ELECTRICITY PRICING POLICY

REVIEW

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THIS IS A REVIEWED VERSION OF THE ELECTRICITY PRICING POLICY

GENERAL EXPLANATORY NOTE

______ WORDS UNDERLINED WITH A SOLID LINE AND HIGHLIGHTED IN YELLOW INDICATE INSERTIONS IN EXISTING ENACTMENTS.

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ABBREVIATIONS:

COS:	Cost of Supply
CPA;	Central Purchasing Agency
DMRE:	Department of Mineral Resources and Energy
DPE:	Department of Public Enterprises
DUoS:	Distribution Use of System
DTI:	Department of Trade and Industry
EDI:	Electricity Distribution Industry
EPP:	Electricity Pricing Policy
ESI:	Electricity Supply Industry
FBE:	Free Basic Electricity
HV:	High Voltage
IPP:	Independent Power Producer
LRMC:	Long Run Marginal Cost
LGMSA:	Local Government Municipal Systems Act
LV:	Low Voltage
MV:	Medium Voltage
MSOE:	Municipal Surcharge on Electricity
NPA:	Negotiated Pricing Agreement
NRS:	Rationalised User Specification
NERSA:	National Energy Regulator of South Africa
PPA:	Power Purchasing Agreement
PV	Photovoltaics
ROA:	Return on Assets
ROE:	Return on Equity
SADC	Southern African Development Community
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, 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/ night or the lowest point on the load demand curve. Alternatively, “base-load demand” means a relatively continuous level of electricity demand.
Capacity charge	See definition of standby charge.
Central Purchasing Agency	Means an entity assigned to fulfil the role of the single or wholesale buyer to maintain system integrity in a competitive environment.
Codes	Any Code published 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	A standard procedure for deriving and allocating approved revenue to end-customers for the purposes of arriving at the cost-reflective unit costs. This may also be referred to as the Cost of service study.
Cost-reflectivity	The pricing method to reflect the full economic cost of supplying electricity to a customer.
Cross-subsidy (within the sector)	Over-recovery of revenue from customers in some tariff classes whether intentional (e.g. electricity levies) to balance the under-recovery of revenue from customers in other tariff classes (i.e. electricity subsidies) as calculated in the *cost of* supply study or unintentional by way of unidentified surcharges within the EDI or as a natural consequence of cost pooling or within the ESI to recover legacy costs. (Note definition for subsidies).
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 132kV or less.
Distribution charges	The grouping of the use of the distribution system (*DUoS)* charges, retail and connection charge.
Distribution use of system (DUoS) charges	Unbundled regulated tariffs charged by the distributor to the 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.
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 132Kv.
Electricity supply industry (ESI)	Generation, transmission, wholesale and distribution.
Energy charges	Charges based on the amount of energy consumed.
Free basic electricity (FBE)	The State's Free Basic Electricity initiative, which allows for a limited amount of free electricity as deemed necessary to provide basic services as determined and funded in terms of State policy in order to alleviate poverty.
Flexible distribution services	Services aimed at modifying generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterise flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location etc.
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 various options for the supply of electricity.

Legacy costs/contracts	Costs or contracts associated with mandatory government energy procurement programmes and Eskom new build programme.
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.
Medium voltage (MV)	Nominal voltage levels greater than 1 kV and up to and including 44kV.
Municipal surcharge	A charge in excess of 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.
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.
Net-billing	Means a credit mechanism where the customer's generation is synchronised with the grid (grid tied), and at times, there may 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.
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	Ratio of the Root Mean Square (RMS) value of the active power (kW) to the apparent power (kVA), measured over the same integrating period.
Prosumer	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.
Retail	The function related to the supply of electricity and network services.
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 / 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 cost 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 equate to that of 'total capital' this can also be referred to as 'return on total capital'.
Short term	A period of less than one (1) year.
Small power tariff	A tariff for customers with a supply of 100kVA 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 of the electricity sector, to lower the charges to particular customer categories. (Note definition for cross-subsidies)

Standard connection / standard supply charge	The standard fee charged for a standard connection as set out in an approved schedule of fees.
Tariff	A combination of charges and rates covering different aspects of electricity supply, price signals and cross subsidies grouped into a coherent set of charges.
Tariff structure	The combination of different charges and the relationship to each other.
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.
The Act	Means the Electricity Regulation Act, 2006 (Act No. 4 of 2006).
Trader	A legal entity licensed or registered to engage in the buying and selling of electricity as a commercial activity.
Transmission	As defined in the Codes.
Transmission system	Power lines and substation equipment that operate at a nominal voltage of more than 132kV and as defined in the Codes.
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.
Vesting Contract	Means a contract or other financial arrangement between Eskom Holdings SOC Limited and a distribution licensee for the sale of a specified amount of electricity at a specified price as a mechanism to facilitate the transition to a competitive market.
Wheeling	The transportation of electricity by an electricity supplier (utility) to a third party through a network not owned, controlled or leased by either party.
Wheeling charges	Wheeling charges are the same as network charges and transmission use of system charges.
Weighted average cost of capital	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 BACKGROUND

1.1 Present Structure of the Electricity Supply Industry (ESI)

The South African ESI is rapidly transitioning from the historically vertically integrated model towards an unbundled environment with independent generators supplying customers and trading independent of the dominant utility Eskom. Meanwhile, as the only transmission licensee, Eskom is responsible for all transmitted electricity. The responsibility for distribution is shared between Eskom, the municipalities and other licensed distributors.

1.2 Electricity Sector Objectives

To place the Electricity Pricing Policy (EPP) document into perspective, it is necessary to summarise the electricity sector objectives as detailed in the White Paper on the Energy Policy of the Republic of South Africa (WP) of 1998 as follows:

a. improved social equity by addressing the requirements of the low income;
b. enhanced efficiency and competitiveness to provide low-cost and high-quality inputs to all sectors;
c. environmentally sustainable short and long-term usage of our natural resources;
d. the right of choice of electricity supplier;
e. competition in especially the generation sector;
f. open non-discriminatory access to the transmission system; and
g. private sector participation in the industry.

Furthermore, specific objectives addressed in the abovementioned document refer to ensuring that electrification targets are met; the provision of low-cost electricity; better price equality; financial viability; improved quality of service and supply (including security of supply); proper co-ordination of operation and investments and the attraction and the retention of a competent work force.

In view of the above, the State seeks to achieve an appropriate balance between meeting social equity, economic growth, environmental goals and establishing a market-based environment. This policy document seeks to obtain a balance between several competing objectives, inter alia: affordable electricity tariffs for the low-income consumers and cost reflective electricity tariffs for all the other consumers. In this regard, electricity prices should reflect efficient market signals, accurate cost of supply and concomitant price levels that would ensure financial viability of the electricity sector in its entirety.

1.3 Key Challenges for the Electricity Distribution Industry (EDI)

The EDI is currently faced with various key challenges. The introduction of the EPP is not meant to solve all the challenges, but to guide NERSA and Licensees for a standardised approach to electricity pricing. The following contains a list of main challenges, without detailed discussions and motivations, to give a clearer view of the present situation and to illustrate possible benefits of an EPP:

a. Too many tariff structures being used.

b. No standardised approach for tariff development for determining revenue.

c. Funding and capacity shortages and backlog of investments.

d. Non-payment of bulk electricity services.

e. Lack of capacity to develop appropriate tariffs.

f. Networks are inadequately maintained, resulting in maintenance and refurbishment backlogs giving rise to high cost of interruptions.

g. Loss of revenue due to inadequate tariffs and tariff structure.

h. Competition in the energy sector and wheeling of energy.

i. Lack of transparency for tariff cross-subsidies, funding for cross-subsidies and a lack of an appropriate framework to guide the application of subsidies in tariff structures.

j. How trading of electricity in a future wholesale and market environment will be done.

k. The recovery of costs for flexible distribution services.

1.4 White Papers (WPs) and Legislation

Over the last 25 years, two WPs on the energy industry were published in which both the ESI structure and EPP were addressed. The first one appeared in 1986 and became obsolete as a result of the lifting of the oil embargo; moves towards democracy; the Reconstruction and Development Programme and other developments. Before the second WP, the National Electrification Forum, which incorporated a number of EPP matters, was in operation between 1993 and 1995. The second WP appeared in 1998 and dealt with a large number of EPP matters. This WP became inadequate mainly as a result of new developments exerting a direct influence on EPP issues. These include capacity shortages, gaps in present policies, present challenges and the application of different pricing frameworks between Eskom and the municipal licensees.

A number of legislative developments since 1996, which have a direct influence on an EPP for the electricity industry, became applicable. It is important to mention these briefly because of their relevance for EPP. They are:

a. Constitution of the Republic of South Africa, 1996.

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

c. Local Government Municipal Systems Act (LGMSA), 2000 (Act No. 32 of 2000).

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

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

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

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

h. Electricity Regulation Act, 2006 (Act No. 4 of 2006).

i. Municipal Fiscal Powers and Function Act, 2007 (Act No. 12 of 2007).

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

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

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

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

n. Public Procurement Bill, 2020.

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

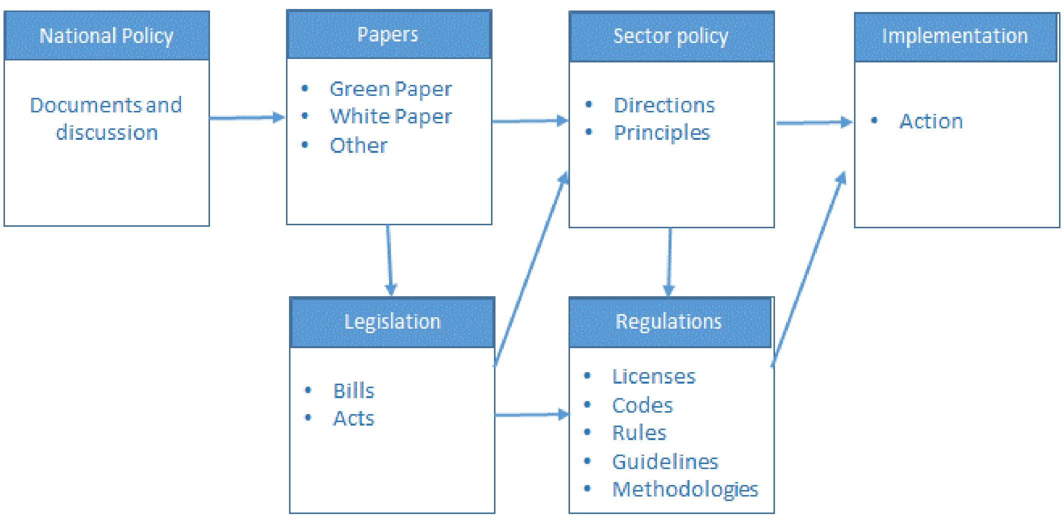
p. Court judgements.

1.5 Need for EPP and Related Policies

There is an urgent need not only for an EPP, but also for a new electricity (or energy) policy. With the requirement to unbundling of Eskom being a precursor to an independent system operator and the development of energy market, the electricity pricing environment is changing.

The EPP should provide direction and principles for the formulation of electricity prices in South Africa. The EPP should also reflect the most recent policies and legislation. The EPP should not be too detailed and should indicate broad level direction. It should also define the accountabilities/responsibilities; focus on the required outcomes and the timing aspects of the outcomes.

Figure 1: The Role of the Electricity Pricing Policy



The ESI is faced with a number of important changes and challenges as pointed out in this document. The emergence of viable 'self-generation' options which are however variable, intermitted and non-dispatchable thus requiring system/grid generation capacity to be maintained as back-up, changes the cost dynamics of the ESI in its entirety.

Failure to respond to this adequately will provide the temporary opportunity to some 'self-generating' consumers to avoid having to pay for their grid services and back up capacity, pushing such costs to consumers who are not 'self-generating'. This will ultimately and in short order make the entire ESI and grid unsustainable, to everyone's severe detriment including the original 'self-generating' consumers and to the entire economy of South Africa.

In addition, it has become evident that some of the key requirements of the first version of the EPP were not implemented, possibly due to discretion allowed on such aspects and lack of monitoring on implementation. Therefore, the setting of more explicit and prescriptive requirements, the limitation of discretion regarding their application, and the introduction of monitoring and confirmation mechanisms to ensure compliance and implementation is required.

While the EPP focuses on national strategies and priorities, the regulatory authority (NERSA) has to develop the Codes, Licenses, rules, guidelines, directives and methodologies in finer detail to ensure the policy's implementation.

2 GENERAL PRICING PRINCIPLES

2.1 General Tariff Principles

Tariffs must comply with the principles set out in section 15 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) (The Act) and section 74 of the Local Government Municipal Systems Act, 2000 (Act No. 32 of 2000) (LGMSA).

Tariff objectives for the:

- Customers, must be affordable, non-discriminatory, predictable and stable and transparent and unbundled;
- Utilities, must ensure revenue recovery, efficient use, cost-reflective and low cost of implementation; and
- State, must ensure social support, be environmentally responsible, be sufficient in developing generation capacity and be fair and equitable.

The above principles, together with some 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 with each other, and trade-offs would need to be made during the process of tariff determination.

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.
	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	Revenue recovery	Revenue from tariffs should reflect the full cost (including a reasonable risk adjusted margin or return) to supply electricity and ensure that the industry is economically viable, stable and fundable in the short, medium and long term.
	Efficient use	Tariffs should promote overall demand and supply side economic efficiency, and be structured to encourage sustainable, efficient and effective usage of electricity.
	Cost reflective	A link between the prices a user must pay towards the cost of serving that user.
	Low cost of implementation	Implementation and transaction costs should be minimised.
State	Social support	Tariff levels and structures should 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 development of least cost options resources 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.
	Returns	Fair and equitable.

2.2 Revenue Requirement

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 competitive market, the usual approach is to institute economic regulation where the regulators may select from a range of methodologies to regulate the industry. Regardless of the method of regulation or price formation, it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future.

Tariffs, therefore, need to be set at a level which would not only ensure that the utility generates sufficient revenues to cover the full costs (including a reasonable margin or return) but would also allow the utility to obtain reasonably priced funding on a forward-looking basis.

Ultimately, the decision to lend money to a regulated utility is made by the financial institution and not the regulator. The regulator, therefore, has a duty to measure the projected results from its regulatory methodologies (taking into account investment cycles and other cost trends) using the same criteria that reasonable commercial lenders would employ. The regulator needs to consult with commercial lenders when assessing the financial viability of the industry on an ongoing basis.

Policy Position 1

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

b) *NERSA, after consultation with stakeholders, must adopt an asset valuation methodology that accurately reflects the replacement value of those assets such as 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; and*

c) *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 tariffs should become cost-reflective over the next five years, except for specific cross-subsidies as provided for in section 8.21.

Policy Position 2

a) *Electricity tariffs must reflect the efficient cost of rendering electricity services as accurately as practical;* b) *The average level of all the tariffs must be set to recover the approved revenue requirement;* c) *The tariff structures must be unbundled as far as possible to recover costs as follows:* (i) *The wholesale energy purchase price reflecting (aa) the electricity generation infrastructure capacity costs for generation capacity required by the System Operator; and (bb) reflecting energy costs, with these two components reflecting the wholesale energy related purchase price;* (ii) *The wholesale Transmission tariffs reflecting the Transmission network usage cost;* (iii) *The Distribution tariffs reflecting distribution network usage cost, and* (iv) *Service and administration tariffs reflecting service and administration costs.*

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/available, which in turn determines what quantities could 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 be shown.

Policy Position 3

a) *The customer bill must comply with NRS 047.*

2.5 Non-Discrimination

There are currently a number of 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 could only be extended to all customers once these discriminatory pricing practises are removed. The obstacles should, therefore, be addressed and removed.

Policy Position 4

a) *All forms of discriminatory pricing practices must be identified and removed, other than those permitted under specific cross-subsidisation / developmental programmes or be transparently reflected to unlock the full potential of electricity to all.*

2.6 Access to and Use of Networks

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 the 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 license conditions and tariff schedules.

The full cost to operate the networks should be reflected in the various connection and use of system charges. In other words, no additional charges are needed to facilitate the wheeling of electricity between two parties, unless such wheeling would result in incremental costs. Southern African Power Pool (SAPP) rules would apply for the recovery of cost 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.

Policy Position 5

a) Fair and non-discriminatory access to and use of networks to all users of the relevant networks for all delivery of energy whether wheeling from a third- party supplier or the utility;
b) The full cost to operate and maintain the networks shall be reflected in the use of system charges and, therefore, no additional charges, except for the cost of administration for wheeling of electricity (compared to directly supplied customers) will be levied;
c) Any incremental connection costs and its 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 cost 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 in very high demand periods, or where there are capacity constrained periods.

b. Critical peak pricing tariffs: Tariffs are introduced with certain periods of very high 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. Green energy tariffs: Tariffs offered to customer to meet.

These products, in conjunction with enabling technologies, could significantly increase sales and the penetration of demand response programmes and products.

Policy Position 6

a)	*In addition to the standard range of pricing products, provision must also made for the development and introduction of special products and prices to achieve specific goals, the cost of which will be treated according to the regulatory methodology; and*
b)	*NERSA needs to develop a framework that allows for quick turn-around for such tariff approvals required for short-term needs.*

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 10 years. The outlook should be updated on a frequent basis to signal the overall expected trend in electricity prices. Ideally, the forecast should show the contribution of generation (all of its major sources inclusive of State-Owned Entities and independent/privately-owned), transmission and distribution to the forecast price level for some representative notional customers. These forecasts should be treated as indicative and will not be binding on any of the players.

Policy Position 7

a)	*NERSA, after consulting with stakeholders, should develop and publish, every three years, a multi-year price path covering at least 10 years forward.*

3 PRICING INTERFACES

The EPP has been developed without a specific industry structure in mind. This would ensure 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.

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

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

c. Licensed or registered generators and traders may (but are not obliged) sell electricity to: A Central Purchasing Agency, a licensee, a wholesale or retail customer, a licensed or registered trader, or to self.

d. Wholesale electricity prices may consist of wholesale energy prices (determined either through a regulated wholesale tariff or on a wholesale competitive market), capacity prices, standby prices, legacy cost recovery, subsidy charges, and Transmission network charges.

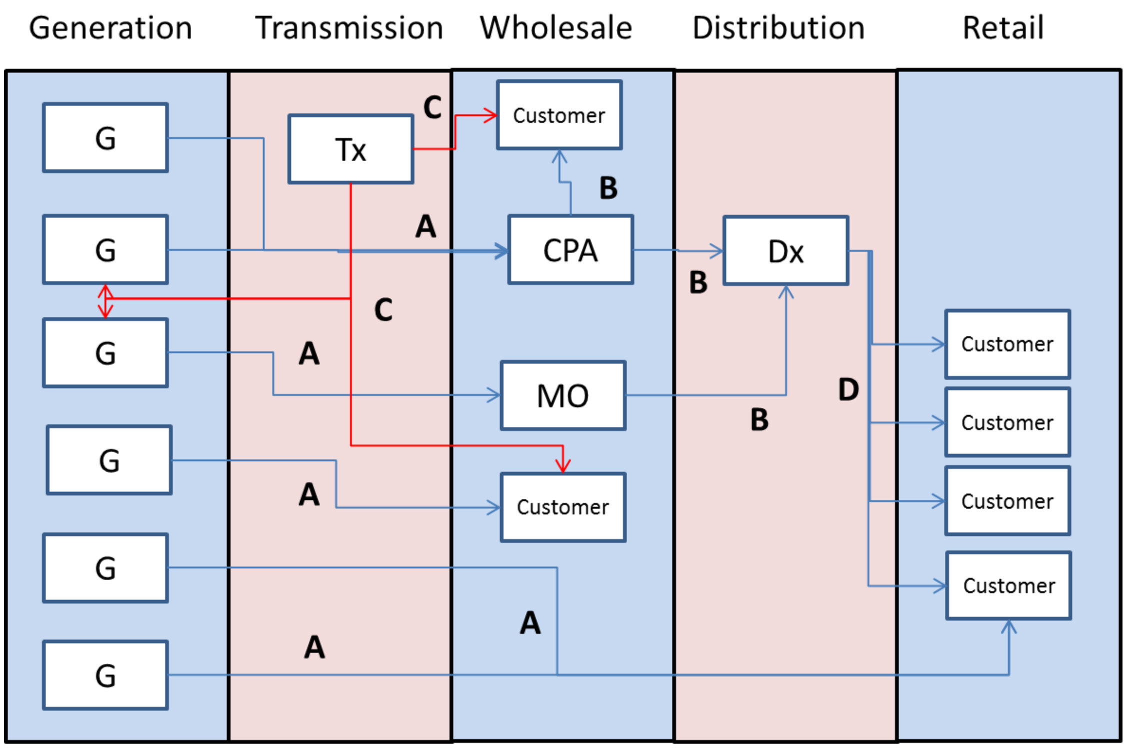
e. A competitive wholesale market is expected to be developed, comprising two key functions, specifically the Market Operator which operates the trading platforms between generators, retailers, customers and traders, takes no ownership of the energy traded; and the Central Purchasing Agency that takes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

f. Purchases by organs of state shall be subject to compliance with the Electricity Regulations on New Generation Capacity.

g. Distributors, licensed traders and customers may also enter into bi-lateral or direct power purchase contacts.

h. Distributors will fulfil their regulated retail function associated with the purchase of energy from the wholesaler/market to their customers. Retail prices comprise the final regulated prices to retail customers.

Figure 2: Basic Diagram to illustrate the key Functions and Pricing Interfaces



Functions:
G: Generators (incl imports)
Tx: Transmission
CPA: Central Purchasing Agency
MO: Market Operator
Dx: Distribution

Interfaces:
A: Generator Pricing
B: Wholesale Pricing
C: Transmission Pricing
D: Distribution Pricing

4 GENERATOR PRICING

4.1 Applicability

A licensee with generating capability should be subject to regulated generator pricing under this policy only when that licensee is deemed dominant as per the definitions in the Competition Act[1]. Such dominance may be valid for a section of the electricity industry, or in a broader market context. A licensee that is not dominant, or does not have the ability to exercise independent pricing power, should be able to set prices based on a competitive market outcome and not subject to the conditions in this section. A network business that owns generating capability shall

[1] Eskom Generation would be assumed to be dominant in its current form. It is possible under a restructured Eskom Generation with strict rules around competitive behaviour, that individual clusters may not be dominant and enjoy the same freedoms as other non-dominant generators.

be deemed to be dominant through the vertical relationship and shall be subject to the conditions of this section.

This section is applicable to licensed and registered generators (including renewable generators and co-generators) in South Africa as well as all licensed importers of electricity to South Africa that meet the dominant licensee threshold established above. Imported electricity prices would also form part of regulated generator prices in South Africa. This is necessary as it could affect the security of supply and price levels for local customers.

To the degree that operating market models and platforms have not been established or are still in the process of being established, this section will be applicable to licensees and registered generators similar to the case of a deemed dominant licensee, until formal implementation of such market models and platforms and formal migration of licensees thereto.

Policy Position 8

a) *Electricity sold by licensed or registered generators in South Africa deemed to be dominant and from all approved importers of electricity to South Africa also deemed to be dominant must fall within the scope of the EPP.*

4.2 Generation Tariff Structure

Pricing structures for electricity purchases from generators would reflect the underlying cost structure behaviour and dynamics. Alternatively, or in combination where appropriate, 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 will experience unacceptable poor quality of supply including very frequent interruptions, frequency drifts and voltage fluctuations. This approach creates the opportunity for a generator that provides ancillary services to earn more revenue than one not providing such services.

It is important to note that some customers are able to provide certain ancillary services at a lower cost than generators. It is, therefore, essential that customers be given the opportunity to sell these ancillary services to the market on a fair and non-discriminatory basis.

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

Pricing structures may include various incentive mechanisms on both the supplier as well as customer, applicable to aspects within such party's control. For aspects outside of the control of the supplier, the pricing structures should include the cost of hedging or insuring against such risks, or incorporate appropriate pricing adjustment mechanisms to mitigate the risk to the supplier; alternatively, the supplier's return on capital and thus price should be appropriately increased to reflect such increased risk.

Policy Position 9

a) Generating pricing structures must reflect the cost of supply of the generator or alternatively any approved PPA;

b) The generator pricing structure can consist of the following; 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; and

d) Generator pricing structures must not hinder efficient and least-cost dispatch of the generating units.

4.3 Generation Tariff Level

Prices for electricity purchases from existing generators should be based on the conditions either 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, efficient and prudent operator.

Prices for electricity purchases from new supply options should be evaluated against an appropriate reference, which 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 reserve margin or capacity adequacy, risk of unserved energy or load shedding, etc.

Competing projects should be assessed using the same criteria. The criteria should be fair, non-discriminatory and transparent. To the degree that competing projects will result in the same avoided system cost, the projects should be assessed against each other based on the discounted present value of the total life cycle cost i.e., the least cost approach, or on the least levelised cost / kWh where appropriate.

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; and*   *c) NERSA may 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 or wholesale buyer own cost charges. A detailed discussion of the wholesale energy and transmission pricing characteristics is provided in this section 5.

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 or not at certain times and 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 to 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 degree that operating market models and platforms have not been established or are still in the process of being established the wholesale pricing will effectively be hedged back to the regulated pricing approach as discussed under section 4.1 above, until formal implementation of such market models and platforms and formal migration of licensees and registered generators 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 need to encourage the efficient use of electricity at all times. Wholesale electricity sales should be based on TOU energy prices to promote the efficient use of electricity as well as standby / 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 different 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 pointing out issues relating to between 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 other customers this reduces the burden on the system from a total capacity point of view but allows that the capacity costs (incurred by the Central Purchasing Agency in ensuring back-up capacity on the network) can be dispersed among all consumers and reduces the absolute capacity required for backup. A stand-by/capacity demand charge could result in high costs for low load factor customers, which might be unpopular, but indicates the true cost of required back-up on all consumers. Refer also to section 5.1.5 for further rationale.

It will also function as an incentive on low-load-factor customers to either change their demand patterns or to install own battery or other storage or peak-shifting systems, which, if it comes at a lower cost than the system cost of establishing additional peak capacity, will imply overall net gain to the South African economy.

Policy Position 11

a) The wholesale energy price structure shall include a wholesale energy tariff which encourages the efficient use of electricity at all times and must reflect the TOU structure differentiated cost of supply/pricing signal;
b) The wholesale energy price structure shall also include a capacity / standby charge to signal the capital-related costs for generation capacity applied to all customers as a demand related (R/kW) charge;
c) The wholesale energy price structure shall include a regulated legacy recovery charge and a subsidy charge to ensure recovery of legacy costs and subsidies as approved by NERSA (to be included in the Transmission charges structure); and
d) The wholesale energy tariff structure must be periodically reviewed and updated by the Central Purchasing Agency and approved by NERSA, considering its impact and implementation on customers.

A Central Purchasing Agency (CPA) will hold the legacy PPAs (with the Renewable Energy IPP Programme as well as other IPP programmes) and Vesting Contracts (that is, contracts or other financial arrangements between Eskom Holdings SOC Limited and a distribution licensee for the sale of a specified amount of electricity at a specified price as a mechanism to facilitate the transition to a competitive market. The CPA must sell this energy through the competitive market or the wholesale energy tariff.

A legacy deficit is likely to arise as the future competitive market prices will be less than the legacy PPA costs. This deficit may be managed through a separated recovery charge to ensure that customers exercising choice of supplier (via the competitive markets or self-supply) continue to contribute to these legacy costs. This could be levied as a demand charge or fixed charge associated with the Transmission network charges.

There are inherent tariff cross-subsidies prevalent at a wholesale level between different retailers and direct customers. If these tariff cross-subsidies continue to be funded through electricity tariffs, then a mechanism will have to be developed to ensure consumers of energy are not able to avoid contribution to these charges. The recovery would be recovered through a charge raised at the Transmission network level, as either a fixed charge or a demand related charge. Revenues collected through these charges will accrue to a national subsidy fund to be managed by NERSA.

5.1.3 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 similar to generator pricing structures there should be minimal differences between the revenue earned for the selling of wholesale energy and the cost paid to purchase the 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 12

a) *Wholesale energy prices must align with the cost of wholesale purchases, including capacity, energy and ancillary services and as far as possible provide the correct signals for different 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.*

5.1.4 Ancillary services and charges

Ancillary charges are for services supplied to the Transmission network operator 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 significant 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 includes services provided by demand response and generators. Ancillary services include inter alia; the provision of operating reserves, frequency control, generator-islanding, black-start, constrained generation and reactive energy support.

Ancillary services costs include demand response, 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. This is dealt with further in section 5.1.5.

Policy Position 13

a) *The cost of ancillary services provided by 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 by ancillary service related charges and such charges may be based on consumption and/or on capacity; and*

c) *The recovery mechanism for ancillary services should allow for the faster recovery of over-and-under expenditure relating to regulatory approved tariffs.*

5.1.5 Standby/capacity charges

A standby charge is applicable to recover capacity costs associated with providing backup power when the customer's generator is out of service. As such, the standby charge functions as an insurance premium, which enables the customer to avoid incurring the cost of 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 network access charges, which apply for at least 12 months or for as long as a standby is required. Hence, the remaining question is whether a separate standby charge should be introduced to recover the capacity-related cost of generation. If introduced, it could have a significant influence on the development of self-generation projects.

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 a customer 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 a situation such as this there is the certainty that over a period e.g., annual cycle, such a customer who does not have own generation capacity would consume sufficient volume of 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, therefore, is different for a customer who has a generator that does not produce electricity on a consistent basis and there is no long-term intention or certainty that such 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, it could be compared to an insurance policy with hourly premiums that only requires the normal hourly premium to be paid for the hour during which a claim is registered. Clearly that will be unacceptable – such customer will 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 his switchable block-load will be paying for the coverage by virtue of his high volume of consumption, 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 14

a) The cost of providing generator standby services to all customers (including customers with 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 services charges to cover for any shortfall.

5.2 Transmission pricing

5.2.1 Applicability

Transmission pricing is applicable to licensees, registered generators and customers who qualify to wheel energy through 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, cost of losses, administration and service costs and where applicable connection costs. These charges will apply to generators and loads but may be different.

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 or R/account);
- 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 network assets that are shared. This is to prevent “second comers / free riders” from benefiting once the “first user” has paid for the system.

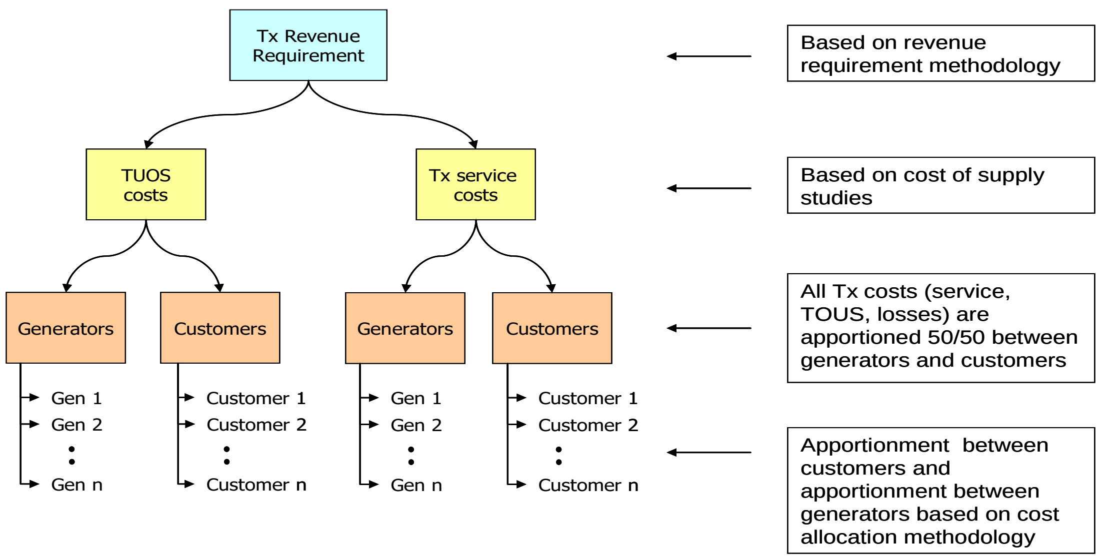
d. Although customers would pay for the assets, the network company will own and maintain the assets.

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

More specific policy guidance is provided in respect of charges to generators (refer to section 5.2.45) as well as the geographic differentiation of transmission charges (refer to section 5.2.6).

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 3: Transmission Cost Allocation between different Generators and between different Customers



Policy Position: 17

a) *Transmission tariffs must be unbundled (e.g., charges for: TUOS, 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 and service and administration charges, etc.;*

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

d) *No customer connecting to the Transmission system shall be permitted to avoid contribution to approved cross-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 meet his approved revenue requirement. Tariff levels should be determined in accordance with:

- the approved Codes;
- an approved cross-subsidy framework; and
- regulatory rules and other regulatory requirements.

Policy Position 15

a) The transmission tariffs need to be set at a level that must allow the licensee to earn its approved 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 opeator'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 16

a) Transmission network operator must undertake the required analyses to determine the extent of investment and resources required to provide new capacity, refurbishment and maintenance;
b) NERSA must give due cognisance to requests for funding to be recovered in tariffs to provide for the above requirement.

5.2.5 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 influence 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 has to 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 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 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 the 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, and hence promotes economic efficiency.

A reasoning that only consumers should pay for Transmission costs based on the assumption that only load customers need the transmission network, is of course not correct. The location of a generator also has an influence on the cost of transmission, similar to the location of the load. Thus, generator location will be driven by access to the grid, access to fuel and renewable energy sources.

Due to the reasons often linked to fuel cost, economies of scale and others, generators are rarely located in the near vicinity of their customers, but closer to or in areas where it is cost effective to produce power. This implies that the Transmission network operator should build network to transmit the 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.

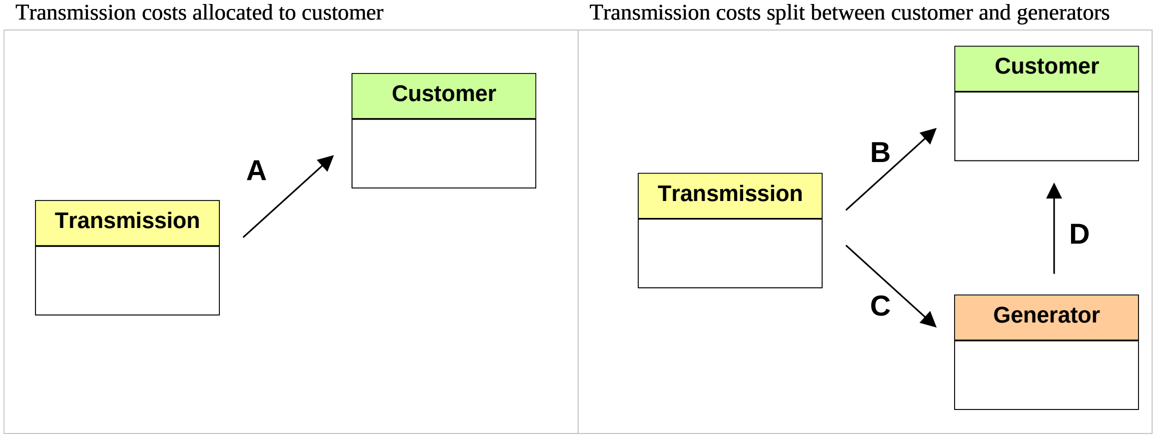
The implications, if load customers pay for all transmission costs, are that:

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 (see section 5.1.2). If generators do not pay transmission network charges all the transmission costs will be recovered from load customers through demand (kVA) charges. 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.

The above concepts are demonstrated in the following figure.

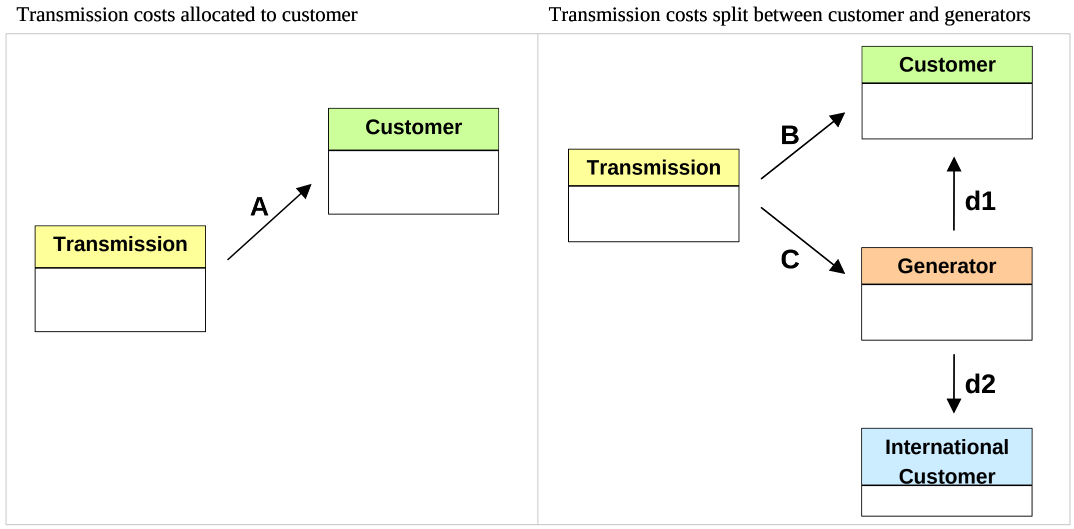
Figure 4: Illustration of Cost Split between Customers and Generators



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

The deviation from cost-reflective tariffs and the user-pay principle if generators do not pay for the use of the transmission network becomes more obvious when 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 5: Illustration of Cost Split between Customers (local and international) 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 as long as the cost allocation is fair and reflective of the costs.

Policy Position 17

a) *Transmission network costs must be apportioned 50/50 between generators and customers to more accurately reflect the cost of supply;*

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 in order not to disadvantage South African based generators.*

5.2.6 Transmission Charges Geographic Differentiation

The TUoS charges for both generators and loads are based on zones. The zones loads are geographic based and the zones for generators considers both 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 generally 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 18

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, DMRE and NERSA must evaluate the redefinition of geographic differentials for customers assessing the price stability, comparing the current generation mix with that foreseen in the next 10 years; and*

c) *The transmission license holder, DMRE and NERSA must investigate different options and adopt the most appropriate method for allocating costs between generators.*

5.2.7 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 19

a) *Use of system charges will be the regulated Transmission charges determined in accordance with this Section 5.2;*

b) *Cross border customers will be required to pay connection charges in accordance with the Code and connection charge policy. Where there are deviations that are warranted, they should be approved by NERSA;*

c) *Import will be treated as a generators and export as a load 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, they should be approved by NERSA.*

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 (as the case may be in future) in the second instance.

Cross border customers must not pay or receive subsidies intended for South African customers.

Policy Position: 20

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 SOUTH AFRICAN NEGOTIATED PRICING AGREEMENTS (NPAS)

NPAs may be applied to South African customers and cross-border customers. All cross-border agreements are negotiated and are therefore in their nature NPAs. These agreements will be in terms of the principles provided for in this paragraph.

NPAs are not necessarily designed not to obtain a reduced electricity price but to obtain long term price certainty. NPAs are permitted and refer to any price agreement that may deviate from approved standard tariff levels and structures whether it applies over a short term or a multi-year period. NPAs are required to address country competitiveness to ensure the sustainability and growth of industry in South Africa through electricity price certainty. NPAs can be for both established industries, both operational and idle capacity, and new investments in industry in the country. NPAs can also be for established or new industry located cross border to ensure the sustainability and growth of industry in SADC.

NPAs should focus on sectors that are energy-intensive (electricity usage) and sustaining them makes the most benefit to the stability of the ESI; in that having such an industry helps dilute the electricity costs for the rest of the customer base (high load factor) and assists the System Operator with managing the power system (interruptability and demand response). NPAs may also incorporate and reflect that the true net system cost to supply a particular customer might be less than what the normal tariff products would be able to reflect.

NPAs should be structured in a way to minimise deviations from standard prices and must take cognisance of the long-term viability of both the ESI and the specific sector. NPAs at inception must not be below the true cost of supply to such customers and should include an appropriate risk premium. NPAs may have fixed increases to provide escalation certainty and should then include an appropriate real adjustment to mitigate against the risk of the costs and the price diverging over time. NPAs may grant reprieve on subsidies, levies and taxes.

Any NPA (incentive price) is approved in the country's interest, as such, for the sustainability of the ESI, any revenue shortfall or excess to the licensee can be recovered through the applicable regulatory process. A commodity and currency linked electricity price is permitted, however where appropriate, hedging mechanisms should be put in place with parties outside of the ESI.

NPAs need to be evaluated against the appropriate price projections on a discounted basis over the life of the project. Factors that should be taken into consideration include period, TOU, location, voltage level and risks.

All existing NPAs should be honoured until the end of contract or extended with NERSA approval. Either customers would purchase electricity at an approved standard tariff or an approved new NPA based on the latest NPA framework.

Policy Position 21

a) *DMRE must provide NPA framework/s and updates as appropriate, and NERSA will approve and monitor NPAs in accordance with these framework/s;*

b) *Revenue shortfall or excess to the licensee resulting from NPAs can be recovered through the applicable regulatory process through approved subsidies as provided for under Section 8.21, or through external funding provided to the licensee;*

c) *The above framework will have to prescribe how this will be funded and if through tariffs, which Licensee will be responsible for managing the funding, whether at wholesale or retail level;*

d) *Existing NPAs will be honoured until the end of contract;*

e) *South African customers will not cross-subsidise cross border NPAs; and.*

f) *All applications must be treated in accordance with the approved processes and frameworks and be approved by NERSA.*

8 DISTRIBUTION AND RETAIL PRICING

Distribution pricing includes components of both retail and network services. For some customers, distributors would act 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 and some form of administration.

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

Policy Position 22

a) NERSA shall develop a national tariff framework to guide how tariffs are structured while recognising need for innovation in development and the approval of updates to tariff structures.

8.1 Tariff Level and Structure

This first section will address the key principle for distribution pricing, namely that tariffs should be designed from cost reflective principles and must be in support of cost reflectivity and transparency. Cost-reflectivity includes the tariff level and the tariff structure. Provision can, however, made for deviations from cost and these are covered under the section on cross-subsidies in Section 8.21.

The tariff level is that revenue sufficient for a Licensee to recover its costs plus a fair return, whereas the structure is where the allowed revenue is broken up into different types of charges and recovered through these charges.

For all Distributor's their costs should be based on an appropriate methodology that treats all Distributors the same and should not be based on historic benchmarks, but a uniform regulatory method that fairly considers an acceptable level for returns on assets. A cost-of supply (CoS) study should not be used to justify costs, but to allocate costs based on approved revenue.

Policy Position: 23

a) Tariff levels shall recover the NERSA allowable revenues / 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 the EPP; and

c) *NERSA shall develop a consistent regulatory method for the approval of revenues for all Distributors*

8.2 Cost of Supply Studies

A cost of supply (CoS) methodology (also referred to as a Cost-to-serve study[2]) is needed to understand costs for tariff design purposes and cross-subsidies, not to justify costs.

Policy Position 24

a) *Electricity distributors shall provide CoS studies to propose new tariffs, special pricing and products or tariff structure changes to NERSA and submit an updated CoS study at least every 5 years to NERSA to inform on the current customer base (all customer categories), relationships between cost components and sales volumes;*

b) *CoS studies' models and approaches are to be based on a cost causation principle;*

c) *CoS studies must be done according to the approved NERSA standard and revenue approval methodology to reflect changing costs of sales and customer behaviour informed by data-based cost allocation assumptions; and*

d) *The CoS study report and costing methodology used to arrive at the unit costs to derive tariffs must accompany (or precede) applications to NERSA for changes to retail tariff structures including the associated approved of wholesale/purchase tariffs.*

8.3 Customer Categories

Each customer/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, therefore, a need to pool costs based on customer categories, including both loads and generators. For this reason, costs and tariffs need to be differentiated by the type of usage profile and by type of customer. Such differentiation should be applied when the cost of any category differs significantly from another category.

[2] This is to differentiate between justification of costs such as done to determine approved revenue versus a cost allocation exercise which allocates the approved revenue.

Policy Position 25

a) *The number of customer categories for costing, tariffing, special pricing and products purposes should be justifiable to NERSA based on cost drivers and the entire customer base including load, generator, wheeling, trading and aggregator customers considering the following:*

(i) *consumption and/or generation patterns e.g., usage or export, load factor and time-of-use consumption or export;*

(ii) *type, size, demand e.g., notified maximum demand (including export demand)1 phase or 3 phase, capacity level, overhead or underground, high/low density, multiple connection points), load or generator;*

(iii) *type of metering, e.g., post-paid or pre-payment, SMART metering or remote metering;*

(iv) *position on the network, density of supply, transmission zone, voltage of the supply and the system from which the supply is taken;*

(v) *use of customer service channels and type of account management made available to the customer;*

(vi) *contribution to network losses; and*

(vii) *provision of energy storage;*

b) *A new category can be created where costs or nature of supply justifiably differ from existing categories; and*

c) *Sub-categories could also be created when there is justifiable differentiation of components of costs.*

8.4 Cost Drivers and Components in CoS Studies

The cost components and cost drivers that should be included in CoS studies must be identified to reflect the allocation of their costs accurately.

Policy Position 26

NERSA must ensure that, within three years, CoS information shall be unbundled to reflect, where appropriate/practical, the approved revenue requirement into the following cost components as far as possible:

a) *Energy purchase cost based on the energy purchase price structure;*

b) *Transmission network charges reflecting the Transmission purchase tariff structure;*

c) *Cost of Distribution and Transmission losses per transmission zone and voltage of supply;*

d) *Cost of Distribution network services per voltage of supply;*

e) *Retail costs per supply size, types of services rendered and metering; and*

f) *The CoS study should in the results provide a view of the subsidies compared to the existing tariffs.*

8.5 Cost-reflective Tariff Structures

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

The EPP should guide the industry on recovery of fixed costs through fixed charges. Tariffs that currently recover fixed costs through a variable charge impose a revenue risk on the Distributor and increases tariffs to all its customers. The correct separation and structuring of network, retail, and energy costs in the tariff charges provides the correct economic signals and payback period for alternative energy decisions by comparing the energy cost of the utility versus the energy cost of the alternative.

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

- a reduction in sales and volumes will result in lower bills by not only in the energy value, but also in the network value; and
- this is not equitable or fair on 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 network costs will remain for capex, continued maintenance and operations, even when there is reduced consumption. These costs would still have to be recovered thorough tariff, resulting in increases to tariff charges. Therefore, if the electricity industry does not to restructure existing distribution tariffs to meet a changing ESI environment, all customers will be negatively affected. Customers who opt for alternative sources of energy should also equitably face the cost for their backup energy supply from Distributors; otherwise, unintended tariff subsidies would result.

For some customer categories, for ease of customer understanding, the various cost components can be simplified for some tariffs to a fewer number of charges (more bundled) but should reflect the full cost of supply for the group of customers charged through at the simplified tariffs.

Policy Position 27

The charges reflecting the unbundled costs, should be structured as far as possible to include:

a) Energy costs in clkWh and generation capacity charge reflecting the purchase cost structure;

b) Transmission network charges reflecting the Transmission purchase price structure;

c) Distribution network charges in R/kVA based on maximum demand per billing period;

d) Distribution network charges in R/KVA or R/kW/ month or R/Amp/ month based on annual capacity;

e) Customer service charges in R/customer or /Point of delivery (POD) / day/months based on the size of the supply;

f) Administrative charges in R/POD/or month/day;

g) Charges for poor power factor;

h) A TOU energy net-billing rates for prosumers;

i) Charges for the cost of losses; and

j) For ease of customer understanding, tariffs for some customer categories will not reflect all the above cost components. The applicable charges whether unbundled or bundled must however cover the full cost of all the above cost components, except where approved cross-subsidies are applied.

8.6 Rationalising Electricity Tariff Structures in the EDI

NERSA, together with the industry, should develop for the EDI, a national guideline to standardise tariff structures. This would facilitate for all Distributors, the tariff design process, transparency, and ease of understanding by all stakeholders. Distributors will need to adapt their tariffs in compliance to the national guideline. The tariff levels may remain different for each utility to match their local circumstances, demographics and costs.

Policy Position 28

a) NERSA shall provide a framework to guide the standardisation of existing electricity Distributors' tariff structures amongst all licensees, based on the policy positions set out in this EPP.

8.7 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 in order to address these electricity distribution issues. At a minimum, structural changes to tariffs should be done based on a CoS study and may include pricing signals.

Policy Position 29

a) Tariff structure and levels shall be aligned with the results from the updated CoS studies and will reflect the associated revenue requirement;
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 and provide reasons for decisions with guidance.

8.8 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 and are as follows:

- Distribution network costs – 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 charges – pass-through cost from Transmission.

- Administration and service costs related to the provision of a network service.
- Subsidy charges – network related subsidies that should not be avoided.

Network tariffs need to be reformed to move away from variable based charges (e.g., c/kWh) to tariff structures that 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 photovoltaics (PV) and their own generation also face the same cost of the network 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 be raised for both generators and loads;

b) DUoS and embedded TUoS charges shall be the basis for all network-related charges and shall be based on cost causation related to capacity used, the voltage, Transmission zone, losses and whether a supply is classified as urban or rural based on an updated CoS study;

c) DUoS and embedded TUoS charges for loads shall recover the cost of managing and operating the Distributor's network, providing flexible services, distribution losses, TUoS costs (including ancillary services), retail costs and where applicable, the NERSA approved contribution to subsidies for all users of the Distribution network, both local and cross-border;

d) DUoS charges for generators shall recover the cost of managing and operating the Distribution network, Distribution losses, ancillary services and retail costs;

e) Unbundled DUoS charges will comprise at a minimum a fixed network capacity charge based on reserved capacity for loads and generators. Other charges may include a variable network demand charge based on monthly maximum demand or consumption for loads;

f) *The above shall also apply to all small power tariffs except for subsidised lifeline tariffs;*

g) *NERSA shall pursue the phasing-in of cost reflectivity for distribution network charges' structures within the next 5 years; and*

h) *NERSA shall develop a national DUoS charges framework to prescribe the requirements set out above.*

8.9 DUoS Charges for Wheeling

In compliance with The Act and 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 involved in a wheeling transaction; and*

e) *A wheeling customer will not be allowed to avoid contribution to approved cross subsidies.*

8.10 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 value-added services.*

8.11 Crediting for energy exported into the Network (Net-Energy 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. Depending on legislation, this customer may be required to be registered 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 TOU 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 TOU 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.

8.12 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 34

a) The pricing signal to be provided to customers must reflect 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 motivated specifically and be approved by NERSA.

8.13 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 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 TOU 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 35

Tariffs must include TOU energy rates as follows: *a) that reflect the energy purchase price;* *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.*

8.14 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 generally 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 a network (length of line considerations), although both could be supplied at the same supply voltage.

c. To reflect supply voltage differentials, whether connected directly to a substation or deep within the network requires a very complex CoS study and would create more voltage categories that may complicate the CoS 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 36

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 grouping;* *b) based on the cost and losses differences from the CoS 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.*

8.15 Domestic (Residential) Tariffs

There is a large number of 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 37

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 DMRE suite of supply options guidelines;

b) At the next level a tariff to contain unbundled tariff charges to reflect network charges based on capacity, a customer service charge, and an 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).

8.16 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 are 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 38

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 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 as set out in 2.2;*

c) *These assets would, however, be included for provisions relating to all operating expenses; and*

d) *A consistent methodology must be applied in the industry to govern the determination of connection charges payable by customers / developers to ensure a fair and non-discriminating practice for all participants.*

8.17 Public Lighting

Many municipalities consider public lighting to be part of the electricity supply service and as such, expenses have to be covered by electricity customers. 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 very 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 39

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.*

8.18 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 is able to maintain a reasonable level of service quality for its customers.

Policy Position 40

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 to be recovered in tariffs to provide for capital for refurbishment of standard assets 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 from the electricity sector are not used to fund other sectors; and*

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

8.19 Distribution Losses and Bad Debt

Distribution losses comprise both technical and non-technical losses. Non-technical losses and bad debt are a problem with a very 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 in particular, IPP connections in low load areas are increasing losses. A NERSA methodology must accommodate this changing environment.

Policy Position 41

a) *NERSA must develop a 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.*

8.20 Reseller Charges

Resellers are registered parties that purchase electricity from a licensee for resale to tenants or homeowners. A reseller must comply with Schedule 2 of The Act, regarding the raising of tariff charges. NERSA has a guideline related to resellers, which must be updated to reflect current legislation.

One area that is not clear is the monitoring of compliance of resellers with The Act and the settling of disputes. Licensee can mediate, but do not have any regulatory or legal powers in terms of The Act to instruct resellers to be compliant, other than disconnection.

Policy Position 42

a) *Non-licensed resellers of electricity shall provide the electricity at terms, tariffs and services in compliance to Schedule 2 of The Act;*

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.*

8.21 Free Basic Electricity (FBE)

The implementation of FBE must be done in accordance with the DMRE Electricity Basic Services Support Tariff (Free Basic Electricity) policy. The application of the FBE needs to be continually monitored to ensure it is applied correctly to ensure implementation addresses the needs of the targeted customers.

FBE is meant to be funded through the equitable share allocation to Local Government and not through the revenue requirement of the Licensee.

Policy Position 43

a)	*Where Local Government wish to apply free electricity in excess of the amount provided for the equitable share to more customers or for more kWhs, this shall be funded outside of electricity income.*

8.22 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 44

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

8.23 Cross-Subsidies

Cross-subsidies in electricity tariffs exist, where customers either pay more or less than the cost of supply. These are inherent due to cost pooling, tariff-design, to address affordability by those paying the subsidies and, to specifically subsidise a particular group of customers or sustainable electricity supply investments.

There are extensive debates in the industry on tariff cross-subsidies, how they should be funded, who should pay and who should receive and what should be done in this respect. This, in particular, is relevant due to the changing nature of the ESI, where customers can have own generation and avoid contributing to subsidies increasing the burden on the remaining customers.

Affordability is an argument made by both those receiving the subsidies and those paying the subsidies. Removal of the tariff cross-subsidies would result in sharp tariff increases to recipients. On the opposite increased contribution to cross subsidies motivates requests for exemption from subsidy payments or defection to own generation or alternative energy sources. This will result in higher tariff subsidy payments from the contributing customers (wheeling and load) that remain unless cross-subsidy funding is located outside the tariff base.

All customers that use the Licensee's network for fairness and equity should not avoid an equivalent contribution to subsidies otherwise this would lead to undue discrimination. Generators may be excluded from contributing to cross subsidies to avoid double cross subsidy payments by customers receiving their energy. Therefore, all customers on the network should contribute at an equivalent and fixed rate to subsidies relative to their network demand.

The application of cross-subsidies is not uniform in the electricity industry, there is no national framework guiding the application of tariff related subsidies and, there is a lack of transparency as to the level of subsidies received and contributed by the different Licensees' customers.

Policy Position 45

a) *DMRE shall develop together with NERSA, 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 application of only specifically approved cross-subsidies must be instituted in the ESI to address certain socio-economic and environment needs as provided for by National legislation and regulations;*

c) *All cross-subsidies in electricity tariffs shall be made transparent, while moving towards cost-reflective and transparent tariffs in the ESI;*

d) *Any levies and surcharges raised by Municipalities need to be treated as per Policy Position 46;*

e) *No load customer shall be allowed to avoid contribution to subsidies unless approved otherwise by NERSA;*

f) *Generators may be excluded from subsidy contribution so long as this avoids double-counting subsidy contributions for the loads they serve;*

g) *A subsidy paid for by Distributors in their energy purchases is a pass-through to their end-customers;*

h) *Removal of subsidies from a Distributor's tariff base will be subject to prior implementation of transparent and justifiable tariff subsidy charges and the availability of alternative cross subsidy funding through the DMRE national subsidy framework;*

i) *NERSA approval will be required to give effect to the removal of tariff cross subsidies and the adjusted tariff rates thereof;*

j) *Tariff charges to recover remaining tariff cross subsidies should be ideally structured as fixed charges;*

k) *Tariff cross-subsidies that are a contribution to a wider electricity consumer base than a single Distributor may be implemented at the wholesale level; and*

l) *Licensees are required to establish and publicise the average level of cross-subsidy between tariff categories (receipt and contributions).*

8.24 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 probably 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.

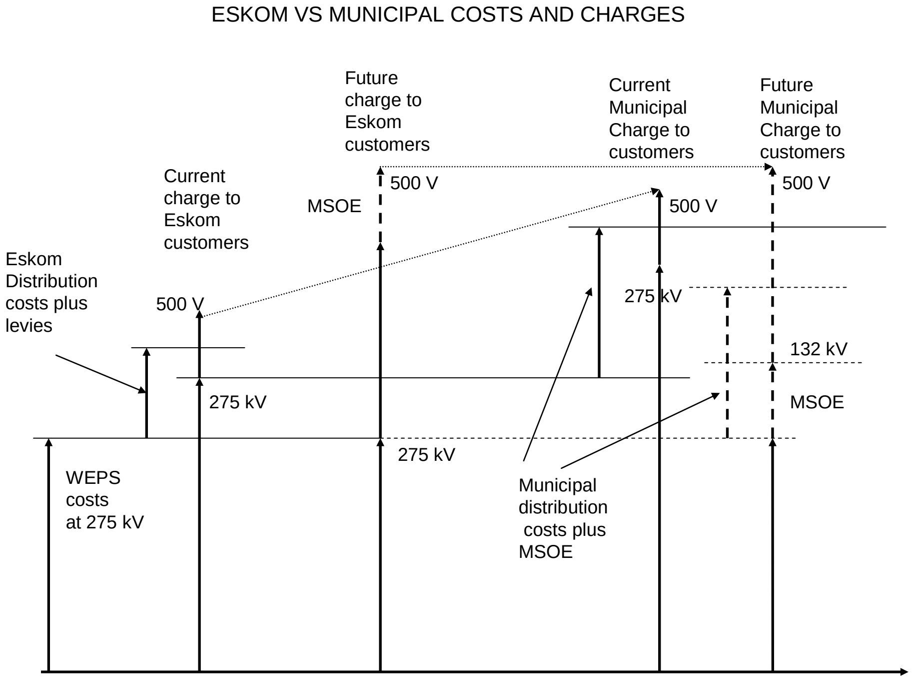
Some municipalities have already introduced a transparent MSOE without phasing out the existing hidden surpluses. This is totally against the intention of the legislation to regulate the application of the MSOE. Furthermore, it is also uncertain as to whether these municipalities have ring-fenced their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

Policy Position 46

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

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

Figure 6: 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 very low.

9 DEMAND SIDE FLEXIBLE SERVICES

Demand side flexible services and products are needed to optimally manage 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 47

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 and be reported on per revenue review period to demonstrate the costs and the benefit by licensees.*

c) *NERSA must decide on the amount of funds to be allocated to demand and supply side flexible options based on requests made by the licensee.*

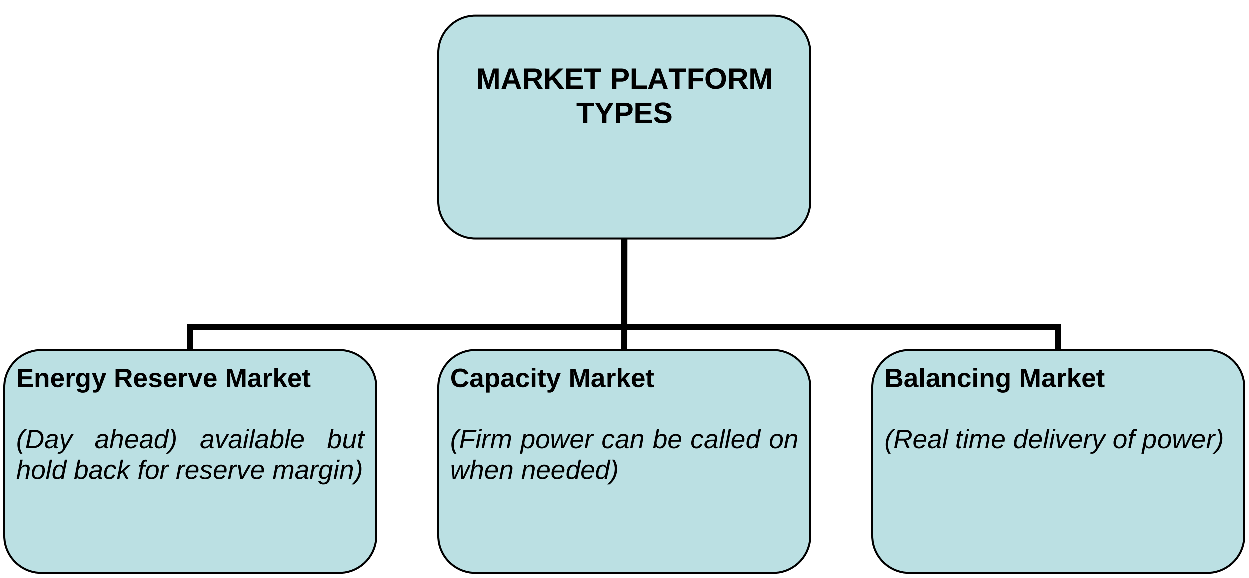
d) *The funds shall be applied and prioritised on a reliability and security of supply and/or least cost per saved MVA/MW basis.*

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.*

10 MARKET PLATFORMS

The EPP assumes a mostly regulated environment, while in the future there may be markets and parts of the industry that would not need the current type of regulation. It is also to be noted that the inputs provided are done subject to the approval by NERSA of the market platforms structure of the ESI and how a competitive energy market will function in the future. The following provides potential markets platforms in the future which provide context for inputs in this document. Markets platforms to support the effective operations of both a supply side sector as well as a demand side sector. These are depicted in the figure below:

Figure 7: Market Platform Types



Policy Position 48

a) *NERSA must consider the impact and the effective operations of both a supply side sector as well as a demand side sector in approving any market platform model;*

b) *NERSA must make sure the platform addresses the medium-term security of supply and operational efficiency, forecasting errors and failures of generators or networks, support the effectiveness of the network; ensuring non dispatchable capacity is enabled, support the effectiveness of the market and drive competitive options for customers, and drive capital investment, delivering the IRPA; and ensuring the long-term security of supply; and*

c) *NERSA must develop the market rules/codes.*

11 REGULATION

DMRE determines the EPP to be applied in the ESI and NERSA is tasked with establishing these or to establish the rules, regulations, codes, directives, programmes and projects in finer detail. In terms of The Act NERSA is *inter alia* responsible for the consideration and issuing of licenses for all operating functions, regulation of prices and tariffs and mediation of disputes. Based on the objectives of The Act, it is necessary to accentuate the following with regard to the efficient execution of the EPP:

a. The required amendments to the Acts to enable an unbundled industry.

b. Appropriate frameworks, rules and codes to be in place by NERSA to guide the industry.

c. Orderly coordination of licensing, system of appeals and public hearings are important aspects in the regulation process.

d. Appropriate timescales in respect of submissions and feedback of information to various parties are essential to ensure cooperation in all respects.

e. The nature of cooperative regulation should be established. The tougher the attitude of the regulatory personnel, the more difficult co-operation could become. A balanced approach is necessary.

f. A justification for and acceptance of all aspects of regulation are required because the level of tariffs is argued in many instances. A case has to be made for *ex post* and *ex ante* regulations because they could affect the magnitude of the adjustments. NERSA should timeously provide reasons for decisions for all submissions made to it.

g. The acceptance of a fair return on capital employed is necessary. Returns in line with the risks involved should be the aim and should include full costs as well as a reasonable margin. Please also see the application of this concept under section 2.2.

h. The formulation of the primary objectives of stakeholders aligned with ensuring a balance between the required capital investments (adequate capacity) and utilisation levels is attained.

i. Economic and technical efficiency is necessary to minimise prices and maximise both supply and service quality.

j. Competition as far as possible and justified is required.

k. Price discrimination should be justified.

l. Standardisation where applicable in the ESI is necessary.

m. Disputes and complaints should be addressed promptly and NERSA to establish an escalation and dispute process in consultation with all stakeholders.

The above requirements imply that the acts of NERSA should demonstrate *inter alia* the following attributes: Openness, transparency, aptness, informative, timeliness, efficiency, customer focus, fairness and equity, independence, honesty and integrity.

12 CONCLUSION

It is essential that the proposed EPP should receive the highest possible priority. The ESI is faced with a number of important changes and challenges as pointed out in this document. Although there are perhaps other burning issues to be addressed at this stage, the finalisation and implementation of the proposed EPP would make a very important contribution to the state of the industry. The EPP involves *inter alia* aspects of wholesale, generation, transmission, distribution, cross-subsidies, flexible services to meet supply and demand, and regulatory matters.

South Africa needs to make substantial investments in the generation, transmission and distribution industries to meet the growing demand of an expanding economy. In addition, it is recognised that certain infrastructure backlogs also need to be addressed to maintain and improve quality of supply and service delivery. Independent power producers and renewable energy projects will play a more prominent role in South Africa’s future energy mix.

It is this backdrop that necessitates that the industry moves towards tariff levels and structures that will ensure sustainable and viable industry. In addition, the EPP highlights the importance of non-discriminatory pricing practices as well as the need to promote pricing standardisation, transparency and the unbundling of tariffs. These are essential requirements to attract investments and to unlock efficiencies.

The EPP has been formulated using a number of key assumptions and pricing interfaces, namely; wholesale prices, generator prices, wholesale prices, transmission prices and distribution prices.

The EDI should apply cost reflective tariffs for properly defined customer categories within a short period of time. The tariffs need to be set according to the results from the CoS studies which must be undertaken periodically, and all possible type of costs should be shown as transparently as possible.

The underlying approach in the development of the various policy positions is to promote economic efficiency while providing scope for the introduction of approved and transparent subsidies and support mechanisms. To this effect, the EPP acknowledges the need for cross-subsidies, but that this needs to be done in terms of a separate national subsidy framework with the transparent mechanisms of how each should be treated to ensure that the needs of various customer categories are addressed and that proper decisions are made.

The need to increase the utilisation of the generation, transmission and distribution infrastructure, managing the system and natural resources in the country should be addressed with the application of appropriate pricing strategies. These include the provision of pricing strategies to ensure the provision of flexible services, energy efficiency, and other strategies funded from a range of sources to mobilise resources optimally.

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