COST OF SUPPLY FRAMEWORK

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ABBREVIATIONS AND ACRONYMS

Ave LF	Average Load Factor
Ave PF	Average Power Factor
A&E	Average & Excess
A&G	Administrative and General Expenses
APP	Average Purchase Price
c/kWh	Cent per kilowatt-hour
CAD	Cost Allocation Diagram
COS	Cost of Supply
Dx	Distribution
EPP	Electricity Pricing Policy
GND	General Network Diagram
Gx	Generation
HV	High Voltage
IPP	Independent Power Producer
kVA	Kilovolt-Amps
kWh	Kilowatt-hour
LV	Low Voltage
MTS	Main Transmission Substation
MV	Medium Voltage
MWh	Megawatt-hour
NERSA	National Energy Regulator
O&M	Operation and Maintenance Expenses
R/kVA	Rand per Kilovolt-Amps
R&M	Repairs and Maintenance
RND	Reduced Network Diagram
Tx	Transmission

EXECUTIVE SUMMARY

The National Energy Regulator (NERSA) is a regulatory authority established as a juristic person in Terms of Section 3 of the National Energy Regulator Act, 2004 (Act No. 40 of 2004). NERSA's mandate includes regulation of the electricity supply industry. According to Section 4(ii) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006), the Energy Regulator must regulate electricity prices and tariffs.

Policy position 23 of the Electricity Pricing, 1998 (GG No. 31741 of 19 December 1998) (“the 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. This must be done according to the approved National Energy Regulator of South Africa (NERSA or ‘the Energy Regulator’) standard to reflect changing costs and customer behaviour.*

In support of the above Acts, NERSA developed a COS Framework to be used by all licensed electricity distributors (‘licensees’) in South Africa. The framework will be used as a guideline to licensees when developing their COS studies.

A consultation paper on the COS Framework was published for written comments and a public hearing was held for further comments on the framework. NERSA considered all comments when developing the final COS Framework.

1 BACKGROUND

A Cost of Supply (COS) study is one of the most important considerations in establishing and designing electricity rates that are implemented to provide the service required by customers and recover costs incurred by licensees. The objective of COS study is to apportion all costs required to service customers among each customer class in a fair and equitable manner. The National Energy Regulator (NERSA) has developed the COS Framework in order to promote sustainability of the electricity supply industry while protecting customers against unduly high prices.

2 SCOPE

The framework is meant to assist all licensed electricity distributors in performing their cost of supply studies.

The COS Framework aims at assisting all licensees, with focus being placed on smaller licensees that have limited capacity and experience data base challenges. Licensees that have advanced capacity and data warehouses can expand the adopted approach to a level that will meet their specific needs.

The framework primarily focuses on the distribution business of a licensee, nonetheless, it is also acknowledged that certain distributors also have own generation plants and others have/might progress into transmission capacity. Therefore, the framework includes cost drivers relating to generation, distribution and transmission of electricity.

The framework follows a four-step process. The steps cover revenue requirement, cost functionalisation, cost classification and cost allocation with an ultimate goal of rate setting.

The framework serves as a regulatory standard that will guide licensees to develop their individual COS studies and submit them to the Energy Regulator for consideration. All licensees are required to submit their COS studies to the Energy Regulator.

3 DEVELOPMENT OF THE COS FRAMEWORK

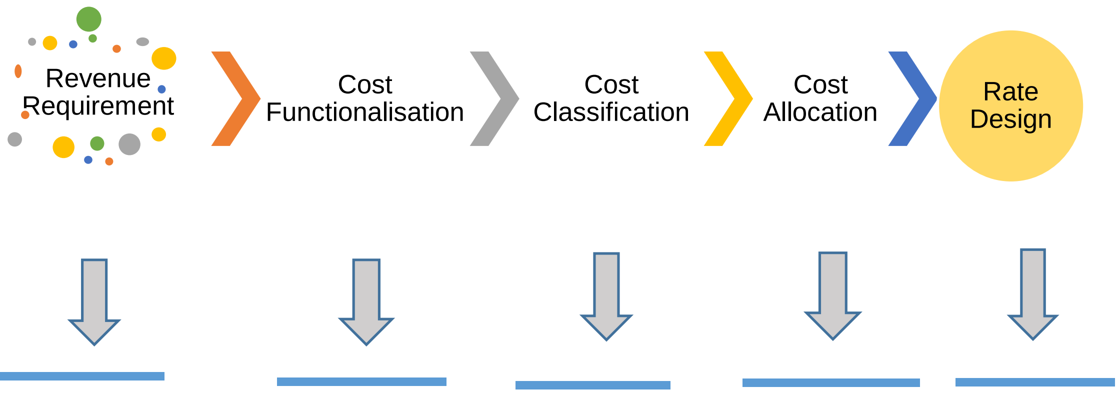
3.1 Approach followed in developing the Framework

The approach that was followed in developing the COS Framework includes desktop research, examining presentations and papers, as well as attendance of relevant workshops that looked into existing approaches to COS studies. Discussions were also held with stakeholders and relevant legislations in the field of COS were was also considered. After careful analysis and consideration of the above, an approach that closely relates to the environment for licensees in South Africa was adopted.

3.2 The adopted approach towards COS Framework

The Embedded Cost Basis was adopted in the development of COS Framework in South Africa. This approach determines the apportionment of accounting-based revenue requirement using the functionalisation, classification and allocation processes with the ultimate goal of rate setting. Figure 1 below depicts the steps of the adopted approach, which will be discussed in detail in the paper.

Figure 1: COS Steps



Specifies the level of revenue that is sufficient to cover a licensee's cost of service and gives an appropriate profit margin. It gives an amount to be recovered by retail rates.

Assigns the determined costs to major functions of the licensee. This involves distributing measurable costs into functional categories such as generation, transmission, distribution and customer related

Classifies/ divides costs into specific categories such as energy, demand and customer-related

Apportions the classified costs into respective classes of service. It determines how many rands to collect from various rates or customer classes.

Determines how to collect the allocated rands from customer groups.

3.2.1 Cost of Supply Steps

3.2.1.1 <u>Revenue Requirement</u>

A licensee, in order to remain viable, must be given the opportunity to recover its total costs incurred in providing electricity services, plus a reasonable margin. The revenue requirement of a licensee is the total cost to supply electricity to all customer categories plus a margin as determined by the Energy Regulator. Section 2.2 of the Electricity Pricing, 1998 (GG No. 31741 of 19 December 1998) ("the EPP") states:

> *In the absence of competition, regulators may select from a range of methodologies to regulate the industry. All these options have some advantages and disadvantages. Regardless of the method of regulation or price formation it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future.*

It is under this premise that NERSA has explored numerous options available to determine licensees' revenue requirements; these methods include rate of return, price cap, revenue cap, yard stick regulation and benchmarking approach.

After careful consideration of the above methods, NERSA decided not to adopt any of them, as they are not practical in the environment of licensees due to various challenges that include, among others:

- difficulty of implementation where accounting and property records are poor as is the case with most licensees;
- assuming that all licensees are operating under the same perfect conditions;
- providing weak incentives for licensees to operate efficiently;
- possibility of lowering licensees' service levels; and
- limiting competitiveness.

Policy Position 1 of the EPP states:

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

In support of the above policy position, NERSA adopted the Cost Plus Methodology as an interim methodology for implementation by licensees, including small licensees with limited capacity and database challenges. It should be noted that the Cost Plus Methodology can be too basic and limiting to well established licensees that have advanced capacity and data warehouses. Licensees are encouraged to start keeping records and building databases and capacity in preparation for the progressive revenue requirement methodology. The Cost Plus Methodology is discussed in detail below.

a) ***Cost Plus Methodology – the adopted revenue requirement approach***

This methodology determines the revenue requirement by allowing the licensee to recover the total cost to supply electricity, including a reasonable margin that is represented by a percentage surplus. The Cost Plus Methodology is made up of various cost components plus a reasonable profit margin, as indicated in Table 1 and discussed in detail below:

- purchases [this includes purchases from Eskom, Independent Power Producers (IPPs), own generation and other sources];
- operating costs;
- repairs and maintenance;
- depreciation/amortisation of refurbishment and capital costs;
- interest on loans; and
- shared costs.

Table 1: Approach to 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**

[1] This refers to consumption by electricity department
[2] The tolerable range is 5% - 12%

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 %**

i. *Purchases*

This takes into account purchases from Eskom, IPPs, other sources and own generation. The licensee should use the purchases for the test period to forecast sales for the financial year that it is applying for. The forecast purchases should include street lighting electricity, own use electricity and the allowable loss factor. The allowable loss factor is defined as 10% of total anticipated purchases (refer to Table 1 above). This represents a 10% energy loss as per current NERSA benchmarks. The tolerable range for energy losses is 5-12%. Licensee that have an efficient system can reduce losses to below 10%. Licensees will be 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.

ii. *Operational expenditure*

- The licensee will be allowed operational expenditure in line with the following principles:
  - o Allowable expenses relate to all expenses that are incurred in the production and supply of electricity. These costs include normal

operating expenditures such as manpower or labour costs and overheads (centrally administrative and general expenses allocated) that are normally recovered within one financial year, but excludes refurbishment costs that must be capitalised.

- Expenses must be incurred in the normal operations and supply of electricity.
- Expenses must be prudently and efficiently incurred and must be at arm’s length transaction. Licensees must have a competitive procurement policy and demonstrate to the Energy Regulator that it has been strictly adhered to in its procurement processes.
- 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 the Energy Regulator is satisfied that those expenses have been prudently and efficiently incurred.
- Allowance for the human resources costs will be at reasonable levels. The Energy Regulator 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.
- Other expenses that are not related to the core business of supplying electricity will also be disallowed.

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

iii. <u>Shared Costs</u>

Shared cost should be limited on the basis of usage or causation by the licensee or electricity department. Costs that contain characteristics of different cost drivers must be classified and allocated according to their characteristics.

iv. Depreciation

- Depreciation shall be based on the straight line method of depreciation and on the expected useful life of the assets.

- NERSA will determine and publish the useful life of various assets of licensees.
- Refurbishment costs shall be capitalised and amortised over the expected useful and economic lives of the refurbished assets.

v. *Repairs and maintenance*

A minimum of 6% of total cost (before profit margin) will be allowed for repairs and maintenance. Repairs and maintenance expenditure exceeding 6% will be assessed on a case-by-case basis by the Energy Regulator.

vi. *Margin*

After total costs have been ascertained, the revenue requirement will be determined by adding a profit margin. The margin is represented by the surplus to be earned by the licensee. The surplus is determined by the Energy Regulator after taking into account the peculiar circumstances of each licensee. Currently, the Energy Regulator uses a tolerable range of 10-20% and a target of 15% on the percentage surplus.

Note: In cases where a licensee does not have sufficient resources to deal with internal challenges, the licensee must develop a comprehensive plan demonstrating the inability to address these challenges and apply to the Energy Regulator. Should there be funds awarded for corrective measures, such funds should be ring-fenced and reported on.

3.2.1.2 Cost Functionalisation

Cost functionalisation entails the arrangement of costs according to 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 as shown in Table 2 below.

Table 2: Cost Functionalisation

Function	Activity/Cost
Generation (Gx)	relates to all costs that are involved in the generation of power.
Transmission (Tx) [3]	includes all costs associated with the transfer of power from one geographical location to another within a system.

[3] This accommodates licensees that might progress into transmission capacity

Distribution (Dx)	relates to the transfer of power from the transmission system through the distribution system to consumers.
Customer-Related Cost	relates to number and type of customers served.

a) Importance of Cost Functionalisation

Cost functionalisation is critical for determining efficient rates. It also paves a way for the next steps, which are cost classification and allocation. Functionalisation requires the licensee's accounting records to be kept according to a uniform system of accounts, based on the adopted system. The costs are recorded in specific accounts or sub-accounts.

b) Practical approach to Cost Functionalisation

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 and customer-related, as depicted by a practical example in Table 3 below.

Table 3: Approach to cost functionalisation (a practical example)

Cost	Gx	Tx	Dx	Customer-Related
Underground conductors			X	
Transmission lines		X		
Fuel costs	X			
Admin salaries				X
Collection Agency Fee				X

3.2.1.3 Cost Classification

After a licensee's revenue requirement is separated by function, the next step is to classify costs into cost components. 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.

Cost classification is a two-step process. First, functionalised costs are classified as either fixed or variable costs. Next, 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 cost

Firstly, functionalised costs are classified as either fixed or variable costs, 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 & General (A&G) expenses.

Variable costs are costs which 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 then classified as energy, demand or customer-related as indicated in Table 4. The energy and demand components are generally associated with providing peak and annual services (refer to Table 4). Variable costs are classified to the energy component in order to match their recovery with the level of output.

Table 4: Cost Drivers

Cost Driver	Characteristics
Demand	Triggered by peak demands and fixed in nature
Energy	Vary with volume of energy increased
Customer-Related Cost	Depend on number and type of consumer served

The energy-related classification consists of those expenses that vary with changes in the unit consumption of kilowatt-hours (kWh), such as purchased power or energy charges. The energy-related classification also consists of costs that are associated with the supply of energy to meet the electricity requirement of the licensee.

Demand costs are associated with meeting the system output and demand requirements or peak demand of each customer and overall peak of a licensee.

Demand classification relates to providing capacity to serve portions or all of the system load requirements.

Certain distribution plant accounts and associated operation and maintenance charges are classified as jointly demand and customer-related. These are expenses that are incurred to provide service to a customer and are also expected to meet customer peak demand requirements. As an example, the number of poles and transformers in a licensee's system varies, in part with the number of customers served by the utility. These items also represent capacity on the utility system available to meet peak demand requirements. Thus they exhibit attributes of both demand and customer charges. The customer component of joint related accounts is that portion of expense that varies with the number of customers.

The customer-related classification is directly related to each electricity user and varies by the number and type of customers served. Customer-related classification consists of those expenses that vary with the number of customers served and volume of energy sold. Customer costs are associated with billing functions, accounting and other expenses that are necessary to connect new customers to the system and serve the licensee's customers. These costs typically vary by the type of customer served, with large industrial customers being the most expensive group of users to connect to the system.

Table 5 below shows how different costs that have been assigned to different functions can be classified:

Table 5: Cost functions and classification

Function	Cost classification
Gx	Demand-Related Energy-Related
Tx	Demand-Related
Dx	Demand-Related Consumer-Related

The above costs vary by the type of customer served. The sum of the demand, energy and customer-related costs within a given class is the cost to serve that class.

3.2.1.4 Cost Allocation

Cost allocation apportions the classified costs into respective classes of service. It sets out an approach that a licensee should follow to allocate costs to different customer categories when it undertakes COS studies.

a) Cost Allocation Methodology

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 therefore is a closer approximation of the true economic cost of providing the service.

This methodology allows for cost chain involved in the supply of electricity to be understood. The function of the cost chain ranges from the production of electricity, transmission of produced energy over power lines to load centres, 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.

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).

There are various factors that influence the costs of providing electricity to customers and they vary depending on, among others, the quantity of electricity used, the size of supply required, the period when electricity is used, the geographic location of the customer, the voltage at which supply is provided and the power factor.

i. *Energy cost allocation*

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 simply be passed on to all lower voltage levels with an additional adjustment for losses.

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:

- calculate the time-differentiated consumption (if required) of every customer group at each voltage level; and
- multiply the consumption by the loss differentiated purchase rates.

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

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 agricultural 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.

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) with the total consumption of the customer.

ii. *Demand cost allocation*

The demand cost allocation method is used for all costs that are classified as being demand-driven. This includes the network capital cost, the operations and maintenance cost of some networks, demand purchase cost and the wires component of the purchase cost (if applicable). For the purpose of 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. The cost of the 132kV assets, for example, will be determined based on the demand imposed by each customer group on the 132kV network and the cost of these assets.

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

- calculate the proportion of each asset category in the RND that should be allocated to each customer group;
- sum all cost portions for all applicable assets per customer group; and
- divide the total cost by the sum of the customer groups' undiversified maximum demands to calculate a R/kVA cost.

iii. *Customer costs allocation*

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.

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. The number of large customers, for example, is used to divide the cost of meter reading for large customers.

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 equivalent to several small customers. Therefore, a bigger proportion of the cost is allocated to the large customer.

b) Cost allocation process

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

- energy cost driver, which relates to kWh consumed plus the network technical losses;
- transmission network, which relates to diversified network demand as measured at main transmission sub-station;
- distribution network, which refers to the network maximum demand relative to the system demand; and
- 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. Phase 1

The first phase of the process of cost allocation involves conducting of the following activities in order to arrive at the Cost Allocation Diagram (CAD):

- Conducting a network cost of supply study. The study is achieved by conducting a bay-by-bay study.
- Derivation of the General Network Diagram (GND). This is achieved by reviewing the network topography and obtaining the network lines and transformation assets and capacity details.
- 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 is analysed, it must then be summarised and captured in relevant templates.
- 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***

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

- revenue requirement per licensee will be achieved by effecting the approved revenue for licensee.
- purchase tariffs will be achieved by determining energy rates and by the distribution network charges and zonal loss factors.
- updating the distribution network loss factors.
- conducting an electricity sales forecast.
- determining the customer categories.

iii. ***Phase 3***

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

- 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 calculations 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 6: Loss factors

Cost for total losses
$= \sum\{\text{Delivered energy}_t \times (\text{distribution loss factor}_{VU/R} \times \text{transmission loss factor}_Z - 1) \times P_t\}$
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.

- Transmission loss factors are geographically differentiated, whereas the Distribution loss factors are based on estimated average losses per voltage category – the voltage level and rural and urban networks are differentiation as indicated in Table 7 below.

Table 7: 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

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.

- Distribution network. The principle 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) is provided through rural and urban differentiation. The voltage differentiation is based on the following categories.

Table 8: 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	

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. Diversity is therefore considered when allocating the costs.

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.

- 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 9: 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

3.2.1.5 Rate Setting

Once all costs have been allocated to customer classes, they are translated into unit rates. Rates are designed to recover the jurisdictional cost of service. While taking into account the cost incurred in serving a particular class of customers, the below principles are also considered in rate setting.

a) Principles of rate setting

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.

Table 10: Principles and objectives of rate setting

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

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

- *Cost Reflectivity*

  To ensure long-term viability of the industry, regulators typically permit the regulated entities to set prices that generate sufficient revenue to cover total costs. This is the amount that is determined and required to produce energy, maintain and develop its networks, serve customers, and to provide a reasonable profit. Tariffs that are set below the true cost of supply are arguably the greatest hindrance to a viable, sustainable and growing power sector that is able to consistently meet customer demand and provide reliable supply.

- *Promotion of Efficient Use*

  Pricing is a tool to encourage customers to constrain their consumption or to encourage them to take up services that are less costly to deliver. There should be price signals to customers to which they react according to their level of ‘economic rationality’.

- *Affordability*

  It is widely accepted that affordability stands out as one of the fundamental requirements of electricity pricing in developing countries. Electricity has the potential to improve quality of life by bringing convenience and dignity to the ordinary household, while unlocking the potential for a wider array of business activities. However, affordability does not necessarily mean a very low price of electricity.

  The process of generating, transporting and delivering electricity has associated costs and these need to reflect in the price of the product to send the correct consumption signals to customers. In order for the electricity supply industry to be sustainable, average tariff levels must reflect the cost of supply and should, as far as possible, exclude inefficiencies. Affordability may, nonetheless, necessitate clearly identified subsidies or cross-subsidies targeted towards specific consumers.

- *Predictability & Stability*

  Customers make long-term investment decisions based on the projection of long-term electricity prices. There is thus an obligation on the part of the electricity supply industry to communicate anticipated price trends to the industry. An effective tariff communication plan will:
  - inform customers of future price trends in the industry;
  - keep the licensees and customers informed regarding future tariff structure adjustments;
  - provide clear indications of the tariff application and approval processes;
  - promote confidence within the customers and potential investors; and
  - announce price increases in advance so that customers can prepare for the impact.

- *Transparency*

  Tariff schedules should be easy to read, understand and interpret, with no embedded or hidden costs. Tariff transparency enhances customer confidence in the fairness of tariff levels. In seeking transparency in tariffs, there should be no components on the customer invoice that are not presented on the official tariff schedule. Tariff structures in a regulated environment should be kept simple. Unnecessarily complex tariff structures needlessly increase the administrative burden and push up the cost of providing electricity.

b) Tariff Components/Principal Cost Categories

There are three principal cost categories in the electricity supply industry that have a bearing on tariff structure namely:
- costs that vary with customer numbers and service intensity (R/month);
- costs that vary with capacity/demand (kVA); and
- costs that vary with energy (kWh).

The basic principle to be employed by the regulated entity in structuring tariffs should be to seek optimal cost-reflectivity by retaining the principal cost categories as tariff components and mapping the respective costs to them.

c) Rate Design Methodology

After all the costs plus a reasonable profit margin are allocated to different customer classes. The required revenue will be broken into demand-related charge (R/kVA), customer-related charge (R/month) and energy-related charge (c/kWh) in line with the principles and formulas contained in the South African Distribution Tariff Code.

The End