Annexure 1

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

MULTI-YEAR PRICE DETERMINATION METHODOLOGY

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Abbreviations and Acronyms

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
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
K_d	Cost of debt
K_e	Cost of equity
L&T	Government imposed levies or taxes (not direct income taxes)
LRMC	Long Run Marginal Cost
M&V	Measurement and Verification
MEAV	Modern Equivalent Assets Value
MIRTA	Minimum Information Requirements for Electricity Tariff Applications
MRP	Market Risk Premium
MWh	Mega Watt hours
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa
O&M	Operating and Maintenance
OCGT	Open Cycle Gas Turbine
PBR	Performance Based Regulation
PCP	Power Conservation Programme
PE	Primary Energy costs
PPA	Power Purchase Agreement
QoS	Quality of Service
R&D	Cost related to research and development programmes/projects

R/ton	Rand per ton
RAB	Regulatory Asset Base
RAV	Revaluation Asset Value
RCA	Regulatory Clearing Account
Rf	Risk free rate of interest
RREEDSM	Required Revenue Energy Efficiency and Demand Side Management
SANRAL	South African National Road Agency Limited
SQI	Service Quality Incentives
TD	Tariff Design
TNC	Transmission and Network costs
TOC	Trended Original Cost
WACC	Weighted Average Cost of Capital
WEPS	Wholesale Electricity Pricing System
WUC	Work Under Construction
β	Beta

1 Introduction

The Multi-Year Price Determination (MYPD) Methodology is developed for the regulation of Eskom's required revenues. It forms the basis on which the National Energy Regulator of South Africa (NERSA or 'the Energy Regulator') 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 by the licensee (Eskom). The Methodology also provides for Services Quality Incentives (SQI) for Eskom. On an annual basis, the MYPD runs concurrently with Eskom's financial year(s). A second MYPD period started from 01 April 2010 to 31 March 2013, with the next one scheduled to run from 01 April 2013 to 31 March 2018[1].

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

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. to ensure reasonable tariff stability and smoothed changes over time consistent with socio-economic objectives of the Government;
3. to appropriately allocate commercial risk between Eskom and its customers;
4. to provide efficiency incentives without leading to unintended consequences of regulation on performance;
5. to provide a systematic basis for revenue/tariff setting; and
6. to ensure consistency between price control periods.

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.

[1] There was an interim price determination during the 2009/10 Eskom financial year due to unforeseen increases in fuel costs and Eskom's capital expansion programme.

2 Legal Basis

The legal basis for the MYPD Methodology lies 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.

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.

3 Allowable Revenue

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

3.2 The following formula must be used to determine the AR:

AR = (RAB x WACC) + E +PE + D + TNC + R&D + IDM + SQI + L&T +/- 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

TNC = Transmission and Network Costs

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)

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

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

3.5 Common costs will be allocated to the divisions according to an appropriate formula which will be subject to approval by the Energy Regulator.

3.6 Transmission revenues will be treated as pass-through costs at generation and distribution level to avoid double-regulation.

3.7 Generation revenues will be treated as pass-through costs at distribution level to avoid double-regulation.

4 Applicability of MYPD Mechanism

4.1 The Methodology shall be used for the evaluation of Eskom's MYPD applications.

4.2 In the application of the Methodology, the Energy Regulator shall not be precluded 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.

4.3 All expenses (that is operating and maintenance, primary energy, and research and development) are to be categorised in accordance with the guidelines on the Minimum Information Requirements for Electricity Tariff Applications[2] (MIRTA).

5 Weighted Average Cost of Capital

5.1 **Formula**

5.1.1 The Weighted Average Cost of Capital **(**WACC) is the weighted average of the expected cost of equity and cost of debt. The following formula must be used to determine the WACC:

WACC = Kd * g +[Ke/(1-tc)]* (1 – g)

Where:

WACC = pre-tax, real cost of capital

g = gearing

Kd = cost of capital

Ke = cost of equity

5.2 **Gearing**

5.2.1 The Energy Regulator strives to use the optimal gearing based on its actual calculations done on the application.

[2] The Energy Regulator has approved minimum information requirements that will provide clarity on information needed for tariff applications and act as guidance to the applicant as to the type of information required by NERSA for tariff determination and decision-making.

5.2.2 For purposes of regulation, the Energy Regulator will use a debt equity ratio of 65% as a capital structure used in the determination of the expected cost of capital.

5.3 **Cost of Equity**

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

$$Ke = [rf + (\beta * MRP)]/(1-tc)$$

Where:

Ke = Pre-tax, real cost of equity. This is due to Eskom not getting an explicit tax allowance in the Allowable Revenue formula. The revenue to pay for the tax is generated by specifying a pre-tax cost of equity.

rf = Risk free interest rate. The average of the real monthly marked-to-market risk free rate for the preceding 300 months for all government bonds with at least a 10-year maturity as at 12 months before the commencement of the tariff period under review will be used.

β = The beta must be determined by proxy. As a proxy the average of at least six utilities companies listed in the stock exchange must be used. 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 both internationally and nationally over a period at least 25yrs. The Energy Regulator will use the proxy of Credit Suisse and/or Johannesburg Stock Exchange (JSE) All Share Total Index (ALSI) for the preceding (at least) 300 months for the calculation of the premium, whichever one is considered suitable.

5.4 **Cost of Debt**

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

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

Kd = rf + dÞ

Where:

Kd = pre-tax cost of debt measuring the average cost of debt for the contracted borrowing for the tariff period under review and taking into account the forward-looking view of expected interest rates yield curve.

Rf = Risk free interest rate. The average of the real monthly marked-to-market risk free rate for the preceding 300 months for all government bonds with at least a 10-year maturity as at 12 months before the commencement of the tariff period under review will be used.

dÞ: The debt premium will be determined as follows:

- The spread between the licensee bond rates and Government bond rates with the same maturity as well as other comparable international licensees with similar credit ratings and multi-year regulatory framework.
- Estimates of debt premium from financial institutions such as investment banks and credit rating agencies will also be considered.

6 Regulatory Asset Base

6.1 Criteria for including an asset in the asset base

6.1.1 The Regulatory Asset Base (RAB) must represent assets used to provide regulated service by each of Eskom business operations of electricity generation, transmission and distribution.

6.1.2 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.

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

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

6.1.5 The RAB should, however, exclude any capital contributions by customers, though allowance will be made for electrification assets to allow for future replacement of such assets by Eskom at the end of their useful life.

6.1.6 Respective regulated operations of Eskom will be allowed to earn a rate on the RAB of the regulated operations based on the WACC.

6.1.7 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.

6.1.8 Only assets used in regulated operations and that meet the following criteria will be included in the RAB to allow the licensee to earn a reasonable return on assets as informed by an allowable return on assets:

6.1.8.1 Fixed assets must be long-term in nature and must be used and useable.

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

6.1.8.3 Used and useable means that assets should be in a condition that makes it possible to supply demand in the short-term (within 12 months).

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

6.1.8.5 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. Such capitalisation will however exclude interest during construction.

6.2 **The Basis for Valuation of the Regulatory Asset Base**

6.2.1 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.

6.2.2 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 sustainability.

6.2.3 The 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 should be independently determined and 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.

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

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

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

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

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

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

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

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

6.3 Depreciation and Return on Assets

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

6.3.2 In line with the EPP, full cost reflectivity[3] 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.

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

6.3.3 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 returns.

6.4 Depreciation on Regulatory Asset Base

Calculation of Depreciation

6.4.1 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 useful life year 0/total useful life)

AC y-1= MEAV*(remaining useful life year -1/total useful life)

6.4.2 The depreciating period will vary according to the economic useful life of various asset classes or groups of asset classes in the respective regulated operations of the licensee.

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

6.4.3.1 **Step one**: Revalue the asset to obtain a MEAV value. NERSA will consider the MEAV study conducted by Eskom and approve what it considers to be an appropriate MEAV value.

6.4.3.2 **Step Two**: This MEAV value is then depreciated (according to the expired useful life and remaining useful life of the asset) to arrive at the DRC. Formulae DRC=MEAV*(remaining useful life/total useful life).

6.4.3.3 **Step Three**: Phase in the DRC over a number of years. (The first DRC value was being phased in over 5 financial years and commenced in

2010/11 in accordance with the MYPD2 NERSA decision. The MYPD3 phase in will be on a straight line basis over five financial years commencing in 2013/14. NERSA may adjust the period in the light of Eskom's progress in implementing its investment programme).

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

6.4.5 All assets in the indexed historic asset base will be depreciated over a period in line with the accounting policies of the licensee years.

6.4.6 Useful lives ranging from 10 to 80 years will be used to depreciate all used or useable network assets.

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

6.5 Net Working Capital

6.5.1 Net working capital refers to trade receivables, trade inventory, reasonably incurred future fuels less trade payables reasonably required for the operation of the regulated business.

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

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

6.5.4 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 of 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.

6.6 Works Under Construction

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

6.6.2 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.

6.6.3 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.

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

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

6.6.4.2 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.

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

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

6.6.4.5 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.

6.7 Works Under Construction Cost Variance Mechanism

6.7.1 Aspects of the WUC will have to be forecasted at the beginning of the MYPD cycle. Therefore, the costs of WUC 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.

6.7.2 To accommodate the unstable environment in which the WUC cost will be undertaken, the approach for adjusting works under construction for cost and timing variances will be as follows:

6.7.2.1 Eskom will annually report to the Energy Regulator on its capital expenditure programme, providing information on timing and cost variances.

6.7.2.2 At the end of each financial year, Eskom will provide the Energy Regulator with a final reconciliation report of the actual works under construction incurred.

6.7.2.3 On receipt, the Energy Regulator will record all efficient works under construction above or below the approved amount on the works under construction carryover account (CECA) and quantify Eskom's exposure.

6.7.3 Balances on the CECA will be adjusted as follows in the Regulatory Clearing Account (RCA) as follows:

6.7.3.1 At the end of the financial year, if there is any under-expenditure compared to forecasted works under construction, the value of the RAB will be adjusted downwards for works under construction not undertaken and the revenues for the subsequent financial year adjusted to compensate for the return earned on unused funds in the previous MYPD. For any over-expenditure approved by the Energy Regulator compared to forecasted works under construction, the balance will be added to the RAB and Eskom will be allowed additional returns on the CECA balance to recover the costs of the over-expenditure for that year. This approach will effectively minimise any potential windfall losses or gains should the approved capital expenditure differ from the actual expenditure.

7 Expenses – Operating and Maintenance

7.1 Section 15(1)(a) of the Electricity Regulation Act, 2006 (Act No. 40 of 2006) 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;

7.2 The EPP position 1(a) further states that:

b) 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.

7.3 Costs related to Operating and Maintenance (O&M) will be allowed. The reasonableness of such expenses will, subject to paragraph 7.4, be determined by the Energy Regulator on a case-by-case basis.

7.4 These costs are to be categorised in accordance with the Regulatory Reporting Manuals RRM.

7.5 The fully allocated cost attribution approach for the allocation of costs is used. This approach is as per the methodology contemplated in the RRM (as contained in the Energy Regulator-approved Cost Allocation Manual).

7.6 **Principles regarding expenses**

7.6.1 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.

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

7.6.3 Expenses must be prudently and efficiently incurred and must be at arm's length transaction. Eskom must have a competitive procurement policy and demonstrate to the Energy Regulator that it has been strictly adhered to in its procurement processes.

7.6.4 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.

7.6.5 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.

7.6.6 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.

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

7.7 Efficiency of operating costs

7.7.1 In classifying operating costs further into controllable or non-controllable elements, the Energy Regulator will decide on incentives to Eskom to minimise costs that are under its control as well as encourage it to reduce some of the costs that are not under its control.

8 Primary Energy

Criteria for Allowing Primary Energy Costs

8.1 All rules applicable to operating expenditure shall apply to the primary energy costs.

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

8.3 Coal Costs

8.3.1 Coal will be treated as a single cost centre without differentiating between the various coal sources (for example cost plus contracts, fixed price contracts, short-term contracts and long-term contracts).

8.3.2 The Energy Regulator will determine and approve the coal benchmark cost (i.e. an average cost of coal R/ton), and Alpha for each year will be determined as part of the MYPD3 final decision.

8.3.3 The coal benchmark price is determined by the Energy Regulator in order to be used in comparison with the actual coal cost for the purpose of determining pass-through costs.

8.3.4 The coal benchmark price will be compared to Eskom's actual cost of coal burn (R/ton) using a Performance Based Regulation (PBR) formula. The PBR formula is the maximum amount to be allowed for pass-through, calculated by applying the following formula:

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

Where:

Actual Cost = Actual unit cost of coal burn in a particular financial year

Benchmark Price = Allowed coal burn cost/coal burn volume (R/ton)

Actual Coal Burn Volume = Actual ton of coal burn in a particular financial year

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

8.3.5 The pass-through component of the coal burn cost is equal to the coal burn volume variance plus Alpha times the coal burn cost variance:

Pass through coal burn cost = PBR cost (Rand) minus Allowed Coal burn cost (Rand)

= Coal burn Volume variance + Alpha x (Coal burn cost Variance)

Where:

Coal burn Volume variance (Rand) = (Actual coal burn volume minus projected coal burn volume) x Benchmark coal cost

Coal burn cost variance (Rand) = (Actual coal burn cost minus Benchmark coal cost) x Actual coal burn volume

8.3.6 The coal benchmark price will be used to determine the resulting allowed actual coal burn cost (R/ton) and transferred to the RCA. The amount transferred to the RCA will therefore be calculated as the difference between the PBR amount and the amount forecast/allowed in the MYPD decision.

8.3.7 The coal stock level (stock days) will be reviewed by the Energy Regulator when necessary.

8.4 **Gas Turbine Generation Costs**

8.4.1 Gas turbine generation [Open Cycle Gas Turbine (OCGT)] costs will be allowed as a full pass-through cost, but limited conditional to volumes allowed by the Energy Regulator, except where such use is necessary to ensure security of supply. This is only applicable to Eskom's OCGT.

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

8.4.3 In cases where there are any variances in the operation of the gas turbine, the reasonableness of such expenses will be subject to review by the Energy Regulator to determine the efficiency and prudency review in which Eskom has to demonstrate that it has maximised the availability and utilisation of cheaper resources such as Integrated Demand Management (IDM) and Demand Market Participation (DMP).

8.4.4 The pass-through cost must be equal to the gas turbine production volumes (energy sent out) of electricity in the MYPD production plan, converted to litres of fuel oil/gas consumed using the fuel efficiency of the gas turbine, and multiplied by the difference between the actual unit price of fuel (R/litre) and the MYPD unit price of fuel (R/litre).

8.4.5 A full pass-through cost shall be allowed where there are variances as a result of fluctuations in the unit cost of fuel.

8.4.6 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.

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

8.5 Other Primary Energy Costs

8.5.1 Other primary energy costs such as nuclear, hydro, and sorbent, will be allowed as pass-through costs.

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

8.6 Road Repairs and Maintenance

8.6.1 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.

8.6.2 Eskom will be allowed a full pass-through cost for the toll fees to be paid to the relevant road authority.

8.6.3 For Eskom’s own roads, it will be allowed to pass through cost for repairs and maintenance

9 Purchases from Independent Power Producers

9.1 In accordance with the provisions of Section 14(f) of the Electricity Regulation Act, the Energy Regulator shall, as a condition of licence, review power purchase agreements (PPAs) entered into by licensees before signature. This also includes all PPAs considered under the Ministerial Determination by the Department of Energy

(DoE). In evaluating the MYPD, the cost associated with the Independent Power Prducers (IPPs) will be done based on the conditions of the respective PPAs.

9.2 The Energy Regulator will review the efficiency and prudency of the IPP before and after PPA contracts are concluded.

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

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

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

9.6 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.

9.7 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.

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

9.9 Each pass-through cost will be reviewed by the Energy Regulator to determine the efficiency and prudence with which pass-through costs have been incurred above.

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

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

10 Research & Development

10.1 The Energy Regulator shall consider the core research and development (R&D) activities based on the following criteria:

10.1.1 The purpose and goal of R&D should be clear.

10.1.2 The development costs will be capitalised when the projects indicate that future economic benefits will flow into the entity, and when they are technically feasible and their expenditures can be reliably measured. Eskom will provide the details around the readiness of the projects.

10.2 The following criteria gives guidance with regard to which projects are acceptable:

10.2.1 those which will result in improved efficiency;

10.2.2 those which will result in extended plant life;

10.2.3 those which will result in lower operating costs;

10.2.4 those which will result in a better load factor or power factor;

10.2.5 those which will result in a better understanding of load behaviour; and

10.2.6 those which relate to the design, construction, selection and operation of projects in the build plan or demo plant of those technologies which might form part of a future build plan.

10.3 In addition, the following environmental projects are allowed:

10.3.1 those related to developing, designing, selecting and operating renewable energy sources;

10.3.2 those related to better usage of water, less pollution and less global warming; and

10.3.3 climatology projects related to environmental impact or forecasting of availability of natural resources and weather patterns.

10.4 Further considerations will be:

10.4.1 The costs undertaken by Eskom will be allowed if they are likely to benefit customers. The licensee will have to justify the expenses incurred in the R&D activities.

10.4.2 The costs in the R&D should be prudently incurred.

10.4.3 There must be proper governance procedures in place with industry input in terms of project selection and review.

The Energy Regulator shall make the final decision in allowing or disallowing the R&D expenses.

11 Integrated Demand Management Costs

11.1 Energy Efficiency and Demand Side Management

11.1.1 The Energy Efficiency and Demand Side Management (EEDSM) revenue requirement will be calculated as follows:

Revenue Requirement (RREEDSM) = Projects cost or programme cost + Operating cost + Measurement & Verification (M&V) cost

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

11.1.1.2 The projects' costs will be benchmarked with the cost of peaking, base-load or mid-merit power stations where applicable and the funding will be on the basis of the life cycle cost of the project compared with the avoided cost of supply.

11.1.1.3 EEDSM programmes/projects that are funded by other stakeholders, e.g. Treasury/DoE should be excluded from the required revenue.

11.1.1.4 IDM operating cost will have to be in line with the operation and functions of IDM including labour, marketing and overheads. The energy targets shall be evaluated on the basis of the energy efficiency targets of the DoE and Eskom's contribution to the EEDSM in the IRP2010.

11.1.1.5 Ideally, the overall EEDSM programmes will be evaluated using the life cycle cost of the programme and be compared to the avoided cost of supply based on the Long Run Marginal Cost (LRMC). If the life cycle cost of the programme is greater than the avoided cost of supply the programme will be rejected. The avoided cost of supply shall be determined using the annual average long run marginal cost of generation, for a period equal to the life cycle of the EEDSM programme, seasonally, weekly, and hourly differentiated and adjusted for network costs and losses based on the Wholesale Electricity Price System (WEPS).

11.1.1.6 The M&V costs shall be limited to a benchmark of 5% of the total project cost.

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

11.1.1.8 IDM will incur penalties for under achieving their targets. In case of non-performance, the penalty will be calculated as follows:

Penalty(R) = total allowed revenue /projected MW target X MW unsaved

= R/MW X MW unsaved

11.1.1.9 In terms of reporting demand savings, the following rules will apply:

a) Where the measured and verified evening peak demand saving is the highest daily demand saving achieved by the project, the evening demand saving will be reported.
b) Where the measured and verified morning peak demand saving is more than the measured and verified evening peak demand saving, the recognised demand savings will be equal to the measured and verified evening peak demand savings plus a factor multiplied by the difference between the measured and verified morning and evening peak demand savings.
c) The factor will rate the importance of the morning peak vs. the evening peak.
d) The factor will be calculated as the average of the ratios of the system daily morning peak demands and the system daily evening peak demands for the preceding calendar year.

e) The formula for recognised demand savings where the morning peak demand savings are higher than the evening peak demand savings is as follows:

Recognised demand savings = PE + factor[4] x (PM - PE)
Where:
PE = Measured and Verified Evening peak demand savings
PM = Measured and Verified Morning peak demand savings

$$\text{Factor} = 1/249 \sum_{\text{i}=1}^{249} \frac{\text{Pmi}}{\text{Pei}},$$

Where:
Pmi = the system daily morning peak demand
Pei = the system daily evening peak demand

11.1.1.10 Recognised demand savings exclude weekends and public holidays.

11.1.1.11 If the evening peak demand savings are equal to or higher than the morning peak demand savings, then the recognised demand savings are:

Recognised savings = PE

11.1.1.12 The morning peak is considered to be from 07:00 to 10:00 and the evening peak is considered to be from 18:00 to 20:00 Monday to Friday or any other deviation in the peak hours that is caused by the changes in the daily load profile.

11.2 **Principles of the avoided cost determination**

11.2.1 The avoided generation cost will be determined on the basis of the annual average long run marginal cost of generation derived from the IRP applicable at the time.

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

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[4] Factor is an average of the ratio of system daily morning peak demand/ system daily evening peak demand of the preceding calendar year period.

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

11.3 Demand Market Participation

DMP cost = tariff (R/MWh) x MWh + programme administration costs

11.3.1 The DMP will be evaluated using the available data on customers that previously participated and the response of those customers, to estimate the market potential of several types of demand response programmes. The process of estimating large and small aggregated customer demand response market potential in an Eskom supply areas will involve the following steps:

11.3.1.1 Projecting the targets based on the projected economic dispatch and any potential short fall of energy or capacity.

11.3.1.2 Considering types of demand response options by using available data to estimate customers' participation in voluntary programmes and those with contractual obligations.

11.3.1.3 Determining the appropriate price/tariff below the price of peaking station.

11.3.1.4 The tariff/price should benchmark at the cost of OCGT (including capital, operating and fuel costs) applicable at the time as a base and will be escalated with the Consumer Price Index (CPI) annually. OCGT is used for supplying peak demand; therefore DMP will then be used to provide a flexible and cheaper alternative to OCGT.

11.4 Power Conservation Programme

11.4.1 The Power Conservation Programme (PCP) Regulations and Regulatory Framework has not yet been finalised, therefore the PCP/Energy Conservation Schemes (ECS) rules for the MYPD3 will be finalised as soon as these frameworks have been concluded.

11.5 PCP/ECS Safety Net Programmes

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

11.5.2 The mandatory implementation will be implemented at no cost to Eskom with zero penalties, until the promulgation of the ECS policy, to be developed by the DoE.

11.5.3 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 EEDSM DMP and OCGT, which would only be activated during times of crisis.

12 Service Quality Incentives

12.1 The SQI are used as a measure to encourage Eskom to improve their reliability of supply. A portion of Eskom's allowable revenue will be channelled towards the SQI schemes. The performance review and setting of new targets for Eskom Transmission and Distribution will be done at the end of each MYPD control period. The performance results are used to adjust the revenue requirements for the next control period; rewards/penalties are applied according to the performance achieved by Eskom on the parameters set in the schemes.

12.2 The SQI scheme has the following measures: system minutes < 1, system minutes ≥ 1, line faults/100km and System Average Interruption Duration Index (SAIDI). These measures and the reward/penalty targets are clearly specified in the SQI scheme.

12.3 The objective of the service quality incentives is to ensure that the provision of good quality of supply (QoS) is rewarded, and poor QoS is penalised. Eskom should not achieve reduced expenditure at the expense of deterioration in the QoS to customers.

13 Taxes and Levies (not income taxes)

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

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

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

13.4 Principles regarding taxes and levies

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

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

13.4.3 Eskom must ensure that the cost of the taxes and levies is specified and that the calculation thereof is clear and concise.

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

14 Risk Management Control & Pass-Through Mechanisms

14.1 Risk Management Device

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 which has been approved by the Energy Regulator is accumulated and is managed as follows:

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

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

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

14.1.4 Adjusting for prudently incurred under-expenditure on controllable operating costs as may be determined by the Energy Regulator.

14.1.5 Adjusting for other costs[5] and revenue variances where the variance of total actual revenue differs from the total allowed revenue. In addition, a last resort mechanism is put in place to trigger a re-opener of the price determination when there are significant variances in the assumptions made in the price determination.

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

14.2 The Regulatory Clearing Account

The RCA is used to debit/credit all the aforementioned potential adjustments to Eskom's allowed revenue and must be used as follows:

14.2.1 The RCA will be created at the beginning of the financial year and continuously monitored. The evaluation of the account (for the purpose of determining the pass-through and/or claw-back) will be done with actuals for the full financial year.

14.2.2 This account must be updated quarterly so as to use it for regular alerts to customers of any possible adjustment in the coming year. Eskom must therefore submit actual financial data on a quarterly basis.

14.2.3 The RCA balance will be measured as a percentage of total allowed revenue and will act as a trigger for a re-opener as follows:

14.2.3.1 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.

14.2.3.2 If the RCA balance is between 2% and 10%, the amount is allowed as a pass-through in the next financial year without the need for a full stakeholder consultation process.

14.2.3.3 If the balance is greater than 10% of the allowable revenue, there will be a full stakeholder consultation process before any pass-through is allowed.

14.2.4 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. The Energy Regulator will only have to determine the timing of when it should be passed through or clawed-back.

14.2.5 Eskom will, on a quarterly basis, present the Energy Regulator with possible adjustments based on the Methodology, the costs to date and the projections to year-end.

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

14.2.7 The review will be performed on receipt of audited statements from Eskom.

15 Tariff Design

15.1 The Energy Regulator will consider the approval of tariff designs and structures after due consideration of the legal and policy frameworks in place.

15.2 The tariff design principles must meet the objectives as set out in the EPP. The following, among others, are the key objectives that should be considered:

15.2.1 Tariffs should be affordable.

15.2.2 Tariffs should be equitable and fair.

15.2.3 Tariffs should be easy to understand and apply.

15.2.4 Tariff levels and structures should accommodate social programmes.

15.2.5 Tariffs should be transparent.

15.2.6 Revenue from tariffs should reflect the full cost (including a reasonable risk adjusted margin or return) to supply electricity and ensure that the industry is economically viable, stable and fundable in the short, medium and long term.

15.3 In designing the tariffs, the following should be considered:

15.3.1 Costs must be functionalised into the different unbundled services to which they relate (i.e. Generation, Transmission and Distribution).

15.3.2 Cost of Service: Eskom must determine its cost of service as contemplated in the EPP for each of the ring-fenced licensed entities.

15.3.3 Customer class definitions: customer classes must be identified and properly defined.

15.3.4 Class revenue allocation: revenues must be allocated (either on embedded cost or marginal cost basis) to be collected from the defined customer classes. The revenue to be collected from each customer category is before adjustments for cross subsidies (as stated below) to ensure that the cost structure can be tracked (cost-reflective).

15.3.5 Tariff design for each class:

15.3.5.1 Tariff design objectives that achieve a reasonable balance between the various EPP positions must be maintained.

15.3.5.2 Tariff structure should ideally follow the cost structure – to the extent feasible given metering, customer understanding, and acceptable bill impact.

15.3.5.3 Furthermore, the tariffs must give end users proper information regarding the costs that that their consumption imposes on the licensees' business and must permit the cross-subsidy of tariffs to certain categories of customers.

15.3.6 Bill and consumption impact analysis: understanding the impact of the rates designed on the typical customer. This requires that after the design of new tariff structures or restructuring of an existing tariff structure, the licensee should consider the impact of such changes to a typical customer based on historical data (consumption patterns etc.).

15.3.7 Adjustment of revenues/cross-subsidies between customer classes to address certain socio/political/environmental needs:

15.3.7.1 Adjustment to tariffs to provide for cross-subsidies between customer classes to address certain socio/political/environmental needs will be allowed.

15.3.7.2 The licensee may propose adjustments to tariff structures/principles (that are in place to address the aforementioned issues) if such adjustments will enhance effective targeting of such programmes to benefit the intended customers groups.

15.3.7.3 Adjustments of revenue between customer classes must be done so that the cross-subsidies are quantified transparently while at the same time ensuring simplicity and transparency of rates.

15.3.8 Final Retail Tariffs: the licensee must ensure that final tariff levels proposed enables the allowable revenue, based on the approved sales forecast, to be recovered.

16 Sales Volumes

16.1 Principles of sales volume forecast

16.1.1 The sales forecast must be based on all customer categories.

16.1.2 The loss factor must be calculated based on the historical pattern and must be at all main transmission and distribution substations.

16.1.3 The customer consumption categories must include seasonal patterns.

16.1.4 The load forecast must include the assumptions regarding energy conservation programmes.

16.1.5 Eskom must furnish the Energy Regulator with the projected sales which support the ten-year forward-looking price path as per the EPP.

16.1.6 In order to verify the load forecast, the Energy Regulator requires the energy wheel, which includes all the details on energy demand, supply, imports, export, losses, own use and sales.

17 Review and Modification of the MYPD Methodology

17.1 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.

17.2 The Energy Regulator will make decisions on the interpretation of the various clauses of the Methodology, but any party will be entitled at any stage to take decisions of the Energy Regulator on review or appeal as contemplated in the enabling legislation.

The End.