~~ANNEXURE 1~~

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Annexure C

# MULTI-YEAR PRICE DETERMINATION (MYPD) METHODOLOGY

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## Abbreviations and Acronyms

| | |
|---|---|
| $K_d$ | Cost of debt |
| $K_e$ | Cost of equity |
| $R_f$ | Risk free rate of interest |
| AR | Allowable Revenue |
| CAPM | Capital Asset Pricing Model |
| CECA | Capital Expenditure Clearing Account |
| CPI | Consumer Price Index |
| DMP | Demand Market Participation |
| DoE | Department of Energy |
| DRC | Depreciated Replacement Cost |
| DSLI | Distribution Supply Loss Index |
| dÞ | Debt Premium |
| E | Expenses |
| ECS | Energy Conservation Scheme |
| EEDSM | Energy Efficiency and Demand Side Management |
| EPP | The South African Electricity Supply Industry: Electricity Pricing Policy GN 1398 of 19 December 2008 |
| GDP | Gross Domestic Product |
| GWh | Giga Watt hours |
| IDM | Integrated Demand Management |
| IPP | Independent Power Producer |
| IRP | Integrated Resource Plan |
| JSE ALSI | Johannesburg Stock Exchange All Share Index |
| L&T | Government imposed levies or taxes (not direct income taxes) |
| LRMC | Long Run Marginal Cost |
| M&V | Measurement and Verification |
| MEAV | Modern Equivalent Asset Value |
| MRP | Market Risk Premium |
| MTSAO | Medium-Term System Adequacy Outlook |
| MWh | Mega Watt hours |
| MYPD | Multi-Year Price Determination |
| NERSA | National Energy Regulator |
| O&M | Operating and Maintenance |
| OCGT | Open Cycle Gas Turbine |
| PBR | Performance Based Regulation |
| PCP | Power Conservation Programme |
| PE | Primary Energy |

| | |
|---|---|
| PPA | Power Purchase Agreement |
| QoS | Quality of Supply |
| R&D | Research and Development |
| R/ton | Rand per ton |
| RAB | Regulatory Asset Base |
| RAV | Revaluation Asset Value |
| RCA | Regulatory Clearing Account |
| RREEDSM | Required Revenue Energy Efficiency and Demand Side Management |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SANRAL | South African National Road Agency Limited |
| SQI | Service Quality Incentives |
| TD | Tariff Design |
| TNC | Transmission and Network costs |
| TOC | Trended Original Cost |
| UCT | Unit Capability Factor |
| WACC | Weighted Average Cost of Capital |
| WEPS | Wholesale Electricity Pricing System |
| WUC | Work Under Construction |
| β | Beta |

## DEFINITIONS

| | |
|---|---|
| Short-Term (ST) contracts: | Contracts with a duration of one to three years. Coal from ST contracts is typically further away from the power station than coal from Long-Term (LT) contracts. The coal from ST contracts is transported by road or rail. |
| Medium-Term (MT) contracts: | Contracts with a duration of three to ten years. Coal from MT contracts is typically further away from the power station than coal from Long-Term (LT) contracts. The coal from MT contracts is transported by road or rail. |
| Long-Term (LT) contracts: | Cost Plus and Fixed Price contracts that have a duration longer than 10 years. Coal from LT contracts is mostly transported by conveyor belt, but at times by road or rail depending on the economic viability of each case. |
| Integrated Resource Plan | A resource plan established by the national sphere of government to give effect to national policy |

# 1 Executive Summary

1.1 To enhance regulation, certain sections of the Methodology have been revised to align objectives and increase transparency while minimising regulatory risks.

1.2 Lessons learnt from the previous Regulatory Clearing Account (RCA), as well as the stakeholder comments during the methodology consultation process, highlighted that certain sections of the Methodology did not adequately address some of the intended objectives, particularly with reference to Open Cycle Gas Turbines (OCGTs), sales volumes and coal procurement.

1.3 A major risk factor that was highlighted was the inaccuracies in sales volumes projections, as well as plant availability projections. Sales volume variations have been one of the largest components of Revenue Variance in the previous RCA and the rules have been revised to deal with this problem. Furthermore, a new section, namely 'Production Plan', has been introduced for alignment and to improve transparency.

1.4 During the RCA evaluation process, it was found that Eskom had been implementing maintenance activities without an improvement in the availability levels. In assessing the use of OCGTs, the Energy Regulator found that the OCGT rules had to be amended to take into account the collective impact of the entire fleet performance on OCGT utilisation. The OCGT rules have been further amended to be aligned with underlying principles defined in terms of least cost dispatch and referencing Scheduling and Dispatch Rules as recommended during the consultation process.

1.5 Another key risk area was coal procurement. Coal costs have been increasing rapidly and it was not clear where the cost increases were coming from. To enhance transparency the Energy Regulator has amended the rules such that the single cost centre is disaggregated into various contract types because of the different risks per contract type.

1.6 New sections, such as 'Ring-fencing of costs', have also been included to minimise the risk of misallocation of funds.

1.7 The Energy Regulator envisages that implementing these amendments will improve efficiencies and minimise regulatory risk

# 2 Introduction

2.1 The Multi-Year Price Determination (MYPD) Methodology ('the Methodology') is developed for the regulation of Eskom's required revenues. It forms the basis on which the National Energy Regulator (NERSA) will evaluate the price adjustment applications received from Eskom. The MYPD was first introduced in 2006 for implementation from 01 April 2006 to 31 March 2009. It is a cost-of-service-based methodology with incentives for cost savings and efficient and prudent procurement and overall operations by the licensee (Eskom). The Methodology also provides for Services Quality Incentives (SQI) for Eskom. The MYPD runs concurrently with Eskom's financial year(s).

2.2 In developing the MYPD Methodology, the following objectives were adopted:

2.2.1 to ensure Eskom's sustainability as a business and limit the risk of excess or inadequate returns, while providing incentives for new investment;

2.2.2 to ensure reasonable tariff stability and smoothed changes over time consistent with socio-economic objectives of the Government;

2.2.3 to appropriately allocate risk between Eskom and its customers;

2.2.4 to provide efficiency incentives without leading to unintended consequences of regulation on performance;

2.2.5 to provide a systematic basis for revenue/tariff setting; and

2.2.6 to ensure consistency between price control periods.

# 3 Legal Basis

**3.1** The legal basis for the MYPD Methodology is provided in the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the Act'). Section 4(a)(ii) of the Act states that 'the Regulator must regulate prices and tariffs'. Further, section 15(1) and (2) of the Act prescribes the following tariff principles:

*(1) A license condition determined under section 14 relating to setting or approval of prices, charges and tariffs and the regulation of revenues –*

*a) Must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;*

*b) Must provide for or prescribe incentives for the continued improvement of the technical and economic efficiency with which the services are to be provided;*

*c) Must give end users proper information regarding the costs that their consumption imposes on the licensee's business;*

*d) Must avoid undue discrimination between customer categories; and may permit the cross subsidy of tariffs to certain classes of customers.*

*(2) A licensee may not charge a customer any other tariff and make use of provisions in agreements other than that determined or approved by the Regulator as part of its licensing conditions.*

**3.2** Including the provisions of section 14(1)(e), apart from the Act, the Electricity Pricing Policy (*Electricity Pricing Policy GN 1398 of 19 December 2008*) ('EPP') gives broad guidelines to the Energy Regulator in approving prices and tariffs for the electricity supply industry.

# 4 Applicability of MYPD Methodology

**4.1** The Methodology is subordinate to the requirements of the Electricity Regulation Act and the Electricity Pricing Policy. The requirements from these two documents will at all times supersede those of the Methodology.

**4.2** The Methodology shall be used for the evaluation of Eskom's MYPD and Regulatory Clearing Account (RCA) applications.

**4.3** In the application of the Methodology, the Energy Regulator may apply reasonable judgement on Eskom's revenue (or any component thereof) after due consideration of what may be in the best interest of Eskom, the overall South African economy and the public.

**4.4** NERSA shall from time to time, as and when necessary request Eskom to submit information and additional schedules in the manner considered suitable to allow NERSA to analyse such information and schedules for the purpose of making decisions on Eskom's application.

**4.5** Any non-compliance with the procedure set out in this Methodology may be condoned by the Energy Regulator on application by Eskom. The following factors shall be taken into account by the Energy Regulator in deciding whether or not to grant condonation:

a) the extent or degree of deviation;
b) the explanation for the deviation;
c) the impact of the deviation on the achievement of the objectives of the Methodology; and

d) the prejudice to be suffered by Eskom, the members of the public and the economy if condonation is granted or not granted.

**4.6** The development of the Methodology does not preclude the Energy Regulator from applying reasonable judgement on Eskom's revenue after due consideration of what may be in the best interest of the overall South African economy and the public.

# 5 Allowable Revenue

**5.1** The Allowable Revenue (AR) for Eskom for the MYPD period must be determined by applying the AR formula.

**5.2** The following formula must be used to determine the AR:

$$AR = (RAB \times WACC) + E + PE + D + R\&D + IDM \pm SQI + L\&T \pm RCA$$

Where:

$AR$ = Allowable Revenue
$RAB$ = Regulatory Asset Base
$WACC$ = Weighted Average Cost of Capital
$E$ = Expenses (operating and maintenance costs)
$PE$ = Primary Energy costs (inclusive of non-Eskom generation)
$D$ = Depreciation
$R\&D$ = Costs related to research and development programmes/projects
$IDM$ = Integrated Demand Management costs (EEDSM, PCP, DMP, etc.)
$SQI$ = Service Quality Incentives related costs
$L\&T$ = Government imposed levies or taxes (not direct income taxes)
$RCA$ = The balance in the Regulatory Clearing Account (risk management devices of the MYPD)

**5.3** Each division's revenue will be calculated separately, with the overall price/revenue determined at distribution level and communicated as such to customers.

**5.4** The formula above must be applied to the three Eskom divisions by allocating the relevant costs to the division that incurred such costs.

**5.5** Common costs will be allocated to the divisions according to an appropriate formula that will be subject to approval by the Energy Regulator.

**5.6** Transmission costs will be treated as pass-through costs at distribution level.

**5.7** Generation costs will be treated as pass-through costs at distribution level.

**5.8** The allowed revenue must be based on all customer categories.

# 6 Sales Volumes

## 6.1 Principles of sales volume forecast

6.1.1 The sales forecast must be based on all customer categories of the standard tariff, international, negotiated pricing agreements and others.

6.1.2 Eskom should include an explanation on the process and assumptions used to compile the sales forecast.

6.1.3 The load forecast must include assumptions used in the sales forecast not only limited to the Integrated Demand Management (IDM) programmes, Gross Domestic Product (GDP) and price elasticity of demand.

6.1.4 The calculation of the transmission and distribution loss factors should be calculated as per the Tariff Grid Codes and submitted together with the MYPD application.

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.

# 7 Production Plan

**7.1** Eskom must furnish the Energy Regulator with the risk adjusted production plan and the energy wheel that is aligned to the forecasted sales above to be reviewed and approved by the Energy Regulator.

**7.2** The energy wheel diagram for each year of the MYPD must reflect all generation sources together with the power purchased from Independent Power Producers (IPPs) and international purchases.

**7.3** The plan shall be adjusted accordingly when the sales volumes are adjusted to ensure alignment.

# 8 Weighted Average Cost of Capital

## 8.1 Formula

8.1.1 The Weighted Average Cost of Capital **(**WACC) is the weighted average of the expected cost of equity and cost of debt. The following formula will be used to determine the pre-tax real WACC:

$$WACC = \left[\{Kd \times g\} + \{\frac{Ke}{(1-tc)} \times (1-g)\}\right]$$

Where:

| | | |
|---|---|---|
| $WACC$ | = | pre-tax, real cost of capital |
| $Kd$ | = | pre-tax cost of debt |
| $g$ | = | gearing |
| $Ke$ | = | post-tax cost of equity |
| $tc$ | = | company tax rate |

## 8.2 Cost of Debt

8.2.1 The expected real cost of debt consists of the expected risk free rate and the utility's debt premium.

8.2.2 The cost of debt is determined by using the following formula:

$$Kd = rf + d\text{Þ}$$

Where:

K$d$ = pre-tax, real cost of debt measures the average cost of borrowing for Eskom, taking into account the forward-looking view of interest rates. Estimation of cost of debt by financial institutions can also be considered.

$rf$ = Risk free rate is calculated as an average of the marked-to-market rate of the nominal government bond with at least 10-year maturity. The calculation will consider the preceding 30 days, starting at least two months before the submission of the tariff application.

$d$Þ: The debt premium will be determined as follows:

a) The spread between the licensee and government bond rates with the same maturity and/or other comparable international licensees with similar credit ratings.
b) Estimates of debt premium from financial institutions such as investment banks and credit rating agencies can also be considered.

8.2.3 The real cost of debt will be determined by converting the nominal sum of Rf and dÞ to real using the expected rate of inflation.

## 8.3 Gearing

8.3.1 The Energy Regulator strives to use an optimal targeted gearing ratio, which is a function of the capital structure used in the determination of the expected cost of capital.

8.3.2 The gearing ratio estimated by financial institutions for comparable companies can also be considered.

## 8.4 Cost of Equity

8.4.1 The Cost of Equity (Ke) must be determined by the Capital Asset Pricing Model (CAPM) by applying the following formula:

$$Ke = [rf + (\beta \times MRP)]$$

Where:

$Ke$ = Post-tax, real cost of equity is calculated by using the following parameters.

$rf$ = Risk free rate is calculated as an average of the marked-to-market rate of nominal government bond with at least 10-year maturity. The calculation will consider the preceding 30 days, starting at least two months before the submission of the tariff application. The nominal risk free rate will be converted to real using the expected rate of inflation.

$\beta$ = The beta will be determined by proxy. The proxy will be determined by considering an average of at least six global utilities listed in the stock exchange. The methodology to be used to determine the beta is set out in Note 1.

$MRP$ = Market risk premium will be determined by using recent MRP studies conducted by credible entities. The Energy Regulator will use the MRP published by Credit Suisse and/or the spread between the return on Johannesburg Stock Exchange (JSE) All Share Total Index (ALSI) and the risk free rate.

### 8.5 Conversion of nominal to real

8.5.1 The expected inflation rate will be used to convert the nominal portion of WACC to real WACC, using the Fischer equation.

### 8.6 Inflation

8.6.1 The expected inflation rate to be used for the conversion of nominal values to real will be determined by the Energy Regulator.

### 8.7 Company tax rate

8.7.1 The applicable company tax rate will be used by the Energy Regulator as set by the South African Revenue Services (SARS).

## 9 Regulatory Asset Base

### 9.1 Criteria for including an asset in the asset base for the depreciation and return purposes

9.1.1 The Regulatory Asset Base (RAB) must represent assets used and usable to provide regulated service by each of Eskom business operations.

9.1.2 The RAB of the regulated business operations must therefore only include assets necessary for the provision of regulated services based on the net depreciated value (residual value) of allowable fixed assets necessary to allow the utility reasonable return to be financially viable and sustainable while preventing unreasonable price volatility and excessive sustainability.

9.1.3 The RAB must consist of existing Fixed Assets in use, New Investments, Works Under Construction (WUC) excluding interest during construction[3], as well as making allowance for Net Working Capital to allow the respective operations of Eskom to meet short-term obligations.

[3] Only for the purpose of earning a return

9.1.4 The allowance for Net Working Capital will be calculated in a way that gives consideration to good practice targets to give incentives to Eskom to manage working capital optimally.

9.1.5 The RAB should exclude any capital contributions by customers. Allowance will be made for electrification assets to allow for future replacement of such assets at the end of their economic life.

9.1.6 Respective regulated operations of Eskom will be allowed to earn a return on the RAB of the regulated business operations based on the WACC.

9.1.7 Assets used partly for regulated revenues and of unregulated revenues will be proportionally allocated among these activities to avoid cross-subsidisation between regulated and unregulated businesses.

9.1.8 Only assets used in regulated business operations that meet the following criteria will be included in the RAB to allow the licensee to earn a reasonable return on assets based on the WACC:

9.1.8.1 Fixed assets must be used and useable, which means that assets should be in a condition that makes it possible to supply demand in the short-term (within 12 months).

9.1.8.2 Fixed and other assets that are not used and/or in a useable form will therefore not be included in the RAB.

9.1.8.3 The exception to the criteria is that the capital expenditure of expansionary nature, to create additional capacity (i.e. which is not used and usable) should be capitalised and included in the RAB as and when construction costs are incurred for return purposes. Such capitalisation will however exclude interest during construction.

9.1.8.4 WUC will be excluded from RAB for the purposes of depreciation.

9.1.8.5 Efficient working capital will be included in the RAB for the purposes of calculating the return.

## 9.2 The Basis for Valuation of the Regulatory Asset Base

9.2.1 Policy position 1 (a) of the Electricity Pricing Policy (*Electricity Pricing Policy GN 1398 of 19 December 2008*) states that:

> *The revenue requirement for a regulated licensee must be set at a level which covers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values. The regulator, after consultation with stakeholders, must adopt an asset valuation methodology that accurately reflects the replacement value of those assets such as to allow the electricity licensee to obtain reasonably priced funding for investment; to meet Government defined economic growth.*
>
> *In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and*

*shocks while ensuring financial; viability, continuity, fundability and stability over the short, medium and long term assuming an efficient and prudent operator.*

9.2.2 The Energy Regulator has adopted an asset valuation methodology whereby the current cost of replacing an asset with its modern equivalent asset is adjusted for physical deterioration and all relevant forms of obsolescence and optimisation to allow reasonable return on such RAB to ensure the financial viability and sustainability of Eskom while preventing unreasonable price volatility and excessive returns.

9.2.3 This methodology is also referred to as the Modern Equivalent Assets Value (MEAV) and is used as the basis for valuation of Eskom's RAB. Modern equivalent assets are similar to existing assets having equivalent productive capacity, however built using modern material, technology and design. The MEAV submitted by Eskom in line with 9.4.3 below should be independently verified by the Energy Regulator. The MEAV of the RAB should be adjusted for the associated increased operational efficiency due to the use of modern technology. Efficiencies that can be extracted from operating expenditure must also be considered.

9.2.4 Depreciated Replacement Cost (DRC) will be used as the basis for estimating the cost of constructing a modern equivalent asset.

9.2.5 DRC will be derived from the modern equivalent asset value for the replacement of fixed assets that have been adjusted by accumulated depreciation taking into account the age and condition of the asset.

9.2.6 The MEAV focuses on valuing the cost of assets needed to provide the equivalent service provided by existing assets.

9.2.7 Valuation of the RAB should take the following criteria for valuation of assets into consideration:

9.2.7.1 All assumptions used in determining the starting value for the RAB must be clearly stated.

9.2.7.2 The assumptions underlying the MEAV must be transparent and predictable and also be made available to the users of electricity whenever necessary.

9.2.7.3 The value must be based on delivering the current level of service using the MEAV, in accordance with good international regulatory practice.

9.2.7.4 The MEAV must be determined objectively and be verifiable to optimise the impact of revaluated RAB on the allowed return to the utility.

## 9.3 Depreciation and Return on Assets

9.3.1 Regulatory depreciation and return on the RAB provides the regulatory mechanisms under which capital investment costs are recovered on a cost reflective basis over the course of its economic/regulatory economic life.

9.3.2 In line with the EPP, full cost reflectivity[4] with respect to depreciation and return on assets cost recovery will be implemented over a reasonable period to allow Eskom reasonably priced funding for investment.

9.3.3 The Energy Regulator will, however, apply reasonable regulatory judgment in balancing between the need to smooth price increases, allowing the licensee a reasonably cost reflective return on investment, and preventing excessive or inadequate returns.

## 9.4 Depreciation on Regulatory Asset Base

### Calculation of Depreciation

9.4.1 Annual Depreciation will be calculated by deducting the Accumulated Depreciation of the previous year (year-1) from the Accumulated Depreciation the current year (year 0) using the following formula:

$D = AC_{y0} - AC_{y-1}$

$D$ = Depreciation and amortisation of replacement cost adjustment

$AC_{y0}$ = MEAV*(remaining economic life year 0/total economic life)

$AC_{y-1}$ = MEAV*(remaining economic life year -1/total economic life)

9.4.2 The economic life for the regulated Generation, Transmission and Distribution assets shall be determined by the Energy Regulator in consultation with the relevant stakeholders.

9.4.3 The RAB to be used for the depreciation of the assets will be the RAB as approved by the Energy Regulator.. The DRC is arrived at, for each regulated asset, by the following steps:

9.4.3.1 **Step one:** Eskom will submit the MEAV study to the Energy Regulator.

9.4.3.2 **Step two:** The Energy Regulator will review and approve an appropriate MEAV value.

9.4.3.3 **Step three**: This MEAV value is then depreciated (according to the expired economic life and remaining economic life of the asset) to

[4] The pricing method is to reflect the full economic cost of supplying electricity to a customer.

arrive at the DRC. Formula DRC = MEAV*(remaining economic life/total economic life).

9.4.3.4 **Step four:** Phase in the DRC on a straight line basis over the MYPD4 period. The Energy Regulator may adjust the period in the light of Eskom's progress in implementing its investment programme.

9.4.4 WUC will be excluded from RAB for the purposes of depreciation.

## 9.5 Net Working Capital

9.5.1 Net working capital refers to trade receivables, reasonably incurred future fuels [i]less trade payables required for the operation of the regulated business.

9.5.2 Trade receivables represent current assets due to the utility because of the sale of electricity on credit. A maximum of 45 days sale of electricity by the regulated business operations will be included in the RAB to the extent that such trade receivables do not attract interest in the hands of the utility.

9.5.3 Inventory refers to coal, nuclear fuel, maintenance spares and consumables held in efficiently operation of the regulated business.

9.5.4 Trade payables refer to current liabilities for which the amount to be settled is usually with respect to the normal operations of the utility and excludes provisions. A minimum trade payable turnover of 60 days of trade purchases from suppliers will be included in the RAB to the extent that such payables do not attract interest payments.

## 9.6 Works Under Construction

9.6.1 Capital WUC are qualifying construction costs incurred with respect to projects with a long construction period (longer than 12 months).

9.6.2 Capital WUC should be stated at cost consisting of the cost of material and direct labour and any cost directly attributable to bringing it to its present location and condition.

9.6.3 To the extent that the assets are financed by borrowing, such borrowing costs attributable to construction of qualifying assets will not be capitalised as part of these assets over the period of construction.

9.6.4 The criteria for allowing inclusion of WUC as part of the RAB are as follows:

9.6.4.1 The WUC projects to be included in RAB are with respect to the creation of additional generation, transmission and distribution capacity.

9.6.4.2 The WUC projects for additional electricity generation undertaken must be evaluated against the Integrated Resource Plan (IRP) of the National Government of South Africa. The Energy Regulator must be

able to evaluate and compare such a project with similar projects that Eskom has undertaken in the past.

9.6.4.3 The WUC must not necessarily be based on the least-cost model of the IRP; however, the least cost model should be seen as an indication of the costs.

9.6.4.4 Costs in the WUC programme must be disaggregated with full details on the activities undertaken.

9.6.4.5 All WUC allowed must be subject to reviews and audits and any amounts identified to be imprudent must not be allowed in the risk management device on an annual basis.

# 10 Expenses – Operating and Maintenance

**10.1** Section 15(1)(a) of the Act states that:

*A license condition determined under section 15 relating to setting or approval of prices, charges and tariffs and the regulation of revenues –*

*a) must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.*

**10.2** The EPP Position 1(a) further states that:

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

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

## 10.4 Principles regarding expenses

10.4.1 Allowable expenses relate to all expenses that are incurred in the production and supply of electricity. These costs include normal operating expenditures, maintenance (excluding refurbishment costs that must be capitalised), manpower or labour costs, and overheads (centrally administrative and general expenses allocated) that are normally recovered within one financial year.

10.4.2 Manpower costs should be allowed in accordance with the allowable revenue; any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges as detailed in 17.1.1.1

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

10.4.4 Expenses must be prudently and efficiently incurred and must be at arm's length transactions.

10.4.5 For any expenses incurred under abnormal or extraordinary circumstances, consideration shall be given to spreading such expenses over a number of years. This consideration may also apply to particular types of expenditure within management's control only for purposes of tariff smoothing and once the Energy Regulator is satisfied that those expenses have been prudently and efficiently incurred.

10.4.6 Allowance for the human resources costs should be at reasonable levels. The Energy Regulator may require access to wage settlement documents to verify the reasonability of these costs.

10.4.7 Costs relating to corporate social investment, expenses on charitable donations and broad social development activities cannot be included as qualifying (regulated) expenses unless it can be shown that these costs benefit tariff paying customers.

10.4.8 Other expenses that are not related to the core business of supplying electricity will also be disallowed.

10.4.9 Expenses forecast will be based on the most recent prudently and efficiently incurred actual costs taking into account the fixed and variable nature of such costs.

10.4.10 Operating expenses referred to as other costs must be unbundled.

# 11 Research & Development

**11.1** The Energy Regulator shall consider the core Research and Development (R&D) activities based on the following criteria:

11.1.1 the purpose and goal of R&D; and

11.1.2 the development costs will be capitalised:

11.1.2.1 when the projects indicate that future economic benefits will flow into the entity,

11.1.2.2 when they are technically feasible, and

11.1.2.3 when the expenditure can be reliably measured. Eskom will provide the details around the readiness of the projects.

**11.2** The following criteria provide guidance with regard to which projects are acceptable:

11.2.1 those that will result in improved efficiency;

11.2.2 those that will result in extended plant life;

11.2.3 those that will result in lower operating costs;
11.2.4 those that will result in a better load or power factor;
11.2.5 those that will result in a better understanding of load behaviour; and
11.2.6 those that relate to the design, construction, selection and operation of projects in the build plan or demo plant of those technologies that might form part of a future build plan.

**11.3** In addition, the following environmental projects are allowed:
11.3.1 those related to developing, designing, selecting and operating renewable energy sources;
11.3.2 those related to better usage of water, less pollution and less global warming; and
11.3.3 climatology projects related to environmental impact or forecasting of availability of natural resources and weather patterns.

**11.4** Further considerations will be the following:
11.4.1 The costs undertaken by Eskom will be allowed if they are likely to benefit customers. Eskom will have to justify the expenses incurred in the R&D activities.
11.4.2 The costs in the R&D should be prudently incurred.
11.4.3 There must be proper governance procedures in place with industry input in terms of project selection and review.

**11.5** The Energy Regulator shall make the final decision in allowing or disallowing the R&D expenses which will form an explicit separate line item in the Operating and Maintenance cost application.

# 12 Primary Energy

### Criteria for Allowing Primary Energy Costs

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

### 12.2 Coal Costs

12.2.1 The Energy Regulator will approve the coal benchmark price (i.e. average R/ton) per contract type (Cost Plus, Fixed Price, Medium-Term and Short-

Term) and Alpha for each contract type in the final MYPD decision.

12.2.2 The R/ton coal price and R/ton/km transport cost (rail and road) shall be escalated using the formula in the contracts. Contract parameters (mining input costs like steel, labour, diesel, spare parts, rubber, electricity and tyres) in the indexation formula shall be adjusted using the industry accepted level of inflation available in the public domain.

12.2.3 Future coal procurement will be informed by the long-term coal procurement strategy that will be submitted to the Energy Regulator at the time of MYPD application. This strategy should demonstrate how Eskom will purchase least cost coal.

12.2.4 The forecasts indicated below shall be submitted together with the MYPD application:

a) Coal volumes burnt per station, per contract type and per supplier.
b) Coal volumes purchased per station, per contract type and per supplier.
c) Coal stockpiles tons per station.
d) Coal costs (R/ton delivered) per station, per contract type and per supplier.
e) Coal quality per station (CV, burn rate, ash content) and per supplier.
f) Road transport costs for each station: tons moved, kilometre travelled and payment rate.
g) Rail transport costs for each station: tons moved, kilometre travelled and payment rate.
h) Price escalations indices (electricity, diesel, mechanical spares, labour, tyres, etc.) for mining and transport for each year of the MYPD.
i) Start date and expiry date of each coal contract per power station.

12.2.5 The following coal handling costs per station shall be submitted with the MYPD application: building-up stockpiles, recovering from stockpiles, maintaining stockpiles, tons moved, kilometre travelled and payment rate.

## 12.3 Gas Turbine Generation Costs

12.3.1 Gas turbines are provided to operate during peak periods as well as emergency situations. Subject to the conditions set out in this Methodology, gas turbine generation cost will be allowed as a full pass-through cost, but limited to volumes allowed by the Energy Regulator, except where such use was necessary to ensure security of supply due to events outside of management control.

12.3.2 Capacity constraints shall be mitigated by gas turbine generation as a last resort. For avoidance of doubt, gas turbine generation should be employed before implementation of load shedding activities.

12.3.3 Price variances due to higher than projected diesel prices will be allowed as pass-through but limited to the allowed volumes based on allowed energies, according to the equation below:

$$Allowed\ Volumes\ (l) = Allowed\ Energies_{Per\ Station}\ (MWh) * Efficiency_{Per\ Station}\left(\frac{l}{MWh}\right)$$

And

$$Price\ Variance = (Allowed\ Volumes\ (l) * Average\ Diesel\ Price_{Actual}\left(\frac{R}{l}\right)) - Allowed\ Diesel\ Cost\ (R)$$

12.3.4 A full pass-through cost shall be allowed where there are variances as a result of fluctuations in the unit cost of fuel, subject to Eskom demonstrating that its procurement processes comply with relevant legislation and are consistent with industry standards. High differences between actual unit price and market prices are to be assessed for prudency.

12.3.5 The extent at which OCGTs are used is directly dependent on the performance of the rest of the Eskom fleet, particularly the baseload power plants (i.e. coal fleet and nuclear). For this reason, the MYPD determination will be made after full consideration of the production plan for the period under consideration and taking into account the entire energy supply chain.

12.3.6 Eskom must ensure that plant performance projections that form the basis of MYPD applications are as accurate as possible to reduce the large variations between planned and actual plant performance. The projections must take into account all/any relevant history conditions that have resulted in the current condition of the plant.

12.3.7 The variances (i.e. difference between MYPD allowed costs and actual incurred costs) together with reasons shall be presented to the Energy Regulator for the full financial year (audited financial statements). These variances shall be based on actual costs for the full financial year.

12.3.8 After approval by the Energy Regulator, the variance shall be debited or credited to the RCA.

## Other Primary Energy Costs

### 12.4 Nuclear

12.4.1 Eskom must:

12.4.1.1 determine the nuclear operation costs;

12.4.1.2 demonstrate (detailed calculation) how the costs were determined; and

12.4.1.3 provide the assumption considered when determining the costs.

### 12.5 Nuclear plant decommissioning costs

12.5.1 The costs will be based on the decommissioning study undertaken by Eskom, which shall be reviewed and approved by the Energy Regulator.

12.5.2 Eskom must provide the decommissioning for justification of the costs above.

### 12.6 Start-up Oil and Gas

12.6.1 Eskom must:

12.6.1.1 determine the costs;

12.6.1.2 demonstrate (detailed calculation) how the costs were determined; and

12.6.1.3 provide the assumption considered when determining the costs.

### 12.7 Sorbent

12.7.1 Eskom must:

12.7.1.1 determine the costs;

12.7.1.2 demonstrate (detailed calculation) how the costs were determined; and

12.7.1.3 provide the assumption considered when determining the costs.

### 12.8 Water procurement

12.8.1 Eskom must:

12.8.1.1 determine the costs per station for the water to be procured and highlight the amounts of water that will be designated for each process per plant;

12.8.1.2 demonstrate (detailed calculation) how the costs were determined; and

12.8.1.3 provide the assumption considered when determining the costs.

### 12.9 Water treatment

12.9.1 Eskom must determine the costs per station, particularly the cost of chemicals, electricity usage and labour.
12.9.2 Eskom must demonstrate (in a detailed calculation per station, highlighting the costs mentioned above) how the costs were determined.
12.9.3 Eskom must provide the assumption considered when determining the costs per station.

### 12.10 Road Repairs and Maintenance

12.10.1 Government and the relevant road authority will be responsible for road repairs and maintenance. Eskom will pay a toll fee (Shadow toll) to SANRAL based on the beneficial use of the roads for coal haulage.
12.10.2 Eskom will be allowed a full pass-through cost for the toll fees to be paid to the relevant road authority.
12.10.3 For Eskom's own roads, it will be allowed to pass through cost for repairs and maintenance.

## 13 Purchases from Independent Power Producers

**13.1** In accordance with the provisions of Section 14(f) Section 34 and Section 35 of the Electricity Regulation Act, the Energy Regulator shall review Power Purchase Agreements (PPAs) entered into by licensees before signature. This includes all Short-Term Power Purchase Programmes (STPPP), Medium-Term Power Purchase Programmes (MTPPP), Long-Term Power Purchase Programmes and cross boarder IPPs. This also includes all PPAs considered under the Ministerial Determination by the Department of Energy (DoE). In evaluating the MYPD, the cost associated with the Independent Power Producers (IPPs) will be incurred based on the terms and conditions of the respective PPAs.

**13.2** The Energy Regulator will review the efficiency of all contracts before such contracts are concluded to ensure prudency as well as fair risk allocation between the IPP and the buyer (Eskom).

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

**13.4** Use-of-system charges incurred by the buyer in line with the PPA from IPPs will be allowed as a full pass-through cost.

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

**13.6** Termination amounts payable by the buyer, designated pursuant to New Generation Capacity regulations, in accordance with provisions of PPAs reviewed by the Energy Regulator, will be allowed as full pass-through costs.

**13.7** Administration costs of the PPAs will be reviewed by the Energy Regulator to determine the efficiency and prudency with which the costs will be allowed as a pass-through cost.

**13.8** Hedging costs against exposure to risks allocated to the buyer in the PPAs will be allowed as a pass-through cost.

**13.9** Each pass-through cost incurred will be reviewed by the Energy Regulator during the RCA evaluation to ensure that each cost item was incurred in compliance with the terms and conditions of the contracts and efficiently.

**13.10** Some cost items such as deemed energy payments requires Eskom to demonstrate that the payments were not as a result of its inefficiencies in operating the network [e.g. late completion of connection works as signed in the PPA (or agreed budget quotations) or unnecessary delays in rectifying faults].

**13.11** Other costs, such as administration costs of the PPAs, may result in double counting of costs if those costs were included in manpower cost because the administration of PPAs is currently done by Eskom employees.

**13.12** Over and above the MYPD allowance, pass-through costs shall be reviewed by the Energy Regulator to determine the efficiency and prudency under which they have been incurred.

**13.13** When Eskom makes an MYPD application, at least the following should be provided to the Energy Regulator:

13.13.1 Detailed energy and cost assumptions of IPP purchases per plant and technology (renewable and conventional), including short and medium-term agreements.

**13.14** The IPP application will be based on most recent information available at the time that the application is prepared. The information sources shall include:

13.14.1 the IPP contract (if available);
13.14.2 historical information of similar IPPs (if applicable);
13.14.3 information from the DoE IPP office;
13.14.4 information from the IRP; and
13.14.5 any other valid information source.

# 14 Integrated Demand Management

**14.1** Eskom must develop and submit a five-year demand resource potential assessment including technical potential and estimated achievable potential. The five-year plan should be updated annually.

**14.2** Levelised cost of IDM resources should be based on the Total Resource Cost (TRC) and must be provided upon application for implementation of existing as well as new demand side resources.

**14.3** The IDM programmes considered in the MYPD rules are classified as detailed below.

## 14.4 Energy Conservation (EC)

14.4.1 Energy Efficiency (EE) programmes effect energy savings during the day on working days with a duration of more than 1600 hours per financial year.

## 14.5 Demand Reduction (DR)

14.5.1 Demand response, demand reduction, demand curtailment, demand market participation and demand response aggregation programmes are programmes aiming to reduce the demand during peak hours.

## 14.6 Integrated Demand Management Revenue

14.6.1 The IDM revenue requirement will be calculated as follows:
$RRIDM = RR_{ec} + RR_{dr}$, where
$RR_{ec}$ – the revenue requirement for the EC programme; and

$RR_{dr}$ – the revenue requirement for the DR programme.

The revenue requirement per programme will be calculated as follows

$RR_{pr} = (PC) + OC + M\&V$, where

$RR_{pr}$ – the revenue requirement for the programmes above;

$PC$ – programme cost;

$OC$ – operating cost of the programme; and

$M\&V$ – measurement and verification cost of the programme.

The revenue requirement for the EC programme will be determined as follows:

$PC_{ec} = AC_{base} \times Target$, where

$PC_{ec}$ is the programme cost of the EC programme, R;

$AC_{base}$ – avoided cost of supply of baseload generation, R/MWh; and

$Target$ – demand savings of the programme, MWh.

14.6.2 The energy efficiency savings should be achieved for at least 1600 hours during working days per annum.

14.6.3 The revenue requirement for the DR programme will be determined as follows:

$PC_{dr} = AC_{peak} \times Target$, where

$PC_{dr} =$ the programme cost of the DR programme, R;

$AC_{peak}$ – avoided cost of supply for peak generation, R/MW; and

$Target$ – energy savings of the programme, MW.

14.6.4 The demand savings under the DR programme should be measured and verified only during the peak hours of working days, or in total the demand savings should be achieved over 1560 peak hours during working days. The annual reduced demand shall be measured as the average of the MW reduction over the peaking hours of the year.

14.6.5 Eskom shall submit a full breakdown of all IDM programmes/technologies with their estimated costs, demand and energy savings to the Energy Regulator with the MYPD application.

14.6.6 The projects' capital costs (R/kW) will be benchmarked with the capital cost (R/kW) of peaking and baseload power stations where applicable.

14.6.7 The funding will be on the basis of the life cycle cost of the project compared with the avoided cost of supply calculated for the life of the project. IDM programmes/projects that are funded by other stakeholders, e.g. Treasury/DoE, should be excluded from the required revenue.

14.6.8 The IDM projects and costs shall be aligned with the applicable IRP, the Medium-Term System Adequacy Outlook (MTSAO) and production plan of generation.

14.6.9 The overall IDM project costs will be evaluated using the life cycle cost of the project and should be less than the relevant (baseload and peak)

avoided cost of supply calculated for the life of a project. The avoided cost of supply shall be determined using the annual average marginal cost of generation, for a period equal to the life cycle of the project, seasonally, weekly, and hourly differentiated and adjusted for network costs and losses based on the Wholesale Electricity Price System (WEPS).

14.6.10 Based on international best practices, M&V costs range from 5% to 10% of the total project cost; considering the specific local conditions and previous experience the M&V costs shall be limited to 8% of the total project cost.

14.6.11 In order to minimise costs, M&V shall not be implemented after the expiry of the contract between Eskom and the customer, i.e. M&V costs shall only be allowed for projects still under contract.

14.6.12 The IDM funds shall be approved subject to the above and on the condition that Eskom shall submit performance reports annually reflecting expenditure (R), energy (GWh) and demand savings (MW) per project and the Energy Regulator shall have the final decision in allowing or disallowing the IDM programmes.

14.6.13 Eskom will incur penalties for underachieving the targets.

14.6.14 In case of non-performance, the penalty will be calculated as follows:

$$Penalty_{ec}(R) = \frac{allowed\ Revenue}{Projected\ MWh\ target} \times MWh\ unsaved \text{ or, } \frac{R}{MWh} \times MWh\ unsaved$$

$$Penalty_{dr}(R) = \frac{allowed\ Revenue}{Projected\ MW\ target} \times MW\ unsaved \text{ or, } \frac{R}{MW} \times MW\ unsaved$$

14.6.15 In terms of reporting demand/energy savings, the following rules will apply:

14.6.15.1 The savings should be reported for the actual period for which the project was implemented, i.e. demand/energy savings and period for which they have been achieved. Annualising of the energy and demand savings will be disallowed. Recognised demand/energy savings exclude off-peak hours, weekends and public holidays.

14.6.15.2 The system peak hours are considered the hours when the system experiences maximum loading. The peak hours in the morning is considered to be from 07:00 to 10:00 and the evening peak from 18:00 until 20:00 during working days of the summer months (September to April); and from 06:00 until 09:00 and from 17:00 until 19:00 during working days of the winter months (May, June, July and August) or as may be changed by notice of one month provided by Eskom to the Energy Regulator.

## 14.7 Principles of the avoided cost of supply determination

14.7.1 The avoided cost of supply includes the avoided generation, transmission and distribution costs.

14.7.2 The avoided generation cost will be determined on the basis of the annual average marginal cost of generation for the life of the programme aligned with the IRP, the MTSAO and generation production plans applicable at the time.

14.7.3 The avoided transmission cost infrastructure charge will be based on the WEPS network charge.

14.7.4 The avoided distribution cost shall be calculated on the basis of the WEPS network charge variable according to voltage supply level.

## 14.8 Demand Reduction (DR) Programmes

14.8.1 Eskom should submit an annual update of the market potential of the DR programmes and the associated costs.

14.8.2 The System Operator should submit monthly reports on the DR programmes' cost and performance to the Energy Regulator.

14.8.3 The System Operator should submit the methodology and models for calculating the ceiling costs of the DR programmes and ancillary services for consideration by the Energy Regulator.

14.8.4 The System Operator should submit annual plans and targets for the DR programmes and ancillary services.

14.8.5 The cost of EC projects should be benchmarked at the cost of baseload plant, including capital, operating and fuel costs applicable at the time.

14.8.6 The cost of DR projects should be benchmarked against the cost of peaking plant (OCGT), including capital, operating and fuel costs applicable at the time.

14.8.7 Demand response aggregation programmes will be subject to the same rules.

## 14.9 Power Conservation Programme

14.9.1 The Power Conservation Programme (PCP) Regulations and Regulatory Framework have not yet been finalised..

## 14.10 PCP/ECS Safety Net Programmes

14.10.1 In the absence of any electricity shortfall, the ECS shall be implemented on a voluntary basis.

14.10.2 The mandatory implementation will be implemented at no cost to Eskom with zero penalties, until the DoE promulgates the ECS policy.

14.10.3 In the event of an electricity shortage, the ECS funded through electricity tariffs shall come into operation after considering all possible Demand Side

Management Programmes such as EEDSM, DMP and OCGT, which would only be activated during times of crisis.

# 15 Service Quality Incentives

**15.1** The objective of the Service Quality Incentives (SQIs) is to ensure that the provision of good quality of service is rewarded, and poor service penalised. Eskom may not achieve reduced expenditure at the expense of a deterioration in the quality of service it provides to customers.

**15.2** SQIs are used as a measure to encourage Eskom to improve its quality of service to its customers. A portion of Eskom's allowable revenue will be channelled towards the SQI schemes. The performance review and setting of new targets for Eskom Generation, Transmission and Distribution will be done at the beginning of each financial year. The annual performance results will be used to adjust the revenue requirements for each financial year according to the RCA. The rewards/penalties are applied according to the performance achieved by Eskom on the targets set at the beginning of each financial year.

**15.3** The SQI scheme has the following measures: Unit Capability Factor (UCF) for Generation, System minutes and line faults/100km for Transmission, System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Distribution Supply Loss Index (DSLI) for Distribution. These measures and the reward/penalty targets are clearly specified in the SQI scheme.

# 16 Taxes and Levies (not income taxes)

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

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

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

### 16.4 Principles regarding taxes and levies

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

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

16.4.3 Eskom must ensure that tax and levy costs are specified and that the calculation thereof is clear and concise.

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

## 17 Risk Management Control & Pass-Through Mechanisms

### 17.1 Risk Management Device

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

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

17.1.1.2 Allowing the pass-through of prudently incurred primary energy costs as per Section 12 of the Methodology.

17.1.1.3 Adjusting capital expenditure forecasts for cost and timing variances as per Section 17.2.6 of the Methodology.

17.1.1.4 Adjusting for prudently incurred over or under-expenditure on operating costs as may be determined by the Energy Regulator.

17.1.1.5 Adjusting for other costs[7] and revenue variances where the variance of total actual revenue differs from the total allowed revenue..

### 17.2 The Regulatory Clearing Account

17.2.1 The RCA is used to debit/credit all the aforementioned potential adjustments to Eskom's allowed revenue and must be used as detailed below.

[7] Includes but not limited to taxes and levies (as defined), sales volumes and customer number variances.

17.2.1.1 The RCA will be the evaluation account (for the purpose of determining the pass-through and/or claw-back) that will consist of the variance between the actuals for the full financial year and what was allowed in the MYPD decision of the Energy Regulator.

17.2.1.2 This account will be evaluated on a year-by-year basis after an application by Eskom to the Energy Regulator for adjustment and shall be based on audited financial statements.

17.2.1.3 The RCA balance will be measured as a percentage of the total allowed revenue and will act as a trigger for a new application as follows:

a) If the RCA balance is less than or equal to 2% of the allowable revenue, then there will be no immediate pass-through adjustment, but the RCA balance will be carried over to the next financial year.

b) If the RCA balance is between 2% and 4%, the amount is allowed as a pass-through in the next financial year after a notice and stakeholder comment process in the year in which the variance occurs.

c) If the balance is greater than 4% of the allowable revenue, Eskom must make a completely new application for a new MYPD determination.

17.2.2 The adjustments to be included in the RCA and balance of the RCA will be approved by the Energy Regulator in terms of the MYPD Methodology.

17.2.3 The Energy Regulator will then review Eskom's submission and make a preliminary assessment of any adjustments required in the subsequent financial year's tariffs.

17.2.4 <u>Sales Volumes</u>

17.2.4.1 Variances between the forecast and actual sales volumes shall be assessed and analysed to determine the cause of the variance[8] then the Energy Regulator will make the decision whether to allow such variances.

17.2.5 <u>Production Plan</u>

17.2.5.1 The Energy Regulator shall make an assessment of generation plant maintenance quality against the maintenance plan submitted to the Energy Regulator. This assessment will seek to ascertain the efficiency and prudency of maintenance planning

[8] Such as load curtailment

processes as well as the implementation of maintenance plans.

17.2.5.2 The quality of maintenance assessment will further assess whether the planned fleet availability levels have been achieved and how the quality of maintenance or lack thereof has affected the entire fleet availability.

17.2.5.3 In the event of any change to the maintenance plans submitted during the MYPD application, Eskom must notify the Energy Regulator of such changes in writing.

17.2.5.4 A comprehensive reason for variance between the planned and actual plant performance is to be supplied to the Energy Regulator with the RCA application, highlighting the variance in the assumptions made as well as the reasons for that variance.

17.2.6 Regulated Asset Base

17.2.6.1 Certain aspects of RAB will have to be forecasted at the beginning of the MYPD cycle. Therefore, the value of RAB that earns a return will change/deviate from the forecast in line with global market factors such as exchange rates, availability and costs of financing, and costs of key inputs.

17.2.6.2 To accommodate the unstable environment, the approach for adjusting RAB for cost and timing variances will be as follows:

a) Eskom will annually report to the Energy Regulator on its capital expenditure programme, providing information on timing, cost variances and reasons including reconciliations.

b) The Energy Regulator will then assess the capital expenditure variances under the following categories for each of Eskom's regulated businesses:

i. Depreciation;
ii. Net Working Capital;
iii. WUC; and
iv. Other Asset Movements (e.g. mothballing).

17.2.6.3 Eskom's actual capital expenditure will be assessed against MYPD original assumptions. As part of the submission of its Capital Expenditure Programme, Eskom will detail the reasons for the variances, after which the Energy Regulator will assess these for prudence.

17.2.6.4 Any over-expenditure deemed prudent by the Energy Regulator will be allowed/added to the RAB to allow Eskom to recover additional returns. The opposite scenario where an under-expenditure is recorded will be treated the same by deducting it from the RAB value to earn a lessor return.

17.2.6.5 Such variances can emanate from the categories listed in 17.7.2.2 above.

17.2.6.6 This approach will ensure that Eskom is not allowed to earn undue returns on the delayed build, scrapped assets or any other variances that are as a result of Eskom's inefficiencies or decisions that are not in the original MYPD decision.

17.2.7 Expenses – Operating and Maintenance

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

17.2.7.2 The Energy Regulator may make use of the sharing mechanism in adjusting for over and under expenditure.

17.2.8 Coal

17.2.8.1 The allowed coal cost for the RCA purposes will be determined by comparing the coal benchmark costs with Eskom's actual costs of coal (R/ton cost) using a Performance Based Regulation (PBR) formula per contract type. The allowed actual total cost is calculated by applying the following formula on a contract type basis:

$$Allowed\ actual\ cost(Rand) = [Alpha\ x\ Actual\ Unit\ Cost\ of\ Coal\ Burn + (1 - Alpha)\ x\ Benchmark\ Unit\ Cost\ of\ Coal\ Burn]\ x\ Actual\ Coal\ Burn\ Volume$$

Where:

$Actual\ Unit\ Cost$ = Actual unit cost of coal burn in a particular financial year (R/ton).

$Benchmark\ Cost$ = Allowed coal burn unit cost for the contract type for the year considered (R/ton).

$Actual\ Coal\ Burn\ Volume$ = Actual tonnage of coal burn in the financial year considered.

$Alpha$ = Alpha is the factor that determines the ratio in which risks in coal burn expenditure is divided: i.e. those that are passed through to the customers, and those that must be carried by Eskom. Any number of the alpha between 0 and 1, set to share the risk of the coal cost variance between licensees and its customers.

17.2.8.2 NERSA will monitor the projections against the actuals in order to assess prudency in the variation in the coal mix.

17.2.8.3 Additional coal[9] and transport costs arising from events beyond the control of Eskom or the mine (reduced energy sales, geological problems, mine flooding, roads flooding, strikes, coal quality, etc.) shall firstly be recovered as per the clauses of the contracts and if such recoveries are not enough to cover all the costs incurred by Eskom, then the Energy Regulator may consider the prudency of further recoveries from the tariff.

17.2.8.4 Additional coal and transport costs arising from events within the control of Eskom may not be recovered from the tariff if the events were within the control of Eskom. If the events are within the control of the contractors, then Eskom shall recover such costs from the contractor by using the mechanisms in the contract. The events leading to additional costs may include but not be limited to:

a) failure to meet the migration deadlines from road to rail transportation;
b) failure to do planned maintenance on the mine-to-station conveyor belt system, silos and other coal handling infrastructure; and
c) delays in bringing equipment undergoing planned maintenance back online.

17.2.8.5 Additional coal purchase costs shall not be recovered from the tariff if Eskom does not keep the planned stockpile levels at each station. In the event of coal shortage supply to the station, Eskom shall firstly use stockpiles before making purchases from alternative suppliers.

17.2.8.6 Eskom shall at all times maintain the approved stockpile levels to mitigate the risk of prolonged non-delivery of coal to the station due to mine strikes or any other reasons.

17.2.8.7 The RCA application shall include the actuals for the information stated under MYPD section 12.2.

1. [9] Additional costs refer to costs incurred by Eskom on top of what the Energy Regulator has already approved.

17.2.9 Open Cycle Gas Turbines (OCGTs)

17.2.9.1 During the RCA process, in assessing the prudency of OCGT operation beyond the allowed amount, consideration will be given to how the circumstances arose that required such operation. The assessment will consider efficiency in operation of the rest of the generation fleet, particularly the coal fleet, as well as efficiency in the dispatching of all plants in terms of least cost, as defined by the Scheduling and Dispatch Rules (SDR).

17.2.9.2 Under an unconstrained generation capacity scenario, such as where there is no energy supply shortage, OCGTs are expected to be operated only during peak hours. However under a constrained generation capacity scenario, OCGTs can be used during off-peak hours. This use, outside normal operation, will be assessed for prudency and efficiency taking into account all contributing factors including the assessment of the reasons for the constrained supply condition.

17.2.9.3 The usage of OCGTs during off-peak periods shall be justified by Eskom, demonstrating the prudency and efficiency of doing so. It must be demonstrated by Eskom that all available, dispatchable and cheaper sources have been exhausted prior to the usage of OCGTs, including IDM and DMP options, taking into account all technical constraints and ensuring the security of supply.

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

17.2.10 Purchases from Independent Power Producers

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

# 18 Ring-Fencing and the Reallocation of Allowances

**18.1** The Eskom application in terms of costs, revenues and capital items must be done on the basis of ring-fenced divisions and the determined amounts for each division may not be reallocated between divisions without the Energy Regulator's approval.

**18.2** The determination is done on the basis of an application done in good faith and based upon the approved Corporate Plan and Corporate Strategy for the period of the application. It is therefore expected that the specific items dealt with in the determination will be implemented according to the determination and that targets and assumptions that form part of the application and the determination will remain for the period of the determination.

**18.3** Specifically where the impact of reallocation is not upon Eskom alone but has significant impact on other industry stakeholders, the approved plans incorporated in the MYPD decision must be implemented and any deviations must be approved by the Energy Regulator.

**18.4** Eskom is expected to generate a Transmission Development Plan, which will see Eskom meeting its Grid Code obligations and obligations in terms of the known Integrated Resources Plan, thus the approved capital allocations and implementation of the forecast projects needs to be honoured.

**18.5** The principles above also apply to loan covenants, generation projects and approved amounts for improving the efficiency of Eskom.

# 19 Review and Modification of the MYPD Methodology

**19.1** The Energy Regulator will conduct a review of the MYPD Methodology as and when required to ensure that the contents of the Methodology reflect the current regulatory circumstances. The Energy Regulator also recognises that special circumstances may arise that may necessitate changes to be effected to the Methodology. The Energy Regulator will continuously incorporate justifiable changes that are considered necessary to immediately capture clarity, transparency and regulatory efficiency benefits.

**The End.**

# Appendix 1: Reason for Changes

## 20 Allowable Revenue

Due to misinterpretations that were noted as errors in the last RCA, this section has been amended to clarify what constitutes allowable revenue provided for in the MYPD.

## 21 Sales Volumes

The rule included minimises the historically high sales variance and promotes accuracy in forecasting.

## 22 Production Plan

This is a new section that has been added to the Methodology. It is in response to the high variations between the planned production plan volumes as per the production plan submitted during the MYPD application and the actual production volumes that are generated. The rules highlight that the production plan submitted with the MYPD application must be risk adjusted, that is, it must take into account all present and historic conditions that have contributed to the availability levels of the plant. It must therefore be a realistic production plan to ensure reduced variances during RCA period.

## 23 Regulatory Asset Base

### 23.1 The Basis for Valuation of the Regulatory Asset Base

The Valuation of assets has been revised to eliminate the element of double counting due to revaluing and indexing simultaneously over the MYPD period. As a result, no indexation has been included in the MYPD 4 Methodology. Eskom will have to revalue its assets prior to submission.

### 23.2 Depreciation and Return on Assets

The asset useful lives will now be determined in line with the Grid Code.

# 24 Primary Energy

## 24.1 Coal Costs

24.1.1 The existing coal methodology treats coal as a single cost centre assigning one value for alpha, making it difficult to ascertain which coal contracts cause coal price variations. The Energy Regulator now proposes disaggregation of coal costs into various contract types because of the differing risks associated per contract type (Long-Term, Cost Plus, Medium-Term and Short-Term contracts). As a result, each contract type will have its own alpha. This will ensure better transparency and symmetry of information between Eskom and the Energy Regulator. It will further ensure the better allocation of risks between Eskom and the customers.

## 24.2 Gas Turbine Generation Costs

24.2.1 The rules are making provision for testing prudency of fuel procurement processes, they also seek to highlight the impact of the entire generation fleet on the use of OCGTs. The explicit dictating of merit order, as well as time of use in relation to OCGT utilisation, is removed, only highlighting principles of least cost dispatch as defined in SDR. The risk of inefficiencies in the generation fleet is mitigated in allowing additional generation, above MYPD allocation, to be recouped at the cost of the technology that should have been available.

## 24.3 Other Primary Energy Costs

24.3.1 The existing rules did not adequately deal with costs relating to Other Primary Energy. In hindsight, based upon the experience gained during the RCA process, the requirements in the proposed rules ensures more transparency between Eskom and the Energy Regulator.

# 25 Risk Management Control & Pass-Through Mechanisms

## 25.1 The Regulatory Clearing Account

This section was changed in consideration of the MFMA and MSA requirements applicable to the MYPD application.

For ease of reading and understanding, structural changes have been made. All rules related to RCA have been put together per section and added to this section.

25.1.1 Sales Volumes

The rule is introduced to curb the high variances in sales volumes.

25.1.2 Production Plan

25.1.2.1 This RCA requirement seeks to assess the quality of maintenance being implemented and judge against the improvement in availability that was projected during MYPD application. This will then inform the judgement of prudency in the operation of the generation fleet for allowance of OCGTs and other more expensive energy sources that may be used above allowed volumes.

25.1.3 Cost Variance Mechanism related to RAB

25.1.3.1 The CECA mechanism as identified in the MYPD3 spoke to only WUC as a possible variable for risk adjustment. For the purposes of the MYPD 4, this CECA mechanism has been expended to include other elements including:
Depreciation – This amount will differ when commissioning dates differ
Net Working Capital – This will be subject to efficiency testing based on the set criteria
WUC (Excluding IDC) – Already existing
Other Asset Movements (Asset transfers & Disposals etc.)

25.1.4 Coal

25.1.4.1 Disaggregating the coal from a single cost centre to contract type will be a mechanism that will be applied to test if it is adhering to its procurement projections, enhancing transparency.

25.1.5 Open Cycle Gas Turbines (OCGTs)

25.1.5.1 The rule enhances prudency assessment of OCGT utilisation, taking into account the entire generation fleet. This will encourage accuracy of the fleet production plan, decreasing variances that result in a large RCA.

25.1.6 Other Primary

25.1.6.1 These areas have been expanded and separated. The aim is to outline how the prudency test of the costs will be tested.

[i] Advances with related borrowing costs which are deferred in the licensee's statement of financial position