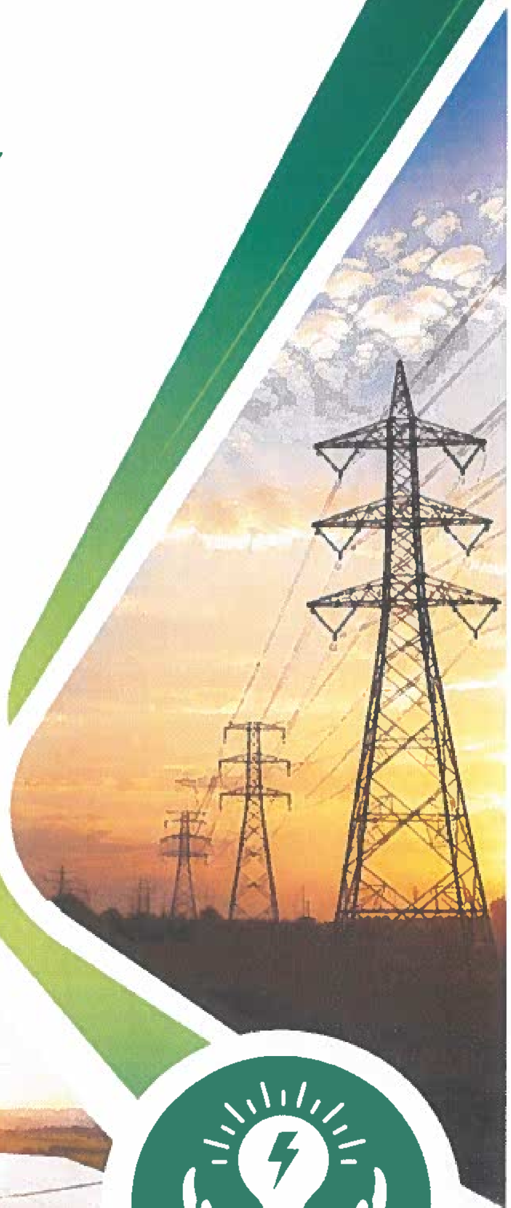
REVISED ELECTRICITY PRICING POLICY (EPP 2026)

OF THE

SOUTH AFRICAN ELECTRICITY SUPPLY INDUSTRY



electricity & energy
Department:
Electricity and Energy
REPUBLIC OF SOUTH AFRICA

TABLE OF CONTENTS

LIST OF FIGURES:

ABBREVIATIONS:

COS	Cost of Supply
CPA	Central Purchasing Agency
CTS	Cost to Serve
DEE	Department of Electricity and Energy
DPE	Department of Public Enterprises
DTI	Department of Trade and Industry
DUoS	Distribution Use of System
EDI	Electricity Distribution Industry
EPP	Electricity Pricing Policy
ERAA	Electricity Regulation Amendment Act,2024 (Act No 38 of 2024)
ESI	Electricity Supply Industry
FBE	Free Basic Electricity
HV	High Voltage

EPP	Electricity Pricing Policy
ERAA	Electricity Regulation Amendment Act,2024 (Act No 38 of 2024)
ESI	Electricity Supply Industry
FBE	Free Basic Electricity
HV	High Voltage
IPP	Independent Power Producer
LGMSA	Local Government Municipal Systems Act
LRMC	Long Run Marginal Cost
LV	Low Voltage
MSOE	Municipal Surcharge on Electricity
MV	Medium Voltage
NERA	National Energy Regulator Act, 2004 (Act No 40 of 2004)
NERSA	National Energy Regulator of South Africa
NPA	Negotiated Pricing Agreement
NRS	National Rationalised User Specifications
NSP	Network Service Provider
PPA	Power Purchasing Agreement
ROA	Return on Assets
ROE	Return on Equity
SAPP	Southern African Power Pool
TOU	Time of Use
TUoS	Transmission Use of System
WACC	Weighted average cost of capital
WEPS	Wholesale Electricity Pricing System
WP	White Paper

DEFINITIONS:

Ancillary services	Ancillary services include, inter alia, the provision of operating reserves, frequency control, generator islanding, black-start capability, constrained generation, and reactive energy support.
Avoided system cost	The cost that a utility would have incurred to meet its supply obligations if it did not buy power from another party.
Base-load demand	The regular, consistent electrical demand required at any time of the day or night, or the lowest point on the load demand curve. Alternatively, "base-load demand" means a continuous level of electricity demand.
Available Capacity	The available and usable capacity of the assets deployed by a licensee in the delivery of the service or services of the licensed activity.
Capacity charge	See definition of standby charge.
Utilised Capacity	The actual capacity used and measured to deliver a service or services of the licensed activity when called upon to do so by the system operator.
Central purchasing agency	The entity assigned to fulfil the role of the Single Buyer while allowing for a transition to a competitive market with consumer choice. The CPA remains the Buyer for legacy power purchase contracts and may purchase additional capacity and energy as required to maintain system integrity in a future competitive environment.
Codes	Any Code adopted by NERSA, as applicable.

Connection charge	A charge recouped from the customer for the cost of providing new or additional capacity (irrespective of whether new investment is required or not). This is recovered in addition to the tariff charges as an up-front payment (connection fee) or as a monthly charge where the distributor finances the connection.
Cost-of-supply (CoS) study	Cost of Supply establishes the total costs and returns that must be recovered establishing the required electric utility revenues.
Cost-reflectivity	The pricing method to reflect the full and efficient cost of supplying electricity to a customer.
Cost to serve (CTS)	Determines how that recovery is distributed across customers through a standard procedure for deriving and allocating required revenue to end-customers for the purposes of arriving at unit costs to tariffing.
Customer	The same as end-user. A user of electricity [or a service relating to the supply of] who consumes such electricity.
Cross-subsidy (within the sector)	Over-recovery of revenue from customers in some tariffs used to balance the under-recovery of revenue from customers in other tariffs This consists of Inter-tariff subsidies that occur when customers in a tariff pay higher as a contribution towards lower prices to other tariff customers. Intra-tariff subsidies occur within the same tariff when some customers pay higher or lower than others in the same tariff due to the pooling of customers with different consumption profiles in the same tariff. This may be recovered concurrently with another sectorial subsidy under a subsidy framework (see subsidy framework).
Dedicated network	Customer dedicated assets are assets created for the sole use of a customer to meet the customer's technical specifications and are unlikely to be shared in the distributor's planning horizon by any other end-use customer.
Distribution network/system	An electricity network with assets operated at a nominal voltage of 132 kV or less.
Distribution charges	The grouping of distribution use-of-system (*DUoS*) charges, retail charges, and connection charges.
Distribution use of system (DUoS) charges	Unbundled regulated tariffs charged by the distributor to distribution network services customers for making capacity available and for use of the distribution system.
Distributor	A licensee or its appointed representative who constructs, operates and maintains the distribution network, and as defined in the Codes.
Energy charges	Charges raised to recover the cost of energy.
Embedded TUoS charges	The transmission TUoS charge raised to customers connected to a distribution network.
Electricity distribution industry (EDI)	The distribution industry connected to supply voltage not exceeding 132 kV.
Electricity supply industry (ESI)	Generation, transmission, wholesale and distribution, system operator, market operator, and CPA.
End-user	A user of electricity [or a service relating to the supply of who consumes such electricity.
Free basic electricity (FBE)	The State's Free Basic Electricity initiative, which provides a limited amount of free electricity deemed necessary to provide basic services, as determined and funded in terms of State policy to alleviate poverty.

Flexible distribution services.	Services aimed at modifying generation injection and/or consumption patterns in reaction to an external signal, such as a price signal or activation, to provide a service within the energy system. The parameters used to characterise flexibility include the amount of power modulation, duration, rate of change, response time, and location.
Generation	The production of electricity by any means.
High voltage (HV)	Nominal voltage levels equal or greater than 44 kV up to and including 132 kV.
Cross border customers	Customers who are situated outside the borders of the Republic of South Africa.
Least-economic cost	The lowest value of the sum of the life cycle costs to both the supplier and the customer referring to diverse options for the supply of electricity.
Legacy costs/contracts	Costs or contracts associated with mandatory government energy procurement and or network capital programmes.
Long run marginal cost	The additional cost incurred when production is increased by one unit assuming that all input costs are variable, including capital.
Long term	A period of more than five (5) years.
Losses	Technical and non-technical. (See separate definitions for technical and non-technical losses).
Low voltage (LV)	Nominal voltage levels up to and including 1 kV.
Medium term	A period of between one (1) and five (5) years.
Merit Order Dispatch	Available sources of energy, especially electrical generation, are ranked based on an ascending order of tariffs or prices. The purpose of merit order dispatch is to enable the lowest net cost electricity to be dispatched first.
Medium voltage (MV)	Nominal voltage levels greater than 1 kV and up to and including 44 kV.
Municipal surcharge	A charge above the municipal cost of supply that a municipality may impose on fees for a municipal service provided by or on behalf of a municipality, in terms of section 229(1)(a) of the Constitution and the Municipal Finance Management Act.
Negotiated Pricing Agreements (NPA)	Any price agreement that may deviate from approved standard tariff levels, structures, service fees, network standards, and capital contributions aimed at offering incentive pricing so priority and strategic industrial sectors can operate competitively, retain capacity, and attract new investment.
National Energy Regulator of South Africa (NERSA)	A legal entity established in terms of the National Energy Regulator Act (Act 40 of 2004) to regulate the ESI in South Africa.
National transmission power system	The interconnected transmission power system used for the transmission of electricity produced by generation facilities for purposes of the supply of electricity to customers within and outside South Africa, above132kV.
Net-billing	An energy credit mechanism where the customer's generation is synchronised with the grid (grid-tied), and where there may, at times, be export of energy.
Network	Electrical infrastructure needed to transport electrical energy from a source of generation to a point of consumption.

Network charges	Charges designed to recover costs (including capital, operations, maintenance, and refurbishment) for the provision of network capacity required by and reserved for the customer.
Network Service Provider (NSP)	NSP is a legal entity that is licensed to provide network services ownership and maintenance.
Non-technical losses	Loss in revenue because of energy consumed but not paid for (unaccounted for energy), e.g. because of poor administration or theft.
Power factor	The ratio of the root means square (RMS) value of the active power (kW) to the apparent power (kVA), measured over the same integrating period.
Price	A charge for electricity to an end-use consumer that reflects the costs that their consumption imposes on the licensee's business and may include price signals and cross-subsidies grouped into a coherent set of charges.
Distributor end-user incentives	Incentives in the form of bill credits or cash payouts to end-users for participating in utility-owned embedded generation e.g. utility-owned rooftop solar PV.
Prosumers	A prosumer is a customer who both consumes and produces electricity.
Quality of supply	Technical parameters that describe the electricity supplied to customers according to standard (NRS 048) and any other NERSA prescribed requirements.
Regulatory Accounts	A standardised system of accounts designed to identify and categorise the costs of providing services and to provide a basis for calculating the level of revenue required to cover all the utility's costs, including a return on investment. The costs of providing services are already captured in the utility's accounting systems and need to be reorganised for the regulatory accounts.
Retail	The function related to the supply of electricity and network services.
Retail margin	A capped or benchmarked electricity retailing risk margin for commercial risks including wholesale price and volume risk, hedging costs, customer acquisition and retention costs, bad debt, and balancing/settlement obligations.
Resellers	Entities that are registered to purchase electricity from licensed distributors and resell it to their end-use customers.
Replacement cost	The cost of installing a new system in the relevant year.
Reserve margin	The percentage by which the net installed generating capacity exceeds the expected or actual peak demand during a specified period.
Return on assets	The return on assets is the actual amount of earnings by a company in a particular year, before deducting interest costs and tax charges, expressed as a percentage of the value of the total assets of the company. Given that the value of 'total assets' always equates to that of 'total capital,' this can also be referred to as 'return on total capital.'
Required Revenue	The Regulator determines the allowed revenue a regulated company could earn if it operates efficiently, providing regulated companies with an opportunity to recover costs and make a reasonable return. It is not a guarantee of revenue. Allowed Revenue shall have the same meaning.
Short term	A period of less than one (1) year.

Single buyer	The entity that has been appointed to purchase electricity from generators on behalf of the industry.
Small power tariff	A tariff for customers with a supply of 100 kVA or less.
Standby charges	A standby charge is typically an annual fee charged by the utility for providing backup power for a grid-connected supply.
Subsidy (from outside of the sector)	The application of funds generated from taxes, levies, and other sources outside the electricity sector to lower the charges to end-customer prices. (See the definition of cross-subsidies).
Subsidy framework	A combination of policy tools aimed at improving electricity affordability for low-income households through targeted energy access and affordability interventions outside the tariff structure and may be supported by inter-tariff and intra-tariff subsidies where necessary.
Standard connection / standard supply charge	The standard fee charged for a standard connection as set out in an approved schedule of fees.
Tariff	A charge to a customer or end user in respect of a licensed activity or registered activity, other than a surcharge, tax, levy, or duty imposed by a municipality in terms of section 229 of the Constitution of the Republic of SouthAfrica,1996.
Tariff structure	The combination of different charges and the relationship to each other that reflect the full and efficient cost to supply each of the services charged for.
Technical losses	The loss of energy within the networks as a natural consequence of transporting energy because of the characteristics of the physical equipment, usually associated with dissipation.
Trader	A legal entity licensed or registered to engage in the buying and selling of electricity as a commercial activity.
Transmission	The conveyance of electricity through a transmission power system, excluding trading; 'transmit' and 'transmitting' have corresponding meanings.
Transmission system	Power lines and substation equipment that operate at a nominal voltage of more than 132 kV.
Transmission use of system (TUoS) charges	Unbundled regulated tariffs charged for the use of the transmission system.
Transparency	The explicit reflection of all composite costs that constitute a tariff, for example: energy charges, demand charges, basic charges, levies, cross-subsidies (receipt and contribution), and MSOE.
Wheeling	Third-party wheeling is a financial transaction where through bi-lateral or multi-lateral transactions, a Generator sells their generated electrical energy to another party, wheeling the energy through the existing distribution or transmission network of an NSP.
Wheeling Network charges transportation of energy for third-party	The use-of-system (UoS) charges are charges meant to recover the costs associated with the use of and making capacity available on an electricity network. These charges are the unbundled regulated tariffs, charged by the NSP for making transmission or distribution capacity available generators and loads including unavoidable inter-tariff and intra-tariff subsidies.

Wheeling service and administration charge	Any additional service and administration charges for the third-party wheeling transaction to recover costs including metering, billing, reconciliation, data management, and other related costs.
Weighted average cost of capital	The WACC is the percentage cost of debt and the percentage cost of equity, aggregated after weighting each cost in relation to the proportion that debt capital and equity capital constitute of total capital. It is the average cost of the total capital.

1. INTRODUCTION AND BACKGROUND

South Africa's Electricity Supply Industry (ESI) is undergoing a fundamental structural transformation, transitioning from a vertically integrated, monopoly-based system to an unbundled and increasingly competitive electricity market. This transition marks a decisive shift from the context in which the 2008 Electricity Pricing Policy (EPP) was developed, which assumed a centrally planned system dominated by Eskom.

At the centre of this reform is the unbundling of Eskom into separate generation, transmission, and distribution functions. This restructuring, supported by amendments to the Electricity Regulation Act, 2006, the introduction of generation licensing exemptions, and the Electricity Regulation Amendment Act, 2024, establishes the foundation for a reconfigured electricity sector characterised by multiple market participants, unrestricted access to the network, and competitive procurement and supply arrangements.

The emergence of a distinct transmission function, operating as a neutral system and market operator, is a critical enabler of this evolving market structure. It facilitates non-discriminatory access to the grid, supports transparent price formation, and enables increased participation by independent power producers, municipalities, and other market participants.

Concurrently, technological developments, including renewable energy, embedded generation, and energy storage, are accelerating the decentralisation of electricity supply and reshaping consumption patterns and distribution network investment needs. These developments introduce new operational and regulatory complexities, requiring a pricing framework that is responsive to diverse generation sources, evolving demand profiles, increasingly dynamic market arrangements, increased complexity in distribution network management including support for community-led renewable initiatives.

Within this context, the existing Electricity Pricing Policy is no longer fully aligned with the structure and functioning of the evolving ESI. A revised policy framework is therefore required to define clear pricing principles across the value chain, support efficient market outcomes, and provide regulatory certainty.

This revised Electricity Pricing Policy seeks to establish a coherent, transparent, and forward-looking pricing framework aligned with the restructured electricity sector. It provides the basis for cost-reflective tariffs, promotes efficient investment and operation, and incorporates mechanisms to address affordability and ensure equitable access to electricity.

1.1 PURPOSE OF THE ELECTRICITY PRICING POLICY (EPP)

The purpose of the revised Electricity Pricing Policy is to provide a unified and coherent framework for electricity pricing in a transitioning electricity sector.

It aims to:

- Establish cost-reflective and efficient pricing across the electricity value chain.
- Support the transition to an unbundled and competitive electricity market.
- Ensure transparent, predictable, and non-discriminatory tariff structures.
- Enable sustainable investment in generation, transmission, and distribution infrastructure.
- Balance economic efficiency with affordability and social equity considerations; and
- Provide clear guidance for regulatory decision-making by the energy regulator.

1.2 LEGISLATIVE CONTEXT

South Africa's electricity sector is shaped by an interlinked framework of legislation, policy documents, and judicial precedents. Key instruments include:

1996 – Constitution of the Republic of South Africa

1998 – Competition Act, 1998 (Act No. 89 of 1998)

1999 – Public Finance Management Act, 1999 (Act No. 1 of 1999)

2000 – Local Government: Municipal Systems Act, 2000 (Act No. 32 of 2000)

2000 – Promotion of Administrative Justice Act, 2000 (Act No. 3 of 2000)

2001 – Eskom Conversion Act, 2001 (Act No. 13 of 2001)

2003 – Municipal Finance Management Act, 2003 (Act No. 56 of 2003)

2004 – National Energy Regulator Act, 2004 (Act No. 40 of 2004)

2006 – Electricity Regulation Amendment Act, 2024 (Act No. 38 of 2024)

2007 – Electricity Regulation Amendment Act, 2007 (Act No. 28 of 2007)

2007 – Municipal Fiscal Powers and Functions Act, 2007 (Act No. 12 of 2007)

2008 – Consumer Protection Act, 2008 (Act No. 68 of 2008)

2020 – Electricity Regulations on New Generation Capacity, 2020 (GN 1093, GG 43810 of 16 October 2020)

2020 – Public Procurement Bill, 2020

2022 – Amendment to Schedule 2 of the ERA: Licensing Exemption and Registration Notice, 2022 (GN 2875, GG 47757 of 15 December 2022).

2. GENERAL PRICING PRINCIPLES

2.1. General Tariff Principles

Section 15 of the Electricity Regulation Act, 2006, as amended, states that the setting of prices, charges, tariffs:

a. must enable an efficient licensee to recover the full cost of its licensed activities;

b. must allow for a reasonable return proportionate to the risk of the licensed activity;

c. must provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided;

d. must give end users proper information regarding the costs that their consumption imposes on the licensee's business;

e. must avoid undue discrimination between customer categories;

f. may permit the cross-subsidy of tariffs to certain categories of customers;

g. may have regard to the need to ensure security of supply, the diversity of supply and to promote renewable energy; and

h. tariff determinations must consider all planned projects reflected in the integrated resource plan and the transmission development plan as far as these projects shall impact on the costs of the licensee, for the period during which the tariff shall apply.

The Act further states that a licensee may not charge a customer any other tariff and use provisions in agreements other than those determined or approved by NERSA as part of its licensing conditions. Notwithstanding the above, NERSA may in prescribed circumstances approve a deviation from set or approved tariffs and a licensee may charge a customer a tariff which has not been set or approved by the Regulator where such tariff is charged pursuant to a direct supply agreement or arises as an outcome of a competitive market.

Other principles from the LGMSA include:

a. Users of municipal services should be treated equitably in the application of tariffs.

b. The amount individual users pay for services should be in proportion to their use of that service.

c. Low-income households must have access to at least basic services through:

- tariffs that cover only operating and maintenance costs;
- special tariffs or lifeline tariffs for low levels of use or consumption of services or for basic levels of service; or
- any other direct or indirect method of subsidisation of tariffs for low-income households.

d. Tariffs must reflect the costs associated with rendering the service, including capital, operating, maintenance, administration and replacement costs, and interest charges.

e. Tariffs must be set at levels that facilitate the financial sustainability of the service, considering subsidisation from sources other than the service concerned.

f. Provision may be made for the promotion of local economic development through special tariffs for categories of commercial and industrial users.

g. The economical, efficient, and effective use of resources, the recycling of waste and other appropriate environmental objectives must be encouraged.

h. The extent of subsidisation of tariffs for low-income households and other categories of users should be fully disclosed.

i. A tariff policy may differentiate between various categories of users, debtors, service providers, services, service standards, geographical areas, and other matters if such differentiation does not amount to unfair discrimination.

In addition to the above principles drawn from the legislation, the following are central in any regulated pricing framework:

a) Standardised regulatory accounts are required in the proper exercise of economic regulation.

b) Demand profiles drive the deployment of generators from the cheapest to the most expensive; and

c) Consumer affordability data and analysis should inform a well-structured subsidy framework.

Notwithstanding the above legal and regulatory principles, there are several pricing principles with specific relevance to the transitional environment of the South African electricity industry, as follows:

a) Shift from regulating individual licensees to regulating an industry.

b) The establishment of standardised regulatory accounts using the same data as for other sets of accounts, such as tax accounts, etc.

c) Application of activity-based costing principles to licensee operating activities.

d) Application of the principle of an opportunity to earn allowed revenue rather than a guarantee thereof.

e) Design and implementation of unbundled cost-reflective tariffs.

f) The need for understanding of the impact of the overall consumer demand profile on the cost of supplying electricity and servicing electricity end-users; and

g) The need for a clear understanding of the affordability of cost-reflective prices for each consumer tariff.

The above principles, together with other tariff objectives, are summarised in the following table. The table shows that different stakeholders have different expectations of tariffs. These objectives are sometimes in conflict, and trade-offs need to be made during the tariff determination process.

Table 1: Summary of Tariff Objectives

Stakeholder	Tariff Objectives	Description
Customer	Affordable	Price levels should assume an efficient and prudent utility; in other words, prices should be prudent and based on least life-cycle cost options and exclude inefficiencies. Consumers have the right to apply for direct contract prices that reflect the NERSA-allowed cost of supply and services consumed.
	Cost reflective	Must give end-users proper information regarding the costs that their consumption imposes on the licensee's business both in cost level and structure.
	Unbundled billing	End-user prices will be broken down according to the relevant components of the cost to serve, and all imposts, such as levies, subsidies, and surcharges, etc., will be transparently itemised in the billing process.
	Non-discriminatory	Tariffs should be equitable and fair.
	Predictable and stable	Prevent price shocks and keep customers informed about future price trends.
	Transparent and unbundled	Full disclosure of cost (no hidden charges). Cost should be unbundled. Tariffs should be easy to understand and apply.
Utility	Tariffs set at an electricity industry level	Taking cognisance of industry changes, tariffs and prices will be set at an industry level rather than at an individual company level. This is to reduce the administrative burden of setting tariffs for every

Stakeholder	Tariff Objectives	Description
		licensee in the electricity industry and to incentivise efficient licensed activities.
	Revenue recovery	Revenue from tariffs should reflect the full and efficient cost, including a reasonable risk-adjusted margin or return, for a licensed activity and ensure that the industry is economically viable, stable, and fundable in the short, medium, and long term. Licensees are provided with an opportunity for revenue recovery for their licensed activities.
	Efficient use	Revenue recovery is not guaranteed, and utilities must seek efficiencies during their licensed activities. Tariffs should promote overall demand- and supply-side economic efficiency and be structured to encourage sustainable, efficient, and effective use of electricity. Efficiency will be incentivised by setting tariffs against the efficient use of assets by assessing utilised capacity against available capacity.
	Cost reflective	A link between the price level and structure that an end-user must pay and the cost of serving that end-user including any Distributor or retailer product incentives for participation in utility-owned embedded generation, demand response, and flexibility programmes.
	Low cost of implementation	Implementation and transaction costs should be minimised. To achieve this, the Regulator will approve a standardised set of regulatory accounts.
	Returns	Fair and equitable commensurate with the risk borne and sufficiency to attract and retain capital efficiently.
	Retail margin	Fair and equitable commensurate with the trading risk borne by the Retailer or Distributor.
State	Social support	Tariff levels and structures should transparently accommodate social programmes.
	Environmentally responsible	The production and transport of electricity should be done in a sustainable way and be mindful of the impact on the environment.
	Sufficiency in generation capacity	Expansion through the development of least-cost resource options in line with national resource planning.
	State subsidies	Industry needs to achieve and maintain financial sustainability without ongoing State subsidies. This does not preclude provision for targeted subsidies such as FBE within or outside a subsidy framework.

2.2. Revenue Requirement

The revenue requirement for a licensee must be set at a level that covers the full and efficient cost of production, including a reasonable risk-adjusted margin or return on appropriate asset values. In the transition to a competitive market, the revenue requirement approach will be to institute economic regulation aimed at mimicking competitive conditions to steer prices towards efficient levels. Therefore, if well implemented, economic regulation should lead to efficient prices. It is applicable to regulated licensees, excluding market, licensee embedded own-generation and end-customer related energy purchases, private generators, and other market participants.

Given the electricity supply industry's size and its commercial and industrial customer base, the industry has the potential to generate strong cash flows to sustain a financially viable industry, as well as to place South Africa in a favourable competitive position internationally regarding access to and the price of electricity. At electricity prices that reflect prudent and efficient costs, the need for direct State support and subsidies should, apart from funding social objectives, be minimal.

Economic theory suggests that a perfectly competitive market would produce efficient prices. The electricity industry in South Africa is currently not structured to deliver perfect competition, but this does not diminish the importance of efficient electricity prices in any way. In the absence of a perfectly competitive market, the usual approach is to institute economic regulation, which is aimed at mimicking the competitive conditions to steer prices towards efficient levels. Therefore, if well implemented, economic regulation should lead to efficient prices.

Efficient electricity prices would lead to:

a. the optimum allocation of scarce resources including financial, human, and natural resources;
b. the optimum usage of electricity;
c. the optimum generation of electricity;
d. the optimum usage of the different energy forms (e.g. electricity, gas, oil, and coal); and
e. a financially viable industry.

Policy Position: 1

a) NERSA must, within 12 months of this Policy coming into effect and after consultation with stakeholders, review and adopt an asset valuation methodology and investment prudency framework that will ensure the financial and economic sustainability of the utility for historical replacement and new capital, ensuring that all asset classes/types are both prudent and financially sustainable; and

b) NERSA will move away from regulating licensee revenues and shall apply a regulatory method for the determination of required revenues for regulated licensed activities in the electricity industry; and

c) *When applying for a revenue requirement for a licensed activity, the applicant shall use the standardised set of regulatory accounts approved by NERSA; and*
d) *The tariff structure and level must be set to allow licensees the opportunity to earn their required revenue and must be determined in accordance with the cost-of-supply methodology for each licensed activity; and*
e) *Tariffs must reflect the efficient cost of rendering electricity services as accurately as practical as approved by NERSA.*
f) *Revenues determined by the revenue requirement methodology are not guaranteed, and reopeners, as a risk mitigation mechanism, will only be considered when the entire electricity industry is impacted by severe exogenous shocks or industry-wide force majeure-type events.*
g) *The revenue requirement for a regulated licensed activity must be set at a level that covers the full and efficient cost of supply, including a reasonable risk-adjusted margin or return on appropriate and prudent asset values and retailing risks.*
h) *NERSA, after consultation with stakeholders, must adopt an investment prudency framework and an asset valuation methodology that accurately reflects the prudency and replacement value of those assets, to allow the electricity utility to be financially sustainable, meet its debt-service obligations for the full tenor of the debt, and achieve stand-alone investment-grade credit ratings;*
i) *This will enable the licensee to obtain reasonably priced funding for investment to facilitate the establishment of infrastructure; to meet Government defined economic growth at an efficient price of electricity; and*
j) *In addition, the regulatory methodology should anticipate investment cycles and other cost trends to prevent unreasonable price volatility and shocks while ensuring financial viability, continuity, fundability, and stability over the short, medium, and long term, assuming an efficient and prudent operator.*

2.3. Cost Reflectivity

All Licensed utility-owned Generation, Transmission, Distributor, and retail tariffs should become cost-reflective over the next five years, except for specific cross-subsidies and/or subsidies (from outside of the sector) and/or as an outcome of the subsidy framework.

Policy Position: 2

a) *Electricity tariffs must reflect the efficient cost of rendering electricity services as accurately as practical; and,*
b) *Electricity prices to end-users must give end users proper information regarding the costs that their consumption imposes on the licensee's business; and*
c) *To achieve (a) and (b), tariff applications must be in the form of regulatory accounts as approved by NERSA from time to time; and,*

d) The average level of all the tariffs must be set for the electricity industry to provide an opportunity to recover the revenue requirement for each licenced activity; and,

e) The tariff structures must be unbundled as far as possible to recover costs as follows:

(i) The wholesale energy purchase price, reflecting: (a) the electricity generation infrastructure capacity costs for generation capacity; (b) variable generation costs; and (c) flexibility and balancing costs, with these components collectively reflecting the wholesale energy-related purchase price.

(ii) The wholesale transmission tariffs, reflecting the transmission network usage cost, including investment costs for infrastructure development and ongoing depreciation costs of assets.

(iii) The distribution tariffs, reflecting distribution network usage cost, incorporating investment costs for network expansion and maintenance, as well as depreciation costs associated with the infrastructure over time.

(iv) Service and administration tariffs, reflecting service and administration costs and the retail margin.

2.4 Transparency and Unbundling on the Bill

Billing processes and customer invoices should communicate relevant information to customers regarding their consumption and costs. Full disclosure (transparency) and breakdown (unbundling) of all key cost drivers, where practical, are essential features that would empower customers to make informed consumption decisions. Accounting 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.

In addition, the extent to which unbundling may be done on the bill depends on the type of metering installed or available, which in turn determines what quantities can be measured and the capability of the billing system. Strategies need to be put in place so that these problems may be overcome and the maximum practical levels shown.

Policy Position: 3

a) The customer bill must comply with NRS 047, as amended from time to time.

b) The customer bill shall communicate full disclosure and breakdown of constituent tariffs for each service consumed and any other itemised imposts, such as levies, subsidies, and surcharges, etc., to customers regarding their consumption or energy purchases by the retailer.

2.5 Non-Discrimination

There are currently several obstacles, principally relating to cross-subsidies that prevent the full implementation of a non-discriminatory pricing approach.

These discriminatory practices have created a situation where similar customers are subject to significantly different tariffs without any real differences in the cost of supply. This undermines the efficient allocation of resources and prevents healthy competition within similar industries. This means that the full potential and benefits of electricity can only be extended to all customers once these discriminatory pricing practices are removed. The obstacles should therefore be addressed and removed.

Policy Position: 4

a) *NERSA must, within 12 months of this policy coming into effect, address all forms of discriminatory pricing practices, other than those permitted, to unlock the full potential of electricity for all.*

2.6 Access to and Use of Networks (Transmission and Distribution)

Network (transmission and distribution) owners have an obligation to allow customers access to and use of their networks to wheel power, irrespective of the supplier of the power, provided that the customers are not in arrears in paying all relevant charges as approved by NERSA from time to time. Such access would not violate any financial, technical, and safety requirements as set out in the relevant grid codes, licence conditions, and tariff schedules.

The full cost of operating the networks should be reflected in the various connection and use-of-system charges. In other words, additional charges may be needed to facilitate the wheeling of electricity between two parties given that wheeling does result in incremental risks and costs for the Distributor and/or retailer. Southern African Power Pool (SAPP) rules would apply for the recovery of costs and payment of wheeling services for SAPP transactions.

If network constraints cause congestion and wheeling parties are affected, then NERSA has the responsibility to develop a mechanism that would allocate network capacity between interested parties. Such a mechanism needs to be fair, non-discriminatory, and transparent. In addition, the methodology needs to encourage the use of distribution and transmission assets to maximise the benefit to all users and not permit economic bypass. Network operators shall have an obligation to maximise the available capacity to market parties, ensuring that all available capacity is used efficiently and in a manner that optimises the overall benefit to users.

Policy Position: 5

a) Fair and non-discriminatory access to and use of networks shall be available to all users of the relevant networks for all delivery of energy, whether wheeling from a third-party supplier or from the utility;
b) The full cost to operate, maintain, and depreciate the networks, including the necessary investment for their development, shall be reflected in the use of system charges. Therefore, additional charges based on cost of administration and availing services associated with the wheeling of electricity, will be levied.
c) Any incremental connection costs and their fair share must be recovered as a connection charge;
d) Wheeling of electricity can only be permitted if the action complies with all legal, technical, safety and commercial requirements;
e) A methodology for transmission and distribution wheeling, including the treatment of network congestion, must be developed by NERSA; and
f) Southern African Power Pool (SAPP) rules would apply for the recovery of costs and payment of wheeling services for cross-border transactions.

2.7 Special Products

In addition to the standard range of pricing products, provision should also be made for the development and introduction of special products and prices. These products would typically be:

a) Curtailable and interruptible rates: Customers are paid/rebated to reduce consumption during very high-demand periods or capacity-constrained periods.
b) Critical peak pricing tariffs: tariffs are introduced with certain periods of extremely unaffordable prices when the system's reliability is threatened, and lower tariffs in other periods.
c) Real-time pricing products: Rates are provided ahead of time (usually on an hourly or daily basis).
d) Short-term flexible products and services to meet supply and demand.
e) Utility-owned renewable energy services to licensee end-customers that may include solar-PV solutions or battery energy storage solutions.

These products, in conjunction with enabling technologies, could significantly increase sales and the penetration of demand-response programmes and products and reduce the cost to supply and serve end-users.

Policy Position: 6

a) Along with standard pricing products, there should also be provision for creating special products and prices to meet specific goals.
b) The cost of these products will follow the regulatory guidelines. Additionally, this matter should be open to public consultation by NERSA; and

c) *NERSA needs to develop a framework that allows for quick turnaround for tariff approvals required for short-term needs and new product innovations benefiting optimum electricity pricing and use of new technologies.*

2.8 Long-Term Price Outlook

Given that customers have long-term planning requirements, there is wide support for the publication of a long-term price outlook. The price forecast should cover two aspects, namely the average national price of the entire value chain up to the point of sale to municipalities, as well as the average municipal price to each municipality's clients/consumers.

The price forecast should include a reasonable period of not less than five years. The outlook should be updated frequently to signal the overall expected trend in electricity prices. Ideally, the forecast should show the contribution of generation (including all major sources, whether SOE-owned or independent/privately owned), transmission, and distribution to the forecast price level for some representative notional customers.

Policy Position: 7

a) *NERSA, after consulting with stakeholders, should develop and publish annually a multi-year price path covering at least five years forward updated every 2 years aligned to the Integrated Resource Plan (IRP) whilst catering for private generation pipeline including implications from embedded low-voltage own-generation trends.*

3. PRICING INTERFACES

The EPP has been developed without a specific industry structure in mind. This ensures that the policy recommendations and positions remain valid under several industry scenarios. However, some basic assumptions had to be made regarding the key functions and pricing interfaces in the industry. If needed, these assumptions could be developed in more detail through separate policies over time. The assumptions are briefly discussed and illustrated below.

Generators may be owned by Eskom, municipalities, independent power producers, and private persons or entities.

South Africa may import and export electricity to and from other African countries and would follow SADC protocols in the wheeling of power between neighbouring countries.

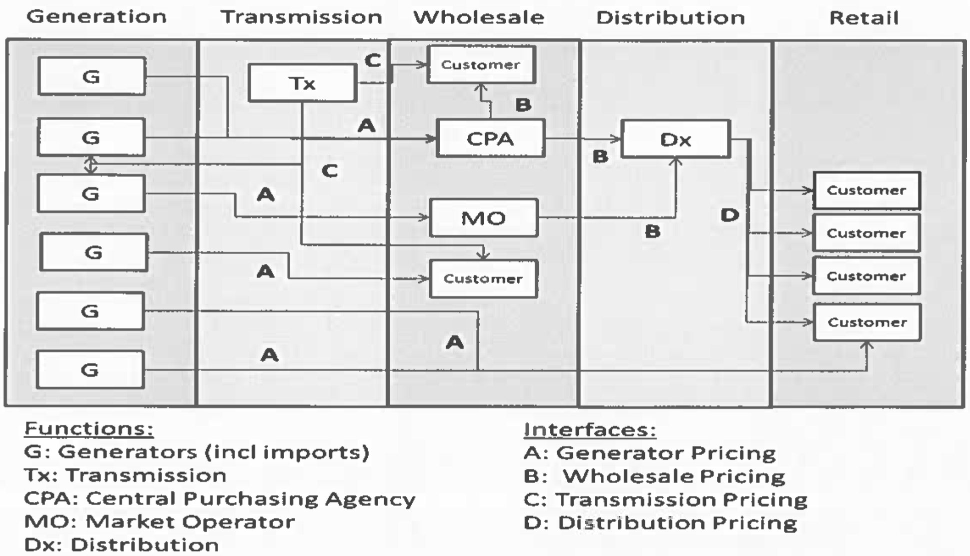
Licensed or registered generators and traders may, but are not obliged to, sell electricity to a central purchasing agency or single buyer, a licensee, a wholesale, or retail customer, a licensed or registered trader, or themselves.

Wholesale electricity prices may consist of wholesale energy prices, determined either through a regulated wholesale tariff or a competitive wholesale market, capacity prices, standby prices, legacy cost recovery, subsidy charges, transmission network charges, ancillary service charges, distribution network charges, balancing services, reserve prices, congestion management charges, environmental compliance costs, and consider carbon pricing mechanisms.

A competitive wholesale market is expected to be developed, comprising two key functions: the Market Operator, which operates the trading platforms between generators, retailers, customers, and traders and takes no ownership of the energy traded; and the Central Purchasing Agency, which takes ownership of energy purchased through legacy contracts and sells this energy to wholesale customers.

Purchases by organs of state shall be subject to compliance with the New Generation Regulations. Generators, distributors, licensed traders, and customers may also enter bilateral or direct power purchase contracts. Distributors will fulfil their regulated retail function associated with the purchase of energy from the wholesaler or market for their customers. Retail prices comprise the final regulated prices to retail customers.

Figure 1: Basic diagram illustrating the anticipated key functions and pricing interfaces.



4 GENERATOR PRICING

4.1 Applicability

Applies to all licensed or registered generators (including renewable generators and co-generators) in South Africa as well as all licensed importers of electricity to South Africa. Imported electricity prices would also form part of regulated generator prices in South Africa. This is necessary as it could impact on the security of supply and price levels for local customers. International wheeled energy (energy transported via South Africa to facilitate a transaction between SAPP members) does not form part of wholesale energy prices in South Africa. NERSA may develop criteria to exclude certain generators and import options from the EPP requirements, for example:

a) Transactions that originate and terminate outside the borders of South Africa fall outside the scope of this policy.
b) Private generators producing electricity for their own use and where the electricity is not conveyed over any public networks would fall outside the scope of this policy.

Policy Position: 8

a) Electricity from both licensed and registered generators in South Africa and from all approved importers of electricity to South Africa must fall within the scope of the EPP.

4.2 Tariff Structure

Pricing structures for electricity purchases from generators would reflect the underlying cost structure. Alternatively, the pricing structure would reflect the contractual commitments and agreements between the buyer and seller.

In addition to the sale of energy and capacity, some generators also provide ancillary services to ensure that the quality of electricity falls within acceptable standards. Ancillary services include, inter alia, the provision of operating reserves, frequency control, generator islanding, constrained generation, and reactive energy support. Without these services, customers may experience unacceptable quality of supply, including frequent interruptions, frequency deviations, and voltage fluctuations.

This approach creates an opportunity for a generator that provides ancillary services to earn more revenue than one that does not provide such services. It is important to note that some customers can provide certain ancillary services at a lower cost than generators. It is therefore essential that customers are given the opportunity to sell these ancillary services into the market.

Pricing structures for generators usually consist of a combination of capacity, energy, and ancillary service charges. These charges may be TOU-differentiated to encourage availability and production during certain periods. Tariff structures should not impede the least-cost dispatch of different generating sets and supply options.

Policy Position: 9

a) *Generator pricing structures must reflect the generator's cost of supply or, alternatively, any NERSA-approved PPA.*
b) *The generator pricing structure may consist of capacity, energy, and ancillary service charges.*
c) *Customers who are able must be given the opportunity to sell ancillary services to the market on a fair and non-discriminatory basis.*
d) *Generator pricing structures must not hinder efficiency or least-cost dispatch of generating units.*

4.3 Tariff Level

Electricity purchases from existing generators should be based on either the conditions set out in the PPA or be based on a regulatory methodology that would produce satisfactory financial performance over the short, medium, and long term assuming a competent and prudent operator. Electricity purchases from new supply options should be evaluated against an appropriate reference.

This reference is defined as the avoided system costs. The determination of avoided cost considers factors such as discount rate, duration, capital costs, fixed and variable operating costs, TOU, location, voltage level, and specific risk factors. Competing projects should be assessed using the same criteria. The criteria should be fair, non-discriminatory, and transparent. This aspect is expected to be addressed in the design of the single buyer.

Policy Position: 10

a) The price paid for electricity generated in South Africa or imported to South Africa must be based on either the appropriate and approved regulatory method or on conditions set out in the approved PPA. *b) Electricity purchases from new supply options must be evaluated and approved subject to ex ante approval of the power purchase agreements.* *c) NERSA must approve a framework to expedite the determination and approval of prices from supply options (e.g., short-term purchases).*

5. WHOLESALE PRICING

Wholesale pricing comprises wholesale energy and capacity charges, transmission charges, and the single buyer's own-cost charges.

5.1. Wholesale Energy Pricing

The wholesale market in the future will include competitive elements (with dynamic market prices as well as long- and short-term hedging contracts), physical bilateral contracts between generators and consumers, and legacy long-term PPAs.

The wholesale tariff structures should reflect a need for capacity charges raised on all customers. Generation capacity is created for purposes of capacity adequacy, system security, reserves, etc., whether it is used at certain times or not. With more customers being allowed to privately purchase energy, the cost of providing this back-up needs to be covered. Otherwise, this creates cross-subsidies for those with private generation.

Initially, before a fully-fledged market is in place, the proposed structure therefore needs to include an energy rate applied as a time-of-use differentiated variable c/kWh charge and an energy-related capacity rate R/kW applied as a demand charge. To the extent that operating market models and platforms have not been established, or are still being established, wholesale pricing will effectively be hedged back to the regulated pricing approach until the formal implementation of such market models and platforms and the formal migration of licensees thereto.

5.1.1. Applicability

The applicability would be to all customers eligible to participate in the wholesale energy market.

5.1.2. Wholesale Energy Pricing Structure

Wholesale electricity pricing structures must always encourage the efficient use of electricity. Wholesale electricity sales should be based on TOU energy prices to promote efficient electricity use, as well as standby or capacity charges applied as a demand charge. The demand and supply dynamics in an integrated electricity system change constantly. It is therefore necessary to periodically review and, if necessary, update the TOU definition for the purpose of wholesale energy pricing to keep pace with the latest developments.

The wholesale tariff structure needs to reflect the true costs in the supply chain and highlight various products and services arising from changes in the industry. Given the fixed and variable costs of generators, some stakeholders believe that generators' costs should be recovered through a combination of capacity charges (R/kVA) and energy charges (c/kWh). Against this background, there is merit in pointing out issues relating to fixed and variable charges, especially at the wholesale level.

A customer's energy demand charge may not be an accurate reflection of costs imposed on generators, considering that the customer's peak demand and the system peak may not occur at the same time. However, given the growth in variable energy resources, the requirement for back-up capacity is not related to the demand peak, as may have been the case historically.

Where a customer's peak demand is not strongly correlated with that of other customers, this reduces the burden on the system from a total capacity point of view. It also allows the capacity costs incurred by the Central Purchasing Agency in ensuring back-up capacity on the network to be dispersed among all consumers and reduces the absolute capacity required for backup. A standby or capacity demand charge could result in excessive costs for low-load-factor customers, which may be unpopular, but it indicates the actual cost of required back-up for all consumers.

It will also function as an incentive for low-load-factor customers to change their demand patterns or install their own battery, storage, or peak-shifting systems. If these options are available at a lower cost than the cost of establishing additional peak generation capacity, they will result in an overall net benefit to the South African economy.

Policy Position: 11

a) *The wholesale energy tariff structure shall include a wholesale energy tariff to always encourage the efficient use of electricity and must reflect the TOU structure differentiated cost of supply/pricing signal.*

b) *The wholesale energy tariff structure shall also include a capacity / standby charge to signal the capital-related costs for generation capacity applied to all wholesale customers as a demand related (R/kW) charge;*
c) *The wholesale energy tariff structure shall include a regulated legacy recovery charge and a subsidy charge to ensure recovery of legacy costs and the equitable recovery of wholesale, Distribution and retail subsidies as approved by NERSA, to be included in the transmission charge structure; and*
d) *The wholesale energy tariff structure and subsidies must be periodically reviewed and updated by the central purchasing agency and approved by NERSA, with the approval process subject to public consultation, considering its impact and implementation on customers.*
e) *The reimbursement of Distributor and retailer subsidies will be determined annually by the NERSA as per the Energy Regulator developed national subsidy framework.*

5.1.3. Central Purchasing Agency

The transition to a competitive Electricity Supply Industry requires arrangements that facilitate the orderly migration from the current single-buyer model to a multi-market electricity trading environment. As part of this transition, legacy Power Purchase Agreements (PPAs), including those concluded under the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) and other Government-approved Independent Power Producer (IPP) procurement programmes, will continue to be honoured to preserve contractual certainty, investor confidence and security of electricity supply.

To support this transition, a Central Purchasing Agency (CPA) will be established to manage legacy PPAs and facilitate the efficient allocation and sale of the associated electricity into the wholesale market.

Policy Position: 12

a) *Central Purchasing Agency (CPA) to hold and administer legacy Power Purchase Agreements (PPAs), including agreements concluded under the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) and other Government-approved IPP procurement programmes.*
b) *The CPA shall recover the costs associated with these legacy PPAs by selling the contracted electricity.*
c) *NERSA shall develop and approve the regulatory framework and pricing methodology governing the wholesale energy tariff applicable to electricity sold by the CPA and execution of the subsidy framework at the Wholesale level.*

5.1.4. Wholesale Energy Price Level

Wholesale sales should cover the total cost of wholesale purchases and services. Given that the wholesale energy pricing structure will be like generator pricing structures, there should be minimal differences between the revenue earned from selling wholesale energy and the cost paid to purchase electricity from generators. The application of legacy charges to manage legacy PPAs could result in differences between revenue earned and costs paid to these generators.

These differences should be addressed through over/under recovery mechanisms as part of the regulatory methodology for wholesale energy purchases and sales. The over/under recovery mechanism should ideally be dynamic and respond timeously to changes in the legacy differences (and avoid significant cash flow issues for the Central Purchasing Agency).

Policy Position: 13

a) *Wholesale energy tariffs must align with the cost of wholesale purchases, including capacity, energy, and ancillary services and as far as possible provide the correct signals for various products and services at the wholesale level; and*
b) *NERSA must develop a dynamic and timeous over/under recovery mechanism to deal with mismatches between legacy energy costs and revenues at the Wholesale and retail levels.*

5.1.5. Ancillary services and charges

Ancillary charges are for services supplied to the National Transmission Company by generators, distributors, or end-use customers, necessary for the reliable and secure transport of power from generators to distributors and other customers. In future, there may be a considerable number of parties participating in providing these services across the value chain in an ancillary service market.

Ancillary services are as defined in the Grid Code and include services provided by demand response and generators. Ancillary services include, inter alia, the provision of operating reserves, frequency control, generator islanding, black-start capability, constrained generation, and reactive energy support. Ancillary service costs include demand response and other dispatchable and non-dispatchable resources on the demand side.

The costs associated with ancillary services provided by network service providers would be recovered via network charges, and the ring-fenced cost incurred by the System Operator to operate the system would be recovered through Ancillary Services charges. Ancillary service charges should ideally be fixed charges based on capacity to ensure that all customers fairly contribute towards the costs of providing these services. With more private generation being permitted, in addition to ancillary services, there is a need to raise standby charges for the back-up capacity required.

Policy Position: 14

a) *The cost of ancillary services provided by the transmission network operator must form part of the transmission network charge;*
b) *The System Operator is to ring-fence its costs and the cost of operating the system, which is to be recovered through ancillary service-related charges, and such charges may be based on consumption and/or capacity; and*
c) *The cost-recovery mechanism for ancillary services should allow for the faster recovery of over- and under-expenditure relating to regulator-approved tariffs aligned to the adjustment of retail tariffs.*

5.1.6. Standby/capacity charges

A standby charge is applicable to recover capacity costs associated with continuously providing backup power to serve customers when their own generator or wheeled energy is out of service or unavailable as such, the standby charge functions as an insurance premium, which enables the customer to avoid incurring the cost of its own back-up capacity. The question arises as to whether a separate standby charge should be introduced in South Africa. The standby charge components for network costs (transmission and distribution) have already been introduced by way of generation capacity charges.

Hence, the remaining question is whether a separate standby charge should be increased to recover the under-recovery of separate capacity-related cost of generation. If introduced, it could have a considerable influence on the development of self-generation projects and impacts on low load factor end-users like small commercial and households. There is little doubt that any form of backup service will cost real money to provide.

It should be noted that standby or backup generator capacity is also constantly provided to customers who do not have self-generators. For example, the industry needs to carry sufficient plant and operating reserves to meet the needs of customers with large switchable block loads.

These customers are currently allowed to switch their loads in or out without notice and without incurring standby charges. However, in such a situation, there is certainty that, over a period such as an annual cycle, a customer who does not have own-generation capacity would consume sufficient electricity to cover the fixed capacity costs applicable to that customer's load factor and profile, assuming that capacity charges are recovered through volumetric tariffs.

This situation is therefore different for a customer who has a generator that does not produce electricity on a consistent basis and where there is no long-term intention or certainty that such a self-generating customer, or wheeling customer, would consume a sufficient volume of electricity to cover the fixed capacity costs applicable to that customer's load factor and profile.

For this latter type of self-generating customer, the position could be compared to an insurance policy with hourly premiums that requires the normal hourly premium to be paid only for the hour during which a claim is registered. That would be unacceptable: such a customer would be required to pay a premium for all hours for which risk coverage is received.

In contrast, the non-self-generating customer with a similar frequency of load fluctuation for switchable block load would pay for the coverage by virtue of high consumption volumes, given that the premium is embedded in the volumetric consumption charge.

It is thus proposed that a generation standby charge be applied to all customers at the wholesale level (and consequently carried through to retail customers) to ensure sufficient dispatchable capacity on the South African grid to meet customer demand.

Policy Position: 15

a) The cost of providing generator standby services to all customers, including customers with their own generators, must form part of the wholesale prices; and

b) The costs of system balancing shall, to a reasonable extent, be borne by those causing the imbalance. However, a balancing charge may be applied as part of ancillary service charges to cover any shortfall.

c) NERSA and the Market Operator must ensure that system balancing is fair and transparent and provides appropriate price signals for consumers to manage their consumption or Distributors to support end-users balancing risks in line with the costs of imbalance as reflected in the related Distributor balancing charges for associated risk mitigation.

5.2. Transmission pricing

5.2.1. Applicability

Transmission pricing is applicable to licensees and customers who qualify to access and use the transmission system.

5.2.2. Transmission Tariff Structure and Connection Charges

To encourage cost-reflective pricing, transmission charges must be unbundled to reflect Transmission Use of System (TUoS) costs, the cost of passed-through ancillary services, network losses, administration, and service costs, and, where applicable, connection costs. These charges will apply to generators and loads but may differ.

The charges will comprise:

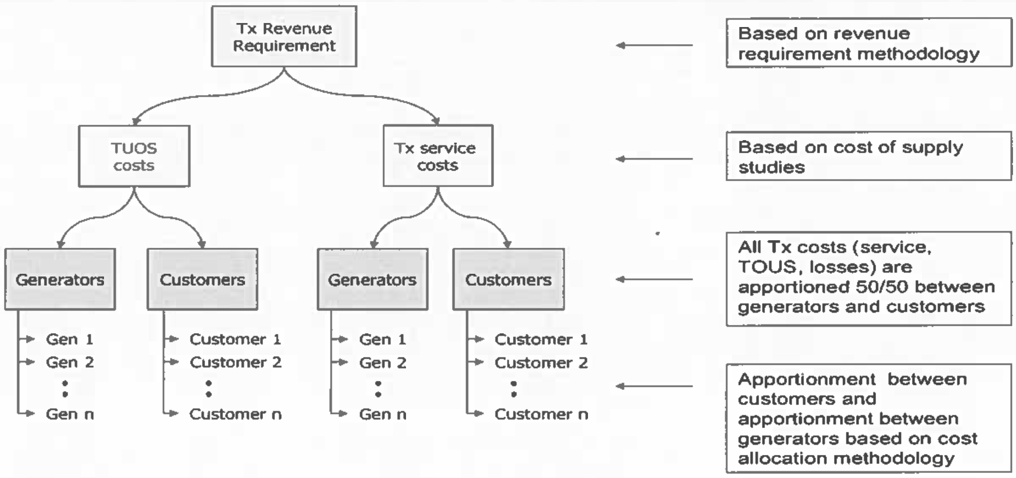
- connection charges;
- use of system charges based on annual capacity and transmission zones (in R/kVA or R/kW);
- ancillary service charges (in R/kVA or R/kW or c/kWh);
- line losses (in c/kWh);
- service and administration charges (in R/POD);
- charge for the recovery of national subsidies and/or other legacy costs (in R/kVA or c/kWh); and
- if required, additional charges may be introduced to better reflect the cost of supply, such as reactive energy charges, congestion charges, etc.

Connection charges need to be fair and must be calculated in accordance with the principles and rules set out in the relevant sections in the Code. The connection charges principles should be aligned to the following:

a. The basis on which connection charges are calculated by the licensee should be clear and transparent.
b. Customers should not pay twice for the same infrastructure.
c. There needs to be a fair and transparent reimbursement mechanism in the connection charge policy to deal equitably with shared network assets. This is to prevent second comers/free riders from benefiting once the first user has paid for the system.
d. Although customers would pay for the assets, the network company will own and maintain the assets.
e. The contracting parties should also have a clear understanding of funding and payment for the repair, refurbishment or even replacement of connection assets.

The different transmission costs (services) and their relation to the transmission revenue requirement and the cost recovery from generators and customers are summarised in the following figure.

Figure 2: Transmission cost allocation between different generators and different customers.



Policy Position:16

a) *Transmission tariffs must be unbundled (e.g. charges for: TUOS, ancillary services costs, line losses, customer services, and connection) to reflect more accurately the cost of supply;*

b) *The transmission tariff structure must reflect the overall cost of supply and could consist of a combination of capacity, energy loss factors, ancillary services, service, and administration charges, etc.;*

c) *Connection charges must be fair and calculated in accordance with the Code;*

d) *No customer connecting to the transmission system shall be permitted to avoid contributing to approved subsidies or legacy costs unless allowed by NERSA; and*

e) *The calculation of charges for the unbundled services should be in line with the principles set out in the Codes to ensure fairness and transparency in the way transmission charges are calculated.*

5.2.3. Transmission Tariff Levels

The transmission tariffs need to be set at a level that would allow the licensee to recover its approved revenue requirement.

Tariff levels should be determined in accordance with:

- the approved Codes.
- an approved cross-subsidies and/or subsidy framework; and
- tariff structures and annual adjustment regulatory rules and other regulatory requirements.

Policy Position: 17

a)	*The transmission tariffs need to be set at a level that provides the licensee with an opportunity to earn its approved annual revenue requirement; and*
b)	*Tariff levels must be determined in accordance with approved standards, codes, frameworks, and other regulatory requirements.*

5.2.4. Transmission Investment for New Capacity, Refurbishment and Maintenance

The Transmission network service provider's revenue determination should be set at a level that provides adequate recovery to meet its investment obligations in terms of the Transmission Development Plan, refurbishment, and maintenance.

Policy Position: 18

a)	*Transmission must undertake the required analyses to determine the extent of investment and resources required to provide new capacity, refurbishment, and maintenance;*
b)	*NERSA should assess and approve reasonable funding requests for investments in regulated assets to ensure the transmission network's expansion, maintenance, and refurbishment align with the Transmission Development Plan.*

5.2.4.1. Transmission Charges to Generators and Loads

Electricity is characterised by significant transport, transmission, and distribution costs. The location of generation relative to the location of consumption within an electricity grid influences the costs of supplying customers. The costs of electricity transmission fall into two categories:

- **Infrastructure and operating costs:** Infrastructure costs include power lines, cables, transformers, and other equipment. Operating costs include the cost of building and maintaining these assets.

- **Short-Run Marginal Costs:**
    - **Losses costs:** The transportation of electricity along transmission lines results in electrical energy losses. This lost energy must be replaced, at a cost, by increasing total generation output.

- **Constraint costs:** When transmission capacity is not available to accommodate power flows, instead of transporting power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all areas.

The mechanisms used to allocate these transport costs to generators can materially affect the value of a generator and the value of its output. The mechanism can also affect generators' locational decisions. Signalling electricity transport costs to generators through energy and/or infrastructure prices can give them an incentive to make an efficient trade-off between all the factors that vary by location.

For example:

- The choice of where to locate wind farms entails a trade-off between regional variation in wind speeds and the costs they impose on the transmission system.
- The choice of where to locate gas-fired generators entails a trade-off between regional variation in gas and electricity transmission system costs.
- The signals conveyed to investors through charges that recover the costs of infrastructure, constraints, and losses therefore provide a means of ensuring that generation investors make a least-cost trade-off between their own generation costs and the transmission costs that their presence imposes on the system, thereby promoting economic efficiency.

The reasoning that only consumers should pay for transmission costs, based on the assumption that only load customers need the transmission network, is not correct. The location of a generator also influences the cost of transmission, as does the location of the load. Generator location will be driven by access to the grid, fuel, and renewable energy sources.

Owing to reasons often linked to fuel cost, economies of scale, and other factors, generators are rarely located near their customers, but closer to, or in, areas where it is cost-effective to produce power. This implies that the Transmission Company should build the network to transmit generated power to areas where it is required.

The costs of operating and maintaining the network as well as the portion of capital costs not recovered directly from the generators (that is, socialised) will need to be recovered based on accepted principles. Without locational signals, the cost of socialising means that all pay the same and generators causing the costs are not exposed to the correct pricing signal, as they may choose locations that are more suitable for themselves and less suitable for the Transmission Company or country. Therefore, the costs should equally be allocated to the generators and include locational signals.

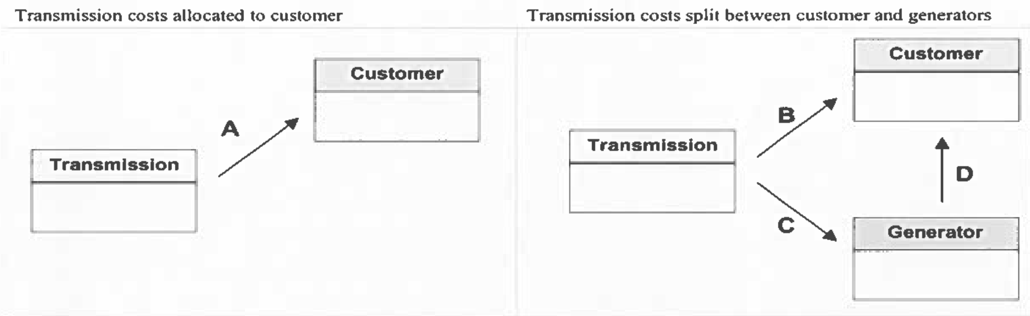
The implications, if load customers pay for all transmission costs, are that:

a. The approach deviates from the principle that the user-must-pay. In this instance, as described above, the generator is also a user of the transmission system and should, therefore, pay according to this principle.

b. Whether the generator pays or does not pay causes a considerable shift between energy and demand charges. For generators selling energy to the wholesaler, the transmission network charges are a pass-through and added to the energy charges as described under wholesale energy pricing. If generators do not pay transmission network charges all the transmission costs will be recovered from load customers through demand (kVA) charges.

c. In other words, whether generators pay for transmission costs or not affect whether load customers pay for transmission through a combination of energy or demand charges or through demand charges only. This would in turn have a significant impact on the cost of customers at lower load factors.

Figure 3: Illustration of cost split between customers and generators.

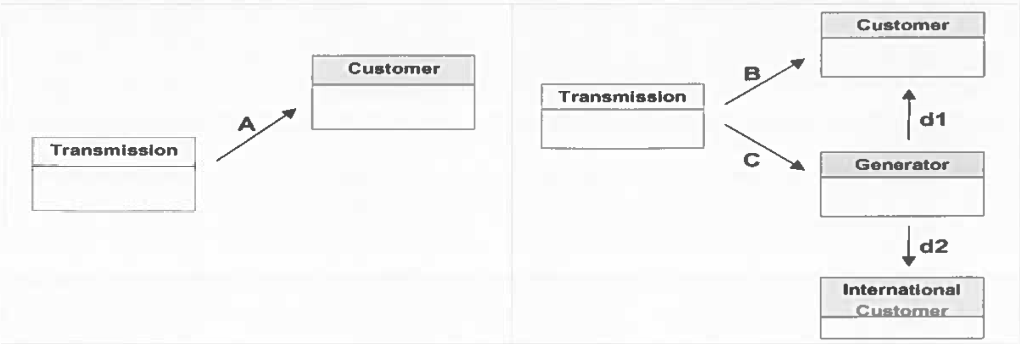


Note:
A = B + C
A, B & C (kVA charges)
D (energy charge)

The deviation from cost-reflective tariffs and the user-pay principle becomes more obvious if generators do not pay for the use of the transmission network, particularly where some of the electricity produced in the country is exported. See Figure 5 for a simple illustration. This may lead to a situation where local customers subsidise international customers for the use of the transmission networks. This is illustrated by the fact that A > B + d1 in Figure 5. This is not a desirable outcome and should be avoided, given that the volume of international trade in SAPP is expected to increase over time.

Figure 4: Illustration of cost split between customers (local and international) and generators.

Transmission costs allocated to customer | Transmission costs split between customer and generators



Comments:
A = B + C
C = d1 + d2
B + d1 < A
A, B & C (kVA charges)
d1 & d2 (energy charge)

The allocation of transmission costs could impact on the competitiveness of generators. This should not present a problem if the cost allocation is fair and reflective of the costs.

Policy Position: 19

- a) *Transmission network costs must be apportioned 50/50 between generators and customers to reflect the cost of supply more accurately;*
- b) *The transmission tariff structure will be based on a zonal pricing methodology;*
- c) *Transmission losses costs will be allocated directly to loads and generators;*
- d) *Transmission service and other costs must be allocated rationally between loads and generators and must reflect the cost to provide the service; and*
- e) *The apportionment between generators and customers must be reviewed from time to time to ensure compliance with regional approaches, so as not to disadvantage South African-based generators.*

5.3. Transmission Charges Geographic Differentiation

The TUoS charges for both generators and loads are based on zones. The zones for loads are geographically based, while the zones for generators consider both the geographical location and electrical proximity of the generator to loads. These are explained as follows:

a) Load Zones

The TUoS tariffs for loads are based on a concentric-pricing approach. The charge is geographically differentiated in four zones based on the distance of the location of the load from Johannesburg, measured in kilometres. This differentiation methodology is arbitrary and results in non-cost-reflective charges. It is argued in the industry that the different approaches for determining charges for generators and loads create artificial arbitrage opportunities and economic discrepancies that are difficult to explain. It is recommended that the approaches be harmonised in the medium to longer term.

b) Generator Zones

TUoS tariffs for generators are derived from load-flow simulations on the Transmission system as it is planned to be in operation. Generation units are dispatched in proportion to their installed capacity to match peak demand. The cost of the Transmission asset is allocated to generators based on the proportional installed capacity and contributions to power flows for the different Transmission assets. The current charging methodology only recognises peak security as a driver of Transmission charging.

The integration of renewable generation brings fundamental challenges in Transmission planning and charging. The current Transmission pricing methodology does not appropriately reflect the costs imposed by different types of generators (in particular, renewable generators) on the electricity Transmission network.

The charging methodology only recognises peak security as a driver of network usage and assumes that all types of generation within an area of the network (a generation charging zone) contribute equally to network use. In doing so, it overlooks the fact that some generators use the Transmission system more during the peak hours and some less. Under the current methodology, all types of generators are assumed to provide peak security. The additional advantage will be to dampen fluctuations that would otherwise be observed.

Policy Position: 20

a) *The current transmission geographic differentials for loads must remain until they are updated by an approved redefinition of geographic differentials;*
b) *The transmission licence holder, DEE, and NERSA must evaluate the redefinition of geographic differentials for customers by assessing price stability and comparing the current generation mix with that foreseen in the next 10 years; and*
c) *The transmission license holder, DEE and NERSA must investigate different options and adopt the most appropriate method for allocating costs between generators.*

5.4 Transmission Charges for Cross-Border Transactions

South Africa is an active participant in SAPP development and trading. To prevent any cross-subsidisation between South African and SAPP customers, it is important that the same transmission tariffs, connection charges, and principles should apply to international customers connected to the transmission system.

Policy Position: 21

a) *Use of system charges will be the regulated Transmission charges.*
b) *Cross-border customers will be required to pay connection charges in accordance with the Code and connection charge policy. Where deviations are warranted, they should be approved by NERSA;*
c) *Imports will be treated as generators and exports as loads for tariff purposes; and*
d) *The financing of connection assets for cross-border customers will be in accordance with the Codes and where there are deviations that are warranted, NERSA should approve them.*

6. CROSS-BORDER SALES

The relevant licences granted by NERSA will enable cross-border trade. All cross-border trades will be in terms of the South African Grid Code and Distribution Codes in the first instance, and Southern African Power Pool (SAPP) rules or any other African power pool in the future in the second instance. Cross-border customers must not pay or receive subsidies intended for South African customers.

Policy Position: 22

a) *Cross-border customers must not receive subsidies intended for South African customers.*
b) *South African customers must not subsidise the export of electricity; and*
c) *International contracts will be subject to South African energy conservation and load-curtailment legislation, regulations, and/or rules.*

7. DISTRIBUTION AND RETAIL PRICING

Distribution Pricing includes components of both retail and network services. For some customers, distributors would function as the retailer for the purchase of power and for others, they may purchase directly from the wholesaler, the market or through wheeling. For both scenarios, distributors would be providing network services, customer services, and administration.

However, electricity pricing in the distribution sector is disjointed, with no clear framework on tariff structures, resulting in a multitude of retail tariff variants. Bundled tariffs make it difficult to separate the different services being provided and to show cross-subsidies transparently. Tariffs between Eskom and other distributors are also regulated differently by NERSA. Therefore, NERSA must develop a framework aligned with the principles set out in this policy document, with which licensees must be required to comply.

Policy Position: 23

a) *NERSA shall develop a national tariff framework within 12 months of this policy coming into effect to guide how tariffs are structured, while recognising the need for innovation in the development and approval of updates to tariff structures, new products and services.*

7.1 Tariff Level and Structure

This first section addresses the key principle for distribution pricing, namely that tariffs should be designed according to cost-reflective principles and should support cost reflectivity and transparency. Cost reflectivity includes the tariff level and the tariff structure. Provision may, however, be made for deviations from cost level and structure. The tariff level is the revenue sufficient for a licensee to recover its costs plus a fair return, whereas the tariff structure is the way the allowed revenue is broken down into different types of charges and recovered through those charges.

For all distributors, their costs should be based on an appropriate methodology that treats all distributors consistently and should not be based on historical benchmarks, but on a uniform regulatory method that must fairly enable an efficient licensee to recover the full cost of its licensed activities considering a level of return on assets that is commensurate with the risk borne and sufficiency to attract and retain capital efficiently. A cost-of-supply (CoS) study should be used to justify costs to obtain allowable required revenue and the cost to serve (CTS) to allocate costs based on approved required revenue.

Policy Position: 24

a) *Tariff levels shall provide the licensee with an opportunity to recover the NERSA-allowable revenues or revenue requirements per financial year;*
b) *Tariff structures shall reflect the NERSA-allowed revenues in terms of the cost structure and components of the allowable revenues determined in terms of the principles set out in this policy; and*
c) *NERSA shall, within 12 months of this policy coming into effect, develop a consistent regulatory method for determining the allowable revenues for all distributors and annual adjustments that sustain tariff cost reflectivity, including a standardised set of regulatory accounts.*

7.2 Cost of Supply Studies

A cost-of-supply (CoS) methodology (for price level) and a cost-to-serve study (CTS) methodology (for price structure) is needed to understand costs for tariff design and development purposes as well as cross-subsidies and/or the subsidy framework contributions. The cost components and cost drivers that should be included in cost-of-supply studies must be identified from NERSA-allowed revenues and reflected the allocation of costs (CTS) accurately.

NERSA must develop a standard that will provide guidance for the development of the CoS and CTS studies. This standard must address the following cost components as far as possible:

- Energy purchase cost based on the energy purchase price structure.
- Transmission network charges reflecting the Transmission purchase tariff structure.
- Cost of distribution and transmission losses per transmission zone and voltage of supply.
- Cost of distribution network services per voltage of supply.
- Retail costs per supply size point of delivery (PoD), type of services rendered, and metering; and
- Measures to ensure that CTS studies provide a view of the inter-tariff and/or subsidy framework subsidies compared to the existing tariffs.

Policy Position: 25

a) Electricity distributors shall provide CoS or CTS studies to NERSA to support their applications for new tariffs or tariff structure changes.

b) CTS study models and approaches are to be based on the cost-causation principle.

c) This must be done according to the approved NERSA standard to reflect changing costs and customer behaviour.

d) CTS studies must be done in accordance with the approved NERSA standard. The standard must address the following components as far as possible:

i. Energy purchase costs

ii. Transmission purchase costs

iii. Distribution network costs

iv. Retail costs

v. Product or service Incentives and other related costs

e) Electricity distributors shall submit CTS studies to NERSA at least every five years to inform the current customer base (all customer categories) and the relationships between cost components and sales volumes.

7.3 Customer Categories

Each customer or customer category has a different load profile, demand, and load factor and, consequently, the energy and network costs differ. However, as it is not possible to have tariffs for each customer, there is a need to pool costs based on customer costing categories, including both loads and generators. For this reason, costs and tariffs need to be differentiated by type of usage profile, voltage of supply and density in the area of supply connection(rural/urban). Such differentiation should be applied when the cost of any customer costing category differs significantly from another.

Policy Position: 26

a) Customer categories for costing, tariff design, new tariff or product or service development, special pricing arrangements, and electricity products must be justifiable to NERSA and based on the underlying cost drivers across the customer base, including load, generator, wheeling, trading, and aggregator customers. In determining customer categories, consideration must be given to:

i. Consumption and generation characteristics;
ii. Customer demand, size, and supply or export location characteristics;
iii. Metering arrangements;
iv. Network configuration and voltage level;
v. Customer service and account management requirements;
vi. Contribution to network losses; and
vii. The provision of energy storage or renewable energy services, where applicable.
b) A new customer costing category may be established where the cost of supply or nature of service is materially different from existing categories.
c) Customer costing sub-categories may be created where there is a justifiable distinction in cost components or service characteristics that supports more appropriate tariff differentiation.

7.4 Cost-reflective Tariff Structures

A cost-reflective tariff structure is one that reflects costs as closely as possible. For distributors, this cost starts with their purchase costs for energy and transmission network services, the Eskom distribution charges for distributors that elect to be supplied from Eskom Distribution, and, for municipal licensees, their own distribution costs.

Tariffs that currently recover fixed costs through a variable charge impose revenue risk on the distributor and increase tariffs for all customers. The correct separation and structuring of network, retail, and energy (variable and fixed) costs in tariff charges provide the correct economic signals and payback period for alternative energy decisions by comparing the utility's energy cost with the cost of the alternative energy source.

If tariffs are not correctly structured to reflect fixed and variable costs:

- a reduction in sales and volumes will result in lower bills, not only for variable energy, but also for fixed energy capacity as well as network charges; and
- this is not equitable or fair to those who, for example, are not able to afford alternative energy sources.

This loss in revenue when the bill is reduced must still be recovered, as energy capacity and network costs will remain for required capital expenditure, continued maintenance, and operations, even when consumption is reduced. These costs would still have to be recovered through tariffs, resulting in increases to tariff charges. Therefore, if the electricity industry does not restructure existing distribution tariffs to meet a changing ESI and EDI environment, all customers will be negatively affected. Customers who opt for alternative sources of energy should also equitably face the cost of their back-up energy supply from distributors; otherwise, unintended tariff subsidies may result.

For some customer categories, and for ease of customer understanding, the various cost components can be simplified into fewer charges for some tariffs (that is, more bundled) but should still reflect the full cost of supply for the group of customers charged through the simplified tariffs.

Policy Position: 27

a) The charges reflecting the unbundled costs, should be structured as far as possible to include:
b) Energy costs in c/kWh and generation capacity charge reflecting the wholesales energy purchase cost structure;
c) Transmission network and ancillary charges reflecting the Transmission purchase price structure;
d) Distribution network charges in R/kVA based on maximum demand per billing period;
e) Distribution network charges in R/KVA or R/kW/ month or R/Amp/ month based on annual capacity;
f) Customer service charges in R/customer or /Point of delivery (POD) / day/months based on the size of the supply;
g) administrative charges in R/POD/or month/day;
h) Charges for poor power factor as transparent and separate line items,

i) A TOU energy net-billing rates for prosumers, *j) Charges for the cost of losses,* *k) Wheeling crediting charges,* *l) Net-billing credit charges,* *m) utility-owned embedded generation, storage, and demand management incentives for participating end-users,* *n) Cross-subsidy charges; and* *o) All applicable charges whether unbundled or bundled must however enable the recovery of the full allowed revenues (costs plus returns).*

7.5 Rationalising Electricity Tariff Structures in the EDI

NERSA, in collaboration with the electricity industry, should develop a national guideline for the EDI to standardise electricity tariff structures and other pricing mechanisms (including product and services principles and incentives, subsidies and wheeling crediting). This will facilitate a consistent approach to tariff or product or service design and development across all distributors, enhance transparency, and improve stakeholders' understanding of electricity tariffs. Distributors will be required to adapt their tariff structures and other pricing mechanisms in compliance with the national guideline. However, tariff levels may continue to differ between utilities to reflect local circumstances, demographics, and cost structures.

Policy Position: 28

a) NERSA shall, within 12 months of this Electricity Pricing Policy (EPP) coming into effect, develop, consult on, and finalise a framework to guide the standardisation of electricity tariff structures and other pricing mechanisms (products and services principles and incentives, subsidies and wheeling crediting) for all licensed electricity distributors. *b) The framework shall establish a common industry tariff structure and pricing mechanisms consistent with the policy positions contained in this EPP and shall be developed through an open and transparent public consultation process.*

7.6 Changes to Tariff structures

Structural changes will be required when cost drivers, customer segmentation and pricing signals need to be more reflective of the Distributors' customers' needs and business requirements. Delayed changes to existing tariff structures may result in energy consumption inefficiencies, purchase cost under-recovery, Distributor volume risks and create unintended cross-subsidies. Customers need to receive the correct signals in a timeous manner to address these electricity distribution issues. At a minimum, structural changes to tariffs should be done based on a cost-of-supply and cost to serve studies and may include pricing signals.

Policy Position: 29

a) *NERSA must ensure that Tariff structure and levels shall be aligned with the results from an updated CoS and CTS studies and will reflect the associated revenue requirement for the licenced activity and cost structure characteristics.*
b) *NERSA may approve changes to tariff structures where tariffs are combined or rationalised, using existing tariff revenue without a CoS study, and.*
c) *NERSA shall timeously evaluate all submitted structural changes, new tariffs, crediting charges, products and services and provide reasons for decisions with guidance.*

7.7 Distribution use-of-system (DUoS)/Network Charges

The distribution network costs are the costs of a Distributor associated with capital (regulated return on assets and depreciation) for new and refurbishing of existing infrastructure, maintenance, and operations and for flexible service provided. Use of system charges can also be used for raising of subsidies and other charges that may not be avoided.

DUoS charges are unbundled network related charges that reflect these distribution costs, plus any contribution to network-related subsidies applicable to loads and generators and are as follows:

- Distribution network costs – may be split into fixed and variable components.
- Ancillary service cost – pass-through cost from the System Operator in Transmission and distribution related service cost.
- Embedded Transmission network and ancillary charges – pass-through cost from Transmission.
- Administration and service costs related to the provision of a network service including wheeling.
- Subsidy charges – network related subsidies that shall are not avoided by any users of the network.

Network tariffs need to be reformed to move away from variable based charges (e.g. c/kWh) to tariff structures that had better reflect the fixed costs and the demand users of the Distribution network impose on the network. This is an appropriate mechanism to compensate Distributors for providing the network and required capacity e.g. ensure that customers with PV self-generation also bear the same network costs as other customers.

Without a distribution network, energy generated cannot be delivered. The Distribution network business is just as important as the generation of electricity because network assets; wires, poles and transformers are needed to transport the energy from the generator to the consumer and to accommodate bi-directional flow of energy where the customer is both a consumer (load) and a generator.

Distributors are required to pay TUoS charges to reimburse the Transmission network operator for use of the transmission system. Similarly, Distributors will need to recover this transmission cost through an embedded TUoS charge. Consequently, the Distribution network charges comprise the DUoS and the embedded TUoS charges.

Policy Position: 30

a) *DUoS charges shall apply to both generators and loads.*
b) *Charges shall be cost-reflective and based on an updated cost-of-supply and cost to serve studies, considering capacity, voltage level, transmission zone, network losses, and urban or rural classification (density of supply area).*
c) *DUoS and embedded TUoS charges shall recover the full cost of operating and maintaining the distribution network, including ancillary services, retail services, and approved subsidies where applicable.*
d) *DUoS charges shall be unbundled to improve transparency, with a minimum fixed network capacity charge and additional demand- or consumption-based charges where appropriate.*
e) *The charging principles shall apply to all small power tariffs, except subsidised lifeline tariffs.*
f) *NERSA shall implement a phased transition to cost-reflective distribution network charges within five years of the policy coming into effect.*
g) *NERSA shall develop a national DUoS charging framework, including standardised regulatory accounts, to ensure consistency and regulatory certainty across the electricity distribution sector within 12 months of the policy coming into effect.*

7.8 DUoS Charges for Wheeling

In compliance with the Electricity Regulation Amendment Act, the transmission and distribution licences, Licensees must provide non-discriminatory access to the grid. Therefore, access and the DUoS and TUoS charges for the delivery of energy are, therefore, independent of the supplier of the energy or the buyer of the energy. Where energy is wheeled through a bilateral arrangement/contract, the charges for the delivery of the energy will be the same charges as for customers buying their energy from the licensees, plus and associated administrative costs.

Policy Position: 31

a)	*A generator wheeling energy will pay the standard generator DUoS charges as applicable;*
b)	*A load buying wheeled energy will pay the standard load DUoS and TUoS charges as applicable;*
c)	*No wheeling customer will be subsidised by a non-wheeling customer;*
d)	*A wheeling customer will have to pay the administration costs and any additional wheeling service charges required for a wheeling transaction; and*
e)	*A wheeling customer will not be allowed to avoid contribution to approved cross subsidies or subsidy framework contributions.*
f)	*All charges will be identified in the standardised set of regulatory accounts.*

7.9 Retail Charges

Retail charges recover the cost of administration (meter reading, billing), energy trading, wheeling transactions, and customer service (including support, queries, applications, quotation, and call centres).

Policy Position: 32

a)	*Retail charges shall be based on appropriate segmentation linked to the level of administration required the type and the level of service provided to the customer;*
b)	*Except for lifeline tariffs all tariffs will pay cost-reflective (level and structure) retail charges;*
c)	*For any additional services or transactions required on the bill an additional administration charge will be raised; and*
d)	*Additional retail charges may be applicable for additional products and/or services.*
e)	*All charges will be identified in the standardised set of regulatory accounts.*

7.10 Crediting for Energy Exported into the Network (Net-Billing Tariffs)

Load customers generating some electricity may choose to export this energy into the Distribution network and receive a credit for the exported energy.

In this context, net-energy billing is a mechanism applied when the customer's generation is synchronised with the grid (grid-tied), some energy is exported, and a credit is provided on this exported energy. The utility or another party does not purchase this energy; the energy still belongs to the customer using the grid as a bank. Such customers may be required to register or apply for a generation licence.

The benefits of using the network despite customer having their own generation include:

- The grid is a virtual battery, that is, it can temporarily store excess energy and can accommodate more storage than a battery.
- The customer can benefit from a net-billing tariff, which is a debit and credit process for energy consumed and produced at the same point of supply and not a netting of import consumption kWh and export production kWh.
- If net billing is combined with storage, the customer can benefit by reducing higher peak power charges. Storage could include hot water and batteries (including electric cars).
- The grid provides ancillary services that the customer would otherwise have to provide such as supplemental and back-up power and a fault level.
- The customer can also provide ancillary services to the grid provider and the System Operator, that is, remote control over the generation and/or storage, for which the customer can be compensated.

With grid-tied and net-energy-billing tariffs, it is important that appropriate charges are raised for the use of the network and the services being provided and that these charges are not raised as volumetric c/kWh charges as far as possible. If tariffs do not reflect cost causation, this means that customers with own generation could end up being subsidised by customers without by reducing their contribution to covering network and retail costs, while shifting those costs onto utility customers who do not have own generation.

At a minimum, TOU tariffs should be mandatory to ensure fair payment and compensation in the various time-of-use periods. Tariffs that reflect costs in different time periods, including net billing, will encourage storage, the reduction of peak demand and result in a reduction of costs for the utility and the customer.

Policy Position: 33

a) Net-energy billing will be allowed, subject to any licensing or registration required by law and in compliance with NERSA rules; *b) The net-energy billing customer will be required to be at a minimum on a time-of-use tariff;* *c) The net-energy billing customer will be required to pay the relevant DUoS and TUoS charges for the use of the Distribution grid associated with consumption;* *d) The net-energy billing customer will be required to pay the relevant DUoS or TUoS charges for the use of the grid associated with export of energy;* *e) A credit rate for energy exported into the Distribution grid will be given based on avoided purchase cost;* *f) DUoS, embedded TUoS, and retail charges will always be payable and will not be credited against the value of energy exported into the Distribution grid;* *g) This compensation will be done on a time-of-use basis for the value of the energy exported;* *h) An additional retail charge will be raised to cover the incremental cost associated with the additional billing transaction; and* *i) NERSA shall establish a framework for the raising of net-energy billing rates and approve such rates.*

7.11 Wheeled Energy (Wheeling)Wheeling Tariffs for Loads and Generators

All customers using the Network whether load or generator are subject to Use-of-System charges, regardless of whether energy is supplied by the Licensee or through third-party wheeling. These charges enable the Licensee to recover Network costs. Tariffs must comply with the EPP and the Codes and be approved by NERSA. Connection charges may be applied separately to cover upfront connection costs.

Charges for Loads

Charges for loads should preferably be based on unbundled and explicit Use-of-System charges applicable to Wheeled Energy. Where such unbundled charges have not yet been approved, bundled Use-of-System charges that inherently include wheeling-related network costs may be applied as an interim measure.

Charges for Generators

Charges applicable to generators must be determined in accordance with the Licensee's approved methodology and must comply with the applicable Codes. Any additional administrative costs arising from third-party wheeling arrangements may be recovered by the Licensee.

All network users must contribute towards NERSA approved subsidies or municipal surcharges, irrespective of the source of energy supplied. Such subsidies and surcharges should be transparent and supported by an approved cost-of-supply and cost to serve study. Connection charges may also be levied separately from the applicable Use-of-System charges.

Calculating Avoided Energy Cost – Wheeling

Wheeled Energy must be accounted for through either an approved Wheeling Credit Rate or Wheeling Tariff, or by separately identifying Wheeled Energy on the customer's bill. The Licensee remains responsible for determining the applicable rules and accounting mechanisms for the treatment of Wheeled Energy.

Policy Position: 34

a) *All parties must comply with all applicable laws, Codes, and agreements when conducting electricity-related activities.*
b) *Transmission, distribution, and trading activities require NERSA licences under the Electricity Regulation Act (ERA); some distribution licences include inherent trading rights.*
c) *Schedule 2 activities are exempt from licensing but must be registered with NERSA, including resellers and generators wheeling electricity (provided no sale to an organ of state occurs).*
d) *Use-of-system charges, Wheeling Credit Rates/Tariffs and related service charges require NERSA approval; generators and buyers are responsible for all third-party wheeling charges.*
e) *Licensees may impose conditions on wheeling transactions, provided they do not conflict with the ERAA, applicable Codes, this guidance, or the EPP.*

7.12 Cost-Reflective Versus Pricing Signal

Customers respond to the signal provided through electricity prices.

Tariffs have the objective of creating a specific signal to customers to achieve specific objectives. Tariffs are not solely about cost causation and price signalling but also cater for other objectives like capacity to supply.

In addition to being cost-reflective, the price signals in tariffs should meet a range of objectives, which may include:

i. manage generation capacity and related cost recovery;
ii. meet the System Operator's requirements to optimise the operation of the power system;
iii. provide the right economic signals that promotes economic efficiency;

iv. incentivise investment for the benefit of both the customers and licensee; and
v. improve financial sustainability by increasing efficiencies in operating costs.

Policy Position: 35

a) *The pricing signal to be provided to customers using the baseline cost reflective price and must reflect itemised costs and other objectives to ensure operational and financial sustainability, and*
b) *Any additional pricing signals over and above recovering the costs and ensuring operational and financial sustainability must be itemised and motivated specifically and be approved by NERSA.*

7.13 Retail Energy Charges

The load profiles of customers differ significantly and therefore, the application of tariffs with single energy charges does not reflect the system usage or the wholesale tariff and this may result in uneconomic use of the system and, result in increased costs and under-recovery of revenue. In addition, if customers only pay an average single energy rate, but rely on the system for peak power, this will result in these customers being cross subsidised by customers that use electricity more effectively. TOU signals also provide customers with the opportunity to save if they do respond.

The changing electricity environment is becoming more important for customers to have time-of-use signals as the installation of PV reduces consumption, but not necessarily peak demand. For these reasons, the application of TOU tariffs to all customers in the industry, except for the lifeline tariffs and, where practical should be actively promoted.

Policy Position: 36

Tariffs must include TOU energy rates as follows:
a) *reflect the cost to serve;*
b) *be applicable to all customers supplied at MV or above within two years;*
c) *be applicable to all customers with three-phase connection or above 100 kVA within five years; or*
d) *be applicable to all cases where the metering provides such features within five years, and*
e) *be applicable to all customers that have grid-tied embedded generation.*

7.14 Voltage and Position Differentiation

Most utilities currently apply tariff differentials based on the supply voltage due to the difference in costs and losses at the different supply voltages. However, these tariff differentials are not necessarily cost-reflective resulting in subsidies from one voltage level to the next. The following highlights some of the issues identified:

a. The level of the differentials between supply voltages in tariffs is smaller than the actual cost differences.

b. The differentials are only applied to the supply voltage and do not reflect the point on the network where the supply is connected. Costs differ significantly for supplies directly connected from the lower voltage side of a substation and that of a customer taking a supply from deep within in a network (length of line considerations), although both could be supplied at the same supply voltage.

To reflect supply voltage differentials, whether connected directly to a substation or deep within the network requires a complex cost-of supply study and would create more voltage categories that may complicate the CTS study and increase the number of resulting tariff structures. This may encourage customers to request a direct connection to substations, and this may not necessarily be economical for the Distributor or other customers.

This would result in uneconomic by-pass where customers would seek to own connection assets and avoid paying lower voltage network charges that include costs for shared network assets, or duplication of distribution networks.

Policy Position: 37

Voltage and supply position differentials must be applied in tariffs within a licensed distributor as follows:

a) based on the justifiable supply voltages, per customer and customer costing grouping;
b) based on the cost and losses differences from the cost to serve study;
c) to be applied to tariff charges as applicable; and
d) NERSA must drive a plan for phased increases in tariffs at lower voltages and a commensurate decrease of tariffs at higher voltages where voltage differentials do not reflect costs and where itemised costs will be identified in the regulatory accounts.

7.15 Domestic (Residential) Tariffs

There is many domestic (residential) tariffs and tariff structure being used in the EDI and these need to be rationalised through a NERSA framework. Distributors should charge cost-reflective tariffs for domestic customers, through common structures, while also catering for cross-subsidisation of some customers through lifeline tariffs. The detailed provisions for low-income customers are discussed in the cross-subsidy section.

Inclining block rate tariffs and tariffs that do not reflect cost-causation in an unbundled way should be removed unless they are used to provide cross-subsidies. Inclining block rate tariffs for higher consumption residential tariffs are not appropriate as they provide no TOU signal do not reflect unbundled costs (energy, network, and retail) accurately and this may lead to an incorrect signal to customers when deciding on sources of alternate energy sources. Inclining block rate tariffs are not necessarily linked to the cost of additional consumption and, do not reflect the additional demand imposed. The tiers in inclining block tariffs may be arbitrarily set, and there is little evidence of any customer response to inclining block tariffs.

Policy Position: 38

Domestic tariffs to become more cost-reflective, offering a suite of supply options with progressive capacity-differentiated tariffs and connection fees:

a) At the one end a lifeline inclining block-rate tariff or a single energy rate tariff with no basic charge, up to 60 Amps single-phase and connection charges. aligned to the DEE suite of supply options guidelines;
b) At the next level, a tariff to contain unbundled tariff charges to reflect itemised network cost-reflective charges based on capacity, an itemised customer service charge, and an itemised energy charge with cost-reflective connection charges; and
c) At the final level TOU tariffs must be instituted on the same basis as above, but with TOU energy rates for all three-phase connection (subject to smart metering roll-out).

7.16 Treatment of Connection Charges

Funding of capital costs for the provision of capacity is funded either through tariffs or from other sources such as:

a. By way of connection charges as a contribution to the cost of any existing or future infrastructure that would be used, that is not recovered through tariff charges.
b. The State electrification fund grant towards the cost of establishing networks to supply new customers and maintain low connection fees.
c. In many cases developers or customers would establish and fund infrastructure and then hand them over to the utility at no compensation.

Connection charges need to be fair and must be calculated in accordance with the principles and rules set out in the relevant sections in the Distribution Code. The connection charges principles should be aligned to the following:

a. The basis on which connection charges are calculated by the licensee should be clear and transparent.

b. Customers should not pay twice for the same infrastructure.

c. There needs to be a fair and transparent reimbursement mechanism in the connection charge policy to deal equitably with network assets that are shared. This is to prevent "second comers / free riders" from benefiting once the "first user" has paid for the system.

d. Although customers would pay for the assets, the network company will own and maintain the assets.

e. The contracting parties should also have a clear understanding of funding and payment for the repair, refurbishment or even replacement of connection assets.

The issue at stake is whether a utility should be allowed to apply depreciation and earn a return on these assets which are funded by the customers outside of the tariff. If this is allowed, it would mean that customers would have to pay twice for the same network assets. The principle thus is when the upgrade or refurbishment of these assets is due, the required funds could either be funded from approved revenue or debt, which in turn would need to be recovered through tariffs for which all customers would then eventually need to pay.

A wide range of practices used to be applied to recover a connection charge from customers towards the cost of infrastructure being used for the new capacity. An industry standard (NRS-069 Guidelines for Distribution connection charges for loads) was established to standardise the methodology for how connection charges for loads are calculated in South Africa and its application is a Grid Code requirement.

The Distribution Code also provides guidance with regards to the connection charge policies that should be applied to recover capital costs from customers.

Policy Position: 39

a) Any assets which are not financed by the distributor, but from sources such as: State grants, connection charges and connection fees, self-build infrastructure handed to the utilities, shall be identified in the regulatory accounts and excluded from the asset base for the purpose of determining depreciation and return on assets and in the same way these costs be excluded from COS studies;

b) The provision for the replacement of these assets when it becomes due shall form part of the Licensee's revenue requirements.

c) *These assets would, however, be included for provisions relating to all operating expenses; and*
d) *Regulatory accounts in support of a consistent methodology must be applied in the electricity industry to govern the determination of connection charges payable by customers / developers to ensure a fair and non-discriminating practice for all participants.*

7.17 Public Lighting

Many municipalities consider public lighting to be part of the electricity supply service and as such, electricity customers must cover expenses. Public lighting is, however, a municipal service which is a consumer of electricity and not part of electricity supply. This is a service to the community, not to the electricity customer. The type of lighting and replacement of lights are subjects affected by the voters of the municipality and subject to issues of aesthetics, road safety, and public safety. These matters do not form part of electricity supply and are quite different to the criteria for determining expenditure on electricity networks.

Worldwide systems of public lighting are considered part of municipal services and are thus paid by these authorities. The only exceptions are some developing countries where proper functioning municipal services have not been established. It is important to understand that it is not proposed that municipalities should now charge the taxpayers more, but rather that the cost of public lighting should be shown separately and be charged separately to the municipality. The municipality may in turn recover this money from the Municipal Surcharge on Electricity (MSOE) or any other source such as rates.

Policy Position: 40

a) *Public lighting, including streetlights, high mast lights, parking area lights, and traffic lights are considered as consumers of electricity and are not part of electricity supply;*
b) *The associated charges must cover capital and operating costs associated with energy, electricity network, dedicated lighting networks, and lighting services;*
c) *Such services may be provided by electricity utilities, but such costs must be charged to the appropriate owner, in most cases the municipality; and*
d) *The municipality can in turn fund such service from the MSOE.*

7.18 Refurbishment and Maintenance

There is a significant challenge in the distribution industry related to the backlog of appropriate maintenance and refurbishment of infrastructure. This needs to be addressed so that the asset can maintain a reasonable level of service quality for its customers.

Policy Position: 41

a) Licensees must undertake the required analyses to determine the extent of backlog of maintenance / refurbishment and put strategies in place to catch up.

b) NERSA must give due cognisance to requests for additional funds, itemised in the regulatory accounts and to be recovered in tariffs to provide for capital for refurbishment of standard asses and all operating expenditure, including staff to manage such projects and undertake the required work.

c) The above must be done with due cognisance with proper ring-fencing to ensure that the needed funds not from the electricity sector is used to fund other sectors; and

d) The refurbishment of premium assets will be funded outside the tariffs in accordance with the Distribution Code.

7.19 Distribution Losses and Bad Debt

Non-technical losses and bad debt have become a massive problem with a significant impact on electricity sales, maximum demand, and viability of many licensees. The question is whether such high non-technical losses and subsequent bad debt could be a legitimate cost which should be recognised as part of efficient electricity supply costs, and how it should be treated.

Policy Position: 42

a) NERSA must develop acceptable standards for non-technical losses and provision for bad debt in the regulatory accounts and related revenue requirements.

b) The component of non-technical losses and bad debt which exceeds the approved standard must be considered unacceptable and be removed from the allowed revenue base that would otherwise impact on the return of owners.

Distribution losses comprise both technical and non-technical losses. Non-technical losses and bad debt are a problem with a significant impact on electricity sales, maximum demand, and viability of many licensees. In addition, the ability to enforce payment has become politicised and exceedingly difficult resulting in significant under-recovery of revenue by Licensees. The question is whether such high non-technical losses and subsequent bad debt could be considered a legitimate cost to be recognised as part of efficient electricity supply costs, and how it should be treated.

Losses will increase as more customers are added to the network and IPP connections in low load areas are increasing losses. A NERSA methodology must accommodate this changing environment.

Policy Position: 43

a) NERSA must develop a data-based methodology to quantify and establish technical, non-technical losses and provision for bad debt, and
b) The component of technical, non-technical losses and bad debt that exceeds the approved standard must be considered unacceptable and be removed from the approved revenue base that would otherwise affect all customer electricity tariffs.

7.20 Reseller Charges

Resellers are registered entities that purchase electricity from a licensed supplier for onward sale to tenants, homeowners, or other end-users. All resellers must comply with the provisions of Schedule 2 of the Electricity Regulation Amendment Act (ERAA), particularly regarding the setting and application of tariff charges. The National Energy Regulator of South Africa (NERSA) has issued guidelines for resellers; these guidelines should be reviewed and updated regularly to reflect current legislation and regulatory requirements.

A key area requiring clarification is the monitoring and enforcement of compliance by resellers. While licensees may assist in mediating disputes or addressing non-compliance issues, they do not hold regulatory or legal authority under the ERAA to compel resellers to comply with the Act, except through the disconnection of supply in accordance with applicable procedures. Mechanisms for compliance monitoring and dispute resolution should therefore be clearly defined to ensure transparency and legal certainty.

Policy Position: 44

a) Non-licensed traders of electricity shall provide the electricity at terms, tariffs, and services in compliance to Schedule 2 of ERAA;
b) NERSA shall provide rules to licensees and resellers regarding electricity resale pricing principles; and
c) The Licensee shall mediate disputes relating to electricity resale and if there is no resolution, NERSA shall be the final arbiter, and such conditions must be included into the Licensee's electricity supply agreement with the reseller.

7.21 Electricity vendors

Vendors facilitate prepaid electricity purchases by providing token sales services and receiving commissions for these services. Currently, this sector is unregulated and lacks standardization, creating the potential for excessive fees and unfair margins. There is a clear need to develop a standardized pricing framework and monitoring mechanism to ensure that vending fees are transparent, fair, and consistent. Implementing such measures will ensure that prepaid electricity vending services operate in a regulated, transparent, and consumer-protective manner, while standardizing vendor practices across the sector.

Policy Positions: 45

a) NERSA must within 12 months of coming into place of this policy develop and implement a standardized pricing framework for electricity vending services. *b) Define allowable service fees and commission structures to prevent excessive margins.* *c) Establish a monitoring and compliance mechanism to ensure transparency and adherence to the framework.* *d) Conduct periodic reviews of fees and commissions to reflect market and technological changes.* *e) Monitor vendor compliance with the pricing and reporting requirements.* *f) Investigate consumer complaints and enforce the framework through penalties or corrective measures where necessary.*

7.22. Electricity Tariffs for Organs of State

When organs of the state are supplied with electricity, standard NERSA approved tariffs charges should be applied. There should be no preferential tariffs as this practice would under-recover revenue and create subsidies. The full cost of providing electricity to organs of state should be charged to ensure that the appropriate pricing signals are provided to ensure efficient use.

Policy Position: 46

a) No special electricity tariffs or terms shall be permitted for organs of state or State funded institutions including schools and clinics / hospitals, and. *b) Organs of state shall be required to budget and pay for the full cost of electricity services based on NERSA approved unbundled and cost reflective electricity prices.*

7.23 Municipal Surcharge on Electricity (MSOE)

Currently a significant amount of electricity revenue is used by many municipalities to subsidise other municipal services. This is done by way of a transparent so-called "surplus," but also by way of various un-transparent methods such as: provision of streetlights, overstated administrative charges, unfair surcharges on materials handling, understated internal usage charges, etc. Until municipalities have completely ring-fenced their activities, overstated charges to electricity departments will continue.

The MSOE will be regulated through norms and standards for electricity surcharges (as and when introduced) as provided for in the Municipal Fiscal Powers and Functions Act. When regulations on electricity surcharges are introduced, the regulation of the "base tariff" will be the responsibility of NERSA (which will be exclusive of the electricity surcharge), and the Minister of Finance/National Treasury will be responsible for the regulation of the MSOE.

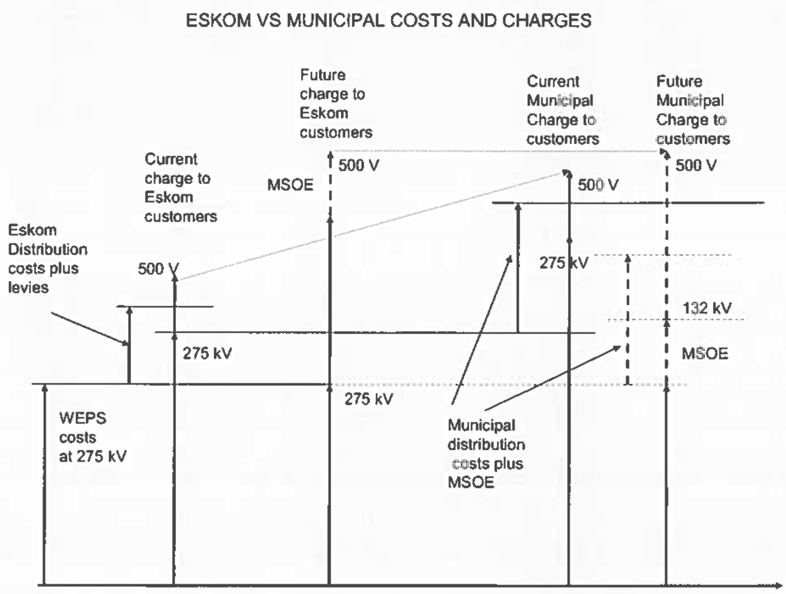
Some municipalities have already introduced a transparent MSOE without phasing out the existing hidden surpluses. This is totally against the intention of the legislation to regulate the application of the MSOE. Furthermore, it is also uncertain as to whether these municipalities have ring-fenced their activities to quantify the hidden surpluses.

Policy Position: 47

a) *Under no circumstances shall the new MSOE be introduced in addition to the current non-transparent / un-ring-fenced surpluses as identified in the regulatory accounts.*

b) *NERSA shall regulate the electricity prices excluding the transparent MSOE.*

Figure 5: Future Treatment of MSOE and cost reflective Eskom Charges



Municipalities apply the rule of cutting off or not selling pre-payment electricity as a measure also to recover municipal rates revenue. In areas where this is not done the rates payment levels are extremely low.

8. DEMAND SIDE FLEXIBLE SERVICES

Demand side flexible services and products are needed to optimally mange the system and grid. These can be used to reduce demand, capacity constraints and even energy requirements. Some examples of such products and services to incentivise investment in the space are:

- Voltage support for local, regional, and national needs
- Unbalance support
- Constraint management
- Energy storage
- Support for planned and unplanned outages
- Phased balancing
- Tariff products
- Demand response mechanisms.

Policy Position: 48

a) *NERSA must consider the impact and the effectiveness of demand and supply side flexible options in determining revenue requirements of licensees.*
b) *These demand and supply side flexible options must also be ring-fenced in the regulatory accounts and be reported on per revenue review period to demonstrate the costs and the benefit by licensees.*
c) *The Regulator must decide on the amount of funds to be allocated to demand, and supply-side flexible options based on requests made by the licensee.*
d) *The funds shall be applied and prioritised on a reliability and security of supply and/or least cost per saved MVA/MW basis.*
e) *All parties in the ESI shall be treated fairly and independently based on the measure to which the application meets the qualification criteria as prescribed by the Codes.*

9. UTILITY-OWNED EMBEDDED GENERATION

In line with evolving technologies, Distributors can establish utility-owned embedded generation including microgrids and roof-top solar PV energy services. Microgrid pricing should reflect the cost to supply and serve end-users with the resultant tariffs approved by the NERSA. Incentives for utility-owned embedded generation credited to participating Distributor customers should be based on cost to supply and serve participating customers and self-funded within the utility owned embedded generation business models.

Policy Position: 49

a) NERSA must consider the impact and the effectiveness of utility-owned embedded generation including microgrids and rooftop solar PV in determining Licensee revenue requirements.
b) Utility-owned embedded generation must also be ring-fenced in the regulatory accounts and be reported on per revenue review period to demonstrate the costs and the benefit by licensees and end-users.
c) The Regulator must decide on the amount of funds to be allocated to utility-owned embedded generation products and services based on requests made by the licensee.
d) The funds shall be applied and prioritised on a reliability and security of supply and/or least cost per saved MVA/MW basis.

10. SUBSIDIES

Electricity affordability is one of South Africa's most critical socio-economic and policy challenges. Rising tariffs, structural inefficiencies in the energy sector, and entrenched inequality have increased the burden on low-income households, businesses, and the broader economy. Existing measures have not provided sufficient relief, highlighting the need for a clear and consistent policy approach. Ensuring affordable electricity is essential not only for equitable access to energy services but also for sustaining economic competitiveness and maintaining social stability. Affordability concerns are raised both by those who benefit from subsidies and by those who finance them.

Cross subsidies in electricity tariffs occur when some customers pay more or less than the actual cost of supply. These subsidies are embedded in cost pooling and tariff design and are applied both to improve affordability for targeted groups of customers and to support sustainable electricity supply investments.
Within South Africa, there is ongoing debate on the future of tariff cross-subsidies: how they should be structured, who should contribute, who should benefit, and how the system should adapt to the changing electricity supply industry (ESI). Increasingly, customers can generate their own power and reduce their reliance on the grid, which allows them to avoid contributing to subsidies. This trend narrows the funding base and places a heavier burden on the customers who remain fully grid dependent.

The removal of tariff cross-subsidies would result in steep tariff increases for current recipients. On the other hand, increasing subsidy contributions for other customers has led to pressure for exemption or prompted a shift towards self-generation and alternative energy sources. This creates a cycle where the remaining grid-connected customers, particularly those reliant on wheel or direct supply carry a greater share of the subsidy burden, unless funding is located outside the tariff base.

For fairness and equity, all customers who use a licensee's network should contribute proportionately to subsidies. Allowing some to avoid contributions results in undue discrimination. Generators may, however, be excluded to prevent double subsidisation, as their customers would otherwise face charges both through the generator and the network. A more balanced approach is for all network-connected customers to contribute at a fixed and proportionate rate, based on their level of network demand.

At present, the application of cross-subsidies is inconsistent across the electricity industry. There is no national framework providing clear guidance on how tariff-related subsidies should be structured, and transparency is limited regarding both the contributions made and the subsidies received by customers across different licenses. This absence of a uniform framework represents a critical policy gap that requires urgent intervention to ensure fairness, consistency, and sustainability in the application of cross-subsidies.

Policy Position: 50

a) DEE, NERSA, and National Treasury shall within 12 months of coming into effect of this Policy, develop a national subsidy framework to guide the application of tariff subsidies which should seek to balance the subsidy's impact on the price and affordability of electricity to recipients and contributors.
b) The core principle of the national subsidy framework will be that subsidies are determined after cost reflect tariffs have been determined and based on a consumer affordability study.
c) The framework should also define the qualification criteria for contributing to subsidies (e.g. size of supply/connection, consumption volumes), qualification criteria for receiving subsidies (e.g. size of supply, consumption volumes), maximum threshold for subsidy contribution levels in relation to some measure, e.g. not more than 10% of total revenues recovered from customer group.
d) The framework may identify specific subsidies (outside the sector) and cross-subsidies which must be instituted in the ESI to address certain socio-economic and environment needs.
e) All subsidies in electricity prices shall be made transparent, while moving towards cost-reflective and transparent prices in the electricity industry.
f) The following principles factors shall be considered in the development.
g) NERSA approval will be required to give effect to the removal of price subsidies and the related adjusted prices.

h) *Charges to recover remaining subsidies should be ideally structured as fixed charges added to the consumer price.*
i) *Tariff subsidies that are a contribution to a wider electricity consumer base than a single Distributor may be transparent and itemised and implemented at the wholesale level; and*
j) *Licensees are required to establish and publicise the average level of subsidy between tariff categories (receipt and contributions) and itemise the same in the billing process.*

10.1 Low Income Customer Tariff Subsidisation

The provision of subsidies for low-income domestic customers is unavoidable and will remain a requirement for at least the next ten years. This measure is necessary to ensure that electricity remains accessible and affordable for poor households, while equitably balancing the costs of supply across all customer categories.

The following mechanisms will collectively contribute to achieving this objective:

a. a state subsidy towards the network capital cost;
b. charging of a low connection fee;
c. implementation of a tariff structure that provides maximum subsidisation at low consumption levels, with gradually reducing cross-subsidies as consumption increases; and
d. the granting of Free Basic Electricity (FBE) and any other new government electricity subsidy mechanism.

It is not practical for most licensees to determine household income directly. For implementation purposes, licensees have therefore used low consumption levels and low installed capacity as the primary criteria to approximate low-income customers.
In view of the above, the following is proposed:

Policy Position: 51

Qualifying customers shall be subsidised through the application of a lifeline tariff:
a) a single energy rate tariff;
b) with no fixed charge;
c) limited in capacity to of not more than 60 Amps; and
d) *nominal connection fee.*

10.2 Free Basic Electricity (FBE)

The Free Basic Electricity (FBE) policy is a critical instrument designed to ensure that low-income households have access to a basic level of electricity. While the policy framework is clearly outlined in the Department of Energy and Electricity (DEE) Basic Services Support Tariff (Free Basic Electricity) Policy, several gaps and challenges continue to hinder effective implementation.

A key policy gap is the limited mechanisms for monitoring and evaluating the application of FBE at municipal and licensee levels. Without robust oversight, there is a risk that the intended beneficiaries do not consistently receive the allocated support, undermining the policy's objectives. Additionally, the funding mechanism primarily through equitable share allocations to local government rather than the revenue requirements of the electricity licensee creates challenges in ensuring that municipalities have sufficient and predictable resources to implement FBE effectively.

Other challenges include inconsistent application across municipalities, lack of clear guidelines for targeting beneficiaries, and insufficient integration with broader social support programs. These gaps result in variability in access, with some households not receiving the intended benefits, while others may receive more than their entitlement. Addressing these gaps is critical to ensure that FBE achieves its intended social and economic outcomes.

The following principles will apply:

a) The free basic allocation of electricity units is to be made available to all qualifying: households that meet the requirements of self-targeting. Where more than one dwelling is bulk metered; the Service Providers will need to take this into account in allocating the free basic service.
b) Normal municipal connection fees levied by the distributor will be applied to all new electricity services.
c) Basic charges/fixed charges, if applicable, will only become effective when monthly consumption exceeds the free allocation.
d) No carryover of the free basic electricity allocation or any portion thereof from one month to the next is to be permitted for credit metered customers. This will particularly address cases of unoccupied households claiming cumulative EBSST.
e) Free EBSST allocations not claimed by prepaid metered customers in any month calendar will be forfeited, subject to proper billing by the Service Provider to the Service Authority in respect of the claim arising from such provision of free basic electricity to all qualifying households.
f) In respect of the credit-metered households, the free allocation should be applied to the account if electricity is consumed in any billing period. If the consumption is less than the free quota, the

amount of consumption is issued free, subject to the proper billing of the Service Provider to the Service Authority in respect of the claim for providing free basic electricity to all qualifying households.

g) The distribution/allocation of the free basic electricity allocation must be as simple as possible to obviate the need for high levels of capital/upgrading and administration expenditure.
h) Consumer discipline must be upheld. No free basic electricity allocation is to be made available following disconnection from the electricity supply for reasons normally applicable in the distributor's environment such as meter/system tampering or non-payment, until the consumer has met all the distributor's/authority's requirements to have the supply restored.
i) No cash/voucher/service will be payable in lieu of the free basic electricity allocation or non-grid operational subsidy for household connected to the non-grid systems.
j) The free basic electricity allocation/subsidy will only be affected when a qualifying consumer has been officially connected to the electricity supply system of a Service Provide.

Policy Position: 52

a) The DEE in consultation with COGTA and National Treasury will determine the extent of provisions of free basic electricity, which can be funded thorough governmental transfer on an annual basis.
b) The allocation shall be subject to periodic review to align with evolving household consumption patterns and developmental requirements.
c) The cost of providing free basic electricity shall be included in the MTEF budget allocation.
d) A comprehensive 2-year review of FBE impact should be conducted by NERSA and the DEE through a study after coming into place of this policy.
e) This study must assess coverage, effectiveness, equity, sustainability, and alignment with national objectives, informing necessary policy adjustments.

10.3 Free Basic Alternative Energy

The Free Basic Alternative Energy (FBAE) initiative is a critical intervention aimed at supporting indigent households in areas without access to the national electricity grid. By providing households with a limited allocation of basic energy, FBAE helps meet essential needs such as cooking, lighting, and other minimal energy services. Funding for this initiative is drawn from the Equitable Share grant and allocated to municipalities that serve communities where no electricity infrastructure exists.

Despite its importance, recent assessments have highlighted several gaps and challenges in the implementation of FBAE. These include limited coverage in remote and un-electrified areas, inconsistencies in energy allocation across municipalities, and difficulties in monitoring and verifying actual usage by intended beneficiaries. Additionally, there is a growing need to align FBAE with sustainable energy solutions to ensure that the support provided is environmentally responsible, cost-effective, and resilient to evolving energy demands.

Addressing these gaps is essential to ensure that FBAE fulfils its mandate of promoting energy equity, improving living conditions for vulnerable households, and contributing to broader national objectives for sustainable and inclusive energy access.

Policy Position: 53

a) Municipalities must exercise diligent in selecting the beneficiaries of the FBAE program to uplift the un-electrified indigent household.

b) Municipalities have a responsibility to administer and provide FBAE to indigent households within their jurisdiction.

c) Municipalities must select suitable energy carries/s to be funded and supplied through their areas.

d) Municipalities must conduct awareness campaigns informing the beneficiaries on how to apply the chosen energy carriers.

10.4 Negotiated Pricing Agreements (NPAs)

Negotiated Pricing Agreements (NPAs) provide a structured mechanism to allow deviations from standard approved tariffs, service fees, network standards, or capital contributions. The framework is designed to support the continuity of existing businesses at risk of failure and to enable the restart of production capacity that has been dormant due to market constraints, safeguarding jobs, and economic activity.

NERSA and the applicable Licensees will apply following principles to the processing and assessment of all consumer applications:

a) The financial assessment of the reference base incentive price for Short-term framework NPAs is to be against the approved annual MYPD figures.

b) The incentive price level must include an appropriate risk premium and be set at the highest possible level that remains compatible with the applicant's sustainability and the licensee's cost of supply.

c) Any incentive-price NPA shall be approved only if it is in the national interest. To safeguard the sustainability of the ESI, any revenue shortfall incurred by the licensee may be recovered through the applicable regulatory process. The base incentive price will be subject to annual escalation for the duration of the NPA.

d) Applications will be evaluated on their own merits, taking account of the short-term market dynamics faced by the Applicant and the Licensee.

e) Any NPA granted in terms of this framework will be aimed at retaining electricity consumption, jobs and avoid imminent closure of the operation that would have happened without the intervention. The baseline electricity consumptions used to determine potential consumption decrease in the future should be measured over the last 3years.

f) Processing, assessment, and approval timeframes will be kept to the maximum duration of 60 days aligned to NERSA internal process. The duration will start counting after the application is submitted to NERSA.

g) The request for a NPA by the applicant must be supported by the Department of Trade, Industry and Competition (the dtic).

h) Any party that receives information from other parties because of any Application arising from this framework, will be obliged to respect the confidentiality of the information supplied and will only disperse the information as permitted in terms of this document, unless given written permission to do so by the owner of the information.

i) Applications already submitted, are deemed to have been applied for under the reviewed framework and should be prioritised under the reviewed framework as a matter of urgency.

j) If an application has already been submitted at the time that this Framework comes into operation, the application will be regarded as valid. In such circumstances the application will be prioritised and be considered under the provisions of the amended Framework.

Policy Position: 54

a) *NPAs are permitted but must be structured in a way to minimise price distortions.*
b) *Commodity price risk exposure must be hedged outside of the ESI.*
c) *Existing NPAs will be honoured until the end of contract.*
d) *The evaluation of NPAs at inception must be based on the cost of supply (excluding cross-subsidies) on a discounted cash flow basis over the period of the agreement.*
e) *The cost of supply for NPAs intended for the sale and consumption of electricity in South Africa must be defined by the electricity price forecast which will be based on the prevailing regulatory methodologies in South Africa inclusive of an appropriate risk premium.*
f) *DEE must develop a transparent NPA application and approval process to ensure adequate evaluation and consultation with key stakeholders, including National Treasury.*
g) *DEE must update the NPA pricing framework setting out the evaluation criteria.*
h) *NERSA will approve and monitor NPAs in accordance with the framework.*
i) *All applications must be treated in accordance with the approved processes and frameworks and be approved by NERSA.*

11. REGULATIONS

The Department of Electricity and Energy (DEE) is responsible for determining the EPP for the electricity sector. NERSA is mandated to develop and implement the rules, regulations, codes, programmes, and projects necessary to give effect to the EPP. In terms of ERAA, 2024, NERSA is responsible for licensing electricity industry activities, including generation, transmission, distribution, import, export, and trading; regulating and approving tariffs in line with the EPP; and facilitating dispute resolution within the electricity sector.

The ERAA, 2024, introduces significant reforms, including the establishment of a Transmission System Operator (TSO) and an open market platform for competitive electricity trading. These reforms are intended to modernise the electricity sector, strengthen energy security, and support the integration of renewable energy.

To support effective implementation of the EPP, priority should be given to the development and enforcement of a comprehensive regulatory framework aligned with the policy, as well as ongoing monitoring and evaluation to identify challenges and support continuous improvement. Through these measures, DEE and NERSA can promote the efficient implementation of the EPP and support a reliable, affordable, and sustainable electricity supply system.

12. CONCLUSION

The EPP, determined by the DEE and implemented by NERSA, provides a strategic framework for a modern, competitive, and sustainable electricity sector. Under the ERAA, key reforms including the establishment of a Transmission System Operator and an open electricity market strengthen regulatory oversight, promote renewable energy investment, and enhance energy security. By prioritising a robust regulatory framework, transparency, competition, and continuous monitoring, DEE and NERSA will ensure the EPP delivers a reliable, affordable, and sustainable electricity system that supports South Africa's long-term economic and social development goals.

This Electricity Pricing Policy shall be reviewed by the DEE every five (5) years unless prevailing circumstances and challenges require immediate revision to be considered and undertaken.