Cost of Supply Framework and Pricing Methodology for Electricity Distributors in South Africa

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1. INTRODUCTION

1.1 Section 4(c) of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ('the NERA') empowers the National Energy Regulator of South Africa (NERSA) with the responsibility to undertake the functions detailed in section 4 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the ERA').

1.2 The ERA sets out NERSA's powers and functions. Of relevance to this application is section 4(a)(ii), wherein NERSA is empowered and required to regulate prices and tariffs.

1.3 Section 15(1) of the ERA prescribes the principles that should govern the setting and approval of tariffs, as follows:

a) Tariffs and revenues must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.
b) Tariffs must also give end-users proper information on the costs that their consumption impose on the business.
c) Tariffs must avoid undue discrimination between users, and may permit cross-subsidisation between certain classes of customers, but should avoid discrimination between customer categories.
d) Tariffs should also provide an incentive for technical and economic efficiency improvements.

1.4 The Electricity Pricing Policy (EPP) states that 'Electricity distributors shall undertake Cost of Supply (COS) studies at least every five years, but at least when significant licensee structure changes occur, such as in customer base, relationships between cost components and sales volumes'. It also states that the cost of service methodology used to derive tariffs must accompany tariff applications to the Energy Regulator for changes to tariff structures. Eskom last applied for the revision of its tariff structures in 2012 based on the cost of supply study that it had conducted then.

1.5 At its meeting held on 29 October 2015, the Energy Regulator approved the COS Framework to assist licensees in undertaking COS studies. Subsequent to the approval, the framework was enhanced to include the useful lives of electricity assets to be used for depreciation purposes. This was approved on 29 March 2016.

2. COST OF SUPPLY STEPS

2.1 The framework primarily focuses on the distribution business of a licensee. Nonetheless, it is also acknowledged that certain distributors have their own generation plants, and others have progressed or might progress into transmission capacity. Therefore, the framework includes cost drivers relating to electricity generation, distribution and transmission. The framework follows a four-step process. The steps cover revenue requirement, cost functionalisation, cost classification and cost allocation with the ultimate goal of rate setting.

2.2 The Embedded Cost Basis was adopted in the development of the COS Framework in South Africa. This approach determines the apportionment of accounting-based revenue requirements using the functionalisation, classification and allocation processes with the ultimate goal of rate setting.

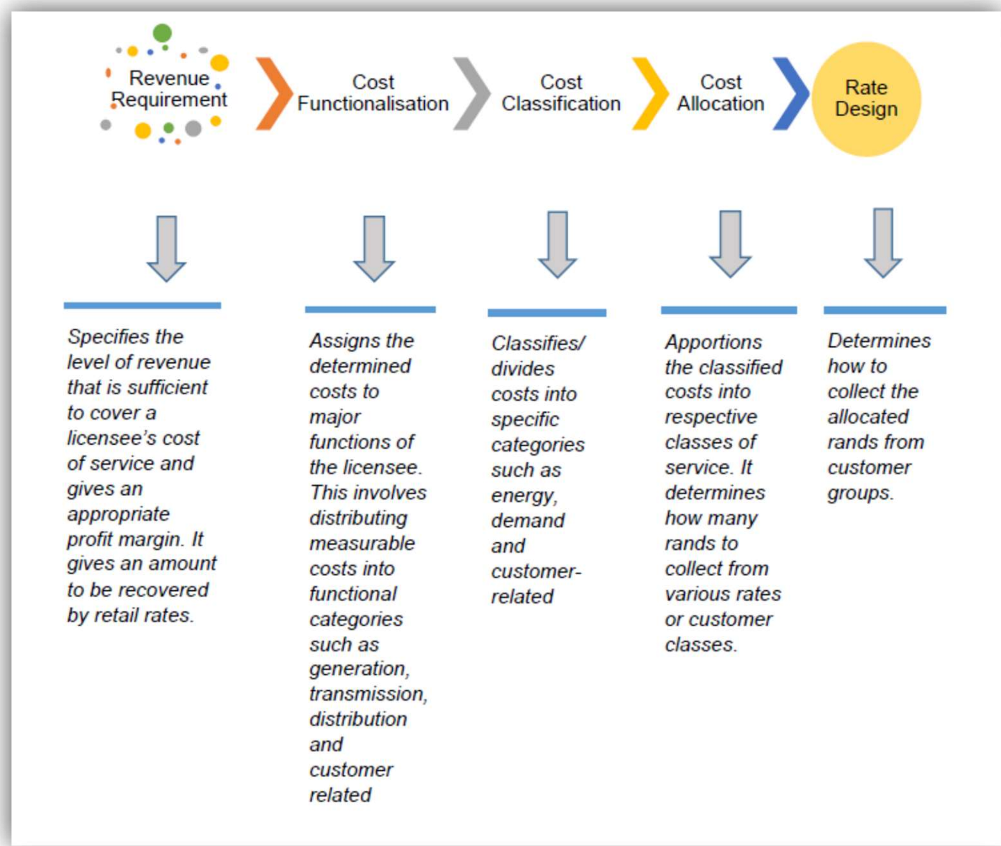

Figure 1: Cost of supply process

3. RING-FENCING

3.1 Classification and allocation of cost according to functions ensures that licensees achieve accounting ring-fencing. Cost functionalisation entails the arrangement of costs according to the major operating functions of a licensee, such as production/generation, transmission, distribution or customer-related costs. This assists in facilitating a determination in terms of which customer groups are responsible for such costs. All costs should be assigned to the major functions of a licensee. Costs can be assigned to different functions within a licensee.

3.2 For electricity, the following key accounts should ideally be delineated:

a. Customer services
b. Networks
c. Energy.

3.3 The ring-fencing enforced by NERSA is the separation of accounts through the submission of the regulatory accounts. NERSA is not mandated to dictate how municipalities should spend their revenues, but is mandated to inspect the electricity account, and advise on and set tariffs based on the submitted regulatory accounts.

3.4 The ERA empowers NERSA to establish norms and standards and key performance indicators (KPIs) for municipalities to ring-fence their accounts through the submission of statements of electricity accounts. According to section 2.4 of the Electricity Pricing Policy (EPP), ring-fencing of key electricity functions (e.g. generation, networks, wholesale/retail and customer services) is the first step towards achieving accurate, transparent and unbundled accounts.

3.5 The revenue earned by the electricity business, as presented in the segments, must align with what is reported in the financial statements. Inter-segment transactions should be based on cost recovery, plus a return, in line with revenue requirement determination. All direct corporate overhead costs should be allocated to the relevant segments, and a cost driver apportionment should be used to split the remaining overhead costs on an equal basis between segments.

3.6 The following major costs and revenues should be ring-fenced:

a) Services supplied by the electricity department to the rest of the municipality, where no charge is levied to cover the cost of supplying such service.
b) Electricity equipment and other resources used by the rest of the municipality with no charge. This typically includes heavy vehicles, large machinery and meter readers.
c) Public lighting, including streetlights, high-mast lights, traffic lights and parking lot lights. This service is considered a municipal service and not part of electricity supply, although the service is provided by the electricity department.
d) Electricity for own use by the municipality: Many municipalities have a different set of tariffs for the supply of electricity for use by their facilities, such as municipal buildings, stores, sewerage supplies, water pumping, and sometimes by staff.
e) Services the municipality provides to the electricity department: Typical services include meter reading and billing, revenue collection, general accounting and administration, telephones and stores.
f) Funding of capital expenditure: Some assets are still funded from external loans and some from internal consolidated loan funds.
g) Government grant funding: This distorts the normal profitability of departments and complicates the fair allocation of costs and revenues.

3.7 The following combination of allocation principles can be used:

a) HR costs: A combination of staff costs and staff numbers
b) IT costs: A combination of computer numbers and computer asset values
c) Land and buildings: Asset values
d) Equipment: A combination of replacement values, purchase prices and number of assets

e) Financial and other services: A combination of the number of customers served and the revenues.

3.8 All allocation ratios and principles should be set out in the manual used to ring-fence costs and revenues.

4. REVENUE REQUIREMENT

4.1 Licensees can choose between the cost-plus or rate of return methodologies. The methodology to recover revenues will be based on whether a licensee can supply an up-to-date asset register; if not, the preferred approach is the cost-plus methodology.

a) Cost-plus methodology

Current COS Framework Provisions

4.2 The cost-plus methodology means that a profit margin is added to determine a licensee's revenue requirement after all costs have been ascertained. The margin is represented by the surplus to be earned by the licensee.

4.3 After considering each licensee's particular circumstances, NERSA determines the surplus to be earned by the licensee. Currently, NERSA uses a tolerable range of 10 to 20%, with a target of 15% on the percentage surplus.

Table 1: Formula for the Cost Plus methodology

Total Required Purchases (MWh)	
(a) Sales forecast (Expected sales to customers)	X
(b) Electricity purchased for own use[1]	X
(c) Street lighting	X
(d) = (a) + (b) + (c) Total sales forecast	X
(e) Allowable loss factor (Represents a percentage energy loss of 10%)[2]	1.10
(f) = (d) x (e) Required purchases	XX

Sources of Electricity Purchases	(g) Volume (MWh)	(h) Weight (%)	(i)= (j) / (g) Average Purchase Price(c/kWh)	(j) = (g) x (i) Total Cost (R)
Purchases from Eskom				X
Purchases from IPPs				X
Own Generation				X
Purchases - Other options				X
Total		100%		XX

Add other costs	
Operating expenditure	X
Shared costs	X
Depreciation/amortisation of refurbishment and capital costs	X
Interest on loans	X
(k) Total costs before Repairs and Maintenance (R&M) costs	XX
(l) = (k) x 6% Repairs and Maintenance costs at 6% of total costs before R&M	X
(m) = (k) + (l) Total costs before surplus	XX
(n) = (m) + 15% Add surplus allowable	15%
(o) = (m) + (n) **Total Allowable Revenue**	XXX
(p) = (o) / (f) Average selling price	X
(q) Previous year price	X
(w) = (p) / (q)-1 x100 Average percentage price increase	X %

Source: NERSA COS framework (2016, p.g 8 & 9)

4.4 A profit margin is required for a licensee to be efficient, sustainable and able to recover its costs to provide electricity to customers. If a surplus is not realised, a licensee is expected to maximise its efficiencies within its cost structures and not use the tariff application process as a profit-generating mechanism. Utilities in South Africa have applied for higher tariff increases due to declining percentage surplus and sustainability. Therefore, it is important that the proposed framework addresses the mark-up issue.

4.5 Due to some licensees' limited capacity to realise a surplus since they buy electricity from Eskom at the Nightsave tariff, NERSA will assess the application submitted and adjust it to consider the prevailing market conditions.

4.6 Since a licensee should add all its costs and a mark-up to determine its surplus, it should further demonstrate to NERSA the efforts it has put in place to deal with a decline in the surplus, which may include reducing its costs and other initiatives.

b) Rate of return

4.7 The current framework does not cater for an alternative to ascertain the licensee's revenue requirements. The amendment of the framework includes the rate of return (ROR) as an alternative to determining the revenue requirement of a licensee.

Formula for the ROR methodology

4.8 The formula highlights the three broad components of the ROR that will be used to calculate the revenue requirement, as discussed below:

$$R = E + (V - d + w) \times r$$

Where:
R = the required revenue of the regulated entity;
E = the operating expenditure
V = the value of the regulatory asset base
d = the accumulated depreciation on the regulatory asset base
W = the allowance for working capital held by the regulated entity
r = the calculated rate of return using the weighted average cost of capital (WACC).

<u>Rules on the Rate of Return</u>

4.9 The return on assets plays a major role in the application of the ROR methodology. It rewards the municipality for investing in the business. The fundamental principle is that the more the utility is exposed to risk, the more returns will be required to compensate for such risk. The rate of return shall be calculated using the WACC.

5. SALES

5.1 The first step in the revenue determination under the current framework is the sales forecast determination.

5.2 Sales are a key requirement in the business planning process as it includes planning for financial, human and physical resources to be utilised by a business. If the forecast sales are not realised, there is an expectation that a business will reduce its fixed costs over the medium to long term, as variable costs would have already decreased. However, this may be challenging in a natural monopoly business, such as electricity distribution, because this sector provides collective services shared by a number of users. Also, a huge portion of the costs are fixed. In addition, the sales/load forecasting approach is critical to ensuring that planning for the future resource needs of a utility is accurate, otherwise, a utility may over-invest in assets that then become stranded. Utilities in South Africa have applied for higher increases in revenues/tariffs due to declining sales. Therefore, it is important that the proposed framework addresses the sales issue.

5.3 Electricity distributors should provide the methodology and assumptions used to compile the sales forecast. The sales volume forecast assumptions must reflect the current conditions of the market at the time of the application and should consider the most recent actual volumes.

5.4 Due to the limited ability of some of the distributors to develop and implement a sales forecast methodology, NERSA will assess the sales forecast submitted and adjust it to take into account prevailing market conditions. NERSA may set a sales forecast applicable to a group of licensees and use this as a basis for COS studies and tariff setting.

5.5 Since sales trends are stable over time, distributors should demonstrate to NERSA the efforts they have put in place to deal with the decline in sales, which may include reducing their costs and implementing sales and marketing and other initiatives (subject to limitations in terms of capacity constraints).

5.6 The sales forecast should include own use, the impact of small-scale embedded generation (SSEG), load-shedding and other factors on the expected sales.

5.7 A sales forecast is a necessary requirement for projections for resources needed by a business, however the requirement determines revenues required by a business to cover its costs, both fixed and variable.

6. PURCHASES

6.1 The current framework takes into account purchases from Eskom, independent power producers (IPPs), other sources and own generation. The current framework further allows the licensee to use the purchases for the test period to forecast sales for the financial year that it is applying for. The forecast purchases, including the street lighting electricity, own use electricity and the allowable loss factor, are also considered by the current framework. The allowable loss factor is defined as 10% of the total anticipated purchases. This represents a 10% energy loss as per the current NERSA benchmarks. The tolerable range for energy losses is 5 to 12%. Licensees that have an efficient system can reduce losses to below 10%. Furthermore, licensees are incentivised for losses below 10%. The forecast purchases are weighed against the percentage contribution of each source of electricity to arrive at the average purchase price (APP) and, consequently, the total purchase cost of a licensee.

6.2 The cost associated with electricity purchases or the procurement of energy from different sources plays an important part in setting rates for electricity distributors. The cost of buying electricity from Eskom is efficient, because the purchase price is set and approved by the Energy Regulator. However, electricity purchases or procurement of energy and capacity from IPPs will be incurred based on the terms and conditions of the respective power purchase agreements (PPAs). The Energy Regulator would have set the prices for licensed IPPs, while contracting between electricity distributors and unlicensed generation facilities has not been tested for efficiency. This means an electricity distributor can procure energy from an unregistered third party and pass through an inefficient cost to the customers.

6.3 In evaluating applications based on the COS framework/methodology, the cost associated with the IPPs will be tested for efficiency and prudency.

6.4 The licensed distributor must furnish NERSA with PPAs or any agreements that are in place between themselves and generation facilities, as well as invoices from the previous revenue period.

7. REGULATORY ASSET BASE (RAB)

7.1 The calculation of the RAB is meant to provide a basis for licensees to determine their respective depreciation based on the straight line approach and a return based on the WACC.

7.2 In enhancing this section, NERSA has taken guidance from section 15(1) of the ERA, which requires that an efficient licensee must recover the full cost of its licensed activities, including a reasonable margin or return. In getting to a reasonable asset base, NERSA requires licensees to value their assets using the indexed historic cost approach to determine the RAB replacement cost.

RAB initial measurement

7.3 Items of property, plant and equipment should initially be recorded at cost. Cost includes all costs necessary to bring the asset to working condition for its intended use. This would include its original purchase price and costs of site preparation, delivery and handling, installation, related professional fees for architects and engineers, and the estimated cost of dismantling and removing the asset and restoring the site.

Measurement subsequent to initial recognition

7.4 Licensees should use the indexed cost model to ascertain the replacement value of assets. The asset should be valued at an indexed cost, less the accumulated depreciation and impairment.

De-recognition (retirements and disposals)

7.5 Assets should be removed from the RAB on disposal or when withdrawn from use, and no future contribution to electricity supply is expected from their disposal.

Disclosure

7.6 For each major class of property, plant and equipment, licensees should disclose the following as a minimum:

a) The basis for measuring the carrying amount
b) Depreciation method(s) used
c) Useful lives or depreciation rates
d) Gross carrying amount and accumulated depreciation and impairment losses
e) Reconciliation of the carrying amount at the beginning and the end of the period, showing additions, disposals, impairment losses and reversals.

RAB performance indicators

7.7 NERSA will use the System Average Interruption Frequency Index (SAIFI) or System Average Interruption Duration Index (SAIDI) as RAB performance measurement tools to adjust the network availability charges to customers.

a) **SAIFI:** Represents the average number of times a customer experiences an outage during the year.
b) **SAIDI**: Describes the total duration of the average customer interruption.

7.8 These RAB performance indicators are meant to incentivise licensees to improve the performance of the RAB (networks) in delivering reliable and uninterrupted services.

8. DEPRECIATION

8.1 Depreciation is catered for in the cost component of the COS that licensees must recoup from tariffs.

8.2 Depreciation plays a vital role for the licensee to recoup the investment on its regulated assets to further invest in the business activity to ensure an uninterrupted supply of electricity to customers.

8.3 Regulatory depreciation of electricity asset provides the regulatory mechanisms under which capital investment costs by licensees are recovered on a cost-reflective basis over the course of its economic/regulatory economic life.

8.4 Depreciation is calculated on the RAB on a straight-line basis over the useful economic life of the asset using the following formula:

D = RAB X (remaining useful life / total useful life)

Where:
D = Annual depreciation
RAB = Regulatory Asset Base
Remaining useful life = an accounting estimate of the number of years the asset is likely to remain in service/use for the purpose of cost-effective revenue generation.
Total useful life = an estimation of the length of time the asset can reasonably be used to generate income and be of benefit to the municipality/ licensee.

8.5 Refurbishment costs shall be capitalised and amortised over the expected useful and economic lives of the refurbished assets.

9. AMORTISATION OF LONG-TERM DEBT/INTEREST ON LOANS

9.1 NERSA, in consultation with the relevant stakeholders, shall determine the economic life of the regulated electricity asset.

Interest on loans and capital repayments

9.2 Interest on loans will be based on the amount of interest paid to cover the loans acquired for the acquisition and refurbishment (repairs and maintenance) of the assets utilised on licensed activities.

9.3 Long-term loans must be taken only to acquire long-term assets. The municipality must clearly ring-fence loans taken for the electricity business from other loans of the municipality.

9.4 The municipality must provide evidence that the loans were procured efficiently and concluded using arm’s length principles.

10. RETURN ON ASSETS (ROA)

10.1 The return on assets shall be calculated using the WACC, which comprises the cost of equity and cost of debt. The formula is as follows:

$$WACC = (K_d \times G) + [K_e (1 - G)]$$

Where:
K_d = *cost of debt*
G = level of Gearing
K_e = *cost of equity*

Cost of debt

10.2 The cost of debt (Kd) reflects the interest that is payable by the regulated licensee.

10.3 The risk-free rate shall be used as a proxy for the cost of debt.

10.4 In estimating the cost of debt, an appropriate debt premium shall be added to the risk-free rate of return.

Gearing

10.5 For the purpose of regulation, the licensee will determine its optimal gearing based on its actual calculation of its capital structure (debt–equity ratio of the capital structure).

10.6 NERSA will use licensee-specific gearing based on submitted information per application.

Cost of equity

10.7 The Capital Asset Pricing Model (CAPM) shall be used in determining the cost of equity as follows:

$$Ke\ Real = Rf + (Mrp^{*}\ \beta)$$

Where:
Ke = Nominal cost of equity
Rf = risk free rate
Mrp = market risk premium
β = beta

11. OPERATING EXPENDITURE

11.1 Section 3.2.1.1(a)(ii) of the current COS Framework provides that the licensee will be allowed operating expenditure in line with six key principles, namely:

a) Allowable expenses relate to all expenses incurred in the production and supply of electricity. These costs include normal operating expenditures, such as labour costs and overheads (centrally administrative and general expenses allocated), that are normally recovered within one financial year, but exclude refurbishment costs that must be capitalised.
b) Expenses must be incurred in the normal operation and supply of electricity.
c) Expenses must be prudently and efficiently incurred and through at arm's length transaction. Licensees must have a competitive procurement policy and demonstrate to NERSA that it has strictly adhered to its procurement processes.

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

e) Allowance for the human resources costs will be at reasonable levels. NERSA may require access to wage settlement documents to verify the reasonability of these costs. Costs relating to corporate social investment, expenses on charitable donations and broad social development activities cannot be included as qualifying (regulated) expenses unless it can be shown that these costs benefit tariff-paying customers.

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

NB: In classifying operating costs further into controllable or non-controllable elements, the Energy Regulator will decide on incentives for the licensee to minimise costs that are under its control and encourage it to reduce some of the costs that are not under its control.

12. SHARED COSTS

12.1 Shared costs should be limited based on the usage or causation by the licensee or electricity department. Costs containing different cost drivers' characteristics must be classified and allocated according to their characteristics.

12.2 The electricity distributor should start with ring-fencing its electricity business to assign shared costs to its cost objective in an equitable manner in terms of the benefit provided.

12.3 The electricity distributor should provide a method or assumptions used to determine the proportionate benefit provided by an activity or services to the shared cost.

13. NOTIFIED MAXIMUM DEMAND EXCEEDANCES

13.1 The COS Framework must outline the costs that NERSA will not allow through the tariff. This is to ensure that licensees know upfront which costs are not regarded as prudently incurred costs. The list of these costs does not necessarily have to be exhaustive, but it is necessary to highlight the costs that have arisen over the years. To be included on this list is the cost paid towards penalties for NMD exceedances. Licensees should be instructed to manage their NMD costs by charging or imposing penalties for exceedances on their customers. This is to ensure that the customers responsible for the NMD penalties pay for the penalties so that this cost is not socialised. Each customer's NMD requirements contribute to the peak demand of the system. If each customer stays within their NMD, the system peak remains within what was planned, or what it was designed for. The licensees must be transparent in terms of the methodology used to determine the penalties. As far as is reasonably possible, the costs should be based on the additional cost to the licensee for the provision of the additional capacity or the new peak that was not planned.

13.2 The framework should clearly indicate that no costs will be allowed for NMD exceedances or payments made for penalties as a result of licensees exceeding their NMD. Eskom charges its customers for NMD exceedances, therefore, municipalities must do the same. Failure to do so by the municipalities will result in the cost of penalties being socialised should they be allowed through the tariff. The framework must also obligate licensees to be transparent in terms of the formula used to determine penalties related to NDM exceedances. This may require the identification of costs that vary with capacity/demand (kVA) and using that as a basis to determine penalty charges.

14. REPAIRS AND MAINTENANCE

14.1 Municipalities must provide NERSA with the planned scope of maintenance work to be done in the assessment period and the itemised costs thereof.

14.2 The money allocated towards maintenance should not be based on benchmarks or estimates but on actual cost to maintain the network based on the scope of work. The maintenance plan should outline the scope of work, including the cost of each maintenance activity that will be carried out according to the Original Equipment Manufacturer (OEM) of the various plant equipment.

14.3 The maintenance budget should be derived from the maintenance plan. There must, therefore, be a correlation between the maintenance plan and the budget.

14.4 The maintenance philosophy, which outlines the various maintenance strategies for various equipment, must be provided. This should indicate, as a minimum, which maintenance strategy (preventative, predictive or run-to-failure) will be adopted for various equipment. The Life of Plant Plan that indicates the remaining life of major assets and what high-level maintenance work is required to ensure that these assets reach their designed lives, i.e. General Outage (GO), Major General Outage (MGO), Interim Repairs (IR), and the high level scope of each, should also be provided. This will give NERSA assurance that the network will reach its designed life.

14.5 Having provided the cost of performing maintenance for a 50kVA transformer, for example, NERSA should benchmark this cost with other similar utilities to allow or disallow the full cost. This will ensure that the maintenance budget is within the range of other utilities that carry out similar maintenance activities.

15. COST FUNCTIONALISATION

15.1 The current framework requires that all costs be assigned to the following three major operating functions of a licensee:

a) Production/generation (Gx)
b) Transmission (Tx)
c) Distribution (Dx) or customer-related costs.

15.2 This arrangement assists in facilitating a determination as to which customer groups are jointly responsible for such costs. Costs such as administrative and general expenses, as well as costs associated with the general plant are considered joint costs and are not functionalised to production, transmission or distribution directly; but are allocated to these functions on a basis that is appropriate to the particular cost (e.g. plant or labour ratios).

15.3 Cost functionalisation is critical in determining efficient rates. In this process, there is a prescribed uniform system of accounts where accounting records are commonly kept. Based on the accounting instructions accompanying the uniform system, costs are recorded in specific accounts or sub-accounts.

15.4 According to the COS Framework, most of a licensee's costs can be directly assigned to relevant functions. However, certain costs, such as shared costs, cannot be assigned to specific functions. Nonetheless, they should be allocated. Straight-forward costs should be assigned and allocated to a relevant function of the licensee, namely generation, transmission, distribution or customer-related.

15.5 Due to some distributors' lack of capacity to functionalise costs appropriately, NERSA will assess the study submitted and identify areas to take into account given the prevailing market conditions. NERSA may set parameters applicable to a group of licensees and use them as a basis for COS studies and tariff setting.

16. COST CLASSIFICATION

16.1 The objective of cost classification is to arrange costs into groups that bear a relationship to a measurable cost-defining characteristic of rendering the service.

16.2 The current framework classifies the cost between fixed and variable. The fixed and variable costs are classified as demand, usage or energy and customer-related. The sum of these three types of costs within a given class is the cost to serve that class.

a) Process of cost classification between fixed and variable costs

Functionalised costs are classified as fixed or variable, depending on their characteristics. Fixed costs are costs that remain constant regardless of the volume of output, and are predominately associated with capital investment. Fixed costs include investment-related costs such as return, taxes, as well as certain operation and maintenance (O&M) expenses, including labour and administrative and general (A&G) expenses. Variable costs are costs that vary with the volume of output. Variable costs primarily consist of fuel costs. The non-labour portion of certain O&M expense accounts can also be classified as variable costs. Non-labour costs include materials and supplies.

b) *Process of cost classification between energy, demand and customer-related costs*

After functionalised costs are classified as fixed or variable, they are classified as energy, demand or customer-related costs. The energy and demand components are generally associated with providing peak and annual services. Variable costs are classified as the energy component to match their recovery with the level of output.

16.3 The purpose of the COS study is to ensure that licensees recover all the costs associated with supplying a customer. Therefore, when a municipality designs a tariff, it is important to ensure that all the related cost drivers are classified and eventually allocated to the relevant customer.

16.4 According to the COS Framework, most of a licensee's costs can be directly assigned to relevant functions. This principle should also apply in a one-part tariff, where the final tariff that a customer pays has embedded all the costs related to supplying that customer (i.e. demand and customer-related costs).

17. COST ALLOCATION

Cost allocation methodology

17.1 The adopted methodology for cost allocation is the asset valuation methodology. This methodology accurately reflects the replacement value of a licensee's assets. It uses annualised replacement costs and is a closer approximation of the true economic cost of providing the service.

17.2 This methodology allows for the cost chain involved in the supply of electricity to be understood. The function of the cost chain ranges from the production of electricity, the transmission of produced energy over power lines to load centres, the transportation and transformation of the power over the distribution networks, delivering the energy to the end-users, providing support services to such end-users, and the billing of end-users.

17.3 The adopted approach limits cost allocation to the following cost drivers: energy-driven costs (in monetary units, c/kWh), demand-driven costs (R/kVA) and customer driven costs (R/customer).

17.4 Various factors influence the costs of providing electricity to customers. They vary depending on, among others, the quantity of electricity used, the size of supply required, the period when electricity is used, the customer's geographic location, the voltage at which supply is provided and the power factor.

Energy cost allocation

17.5 The energy cost component of a licensee consists of costs that would vary with changes in the unit consumption of energy. The energy cost component of purchases is easy to allocate, because the purchase rates can be passed on to all lower voltage levels with an additional adjustment for losses.

17.6 The losses are determined by assuming loss factors for each network component and then comparing the cumulative losses to a network position with the expected loss values for that particular network location. If the cumulative losses of the network components do not compare with the expected or theoretical losses, the loss factor of every network component should be scaled accordingly. The share of total cost attributable to a customer group is calculated as follows:

a) Calculate the time-differentiated consumption (if required) of every customer group at each voltage level

b) Multiply the consumption by the loss differentiated purchase rates.

17.7 The result of this allocation is a Rand value for each customer group at each voltage level representing the energy purchase cost.

17.8 Additional costs, such as overheads and other energy-related costs, can be incorporated with the calculated (energy-related) unit costs. These costs can be applied to specific customers. The total cost must be divided by the total energy consumption for relevant customers to derive a unit energy-related cost for each customer in the category. This derived unit cost must be added to the unit purchase cost for each agricultural customer.

17.9 The total energy-related cost for each agricultural customer can now be determined by multiplying the unit energy-related cost (including the additional energy-related costs) by the total consumption of the customer.

Demand cost allocation

17.10 The demand cost allocation method is used for all costs classified as demand-driven. This includes the network capital cost, the operations and maintenance cost of some networks, the demand purchase cost and the wires component of the purchase cost (if applicable). For this framework, the average and excess (A&E) method is adopted under demand cost allocation. The A&E method is used to allocate the cost of each asset category in the Reduced Network Diagram (RND) to each applicable customer group (refer to Appendix A for illustration). If a customer group uses a specific asset, that customer group should be included in the allocation of the cost of the asset group. For example, the cost of the 132kV assets will be determined based on the demand imposed by each customer group on the 132kV network and the cost of these assets.

17.11 The allocation of a share of the network capital to a specific customer group is then calculated as follows:

a) Calculate the proportion of each asset category in the RND that should be allocated to each customer group.
b) Sum all cost portions for all applicable assets per customer group.
c) Divide the total cost by the sum of the customer groups' undiversified maximum demands to calculate the R/kVA cost.

Customer cost allocation

17.12 Customer costs vary by the type of customer served. The number of customers or weighted number of customers is the basis for the customer allocation factors.

17.13 The total cost of a function is divided by either the number of customers or the weighted number of customers triggering such a cost component. For example, the number of large customers is used to divide the cost of meter reading for large customers.

17.14 The customer service cost, for example, is divided by the weighted customer numbers to determine the unit cost per customer. The principle is that one large customer is the equivalent of several small customers. Therefore, a bigger proportion of the cost is allocated to the large customer.

A. Cost allocation process

17.15 The cost allocation process involves allocation along cost drivers for:

a) energy cost drivers, which relate to kWh consumed plus the network technical losses;
b) transmission network, which relates to diversified network demand as measured at main transmission sub-station;
c) distribution network, which refers to the network maximum demand relative to the system demand; and
d) retail/customer-related, which relates to the point of delivery share of total retail costs differentiated by the type of service and customer demand size.

i. <u>Phase 1</u>

17.16 The first phase of the process of cost allocation involves conducting the following activities to arrive at the cost allocation diagram (CAD):

a) Conducting a network cost of supply study. The study is achieved by conducting a bay-by-bay study.

b) Derivation of the general network diagram (GND). This is achieved by reviewing the network topography and obtaining the network lines, transformation assets and capacity details.

c) Determining distribution assets per replacement value using overnight cost. This is achieved by using the network data obtained to cost each asset category per voltage level, i.e. high voltage (HV), medium voltage (MV) and low voltage (LV). Thereafter, LV supplies should be analysed by making assumptions and cost LV. Once the information has been analysed, it must be summarised and captured in relevant templates.

d) Derivation of the CAD: This is the last step, which will be achieved by consolidating the GND and replacement costs (or overnight costs) into the CAD.

ii. Phase 2

17.17 The second phase of the process involves costing information, which is achieved by conducting the following activities:

a) Effecting the approved revenue for a licensee to achieve the revenue requirement per licensee.

b) Determining energy rates, distribution network charges and zonal loss factors to achieve purchase tariffs.

c) Updating the distribution network loss factors.

d) Conducting an electricity sales forecast.

e) Determining the customer categories.

iii. Phase 3

17.18 The third phase of the process involves cost allocation, which is achieved by conducting the following activities:

a) Active energy and technical losses: The cost of electrical losses is unbundled and recovered as a function of (a) the appropriate loss factors for the relevant voltage level, whether urban or rural and (b) distribution cost of energy purchases cost on a time-of-use basis. Since the purchase rates are currently differentiated according to the time of use, the measurements and calculation of losses will follow the same time-of-use periods. In calculating the cost of these losses for customers, both transmission and distribution loss factors are considered in allocating the costs, as follows:

Table 2: Loss factors

Cost for total losses **= ∑{Delivered energy$_t$ x (distribution loss factor$_{VU/R}$ x transmission loss factor$_Z$-1) x P$_t$}** **Where:** **VU/R = at the relevant voltage level and urban/rural differentiation and** **Z= transmission zone and** **t = the appropriate Peak, Standard or Off - peak (PSO) time period and** **P$_t$= Purchase energy price for each PSO time period.**

b) Transmission loss factors are geographically differentiated. In contrast, the Distribution loss factors are based on estimated average losses per voltage category – the voltage level and rural and urban networks are differentiated as indicated in Table 3 below.

Table 3: Distribution loss factors per voltage category

	Urban	Rural
Voltage	**Loss Factor**	**Loss Factor**
<500V	1.0912	1.1189
≥500V - <66kV	1.0560	1.0900
≥66 – ≤132 kV	1.0174	NA
> 132 kV	0.0000	NA

c) The geographical position of a supply point has an impact on electrical losses, i.e. the further the point of supply is from the source of the supply, the higher the losses. As losses are a cost to the business, they are allocated to customer categories based on the amount of losses determined. Losses over urban and rural networks are different and, therefore, loss factors are associated with different geographic positions. Therefore, voltage also has an impact on losses.

d) Distribution network: The principal cost drivers for the network business are the voltage at which customers receive supply, the location of the customer and the capacity of the supply. Distribution network costs are therefore allocated according to Distribution's current voltage level and geographic categories on a R/kVA basis. The geographic (local and density signal) signal is provided through rural and urban differentiation. The voltage differentiation is based on the following categories.

Table 4 : Voltage level categories

VOLTAGE Urban	**VOLTAGE Rural**
< 500 V	< 500 V
≥ 500 V and < 66 kV	≥ 500 V and < 66 kV
≥ 66 kV and ≤ 132 kV	
> 132 kV	

e) Network costs are allocated at each voltage level using the average and excess statistical method. This method takes into account the impact of a customer's capacity on average on the network, plus any peak impact. Therefore, diversity is considered when allocating the costs.

f) The density of customers also has an impact on distribution cost per connection, i.e. the greater the density, the lower the cost per connection. Therefore, costs are differentiated into rural and urban networks. This will ensure that costs are allocated correctly.

17.19 Retail service: This includes the costs associated with marketing, meter reading, billing, and direct customer services and corporate overheads. The abovementioned costs are allocated per customer, as the total cost divided by the number or weighted average number of customer categories imposing that cost component. These costs are allocated based on the capacity of the customer, split between administration and service-related costs into the categories, as shown in the table below.

Table 5: Retail cost categories

Small	≤ 100 kVA
Medium	>100 kVA and ≤ 500 kVA
Large	>500 kVA and ≤ 1 MVA
Very Large	> 1 MVA
Key Customers	As per qualification criteria

17.20 The assets (in the asset register) are grouped into different voltage levels (HV, MV and LV), the ratio/percentage of each voltage is determined and the cost is apportioned on the basis of that voltage ratio.

17.21 The network cost should be split into both fixed and variable cost as follows:

a) <u>Allocation of network capital costs:</u> These are the fixed costs of the distribution network and are allocated by the number of PODs per voltage level. The costs are allocated on a pro-rata PoD, and this will be recovered in R/PoD/month.

b) <u>Allocation of Eskom's NMD-related costs:</u>
- This cost is driven by the network peak, therefore, it is allocated according to each customer category's contribution to the network peak. Generic load profiles are used to calculate each customer category's contribution to the network peak.
- First step – determine kWh consumption in the NMD period by multiplying the customer peak demand contribution by the projected volumes.
- Second step – derive the percentage contribution to NMD by proportioning each customer kWh.
- Lastly, the customer percentage contribution ratios are used to determine the rate for each customer category (the rate will be R/PoD/month).

c) <u>Allocation of variable maintenance costs</u>:
- If maintenance is due for each unit produced and has a cost per unit, then it would be a variable cost.
- If allocated using pro-rata energy consumption, the unit of measure is R/kWh.

18. RATE SETTING AND ANNUAL ESCALATION MECHANISM

18.1 While taking into account the cost incurred in serving a particular class of customers, the following principles are also considered in rate setting.

18.2 When formulating a tariff methodology, a number of key principles and/or objectives must be considered. These principles represent the often conflicting requirements of different stakeholders and inform the analysis and decisions around the most appropriate regulatory options and detailed pricing approaches adopted.

18.3 The table below summarises the tariff objectives from a licensee's point of view.

Table 6: Pricing objectives from a licensee's point of view

Stakeholder	Tariff objective	Description
Licensee	Cost reflective	All prudently incurred cost should be recovered and yield reasonable profit
	Encourage efficient use	Appropriate price signals that will encourage efficiency
	Implementation cost	Implementation costs should be low

18.4 The table below shows the pricing objectives from a customer's point of view.

Table 7: Pricing objectives from a customer's point of view

Customer	Affordability	Price will exclude inefficiency (energy losses)
	Predictable and stable	The customer should be able to forecast future tariffs
	Transparent	Easy to read and apply, with no hidden costs

18.5 Three cost categories in the electricity supply industry have a bearing on tariff structure, namely:

a) costs that vary with customer numbers and service intensity (R/month);
b) costs that vary with capacity/demand (kVA); and
c) costs that vary with energy (kWh).

18.6 Tariff design should achieve several objectives, including cost recovery and achieving economic efficiency by sending signals to consumers. The applicability of each charge or combination of charges should achieve a combination of these objectives. The framework should clarify which charges are applicable to specific customers and under which specific conditions they should be applied. It should provide rules applicable to each tariff component. It should also balance the simplicity and transparency of costs.

Annual price adjustments

18.7 An adjustment index will be issued to licensees to allow them to submit the tariff applications, which will be used to determine the costs that must increase with CPI, purchase costs and other OPEX. Where annual plans, such as repairs and maintenance and CAPEX plans, have been assessed and approved by NERSA, these can be adjusted based on that.

19. WHEELING CHARGES

19.1 Wheeling customers use the electricity grid to transport the electricity from the generator, and these network costs are covered through a wheeling tariff, or a use-of-system (UOS) charge. Municipalities have had difficulties getting their wheeling UOS tariffs approved by NERSA. NERSA's reason is that it lacks a wheeling framework on which wheeling tariff approvals could be based.

19.2 Municipalities employ a 'wheeling credit' method, which uses existing tariffs to recover the UOS charge and therefore does not require NERSA approval. The wheeling credit method was first developed by Eskom. Instead of explicitly charging a UOS charge on the wheeled energy units, the customer is charged full retail tariffs for all energy consumed (wheeled and non-wheeled energy units). At the end of the month, a credit is given for all wheeled energy, meaning that the customer only pays the resultant UOS charge for wheeled energy.

19.3 The two UOS tariff approaches for wheeling – the explicit UOS charge and the 'wheeling energy credit method' – are shown below.

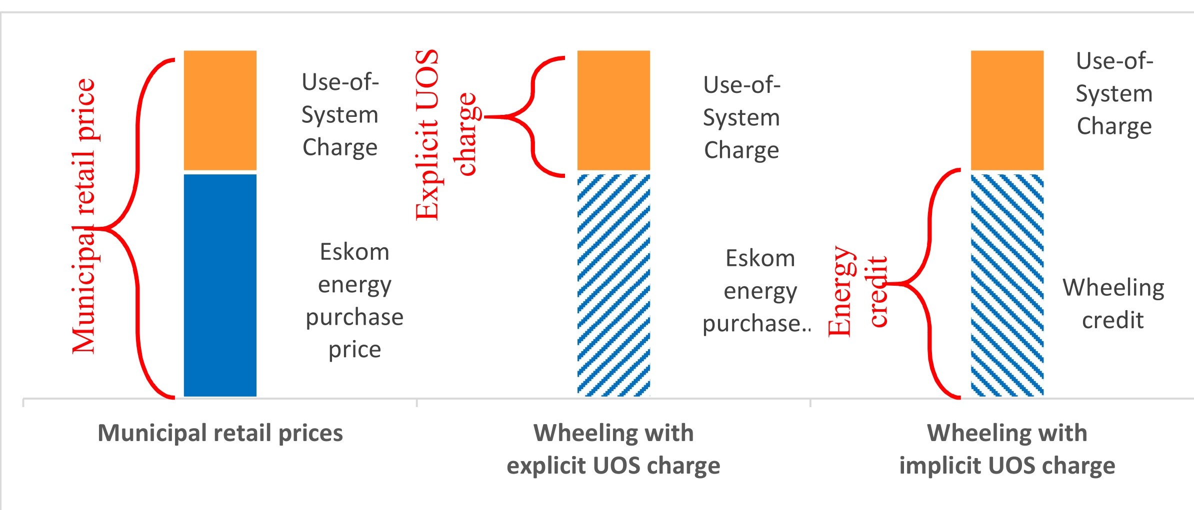

Figure 2: Graphical representation of wheeling billing alternatives

19.4 It is important to emphasise that both the explicit wheeling UOS charge and the wheeling energy credit approach result in the exact same revenue recovery for the municipality.

Explicit use-of-system charges

19.5 Under this approach, the customer receiving wheeled electricity pays an explicit UOS charge for each unit of wheeled energy. The UOS charge should equate to the municipality's existing retail tariffs, less Eskom's energy purchase costs. As such, the UOS charge covers all approved fixed, demand and energy charges, including contribution to regulated surpluses and subsidies.

$$UOS\ Charge = Municipal\ Energy\ Tariff - Eskom\ Energy\ Purchase\ Price$$

Implicit use-of-system charges – 'wheeling credit method'

19.6 This approach aligns with Eskom's existing wheeling methodology,[1] whereby the off-taker's account is credited to the value of the wheeled energy received. The wheeling energy credit is to the value of the wholesale electricity pricing structure (WEPS), less losses. For generators connected to Eskom's network, these credits will be passed onto the municipal account, which will then be relayed to the off-taker's account. For generators connecting to the municipal grid, the municipality will generate the wheeling credits based on the amount of energy metered at the generator's supply point.

19.7 The billing process is outlined as follows:

a) Full tariff charges (i.e. normal non-wheeling retail tariffs) are raised for all the energy supplied through the meter, both the utility-sold energy and the wheeled energy. These tariffs include all approved fixed, demand and energy charges, including contribution to regulated surpluses and subsidies.
b) The wheeled energy is then credited to the customer's bill using the kWh allocated to the off-taker's account multiplied by the WEPS.
c) Therefore, the effective UOS charge for wheeled energy is the full tariff charges (i.e. normal non-wheeling retail tariffs) minus the Eskom energy purchase price.

19.8 The energy credit method is a simpler billing process and does not require an introduction of a new UOS tariff. The UOS charge is already recovered through normal prices, and the billing system is adjusted to credit the customer at the WEPS credit rate for all energy wheeled, less losses, since the municipality did not have to purchase this electricity from Eskom and recognise the cost of line losses.

19.9 The energy credit method requires that all wheeling customers be on a time-of-use tariff and billed in full for all energy received (wheeled and non-wheeled energy). At the end of the billing period, the wheeling customer should be credited for all wheeled energy received, excluding losses at Eskom's WEPS TOU energy rate.

[1] See Table 47 of Eskom's Schedule of Standard Tariffs

ANNEXURE 1: PROPOSED STANDARD STRUCTURES

1. The Distribution Tariff Code (version 6.2) specifies tariff categories applicable to different types of supplies. It is recommended that this approach be adopted to standardise tariff charges across South Africa, with modifications where applicable.

Table 1: Tariff structures for TOU-based tariffs

	TOU tariff for large supplies (e.g. > 500 kVA)	**TOU tariff for medium-sized supplies (e.g. 25 kVA to 500 kVA)**	**TOU tariff for residential See residential**
Retail charges	Based on capacity	Based on size	
Administration charges	R/point of delivery/day	R/point of delivery/day	
Service charges	R/account/day	R/account/day	
Energy charges	Includes only energy costs	Includes energy and variable network costs (network demand charge)	
	• Peak, standard and off-peak TOU c/kWh rates expressed at the highest voltage level • Seasonally and hourly differentiated ✪#	• Peak, standard and off-peak TOU c/kWh rates expressed at the highest voltage level • Seasonally and hourly differentiated ✪#	
Reactive energy charges	c/kvarh	c/kvarh	
Transmission network charges			
Transmission network charge	R/kVA ✪ - based on utilised capacity in all periods	R/kVA ✪ - based on utilised capacity in all periods	
Transmission reliability services charge	Separate c/kWh charge #	Separate c/kWh charge #	
Distribution network charges			
Network access charge	R/kVA charged on utilised capacity*	R/kVA charged on utilised capacity*	
Network demand charge	R/kVA - based on actual demand in peak and standard periods*	c/kWh – charged in peak and standard periods*	
Levies	Separate c/kWh charge	Separate c/kWh charge	

2. The table below shows the recommended tariff structures for non-TOU-demand based tariffs.

Table 2: Recommended tariff structures for non-TOU-demand based tariffs

	Tariff for large supplies (e.g. > 500 kVA)	**Tariff for medium-sized supplies (e.g. 25 kVA to 500 kVA)**
Retail charges	Based on size	Based on size
Administration charges	R/point of delivery/day	R/point of delivery/day
Service charges	R/account/day	R/account/day
Energy charges	Includes c/kWh energy costs and R/kW peak energy costs	Includes c/kWh energy costs and R/kW peak energy costs and variable network costs (network demand charge)
	• Seasonally differentiated expressed at the highest voltage category ✪#	• Seasonally differentiated expressed at the highest voltage category ✪#
Reactive energy charges	c/kvarh	c/kvarh
Transmission network charges		
Transmission network charge	R/kVA ✪ - based on utilised capacity in all periods	R/kVA ✪ - based on utilised capacity in all periods
Transmission reliability services charge	Separate c/kWh charge #	Separate c/kWh charge #
Distribution network charges		
Network access charge	R/kVA charged on utilised capacity*	R/kVA charged on utilised capacity*
Network demand charge	R/kVA - based on actual demand in peak and standard periods*	c/kWh – charged in peak and standard periods*
Levies	Separate c/kWh charge	Separate c/kWh charge

3. The table below shows the tariff structures for residential tariffs.

Table 3: Recommended tariff structures for residential tariffs

	Lifeline tariff (for low users of electricity)	Tariff for medium to high users	TOU tariff for residential
Retail charges	Not size-differentiated	Not size-differentiated	Not size-differentiated
Administration charges	Included in energy rate	Included in service charge	Included in service charge
Service charges	Included in energy rate	R/point of delivery/day	R/point of delivery/day
Energy charges	Includes all costs	Includes energy, transmission and variable distribution network costs (network demand charge)	Includes energy, transmission and variable distribution network costs (network demand charge)
	• Charges differentiated based on the supply size (Amp) • Tariff more expensive for higher supply sizes • Rates receive a subsidy	One single rate or rate seasonally differentiated expressed at the low voltage level	• Peak and off-peak TOU c/kWh rates expressed at the low voltage level • Seasonally and hourly differentiated
Reactive energy charges	N/A	N/A	N/A
Transmission network charges			
Transmission network charge	Included in energy rate	Included in network access charge	Included in network access charge
Transmission reliability services charge	Included in energy rate	Included in energy rate	Included in energy rate
Distribution network charges			Included in energy rate equally in all time periods
Network access charge	Included in energy rate	R/customer/day – based on supply size (kVA or Amp)	R/customer/day – based on supply size (kVA or Amp)
Network demand charge	Included in energy rate	Included in energy rate	Included in energy rate – charged in peak and standard periods only*#
Levies	NA	Included in energy rate	Included in energy rate
Subsidies	Included in energy rate		

4. The table below shows the recommended tariff structures for non-TOU small (non-residential) supplies.

Table 4: Recommended tariff structures for non-TOU small (non-residential) supplies

	Metered supply	Non-metered supply
Retail charges	Not size-differentiated	Not size-differentiated
Administration charges	Included in service charge	Included in service charge
Service charges	R/point of delivery/day	R/point of delivery/day
Energy charges	Includes energy, transmission and variable distribution network costs (network demand charge)	Includes energy, transmission and variable distribution network costs (network demand charge)
	One single rate or rate seasonally differentiated expressed at the low voltage level	One single rate or rate seasonally differentiated expressed at the low voltage level x fixed level of consumption
Reactive energy charges	N/A	N/A
Transmission network charges		
Transmission network charge	Included in network access charge	Included in energy rate
Transmission reliability services charge	Included in energy rate	Included in energy rate
Distribution network charges		
Network access charge	R/customer/day – based on supply size (kVA or Amp)	Included in energy rate
Network demand charge	Included in energy rate	Included in energy rate