Regional Harmonization of Regulatory Frameworks and Tools for Improved Electricity Regulation in COMESA

Training Manual on Cost Reflectivity Assessment

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1 Cost Reflectivity Assessment Framework Tool and Training Manual

1.1 Cost Reflectivity Assessment Framework Tool (CRAFT)

Please refer the Microsoft Excel file titled “CoS Model_v1” enclosed with this report.

1.2 Training Manual for use of the Cost-of-Service Model

1.2.1 Glossary of key terms used in the model

S. No.	Term	Definition
1	Capacity charge (Power Purchase)	Capacity charge (fixed charge) covers the power project company's fixed costs, including a return on equity
2	Capital works in progress (CWIP)	Capital work in progress (CWIP) is the cost of fixed assets that are still being constructed or developed and aren't yet ready for use. It is a balance sheet item that includes expenses like construction costs, equipment purchases, and other project-related expenditures.
3	Consumer grant funded assets (CGF)	CGF assets are those financed by customers or grant money, which need to be excluded when calculating costs to be recovered from tariffs
4	Consumer security deposit (CSD)	Consumers pay their electricity bill after the bill is generated. The security deposit in electricity bill is taken by customers to ensure that the electricity board does not incur any loss. In case the customer does not pay their electricity bill, despite notice and warning being given - the amount of their electricity bill will be deducted from the security deposit. The amount of the deposit is usually based on the average monthly cost of electricity over the previous year.
5	Coincidence factor	Coincidence factor is the ratio of coincident peak of a customer category's load curve to the category peak i.e. non-coincident peak
6	Coincident peak (CP)	Coincident peak is contribution of each consumer category to the system peak demand or the consumer category demand value at the time of system peak
7	Customer related assets	Customer related assets include assets such as customer service line, customer transformer, meters, etc.
8	Customer related cost	Customer related costs vary with the number of customers. These include all costs associated with the provision of electricity services to customers. E.g. costs associated with service connection, metering, billing, collection, and customer service.
9	Demand charge (Revenue - Electricity Tariff)	Demand charges are capacity-based (priced per-kW) components of a distribution tariff which charge a user according to the maximum power they consume during a given time-period. Demand charges are a component of commercial electricity tariff that are based on a customer's peak power usage during a billing period. They are designed to help utilities recover the costs of generating and distributing power.
10	Demand related assets	Demand related assets include assets such as lines, transformers, substations, systems & instrumentation, etc.
11	Demand related cost	Demand-related costs include all costs associated with creating the generation capacity and network capacity (transmission and distribution) to fulfil consumer demand and operating such capacity. e.g. debt servicing cost associated with acquisition of fixed assets, depreciation of fixed assets, O&M expenses related to fixed assets.
12	Energy charge (Power Purchase)	Energy charge covers the variable cost of energy generation.
13	Energy charge (Revenue - Electricity Tariff)	Energy charges are a variable component of an electricity tariff that is applied to the total amount of electricity consumed during a billing period

S. No.	Term	Definition
14	Energy consumption	Energy consumption is energy sales plus non-technical losses
15	Energy requirement	Energy requirement is energy consumption plus technical losses
16	Energy related cost	Energy related costs vary with the volume of consumption. Energy consumption-related costs include all costs associated with the generation of energy units. E.g. primary fuel cost and startup fuel cost.
17	Fixed charge (Revenue - Electricity Tariff)	The fixed charge component of an electricity tariff is a fee that covers the cost of maintaining the infrastructure needed to supply electricity to a home or business. This charge is independent of the actual electricity consumption and is usually the same each month. It is also known as the customer charge.
18	Gross fixed assets (GFA)	Gross fixed assets (GFA) is an accounting term that refers to the total cost of a business's fixed assets, including equipment, machinery, and property.
19	High Voltage (HV)	High voltage as a general practice has been considered as a voltage level above 66 kV
20	Load factor	Load factor is the ratio of actual energy consumption to peak energy consumption for a particular consumer category
21	Low Voltage (LV)	Low voltage as a general practice has been considered as a voltage level of 230 V, 400 V etc.
22	Medium Voltage (MV)	Medium voltage as a general practice has been considered as a voltage level from 11 kV upto 66 kV
23	Meter rent	Meter rent is a monthly fee that customers pay if they don't own their electricity meter. The electricity distributor usually owns the meter, and the customer pays the rent during the billing period. The meter rent is listed on the customer's electricity bill.
24	Non-Coincident Peak (NCP)	Non-coincident peak is the peak demand of each customer category
25	Net fixed assets (NFA)	Net fixed assets (NFA) is the total value of a company's gross fixed assets, minus the total accumulated depreciation on the same
26	Net fixed assets (NFA) financed by the utility	This involves deducting accumulated depreciation on assets financed by utility from GFA financed by utility. The accumulated depreciation on assets financed by utility is considered after deduction of accumulated depreciation on CGF assets.
27	Non-technical losses	Non-technical losses arise from several reasons including theft, un-billed accounts, and estimated customer accounts, errors due to the approximation of consumption by un-metered supplies, metering errors etc.
28	Technical losses	Technical losses are regarded as the electrical system losses which are caused by network impedance, current flows and auxiliary supplies. The sources of technical losses may be directly driven by network investment or by network operation. Technical losses are the losses that occur within the distribution network due to the cables, overhead lines, transformers and other substation equipment that we use to transfer electricity.
29	Provision for bad debts	A provision for bad debts is an estimate of the amount of money a company owes that is unlikely to be paid back. It's also known as a provision for doubtful debts or an allowance for doubtful accounts. A company might make a provision for bad debts to cover debts that are not expected to be paid during an accounting period. The provision is based on an

S. No.	Term	Definition
		estimate of how much of the accounts receivable will not be collected during the given period. A general provision, such as 2% of debtors, cannot be deducted for tax purposes. However, a specific provision can be deducted if there is documentary evidence that the debts are unlikely to be paid.
30	Reconnection charges	Reconnection charges apply when a service line is disconnected for payment defaults, breach of supply conditions, or a temporary request from the consumer. Reconnection is allowed within six months of disconnection, but no charges apply if the disconnection was due to a natural calamity. Reconnection charges for electricity vary by provider and the reason for disconnection.
31	Regulated asset base (RAB)	RAB is derived by adding capital works in progress (CWIP) and net working capital (NWC) to net fixed assets (NFA) financed by utility
32	Return on RAB	Return on RAB is the rate of return on the regulated asset base (RAB) as approved by the regulator. In case of absence of a regulator approved rate of return, same can be considered as the weighted average cost of capital (WACC).
33	Revenue Requirement (RR)	Revenue requirement (RR) is the sum of all operating, capital and financing costs along with a return on capital which need to be recovered from customers through tariff, adjusted for any income obtained from customers through non-tariff sources (e.g. meter rent, delayed payment penalties, interest earned on security deposit, etc.).
34	Strategic Business Unit (SBU)	A strategic business unit (SBU) is a business unit within a larger organization that operates as a separate division with its own plans and activities. SBUs are profit centers that focus on a specific market segment. In the present context, SBU means Generation, Transmission, Distribution-Urban, Distribution-Rural, Corporate & Shared services
35	Weighted average cost of capital (WACC)	The weighted average cost of capital (WACC) is the average rate that a utility pays to finance its assets. It is calculated by averaging the rate of all of the company's sources of capital (both debt and equity), weighted by the proportion of each component. In this model, in absence of a regulator approved rate of return, same may be used to calculate the return on RAB

1.2.2 Choosing the reference year

Cost-of-Service (CoS) assessments are done on whole of the year cost data. Timely and reliable data is critical, and hence the latest financial year for which audited financial data is available, must be preferred. In case the regulator has set the tariff determination methodology, in that case the utility can adopt the regulatory costs being allowed by the regulator for the determination of the cost-of-service results.

1.2.3 Structure of the CoS model

The sheet structure of the model is explained below:

1. **'RR'**: A buildup of the revenue requirement (RR) to be recovered from tariffs, including the return to be earned on regulated asset base (RAB), is developed in this sheet.
2. **'Customer'**: Customer category-wise data covering customer count, geography, voltage level, energy sales, connected load, connection charge, load factor, coincidence factor, and revenue from electricity sales is inputted in this sheet. The data inputted is further built upon to derive the complete energy balance (GWh) and power balance (MW) for each customer category, which entails adding non-technical and technical losses to sales quantum, to derive the requirement to be inputted into the system to meet the demand of each category.
3. **'Loss'**: This sheet provides a facility to input key assumptions related to technical and non-technical losses, voltage-wise. The model includes a segregation across 3 voltage classes - HV: above 66 kV, MV: above 400 V and up to 66 kV, and LV: 230 V, 400 V. The sheet derives the energy (GWh) and power (MW) balance for the system at each voltage level. This output is used in the 'Customer' sheet to derive the energy and power balance for each customer category.
4. **'Assets'**: This sheet functionalizes the assets reported in financial statements into categories which are the building blocks for cost of service. Assets includes fixed assets (plant & machinery, land, buildings and other assets), accumulated depreciation, assets under construction (capital works-in-progress or CWIP), current assets and current liabilities (working capital). These elements are used to build the RAB, and hence this sheet helps derive the functionalized RAB. The functionalization is carried out at multiple levels: i) strategic business units (SBUs) of Generation, HV network, MV network, and LV network; ii) geographical segregation of Urban and Rural; (iii) purpose-based segregation of Demand-related and Customer-related assets.
5. **'Expenses'**: This sheet functionalizes the expenses reported in financial statements into categories which are the building blocks for cost of service. Expenses include operational (fuel, power purchase, transmission, staff, maintenance, administrative and general) and non-operational (depreciation, interest and financing, provision for bad debts). The functionalization is carried out at multiple levels: i) strategic business units (SBUs) of Generation, HV network, MV network, and LV network; ii) geographical segregation of Urban and Rural; (iii) purpose-based segregation of Energy-related, Demand-related and Customer-related expenses.
6. **'V.Realloc'**: This sheet reallocates the voltage-levels based functionalized allocations to reflect the contribution of assets at higher voltages in serving customers at lower voltages. The re-allocation covers Demand (Network)-related RAB and Demand (Network)-related Expenses.
7. **'Output'**: This sheet presents the results of CoS exercise by tabulating the cost to serve each customer category alongside the revenue recovered from tariffs. The Energy-related, Demand-

related and Customer-related costs are compared with the recoveries from Energy charge, Demand chargeand Fixed charge.

1.2.4 Operating the model and deriving results

1. Enter data and assumptions in cells with blue text. Cells which are in black text are formula driven and "read-only".
2. Data and assumptions are to be entered in sheets titled "RR", "Customer", "Loss", and "Assets". Refer to the accompanying notes in the model for guidance.
3. After inputting data in "Customer" and "Loss" sheets, review the parameter of "Energy loss => Demand loss conversion factor" in the "Loss" sheet. This factor denotes the relationship between demand loss (in MW terms) and energy loss (in GWh terms) and needs to be entered manually. The value is to be determined using a trial-and-error method, by inputting values incrementally greater than 1 and ensuring that value in the cell marked "ERROR" is minimized as close to zero as possible. Doing so will ensure that the voltage-wise demand loss and energy loss figures are internally consistent.
4. The results can be viewed in "Output" sheet as customer category-wise cost incurred, revenue recovered through tariffs and percentage cost reflectivity of tariffs.

1.2.5 Methodology of the CoS model

The model methodology can be explained in five steps:

1. Deriving customer category-wise energy balance and power balance
2. Functionalizing assets
3. Functionalizing expenses
4. Reallocating demand-related RAB and RR, voltage wise
5. Deriving cost of service results

Each of these steps is described in detail in the following sections.

1.2.5.1 Deriving customer category-wise energy balance and power balance

Sales = Billed to customer
Consumption = Sales + Non-technical losses
Requirement = Consumption + Technical losses

This step derives the energy balance and power balance for each customer category. Starting with the sales data (both energy sales in GWh and power sales in MW terms), the non-technical and technical losses are added to each category to derive the energy requirement (GWh) and the coincident contribution to system peak demand (MW) of each category. These are further used as allocation factors in various steps of the cost-of-service analysis.

Deriving energy and power balance is a two-step transformation process:

1. From sales to consumption
2. From consumption to requirement

From sales to consumption

Deriving consumption in terms of gigawatt hours is fairly straightforward. The non-technical losses for each category are simply added to energy sales to derive the energy consumption in terms of gigawatt hours. To derive the power consumption in terms of megawatts, firstly the non-coincident peak power consumption is derived from energy consumption for each category by applying the respective load factor. Non-coincident peak power consumption is then transformed to coincident peak power consumption in terms of megawatts by applying the coincidence factor for each category.

From consumption to requirement

The energy requirement is derived by adding technical losses (in GWh terms) to energy consumption derived earlier. The coincident contribution to peak demand (which is nothing but requirement for power) is derived by adding technical losses (in MW terms) to coincident peak power consumption derived earlier.

The technical losses for each category are derived using the following process. Firstly, the technical losses in terms of gigawatt hours, are assumed for the three voltage levels namely HV, MV and LV. Each of the three loss figures are then transformed to technical losses in terms of megawatts by assuming a conversion factor called 'demand loss to energy loss factor'. This factor is generally incrementally greater than 1, and in most cases between 1.1 to 1.3. The technical loss (both in GWh and MW terms) for each category is then computed based on the share of energy consumption (GWh) or coincident peak power consumption (MW) (as the case maybe) of that category in the total energy consumption or coincident peak power consumption for its voltage level (HV, MV, or LV).

1.2.5.2 Functionalizing assets

The first step of functionalization of assets involves breaking out the utility's asset base into key strategic business units (SBUs) of generation, HV network, MV network and LV network. The MV and LV network SBUs are further subdivided into Urban and Rural units. The 3 network SBUs put together should cover the entire network of utility to which all its customers are connected, including customers connected at transmission voltage levels. In the next step, the asset base is further classified as demand-related or customer-related.

The aim of the exercise is twofold: i) derive asset-based allocation factors[1] for allocating key elements in the cost-of-service analysis; and ii) derive functionalized RAB for estimating return on RAB for customer categories.

The process involves following steps:

1. Functionalizing Gross Fixed Assets (GFA)
2. Deriving functionalized Net Fixed Assets (NFA) financed by the utility
3. Deriving functionalized RAB

[1] *As electricity is asset intensive business, asset-based allocations are the most appropriate way to segregate costs between different parts of the business.*

Functionalizing Gross Fixed Assets (GFA)

The need for functionalizing GFA arises from the fact that the assets reported in Utility's financial statements are functionalized into broad categories of plant, lines, networks (plant & machinery or 'P&M' in short); land and buildings; and other assets. For deriving the cost of service for each customer category, a more granular classification is needed as shown below.

SBU	1st level functionalization	2nd level functionalization
Generation	-	-
HV network	-	Demand-related assets
	-	Customer-related assets
MV network	Urban	Demand-related assets
	Rural	Customer-related assets
LV network	Urban	Demand-related assets
	Rural	Customer-related assets

Firstly, P&M is allocated to the above functions based on actual asset values as provided in Utility's asset register. Secondly, the remaining GFA, i.e., land, buildings and other assets are functionalized based on the ratio of allocation of P&M. The sum of all GFA so functionalized is referred to as "Unadjusted GFA" since it is not adjusted for customer or grant financed (CGF) assets.

The next step involves functionalizing CGF assets and deducting them from "Unadjusted GFA" to derive the "Adjusted GFA". The CGF assets should be functionalized as per the values provided in Utility's asset register.

Deriving functionalized Net Fixed Assets (NFA) financed by the utility

This involves deducting Accumulated depreciation on assets financed by Utility from GFA financed by Utility. The accumulated depreciation on assets financed by Utility is considered after deduction of accumulated depreciation on CGF assets. The total accumulated depreciation on assets financed by Utility is then functionalized in proportion of GFA financed by Utility (Adjusted GFA).

Deriving functionalized RAB

The final step involves derivation of the functionalized RAB. The RAB is derived by adding capital works in progress (CWIP) and net working capital (NWC) to NFA financed by Utility. The CWIP value is functionalized in proportion of Adjusted GFA. Next, NWC is computed as the sum of the following:

1) O&M expense (1 month): fuel cost of generation, staff costs, maintenance expenses, admin & general expenses
2) Receivables (2 months): Tariff receivable from sale of electricity
3) Minus -> Trade payables (1 month): power purchase cost, transmission charges
4) Minus -> Consumer security deposit

Post this, NWC is functionalized in two steps: (i) by allocating to SBUs based on SBU's share of total expenses, and (ii) allocating demand-related and customer-related assets in proportion of unadjusted GFA (which includes CGF assets).

1.2.5.3 Functionalizing expenses

This section deals with the process of functionalizing expenses to allocate them to energy-related, demand-related, and customer-related costs. The expenses are considered on a net basis, after deducting the non-tariff income recovered from consumers.

It is to be noted that interest and financing expenses are not included in net expenses. This is because interest expense is an integral part of the return on RAB, which is funded by both equity and debt. Further, depreciation does not include depreciation charged on customer financed assets.

Net Expenses =
Operating expenses (fuel, power purchase, staff costs, maintenance, A&G, provision for bad debts) plus
Depreciation less
Non-tariff income

The cost functions for which functionalization has been carried out are given below.

SBU	1st level functionalization	2nd level functionalization
Generation	-	Energy-related cost
		Demand-related cost
HV network	-	Energy-related cost
		Demand-related cost
		Customer-related cost
MV network	Urban	Energy-related cost
	Rural	Demand-related cost
		Customer-related cost
MV network	Urban	Energy-related cost
	Rural	Demand-related cost
		Customer-related cost

As a first step towards functionalization, the fuel cost and energy charge (power purchase cost) are functionalized. While the fuel cost is directly allocated to variable costs under 'Generation' SBU, the energy charge (power purchase cost) is allocated to customer categories based on their energy requirement.

Capacity charge (power purchase cost) and transmission charges are allocated to customer categories based on their contribution to system peak demand.

Next, the maintenance and A&G costs are functionalized into demand-related and customer-related costs because they are either demand related or customer related. The functionalization is carried out based on unadjusted GFA (including CGF assets since Utility has to incur maintenance and A&G expenses on these assets as well).

The staff costs are functionalized as per following process: (i) allocation to SBUs based on staff count, (ii) allocation to demand-related and customer-related costs within the SBUs based on unadjusted GFA values.

The depreciation expense on assets financed by utility is functionalized into demand-related and customer-related costs based on adjusted GFA. The CGF linked values are removed for allocation purposes since depreciation is not supposed to be charged on CGF assets.

In the final step, non-tariff income items are functionalized. As these are income, they are treated as a 'negative' expense. These are allocated only to customer-related costs. The allocation is done based on the count of customers. This is because these income items are proportional to the number of customers served.

1.2.5.4 Reallocating demand-related revenue requirements, voltage-wise

In an electricity transmission and distribution system, demand-related assets (e.g. substations, transformers, lines) at HV are used to serve not only HV customers but also MV and LV customers. Similarly, MV assets are used to serve LV customers as well. Hence, some portions of the costs associated with such assets at higher voltages (demand-related RAB and demand-related expenses) need to be allocated to lower voltages.

The reallocation is undertaken based on voltage-wise share of peak demand. As a first step, the costs at HV are allocated to HV based on the share of HV peak demand. The balance unallocated HV costs are then added to MV costs to 'update' the MV costs. The 'updated' MV costs are allocated to MV based on MV's share of peak demand, while the balance unallocated MV costs are added to LV costs to derive the 'updated' LV costs. Thus, at the end of this process, the demand-related RAB and demand-related expense, reallocated to HV, MV, and LV levels are obtained. Upon applying the rate of return to RAB and adding it to expenses, the final revenue requirement (RR) re-allocated amongst HV, MV, LV levels is obtained.

		HV	MV		LV	
			Urban	Rural	Urban	Rural
Generation SBU	Energy-related RR	X	X	X	X	X
	Demand-related RR	X	X	X	X	X
Network-related	Energy-related RR	X	X	X	X	X
	Demand-related RR	X	X	X	X	X
	Customer-related RR	X	X	X	X	X

1.2.5.5 Deriving cost of service results

In this final step, unitary costs of the above functionalized RR elements are obtained. These unitary costs are multiplied with the sales quantity of each customer category to obtain the cost of service.

	Deriving unitary cost		Energy CoS		Demand CoS		Customer CoS	
	Factor	*Unitary cost (a)*	*Quantity (b)*	*Cost a X b*	*Quantity (c)*	*Cost a X c*	*Quantity (d)*	*Cost a X d*
Energy-related RR	Energy Sales (GWh)	$$$/ kWh		X				
Demand-related RR	NCP Sales (MW)	$$$/ kW				X		
Customer-related RR	Customer count	$$$/ Customer						X

The total cost of service is calculated as the sum of Energy, Demand and Customer cost of services.

The CoS for each customer category is compared with the Revenue recovered from energy charge, demand charge, and customer charge to calculate the percentage cost recovery. The cost recovery percentage results are presented charge-wise as well as on a consolidated basis for each customer category.