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MANUAL FOR THE ERA TARIFF MODEL VER 4.0

A report to the Electricity Regulatory Authority

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Abbreviations

CPI	Consumer Price Index
ERA	Electricity Regulatory Authority of Uganda
GWh	Giga-watt hour
HV	High Voltage
kWh	Kilo-watt hour
LV	Low Voltage
PPI	Producer Price Index
ToU	Time of Use
UEDCL	Uganda Electricity Distribution Company Limited
UETCL	Uganda Electricity Transmission Company Limited
US	United States
USD	United States Dollar
VAT	Value Added Tax

Note: Parameters used in equations are defined below each equation for convenience.

Glossary

Adjustment factor	Difference between base tariffs and alternative tariffs attributable to variations in fuel prices, exchange rates and inflation
Alternative tariff	Electricity tariffs calculated from updated real-time data
Available capacity	Generation capacity that is made available for use, regardless of whether that capacity is used to generate electricity
Base tariff	Electricity tariff calculated at beginning of calendar year using fixed input factors throughout the year, making base tariffs constant for the calendar year
Bulk supply	Electricity supplied from the transmission system to the distribution system
Capacity price	The price payable for generation capacity, expressed as a charge per MW
Capital structure	The proportion of debt and equity used to finance the company’s assets
Commercial losses	Losses arising from theft or electricity or meter tampering.
Concession fees	The fee payable to the asset owner for the lease of assets under the concession contract.
Customer category	A category of customers for tariff purposes, denoted by voltage of supply and type of use (e.g. domestic, commercial, industrial).
Demand charge	A fee applicable per unit of maximum demand (or notified maximum demand)
Distribution losses	Total losses in the distribution system, comprising both technical and commercial losses.
Distribution price	The price for provision of distribution services. This excludes the cost of the power procured by the distribution company.
Embedded generator	An electricity generators that is connected to the distribution system (as opposed to the transmission system)
End-user tariffs	Prices charged to Umeme’s customers, comprising fixed fees, energy charges and maximum demand charges (where applicable).
Energy charge	A fee applicable per unit of energy consumed

Fixed fee	A fixed monthly fee as part of a tariff structure
Flat rate energy tariff	A single energy charge, i.e. not differentiated according to the volume of energy consumed
High voltage	Supply at transmission level voltage (66 kV and above)
Lifeline rate	A subsidised electricity price applicable for small quantities of electricity consumed, intended to provide a benefit to the poor
Load profile	The share of energy that is used in different time periods
Low voltage	Supply at voltages below 11 kV (400 V)
Medium voltage	Supply at voltages higher than Low voltage and lower than High voltage (usually 11 kV and 33 kV)
Operating & maintenance costs	The costs of operations and maintenance, including staff costs, repairs and maintenance, overhead costs and other operating expenses.
Power supply price	The portion of the end-user tariff that recovers the cost of bulk power supply.
Regulatory fees	Fees paid by the Licensee to ERA
Retail tariffs	Equivalent to end-user tariffs
Return on equity	The allowed return on the investor's equity investment
Return on investment	The allowed return on the investor's total investment, whether funded by debt or equity.
Revenue requirement	The amount of revenue that a company requires to meet its regulated costs.
Target availability	The targeted availability of generation units that is allowed for tariff determination.
Technical losses	The losses that are incurred due to transportation of electrical energy across networks and transformers.
Tested capacity	The capacity at the generation station that has been tested as available for dispatch.
Time of use	Refers to tariffs that have different prices for energy consumed at different times of the day or week
Transmission losses	The technical losses that occur in the transmission network
Working capital	Capital required to maintain adequate cash flow in the business, including capital to cover arrears and inventories.

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1. INTRODUCTION

1.1 Objectives

The objective of this manual is to provide a guide to the use of the tariff model operated by ERA for determining electricity prices in Uganda. The model has been in existence since 2001 and is dynamic to reflect changing sector conditions. The model computes retail tariffs, bulk supply tariffs and the Eskom generation tariff.

The first version of the Manual has been made for the Tariff Model set up for the years 2006 to 2011. In 2010 an extension of the model has been made that upgrade the model to the years 2010 to 2018. A further major upgrade to the model was undertaken in 2012 to convert the model from quarterly to monthly resolution, and to enable the model to calculate tariff adjustment factors based on the movements of macroeconomic parameters.

In creating this manual, it is intended to formalise the model development process, and updates to the manual will provide an opportunity for documenting these updates.

The primary target audience is intended to be officials of ERA whose job it is to implement the tariff methodology. In addition, ERA may opt to share the tariff model with the utilities in Uganda, and the manual will be a valuable tool for officials as they use the tariff model. Lastly, ERA may provide the tariff model to the public or selected stakeholders as part of its consultations and in the interests of transparency. In this case, the manual should be provided together with the tariff model.

1.2 Tariff methodology

The theoretical basis for the tariff model is the tariff methodology that is built into the licences issued by ERA. Basic principles of the methodology are:

- Tariffs should recover a target revenue requirement for each company;
- The revenue requirement should cover the costs of operation, with certain costs being cost allowances rather than actual costs;
- The revenue requirement provides for a return on capital invested, regardless of capital structure or interest payments. However, all debt servicing obligations relating to development finance (concessionary loans) are pass through items and the related assets do not attract a return on capital;
- Tariffs for end-users should be structured so that the costs allocated to each user group are broadly reflective of the costs imposed by that group;
- Time of use price signals are implemented in the case of the bulk supply tariff, as well as certain customer categories, to provide incentives to shift consumption from peak to off-peak periods.
- For each period, a set of *base tariffs* should be calculated. These base tariffs are derived on the basis of input parameters remaining unchanged throughout the year and are presented in electricity bills as the benchmark cost level for the calendar year. Base tariffs are thus constant in a calendar year;
- For each period calculate *alternative tariffs*, based on real-time input parameters that vary on a monthly basis. The difference between *base* and *alternative* tariffs are referred to as *adjustment factors*, i.e. the change in revenue requirement accruing to changes in macroeconomic parameters away from base assumptions in any month.

These factors are to be presented in electricity bills, distinguishable between distinct parameter changes and to consumer groups and time of use.

The tariff methodology has strong incentive elements in it. These incentive elements include:

- There is no reconciliation of revenue collected to cover distribution costs and the actual costs of distribution. Since the distribution component of end-user tariffs is based on the preceding year's sales, there is an incentive to grow the size of the market.
- Similarly, the distribution component of end-user tariffs is based on a sales target which takes account of target rather than actual losses. Any loss reduction faster than the target will increase net income, and so there are loss reduction incentives.
- The operating costs of generation and distribution are based on target levels and not actual amounts. Hence, there is an incentive to reduce costs below these levels.

It should be noted that for the distribution company, the revenue collected from customers to cover power purchases is reconciled against the amounts paid to procure power. Hence, the distribution utility does not make any profit or loss on the pass-through of power supply costs, even if demand changes or if losses change from the initial assumptions in the tariff determination.

1.3 The tariff model

The tariff model is a single excel spreadsheet, which includes some programming macros embedded in the model. In order for these macros to function, the option to enable macros should be selected if prompted on opening.

The model is designed to compute tariffs from 2011 to 2019 on a monthly basis, and provides the ability to track developments over this time period. The period can always be extended beyond 2011 through an amendment to the model. By entering estimated data for future years, it can also be used to project tariff developments over this time period.

The tariff model is structured with:

- Three output sheets;
- Six input sheets and one reconciliation sheet;
- Two consolidated data sheets; and
- Ten calculation sheets.

Figure 1 Structure of the tariff model

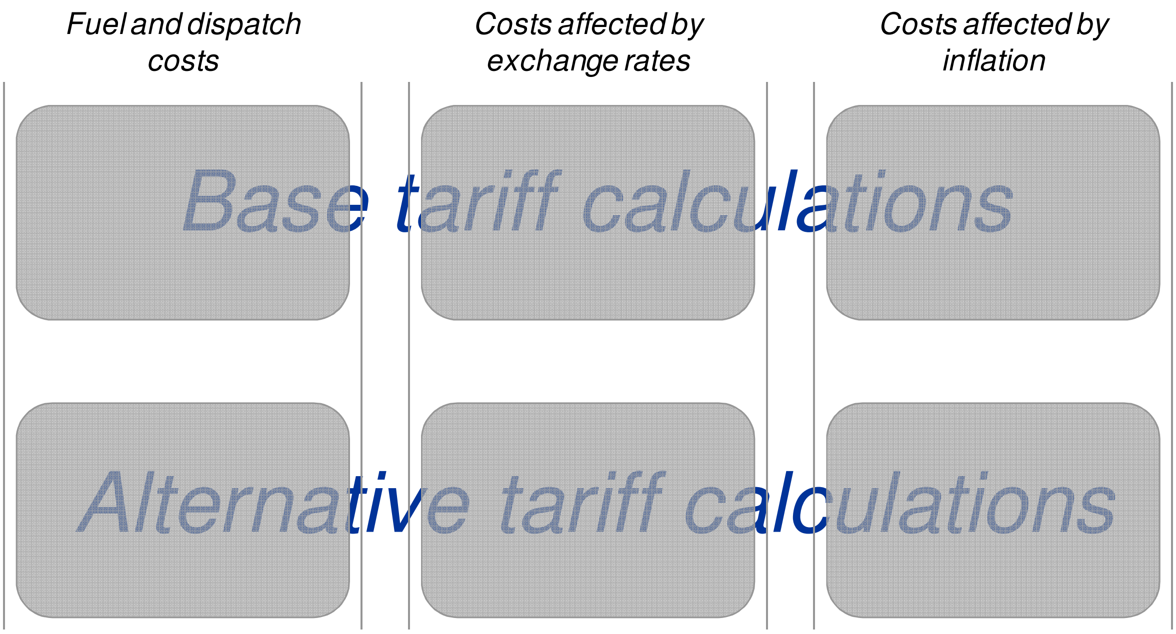
Output sheets	1. **OUTPUT Summary** consolidates in one place the key inputs and outputs for a selected month of a selected year for base and alternative tariffs respectively. 2. **OUTPUT Schedules** is where the base and alternative tariffs as well as adjustment factors (also broken down to power supply element and distribution margin) are presented for each customer group for each month for one chosen year. 3. **OUTPUT Rev Req** summarises the revenue requirement for each element of the business, and shows the average unit costs of

	power supply.
Input sheets	1. **INPUT Monthly** is where monthly recorded parameters are entered, enabling a monthly updating of tariffs. There are two sets of parameter values, base and alternative, allowing for separate calculations of base tariffs and alternative tariffs, and thus calculation of adjustment factors. This sheet also contains an unspecified cost component to comprise any tariff adjustment not adhering to licence rules for both base and alternative tariffs. 2. **INPUT Bulk energy** is where monthly data for UETCL sales, exports and losses are entered on a monthly basis. As in the INPUT Monthly sheet, this sheet contains different sets for base and alternative bulk purchase values. 3. **INPUT Power Purchase** is where UETCL purchases of power are entered both in volume and in cost. Costs are reported as total costs in Shs millions derived from purchased volumes times unit costs in sh/kWh for each plant. Unit costs are pulsed from INPUT E&C costs. 4. **INPUT Dist** is where all the required inputs for the distribution business are entered. 5. **INPUT Gen & Trans** is where all the required inputs for the generation and transmission businesses are entered. 6. **INPUT E&C costs** is where costs per plant (per kWh) are entered and calculated. This input sheet contains costs both for base and alternative tariff values. Input parameters directly entered in this sheet are operating costs (or pre-specified tariffs) for each plant, capacity costs and fuel conversion factors. Fuel prices are pulled from the INPUT Monthly sheet. On the basis of these inputs, this sheet contains final costs per plant per month in shs/kWh. 7. **Reconciliation** is where inputs to enable the monthly and annual reconciliations are entered, and where the reconciliation amounts are calculated.
Data sheets	1. **Financial data**: This is where the financial inputs to the calculations are consolidated, and converted from a tariff year basis to a calendar year basis, if necessary. No new input is required on this page. 2. **Technical data**: This is where the technical inputs to the calculations are consolidated, and converted from a tariff year basis to a calendar year basis, if necessary. No new input is required on this page.
Calculation sheets for generation and bulk supply tariffs	1. **Gen** is where the capacity payments are calculated based on the costs of the Genco, the tested capacity and the target availability. 2. **BST** is where the bulk supply tariff is calculated based on the costs of UETCL, bulk electricity sales and export revenues and volumes.
Calculation sheets for distribution	1. **Loss Factors** calculates the loss factors required to determine tariffs, based on the targeted losses in the distribution network. 2. **Energy Flows** calculates the targeted energy sales for each customer category, by time of use as well as the flows into the HV and LV distribution networks.

	3. **Dist Cost** calculates the revenue requirement of the Disco based on its costs. 4. **Dist Margin** calculates the costs per kWh for each customer category to cover the distribution revenue requirement.
Calculation sheets for tariff structures	1. **Power Supply Tariffs** calculates the costs per kWh for each customer category to cover the costs of power purchases. 2. **Retail price** calculate the total unit costs of electricity supply, covering both costs of power purchases and distribution costs, and adjusted for collection rates. This page also calculates the Generation Levy applied to end-user sales. 3. **Trf Structures** calculates the distribution energy charge given the standing charges and maximum demand charges, and the lifeline tariff. 4. **Results check** performs a check to verify that the revenues received from the tariff structure equal to total costs in the industry.

In addition to being separately identifiable to elements in the supply chain, tariffs are also separately identifiable to components influenced by the macroeconomic parameters fuel prices, exchange rates and inflation. For example, one sheet where this is done is the Trf Structures sheet, which conceptually can be described by the figure below.

Figure 2 Conceptual illustration of tariff calculation methodology as it appears in various worksheets



The sum of the cost components affected by various macroeconomic parameters comprises the total end-user tariffs. The difference between base tariffs and alternative tariffs give the adjustment factors, which on the basis of this methodology can be calculated either as a total adjustment factor or as three separate adjustment factors accruing to the different macroeconomic parameters.

1.4 Structure of manual

This manual is structured in the following sections:

- Chapter 2 describes the methodology for calculating base tariff components;
- Chapter 3 describes how alternative tariff components are calculated, and how the adjustment factors are calculated based on the difference between alternative and base tariff values;
- Chapter 4 describes the model structure in more detail;
- Chapter 5 specifies the inputs and results;
- Chapter 6 makes some final remarks

The annex to the manual provides a place for recording updates and amendments to the model.

1.5 Model version

The current version of the tariff model is Version 4.0, September 2012.

2. BASE TARIFF METHODOLOGIES

This chapter presents the theoretical expressions for calculations of *base* tariffs, i.e tariffs calculated at the start of the year. Base tariffs are derived on the basis of best estimates for the modelled year, and input parameters remain constant throughout the year, yielding a fixed base tariff for a calendar year. However, although base tariffs will be constant throughout the year, they are calculated using a monthly resolution of some input parameters. This is reflected in the formulas below.

In the formulas below, base tariff parameters are notated with the suffix *0*.

2.1 Derivation of generation price

2.1.1 Tariff structure

The price for Eskom generation is charged as a ***capacity price***. This means that the payment is determined as the product of the capacity at the complex, and the capacity price.

$$PMT = CP * CC \quad \text{.......................}(i)$$

Equation (i) determines the payment made to Eskom as the product of a capacity price and the available capacity

Where:

PMT = The Capacity Payment in Shillings.

CP = The Capacity Price in Shillings per kW.

CC = Complex Capacity in kW.

"Complex Capacity" is defined as the capacity declared by the Company as being capable of dispatch; provided, however, that if for any given hour UETCL dispatches the full capacity declared to be available, and the station does not deliver such amount, the Complex Capacity for that hour shall be the amount actually delivered. The payment is determined for all hours in the month.

2.1.2 Determination of the Capacity price

The Capacity Price is determined as follows:

$$CP_0 = \mathrm{Re}\,v\,\mathrm{Re}\,q_B \big/ [TC \times 8760 \times TA] \quad \text{.......................}(ii)$$

Equation (ii) determines the capacity price for Eskom's generation as the ratio of the company's revenue requirement to the number of MW-hours available in a year.

Where:

CP_0 = The Capacity Price in Shillings per kW. Base values.

$RevReq_0$ = The annual revenue requirement in shillings. Base values.

TC = the Tested Capacity in kW.

TA = the Target Availability as a percentage.

2.1.3 Determination of the revenue requirement

The annual revenue requirement is determined as:

$$RevReq_0 = IN_0 + OM_0 + R \quad \text{(iii)}$$

Equation (iii) determines the revenue requirement for Eskom as the sum of its investment (or asset-related) costs, the operating and maintenance allowance, and the concession fee.

Where

IN_0 = the Investment Component of the revenue requirement, base values;

OM_0 = the Operating and Maintenance Component of the revenue requirement, base values;

R = the Concession Fee Component of the revenue requirement;

Investment Component

This refers to the investment related portion of costs, and includes capital recovery (i.e. depreciation - "CR"), a return on investment ("RT") and allowance for income tax ("TX").

These costs are calculated in Dollars and converted to Shillings in each quarter of each year "y", as follows:

$$IN_{m,0} = \lfloor CR_y + RT_y + TX_y \rfloor \times QXR_{y,m,0} \quad \text{(iv)}$$

Equation (iv) determines the investment or "asset-related" costs of Eskom as the sum of capital recovery (equivalent to depreciation), return on investment and taxation. The costs are calculated in US dollars and converted to shillings at the prevailing exchange rate.

Where:

CR_y =Annual capital recovery charges in year "y" equivalent to depreciation expenses related to asset investments made by the Company denominated in Dollars.

$= GI_y * DPR_y$

And where:

GI_y = Gross accumulated investments in plant in service made by the Company as of the end of year "y-1".

DPR_y = The weighted average depreciation rate (expressed as a percentage), weighted by gross accumulated asset values, applicable in year "y-1" in accordance with International Accounting Standards or standards adopted by the Authority.

RT_y = Return on the Company's capital investments

$$= NI_y * ROI$$

And where:

NI_y = Net accumulated investments in plant in service made by the Company as of the end of year "y-1"

$$= GI_y - ACR_y$$

And where:

GI_y = Gross accumulated investments in plant in service made by the Company as of the end of year "y-1".

ACR_y = Cumulative capital recovery charges for the period beginning with the Transfer Date and ending on the end of year "y".

ROI = Allowed return on investment.

TX_y = Income taxes payable with respect to the return on the Company's capital investments.

$$= RT_y \times T_y / (1 - T_y)$$

The above formula determines the allowance for taxation as a function of the after-tax return (RT_y) and the prevailing taxation rate (T_y). Given that the after-tax return is RT_y, then the pre-tax return is equal to $RT_y/(1-T_y)$. And so the taxation amount is the difference between these two amounts – given by the formula above. Note that this formulation does not make allowance for the tax deductible nature of interest expenses, and in effect assumes that all capital is funded by equity – an assumption that overstates the tax liability.

And where:

RT_y = Return on the Company's capital investments

T_y = Applicable Ugandan corporate income tax rate in percent.

$QXR_{y, m, 0}$ = The USh to Dollars exchange rates posted by the Bank of Uganda on the last day of the month ending one month before the start of each month "m" of any year "y", base values.

O&M Component

The O&M Component is the sum of the O&M allowance, and the applicable regulatory fees.

The O&M allowance is determined from the USD amount set in the licence, and is adjusted on a quarterly basis for (a) Uganda price inflation, and (b) monthly changes in the USD exchange rate, as set forth below, and further adjusted by an efficiency factor to provide an incentive for increased productivity.

$$OM_{y,m=1,0} = LOM_{m,0} + EOM_{m,0} + RF_y \quad \text{(v)}$$

Equation (v) calculates the operating and maintenance allowance as the sum of the local-currency denominated O&M costs, the foreign exchange denominated O&M costs and regulatory fees.

Where:

$$LOM_{y,q,0} = GOMC_y \times LC_y \times {INI_{q,0}}/{INI_R} \times QXR_R$$

$$EOM_{y,m,0} = GOMC_y \times EC_y \times QXR_{y,m,0}$$

And where:

$GOMC_y$ = Net operating and maintenance fees for year "y" as set in the licence.

$LOM_{y,q,0}$ = The shilling portion of $GOMC_y$ base values.

$EOM_{y,q,0}$ = The US dollar portion of $GOMC_y$ base values.

LC_y = Local currency content of the Company's net operating costs in year "y".

EC_y = 1 - LC_y = Foreign currency content of the Company's net operating costs in y

$INI_{q,0}$ = Index of composite underlying consumer price inflation published by the Uganda Bureau of Statistics over the three months immediately prior to the date of calculation

INI_R = Index of composite underlying consumer price inflation as of the Transfer Date.

$QXR_{y,m,0}$ = As defined above.

QXR_R = The exchange rate at the transfer date

RF_y = Estimated regulatory fees, in Shillings, to be paid to the Authority by the Company in year "y", including such adjustments as may be required to reconcile such estimates to amounts actually paid over time.

Concession Fee

The Concession Fee paid by the Company to UEGCL under the Concession Agreement, is expressed in Dollars and converted to Shillings on a quarterly basis.

2.2 Derivation of BST

2.2.1 Tariff structure

UETCL charges distributors on a ***time-of-use (ToU) energy charge***. The time of use periods are set by ERA and may be amended from time to time should the load profile change. At present, there are three time periods:

- Peak: the five hours between 18:00 and 23:00
- Shoulder: the thirteen hours between 05:00 and 18:00
- Off-peak: the six hours between 23:00 and 05:00

2.2.2 Determination of the bulk supply tariff

The three components of the BST are determined as:

$$BST_{m,sh,0} = \mathrm{Re}\,v\,\mathrm{Re}\,q_{m,0} \big/ Sales_{m,0} \quad \text{.......... } (vi_a)$$

$$BST_{m,pk,0} = BST_{m,sh,0} \times Peak\_Factor \quad \text{.......... } (vi_b)$$

$$BST_{m,op,0} = \left[\mathrm{Re}\,v\,\mathrm{Re}\,q_0 - \left(BST_{m,pk,0} \times Sales_{m,0} \times Pk\right) - \left(BST_{m,sh,0} \times Sales_{m,0} \times Sh\right)\right] \big/ \left(Sales_{n,0} \times Op\right)$$

(vi_c)

Equations (vi_a) to (vi_c) calculate the bulk supply tariff for each load period. The shoulder BST is determined as the average price for bulk energy (i.e. revenue requirement divided by total sales). The peak BST is determined as the shoulder price plus a premium, and the off-peak price is determined as the residual price so that the total revenue from sales in all load periods equals the revenue requirement.

Where

$BST_{m,xx,0}$ = the base Bulk Supply Tariff for period "xx": "pk" = peak, "sh" = shoulder and "op" = off-peak for each month.

$RevReq_0$ = The base revenue requirement for UETCL.

$Sales_{m,0}$ = The base sales by UETCL to distributors for each month.

Pk, Sh, Op = The load profile of sales by UETCL to distributors.

The revenue requirement is adjusted on a monthly basis to reflect changes in power purchase costs. To calculate the BST on a monthly basis, the revenue requirement for that month is used, and the energy sales are those bulk sales from the preceding month.

2.2.3 Determination of the revenue requirement

The revenue requirement for UETCL is made up of the following:

$$\mathrm{Re}\,v\,\mathrm{Re}\,q_0 = NPP_0 + IN + OM_0 + OTHER \quad \text{.......} \quad (vii)$$

Equation (vii) determines the revenue requirement for UETCL as the sum of its net power purchase costs, investment (or asset-related) costs, the operating and maintenance allowance, and other charges.

Where

NPP_0 = The net cost of power purchases, base values;

IN = the Investment Component of the revenue requirement;

OM_0 = the Operating and Maintenance Component of the revenue requirement, base values;

OTHER =the "Other Component" of the revenue requirement;

Net power purchase costs

The net power purchase costs for any month are determined as the total cost of power procurement, less any revenue from exports and wheeling, as incurred in the preceding quarter.

$$NPP_{m,0} = \frac{\left[\sum_i^n[(C_{i,m,0}) * G_{i,m,0} S_i] + OM_{i,m} * G_{i,m,0} + \sum_i^n [P_{i,m,0}]\right]}{G_{m,0}} \quad \text{.......} \quad (viii)$$

Equation (viii) determines the net power purchasing costs for fuel as the sum of costs from purchasing fuel from all independent power producers as incurred by UETCL each month.

Where:

$TUDF_y$ = the Target Uncollected Debt Factor for the year y as set by the Authority

LD_y = the target system Loss factor in Distribution for the year to which the adjustment relates as set by the Authority

LT_y = the target system Loss factor in Transmission for the year to which the adjustment relates as set by the Authority

$C_{i,\,m,\,0}$ = actual price in Shs/kg paid by the thermal power producer for fuel consumed by the plant i during the calendar month immediately preceding each Billing Period for the thermal plant. This price also includes an exchange rate component as the price paid by the thermal power plant is in US dollars. All base values.

$G_{i,\,m,\,0}$ = electric energy in kWh purchase by UETCL from the thermal power plant i during the calendar month immediately preceding each billing period for the thermal plant. Base values

$G_{m,\,0}$ = total of all kWh purchased by UETCL from all electric power producers during the calendar month immediately preceding each billing period, base values.

S_i = specific fuel consumption in kg/kWh for the following thermal plants as licensed by the Authority

Jacobsen Uganda Power Co Ltd. = 0.2138 kg/kWh purchased

Electromaxx Limited = 0.2437 kg/kWh purchased

$OM_{i,\,m}$ = operation and maintenance costs for thermal plants

n = the total number of thermal electric power producers from which UETCL purchased power during the calendar month immediately preceding each billing period

$P_{i,\,m,\,0}$ = total power purchase costs by UETCL in the month proceeding the billing period at the base exchange rate, base inflation, base fuel prices and any other emergency/unexpected costs incurred as approved by the Authority, with the exception of purchase costs from fossil plants.

The tariff model includes a special sheet for entering the volumes and costs of power procurement by UETCL.

Investment component

The investment component is determined on an annual basis and is not adjusted for each quarter. It is determined as:

$$IN = DEP + IoD + RoE + RoWC + TX \quad \text{(ix)}$$

Equation (viii) determines the investment (or asset related) component of UETCL's costs as the sum of depreciation, interest charges, return on equity, return on working capital and taxation.

Where:

DEP = The depreciation allowance for the year;

IoD = Interest on debt for the year;

RoE = Return on equity, equal to the product of the allowed return and the equity (net assets less liabilities);

RoWC = The return on working capital, equal to the product of the allowed return and the allowed working capital.

TX = Income taxes payable with respect to the return:

$$= (RoE + RoWC) \times T_y / (1 - T_y)$$

The above formula determines the allowance for taxation in a similar manner as for Eskom Generation. However, instead of working with the full return allowance (RT_y in the case of Eskom), it uses only the return on equity (RoE) and the return on working capital (RoWC), i.e. interest expenses are excluded as they are tax deductible.

O&M component

The O&M component is a fixed amount for the year as approved by ERA. As in the case of generation, the O&M component it is partly payable in US dollars and partly in shillings as dictated by a pre-specified rate.

$$OM_{y,m=1,0} = LOM_{m,0} + EOM_{m,0} \quad \text{.......} (x)$$

Equation (v) calculates the operating and maintenance allowance as the sum of the local-currency denominated O&M costs, the foreign exchange denominated O&M costs and regulatory fees.

Where:

$$LOM_{y,q,0} = TOMC_y \times LC_y \times INI_{q,0} / INI_R \times QXR_R$$

$$EOM_{y,m,0} = TOMC_y \times EC_y \times QXR_{y,m,0}$$

And where:

$TOMC_y$ = Net operating and maintenance fees for year "y" as set in the licence.

$LOM_{y, q, 0}$ = The shilling portion of $GOMC_y$ base values.

$EOM_{y, q, 0}$ = ... The US dollar portion of $GOMC_y$ base values.

LC_y = Local currency content of the Company's net operating costs in year "y".

$EC_y = 1 - LC_y$ = Foreign currency content of the Company's net operating costs in y

$INI_{q, 0}$ = Index of composite underlying consumer price inflation published by the Uganda Bureau of Statistics over the three months immediately prior to the date of calculation

INI_R = Index of composite underlying consumer price inflation as of the Transfer Date.

$QXR_{y, m, 0}$ = ... As defined above.

QXR_R = The exchange rate at the transfer date

RF_y = Estimated regulatory fees, in Shillings, to be paid to the Authority by the

Company in year "y", including such adjustments as may be required to reconcile such estimates to amounts actually paid over time.

Other component

The "Other component" includes the allowance for UETCL's Liquidity Fund, the Rural Electrification Levy, Generation Levy on exports, less any other revenue received by UETCL.

The Rural Electrification Levy and the Generation Levy on exports are based on quarterly sales volumes, and so are calculated on a quarterly basis. Other amounts are set on an annual basis.

2.3 Derivation of end-user tariffs

2.3.1 Tariff structures

The tariff model is designed for the following six tariff categories:

Tariff categories			Tariff structures		
Code	**Use**	**Voltage level**	**Fixed charge**	**Demand charge**	**Energy charge**
Code 10.1	Domestic	LV	Yes	No	2 blocks
Code 10.2	Commercial	LV	Yes	No	Flat rate or ToU
Code 20	Medium industrial	LV	Yes	Yes	Flat rate or ToU
Code 30	Large industrial	MV	Yes	Yes	Flat rate or ToU
Code 40	Very large industrial	HV	Yes	Yes	ToU
Code 50	Streetlights	LV	No	No	Flat rate

The tariff structures for each tariff category are also shown in the table. All tariff categories except Code 50 (streetlights) have a fixed charge. Only Codes 20 and 30 have a maximum demand charge, and this charge is in two steps for Code 30. Code 10.1 has a "lifeline" energy charge – that is, the first amount of electricity is charged at a concessionary rate. Codes 10.2, 20 or 30 can have their energy charged either with a ToU tariff, or a flat rate, depending on the type of meter installed. Code 40 has a ToU tariff, and Code 50 is a flat rate energy tariff.

The tariff methodology for determination of end-user tariffs is described in the Annex to the licence for Umeme. The detailed methodology is 20 pages long, and is not reproduced here. Instead, a description of the method is provided. For detailed equations, it is necessary to refer to the licence itself.

Tariff components

There are four components to the tariff:

- **The power supply charge**: This is a pass through of the BST, taking account of load profiles and distribution losses.
- **The distribution charge**: This is to recover the costs of distribution.
- **Tariff relief**: This is a reduction in the tariff as a result of direct subsidy provided by Government.
- **Generation levy**: Lastly, there is a small levy added to the tariff in accordance with legislation (0.3%).

All tariff calculations are preformed net of VAT, i.e. VAT must be added to the final tariff in the utility's bills.

2.3.2 Determination of the power supply charge

The power supply charge is determined as the weighted average of the different ToU components of the BST, with the weights based on the load profile for each customer category, with the price adjusted for distribution losses.

The basic formula for this is:

$$PSP_{c,0} = \frac{1}{(1 - LF_c)} \times \sum_t LD_{t,c} \times BST_{t,0} \quad \text{(xi)}$$

Equation (ix) provides the basic formula for the determination of the power supply price as the weighted average bulk supply tariff (weighted by the load profile of a specific customer group), adjusted upwards for losses to that customer group.

Where

$PSP_{c,0}$ = The power supply price for customer group "c", base values

LF_c = The distribution loss factor for customer group "c"

$LD_{t,c}$ = The load profile for customer group "c" in load period "t"

$BST_{t,0}$ = The Bulk Supply Tariff for load period "t", base values

This basic formula is more sophisticated in the actual implementation for three reasons:

- Provision is made for Umeme to purchase from UETCL and embedded generators. Hence, there may be two sets of "bulk supply tariffs", and the actual rate to use should be the weighted average of these two sets (weighted by consumption in that load period).

- Provision is made for a reconciliation of actual power procurement costs against revenue received in the preceding quarter. Thus, the power supply price for the following quarter will be adjusted upwards if recovery was less than actual purchase costs, and vice versa.
- A collection rate factor is applied to account for bad debt. That is, the power supply price is increased to account for a collection rate of less than 100%.

The power supply charge for different customer groups will vary in accordance with two factors:

- Each customer group will have a different loss factor. Loss factors are differentiated by voltage level.
- Each customer group will have a different load profile.

For customer groups with the option of ToU energy charges, the power supply tariff itself will have a ToU structure to it. In these cases, there is no need to weight the charged BST by the load profile of that customer group. Instead, the PSP in the peak period will simply be the BST in the peak period adjusted by the loss factor, and so on for other load periods.

2.3.3 Determination of distribution charges

Determination of average distribution charges

Distribution charges are determined for each customer category in the following manner:

1. The revenue requirement for distribution is determined as described Section 2.3.6;
2. The revenue requirement is split into two portions – one part being to reflect the costs of HV assets, and the other to reflect the costs of LV assets. This split is based on pre-determined factors – the HV and LV cost allocation factors.
3. The costs allocated to HV and LV assets are converted to a unit price by dividing by the energy supplied at the HV and LV levels respectively;
4. The unit cost is structured into peak, shoulder and off-peak ToU charges by applying ToU weights (which may be different from the weights used to create the ToU charges for the BST);
5. The unit costs are then differentiated by customer group by applying the loss factors applicable to each customer group;
6. A ToU distribution price can then be calculated for each customer group by summing the unit costs at the HV and LV level (for HV customer groups, only the HV unit cost is taken);
7. An average distribution price can then be calculated for each customer group by taking the weighted average of the ToU charges, with the weights equal to the load profile of each customer group;
8. The average distribution price is finally adjusted for a collection rate factor in a similar manner as for the power supply price.

In the determination of these distribution prices, it is important to note that the energy volumes used in Step 3 are not the actual energy volumes, but rather “sales targets”. These targets are determined from the preceding year’s bulk purchases, less target losses. As a result, distribution prices are based on the previous year’s sales (not this year’s sales) and on target not actual losses.

Determination of distribution energy charges

The distribution price determined above is the average price to be recovered from customers. This average price is recovered from a combination of fixed charges, demand charges and energy charges. It is important to note that the fixed monthly charges and the maximum demand charges are determined exogenously, and not by the tariff model itself.

In order to determine the energy charge, the average distribution price is adjusted downwards to reflect the revenue to be received from fixed and maximum demand charges.

In addition, for Code 10.1, the first block of energy consumed is charged at a "lifeline" rate. The cost of this lifeline must be recovered from a surcharge on energy consumed by Code 10.1 customers above the lifeline rate. This surcharge is calculated and added to the distribution charge for Code 10.1. *In order to distinguish how surcharge calculations vary with changes in macroeconomic parameters, the tariff model calculates three separate surcharge components attributable to 1) changes in fuel prices, 2) changes in real exchange rate and 3) inflation.*

For customers on ToU charges, the ToU charges are then determined based on the ToU distribution charges and not the weighted average distribution price.

2.3.4 Determination of tariff relief

Tariff relief is an offsetting factor to end-user tariffs based on a pre-fixed tariff regulation rule. This rule dictates that the tariff level (power supply charges plus distribution charges) cannot exceed a certain level. If this pre-specified level is exceeded, the tariff model calculates a relief factor (negative) to offset the end-user tariff. Although this regulation rule is due to be made redundant, the tariff model has retained this calculation procedure, though the user will have to enable the calculation routine specifically before applying it.

The tariff model incorporates special routines to determine the amount of tariff relief. In summary:

- The user is required to determine the regulation rule, which means quantifying the targeted (or maximum) increase in tariffs over 2004 reference levels. These inputs are made for each month in the year, and for each tariff category. If no figures are entered, then no tariff relief is applied.
- The model then calculates the subvention required to reach this targeted increase, and presents both the unit tariff relief (shs/kWh) for each tariff category, and the total amount of subsidy required from Government.

2.3.5 Determination of generation levy

This is determined as 0.3% of the average retail price per customer category.

2.3.6 Determination of the revenue requirement

The overall revenue requirement for distribution (separate from power procurement costs) is determined in a similar manner to that of generation. That is, it is comprised of the following components:

$$DS_{y,m,0} = OPN_{y,m,0} + LP_{y,q} + IN_{y,m,0} \quad \text{.......} \quad (xii)$$

Equation (x) sets out the allowed cost of distribution services (i.e. the revenue requirement for network operations, excluding power purchases and losses) as the sum of operating and maintenance costs, the lease payment and the investment (i.e. asset-related) costs.

Where:

$DS_{y,q}$ = Umeme's total costs of providing distribution network and retail supply services for quarter "q" of year "y".

$OPN_{y,q}$ = Umeme's total operating costs, net of lease payments to UEDCL and costs associated with Licensee's capital investments, for quarter "q" of year "y".

$LP_{y,q}$ = Payments made to UEDCL under the Lease for the use of assets provided by UEDCL for quarter "q" of year "y".

$IN_{y,q}$ = Costs related to new capital investments in equipment and facilities necessary to serve customers, including capital recovery costs, agency loan expenses, return on investment and income taxes for quarter "q" of year "y".

Operating and maintenance costs

Operating and maintenance costs are determined in the same way as for generation (see Section 2.1.3), with three sophistications:

- A stamp tax, applicable only in year 1 (i.e. the first year of Umeme operations), is included in the costs. The stamp tax was a once-off transaction cost incurred by Umeme, and so is not repeated in subsequent years;
- A transition credit, also applicable only in year 1, is subtracted from the overall operating and maintenance costs. The transition credit was a special arrangement negotiated as part of the Umeme transaction that was designed to reduce the tariff impact of the transition from UEDCL to Umeme. As with the stamp tax, it was a once-off measure that is not repeated in subsequent years;
- Other revenues from customers, separate from connection charges and tariff schedules (e.g. meter testing fees etc) are also subtracted from the overall operating and maintenance costs.

Lease payments

Payments made to UEDCL under the Lease, as expressed in United States Dollars (USD), are determined by estimate at the beginning of each year "y", converted to Ugandan Shillings and subject to adjustments for (a) reconciliation of actual Lease-related revenues and costs, and (b) changes in the exchange rate on a quarterly basis, as follows:

$$LP_{y,m,0} = \left(LP_y + LPR_y\right) \times QXR_{y,m,0} \quad \text{(xiii)}$$

Equation (xi) determines the allowance for lease payment as the actual lease payment in dollars, converted to shillings at the prevailing exchange rate. The actual lease payment is the sum of the expected lease payment for the period, plus any reconciliation from the preceding period.

Where:

$LP_{y,m,0}$ = The estimated quarterly amount of lease payments to be paid by Licensee to UEDCL pursuant to the Lease during quarter "q" of year "y" in USD.

LPR_y = The amount required to reconcile the Lease Payments and related revenues equal to: (a) Lease Payments paid by to UEDCL less (b) revenues billed to retail customers with respect to the Lease Payment component of the Retail Tariff during the prior tariff year.

$QXR_{y,m,0}$ = The average of the official buying and selling exchange rate of the Ugandan Shilling to the USD posted by the Bank of Uganda on the last working day of the month ending one month before the first day of each quarter "q" of the current year "y".

Investment related costs

The investment related costs are determined in the same manner as for generation (see Section 2.1.3) with the following sophistication:

- For assets funded by debt from development finance institutions, no return is earned on the asset value and instead the actual interest payments are included in the costs.

3. ADJUSTMENT FACTOR CALCULATIONS

The previous chapter outlined base tariff calculations, i.e. tariffs derived on the basis of input parameters with constant value throughout the calendar year. In reality, however, several of these input factors can and do change frequently. So long as certain contracts between parties in the electricity supply chain are not fixed to annual levels, changing input parameters means a change in costs for companies involved in supplying electricity. This version of the tariff model has been designed to incorporate how these changing input parameters affect costs of electricity supply and how this translates into revenue requirements and ultimately tariffs. Another feature of this model is to identify the exact impact of the different input assumptions. In order to capture both these effects, this latest tariff model calculates two sets of tariffs; *base tariffs (*as described in the chapter above) and a near-identical set of *alternative tariffs* using different input assumptions for the three macroeconomic variables fuel prices, exchange rates and inflation. The difference between base and alternative tariffs is referred to as adjustment factors.

This chapter presents formulas for adjustment factors directly. We do not present equations for alternative tariff calculations – they are in any case identical to the formulas presented in chapter 2 with the exception of using suffix *A* rather than *0*.

3.1 Fuel prices

Changes in fuel prices affect UETCL's costs of purchasing power from IPPs with fossil-fired electricity generation in their portfolio. Hence, changes in fuel prices affect the revenue requirement of BST stemming from the NPP component as described in equation vii. It is worth noting that the fuel price adjustment factor also contains changes in revenue requirement due to changes (from base) in quantities of purchased power.

The expression for the fuel price adjustment factor is presented below:

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(T)_{FP,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(T)_{FP,0} \equiv FPAF \quad \text{.......} (xiv)$$

Equation (xiv) shows FPAF as an identity of the difference between the RevReq component for base values and for alternative values as driven by fuel prices.

A rewriting of the formula can thus be expressed as:

$$FPAF_m = \left(\frac{1}{1-TUDF_y}\right) * \left(\frac{1}{1-LD_y}\right) * \left(\frac{1}{1-LT_y}\right) * \frac{\left[\sum_i^n\left[(C_{i,m,A}-C_{i,m.0})*G_{i,m;A}S_i\right]+OM_{i,m}*G_{i,m}+\sum_i^n\left[P_{i,m,A}-P_{i,m,0}\right]\right]}{G_{m,A}} \quad (xv)$$

Equation (xv) shows the fuel price adjustment factor, which is defined by the difference in fuel costs for thermal plants (C) and differences in dispatch for all other plants (P). It should be noted that as fuel costs for thermal plants are in US dollars, exchange rate fluctuations away from base values will also be captured in this expression.

Where

$C_{i,\,m,\,A}$ = actual price in Shs/kg paid by the thermal power producer for fuel consumed by the plant i during the calendar month immediately preceding each Billing Period for the thermal plant. This price also includes an exchange rate component as the price paid by the thermal power plant is in US dollars. Alternative values.

$G_{i,\,m,\,A}$ = electric energy in kWh purchase by UETCL from the thermal power plant i during the calendar month immediately preceding each billing period for the thermal plant. Alternative values.

$G_{m,\,A}$ = total of all kWh purchased by UETCL from all electric power producers during the calendar month immediately preceding each billing period, alternative values.

$P_{i,\,m,\,A}$ = total power purchase costs by UETCL in the month proceeding the billing period at the alternative exchange rate, alternative inflation, alternative fuel prices and any other emergency/unexpected costs incurred as approved by the Authority, with the exception of purchase costs from fossil plants.

3.2 Exchange rates

Foreign exchange rates affect costs for all companies involved in supplying power, as part of these companies' costs are set in US dollars, and are in turn paid using shillings. Hence, a depreciation of the shilling will raise costs and an appreciation will lower costs. Below, we present the exchange rate adjustment factors for all the electricity supply companies in turn (where *G* refers to Eskom, *T* refers to UETCL and *D* refers to Umeme):

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(G)_{EX,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(G)_{EX,0} \equiv FERFAF(G)_m \quad \text{....... (xv)}$$

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(T)_{EX,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(T)_{EX,0} \equiv FERFAF(T)_m \quad \text{....... (xvi)}$$

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(D)_{EX,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(D)_{EX,0} \equiv FERFAF(D)_m \quad \text{....... (xvii)}$$

Expressions (xv) – (xvii) are identities for exchange rate adjustment factors for generation, transmission and distribution, respectively, describing changes in revenue requirements between base and alternative tariffs attributable to differences between alternative exchange rates and base exchange rates.

Total changes in tariffs attributable to exchange rates can be expressed as:

$$FERFAF_m = \left(\frac{1}{1-TUDF_y}\right) * \left[\frac{FERFAF(G)_m + FERFAF(T)_m + FERFAF(D)_m}{TGU_m}\right] * X_0 \quad \text{....... \textbf{(xviii)}}$$

Equation (xviii) describes the total exchange rate adjustment factor as the sum of adjustment factors for all parties in the electricity supply chain.

Where:

$FERFAF_m$ = overall Foreign Exchange Rate Fluctuation Adjustment Factor in month m

$FERFAF(G)_m$ = the Foreign Exchange Rate Fluctuation Adjustment Factor in month m relating to Generation

$FERFAF(T)_m$ = the Foreign Exchange Rate Fluctuation Adjustment Factor in month m relating to Transmission

$FERFAF(D)_m$ = the Foreign Exchange Rate Fluctuation Adjustment Factor in month m relating to Distribution

TGU_q = total projected kWh purchased by UETCL from electric power producers in month m. This includes any potential new power plants

X_0 = base exchange rate for the base period

Exchange rate adjustment factors for generation can be expressed as:

$$FERFAF(G)_m = \left(\frac{1}{1-LD_y}\right) * \left(\frac{1}{1-LT_y}\right) * \left[CR_y + RT_y + GOMC_y + TX_y\right] * Z_A \qquad \textbf{(xix)}$$

Equation (xix) shows the exchange rate adjustment formula for Generation.

Where:

CR_y = annual capital recovery charges in year y equivalent to depreciation expenses related to asset investment made by the company in USD

RT_y = annual generation return on investment in year y in USD

$GOMC_y$ = annual generation operation & maintenance costs in USD

TX_y = annual income tax payable with respect to the return on the company's capital investment in year y in USD

Z_A = proportionate change in the exchange rate (X_A) in the current billing period t from the base exchange rate (X_0), where:

$$Z_A = \frac{X_A - X_0}{X_0}$$

Exchange rate adjustment factors for transmission can be expressed as:

$$FERFAF(T)_m = \left(\frac{1}{1-LD_y}\right) * \left(\frac{1}{1-LT_y}\right) * [PP_m + C_m + I_m - E_m] * Z_A \qquad \textbf{(xx)}$$

Equation (xx) shows the exchange rate adjustment formula for Transmission (UETCL).

Where:

PP_m = sum of the foreign currency costs paid by UETCL to electric power producers in the calendar month immediately preceding current billing period

C_m = sum of the foreign currency costs for operation and maintenance incurred by UETCL in the calendar month immediately preceding current billing period

I_m = foreign currency costs paid by UETCL for power imports

E_m = foreign currency revenue for UETCL for power exports

Exchange rate adjustment factors for distribution can be expressed as:

$$FERFAF(D)_q = \left(\frac{1}{1-LD_y}\right) * \left[CRd_y + ROI_y + TXd_y + LP_y + CD_y + (DOMC_y * EC_y * \left(\frac{INI_{eq}}{INI_{eR}} - 1\right)\right] * Z_A \quad \textbf{(xxi)}$$

Equation (xxi) shows the exchange rate adjustment formula for Distribution (Umeme).

Where:

CRd_y = annual capital recovery charges for distribution in year y equivalent to depreciation expenses related to asset investment made by the company in USD

ROI_y = annual distribution return on investment in USD in year y

$DOMC_y$ = annual foreign currency for distribution in year y in USD

TXd_y = income tax payable for distribution with respect to the return on the company's capital investment in year y

LP_y = annual USD lease payments in year y

CD_y = other annual USD costs incurred by distribution companies in year y

EC_y = USD content of Umeme's operating costs in year y expressed as a percentage of total operating costs

INI_{eR} = the producer price index for finished goods less food and energy, series ID WPUSO3500 as calculated and published by the United States Bureau of Labor Statistics equal in February 2012 to 181.3

INI_{eq} = the producer price index for finished goods less food and energy in quarter q, series ID WPUSO3500 for the month preceding the quarter to which the adjustment relates to calculated and published by the United States Bureau of Labor Statistics. For instance, inflation rate adjustments calculated for the period January-March in a given year will be based on November in the preceding year.

3.3 Inflation

Several payments made by utilities in the electricity supply chain are inflation-adjusted. Inflation fluctuations will therefore imply cost fluctuations to these utilities. These costs, like the costs associated with fuel price and exchange rate fluctuations, will be passed on to consumers.

Inflationary adjustment is done on a quarterly basis using the index composite underlying consumer price inflation for the month preceding the quarter to which the tariff relates as published by the Uganda Bureau of Statistics. There will therefore be a time-lag in the inflation recovery. Below, we present the inflation rate adjustment factors for all the electricity supply companies in turn (where *G* refers to Eskom, *T* refers to UETCL and *D* refers to Umeme):

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(G)_{IN,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(G)_{IN,0} \equiv IRAF(G)_q \quad \text{(xxii)}$$

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(T)_{IN,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(T)_{IN,0} \equiv IRAF(T)_q \quad \text{(xxiii)}$$

$$\mathrm{Re}\,v\,\mathrm{Re}\,q(D)_{IN,A} - \mathrm{Re}\,v\,\mathrm{Re}\,q(D)_{IN,0} \equiv IRAF(D)_q \quad \text{(xxiv)}$$

Expressions (xxii) – (xxiv) are identities for inflation rate adjustment factors for generation, transmission and distribution, respectively, describing changes in revenue requirements between base and alternative tariffs attributable to differences between alternative inflation rates and base inflation rates.

Total changes in tariffs attributable to inflation rates can be expressed as:

$$IRAF_q = \left(\frac{1}{1-TUDF_y}\right) * \left[\frac{IRAF(G)_q + IRAF(T)_q + IRAF(D)_q}{TGU_q}\right] \quad \textbf{(xxv)}$$

Equation (xxv) describes the total inflation rate adjustment factor as the sum of adjustment factors for all parties in the electricity supply chain.

Where:

$IRAF_q$ = overall Inflation Rate Adjustment Factor in quarter q

$IRAF(G)_q$ = Inflation Rate Adjustment Factor for Generation (Eskom) in quarter q

$IRAF(T)_q$ = Inflation Rate Adjustment Factor for Generation (UETCL) in quarter q

$IRAF(D)_q$ = Inflation Rate Adjustment Factor for Distribution (Umeme) in quarter q

Inflation rate adjustment factors for generation can be expressed as:

$$IRAF(G)_q = \left(\frac{1}{1-LD_y}\right) * \left(\frac{1}{1-LT_y}\right) * \left[GOMC_y * LC_y * \left(\frac{INI_q}{INI_R} - 1\right)\right] * X_R \quad \textbf{(xxvi)}$$

Equation (xx) shows the inflation rate adjustment formula for Generation.

Where:

GOMC = Eskom annual total operating and maintenance expenses in year y

LC_y = local currency content of Eskom's net operating costs in year y expressed as a percentage of total net operating costs

INI_q = index of composite price inflation equal to the average quarterly value of end of month values as calculated and published by Uganda Bureau of Statistics over the three months prior to the date of calculation.

INI_R = reference index of composite underlying consumer price inflation equal to the base reference rate used in the computation of the base tariff (87.9 for Eskom).

X_R = the reference exchange rate of USh 2000 per US dollar for Eskom.

Inflation rate adjustment factors for transmission can be expressed as:

$$IRAF(T)_q = \left(\frac{1}{1-LD_y}\right) * \left(\frac{1}{1-LT_y}\right) * \left[TOMC_y * LC_y * \left(\frac{INI_q}{INI_R} - 1\right)\right] * X_R \quad \textbf{(xxvii)}$$

Equation (xxvii) shows the inflation rate adjustment formula for Transmission (UETCL).

Where:

$TOMC_y$ = UETCL annual total operating and maintenance expenses in year y

LC_y = local currency content of UETCL's net operating costs in year y expressed as a percentage of total net operating costs

INI_q = index of composite price inflation equal to the average quarterly value of end of month values as calculated and published by Uganda Bureau of Statistics over the three months prior to the date of calculation.

INI_R = reference index of composite underlying consumer price inflation equal to the base reference rate used in the computation of the base tariff which for UETCL is the rate at the transfer date.

X_R = the reference exchange rate, which for UETCL is the rate at the time of transfer.

Inflation rate adjustment factors for distribution can be expressed as:

$$IRAF(D)_q = \left(\frac{1}{1-LD_y}\right) * \left[\left(DOMC_y * LC_y * \left(\frac{INI_q}{INI_R} - 1\right) * X_R\right)\right] \quad \textbf{(xxviii)}$$

Equation (xxviii) shows the inflation rate adjustment formula for Distribution (Umeme).

Where:

DOMC = Umeme annual total operating and maintenance expenses in year y

LC_y = local currency content of Umeme's net operating costs in year y expressed as a percentage of total net operating costs

INI_q = index of composite price inflation equal to the average quarterly value of end of month values as calculated and published by Uganda Bureau of Statistics over the three months prior to the date of calculation.

INI_R = reference index of composite underlying consumer price inflation equal to the base reference rate used in the computation of the base tariff, set to 187.3 for Umeme.

X_R = the reference exchange rate of USh 2372.5 for Umeme.

4. MODEL STRUCTURE

4.1 Results sheets

There are three results sheets:

- **OUTPUT Summary** consolidates in one place the key inputs and outputs for a selected month of a selected year.
- **OUTPUT Schedules** is where the base and alternative tariffs as well as adjustment factors(also broken down to power supply element and distribution margin) are presented for each customer group for each month for one chosen year.
- **OUTPUT Rev Req** summarises the revenue requirement for each element of the business, and shows the average unit costs of power supply.

4.1.1 OUTPUT Summary

In this sheet, the user selects the particular quarter and year of interest, and the sheet presents all the input and output data for that period. The presentation is structured by generation, transmission and end-user tariffs. The sheet allows the user to select two different time period and compare these two results, i.e. two sets of data are presented.

The data presented in the sheet is shown below. It covers the following types of information:

- Data inputs;
- Revenue requirement;
- Prices;
- Price increases.

Figure 3 Summary inputs and results for Generation

Eskom Generation Tariff

Year and month here

Input parameters

Target availability	%	97%
Gross accumulated investments in plant	US$ thous	11,492
Weighted average depreciation rate	%	5%
Estimated regulatory fees	USh mill	807
Net operating & maintenance fees	US$ thous	4,976
Local currency content in opex	%	61%
Estimated concession fee	US$ thous	9,665
Return on Investment	%	12%
Tested capacity	MW	138.7

Input: Macro-economic parameters

Exchange rate	USh to US$	2,513
US Producer Price Index	index	177
CPI	index	149

Results

Revenue requirement	USh mill	46,384
Average Capacity Price	USh / MW	29,774

Generation tariff increases	Ref date	Tariff Ush/MW	Increase since ref	Increase per annum
Since 2011	2011 JAN	23,245	28%	13%
Since 1 year ago	2012 JAN	29,348	1%	1%
Since last month	2012 DEC	29,348	1%	6%

This compares the new tariffs with tariffs from previous periods, calculating the increase and average increase p.a.

Figure 4 Summary inputs and results for Bulk Supply Tariff

Bulk Supply Tariff

Year and month here

Input: Operating costs

Staff Expenses	USh mill	11,886
Other Staff costs	USh mill	1,827
Thermal Generation	USh mill	-
Transport	USh mill	1,250
Repairs & Maintenance	USh mill	2,146
Admin expenses	USh mill	4,121
Other opex costs	USh mill	3,386
Efficiency requirement	%	0.0 %

Input: Other costs

Liquidity Fund	USh mill	-
Stabilisation Fund	USh mill	-
RE levy	%	5.0 %
Generation levy	%	0.3 %
Insurance charges	USh mill	-
Special charges	USh mill	(5,656)
Days outstanding	days	-
Peak weighting factor		1.13

Input: Asset related costs

Assets	USh mill	57,548
Liabilities	USh mill	-
Principal Payment	USh mill	12,756
Net interest	USh mill	-
Return on equity	%	8%

Input: Technical parameters

Transmission loss factor	%	3.8 %
Load profile	Peak	29%
	Shoulder	49%
	Off-peak	21%

Input: Bulk energy

	GWh	Shs mill
Domestic purchases	329	79,014
Imports	2	1,419
Exports	21	7,604

Results

Revenue requirement		
Net Energy purchases	Ush mill	821,825
Transmission costs	Ush mill	92,624
Total	Ush mill	914,449

Bulk supply tariff		
Peak	Ush/kWh	309.2
Shoulder	Ush/kWh	273.6
Off-peak	Ush/kWh	228.4

Bulk tariff increases	Ref date	Tariff Ush/kWh	Increase since ref	Increase per annum
Since 2011	2011 JAN	84.7	223%	80%
Since 1 year ago	2012 JAN	155.6	76%	76%
Since last quarter	2012 DEC	260.8	5%	20%

This compares the new tariffs with tariffs from previous periods, calculating the increase and average increase p.a.

Figure 5 Summary inputs and results for End User Tariffs

End User Tariffs

Year and month here

Input: Operating costs*

Net operating costs	USD thous	26,963
Distribution efficiency	%	0.5 %
Days lag	days	30
Uncollected debt	%	3.8 %
Lease payment	USD mill	17

Input: Allocation factors

		Peak	Shoulder
High Voltage WF		1.1	1.0
Low Voltage WF		1.1	1.0
HV allocation factor	45%		

Input: Financial inputs

Total revenues previous year	Ush mill	479,272
Regulatory fees	USD thous	250
Other revenue	Ush mill	5,589
Annual invest-ments	USD mill	20
Agency loans	USD mill	-
Interest on Agency Loans	USD mill	-
Depreciation rate	%	9.7 %
Local content	%	67%
Return on investment	%	20%
Corporate tax	%	30%
Generation levy	%	0.3 %

Input: Losses & bulk purchases

HV technical loss factor*		6.2 %
Overall distribution loss factor*		25.7 %
Bulk purchases (UETCL)**	GWh	3,201
Bulk purchases (other)**	GWh	-

Notes:

* Data for 1st, 2nd etc years from start-up: Conversion factors are applied to convert to calandar year data

** For previous year

Input: Customer category information

		10.1	10.2	20	30	40	50
Commercial losses	%	19%	19%	19%	19%	19%	19%
Load profiles	Peak	36%	16%	24%	24%	31%	60%
	Shoulder	44%	72%	58%	52%	46%	0%
	Off-peak	20%	12%	18%	25%	23%	40%
Previous year end-user sales	GWh	458	271	254	736	0	3
Previous year customer numbers		460,793	42,076	1,283	343	-	426

Results

Distribution revenue requirement	USh mill	181,487

Tariffs (energy component only) Ush/kWh		10.1	10.2	20	30	40	50
Power supply	Ush/kWh	396	391	392	371	376	396
Distribution	Ush/kWh	140	108	88	24	35	113
Tariff relief	Ush/kWh	-	-	-	-	-	-
Generation levy	Ush/kWh	1.6	1.5	1.5	1.2	1.2	1.5
TOTAL energy price	Ush/kWh	538	500	481	397	412	510

Previous tariffs (energy component only) Ush/kWh		10.1	10.2	20	30	40	50
In 2011	2011OCT	294	306	280	186	201	311
1 year ago	2012JAN	346	372	347	248	265	381
Last quarter	2012DEC	503	527	502	394	413	537

Percentage increase in tariff %		10.1	10.2	20	30	40	50
Since 2011	2011OCT	83%	64%	72%	113%	105%	64%
Since 1 year ago	2012JAN	55%	35%	39%	60%	55%	34%
Since last quarter	2012DEC	7%	-5%	-4%	1%	0%	-5%

Annual percentage increase in tariff %pa		10.1	10.2	20	30	40	50
Since 2011	2011OCT	35%	28%	31%	46%	43%	28%
Since 1 year ago	2012JAN	55%	35%	39%	60%	55%	34%
Since last quarter	2012DEC	7%	-5%	-4%	1%	0%	-5%

4.1.2 OUTPUT Schedules

This sheet gives the detailed tariff schedules for Eskom generation, bulk supply tariff and end-user tariffs. The sheet includes detailed tariff structures for each quarter and each year from 2010 to 2018.

An example schedule for one quarter of one year is presented below.

Figure 6 Tariff schedules for January, 2013

2013 **JAN**

Base

Capacity fee 29,774 Shs/MW per hour

	Peak	Shoulder	Off-peak	
BST	368.4	326.1	272.2	Shs/kWh

	Code 10.1	Code 10.2/10.3	Code 20	Code 30	Code 40	Code 50
	Dom-estic	Comm-ercial	Medium Industrial	Large Industrial	Tx large Industrial	Street-lights
Standing & max demand charges						
Monthly fee	3,360	3,360	22,400	70,000	81,200	-
Max demand 1			5,000	3,690		
Max demand 2				3,354		
Power supply (Shs/kWh)						
Average	472.2	465.77	466.76	442.37	447.6	471.4
Peak		526.3	527.4	500.6	505.6	
Shoulder		465.8	466.7	443.0	447.5	
Off-peak		388.9	389.6	369.9	373.6	
Distrib charge (Shs/kWh)						
Average	207.3	147.8	124.3	34.8	47.7	153.9
Peak		167.0	140.5	39.3	53.9	
Shoulder		147.8	124.3	34.8	47.7	
Off-peak		123.45	102.35	30.35	39.32	
Tariff relief						
Government tariff relief	-	-	-	-	-	-
Generation levy						
Generation levy	1.9	1.8	1.9	1.5	1.5	1.9
Total energy tariff (Shs/kWh)						
Average	681.4	615.4	592.9	478.6		627.1
Peak		695.2	669.7	541.3	561.0	
Shoulder		615.5	592.9	479.2	496.6	
Off-peak		514.2	493.9	401.7	414.4	
Adjustment tariff fuel						
Average	-	-	-	-	-	-
Peak		-	-	-	-	
Shoulder		-	-	-	-	
Off-peak		-	-	-	-	
Adjustment tariff ER						
Average	-	-	-	-	-	-
Peak		-	-	-	-	
Shoulder		-	-	-	-	
Off-peak		-	-	-	-	
Adjustment tariff Inflation						
Average	-	-	-	-	-	-
Peak		-	-	-	-	
Shoulder		-	-	-	-	
Off-peak		-	-	-	-	
Total adjustment tariff						
Average	-	-	-	-	-	-
Total energy tariff (Shs/kWh) w adjustments						
Average	681.4	615.4	592.9	478.6		627.1
Peak		695.2	669.7	541.3	561.0	
Shoulder		615.5	592.9	479.2	496.6	
Off-peak		514.2	493.9	401.7	414.4	

In the figure above, identical figures have been used for base and alternative tariff calculations. As a result, adjustment factors are all zero. Any difference between input parameters in the base and alternative tariffs would subsequently imply that adjustment factors are positive or negative, depending on the relative relationship between base and alternative input parameters.

It should be noted that a change in dispatch levels – all else equal – will result in a non-zero adjustment factor for all three categories. This is because adjustment factors, like tariffs, are displayed in shs/kWh. While changes in dispatch does not mean, say, an increase in exchange rate-related costs, higher dispatch means increased sales, implying that exchange rate-related costs *per unit sold kWh* decreases.

4.1.3 OUTPUT Rev Req

This sheet presents the revenue requirements for each component of the industry. Results are given for each month of each year.

An example of the results for one year is presented below.

Figure 7 Revenue requirement results for 2011 and 2012

		Total Rev Require-ment	Share of Total Revenue Requirement		
		USh mill	Eskom Generation	Transmission (including other power purchases &	Umeme Distribution
2011	OCT	**900,383**	**4%**	**81%**	**15%**
	NOV	**969,878**	**4%**	**81%**	**15%**
	DEC	**822,222**	**5%**	**77%**	**18%**
2012	JAN	**663,539**	**7%**	**67%**	**26%**
	FEB	**630,236**	**7%**	**65%**	**27%**
	MAR	**697,519**	**7%**	**69%**	**25%**
	APR	**640,350**	**7%**	**66%**	**27%**
	MAY	**674,192**	**7%**	**68%**	**26%**
	JUN	**675,809**	**7%**	**68%**	**25%**
	JUL	**939,286**	**5%**	**77%**	**18%**
	AUG	**958,767**	**5%**	**77%**	**18%**
	SEP	**952,180**	**5%**	**77%**	**18%**
	OCT	**1,038,563**	**4%**	**79%**	**17%**
	NOV	**1,031,310**	**4%**	**79%**	**17%**
	DEC	**1,077,564**	**4%**	**80%**	**16%**

4.2 Input sheets

There are five basic input sheets, plus a sheet to manage the reconciliation inputs and calculations. For sheets containing data on a monthly resolution, all data series contain two sets of calculations, one for base tariffs and one set for alternative tariffs.

- **INPUT Monthly** is where monthly recorded parameters are entered, enabling a monthly updating of tariffs. There are two sets of parameter values, base and alternative, allowing for separate calculations of base tariffs and alternative tariffs, and thus calculation of adjustment factors. This sheet also contains an unspecified cost component to comprise any tariff adjustment not adhering to licence rules for both base and alternative tariffs.

- **INPUT Bulk energy** is where monthly data for UETCL sales, exports and losses are entered on a monthly basis. As in the INPUT Monthly sheet, this sheet contains different sets for base and alternative bulk purchase values.
- **INPUT Power purchase** is where UETCL purchases of power are entered both in volume and in cost. Costs are reported as total costs in Shs millions derived from purchased volumes times unit costs in sh/kWh for each plant. Unit costs are pulsed from INPUT E&C costs.
- **INPUT Dist** is where all the required inputs for the distribution business are entered.
- **INPUT Gen & Trans** is where all the required inputs for the generation and transmission businesses are entered.
- **INPUT E&C costs** is where costs per plant (per kWh) are entered and calculated. This input sheet contains costs both for base and alternative tariff values. Input parameters directly entered in this sheet are operating costs (or pre-specified tariffs) for each plant, capacity costs and fuel conversion factors. Fuel prices are pulled from the INPUT Monthly sheet. On the basis of these inputs, this sheet contains final costs per plant per month in shs/kWh.
- **Reconciliation** is where inputs to enable the monthly and annual reconciliations are entered, and where the reconciliation amounts are calculated.

Section 5 details the inputs in each of these sheets.

The inputs are consolidated into two data sheets:

- **Financial data**: This is where the financial inputs to the calculations are consolidated, and converted from a tariff year basis to a calendar year basis, if necessary. No new input is required on this page.
- **Technical data**: This is where the technical inputs to the calculations are consolidated, and converted from a tariff year basis to a calendar year basis, if necessary. No new input is required on this page.

4.3 Calculation sheets

As with input data, all series with monthly resolution are duplicated into one set for base tariff calculations and one set for calculation of alternative tariffs. There are ten calculation sheets as follows:

- **Gen** is where the capacity payments are calculated based on the costs of Eskom and other small hydro producers, the tested capacity and the target availability.
- **BST** is where the bulk supply tariff is calculated based on the costs of UETCL, bulk supply sales and export revenues and volumes.
- **Loss Factors** calculates the loss factors required to determine tariffs, based on the targeted losses in the distribution network.
- **Energy Flows** calculates the targeted energy sales for each customer category, by time of use as well as the flows into the HV and LV distribution networks.
- **Dist Cost** calculates the revenue requirement of the Disco based on its costs.
- **Dist Margin** calculates the costs per kWh for each customer category to cover the distribution revenue requirement.

- **Power Supply Tariffs** calculates the costs per kWh for each customer category to cover the costs of power purchases.
- **Retail price** calculates the total unit costs of electricity supply, covering both costs of power purchases and distribution costs, and adjusted for collection rates. This page also calculates the Generation Levy applied to end-user sales.
- **Trf Structures** calculates the distribution energy charge given the standing charges and maximum demand charges, and the lifeline tariff.
- **Results check** performs a check to verify that the revenues received from the tariff structure equal to total costs in the industry.

4.4 Programming

The tariff model incorporates automated routines in order to:

- Determine the level of tariff relief;
- Print the sheets.

These routines are implemented as macros in visual basic. The print routines are straightforward and do not require explanation.

The routines to determine the tariff relief make use of Excel's "goal seek" function. That is, the targeted tariff increase relative to levels in 2004 Q3 is specified[1], and the amount of tariff relief is varied using the goal seek function until the actual tariff increase equals the targeted increase. The routines are lengthy as this calculation must be undertaken for each customer group for each quarter of each year. However, the basic routine is the same and merely repeated for each case.

The goal seek routine is presented in the text box below.

[1] The user has the ability to alter both the reference tariff and the targeted increase level to this reference.

Table 1 Goal-seek macro, VBA coding

```
Dim ResultRange As Range
   Dim GoalRange As Range
   Dim ChangingCell As Range
   Set ResultRange = Range("I394:N492")
   Set GoalRange = Range("I288:N386")
   Set ChangingRange = Range("I181:N279")
   If Range("GoalSeek").Value = "Enable" Then
   Range("ReliefArray") = "0"
      For i = 1 To ResultRange.Coun
         If GoalRange.Cells(i) <> "" Then
            ResultRange.Cells(i).GoalSeek Goal:=GoalRange.Cells(i).Value,
                 ChangingCell:=ChangingRange.Cells(i)
         End If
      Next i
   Else
   MsgBox "GoalSeek function is disabled. Change cell W9 in User_s manual worksheet if you want to enable
                 it."
   End If
   End Sub
```

5. SPECIFICATION OF INPUTS

5.1 INPUT Monthly

The following data is entered in this sheet:

Category	Input	Data source
Umeme power purchases	From UETCL (GWh)	Data for each quarter should be the energy for the 3 months ending one month prior to the quarter.
	From other sources (GWh)	
Macro Economic parameters	Exchange rate (Ush per USD)	Data for each quarter should be for last day of the month ending one month prior to the quarter
	US PPI	
	Uganda CPI	
	Fuel prices (USD/tonne)	
Tested Capacity	Eskom Tested Capacity (MW)	Only adjust if tests reveal that capacity has changed.
Residual	A catch-all parameter to capture any impact on the tariff otherwise not specified in the model, in sh mill.	Monthly basis

Parameters described in the table above are duplicated, implying that there is one set of inputs for base values and one set for alternative values. The tables used to enter the data are presented below (for 2011).

Figure 8 INPUT Monthly data inputs tables

		UMEME PURCHASES - BASE		UMEME PURCHASES - ADJUSTMENT		MACRO-ECONOMIC PARAMETERS - BASE			
		UETCL	Other	UETCL	Other	Exchange rate	US Producer Price Index	Uganda CPI	HFO price
		GWh	GWh	GWh	GWh	USh to US$	index	index	USD/Mton
2011	JAN	555	0	555	0	1,874	172.0	138.6	489.9
	FEB	555	0	555	0	1,874	172.0	138.6	489.9
	MAR	555	0	555	0	1,874	172.0	138.6	489.9
	APR	555	0	555	0	1,874	172.0	138.6	489.9
	MAY	555	0	555	0	1,874	172.0	138.6	489.9
	JUN	555	0	555	0	1,874	172.0	138.6	489.9
	JUL	555	0	555	0	1,874	172.0	138.6	489.9
	AUG	555	0	555	0	1,874	172.0	138.6	489.9
	SEP	555	0	555	0	1,874	172.0	138.6	489.9
	OCT	579	0	579	0	2,032	173.0	139.5	489.9
	NOV	591	0	591	0	2,230	173.3	141.0	489.9
	DEC	602	0	602	0	2,264	173.4	143.8	489.9

5.2 INPUT Bulk Energy

This sheet is used to input UETCL's sales to Umeme, exports and losses on a monthly basis. Data are entered both in volumes, GWh, and in income in million shillings. Income levels are entered as a user-specified price directly in the income tables multiplied by the volume as defined in the volume table above. These datasets are entered both for calculation of base and alternative tariffs.

The following data is entered in this sheet for base tariffs and alternative tariffs respectively:

Category	Input	Comment
Bulk energy sales to Umeme & exports (GWh)	volumes for all sales of power plus exports minus losses	Forecast volumes for the year should be entered, and updated with actual data monthly.
	Export and wheeling volumes	
Income for UETCL from bulk sales & exports (Ush mill)	Income for UETCL based on sales to Umeme	Forecast volumes for the year should be entered, and updated with actual data monthly.
	Export and wheeling revenues	

5.3 INPUT Power purchase

This sheet is used to input UETCL's bulk energy purchases and imports on a monthly basis. The average prices at which UETCL purchases power from the generators may be entered as per the power purchase agreements, overwriting the formulas.

In order to distinguish between base and alternative tariffs, there are two input series for purchase *volumes*, and three series for purchase *costs*. The two different volume series refer to, respectively, purchased volume input assumptions for base tariffs and alternative tariffs. For purchase costs, one set is for calculations of total purchasing costs for base tariffs. There are furthermore two separate purchase cost tables for calculation of alternative tariffs, so as to enable the model to distinguish between adjustment costs accruing to fuel prices (and purchase volumes) and adjustment costs accruing to exchange rates.

The following data is entered in this sheet for base tariffs and alternative tariffs respectively:

Category	Input	Comment
Bulk energy purchases & imports (GWh)	Purchase volumes for all sources of bulk power supply	Forecast volumes for the year should be entered, and updated with actual data monthly or extracted from the supplementary dispatch model.
	Import volumes	
Cost of bulk energy purchases & imports (Ush mill)	Purchase costs for all sources of bulk power supply	Forecast volumes for the year should be entered, and updated with actual data quarterly.
	Costs for imports	

5.4 INPUT Dist

This sheet is used to enter all data pertaining to distribution.

The following data is entered in this sheet:

Category	Input	Data source
Commercial loss factors	Specified by customer category	As set in Schedule A-3 to Licence and updated by ERA
Time of use factors	Specified by customer category	As set in Schedule A-3 to Licence and updated by ERA
Distribution loss factors	HV Tech Loss Factor	As set in Schedule A-4 to Licence
	Overall distribution loss factor	

Category	Input	Data source
Operating cost parameters	Net operating costs (USD)	As set in Schedule A-5 to Licence
	Distribution efficiency (%)	
	Days lag (days)	
	Uncollected debt (%)	
	Lease payment (USD)	As per lease agreement
ToU Weighting factors	BST peak factor	As set in Schedule A-6 to Licence and updated by ERA
	HV weighting factor (peak and shoulder)	
	LV weighting factor (peak and shoulder)	
Other factors	HV allocation factor (%)	As set in Schedule A-6 to Licence and updated by ERA
	Local content (%)	
	Return on investment (%)	As set in Licence
	Corporate tax (%)	As prevailing
	Generation levy (%)	As set in Electricity Act
Financial inputs for distribution	Total revenues previous year (Ush mill)	From previous year's accounts
	Regulatory fees (USD thou)	ERA to input annually
	Other revenue (Ush mill)	
	Annual investments (USD thou)	
	Agency loans (USD thou)	
	Interest on agency loans (USD thou)	
	Average depreciation rate (%)	
	Stamp Tax (%)	Applicable to first year only
	Uncollected debt (Ush mill)	
	Transition credit (USD thou)	
Sales, bulk purchases, customer numbers and maximum demand billing quantities	End user sales per tariff category (GWh)	At the end of each year, update that year's data
	Bulk purchases from UETCL (GWh)	
	Bulk purchases from other (GWh)	
	Customer numbers	
	Average demand subject to capacity charges	
Lifeline inputs	Energy at lifeline (kWh/month)	ERA to update annually
	Lifeline rate (Ush/kWh)	
Tariff relief	Tariff relief amounts (Ush mill per tariff group)	Values are calculated on pressing the macro button
	Target tariff increase (%)	ERA to enter the target increase
	Resulting tariff increase (%)	Values are calculated

5.5 INPUT Gen & Trans

This sheet is used to enter all data pertaining to generation and transmission.

The following data is entered in this sheet:

Category	Input	Data source
Generation inputs	Target availability (%)	ERA to update annually
	Gross accumulated investments (USD thous)	
	Average depreciation rate (%)	
	Regulatory fees (Ush mill)	
	O&M costs (USD thous)	
	Local currency content (%)	
	Estimated concession fee (USD thous)	
	Retail revenues attributable to concession fee (USD thous)	
	Actual concession fee paid (USD thous)	
Period weighting factors	Peak	ERA to enter
	Shoulder	
	Off-peak	Calculated
Transmission operating costs and other operating parameters	Staff expenses (Ush mill)	ERA to enter and update annually
	Other staff costs (Ush mill)	
	Thermal generation (Ush mill)	
	Transport (Ush mill)	
	Repairs and maintenance (Ush mill)	
	Admin expenses (Ush mill)	
	Other opex costs (Ush mill)	
	Efficiency requirement (%)	
	Transmission loss factor (%)	
	Load profile (%)	
Transmission asset related costs	Liquidity Fund (Ush mill)	ERA to enter and update annually
	Stabilisation Fund (Ush mill)	
	RE Levy (%)	
	Generation Levy (%)	
	Insurance Charges (Ush mill)	
	Special charges (Ush mill)	

5.6 INPUT E&C costs

This sheet contains three sets of cost components for the existing and planned power plants in Uganda:

- Fuel costs for thermal plants, taking into account the cost of HFO, fuel conversion factors and plant efficiency, in USD/kWh
- O&M costs for all plants, in USD/kWh
- Capacity costs for all, in USD/kWh

O&M costs remain identical for both base and alternative tariff inputs, while there are two different sets for both fuel price calculations and capacity costs. A more detailed set of required inputs are presented in the table below:

Category	**Input**	**Comment**
Plant capacity costs	Cost for supplying capacity	ERA to update annually for plants where this is available
Plant tariffs/plant running costs (shs/kWh or USD/kWh – as appropriate)	Tariffs for plants as set in licences	ERA to update whenever new plant tariffs are released
	Any other running costs for plants	
Fuel conversion factors and fuel transport costs per thermal plant	IOC in USD/Mtonn	ERA to update on an annual basis, as dictated by thermal plant licences
	FLOC in USD/Mtonn	
	GFC per plant in kJ/kWh	
	LOC lubricating costs in Euro/MWh	
	Exchange rate Euro/USD	
Total costs per plant in shs/kWh	Unit cost per plant, applying above inputs and exchange rates and fuel prices from INPUT Monthly	These fields are calculated.

5.7 Reconciliation

The following reconciliation is undertaken for Umeme:

- PSP Reconciliation: Reconciliation of Umeme's cost of power purchases against the revenue received from the power supply price component of end-user prices.
- Lease reconciliation: Reconciliation of the revenue collected from customers to cover the lease fee, and the actual amount paid on the lease.

The sheet "Reconciliation" determines these two reconciliation amounts, and also includes space for the inputs necessary to undertake the reconciliation.

5.7.1 PSP Reconciliation

In order to determine the PSP reconciliation amount, the model requires:

- The cost of power purchases in each quarter;
- The actual end-user sales in each quarter (for each tariff category, including sales at different load periods for customers on ToU tariffs).

From this data, the model then determines the PSP reconciliation amount.

5.7.2 Lease Reconciliation

In order to determine the lease reconciliation amount, the model requires as input:

- The actual lease payments on a quarterly basis;
- Any amounts offset by Umeme in accordance with Sections 2.5(d) and 4.2(b)(ii) of the Lease and Assignment Agreement (these off-set amounts are to compensate Umeme for specific losses, and should hence not be reconciled).

The reconciliation is then determined by comparing the sum of the actual lease payments and the off-set amounts with the share of revenue that can be attributed to the lease payment. The latter is determined as a percentage of the distribution charge.

6. FINAL REMARKS

6.1 Differences between the tariff model and Umeme's licence

Annex A sets out two differences between the tariff model and the tariff methodology contained in Umeme's licence. The differences relate to errors in the tariff method as described in the licence.

In addition, the tariff methodology does not prescribe how to determine detailed tariff structures from the average tariffs per customer category. Hence, the routines in the tariff model that determine ToU tariffs for certain customer categories, the lifeline tariff and the structure of fixed charges, demand charges and energy charges are all extensions to the methodology in the Licence.

6.2 Future developments

The tariff model reflects a regulated system of cost and income calculations for both suppliers, distributors and users of electricity. Any change in the regulation will thus necessitate a review of the model. At the same time, the current model is designed to a standard, both in terms of appearance and functionality based on user requirements also probed to changes. In brief therefore, future developments to the model are likely.

There are at the moment no firm development plans, though the consultant would encourage ERA to revise model functionality at a suitable time. In particular, the model is at the moment quite rigid as far as adding new production facilities are concerned. Also, the model would, again from the consultant's point of view, benefit from a better userface description of what represents inputs and calculations.

ANNEX A - DIFFERENCES BETWEEN THE MODEL AND UMEME'S LICENCE

A.1 Amendment to methodology

In implementing the update to the tariff model, it was discovered that there is an error in the determination of the Distribution Margin (i.e. the average distribution mark-up for each customer category) that implies an over-recovery of costs of around 5%. The previous version of the tariff model did not have this error as it implemented an earlier version of Annex A which had a different approach to the determination of the Distribution Margin.

The error arises in the calculation of the unit costs associated with the LV network (i.e. for customer groups 10.1, 10.2, 20 and 50). The formulae for determining the HV and LV Distribution Margins are:

$$HVDP_{t,c,y,q} = \frac{DS_{y,q} * HVCA}{HVE_y * (1 - LF_c)} * HVWF_t \qquad \text{.....................(1)}$$

$$LVDP_{t,c,y,q} = \frac{DS_{y,q} * LVCA}{LVE_y * (1 - LF_c)} * LVWF_t \qquad \text{..........................(2)}$$

The mistake arises from the fact that the same term LF_c is used in both equations, whereas a different term should be used in the second equation. A new parameter must be introduced into the Annex as follows (applicable only to customers served at LV):

$$LVLF_c = \frac{LVCL_c + LVTL_c}{LVST_c + LVCL_c + LVTL_c} \qquad \text{...................(3)}$$

This new parameter should replace the term LF_c in Equation (2) above to give:

$$LVDP_{t,c,y,a} = \frac{DS_{y,q} * LVCA * LVWF_t}{LVE_y * (1 - LVLF_c)} \qquad \text{................(4)}$$

This amendment has been implemented in the Tariff Model.

A.2 Incomplete formula

In addition, a formula in the methodology is incomplete. On Page A-8 is the equation:

$$HVTLL_c = (HVE * HVTLF) - \Sigma_c\, HVTLH_c$$

This equation is intended to calculate the total losses on the HV network attributable to sales to LV customers, ***by customer group***. It does not determine the allocation by customer group, but only calculates the total losses. In order to correct the formula, it should be revised to read:

$$HVTLL_c = \left[\, (HVE * HVTLF) - \Sigma_c\, (HVTLH_c) \,\right] * \left[\, LVST_c / \Sigma_c\, (LVST_c) \,\right]$$

This amended formula has been implemented in the tariff model.

ANNEX B - CHANGES TO THE MODEL

Changes to the model since version 3.0 are recorded below:

Model version number	**Changes made**
Version 4.0 pre-beta	Fuel prices added as component to INPUT Quarterly
Version 4.0 pre-beta	INPUT E&C costs sheet created,
Version 4.0 pre-beta	All series relating to UETCL activities converted to monthly resolution
Version 4.0 Beta	Duplication of all series to calculate two sets of tariffs – base and alternative
Version 4.0 Beta	Extension of tariff cost components, separable by fuel prices, exchange rates and inflation
Version 4.1 Beta	Revision of output sheets to show adjustment factors
Version 4.1 Beta	Full conversion to monthly resolution
Version 4.2 Beta	Revision of results check sheet
Version 4.2 Beta	Revision of macros

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Pöyry Management Consulting (Norway) AS

Schweigaards gate 15 B
N-0191 Oslo
Norway

Tel: +47 45 40 50 00
Fax: +47 22 42 00 40
www.poyry.no
E-mail: oslo.ecno@poyry.com

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www.poyry.com