38 218 | 40 095 | 43 222 | 46 987 | 48 533 |
| Eskom total expenditure | 61 658 | 44 982 | 55 198 | 63 322 | 62 716 |
| % Spent | 61% | 12% | 28% | 35% | 29% |

93. The following sections will discuss the individual operating expenditure line items in detail.

94. Employee Benefit Costs

94.1. Employee benefit costs are the manpower costs incurred by Eskom in the Generation, Transmission and Distribution businesses. Eskom is applying for R28 390m for employee benefit costs, including those that fall under corporate overheads.

94.2. The total employee benefit costs applied for under Generation, Transmission and Distribution business amount to R 22 614m for the year 2018/19 as shown in Table 62 below. Eskom changed this figure due to an error in the transmission script. In the original submission the transmission amount was R1 686m. In the revised schedule it is reflected as R1 508m, which results in R22 436m being the amount applied for. See Table 66.

**Table 62: Employee Benefits Costs excluding Corporate Overheads**

| Employee costs R'm | Actual | Projection | Apllication |
|---|---|---|---|
| | 2016/17 | 2017/18 | 2018/19 |
| Generation | 9 733 | 10 358 | 10 810 |
| Transmission | 1 558 | 1 648 | 1 686 |
| Distribution | 10 277 | 10 293 | 10 118 |
| | 21 568 | 22 299 | 22 614 |

94.3. The total employee benefit costs applied for under corporate overheads amount to R5 776m for the year 2018/19. See Table 63.

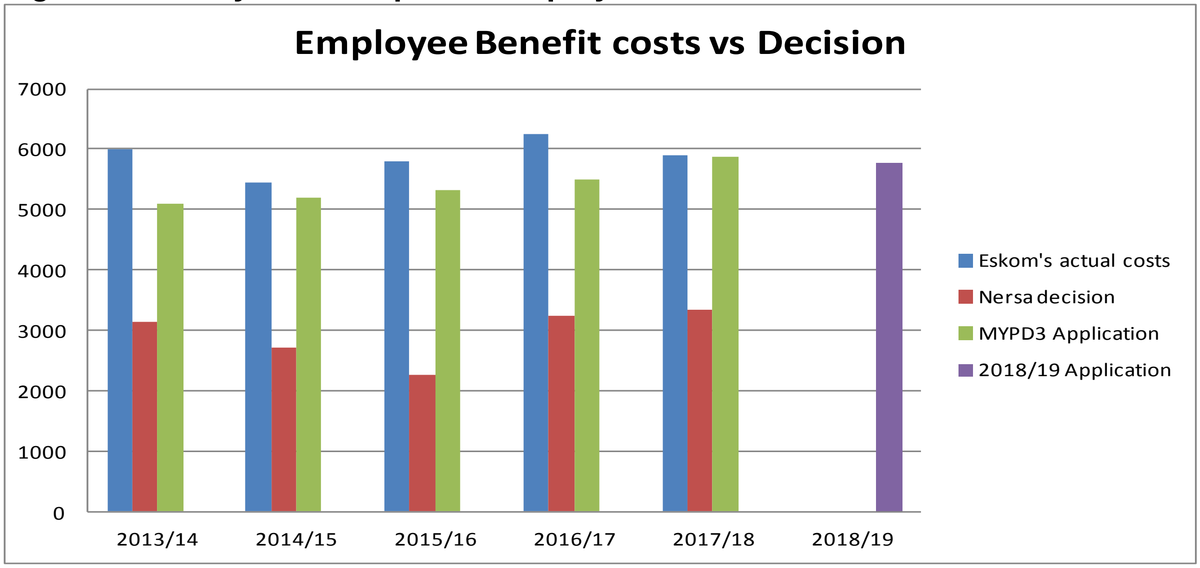
**Table 63: Eskom Application - Corporate Employee Benefits Costs**

| Corporate overheads R'm | Actual 2016/17 | Projections 2017/18 | Application 2018/19 |
|---|---|---|---|
| Employee Benefit | 6 244 | 5 912 | 5 776 |

94.4. The trend in Eskom's corporate employee benefit costs since 2013/14 has been declining by an average of 0.52%, in line with the declining headcount. There was however an above-inflation increase in 2016/17, which was explained as an extraordinary provision of R475m made for the closing of disparities in salaries between previously disadvantaged employees and their counterparts. A further provision of R319m for the 2017/18 financial year was made due to the agreements reached with the Trade Unions.

94.5. Although there is an average declining trend in Eskom's actual corporate employee benefit costs, the costs have exceeded NERSA's decision throughout the MYPD3 control period. Figure 11 illustrates the trend in these costs.

**Figure 11: Analysis of corporate employee benefit costs and NERSA decision**




94.6. Although there's a projected decline in employee benefit costs for 2017/18 and 2018/19 in line with the reduction in headcount, Eskom continues to significantly overspend on what was allowed. The reason provided by Eskom for these variances is that the actual corporate operating costs during the first two years of the MYPD2 period and the last year's projections were not factored into the decision. On the contrary, there were vast over-expenditures over the MYPD2 period, which were regarded as inefficient by NERSA. Furthermore, the graph in Figure 11 shows that Eskom not only exceeded NERSA's decision, but that it had exceeded its own costs as applied for over the entire MYPD3 control period. This implies that even if Eskom had been allowed the costs as applied for over MYPD3, it would have still overspent on the decision.

94.7. Approximately 84% of Eskom's staff complement belong to the bargaining unit and 16% are positioned at managerial and executive level as can be seen in Table 64. The wage settlement agreement has a significant impact on the employee benefit costs because of a higher contribution at a bargaining level. Employee benefit costs are influenced by three main factors, namely:

a) staff complement;
b) employee benefit increases; and
c) level of remuneration.

**Table 64: Staff complement per level (numbers of employees)**

| Staff complement segment | Actuals 2016/17 | Projection 2017/18 | Application 2018/19 |
|---|---|---|---|
| Executive | 473 | 465 | 442 |
| Management | 6 410 | 6 303 | 5 989 |
| Bargaining | 35 057 | 34 470 | 32 755 |
| **Total staff complement** | **41 940** | **41 238** | **39 186** |
| **Percentange Contribution of each segment** | | | |
| Executive | 1.1% | 1.1% | 1.1% |
| Management | 15.3% | 15.3% | 15.3% |
| Bargaining | 83.6% | 83.6% | 83.6% |
| **Employee benefit costs** | **21 568** | **22 299** | **22 614** |

94.8. Eskom indicated that the increase in the employee benefit costs is due to the additional employees for the new-build programme under the generation business. They further indicated that significant efficiencies have been realised in the existing power station fleet to cater for the increase in employees in newly commissioned power stations.

94.9. Table 65 shows the total generation head count excluding additions from the new build programme, which is 10 942. Including new-build additions of 886 then amounts to a total generation head count of 11 828. The addition of employees from new build resulted in the increase in the number of employees by 8.1%.

94.10. Generation's addition of employees for the new-build has contributed to an increase in employee benefit costs by R809.8m (0.914m*886). The average costs per employee improved from R0.988m to R0.914m given the employee benefit costs of R10 810m.

**Table 65: Impact of new-build on Generation employee benefits costs**

| Generation Head Count | Actuals | Projection | Application |
|---|---|---|---|
| | 2016/17 | 2017/18 | 2018/19 |
| Manpower costs R'm | 9 733 | 10 358 | 10 810 |
| Total generation Head Count | 11 966 | 12 013 | 11 828 |
| Less new Build | - 701 | - 819 | - 886 |
| *New Nuclear* | - 36 | - 36 | - 36 |
| *Renewables* | - 43 | - 46 | - 40 |
| *Medupi* | - 368 | - 434 | - 450 |
| *Kusile* | - 254 | - 303 | - 360 |
| Old Business Headcount | 11 265 | 11 194 | 10 942 |
| Average cost per head count total generation R'm | **0.813** | **0.862** | **0.914** |
| Average cost per head count old business R'm | **0.864** | **0.925** | **0.988** |
| Manpower costs percentage increase | | 6.0% | 6.00% |
| Head count percentage increase | | 7.32% | 8.10% |

94.11. Within the transmission business, the extended transmission network requires additional resources to monitor and maintain assets. The cost of maintaining the transmission network is influenced by the geographical size of the network, condition as well as the increased asset base.

94.12. For the distribution business, the total employee benefits costs for 2018/19 has reduced by 1.7% (see Table 66). The application states that the annual salary increase, and training and development costs are kept below inflation.

94.13. Constraints in terms of planned outages have an impact on maintenance costs, as specialised skills and equipment are required to perform live line maintenance. These have prompted an increase in the employee benefit costs for the transmission business. The employee benefit costs have reduced from R1 648m to R1 508m and the average cost per employee has increased from R0.782m to R0.752m, which is a -3.7% decrease as per Table 66.

**Table 66: Employee benefit costs and headcount analysis**

| Staff Complement and Emplyee costs | Actual 2016/17 | Projection 2017/18 | Apllication 2018/19 | Percentage Change |
|---|---|---|---|---|
| Generation R'm | 9 733 | 10 358 | 10 810 | 4.4% |
| Generation Head count | 11 966 | 12 013 | 11 828 | -1.5% |
| Average cost per employee | **0.813** | **0.862** | **0.914** | 6.0% |
| Percentage increase | | **6.01%** | **6.00%** | |
| Transmission R'm | 1 558 | 1 648 | 1 508 | -8.5% |
| Transmission Head count | 2 169 | 2 108 | 2 004 | -4.9% |
| Average cost per employee | **0.718** | **0.782** | **0.752** | -3.7% |
| Pernatage increase | | **8.8%** | **-3.7%** | |
| Distribution R'm | 10 277 | 10 293 | 10 118 | -1.7% |
| Distrubution Head count | 19 424 | 18 935 | 17 843 | -5.8% |
| Average cost per employee | **0.529** | **0.544** | **0.567** | 4.3% |
| Pernatage increase | | **2.7%** | **4.3%** | |
| **Total manpower costs** | **21 568** | **22 299** | **22 436** | 0.6% |
| **Total head count** | **33 559** | **33 056** | **31 675** | -4.2% |
| **Average ost per employee** | **0.643** | **0.675** | **0.708** | 5.0% |
| **Percentage increase** | | **5.0%** | **5.0%** | |
| **Percentage Contribution Head cout** | | | | |
| **Gx** | 36% | 36% | 37% | |
| **TX** | 6% | 6% | 6% | |
| **Dx** | 58% | 57% | 56% | |
| **Percentage Contribution costs** | | | | |
| **Gx** | 45% | 46% | 48% | |
| **TX** | 7% | 7% | 7% | |
| **Dx** | 48% | 46% | 45% | |

94.14. The total employee benefit costs applied for is R22 436m. Eskom reconciled this figure from R22 614m due to an error in the transmission script. In the original submission, the transmission amount was R1 686m. In the revised schedule it is reflected as R1 508m. The amount that Eskom originally applied for has reduced to R22 436m.

94.15. Eskom is projecting to increase employee benefit costs to R22 299m in 2017/18 from the actual employee benefit costs of R21 568m in 2016/17, which translates to a 3% increase. For 2018/19 Eskom is forecasting to increase its employee benefit costs to R22 436m, which translates to a 0.6% increase from 2017/18.

94.16. Eskom is projecting to reduce employee headcount to 33 056 in 2017/18 from the actual of 33 559 employees in 2016/17, this translates to a 2% reduction. For 2018/19 Eskom is forecasting a further decrease its employee headcount to 31 675 which translates to a 4.2% decrease as illustrated in Table 66. The reduction in the employee headcount is not due to restructuring by Eskom, but through natural attrition and employees leaving for various reason such as voluntary retirement.

94.17. The average cost per employee for Eskom is R0.643m for 2016/17, R0.675m for 2017/18 and R0.708m for 2018/19. There is an increase of 5% based on the average cost per employee, which is an inflation increase. The highest increase is in generation (6%), followed by distribution at 4.3% and transmission at a reduction of 3.7%.

94.18. Based on Table 66, the distribution business contributes 56% of the head count and 45% of employee costs; while the generation business contributes 37% of the head count, yet accounts for 48% of the employee costs.

94.19. According to the World Bank report 'Financial Viability of Electricity Sectors in Sub-Saharan Africa[8] Eskom's averaged staff costs per employee compared to other countries are high at $61 000 per employee. This translates to R0.708m average cost per employee for Eskom using R11.60 exchange rate as at 17 December 2014. Other countries' utilities average costs were at $13 000 when South Africa is excluded from the list. This means that the average costs per employees for other utilities using the rand/dollar exchange rate of R11.60 amounts to R0.151m.

94.20. The World Bank study states that in the year 2014, Eskom was overstaffed by 27 543 employees given the staff compliment of 41 787. According to the benchmark, Eskom's staff complement must at least be 14 244 based on the Australian Institute of Company Directors (AICD). AICD estimates 413 customers per employee in the developing countries. This implies an overstaffing percentage of 66% for Eskom. With the forecast decline in the number of employees to 39 186 in 2018/19, Eskom will be overstaffed by 24 942, which is 64% overstaffed.

94.21. Although Eskom is overstaffed by 66%, according to the World Bank study, there are limitations that need to be considered. The limitations of overstaffing analysis are that the benchmarking analysis is simplified to be able to cover dozens of countries for cross-country comparison. It

[8] Trimble, Christopher Philip and Kojima, Masami and Perez Arroyo, Ines and Mohammadzadeh, Farah, Financial Viability of Electricity Sectors in Sub-Saharan Africa: Quasi-Fiscal Deficits and Hidden Costs (August 9, 2016). World Bank Policy Research Working Paper No. 7788. Available at SSRN: https://ssrn.com/abstract=2836535

is for this reason that results for any individual country should not be used as a substitute for an in-depth country level analysis.

94.22. The abovementioned benchmark of 413 customers per employee is based on Latin America, which may not be a fair comparison to use for optimal employment in Transmission and Distribution. Density of customers may be much higher in Latin America with much higher per capita income.

94.23. However, NERSA has decided to benchmark Eskom against its own performance due to the limitation of the World Bank study. The benchmark compares Eskom's performance in the financial year 2007/8 and the application year 2018/19. The study shows that in year 2007 Eskom was able to produce 239 109GWh with 32 954 employees, which resulted in 7.26GWh per employee. Eskom is applying to produce 216 771GWh with 39 186 employees which translates to 5.3GWh/employee. This means that Eskom is producing less GWh with more employees and higher employee costs. The excess employees based on this analysis amount to 6 232. The cost of excess employees based on the inflationary adjusted average rate of R0.608m per employee amounts to R3 785m.

94.24. Table 67 shows the contribution of employee benefit costs and number of employees in relation to sales volume and GWh sent out.

**Table 67: Analysis of GWh and number of employees for each business**

| Volumes to number of employees | Actuals 2014/15 | Actuals 2015/16 | Actuals 2016/17 | Projection 2017/18 | Application 2018/19 |
|---|---|---|---|---|---|
| Sales Volumes(GWh) | 216 274 | 214 487 | 214 590 | 214 468 | 216 208 |
| Total Electricity generated | 226 300 | 219 979 | 220 166 | 221 395 | 216 771 |
| Employee benefits costs ( R'M) | 16 645 | 18 928 | 21 563 | 22 299 | 22 614 |
| Number of employees excluding corporate | 32 616 | 35 063 | 3 359 | 33 056 | 31 675 |
| GX Head count | 11 851 | 13 019 | 11 966 | 12 013 | 11 828 |
| Tx Head count | 2 057 | 2 189 | 2 169 | 2 108 | 2 004 |
| Dx Head count | 18 708 | 19 855 | 19 424 | 18 935 | 17 843 |
| Total number of employee including corporate | 41 787 | 35 063 | 41 940 | 41 238 | 39 186 |
| Number of customers | 5 977 | 5 689 | 5 478 | 6 277 | 6 568 |
| GWh sold per Dx employee | 11.56 | 10.80 | 11.05 | 11.33 | 12.12 |
| GWh sent out per Gx employee | 19.10 | 16.90 | 18.40 | 18.43 | 18.33 |

94.25. According to Table 68, salaries contribute 53% to the total employee benefit costs followed by allowances at 11.9%. Bonuses contribute 9.9% while overtime contributes 8.1%. The lowest contributions are Training & Development and temporary staff at 0.7% and 2.0%

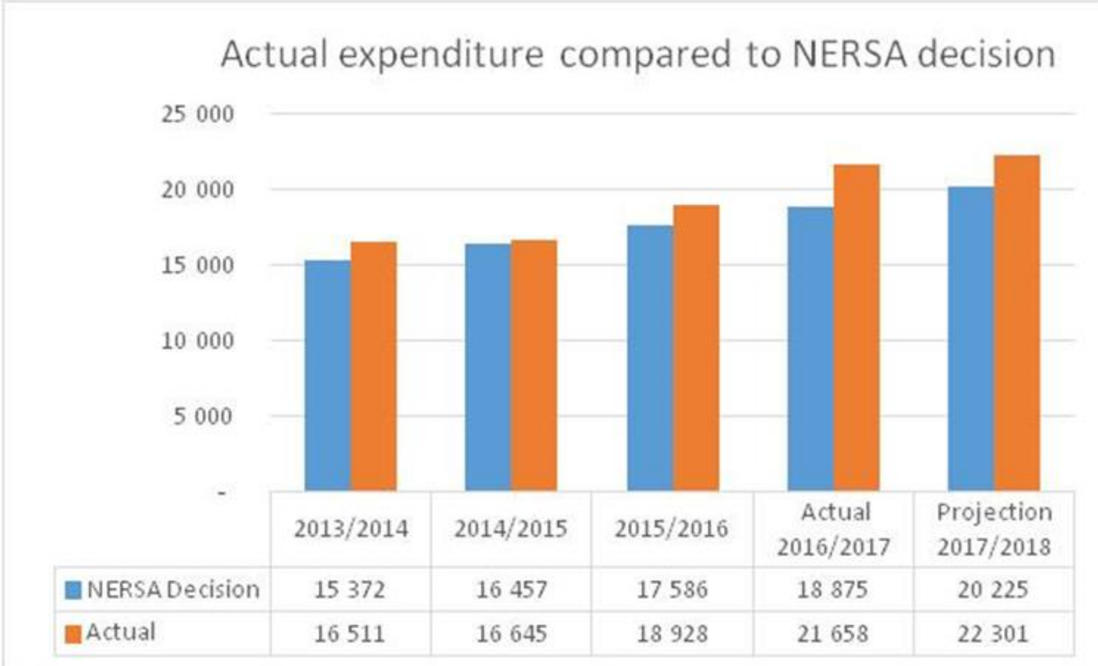
respectively. Overall, the major contributor to total employee benefit costs is salaries.

**Table 68: Contribution of Major Employee Benefit Costs to Total**

| Contribution of Major Employee Benefit Costs to the Total Cost | | | | |
|---|---|---|---|---|
| | **Dx** | **Tx** | **Gx** | **Total** |
| Salaries | 6 096 | 960 | 5 011 | 12067 |
| **Contribution to total cost** | **56.4%** | **56.9%** | **49.5%** | **53.4%** |
| Overtime | 598 | 69 | 1 174 | 1 841 |
| **Contribution to total cost** | **5.5%** | **4.1%** | **11.6%** | **8.1%** |
| Allowances | 1 215 | 179 | 1 290 | 2 684 |
| **Contribution to total cost** | **11.2%** | **10.6%** | **12.7%** | **11.9%** |
| Training and Development | 90 | 21 | 48 | 159 |
| **Contribution to total cost** | **0.8%** | **1.2%** | **0.5%** | **0.7%** |
| Bonuses | 1 238 | 196 | 805 | 2 239 |
| **Contribution to total cost** | **11.45%** | **11.63%** | **7.96%** | **9.90%** |
| Temporary staff | 50 | 52 | 359 | 461 |
| **Contribution to total cost** | **0.5%** | **3.1%** | **3.5%** | **2.0%** |
| **Total employee benefit costs** | **10 810** | **1 686** | **10 118** | **22 614** |

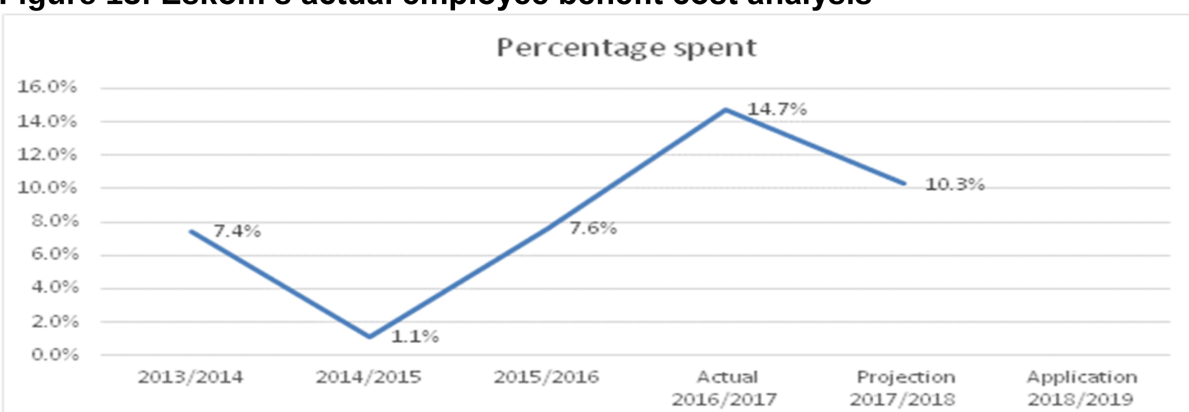
94.26. The graph in Figure 12 shows the trend of Eskom's actual expenditure compared to NERSA's decisions. For the financial years 2013/14 to 2016/17 Eskom has been spending above what NERSA has allowed in the MYPD3 decision by a small margin. This implies that Eskom's expenditure is not aligned to NERSA's decision. Only in 2014/15 the actual expenditure was closer to the NERSA decision; in all the other years Eskom has consistently spent above the NERSA decision.

**Figure 12: Trend analysis on Manpower actual cost vs. NERSA decision**




94.27. Based on the 2016/17 actual costs and 2016/17 MYPD3 approved figures, NERSA has observed an over-expenditure of 14.27% (see Figure 13) for that year. There are three cost drivers to employee benefits costs, namely, staff complement, employee benefits increase and level of remuneration.

**Figure 13: Eskom's actual employee benefit cost analysis**




94.28. The graph in Figure 13 shows the build-up to the application year, which implies that there has been an increase in manpower expenditure above the NERSA decision two years before the application year. Eskom is projecting to spend 10.25% above what is approved by NERSA. Although this is a decline from 14.74%, the base was set high due to a double digit increase in 2016/17 (from 7.63% to 14.74%).

**Table 69: Items that have led to an increase in Employees Benefit Costs**

| Items that has increased significantly above inflation as per MIRTA templates | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2013/14 Actual | 2014/15 Actual | 2015/16 Actual | 2016/17 Actual | 2017/18 Projected | 2018/19 Application | Average increase | Adjustments | NERSA Approved |
| **Incentive bonuses** | **1 027** | **1 158** | **1 508** | **2 304** | **2 194** | **2 239** | | **819** | **1 420** |
| Percentage increase | | *12.8%* | *30.3%* | *52.8%* | *-4.8%* | *2.1%* | *31.9%* | | |
| NERSA adjusted | | 1 100 | 1 178 | 1 262 | 1 351 | 1 420 | | | |
| Balance | | **58** | **330** | **1 043** | **843** | **819** | | | |
| **Leave pay** | **179** | **172** | **425** | **468** | **498** | **520** | | **520** | **-** |
| Percentage increase | | *-3.9%* | *147.6%* | *10.0%* | *6.4%* | *4.4%* | *51.2%* | | |
| NERSA adjusted | | 192 | 205 | 220 | 235 | 248 | | | |
| Balance | | **-20** | **220** | **248** | **263** | **271** | | | |
| **Annual bonus** | **290** | **245** | **575** | **657** | **700** | **730** | | **327** | **403** |
| Percentage increase | | *-15.6%* | *135.1%* | *14.3%* | *6.4%* | *4.4%* | *44.6%* | | |
| NERSA adjusted | | 310 | 332 | 356 | 381 | 403 | | | |
| Balance | | **-66** | **243** | **301** | **318** | **327** | | | |
| **Chairmans awards** | **31** | **18** | **6** | **100** | **107** | **111** | | **111** | **-** |
| Percentage increase | | *-42.6%* | *-66.1%* | *1554.2%* | *6.4%* | *4.4%* | *481.8%* | | |
| NERSA adjusted | | 33 | 36 | 38 | 41 | 43 | | | |
| Balance | | **-15** | **-30** | **62** | **66** | **68** | | | |
| **Total** | **1 527** | **1 592** | **2 515** | **3 530** | **3 498** | **3 600** | | **1 777** | **1 823** |

94.29. According to information in MIRTA templates, the increase in the employee benefit costs has been influenced by increases in incentive bonuses pay out, leave pay outs, annual bonuses and increase in the chairman's award pay out. All these items are within management control and could have been managed so that they do not increase significantly. The average increase from the financial period 2013 to 2016 for each of the identified items is above 30%.

94.30. In the MYPD3 decision, the Energy Regulator approved an increase of 5.60% plus 1.46%, which took into account the average growth in the headcount over the MYPD3 control period.

94.31. According to Eskom's 2016/17 Annual Financial Statements (AFS), Eskom paid performance awards to its executives and non-executive members despite the prevailing financial and non-financial conditions of the entity. The Board determined performance conditions and targets, which include ensuring business sustainability, reliable electricity supply, providing for future power need and supporting development objective of South Africa.

94.32. The company's profit at a Group level had declined from R5 151m (2015/16) to R888m (2016/17) and the interest cover ratio was less than one. All these were indications of an unsustainable business. Eskom continued to pay bonuses amounting to R2 140m, which is 42% of its net profit despite the prevailing conditions as per the 2015/16 AFS.

94.33. To limit the over-expenditure in incentive bonuses, NERSA has adjusted the 2016/17 amount to R1 209m from R2 304m using the MYPD3 approved rate of 7.1% (5.6% plus 1.46%). The application amount of R2 239m has been adjusted by inflation of 5.1% (the BER inflation rate) and this has resulted in the reduction of R819m.

94.34. The occasional and service leave pay is an expenditure item whereby an employee accumulates leave days over a period and later sells those days back to Eskom. These are the days over and above the annual leave days, and are accumulated every month at a lower rate. Employees are allowed to sell a minimum of seven days. Given the prevailing financial position of the entity in 2016/17 an amount of R 468m should not have been paid. This item has increased by an average of 51.2% over the MYPD3 control period. The application amount of R520m for leave pay has been disallowed completely.

94.35. Eskom has overspent by an average of 44% on annual bonuses over the MYPD3 control period despite the decrease in its sales volumes and low profit. Eskom has applied to spend R730m for annual bonuses, which are an increase of 4% from R700m projected for 2017/18. The base amount of 2016/17 was increased by 14.3%. NERSA has adjusted the expenditures on annual bonuses by 7.1% to determine a new base of R356m, which has resulted in the reduction of the application amount by R327m.

94.36. The chairman’s award is also one of the items that has led to a rise in the employee benefit costs. Although the amount of expenditure is low compared to other components of employee benefit costs, the over-expenditure is extremely high. The amount of R111m for the chairman’s award has been completely disallowed.

94.37. Eskom is increasing its employee benefit costs by inflation of 5.9% in the year 2018/19. Due to the positive relationship between sales volume and employee benefits costs it is anticipated that there must be a reduction in the employee costs as sales decrease. The number of employees is also declining, which is another reason for Eskom to decrease their employee benefit costs instead of increasing them.

94.38. Eskom has also over-spent on the NERSA-approved employee benefit costs in the MYPD3 determination. The increase has not taken into consideration the NERSA-approved manpower cost.

94.39. NERSA therefore decided on a R24 314m expenditure on employee benefit costs, which is a 13.8% decrease from the R28 212m Eskom applied for. The recommended figure was adjusted by R3 785m for cost of access employee, plus R111m chairman's award costs.

**Table 70: Total Employee Benefit Costs allowed**

| Employee Benefit Costs (R'm) | | |
|---|---|---|
| **Eskom Application** | **NERSA Adjustments** | **NERSA Final** |
| 28 212 | -3 898 | 24 314 |

95. Maintenance Costs

95.1. Eskom has applied for an amount R17 665m as its maintenance costs for 2018/19. Generation accounts for 66% of the total cost of maintenance, Transmission accounts for 5% and Distribution accounts for 29%. The projected expenditure of Eskom's maintenance costs for 2017/18 is higher by 5.32% from the approved MYPD3 amount of R14 812m. In the financial year 2016/17, Eskom has underspent on their maintenance amount by R568m from the approved amount mainly due to the Distribution division being able to extract efficiencies in their maintenance activities. Table 71 shows how the different divisions have spent their maintenance costs for the 2016/17 financial year and projections for 2018/19 against the approved maintenance costs for MYPD3.

**Table 71: Analysis of Over and Under Expenditure on Maintenance costs**

| Maintenance cost per Division (R'M) | 2016/17 | | | 2017/18 | | |
|---|---|---|---|---|---|---|
| | **Decision** | **Actuals** | **Over/Under** | **Decision** | **Projection** | **Over/Under** |
| Generation | 7 185 | 9 206 | 2 021 | 6 809 | 9 999 | 3 190 |
| Transmission | 564 | 712 | 148 | 597 | 759 | 162 |
| Distribution | 6 966 | 4 229 | -2 737 | 7 407 | 4 851 | -2 556 |
| **Total** | 14 715 | 14 147 | -568 | 14 812 | 15 609 | 796 |

95.2. The Generation and Transmission divisions have been overspending on the approved amounts as shown in Table 71. The practice of overspending on the NERSA-approved allowance should be discouraged. The effort by Distribution to cut on their approved amounts is a good indication that efficiencies can be extracted from Eskom in all its divisions.

95.3. Eskom has applied for an increase of 13% from the projected expenditure of 2017/18 and an increase of 19% from the approved 2017/18 amount in the MYPD3 control period. See Table 72.

**Table 72: Eskom Application – Maintenance costs**

| Maintenance cost per Division (R'M) | 2016/17 Actuals | 2017/18 Projections | 2018/19 Application | % Cost Contribution |
|---|---|---|---|---|
| Generation | 9 206 | 9 999 | 11 681 | 66 |
| Transmission | 712 | 759 | 843 | 5 |
| Distribution | 4 229 | 4 851 | 5 140 | 29 |
| **Total** | 14 147 | 15 609 | 17 664 | 100 |

95.4. Generation's maintenance costs increased by 17% from the projections of the final spend of 2017/18. The major driver of this high increase is that Koeberg will undertake two long duration outages of 90 days for each unit to undertake its nuclear refuelling, carry out major maintenance and perform the necessary station inspections and reconfiguration to optimise station performance. The maintenance costs associated with the above activities amount to an additional amount of R1 583m, which is a major cost driver for Generation's maintenance costs for 2018/19. See Table 73.

**Table 73: Generation Maintenance costs**

| Maintenance cost per Division (R'M) | 2016/17 Actuals | 2017/18 Projections | 2018/19 Application |
|---|---|---|---|
| Generation | 9 206 | 9 999 | 11 681 |
| NERSA Adjustment | | | -2 230 |
| **Total** | 9 206 | 9 999 | 9 451 |

95.5. Based on the generation maintenance actuals of R9 206m for 2016/17, the amount of R892m has been disallowed from the application. The basis of this adjustment is that the projections for 2017/18 are excessive and thus the additional amount of R1 583m is allowed over and above the R9 206m of actual spend for 2016/17. Maintenance costs associated with Arnot and Hendrina of R711m and R627m are completely disallowed as there is excess capacity on the network and the two stations should not be running at this stage. A total of R2 230m is disallowed for maintenance for 2018/19. A total amount of R9 451m is therefore allowed for 2018/19 for Eskom Generation to undertake all of its scheduled maintenance work. See Table 73.

95.6. Transmission has applied for R843m for 2018/19, which is an 11% increase from the projected spend of 2017/18. The projected expenditure of 2017/18 is also disregarded and the cost considered as a basis for the increase of 2018/19 is based on the actuals of 2016/17 of R712m. The actuals from 2016/17 are escalated by CPI for the two years to the final value of R788m, therefore a total amount of R55m is being disallowed from the application. See Table 74.

**Table 74: Transmission Maintenance costs**

| Maintenance cost per Division (R'M) | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|
| | Actuals | Projections | Application |
| Transmission | 712 | 759 | 843 |
| NERSA Adjustment | | | -55 |
| **Total** | 712 | 759 | 788 |

95.7. Distribution has applied for R5 140m as its maintenance costs for 2018/19. The distribution division has been able to extract efficiencies from its operations as it has substantially underspent on its maintenance activities. An amount of R179m for accelerated universal access programme is being disallowed from the application as it is not considered a new activity, but rather an ongoing activity for which maintenance costs associated with such networks have always been catered for in the past. Distribution is therefore allowed an amount of R4 961m. See Table 75.

**Table 75: Distribution Maintenance costs**

| Maintenance cost per Division (R'M) | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|
| | Actuals | Projections | Application |
| Distribution | 4 229 | 4 851 | 5 140 |
| NERSA Adjustment | | | - 179 |
| **Total** | 4 229 | 4 851 | 4 961 |

95.8. A total amount of R15 200m has been allowed from the amount of R17 665m. An amount of R2 465m has been disallowed from the application for 2018/19. It should be noted that there has been a significant improvement in plant performance, which has seen a decrease in the Unplanned Capacity Loss Factor (UCLF) and Other Capacity Loss Factor (OCLF) collectively decreasing from 14.4% to 10.6%. The amount approved in this application will enable Eskom to perform all of its planned maintenance activities for 2018/19. See Table 76.

**Table 76: Allowed Maintenance costs**

| Maintenance cost (R'M) | | |
|---|---|---|
| Maintenance Applied For | NERSA Adjustments | NERSA Final |
| 17 665 | -2 465 | 15 200 |

96. Other Costs

96.1. Other costs consist of various expenses such as administration costs, telecommunications costs, consulting fees, information management costs, customer services, property management and other general costs. The other costs currently contribute 18% of the total operating costs.

96.2. Eskom applied for other operating costs for 2018/19 financial year amounting to R11 022m as shown in Table 77. These costs exclude IDM, corporate cost and impairment loss. This amount includes the three regulated businesses, namely Generation, Transmission and Distribution. The divisional amounts applied for the 2018/19 financial year are R6 218m for Generation, R765m for Transmission and R4 039m for Distribution.

**Table 77: Analysis of Other costs**

| Other Costs (R'm) | MYPD3 Approved | Actuals | Projections | Application |
|---|---|---|---|---|
| | 2016/17 | 2016/17 | 2017/18 | 2018/19 |
| Generation | 3 000 | 8 452 | 5 541 | 6 218 |
| Transmission | 545 | 631 | 718 | 765 |
| Distribution | 3 273 | 3 414 | 3 843 | 4 039 |
| **Total** | **6 818** | **12 497** | **10 102** | **11 022** |

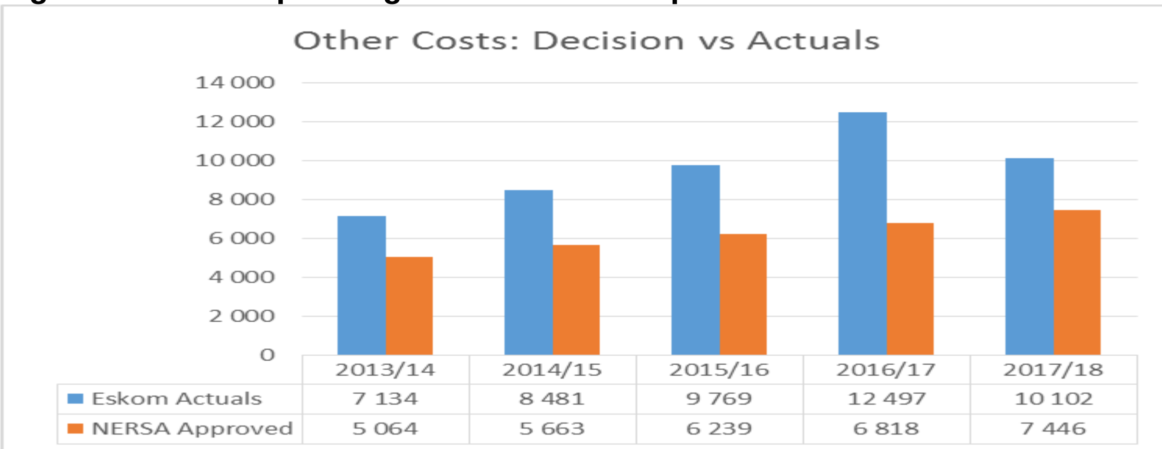
96.3. NERSA approved a total for other operating costs of R6 818m in 2016/17, while Eskom's actual expenditure was R12 497m, which translate to an 83% over-expenditure.

96.4. Eskom cited that the over-expenditure on other costs is attributable to once-off decommissioning provision amounting to R3 266m. This is followed by the insurance cost of R2 025m to expand the new asset base units of Ingula, Medupi and Kusile being commissioned within the Generation division.

96.5. The graph in Figure 14 shows other operating actual costs compared to the NERSA decision.

96.6. Figure 14 shows that Eskom's expenditure is not in line with NERSA's decision. From 2013/14 actuals to 2017/18 projections, Eskom has consistently spent above the NERSA decision.

**Figure 14: Other operating actual costs compared to NERSA decision**




96.7. NERSA's decision is that the decommissioning costs of R3 266m (as referred to above) should not be treated as a once-off provision, but rather be treated the same way as the previous year, as NERSA has already set a precedent. It is therefore prudent for it to be recovered over the remaining useful life of the plants. However, Eskom is allowed to recover a total of R6m and R14m for Peaking station and Coal mine closure rehabilitation decommissioning provision respectively, as per Table 78.

**Table 78: Analysis of allowed decommissioning provision**

| Decommissioning Provision Summary (R'm) | Eskom Decommissioning provision 2016/17 | Allowed Provision 2016/17 | Allowed Provision 2017/18 | Allowed Provision 2018/19 |
|---|---|---|---|---|
| Coal Station decommissioning | 915 | 57 | 62 | 67 |
| Peaking Station | 6 | 6 | - | - |
| Nuclear Spent fuel | 2 330 | 518 | 518 | 518 |
| Coal Mine closure and Rehabilitation provision | 14 | 14 | - | - |
| **Total** | **3 265** | **595** | **580** | **585** |

96.8. In 2017/18, Eskom's projections show an amount of R10 102m, which is 19% less than the 2016/17 actual of R12 497m.

96.9. The Eskom year-on-year growth in other costs shows an average increase of 10% from 2013/14 to 2018/19. Eskom cites that the growth of 10% is due to a decline in costs in 2017/18 as a result of the once-off decommissioning provision being realised.

96.10. According to Eskom, other costs are increasing in line or below the assumed inflation rate of 6.1%. NERSA therefore, does not find any justification for Eskom's current application for other costs to increase above inflation.

96.11. All other costs that are increasing at above inflation rate, for generation, transmission and distribution were adjusted accordingly. This was done in order for Eskom to implement stringent measures to contain their costs.

96.12. In 2018/19, Eskom is allowed to recover an amount of R8 284m, which is a 24.84% decline from R11 022m as per Eskom's 2018/19 application. Therefore, an amount of R2 738m has been disallowed from the application for 2018/19. The above adjusted figure was calculated by adjusting Eskom's 2016/17 actual and extracting all inefficiencies in 2017/18 to arrive at the 2018/19 forecast figure.

**Table 79: NERSA final decision – Other Costs**

| Other Costs (R'm) | 2018/19 | | |
|---|---|---|---|
| | Eskom Application | NERSA Adjustments | NERSA Final |
| Generation | 6 218 | -2 150 | 4 068 |
| Transmission | 765 | -163 | 602 |
| Distribution | 4 039 | -425 | 3 614 |
| **Total** | **11 022** | **-2 738** | **8 284** |

97. Arrear Debt

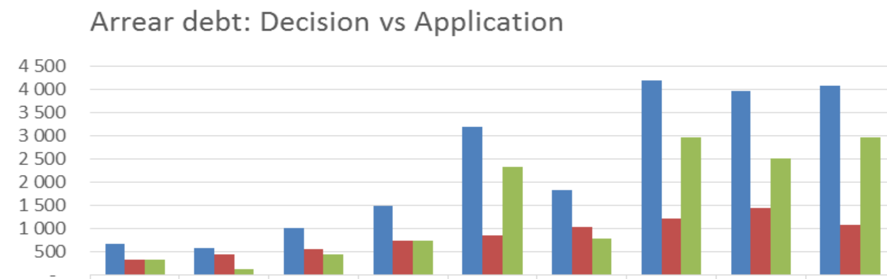
97.1. In 2016/17, Eskom's arrear debt amounted to R4 204m, while the 2017/18 projections reflect an amount of R3 968m. Eskom is currently applying for R4 080m.

97.2. The applied for arrear debt reflects an arrear debt/distribution revenues ratio of 0.5%, which is in line with NERSA's past decision.

97.3. The basis for 0.5% is derived from Eskom's MYPD decision. The Methodology does not state how much the impairments should be, however NERSA has adopted a 0.5% allowance as a provision for arrear debt. The 0.5% of total revenue is deemed reasonable; this means that the Energy Regulator expects Eskom to collect 99.95% of its total debt. Eskom has adopted the 0.5% impairment provision cap based on NERSA's past decision.

97.4. The graph in Figure 15 shows the year-on-year trend of Eskom's actual impairments as compared to NERSA's decision.

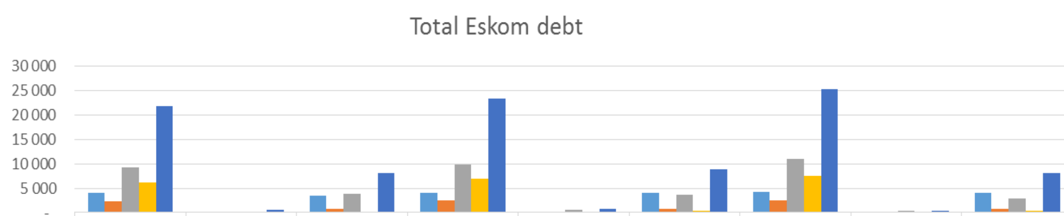
**Figure 15: Arrear debt comparison between the application and the decision**




| | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|---|---|---|---|---|---|
| Gross Impairments | 676 | 578 | 1 021 | 1 487 | 3 199 | 1 832 | 4 204 | 3 968 | 4 080 |
| Less 0.5% of Revenue cap (NERSA Decision) | 345 | 453 | 573 | 749 | 871 | 1 031 | 1 219 | 1 442 | 1 099 |
| Net Impairment | 331 | 125 | 448 | 738 | 2 328 | 801 | 2 985 | 2 526 | 2 981 |

97.5. As can be seen in Figure 16, Eskom's debt is made up of Soweto debt, small power users, municipalities and large power users. The graph also illustrates Eskom's debtor's age analysis between 31-60 days and greater than 60 days debt.

**Figure 16: Distribution of total Eskom debt**




| | 2014/15 | | | 2015/16 | | | 2016/17 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total debt | 31-60 | >60 | Total debt | 31-60 | >60 | Total debt | 31-60 | >60 |
| Soweto | 4 068 | 183 | 3 550 | 4 141 | 39 | 4 014 | 4 205 | 5 | 4 091 |
| Small power users | 2 237 | 71 | 686 | 2 536 | 76 | 816 | 2 465 | 39 | 727 |
| Municipalities | 9 367 | 246 | 3 884 | 9 861 | 553 | 3 748 | 11 102 | 379 | 2 825 |
| Large power users | 6 144 | 21 | 60 | 6 887 | 20 | 389 | 7 560 | 12 | 441 |
| Total | 21 816 | 521 | 8 180 | 23 425 | 688 | 8 967 | 25 332 | 435 | 8 084 |

97.6. Soweto Debt

97.6.1. In 2014/15, the Soweto debt amounted to R4 068m and increased to R 4 141m in 2015/16 to and to R4 205m in 2016/17. Eskom has identified Soweto as a high credit risk area, which means there are difficulties in collecting the overdue amounts from the customers. In 2016/17, Soweto debt is the greatest contributor to the >60 days overdue debt, with R4 091 (52%).

97.7. Municipalities

97.7.1. Municipal debt has also seen increases from 2014/15 (R9 367m) to R9 867m in 2015/16 and increased sharply to

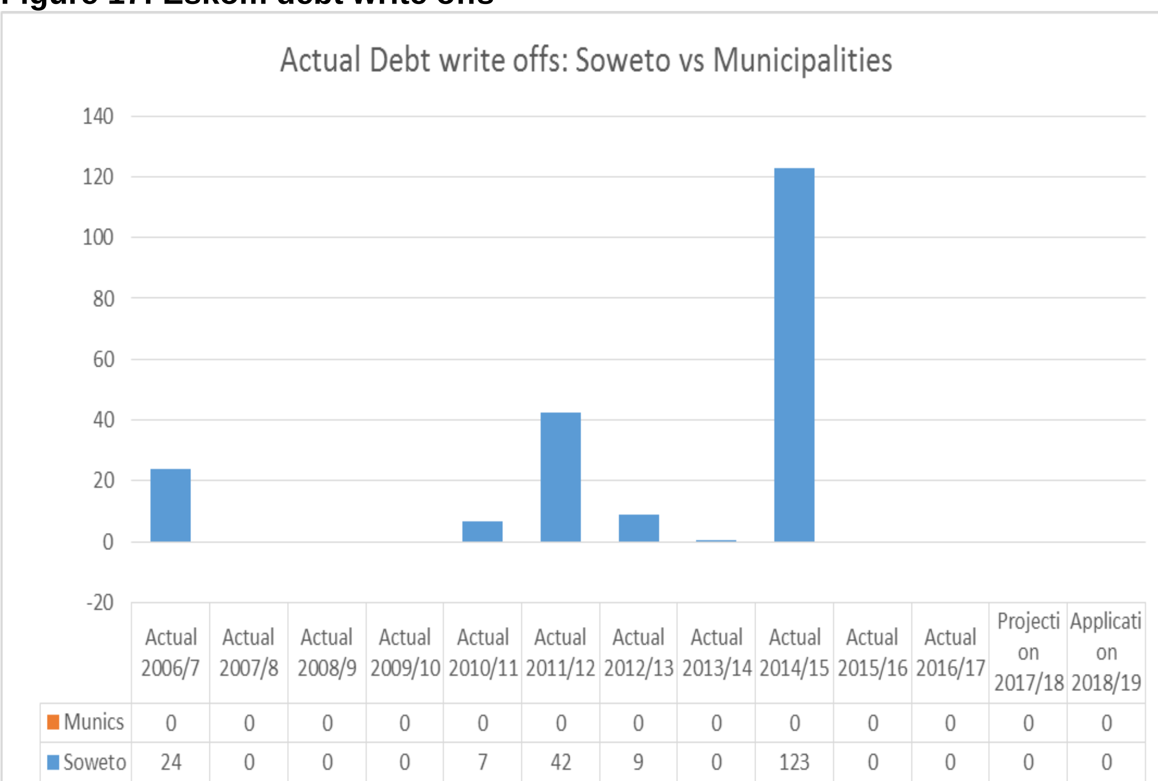
R11 102m in 2016/17. Some of the main causes for the municipal debt are interest charged (prime plus 5.5%) on overdue amount and municipal exceedance of NMD charges due to poor planning on the municipal side.

97.7.2. In order to mitigate the growth in bad debts, Eskom has adopted the following strategies:

a) to continue to offer new customers the prepayment option and convert existing post-paid customers to prepaid;
b) to increase deposits and securities to mitigate future risk by customers identified as potential high-risk defaulters; and
c) by replacing conventional and prepaid electricity meters of municipal customers with Eskom's smart and secure prepaid technology.

97.7.3. As can be seen in Figure 17, Eskom has been writing off Soweto debt since 2006/07 and has not been writing off any of its other customers' debts. The impaired debt for Soweto amounting to R187m is disallowed, which results in savings of R2m. The total allowed arrear debt resulted in an amount of R1 097m as compared to the R1 099m that was requested.

**Figure 17: Eskom debt write offs**




| | Actual 2006/7 | Actual 2007/8 | Actual 2008/9 | Actual 2009/10 | Actual 2010/11 | Actual 2011/12 | Actual 2012/13 | Actual 2013/14 | Actual 2014/15 | Actual 2015/16 | Actual 2016/17 | Projection 2017/18 | Application 2018/19 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Munics | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Soweto | 24 | 0 | 0 | 0 | 7 | 42 | 9 | 0 | 123 | 0 | 0 | 0 | 0 |

97.8. The arrear debt that was applied for as shown in Table 80 is therefore allowed.

**Table 80: NERSA final decision – Arrear debt**

| Arrear debt (R'm) | | |
|---|---|---|
| Eskom Application | NERSA Adjustment | NERSA Final |
| 1099 | -2 | 1097 |

98. Corporate Overheads

98.1. Corporate overhead costs incorporate those costs that are centrally controlled and are required for the generation, transmission and distribution of electricity. In Eskom's value chain, these costs incorporate provision of services at a centralised strategic and operation level. Eskom's application for the 2018/19 financial year amounts to R11 441m as shown in Table 81. However, the manpower cost of R5 776m is excluded and has been dealt with under the employee benefit section above.

**Table 81: Eskom Application – Corporate Overheads**

| | Actuals | Projections | Application |
|---|---|---|---|
| Corporate overheads R'm | 2016/17 | 2017/18 | 2018/19 |
| Employee Benefit | 6 244 | 5 912 | 5 776 |
| Operating Costs | 4 675 | 4 815 | 4 346 |
| Other income | -411 | -419 | -405 |
| Depreciation | 1 163 | 1 018 | 1 724 |
| Net impairment loss | -39 | - | - |
| **Total Corporate overheards** | **11 632** | **11 326** | **11 441** |

98.2. This amount includes employee benefit cost of R5 776m which has been dealt with under the employee benefit section above, as well as other income of R405m. The other income is offset by costs from various business units from the Corporate Division.

98.3. Table 82 reflects corporate operating costs from 2013/14 to the application year 2018/19.

**Table 82: Corporate operating expenditure – year-on-year costs**

| | Actual 2013/14 | Actual 2014/15 | Actual 2015/16 | Actual 2016/17 | Projection 2017/18 | Application 2018/19 | Average % growth |
|---|---|---|---|---|---|---|---|
| Operating costs R'm | 3 415 | 1 477 | 1 558 | 4 675 | 4 815 | 4 346 | |
| Year-on-year growth | | -56.75% | 5.48% | 200.06% | 2.99% | -9.74% | 28.41% |

98.4. The trend in Eskom’s corporate operating costs (actual) reflects an average increase of 28.41% since the 2013/14 to 2018/19 financial years. In spite of the decline in costs in 2014/15, together with below inflation increases in the subsequent years, there was a substantial increase of 200.06% in operating costs in 2016/17. Motivation for the over-expenditure in the various corporate support functions namely; Group Financial Controller and Project Development and Design (PDD) was provided and will be assessed below.

98.5. There are significant expenditures towards consultant’s fees within Group Financial Controller [for the development of the improvement and overall efficiencies through the Design to Cost (DTC) strategy], which Eskom spent during 2016/17, worth R1.6bn. These costs were mainly assigned to Trillian Management Consulting and McKinsey and Company, which have been identified as irregular expenditure under investigation. As a result of this, the 2016/17 base has been readjusted to arrive at a new base for 2017/18 and therefore the costs disallowed.

98.6. Furthermore, other operating costs under the Project Development and Design (PDD) Department are increasing by 86.75% between 2016/17 (R83m) and 2017/18 (R155m); and by 260.6% between 2017/18 (R155m) and 2018/19 (R559m). The significant increase is in respect of the decision that was taken to explore and investigate nuclear as an energy option for Eskom. The costs will be spent in the concept and design realisation phases of the project.

98.7. Eskom further indicated that there is great uncertainty as to whether the project will be approved for execution. In light of this, the allowed operating cost of R155m for 2017/18 has been adjusted by inflation to determine the 2018/19 amount of R163m, in order to discourage over-expenditure. Therefore an amount of R396m has been disallowed for 2018/19.

98.8. The depreciation amount of R1 724m has been fully allowed as applied for.

98.9. Furthermore NERSA benchmarked Eskom’s efficiency level by looking at the performance ratio of other costs per energy sent out in Gigawatt hours (GWh) for the financial years 2007/08 and 2018/19. Eskom achieved a cost per GWh ratio of 0.01 in 2007/08, while in 2017/18 the ratio was 0.02, meaning that Eskom is now producing less GWh at a higher cost than it was in 2007/08. This shows that Eskom has been inefficient in expensing corporate other costs, hence the costs were adjusted accordingly.

**Table 83: Corporate overheads decision**

| Corporate overheads (R'm) | Eskom Application | NERSA Adjustments | NERSA Final |
|---|---|---|---|
| Operating costs | 4 346 | -1 996 | 2 350 |
| Depreciation | 1 724 | - | 1 724 |
| Other income | -405 | - | -405 |
| **Total Corporate overheards** | 5 665 | -1 996 | 3 669 |

99. Conclusion on operating expenditure

99.1. Table 84 shows the total operating expenditure compared to what Eskom has applied for as part of its revenue requirement, adjustments made and what has been allowed.

**Table 84: Overall operating expenditure decision**

| | 2018/19 | | |
|---|---|---|---|
| **R'm** | **Eskom Application** | **Adjustment** | **NERSA Decision** |
| Employee Benefit cost | 28 212 | -3 898 | 24 314 |
| Maitenance | 17 665 | -2 465 | 15 200 |
| Other costs | 11 032 | -2 738 | 8 294 |
| Arrear debt | 1 099 | -2 | 1 097 |
| Corporate Services | 5 665 | -1 996 | 3 669 |
| Other income | -1 452 | | |
| **Total Operating costs** | **62 221** | **-11 099** | 51 122 |

## RESEARCH AND DEVELOPMENT

100. Eskom's 2018/19 tariff application includes Research and Development (R&D) costs of R193 million.

101. According to Eskom, the research projects are reviewed with respect to alignment with the NERSA criteria as stated in the MYPD Methodology. These are listed in Table 85. The projects will be executed over a five-year period from the 2018/19 financial year.

**Table 85: Planned Research Projects for 2018/19**

| Project | Cost | NERSA Criteria | Environmental Criteria | Grand Challenge |
|---|---|---|---|---|
| Coal | n/a | Lower operating costs | Not Applicable | Coal |
| Clean Coal | 15 | Environmental criteria | Better usage of water, less pollution and less global warming | Clean Coal |
| Water | 42 | Environmental criteria | Better usage of water, less pollution and less global warming | Water |
| Gas | n/a | Environmental criteria | Better usage of water, less pollution and less global warming | Gas |
| Renewables | 8 | Environmental criteria | Renewable energy sources | Renewables |
| Nuclear | 15 | Build, plan or demo plant that might form part of a future build plan | Not Applicable | Nuclear |
| Generation Plant Performance and Asset Management | 50 | Improved efficiency | Not Applicable | Generation Plant Performance and Asset Management |
| Transmission Plant Performance and Asset Management | 10 | Improved efficiency | Not Applicable | Transmission Plant Performance and Asset Management |
| Transmission Solutions Build | 6 | Improved efficiency | Not Applicable | Transmission Solutions Build |
| Distribution Plant Performance and Asset Management | 17 | Improved efficiency | Not Applicable | Distribution Plant Performance and Asset Management |
| Future Customer | 23 | Better understanding of load behaviour | Not Applicable | Future Customer |
| Flexibility | 6 | Improved efficiency | Not Applicable | Flexibility |
| **Total Cost (R'm)** | **193** | | | |

102. Eskom has been spending less than what was allowed for the MYPD3 control period. According to Eskom this was due to the following:

102.1. Delays in procurement of projects. Due to the stringent procurement processes that need to be undertaken, certain delays have been experienced that resulted in particular projects being delayed to a subsequent year.

102.2. The majority of research projects are undertaken over multiple years. Thus certain delays are experienced in commencement of projects. This contributes to the variances between the decision and actuals research costs.

102.3. The delays in finalising procurement processes could result in the service provider potentially undertaking projects for other institutions.

102.4. Due to the optimisation of operating costs from the MYPD2 period, there is a continuous optimisation of operating costs in subsequent years.

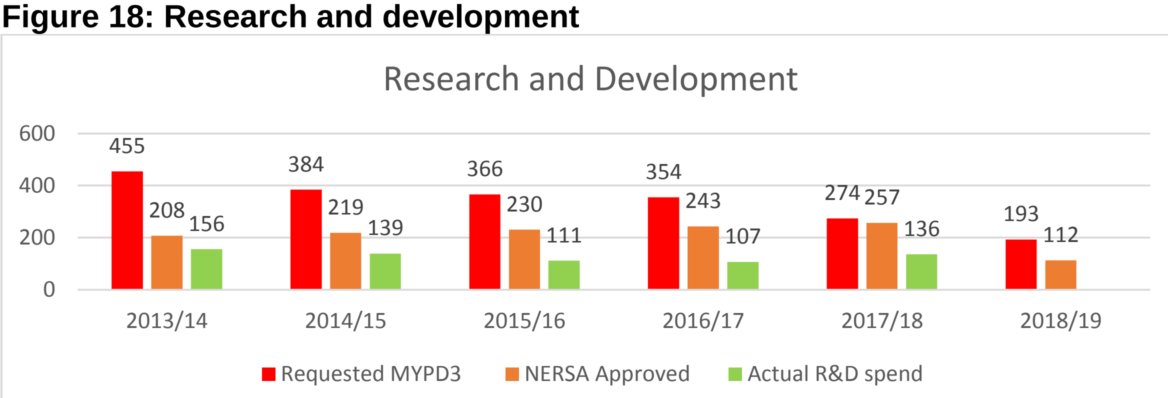
102.5. This research operating cost optimisation continued in each year of the MYPD3 period.

102.6. Thus a similar trend has been experienced over the period

102.7. There have been learnings derived from the manner in which the procurement processes have been addressed. It is felt this would hopefully result in addressing the shortfalls that have been experienced.

102.8. When assessing the Eskom application, a trend analysis of the previous actual cost on R&D showed that Eskom has spent less than what was approved in the MYPD 3 decision. This is shown in Figure18.

**Figure 18: Research and development**




103. Eskom has spent between 25% and 56% less than the approved R&D costs for MYPD3. In 2017/18, Eskom is projecting to spend R136 million, which

translates to a 27% increase from the actual amount spent in 2016/17. In 2018/19, Eskom has forecast the expenditure on R&D to be R193 million.

104. The identified R&D projects in the application were assessed and were found to be in line with the requirements of the R&D rules.

105. However, Eskom has underspent on R&D over the MYPD3 period. The reasons for the under-expenditure provided by Eskom such as stringent procurement processes are not corroborated by reports on governance and procurement at Eskom. NERSA has allowed an inflationary increase of 5.1% on the actual expenditure for 2016/17 of R107million to determine the research and development cost of R112million. Eskom is required, where under-expenditure is experienced, to ring-fence the R&D funds for the projects approved in the 2018/19 period.

**Table 86: Research and Development**

| R'm | Eskom Application | Adjustment | NERSA decision |
|---|---|---|---|
| Research and development (R'm) | 193 | - 81 | 112 |

**SERVICE QUALITY INCENTIVES (SQI)**

106. The service quality incentive (SQI) will still be applicable for the 2018/19 financial year. A total of one per cent of the total revenue approved for Eskom will be allocated towards the SQI scheme for 2018/19.

107. The Transmission division will continue to use the three measures that were used for SQIs during the MYPD3 control period. The three measures used are System Minutes (SM) <1, SM≥1 and line faults/100km.

108. Distribution Division will continue to use the same three measures that were used in the MYPD3 control period. The three measures used are System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Distribution Supply Loss Index (DSLI).

109. Generation division will use the Unit Capability Factor (UCF) as its measure of the SQI.

110. Adjustments arising from SQIs will be considered during the RCA process for this one-year application.

## ENVIRONMENTAL LEVY

111. Eskom applied for R7 994 million environment levy costs based on the 228 390 GWh volumes sent out as shown in Table 87.

**Table 87: Environmental Levy costs**

| | Actuals | Projections | Application | NERSA Decision |
|---|---|---|---|---|
| **Environmental levy** | 2016/17 | 2017/18 | **2018/19** | **2018/19** |
| **Energy sent out (ESO) (GWh)** | **220 166** | **221 395** | **216 771** | **219 853** |
| Non Renewable ESO (GWh) | 215 948 | 216 024 | 211 519 | 214 601 |
| Renewable ESO (GWh) | 4 218 | 5 371 | 5 252 | 5 252 |
| Generated volume (GWh) | 232 462 | 232 900 | 228 398 | 231 726 |
| System average auxilliary % | 7.65% | 7.81% | 7.98% | 7.98% |
| Environmental levy rate (c/kWh) | 3.5 | 3.5 | 3.5 | 3.50 |
| **Environmental levy cost (R'm)** | **8 086** | **8 152** | **7 994** | 8 110 |

112. The environmental levy cost is charged on the production of electricity volumes that are made up of auxiliary consumption, electrical losses and electricity sales volumes. The environmental levy cost is equivalent to the revenue related to the environmental levy.

113. The allowed amount is R8 039 based on the government approved rate of 3.5c/KWh, which is an increase of R99m from the applied figure of R7994m

114. The environmental rate of 3.5c/kWh as approved by government is imposed on the generated volume from coal, nuclear and OCGTs to arrive at the environmental levy costs.

## ECONOMIC IMPACT

115. The Energy Regulator understands the importance of electricity as a primary infrastructural service input into the South African economy and agrees with stakeholders that electricity price increases will have an effect on inflation, GDP growth, employment, exports and the overall competitiveness of local industries.

116. The Energy Regulator conducted an assessment of the impact of Eskom's revenue application on the South African economy, taking into consideration the following key issues:

116.1. Inflation: CPI for low and high-income households, PPI, SMEs and exports;

116.2. Gross Domestic Product (GDP);

116.3. Employment; and

116.4. Income distribution.

117. To determine the impact on the above, the Energy Regulator considered five tariff increase scenarios as follows:

117.1. Scenario 1: 19.9%

117.2. Scenario 2: 15.0%

117.3. Scenario 3: 10.0%

117.4. Scenario 4: 8.0%

117.5. Scenario 5: 5.23%

118. The impact calculations performed entail the quantification of the total effect of the electricity tariff increase on the economy[9]. It involves calculating the direct, indirect, and induced impacts of such an electricity price change; firstly, on price levels in the economy (inflation) as measured at various levels of household income groups, as well as the effect on the real economy measured in terms of macroeconomic variables such as economic growth (GDP), employment, poverty alleviation, etc.

119. Inflation

119.1. Inflation impact of the price increases was done in terms of consumer, producer and export prices. Consumer inflation (CPI) was further

[9] To quantify the magnitude of the impact of electricity tariff increases, the following set of economic instruments are applied; the Leonfief price impact model, the international trade model, the macroeconomic impact assessment model (MEIA) and OLS regression analysis.

looked at in terms of overall CPI and CPI for different income groups (Low and High).

119.2. Table 88 shows the impact of the five tariff increase scenarios on different inflation measures and exports.

**Table 88: Total Economic Impact of electricity tariff increase scenarios on inflation and exports**

| Scenario | 19.9% | 15.0% | 10.0% | 8.0% | 5.23% |
|---|---|---|---|---|---|
| CPI: (%) | 1.50 | 1.13 | 0.75 | 0.60 | 0.39 |
| PPI (%) | 1.48 | 1.12 | 0.74 | 0.59 | 0.39 |
| Exports | 1.46 | 1.10 | 0.73 | 0.59 | 0.38 |

119.3. A 19.9% increase will increase total CPI by 1.5% compared to 0.60%, 0.75% and 1.13% in the cases of 8.0%, 10.0% and 15.0% tariff increases respectively, while the 5.23% tariff increase as approved by NERSA has the smallest impact on CPI of only 0.39%.

119.4. South Africa's export prices will be pushed up by nearly 1.46% on average, while the PPI will be pushed up by 1.48% if the 19.9% increase is assumed and fully passed on, compared to an increase of only 0.39% if the NERSA-approved tariff increase of 5.23% is implemented. There is no doubt that a 19.9% increase in tariffs will negatively affect South Africa's comparative advantage relative to the outside world in general and its main trading partners in particular.

120. Gross Domestic Product (GDP)

120.1. The electricity price increase will negatively affect South African GDP regardless of the rate of the increase. The only difference will be the significance of the impact. This is mainly because the South African economy is highly electricity intensive.

**Table 89: Total impact on GDP**

| Details | 19.9% | 15.0% | 10.0% | 8.0% | 5.23 |
|---|---|---|---|---|---|
| Gross Domestic Product (R million) | -13 650 | -10 289 | -6 859 | -5 488 | -3 588 |
| Gross Domestic Product (%) | -0.35 | -0.26 | -0.17 | -0.14 | -0.09 |

120.2. The macroeconomic impact shown in Table 89 represents the cumulative impact of the proposed 2018/19 electricity tariff increase over time. The multiplier effect of a shock to the economy – in this case, an electricity tariff increase – normally takes more than one year for its impact to be fully felt on the real side of the economy (i.e. ± three years). A 19.9% increase in electricity prices has the potential to reduce GDP by R13 650 million. The negative impact reduces as a lower increase is assumed, for example, the NERSA-approved tariff increase of 5.23% reduces GDP by only R3 588 million (see Table 89 above). Given the fact that the economy has been struggling in the previous years, a 19.9% tariff increase will further suppress growth and prospects of improving economic performance.

121. Impact of electricity tariff increase on International Trade

121.1. The impact on international trade competitiveness is driven by, inter alia, changes in relative prices, i.e. the impact of South African prices becoming higher than those of its main trading partners. The effect on exports and imports for a 19.9% electricity tariff increase are presented in Table 90. As shown in Table 90, exports will decrease by R1 194 million, while imports will increase by R7 075 million resulting in total trade effect of -R8 269 million. The total trade effect of the NERSA-approved increase of 5.23% is -R1 545 million, which is far less than the negative trade effect resulting from the 19.9% increase proposed by Eskom.

**Table 90: International Trade Competitiveness**

| | 19.9% | 15.0% | 10.0% | 8.0% | 5.23% |
|---|---|---|---|---|---|
| **Exports (R million)** | -1 194 | -900 | -600 | -480 | 314 |
| **Imports (R million)** | 7 075 | 5 333 | 3 555 | 2 844 | 1859 |
| **Total Trade Effect (Net Exports) (R million)** | -8 269 | -6 233 | -4 155 | -3 324 | -1545 |

Source: Results generated by SAM based economic model

122. Impact of electricity price increase on Employment and Households

122.1. The combination of the ongoing electricity tariff increases (19.9% scenario) with high inflation, high unemployment and the generally declining household disposable income will likely result in households reducing their electricity usage.

122.2. This is likely to affect access and long-term affordability of electricity for the poor.

122.3. Rising electricity tariffs have an uneven impact on population groups and result in different responses.

122.4. Poor households will normally reduce or abandon electricity usage for inefficient energy sources, while non-poor households do not necessarily reduce their electricity consumption, instead, they reduce their expenditure of luxury goods.

122.5. As can be seen in Table 91, the low-income household group (includes the no-income population) will be the most vulnerable to a substantial electricity price increase.

122.6. Statistics South Africa (StatsSA, 2017) reports that poverty levels are on the rise in South Africa, with more than 50% of the population considered poor. StatsSA reports that the most vulnerable are children (below 17 years), those living in rural areas and those with limited education.

122.7. Some of these low-income households (17.4 million, SASSA, 2017) are already on social grants. An increase of 19.9% will result in a CPI increase of 2.84% for low-income households compared to only 1.46% for high income-income households. The main reason for this is the relatively high proportion that electricity costs account for in low-income household's total budget outlays. This increase will negatively affect the income of the poor, especially those receiving social grants. This impact is reduced to 0.75% for low-income households and to 0.38% for high-income households when the NERSA-approved tariff increase is implemented. The number of people on social grants has surpassed the number of employed people in South Africa.

**Table 91: Impact on different households income groups**

| Details | 19.9% | 15.0% | 10.0% | 8.0% | 5.23% |
|---|---|---|---|---|---|
| CPI: Low Income Households (%) | 2.84 | 2.14 | 1.43 | 1.14 | **0.75** |
| CPI: High-Income Households (&) | 1.46 | 1.10 | 0.73 | 0.59 | 0.38 |
| **Employment (number per year)** | **-16 189** | **-12 203** | **-8 135** | **-6 508** | **-4 255** |

| | | | | | |
|---|---|---|---|---|---|
| Skilled labour (number per year) | -6 649 | -5 012 | -3 341 | -2 673 | -1 748 |
| Employment impact on semi-skilled labour | -6 910 | -5 209 | -3 473 | -2 778 | -1 816 |
| Employment impact on unskilled labour | -2 630 | -1 982 | -1 321 | -1 057 | -691 |
| **Impact on Households (R million)** | **-6 367** | **-4 799** | **-3 199** | **-2 559** | **-1 673** |
| Employment impact on low-income households | -930 | -701 | -467 | -374 | -244 |
| Employment impact on medium Income households | -1 507 | -1 136 | -757 | -606 | -396 |
| Employment impact on high-income households | -3 930 | -2 962 | -1 975 | -1 580 | -1 033 |

123. Employment

123.1. The reduction in GDP growth associated with electricity price increases will result in a number of job losses for semi-skilled and unskilled workers. If a 19.9% electricity price increase is assumed, about 9 540 semi-skilled and unskilled jobs will be lost, while a 5.23% tariff increase will result in only 2 507 jobs lost.

123.2. A 19.9% tariff increase will result in low-income households losing approximately R930million in income, which represents a negative effect on poverty and inequality alleviation. However, approximately only R244million will be lost from a 5.23% tariff increase. It should be noted that in South Africa, for every job lost, approximately 5 to 10 family members lose out on their only source of livelihood.

123.3. This will be exacerbated by the fact the latest StatsSA Quarterly Labour Force Survey Quarter 3: 2017 report indicate that there was an increase in the unemployment rate by 0.6% to 27.7% with the informal sector and the agricultural sector shedding employment losses of 71 000 and 25 000 respectively.

124. Impact of electricity tariff increase on SMMEs

124.1. Small, Medium and Micro Enterprises (SMMEs) play an important role in the South African economy. They can be key drivers of economic growth, innovation and job creation. The definition for SMMEs encompasses a very broad range of firms, some of which includes formally registered, informal and non-VAT registered organisations (The DTI, 2008).

124.2. SMMEs are particularly vulnerable to shocks in their external environment due to a general lack of skills and resources. A reliable, abundant, low priced source of electricity is critical to the success of the business sector in South Africa especially SMMEs. SMMEs in South Africa are generally more vulnerable to the pressures of the market than larger firms (Cant & Wild, 2013[10]).

124.3. Although the SMMEs are less electricity intensive, they are highly vulnerable to electricity price increases, more so than any other business in South Africa. This is specifically true given the low demand for goods and services and the fact that SMMEs cannot pass on any increases in costs to their consumers.

125. Commodity price impacts of Electricity tariff increase

125.1. Table 92 shows different scenarios of the total impact on the price of commodities due to electricity tariff increase for 2018/19. The most affected industries include mining, sugar cane, livestock farming, paper and paper products, textiles, clothing, basic chemicals, non-metallic mineral products etc. The 5.23% tariff increase as approved by NERSA has a moderate impact on commodity prices as shown in Table 92.

**Table 92: Impact of electricity tariff increase on the different economic sectors and subsectors**

| Economic Sectors | Scenarios | | | | |
|---|---|---|---|---|---|
| | 19,9% | 15,0% | 10,0% | 8,0% | 5,23% |
| **Primary Sector** | | | | | |
| **Primary Sector (total)** | **1,03%** | **0,78%** | **0,52%** | **0,42%** | **0,27%** |
| Cereal Farming | 0,72% | 0,54% | 0,36% | 0,29% | 0,19% |
| Table Grape Farming | 1,13% | 0,85% | 0,57% | 0,45% | 0,30% |
| Wine Grape Farming | 1,59% | 1,20% | 0,80% | 0,64% | 0,42% |
| Other Deciduous | 0,80% | 0,60% | 0,40% | 0,32% | 0,21% |
| Citrus | 0,73% | 0,55% | 0,37% | 0,29% | 0,19% |
| Sub-Tropical Fruit | 0,82% | 0,62% | 0,41% | 0,33% | 0,22% |

[10] Cant, M.C. and Wild, J.A., 2013. Establishing the challenges affecting South African SMEs. *The International Business & Economics Research Journal (Online)*, *12*(6), p.707.

| | | | | | |
|---|---|---|---|---|---|
| Sugar Cane | 1,92% | 1,45% | 0,97% | 0,77% | 0,51% |
| Vegetable Farming | 0,96% | 0,72% | 0,48% | 0,39% | 0,25% |
| Dairy Farming incl. eggs | 1,09% | 0,82% | 0,55% | 0,44% | 0,29% |
| Livestock Farming | 1,01% | 0,76% | 0,51% | 0,41% | 0,27% |
| Poultry (White Meat excl. Eggs) | 0,75% | 0,56% | 0,37% | 0,30% | 0,20% |
| Game Farming | 0,85% | 0,64% | 0,43% | 0,34% | 0,22% |
| Fishing | 0,70% | 0,53% | 0,35% | 0,28% | 0,18% |
| Forestry | 0,67% | 0,50% | 0,33% | 0,27% | 0,17% |
| Other Agriculture | 1,06% | 0,80% | 0,53% | 0,43% | 0,28% |
| Coal | 1,19% | 0,90% | 0,60% | 0,48% | 0,31% |
| Crude Oil | 0,00% | 0,00% | 0,00% | 0,00% | 0,00% |
| Precious Metal and Minerals | 1,96% | 1,48% | 0,99% | 0,79% | 0,52% |
| Metal Ores | 1,53% | 1,16% | 0,77% | 0,62% | 0,40% |
| Other Mining | 1,18% | 0,89% | 0,59% | 0,47% | 0,31% |
| **Secondary Sector** | | | | | |
| **Secondary Sector (total)** | **1,14%** | **0,86%** | **0,57%** | **0,46%** | **0,30%** |
| Meat | 0,79% | 0,60% | 0,40% | 0,32% | 0,21% |
| Fish | 0,78% | 0,59% | 0,39% | 0,32% | 0,21% |
| Fruit and Vegetables | 1,07% | 0,81% | 0,54% | 0,43% | 0,28% |
| Oil and Fat Products | 0,69% | 0,52% | 0,35% | 0,28% | 0,18% |
| Dairy Products | 1,13% | 0,85% | 0,57% | 0,46% | 0,30% |
| Grain Mill Products | 0,89% | 0,67% | 0,45% | 0,36% | 0,23% |
| Sugar | 1,15% | 0,87% | 0,58% | 0,46% | 0,30% |
| Bakery Products | 1,26% | 0,95% | 0,64% | 0,51% | 0,33% |
| Animal Feed Products | 0,72% | 0,54% | 0,36% | 0,29% | 0,19% |
| Other Food Products | 0,96% | 0,72% | 0,48% | 0,38% | 0,25% |
| Beverages and Tobacco | 0,98% | 0,74% | 0,49% | 0,39% | 0,26% |
| Textiles | 1,56% | 1,18% | 0,78% | 0,63% | 0,41% |
| Clothing | 1,29% | 0,97% | 0,65% | 0,52% | 0,34% |
| Leather Products | 0,96% | 0,72% | 0,48% | 0,39% | 0,25% |
| Footwear | 1,01% | 0,76% | 0,51% | 0,41% | 0,27% |
| Sawmilling and Planning of Wood | 1,16% | 0,88% | 0,59% | 0,47% | 0,31% |
| Wood products | 1,27% | 0,96% | 0,64% | 0,51% | 0,33% |
| Paper and Paper Products | 1,35% | 1,01% | 0,68% | 0,54% | 0,35% |

| | | | | | |
|---|---|---|---|---|---|
| Publishing and Printing | 1,01% | 0,76% | 0,51% | 0,41% | 0,27% |
| Petroleum | 0,55% | 0,41% | 0,28% | 0,22% | 0,14% |
| Basic chemicals | 1,33% | 1,00% | 0,67% | 0,54% | 0,35% |
| Other chemicals | 1,32% | 1,00% | 0,67% | 0,53% | 0,35% |
| Rubber Products | 1,26% | 0,95% | 0,63% | 0,51% | 0,33% |
| Plastic Products | 2,78% | 2,09% | 1,39% | 1,12% | 0,73% |
| Non-Metallic Mineral Products | 1,28% | 0,97% | 0,64% | 0,51% | 0,34% |
| Basic Metal Products | 1,76% | 1,33% | 0,89% | 0,71% | 0,46% |
| Machinery and Equipment | 0,91% | 0,69% | 0,46% | 0,37% | 0,24% |
| Electrical Machinery and Apparatus | 1,14% | 0,86% | 0,57% | 0,46% | 0,30% |
| Renewable Energy Machinery | 1,01% | 0,76% | 0,51% | 0,41% | 0,26% |
| Communication and Medical Equipment | 1,05% | 0,79% | 0,53% | 0,42% | 0,28% |
| Electronic Equipment | 1,03% | 0,78% | 0,52% | 0,42% | 0,27% |
| Manufacturing of Transport Equipment | 1,10% | 0,83% | 0,55% | 0,44% | 0,29% |
| Furniture | 1,17% | 0,88% | 0,59% | 0,47% | 0,31% |
| Other Manufacturing and Recycling | 1,01% | 0,76% | 0,51% | 0,41% | 0,27% |
| **Tertiary Sector** | | | | | |
| **Tertiary Sector (total)** | **0,88%** | **0,66%** | **0,44%** | **0,35%** | **0,23%** |
| Water | 0,81% | 0,61% | 0,41% | 0,33% | 0,21% |
| Buildings and Other Construction | 0,90% | 0,68% | 0,45% | 0,36% | 0,24% |
| Wholesale and retail trade | 0,81% | 0,61% | 0,41% | 0,33% | 0,21% |
| Catering and accommodation services | 0,97% | 0,73% | 0,49% | 0,39% | 0,26% |
| Transport and storage | 0,76% | 0,58% | 0,38% | 0,31% | 0,20% |
| Communication | 0,67% | 0,51% | 0,34% | 0,27% | 0,18% |
| Finance and insurance | 0,71% | 0,54% | 0,36% | 0,29% | 0,19% |
| Business services | 0,98% | 0,74% | 0,49% | 0,39% | 0,26% |
| Business Process Management | 1,10% | 0,83% | 0,55% | 0,44% | 0,29% |
| Community, social and personal services | 1,04% | 0,79% | 0,52% | 0,42% | 0,27% |
| **OVERALL TOTAL** | **1,48%** | **1,12%** | **0,74%** | **0,59%** | **0,39%** |

Source: Results generated by SAM based Leontief Price Model

126. The impact of electricity tariff increases on electricity volume

126.1. It is important to note that a high electricity price increase, i.e. 19.9%, will result in a decline in electricity demand (volume GWh) and consequently a decline in electricity revenue. The perception that a 19.90% increase in electricity price will result in 19.9% increase in revenue is not true. There is an inverse relationship between electricity price increase, revenue generated and volume of electricity consumed.

126.2. In order to calculate the impact of electricity tariff increases on the electricity volume demanded, NERSA estimated a set of regression equations where electricity demand was assumed to be a function of real GDP, relative prices (ratio of electricity price and PPI) and mining and manufacturing as a percentage of real GDP. Table 93 shows the impact of electricity price increases on electricity volumes.

**Table 93: Impact of electricity price increase on electricity volume (GWh)**

| | 19,90% | 15,0% | 10,0% | 8,0% | 5,23% |
|---|---|---|---|---|---|
| **2017/18 (Current estimated usage)** | 211 982 | 211 982 | 211 982 | 211 982 | 211 982 |
| **2018/19 (Projected usage with different electricity tariff increase scenarios)** | 206 480 | 209 603 | 212 790 | 214 064 | 215 830 |
| **A. Difference 2017 and 2018** | | | | | |
| **GWH** | -5 502 | -2 379 | 808 | 2 082 | 3 848 |
| **Percentage** | -2,6 | -1,1 | 0,4 | 1,0 | 1,8 |
| **B. Difference between 5.23 and other scenarios** | | | | | |
| **Volume (GWh) losses: (volume difference to price change higher than inflation)** | -9 345 | -6 227 | -3 040 | -1 766 | |
| **Price per GWh (Rm)** | 0,94 | 0,94 | 0,94 | 0,94 | |
| **Negative volume impact on income (Rm)** | -8 784 | -5 853 | -2 857 | -1 660 | |

Source: Results generated by the regression analysis

126.3. It can be observed from Table 93 above that the electricity volume decreases when the increase is above the inflation rate. For example, if the electricity price increase is 19.9%, the decrease in volume will be 2.6% relative to an increase of 1.8% associated with a 5.23% tariff increase. This relates to a swing of approximately 9 345GWh translating to an income loss of approximately R8 784million for the 2018/19 FY. In Table 93 it is also evident that the lower the increase in the electricity price, the lower is the impact on volumes. It is clear that, for Eskom to deal with revenue shortages, tariff increase is not a long-term solution as such a move will eventually incentivise electricity consumers to look for alternative energy sources, and that will cause Eskom to increase tariffs even further. Other viable alternatives need to be considered by Eskom in this regard.

126.4. It is important to highlight the point that when the electricity price rises steeply, the volume of electricity demand will decline significantly. This will also have a negative effect on electricity sales revenue. When the price rises steeply, households and firms utilise less electricity by, for instance, adopting new electricity saving technologies and behavioural changes as far as the electricity consumption is concerned. However, it is important to note that the total impact of the electricity price increase on volumes will not necessarily occur during the 2018/19 financial year due to the time lag effect. The consumers of electricity, for instance, will not be able to adjust completely their consumption behaviour in the short term.

126.5. Overall, the 5.23% tariff increase as approved by NERSA has a moderate impact on the different socio-economic indicators compared to the 19.9% tariff increase proposed by Eskom. The 5.23% tariff increase is in line with government policy to reduce income inequality, poverty and unemployment.

**FINANCIAL IMPACT**

127. The ease with which Eskom can meet its interest payment is an indication of the degree of risk associated with its debt policy, interest and capital. The interest coverage ratio provides a measure of this.

128. The debt coverage ratio also indicates the earnings available for the required interest payment as shown in Table 94.

**Table 94: Financial Ratio Analysis**

| 2018/19 Financial Ratios | |
|---|---|
| Debt Service Ratio | Interest Cover Ratio |
| 1.05x | 1.37x |

129. Eskom's Interest Cover ratio is expected to be 1.37x .This implies that Eskom will be able to cover its interest expense through its operating activities.

130. The Debt-Service Coverage Ratio (DSCR) is a measure of the cash flow available to pay current debt obligations. The ratio states net operating income as a multiple of debt obligations due within one year. Eskom's DSCR of 1.05x

also implies that Eskom will be able to meet its current debt obligations as they become due.

131. Table 95 indicates that Eskom's free cash flow is expected to be positive. Eskom can further improve its cash flow position with Capex rationalisation along with better working capital management.

**Table 95: NERSA's forecast of Eskom's Free Cash Flow**

| NERSA Free Cash Flow (FCF) Calculation | 2018/19 |
|---|---|
| **Revenue** | **190 721** |
| % Growth | n/a |
| Selling and General Administrative Expenses | 138 047 |
| Primary Energy + Other | 86 925 |
| % Revenue | *45.6%* |
| Operational Expenditure | 51 122 |
| % Revenue | *26.8%* |
| **EBITDA** | **52 675** |
| % Margin | *27.6%* |
| Capital Expenditure | 29 388 |
| %Revenue | *15.4%* |
| Change in Working Capital | -8 779 |
| %Revenue | *4.6%* |
| **Free Cash Flow** | **32 066** |

132. If Eskom reduces its costs to levels provided for in this RfD, given that there has been no sustainable sales growth over the past few years, Eskom should review its financial policy to improve its standalone risk profile, therefore lowering its financial burden in the long run, which is associated with its interest expense and principal repayments.

133. A credit rating is an assessment by an independent rating agency (i.e. Moody's; S&P or Fitch) of a company's ability and willingness to make full and timely payments of amounts due on its debt obligations. These ratings are typically required for companies seeking to raise debt financing in the capital markets.

134. If Eskom reduces its required Capex and improves working capital management, this will limit its funding requirements to reasonable levels. This can ultimately lead to lower expected interest costs than projected in 2018/19.

135. For Eskom management to start creating value, both profitability and growth needs to improve as recommended above. This needs to be driven by Eskom's goals and strategic objectives.

## ESKOM’S RETAIL TARIFF STRUCTURAL ADJUSMENTS (ERTSA)

136. NERSA approves Eskom’s allowed revenue for a particular period based on a forecast average energy demand. Eskom is then required to annually submit its retail tariff adjustment application to NERSA for approval.

137. The ERTSA will consist of an application for the rate of adjustment to tariffs applicable to the respective customer groups, as well as the proposed schedule of standard tariffs applicable to each of the customer groups for the year.

138. The ERTSA decision will contain the detailed tariff table for each customer category, including the tariffs for local authorities (municipalities).

## CONCLUSION AND RECOMMENDATION

139. On the conspectus of the facts and evidence presented to the Energy Regulator, it is appropriate to approve the allowed revenues, standard averages prices and percentage price increases as set out above for Eskom’s revenue application for 2018/19.

***End.***